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RENEWABLE POWER GENERATION COSTS IN 2023

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About IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation that supports countries in their transition to a sustainable energy future and serves as the principal platform for international co-operation, a centre of excellence, and a repository of policy, technology, resource and financial knowledge on renewable energy. IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy, in the pursuit of sustainable development, energy access, energy security and low-carbon economic growth and prosperity. **www.irena.org**

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FOREWORD

Francesco La Camera

Director-General

International Renewable Energy Agency

At COP28, the outcome of the First Global Stocktake called on all parties to the UNFCCC to triple renewable power generation capacity and double the rate of energy efficiency improvement by 2030. Dubbed the UAE Consensus, and built upon the on the recommendations of IRENA, this embodied the global determination to rapidly scale up renewables.

The year 2023 marked a significant milestone in this journey. The record growth of 473 GW of installed capacity, coupled with a continued decline in technology costs, indicate that world is embracing the transition away from fossil fuels.

Renewable power is increasingly cost-competitive with fossil fuels – 81% of renewable capacity additions in 2023 produce cheaper electricity than fossil fuel alternatives – and the accelerated deployment of renewable power continues to trigger technology advancements in a virtuous cycle of production efficiency and cost reduction.

Solar PV, wind and hydropower experienced the most considerable cost decreases in 2023. The global average cost of electricity (LCOE) from solar PV fell by 12%, offshore wind and hydropower by 7%, and onshore wind by 3%, with China once again dominating new capacity additions. The global average cost of electricity from utility-scale solar PV fell to USD 0.044 per kilowatt-hour (kWh) and onshore wind to USD 0.033/kWh.

Low-cost renewables incentivise greater ambition; in the coming years, remarkable growth across all renewable energy sources is expected. Yet, it remains crucial to ensure the progress and deployment of renewables balances different technologies and is distributed more equitably across countries and regions.

The energy transition relies on key enablers, including physical infrastructure (such as for energy storage and flexibility), policy and regulation, international collaboration, and strengthened institutional and human capacities.

Renewable energy reduces exposure to volatile fossil-fuel import bills, lowers average electricity system costs, and avoids the damaging impacts of high electricity prices on consumers and industry. It offers policy makers a compelling solution to reduce fossil fuel dependency, limit damage to environmental and human health, enhance energy security and drive economic development.

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ABBREVIATIONS

AC	alternating current
AI	artificial intelligence
ARA	Amsterdam-Rotterdam-Antwerp
BES	battery energy storage
BNEF	Bloomberg New Energy Finance
BoP	balance of plant
BoS	balance of system
CAES	compressed air energy storage
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CHP	combined heat and power
CO_2	carbon dioxide
CoC	cost of capital
COD	commercial operation date
CSP	concentrated solar power
DC	direct current
DCF	discounted cash flow
DNI	direct normal irradiation
DWS	diamond wire sawing
EIA	Energy Information Administration (of the United States)
EPC	engineering, procurement and construction
ETS	Emissions Trading Scheme
EU	European Union
EV	electric vehicle
FiT	feed-in-tariff
G20	Group of 20
GDP	gross domestic product
GJ	gigajoule
GW	gigawatt
GWh	gigawatt hour
HJT	heterojunction
HTF	heat transfer fluid
GW	gigawatt
IBC	interdigitated back contact
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IFC	International Finance Corporation
ILR	inverter loading ratio
IMF	International Monetary Fund
IPCC	Intergovernmental Panel on Climate Change
IPP	independent power producer
IRENA	International Renewable Energy Agency
kg	kilogramme
km	kilometre
kW	kilowatt
kWh	kilowatt hour
LCOE	levelised cost of electricity
LDES	long duration energy storage
km	kilometre
LFP	lithium iron phosphate
m^2	square metre
mg	milligrams
mm	millimetre
MW	megawatt
MWh	megawatt hour
O&M	operations and maintenance
OECD	Organisation of Economic Co-operation and Development
OEM	original equipment manufacturer
OPEX	operational expenses
PEG	Gas Exchange Point (Pointe d'échange de gaz – France)
PERC	passivated emitter and rear cell
PPA	power purchase agreement
PTC	parabolic trough collector
PV	Photovoltaic
R&D	research and development
SHJ	silicon heterojunction
ST	solar tower
TopCon	tunnel oxide passivated contact
TTF	Title Transfer Facility (Netherlands)
TW	terawatt
TWh	terawatt hour
USD	US dollars
WACC	weighted average cost of capital
W	watt
µm	micrometre

EXECUTIVE SUMMARY

HIGHLIGHTS

- Renewable power capacity additions set a record in 2023 with 473 GW of new installed capacity – a 54% increase compared to 2022 additions, and the largest annual growth since 2000.
- Total global renewables capacity in 2023 increased by 14% rate, from 3 391 GW in 2022 to 3 865 GW in 2023.
- In 2023, the global weighted average costs of electricity from newly-commissioned utility-scale solar photovoltaic (PV), onshore wind, offshore wind, concentrated solar power (CSP) and hydropower fell (Table S1).
- China represented the largest market for solar PV (63%), onshore wind (66%), offshore wind (65%) and hydropower (44%) in 2023. This was due to the country's substantial renewable additions in 2023, which drove the decline in the global weighted average costs for these technologies.
- In 2023, the total renewable power deployed globally since 2000 had saved an estimated USD 409 billion in fuel costs in the power sector.
- Battery storage annual capacity additions increased from 0.1 GWh gross capacity in 2010 to 95.9 GWh gross capacity in 2023. Between 2010 and 2023, the costs of battery storage projects declined 89%, from USD 2 511/kWh to USD 273/kWh.
- The competitiveness of renewable technologies remains, despite fossil fuel prices returning closer to their post-2010 cost range.
- In 2010, the global weighted average LCOE of onshore wind was 23% higher than the weighted average LCOE of fossil fuel; in 2023, the global weighted average LCOE of new onshore wind projects was 67% lower than the weighted average of those fossil fuel-fired solutions.
- In 2010, the global weighted average LCOE of solar PV was 414% higher than the weighted average LCOE of the cheapest fossil fuel-fired solution; however, driven by a spectacular decline in costs, in 2023, solar PV cost 56% less than the least-cost weighted average fossil fuel-fired solution.

Table S1 Total installed cost, capacity factor and LCOE trends by technology, 2010 and 2023

	Total installed costs (2023 USD/kW)			Capacity factor (%)			Levelised cost of electricity (2023 USD/kWh)		
	2010	2023	Percent change	2010	2023	Percent change	2010	2023	Percent change
Bioenergy	3 010	2 730	-9%	72	72	0%	0.084	0.072	-14%
Geothermal	3 011	4 589	52%	87	82	-6%	0.054	0.071	31%
Hydropower	1 459	2 806	92%	44	53	20%	0.043	0.057	33%
Solar PV	5 310	758	-86%	14	16	14%	0.460	0.044	-90%
CSP	10 453	6 589	-37%	30	55	83%	0.393	0.117	-70%
Onshore wind	2 272	1 160	-49%	27	36	33%	0.111	0.033	-70%
Offshore wind	5 409	2 800	-48%	38	41	8%	0.203	0.075	-63%

Notes: CSP = concentrated solar power; kW = kilowatt.

ANNUAL RENEWABLE POWER CAPACITY ADDITIONS BROKE A RECORD IN 2023, WITH TOTAL INSTALLED CAPACITY INCREASING 14%, YEAR-ON-YEAR.

In 2023, solar PV and onshore wind together represented more than 95% of the 473 GW in added renewable energy capacity.[1] Solar PV experienced an increase of 73% on 2023, adding 346 GW, while onshore wind added 104 GW, representing 48% year-on-year growth. Meanwhile, offshore wind capacity additions reached 11 GW, marking a 27% rise compared to 2022. This was, however, still below the record capacity additions of 2021 for this technology.

New additions were more modest for other technologies, such as concentrated solar power (CSP), geothermal, bioenergy and hydropower. Combined, these totalled 12 GW of additional installed capacity in 2023, of which 7 GW was hydropower. Annual additions for CSP and geothermal have been flat in recent years, while hydropower and bioenergy experienced a decrease in 2023 compared to 2022.

The growth in renewable power capacity additions reflects global efforts to transition the power sector to a higher share of renewables. New capacity additions, however, remain below the level needed to reach the goal of tripling capacity that was agreed in the UAE Consensus at COP28. Most importantly, the tripling of renewable power capacity must be accompanied by key enablers, notably grid expansion and storage.

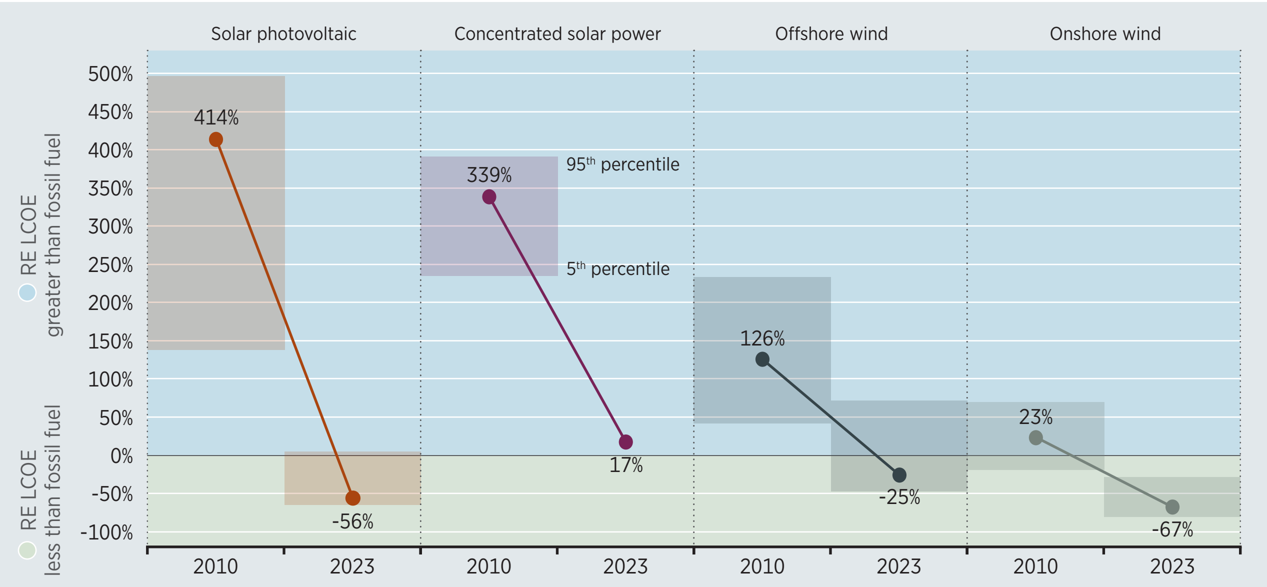
Data from the *IRENA Renewable Cost Database* and an analysis of recent power sector trends nonetheless reaffirms the essential role of renewables in reaching climate targets, while demonstrating the economic viability of these technologies compared to fossil fuels.

[1] *In this report, "renewable energy capacity" refers to the net generating capacity of power plants and other installations utilising renewable energy sources to produce electricity, commissioned within the respective year.*

After decades of falling costs and improving performance in solar and wind technologies, the economic benefits of renewable power generation – in addition to its social, developmental and environmental benefits – are now compelling.

In 2010, the global weighted average LCOE of onshore wind was USD 0.111/kWh. This was 23% higher than the weighted average cost of new capacity additions for fossil fuels*, which stood at USD 0.090/kWh. By 2023, however, the global weighted average LCOE of new onshore wind projects was USD 0.033/kWh – 67% lower than the weighted average fossil fuel-fired cost, which had risen to USD 0.100/kWh (Figure S2). Over the same period, the global weighted average LCOE of offshore wind went from being 126% more expensive than the weighted average fossil fuel cost to being 25% less expensive. The cost fell from USD 0.203/kWh to USD 0.075/kWh.

Figure S1 Change in global weighted average LCOE for solar and wind compared to fossil fuels, 2010-2023



Note: RE = renewable energy.

CSP, meanwhile, saw its global weighted average LCOE fall from being 339% higher than the weighted average fossil fuel option in 2010 to just 17% higher in 2023. Utility-scale solar PV had a global weighted average LCOE of USD 0.460/kWh in 2010 – 414% more expensive than the weighted average fossil fuel-fired option. Yet, by 2023, a spectacular decline in costs – to USD 0.044/kWh – left solar PV's global weighted average LCOE 56% lower than the weighted average fossil fuel-fired option.

Indeed, while 2023 saw fossil fuel-fired power generation costs fall from their high, 2022 values (Figure 1.6 and Figure 1.7), renewable power generation continued to be less expensive than fossil fuel options. In 2023, around 81% (382 GW) of newly-commissioned, utility-scale renewable power generation projects had costs of electricity lower than the weighted average fossil fuel-fired costs by country/region.

Overall, between 2010 and 2023, 1 690 GW of renewable power generation was deployed that had a lower LCOE than that of the weighted average fossil fuel-fired LCOE.

* *Note: In this report, the weighted average LCOE of renewables was compared to the weighted average fossil fuel LCOE, whereas in previous years this report has used the LCOE of the 'cheapest' fossil fuel-fired option. This is due to recent fossil fuel price reductions.*

RENEWABLE POWER BROUGHT BENEFITS TO THE ECONOMY.

Of the 20 countries[2] for which IRENA has detailed data, nine saw the competitiveness[3] of their utility-scale solar PV improve by more than the global weighted average LCOE in 2023. In 2022, eight countries saw such an improvement.

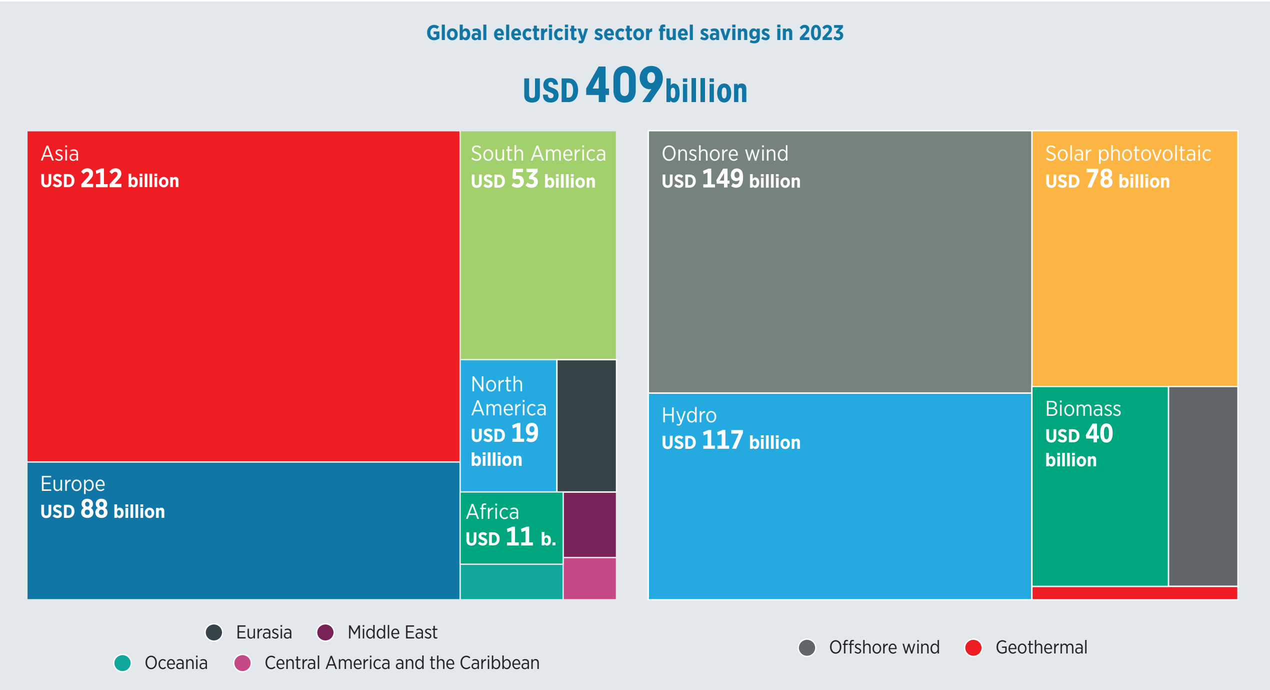
Over the 2022-2023 period, of the 19 countries examined for onshore wind, 16 saw the competitiveness of this technology improve by more than the global weighted average cost of electricity. In all markets, onshore wind was more competitive than the fossil fuel options.

Renewable power continues to save on fuel costs in the electricity sector. The competitiveness rate of solar and wind power was positive, although lower than in 2022. This was a consequence of the decline in fossil fuel prices.

In 2023, the renewable power deployed globally since 2000 saved an estimated USD 409 billion in fuel costs in the electricity sector alone (Figure S3). In the period between 2000 and 2010, Asia registered the highest cumulative savings, estimated at USD 212 billion. In Europe, the figure was USD 88 billion, followed by South America, where savings were estimated at USD 53 billion.

Regarding the technologies, onshore wind represented the highest savings, at USD 149 billion. Hydropower saw the second highest savings, at USD 117 billion, followed by solar PV, with USD 78 billion.

Figure S2 Global fossil fuel cost savings in the electricity sector in 2023 from renewable power added since 2000



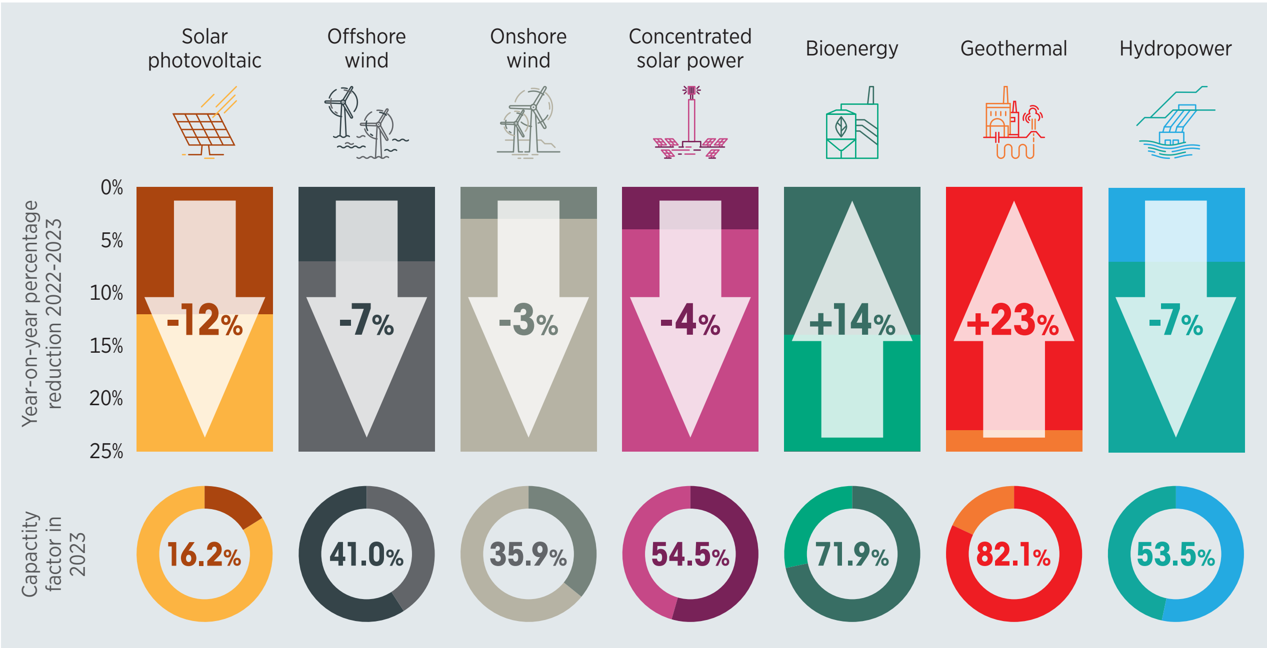
[2] *Detailed data is presented in Figure 1.10 covering the following 20 countries: Argentina, Australia, Brazil, Canada, China, France, Germany, India, Indonesia, Italy, Japan, Republic of Korea, Malaysia, Mexico, Philippines, South Africa, Türkiye, the United Kingdom, the United States and Viet Nam.*

[3] *IRENA has calculated a competitiveness metric for 20 countries. This is based on a weighted average cost of new fossil fuels calculated from project-level capital cost data and country-specific fossil gas and coal fuel marker prices to electricity generators. The competitiveness metric subtracts the country weighted average fossil fuel LCOE from the renewable power LCOE, so negative values represent renewable power LCOEs lower than those of fossil fuels.*

Between 2022 and 2023, the global weighted average total installed cost of newly-commissioned onshore wind projects decreased 13%, from USD 1322/kilowatt (kW) to USD 1154/kW. Over the same period, the global weighted average LCOE for these projects fell by 3%, from USD 0.035/kWh to USD 0.033/kWh (Figure S4).

In 2023, China was once again the largest market for new onshore wind capacity additions, with its share of global new deployment rising from 50% to 66%, year-on-year. This resulted in markets with higher installed costs decreasing their share relative to 2021. If China had been excluded, the global weighted average LCOE curve for onshore wind for the period would have increased 15%.

Figure S3 Global weighted average LCOE reduction and capacity factor from newly commissioned, utility-scale renewable power technologies, 2023



Note: The colour shading indicates the year-on-year percentage LCOE reduction (increase or decrease), starting from top (0%) to bottom (25%).

For newly-commissioned, utility-scale solar PV projects, the global weighted average LCOE decreased by 12% between 2022 and 2023, to USD 0.044/kWh. This was driven by a 17% decline in the global weighted average total installed cost for this technology, from USD 908/kW in 2022 to USD 758/kW for the projects commissioned in 2023.

Overall, 2023 saw solar PV experience a total installed cost decline in major markets. This was due to supply chain easing and reductions in commodity price inflation. European countries registered the biggest decrease in installed costs, with Greece seeing a decline of 48%, the Netherlands 41% and Germany 29%. The biggest markets followed the same trend, including China, which saw a decline of 10%, the United States (4%) and Brazil (5%). India was the exception, recording a 7% increase during 2023.

The offshore wind market added 11 GW of new capacity in 2023 – the second-highest year on record since 2021. China accounted for 65% of the total offshore capacity additions. Indeed, driven by China's share in new capacity additions and the commissioning of projects in new markets, the global weighted average cost of electricity of new projects saw a decrease of 7% in 2023, compared to 2022, from USD 0.080/kWh to USD 0.075/kWh.

Between 2022 and 2023, the global weighted average total installed costs of offshore wind decreased from USD 3 478/kW to USD 2 800/kW, while the weighted average capacity factor for newly-commissioned projects fell slightly, from 42% in 2022 to 41% in 2023.

In 2023, only one CSP project was completed. This resulted in a global weighted average LCOE of USD 0.117/kWh for this technology, representing a 4% decrease compared to 2022.

For newly-commissioned bioenergy for power projects, the global weighted average LCOE rose by 14% between 2022 and 2023, from USD 0.063/kWh to USD 0.072/kWh.

For geothermal power projects, between 2022 and 2023 the global weighted average LCOE of the seven projects commissioned increased by 23%, to USD 0.071/kWh.

Newly-commissioned hydropower projects, in contrast, saw their global weighted average LCOE decrease by 7% between 2022 and 2023, from USD 0.061/kWh to USD 0.057/kWh. Over the same period, the global weighted average total installed cost of new hydropower projects decreased from USD 3 053/kW to USD 2 806/kW – a fall of 8%.

SUBSTANTIAL COST REDUCTIONS IN RENEWABLES FROM 2010 TO 2023 DEMONSTRATE A REMARKABLE RATE OF DEFLATION.

Since 2010, solar PV has experienced the most rapid cost reductions. The global weighted average LCOE of newly-commissioned utility-scale solar PV projects declined from USD 0.460/kWh to USD 0.044/kWh between 2010 and 2023 – a decrease of 90% (Figure S5). This reduction in LCOE has been primarily driven by declines in module prices. These fell by around 93% between December 2009 and December 2023. Between 2018 and 2023, important reductions also occurred in soft costs (59%), modules and inverters (46%), balance of system (BoS) hardware (39%), and installation costs (36%). The median for all-in operations and maintenance (O&M) costs for utility-scale solar PV also decreased 5% between 2022 and 2023.

For onshore wind projects, the global weighted average cost of electricity fell by 70% between 2010 and 2023, from USD 0.111/kWh to USD 0.033/kWh. Cost reductions for onshore wind were driven by two key factors: wind turbine cost declines and capacity factor increases from turbine technology improvements.

Between 2010 and 2023, wind turbine prices outside China fell by between 41% and 64%, depending on the wind turbine price index. Within China, the decline was 73% for the same period. Meanwhile, the global weighted average capacity factor of newly-commissioned onshore wind projects increased from 27% in 2010 to 36% in 2023. This highlighted how technological improvements and cost reductions have made turbine installations cost competitive, even in areas with less favourable wind resources.

For newly-commissioned offshore wind projects, between 2010 and 2023 the global weighted average LCOE declined from USD 0.203/kWh to USD 0.075/kWh, a reduction of 63%. In 2010, China and Europe saw newly-commissioned offshore projects with a weighted average LCOE of USD 0.196/kWh and USD 0.205/kWh, respectively. The weighted average LCOEs of these two groups thereafter diverged, notably in 2021, when newly-commissioned European projects had a weighted average cost of USD 0.057/kWh – lower than the USD 0.085/kWh recorded in China that year. In 2023, the weighted average LCOE in Europe increased to USD 0.066/kWh as a range of more expensive projects were completed, including some in new markets. Europe's LCOE was still around 6% lower than the Chinese projects completed in 2023, which saw a weighted average of USD 0.070/kWh. The difference lies in the wind resource of each region, with Europe having higher wind speeds compared to those in China.

CSP deployment remains stagnant, with only 300 MW added in 2023 and global cumulative capacity standing at 7 GW at the end of 2023. For the period 2010 to 2023, the global weighted average cost of newly-commissioned CSP projects fell from USD 0.39/kWh to USD 0.117/kWh – a decline of 70%. The LCOE of CSP fell rapidly between 2010 and 2020, despite annual volatility. Since 2020, however, the commissioning of projects that were either delayed or included novel designs has seen the global weighted average cost of electricity from this technology stagnate.

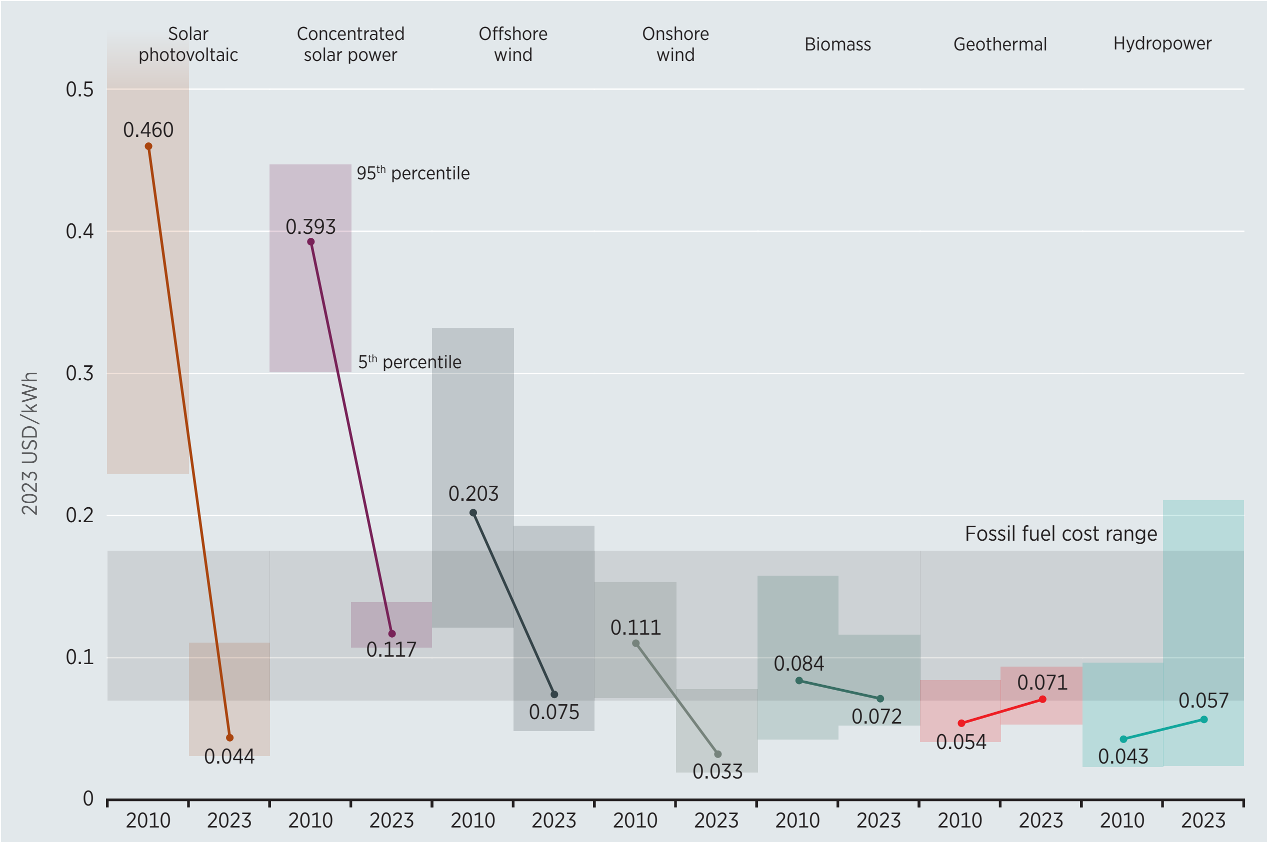
Bioenergy for power's global weighted average LCOE of USD 0.084/kWh in 2023 was 14% higher than the 2022 value and one-quarter lower than the USD 0.072/kWh value recorded in 2010. The increment is due to a shift in market share from 2022, with higher-cost markets now accounting for a greater share. Additionally, between 2010 and 2023 the global weighted average LCOE of bioenergy for power projects had experienced some volatility, without a notable trend upwards or downwards.

For geothermal projects, the global weighted average LCOE was 23% higher in 2023 than in 2022, reaching USD 0.071/kWh. This was still well within the USD 0.077/kWh to USD 0.074/kWh range seen between 2017 and 2021.

Newly-commissioned hydropower projects saw their global weighted average LCOE rise by 33% between 2010 and 2023, from USD 0.043/kWh to USD 0.057/kWh. This was still lower than the average fossil fuel-fired electricity option in 2023. During the period 2022 to 2023, the global weighted average costs decreased by 7%. The spike in costs in 2022 was driven by the commissioning of a number of projects that experienced very significant cost overruns, notably in Canada and the United States.

Electricity storage saw the costs of battery storage projects declined 89% between 2010 and 2023, from USD 2 511/kWh to USD 273/kWh. The cost reduction was driven by scaling up manufacturing, improved materials efficiency and improved manufacturing processes. Additionally, annual capacity additions increased from 0.1 GWh gross capacity in 2010 to 95.9 GWh gross capacity in 2023, with China accounting for almost half of the total global additions (46.5 GWh).

Figure S4 Global LCOE from newly-commissioned, utility-scale renewable power technologies, 2010 and 2023



Note: These data are 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, including weighted average cost of capital (WACC), are detailed in Annex I. The grey band represents the fossil fuel-fired power generation cost in 2023, while the bands for each technology and year represent the 5th and 95th percentile bands for renewable projects.

01 LATEST COST TRENDS

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INTRODUCTION

In 2023, the global effort towards the energy transition gained substantial momentum. There was a welcome acceleration in the deployment of renewables, while at COP28 – held in the United Arab Emirates – the call came to triple renewable power generation capacity and double the rate of energy efficiency improvement by 2030. This showed a great collective interest in meeting the challenging, but achievable, goal of rapidly up-scaling renewables and meeting the Paris Agreement's 1.5°C target (COP28 Presidency *et al.*, 2023).

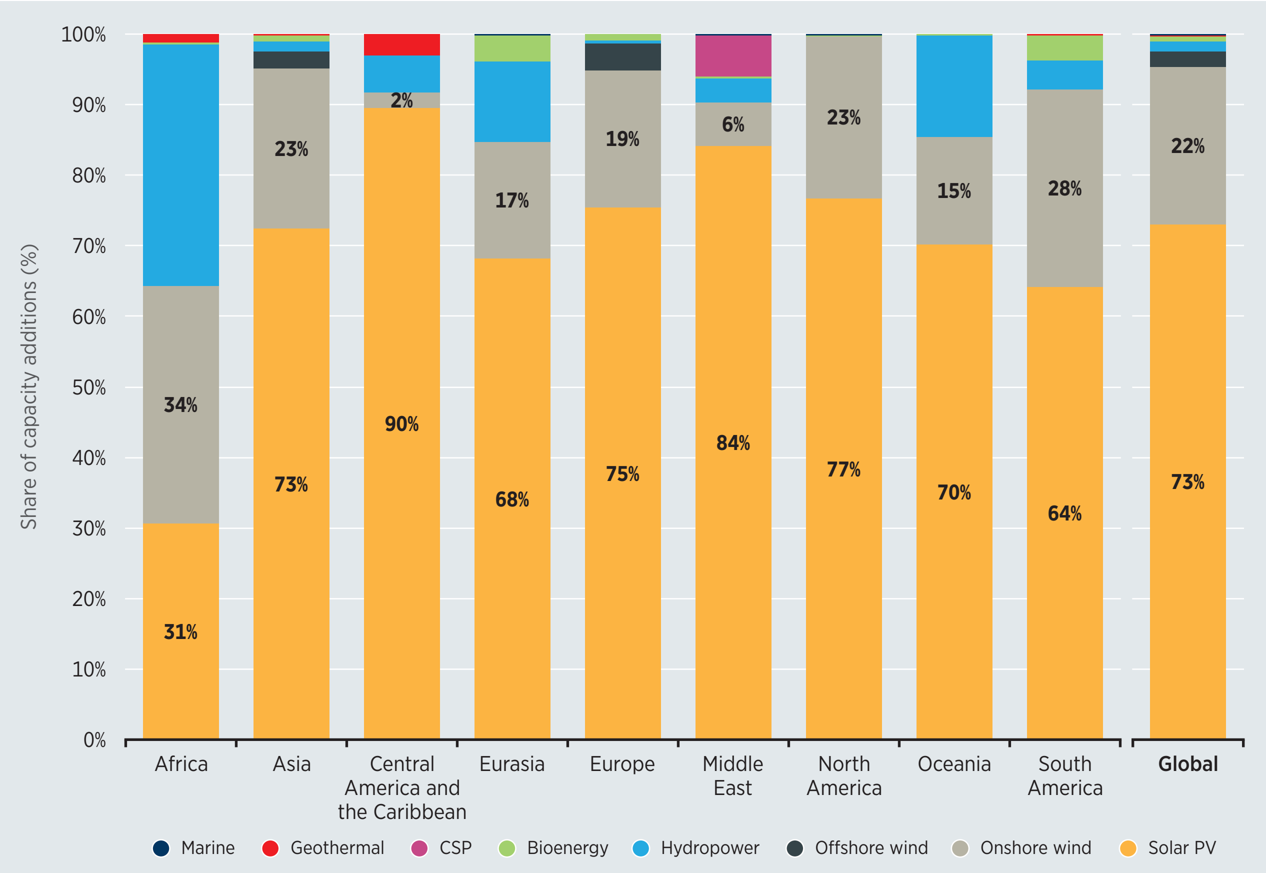
The previous two years had been marked by a fossil fuel price crisis, supply chain challenges and an economy affected by a global pandemic. There had been concerns about the path to green recovery and progress towards the Paris Agreement. In 2023, pivotal discussions and collaborations within the international community occurred. These aimed at encouraging the global expansion of renewable energy, which translated into tangible action plans, demonstrating a shared commitment against climate change.

The progress made in 2023 represents a significant step towards achieving the ambitious goals that have been set. The Global Renewables and Energy Efficiency Pledge, signed by over 130 countries at COP28, calls for the world to achieve 11.2 terawatts (TW) of renewable capacity by 2030. This would mark an increase of around 7.8 TW in eight years. Achieving this goal would mean adding an average of 974 gigawatts (GW) of new capacity annually between 2022 and 2030 (COP28 Presidency *et al.*, 2023).

In the upcoming years, remarkable growth across all renewable energy sources is therefore expected. The technologies that will have the biggest impact on tripling renewable energy capacity are solar photovoltaic (PV) and onshore wind. From these two technologies, a total installed capacity of 8.5 TW is expected – 5.5 TW from solar PV and 3 TW from onshore wind (COP28 Presidency *et al.*, 2023).

On a similar note, the technologies with the highest share of new capacity deployed by region in 2023 were solar PV and onshore wind (Figure 1.1). Solar PV was the technology with the largest share of deployment for all regions except Africa, that year. Onshore wind was the second most deployed technology in six out of nine regions. Africa had a more diverse energy deployment, with the same share for onshore wind and hydropower, at 34%; while in the Middle East, onshore wind and concentrated solar power (CSP) both had 6%; and in Central America and the Caribbean, hydropower was the second most deployed technology at 5%.

Figure 1.1 Share of renewable energy capacity additions by technology in 2023 on a regional level



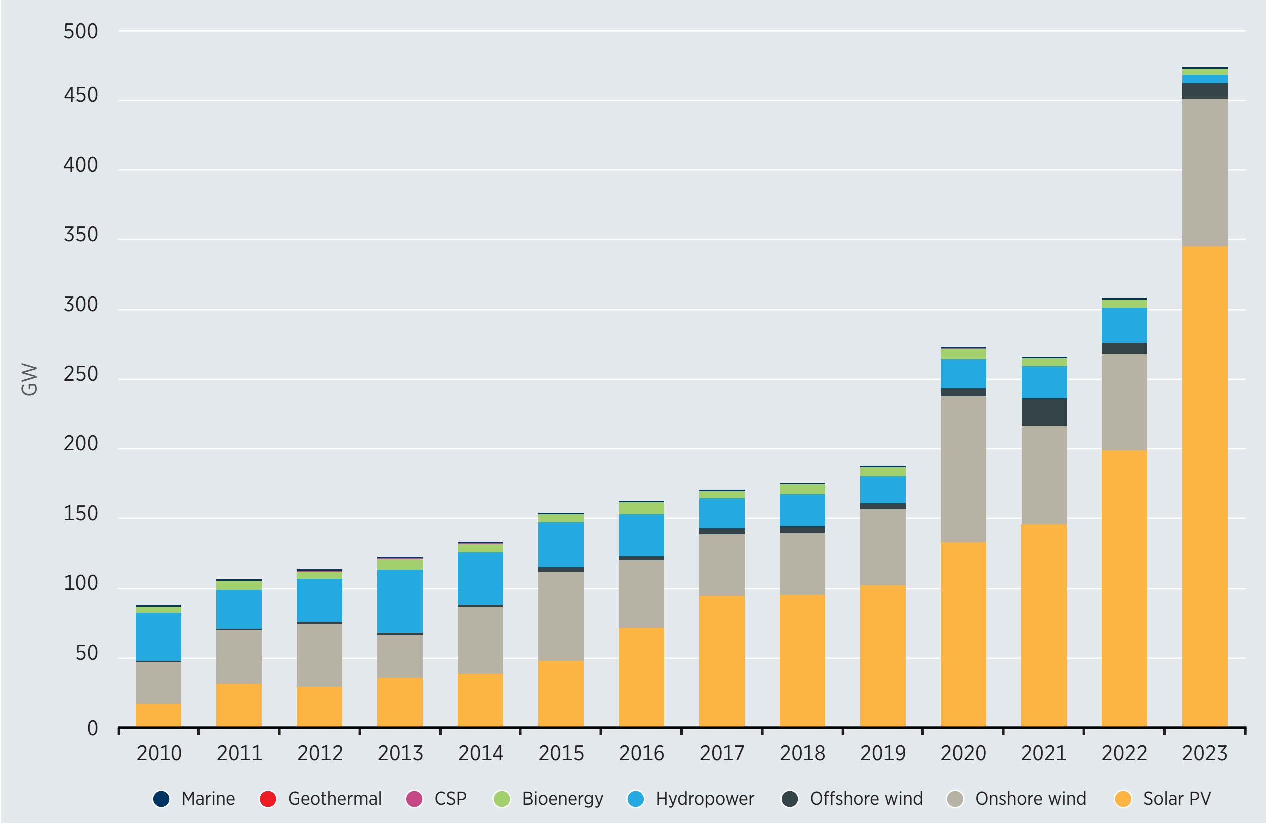
Source: IRENA (2024a).
Notes: CSP = concentrated solar power; PV = photovoltaic.

The year 2023 saw an unprecedented acceleration in the adoption of new renewable energy capacity.[4] Indeed, the global addition of new renewable power capacity grew 54% year-on-year, from 308 GW added in 2022 to 473 GW[5] added in 2023. This set a new record by a significant margin (Figure 1.2). This progress is evident in the first-time addition of more than 300 GW of solar PV and more than 100 GW of onshore wind. In 2023, solar PV capacity additions accounted for almost three-quarters (73%) of total additions, and onshore wind represented 22%. The share of other renewable technologies, totalling 5%, was distributed among offshore wind, hydropower, bioenergy, geothermal and marine.

[4] *Electricity generated is expressed in alternating current (AC)/direct current (DC) for PV and AC-to-AC terms for other technologies in this report.*

[5] *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), which is the date when 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.*

Figure 1.2 Global annual new capacity additions of renewable power, 2010-2023



Source: IRENA (2024a).
Notes: CSP = concentrated solar power; PV = photovoltaic.

Solar PV capacity additions continued to break records in 2023. The 346 GW added represented an increase of 73% over the 200 GW added in 2022. It was almost seven times higher than the 29.4 GW added over a decade earlier, in 2012. China was the largest market for new capacity added in utility-scale solar PV, with its share growing from 45% in 2022 to an estimated of 63% of the global total in 2023. This helped push down the global weighted average total installed cost.

In 2023, the onshore wind energy sector reached a major milestone by adding 104 GW of new capacity, marking a notable 48% increase from the 70 GW added in 2022. China played a significant role in this growth, too, accounting for 66% (69 GW) of the total added capacity in 2023. This figure not only surpassed the total global installed capacity of the previous year, but also more than doubled the 33 GW of newly-installed capacity in China in 2022. Unsurprisingly, China remains the largest market for onshore wind energy, while other markets saw varying results. The United States, for example, added 6 GW of capacity in 2023 – its lowest level of deployment since 2017 – while Brazil achieved a national record in yearly installed capacity, with 5 GW.

Offshore wind capacity additions in 2023 increased by 11 GW, marking a 27% rise compared to the 8 GW added in 2022. This makes 2023 the second-highest year for new offshore wind capacity, with 2021 holding the record, at 20 GW. Asia led the way in new offshore capacity, commissioning 8 GW. China accounted for 88% of this expansion, with 6.8 GW of newly-commissioned offshore wind projects. The remaining capacity expansion occurred in Europe.

The total new additions of other renewable energies in 2023 amounted to around 12 GW. Bioenergy saw an additional 4.4 GW, with China contributing 2 GW of the total. Hydropower capacity additions (excluding pumped hydro) were 7 GW in 2023 – significantly down from the 23 GW of 2022 and marking the lowest level since the year 2000. Geothermal power capacity additions in 2023 were 203 megawatts (MW), while those for CSP were 300 MW, showing an increase on the previous year.

Between 2000 and 2023, renewable power generation capacity worldwide increased more than five times, from 752 GW to 3 865 GW. In 2023, renewables again dominated the capacity additions, accounting for 85.5% of new power generation capacity added. This figure represented a 14% year-on-year increase in cumulative renewable capacity (IRENA, 2024a).

A global effort is now required to increase annual renewable energy capacity growth by 16.4% over the next seven years (IRENA, 2024b). While solar PV and onshore wind installations have set records, other technologies such as hydro, CSP and geothermal have not yet been deployed at the same speed.

Annual battery storage capacity additions increased from 0.1 gigawatt hour (GWh) gross capacity in 2010 to 95.9 GWh gross capacity in 2023. Storage technologies are increasingly being used to accelerate solar and wind deployment by facing challenges related to the slow processing of grid connection requests and the uncertainty around future curtailment or grid congestion regimes. The costs of battery storage projects declined 89% between 2010 and 2023, from USD 2 511/kWh to USD 273/kWh. This was driven by manufacturing scale-up, improved materials efficiency and improved manufacturing processes.

New renewable capacity addition records need to be broken in the years ahead, driven by the competitiveness of renewable power in the global market, net-zero emissions ambitions and the urgency required to keep the Paris Agreement goals in play. Despite the imbalance in the deployment of different renewable energy technologies, the capacity additions in 2023 offer compelling evidence that the tripling goal is achievable, given appropriate action and suitable mechanisms. The fact is, renewable power generation has become, almost everywhere, the default source of least-cost new power generation. Policy makers and all stakeholders should focus on ensuring that policies, regulations, market structures, infrastructures, support instruments, de-risking mechanisms and financing are all rapidly aligned with the tripling target for all renewable energy technologies.

The IRENA cost analysis programme

The IRENA cost analysis programme has been collecting and reporting the cost and performance data of renewable power generation technologies since 2012. The goal of the programme is to provide transparent, up-to-date cost and performance data from a reliable source. These data are vital in ensuring that the potential of renewable energy is properly taken into account by policy makers, energy and climate modellers, and other stakeholders. IRENA's member states also rely on this data collection and reporting. With accurate and transparent data, key decision makers in government and the energy sector can identify the magnitude of the role renewable energy can play in meeting the shared economic, environmental and social goals for the energy transition.

With high learning rates[6] and rapid growth in the installed capacity of renewable energy technologies, access to comprehensive and up-to-date data – by market and technology – is essential. The body of data represented by the *IRENA Renewable Cost Database* allows time-series analysis of key trends in costs and performance, helping to support decisions around the next stage in the energy transition. IRENA's cost reports also provide an opportunity to examine recent trends in commodity costs and equipment pricing and their impact on total installed costs in this period of cost inflation.

IRENA maintains one core database, supplemented by more granular data for a range of metrics. These facilities have been created to ensure IRENA can respond to its member states' needs while providing industry and civil society have easy access to the latest renewable power generation cost and performance data.

The main core database is the *IRENA Renewable Cost Database*,[7] which includes project-level cost and performance data for around 2 706 GW of capacity from around 23 372 projects[8] commissioned up to and including 2023.

The breadth and depth of the data in the *IRENA Renewable Cost Database* allows for a meaningful understanding of variations between countries and technologies, while also showing variations over time. These variations are reported across each technology and cost metric for an analysis of how different cost metrics have changed between particular technologies (*e.g.* solar PV and onshore wind) and in different markets for those technologies over particular chronological periods.

[6] Learning rates are defined as the percentage reduction in cost or price for every cumulative doubling in production or installation.

[7] Annex II provides detailed information on the data for regional coverage by technology. The database is not publicly accessible, but the data used in the charts can be downloaded from IRENA's website.

[8] This excludes projects with an installed capacity of less than 1 MW.

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. The agency now reports regularly on an increasing range of cost and performance metrics (*e.g.* solar modules efficiency and capacity factors for all technologies) across a wider range of countries. This has been driven by the need to better understand cost trends and supply chain dynamics to support decision makers, as the urgency of scaling up renewable power deployment to meet country commitments under the Paris Agreement has become more acute.

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) and its underlying influences. The LCOE of a given technology is the ratio of lifetime costs to lifetime electricity generation. Both of these 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:

- The 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.*).

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

- The operation and maintenance (O&M) costs.

- The LCOE.

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

Where appropriate, the chapters also include additional cost and performance metrics that allow for a more detailed understanding of component costs and how these are driving trends in the LCOE.[9] These contextual data and varied cost 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. Where possible this report discusses the impact of the recent commodity price increases and equipment costs on total installed project costs and the LCOE.

[9] *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.*

Yet, although the 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. Neither does the LCOE take into account that a technology's generation profile means that its value may be higher or lower than the average market price.

The LCOE also does not 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. However, ongoing technological innovations for solar and wind technologies are 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 and/or other energy system resources, 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 - and increasingly, whole energy system simulations. These 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.

Other key points regarding the data presented in this report are:

- All project data are for the year of commissioning, or commercial operation date (COD).[10] In some cases this means a project connected to the grid may not qualify for inclusion if no meaningful generation occurs.[11] 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 projects. It can take up to five years or more for CSP, fossil fuels, hydropower and offshore wind projects.

- The cost metrics exclude the impact of energy financial support to renewables, such as tax credits, carbon pricing, market loans and grants.

[10] Bottom-up benchmark analyses undertaken by other organisations and institutions (e.g. Bloomberg New Energy Finance [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 an onshore wind project for the first quarter of a year based on a 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 engineering, procurement and construction (EPC) contracts are signed.

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

- LCOE results are calculated using project-level total installed costs and capacity factors. For the WACC, technology and country-specific WACC benchmark values are used for 100 countries from IRENA's WACC benchmark tool. This has been calibrated with the results of the IRENA, International Energy Agency (IEA) Wind Task 26 and ETH Zurich cost of finance survey (see Annex I for more details). 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 Annex I for more details.

- Capacity factor data are project developers' estimates of the average lifetime yield of projects, or where these data are not available, estimates by IRENA based on the technology and project location. All capacity factors in this report are for the newly-commissioned projects in a given year, not the stock of installed capacity.[12]

- All cost and capacity factor data are for the alternating current (AC) capacity, except for solar PV. For PV, total installed costs are in direct current (DC) terms. The capacity factor is therefore the so-called AC-DC capacity factor to ensure that the LCOE is then directly comparable with all the other technologies in this report (that is to say, in AC terms).

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

- O&M cost data are a mix of country-specific data from a variety of sources and regional assumptions. The O&M costs are "all-in"; that is to say, they include costs like insurance and head office cost shares that are not included in third-party O&M contracts. See Annex I for more details.

- All data contained within this report are for utility-scale projects of at least 1 MW, except for residential and some commercial solar PV.

- All renewable capacity data are from IRENA's capacity statistics (IRENA, 2024a) unless otherwise noted.

- Data for costs and performance for 2023 are preliminary and sometimes subject to revision.

- LCOE is a static measure of costs that provides useful information, but has its limits.

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

Box 1.1 The importance of understanding real and nominal prices in a period of high inflation

Globally, with some exceptions, the last 30 years has been a period of relatively low inflation compared to the 1970s and 1980s, which were affected by the first and second oil shocks. Since 1994, inflation in the OECD has typically been in the range 0.3% to 4%, yet between 1971 and 1985, inflation did not drop below 6% per year and peaked at 16% in 1974. We have recently seen, therefore, a period of overall price stability.

This has meant that the difference between "nominal" and "real" prices for the span of a few years has not been large and a reasonable approximation of the actual value has been able to be made. This ceases to apply when inflation is high and nominal values from even five years ago, if not "deflated" into real values, can be misleading. For instance, using the United States gross domestic product (GDP) deflator, if a can of drink cost USD 1.00 in 2001, in real terms that can would cost USD 1.02 in 2002 money due to inflation. Taking today's situation, if the can of drink cost USD 1.00 in 2022, its cost would be USD 1.03 in 2023 money.

That difference may seem small, but it is important to realise that if the country-level weighted-average total installed cost in real terms (*e.g.* in 2023 money) for a project commissioned in 2023 is the same as in 2022, the US inflation rates featured above would mean a 3% increase in nominal terms between 2022 and 2023. A positive percentage increase in real terms can therefore be a very significant increase in nominal terms (*i.e* the sticker price seen by the purchaser).

When interpreting the results in the following sections, it is worth remembering this point when trying to identify if the results make sense compared to the nominal values that may have been quoted in the media or are available to the reader through other sources.

Costs in several markets went down in 2023 after the high commodity price inflation in 2022 caused by the crisis in Ukraine and increased manufacturing and supply chain capacity. Cost inflation has not been systemic across the board; it varies in different countries, depending on project lead times and the market size.[13]

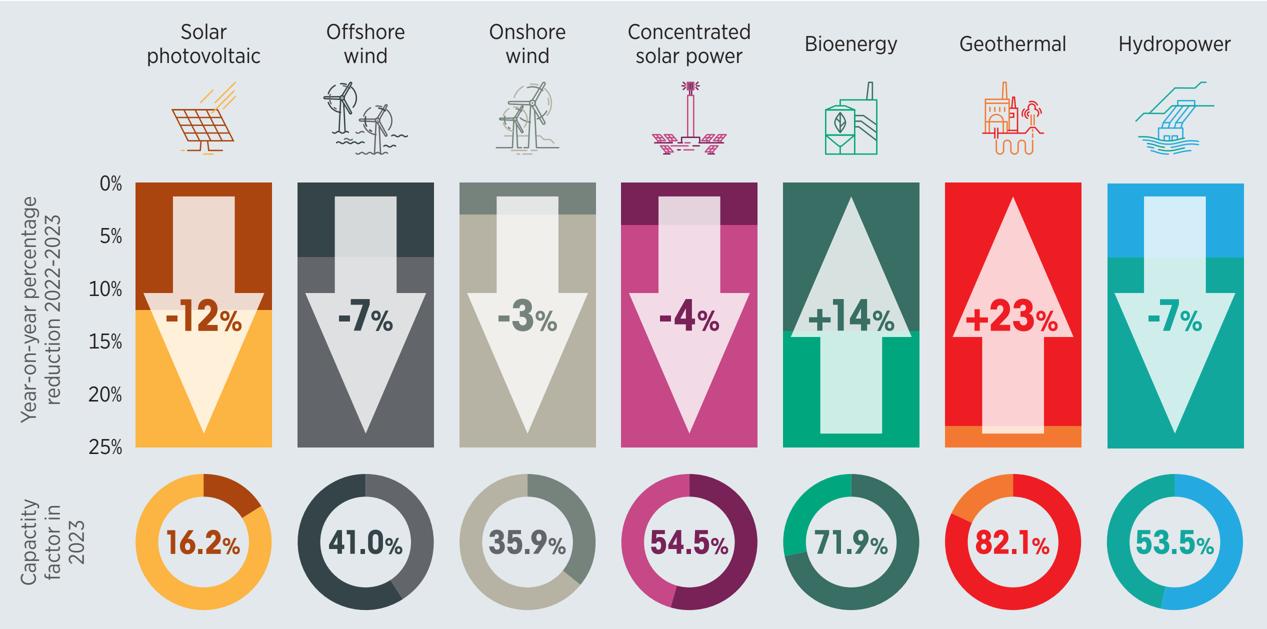
The global weighted average LCOE for solar and wind technologies continued to decrease in 2023, primarily due to China's significant share of deployment in solar PV, onshore and offshore wind. China had the lowest weighted average total installed costs that year for all these technologies, with its costs declining 10%, 14% and 16% year-on-year for solar PV, onshore and offshore, respectively. China's impressive deployment also influenced the global weighted average LCOE and capacity factor.

Progress in manufacturing, large-scale development and ample market competition have resulted in lower project costs in China compared to other countries. For technologies not influenced by China's share of deployment, closely analysing market share is essential for a deeper understanding of cost dynamics and their correlation with higher-cost markets.

[13] *Smaller markets have always experienced significant year-on-year volatility as the nature of renewable power generation projects means that their cost can be heavily influenced by the site location (e.g. access and civil works costs, grid connection, etc.) and the size and experience of the developer.*

In 2023, the year-on-year global weighted average LCOE decreased for all technologies except bioenergy and geothermal (Figure 1.3). Solar PV, the most widely deployed technology, had the largest drop in LCOE. Offshore wind and hydropower decreased in cost that year – the opposite of the upward trend observed in 2022.

Figure 1.3 Global weighted-average LCOE and capacity factors from newly-commissioned, utility-scale renewable power technologies, 2023



In 2023, the global weighted average LCOE of new onshore wind projects commissioned fell by 3%, year-on-year (Figure 1.3), from USD 0.034/kWh to USD 0.033/kWh. China was once again the largest market for new onshore wind capacity additions, with its share of new deployment rising from 50% in 2022 to 66% in 2023. This resulted in markets with higher installed costs decreasing their share relative to 2022. Excluding China would have seen the global weighted average LCOE for onshore wind increase 15% year-on-year for the period 2022 to 2023. Outside of China, five of the top 20 wind markets experienced an increase in their weighted average total installed costs.

For utility-scale solar PV, the global weighted average LCOE of newly-commissioned projects decreased by 12% year-on-year in 2023, to USD 0.044/kWh. This was driven by a 17% decline in the global weighted average total installed cost for this technology, from USD 908/kW in 2022 to USD 758/kW for the projects commissioned in 2023. This was higher than the 4% decline experienced in 2022, as rising PV module and commodity prices at the end of 2021 and into 2022 have had an impact on total costs for a significant number of projects.

In 2023, five of the top twenty markets for solar PV saw their total installed cost increase year-on-year in real terms. Cost increases were between 3% and 7%, with India registering the highest increase, while both Australia and Chile had the lowest. Most of the markets experienced cost decreases, especially European countries. Netherlands had the most notable cost decrease, at 41%, followed by Germany with 29% and France with 20%.

For offshore wind, the global weighted average of LCOE newly-commissioned projects dropped 7% year-on-year in 2023, from USD 0.080/kWh to USD 0.075/kWh. Additionally, between 2022 and 2023 there was a decrease in global weighted average total installed costs from USD 3 478/kW to USD 2 800/kW.

Looking at the situation in Europe, where just 2.8 GW of new offshore wind capacity came online, the weighted average LCOE of newly-commissioned projects also decreased by 7%, from USD 0.073/kWh in 2022 to USD 0.068/kWh in 2023. This was driven by a 21% decrease in total installed costs, year-on-year, to USD 3 138/kW. Over the last eight years, year-on-year volatility has not changed the benefits of economies of scale in large projects, or of supply chain and O&M optimisation. However, with long lead times, projects are more exposed to commodity price fluctuations.[14]

CSP capacity expanded by 300 MW in 2023, continuing a trend of modest new capacity additions. One CSP plant was commissioned each year between 2021 and 2023. With limited deployment, year-to-year cost changes remain volatile. Noting this caveat, the average cost of electricity from the 300 MW added in 2023 was around USD 0.117/kWh, or 4% lower than in 2022.

The global weighted average LCOE of newly-commissioned bioenergy for power projects increased by 14% between 2022 and 2023, from USD 0.063/kWh to USD 0.072/kWh. With seven projects commissioned in 2023 on IRENA's database, the global weighted average LCOE of geothermal power projects increased 19% that year to USD 0.071/kWh. For hydropower, the global weighted average total installed cost and LCOE of newly-commissioned projects decreased by 8% and 7% respectively, from USD 3 053/kW to USD 2 806/kW, and from USD 0.061/kWh to USD 0.057/kWh.

Cost trends, 2010-2023

The global electricity system is undergoing a profound transformation, moving from a system based largely on fossil fuels to one that is based on renewable energy and enhances energy efficiency.

Power systems will become electrified, digitalised and interconnected. One of the challenges in most parts of the world today is identifying how to integrate the maximum amount of solar and wind power possible into current electricity systems. Meanwhile, efforts are being made to evolve regulatory regimes, market structures and rules, as well as the physical infrastructure of the grid, to ensure that grid constraints do not slow the deployment rate.

Policy makers have a triumvirate of immediate solutions in solar power, wind power and energy efficiency. These three options, with their relativity short project lead times – especially for solar and wind power – are vital solutions 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' significant environmental benefits in terms of reduced local pollutants and carbon dioxide (CO_2) emissions, as well as their previously overlooked, but now readily apparent, energy security benefits.

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

The renewable energy conversation, once dominated by concerns about the costs of technology and the challenges of integration, now positions renewables as a major part of electricity systems and security for many nations by reducing dependency on imports of fossil fuels that can send prices soaring. Additionally, the trend is now one of renewables significantly undercutting fossil fuels when new electricity generation capacity is required.

Indeed, renewable power generation has increasingly become the default source of least-cost new power generation. The *IRENA Renewable Cost Database* demonstrates the ongoing competitiveness of the technologies. The period 2010 to 2023 saw a seismic shift in the balance of competitiveness between renewables and incumbent fossil fuel and nuclear options (Figure 1.4).

This analysis excludes any financial support for renewable technologies, so the economic case for the owner or project developer is often even more compelling.

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 90% between 2010 and 2023, from USD 0.460/kWh to USD 0.044/kWh. This cost reduction occurred as global cumulative installed capacity of all solar PV (utility scale and rooftop) increased from 40 GW in 2010 to surpass 1 TW, reaching 1 412 GW by the end of 2023. This very rapid fall in costs from well outside the fossil fuel cost range in 2010 saw the global weighted average LCOE from utility-scale solar PV become 56% lower than the fossil fuel cost average in 2023.

This reduction in LCOE has been primarily driven by declines in module prices, which fell by around 96% between December 2009 and December 2023. Important reductions have also occurred in balance of plant costs, O&M costs and the cost of capital. The module price reductions experienced between 2010 and 2023 were driven by module efficiency improvements, increased manufacturing economies of scale and vertical integration of the supply chain, manufacturing optimisation, and reductions in materials intensity.

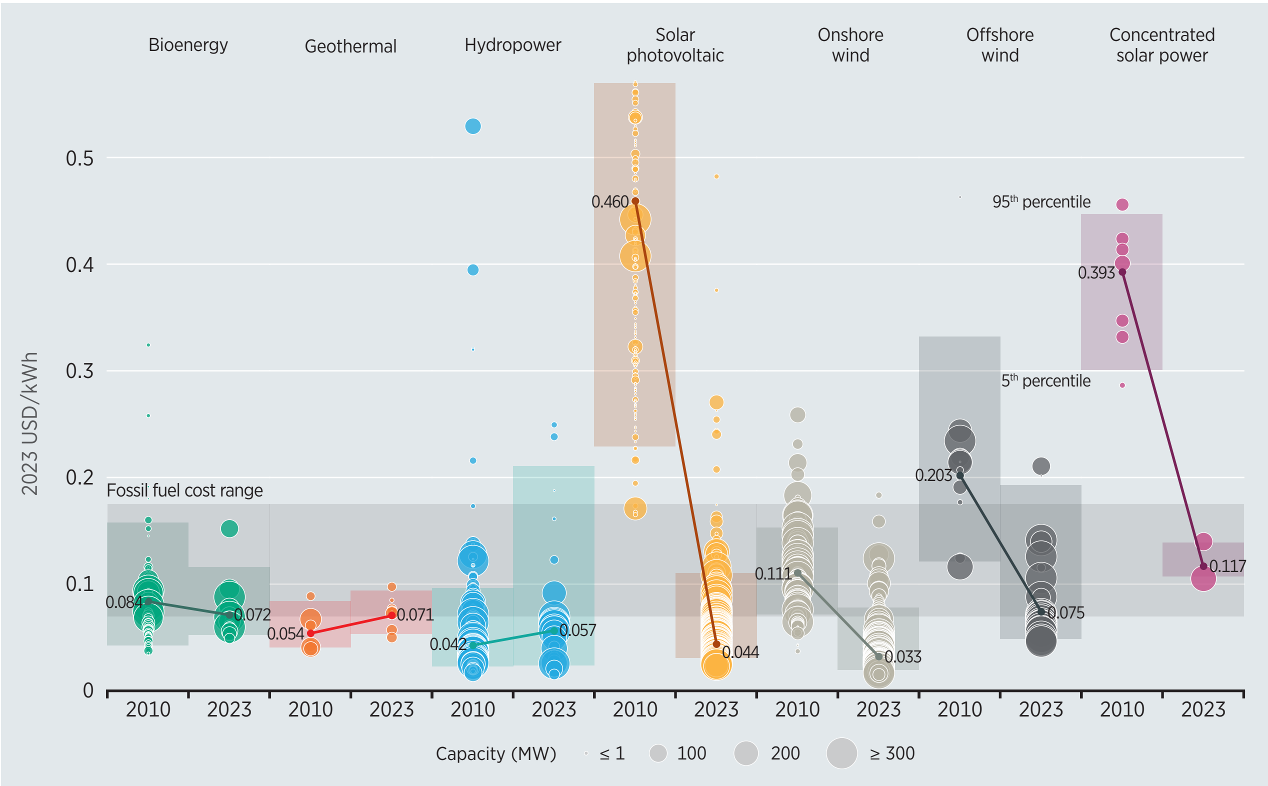
The total installed costs of utility-scale solar PV fell by 86% between 2010 and 2023, driven by module and balance of system (BoS) costs and streamlined and increasingly automated installation. All of this was helped by module efficiency improvements and other factors, as documented in Chapter 3 of this report. The global weighted average total installed cost of utility-scale solar PV declined from USD 5 310/kW in 2010 to USD 758/kW in 2023.

Utility-scale solar PV capacity factors also rose 17% between 2010 and 2023. Initially, this was driven predominantly by growth in new markets, which 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. In recent years, however, it has been the increased use of trackers and bifacial modules – which increase yields for a given resource – that has played a more significant role.[15]

[15] *Unfortunately, project-level data on the use of trackers and module types are not readily available, and what data are available are often not comprehensive. It is therefore difficult to estimate the overall impact trackers have played in increasing capacity factors globally.*

The drop in the cost of electricity from wind power has been remarkable. In 2010, the global weighted average LCOE of onshore wind was USD 0.111/kWh, a figure 23% higher than that year's weighted average LCOE fossil fuel cost range of USD 0.089/kWh. By 2023, the global weighted average LCOE of new projects decreased to USD 0.033/kWh, 67% lower than the weighted average LCOE fossil fuel-fired cost in 2023. This decline occurred as cumulative installed capacity grew from 178 GW to 944 GW.

Figure 1.4 Global weighted-average LCOE from newly-commissioned, utility-scale renewable power generation technologies, 2010-2023



Note: These data are for the year of commissioning. The thick lines are the global weighted-average LCOE value derived from the individual plants commissioned each year. The LCOE is calculated with project-specific installed costs and capacity factors, while the other assumptions, including WACC, are detailed in Annex I. The grey band represents the fossil fuel-fired power generation cost range (USD 0.069/kWh to USD 0.244/kWh), while the bands for each technology and year represent the 5th and 95th percentile bands for renewable projects.

Cost reductions for onshore wind were driven by two key factors: wind turbine cost reductions and capacity factor increases from improvements in turbine technology. Wind turbine prices outside China fell between 41% and 64% between 2010 and 2023, depending on the wind turbine price index (see Chapter 2 of this report). In China, this reduction was even more substantial, at 72%. The Chinese market continues to move at its own rhythm and operates differently from the rest of the world, as contracts often exclude delivery, installation and even towers.

In addition to this, declines in balance of plant costs as the industry has scaled up, as well as increasing average project sizes (notably outside Europe) have also contributed to the falling LCOEs. Also impacting the LCOE decline have been highly competitive supply chains and the falling cost of capital (including the technology premium for onshore wind).

Reductions in O&M costs have also occurred because 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.

Advances in wind turbine technology, wind farm siting and reliability have also led to an increase in average capacity factors. The global weighted average of newly-commissioned projects rose from 27% in 2010 to 39% in 2021. However, this average then dropped to 36% in 2023 due to a decrease in the United States' share of projects and an increase in China's share. The United States continues to deploy projects with 40% and higher capacity factors.

Technological improvements, such as higher hub heights and 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. 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, since then – have deployed in areas of poorer wind resources than in 2010 (see Chapter 2 for more details).

The cost reduction has been even more significant for offshore wind. The global weighted average LCOE of this technology fell from being 126% more expensive than the weighted average LCOE of fossil fuel in 2010 to being 25% less expensive in 2023, with the cost decreasing from USD 0.203 kWh to USD 0.075/kWh. Between 2010 and 2023, the global weighted average total installed costs of newly-commissioned offshore wind farms fell 48%, from USD 5 409/kW in 2010 to USD 2 800/kW in 2023. In Europe, with small numbers of projects being commissioned each year, cost trends tend to be volatile. The growth in new markets within this region, where offshore wind markets first developed, and globally, has introduced additional variability in the global weighted average data. Yet, in the last three years, with China accounting for 87% of new capacity additions in 2021, 49% in 2022 and 65% in 2023, the global weighted average cost and performance metrics have increasingly represented Chinese circumstances.

In 2010, China and Europe saw newly commissioned projects with weighted average LCOEs of USD 0.196/kWh and USD 0.205/kWh, respectively. The weighted average LCOEs of these two groups thereafter diverged, notably in 2021, when newly-commissioned European projects had a weighted average cost of USD 0.057/kWh, which was lower than the USD 0.085/kWh recorded by China that year. In 2023, the weighted average LCOE in Europe increased to USD 0.066/kWh as a range of more expensive projects was completed, including in new markets. Europe's LCOE, was, however still around 6% lower in 2023 than China's, where there was a weighted average of USD 0.070/kWh. Additionally, the global weighted average capacity factor increased from 38% in 2010 to 41% in 2023.

CSP saw its global weighted average LCOE fall from 339% higher than the weighted average fossil fuel option in 2010 to 17% higher in 2023. Even this improvement was surpassed, however, by that of solar PV, whose global weighted average LCOE in 2010 was USD 0.460/kWh, or 414% more expensive than the weighted average fossil fuel-fired option. The spectacular decline in solar PV costs to USD 0.044/kWh in 2023 was then 56% lower than the weighted average fossil fuel-fired option.

CSP deployment remains disappointing, however, with only 300 MW added in 2023 and global cumulative capacity standing at 6.9 GW at the end of 2023. For the period 2010 to 2023, the global weighted average cost of newly commissioned projects fell from USD 0.393/kWh to USD 0.117/kWh – a decline of 70%. Despite the low rate of deployment, cost reductions in CSP had been clearly visible between 2010 and 2020, despite the volatility. Since 2020 though, the commissioning of projects that were either delayed or included novel designs has seen the global weighted average cost of CSP-generated electricity stagnate.

Nevertheless, in 2023 the above decline in the cost of electricity from CSP still placed this technology in the mid- to lower-cost range of new capacity costs from fossil fuels, depending on the country. This remains a remarkable achievement. However, at the end of 2023, the cumulative global capacity of CSP was 200-times smaller than the capacity of solar PV installed.

The decline in the global weighted average LCOE of newly-commissioned CSP projects has been driven by reductions in total installed costs, technology improvements, more competitive supply chains and reduced O&M costs. Improvements in technology that have seen the economic level of storage increase significantly have also played a role in increasing capacity factors. CSP has the potential to accelerate energy storage to meet the demands of power systems.

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-on-year.

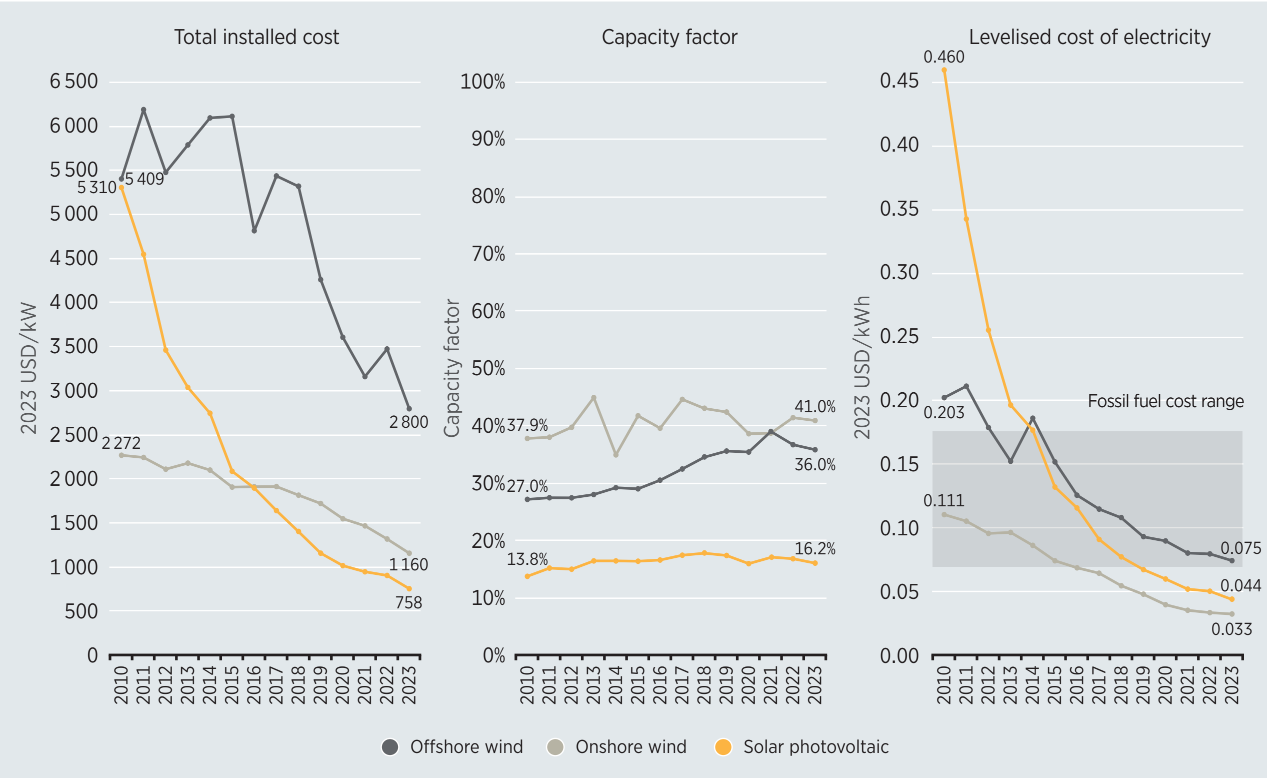
Between 2010 and 2023, the global weighted average LCOE of bioenergy for power projects experienced a certain degree of volatility, but without a notable trend upwards or downwards for most of the period. In 2023, however, bioenergy's global weighted average LCOE of USD 0.072/kWh was 14% lower than its 2010 value of USD 0.084/kWh. The global weighted average total installed costs for this technology in 2023 were USD 2 730/kW, or 9% lower than in 2010. The global weighted average capacity factor of newly-added capacity in 2023 was 72%, which was up on the 2021 figure of 68%.

In 2023, the global weighted average LCOE of geothermal increased 19%, year-on-year, to USD 0.071/kWh. Annual new capacity additions remained modest and deployment in 2023 accounted for 203 MW, with costs higher than 2022, but similar to 2021.

From 2010 to 2023, hydropower experienced an increase in the global weighted average LCOE of 33%, rising from USD 0.043/kWh to USD 0.057/kWh. This was still lower than the weighted average LCOE of fossil fuel-fired alternatives in 2023. Global weighted average total installed costs for hydropower increased by 49% between 2010 and 2023, from USD 1 419/kW to USD 2 806/kW. Additionally, the global weighted average capacity factor remained largely unchanged, rising from 44% to 53% over the same period. Therefore, the LCOE increase has been predominantly driven by the increase in total installed costs per kW over that period.

Figure 1.5 presents the results for global weighted average total installed costs, capacity factors and LCOEs for solar PV, onshore and offshore wind power. Global weighted average total installed costs for each technology fell over the period 2010 to 2023 – by 86% for utility-scale solar PV, 49% for onshore wind and 48% for offshore wind. Globally, utility-scale solar PV total installed costs fell below those of onshore wind in 2016. As the data for capacity factors show, however, improvements in technology made by wind turbine manufacturers have resulted in capacity factors for new onshore wind power projects rising over time. As a result, at a global level, although the LCOE of utility-scale solar PV fell 90% between 2010 and 2023, it still remained around USD 0.011/kWh higher than that of onshore wind. This was also despite falling below the cost of electricity from offshore wind in 2014.

Figure 1.5 Global weighted-average total installed costs, capacity factors and LCOEs from newly-commissioned solar PV, onshore and offshore wind, 2010-2023



Fossil fuel price reduction, 2023

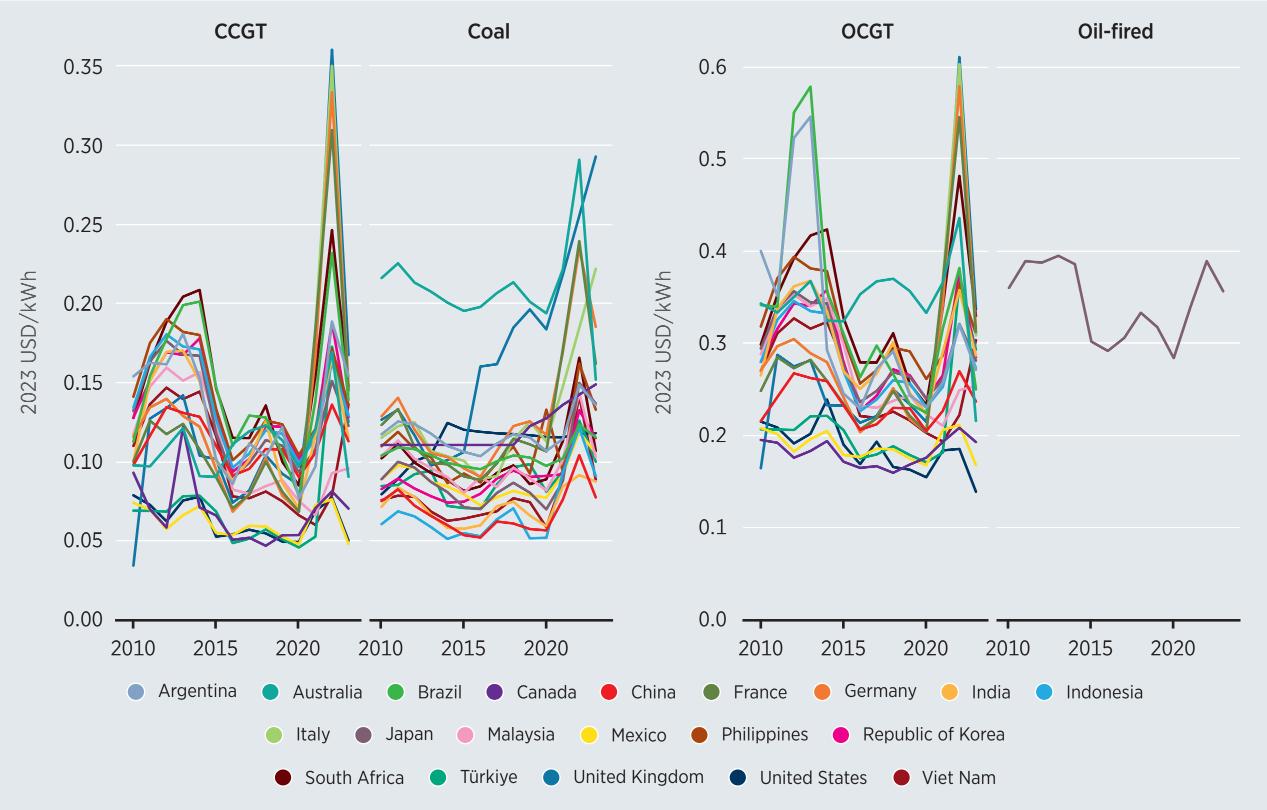
In 2023, fossil fuel prices returned to historic levels after the 2022 price hike crisis. Nonetheless, the period between 2010 and 2023 continues to represent a seismic shift in the balance of competitiveness between renewables and incumbent fossil fuel and nuclear options.

Figure 1.6 presents the results for countries where IRENA was able to collect fossil fuel robust time series data. It shows the LCOE of fossil-fuel fired electricity generation by fuel in different countries between 2010 and 2023. Fossil fuel prices are those that were realised in the year of commissioning. This is not necessarily what project developers have assessed to be the average cost over a plant's 30- to 40-year life, but it provides an indication of the trends in costs.

The figure shows that the LCOE of natural gas-fired plants decreased in most markets during 2023. The decrease ranged from 59% in Italy to 13% in Canada. Malaysia and the Philippines were the exceptions, registering price increases of 3% and 72%, respectively.

Coal LCOE prices also showed that fossil fuel prices returned to historical levels in 2023. Australia experienced the highest decrease in coal LCOE – 48% – followed by Viet Nam, with 37% and South Africa with 35%. The opposite occurred in the United Kingdom, Italy, Canada and the United States, where coal prices increased between 1% and 20%.

Figure 1.6 Fossil fuel-fired LCOE by fuel/technology and year for 20 countries, 2010-2023



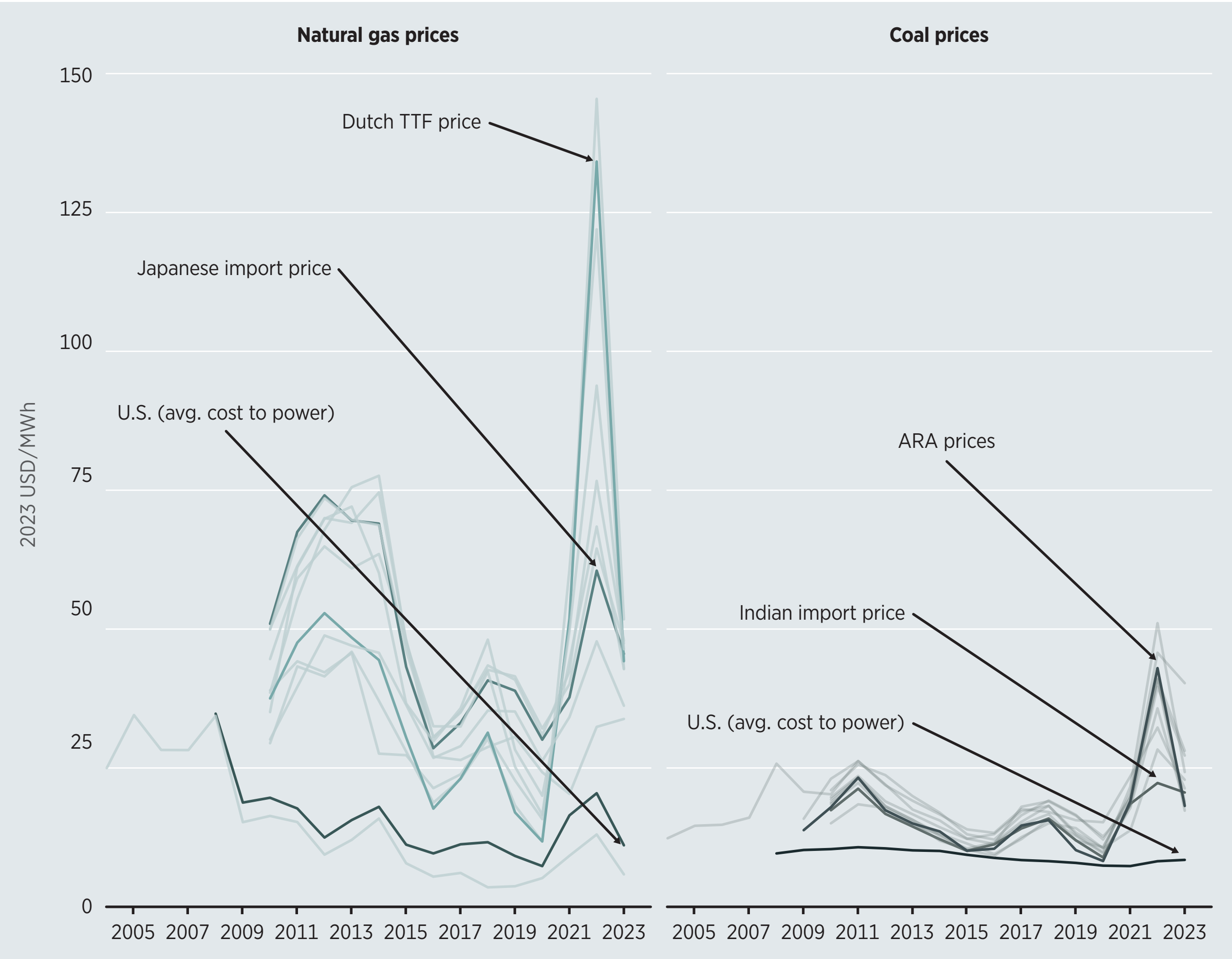
Note: CCGT = combined cycle gas turbine; OCGT = open cycle gas turbine.

The fossil fuel price decrease was driven by a decline in electricity demand during 2023. Fossil fuel generation fell 19% in Europe, representing a record year-on-year reduction of 209 terawatt hours (TWh). The United States also experienced a 1.7% decrease in electricity demand (IEA, 2023). This reduction in electricity demand is a result of a decline in energy intensive industry, decreased demand for heating, increased electrification and a greater share of renewable energy in electricity generation (EMBER, 2024).

As shown in Figure 1.7, in 2023, the fossil gas price marker decreased in most markets. The decline ranged from USD 6.6/megawatt hour (MWh) in Canada to USD 52.3/MWh in the United Kingdom. The Dutch Title Transfer Facility (TTF) pricing node experienced the greatest decrease, at 67%, followed by the French virtual trading point (*Pointe d'échange de gaz* [PEG]) price, which fell 65%, and the National Balancing Point (NBP) price in the United Kingdom, which fell 64%.

Coal was traded at lower costs on an energy content basis. In Europe, the Amsterdam-Rotterdam-Antwerp (ARA) coal price marker and the Richards Bay export marker in South Africa decreased 58% in 2023. The United States was again an exception, with the country experiencing a price increase of 3% during 2023 –the only market covered that saw prices rise.

Figure 1.7 Fossil gas and coal price marker or import cost by country, 2004 to 2023



Notes: TTF = Title Transfer Facility; ARA = Amsterdam-Rotterdam-Antwerp; U.S. = United States; MWh = megawatt hour.

Despite the decrease in fossil fuel-fired power generation costs in 2023 (Figure 1.6 and Figure 1.7), renewable power generation continued to be more competitive than fossil fuel options. In 2023, around 81% (382 GW) of newly-commissioned, utility-scale[16] renewable power generation projects had costs of electricity lower than the weighted average fossil fuel-fired cost by country/region (Figure 1.8).

This analysis includes the weighted average fossil fuel-fired LCOE (by new fossil fuel capacity additions) for the 20 countries highlighted in Figure 1.6, with regional averages for the remaining countries. The fossil fuel-fired LCOE therefore varies by year, depending on changes in capital costs and fuel costs for the fossil fuel plant.

The increased deployment of solar PV has been driving its competitiveness since 2021, when solar PV became more competitive than wind projects. In 2023, 248 GW (72%) of the new utility-scale PV deployed had lower costs than the weighted average fossil fuel LCOE for its country or region. This deployment also represented 65% of all the competitive renewable energy projects in 2023. This was the best result since 2017, when just 9% of newly-added PV capacity was more competitive than fossil fuel options.

In 2023, all 104 GW of onshore wind projects commissioned had electricity costs that were lower than the weighted average fossil fuel-fired LCOE by country/region. This was due to the increase in new onshore wind capacity added in China, which totalled 66% of global annual onshore additions.

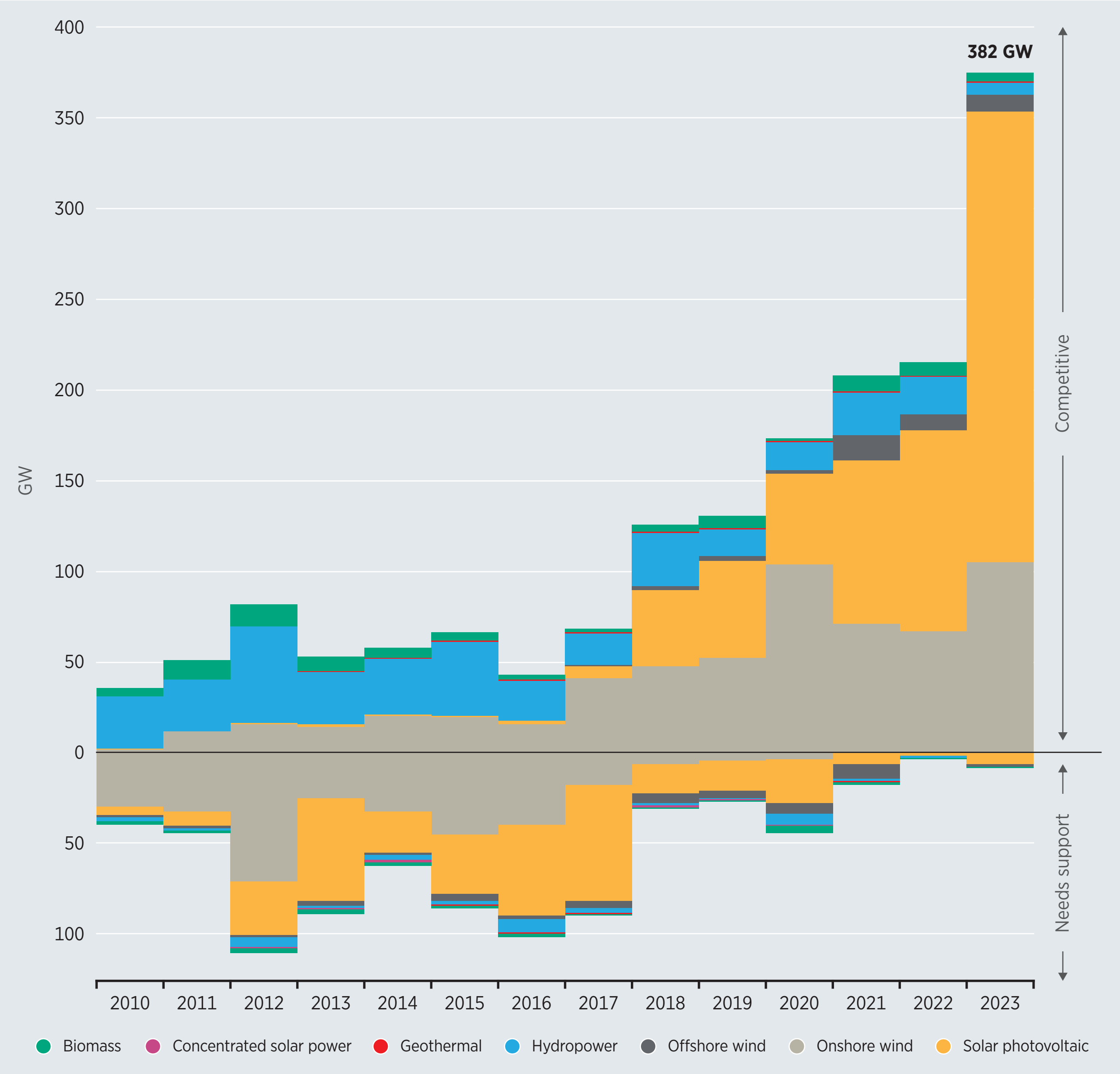
For offshore wind, in 2023, around 10 GW of new capacity additions had LCOEs lower than the country/region weighted average fossil fuel LCOE. This figure represented around 93% of the total new capacity additions in offshore wind tracked in the *IRENA Renewable Cost Database*.

For hydropower, in 2023, 6 GW of projects commissioned had costs that were less than the weighted average fossil fuel-fired LCOE. Bioenergy for power saw 4 GW (97%) of new capacity additions with a lower LCOE than the weighted average fossil fuel-fired LCOE.

Overall, between 2010 and 2023, 1 690 GW of renewable power generation was deployed that had a lower LCOE than that of the weighted average fossil fuel-fired LCOE by country/region. The rapidly improved economics of onshore wind and recently accelerated PV deployment produced an accumulative total of 1 187 GW in 2023 of lower cost electricity. With solar PV capacity additions increasing faster than onshore wind – and the competitiveness of both also accelerating – utility-scale PV added an estimated 601 GW of projects with an LCOE lower than the weighted average fossil fuel-fired LCOE, compared to 586 GW of onshore wind.

[16] *This includes all projects with a capacity of 1 MW or more and includes IRENA's assessment of 473 GW of renewable energy capacity additions in 2023.*

Figure 1.8 New utility-scale renewable power generation capacity competitiveness, 2010-2023



Note: This analysis uses country-level, weighted-average fossil fuel-fired LCOEs for each year for 20 countries (see Figure B1.1) and at a regional level for the remainder. These values are compared to the project-level LCOEs of renewable projects deployed in each year. The 2022 fossil fuel LCOEs have been calculated conservatively, using the 2021 fossil fuel price data.

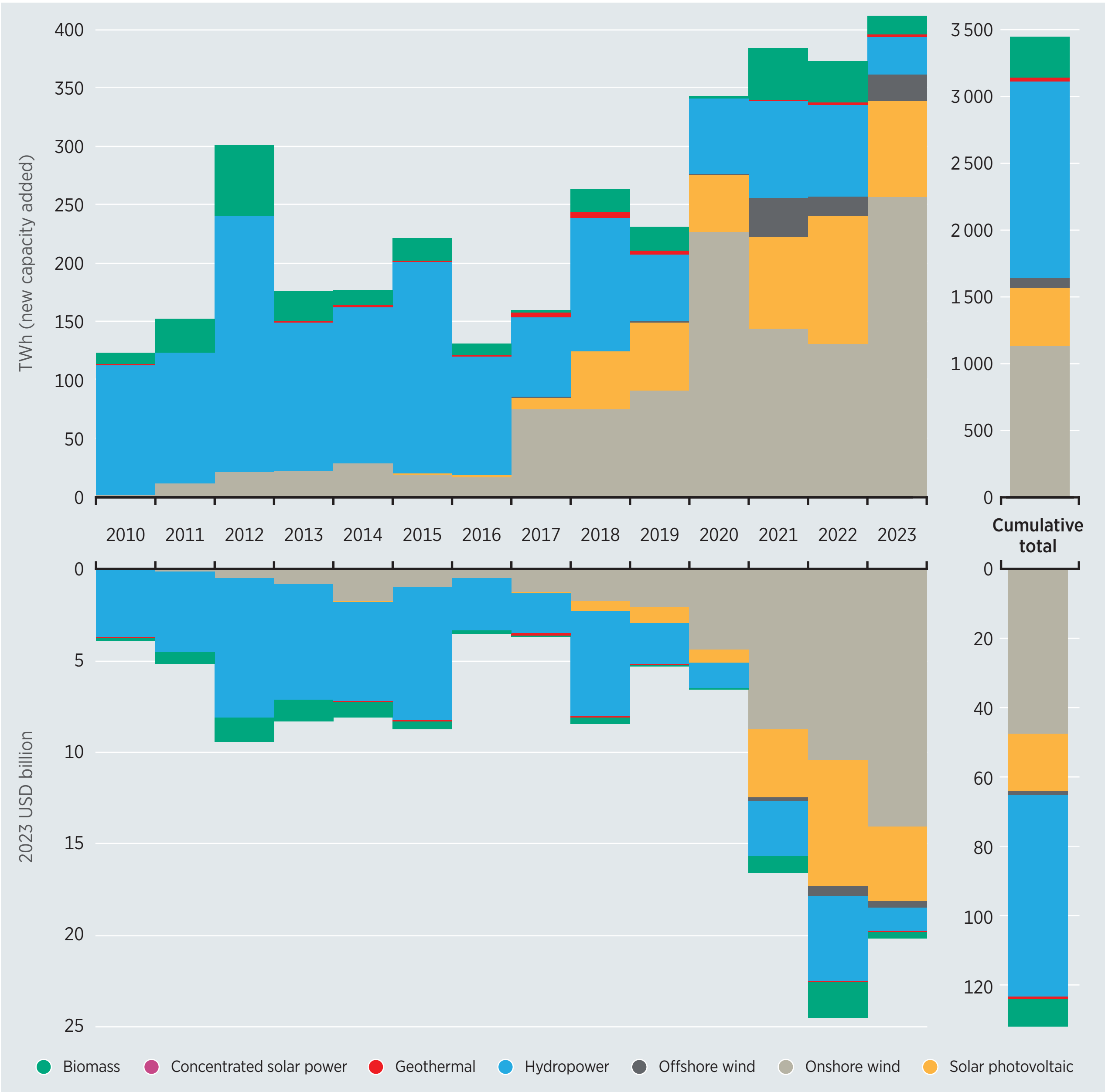
In non-OECD economies, where electricity demand is growing and new capacity is needed, the renewable power generation projects with LCOEs lower than the weighted average fossil fuel-fired LCOE for their country/region will significantly reduce electricity system costs over the life of their operation.

In 2023, in non-OECD countries, the 153 GW of projects with costs lower than the weighted average fossil fuel-fired LCOE will reduce costs in the electricity sector by at least USD 20 billion annually. The majority of these savings – a total of USD 14 billion – will come from onshore wind. Hydropower, with its higher capacity factors, contributes around USD 1.2 billion to these savings. With the increase in fossil fuel-fired generation costs, utility-scale solar PV accounts for USD 4.1 billion.

Globally, between 2010 and 2023, around 1 091 GW of renewable power generation capacity was added in non-OECD countries that had costs lower than the weighted average fossil fuel-fired LCOE in the year of commissioning. Of this total, 353 GW was hydropower (32% of the total), 366 GW was onshore wind (34%) and 295 GW was utility-scale solar PV (27%).

In 2023, this 1 091 GW of additional capacity could have reduced electricity system costs by as much as USD 132 billion. These estimated savings are dominated by hydropower, which likely contributed USD 58 billion, or 44%, of the total. With USD 47 billion in savings annually, onshore wind was likely the second largest contributor (36%), followed by solar PV, with USD 17 billion (13% of the total).

Figure 1.9 Renewable generation and net savings in non-OECD countries from new competitive renewable generation capacity added by year, 2010-2023



Note: TWh = terawatt hour.

Solar PV and wind power competitiveness

Initially, high costs created concerns about the competitiveness of solar PV and wind power technologies when compared to conventional energy sources. Since around 2013, however, the costs of onshore wind have dropped significantly enough to match or be lower than the weighted average fossil fuel-fired cost. At the same time, solar PV is also rapidly approaching this cost level.

Although the degree of improvement in competitiveness differs between solar and onshore wind power, in many markets, the increase in fossil fuel costs during 2021 and 2022 significantly amplified the competitiveness of these two technologies. Indeed, even when coinciding with lower fossil fuel prices – as in 2020 and 2023 – the costs of solar and wind power are now undoubtedly competitive.

For the analysis in Figures 1.10, 1.11, 1.12 and 1.13, the weighted average LCOE of fossil fuels for each year[17] is subtracted from the weighted average LCOE of solar PV and onshore wind, giving a metric on the competitiveness[18] of renewable power. Overall, this metric is influenced by LCOE trends and fossil fuel price fluctuations.

In 2014, Brazil became the first country to see the weighted average LCOE of new utility-scale solar PV fall below the weighted average cost of fossil fuel capacity added. Australia followed in 2016, with its excellent solar resources and high costs for new fossil fuel-fired power generation combining to make PV competitive. Italy saw a similar trend in 2017 and in 2018, Argentina, China, France, Germany, India, the Republic of Korea and the Philippines all reached the crossover point. In 2019, South Africa and Viet Nam achieved this milestone and in 2021, Canada, Indonesia, Japan, Mexico, the United Kingdom and the United States all achieved the same crossover. Except for Japan and the United Kingdom, these are all countries that have historically had very low fossil fuel prices. Finally, for the 20 countries examined, Malaysia and Türkiye saw the weighted average of their new utility-scale solar PV capacity additions in 2022 fall below the estimate of the weighted average fossil LCOE of newly-added capacity.

In 2023, among the countries shown in Figure 1.10, 18 out of 20 markets did not have a negative impact on the competitiveness metric, due to lower fossil fuel prices in 2023; their values remained negative, with solar PV less expensive than fossil fuel. However, the figure shows that the weighted average of their new utility-scale solar PV capacity additions in 2023 fell, when compared to 2022. In countries such as Argentina, Australia, Canada, Mexico and Viet Nam, the competitiveness of new utility scale solar PV projects continued an upward trend during 2023. In contrast, the United Kingdom and South Africa had slightly cheaper weighted average fossil LCOEs than solar PV.

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[17] This is weighted by deployment using the average realised fuel cost in that year from Figure 1.7 and with country-specific cost and capacity factor assumptions.

[18] Caution should be taken when interpreting the absolute levels and comparing countries using the competitiveness metric due to the appropriateness of the LCOE metric in different circumstances, especially, given the uncertainty around realistic 30-year price projections for fossil fuels.

The interaction between the declining weighted average utility-scale solar PV LCOE and the changes in annual weighted average new fossil fuel capacity additions varies by country and year. This results in differences in the competitiveness metric among countries. Figure 1.11 provides an alternative perspective on this data by illustrating the absolute annual change in the competitiveness metric (the difference between solar PV and fossil fuel LCOE).

The years with the most considerable absolute improvement in the difference between the weighted average LCOE of utility-scale solar PV and fossil fuels tended to be in the period 2010 to 2013, given the dramatic fall in solar PV module prices between 2010 and 2013. The exceptions were Argentina, Indonesia, the Philippines, Türkiye and Viet Nam, which commenced large-scale deployment only after this period had passed. As an example, the largest absolute improvement in utility-scale competitiveness was in Brazil in 2014, where the improvement in the year-on-year competitiveness metric between the LCOE of solar PV and fossil fuels was USD 0.32/kWh.

Looking at the change in competitiveness in 2023, when fossil fuel prices were back to historical levels, 5 of the 20 countries with data in Figure 1.11 saw a year-on-year improvement in competitiveness in USD/kWh that exceeded the weighted average LCOE of solar PV that year. This occurred in Australia, Argentina, Canada, Mexico and Viet Nam. In other countries, the improvement in competitiveness in USD/kWh reduced compared to 2022, but solar PV projects were still less expensive than the weighted average fossil fuel LCOE.


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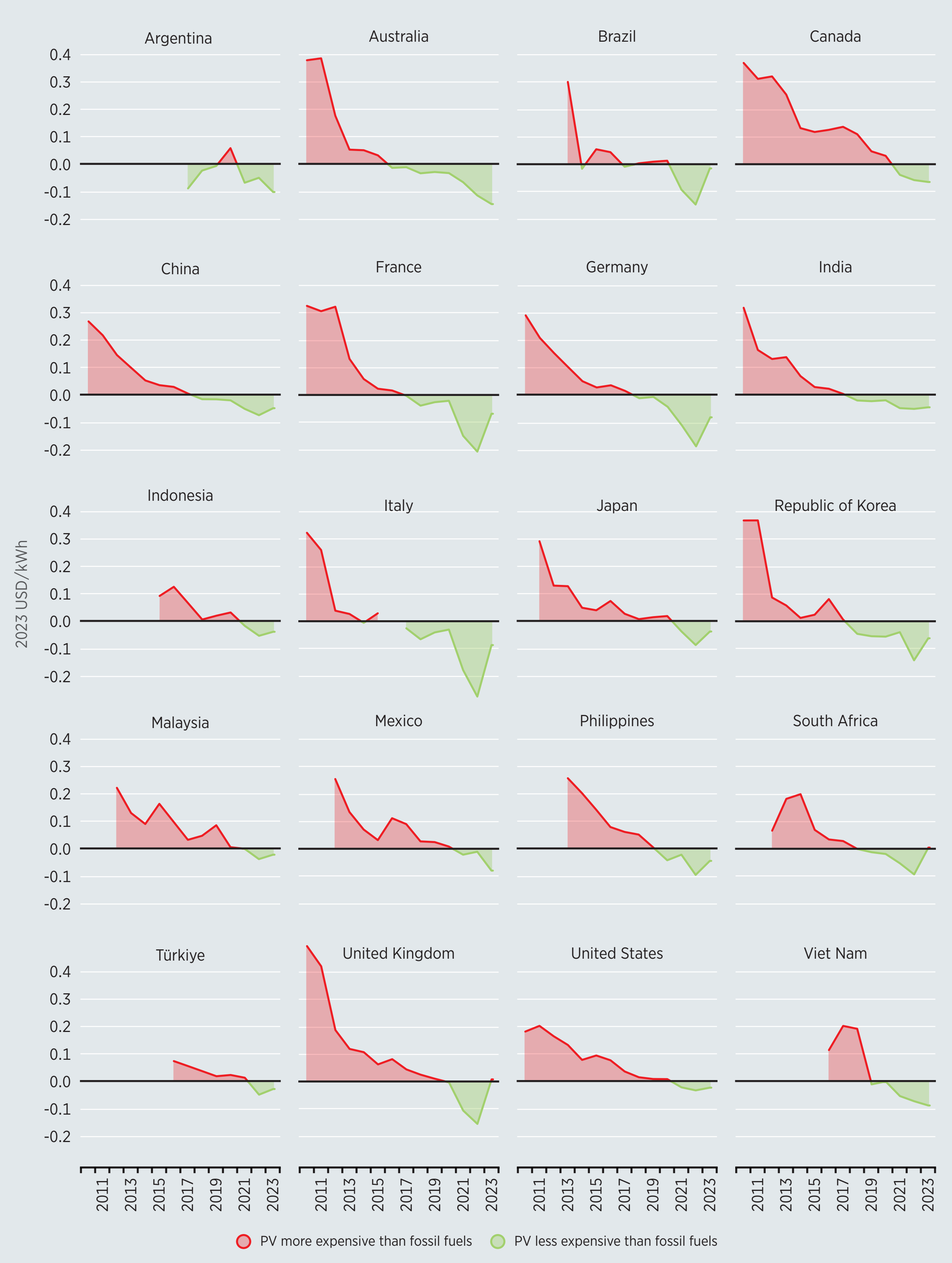
Figure 1.10 Competitiveness trends for utility-scale solar PV by country and year, 2010-2023



Note: The competitiveness metric is the weighted-average LCOE of renewable power minus the weighted-average LCOE of fossil fuels in that year.

Figure 1.11 Annual change in the competitiveness of new-utility scale solar PV capacity added by country and year, 2010-2023

Note: This metric is the annual change in the competitiveness metric in Figure 1.7. The dark green bar indicates the year of highest annual change in competitiveness.

Figure 1.12 presents the same competitiveness metric for onshore wind as in Figure 1.10, but with the difference that the weighted average new fossil fuel-fired LCOE by country is subtracted from that of onshore wind. In 2010, the global weighted average LCOE of onshore wind was USD 0.111/kWh, compared to USD 0.460/kWh for utility-scale solar PV. This resulted in a much closer difference between the two LCOEs. Nonetheless, an improvement in competitiveness is still evident in many of the countries in the sample. With costs rapidly falling into a range that was competitive with fossil fuel-fired power generation, annual changes in competitiveness have sometimes seen countries fluctuate above and below the zero line. This trend is less common in countries with sustained, significant deployment levels throughout the period, such as Australia, Brazil, China, Germany, India, Italy, Mexico, Türkiye, the United Kingdom and the United States.

Another impact of these lower starting costs and declines over time for onshore wind compared to utility-scale solar PV is that many countries experienced periods of often sustained competitiveness in the first half of the period. The exceptions were India, Indonesia, Mexico, the Philippines, South Africa and Türkiye.

The competitiveness of the onshore wind LCOE showed similar trends to solar PV. Following the reduction in fossil fuel prices in 2023, after the crisis in 2022, onshore wind competitiveness decreased in most markets. Countries that experienced an increase in competitiveness during the same period were Australia, Argentina and Canada, while Viet Nam remained flat, registering the same value in 2023 as in 2022. Except for Australia, Argentina, Canada and the Philippines, the other countries listed in Figure 1.13 reported positive values, reflecting a drop in competitiveness due to lower fossil fuel costs. Nevertheless, unlike solar PV, the weighted average fossil fuel LCOE remained higher than that for onshore wind in all 20 markets in 2023.


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Figure 1.12 Competitiveness trends for onshore wind by country and year, 2010-2023

Note: The competitiveness metric is the weighted-average LCOE of renewable power minus the weighted-average LCOE of fossil fuels in that year.

Figure 1.13 Annual change in competitiveness of new onshore wind capacity added by country an year, 2010-2023

Note: This metric is the annual change in the competitiveness metric in Figure 1.9. The dark green bar indicates the year of highest annual change in competitiveness.

Learning curves for solar and wind power technologies

The cost declines experienced by wind and solar power from 2010 to 2023 represent a remarkable rate of cost deflation. Significant advances have contributed to the decline, including technological improvements, reduced O&M costs and, in many countries, improved WACC. For solar PV, increased module efficiency has considerably reduced installed costs. Modules with higher efficiencies reduce the surface area needed and therefore the materials cost per watt for modules and the balance of plant costs. This is because the system area for the same power output is smaller. This dynamic is unique to solar PV. Onshore wind and offshore wind and CSP have all also seen technological improvements that enhance performance and increase capacity factors. In wind energy, the decline in turbine prices and balance of plant costs is driven by regional supply chain maturity, manufacturing innovations, competitive project procurement and lower O&M costs.

The learning curve is widely recognised as a tool for guiding policy design and assessing the implications of renewable energy on system transitions. A learning curve approach illustrates the relationship between cost reduction and technology performance improvement, highlighting how advances in technology and accumulated experience can drive down costs.

Figure 1.14 shows the global weighted average total installed trends for utility-scale solar PV, CSP and onshore and offshore wind from 2010 to 2023, plotted against deployment. This chart puts both these variables on a logarithmic scale (log-log). The slope of a straight line on a log-log chart therefore represents the learning rate for these technologies, which is the average cost reduction (in percentage terms) experienced for every doubling of cumulative installed capacity.

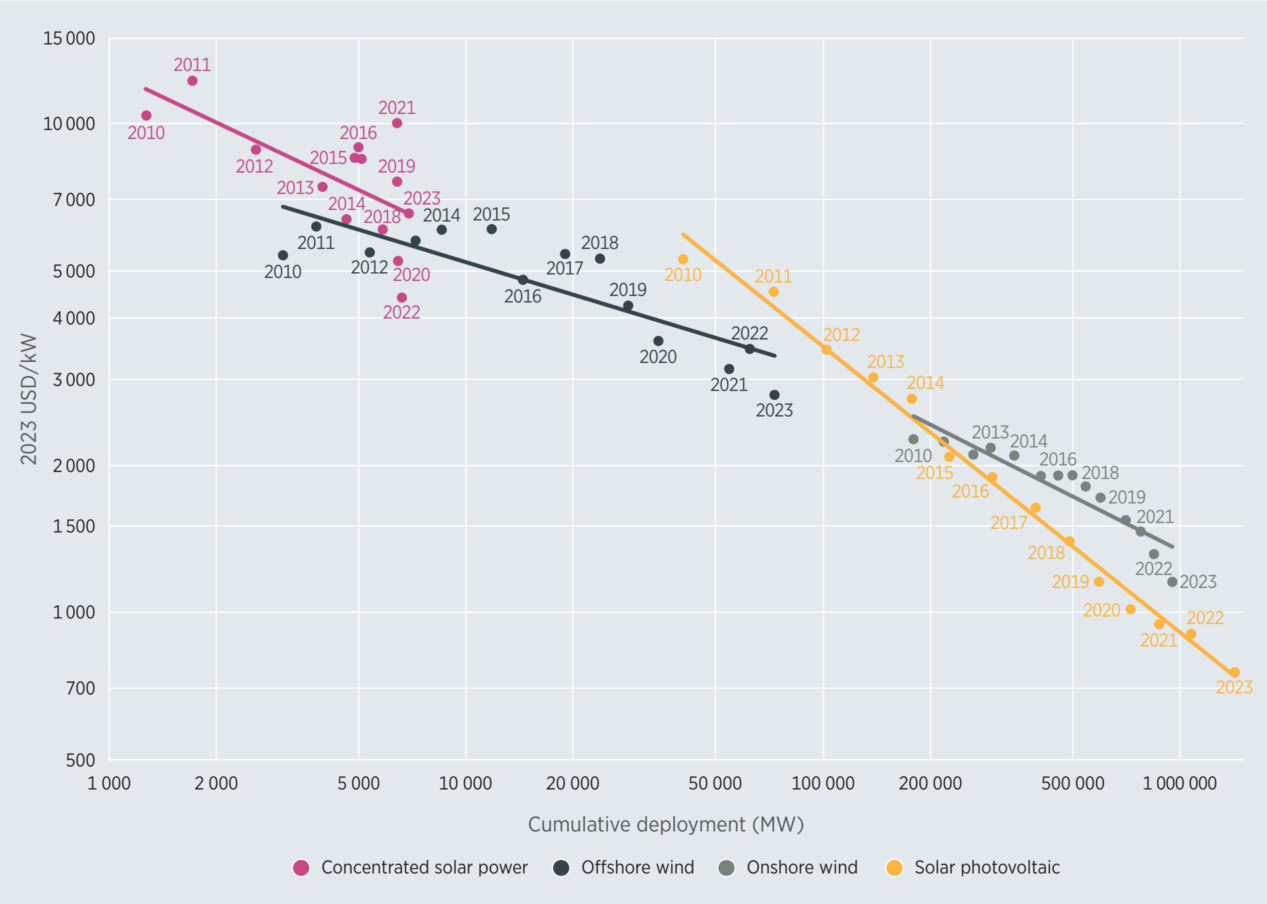
The period 2010 to 2023 is relatively brief, but over 70% of the world's accumulated renewable capacity was developed during this time (IRENA, 2024a). At a technological level, the rate values show similar patterns, with 98% of global cumulative installed solar PV capacity and virtually all the utility-scale deployments occurring during this period. For CSP, the rate was 89%, while for onshore and offshore wind the cumulative installed capacity shares of deployment were 84% and 97%, respectively.

From the period 2010 to 2023, utility-scale solar PV had the highest estimated learning rate for the global weighted average total installed cost. The learning rate of utility-scale solar PV was 33.4%. This was a value that exceeded virtually all previous learning rate analyses based on data for the earlier period of deployment (Grubb *et al.*, 2021), when learning rates might have been expected to be higher than in later periods.

During the same 2010-2023 period, onshore wind had the second highest estimated learning rate for the global weighted average total installed cost, at an estimated 22.6%. IRENA's data for onshore wind run from 1984, so the learning rate from then until 2023 is estimated to have been 8.6%. An apparent structural break in the data, however, poses interesting questions about the relative contribution made by early market research and development (R&D) learning, compared to ongoing innovation and industrial scale up, in driving down costs.

For CSP, the learning rate for total installed costs was 21.4%, with the figure for offshore wind estimated at 14.2% from 2010 to 2023. Over the period analysed, there was a downward trajectory in the costs associated with offshore and onshore wind, as well as solar PV. For CSP, the fluctuations of the last four years are also visible in Figure 1.14.

Figure 1.14 Global-weighted-average total installed cost learning curve trends for solar PV, CSP and onshore and offshore wind, 2010-2023



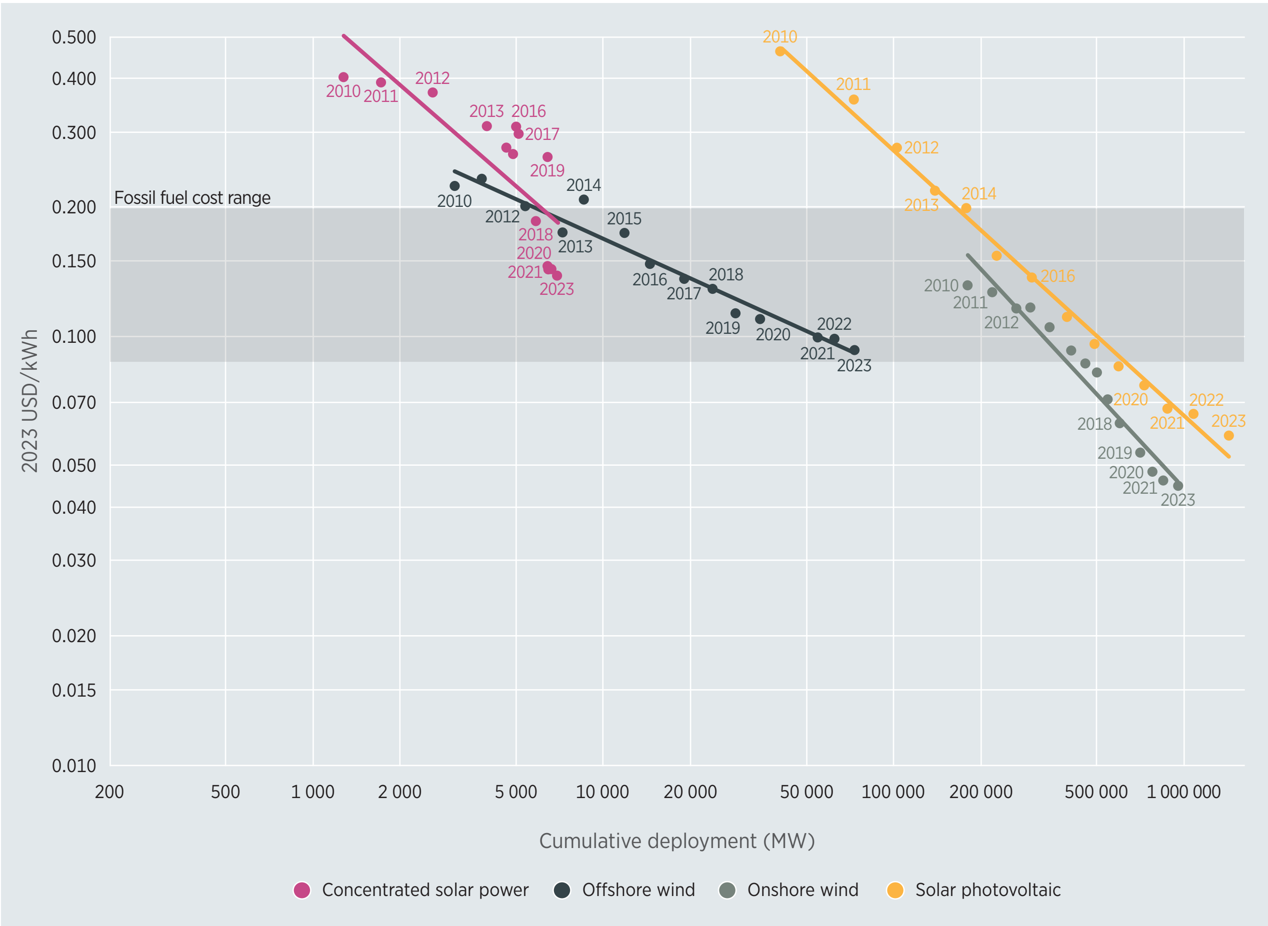
The learning rate for the LCOE is a function of how all the components in the LCOE calculation evolve over time. Following the same methodological approach for visualisation as before, Figure 1.15 shows the global weighted average LCOE learning curve trends for solar PV, CSP and onshore and offshore wind from 2010 to 2023.

The LCOE learning rate for solar PV is estimated to have been 38.5% between 2010 and 2023 – a figure around five percentage points higher than the learning rate for total installed costs. In contrast, the LCOE learning rate for offshore wind over the same period was 22% – an increase of more than half the learning rate for the total installed costs alone. For CSP, the LCOE learning rate was estimated to be 37.2%, which was almost twice the learning rate for total installed costs.

For the period 2010 to 2023, the recent LCOE reductions and relative slowing of cumulative capacity growth (in percentage terms) in onshore wind saw the LCOE learning rate reach a remarkable 43.7% during period up to 2022. This was in part driven by the better characterisation of the WACC for technologies by market, as well as the remarkable cost reductions in China and continued improvements in turbine technology. For the period 1984 to 2023, the learning rate was 22.6%, but again, there appears to be a structural break, with two periods of very different learning rates.

The implications of these high learning rates for solar and wind power should not be underestimated. In the power generation sector, they suggest that accelerated deployment will reduce the transition cost. Furthermore, they have a broader implication as well, suggesting that the characteristics of small,[19] modular technologies will facilitate the rapid manufacturing scale-up and cost reduction necessary to integrate other emerging solutions that contribute to the decarbonisation of various end-use sectors. These range from electrolysers to electric vehicles (EVs), heat pumps to stationary battery storage. Where similar possibilities for scale-up exist, policy makers can have greater confidence that costs will fall rapidly, enabling them to be more ambitious in their policy goals.

Figure 1.15 Global weighted-average LCOE learning curve trends for solar PV, CSP and onshore and offshore wind, 2010-2023



[19] *Small in this context refers to the ability to manufacture large quantities. This is clearly true for solar PV panels, but also true for large, multi-MW wind turbines when compared to fossil fuel plants and todays nuclear.*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Renewables represent energy savings

Globally, the renewable power generation deployed between 2010 and 2023 reduced electricity sector fuel costs by an estimated USD 409 billion[20] (Figure 1.16), assuming marginal supplies would have been sourced at spot market prices.[21] The fuel cost reduction was almost USD 212 billion in Asia and USD 88 billion in Europe. South America also benefitted, with savings potentially in the order of USD 53 billion.

Looking at Asia, annual savings in 2023 were USD 29 billion, 3.5 times higher than in 2010. Indeed, in recent years, Asia has been one of the main drivers in renewable energy deployment. In Europe, savings increased 1.75 times in the same period, rising from USD 4 billion in 2010 to USD 7 billion in 2023. Savings in Africa were more modest, at USD 1 billion, and have remained flat for the past 13 years, even though the continent is home to almost 20% of the global population.

Overall, the largest savings contributions were from solar PV (USD 20 billion) and onshore wind (USD 19 billion). These two represented 87% of the total savings, demonstrating that trends in capacity additions are not evenly distributed.

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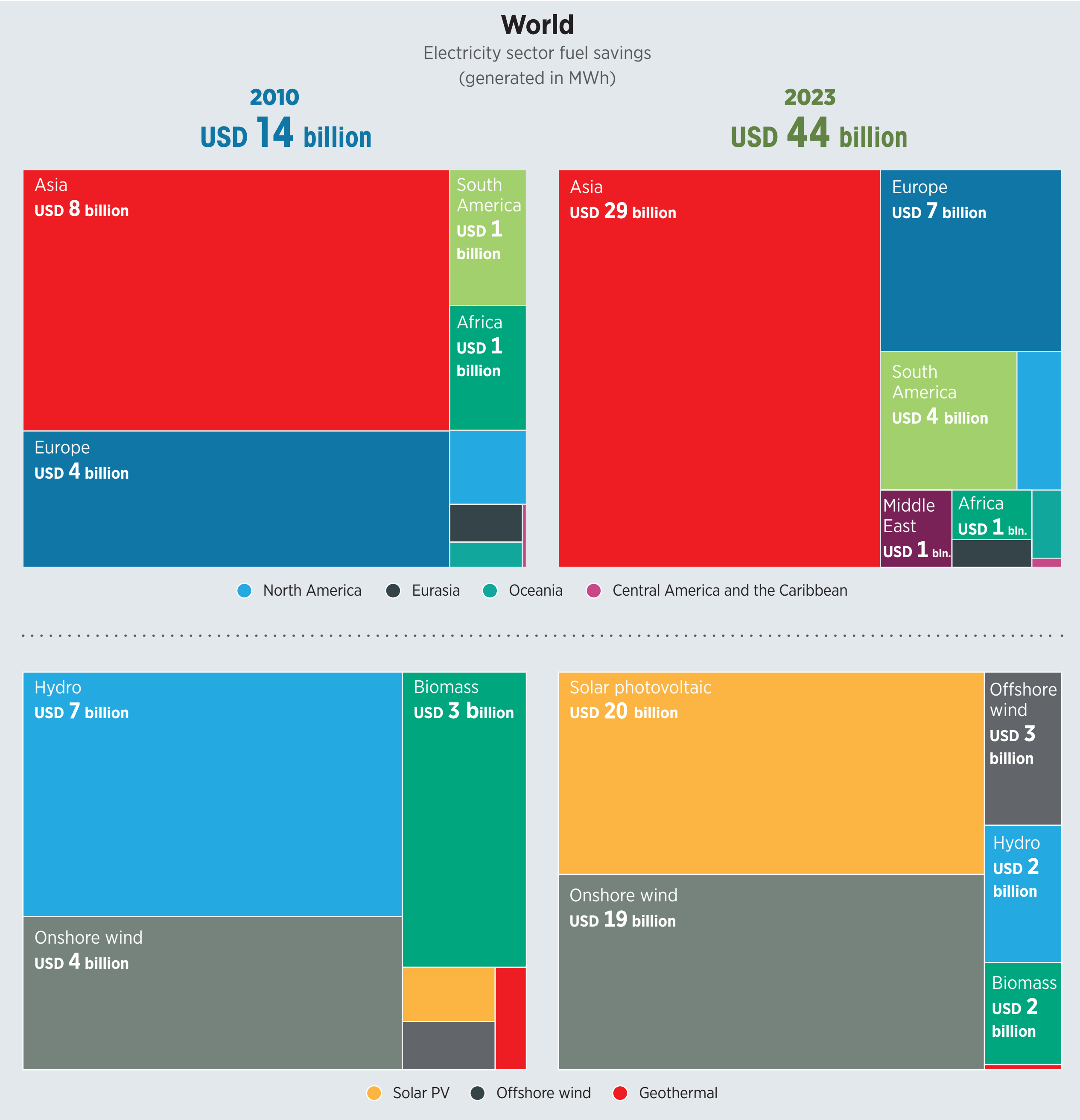
[20] This excludes the LCOE of the renewable technologies – that is to say, the cost of unlocking those fuel savings. Subtracting the renewable projects' LCOE from the fuel savings would not yield the true "net savings", however. This is because this would exclude the reduced O&M and capital costs from reduced fossil fuel use, which are included, for instance, in Figure 1.9. This analysis is given solely in order to understand the fossil fuel cost reduction, and hence imports in importing countries and regions.

[21] This estimate is designed to give an order of magnitude of the benefits of renewable power generation in 2023. The additional fossil fuel demand would have been very significant and the impact of the crisis in that hypothetical world cannot be known with any certainty.

Figure 1.16 Global annual fuel savings in the electricity sector from new deployment of renewable power generation in 2010 and 2023

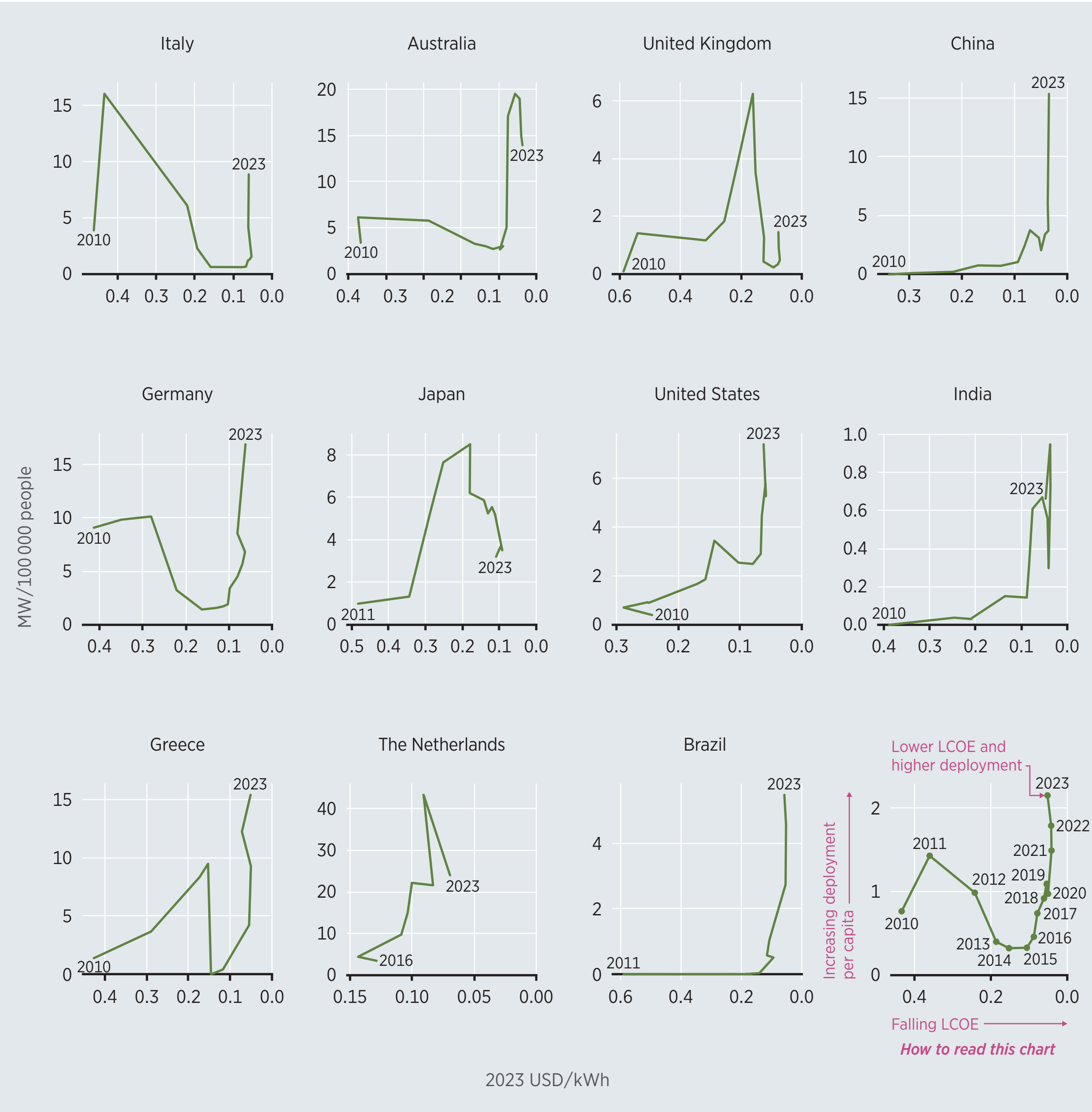


Note: This figure is based on project-level LCOE data for renewables and generated fossil fuel costs.

Looking at the per capita PV additions, apart from the significant variation between countries, major markets registered upward trends and records in 2023 (Figure 1.17). This was the case in China, the United States, Greece, Germany and Brazil. European countries had the highest deployment per capita in megawatt terms. This included Germany, which added 16.9 MW per 100 000 population, followed by Greece, with 15.4 MW. Netherlands experienced a different pattern, with a year-on-year reduction. However, the country still set the record, with 24.1 MW added per 100 000 population. India also experienced a decline in per capita additions, which fell from 0.9 MW added per 100 000 population in 2022 to 0.7 MW in 2023.

The competitiveness of renewables continued to improve in 2023. The year was pivotal for the energy transition in terms of cost decreases and new added capacity. Despite this background, it remains clear that more effort is required to accelerate renewable power generation deployment across different technologies and regions to meet the goals set by the tripling pledge made at COP28. An imbalance exists while renewable power additions are dominated by solar PV and onshore deployment in Asia. It is time to strategically realign policy and regulatory architecture to facilitate targeted investments across the world, prioritising populated regions and countries with limited potential to attract global funds, while ensuring grid planning and expansion to guarantee alignment with capacity growth.

Figure 1.17 Changes by country in annual new solar PV capacity additions per capita compared to LCOE trends, 2010-2023



Source: World Bank (2023).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02 ONSHORE WIND

HIGHLIGHTS

Between 2010 and 2023, the global weighted average levelised cost of electricity (LCOE) of onshore wind fell 70%, from USD 0.111/kWh to USD 0.033/kWh; 3%, year-on-year. In 2023, all 104 GW of onshore wind projects commissioned had electricity costs that were lower than the weighted average fossil fuel-fired LCOE by country/region. The increase in new added capacity of onshore wind in China represented 63% of global annual onshore additions, driving the decline.

The global cumulative capacity of onshore wind increased more than fourfold during the 2010 to 2023 period, from 178 GW to 944 GW.

The global weighted average total installed cost of onshore wind fell 49% between 2010 and 2023, from USD 2 272/kW to USD 1160/kW. In 2023, this figure was down 12% on its 2022 value. The fall was driven by continued cost declines in China, which was the first market worldwide to achieve a cost bellow USD 1000/kW, at USD 986/kW.

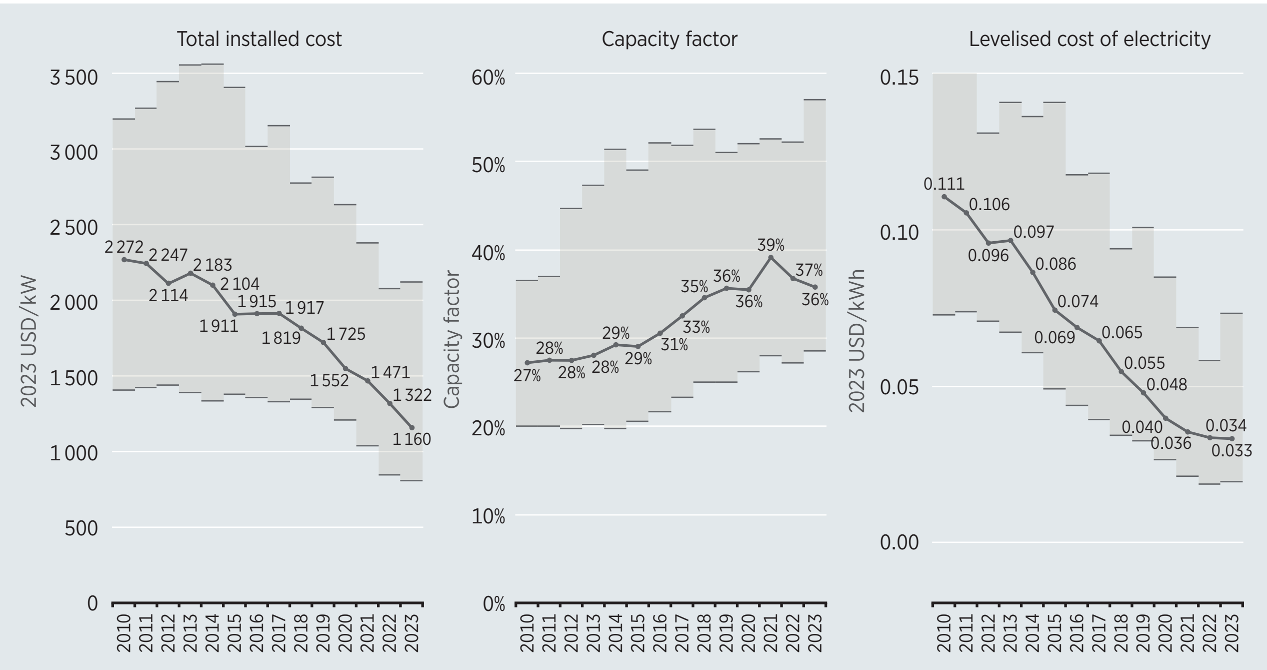
India, Sweden, the United States and a host of smaller markets saw cost increases in 2023, as higher turbine prices outside China impacted project costs.

In 2023, the country weighted average for the 15 markets IRENA has long-term data for saw the total installed cost for onshore wind range from around USD 986/kW to USD 1746/kW, with Japan an outlier at USD 2384/kW (Figure 2.5). Brazil and China had installed costs lower than the global average.

In 2023, average onshore wind turbine prices (excluding China) ranged between USD 706/kW and USD 1040/kW. This was materially lower than in 2022 (Figure 2.3). By 2023, prices in most regions (excluding China) had fallen by between 41% and 64% from 2010 values. In China, by 2023, wind turbine prices had fallen 73% since their 2010 value of USD 884/kW to an average of just USD 233/kW.

Technological improvements have resulted in a more than one-third improvement in the global weighted average capacity factor of onshore wind, which rose from 27% in 2010 to 36% in 2023.

Figure 2.1 Global weighted average and range of total installed costs, capacity factors and LCOEs for onshore wind, 2010-2023



INTRODUCTION

Over the past decade, onshore wind turbine technology has undergone some remarkable advances. In 2023, around 104 GW of onshore wind capacity net additions were installed globally, marking a 48% increase compared to the previous year. The extent of onshore wind deployment was second only to that of solar photovoltaic (PV). China remained the largest market, accounting for 66% (69 GW) of the total added capacity that year, more than doubling its newly-installed capacity in 2022 (32.9 GW). Two other markets – the United States and Brazil – experienced contrasting trends, with the United States' added capacity decreasing 27% compared to 2022. Indeed, 2023 was the lowest year for wind deployment in the United States since 2017. Brazil, meanwhile, achieved a record yearly installed capacity of 5 GW. In Europe, Germany boosted 2023 net additions with 3 GW and became the country with the highest added capacity in the region (IRENA, 2024a).

The onshore wind energy sector has experienced significant expansion due to several key factors. The deployment of larger and more reliable turbines, higher hub heights and larger rotor diameters have all significantly enhanced capacity factors. Furthermore, in addition to technological improvements, economies of scale, heightened competitiveness and the growing maturity of the sector have led to falling total installed costs O&M costs, and LCOEs.

The year 2023 was outstanding, with over 100 GW of onshore wind energy deployed. The factors mentioned above significantly contributed to this achievement, while there was also a growing ambition to increase wind energy's share. Continued technological acceleration is therefore crucial, as are several other factors. These include: addressing challenges such as market volatility; supply chain constraints; permitting timelines; system infrastructure; regulatory arrangements; grid availability; and land availability.[22]

WIND TURBINE CHARACTERISTICS AND COSTS

The total installed cost of an onshore wind project consists of several components, with wind turbines accounting for the largest share of the total – between 64% and 84% (IRENA, 2018). Virtually all onshore wind turbines today are horizontal axis, predominantly using three blades and with the blades upwind.[23] Contracts for these projects typically involve the towers, installation and – except in China – delivery. The other major cost categories include installation, grid connection and development costs. The latter also covers environmental impact assessments and other planning requirement costs, project costs and land costs, with these representing the smallest share of total installed costs.

Wind turbine original equipment manufacturers (OEMs) offer a wide range of designs, catering to different site characteristics,[24] grid accessibility and policy requirements in distinct locations. These variations may also include different land-use and transportation requirements, as well as the technical and commercial requirements of the developer. Additionally, data analytics and advanced layout optimisation offer tailored configurations for individual sites, which amortise product development costs over a larger number of turbines and optimise turbine selection, further reducing the LCOE.

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[22] Most likely in small countries, where repowering and/or installing turbines is dependent on technology development.

[23] Meaning that the rotor blades are facing the wind.

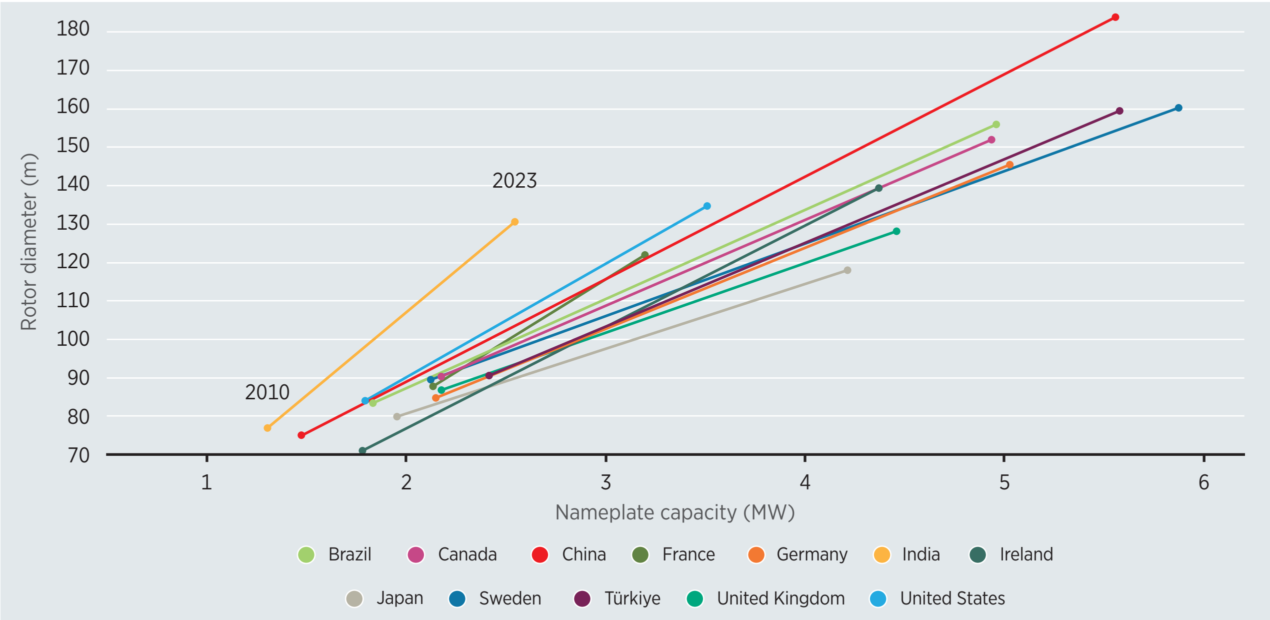
[24] Such as different wind speeds, areas for adequate spacing to reduce wake turbulence and turbulence-inducing terrain features.

Turbines with larger rotor diameters increase energy capture,[25] particularly for wind speeds between cut-in and rated power. This is especially useful in exploiting marginal locations where wind speed distribution does not predominantly fall within the rated power range. In addition, higher hub heights allow access to higher wind speeds at the exact location and increase the range of suitable locations for wind turbines. For instance, a taller hub height means an increased distance between the blade tips and the ground, enabling installation in some forested regions; as turbulence and shear effects decrease with height, the result is higher wind speeds and, therefore, higher capacity factors, given that power output increases as a cubic function of wind speed. The higher turbine capacity also enables more extensive projects to be deployed and reduces the total installed cost per unit for some cost components.[26]

Figure 2.2 illustrates the evolution in weighted average turbine rating and rotor diameter between 2010 and 2023 in some major onshore wind markets. China, Ireland, Brazil, Sweden and Türkiye stand out, with increases of greater than 75% in average rotor diameter of their commissioned projects over the period. In percentage terms, the largest increases in rotor diameter were observed in China (145%), followed by Ireland (96%), Brazil (87%), Sweden (79%) and Türkiye (76%). The largest increases in turbine capacity occurred in China (278%), Sweden (177%), Brazil (171%), Ireland (146%) and Germany (134%).

Of the countries covered in Figure 2.2, in 2023, Sweden had the largest turbine rating, at 5.8 MW, while for the data available, China had the largest turbine rotor diameters, at 184 metres. In 2023, India had the lowest turbine rating, at 2.5 MW, while Japan had the lowest average rotor diameter, at 118 metres. Overall, in 2023, the country weighted average turbine capacity ranged from 2.5 MW to 5.8 MW. This was substantially higher at the upper end than the 2.6 MW to 4.8 MW recorded in 2022. In 2023, the country weighted average rotor diameter ranged from 118 metres to 184 metres. This was materially greater at both ends than the 105 metres to 163 metres recorded in 2022.

Figure 2.2 Weighted average onshore wind rotor diameter and nameplate capacity evolution, 2010-2023



[25] *Energy output increases as a function of the wind speed, air density, power coefficient and the swept area of the blades, with these being key variables in the power output of a wind turbine.*

[26] *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 2.3 illustrates the wind turbine price indices and price trends for the period 1997-2023. Wind turbine prices reached their previous low between 2000 and 2002, followed by a sharp rise. Most markets experienced that peak between 2007 and 2010. This was attributed to higher commodity prices (particularly cement, copper, iron and steel) and supply chain bottlenecks. Additionally, increased government support for renewable energy policies boosted wind deployment. This period, however, also coincided with a significant mismatch between high demand and tight supply, which enabled significantly higher margins for OEMs during this time. Yet, as the supply chain became deeper and more competitive and manufacturing capacity grew, these supply constraints eased, and wind turbine prices peaked. Annual average prices started to fall again in 2011. From 2010 to 2023, average prices (excluding China) fell by between 41% and 64%.

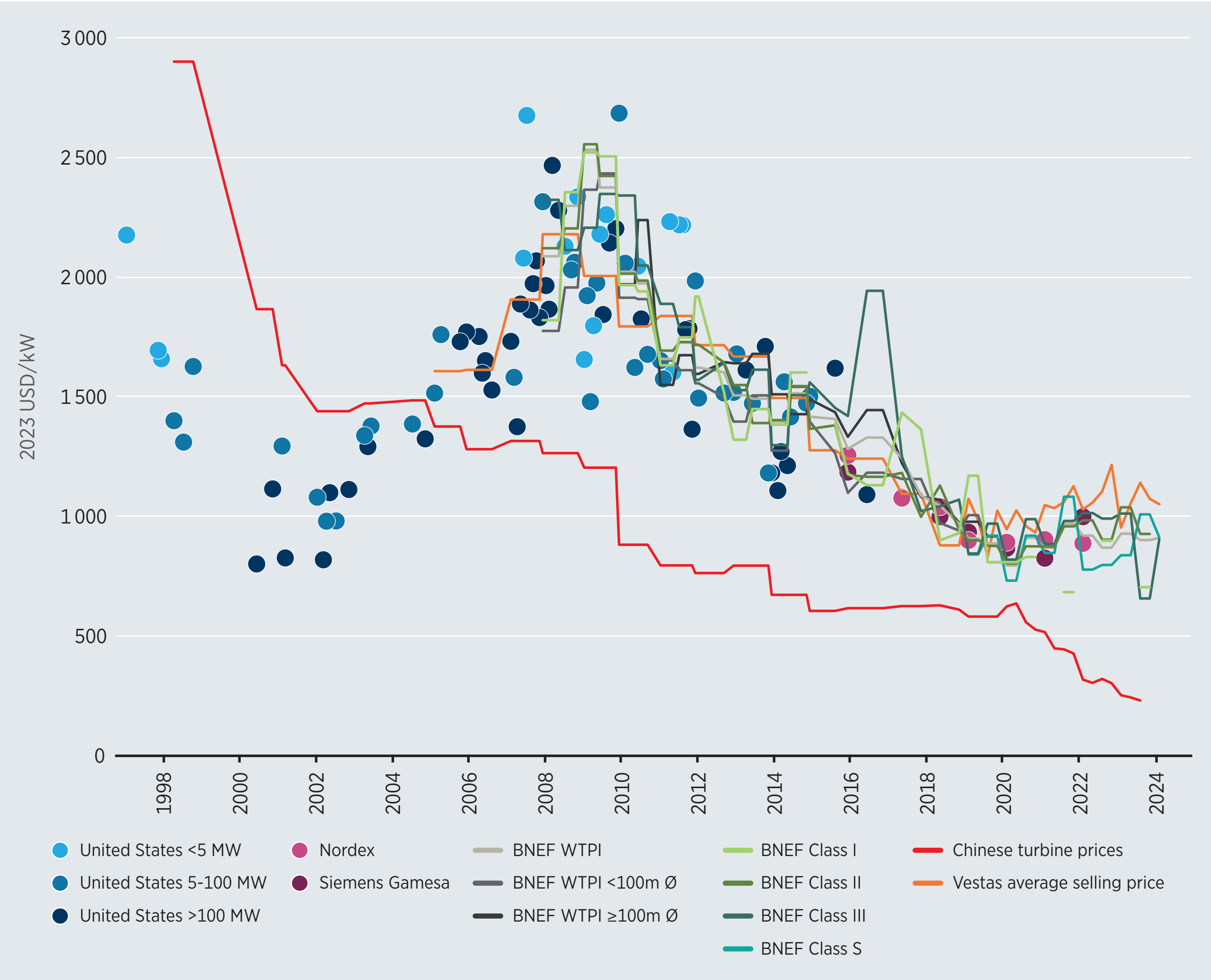
In 2023, quarterly prices were in the range of USD 706/kW to USD 1 040/kW in most major markets, excluding China (Figure 2.3). In China, where wind turbine prices have dramatically fallen from their 1998 peak of around USD 2 800/kW, the decline has been irregular and stepwise. China's turbine market continues to move at its own rhythm and is not comparable to the rest of the world, given that contracts often exclude delivery, installation and even towers. This intense price pressure on manufacturers means they have not been able to increase prices over the past few years. In 2023, average Chinese wind turbine prices fell steadily throughout the year, reaching around USD 233/kW in the third quarter. This marked a 24% reduction compared to the same quarter in 2022, as ongoing pressures from developers continued to drive prices down.

Globally, 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, probably needed to rise and 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).

The increased competition does not make the sector immune from the impact of supply and demand imbalances. The market saw significant growth in 2020, but supply chain constraints due to COVID-19 caused wind turbine pricing to increase in late 2020 and early 2021. Elevated prices continued into 2022 as global commodity prices, notably steel, increased with the crisis in Ukraine. In 2023, prices fluctuated, with Vestas's selling price dropping initially, increasing mid-year, and decreasing again by year-end. This fall then continued, with a slight dip in the first quarter of 2024 due to changes in the geographic location of orders (Vestas, 2023). Additionally, in the second half of the year, BNEF values decreased, influenced by the increased share of Class S turbines in the market (BNEF, 2023a). Furthermore, Vestas and Goldwind saw positive profit margins, indicating a potential return to profitability in 2024 (Wood Mackenzie, 2024).

Wind turbine costs have decreased globally over the last decade despite an increase in rotor diameters, hub heights and nameplate capacities. In 2019, the price gap between turbines with differing rotor diameters narrowed significantly. However, by late 2020, the price difference between Class I and both Class II and Class III[27] wind turbines widened, with this continuing into 2022 and the beginning of 2023. In the second half of 2023, prices for Class I, Class II and Class III turbines decreased, with Class I and Class III experiencing a more significant drop, while prices for Class S turbines increased, reflecting the pattern in market share.

Figure 2.3 Wind turbine price indices and price trends, 1997-2023



Source: Vestas (2024); BNEF (2023); Wiser *et al.* (2023) and Wood Mackenzie (2023).

[27] *This refers to the International Electrical Commission (IEC) 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 square metre) are used to harvest the maximum energy. Class S wind turbines are designed to meet specific site conditions and requirements that fall outside the standard classification.*

TOTAL INSTALLED COSTS

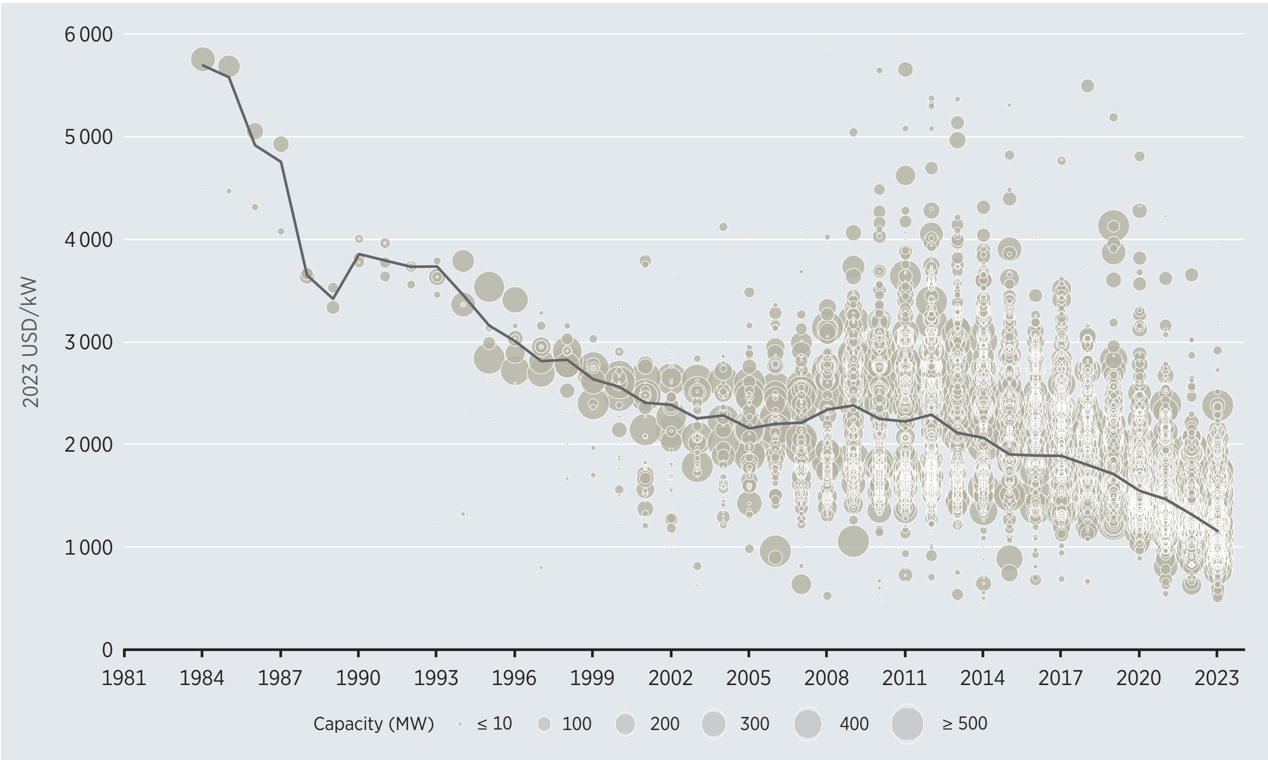
Between 1984 and 2023, the global weighted average total installed cost of onshore wind projects fell by 80%, from USD 5 698/kW to USD 1 154/kW, according to data from the *IRENA Renewable Cost Database* (Figure 2.4). Between 2010 and 2023, the global weighted average total installed cost of onshore wind fell by 49%, from USD 2 272/kW to USD 1 160/kW, with a 12% decline year-on-year in 2023. This decline was driven by wind turbine price and balance-of-plant cost reductions.

The installed costs of individual projects within a country or region can vary widely. This variability is driven by differences in country and site-specific requirements, such as logistics limitations for transportation, local content policies, land-use restrictions, labour costs and other factors.

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 74% in the United States to just 12% in Japan. These comparisons need to be treated with caution, however, given the differing start dates for the first available data. In Japan, for example, the first cost data point is in 2000, while data from some other countries goes back to the start date of 1984.

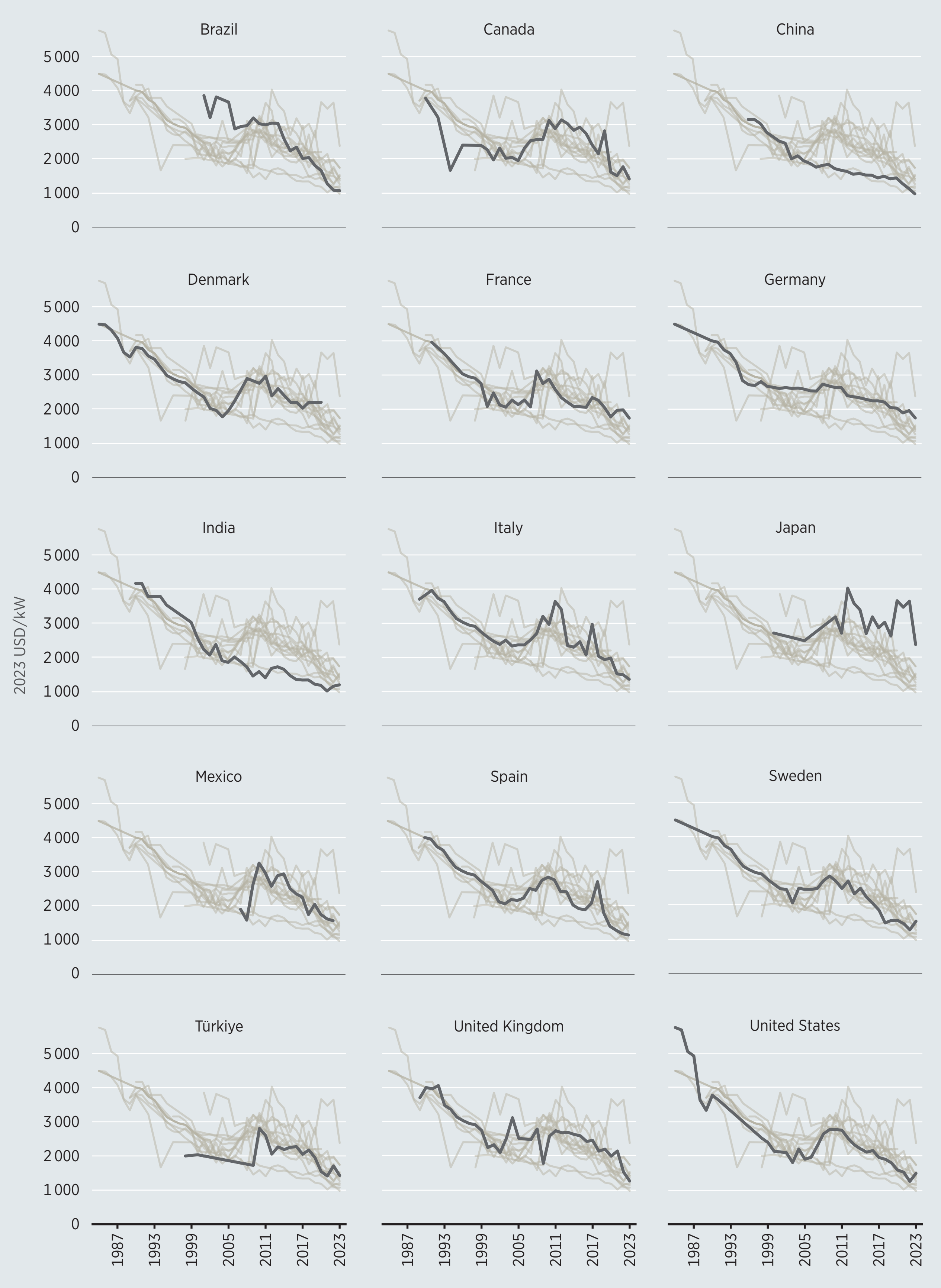
The more competitive, established markets show larger reductions in total installed costs over longer time periods than newer markets. The United States shows a 78% reduction, followed by Brazil, India and Spain (all with reductions within the 71%-72% range). These countries had the largest decrease in total installed costs over their respective time frames. China, meanwhile, saw a reduction of 69% and Sweden a reduction of 66%.

Figure 2.4 Total installed costs of onshore wind projects and global weighted average, 1984-2023



Source: Vestas (2024); BNEF (2023); Wiser *et al.* (2023) and Wood Mackenzie (2023).

Figure 2.5 Total installed costs of onshore wind projects in 15 countries, 1984-2023



Note: Lines represent all 15 markets, with the one in bold corresponding to the market identified at the top of each graph.

From 2010-2023, the trend significant cost reductions in mature markets remained consistent. For instance, Brazil, Spain and Canada had reductions of 55% or more during this period. Between 2022 and 2023, Canada experienced the highest reduction, at 20%. However, a few countries, like the United States, saw increased costs, with a 19% year-on-year rise. This increase was driven by higher interest rates, supply chain constraints and challenges in grid interconnection, resulting in a slow year for installed capacity in the United States. Nonetheless, the Inflation Reduction Act could advance the US wind sector by facilitating the delivery of new clean power, establishing local supply chains and providing jobs and society-wide benefits (GWEC, 2024).

Data at the regional level (Table 2.1) show that the regions with the highest weighted average total installed costs in 2023 were (in descending order): Other Asia, Central America and the Caribbean, Africa, Eurasia, Oceania, Europe, Other South America and North America. Significant convergence has been observed in weighted average installed costs across regions, ranging from USD 1 484/kW to USD 2 019/kW. Notably, several regions are clustered around the USD 1 600/kW mark, reflecting a pattern towards uniform and competitive pricing in the onshore wind sector.

Table 2.1 Total installed cost ranges and weighted averages for onshore wind projects by country/region, 2010 and 2023

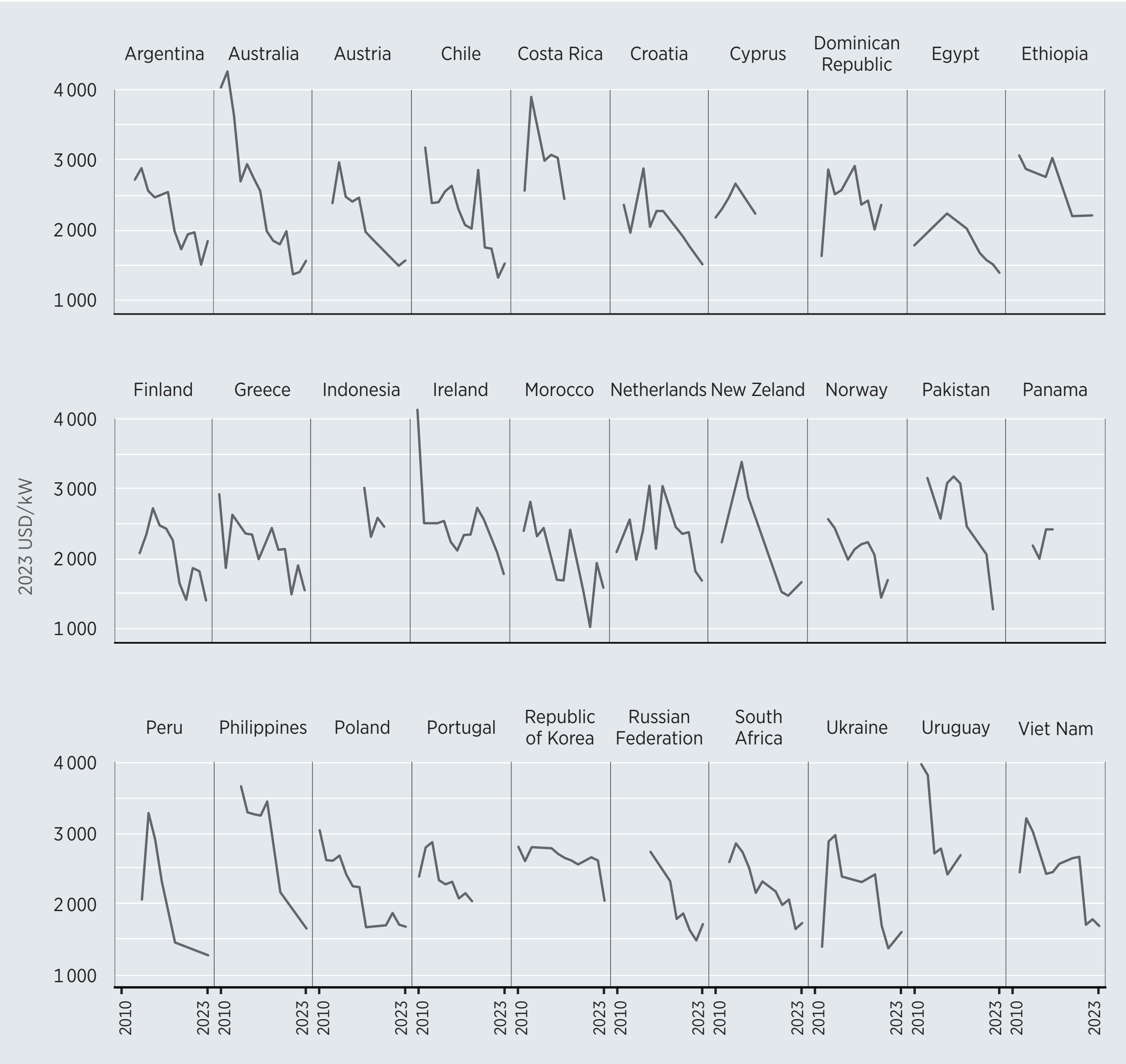
	2010			2023		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2023 USD/kW)					
Africa	1 586	**1 792**	2 343	1 432	**1 614**	1 988
Central America and the Caribbean*	3 079	**3 079**	3 079	1 757	**1 757**	1 757
Eurasia	2 811	**2 811**	2 811	821	**1 611**	2 140
Europe	2 035	**2 791**	4 067	1 092	**1 583**	2 213
North America	2 177	**2 844**	3 693	1 116	**1 484**	2 120
Oceania	3 523	**4 046**	4 449	1 349	**1 610**	1 753
Other Asia	2 130	**2 891**	3 173	1 379	**2 019**	2 439
Other South America**	1 659	**2 462**	3 853	1 083	**1 563**	2 044
Brazil	3 034	**3 034**	3 034	641	**1 079**	1 590
China	1 454	**1 724**	2 018	799	**986**	1 392
India	1 032	**1 594**	1 856	961	**1 208**	1 435

Note: see Annex III for regional country groupings.
* Countries where data were only available for projects commissioned in 2021, not 2023.
** Countries where data were only available for projects commissioned in 2012, not 2010.

Brazil, China, and India, as mature markets, typically have lower cost structures than other countries. In 2023, this was reflected in their average installed costs for onshore wind. China emerged as the most competitive market, achieving a weighted average installed cost below USD 1000/kW for the first time in any market, with a cost of USD 986/kW. China surpassed Brazil's first position in 2022, which had a 2023 value of USD 1079/kW. China saw a 14% decrease in installed cost year-on-year, while Brazil experienced a 1% decrease. Other competitive markets including Spain (USD 1158/kW) and India (USD 1208/kW), showcased competitive weighted average new capacity additions in 2023.

Figure 2.6 shows the weighted average total installed costs trend in smaller markets. In 2023, countries like Australia, Austria, Chile, Croatia, Egypt, Finland, Greece and Peru had competitive costs of around USD 1500/kW. Australia stands out for having the highest reduction from 2010 to 2023, at 61%. Australia did, however, experience an 11% rise in 2023, year-on-year.

Figure 2.6 Onshore wind weighted average total installed costs in smaller markets by country, 2010-2023



CAPACITY FACTORS

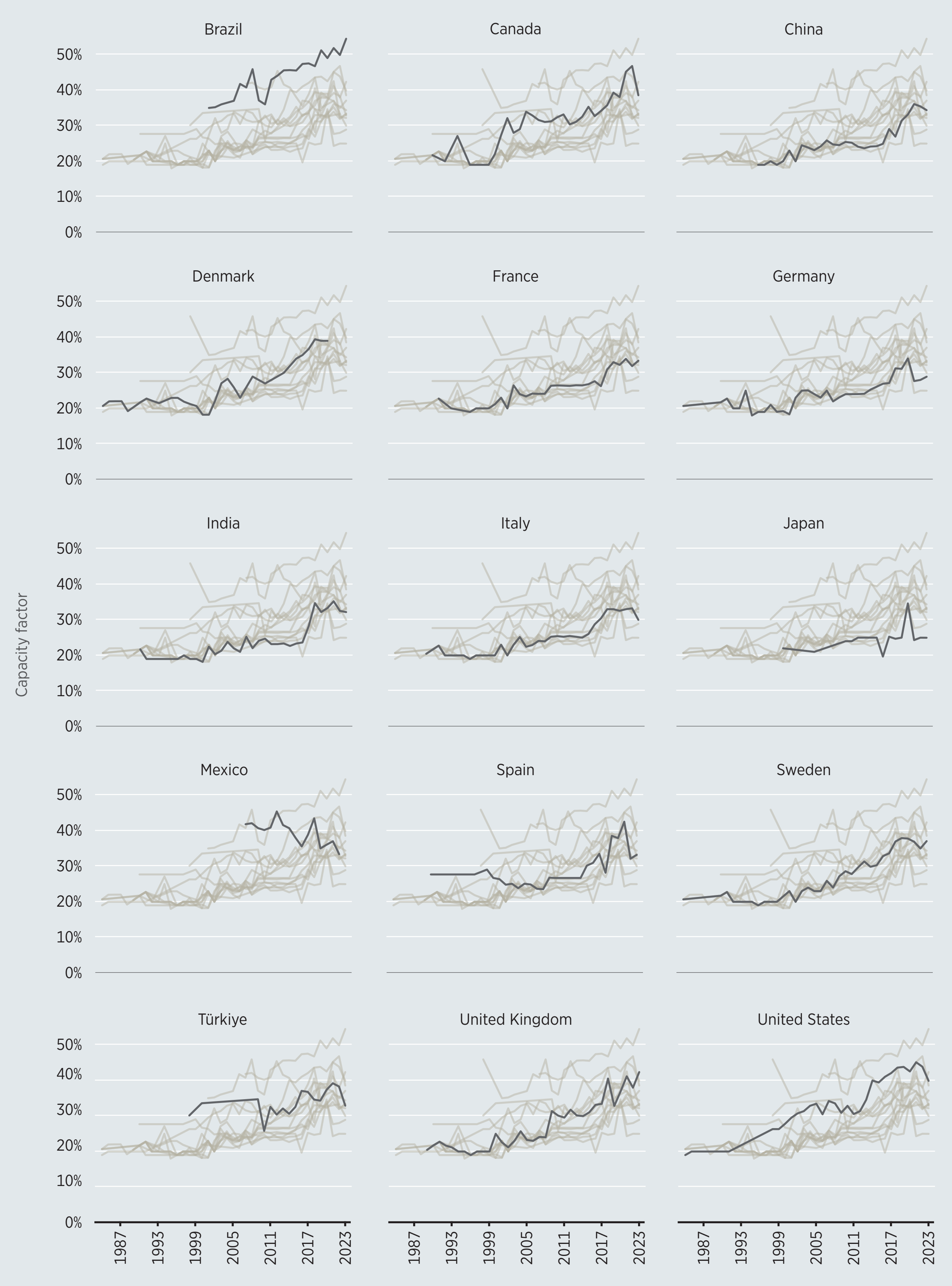
The capacity factor indicates annual energy output, expressed as a percentage of theoretical maximum output. The capacity factor of a wind farm is predominantly determined by two factors: the wind resource where the wind farm is located and the turbine and balance-of-plant systems used.

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 10 years. Indeed, the global weighted average capacity factor for onshore wind increased by 89% between 1984 and 2023, from around 19% in the former year to 36% in the latter. This upward trend was also observed during the 2010 to 2023 period. During those years, the global weighted average capacity factor of onshore wind increased by 33%, from 27% to 36%.

The global weighted average capacity factor for newly-commissioned onshore wind was lower in 2023 than 2022, as a range of markets saw capacity factors fall. This outcome was not unexpected after 2021 – a year marked by exceptional deployment in countries and regions with excellent wind resources, notably the United States and Latin America. Additionally, China's share of global deployment significantly decreased in 2021, while its share of new capacity-added increased in 2022 and 2023. Furthermore, projects were more evenly distributed, worldwide, across lower wind resource locations closer to population centres to mitigate transmission constraints (Wood Mackenzie and American Clean Power Association, 2024).

Ongoing advances in technology, including improved aerodynamic profiles, larger turbines, higher hub heights and expanded swept areas, were significant parameters in the capacity factor outcome (Figure 2.2). Nevertheless, the global distribution of deployment and varying wind resources lead to different local capacity factors, which in turn influence the global weighted average capacity factor. At the same time, even though technological improvements have raised output across the board, not all capacity factor improvements result from advances in turbine technology. The different technologies and different site configurations also impact, albeit to a lesser degree, with differing wind resources continuing to be the dominant factor. Advances in remote sensing and computing have facilitated improvements in wind resource characterisation, however, as has the siting of turbines to minimise wake losses and enhance asset performance. Consequently, these advances have enabled the selection of optimal wind sites and layouts for maximising energy output.

Figure 2.7 Onshore wind weighted average capacity factors for new capacity in 15 countries, 1984-2023



Note: Lines represent all 15 markets, with the one in bold corresponding to the market identified at the top of each graph.

Figure 2.7 depicts the historical evolution of onshore wind capacity factors for newly-commissioned projects[28] in each year across the 15 markets where IRENA has the longest time series data. The figure shows that for the 15 countries examined, average capacity factors increased by just over half. The start dates for commercially deployed projects vary, 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 2023, capacity factors increased 110%. Elsewhere, in Canada, China, Denmark and the United Kingdom, capacity factors increased by more than 77% between their earliest deployment dates and 2023. Brazil, like the United States, has excellent onshore wind resources. In 2022 and 2023, newly-commissioned projects in Brazil had the highest weighted average capacity factor among the 15 countries examined, at 50% and 54%, respectively.

Table 2.2 shows more recent changes in capacity factors for projects commissioned in the same 15 countries for the 2010 to 2023 period. Apart from Mexico, all the countries experienced improvements in their weighted average capacity factors. Brazil and the United Kingdom experienced the largest increases in capacity factors for newly-installed projects, increasing by 51% and 41%, respectively, over the period 2010 to 2023. In total, 4 of the 15 countries shown saw an improvement of at least 30%, while 10 of the 15 showed a 20% or more improvement.

Table 2.2 Country-specific average capacity factors for new onshore wind, 2010, 2022 and 2023

	2010	2022	2023
	%		
Brazil	36	50	54
Canada	32	47	39
China	25	35	35
Denmark*	27	39	39
France	26	32	33
Germany	24	28	29
India	25	33	32
Italy	25	33	30
Japan	24	25	25
Mexico**	40	33	33
Spain	27	32	33
Sweden	29	35	37
Türkiye	26	38	33
United Kingdom	30	38	42
United States	33	44	40

* Countries where data were only available for projects commissioned in 2020, not 2022 or 2023.
** Countries where data were only available for projects commissioned in 2022, not 2023.

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

Figure 2.8 Onshore wind weighted average capacity factors for new projects in smaller markets by country, 2010-2023

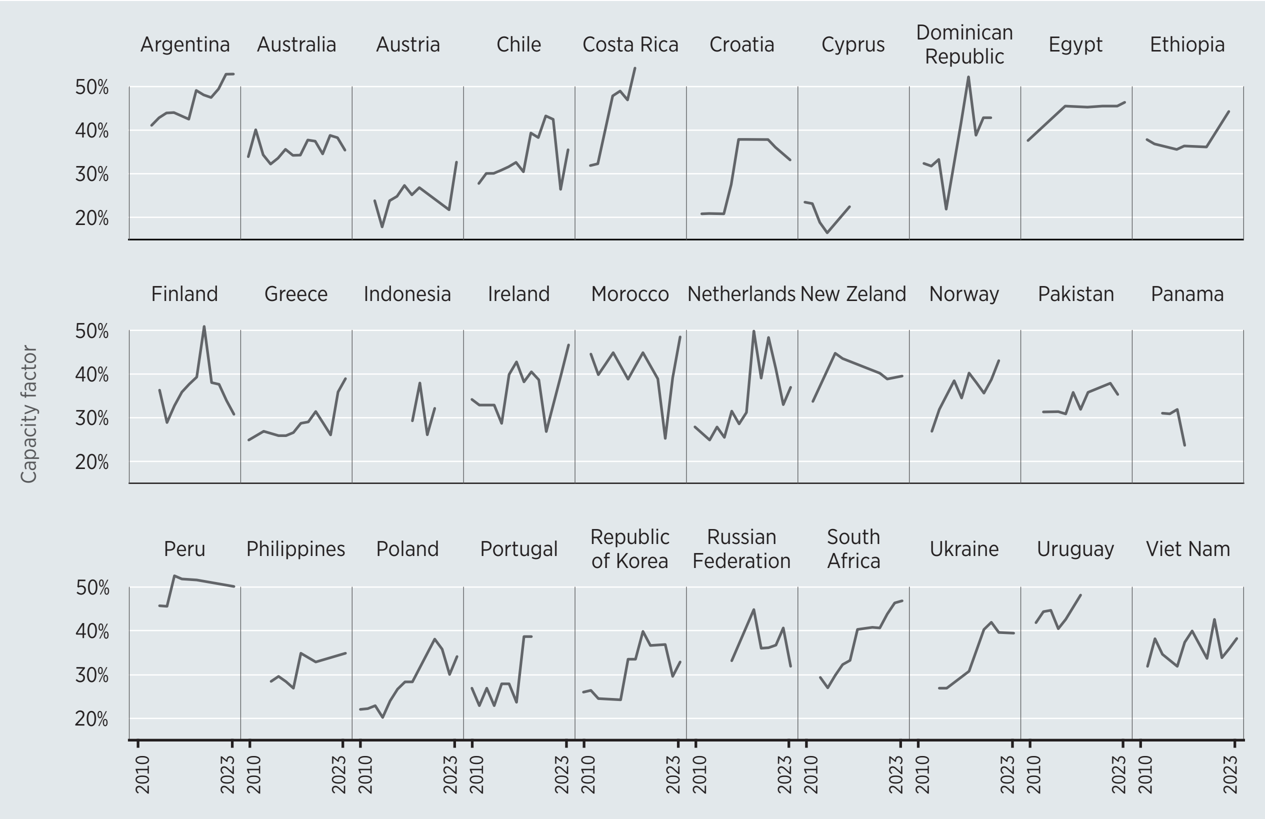


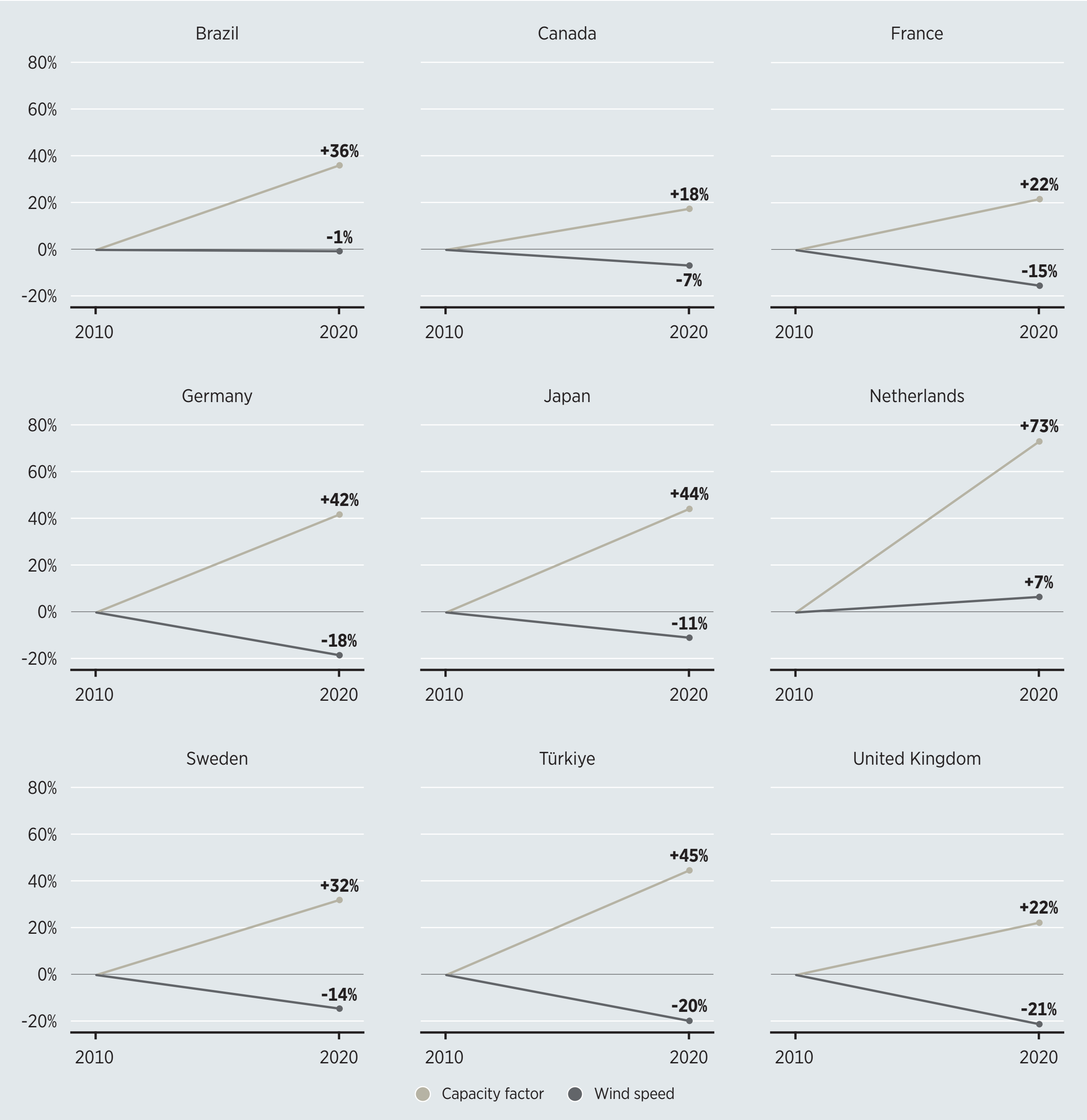
Figure 2.8 shows the increase in the weighted average capacity factor of newly-commissioned onshore wind farms in smaller markets, where deployment is thinner. Almost all countries in Figure 2.8 that have reasonable time series data showed an increasing trend in capacity factors, although there are exceptions to this (*e.g.* Cyprus, Finland and Panama).

However, the overall contribution to capacity factor increases from technology improvements is likely to be underestimated in many countries. The trends in capacity factors in Figures 2.7 and 2.8 mask the fact that many markets saw new projects sited at locations with lower, poorer wind resources over time. Figure 2.9 highlights these trends, where sufficient data could be reliably collected, by showing the change in the weighted average capacity factor and estimated wind resource for individual projects in 2010 and 2020. The figure 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.[29] The latter decline in wind speed for new projects could be due to less access to better wind resources in some countries. In some markets, the decline might also 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 confirms that technological improvements contributed greatly to an increase in the global weighted average capacity factor.

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

Among the nine countries examined in figure 2.9, between 2010 and 2020, the most significant weighted average capacity factor increased was in Netherlands, where it increased 73%. This was 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 underestimated the contribution of technological innovation and improvements in increasing wind farm yields (IRENA, 2022).

Figure 2.9 Change in the weighted average capacity factor and wind speed for new projects by country between 2010 and 2020



Note: The number of projects for which IRENA has sufficient data to perform the analysis contained in this figure is a subset of the total project data. The results are therefore indicative. 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.

O&M COSTS

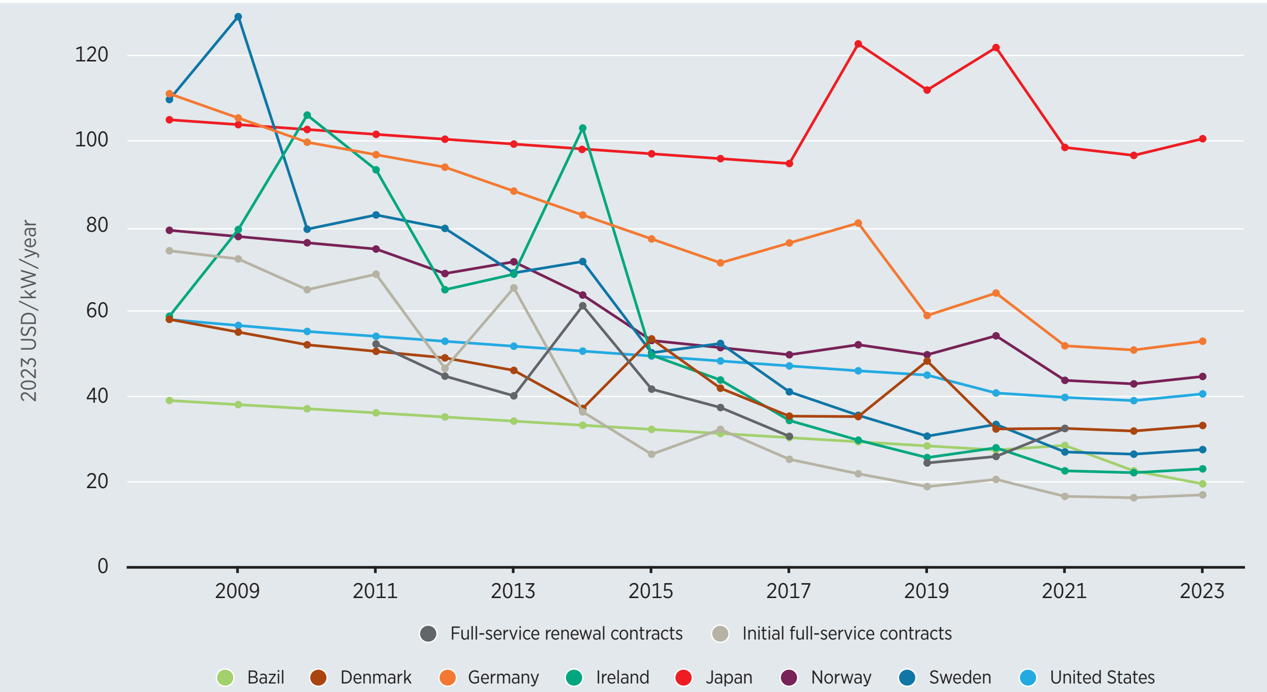
O&M costs for onshore wind often make up as much as 30% of the LCOE for this technology (IRENA, 2018). Improvements in technology, greater competition among service providers, and increased operator and service provider experience are, however, driving down O&M costs. This trend is further facilitated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

Figure 2.10 shows O&M costs in selected countries, along with BNEF O&M price indexes. These indexes 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 74% between 2010 and 2023, while full-service renewal contracts declined by 38% between 2011 and 2023.

At the country level, in 2023, O&M costs for onshore wind ranged from USD 20/kW per year in Brazil to USD 100/kW per year in Japan, with Germany – a country known for having higher-than-average onshore wind O&M costs in Europe – at around USD 53.1/kW per year. 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, such as insurance, land lease payments, local taxes and other factors.

Figure 2.10 Full-service (initial and renewal) O&M pricing indexes and weighted average O&M costs in Brazil, Denmark, Germany, Ireland, Japan, Norway, Sweden and the United States, 2008-2023



Source: BNEF (2023b); Wood Mackenzie (2023b) and IEA Wind (2023).

LCOE

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

In 2023, the O&M costs, comprising fixed and variable components, typically made up between 10% and 30% of the LCOE for most 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 2.11 presents the evolution of the LCOE (global weighted average and project level) of onshore wind between 1984 and 2023. Over that period, the global weighted average LCOE declined by 91%, from USD 0.350/kWh to USD 0.033/kWh. In 2010, the LCOE was USD 0.111/kWh, meaning there was a 70% decline over the decade to 2023. Consequently, onshore wind is now increasingly competing with utility-scale solar PV as the most cost-effective renewable technology without financial support, surpassing more established renewable sources like bioenergy, geothermal and hydropower.

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

- **Turbine technology improvements:** The increase in turbine sizes and swept areas, the optimisation of rotor diameter and turbine ratings (specific power), has led to higher energy yield and improved project viability for the asset owner, based on site characteristics. In addition, advances in wind resource characterisation and project design software have facilitated the site configuration, better exploiting wind resources and reducing output losses due to turbulence. Consequently, this has increased energy yields, reduced O&M costs per unit of capacity and driven down LCOEs (Bolinger *et al.*, 2020).

- **Economies of scale:** Economies of scale have enabled larger production volumes and establish regional manufacturing hubs, reducing costs. Larger turbines and project scales help to amortise project development costs and O&M costs, while creating greater purchasing power for all aspects of the project. Meanwhile, larger turbines mean fewer turbines are needed for a given capacity. This lowers installation costs due to higher turbine ratings.

- **O&M costs:** Digital technologies have allowed for improved data analytics and autonomous inspections. This has been accompanied by improvements in the reliability and durability of new turbines, while larger turbines have reduced the number necessary 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, 2020b).

- **Competitive procurement:** The transition from feed-in-tariff support schemes to competitive auctions has led to further cost reductions. This shift fosters 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 adapted to support regional hubs and countries, reducing labour and delivery costs and further improving competitiveness.

- **Growing maturity of the market:** In a range of established markets, increased operational experience and favourable government regulations and policies have reduced project development and operational risks for onshore wind. These risks are now better understood, with adequate mitigation measures in place.

Many markets are facing challenges that have slowed deployment and increased the costs of onshore wind energy. Barriers such as permitting timelines, environmental approvals, grid availability and market volatility are hindering the sector. Promising efforts to address these issues are being made in a number of markets, however. These include the US Inflation Reduction Act, the European Union (EU) Wind Power Package, and China's new five-year plan, reflecting a global commitment to accelerating renewable energy and improving electricity systems.

Figure 2.11 LCOE of onshore wind projects and global weighted average, 1984-2023

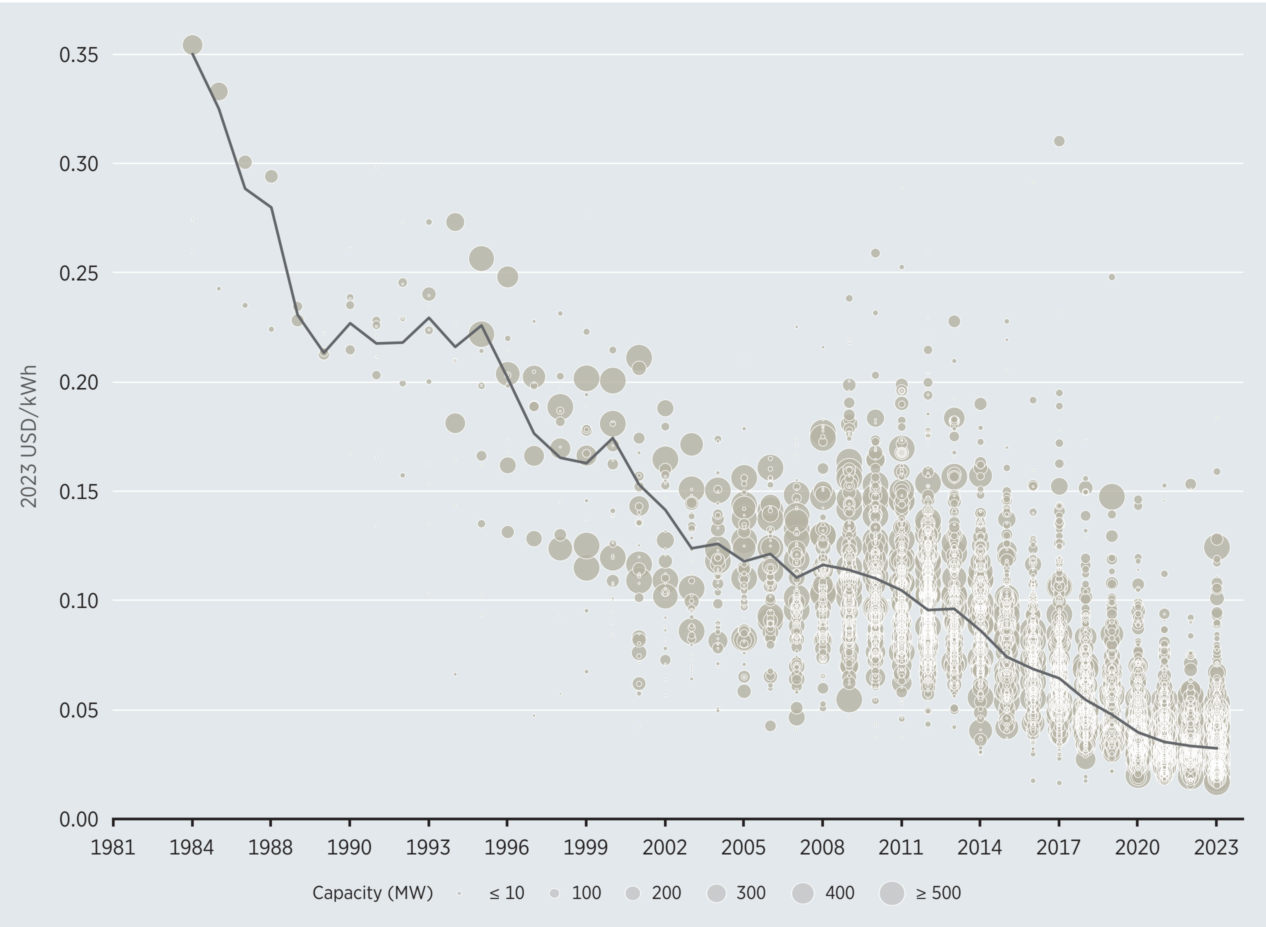


Figure 2.12 shows the historical evolution of the LCOE of onshore wind in 15 countries where IRENA has the most extended time series data. These data should be interpreted carefully, however, as cross-country comparisons are problematic, given the variation in base years for each country and fluctuations in exchange rates. Having noted this, among the 15 countries analysed, the biggest LCOE reduction (89%) was in the United States, which also had the largest reduction (74%) in average total installed costs, while its average capacity factor more than doubled, improving from 19% in 1984 to 40% in 2023. China and the United Kingdom had the subsequent largest reduction at 86%, followed by Sweden and Brazil (84%). In 2023, all the 15 countries analysed in Figure 2.12, except for Japan and Türkiye, had weighted average LCOEs below USD 0.050/kWh. This was a figure well below the weighted average of fossil fuel-fired power generation, which was USD 0.100/kWh.

Figure 2.12 Weighted average LCOE of commissioned onshore wind projects in 15 countries, 1984-2023

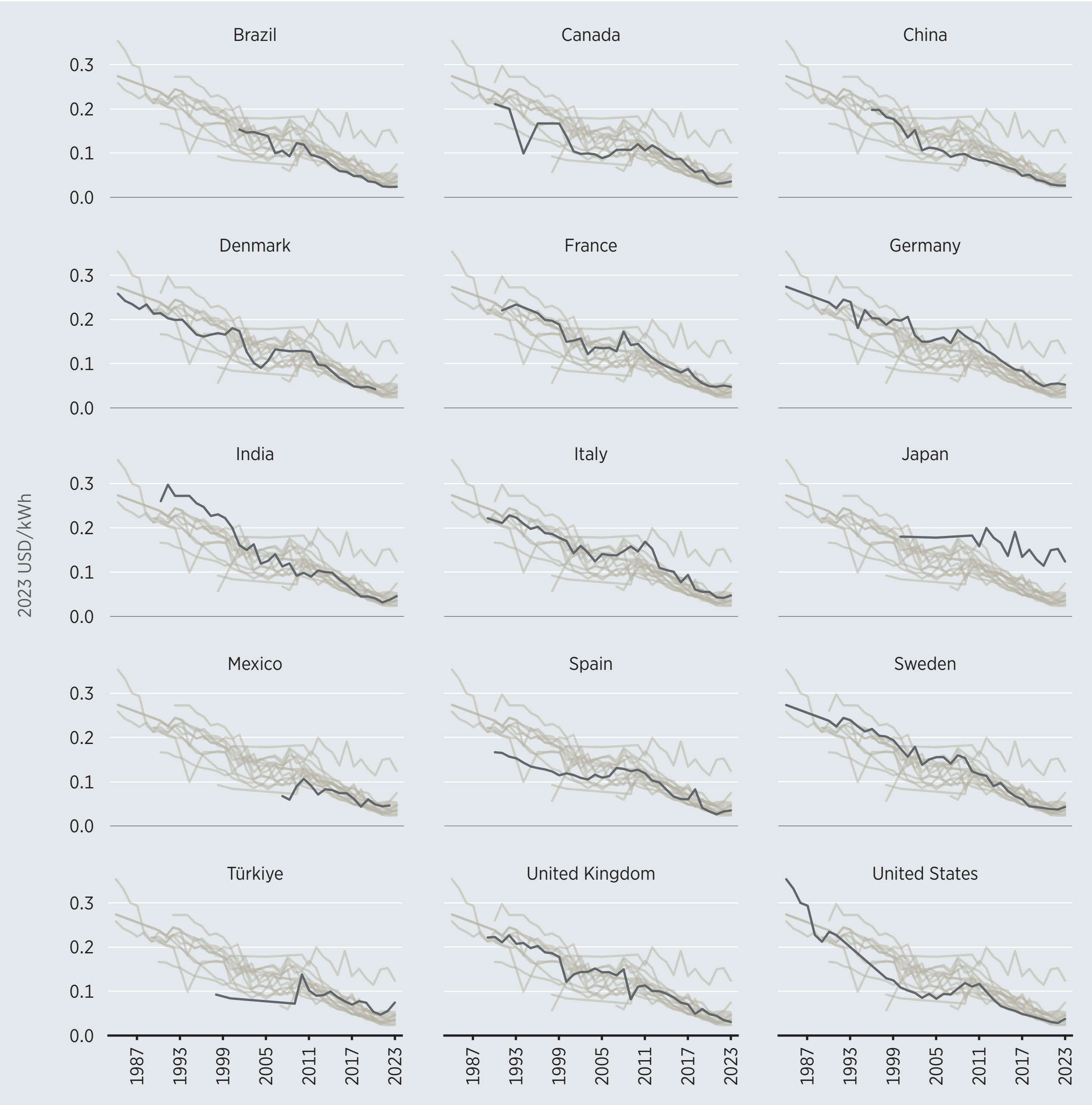


Table 2.3 shows the country/region weighted average LCOE and 5th and 95th percentile ranges by region in 2010 and 2023. All countries and regions in Table 2.3 saw a decrease in their country/region weighted average LCOE of newly-commissioned projects.

In 2023, the highest weighted average LCOE for commissioned projects by region was USD 0.091/kWh, which occurred in the Other Asia category. Projects commissioned in Brazil and China saw the lowest weighted average LCOEs, at USD 0.025/kWh and USD 0.027/kWh, respectively. The highest LCOE reduction between 2010 and 2023 was in Brazil, which saw a fall of 79% (USD 0.120/kWh to USD 0.025/kWh). Oceania had the second highest LCOE reduction for the same period, at 71%; China, Europe, and North America (see Annex III) had reductions of 70%, 67% and 66%, respectively.

Wind power projects are increasingly achieving LCOEs of less than USD 0.040/kWh and in some cases, as low as USD 0.025/kWh. The most competitive weighted average LCOEs below USD 0.050/kWh were observed across different countries: in China, Spain, the United Kingdom, the Netherlands, Lithuania, Ireland, the United States, Canada, Australia, New Zealand, Brazil and Peru. In 2023, the 5th and 95th percentile range for the global weighted average LCOE was between USD 0.018/kWh in Brazil and USD 0.126/kWh in Other Asia.

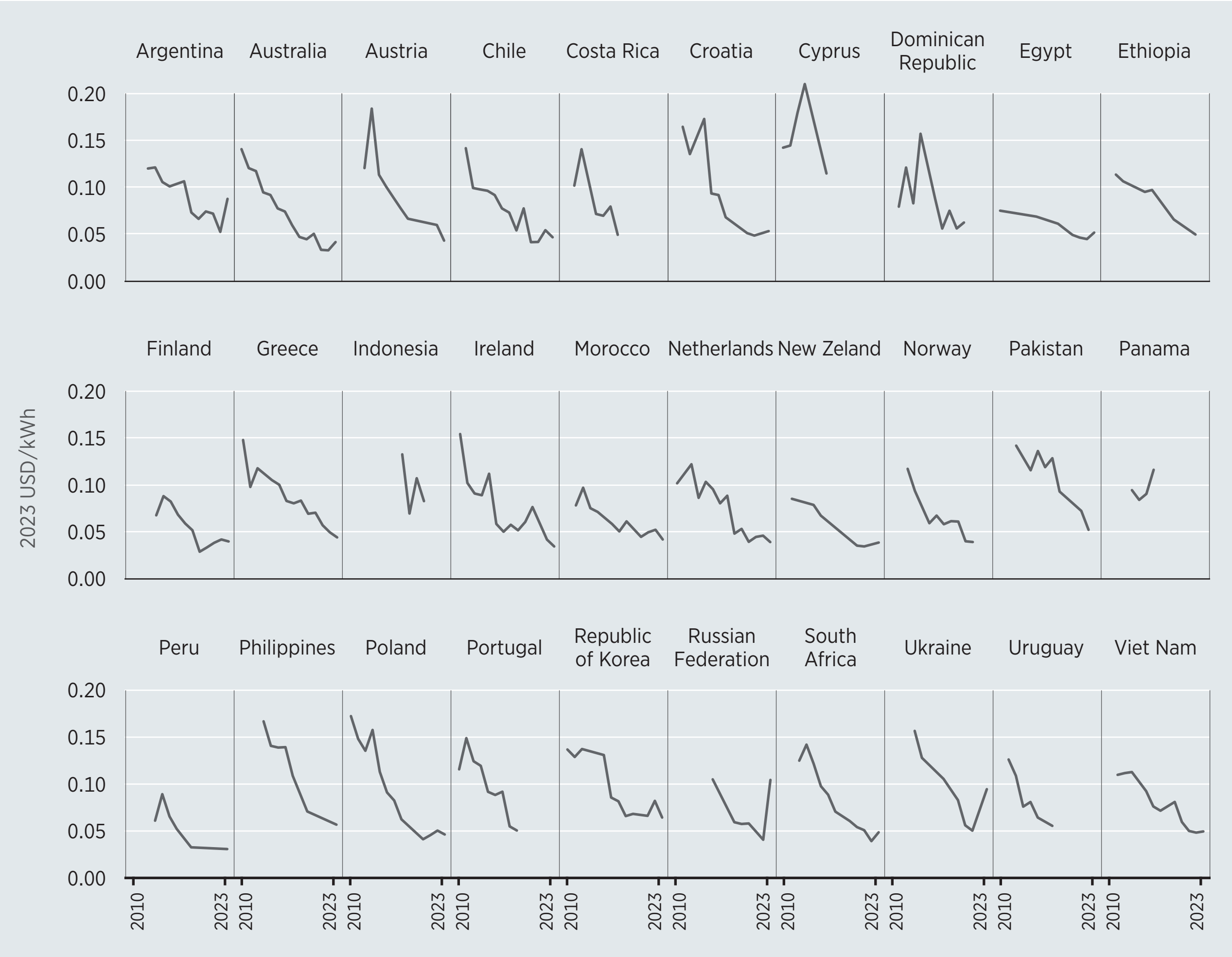
Table 2.3 Regional weighted average LCOE and ranges for onshore wind in 2010 and 2023

	2010			2023		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2023 USD/kW)					
Africa	0.075	**0.075**	0.093	0.043	**0.048**	0.052
Central America and the Caribbean	0.099	**0.099**	0.099	n.a.	**n.a.**	n.a
Eurasia	0.139	**0.139**	0.139	0.043	**0.091**	0.114
Europe	0.093	**0.141**	0.210	0.030	**0.046**	0.071
North America	0.072	**0.112**	0.153	0.030	**0.038**	0.055
Oceania	0.125	**0.141**	0.153	0.033	**0.041**	0.049
Other Asia	0.116	**0.160**	0.173	0.042	**0.083**	0.126
Other South America	0.069	**0.105**	0.336	0.031	**0.056**	0.111
Brazil	0.120	**0.120**	0.120	0.018	**0.025**	0.037
China	0.073	**0.090**	0.112	0.019	**0.027**	0.039
India	0.062	**0.099**	0.123	0.036	**0.046**	0.051

Note: see Annex III for regional country groupings.

Figure 2.13 shows the weighted average capacity LCOE of newly-commissioned onshore wind farms in smaller markets. All countries except Panama – which also experienced a drop in the capacity factor in the most recent data – showed a decreasing trend in LCOE over time. Poland stands out for having the highest reduction from 2010 to 2023, with a 73% decrease.

Figure 2.13 Onshore wind weighted average LCOE in smaller markets by country, 2010-2023

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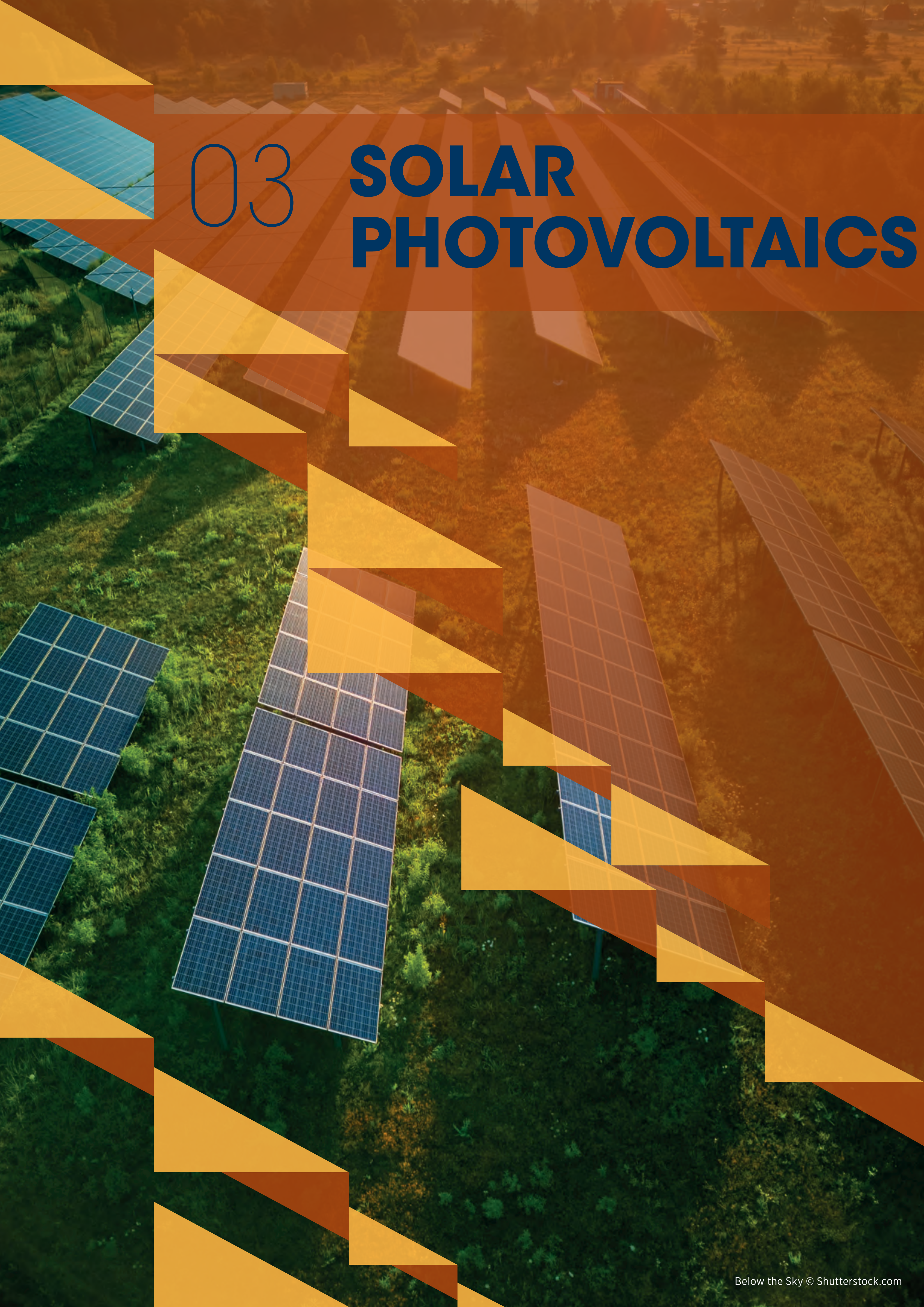


03 SOLAR PHOTOVOLTAICS

Below the Sky © Shutterstock.com

HIGHLIGHTS

The global weighted average levelised cost of electricity (LCOE) of utility-scale solar PV plants declined by 90% between 2010 and 2023, from USD 0.460/kilowatt hour (kWh) to USD 0.044/kWh. In 2023, the year- on-year reduction was 12%.

At an individual country level, the weighted average LCOE of utility-scale solar PV declined by between 76% and 93% between 2010 and 2023.

The cost of crystalline solar PV modules sold in Europe declined by 93% between December 2009 and December 2023.

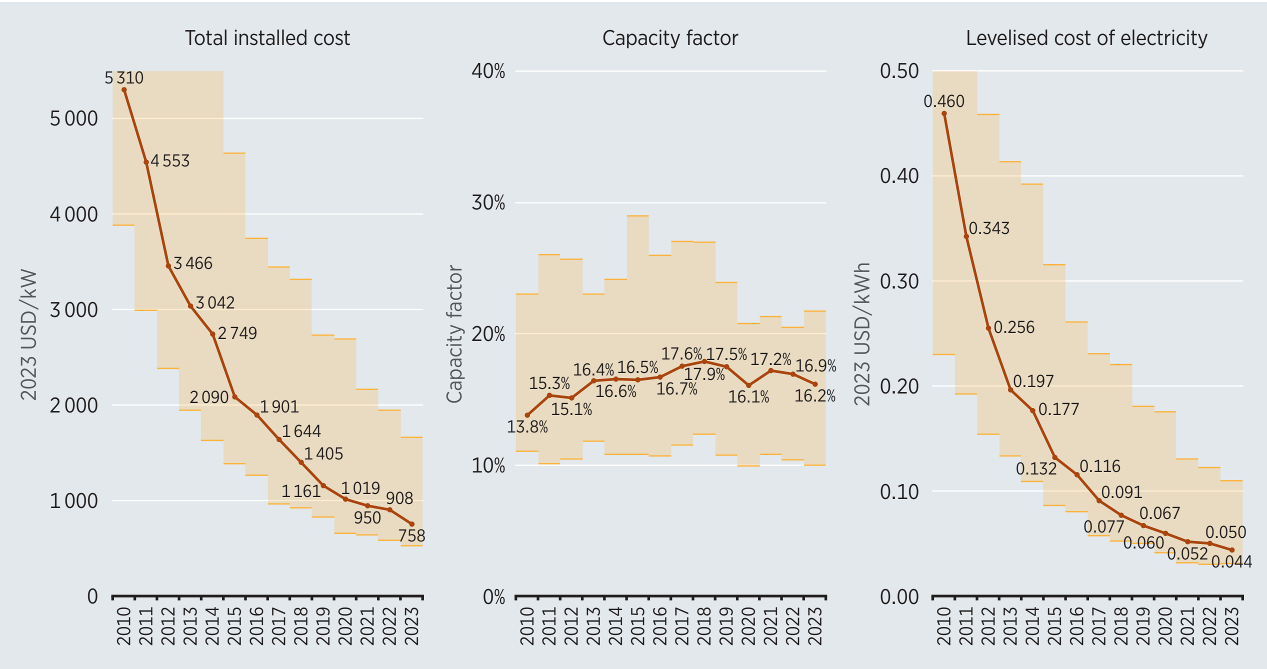
The global capacity weighted average of total installed cost of projects commissioned in 2023 was USD 758/kW, 86% lower than in 2010 and 17% lower than in 2022.

Solar PV capacity grew 35-fold between 2010 and 2023, with over 1 412 GW installed by the end of that period.

On average, in 2023, balance of system (BoS) costs (excluding inverters) made up about 61% of total installed costs of utility-scale PV plants.

The global weighted average capacity factor for new, utility-scale solar PV increased from 13.8% in 2010 to 16.2% in 2023. This change resulted 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 and range of total installed costs, capacity factors and LCOEs for utility-scale solar PV, 2010-2023



RECENT MARKET TRENDS

By the end of 2023, over 1 411 GW of solar PV systems had been installed globally. This represented a 35-fold increase in the technology's deployment compared to 2010. Newly-installed systems totalling about 346 GW were commissioned during 2023. This was 73% more than in 2022 and represented the greatest year-on-year increase in yearly-commissioned capacity since 2011. Since 2016, solar PV has been the technology with the highest annual new capacity additions among all renewable technologies.

Asia has been the leader in installing new solar PV since 2013. The share of new installations in Asia was 53% in 2021 and 59% in 2022. Following that trend, growth in 2023 was higher than in the previous two years, with Asia contributing about 63% of all new installations. In 2023, China drove growth in the region, accounting for around 91% of all new Asian (and about a 63% of all global) installations. Total expansion in Asia more than doubled, year-on-year, from 112 GW in 2022 to 238 GW in 2023. Major capacity increases occurred in China (217 GW) and India (9.5 GW). Japan also added 4 GW, 40% lower than in 2022. Historical markets outside Asia also continued to gain scale. The United States added 24.8 GW of solar capacity in 2023, Brazil added 11.9 GW and Germany and Spain added 14.3 GW and 5.4 GW, respectively (IRENA, 2024a).

TOTAL INSTALLED COSTS

Solar PV module cost trends

Historically, the downward trend in solar PV module costs has been an important driver of improved competitiveness. This technology has also shown the highest learning rates of all renewable energy technologies.

Between December 2009 and December 2023, crystalline silicon module prices declined between 92% and 98% for modules sold in Europe, depending on the type. The weighted average cost reduction was in the order of 93% during that period. During December 2023, mainstream modules were sold for USD 0.16/watt (W), a value 52% lower than in 2022. A wide range of costs exists, however, depending on the module technology considered. Crystalline module prices decreased between 16% and 55% during 2023. Costs varied from as low as USD 0.11/W for the lower-cost modules to as high as USD 0.38/W for bifacial modules. These are becoming standard, with their market share continuing to grow – jumping from 8% in 2019 to 27% in 2020, 28% in 2021, 30% in 2022 and 50% in 2023 (ITRPV, 2024).

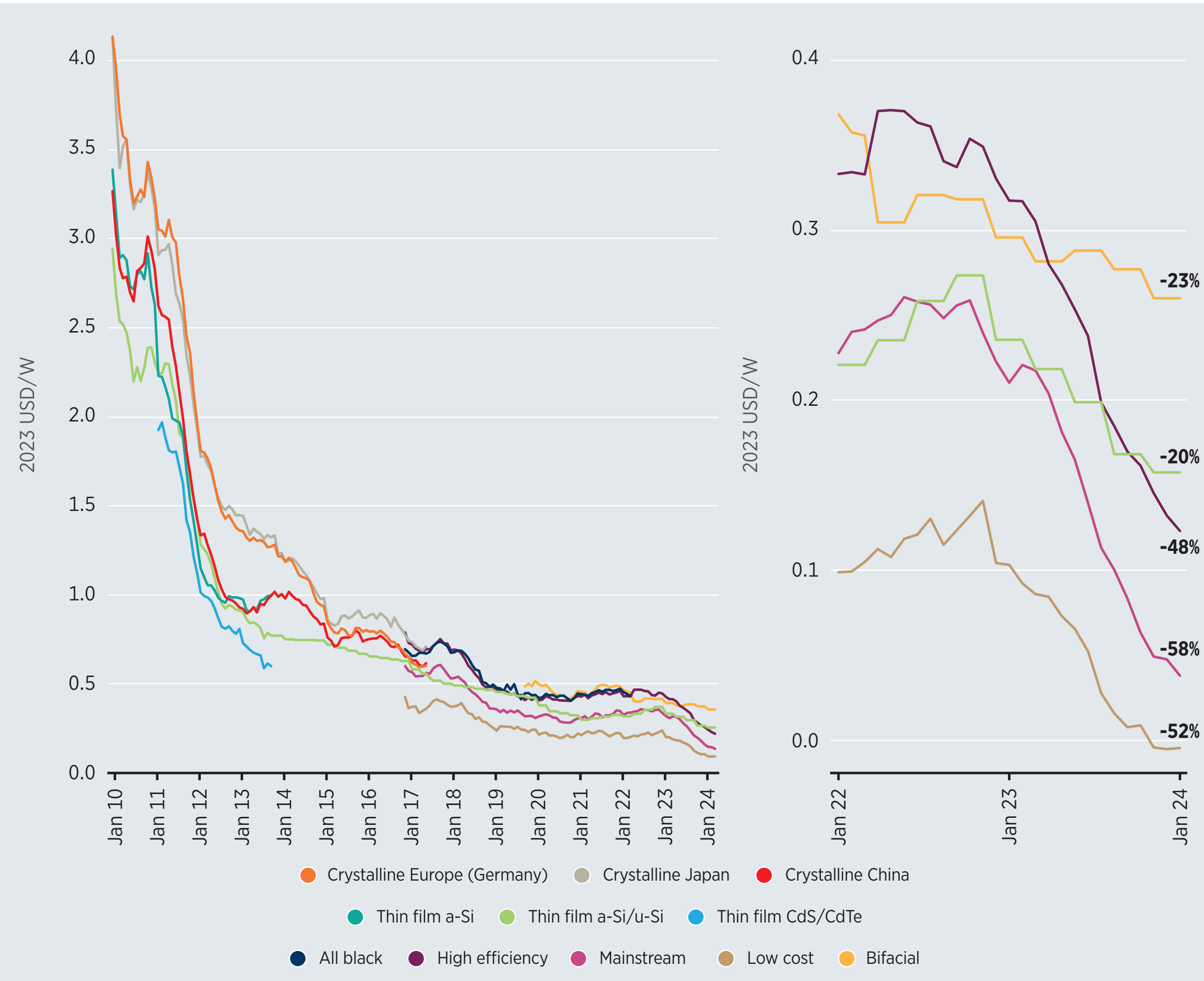
Kaentian Street © Shutterstock.com

The cost difference between bifacial crystalline and mainstream monofacial modules is also widening, reaching 131% during 2023 compared to only 23% in 2022. The growth in the price difference is mainly due to the significant cost decrease of mainstream modules during 2023 for modules sold in Europe (Figure 3.2, graph on the right side).

Thin film offerings sold for USD 0.27/W during December 2023, after a cost decline of 28% between December 2022 and December 2023.

The fall in prices that began during 2022 continued throughout 2023 with more significant drops in all categories. The yearly average price of crystalline modules declined between 9% and 26% during 2023. Low-cost modules had the highest decline, of 26%, followed by mainstream modules (25%) and high efficiency modules (22%). After the period's supply chain disruption, module prices started to fall. This was driven by overproduction and high inventory levels (CRU, 2024). Preliminary data for the first quarter of 2024 show continuous declines, ranging between 12% and 44%, in all module categories (Box 3.1).

Figure 3.2 Average monthly solar PV module prices, 2010 to 2023 (left) and monthly solar PV module prices, 2022 to Q1-2024 (right), by technology and manufacturing sold in Europe



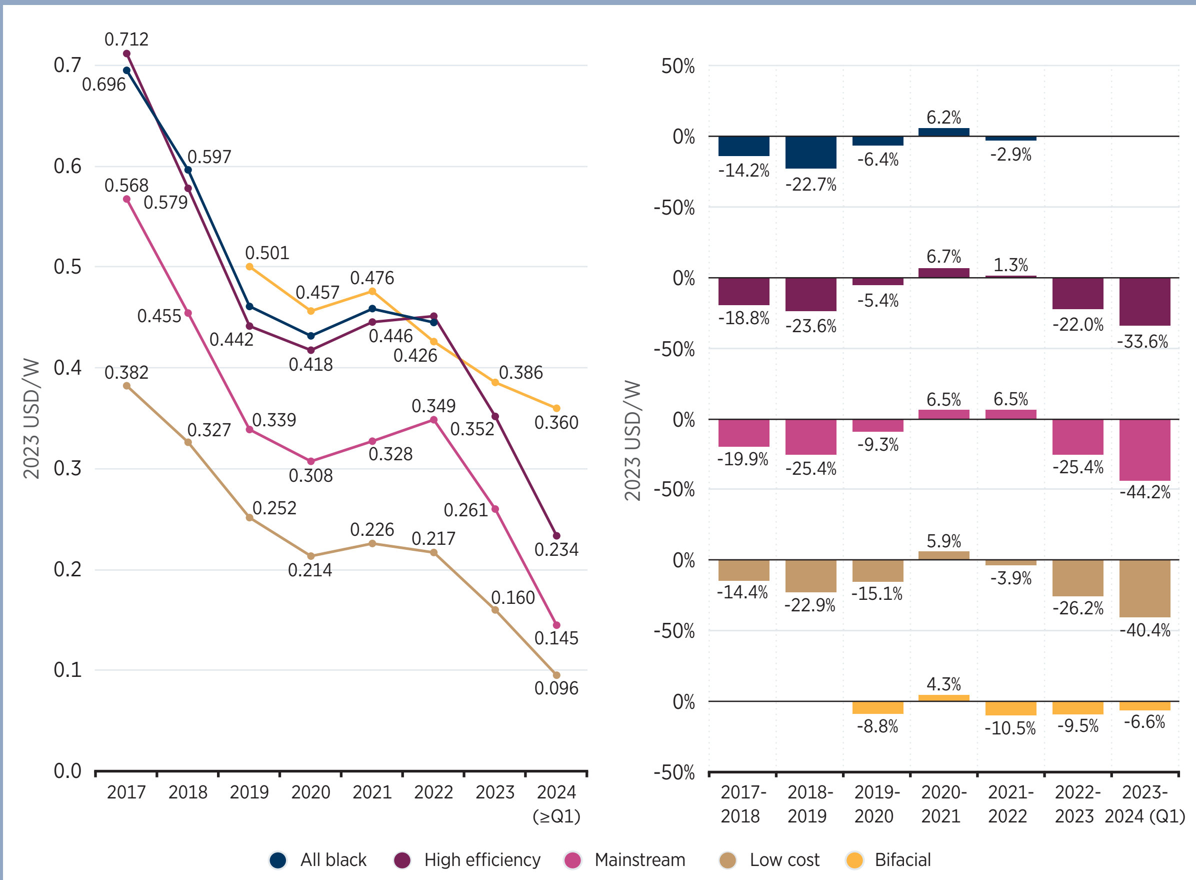
Source: GlobalData (2024); Photon Consulting (2017); pvXchange (2023); Wood Mackenzie (2023).

Box 3.1 Solar PV module cost uptick reversed

In 2021, after a decade of continuous decline, solar PV module prices started climbing. This was driven by supply chain disruptions that led to higher material costs and/or lower availability.

Taking modules sold in Europe as a reference, these developments meant that the price of crystalline solar PV modules increased between 4.3% and 6.7% in 2021, compared to 2020, from a range of between USD 0.214/W and USD 0.457/W to between USD 0.226/W and USD 0.476/W. During 2022, this trend started to reverse. Levels continued to fall in 2023, with prices for mainstream modules – which accounted for about 50% of the market that year – declining 25% to USD 0.261/W. Preliminary data for the first quarter of 2024 show prices reaching USD 0.145/W – the lowest since 2017.

Figure B3.1a Average yearly solar PV module prices by technology sold in Europe, 2010 to 2023 and Q1 2024; average (left) and percentage increase (right)

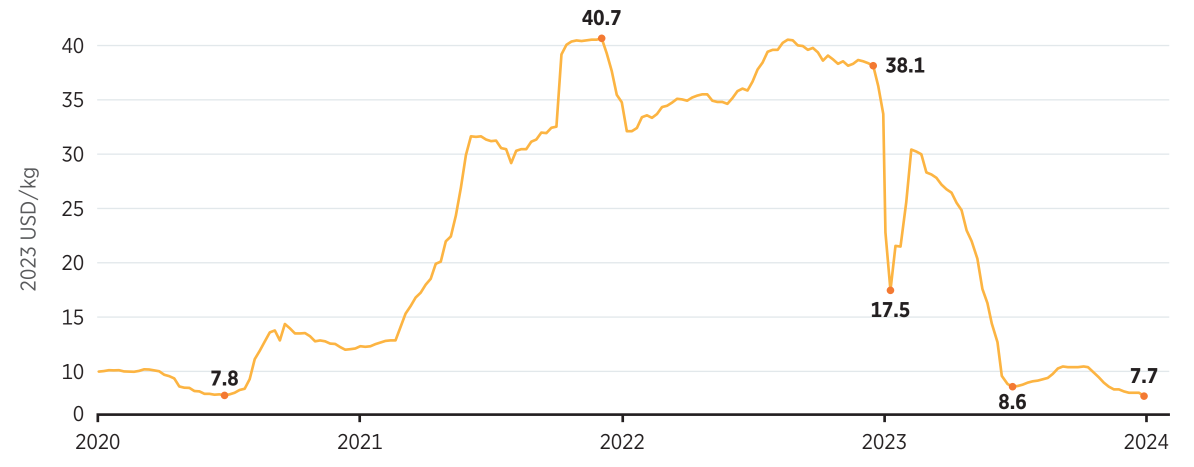


Source: GlobalData (2024); Photon Consulting (2017); pvXchange (2023); Wood Mackenzie (2023).

The reasons for the price uptick that started in 2021 are varied, but a systemic contributor to this increase was the rising price of polysilicon. Challenges related to available polysilicon capacity in China pushed polysilicon prices from around USD 28/kilogram (kg) in 2021 to almost USD 37/kg in 2022, while cell manufacturers raced to supply rising PV demand.

The supply chain did, however, respond rapidly to increased demand and tightened supply, with manufacturers announcing and delivering a rapid increase in supply. In 2023, the market flipped and polysilicon prices fell from USD 23/kg in January to less than USD 8/kg in December. The annual average for 2023 reached USD 15.5/kg – a value 58% lower than in 2022.

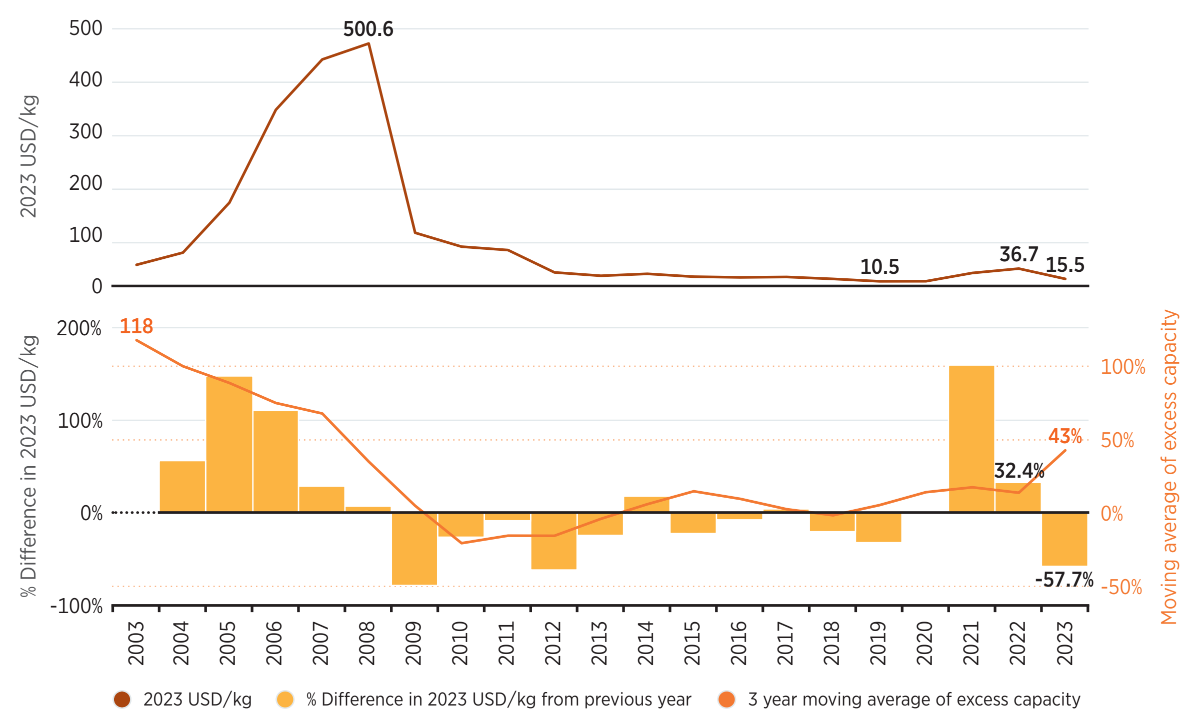
Figure B3.1b Polysilicon price average between 2020 and Q1 2024



Based on: pvXchange (2023); Wood Mackenzie (2023); Bernreuter (2024).

This price flip largely happened due to industry-wide efforts to scale-up production through manufacturing capacity expansions after the shortages of 2021. Yet, further technological improvements in manufacturing have also started to pay off. Preliminary data for the first half of 2024 show the global price average for polysilicon at USD 5.63/kg. This represents a decline of 64% compared to the average price of polysilicon in 2023 (Bernreuter, 2024). This seems indicative of a continuous fall in prices after an increasing trend in excess manufacturing capacity (Figure B3.1c).

Figure B3.1c Polysilicon pricing, percentage change per year and three-year moving average of polysilicon manufacturing capacity utilisation, 2003-2023



Based on: Bernreuter (2024); Wood Mackenzie (2023); Energy Trend (2022).

Various factors are expected to continue to increase solar PV technology's competitiveness in the longer-term. These include: continued improvement in the equipment efficiency of the installed production capacity; manufacturing optimisation by the implementation of lean processes; more efficient use of materials; and design innovation. These 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 – a trend which is expected to continue. The average module efficiency of crystalline modules increased from 14.7% in 2010 to 20.9% in 2021. During 2023, the average module efficiency of passivated emitter and rear contact (PERC) modules was reported at 21.4%, while n-type modules reached efficiencies of 22.5% (ITRPV, 2024). This rise was driven by a market shift from multi-crystalline to more efficient monocrystalline products, while PERC architectures became state-of-the-art module technology and the dominant cell in the market.

The efficiency of PERC modules, however, is expected to grow towards 24.2% for p-type in the next few years, approaching this variety's limits. In terms of cell architecture beyond PERC, new cell and module capacities have been shifting to n-types, as they have higher efficiency. This occurs first of all by focusing on reducing losses at contacts (*e.g.* silicon heterojunction [SHJ] and tunnel oxide passivated contact [TOPCon] technologies); and second, by moving metallisation to the rear of the cell to reduce front-side shading (*e.g.* interdigitated back contact [IBC] or cells). The efficiency of the n-type cell is expected to reach 26.1% in the next 10 years.

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 of between 156 millimetres (mm) and 159 mm and are based on wafer formats known as M2 and G1. Cells are typically connected in series using metallic ribbon, which is 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 (M10) to 210 mm (G12) 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 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 an important performance metric. Higher-power modules reduce BoS costs, which is why larger-area modules are becoming prevalent. However, highest-efficiency modules are more expensive on a USD/W basis and are reserved for premium applications (ITRPV, 2023; Lin, 2019; TaiyangNews, 2021).

The sustainability of the materials used in solar PV modules, the reduction of resources and the increasing recycling rates are gaining in importance as the market continues to grow globally. Technological developments related to this are becoming the focus of many industry efforts.

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 in wafer production is expected to decline 25% for M10 and 30% for G12 in the coming years (ITRPV, 2024). During 2022, kerf loss values of 57 micrometres (μm) were already typical. This was a decline of more than 64% from 2010 (ITRPV, 2023). In 2023, loss values were reported at below 55 μm, which was a decline of about 65% since 2010. 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 finding different ways to reduce metal consumption in cells.

For mono-facial p-type cells, total silver remaining in the cells declined from 400 milligrams (mg) per cell in 2009 to 90 mg/cell in 2020 – a decline of 80%. In 2023, the silver consumption for standard PERC architecture was 74 mg/cell and the median 2023 value reached 9.6 mg/W, a 4% decline compared to 2022. In n-type cells (SHJ 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 comparison with p-types, the consumption ratio is 2.2 and 1.6 higher for SHJ and TOPCon, respectively (ITRPV, 2024). 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. Industry expectations are for the total silver remaining in the cells to reach 7.5 mg/W within the next decade, which corresponds to about 60 mg/cell (ITRPV, 2023).

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[30] 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 at 70% for PERC modules, 80% for TOPCon modules and at the highest, 85% for SHJ modules (ITRPV, 2024).

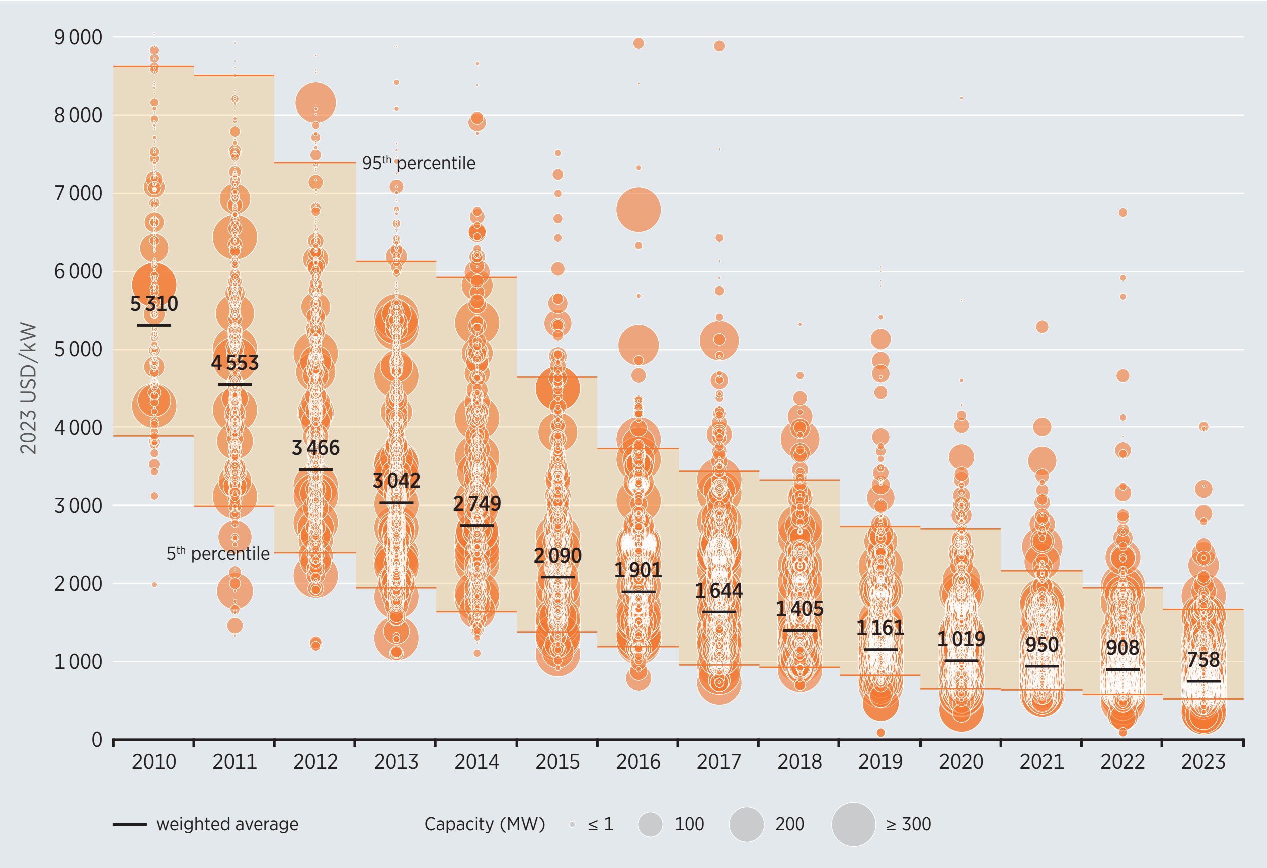
Bifaciality is a characteristic that depends on the structure of cells and modules. The "bifacial gain", or output gain from a bifacial module compared to a monofacial module, however, does not depend only on the bifaciality factor. It also depends on the additional, external conditions of the system 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. Bifacial cells are now dominant, accounting for 70% of the market, while the market share of bifacial modules reached 50% during 2023 (ITRPV, 2024).

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

Total installed costs

The global weighted average total installed cost of utility-scale projects continues to decrease and was USD 758/kW for projects commissioned in 2023. This value was 17% lower than in 2022 and 86% lower than in 2010. During 2023, the 5th and 95th percentile range for all projects fell within a range of USD 526/kW to USD 1663/kW. The 95th percentile value was 15% lower than in 2022, while the 5th percentile value declined by 10% between 2022 and 2023. 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 86% and 81% lower, respectively (Figure 3.3).

Figure 3.3 Total installed cost of utility-scale solar PV by project and weighted average for utility-scale systems, 2010-2023

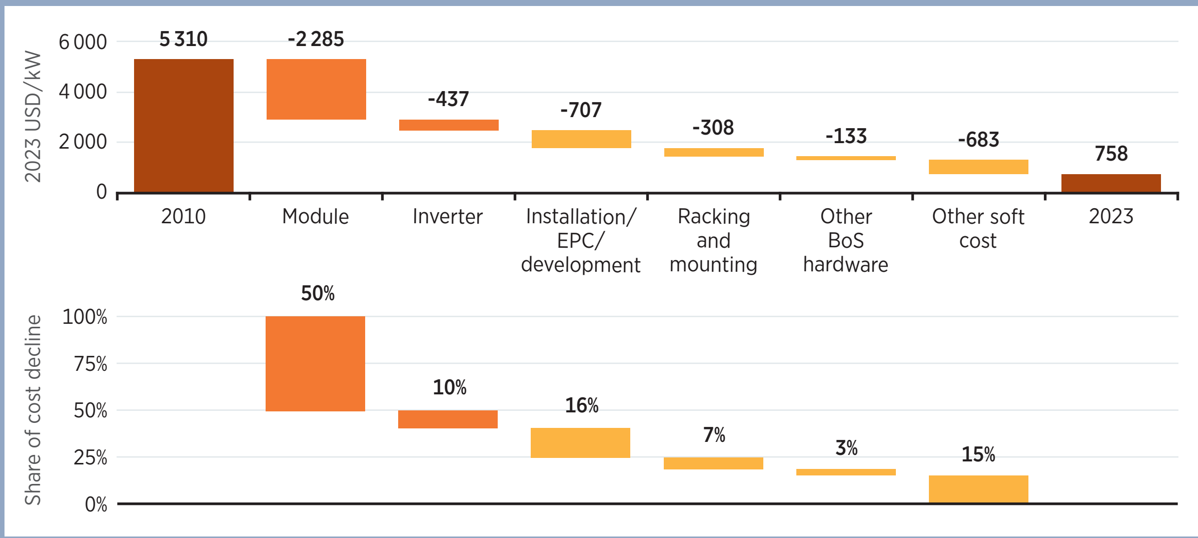


Notes: MW = megawatt; kW = kilowatt.

Box 3.2 Drivers of the decline in utility-scale solar PV total installed costs

Utility-scale solar PV total installed cost reductions are related to various factors. Globally, between 2010 and 2023 module costs accounted for 50% of the total installed costs reduction, while inverters contributed another 10% (Figure B3.2a).

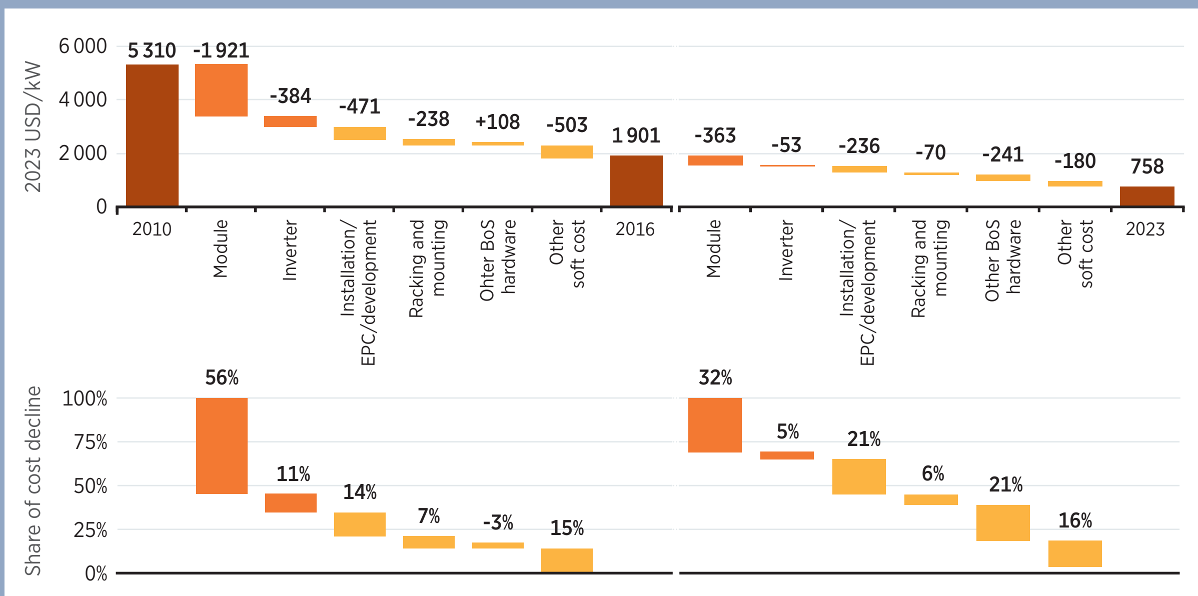
Figure B3.2a Global weighted average total installed costs of utility-scale solar PV systems and cost reductions by source, 2010-2023



Notes: EPC = engineering, procurement and construction; BoS = balance of system; kW = kilowatt.

As project developers gain more experience and supply chain structures continue to develop in more and more markets, declining BoS[31] costs have followed. This has led to an increasing number of markets where PV systems are achieving competitive cost structures, with falling global weighted average total installed costs. This is more evident when looking at the changing drivers of cost reduction for the periods 2010-2016 and 2016-2023 separately (Figure B3.2b).

Figure B3.2b Global weighted average total installed costs of utility-scale solar PV systems and cost reductions by source, 2010-2016 and 2016-2023



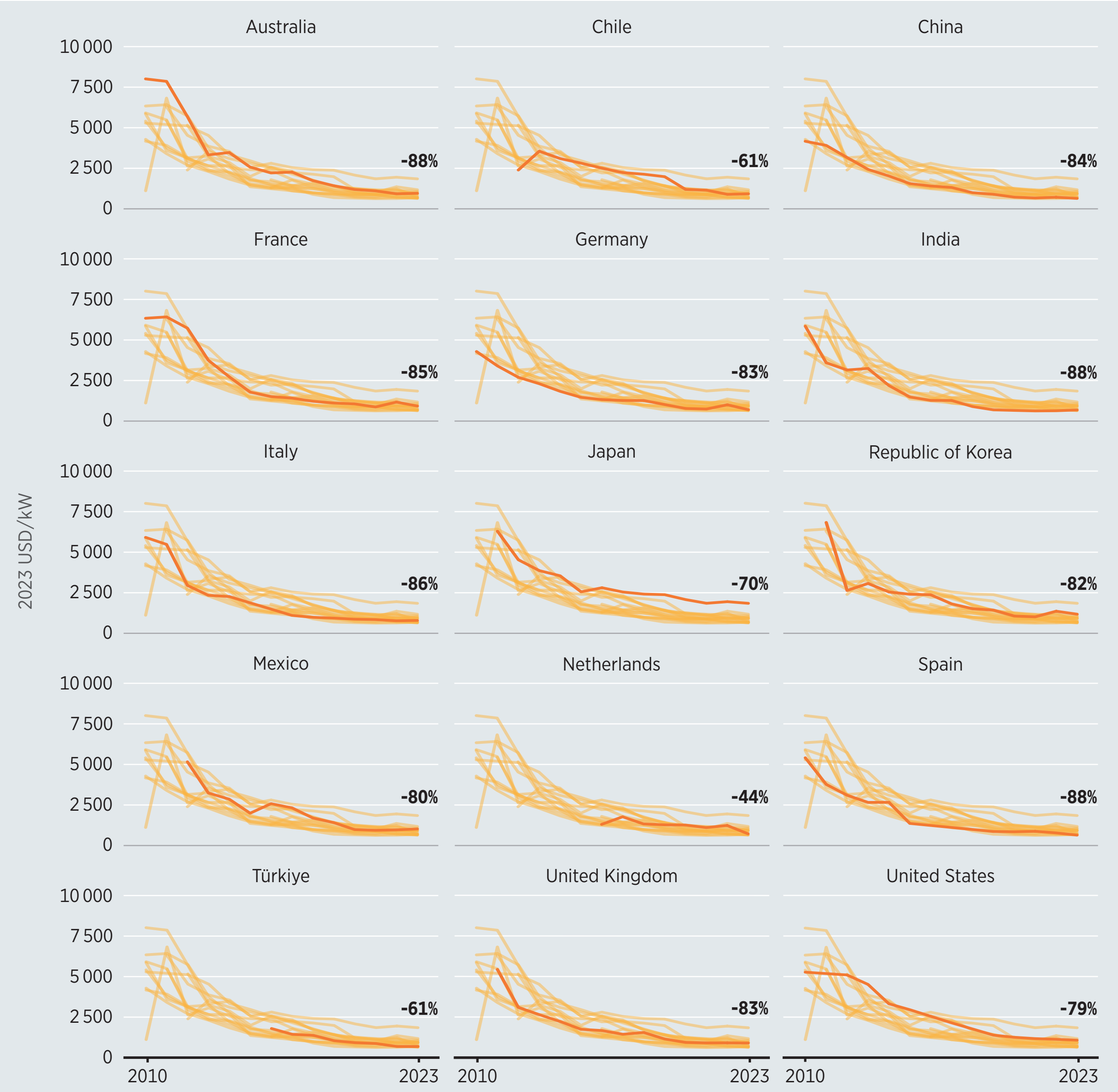
Note: Percentage figures may not total 100 due to rounding up ; EPC = engineering, procurement and construction; BoS = balance of system; kW = kilowatt.

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

While modules and inverters together were behind 67% of the reduction in total installed costs between 2010 and 2016, their contribution was less pronounced between 2016 and 2023, when 37% of the cost reduction was attributable to those categories. In the first period, the "other BoS hardware" category increased slightly (3%) as this was a time when markets started to expand into new geographies beyond the historical markets and supply chains for this were still developing. In the second period of analysis, however, the "other BoS" category contributed about a fifth of the total installed costs reduction. Together, the rest of the categories contributed 36% to the reduction between 2016 and 2023, jumping to 43% in the 2016-2023 period. This highlights the increasing relevance of BoS costs in the competitiveness of solar PV utility-scale projects.

Over the period 2010 to 2023, cost reductions in the countries in Figure 3.4 for which data start in 2010, ranged between 79% (in the United States) to as high as 88% (in Australia and India).

Figure 3.4 Utility-scale solar PV total installed cost trends in selected countries, 2010-2023



Note: Lines represent all 15 markets, the line in bold corresponds to the market identified at the top of each graph.

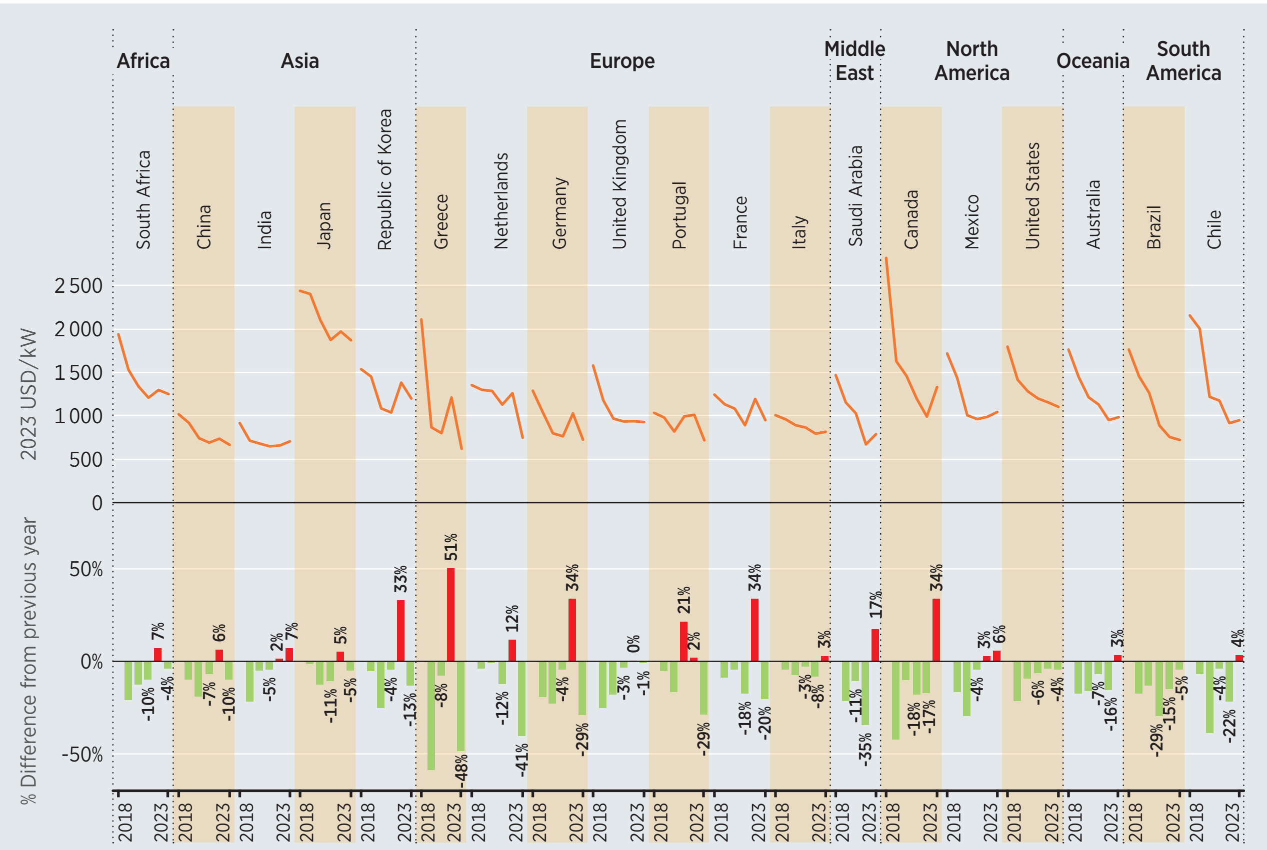
In 2023, markets that saw increases in total installed costs for projects commissioned in 2022 experienced sharp cost declines. For instance, between 2022 and 2023, installed costs in Netherlands had the biggest decline, some 41%, out of the 15 markets displayed. Costs in Germany declined 29% and the country had 20% growth in new solar PV capacity, installing more than 14 GW in 2023.

France added 3 GW that year and costs declined 20%, reaching USD 955/kW. Also in 2023, Australia and Italy saw their total installed costs increase, however, by 3%, while India saw the highest increase – 7% – with 15% growth in new solar PV capacity. Chile and Mexico also experienced slight increases in costs, of 4% and 6%, respectively. China and Spain, meanwhile, both had competitive PV projects with weighted average total installed costs of USD 671/kW in 2023. Between 2022 and 2023, costs declined 10% in China and 17% in Spain. Costs in other Asian markets, such as Republic of Korea and Japan, decreased after an increase of 5% in 2022.

The solar PV market adjusted rapidly in 2023, leaving behind the supply chain constraints that had impacted costs in 2022. In that year, total installed costs increased in the range of 2% to 34% in 8 out of the 15 markets shown in Figure 3.4. In 2023, fewer countries saw costs increases (5 out of the 15 markets), while a lower range of increases – 3% to 7% – was experienced. Cost declines ranging between 4% and 41% were experienced in 9 out of 15 markets in 2023, while in the UK, total installed costs remained flat from 2021.

Figure 3.5 expands the analysis of the evolution of total installed costs to cover the largest global markets. These are measured by their newly-installed utility-scale capacity between 2018 and 2023.

Figure 3.5 Utility-scale solar PV total installed cost trends in major utility-scale markets, 2018-2023



Note: see Annex III for regional country groupings.

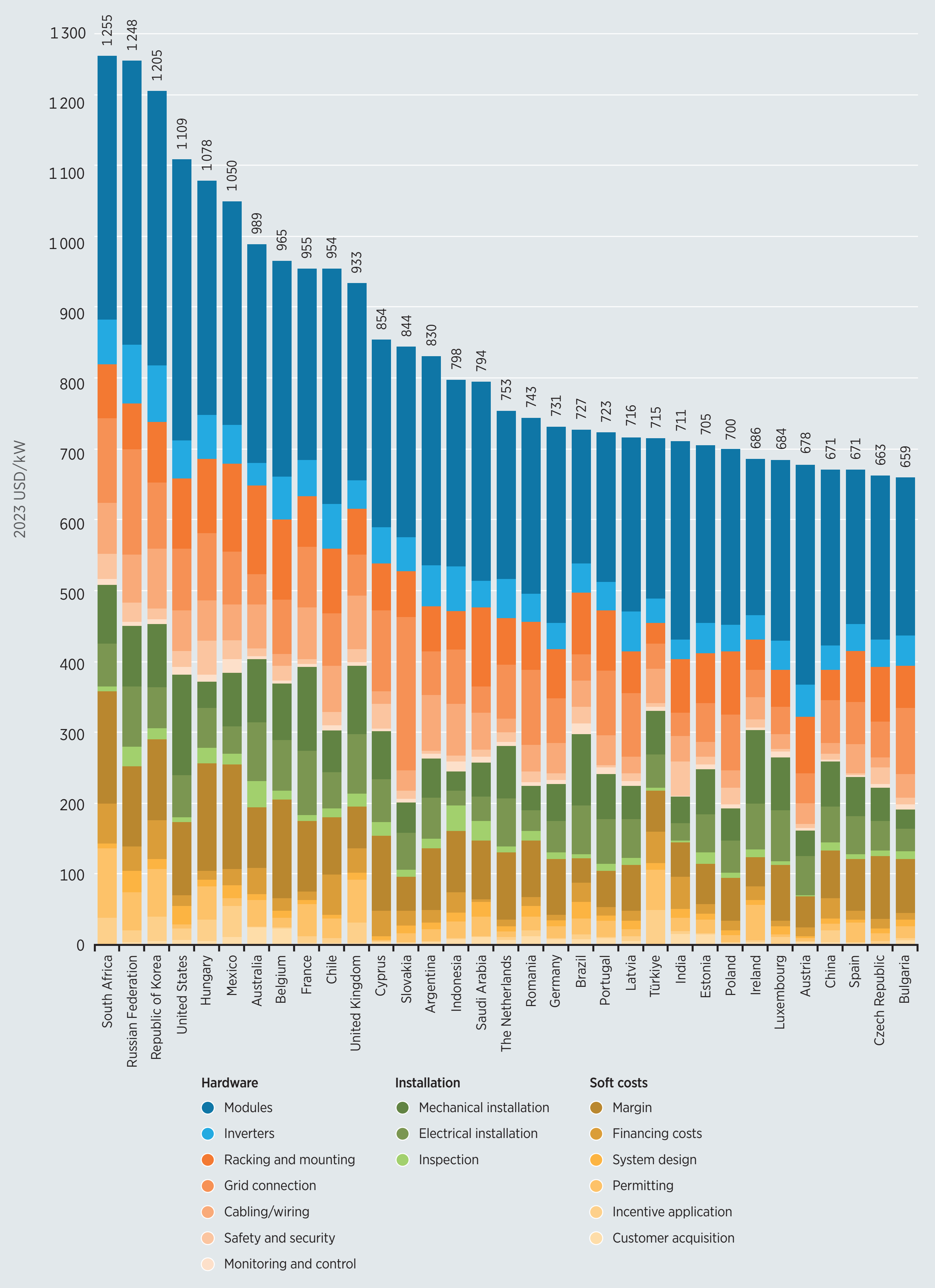
Figure 3.5 shows a downward cost trend over the 2018-2023 period. In a few markets, costs, however, increased either in 2022 or 2023, but despite this, values remained lower than in 2018. In Europe, all major markets apart from Italy experienced total installed cost decreases over the period. These ranged between 1% in United Kingdom to as high as 48% in Greece, which had the greatest cost reductions in 2023 of all the countries shown in Figure 3.5. Major Asian markets saw their total installed costs decrease by between 13% (Republic of Korea) and 5% (Japan). The exception was India, where the cost increased 7%. In total, in 2023, 7 out of the 19 top utility-scale markets saw their total installed costs rise between 3% (Italy and Australia) and 34% (Canada). In Saudi Arabia, total installed costs experienced an increase of 17% in 2023, after a 35% decline during 2022.

Costs in other major global markets declined as well. Between 2018 and 2023, both the United States and Brazil only experienced cost declines. During 2023, total installed costs went down 4% in the United States and 5% in Brazil.

While solar PV has become a mature technology, regional cost variations persist (Figure 3.6). These differences remain not only for the module and inverter cost components, but also for the BoS.[32] 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.

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

Figure 3.6 Detailed breakdown of utility-scale solar PV total installed costs by country, 2023



In 2023, the country average for the total installed costs of utility-scale solar PV for the countries reported in Figure 3.6 ranged from a low of USD 659/kW in Bulgaria to a high of USD 1 255/kW in South Africa.

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 have continued to fall.

In the markets assessed in Figure 3.6, 2023 saw, on average, the BoS share of total costs ranging from a low of 48% in Austria to a high of 68% in Brazil. Also on average that year, BoS costs (excluding inverters) made up about 61% of total system costs. Overall, soft cost categories for the countries evaluated made up 30% of total BoS costs[33] and, on average, 19% of total installed costs during 2023.

Conversely, in Figure 3.6, modules and inverters together (non-BoS costs) ranged from USD 229/kW to USD 483/kW, with their share ranging from 32% to 52%. The average share for that category was 39%.

BoS hardware components made up between 17% and 39% of total installed costs during 2023, with an average share of 26% (equivalent to USD 218/kW). The range of installation costs ranged between 9% and 26% of costs and 16% on average (USD 134/kW).

A better understanding of cost component differences among 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. To track these markets' development – and to be able to devise targeted policy changes that address outstanding issues properly – a detailed understanding of individual cost components remains essential.

An analysis of the time series for historical markets highlights the BoS cost trend by category between 2018 and 2023. Between this period, the countries in Figure 3.7 experienced an average reduction of 47% in the module and inverter category, shifting from between USD 450/kW and USD 1 011/kW to between USD 229/kW and USD 483/kW.

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[33] *IRENA estimates a global capacity weighted average BoS share of 60% for the utility-scale solar PV market during 2023.*

Figure 3.7 Breakdown of utility-scale solar PV total installed costs by country, 2018 and 2023

Notes: BoS = balance of system; kW = kilowatt.

BoS hardware costs declined 39% on average during that period, with the range of costs declining from between USD 165/kW and USD 647/kW in 2018 to between USD 124/kW and USD 314/kW in 2023.

Installation costs declined 36% in 2023, compared to 7% in 2022. The cost range declined from between USD 51/kW and USD 691/kW in 2018 to USD 64/kW and USD 217/kW in 2023. In France and South Africa, installation costs remained the same in 2023 as in 2018. Indonesia was the only market that experienced an increase in costs, recording a hike of 66%.

Over the period, soft costs declined the most, with the average cost reduction 59% in 2023. The range of soft costs fell from between USD 248/kW and USD 1032/kW in 2018 to between USD 122/kW and USD 358/kW in 2023.

During 2018, the BoS share in the markets in Figure 3.7 ranged between 47% and 75%, while in 2023, it ranged between 57% and 68%. Over the period, the average BoS share in those markets decreased slightly, from 63% to 62%.

CAPACITY FACTORS

By the year commissioned, the global weighted average capacity factor[34] for new utility-scale solar PV increased from 13.8% in 2010 to 16.9% in 2022. In 2023 that value was 16.2% (a 4% relative decline). 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. This was in turn followed by a recent uptick. This was likely related to evolution in the technology unlocking 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. 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 26.9% to 20.8%, before increasing to 21.3% in 2021. In 2022, it declined again to 20.5%, but increased to 21.7% in 2023. The 5th percentile value declined less starkly, from 12.4% in 2018 to 9.9% in 2020, before growing to 10.8% in 2021 – a figure very close to its 2019 value. The 5th percentile declined slightly in 2022, to 10.4%, and again to 10% in 2023 (Table 3.1).

Global weighted average capacity factors have been experiencing stagnation. This could be an indication that solar PV projects have been expanding geographically to less-sunny regions. This is the case in United States, which added 25 GW of new capacity in 2023, yet the average capacity factor in the country has followed a flat trend since 2013 (Bolinger *et al.*, 2023).

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. These concurring factors, however, often develop differently by market and can therefore have a varying impact on the weighted average capacity factor (IRENA, 2022).

[34] The capacity factor for PV in this chapter is reported as an alternating current (AC)/direct current (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: 2) and Bolinger et al. (2015).

Table 3.1 Global weighted average capacity factors for utility-scale solar PV systems by year of commissioning, 2010-2023

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%	17.6%	27.0%
2018	12.4%	17.9%	26.9%
2019	10.7%	17.5%	23.9%
2020	9.9%	16.1%	20.8%
2021	10.8%	17.2%	21.3%
2022	10.4%	16.9%	20.5%
2023	10.0%	16.2%	21.7%

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 kW DC.

O&M COSTS

The O&M costs of utility-scale solar PV plants have declined in the last decade, driven by module efficiency improvements that 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 these 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, median O&M costs for utility scale plants declined 74% between 2011 and 2022, from USD 42.3kW/year to USD 11.2kW/year. The scope of these costs includes supervision and engineering, maintenance, rents as well as the training of a sample of 122 projects totalling 6 400 MW of AC. For the period from 2019 to 2021, O&M cost estimates declined between USD 19.6 kW/year and USD 11.4 kW/year, representing a decline of 42% and 2% for the 2019-2021 and 2021-2022 periods, respectively (Bolinger *et al.*, 2023).

Recent costs in the United States are dominated by preventive maintenance and insurance, with these making up 59% to 62% of the total, depending on the system type and configuration.

Recently, average utility-scale O&M costs in Europe were reported at USD 10/kW per year (Steffen *et al.*, 2019; 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 was a reduction of between 16% and 18% with every doubling of the solar PV cumulative installed capacity.

For 2023, projects in the *IRENA Renewable Cost Database* had a capacity weighted average utility-scale O&M cost of USD 10.3/kW per year (a decline of 62% on 2010). This value was 23% lower compared to 2022, when the capacity weighted average utility-scale O&M cost reached USD 13.3/kW per year (a decline of 51% from 2010).[35] These are the estimated total all-in O&M costs, including items such as insurance and asset management that are sometimes not reported in all O&M surveys.

Given the escalating importance of O&M costs, increasing the country granularity of these metrics in the calculation of the LCOE[26] could be beneficial in providing more timely and precise market information. Challenges in obtaining total all-in O&M cost data (and a breakdown by main cost categories) remain prevalent.

IRENA has a database of all-in O&M cost data for 185 utility-scale projects commissioned between 2020 and 2023. These total about 17 GW of capacity. Surveyed results by category, country and region are presented in Figures 3.8 and 3.9.

Figure 3.8 Survey results for the median all-in O&M costs for utility-scale solar PV by cost category and country, 2022-2023

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

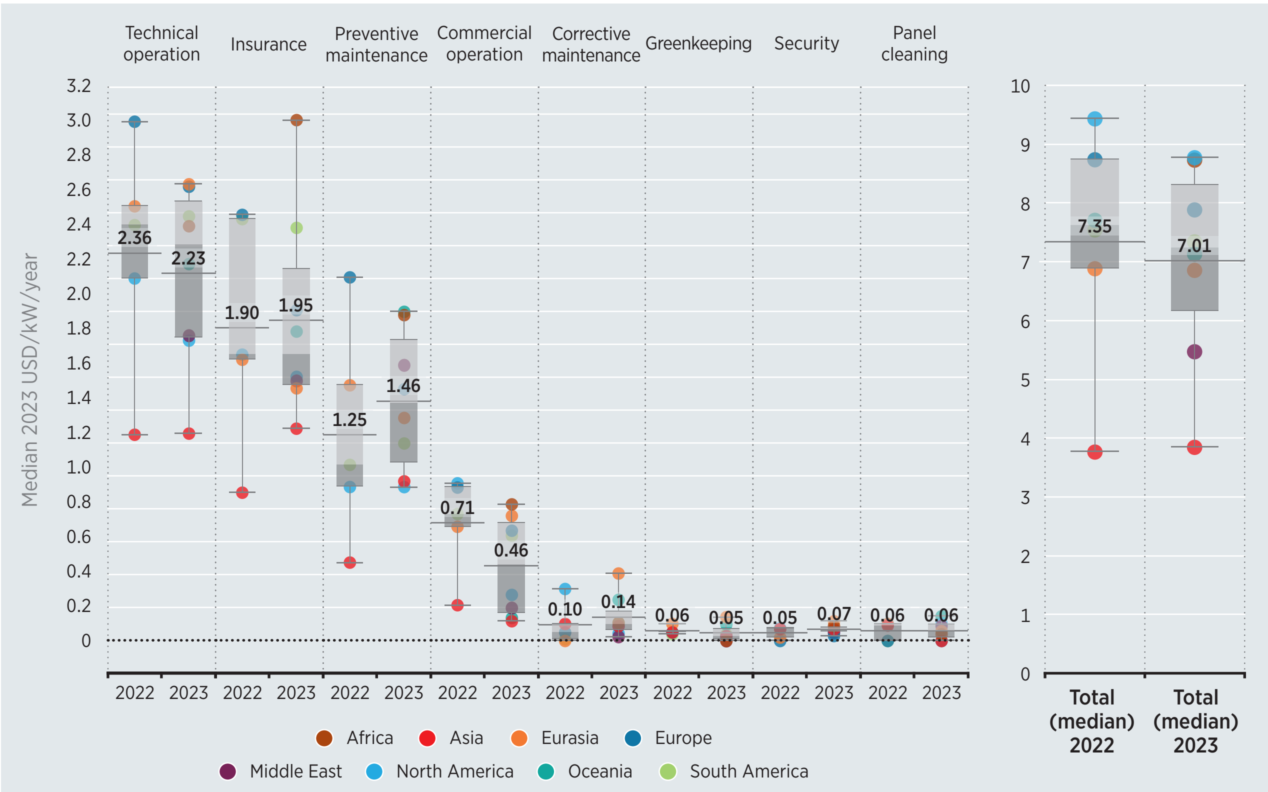
[36] *In this report, IRENA has assumed USD 18.2/kW per year (for OECD countries) and USD 9.2/kW per year (for non-OECD) as an input for the LCOE calculation of projects commissioned in 2023.*

The total O&M costs range between USD 6.4/kW per year and USD 8.9/kW per year. Aggregating all countries, the median for the sample is USD 7.56/kW, a value 7% lower compared to 2022. As with the total installed costs metric, O&M costs show a wide span across markets. In the sample, this range spans from USD 3.6/kW per year in China to USD 13.9/kW per year in Japan.

Looking at the individual cost categories, technical operation, insurance and preventive maintenance make up about 87% of the total O&M costs. Between 2022 and 2023, costs decreased by 7% for technical operations while they increased slightly for insurance and preventive maintenance – by 1.5% and 0.7%, respectively.

A regional perspective reveals that the lowest O&M costs can be found in Asia. In 2023, the surveyed results were USD 3.8/kW per year in the region, which was a value 2% higher compared to 2022 (Figure 3.9).

Figure 3.9 Survey results for the median all-in O&M costs for utility-scale solar PV by cost category and region, 2022-2023



Note: see Annex III for regional country groupings.

In 2023, North America showed the highest total O&M costs in the survey, at USD 8.8/kW per year, compared to USD 9.4/kW in 2022 (a decline of 6%). Median values for Europe were USD 7.9/kW per year, representing a decrease of 10%, which was the highest decline among all regions between 2022 and 2023. Survey results for Oceania were USD 7.1/kW per year, a value 7% lower. Costs in Eurasia and South America were USD 6.9/kW and USD 7.3/kW per year, respectively.

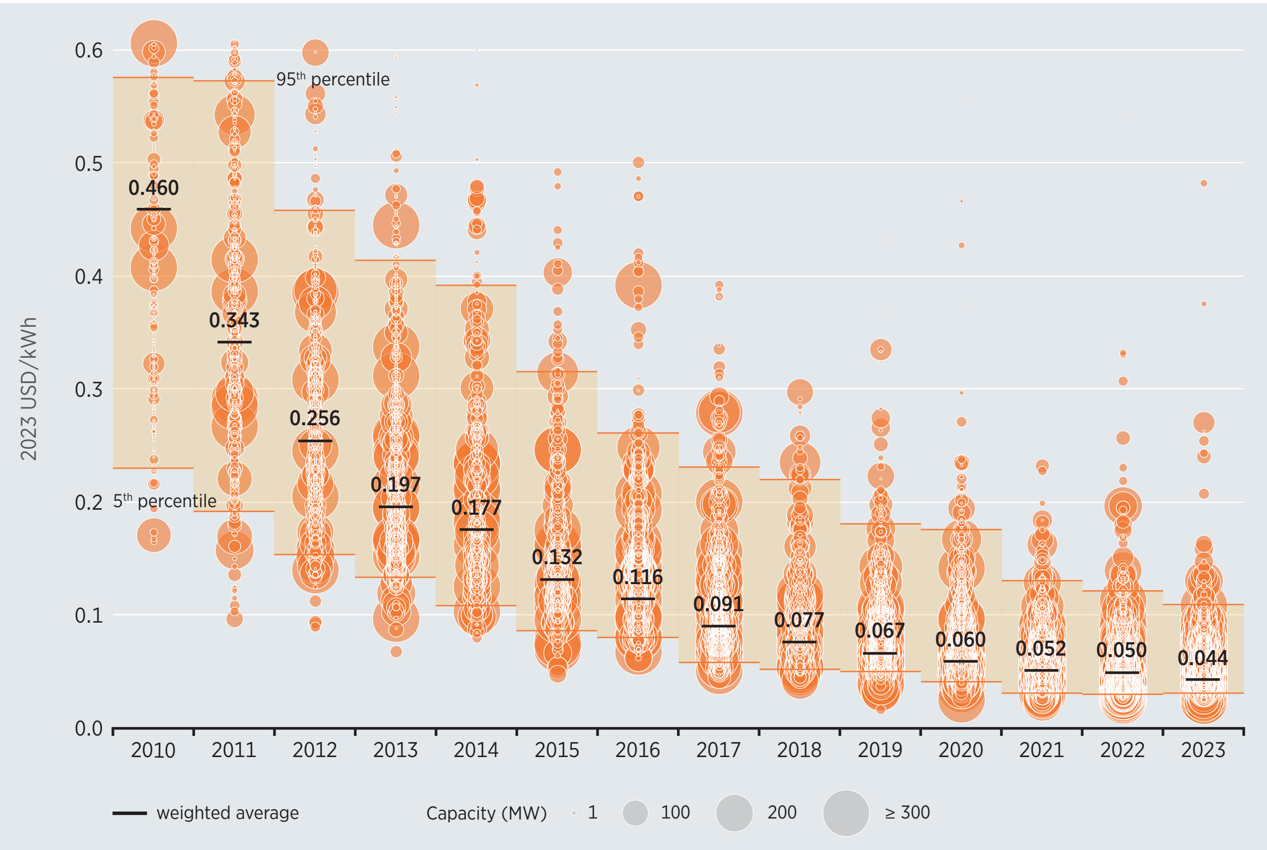
LCOE

The global weighted average LCOE of utility-scale PV plants declined by 90% between 2010 and 2023, from USD 0.460/kWh to USD 0.044/kWh. This 2023 estimate also represented a 12% year-on-year decline from 2022, while the decline between 2021 and 2022 was 3%.

Globally, the range of LCOE costs continues to narrow. In 2022, the 5th and 95th percentile of projects ranged from USD 0.031/kWh to USD 0.122/kWh. In 2023, the range for this metric was between USD 0.031/kWh and USD 0.110/kWh, representing 87% and 81% declines on the 2010 5th and 95th percentile values, respectively. The LCOE range in 2023 (the gap between the 5th and the 95th percentile values) reached its lowest level since 2010 (a decline of 77%). After a stark decline of 24% between 2020 and 2021, the 5th percentile remained flat during 2021 and 2023 to reach USD 0.031/kWh.

In 2020, the 95th percentile value remained flat in relation to its value in 2019, but declined 26% between 2020 and 2021.The 95th percentile value declined 6% between 2021 and 2022 and 10% between 2022 and 2023 (Figure 3.10).

Figure 3.10 Global utility-scale solar PV project LCOE and range, 2010-2023



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

Box 3.3 Unpacking the decline in utility-scale solar PV's LCOE from 2010 to 2023

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.

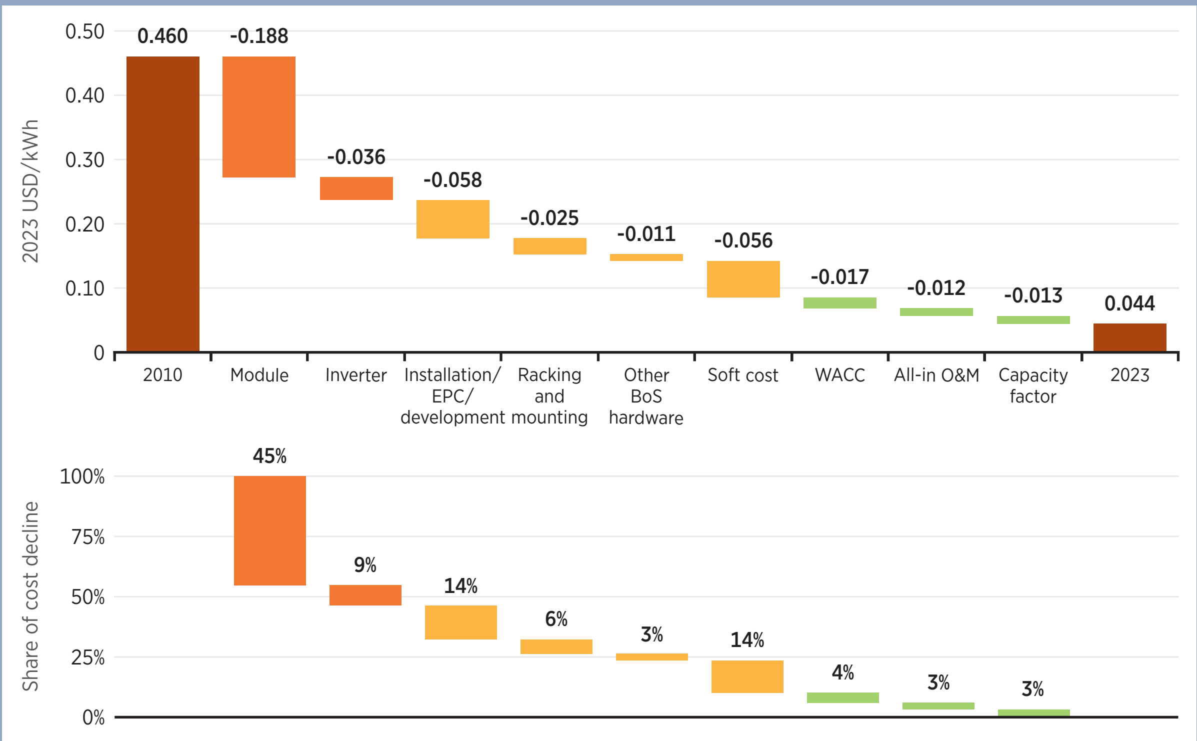
Since 2010, the solar PV industry has seen a variety of technological developments that have contributed to improvements in the competitiveness of the technology. These have occurred along the whole solar PV value chain, from increased deployment of larger polysilicon factories and improved ingot growth methods to the increased ascendancy of diamond wafering methods. With the solar PV industry also seeing the emergence and dominance of newer cell architectures and larger wafer sizes, the sector is constantly seeing innovations that unlock LCOE reductions.

The rapid decline in solar PV module costs has also led to the emergence of new PV markets around the globe. Between 2010 and 2023, the cost declines due to modules alone contributed 45% to the LCOE reduction of utility-scale PV, while inverters contributed another 9% (Figure B3.3a). The costs of other hardware components also declined during the period. Indeed, taken together, racking and mounting and other BoS hardware contributed another 9% to the LCOE reduction between 2010 and 2023.

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 28% of the LCOE decline over the 2010 to 2023 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 B3.3a Drivers of the decline of the global weighted average LCOE of utility-scale solar PV, 2010-2023

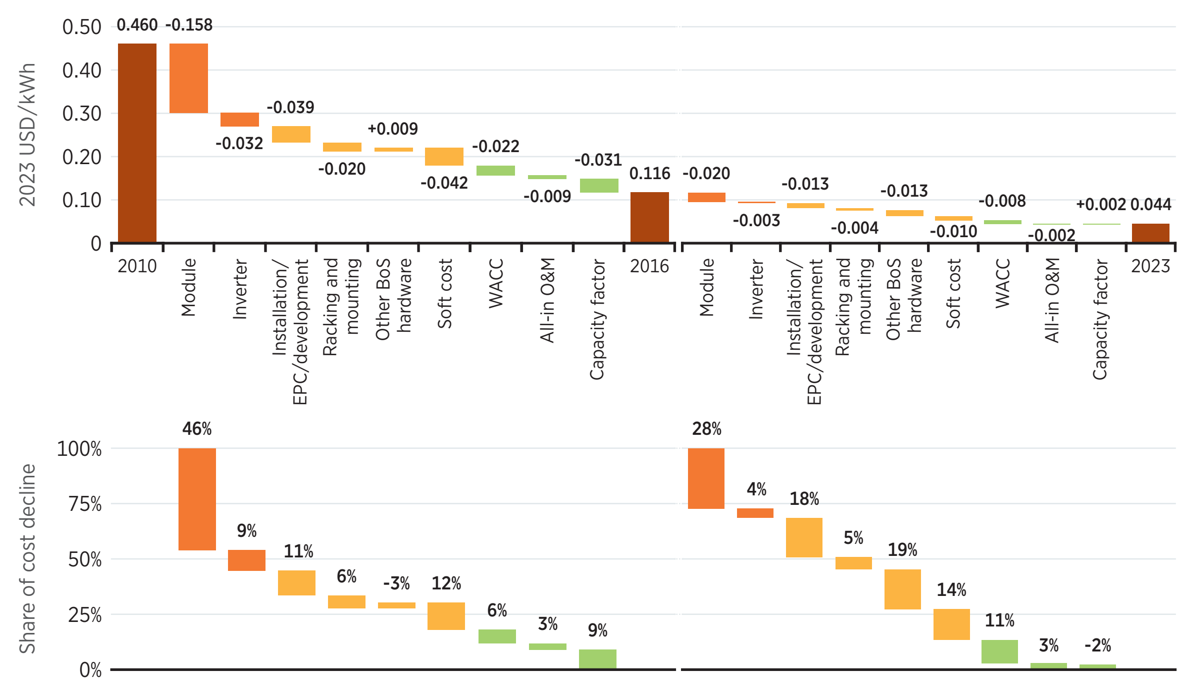


Note: Percentage figures may not total 100, due to rounding up; EPC = engineering, procurement and construction; BoS = balance of system; O&M = operation and maintenance; WACC = weighted average cost of capital.

Looking at two periods separately illustrates the dynamic nature of the drivers for the LCOE of utility-scale solar PV. The global weighted average LCOE of utility-scale PV plants declined by 71% between 2010 and 2016, from USD 0.460/kWh to USD 0.116/kWh.

This fall was driven heavily by module and inverter costs, which together were responsible for 56% of the decline (Figure B3.3b). Between 2010 and 2016, BoS costs (excluding the inverter) accounted for 26% of the reduction. The rest of the decline in that period came from factors such as: better financing conditions, as the technology risk perception started to decline in major markets; O&M costs becoming more competitive; and global weighted-capacity factors increasing as projects were increasingly being built in markets with improving solar resources.

Figure B3.3b Source of the decline in the global weighted average LCOE of utility-scale solar PV in two periods, 2010-2016 and 2016-2023



Note: Percentage figures may not total 100, due to rounding up; EPC = engineering, procurement and construction; BoS = balance of system; O&M = operation and maintenance; WACC = weighted average cost of capital.

Between 2016 and 2023, changing dynamics in global markets caused a very different picture to emerge when analysing the same drivers. Module costs continued to decline during this period and remained the single highest contributor to the LCOE decline. However, module and inverter costs together accounted for 32% of the total LCOE decline between 2016-2023 (compared to 55% between 2010 and 2016). Other BoS hardware and Installation costs had major contribution in the second period, accounting for 19% and 18% of the LCOE fall, respectively. The rest of the BoS categories accounted for another fifth of the LCOE reduction between 2016 and 2023. In total for that period, BoS costs (excluding the inverter) accounted for 56% of the LCOE decline (almost twice as much as between 2010 and 2016).

Between 2016 and 2023, the capacity factor showed a slight increase of 2% compared to 9% decline between 2010 and 2023. During that period, the solar resources available for projects did not change as drastically as between 2010 and 2016.

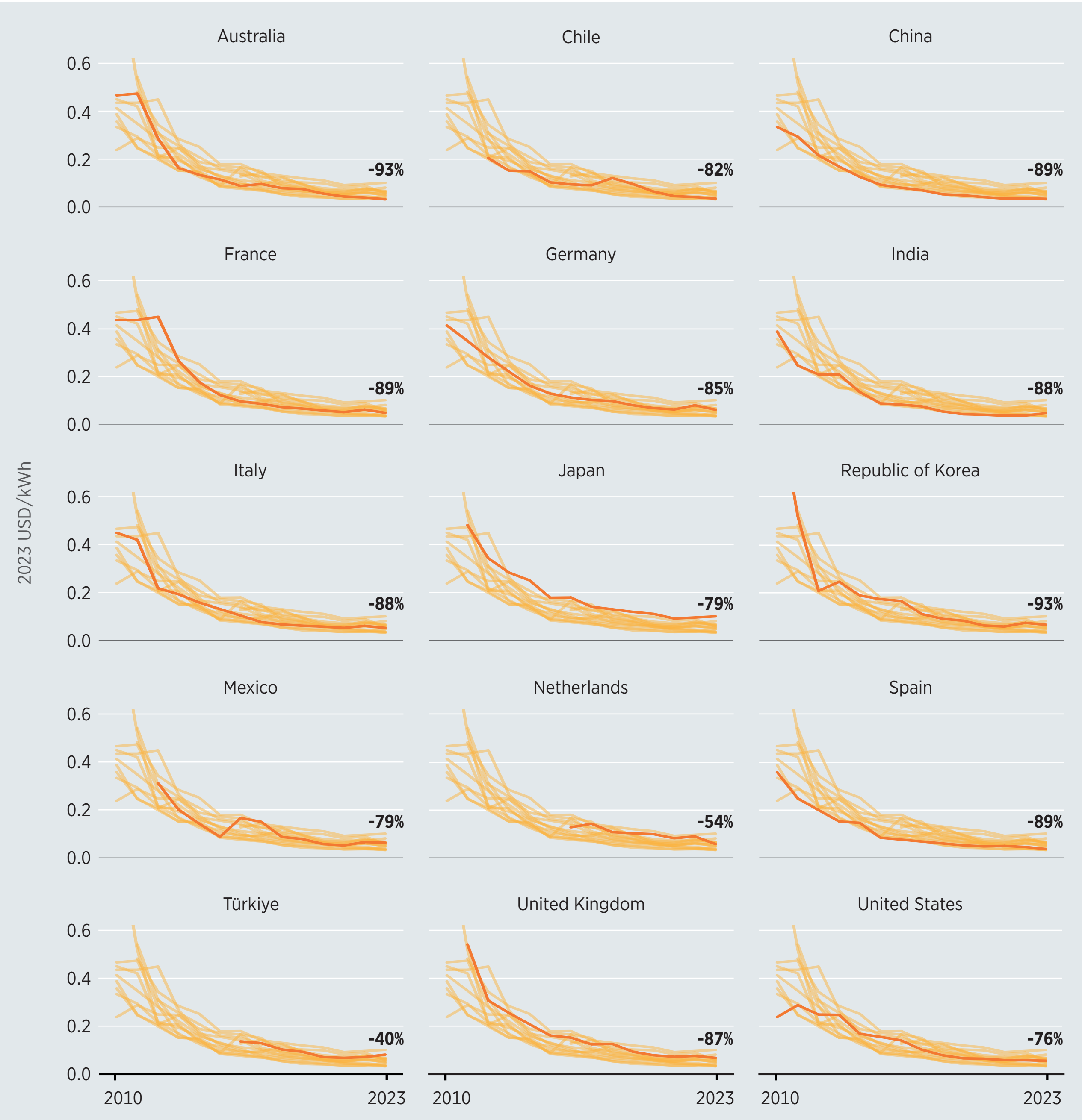
The weighted average cost of capital as a driver of LCOE reductions was 11% between 2016 and 2023, compared to 6% during the first period. This shows that financing conditions continued to improve.

The cost of capital (CoC) for renewable power generation technologies is a major determinant of the cost of electricity from those technologies. Both reliable data and a deep understanding of the composition of the CoC and its drivers are therefore critical information. For instance, for a representative solar PV project or onshore wind project, the total cost of electricity increases by 80% if the CoC is 10% rather than 2%.

IRENA has recognised the need for improved CoC data for some time, given falling borrowing costs and the growing maturity of solar and wind power technologies. The WACC for solar PV in 100 countries was updated – based on the results of the IRENA ETH Zurich and IEA Wind (IRENA, 2023) survey – and incorporated in the LCOE calculations to capture real financing base rates.

The downward trend in the LCOE of utility-scale solar PV by country is presented in Figure 3.11. This shows that in markets where historical data were available from 2010, the weighted average LCOE of utility-scale solar PV declined by between 76% (in the United States) and 93% (in Australia and the Republic of Korea) between 2010 and 2023.

Figure 3.11 Utility-scale solar PV weighted average cost of electricity in selected countries, 2010-2023



Note: Lines represent all 15 markets. The line in bold corresponds to the market identified on the top of each graph.

Among the markets shown in Figure 3.11, in 2023, the lowest weighted average LCOEs in the utility-scale sector were in Australia and China. Between 2010 and 2023, costs in Australia declined 93%, to reach USD 0.034/kWh, while in China they declined 89%, to USD 0.036/kWh. The weighted average LCOE in Australia was 22% lower than the global weighted average, as reported in Figure 3.10.

Figure 3.11 also shows that costs in Chile were the third most competitive among historical markets, at USD 0.036/kWh (9% above Australia). This came after a 14% year-on-year decline. The LCOE of projects in Spain declined 18% and reached a similarly competitive level in 2023, at USD 0.038/kWh. This returned the Spanish market to a trend of declining costs, after an increase of 4% in the LCOE between 2020 and 2021.

In 2023, India had the fourth most competitive cost, at USD 0.048/kWh. This was 26% up on the 2022 LCOE of USD 0.038/kWh.

The LCOE of utility-scale PV in the United States declined 3%, year-on-year, to reach USD 0.057/kWh during 2023 (33% above the global weighted average).

The Netherlands experienced the greatest decrease, with its LCOE falling 35% between 2022 and 2023 to reach USD 0.059/kWh.

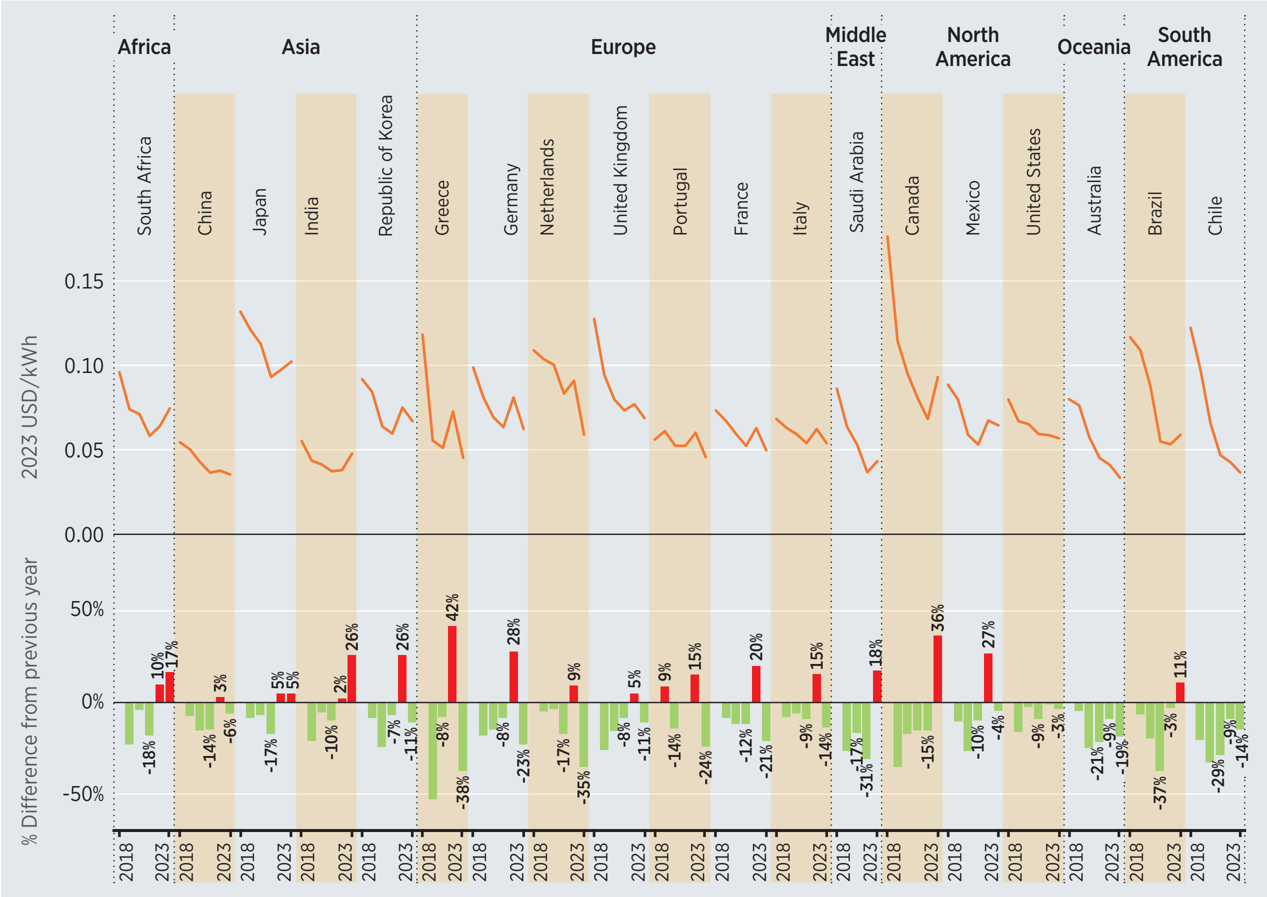
During 2023, the LCOE in Japan increased 5% – as it had done in 2022 – to reach USD 0.103/kWh. This value was 2.5 times the LCOE in Australia, which was the most competitive country amongst those analysed in 2023.

Figure 3.12 examines the weighted average LCOE trend for the top utility-scale markets between 2018 and 2023. Costs declined in 14 of the markets shown in the figure, with major LCOE reductions in the top markets in Europe and Oceania. Indeed, all 8 European markets saw utility scale solar PV costs decrease, with these declines ranging between 11% (in the United Kingdom) and 38% (in Greece). In Oceania, Australia had the most competitive LCOE, with its costs declining 19% over the period.

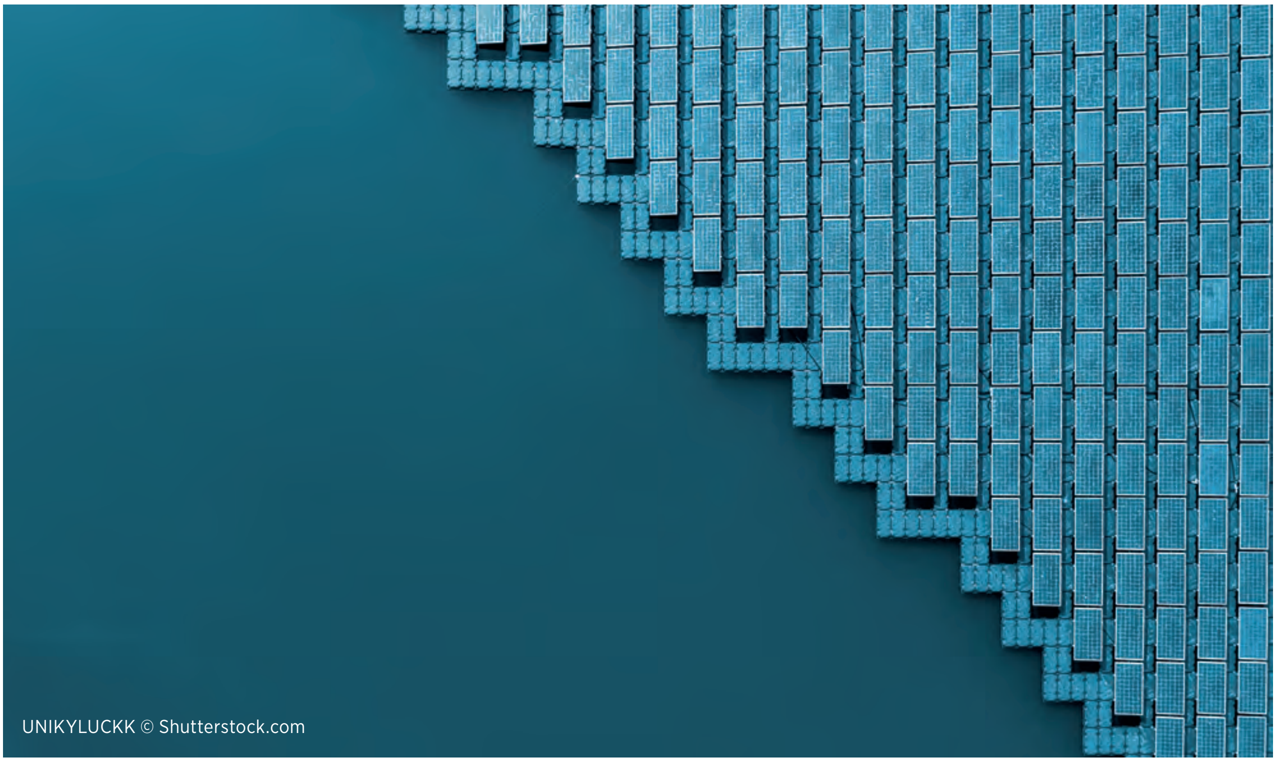
During 2023, the LCOE of projects in Brazil increased 11%, year-on-year, from USD 0.054/kWh to USD 0.059/kWh.

In Saudi Arabia, the LCOE increased 18% in 2023 to reach USD 0.044/kWh, after decreasing 31% during 2022. However, the LCOE in 2023 was still lower than in 2021, when it had been USD 0.053/kWh.

Figure 3.12 Utility-scale solar PV weighted average LCOE trends in major utility-scale markets, 2018-2023



Note: see Annex III for regional country groupings.



04 OFFSHORE WIND

TwiXteR © Shutterstock.com

HIGHLIGHTS

The global weighted average levelised cost of electricity (LCOE) of offshore wind declined by 63% between 2010 and 2023, from USD 0.203/kWh to USD 0.075/kWh. In 2023 alone, there was a 7% reduction, year-on-year.

Between 2010 and 2023, global weighted average total installed costs fell 48%, from USD 5 409/kW to USD 2 800/kW. At its peak – in 2011 – the global weighted average total installed cost was USD 6 195/kW, 2.2 times higher than its 2023 value.

Global cumulative installed capacity of offshore wind increased more than twenty- three-fold between 2010 and 2023, from 3 GW to 73 GW. This was driven almost equally by installations in China and Europe. In 2023, the global cumulative installed capacity of offshore wind increased by 11 GW (17%), year-on-year, of which 7 GW was added in China and 3 GW in Europe.

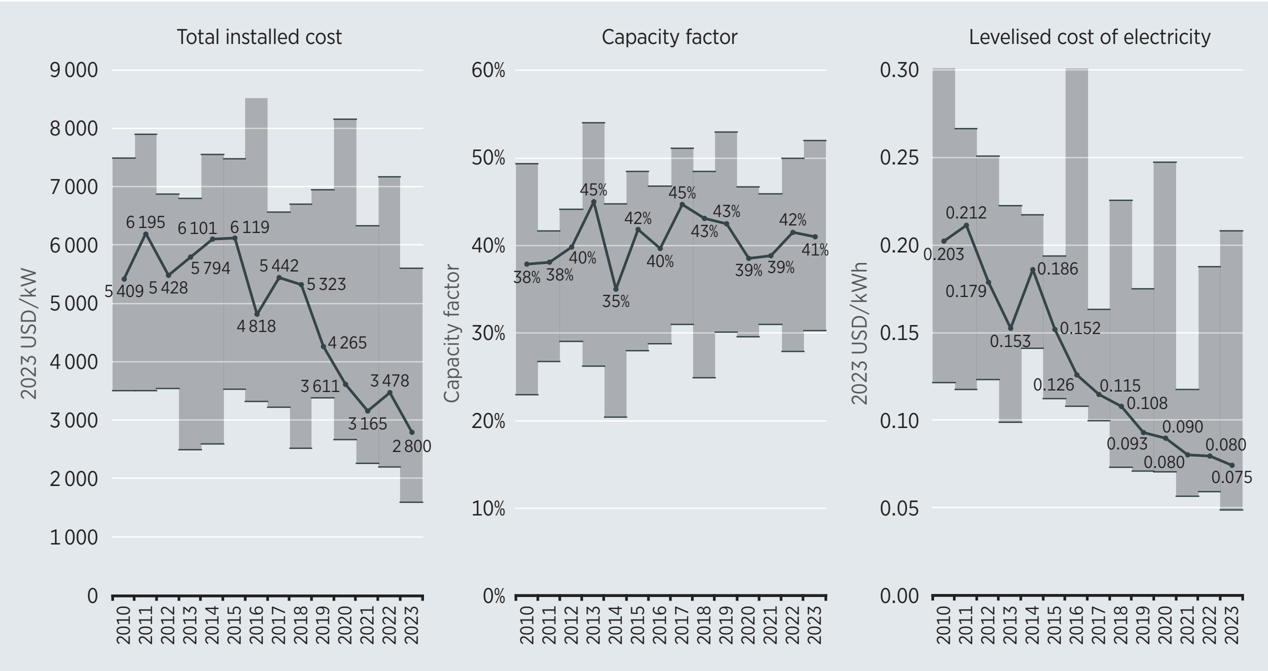
Improvements in technology – including larger turbines with longer blades and higher hub heights – along with access to better wind resources, resulted in an increase in the global weighted average capacity factor. This increased from 38% in 2010 to 45% in 2017, and in 2023 reached 41%.

In Europe, between 2022 and 2023 the weighted average LCOE of newly-commissioned projects went down 8%, from USD 0.073/kWh to USD 0.067/kWh. In 2023, total installed costs decreased 21%, year-on-year, while the weighted average capacity factor of new projects increased from 42% to 48%.

In China, the weighted average LCOE of newly-commissioned projects went down 9% between 2022 and 2023, from USD 0.077/kWh to USD 0.070/kWh. In 2023, total installed costs fell 16%, year-on-year, while the weighted average capacity factor of new projects increased from 37% to 40%.

Overall, total installed cost and LCOE reductions have been driven by both improvements in technology and the growing competitiveness of the supply chain.

Figure 4.1 Global weighted average and range of total installed costs, capacity factors and LCOE for offshore wind, 2010-2023



INTRODUCTION

Offshore wind technology has matured rapidly since 2010. Indeed, cumulative deployed capacity increased more than twenty-four-fold between 2010 and 2023, from 3 GW to 73 GW (IRENA, 2024a). Nearly 11 GW of newly-installed offshore wind was commissioned during 2023 alone, making it the second-highest year recorded for new offshore wind capacity.

Between 2017 and 2020, global annual capacity additions of this technology averaged over 5 GW. In 2021, new offshore wind capacity additions totalled 20 GW, driven by a spike in projects commissioned in China. This total then dropped back to 8 GW in 2022, before increasing to 11 GW of newly-commissioned capacity in 2023. That year, the Asia region led new offshore capacity, with 8 GW commissioned. China accounted for 86% of this expansion, with 7 GW of newly-commissioned offshore wind projects. The remaining capacity expansion occurred in Europe.

Currently, offshore wind makes up around 7.1% of the cumulative onshore and offshore global wind capacity. Plans and targets for future deployment have been expanding as costs have decreased and the technology has matured. A significant expansion of offshore wind is now expected, especially with the Global Renewables and Energy Efficiency Pledge. This pledge, signed by more than 130 countries during COP28, aims to triple renewable power generation capacity from 2022 levels by 2030. An increase of around 431 GW in offshore wind energy is therefore envisioned, up from 63 GW in 2022 to 494 GW in 2030 (COP28 Presidency *et al.*, 2023).

Efforts towards this are already underway. In November 2023, eight EU countries, Norway and the European Commission launched a tender plan in which around 15 GW of offshore wind will be auctioned every year, totalling almost 100 GW between 2023 and 2030 (European Commission, 2023). In addition, in 2023, Germany had its biggest auction to date, awarding 7 GW of new capacity (Bundesnetzagentur, 2023).

Offshore wind farms face more challenging conditions than their onshore counterparts throughout installation, commissioning and their O&M due to the harsh marine environments in which they are situated. Their offshore locations complicate construction and grid connection, further adding to their planning and project development complexity. Consequently, offshore wind projects tend to have higher costs and significantly longer lead times than onshore wind projects.

Offshore wind provides several benefits, including greater and more consistent wind speeds, the ability to transport large infrastructure directly from ports, and the capacity to build larger wind farms that generate more electricity. The vast wind energy potential in open waters, combined with higher level of social acceptance, further strengths its appeal.

The recent increase in deployment, technology improvements, economies of scale and the growing experience of developers and turbine manufacturers have also unlocked cost reductions, particularly for fixed-bottom installations. Fixed-bottom foundations continue to have the biggest share of deployment, but floating offshore wind has now entered the early commercial stage,[37] with the first plants already demonstrating the potential to exploit the vast wind potential of deeper waters.

[37] *See IRENA's Floating Offshore Wind Outlook for more details (IRENA, 2024c).*

Indeed, France has recently announced the winner of what is likely to be the world's first truly commercial scale (250 MW) floating offshore wind project (Ministére de l'Économie, des Finances et de la Souveraineté industrielle and et numérique, 2024)

The increasing maturity of the industry is noticeable in cost-saving programmes. These include 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. This comes 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 achieved by servicing offshore wind farm zones instead of individual wind farms. Furthermore, the increased availability of wind turbine models, as manufacturers continuously learn from recent experience and incorporate improvements into newer products, has also contributed to cost reduction.

An important area of improvement is linked to the ongoing digitisation of the power sector. The increasingly sophisticated use of data analytics and artificial intelligence (AI) enables supply chain efficiencies, siting optimisation, predictive maintenance programmes and anomaly detection. By addressing potential issues before costly failures occur, using vast turbine performance data, or creating scenarios for different strategies, these tools contribute to lower O&M costs and enhance turbine availability.

PROJECT CHARACTERISTICS

The logistical considerations surrounding offshore wind installations are crucial factors that significantly influence total installed costs. Two important factors to consider are the water depth and the distance from shore or port. The latter affects the travel time between the port and wind farm for foundations and turbines during installation, while the water depth impacts the size and type of the foundations. Additionally, the distance to the port and the type of foundation (fixed-bottom or floating) impact O&M costs, decommissioning costs and vessel availability.

Figure 4.2 presents the trends in distance-to-port and water depth between 2000 and 2023 in Europe, compared with China and the rest of the world. The trend towards siting projects in deeper waters and further from shore is most pronounced in Europe, the most mature market for offshore wind. Most recent projects in this region have been in waters between 18 metres and 57 metres deep, with an increasing proportion located between 65 kilometres (km) and 130 km. Although a significant number of European projects – especially recent floating offshore wind demonstrators – remain closer to shore due to their early development stage, it is also expected that in the future, projects will be deployed further from shore.

Figure 4.3 highlights the varying trends in water depth and distance from shore at the country level for Belgium, China, Denmark, Germany, the Netherlands and the United Kingdom. Most of the more distant offshore wind projects can be found in Germany and the United Kingdom. The latter is Europe's largest offshore wind proponent, with 15 GW of installed capacity at the end of 2023. Additionally, in the same year, the United Kingdom partially commissioned is farthest-from-shore wind farm, located around 131 km from the coast at its closest point (Dogger Bank, 2024). Belgium, China, Denmark and the Netherlands are still predominantly developing wind farms in zones closer to shore, although the Netherlands has a significant share of its total offshore wind installed capacity 50 km or more from the coast. All these countries are, however, currently capable of exploiting areas in shallow water, ranging in depth from 20 metres to 40 metres.

With relatively few commissioned offshore wind farms outside the major markets of Europe and China, there is no real global trend in water depth and distance from shore. Most countries continue to prioritise zones close to shore, within 50 km from the coast, albeit with a very wide spread of water depths. These range from 26 metres to 50 metres for utility-scale projects, with depth also depending on aspects related to site location, such as seabed characteristics, as well as other constraints to be considered when developing projects, such as protected areas.

Figure 4.2 Average distance from shore and water depth for offshore wind in Europe, China and the rest of the world, 2000-2023

Source: Wood Mackenzie (2024).
Notes: km = kilometre; m = metre; MW = megawatts.

Figure 4.3 Distance from shore and water depth for offshore wind projects by country, 2000-2023

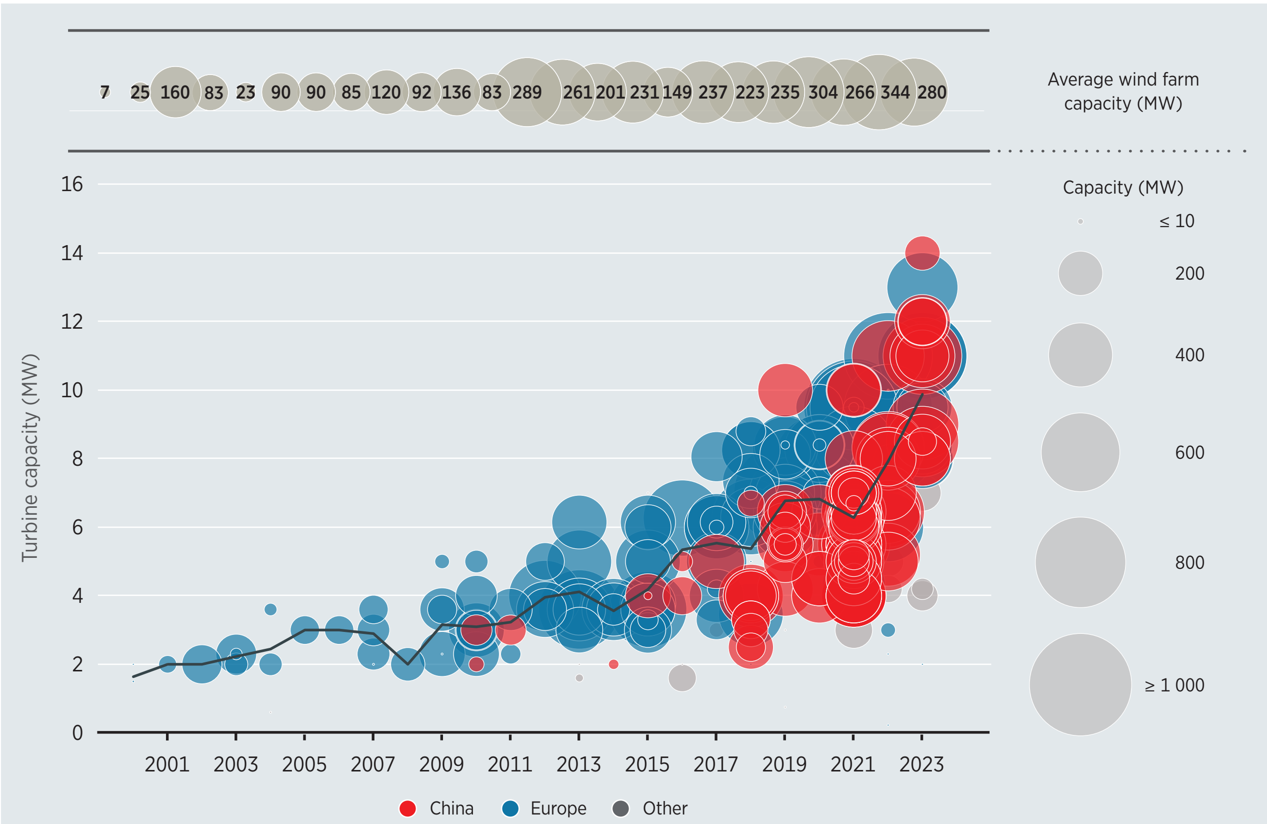
Source: Wood Mackenzie (2024).
Notes: km = kilometre; m = metre; MW = megawatts.

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, 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.

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 those wind farms for which data are available.

The potential of offshore wind is evident with significant progress made in the last few years through scaling of turbines and total project size (Figure 4.4). Between 2010 and 2023, the average offshore wind project size increased by 106%, from 136 MW to 280 MW. The average project size decreased in 2023, by 19% year-on-year, as smaller projects in China and United Kingdom were deployed. Nevertheless, since 2020, several projects have reached capacities exceeding 1 GW and more will be installed in coming years, notably in the United Kingdom. Wind turbine sizes have also been increasing, rising from a weighted average of 3 MW in 2010 to 10 MW in 2023. Moreover, between 2021 and 2022, there was a 29% increment in wind turbine capacities. This was followed by a further 25% increase between 2022 and 2023, as projects began to utilise the next generation of turbines – those in the 11-13 MW size range.

Figure 4.4 Project turbine size, global weighted average turbine size and wind farm capacity for offshore wind, 2000-2023



Source: Wood Mackenzie (2024).
Note: MW = megawatts.

Table 4.1 below shows the characteristics of an average offshore wind farm in China and Europe in 2010, 2017 and 2023. The handful of offshore wind farms commissioned in Europe in 2010 averaged 155 MW in total capacity, with this growing to 470 MW in 2023. Over this period, the water depth of projects increased from 21 metres to 35 metres and the distance to shore reached 35 km. In China, the average offshore windfarm size was 321 MW in 2023, with a weighted average water depth of 29 metres and a distance to shore of 27 km, according to project data in the *IRENA Renewable Cost Database*.

Table 4.1 Project characteristics in China and Europe in 2010, 2017 and 2023

The average offshore wind farm in China vs Europe		2010	2017	2023
Project size (MW)	China	67	255	321
	Europe	155	253	470
Distance from shore (km)	China	12	15	27
	Europe	18	61	35
Water depth (m)	China	9	12	29
	Europe	21	32	35
Hub height (m)	China*	-	92	131
	Europe	83	100	127
Rotor diameter (m)	China	-	171	227
	Europe	112	141	190
Nameplate capacity (MW)	China	2.8	5.0	10.1
	Europe	3.1	5.6	10.4

Source: Wood Mackenzie (2024).

Notes: *Country where data were only available for projects commissioned in 2018, not 2017; m = metres; km = kilometre; MW = megawatt.

Rotor diameters are increasing. Globally, the weighted average rotor diameter of turbines used for commissioned offshore wind projects grew by 84% between 2010 and 2023, and 16% from 2022 to 2023. The weighted average rotor diameter for Europe was 141 metres in 2017, rising 35% to 190 metres in 2023. In China, the diameter increased 33% over the same period, from 171 metres to 227 metres.

The difference in rotor diameter between China and Europe is primarily attributed to the variance in wind speeds. This distinction arises from the fact that the weighted average wind speed of projects in the *IRENA Renewable Cost Database* for China is lower than that of Europe. The wind speed site distribution significantly impacts the energy output, with manufacturers adjusting rotor and turbine sizes to optimise energy generation in differing wind conditions.

TOTAL INSTALLED COSTS

Installing and operating wind turbines in the harsh marine environment offshore increases costs. Compared to onshore wind, planning and project development costs and lead times are also higher and longer. Data must be collected on seabed characteristics and site locations for the offshore wind resource, while obtaining permits and environmental consents entails great complexity and can be time consuming. Logistical costs are higher the farther the project is from a suitable port, while greater water depths require more expensive foundations. Yet, offshore wind has the advantage of economies of scale, meaning that some of these costs are not disproportionately higher than those for onshore wind.

In addition, with more stable wind output – resulting from higher average wind speeds and reduced wind shear and turbulence – higher capacity factors are available offshore than onshore. Additionally, offshore wind farms can be located near coastal demand centres at scale, as seen in regions like China and Republic of Korea. In Europe, meanwhile, offshore wind generation is higher in winter, aligning with peak demand. These factors, among others, ensure offshore wind can provide significant output and, in many cases, a higher value than onshore wind to the electricity system.

Figure 4.5 illustrates the trends in the global weighted average total installed cost of offshore wind farms over time. The global weighted average total installed cost of these farms increased from around USD 2 979/kW in the year 2000 to USD 6 337/kW in 2008. It then bounced around the USD 5 500/kW mark for the period 2008 to 2015, as projects moved farther from shore and into deeper waters. After 2015, this cost began to decline, falling relatively rapidly to USD 3 137/kW in 2021, then rising slightly to USD 3 478/kW in 2022, before decreasing to USD 2 800/kW in 2023.


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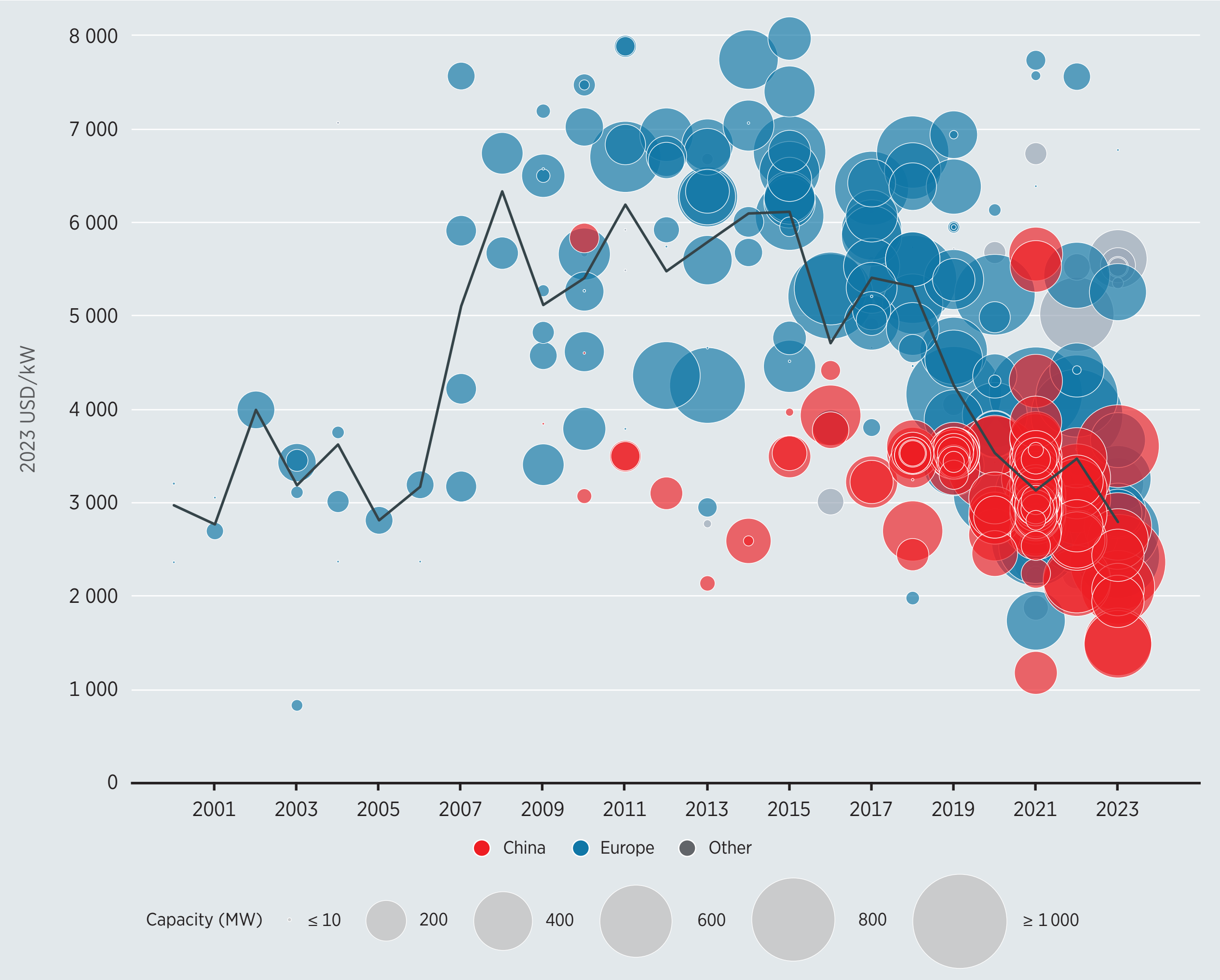
Figure 4.5 Project and global weighted average total installed costs for offshore wind, 2000-2023



Notes: kW = kilowatt; MW = megawatt.

A number of factors explain the increase in total installed costs that occurred after 2006. These include:

- The shift to projects in deeper water and farther from shore and/or ports had the effect of increasing logistical costs, installation costs and foundation costs.
- The increasing scale and complexity of projects required a proportional increase in project development costs (*e.g.* 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. They also increased the cost of the materials used in offshore wind turbines and their foundations, transmission cabling, and other components (IRENA, 2019).

Supply chain bottlenecks for turbines, along with cables and logistics issues, contribute to cost increases, albeit temporary (Green and Vasilakos, 2011; Kostka and Anzinger, 2016). Consequently, the weighted average total installed costs have recently followed a downward trend, falling 55% from their peak in 2011 to a global weighted average of USD 2 800/kW for projects commissioned in 2023.

Significant support for the trend of falling offshore total installed costs came from a variety of factors. These included: lower commodity prices; reduced risks due to stable government policies and support schemes; enhanced turbine designs; standardisation of design and industrialised manufacturing; improvements in logistics (especially with specialised installation vessels and port development supporting the offshore wind sector); and economies of scale from clustered projects in Europe. Yet, due to the relatively thin market compared to onshore wind and solar PV, the annual global weighted average total installed cost remains volatile.

This volatility also stems from the site-specific nature of offshore wind projects, as well as the differences in market maturity and the scale of the local or regional supply chain. Each year's deployment is also distributed slightly differently across markets, adding to the annual volatility. In 2023, for example, China accounted for the majority of total deployment. Global weighted average total installed costs were therefore heavily influenced by China's lower costs, which came from lower commodity prices and labour costs, as well as from the near-shore and inter-tidal nature of most Chinese wind farms.

The choice of the party responsible for the wind farm-to-shore transmission asset is another consequential factor influencing total installed costs. This choice also varies by country. In some cases, the transmission assets are owned by the national or regional transmission network owner, while in other cases they are owned by the wind farm developer.[38] In China, grid connection assets are developed by project owners, or the transmission network owner. In Denmark and the Netherlands, however, grid connections are developed and owned by the network operator. It is therefore important to look at total installed cost trends on a country-by-country basis to understand how cost structures are evolving.

In the year 2023, all the regions and countries listed in Table 4.2 experienced a decrease in weighted average total installed costs. Between 2010 and 2023, Germany had the highest percentage decrease, at 61%, with costs falling from USD 7 476/kW to USD 2 895/kW. Over the same period, China, which has the largest cumulative offshore wind deployment globally (roughly 37 GW), experienced a 54% decline in weighted average total installed cost, from USD 5 145/kW to USD 2 370/kW. In the Netherlands, which had the second largest offshore wind added capacity in 2023 (at 1.48 GW), the project-specific, weighted average total installed cost was USD 2 564/kW.

[38] 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.

Table 4.2 Regional and country weighted average total installed costs and ranges for offshore wind, 2010 and 2023

	2010			2023		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2023 USD/kW)					
Asia	3 307	**5 192**	5 813	1 512	**2 651**	5 564
China	3 230	**5 145**	5 715	1 504	**2 370**	3 225
Japan	5 672	**5 672**	5 672	5 528	**5 528**	5 528
Republic of Korea*	n.a.	**n.a.**	n.a.	5 811	**6 964**	8 118
Europe	4 405	**5 418**	7 476	2 511	**3 138**	4 784
Belgium*	7 027	**7 027**	7 027	3 740	**3 933**	4 300
Denmark	3 797	**3 797**	3 797	2 918	**2 918**	2 918
Germany	7 476	**7 476**	7 476	2 895	**2 895**	2 895
The Netherlands**	4 769	**4 769**	4 769	2 443	**2 564**	2 686
United Kingdom	4 687	**5 273**	5 627	3 284	**3 432**	3 656

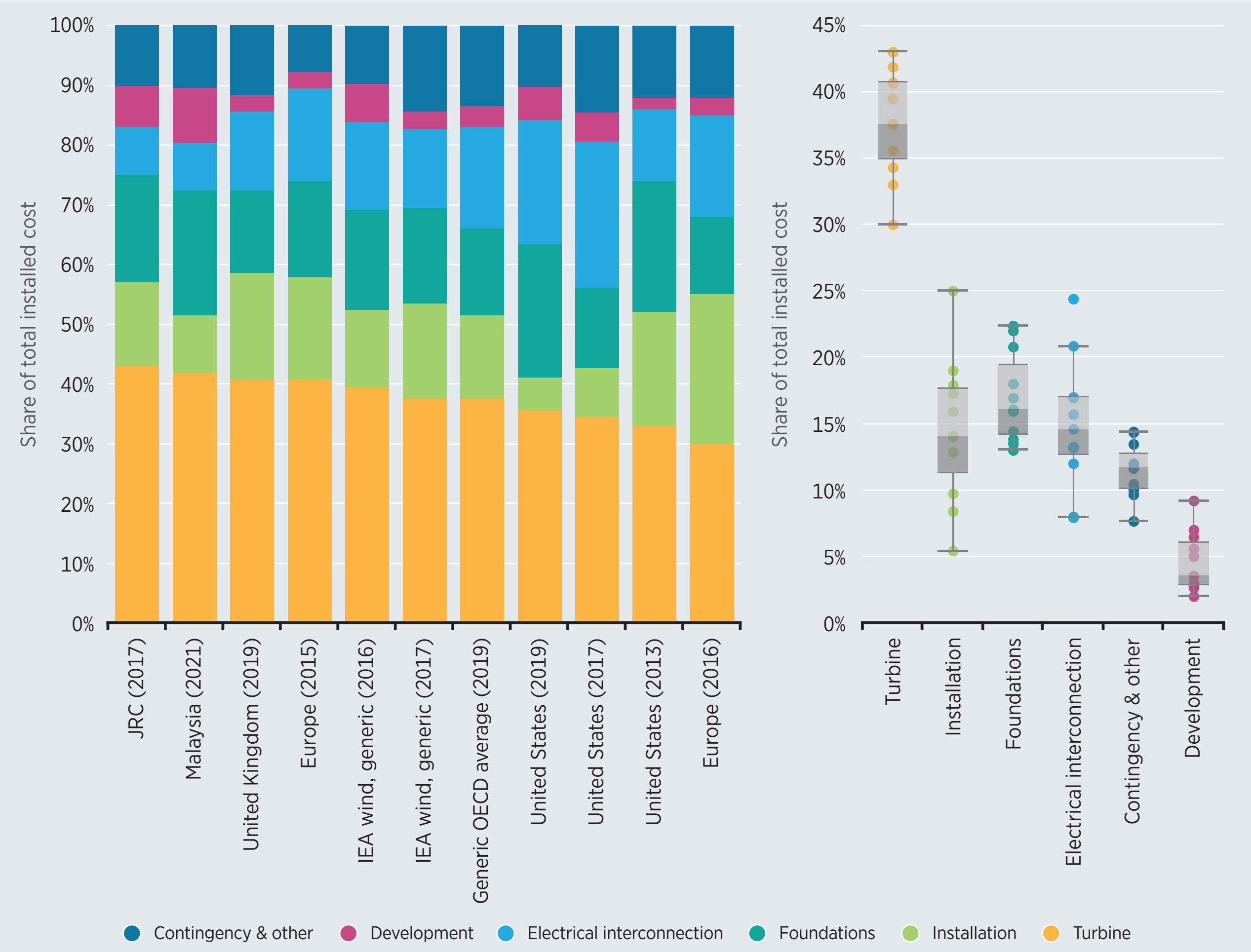
* Countries where data were only available for projects commissioned in 2020, not 2023.
** Countries where data were only available for projects commissioned in 2015, not 2010.

Offshore and onshore wind farms have differing cost breakdowns. This is to be expected, considering offshore wind farms' higher average costs for installation and foundations. Obtaining project-level total installed cost breakdowns is, however, challenging due to confidentiality constraints. Nonetheless, numerous studies do provide estimates for specific markets, often derived from consultations with project developers – although it is sometimes unclear exactly how comparable these data are.

Offshore turbines (including towers) generally account for between 30% and 43% of the total installed cost (Figure 4.6). Other costs, including installation, foundations and electrical interconnection, also take up a sizeable share of the total. Installation costs, from the estimates available, range from 5% to 25% of total installed costs, while contingency/other costs range between 8% and 14%. Electrical interconnection accounts for between 8% and 24% and foundation costs range between 13% and 22%. Development costs – which include planning, project management, insurance during construction (when data is available) and other administrative costs – comprise 2% to 9% of total installed costs.

Offshore wind site characteristics and country policies are additional factors contributing to the differences in cost breakdowns. For example, country policies regarding the ownership of electrical interconnections with the onshore grid or the length of the permitting process can have a significant impact on costs.

Figure 4.6 Representative offshore wind farm total installed cost breakdowns by country/region, 2013, 2015, 2016, 2017, 2019 and 2021



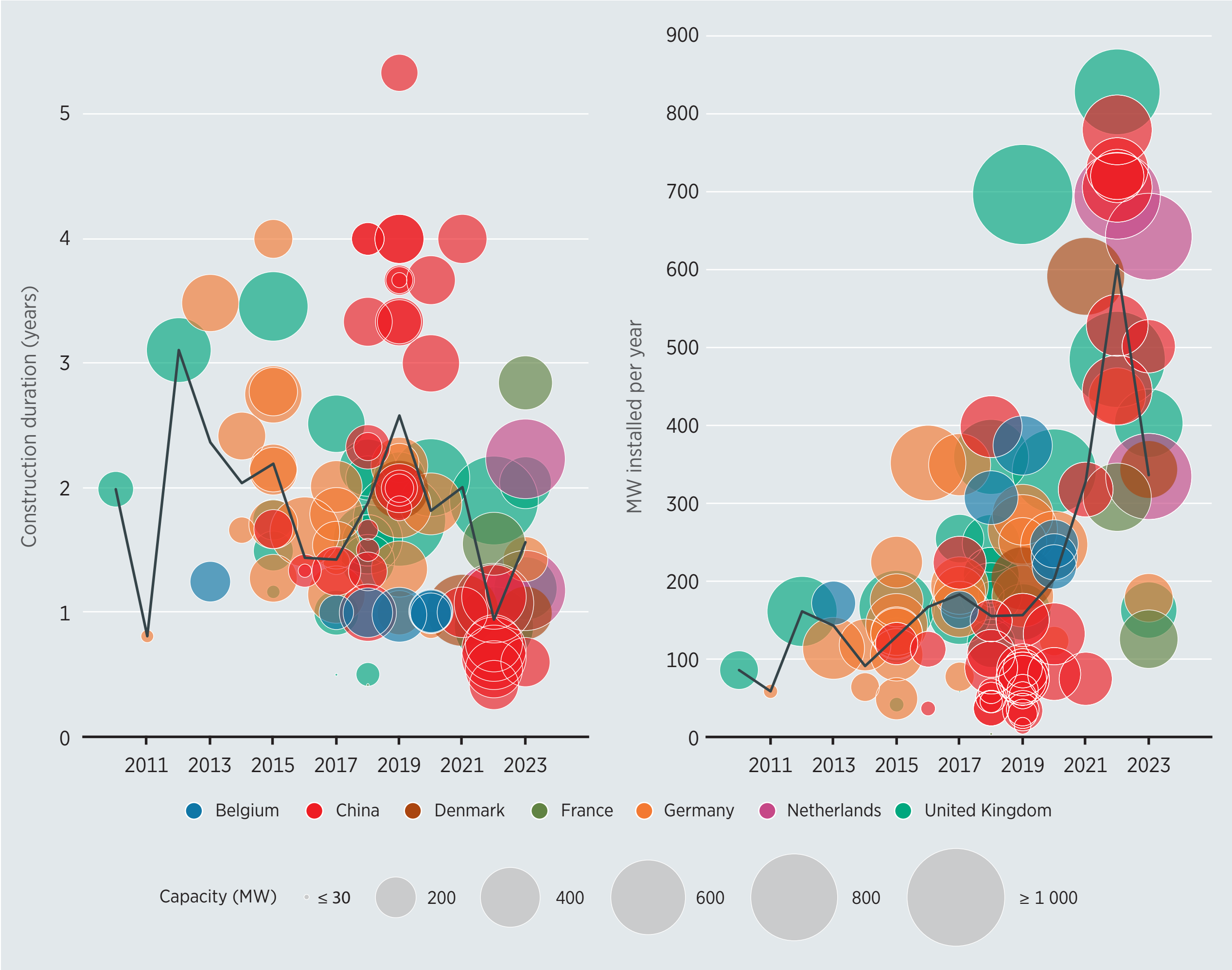
Source: Lacal-Arántegui *et al.* (2018); Alsubal *et al.* (2021); ORE Catapult (2019); IRENA (2016); Smart *et al.* (2016); Noonan *et al.* (2018); Stehly *et al.* (2020); Musial (2018); MAKE Consulting (2016).

As detailed in Figure 4.6, installation costs for turbines are a major contributor to the total cost. The expense of transporting, operating and installing foundations and turbines offshore, along with the distance to port, are other major contributing cost factors.

With the availability of bigger, dedicated installation vessels, the employment of larger turbines and the experience gathered, 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. In 2023, developers shifted their focus to immediate opportunities, due to market uncertainty and risk-aversity. These factors stemmed from supply chains issues and inflation (Wood Mackenzie, 2024c).

To capture the dynamics mentioned above – and given varying project sizes – a better metric than installation time is MW installed per year by project. This is illustrated in Figure 4.7 for Europe since 2010. In these data, the figures increase from 100 MW to 200 MW in the 2010 to 2015 period to between 200 MW and 400 MW for most of the projects per year per project from 2015 to 2020. A significant development has therefore occurred since 2020, with projects now routinely exceeding 400 MW per year.

Figure 4.7 Installation time and MW installed per year by offshore wind projects in Europe and China, 2010-2023



Source: Wood Mackenzie (2024).
Note: Duration data represents the time from first foundation to last turbine; MW = megawatts.

CAPACITY FACTORS

There is a wide range of capacity factors for offshore wind farms. Aspects influencing energy output include: the atmospheric boundary layer conditions; meteorology; the technology deployed; and the wind farm's configuration (*i.e.* the optimal turbine spacing to minimise wake losses and increase energy yields). Additionally, 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 2023, the global weighted average capacity factor of newly-commissioned offshore wind farms increased from 38% to 41%. This was driven by wind turbines with higher hub heights and larger swept areas that enabled turbines to harvest more electricity from the same resource.

In 2023, the capacity factor range (5^{th} and 95^{th} percentile) for newly-installed projects was between 30% and 52% (Figure 4.8). The decline in the global weighted average capacity factors since 2017 and until 2021 has predominantly – but not entirely – been driven by the increased share of China in global deployment. This was around 64% of new capacity added in 2023. As discussed, China's wind resource is generally not as good as in the North Sea, even far offshore, while historically, projects have tended to be located near-shore or in inter-tidal zones, where wind resources are typically inferior to those available further out. China's projects have also not used the very large turbines deployed in Europe and elsewhere. However, turbine size did jump in 2022, as developers had to adjust to a new "grid parity" regime with the end of the country's feed-in-tariff (FiT) programme.

The weighted average capacity factor for projects commissioned in Europe increased by 28% between 2010 and 2023, from 39% to 50%. In Europe, the 5^{th} and 95^{th} percentile capacity factors for projects commissioned in 2023 were 40% and 53%, respectively. In contrast, the weighted average capacity factor for projects commissioned in China in 2023 was 37%, while the 5^{th} and 95^{th} percentiles were 33% and 41%, respectively.

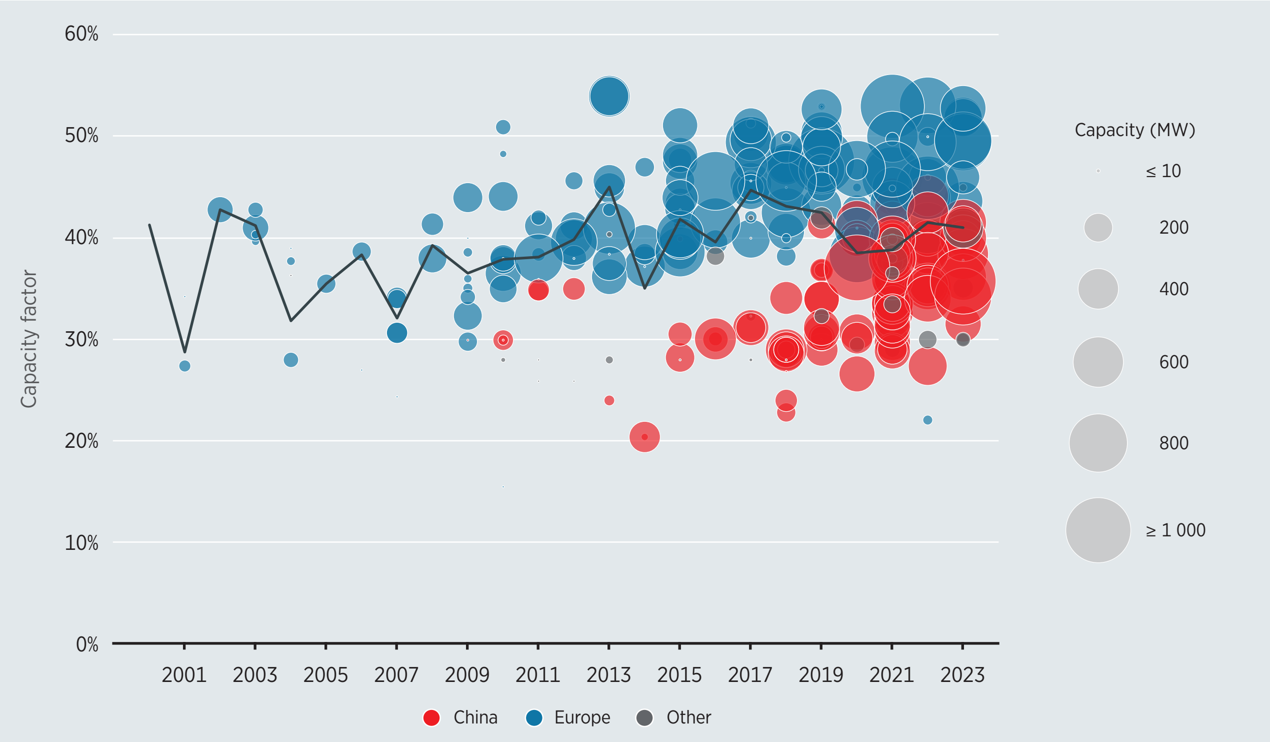
Figure 4.9 shows that offshore wind rotor diameter and hub height followed a similar increasing trend over the period 2010 to 2023. Over that time, the turbine rotor diameter experienced an 84% increase, growing from a weighted average value of 112 metres to 206 metres. Turbine hub height grew by 25%, from a weighted average of 83 metres to 126 metres over the same period. The data for Europe shows the clear contribution technological 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.

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.

A trend towards reduced downtime has also been experienced, as manufacturers leverage operational knowledge from operating wind farm models into new, more reliable designs. The optimisation of O&M practices exemplifies the progress made in reducing unscheduled maintenance. Improvements in data collection and analytics have been unlocked that allow for predictive maintenance and output optimisation.

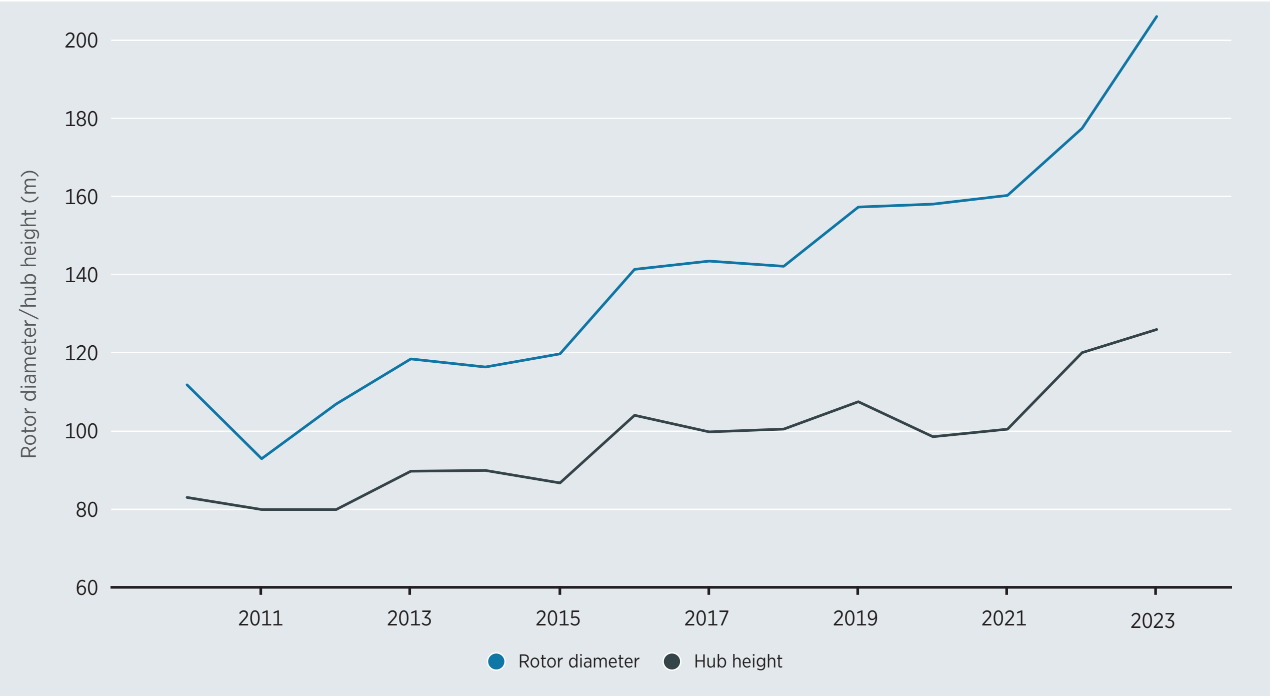
Additionally, advances at the development stage have led to better methods for wind resource characterisation when identifying the best sites. This has resulted in improved wind farm designs that optimise operational efficiency and output.

Figure 4.8 Project and global weighted average capacity factors for offshore wind, 2000-2023



Note: MW = megawatt.

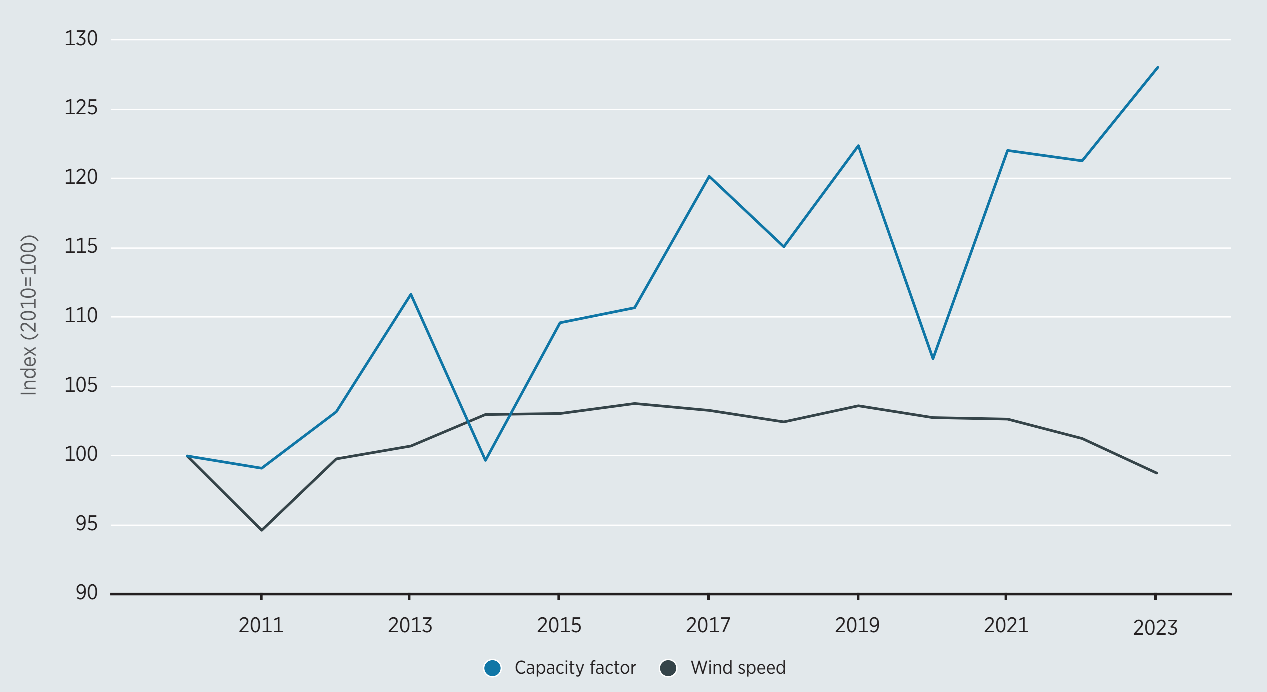
Figure 4.9 Global weighted average offshore wind turbine rotor diameter and hub height, 2010-2023



Note: m = metre

In recent years, larger rotor diameters have improved wind energy harnessing between cut-in and rated power wind speeds, allowing turbine generators to operate at higher output levels. Between 2010 and 2023, the weighted average capacity factor of newly-commissioned projects in Europe increased by around 28%, while the weighted average wind resource for those projects decreased by 1.23%. The year 2020 was something of an outlier for wind projects in Europe, however. The numbers for capacity factor and wind resource were +22% and +4% for 2019 and +22% and +3% for 2021, relative to projects in 2010 (Figure 4.10).

Figure 4.10 Capacity factor and wind speed trends by project in Europe, 2010-2023



Source: Wood Mackenzie (2024).

Table 4.3 Weighted average capacity factors for offshore wind projects in seven countries, 2010 and 2023

	2010	2023	Percentage change 2010-2023
	%		
Belgium*	38	41	↑ 8%
China	30	40	↑ 33%
Denmark	44	52	↑ 18%
Germany	50	46	↓ 8%
Japan	28	30	↑ 7%
The Netherlands**	48	51	↑ 6%
United Kingdom	36	53	↑ 47%

Source: Wood Mackenzie (2024).

* Countries where data were only available for projects commissioned in 2020, not 2023.

** Countries where data were only available for projects commissioned in 2015, not 2010.

The greatest weighted average capacity factor improvement for the period 2010-2023 (Table 4.3) was in the United Kingdom, where there was a 47% increase over the period. Germany was the exception to generally increasing capacity factors during this time. This can be attributed to two factors: the already relatively high capacity factor achieved in 2010, which was 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 and Belgium.

O&M COSTS

O&M costs for offshore wind farms per kW are higher than those for onshore wind, primarily due to the higher cost of accessing the wind site to perform maintenance on turbines and cabling. These costs are 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 (fixed-bottom) wind farms deployed in the Group of 20 (G20) countries.

Limited data are available for offshore wind O&M costs, as with onshore wind. There is also general uncertainty around lifetime O&M costs for offshore wind, owing to limited operational experience, particularly at sites farther from shore. As discussed in the capacity factor section, O&M practices are continuously being refined to reduce costs and improve availability. Consequently, with improved capacity factors and increased competition in O&M provision, O&M costs per kilowatt hour (kWh) have been falling.

In 2018, the representative range for O&M costs in offshore projects was between USD 82/kW per year to USD 151/kW per year (Noonan *et al.*, 2018; Ørsted, 2018). By 2023, O&M costs values had decreased to between USD 77/kW and USD 108/kW per year (Wood Mackenzie, 2023d). 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 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, the turbine OEMs' own service arms, in-house O&M, marine contractors, or a combination of these).

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 GW of offshore wind farms in operation and 10 GW under construction and/or awarded globally. Ørsted was able to reduce O&M costs by over 43% between 2015 and 2018, from USD 138/kW/year to USD 78/kW/year (Ørsted, 2018)

Based on projects commissioned over the last year, IRENA analysis shows that in 2023, O&M costs accounted for USD 0.022/kWh in China, while ranging between USD 0.023/kWh and USD 0.030/kWh in Europe. Lower costs are observed in these established markets, while higher costs are seen in less-established markets, where O&M supply chains have not been fully set up. These values are also influenced by the countries' weighted average capacity factors.

LCOE

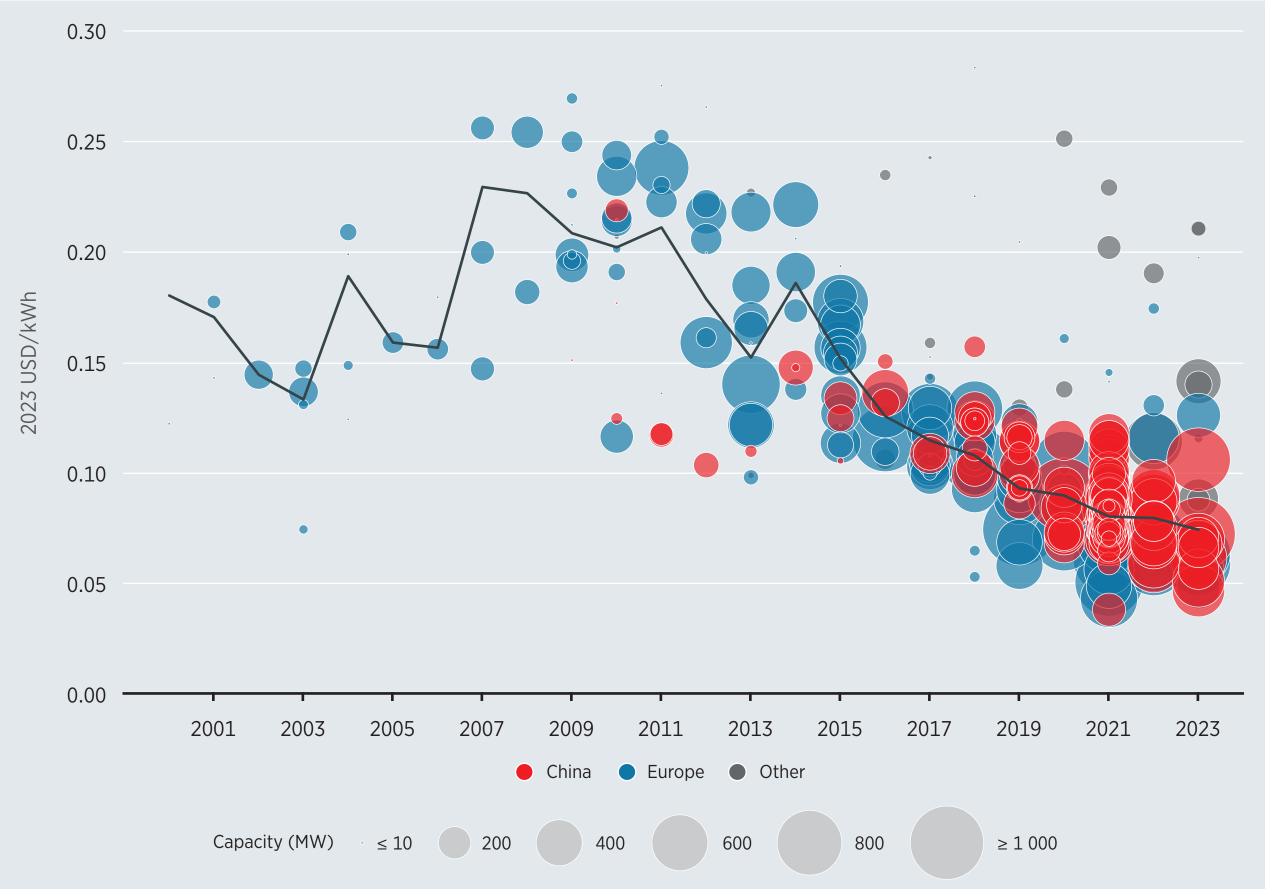
In recent years, a steady stream of increasingly competitive projects has been created. This has been the result of increasing experience and competition, advances in wind turbine technology, the establishment of optimised local and regional supply chains, and strong policy and regulatory support.

Between 2010 and 2023, the global weighted average LCOE of offshore wind fell 63%, from USD 0.203/kWh to USD 0.075/kWh (Figure 4.11). The 2023 figure was 7% down on its 2022 value of USD 0.080/kWh. From its peak in 2011, the global weighted average LCOE of offshore wind had fallen 65% by 2023.

Table 4.4 presents the regional and country weighted average LCOE of offshore wind farms in Europe and Asia. Denmark had the lowest weighted average LCOE for projects commissioned in 2023, at USD 0.048/kWh. The United Kingdom had the highest percentage reduction in country weighted average LCOE values between 2010 and 2023, at 73%. Germany was second highest in this percentage reduction (67%) over the same period. Belgium had the highest starting point for a weighted average LCOE in 2010, at USD 0.244/kWh.

Denmark was also the first country to pioneer offshore wind on 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 the proximity of its projects to shore and their placement in shallower waters compared to neighbouring countries. Additionally, in Denmark, the wind farm-to-shore transmission assets are not the responsibility of the project developer. These factors have therefore collectively contributed to Denmark's lower LCOE.

Figure 4.11 Offshore wind project and global weighted average LCOE, 2000-2023



Source: Wood Mackenzie (2024).

Notes: kWh = kilowatt hour; MW = megawatt.

Table 4.4 Regional and country weighted average LCOE of offshore wind, 2010 and 2023

	2010			2023		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2023 USD/kW)					
Asia	0.133	**0.197**	0.218	0.050	**0.078**	0.211
China	0.130	**0.197**	0.215	0.049	**0.070**	0.091
Japan	0.207	**0.207**	0.207	0.211	**0.211**	0.211
Republic of Korea*	n.a.	**n.a.**	n.a.	0.144	**0.195**	0.246
Europe	0.136	**0.205**	0.241	0.052	**0.067**	0.108
Belgium*	0.244	**0.244**	0.244	0.088	**0.090**	0.092
Denmark	0.117	**0.117**	0.117	0.048	**0.048**	0.048
Germany	0.193	**0.195**	0.201	0.063	**0.063**	0.063
The Netherlands**	n.a.	**n.a.**	n.a.	0.059	**0.061**	0.063
United Kingdom	0.215	**0.224**	0.233	0.056	**0.059**	0.062

Note: kW = kilowatt.

* Countries where data were only available for projects commissioned in 2020, not 2023.

** Countries where data were only available for projects commissioned in 2020, not 2023.

05 CONCENTRATED SOLAR POWER

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HIGHLIGHTS

Between 2010 and 2023, the global weighted average levelised cost of electricity (LCOE) of concentrated solar power (CSP) plants fell by 70%, from USD 0.393/kWh to USD 0.117/kWh. However, between 2021 and 2023, each year only one plant was commissioned, so these years are not necessarily representative.

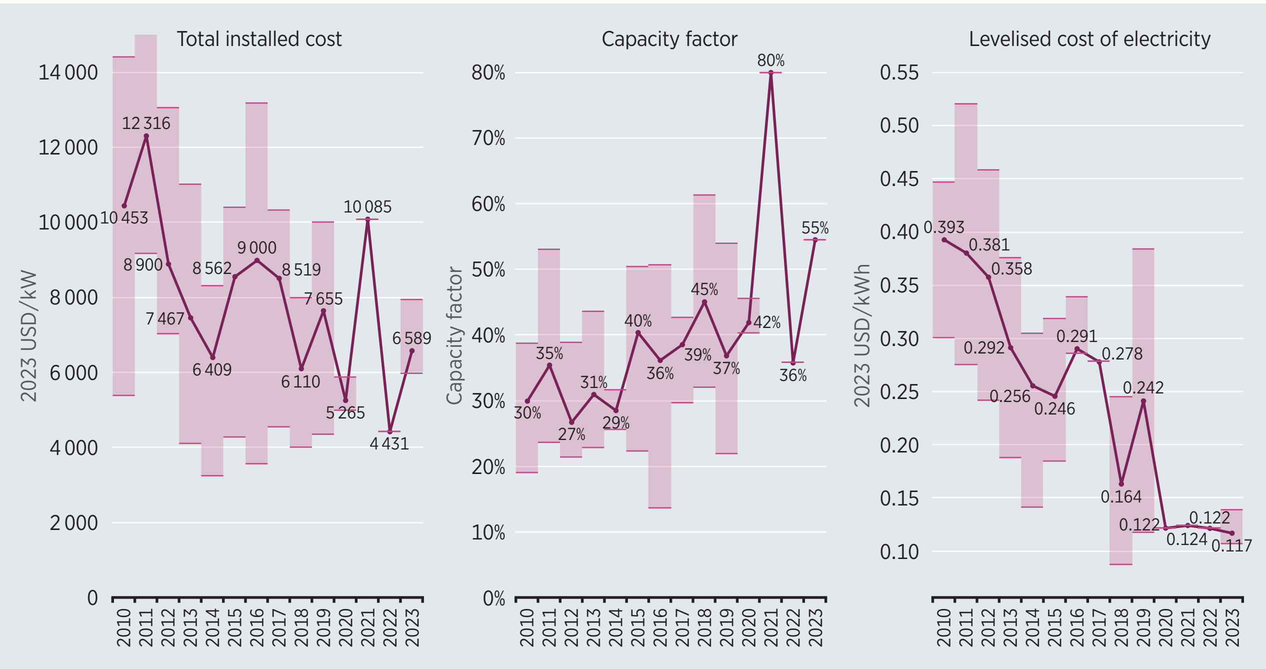
Between 2010 and 2023, the decline in the global weighted average LCOE was primarily driven by reductions in total installed costs (down 37%), higher capacity factors (up 82%) and lower O&M costs (down 48%).

Between 2010 and 2023, global average total installed costs for CSP declined by 37%, to USD 6 589/kW. This was achieved in a setting where project energy storage capacities were increasing continuously.

During 2023, however, total installed costs increased 49% compared to 2022. This reflected the fact that only one project came online in 2023 – a CSP scheme with 15 hours of storage in the United Arab Emirates. In 2022, another very thin market also saw only one project come online in China. The total installed costs of that project were 56% lower than the 2021 value, at USD 4 431/kW. This also represented a 58% decline in costs compared to 2010.

The global weighted average capacity factor of newly-commissioned CSP plants increased from 30% in 2010 to 55% in 2023, as the technology improved, costs for thermal energy storage declined and the average number of hours of storage for commissioned projects increased.

Figure 5.1 Global weighted average and range of total installed costs, capacity factors and LCOEs for CSP, 2010-2023



INTRODUCTION

CSP systems work best and have better economics in areas with a high direct normal irradiance (DNI) – that is, above 2 000 kWh/m^2/year – but can still work at lower values (Trieb and Schillings, 2009). CSP systems use mirrors to concentrate the sun's rays and generate heat, with most contemporary systems then transferring that heat to a heat transfer medium – typically a thermal oil or molten salt. Electricity is then generated through a thermodynamic cycle. This could be, for example, using the heat transfer fluid to create steam and then generate electricity, as in conventional Rankine-cycle thermal power plants. Most commonly, a two-tank, molten salt storage system is used, but designs vary.

Today, CSP plants almost exclusively include low-cost and long-duration thermal storage systems. This gives CSP greater flexibility in dispatch and the ability to target output to periods of high cost in 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.

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 and the receivers.

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 maximise energy absorption across the day, increasing the yield by generating favourable incidence angles of the sun's rays on the aperture area of the collector.

Specific PTC designs 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 a superheated steam which then drives a conventional Rankine-cycle turbine to generate electricity.

Another type of linear-focusing CSP plant – though much less common – uses linear Fresnel collectors. This type of plant relies on an array of almost flat mirrors, placed at different angles 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 meters 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 22% of total CSP deployment at the end of 2023 (SolarPaces, 2024). 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's 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. This central receiver absorbs the heat via a heat transfer medium, which turns into electricity – typically through a water-steam thermodynamic cycle. Some ST designs do away with the heat transfer medium, however, with steam 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 efficiencies with the steam-cycle and power block. Higher receiver temperatures also unlock 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. For this reason – and the fact that they represent most new projects announced in China – their share may grow in coming years.

Globally, cumulative CSP installed capacity grew just over five-fold between 2010 and 2023, reaching almost 7 GW by the end of that period. Since 2020, yearly deployment has been modest. In 2020, only projects in China were commissioned. Hopes for growth in 2021 did not materialise, though 110 MW was commissioned during that year, all from the Cerro Dominador project in Chile. During 2023, the Noor Energy 1/DEWA IV project in the United Arab Emirates was the only project that came online. It includes a tower segment of 100 MW and a parabolic trough of 200 MW.

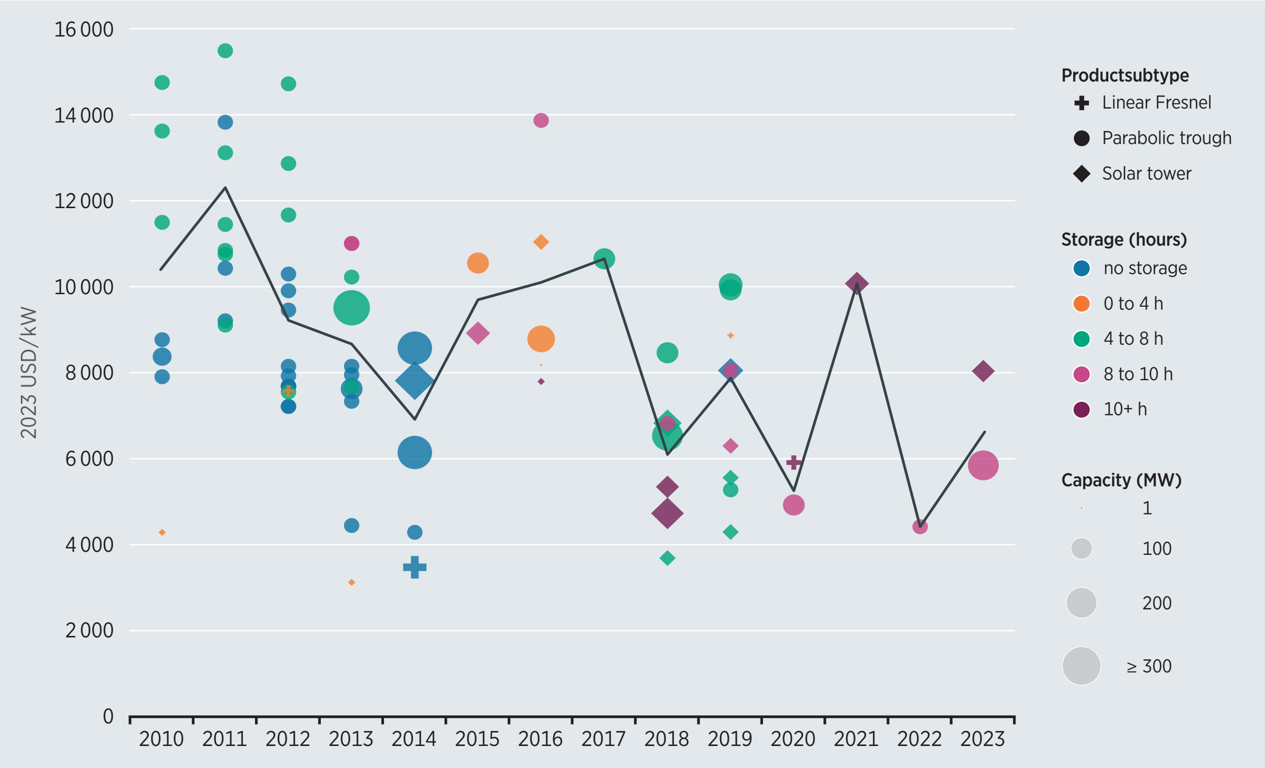
TOTAL INSTALLED COSTS

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 feature has become a cost-effective way to raise capacity factors, while it also contributes to a lower LCOE and greater flexibility in dispatch during the course of the day.

The average thermal storage capacity for solar thermal plants in the *IRENA Renewable Cost Database* increased from 3.5 hours to 11.7 hours between 2010 and 2023. Commissioned in 2021, the Cerro Dominador 110 MW ST project, located in Chile's Atacama Desert, features a storage capacity of 17.5 hours. During 2023, the CSP project in the United Arab Emirates included one storage of 15 hours for the ST and another of 10 hours for the parabolic trough. It is likely that all new CSP projects developed worldwide will include thermal storage.

Between 2010 and 2023, the weighted average total installed cost value for CSP plants in the *IRENA Renewable Cost Database* fell by 37% to reach USD 6 589/kW. This figure reached its lowest value in 2022, when costs were at USD 4 274/kW, representing a 58% decline from 2010 (Figure 5.2).

Figure 5.2 CSP total installed costs by project size, collector type and amount of storage, 2010-2023



Notes: Only projects in the database with information available for all the variables displayed are shown. Data can therefore diverge from the global dataset; h = hour; kW = kilowatt; MW = megawatt.

Figure 5.2 also shows that total installed costs[39] increased to USD 10 085/kW in 2021, before falling back to USD 4 431/kW in 2022. 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 of 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. During 2022, deployment shifted to China, which with its lower cost structure saw the weighted average total installed cost fall to USD 4 431/kW.

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

During 2018 and 2019, the installed costs of CSP plants with storage were equal to or lower than the capital costs of plants without storage commissioned in the 2010 to 2014 period – sometimes even dramatically lower. The projects commissioned in 2018 and 2019 and listed in the *IRENA Renewable Cost Database* had an average of 7.4 hours of storage. This is 2.8 times more than the average storage value for projects commissioned between 2010 and 2014. Storage continued to grow after that, for instance, the weighted average storage level for projects commissioned in 2020 and 2021 was 13.8 hours, which was 85% higher than the levels in 2018 and 2019.

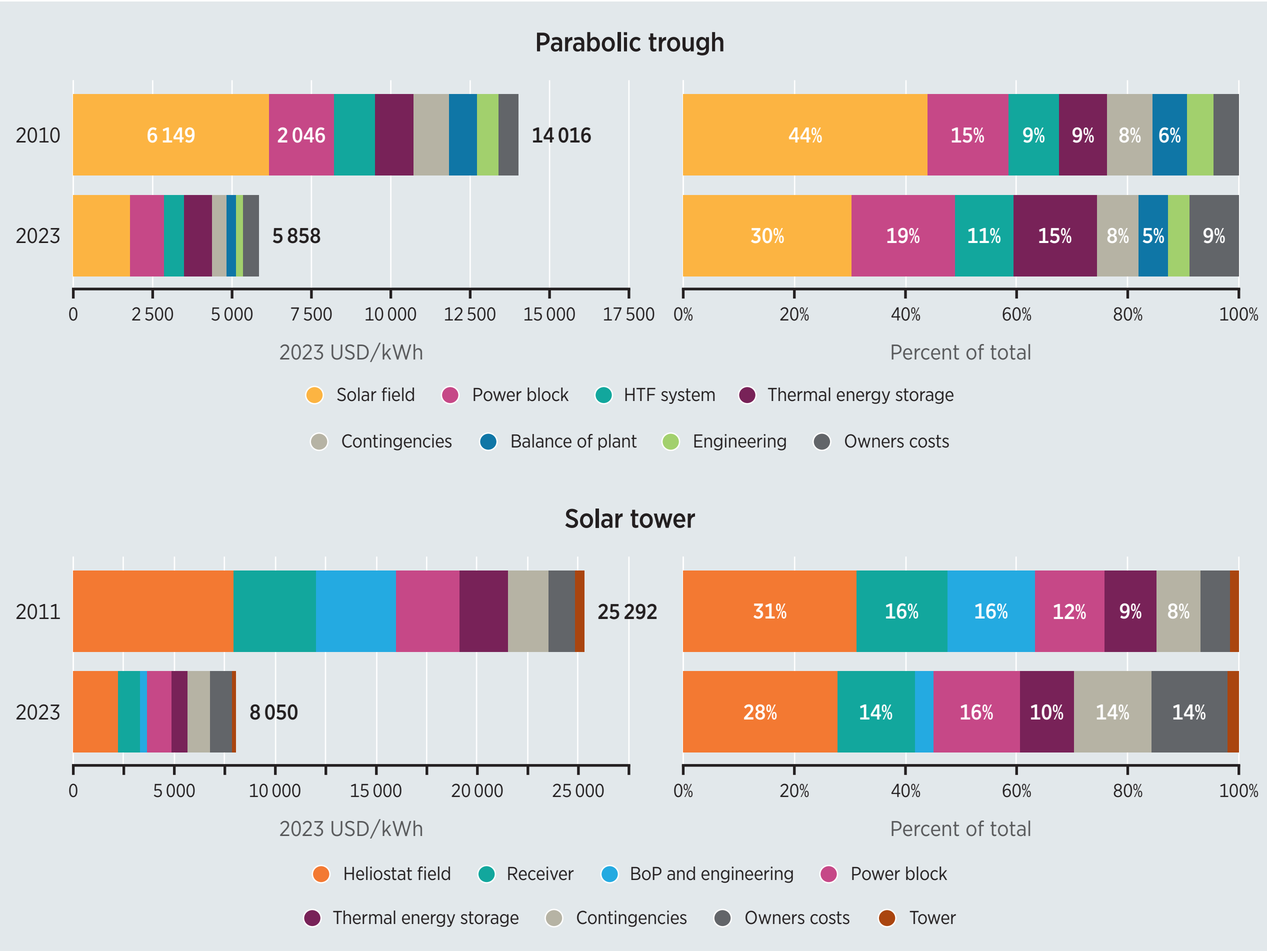
[39] *Total installed costs for CSP projects does not refer to storage costs and capacity. The term is only related to specific costs of commissioned plants in USD/kW of nominal power.*

The capital costs for CSP projects commissioned in 2020 for which cost data are available in the *IRENA Renewable Cost Database* ranged between USD 4 936/kW and USD 5 923/kW. That year, only two projects were completed, both were in China and totalled 150 MW. The data therefore reflects the national circumstances, much as it did between 2010 to 2012 when Spain dominated CSP deployment and therefore the CSP data.

The two projects completed in China in 2020 were also part of a programme of 20 pilot projects. These 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 an ambitious timeline to complete by 2018. Over the next few years ten projects, currently under construction in China, will come online, totalling an installed capacity of 10 GW.

Total installed costs for both PTC and ST plants are dominated by the cost of the components that make up the solar field (Figure 5.3).

Figure 5.3 Total installed cost breakdown of CSP plants by technology, 2010-2011 and 2023



Source: Hinkley (2010); Fichtner (2011).

Notes: HTF = heat transfer fluid; BoP = balance of plant; kWh = kilowatt hour. Percentage figures may not total 100 due to rounding up. Data is representative of global technology values.

In 2010, the solar field of a PTC plant cost an estimated USD 6 149/kW (44% of the total installed cost), but by 2023, this figure had fallen 73% to USD 1 771/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 2023, despite its cost falling by 46% over the same period, from USD 2 046/kW to USD 1 098/kW. This was also the case for the heat transfer fluid system, which increased its share from 9% to 11%, despite these costs per kilowatt falling 52% over the 2010-2023 period, from USD 1 294/kW to USD 619/kW. This also occurred for thermal energy storage. That component's share of total installed costs increased from 9% in 2010 to 15% in 2023, despite the cost itself falling from USD 1 191/kW to USD 869/kW.

At the same time, during that period, the owner's costs share rose from 5% to 9%, with an absolute value change from USD 635/kW to USD 525/kW. The costs of the balance of plant, engineering and contingencies for PTC plants declined by 64%, 68% and 62% respectively. As a result, over the same period, the share of balance of plant in total installed costs declined from USD 855/kW (6% of the total) to USD 310/kW (5%), while engineering costs fell from USD 692/kW (5% of the total) to USD 222/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 11% lower than the weighted average total installed cost in 2023.

For ST plants, this comparison is very similar, with 2011 heliostat field costs only 3% lower than the ST weighted average total installed cost value in 2023. Over that decade, the reduction in the cost of the heliostat field was significant, with costs falling 72% between 2011 and 2023, from USD 7 913/kW to USD 2 240/kW. This drove down the field's share of total installed costs from 31% to 28%. The cost of the receiver fell by 73% over the 2011 to 2023 period, from USD 4 105/kW to USD 1 110/kW, with the receiver's share of total costs falling from 16% to 14%.

Balance of plant and engineering saw the largest reduction, falling 93% over the same period, from USD 4 014/kW to USD 278/kW. This made the factor's share of total costs fall from 16% to just 3%.

Contingencies remain an important overall cost component for STs. This is despite their costs falling by 45% between 2011 and 2023, from USD 2 033/kW to USD 1 112/kW. Contingencies for STs are often higher per kilowatt, as experience with STs remains relatively limited (although it has increased in recent years). There is still greater uncertainty, however, over the replicability of development and construction processes for STs than there is 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 for STs fell by only 16% between 2011 and 2023, with their share of overall costs increasing to 14% in 2023.

CAPACITY FACTORS

For CSP, the determinants of the achievable capacity factor for a given location and technology are the quality of the solar resource and the technological configuration. CSP is distinctive in that the potential to incorporate low-cost thermal energy storage can increase the capacity factor[40] 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.

Over the last decade, falling costs for thermal energy storage and increased operating temperatures have been important developments in improving the economics of CSP. The latter also lower the cost of storage, as higher heat transfer fluid temperatures reduce storage costs. For a given DNI level and plant configuration conditions, higher heat transfer fluid 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 alternatively, less storage medium volume is needed to achieve a given number of storage hours. Since 2010, these combined factors have increased the optimal level of storage at a given location, as a consequence of the increased capacity factor helping minimise LCOE.

These drivers have contributed to the global weighted average capacity factor of newly-commissioned plants rising from 30% in 2010 to 55% in 2023 – an increase of 82% over the decade. The 5^{th} and 95^{th} percentiles of the capacity factor values for projects in the *IRENA 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%. In 2022, a project located in China with 9 hours of storage drove the capacity factor to 36%, a value closer to the 2019 level. In 2023, the capacity factor for the Noor 1/DEWA IV CSP project in the United Arab Emirates was 55%.

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.

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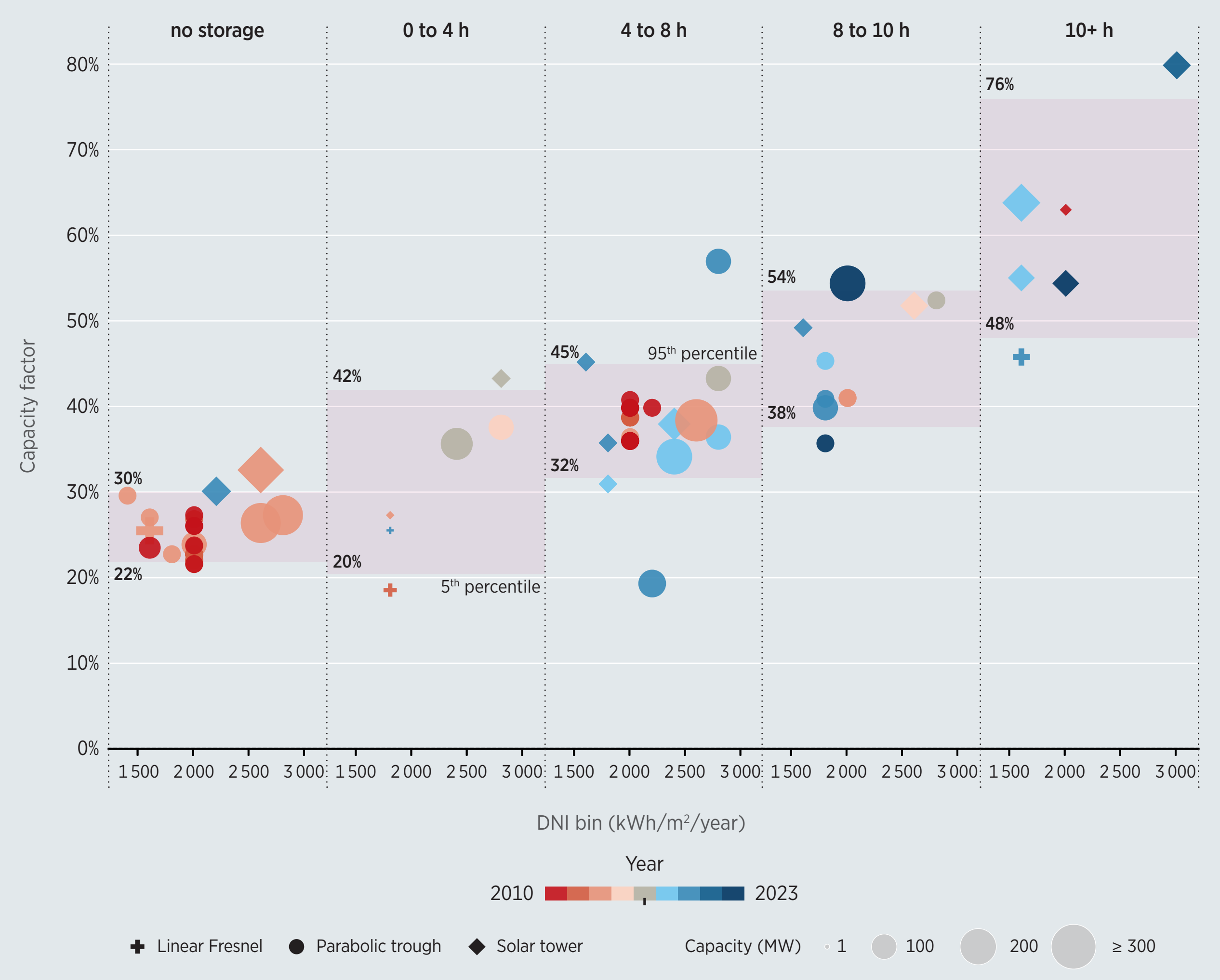
[40] *This is so up to a certain level, given that there are diminishing marginal returns.*

Figure 5.4 Capacity factor trends for CSP plants by DNI and storage duration, 2010-2023



Source: CSP Guru (2022), for DNI values.
Notes: DNI = direct normal irradiance; h = hour; kWh = kilowatt hour; m^2 = metres squared.

For plants commissioned from 2016 to 2020, around four-fifths had at least four hours of storage and 39% had eight hours or more.

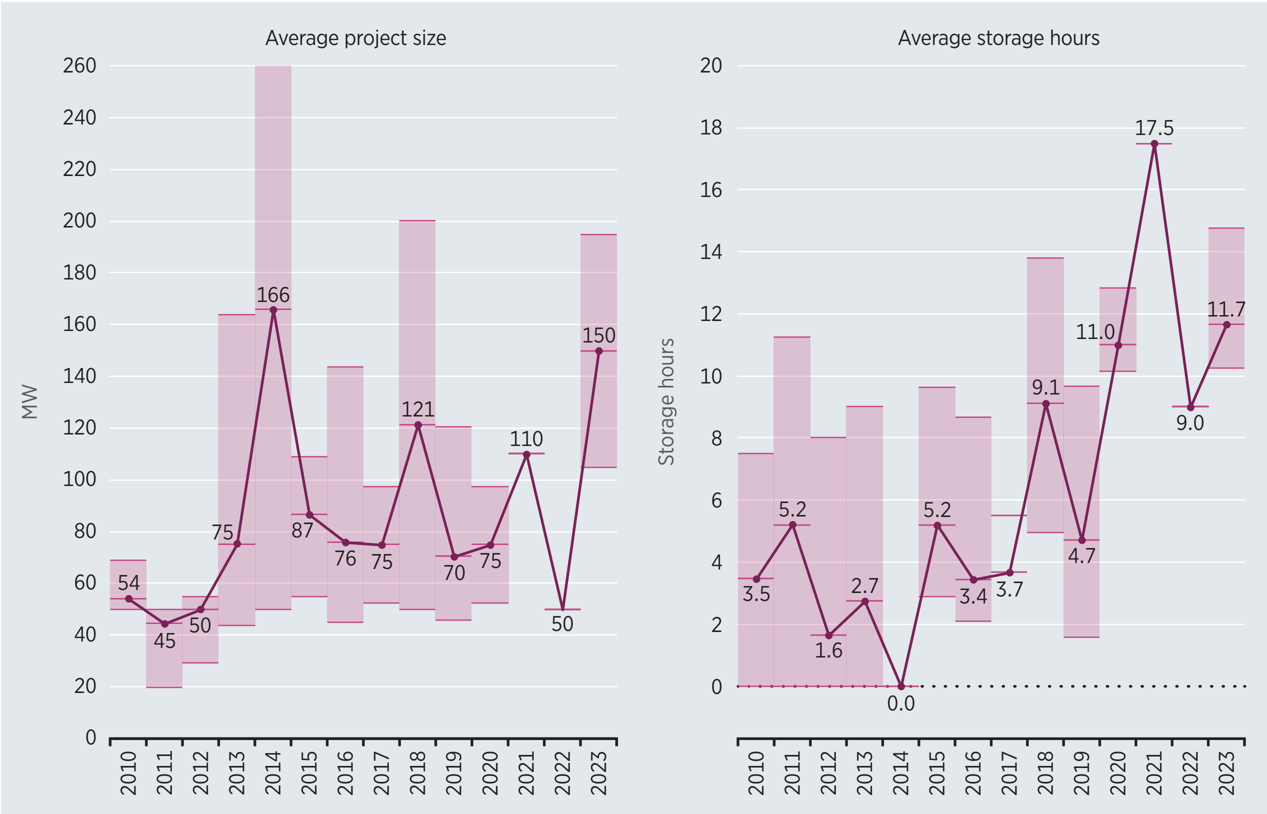
The impact of the economics of higher energy storage levels is evident in that in 2020, newly-commissioned plants had a weighted average capacity factor of 42%, with an average DNI that was lower than for plants commissioned during the 2010 to 2013 period. Indeed, during that period, the weighted average 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.

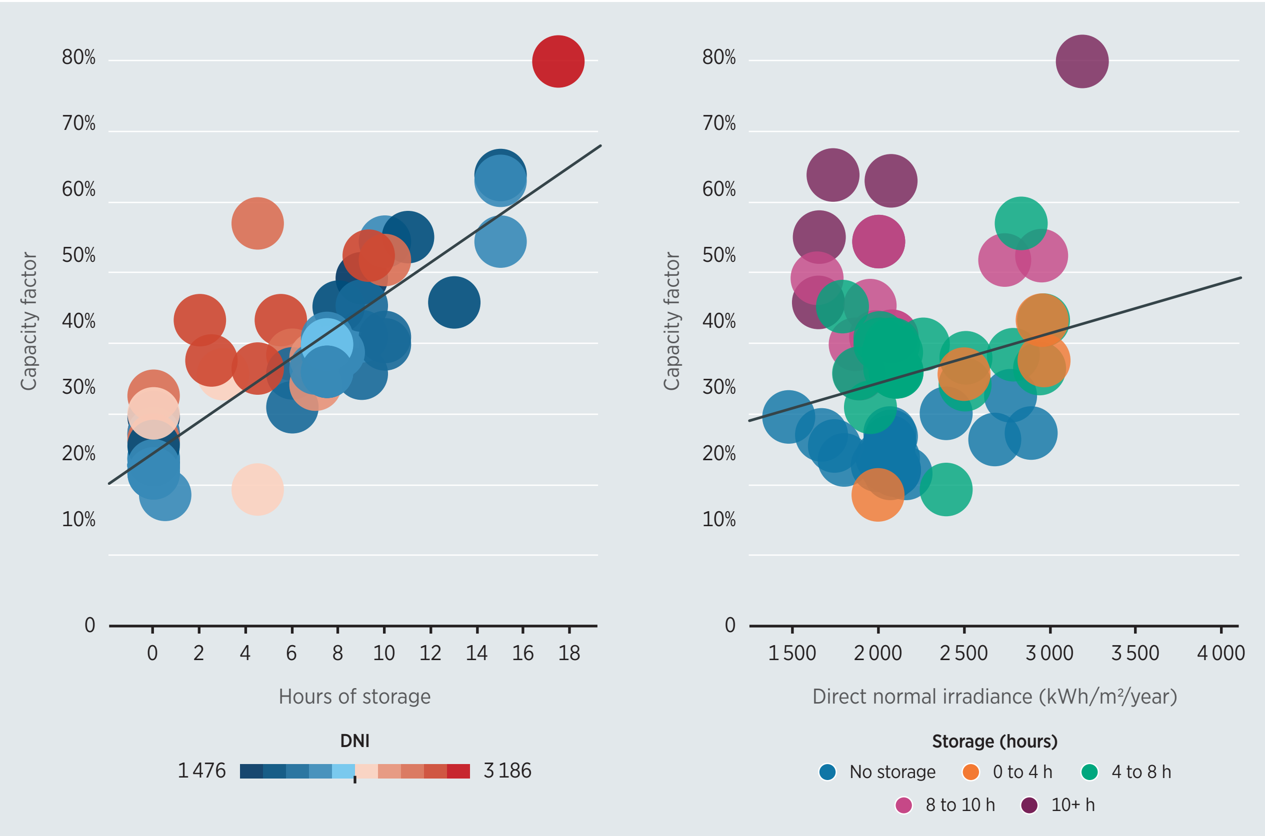
The recent increase in storage capacity has also been driven by the declining costs of thermal energy storage as the market has matured. This is the result of both declining capital costs and of higher operating temperatures, which allow larger temperature differentials in the molten salt storage systems, 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 threefold between 2010 and 2023, from 3.5 hours to 11.7 hours. The Cerro Dominador project in Chile that came online in 2021 features the highest known storage capacity in the world, at 17.5 hours (Figure 5.5).

Figure 5.5 Average project size and average storage hours of CSP projects, 2010-2023



Although, all else being equal, a higher DNI leads to a larger capacity factor, 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 size of the investment (Figure 5.6).

Figure 5.6 Capacity factors, storage hours and the solar resource, 2010-2023



Notes: DNI = direct normal irradiance; kWh = kilowatt hour; m^2 = metres squared.

Yet, improvements in technology 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. This was despite the fact that 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.

O&M COSTS

For CSP plants, all-in O&M costs, which include insurance and other asset management items, 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, however, experience – as well as new designs and improved technology – have helped reduce failure rates for receivers and mirrors, 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 also continue to be an important further contributor to O&M costs. These 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. This is so, even if it is based on an analysis relying on a mix of bottom-up engineering estimates and best-available reported project data (IRENA, 2018; Li *et al.*, 2015; Turchi, 2017; Zhou *et al.*, 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). In these, 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. However, they are about 18% to 20% of the LCOE for comparable 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 0.019/kWh in 2023 (48% lower than in 2010). The weighted average value stayed flat between 2020 and 2022 and declined 11% during 2023.

Table 5.1 All-in (insurance included) O&M cost estimates for CSP plants in selected markets, 2023

Country	Parabolic trough collectors (2023 USD/kWh)	Solar tower (2023 USD/kWh)
Argentina	0.029	0.027
Australia	0.031	0.030
Brazil	0.023	0.023
China	0.025	0.021
France	0.036	0.031
India	0.018	0.018
Italy	0.029	0.027
Mexico	0.019	0.018
Morocco	0.014	0.013
Russian Federation	0.028	0.026
Saudi Arabia	0.013	0.012
South Africa	0.014	0.013
Spain	0.028	0.026
Türkiye	0.021	0.019
United Arab Emirates	0.021	0.023
United States	0.028	0.025

LCOE

With total installed costs, O&M costs and financing costs all falling as capacity factors rose, the LCOE for CSP fell significantly between 2010 and 2023. Indeed, over that period, the global weighted average LCOE of newly-commissioned CSP plants fell by 70%, from USD 0.393/kWh to USD 0.117/kWh.

Figure 5.7 LCOE for CSP projects by technology and storage duration, 2010-2023

Notes: h = hour; kWh = kilowatt hour; MW = megawatt.

With deployment during the 2010 to 2012 period being dominated by Spain – and mostly comprised of PTC plants – 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. Projects commissioned there in 2018 and beyond achieved estimated LCOEs of between USD 0.082/kWh and USD 0.149/kWh. In contrast, the costs for projects commissioned in 2018 and 2019 in Morocco and South Africa tended to be higher.

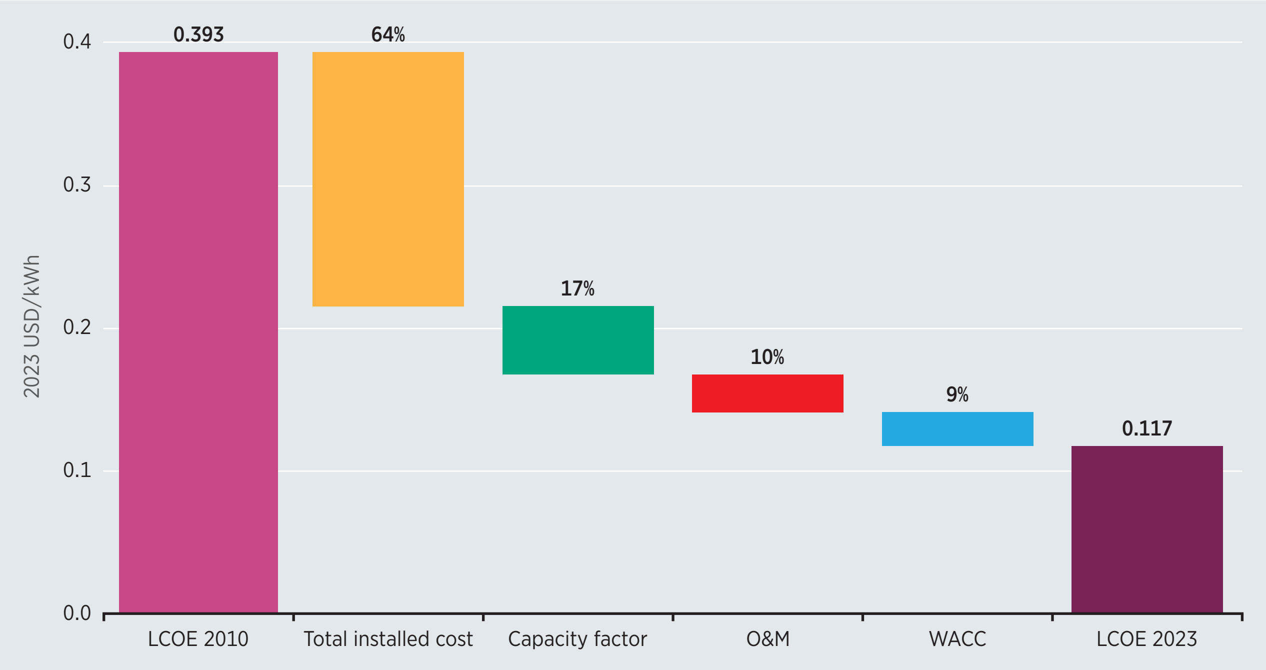
For projects commissioned between 2014 and 2017, their location in places with higher DNIs was a major contributor to increased capacity factors (and therefore lower LCOE values). The weighted average DNI of projects commissioned during that period, at around 2 600 kWh/m^2/year, was 28% higher than in 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 earlier 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 741 MW and 566 MW added in each year respectively. In 2018, plants were commissioned in China, Morocco and South Africa, with LCOEs ranging from a low of USD 0.082/kWh in China to a high of USD 0.258/kWh in South Africa. In contrast, 2019 saw higher LCOEs, as two delayed Israeli projects came online. Costs that year ranged from USD 0.117/kWh for a project in China to USD 0.446/kWh for the Israeli PTC project.

In 2020, deployment 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 0.122/kWh. In 2021, the LCOE value was 2% higher than in 2020, at USD 0.124/kWh – although this was still 68% lower than in 2010. The 2021 figure was, however, based on a very thin market, as is the 2022 figure of USD 0.122/kWh.

Figure 5.8 Reduction in LCOE for CSP projects by source, 2010-2023



Notes: kWh = kilowatt hour; LCOE = levelised cost of electricity; O&M = operation and maintenance; WACC = weighted average cost of capital.

Given this, Figure 5.8 unpacks[41] the 70% decline in the global weighted average LCOE of CSP over the period 2010 to 2023, showing its main constituents.

At 64%, the largest share of the decline was taken by the fall 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 and also improved 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 role of increasingly experienced developers in reducing costs at every step of the development, construction and commissioning process also needs to be acknowledged.

This same analysis yields quite different results for the period 2010 to 2021, given the high total installed costs and the 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 7 GW being deployed globally by the end of 2023.

[41] 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.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06 BATTERY STORAGE

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HIGHLIGHTS

Between 2010 and 2023, the costs of battery storage projects declined 89%, from USD 2 511/kWh to USD 273/kWh. The cost reduction was driven by scaling up manufacturing, improved materials efficiency and improved manufacturing processes.

Annual capacity additions increased from 0.1 GWh gross capacity in 2010 to 95.9 GWh gross capacity in 2023.

China was the leader in new additions and installed 46.5 GWh in 2023, accounting for almost half of the total global additions.

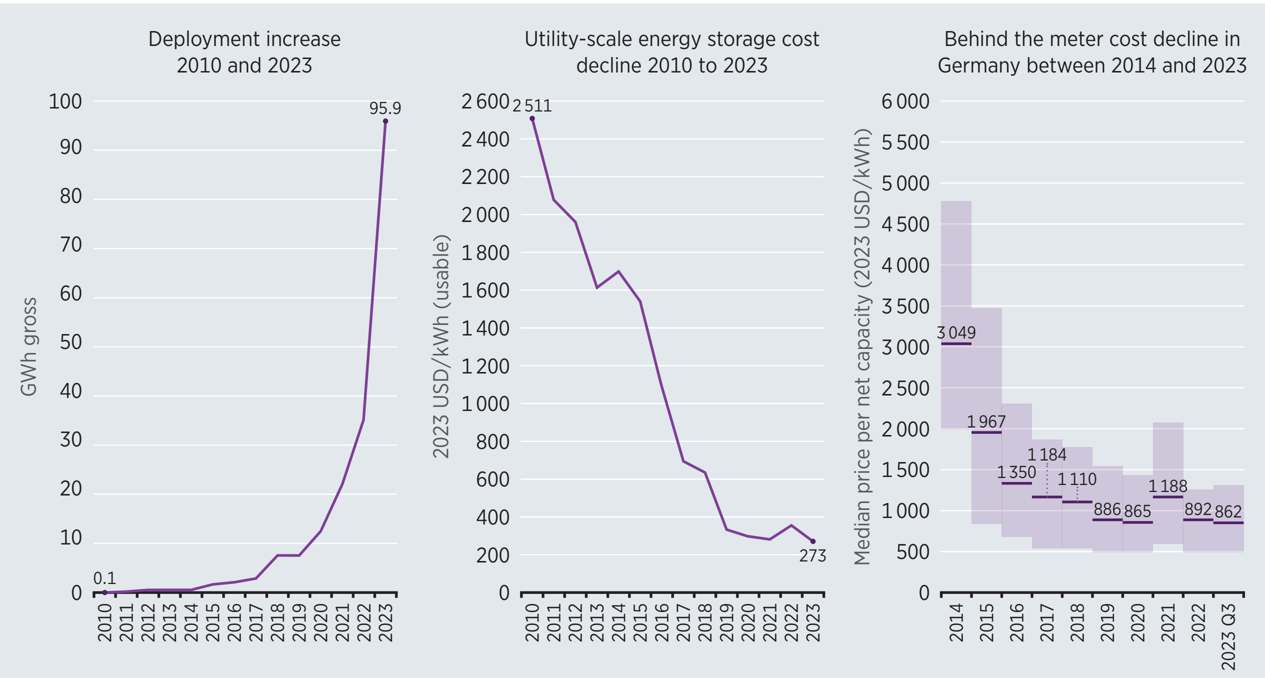
The United States was the second largest market and added 22 GWh, representing almost a quarter of the total new added capacity.

Energy shifting is the main application of electricity storage, with this reaching 67% of total capacity in 2023.

Lithium-ion battery storage costs declined about 82% between 2013 and 2023 due to the global manufacturing expansion.

In the residential sector, Germany was the market leader in Europe in 2023, with an installed capacity of 5.6 GWh. This represented 93% of the total annual addition in the country. Costs declined 72% in Germany between 2014 and Q1 2023.

Figure 6.1 Global deployment increase and utility-scale energy cost decline, 2010-2023, and behind the meter cost decline in Germany, 2014-Q1 2023



INTRODUCTION

The energy transition requires urgent and substantial acceleration across energy supply and end-use sectors, along with the leveraging of technologies to achieve global climate goals.

Currently, the rising competitiveness of renewables in comparison to fossil fuels is driving extensive deployment of the former, while the pledge to triple renewable energy capacity by 2030 agreed at COP28 sets an ambitious and significant target. In the next few years of this decade, an extensive deployment of renewable power generation in more countries and regions is therefore expected. As the electricity system evolves, innovative technologies are also being introduced to facilitate the transition from a fossil fuel-based system to a renewable one.

With a growing share of variable renewable power generation, energy storage will play a crucial role in ensuring the successful delivery of electricity during supply-demand shortfalls.

Electricity storage is already an important tool in minimising overall electricity system costs – mainly using pumped hydropower storage systems. It can also provide ancillary services to the electricity market and energy arbitrage. The latter often involves storing electricity at times of relative surplus, such as overnight, for release when wholesale prices or generating costs are higher.

Today, a wide variety of energy storage solutions are available, including: electrochemical storage (notably lithium-ion batteries, but also flow batteries and other chemistries); thermal energy storage (which employs rocks, bricks or molten salts to store heat); mechanical technologies (using compressed air, liquid air or gravitational potential); and chemical storage (storing energy in chemical bonds, such as hydrogen or its derivatives).

Storage technologies have the potential to provide flexibility, ensure security of supply and deliver economic services. They can be coupled directly with solar PV or wind (as with hybrid generation assets), or function as a standalone asset, or be used in optimising distribution and/or transmission assets and systems. Storage technologies are also being used increasingly to accelerate solar and wind deployment in the face of challenges related to the slow processing of grid connection requests and uncertainty around future curtailment or grid congestion regimes. Additionally, these technologies play a pivotal role in managing grid congestion, as efforts to modernise, renew and expand the grid gather pace. Ultimately, integrating storage solutions is essential for an electricity system that can fully support the widespread adoption of renewable energy.

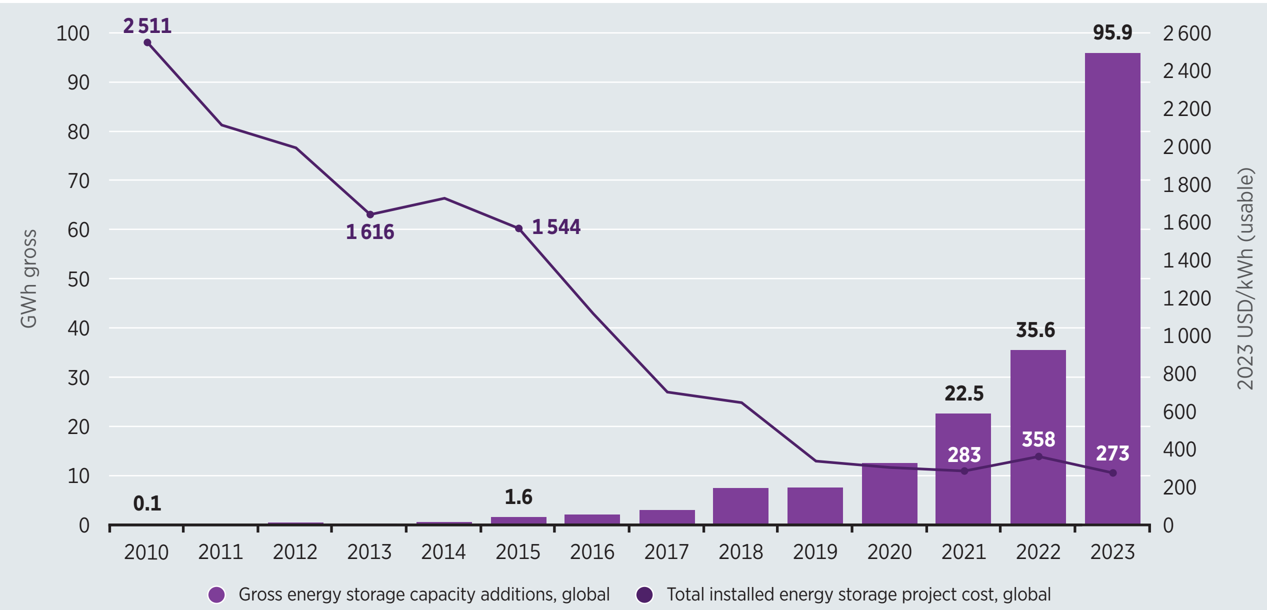
UTILITY-SCALE BATTERY STORAGE COST TRENDS AND DEPLOYMENT

Stationary storage complements and facilitates the rapid rise of installed electricity generation capacity in solar PV and wind. It helps to balance supply and demand, as well as provide ancillary electricity market services (IRENA, 2023). Stationary battery storage installed capacity is expected to grow rapidly by 2030, jumping from around 89 GW (189 GWh) in 2023 to 782 GW (2 205 GWh) in 2030 (BNEF, 2024a).

Globally, the costs of a fully installed and commissioned battery storage project declined 89% between 2010 and 2023, from USD 2 511/kWh to USD 273/kWh. In recent years, this cost reduction has been driven by technological developments that have improved materials efficiency and manufacturing processes, leading to economies of scale. From the manufacturing perspective, the market has been growing, creating competition between suppliers across the whole value chain. Production has rapidly expanded, especially in China, where the supply chain had already established a robust scale of production that was capable of delivering in a short period of time. In 2023, declines in raw material prices also benefited market growth, leading to oversupply and battery cost reductions (IEA, 2024).

Over the same period, new annual capacity additions increased from 0.1 GWh of gross capacity in 2010 to 95.9 GWh of gross capacity in 2023 – a year which saw a record annual increase (Figure 6.2). China led the market in 2023, installing 46.5 GWh. This was 3.25 times more than in 2022 and accounted for almost half total global additions. The United States was the second largest market, adding 22 GWh, which was almost a quarter of total new added capacity. In both countries, this rapid increase in capacity was mainly driven by national and regional energy storage mandates and targets. These will continue to foster deployment in the period ahead. More hybrid projects are expected to come online in the next few years, too, due to the rapid deployment of renewable energy projects.

Figure 6.2 Global gross battery storage capacity additions by year and total installed electricity storage project cost, 2010-2023



Source: BNEF (2024); Schmidt and Staffell (2023).

Notes: Cost data from 2010 to 2015 was calculated based on the capacity, price and experience curve regression data for electrical energy storage technologies model developed by Oliver Schmidt and Iain Staffell; GWh = gigawatt hour; kWh = kilowatt hour.

Since 2019, the primary use of electricity storage has been energy shifting (Figure 6.3). This balances the power system by storing renewable energy production at times of low market prices (leading to low/null revenue), or low demand (leading to curtailments). These circumstances encourage the storing of this energy for its later use at times of peak electricity demand or prices, resulting in improved system efficiency.

Between 2019 and 2023, the share taken by energy shifting more than doubled, reaching 67% of total capacity energy storage additions. The increase in the use of battery energy storage (BES) for energy shifting shows that the fall in electricity storage costs created increasing economic opportunities for time shifting, especially as solar PV penetration rose in certain markets. In the United States, solar PV with storage dominates the year-on-year growth of renewable hybrid projects, with this arrangement having the highest number of plants, PV capacity and energy storage (Berkeley Lab, 2023).

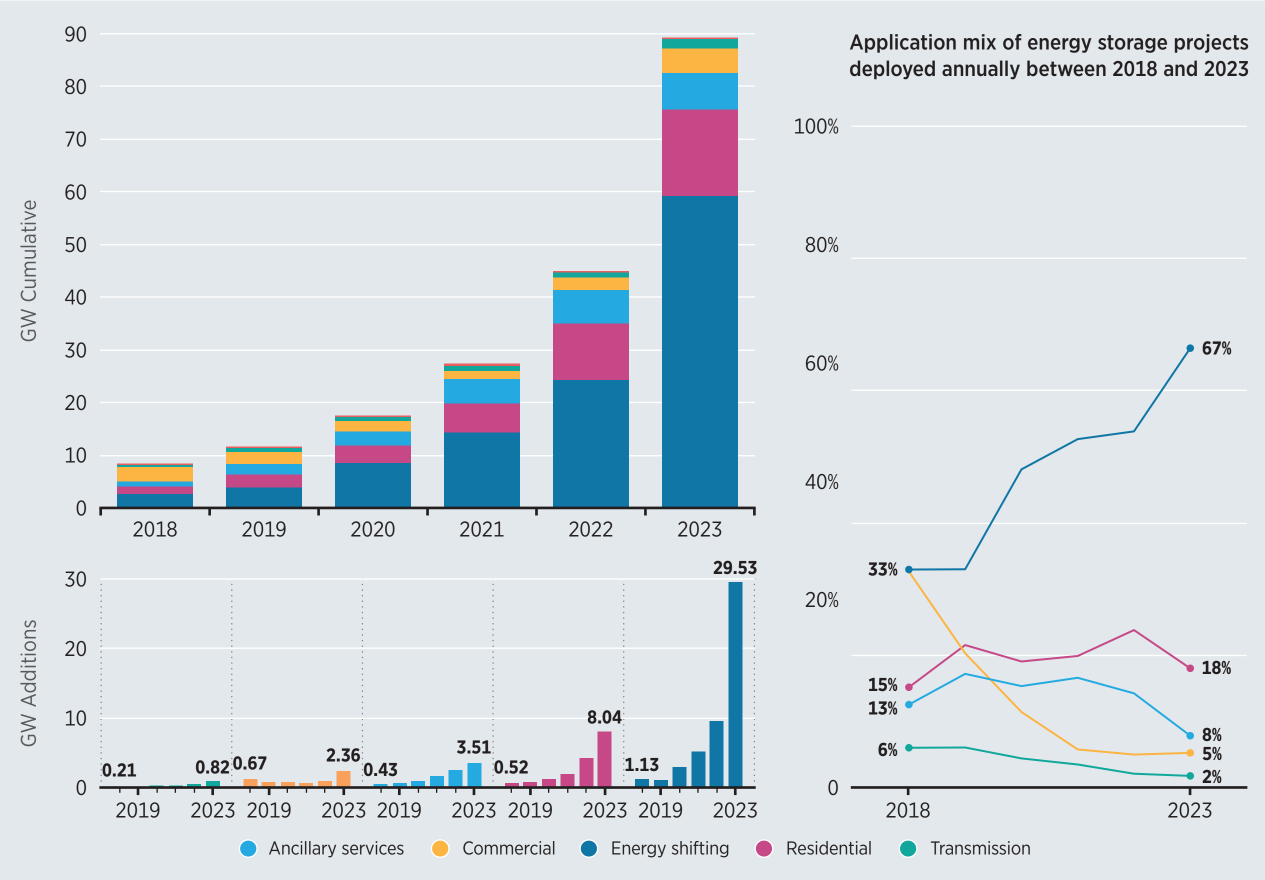
BES added-capacity in 2023 was almost 30 GW – triple the new additions of 2022. In both China and the United States, the large deployment of commissioned, utility-scale solar PV and wind projects – all paired with energy storage – was the main driver of this increase in the share of capacity taken by energy shifting applications.[42]

In the residential segment, capacity-added reached 8 GW, but its share of the energy storage application mix fell from 24% to 18%, as deployment in the utility-scale sector accelerated. Ancillary services also saw their share of the application mix decrease, reaching 8% of all energy storage projects deployed annually in 2023. The new capacity added in that year accounted for 3.5 GW, compared to 2.5 GW in 2022 – a 40% increase. Transmission and distribution were marginal applications, despite the increase in year-on-year added capacity.

Battery storage costs have fallen rapidly in recent years. Available data for representative datasets of the price of lithium-ion cells show them declining by about 82% between 2013 and 2023, as global manufacturing has scaled up. During this period, technology evolved with improved performance in energy density and specific energy.

[42] *These refer to the use of energy storage for renewable integration, price arbitrage and capacity services (BNEF, 2024a).*

Figure 6.3 Battery storage deployment by application



Based on: BNEF (2024)

In 2022, a rise in raw material prices affected the battery market, pushing costs up by 7%. Despite this price fluctuation, however, the supply recovered, and prices fell during 2023. This drove lithium-ion battery cell costs to a record low of USD 139/kWh, a decline of 14% compared to 2022.

Since 2021, lithium iron phosphate (LFP) has been the dominant battery chemistry in the stationary energy storage market and it is expected to remain on top through to 2030. The share, in GWh terms, of LFP in annual battery storage capacity additions jumped from 33% in 2020 to 84% in 2023 (BNEF, 2024a). This market growth was driven by low costs, a higher cycle life and improved safety compared to nickel-based lithium-ion batteries, as well as by the large manufacturing capacity of battery factories in China. LFP cells reached their lowest price in 2023, at USD 95/kWh, while on average, costs were 32% cheaper that year than nickel manganese cobalt oxide cells (BNEF, 2023c).

Turnkey energy storage system costs are available for major markets, with these providing a sense of the cost variation between regions. These costs include the price of battery providers and system integrators and exclude EPC, grid connection and development costs. In 2023, the global weighted average turnkey energy storage costs ranged between USD 325/kWh and USD 260/kWh, according to the system duration (Figure 6.4). As the duration of the system increases from one to four hours, the price decreases around 20%.

Figure 6.4 Turnkey battery storage system prices by market and duration, 2021-2023

Based on: BNEF (2023c).

Note: In the lower half of the chart, the reference line represents the cost ratio compared to the global average; kWh = kilowatt hour.

Figure 6.4 shows the fluctuation in prices between 2021 and 2023 caused by supply chain disruptions and volatility of raw material costs. After increasing in 2022, average battery costs declined during 2023 in all three markets and globally. China has the most competitive market, with prices below the global average. In 2023, electricity storage in China saw a cost decrease ranging from 36% (for a 4-hour system) to 29% (for a 2-hour system). Lower prices in China are mainly due to the well-established supply chain and the large manufacturing capacity, which creates strong domestic market competition. Europe had the lowest cost decrease between 2022 and 2023, ranging from 16% (for a 1-hour system) to 4% (for a 4-hour system). Prices were, however, less expensive than in the United States for all storage systems. Indeed, during 2023, the United States and Europe had battery prices above the global average for all systems, while in 2021 costs were close to the average. In 2023, the United States had the highest cost ratio compared to global prices, at 1.61 for a 1-hour battery system. The main reason for the price discrepancy between regions is the dependence on imported batteries in the United States and Europe. Domestic manufacturing in these two places is more expensive, while markets are less competitive than in China (BNEF, 2023c).

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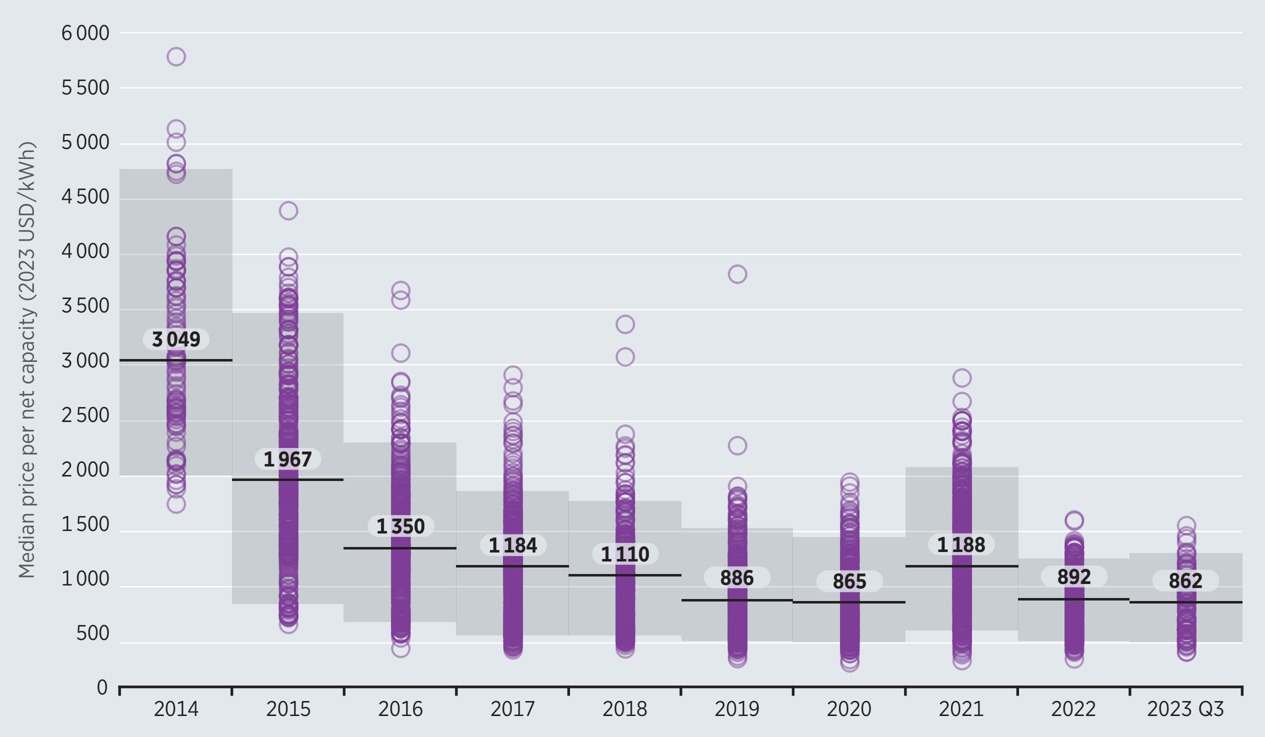
Small-scale battery storage systems are most often installed today in the residential sector, paired with PV. This enables an increase in home consumption, or, potentially, a response to incentives from grid operators and/or distribution companies to manage grid feed-in. Significant potential for growth in behind-the-meter applications remains. Currently, significant battery storage associated with new PV installations continues to be deployed in countries where the right regulatory structure is in place, such as Germany, or in areas with high electricity prices, excellent solar resources and relatively low grid feed-in remuneration – such as Australia.

In terms of the services provided by BES systems, the economics of behind-the-meter storage opportunities — notably for new PV installations — are likely to be a key driver of battery storage growth. In an era of lower feed-in remuneration to the grid, this technology will predominantly provide an electricity time-shift service to increase self-consumption. Given the arbitrage opportunity between electricity tariffs that are higher than feed-in remuneration, BES, associated with new installations of solar PV, is likely to grow rapidly as a result of these drivers. This growth will also include parts of the developing world, where battery and solar can be combined. As BES deployment increases and costs fall, retrofits of BES systems with small-scale solar PV are likely to emerge as an important source of energy storage demand. This is a story of economic opportunity that will arise from continued cost reductions. Growth in the use of aggregated, behind-the-meter BES to provide grid services is much more dependent on the regulatory and market structure in order to provide the economic use case. As the penetration of solar and wind increases, however, this will become more valuable, with policy likely to become more conducive to unlocking this flexibility.

In Europe, residential batteries are the largest source of electricity storage demand. Germany led the residential market in 2023, installing capacity of 5.6 GWh. This accounted for around 93% of the total annual addition in the country (BNEF, 2024a). Time series data for small-scale residential battery systems in Germany suggest prices fell by 71% between 2014 and 2022, reaching USD 892/kWh (Figure 6.5). Data from Q3 2023 shows prices falling to USD 862/kWh – the lowest value since 2014 and a 72% decline from that year. Prices also fell 3% in 2023, compared to 2022.

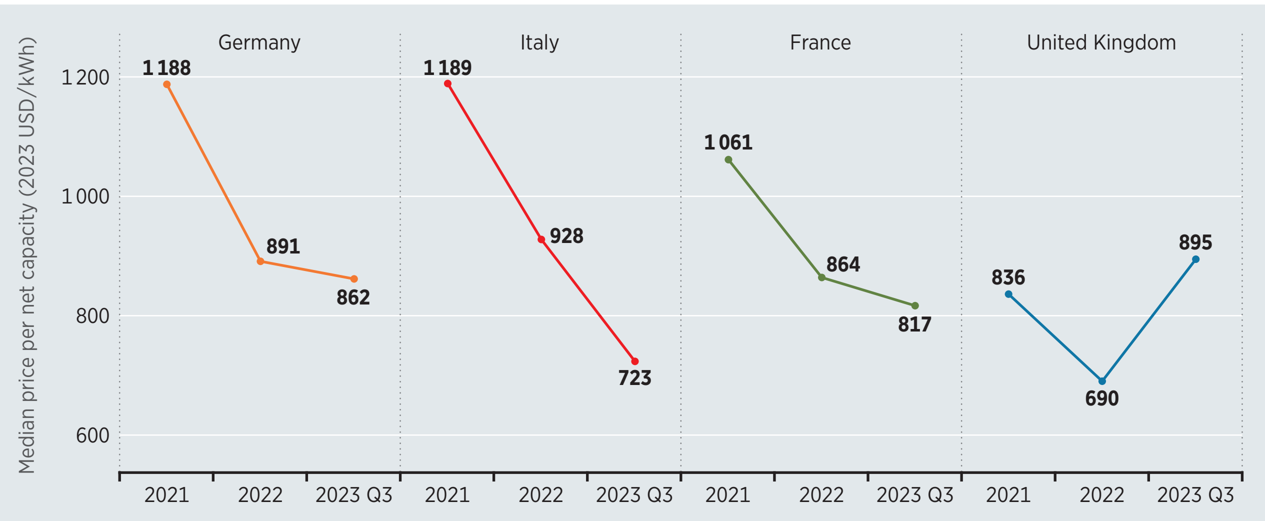
Figure 6.5 Behind-the-meter lithium-ion battery storage cost trends for residential systems in Germany, 2014-Q3 2023



Note: kWh = kilowatt hour.

In the third quarter of 2023, IRENA surveyed battery markets in the United Kingdom, Italy and France (Figure 6.6). Prices in Italy were the lowest amongst those markets, at USD 723/kWh. This was a decline of 22% on 2022 and a value 39% lower compared to 2021. In France, costs were USD 817/kWh – a 5% annual decline –and USD 862/kWh – a 3% decrease – in Germany. In contrast, the United Kingdom experienced a cost increase of 7%, reaching USD 895/kWh. This was the highest value among European markets. This price is also higher than in 2021, when costs in the United Kingdom were the lowest compared to other markets.

Figure 6.6 Behind-the-meter lithium-ion battery storage cost trends for residential systems by country, 2021-Q3 2023



Note: kWh = kilowatt hour.

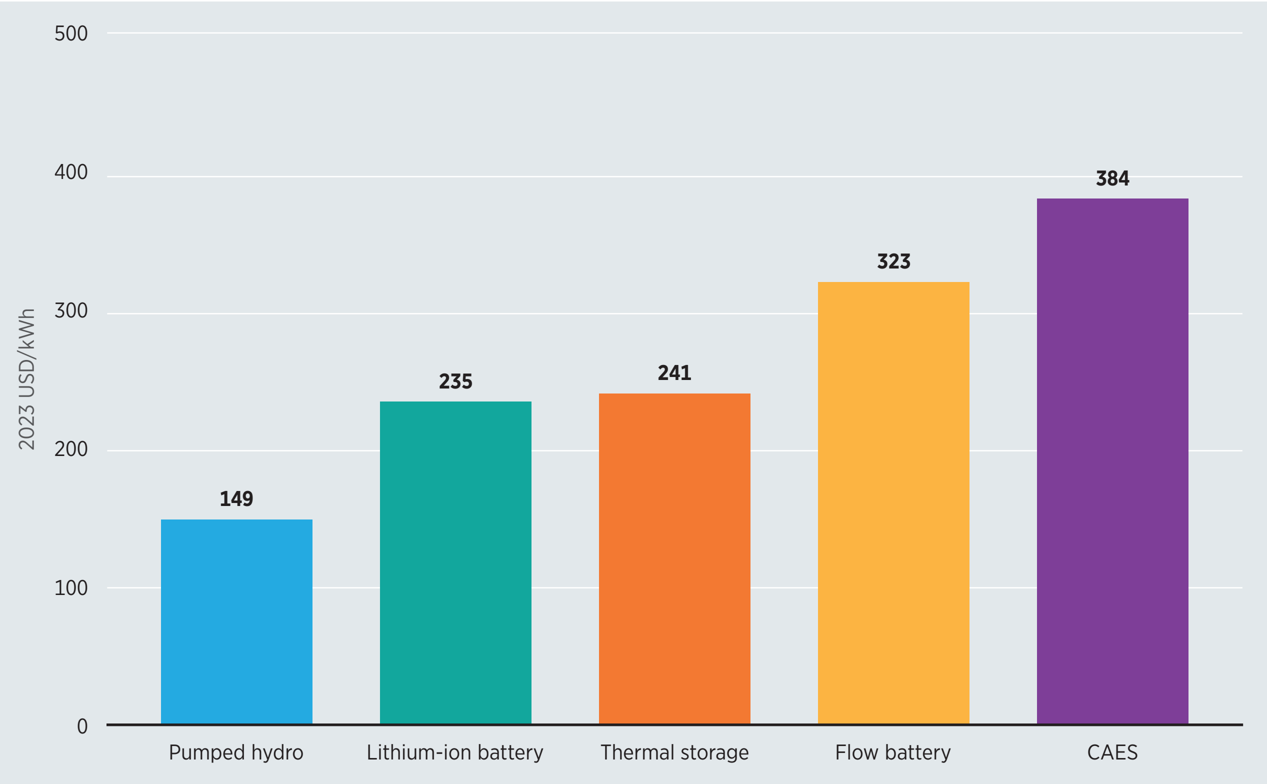
LONG DURATION ENERGY STORAGE

As the energy transition accelerates to 2030, the system will need long-duration energy storage (LDES), as well as a combination of other flexibility measures (bioenergy for power, geothermal, reservoir storage hydropower, demand-side management, interconnectors, *etc.*). LDES technologies are well adapted to ensure the resilience of the electricity system due to their capacity to discharge over long periods of time, especially in a system relying on more variable renewable sources. LDES offer durations of at least six hours and can complement short duration applications, such as Lithium-ion batteries.

A variety of LDES technologies are emerging, including electro-chemical, thermal, mechanical and chemical. Currently, the electricity storage landscape is dominated by pumped hydroelectricity storage (PHS), with around 140 GW of power capacity and 9 TWh of energy capacity (IRENA, 2024d). Some countries have already announced high PHS targets. In China, the total installed capacity of pumped storage is set to reach 62 GW by 2025 and 120 GW by 2030 (CET, 2023). In India, the target for expanded PHS is 175.18 GWh for 2031-2032 (MNRE, 2024).

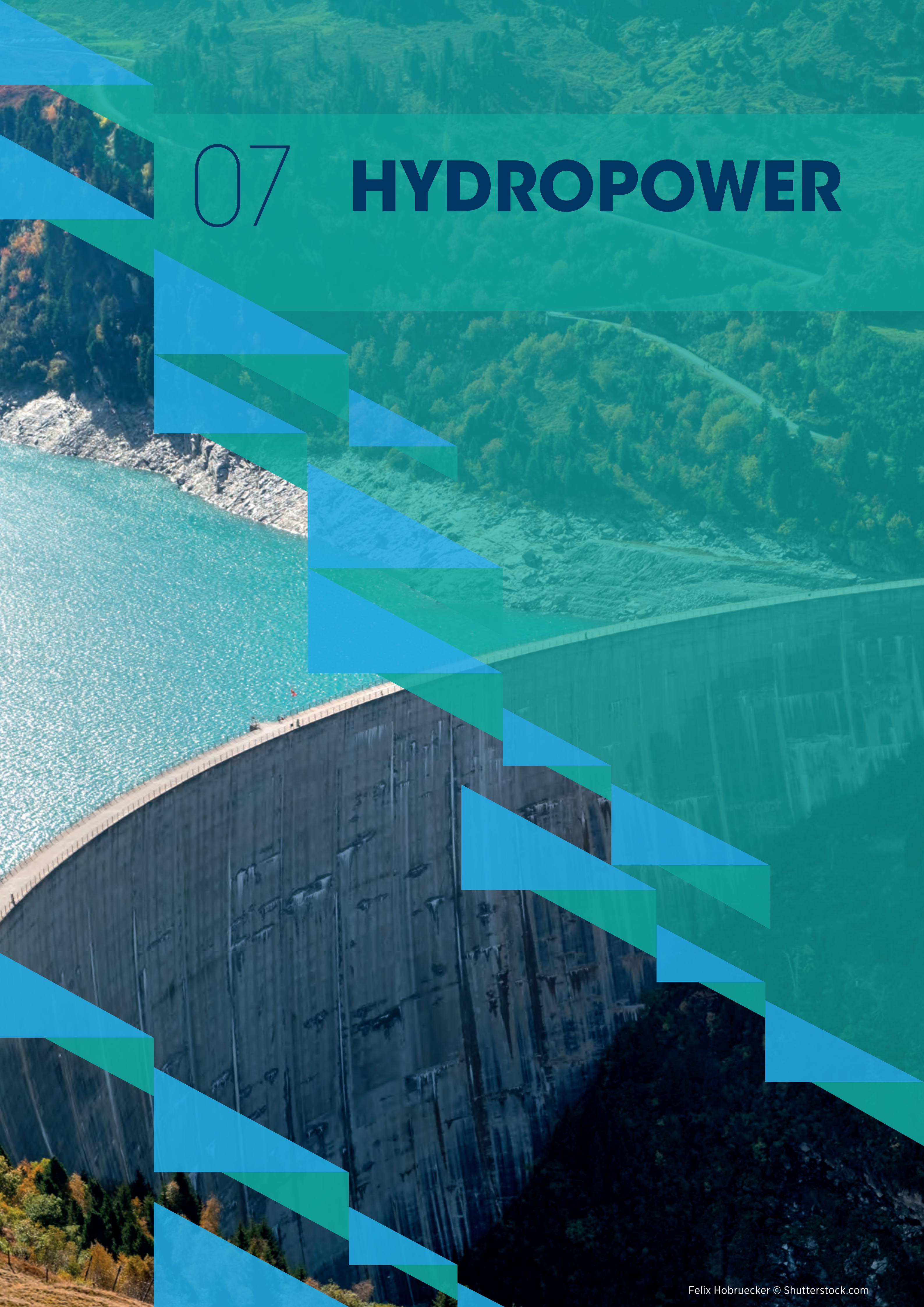
Using the available cost data for LDES from 129 projects with storage durations above 6 hours – combined with a number of secondary data sources – the average price per technology can be seen in Figure 6.7 below. Pumped storage is still the most competitive, with a global average installed cost of USD 149/kWh.

Figure 6.7 LDES global average cost per technology



Source: AURORA(2022, 2023); BNEF (2024b); DESNZ (2023).
Note: CAES = Compressed Air Energy Storage; kWh = kilowatt hour.

07 HYDROPOWER



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HIGHLIGHTS

The global weighted average levelised cost of electricity (LCOE) of newly-commissioned hydropower projects was USD 0.057/kWh in 2023 – 7% lower than the USD 0.061/kWh recorded in 2022 and 33% higher than the projects commissioned in 2010 (Figure 7.1).

In 2023, 100% of the newly-deployed capacity of hydropower projects commissioned that year had an LCOE lower than the country- or region-specific weighted average cost of newly-commissioned fossil-fuel fired capacity.

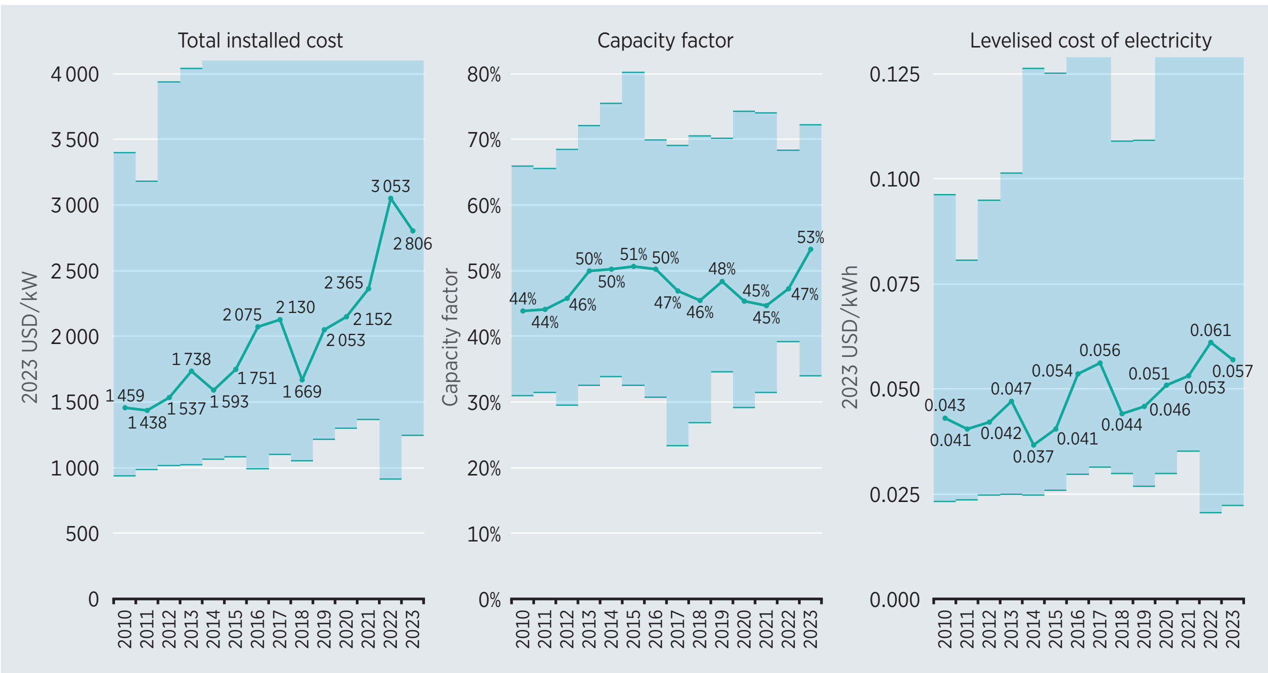
The increase in LCOE since 2010 has been driven by rising installed costs, notably in Asia. This was likely due to an increase in projects in locations with more challenging site conditions and more recent supply chain inflation, which drove up costs.

In 2023, the global weighted average total installed cost of newly-commissioned hydro projects decreased to USD 2 806/kW. This was lower than the 2022 figure of USD 3 053/kW.

The global weighted average total installed cost of hydropower in 2023 decreased after achieving its highest recorded value in 2022. This reduction was primarily attributed to differences in site locations for deployments between the two years. In 2022, there were a number of large projects, notably in Canada and the Lao People's Democratic Republic, with very large cost overruns.

Between 2010 and 2023, the global weighted average capacity factor for hydropower projects commissioned varied between a low of 44% in 2010-2011 and a high of 53% in 2023.

Figure 7.1 Global weighted average and range of total installed costs, capacity factors and LCOEs for hydropower, 2010-2023



INTRODUCTION

Hydropower is a mature and reliable renewable energy generation technology, although its share of global renewable energy capacity has slowly declined in recent years, due to the rapid deployment of wind and solar PV. Indeed, in 2023, the newly-installed capacity of hydropower (excluding pumped hydro) was at its lowest since the year 2000, with 7 GW added. From 2010 to 2023, hydropower's share of total renewable capacity dropped from 76% to 33%. At the end of 2022, hydropower capacity (excluding pumped hydro) held the largest share of global renewable installed capacity; however, by 2023, its 1 265 GW were surpassed by solar PV, which reached 1 411 GW.

Hydropower not only provides a low-cost source of electricity, but also flexibility, especially when the plant includes reservoir storage. This flexibility enables the plant to provide essential services, such as frequency response, black start capability and spinning reserves. These services enhance plant viability by increasing asset-owner revenue streams and facilitate the integration of variable renewable energy sources to meet decarbonisation targets.

Additionally, hydropower can store energy over extended periods, ranging from weeks to years, depending on the size of the reservoir. It does this by holding water until it is needed by grid operators or for multipurpose benefits. Hydropower projects also combine energy and water supply services, including irrigation schemes, municipal water supply, drought management, flood control, navigation and recreation. These services provide local socio-economic benefits and, in some cases, the hydropower capability is developed to meet 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 does not calculate the value of any services beyond electricity generation that are not specific to the site and power market.

TOTAL INSTALLED COSTS

The construction requirements for a hydropower project are influenced by various factors, such as the size, scope and location of the project. Technical considerations, including the "head" (the water drop to the turbine determined by the location and design), reservoir size, minimum downstream flow rate, and seasonal inflows are also crucial characteristics that determine the type and size of the turbine used.

In addition, hydropower plants are broadly classified into three categories:

- Reservoir - or storage - hydropower, which decouples inflows from the turbines. Water storage serves as a buffer that dams can use to store or regulate hydro inflows, decoupling generation time 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. Electricity is used to pump water from the lower to the upper reservoir in times of low demand (mostly during off-peak periods). It is then released in times of high electricity demand. Pumped hydro is mainly used for peak generation, grid stability and ancillary services. It can also integrate more variable renewables by storing abundant renewable generation that is not needed during periods of low electricity demand.

This chapter covers the costs of reservoir and run-of-river hydropower. Given that pumped storage is a storage technology, not a generating technology, it is excluded from this chapter's data.

Hydropower is a capital-intensive technology and bringing it online is a time-consuming process. The latter involves various stages, such as development, permitting, site development, construction and commissioning. Overall, the major cost components include: civil works for plant construction; infrastructure development; grid connection; environmental mitigation; and procurement costs for electro-mechanical equipment. Civil construction (the dam, tunnels, canal and construction of the powerhouse) usually comprises the largest share of total installed costs for large hydropower plants (Table 7.1). Following this, the costs of fitting out the powerhouse (including shafts and, in specific cases, electro-mechanical equipment) are the next most considerable capital outlay, accounting for around 30% of total costs.

The long lead times for these types of hydropower projects (7-9 years or more) mean 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 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 most hydropower projects commissioned between 2010 and 2023 range from a low of around USD 500/kW to a high of around USD 5 000/kW (Figure 7.2). It is not unusual, however, to find projects outside this range. For instance, adding hydropower capacity to an existing dam built for other purposes may have costs as low as USD 450/kW. In contrast, remote sites with poor infrastructure and far from existing transmission networks can cost significantly more than USD 5 000/kW, due to higher logistical, civil engineering and grid connection costs.

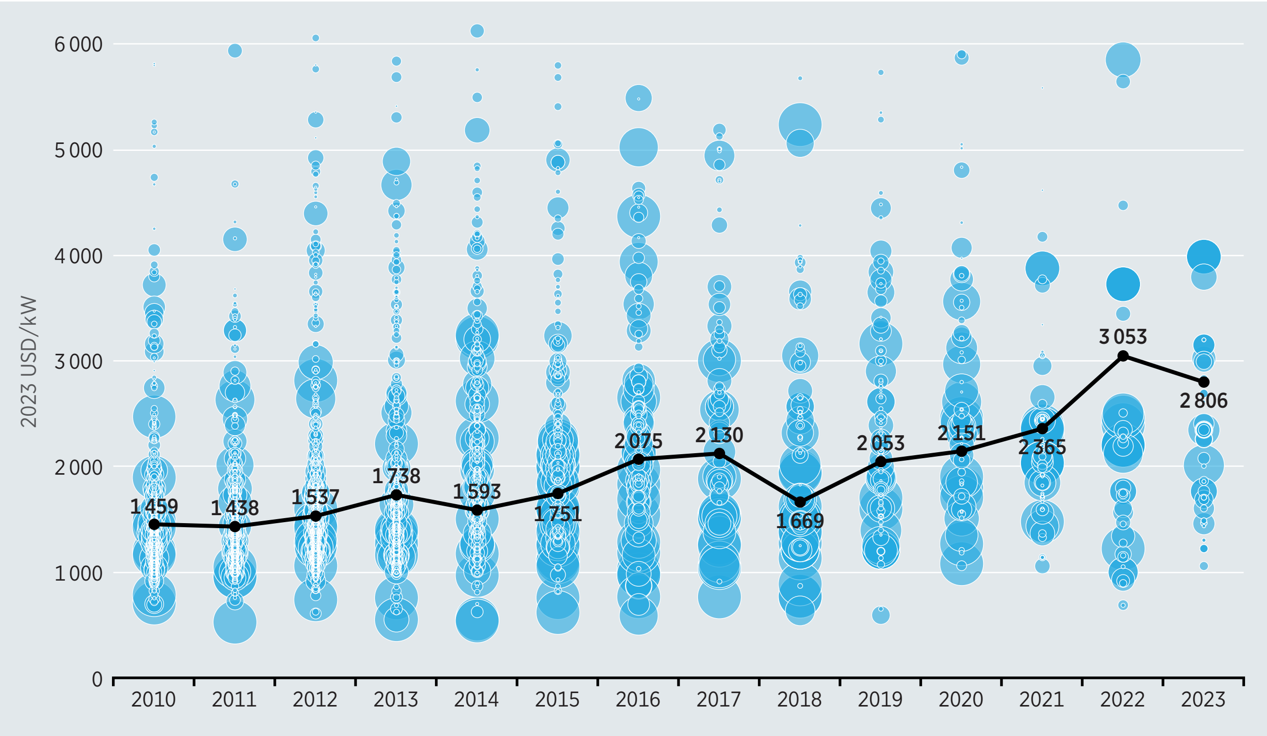
Between 2010 and 2023, the global weighted average total installed cost of new hydropower rose from USD 1 459/kW in 2010 to USD 2 806/kW in 2023 (Figure 7.2). After rising relatively steadily between 2010 and 2017, in 2018 the global-weighted average total installed cost dropped to USD 1 669/kW, only to see a consistent rises thereafter. The year 2023 saw a decrease, however, after the new higher cost level in 2022, with increases driven not just by the share of deployment in different regions, but also an upward trend in project-specific costs.

Table 7.1 Total installed cost breakdown by component and capacity-weighted averages for a sample of hydropower projects in Europe, 2021

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: International Hydropower Association (IHA).

Figure 7.2 Total installed costs by project and global weighted average for hydropower, 2010-2023



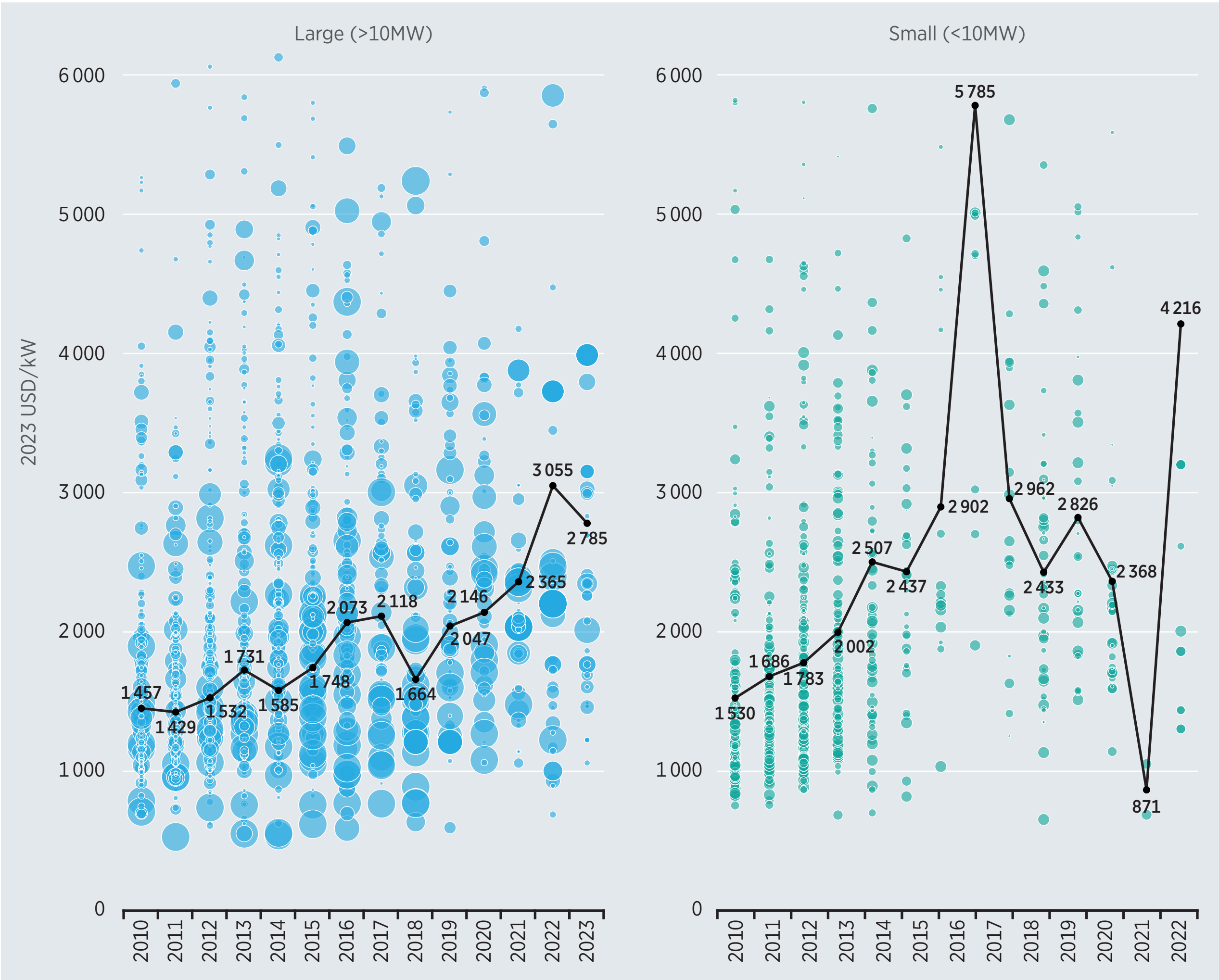
Source: International Hydropower Association (IHA).

The full dataset of hydropower projects in the *IRENA Renewable Cost Database* for the years 2000 to 2023 (Table 7.2) does not suggest that there are strong economies of scale in hydropower projects that are less than around 450 MW in size. The number of projects is not evenly distributed, however, and could likely support different hypotheses by region. 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 2023.

Figure 7.3 presents the distribution of total installed costs by capacity for small and large hydropower projects in the *IRENA Renewable Cost Database*. The global weighted average demonstrates an increasing trend after 2018 and a subsequent decrease in 2023. This pattern can be attributed to the large hydropower data.

The global weighted average total installed cost trends for large hydro (greater than 10 MW in capacity) and small hydro (10 MW or less) suggest that average installed costs for small hydro have increased at a faster rate than for large hydro projects (Figure 7.3). This trend remains to be confirmed, however, given that data in the *IRENA Renewable Cost Database* for small hydropower projects are noticeably thinner for the years 2015 to 2018. While there is better coverage in recent years, the below remains what was available in the period up to 2015.

Figure 7.3 Total installed costs for small and large hydropower projects and the global weighted average, 2010-2023



Notes: kW = kilowatt; MW = megawatt.

Table 7.2 Total installed costs for hydropower by weighted average and capacity range, 2000-2023

2000-2023			
Capacity (MW)	**5th percentile (2023 USD/kW)**	**weighted average (2023 USD/kW)**	**95th percentile (2023 USD/kW)**
0-50	928	**1 871**	3 950
51-100	960	**2 062**	4 191
101-150	1 021	**1 958**	3 865
151-200	931	**1 927**	3 471
201-250	996	**2 120**	3 819
251-300	935	**2 337**	4 280
301-350	1 038	**2 185**	4 947
351-400	756	**1 797**	3 568
401-450	1 329	**2 212**	3 378
451-500	1 076	**1 687**	2 733
501-550	1 238	**2 708**	4 553
551-600	1 504	**2 035**	2 876
601-650	1 185	**1 617**	3 738
651-700	883	**2 192**	2 955
701-750	1 077	**1 731**	2 397
751-800	1 189	**1 747**	2 465
801-850	1 314	**4 119**	12 440
851-900	1 060	**1 802**	2 066
901-950	729	**1 223**	1 484
951-1000	2 474	**2 474**	2 474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Differences in the distribution of total installed costs by capacity between 2010-2015 and 2016-2023 are shown in Figure 7.4. Compared to the period 2010 to 2015, the data for 2016 to 2023 show a reduction in the share of newly-commissioned projects in the USD 600/kW to USD 1 200/kW range. They also show an increase in the capacity of projects above that. The shift in the distribution of small hydropower projects is more pronounced, but was also accompanied by a reduction in the skew of the distribution of projects. There has, however, also been growth in the tail of more expensive projects, compared to the 2010 to 2015 period.

The total installed cost and the weighted average total installed cost of large and small hydropower projects per region and by specific country are presented for two periods in Figures 7.5 and 7.6 below. Between 2010-2015 and 2016-2023, the weighted average total installed costs for almost all the countries shown in Figure 7.5 increased. The exceptions were Brazil, Europe and India, where these costs decreased. Similarly, in Figure 7.6, the exceptions to the increasing trend were Brazil, Eurasia and Europe.

For the 2016 to 2023 period, the total installed costs for large hydropower (more than 10 MW in capacity) were highest in the North America and Oceania regions. In these two areas, there were weighted average installed costs of USD 6 040/kW and USD 4 580/kW, respectively. The next highest total installed cost was in Central America and the Caribbean, where the weighted average was USD 3 967/kW.

Figure 7.4 Distribution of total installed costs of large and small hydropower projects by capacity, 2010-2015 and 2016-2023

In the same, 2016 to 2023 period, the lowest weighted average installed costs for large hydropower were in India – at USD 1 586/kW – and Brazil, at USD 1 707/kW. In Other Asia, the weighted average installed cost was USD 1 972/kW, while in China it was USD 2 017/kW. In the Middle East, this figure was USD 2 038/kW, while in Eurasia it was USD 2 400/kW. In Africa, Other South America, and Europe, the weighted average installed costs were USD 2 608/kW, USD 2 583/kW and USD 2 318/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.

Figure 7.5 Total installed cost by project and capacity weighted averages for large hydropower projects by country/region, 2010-2023

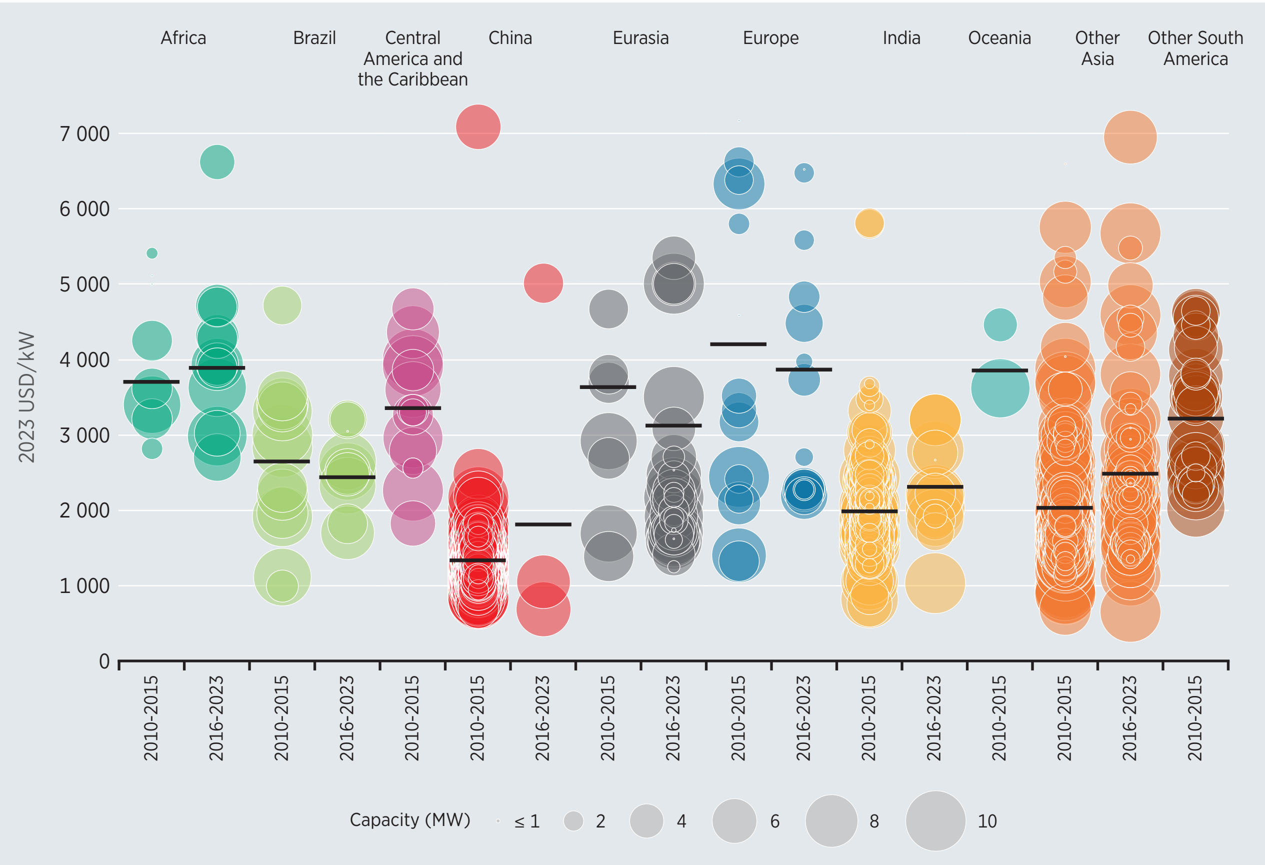
Notes: kW = kilowatt; MW = megawatt; see Annex III for regional country groupings.

Between 2016 and 2023, the total installed cost for small hydropower projects in India was USD 2 317/kW, which was somewhat higher than during the period 2010 to 2015. The total installed costs of small hydropower in Brazil averaged USD 2 455/kW in the period 2016 to 2023, a figure 8% lower than in the period 2010 to 2015. The weighted average installed cost for small hydropower in China was USD 1 346/kW over the period 2010 to 2015. During the period 2016 to 2023, this cost went up to USD 1 829/kW.

In Central America and the Caribbean, Oceania and Other South America regions, data for small hydropower projects commissioned in the period 2016 to 2023 are sparse. Results are therefore only presented for total installed costs during the 2010 to 2015 period.

During that time, the weighted average installed cost for small hydropower in Oceania was USD 3 866/kW, while in Central America and the Caribbean it was USD 3 364/kW and in Other South America, USD 3 230/kW.

Figure 7.6 Total installed costs by project and capacity weighted averages for small hydropower projects by country/region, 2010-2023



Notes: kW = kilowatt; MW = megawatt; see Annex III for regional country groupings.

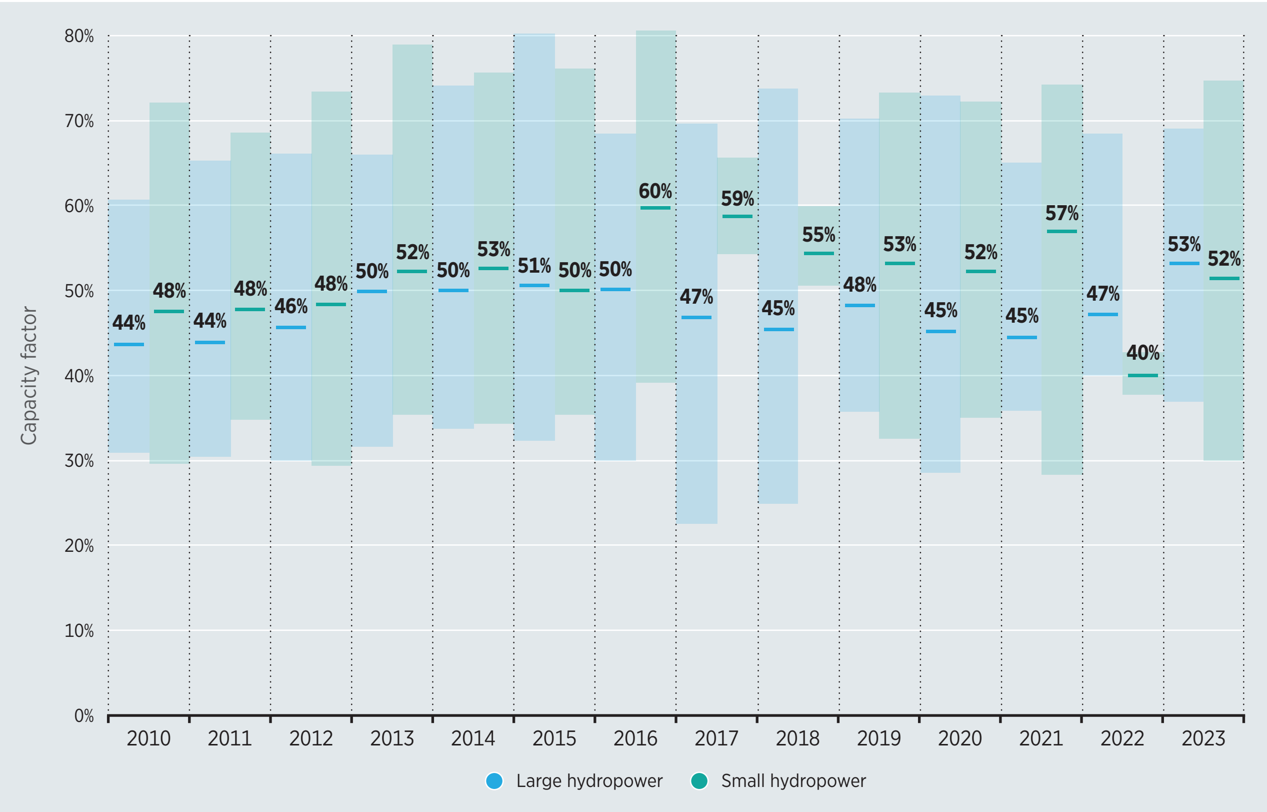
CAPACITY FACTORS

Between 2010 and 2023, the global weighted average capacity factor of newly-commissioned hydropower projects of all sizes increased from 44% to 53%. This rise was largely due to higher capacity factors in Asian markets, particularly China, which contributed 41% of the newly-commissioned hydropower capacity in 2023 and saw a 23% year-on-year increase in its capacity factor. The 5th and 95th percentiles of projects over the period were also within the 23% to 80% range. This wide range is to be expected, given the diverse site characteristics of hydropower projects. In addition, low capacity factors are sometimes a design choice to meet peak demand and provide other ancillary grid services and non-energy services, like flood control, where water levels may be deliberately kept low at certain times.

Between 2010 and 2023, the annual global weighted average capacity factors of newly-commissioned large hydropower projects increased from 44% to 53% (Figure 7.7). The 5th percentile of large hydropower projects ranged from a low of 23% in 2017 to a high of 40% in 2022. For the 95th percentile, the figure ranged from a low of 66% in 2010 to a high of 80% in 2015. The 5th and 95th percentile figures for 2023 were 37% and 69%.

Between 2010 and 2023, the annual global weighted average capacity factor of newly-commissioned small hydropower projects increased from 48% to 52% (Figure 7.7). Excluding the years 2017, 2018 and 2022 – for which there is a lack of data – the annual 5th percentile of small hydropower projects ranged from a low of 28% in 2021 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. The 5th and 95th percentile figures for 2023 were 30% and 75%, respectively.

Figure 7.7 Global weighted average capacity factor, 5th and 95th percentile for small and large ydropower, 2010-2023



In the *IRENA Renewable Cost Database*, there is often a significant regional variation in the weighted average capacity factor. Tables 7.3 and 7.4 represent hydropower project weighted average capacity factors and ranges 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 Other South America, with 61% and 62%, respectively. Between 2015 and 2023, Other South America maintained the highest average capacity factor, at 60%, followed by North America, with 55%. Meanwhile, between 2010 and 2015, North America recorded the lowest average capacity factor for newly-commissioned large hydropower projects, at 37%, while between 2016 and 2023, Europe had the lowest recorded average, at 33%.

Small hydropower projects (less than 10 MW) showed a smaller range of country-level, weighted average variation (Table 7.4). For these, there were country-level average lows of 46% in China and 37% in Other South America during the periods 2010 to 2015 and 2016 to 2023, respectively. Similarly, weighted average capacity factors for newly-commissioned small hydropower projects between 2010 and 2015 were highest in Other South America and Brazil, at 65% and 63%, respectively.

Between 2015 and 2023, 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, at 58%, followed by Other Asia and Africa, with a factor of 56% each, while the weighted average capacity factor in Brazil dropped to 54%.

Table 7.3 Hydropower project weighted average capacity factors and ranges for large hydropower projects by country/region, 2010-2022

	2010-2015			2016-2023		
	5th percentile (%)	Weighted average (%)	95th percentile (%)	5th percentile (%)	Weighted average (%)	95th percentile (%)
Africa	28	**47**	71	34	**51**	78
Brazil	51	**61**	80	39	**46**	62
Central America	27	**48**	63	33	**51**	55
China	31	**46**	57	38	**46**	63
Eurasia	28	**43**	61	29	**42**	68
Europe	14	**41**	70	16	**36**	59
India	29	**47**	63	21	**42**	59
North America	18	**37**	78	35	**55**	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	46	**60**	78

Notes: see Annex III for regional country groupings; n.a. = not applicable.

Table 7.4 Hydropower project weighted average capacity factors and ranges for small hydropower projects by country/region, 2010-2023

	2010-2015			2016-2023		
	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	**40**	43
Eurasia	44	**58**	74	43	**58**	71
Europe	29	**52**	70	28	**43**	66
India	28	**50**	71	34	**48**	60
Other Asia	37	**50**	79	36	**58**	79
Other South America	43	**65**	82	37	**37**	37

Notes: see Annex III for regional country groupings; n.a. = not applicable.

O&M COSTS

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

IRENA had previously collected O&M data on 25 projects commissioned between 2010-2016 (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 higher end of the range, or have above average O&M costs.

Table 7.5 presents the cost distribution of individual O&M items in the sample. As can be seen, operations and salaries take up 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 7.5).

The IEA assumes O&M costs of 2.2% for large hydropower projects and between 2.2% and 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 as those for wind, when expressed as a percentage of total installed costs, although not as low as the O&M costs for solar PV. When a series of plants are installed along a river, centralised control, remote management and an operations team dedicated to managing 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, 2017).

Other studies (Greenpeace, 2015) 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). This 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 and other durable items. Replacement of these is infrequent, with design lives of 40 years or more for electro-mechanical equipment and over 50 years or more for penstocks and tailraces. Civil components – which on average account for 45% of the installed cost – have a longer economic life, usually ranging from 50 up to 100 years.

This LCOE assessment assumes an economic life for hydropower plants of 30 years. This is a conservative assumption, meaning that the original investment is fully amortised by the time any significant reinvestment is needed. These reinvestments are therefore not included in the LCOE analysis presented here. They could, however represent an economic opportunity before the full amortisation of the hydropower project, in order to boost generation output.

Table 7.5 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	**46**	61
Salary	13	**35**	74
Other	5	**15**	28
Material	3	**4**	4

LCOE

In numerous countries, hydropower has historically been a low-cost electricity source. Such places include Norway, Canada, New Zealand, China, Paraguay, Brazil and Angola, among others. Hydropower investment costs vary depending on location and site conditions, resulting in a wide range of installed costs and differences in the LCOE between projects. It is also important to note that hydropower projects can be designed to perform very differently from one another, adding complexity to the assessment of LCOE.

As an example, a plant with low installed electrical capacity could run continuously to achieve high average capacity factors, but may struggle to ramp up production to meet peak demand loads. Alternatively, a plant with a high installed electrical capacity and low capacity factor might 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 in cases where the electricity system requires these services, hydropower can often be the most cost-effective solution.

The approach chosen in each case will be influenced by the characteristics of the site inflows and the requirements 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. Such systems do this by holding back water and thus storing potential energy until it is needed to support daily generation, or a number of flexibility services.

In 2023, the global weighted average cost of electricity from hydropower was USD 0.057/kWh, up 33% from the USD 0.043/kWh recorded in 2010. The global weighted average cost of electricity from hydropower projects commissioned in the years 2010 to 2015 averaged USD 0.041/kWh. This increased to an average of USD 0.052/kWh for projects commissioned over the years 2016 to 2023.

Despite these increases through time, however, 100% of the hydropower projects commissioned in 2023 had an LCOE within or lower than the range of costs for newly-commissioned fossil fuel-fired capacity. In remote locations, hydropower was still the cheapest source of new electricity, given the extensive use of small hydropower, in particular. Such projects can provide low-cost electricity in these locations and increase 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 2023 range from a low of USD 0.016/kWh in Georgia for a 34 MW project to a high of USD 0.250/kWh for a 5.5 MW Canadian project. The latter had high associated costs due to its site location and the impact of extreme weather events on the site.

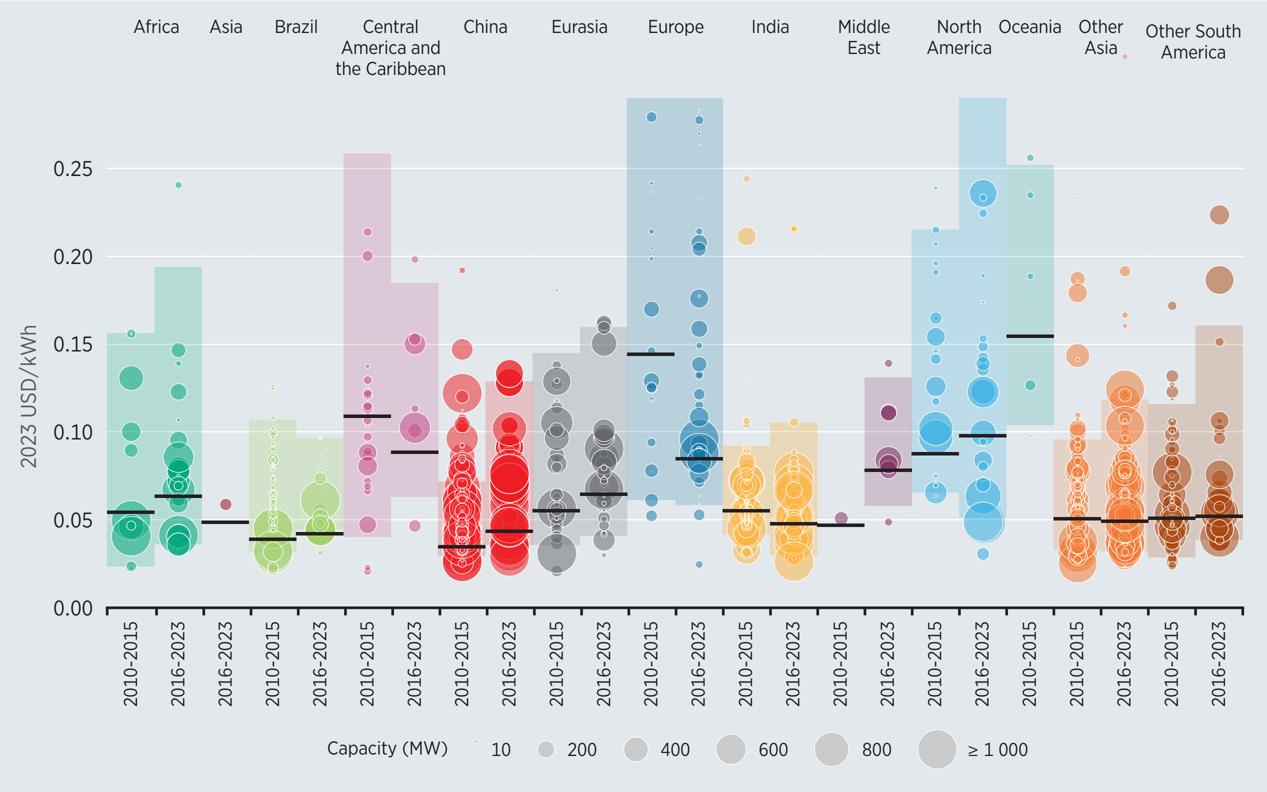
Figures 7.8 and 7.9 present the LCOEs of large and small hydropower projects and the capacity-weighted averages by country/region.

For large hydropower projects, several countries/regions saw an increase in the weighted average LCOE between the periods 2010 to 2015 and 2016 to 2023.

The exceptions were Central America and the Caribbean, Europe, India and Other Asia, where the weighted average LCOE decreased. Meanwhile, China saw a 20% increase in the weighted average LCOE between the two periods, 2010 to 2015 and 2016 to 2023 (Figure 7.8).

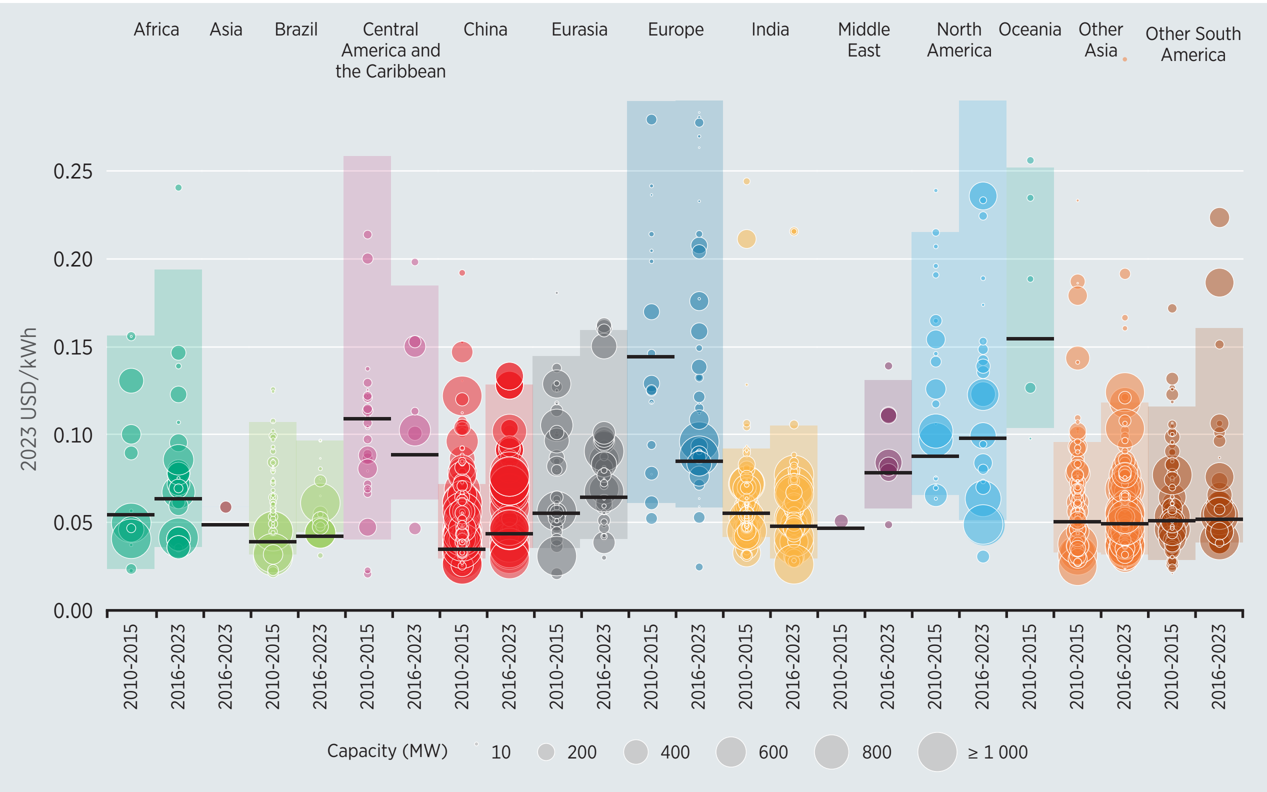
Small hydropower projects showed a decrease in the weighted average LCOE in Africa, Brazil, Eurasia, Europe and Other Asia between the periods 2010 to 2015 and 2016 to 2023. There was, however, a different trend in China and India, where the weighted average LCOE increased. For small hydro, the available data were insufficient for Central America and the Caribbean, and non-representative for Other South America. This meant that the trend for weighted average LCOE for small hydro projects in those regions could not be calculated accurately.

Figure 7.8 Large hydropower project LCOE and capacity weighted averages by country/region, 2010-2023



Notes: kWh = kilowatt hour; MW = megawatt; see Annex III for regional country groupings.

Figure 7.9 Small hydropower project LCOE and capacity weighted averages by country/region, 2010-2023



Notes: kWh = kilowatt hour; MW = megawatt; see Annex III for regional country groupings.

08 GEOTHERMAL

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HIGHLIGHTS

Worldwide, around 203 MW of new geothermal power generation capacity were commissioned in 2023. This was higher than the 181 MW added in 2022.

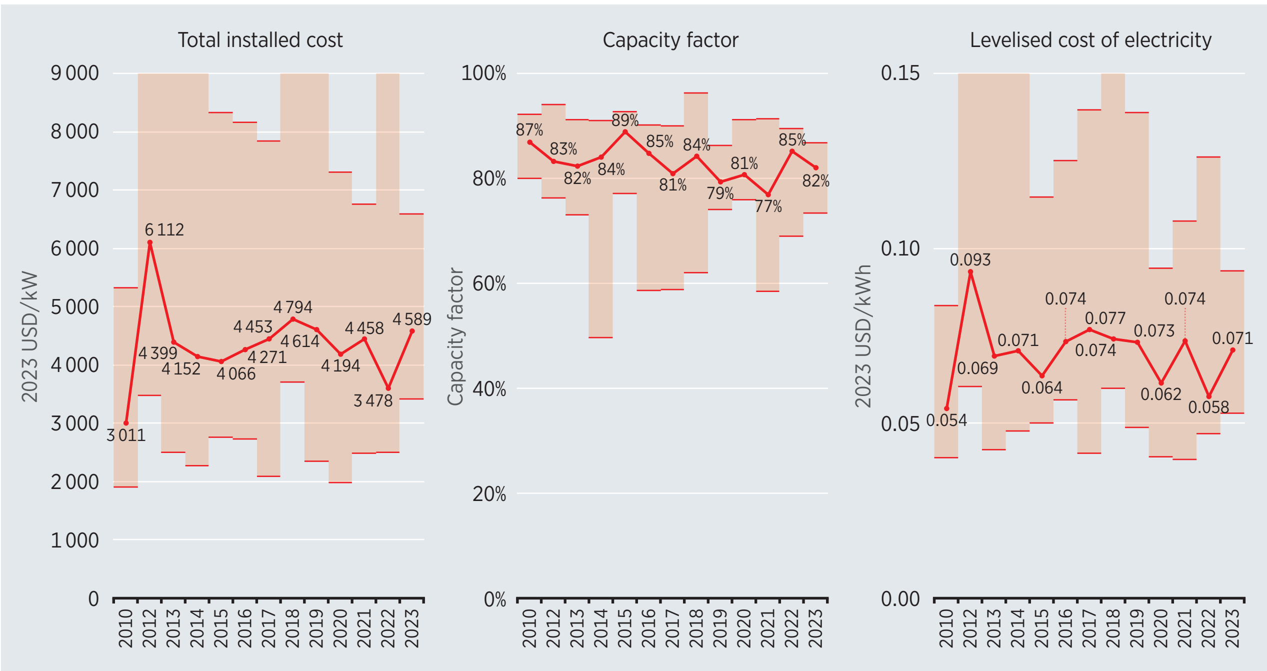
The global weighted average levelised cost of electricity (LCOE) of the projects commissioned in 2023 was USD 0.071/kWh, a value similar to the global average in 2021.

The low deployment rate for geothermal means that weighted average costs and performance are being determined by only a handful of plants each year.

In 2023, the global weighted average total installed cost of the seven plants in IRENA's database was USD 4 589/kW. This was higher than the recent cost decrease of USD 3 478/kW recorded in 2022. The total installed costs of projects commissioned in 2023 ranged from a low of USD 3 413/kW to a high of USD 6 595/kW.

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 2023, the global weighted average capacity factor for newly-commissioned plants was 82%.

Figure 8.1 Global weighted average and range of total installed costs, capacity factors and LCOEs for geothermal, 2010-2023



INTRODUCTION

At the end of 2023, geothermal power generation stations accounted for 0.4% of total installed renewable power generation capacity worldwide, with a total installed capacity of around 15 GW. Cumulative installed capacity at the end of 2023 was almost 50% higher than in 2010. This capacity is mostly located in active geothermal areas. The countries with the largest installed capacities include Iceland, Indonesia, Italy, Kenya, Mexico, New Zealand, the Philippines, Türkiye and the United States.

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 a lower cost than the evenly distributed heat available at greater depths everywhere else on the planet.

The 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 a 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 typically significantly higher due to the deep drilling required, rendering the economics of such initiatives less attractive. Research and development involving 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, although 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 from other renewable power generation technologies.

Indeed, developing a geothermal project presents a unique challenge when assessing the resource and how the reservoir will react once production starts. Subsurface resource assessments and reservoir mapping are expensive to conduct. Once completed, they must be confirmed by test wells that allow developers to build models of the reservoir's extent and flow and how it will react to water and steam extraction 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 until actual operational experience is gained.

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

One of the most critical 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, which in turn also potentially reduces the development cost. This is because poorer than expected results during the exploration phase – such as lower than projected flow rates or reservoir permeability – might require additional drilling or the deployment of wells over a much larger area to generate the expected electricity. There is potential for governments to undertake some resource mapping and make this available to project developers 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. In addition, greater experience in each region has also played a part (IFC, 2013).

Geothermal plants are also distinct 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 O&M practices. Nonetheless, adherence to best international practices for survey and management – with thorough data analysis from the project site – is the best risk mitigation tool available to developers (IFC, 2013), and its 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 PV. The process of extracting reservoir fluid and reinjecting it over the life of the project creates a dynamic situation in which reservoir fluid migration will likely change over time. This has 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 CSP.

Project development, field preparation, production and reinjection wells, the power plant, and associated civil engineering entail significant upfront costs. Geothermal projects are also subject to variations in drilling costs, the trends in 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 EPC.

Geothermal power plant installed costs are highly site sensitive. In this respect, they have more in common with hydropower projects than the more standardised solar PV and onshore wind facilities.

In particular, geothermal power project costs are heavily influenced by reservoir quality – that is to say, temperature, flow rates and permeability – because 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, its thermal properties 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, because extracting the electricity from lower temperature resources is more capital intensive.

The total installed costs of geothermal power plants also include the cost 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 than that for geothermal power plants.

The other main additional cost driver for geothermal is the drilling cost of the production and injection wells. If a large geothermal field needs to be exploited, the costs for field infrastructure, geothermal fluid collection, 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.

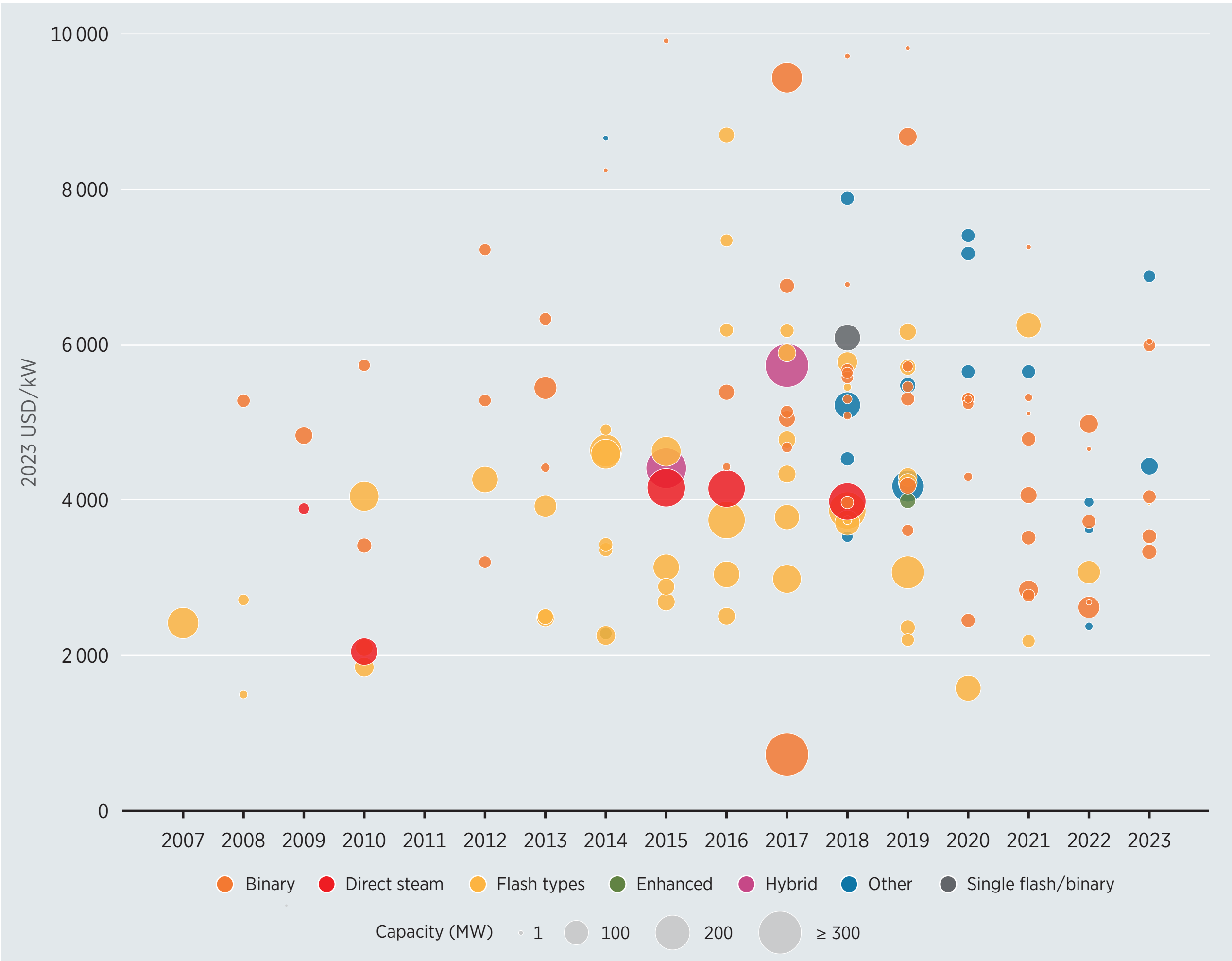
In 2009, the total installed costs of conventional condensing flash geothermal power generation projects were between USD 2 097/kW and USD 4 183/kW. Binary power plants were more expensive: installed costs for typical projects were between USD 2 481/kW and USD 6 062/kW the same year (IPCC, 2011).

Between 2020 and 2023, binary power plants were the dominant technology for newly-commissioned geothermal projects. In this period, installed costs for which IRENA has data were in the range of USD 1587/kWto USD 6 257/kW.

Based on the data available in the *IRENA Renewable Cost Database*, installed costs from 2010 onward 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 – ranging from a high of USD 4 794/kW in 2018 to a low of USD 3 606/kW in 2022. The average in that period was around USD 4 333/kW. The 2023 figure shows an increase of 27% compared to 2022. However, costs were close to the 2021 global average and lower than the high of USD 4 794/kW reported in 2018.

In the more exceptional case of projects where capacity has been 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. This is, however, by no means the norm and it is now rare to see projects with costs below USD 2 000/kW.

Figure 8.2 Geothermal power, total installed costs by project, technology and capacity, 2007-2023



Note: kWh = kilowatt hour; MW = megawatt.

CAPACITY FACTORS

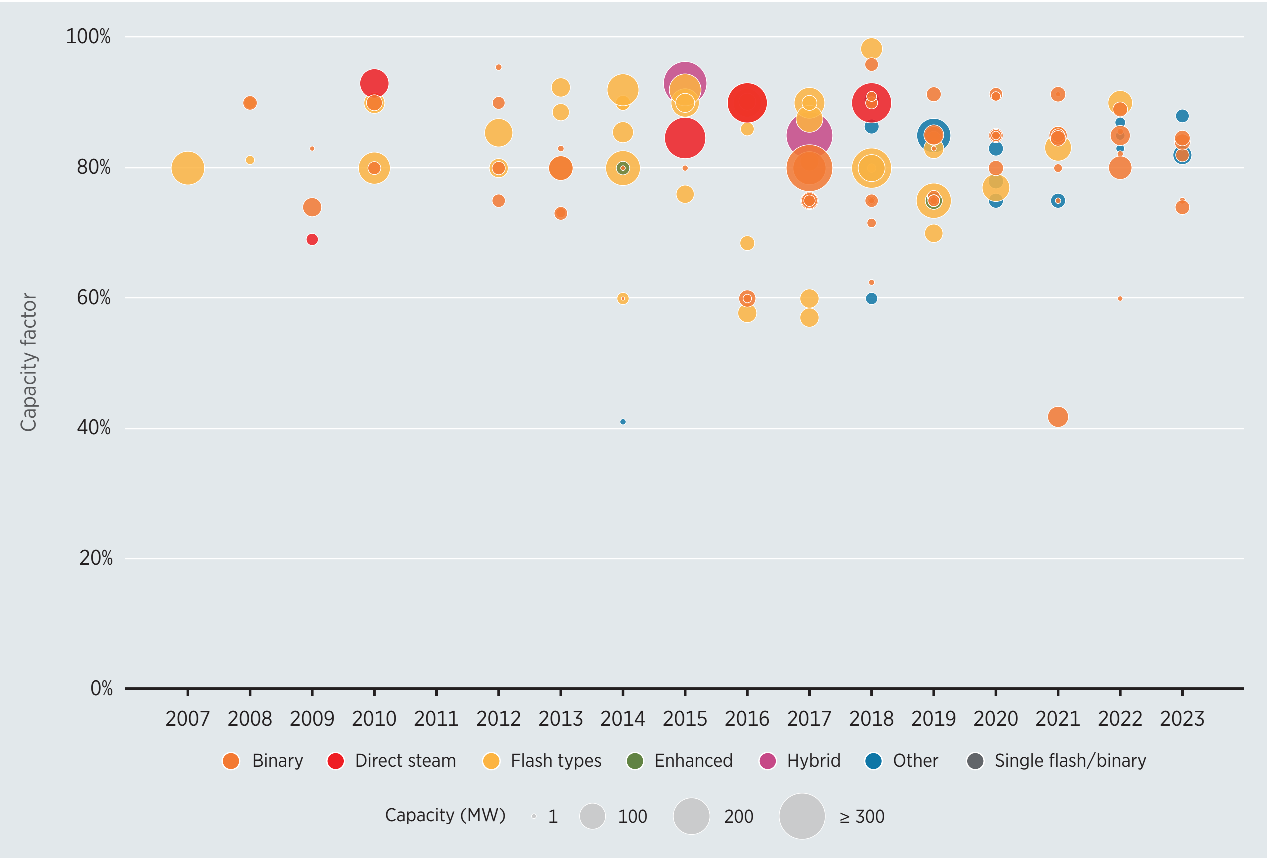
By accessing steam or heated water near the Earth's surface, geothermal plants have a continuous source of energy and tend to operate for most hours of the year.

For the years 2007 to 2023, data from the *IRENA Renewable Cost Database* indicate that geothermal power plants typically had capacity factors that ranged from 50% to more than 95%, with some exceptions. There were, however, significant variations by project, and to a lesser extent between countries. To name just three of the most important drivers, these variations were driven by the quality of the resource, reservoir dynamics and economic factors.

Figure 8.3 presents the capacity factors of geothermal power plant projects in the *IRENA Renewable Cost Database* by year, project size and technology between 2007 and 2023.

The average capacity factor of geothermal plants using direct steam was around 85% during the period, while the average for flash technologies was 82%. Binary geothermal power plants that harness lower temperature resources are expected to achieve an average capacity factor of 80%. In 2023, the global weighted average capacity factor for newly-commissioned geothermal projects was 82%, a 4% decrease compared to 2022.

Figure 8.3 Capacity factors of geothermal power plants by technology and project size, 2007-2023



Note: MW = megawatt.

O&M COSTS

O&M costs for geothermal projects are high relative to onshore wind and solar PV. In particular, this is because over time the reservoir pressure around the production well declines, leading to poorer flow rates. Well productivity therefore deteriorates over time. Eventually, power generation production also falls, if remedial measures are not taken.

To maintain production at the designed capacity factor, the reservoir and production profile of the geothermal power plants therefore require agile management. This will also typically include the need to incorporate additional production wells over the lifetime of the plant. The O&M cost assumption of USD 110/kW/year includes two sets of wells for makeup and reinjection over the 25-year life of the project to maintain performance.

LCOE

The total installed costs, WACC, 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 indicating that 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 reservoir and production wells management to ensure output meets expectations.

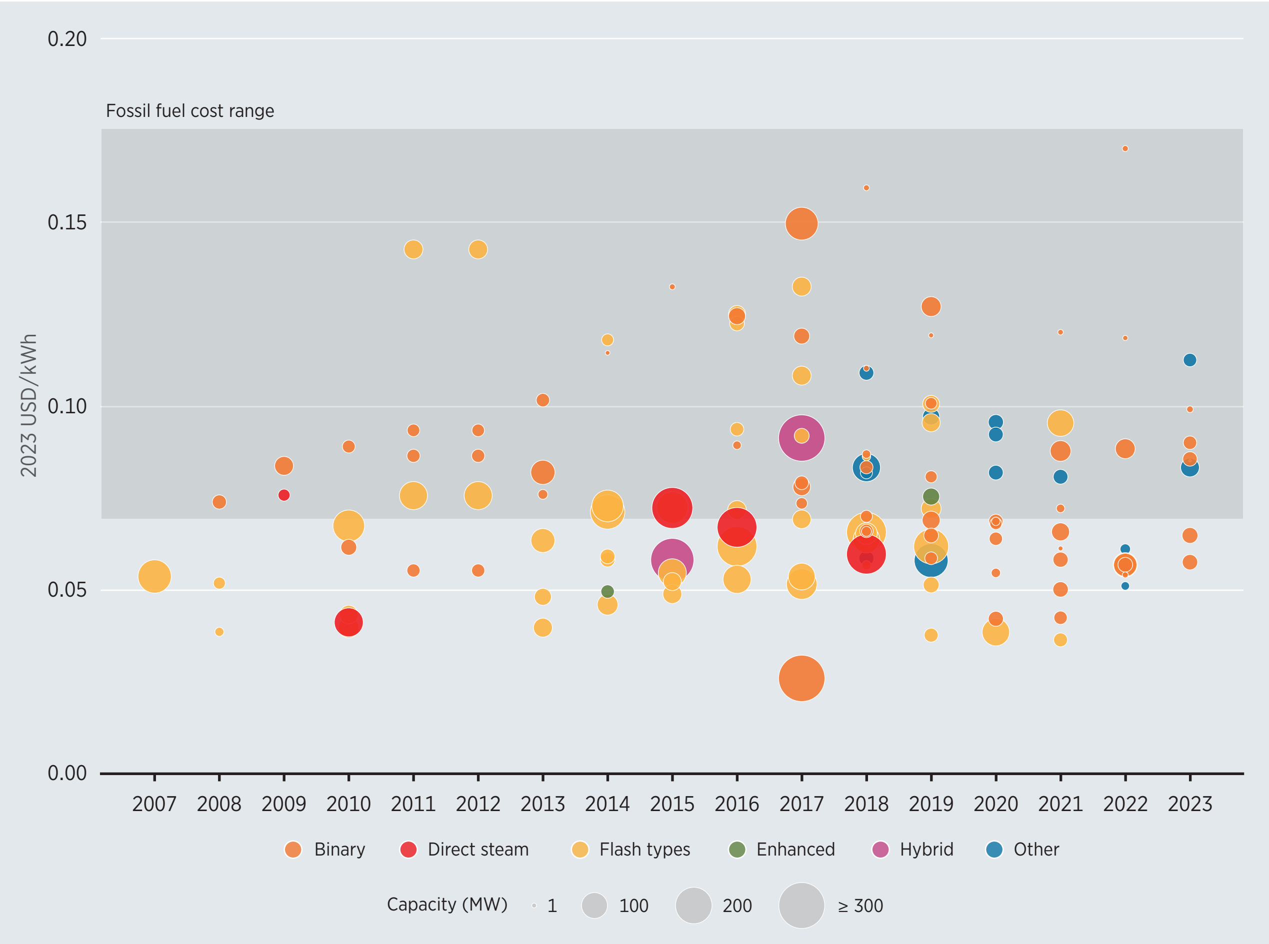
This leads to higher O&M costs. This LCOE analysis assumes O&M costs of USD 115/kW/year and an economic life of 25 years for the project. Capacity factors were taken from project data where available, and national averages were used if none were available.

Figure 8.4 presents the LCOE of geothermal power projects by technology and size for the period 2007 to 2023. During 2023, the LCOE varied from as low as USD 0.053/kWh to as high as USD 0.094/kWh.

The global weighted average LCOE was USD 0.071/kWh in 2023. 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 2016 to 2023, the data available suggest the LCOE was relatively stable for most years, with a global weighted average of between USD 0.071/kWh and USD 0.077/kWh. The low-cost exceptions were registered in 2020 at USD 0.062/kWh and in 2022 at USD 0.058/kWh, driven by very competitive commissioned projects in Kenya.

Figure 8.4 LCOE of geothermal power projects by technology and project size, 2007-2023



Note: kWh = kilowatt hour; MW = megawatt.

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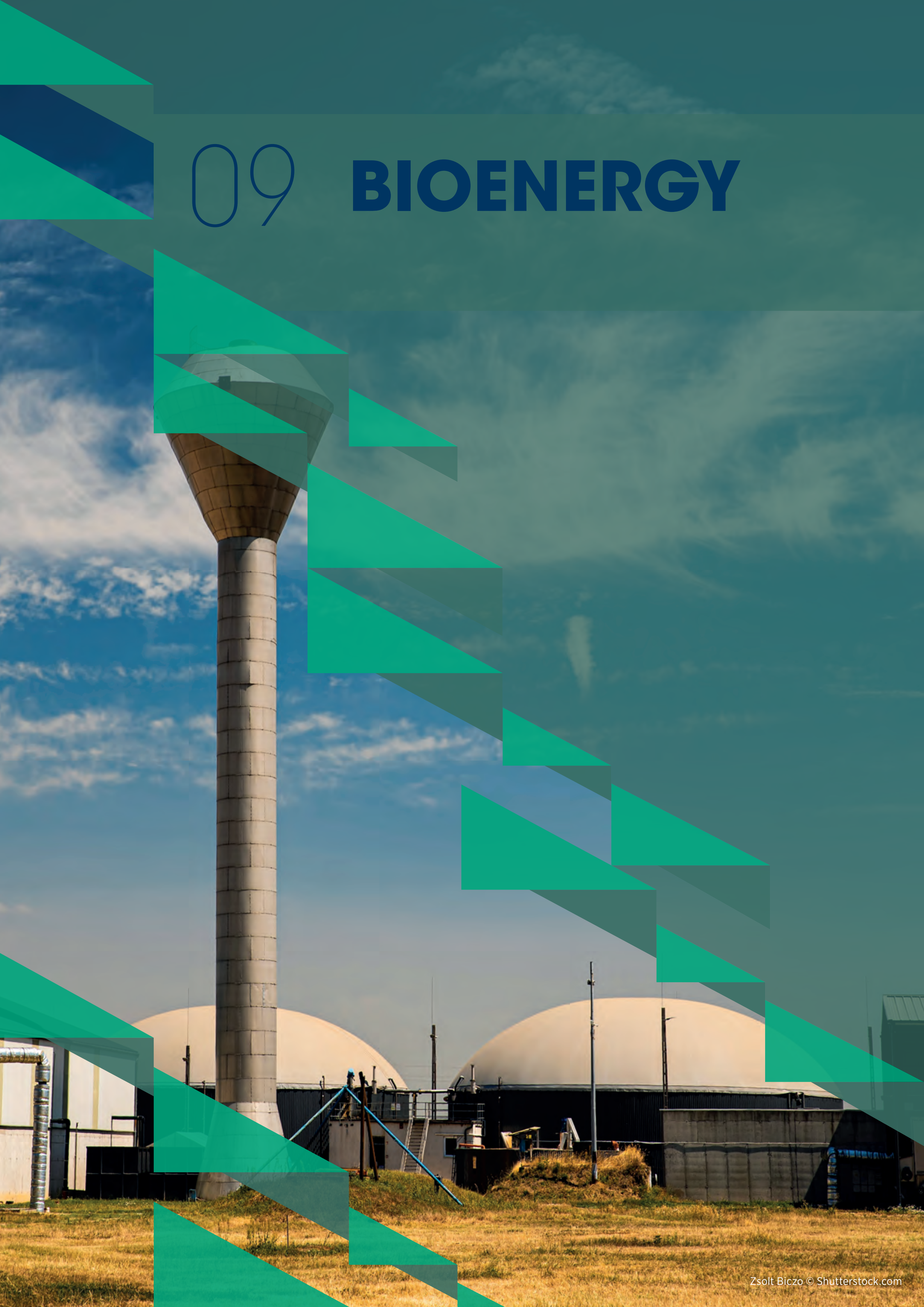
09 BIOENERGY



HIGHLIGHTS

Between 2010 and 2023, the global weighted average levelised cost of electricity (LCOE) of bioenergy for power projects fell from USD 0.084/kWh to USD 0.072/kWh. This figure is higher than the 2022 value of USD 0.063/kWh, but still at the lower end of the cost of electricity from new fossil fuel-fired projects.

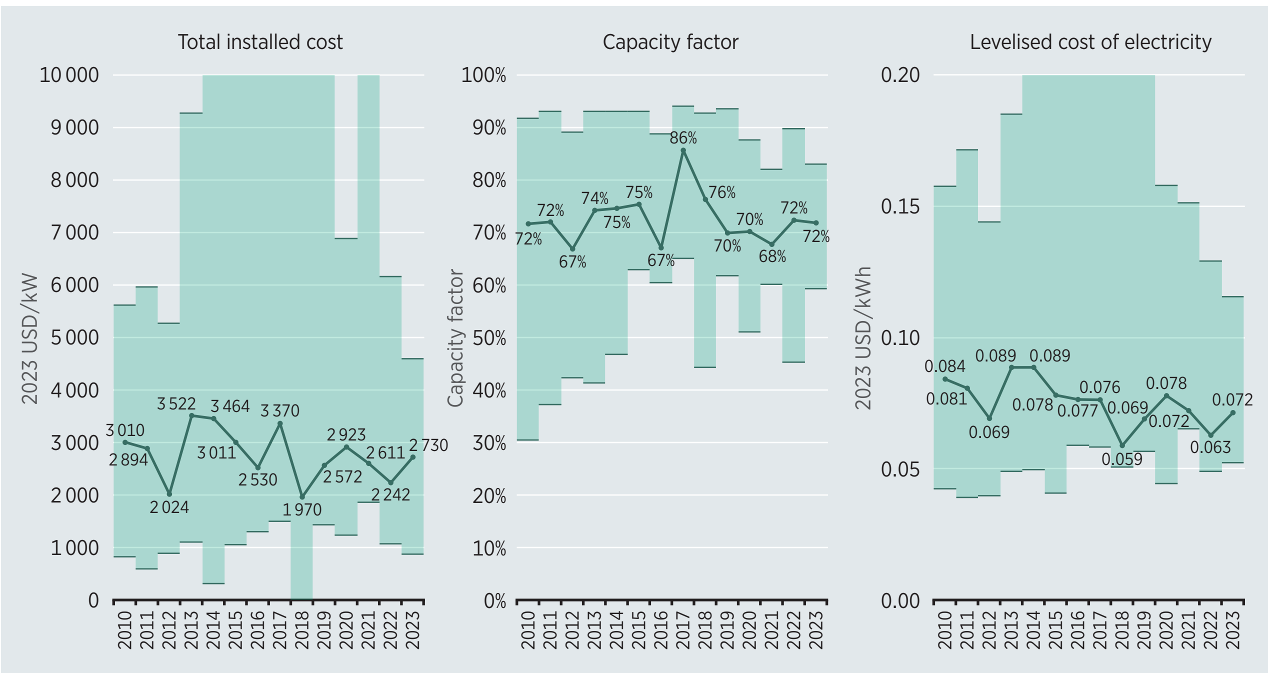
Bioenergy for electricity generation offers a suite of options, spanning a wide range of feedstocks and technologies. Where low-cost feedstocks are available – such as by-products from agricultural or forestry processes onsite – they can provide highly competitive, dispatchable electricity.

For bioenergy projects newly-commissioned in 2023, the global weighted average total installed cost was USD 2 730/kW (Figure 9.1). This represented an increase on the 2022 weighted average of USD 2 242/kW.

Capacity factors for bioenergy plants are heterogeneous, depending on technology and feedstock availability. Between 2010 and 2023, the global weighted average capacity factor for bioenergy projects varied between a low of 67% in 2012 and 2016, and a high of 86% in 2017. The 2023 global weighted-capacity factor value was 72%.

In 2023, by country/region, the weighted average LCOE ranged from a low of USD 0.063/kWh in India and USD 0.066/kWh in China to highs of USD 0.097/kWh in Europe and USD 0.107/kWh in North America.

Figure 9.1 Global weighted average and range of total installed costs, capacity factors and LCOEs for bioenergy, 2010-2023



INTRODUCTION

Power generation from bioenergy can involve a wide variety of feedstocks and combustion technologies. These can range from mature, commercially available types with long track records and numerous suppliers to less mature, but innovative systems. The latter category includes atmospheric biomass gasification and pyrolysis, technologies that are still in the developmental stage, but are now being tested 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).

When examining the use of biomass power generation, it is important to consider three main factors: the type and availability of feedstock; the conversion process; and the power generation technology. While the availability of feedstock is a critical element for the economic success of biomass projects, this report's analysis focuses on the costs of power generation technologies and their economics, with only a brief discussion of delivered feedstock costs.

According to the data analysed, the percentage of bioenergy in total renewable capacity additions has remained below 7% since 2010. In 2023, 4.4 GW of bioenergy projects were commissioned, accounting for 1% of the renewable capacity installed that year. The regions with the highest development were Asia and South America.

BIOMASS FEEDSTOCKS

The economics of biomass power generation differ from those of wind, solar or hydro. This is because biomass relies on the availability of a feedstock supply that is predictable, sustainably sourced, low cost and adequate over the long term. An added complication is that in some sites, the primary usage of the feedstock is not electricity generation; rather, it is intertwined with forestry or agricultural processing activities that may affect when and why electricity generation happens. For instance, electricity generated at pulp and paper mills is mainly used to run these facilities' operations.

Biomass is the organic material of recently living plants, such as trees, grasses and crops. Biomass feedstocks are thus very heterogeneous, with the chemical composition highly dependent on the plant species. The cost of feedstock per energy unit varies widely, from on-site 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. Low-cost residues used for electricity and heat generation include sugar cane bagasse, rice husks, black liquor, other pulp and paper processing residues, sawmill offcuts and sawdust, and renewable municipal waste streams.

Quality heterogeneity of the feedstocks and their physical properties (ash content, density, particle size and moisture) impact the transportation, pre-treatment and storage costs, and the suitability of different conversion technologies. This underscores the importance of feedstock selection and preparation in the biomass industry. Some conversion technologies are relatively robust and can cope with varied feedstocks, while others require more uniformity (*e.g.* some gasification processes).

Collecting and transporting feedstocks from forest residues and dedicated energy crops is cost driven due to their relatively low energy density. Consequently, increasing the distance to the power plant from the feedstock sources raises logistical costs and limits the economic feasibility of the plant. In practical terms, this tends to limit the economic size of bioenergy power plants, as the lowest cost of electricity is achieved once feedstock delivery reaches a certain radius around the plant.

In biomass technologies, the typical share of feedstock costs in the total LCOE ranges between 20% and 50%. Acquiring prices for locally sourced and consumed biomass can be challenging, however. Therefore, available market indicators or estimates from analyses are often employed as proxies for feedstock costs. Alternatively, estimates of feedstock costs from techno-economic analyses that may not necessarily be representative or up to date can be used (see IRENA's *Renewable power generation costs in 2014* [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 than projects in OECD countries, mainly due to lower labour and commodity costs, which allow for the deployment of lower cost technologies with less investment in emissions control, although this may result in higher local pollutant emissions, in some cases.

The main components contributing to the total investment costs of a biomass power plant include 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, such as civil works and roads. While equipment costs tend to make up the majority of the expenses, certain projects may have high costs related to infrastructure and logistics, or remote grid connections. CHP biomass installations have higher capital costs. Their overall efficiency, however, ranges from 80% to 85%, while their ability to produce heat and/or steam for industrial processes or for space and water heating through district heating networks, can significantly enhance their economic viability.

Figure 9.2 presents the total installed cost of bioenergy-fired power generation projects for different feedstocks for the years 2000 to 2023, where IRENA has sufficient data to provide meaningful cost ranges.

Although the pattern of deployment by feedstock varies by country and region, total installed costs across feedstocks tend to be higher in Europe and North America and lower in Asia and South America. This 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.

In China, for the 2000 to 2023 period, the 5th and 95th percentile of projects across all feedstocks saw total installed costs range from a low of USD 728/kW for rice husk projects to a high of USD 6 099/kW for renewable municipal waste projects. In India, the range was from a low of USD 593/kW for bagasse projects to a high of USD 5 050/kW for landfill gas projects.

The range is higher still for projects in Europe and North America. Costs in these two regions ranged from USD 717/kW for landfill gas projects in North America to a high of USD 7 719/kW for renewable municipal waste projects in Europe, during the 2000-2023 period. 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 618/kW to USD 6 625/kW.[43] For the period covered, the weighted average total installed cost for projects in the rest of the world typically ranged between the lower values seen in China and India and the higher values prevalent in Europe and North America.

Figure 9.2 Total installed costs of bioenergy power generation projects by selected feedstocks and country/region, 2000-2023

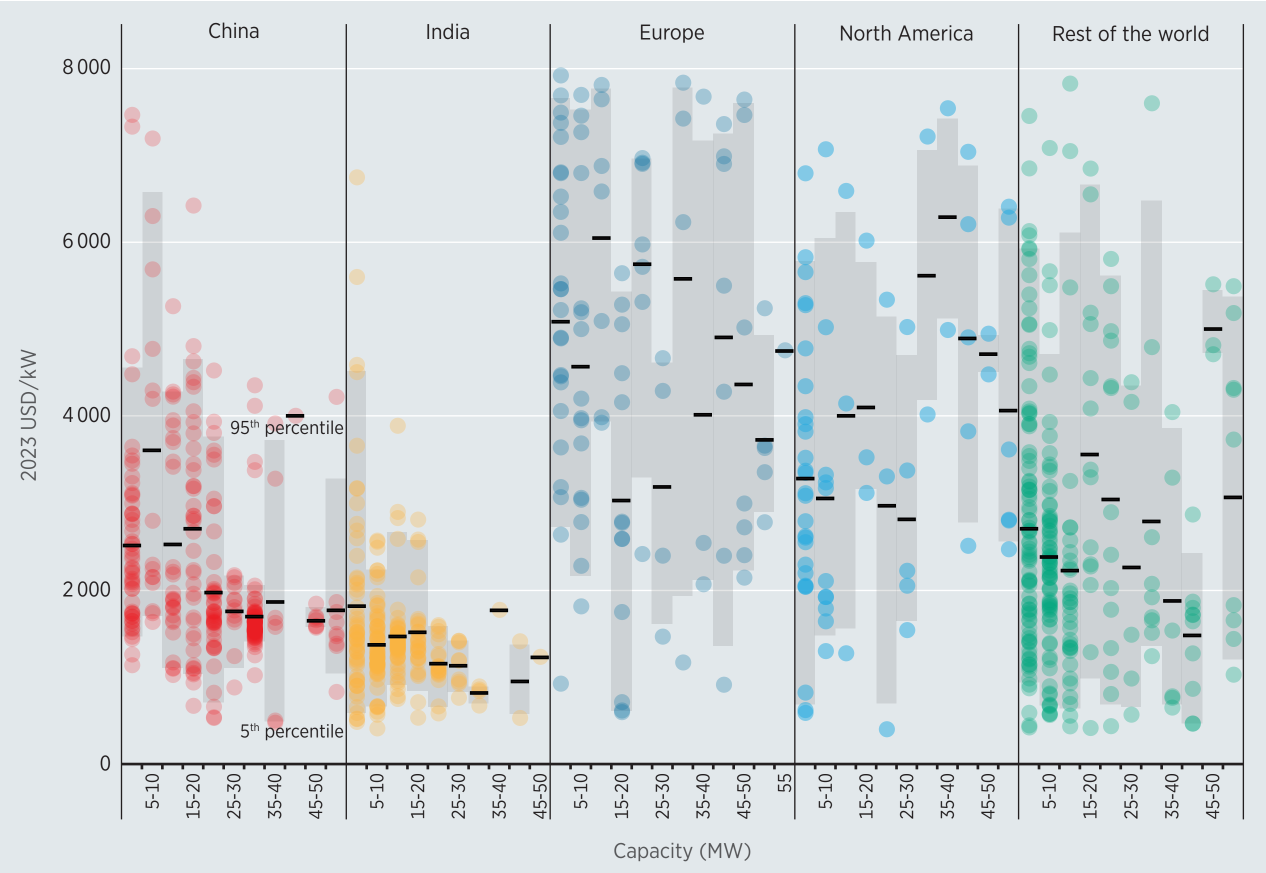
Note: see Annex III for regional country groupings.

[46] *These figures exclude the total installed costs for renewable municipal waste, which are not representative given that there are only three projects in the database.*

Figure 9.3 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 above roughly 25 MW, 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.

Figure 9.3 Total installed costs of bioenergy power generation projects for different capacity ranges by country/region, 2000-2023



Notes: see Annex III for regional country groupings; kW = kilowatt; MW = megawatt.

CAPACITY FACTORS AND EFFICIENCY

When the supply of feedstock remains consistent throughout the year, bioenergy-fired electricity plants can achieve high capacity factors, typically ranging from 85% to 95%. However, if the availability of feedstock is based on seasonal agricultural harvests, the capacity factors are typically lower.

An emerging concern for bioenergy power plants is the potential impact of climate change on feedstock availability and how this might affect 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 9.4 shows that biomass plants that rely on bagasse, landfill gas and other biogases tend to have lower average capacity factors (typically around 50% to 60%) by region. 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 9.4 Project capacity factors and weighted averages of selected feedstocks for bioenergy power generation projects by country and region, 2000-2023

Notes: see Annex III for regional country groupings; MW = megawatt.

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, the utilisation of less advanced technologies and occasional sub-optimal maintenance due to lower than expected revenues lead to reduced overall efficiencies. These can be around 25%. There are many available technologies with higher efficiencies, however, with these ranging from 31% for wood gasifiers to a high of 36% for modern, well-maintained stoker, circulating fluidised bed, bubbling fluidised bed, and anaerobic digestion systems.[44]

Table 9.1 presents data for project weighted average capacity factors of bioenergy-fired power generation projects for the period 2000 to 2023. According to the *IRENA Renewable Cost Database*, North America showed the highest weighted average capacity factor, at 85%, followed by Europe, with 82%. India and the rest of the world showed lower weighted average capacity factors of 68% each, while China recorded 64%.

Table 9.1 Project weighted average capacity factors of bioenergy fired power generation projects, 2000-2023

	2000-2023		
	5th percentile (%)	**Weighted average (%)**	**95th percentile (%)**
China	44	**66**	80
Europe	57	**81**	91
India	35	**68**	90
North America	50	**85**	93
Rest of the world	37	**68**	91

Note: see Annex III for regional country groupings.

O&M COSTS

Fixed O&M costs encompass labour, insurance, scheduled maintenance, routine replacement of plant components (*e.g.* boilers and gasifiers), feedstock handling equipment, and other related expenses. Generally, these costs constitute between 2% and 6% of the total installed costs per year. Larger bioenergy power plants typically have lower fixed O&M costs per kilowatt, due to economies of scale.

Variable O&M costs for bioenergy power plants are generally lower than fixed O&M costs, averaging around USD 0.005/kWh. The primary components of variable O&M costs are replacement parts and incremental servicing costs, including non-biomass fuel expenses such as ash disposal. Due to project-specific variations and limited available data, this report combines variable O&M and fixed O&M costs.

[44] *These assumptions are unchanged since IRENA's Renewable Power Generation Costs 2017 (IRENA, 2018).*

LCOE

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

Figure 9.5 summarises the estimated LCOE range for biomass power generation technologies by feedstock and country/region, where the *IRENA Renewable Cost Database* has sufficient data to provide meaningful insights.

Assuming a cost of capital of between 7.5% and 10% and feedstock costs between USD 1/gigajoule (GJ) and USD 9/GJ (the LCOE calculations in this report are based on an average of USD 1.50/GJ), the global weighted average LCOE of biomass-fired electricity generation for projects commissioned in 2023 was USD 0.072/kWh. This was an increase from USD 0.063/kWh in 2022.

Looking at the full dataset for the period from 2000 to 2023, the lowest weighted average LCOE of biomass-fired electricity generation was found in India, where it stood at USD 0.062/kWh. In addition, India's 5^{th} and 95^{th} percentile values were USD 0.041/kWh and USD 0.112/kWh (Figure 9.5). The highest weighted average for this period was USD 0.104/kWh, recorded in North America, where the 5^{th} and 95^{th} percentiles of projects fell between USD 0.052/kWh and USD 0.209/kWh.

The weighted average LCOE of bioenergy projects in China was USD 0.063/kWh, with the 5^{th} and 95^{th} percentiles of projects falling between USD 0.047/kWh and USD 0.133/kWh. The weighted average in Europe over this period was USD 0.095/kWh, while in the rest of the world it was USD 0.076/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.

The utilisation of municipal waste for bioenergy often results in high capacity factors and serves as an economically viable source of electricity. However, the LCOE for such projects in North America is notably higher than the average in other areas. Given that these projects have been developed primarily to address waste management issues, rather than maximizing electricity production competitiveness, the elevated LCOE may not necessarily hinder their feasibility.

In Europe, such projects sometimes provide heat to local industrial users or district heating networks, generating additional revenue that brings down the LCOE below that presented here. Many of the higher cost projects in Europe and North America, which utilise 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.

Figure 9.5 LCOE by project and weighted averages of bioenergy power generation projects by feedstock and country/region, 2000-2023

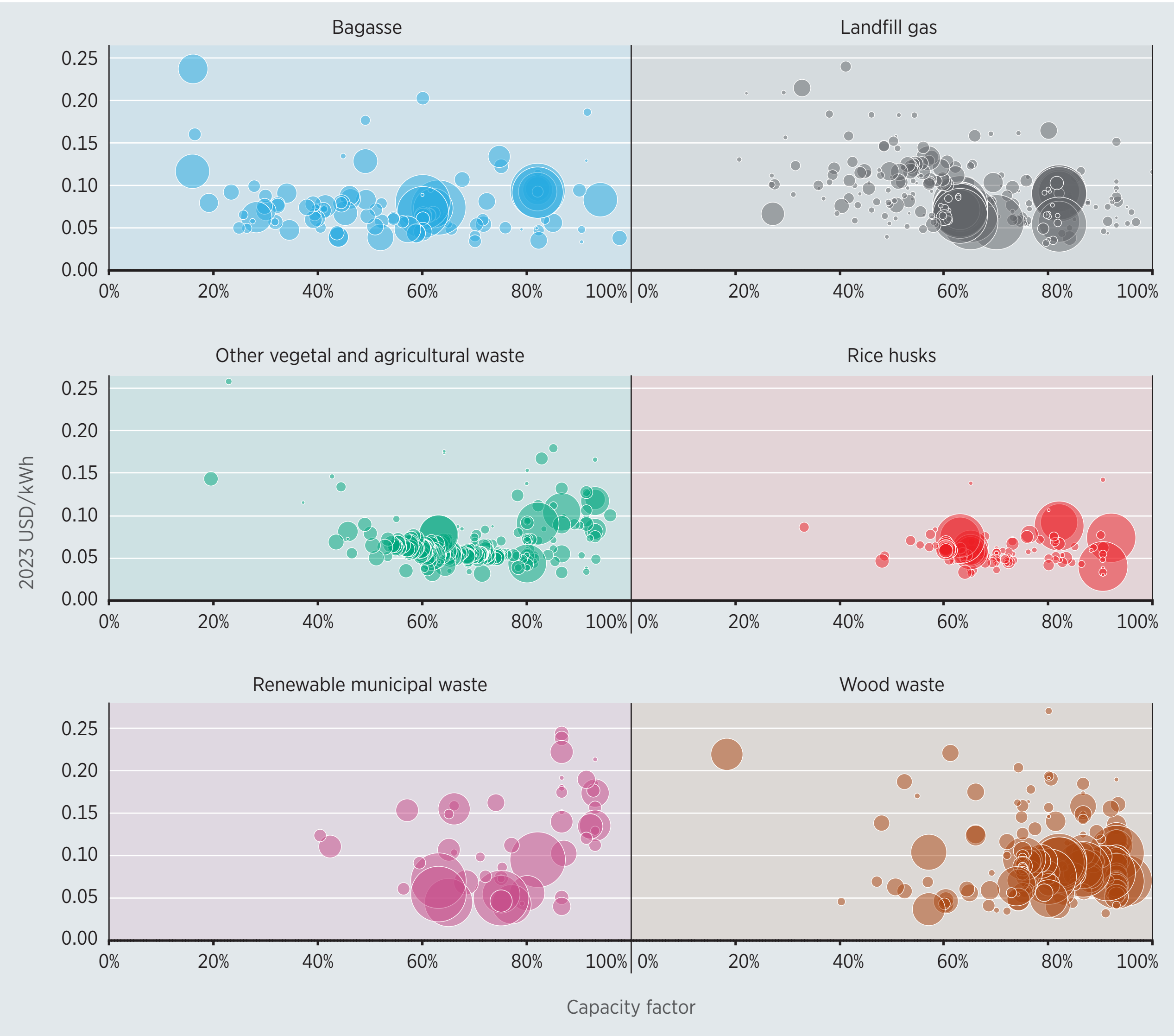
Note: see Annex III for regional country groupings; kWh = kilowatt hour; MW = megawatt.

Figure 9.6 presents the LCOE and capacity factor by project and weighted average for bagasse, landfill gas, rice husks and other vegetal and agricultural waste, all of which are used as feedstock for bioenergy-fired power generation projects. The figure shows how the dynamic relationship with feedstock availability influences the economic optimum for a project. The data for bagasse plants show 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 a continuous feedstock supply enables higher capacity factors. However, this may not necessarily be more cost-effective if it requires supplementing low-cost seasonal agricultural residues with expensive feedstocks. Importantly, the LCOE of these projects is comparable to those 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 waste as the primary feedstock, data tends to show a correlation between higher capacity factors and lower LCOEs in developing countries, as the higher cost projects with capacity factors above 80% are predominantly located in OECD countries.

Figure 9.6 LCOE and capacity factor by project of selected feedstocks for bioenergy power generation projects, 2000-2023



Note: kWh = kilowatt hour.

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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.* solar PV modules or wind turbines), financing costs, total installed costs, fixed and variable O&M costs, fuel costs (if any), and the 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, while improving transparency and confidence in the analysis. It also facilitates the comparison of costs by country or region for the same technologies, enabling the identification of the key drivers in any cost differences.

The five key indicators that have been selected are:

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

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

Clear definitions of the technology categories are provided, where this is relevant, to ensure that cost comparisons are robust and provide useful insights (*e.g.* small hydropower vs. large hydropower). Similarly, functionality has to be distinguished from other qualities of the renewable power generation technologies being investigated (*e.g.* 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 has conducted a number of analyses focusing on individual technologies and markets in an effort to fill this gap (IRENA, 2016).

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 WACC used to evaluate the project – often also referred to as the discount rate – has a critical impact on the LCOE.

To more accurately assess the competitiveness of renewable power, IRENA has created a database of fossil fuel price indices and of the capital costs, efficiency and O&M costs of fossil fuel power plants.

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
It = investment expenditures in the year *t*
Mt = O&M expenditures in the year *t*
Ft = fuel expenditures in the year *t*
Et = electricity generation in the year *t*
r = discount rate
n = life of the system

All costs presented in this report are denominated in real, 2023 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 are a mix of *ex ante* and *ex post* data. The data for project-specific capacity factors for, in virtually all cases, are *ex ante* data and subject to change.

Although the terms “O&M” and “OPEX” (operational expenses) are often used interchangeably, the LCOE calculations in this report are based on “all-in-OPEX”. This is 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; while every effort is made to ensure the data is directly comparable, it is often not possible to verify this with certainty. Indeed, 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 data to compute LCOE calculations. The standardised assumptions used for calculating the LCOE include the WACC, economic life and cost of bioenergy feedstocks.

WACC

The analysis in IRENA cost reports up to an including the year 2020 assumes the WACC for a project to be 7.5% (real) in OECD countries and China, and 10% in the rest of the world. The former figure is lower because in these regions borrowing costs are relatively low and stable regulatory and economic policies tend to reduce the perceived risk of renewable energy projects. In the 2021 edition of the IRENA cost report, the WACC assumptions were reduced to reflect more recent market conditions. Consequently, the previous edition of this report assumed that the WACC of 7.5% used in 2010 for the OECD and China declined to 5% in 2020. For the rest of world, the previous edition assumed that the WACC of 10% in 2010 fell to 7.5% in 2020.

Since 2022, IRENA’s WACC benchmark tool (IRENA, 2023) has been used to give technology- and country-specific WACC benchmark values for 100 countries. These values have been calibrated with the results of the IRENA, IEA Wind Task 26 and ETH Zurich cost of finance survey. That exercise resulted in technology-specific WACC data for onshore wind, offshore wind and solar PV technologies for those 100 countries. These data can be found in the dataset accompanying this report (visit www.irena.org for more details). For countries not included in the benchmark tool and for bioenergy, geothermal and hydropower, simpler assumptions on the real cost of capital have been made for the OECD countries and China, and for the rest of the world. These are in line with the assumptions made in the previous edition of this report (Table A1).

Table A1 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 that the cost of debt and the required return on equity, as well as the ratio of debt-to-equity, varies between individual projects and countries, depending on a wide range of factors. This can have a significant impact on the average cost of capital and the LCOE of renewable power projects. It also highlights an important policy issue: in an era of low equipment costs for renewables, ensuring that policy and regulatory settings minimise perceived risks for renewable power generation projects can be a very efficient way of reducing the LCOE by lowering the WACC.

CHANGING FINANCING CONDITIONS FOR RENEWABLES AND THE WACC

This section discusses in more detail the background to the WACC benchmark model, as well as 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, 2018). Changes in the cost of capital that are not properly accounted for overtime – between countries or technologies – can result in significant misrepresentations of the LCOE, leading to distorted policy recommendations.

Today, however, reliable data that comprehensively cover individual renewable technologies, across a representative number of countries and/or regions, and through time remain remarkably sparse (Donovan and Nuñez, 2012). This is typically due to the extreme difficulty in obtaining project-level financial information due its proprietary nature (Steffen *et al.*, 2019). While there is extensive evidence of declining and lower WACCs than in the assumptions previously used (Steffen *et al.*, 2019), it can be challenging to extract meaningful insights from the data contained in today's literature. This is because 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 are 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 of developing 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 is 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 power purchase agreement (PPA) and/or 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 'benchmark 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 2021 and Q3 2021. This was distributed widely to knowledgeable finance professionals with a detailed understanding of the financing conditions. It 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 2021 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 desktop analysis aiming at deriving 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 could be used to fill in gaps in the survey analysis.[45] 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.

[45] *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.*

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.

IRENA, 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:
Ce = Cost of equity
Cd = 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 2.95%) with a country risk premium for debt (based on credit default swap values)[46] 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 8.9% (or a premium of 5.94% 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. They have also used 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.

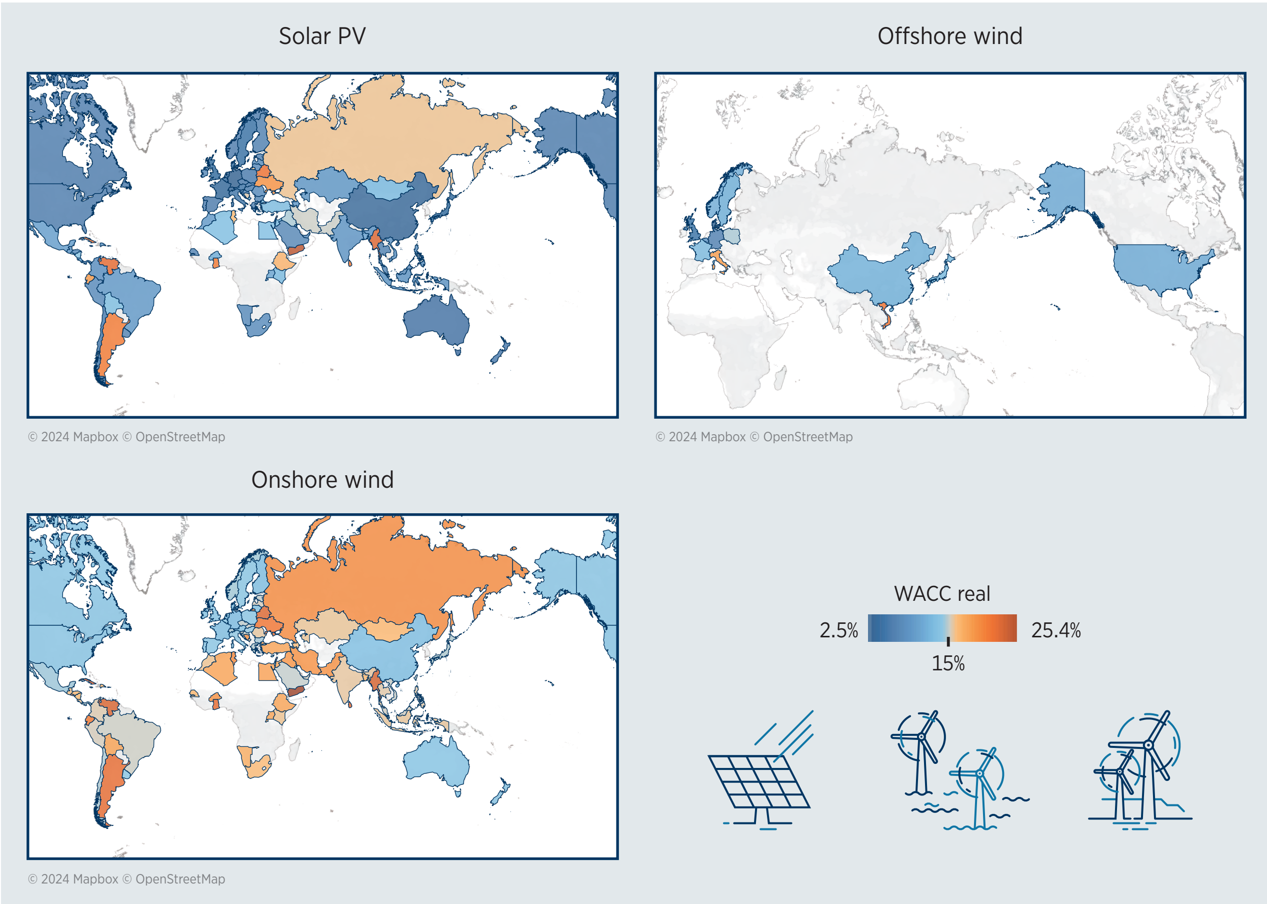
The benchmark tool creates nominal values for each WACC parameter, but by assuming 2.95% inflation (roughly the value in the United States over the last decade), we can transform the results into real values.

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. More detail on the process and the summarised results of the survey can be found in the cost of financing for renewable power report (IRENA, 2023).

[46] *This is based on Country Risk: Determinants, Measures and Implications – The 2020 Edition, (Damodaran, 2020).*

Figure A1 presents the results of the calibrated benchmark tool for the real after-tax WACC values by country/technology. The values used for the LCOE calculations for deployment in 2023 are those in Figure A1, 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, 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 2023.

Figure A1 Country and technology-specific real after-tax WACC assumptions for 2023



Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

The WACC values surveyed in 2021 were generally representative of financing conditions in 2020 and 2021. Given most onshore wind and solar PV projects are financed in the year prior to commissioning, the WACC values used for 2022 are unchanged from the benchmark values for 2021. However, with inflation and interest rates rising rapidly in 2022, the 2023 benchmark WACC values were updated. The lagged impact of rising interest rates on LCOEs will be significant in the upcoming years, given the low cost of finance for renewables that has characterised recent years.

Overall, these more realistic WACC changes have improved the representativeness of the LCOE calculations at a country level. In the case of the WACC assumptions, they 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 another 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.

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 BoS cost is 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 give greater understanding of the drivers of solar PV BoS costs and are the basis for such analysis in this report.

Table A2 BoS cost breakdown categories for solar

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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O&M COSTS

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, while the year of collection or applicability was often not clear. With rising capacity factors for onshore wind, assuming a fixed per kWh figure would have likely been to overstate the actual contribution of O&M to overall LCOE costs, in some cases.

Consistent with last year's report, all O&M assumptions are on a USD/kW basis (Table A3). 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.

Table A3 O&M cost assumptions for the LCOE calculation of onshore wind projects

	2023 USD/kW/year
Sweden	40
Ireland	33
Germany	47
Denmark	35
United States	40
Norway	39
Japan	88
Brazil	26
Canada	35
Mexico	43
Spain	25
United Kingdom	36
France	46
China	26
India	20
Australia	34
Other OECD	40
Other non-OECD	33

Solar PV

Depending on the commissioning year, a different O&M cost assumption is used for the calculation of the solar PV LCOE estimates used 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 A4).

Table A4 O&M cost assumptions for the LCOE calculation of PV projects

Year	OECD 2023 USD/kW/year	Non-OECD 2023 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
2022	17.8	9.2
2023	18.2	9.6

Offshore wind

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

Table A5 O&M cost assumptions for the LCOE calculation of offshore wind projects

	2023 USD/kW/year
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

ANNEX II

The composition of the *IRENA Renewable Cost Database* largely reflects the deployment of renewable energy technologies over the last 10-15 years. In terms of GW, most projects in the database are in China (1 194 GW), the United States (276 GW), India (181 GW), and Brazil (105 GW).

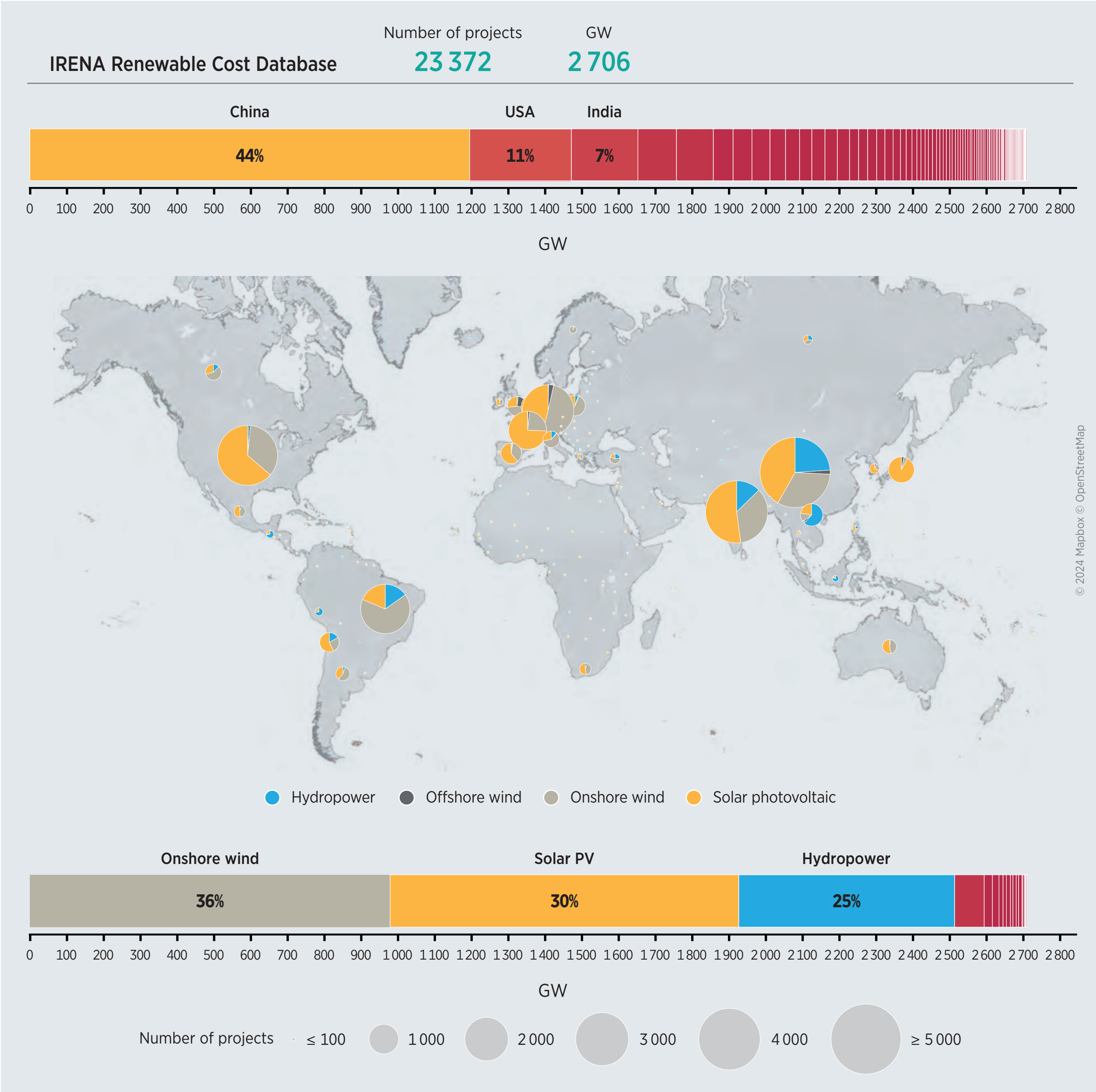
Collecting cost data from OECD countries, however, is significantly more difficult due to greater sensitivities around confidentiality issues. The exception is the United States, where the nature of support policies leads to greater quantities of project data being available.

After these four major countries, Germany is represented by 100 GW of projects, Spain by 54 GW, Japan by 52 GW, the United Kingdom by 49 GW, Viet Nam by 42 GW, Italy by 37 GW, Canada and Australia by 35 GW each, and Türkiye by 33 GW of projects.

Onshore wind is the largest single renewable energy technology represented in the *IRENA Renewable Cost Database*, with 977 GW of project data available from 1983 onwards. Solar PV is the second largest technology represented in the database, with 949 GW of projects, followed by hydropower with 585 GW of projects since 1961, with around 90% of those projects commissioned in the year 2000 or later. Cost data are available for 80 GW of commissioned offshore wind projects, 97 GW of biomass for power projects, 8 GW of geothermal projects and around 7 GW of CSP projects.

The coverage of the *IRENA Renewable Cost Database* is roughly 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 20 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 have only become available more recently and the database is representative from around 2011 onwards, and comprehensive from around 2013 onwards.

Figure A2 Distribution of projects by technology and country in the IRENA Renewable Cost 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

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, the Gambia, Ghana, Guinea, Guinea- Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Namibia, Niger, Nigeria, Rwanda, São Tomé and Príncipe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, South Sudan, Sudan, Togo, Tunisia, Uganda, the 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, the Netherlands, Norway, Poland, Portugal, Republic of Moldova, Romania, San Marino, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, the United Kingdom.

Middle East

Bahrain, Islamic Republic of Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, the United Arab Emirates, Yemen.

North America

Canada, Mexico, the United States.

South America

Argentina, Bolivia (Plurinational State of), Brazil, Chile, Colombia, Ecuador, Guyana, Paraguay, Peru, Suriname, Uruguay, Venezuela (Bolivarian Republic of)

Oceania

Australia, Fiji, Kiribati, Marshall Islands, Micronesia (Federated States of), Nauru, New Zealand, Palau, Papua New Guinea, Samoa, Solomon Islands, Tonga, Tuvalu, Vanuatu.

IRENA

International Renewable Energy Agency

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