IRENA
International Renewable Energy Agency

RENEWABLE POWER GENERATION COSTS IN 2025

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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

The global energy system continues to undergo a profound transformation, with renewables as its driving force. Global renewable power capacity additions continue to set new records, and renewable energy overtook coal to become the world's largest source of installed power capacity in 2025.

Cost competitiveness remains the defining characteristic of renewable power. In 2025, more than 90% of newly commissioned utility-scale renewable projects delivered electricity at a lower cost than the cheapest new fossil-fuel-fired alternative. Onshore wind remained the most affordable new power source, with a global weighted-average levelised cost of electricity (LCOE) of USD 33 per megawatt hour (MWh), followed by solar PV at USD 44/MWh and offshore wind at USD 78/MWh. Meanwhile, gas-fired generation became more expensive, reinforcing the advantage of renewables over fossil fuels.

After more than a decade of steep declines, the costs of solar PV and onshore wind have begun to stabilise, reflecting the maturity of these technologies, and while IRENA's outlook suggests costs will keep falling to 2035, these declines will be less dramatic than in previous years. Enabling technologies, however, continue to experience rapid cost reductions. The installed cost of a four-hour utility-scale battery storage fell by close to 30% year-on-year in 2025 to around USD 140 per kilowatt hour (kWh) — some 95% below its 2010 level. Around one-quarter of new utility-scale solar was paired with storage, and the best hybrid sites now deliver 'firm' around-the-clock power at below USD 85/MWh.

The strategic value of this shift extends well beyond generation costs. In 2025, renewables helped to avoid an estimated USD 480 billion in fossil fuel costs and around 8.4 gigatonnes of carbon dioxide emissions. When the Strait of Hormuz closed in early 2026, the existing renewable fleet provided a vital buffer — renewables have become a genuine geopolitical shock absorber for consumers, businesses and economies as a whole.

Nevertheless, short-term risks remain. Clean-technology manufacturing investment has roughly halved since its 2023 peak, and rising commodity prices and a shifting trade landscape are likely to lift installed costs in the near term. In many markets, the binding constraint is now the cost of capital rather than technology.

Recent events have reiterated the fact that the value of renewables is not confined to their benefits for our climate – a growing share of renewable energy represents a vital strategic investment in resilience, security and competitiveness. This only adds to the urgency of concerted action to rapidly expand grids, storage capacity and system flexibility while expediting the electrification of end-uses, thereby overcoming the remaining barriers to an accelerated global energy transition.

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ABBREVIATIONS

AC	alternating current
Ah	ampere-hour
AI	artificial intelligence
BECCS	bioenergy, carbon capture and storage
BESS	battery energy storage system
BoS	balance of system
A-CAES	adiabatic compressed air energy storage
CAES	compressed air energy storage
CAPEX	capital expenditure
CF	capacity factor
CfD	contract for difference
CSP	concentrated solar power
DC	direct current
EGS	enhanced geothermal systems
EPC	engineering, procurement and construction
EU	European Union
FiT	feed-in tariff
FLOW	floating offshore wind
FPV	floating photovoltaics
GGES	geotechnical gravity energy storage
Gt	gigatonne
GW	gigawatt
GWEC	Global Wind Energy Council
GWh	gigawatt hour
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IHA	International Hydropower Association
IRENA	International Renewable Energy Agency
kW	kilowatt
kWh	kilowatt hour
LCOE	levelised cost of electricity
LCOS	levelised cost of storage
LDES	long-duration energy storage
LFP	lithium iron phosphate
MACSE	Meccanismo di Approvvigionamento di Capacità di Stoccaggio Elettrico [Mechanism for Provision of Electric Storage Capacity]
MW	megawatt
MWh	megawatt hour
NCA	nickel cobalt aluminium
NMC	nickel manganese cobalt
O&M	operations and maintenance
OEM	original equipment manufacturer
OPEX	operating expenditure
pp	percentage point
PPA	power purchase agreement
PSH	pumped storage hydropower
PV	photovoltaic
R&D	research and development
CO_2	carbon dioxide
sCO_2	supercritical carbon dioxide
ST	solar tower
TIC	total installed cost
TOPCon	tunnel oxide passivated contact
TPC	total plant cost
TW	terawatt
UHV	ultra-high voltage
USD	United States dollar
VRB	vanadium redox flow battery
WACC	weighted average cost of capital
W/m^2	watts per square metre
Wp	watt peak

HIGHLIGHTS

After more than a decade of steep declines, in 2025, the levelised cost of electricity (LCOE) from renewables began stabilising. Solar photovoltaic (PV) remained at its 2024 level of USD 44 per megawatt hour (MWh). Wind, however, continued to improve, with onshore wind falling to USD 33/MWh and offshore wind to USD 78/MWh. In contrast, most dispatchable renewable technologies[1] recorded higher costs, with hydropower, geothermal and concentrated solar power rising to USD 62/MWh, USD 89/MWh and USD 115/MWh, respectively. Bioenergy was the exception in this group, with its cost declining to USD 86/MWh.

Since 2010, the cost of solar PV has fallen by 89%, onshore wind by 71%, and offshore wind by 63%. This highlights how renewables are now the cheapest source of new electricity in most markets. In 2025, more than 90% of newly commissioned, utility-scale capacity delivered power at a lower cost than the cheapest, newly-installed fossil-fuel-based alternative.

Between 2024 and 2025, new, natural gas-fired generation increased in cost. A turbine shortage roughly doubled the capital expenditure required for a new, combined-cycle plant to about USD 2 400 per kilowatt in the United States. This also pushed the levelised cost of electricity (LCOE) from gas-fired generation towards USD 100/MWh in higher-gas-cost markets, such as Italy, Germany and Japan. In markets where gas is cheaper, the LCOE remained in the USD 50-60/MWh range. Renewed conflict in the Middle East in early 2026 also suggested higher gas and power prices could persist throughout the year.

China remains the global, low-cost benchmark for wind. In 2025, the LCOE of onshore wind in China stood at USD 27/MWh and offshore wind at USD 49/MWh. This compared with USD 141/MWh for offshore wind in the United States. China is also among the lowest-cost solar markets, at USD 36/MWh, a figure close to that of India, at USD 35/MWh and Brazil, at USD 37/MWh.

IRENA's new cost comparisons for high-reliability hybrid systems show that the firm LCOE of solar-plus-battery systems with a 95% reliability fell from more than USD 100/MWh in 2020 to below USD 85/MWh in 2025 at high-quality sites. Further reductions of around 30% by 2030 and 40% by 2035 are projected.

The installed cost of four-hour utility-scale batteries fell by close to 30% in 2025, to around USD 140 per kilowatt hour (kWh) – around 95% lower than its 2010 level. Costs also fell to below USD 70/kWh in China. These cost reductions are transforming the economics of hybrid renewable systems and strengthening their role in meeting demand reliably.

Falling battery costs are driving the rapid growth of hybrid solar-plus-storage systems. In 2025, around one quarter of all newly commissioned utility-scale solar capacity was paired with battery storage, with the firm LCOE of such systems at high-quality sites falling below USD 85/MWh.

[1] *'Dispatchable' renewables include those technologies that can be adjusted to meet demand when required, namely bioenergy, geothermal, hydropower and concentrated solar power.*

Costs of hybrid systems should keep falling over the next five years, but more slowly and unevenly. The costs of mature technologies, such as solar PV and onshore wind, are plateauing, while batteries and long-duration storage are expected to see further cost reductions as deployment increases. At the same time, the rebound in battery metal prices in early 2026 is a reminder that input cost volatility can slow the downward cost trend.

Emerging technologies are advancing rapidly. Sodium-ion batteries are gaining commercial traction, with rising lithium prices strengthening their business case. The rapid displacement of nickel manganese cobalt chemistry by lithium iron phosphate in recent years suggests that markets can shift quickly once a new technology demonstrates a clear cost and performance advantage.

Next-generation perovskite solar cells are approaching commercial deployment, while long-duration energy storage – including compressed air and flow batteries – is expected to see substantial cost reductions as deployment scales. Ocean energy technologies, such as wave and tidal stream, are nearing industrial deployment. At 2 GW of cumulative deployment, these have projected LCOEs of around USD 120/MWh and USD 140/MWh, respectively.

Cost trajectories will depend on manufacturing dynamics. Clean-technology manufacturing investment has fallen by around half since its 2023 peak. This decline has been driven by China's efforts to curb solar overcapacity and the rollback of the Inflation Reduction Act in the United States. These shifts could affect future supply chains, prices and the pace of deployment.

In addition to technology costs, financing remains a key driver of generation costs. Increasingly, where a project is built matters more than what is built: national macroeconomic conditions explain around 2.3 times as much variation in financing costs as technology, underlining the importance of country risk, policy stability and access to affordable capital.

In 2025, renewables helped avoid an estimated USD 480 billion in fossil fuel costs and about 8.4 gigatonnes of carbon dioxide emissions. This confirms the role of renewables not only as the cheapest new power, but also as a pillar of energy security, economic stability and resilience.

Renewables proved their ability to act as an energy cost shock absorber in 2025. Across three import-exposed Southeast Asian economies – Indonesia, Thailand and the Philippines – the existing renewable fleet avoided around USD 5.7 billion of coal and gas purchases in 2025. Valued at the higher fuel prices seen during the March–May 2026 crisis in the Middle East, those same avoided volumes would have been worth USD 6.5 billion. Had renewable generation been doubled, the avoided fuel cost would have reached USD 12.9 billion – more than twice the baseline saving.

EXECUTIVE SUMMARY

Renewable energy capacity additions reached a new high in 2025. Global renewable power capacity additions exceeded 690 gigawatts (GW) in 2025 – around one-fifth more than in 2024. Solar photovoltaics (PV) contributed more than 500 GW of this total, while wind added around 160 GW. Asia – and above all, China – remained the centre of deployment, with China accounting for close to two-thirds of new solar and three-quarters of new wind capacity. In 2025, renewable energy also overtook coal in terms of total, global installed capacity (IRENA, 2026a) to become the world's largest source of electricity.

Variable renewable costs fell as most dispatchable renewable energy costs rose. In 2025, the global, weighted-average levelised cost of electricity (LCOE) for solar PV remained unchanged compared to 2024, at USD 44 per megawatt hour (MWh).[3] Over the same period, the LCOE of onshore wind decreased to USD 33/MWh and offshore wind to USD 78/MWh. Driving these changes were two opposing factors that largely offset each other: on the one hand, cheaper equipment and lower installed costs; on the other, a higher cost of capital combined with slightly lower capacity factors.

The increases in the costs of most dispatchable renewables was driven by lower output, rather than changes in technology costs. Hydropower rose to USD 62/MWh, geothermal to USD 89/MWh and concentrated solar power (CSP) to USD 115/MWh. Bioenergy was the exception, with LCOE declining to USD 86/MWh due to increased output.

[3] *All values in 2025 USD.*

Figure S1 LCOE, total installed cost and capacity factor trends by renewable technology, 2024–2025*



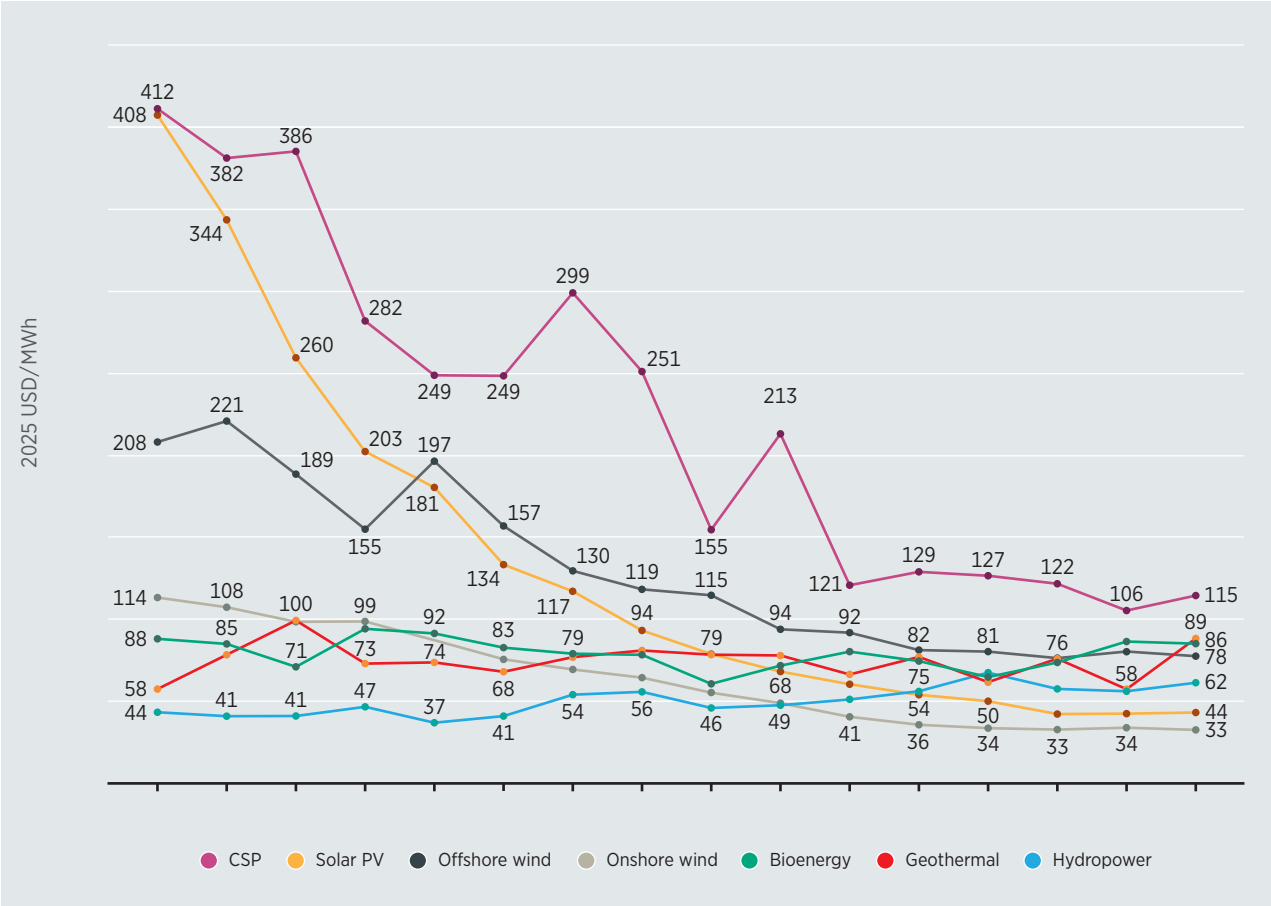
		Onshore wind	Solar PV	Offshore wind	CSP	Hydropower	Geothermal	Bioenergy
LEVELISED COST OF ELECTRICITY	2025 (USD/MWh)	33	44	78	115	62	89	86
	Change 2024–2025	-4%	1%	-3%	9%	9%	53%	-2%
TOTAL INSTALLED COST	2025 (USD/kW)	976	667	2 931	2 418	2 079	5 997	3 606
	Change 2024–2025	-8%	-6%	0%	-36%	-10%	46%	9%
CAPACITY FACTOR	2025	36%	16%	41%	22%	43%	85%	78%
	Change 2024–2025**	2%	-1%	-1%	-19%	-5%	-3%	5%

Notes: * Figures are 2025 USD values; changes are compared to 2024 levels; ** all changes in capacity factor are expressed in percentage points; CF = capacity factor; CSP = concentrated solar power; kW = kilowatt; LCOE = levelised cost of electricity; PV = photovoltaic; TIC = total installed cost.

Renewables retained their cost advantage over fossil fuels. Despite the plateau, renewables remained the most cost-competitive source of new electricity in most markets in 2025. Their advantage over fossil fuels also continued to widen. Since 2010, the LCOE of solar PV has fallen by 89%, CSP by 72%, onshore wind by 71%, offshore wind by 63% and bioenergy by 3%. In contrast, the LCOEs of hydropower and geothermal increased by 41% and 53%, respectively.

The cost of new fossil fuel-fired generation continued to rise. A gas-turbine shortage, driven in part by surging data-centre demand, roughly doubled the capital expenditure associated with a new, combined-cycle plant. In the United States, this level rose to around USD 2 400/kW, while the LCOE from these plants in high gas price markets, such as Italy, Germany and Japan, rose towards USD 100/MWh. As in 2024, more than 90% of utility-scale renewable projects commissioned in 2025 were cheaper than the lowest-cost, new fossil-fuel alternative.

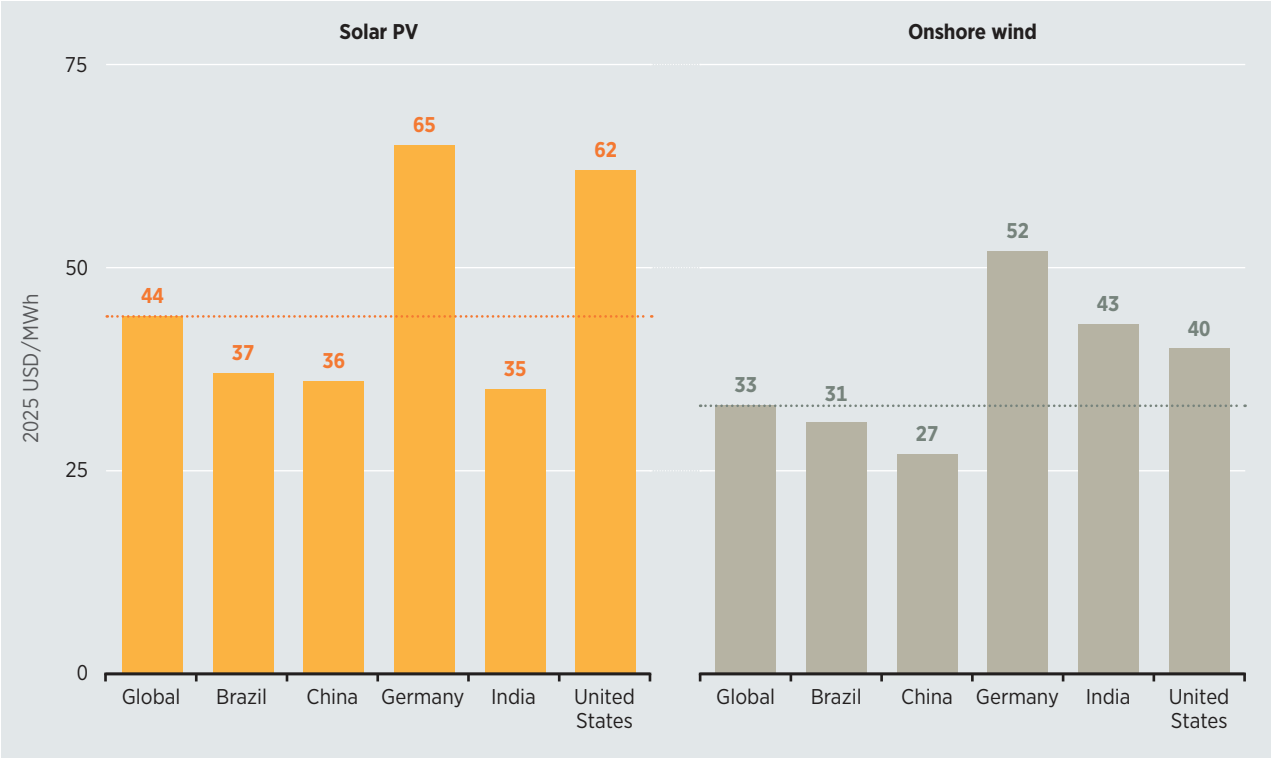
Figure S2 LCOE of renewable power technologies, 2010–2025 (USD/MWh)



Notes: CSP = concentrated solar power; MWh = megawatt hour; PV = photovoltaic; USD = United States dollar.

Cost trends diverged across technologies and regions. Stable global, cost-weighted averages in 2025 masked substantial differences across markets. China recorded the lowest onshore wind LCOE, at USD 27/MWh, and among the lowest solar PV LCOEs, at USD 36/MWh. Across major markets, the LCOE of solar PV ranged from USD 35/MWh in India to USD 65/MWh in Germany. LCOE values in the United States and Germany were also close to double those in China. This was due to permitting delays, interconnection bottlenecks and higher balance-of-system costs. For onshore wind, the LCOE ranged from USD 27/MWh in China to USD 52/MWh in Germany.

Figure S3 Solar PV and onshore wind LCOEs across major markets, 2025 (USD/MWh)



Notes: MWh = megawatt hour; PV = photovoltaic; USD = United States dollar.

Rapid declines in battery costs are transforming the economics of renewable power. In 2025, battery costs fell faster than those of any other energy technology. IRENA estimates the installed cost of a four-hour utility-scale battery at USD 140/kWh, a decrease of close to 30% in a single year and around 95% since 2010. As storage has become more affordable, solar and wind projects are increasingly being paired with battery energy storage systems. This is improving the utilisation of grid connections, shifting generation to periods of higher demand and reducing exposure to low or volatile electricity prices.



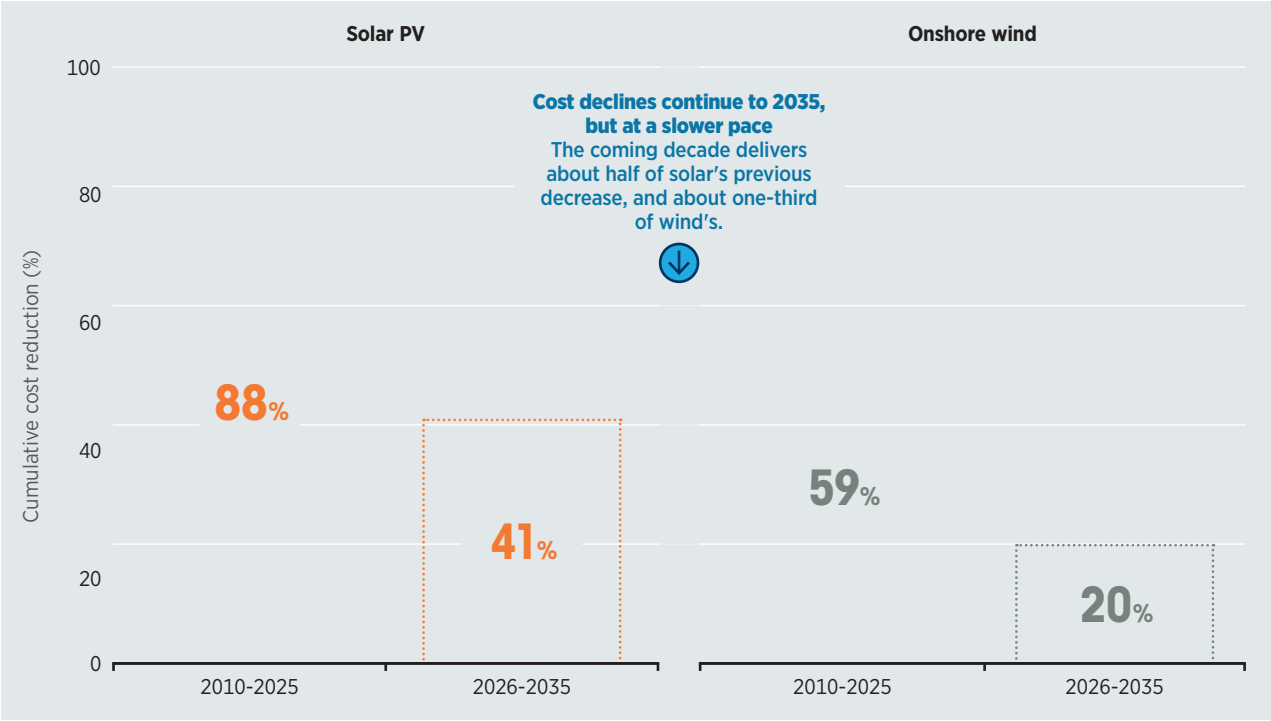
Cost reductions are expected to continue, but at a slower pace. After more than a decade of rapid, learning-driven cost reductions, solar PV and onshore wind have entered a phase of maturity. When permitting, grid connection, engineering and financing costs are included, between 2010 and around 2021, the costs of these two technologies fell, as experience accumulated and risk perceptions adjusted. The remarkable price decreases that followed – with solar module prices dropping by roughly two-thirds between 2022 and 2024 – were primarily driven by a substantial expansion of manufacturing capacity in China. This build-up resulted in a highly competitive landscape characterised by thin margins and prices approaching the cost of production.

This phase of intense competition may now be shifting. Clean-technology manufacturing investment more than halved between 2023 and the end of 2025. At the same time, China is actively consolidating its renewable energy manufacturing sector, while in April 2026 it also removed the value-added tax rebate on exports of certain solar PV products.

In parallel, commodity and component prices have been rising, pushing up Western onshore wind turbine prices, for example. Looking ahead, these developments are likely to exert upward pressure on TICs throughout 2026.

Over the longer term, costs will continue to decline out to 2035, though far more slowly than before. Over the coming decade, TICs are projected to fall by around 40% for solar PV and 20% for onshore wind. These factors are roughly one-half and one-third, respectively, of the reductions recorded since 2010.

Figure S4 Cumulative reduction in global, weighted-average total installed costs for solar PV and onshore wind, 2010–2025 and 2026–2035 (%)



Note: PV = photovoltaic.

Cost reductions are expected to remain uneven across regions. China is set to remain the lowest-cost producer of both solar PV and onshore wind technologies, while the United States and Europe retain a persistent, though narrowing, cost premium. A comparable picture holds for energy storage, both short duration and long duration, with costs projected to continue to decline.

The figures given here are, however, model-based and indicative rather than predictive. Over a ten-year period, substantial uncertainty remains, as global geopolitical developments, industrial policy and supply-chain changes could result in costs being either higher or lower than these projections.

Cost of capital remains the decisive divide between markets. TICs have fallen in price worldwide, yet LCOEs still differ widely between markets; financing now explains much of that gap. IRENA data make the point directly: solar PV installed costs fell by around 6% in 2025, yet the LCOE of this technology remained unchanged. This was because a higher cost of capital offset the cheaper equipment and systems. The biggest cost differences have become driven more by where a project is built than by what is built.

IRENA's cost-of-capital model suggests that country-level macroeconomic conditions, such as sovereign risk, interest rates and inflation, explain about 56% of the variation in financing costs. At 24%, this is roughly 2.3 times the share attributable to technology. The same technology can therefore cost far more to finance in a high-risk economy than in a mature one. This impact is most significant for emerging and developing economies, where most new demand will arise. In these markets, the cost of capital – not the cost of technology – is the binding constraint, with targeted de-risking the critical lever.

Globally, the use of renewables avoided 8.4 gigatonnes of carbon dioxide (CO_2) emissions and saved USD 480 billion in fossil-fuel costs in 2025. Because renewable energy facilities require no fuel once operational, this saving is counter-cyclical: their value increases with rising global fossil-fuel prices – and they do so without any new investment, since the capacity is already in place.

Renewable energy is proving itself as a geopolitical shock absorber. In 2025, the renewable generation of three, import-exposed Southeast Asian economies – Indonesia, Thailand and the Philippines – displaced an estimated USD 5.7 billion of coal and gas that would otherwise have been bought, much of it imported.


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01 LATEST COST TRENDS



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1.1 INTRODUCTION

Renewable power deployment reached a record high

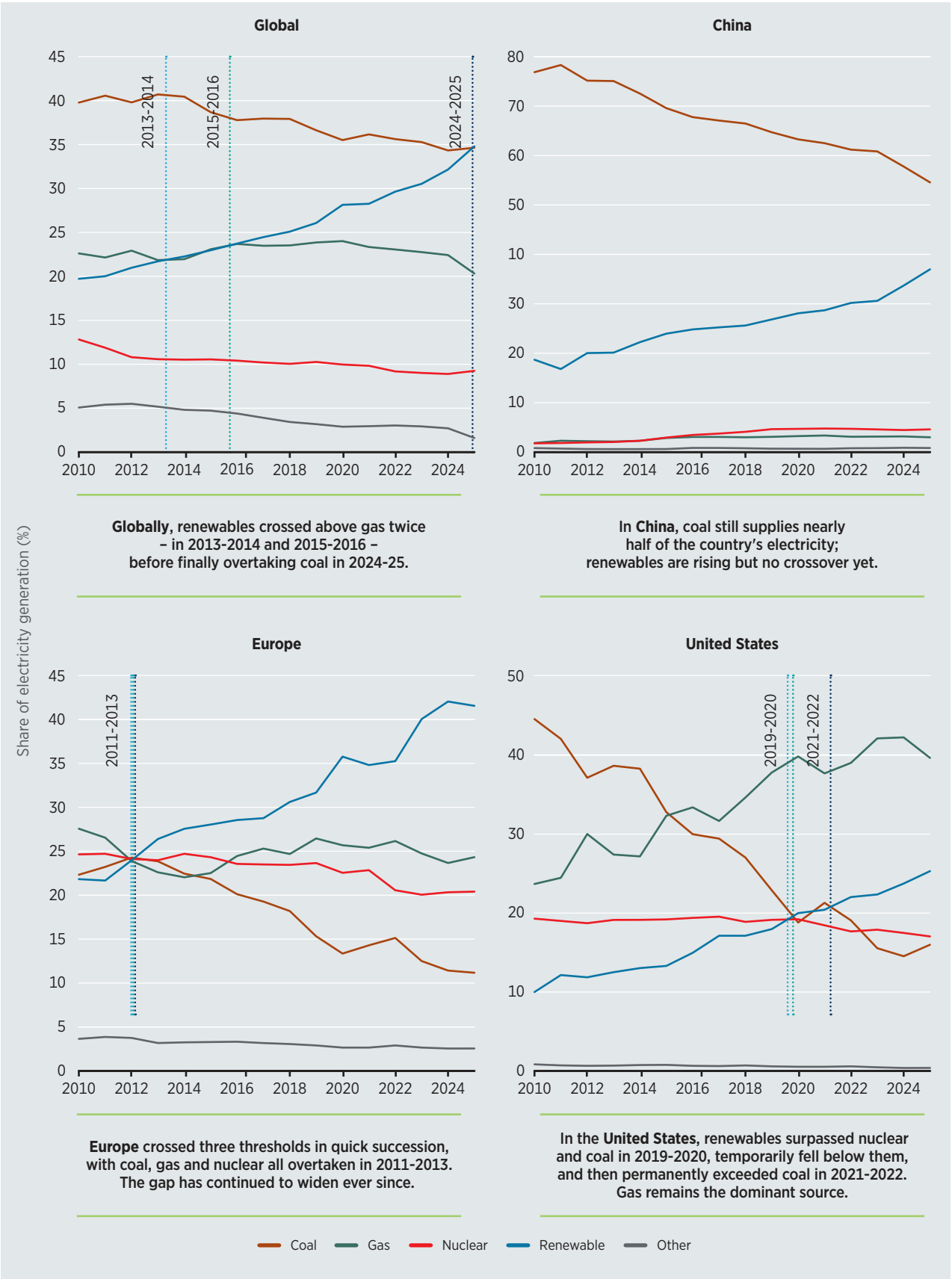
Global renewable power capacity grew by more than 690 gigawatts (GW) in 2025, the largest annual increase on record and around 19% more than the 582 GW added in 2024. Solar and wind power accounted for around 97% of net additions.

In 2025, deployment also remained heavily concentrated in Asia, which accounted for around three-quarters of global new capacity additions. Most of this was in China, which alone added 440 GW. This was close to two-thirds of all new solar and three-quarters of all new wind.

Figure 1.1 shows how increased deployment is translating into generation share – both globally and across the three markets that account for most new capacity (Ember, 2026). Yet, the data also reveal a growing regional divergence. Europe's energy transition is advanced, while in the United States, renewables have only recently surpassed coal. At the global level, this milestone has also only just been reached, while in China – the world's largest energy market – renewable generation still lags behind coal.

The data sources, cost metrics and assumptions underpinning this report, including the IRENA renewable cost database and the methodology used to calculate the levelised cost of electricity (LCOE), are set out in full in the Annex.

Figure 1.1 Evolution of the share of renewables in electricity generation, 2010–2025



Source: (Ember, 2026).

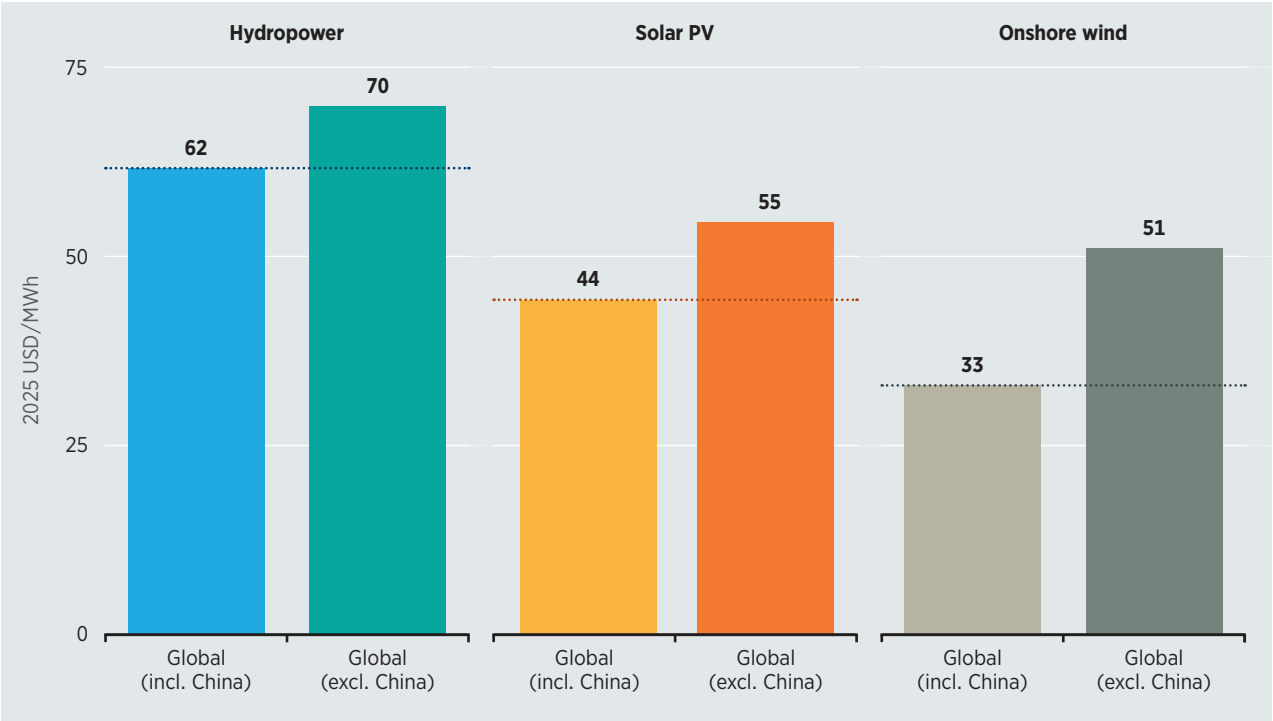
Renewables kept their cost advantage as fossil-fuel costs rose

The global weighted-average levelised cost of electricity (LCOE) from solar photovoltaic (PV) was unchanged in 2025 compared to 2024, at USD 44 per megawatt hour (MWh). The LCOE of onshore wind fell, however, to USD 33/MWh, while that of offshore wind fell to USD 78/MWh. For these variable technologies, two opposing forces broadly offset each other: cheaper equipment and lower installed costs on the one hand, and a higher cost of capital combined with slightly lower capacity factors on the other.

Among dispatchable renewables, costs generally increased, with this trend driven by lower output, rather than changes in technology costs. Hydropower rose to USD 62/MWh, geothermal to USD 89/MWh, and concentrating solar power (CSP) to USD 115/MWh. The latter increase was mainly due to a shift in new Chinese plants towards storage-oriented hybrid operation with low capacity factors. Bioenergy was the exception among dispatchable renewables, with the cost of this technology declining to USD 86/MWh, due to increased output.

These global averages were significantly influenced by China, which accounted for most new renewable capacity in 2025. That country also benefits from a structural cost advantage. If China is excluded, the global weighted-average LCOE was higher, year-on-year, at USD 55/MWh for solar PV (up 23%[1]), USD 51/MWh for onshore wind (up 55%), and USD 70/MWh for hydropower (up 13%). If China is included, however, these figures become USD 44/MWh, USD 33/MWh and USD 62/MWh, respectively, for solar PV, onshore wind and hydropower (see Figure 1.2).

Figure 1.2 Global weighted-average LCOEs, including and excluding China, by technology, 2025



Notes: excl. = excluding; incl. = including; MWh = megawatt hour; PV = photovoltaic; USD = United States dollar.

[1] *These percentages show the increase in the global average when China is excluded and are calculated on unrounded values.*

Although renewable costs were broadly stable between 2024 and 2025, the cost position of fossil-fuel generation worsened. A global gas-turbine shortage, driven in part by surging data-centre demand, roughly doubled the capital cost of new combined-cycle plant. This reached around USD 2 400 per kilowatt (kW) in the United States, while in markets with higher gas costs, such as Japan, Germany and Italy, the LCOE from gas turbine plants headed towards USD 100/MWh. It remained far lower, though, where gas is cheap – in the United States, for example the LCOE was around USD 53/MWh. Nonetheless, BloombergNEF reported a record global average of around USD 102/MWh for the period (BNEF, 2026b).

Against this rising fossil fuel benchmark, more than 90% of utility-scale renewable projects commissioned in 2025 delivered power below the cost of the cheapest new fossil-fuel plant built in the same market. The advantage was widest for variable technologies – about 96% of onshore wind and 91% of solar PV projects undercut the cheapest local fossil-fuel option. It was, however, notably narrower for dispatchable renewables. This reflects the same output-driven cost pressures described above. Independent analysis points the same way, finding wind or solar to be the cheapest source of new utility-scale electricity across key global electricity markets (BNEF, 2026a).

Renewables also have an advantage that is not fully reflected in LCOE estimates: once built, their costs are largely fixed, whereas fossil generation remains exposed to fuel-price volatility – a vulnerability examined in section 1.7.

Firm, round-the-clock renewables: Competitive and quick to build

A recent IRENA study assessed the cost of round-the-clock power supply through co-located battery storage, overbuild and complementary generation (IRENA, 2026b). At high-quality sites, it found that the firm, levelised cost of solar-plus-storage at 95% reliability fell from above USD 100/MWh in 2020 to USD 54–82/MWh by 2025. The study also projects further reductions of about 30% by 2030 and 40% by 2035. This would bring the best sites to a cost level below USD 50/MWh. Firm wind-plus-storage is generally more expensive, reflecting multi-day low-wind periods – although combining solar and wind lowers the cost of both. Large projects already demonstrate this approach: a complex at Al Dhafra in the United Arab Emirates is set to pair 5.2 GW of solar with 19 gigawatt hours (GWh) of storage to deliver a firm 1 GW (an amount equivalent to a medium-sized thermal plant) at around USD 70/MWh (IRENA, 2026b).

Independent analysis shows a similar result. A large and fast-growing volume of co-located solar and storage was commissioned worldwide in 2025, at an average cost below that of new gas-fired generation. Such systems are already cheaper than new gas for most hours of the year across many markets, and for almost all demand in the most favourable cases, such as Spain (BNEF, 2026c).

Indeed, co-located solar and storage has moved into the mainstream, accounting for around one-quarter of the utility-scale solar capacity commissioned globally in 2025 (BNEF, 2025f). This trend reflects growing pressure on standalone solar projects in some markets, where declining daytime prices and increasing curtailment have reduced the value of generation during peak production periods.

The advantage is also beginning to reach the existing fleet, with co-located wind-plus-storage now costing less than the operating costs of existing coal and gas plants in several major economies including China, Germany and the United Kingdom (BNEF, 2026c).

Beyond generation costs, speed of deployment is becoming a decisive advantage. Electricity demand is rising rapidly, driven by data centres, artificial intelligence (AI) workloads and advanced manufacturing. These require not only large volumes of power, but a continuous, high-quality supply with almost no tolerance for disruption.

The pace at which new capacity can be brought online increasingly matters as much as its cost. Hybrid solar, wind and storage systems offer a modular, scalable response. Once grid connection and permitting are secured, these systems can typically be developed and commissioned within 1–2 years, bringing firm capacity online quickly and expanding it progressively as demand grows. Conversely, new gas-fired generation is experiencing extended deployment timelines. Strong worldwide demand for gas turbines has stretched delivery lead times to as long as 5–7 years for many models (Anderson, 2025), while the capital cost of new combined-cycle plants has roughly doubled, now exceeding USD 2 000/kW in some markets. This limits the ability of gas generation to meet near-term capacity needs, particularly in fast-growing power systems.

1.2 TECHNOLOGY SPOTLIGHTS

Onshore wind

Global wind energy additions reached a record of around 159 GW in 2025, of which onshore projects made up about 93%. China alone contributed almost 120 GW of the total. The global, weighted-average total installed cost (TIC) for onshore wind fell to USD 976/kW, leading to a global LCOE of USD 33/MWh. However, these costs varied significantly by region: the LCOE was USD 27/MWh in China, against USD 52/MWh in Germany and USD 40/MWh in the United States. China maintains this cost advantage through both economies of scale and technological advances, while its turbines sold abroad remain cheaper than Western alternatives.

Solar PV

Solar PV remained the largest source of new power capacity in 2025, adding a record 511 GW globally and reaching a cumulative capacity of 2 392 GW. China drove this expansion, with 315 GW of additions, followed by India (37 GW) and the United States (34 GW). The global, weighted-average TIC decreased to USD 667/kW, yet the LCOE remained stable at USD 44/MWh for a second consecutive year. This was because rising capital costs and slightly lower capacity factors offset the reductions in capital expenditure. However, this rapid expansion is increasingly constrained by grid-integration challenges, curtailment and falling capture rates. In response, developers are increasingly pairing new solar capacity with battery storage – a structural shift towards hybridisation examined in Section 1.3.

Offshore wind

The global weighted-average TIC for offshore wind remained broadly stable at USD 2 931/kW in 2025, resulting in an LCOE of USD 78/MWh. This value does not reflect large differences between regions: the LCOE in China fell to USD 49/MWh, while the United States had a commissioning-year LCOE of USD 141/MWh. In response to structural pressures, Western developers cut investment budgets, while governments revised revenue frameworks. For example, the United Kingdom extended support contracts from 15 to 20 years, a change expected to increase project revenues by more than 20%.

Concentrated solar power

CSP added 900 megawatts (MW) in 2025, exclusively in China, raising global capacity to 8.4 GW. While the global weighted-average TIC of CSP reached a record low of USD 2 418/kW, the LCOE rose to USD 115/MWh. This increase reflects a shift towards smaller solar fields. This reduced the capacity factor to 22%, as plants moved from baseload generation to flexible, grid-regulating roles within hybrid systems. Although China is aiming for 15 GW of CSP by 2030, current project pipelines remain modest, with only 7 GW under construction or approved. Nevertheless, the 37% technological learning rate enjoyed by CSP and its long-duration thermal storage capability sustain its strategic role as a complement to variable renewable energy.

Hydropower

Hydropower additions rose 150% year-on-year to 18.4 GW in 2025, following two years of relatively low additions. China accounted for most of the expansion, with Ethiopia – where the Grand Ethiopian Renaissance Dam was commissioned – and India among the other contributors. The global weighted-average TIC for hydropower fell 10%, to USD 2 079/kW, but the LCOE rose 9%, to USD 62/MWh, as less favourable hydrological conditions and higher financing costs offset the decline in capital expenditure. Hydropower's role as a provider of flexibility, storage and water-management services is becoming increasingly strategic, as variable renewables expand.



Hybrid_Production Ethiopi © Shutterstock.com

Geothermal power

Geothermal energy meets less than 1% of global energy demand and remains concentrated in a small number of countries. In 2025, the global weighted-average TIC rose to USD 5 997/kW and the LCOE increased to USD 89/MWh, driven largely by the financing conditions facing new, capital-intensive projects in higher-risk environments. These near-term cost pressures contrast with rapid technological progress. Enhanced geothermal systems (EGS) are delivering substantial reductions in drilling costs, with well costs at some projects in the United States falling by more than half. The International Energy Agency (IEA) projects that next-generation costs could fall by up to 80% by 2035 (IEA, 2024). The sector is also evolving in ways that extend beyond cost reductions, as major technology companies sign long-term offtake agreements for firm clean power, and lithium co-production from geothermal brines emerges as a potential new revenue stream.

Bioenergy

Bioenergy added 3.4 GW in 2025, with deployment concentrated in Japan, China and Brazil. Together, these countries accounted for 71% of additions. The global weighted-average TIC rose by 9%, to USD 3 606/kW, reflecting a change in the geographical location and feedstock mix, rather than an intrinsic cost increase. The capacity factor reached 78%, contributing to a decline in the LCOE to USD 86/MWh. Bioenergy's dispatchable character and its role in waste management continue to support its strategic relevance in many electricity systems.

1.3 ENABLING SYSTEMS: STORAGE, HYBRIDISATION AND DIGITALISATION

Battery storage led the year's cost declines

Battery storage recorded the largest cost decline of any utility-scale technology in 2025, with fully installed costs for utility-scale systems falling around 30% to USD 140 per kilowatt hour (kWh). This was a figure roughly 95% below the 2010 level. Global deployment reached 108-112 GW, a 40–48% rise, year-on-year, that exceeded the historical peak for annual gas-fired capacity additions. China and the United States accounted for around 70% of new capacity, though expansion grew across a wider range of markets. Australia, for example, added nearly 8 GW – nine times its 2024 total. The market also continued to shift from short-duration ancillary services towards energy shifting, with average discharge durations increasing towards three hours and beyond, supported by lithium iron phosphate (LFP) chemistries, which accounted for around 94% of new installations.

Co-location becomes the default for new solar

Co-location has moved from a niche option to the default configuration for new utility-scale solar. Indeed, around a quarter of all utility-scale solar commissioned globally in 2025 was paired with battery storage – a roughly sixfold rise in the co-located share since 2020.

Two forces have been driving this shift:

- **Lower project costs:** Sharing the grid connection, land and balance-of-plant reduces capital costs by around one-fifth relative to building the two assets separately.
- **Changing market conditions**: A rising number of hours of zero or negative wholesale prices in high-penetration markets such as Europe and Australia has eroded the revenues of standalone solar, while adding storage shifts output to higher-value hours. The technology is also entering mainstream capacity planning. Brazil's 2035 expansion plan, for instance, now includes battery storage as a standard portfolio option with defined cost parameters (Empresa de Pesquisa Energética and Ministério de Minas e Energia, 2025).

Optimisation becomes a competitive advantage

Operations and maintenance (O&M) expenditures are becoming an increasingly important component of total costs, as fleets age and labour costs rise. The global solar O&M market keeps growing with the installed base, even after a recent downward revision due to policy changes and tariffs, while its costs have diverged sharply by region. In high-wage markets, such as the United States, costs are now several times higher than in the lowest-cost markets. Inverter replacement is now the single largest cost component worldwide (Wood Mackenzie, 2025a). That cost pressure is increasing the value of digital optimisation. The clearest example is in dispatch: in saturated European markets, battery trading has become a distinct revenue stream, with optimised, two-hour hybrid storage assets in Spain reported to earn several times the prevailing solar capture price (BNEF, 2026d). As variable renewables and storage scale into more complex systems, the ability to optimise operation and market participation is becoming an increasingly important factor in project performance and profitability.

1.4 EMERGING TECHNOLOGIES

Ocean energy

Tidal stream and wave energy remain at the pilot-to-pre-commercial stage, with 71 MW deployed worldwide since 2010 and more than half of that in Europe. A European pipeline of 196 MW across 16 farms is set to come online by 2030, while China has formulated a 400 MW target for the same time horizon. Aggregated learning trajectories suggest that the LCOE could fall to around USD 140/MWh for tidal stream and USD 120/MWh for wave at 2 GW of cumulative deployment (IRENA and OEE, 2023).

Scaling ocean energy beyond current pilot deployments will depend on the policy and regulatory conditions in place. Experience with other renewable technologies suggests that long-term revenue support mechanisms, such as contracts for difference (CfDs), can lower financing costs and improve investor confidence. Clear permitting frameworks and dedicated grid integration procedures have also been identified as important enablers of faster project development.

Long-duration energy storage

Long-duration energy storage (LDES) reached record deployment in 2025, with new-build capacity of 2.0 GW/9.6 GWh – 97% of it in China – bringing cumulative capacity to 5.1 GW/25.6 GWh. In addition, the project pipeline now contains about 97 GW/422 GWh across 26 markets. So far, two technologies dominate deployment – flow batteries (43% of the total) and compressed air energy storage (38%).

Most LDES remains more expensive than lithium-ion, but compressed air and thermal storage are already cheaper for durations beyond eight hours in markets outside China, where lithium-ion costs more. Adiabatic compressed air energy storage (A-CAES) in China can already compete with open-cycle gas peaking plants at moderate capacity factors – an advantage expected to increase out to 2030.

1.5 STRUCTURAL COST DRIVERS AND MARKET DYNAMICS

Concentrated supply chains keep costs low, but raise exposure to risk

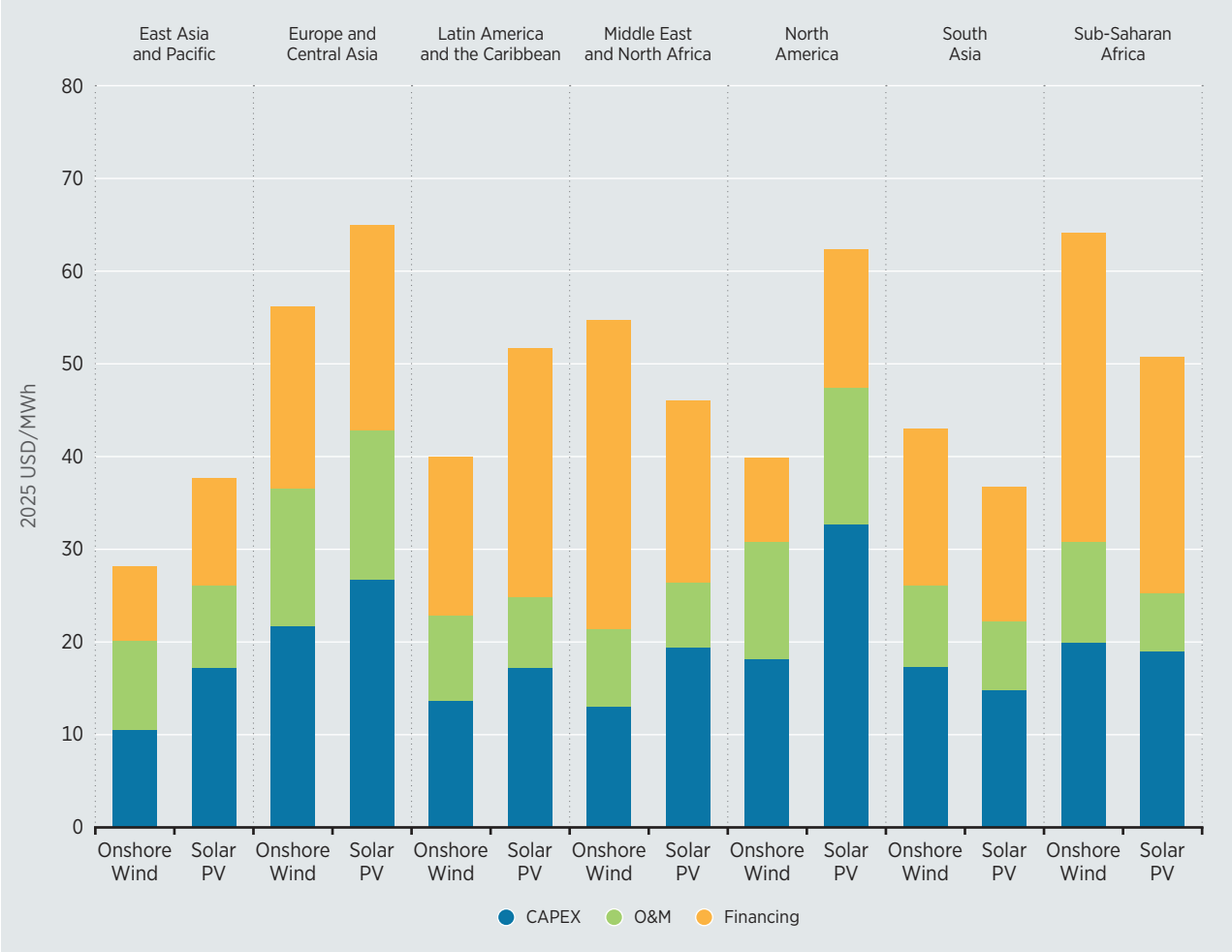
China's manufacturing abundance continued to serve as the primary driver of global cost reductions in 2025. Vertical integration, economies of scale and intense domestic competition maintained Chinese equipment costs significantly below those in other markets, with turnkey prices for four-hour battery systems averaging approximately 40% below the global benchmark (BNEF, 2025b).

This geographical concentration also introduces risk, however, as supply constraints can lead to significant price volatility. This vulnerability was demonstrated by the 2025 gas-turbine shortage, when demand exceeded Western manufacturing capacity. This resulted in substantial increases in both the capital costs and delivery times of new combined-cycle plants (see Section 1.1). Trade frictions and concerns over supply chain concentration have led several governments to support domestic manufacturing, typically at a cost premium.

The cost of capital determines where renewables are cheapest

Renewable projects are capital-intensive. With no fuel to buy, almost all of their lifetime cost is incurred upfront. This makes their economics unusually sensitive to the cost of capital. The weighted average cost-of-capital (WACC) model produced by IRENA shows that this cost varies far more across countries than across technologies. For a standardised, fully contracted project, the real WACC ranges from around 3% in mature, deep capital markets such as the United States and Australia to above 10% in the highest-risk economies. In addition, within any single market, this figure differs only modestly between technologies – typically by well under a percentage point between solar and onshore wind, for example.

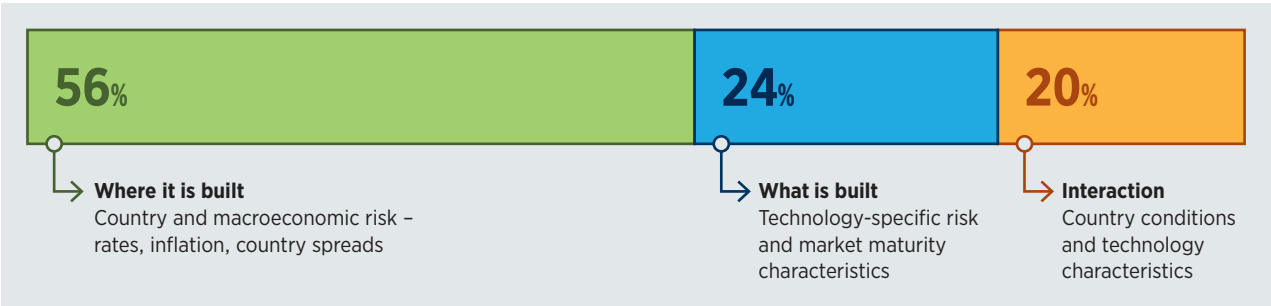
Figure 1.3 LCOE by cost component, technology and region



Notes: CAPEX = capital expenditure; LCOE = levelised cost of electricity; MENA = Middle East and North Africa; MWh = megawatt hour; O&M = operation and maintenance; PV = photovoltaic; USD = United States dollar.

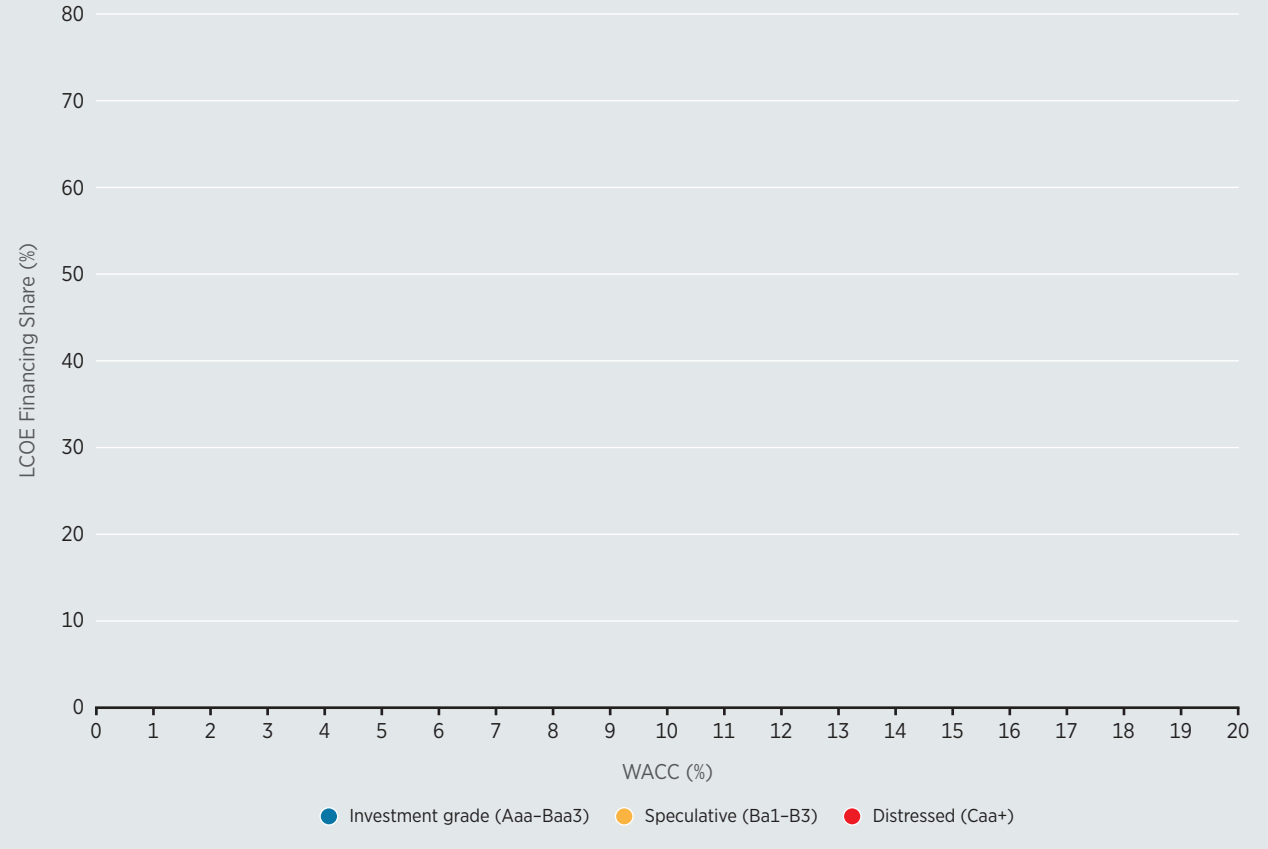
Figure 1.3 makes this visible: across regions, the capital and operating components of cost are broadly comparable, while the financing component widens sharply in higher-risk markets. A formal decomposition confirms this: country-level macroeconomic conditions, such as sovereign risk, interest rates and inflation, explain about 56% of the variation in financing costs. This is some 2.3 times the 24% share attributable to technology. Where a project is built therefore matters more than what is built (see Figure 1.4).

Figure 1.4 Drivers of financing cost variation across markets and technologies



The same technology can therefore cost far more to finance in a high-risk economy than in a mature one. This impact is most significant for emerging and developing economies, where most new demand will arise. In these markets, the cost of capital – not the cost of technology – is the binding constraint, with targeted de-risking the critical lever.

Figure 1.5 WACC and LCOE financing share (%)



Notes: These figures are model-derived, country- and technology-specific estimates. They incorporate macroeconomic risk, an inherent technology-risk component, a market-maturity premium, and risk-adjusted gearing. They do not reflect observed financing terms from individual projects. It is assumed that financing conditions for projects commissioned in 2025 reflect the macroeconomic and market conditions prevailing in 2024 (investment commitments are typically made one year prior to construction). LCOE = levelised cost of electricity; WACC = weighted average cost of capital.



Beyond these national-level conditions, two further factors shape financing costs within any single market: the risk profile of the technology and the degree of revenue certainty. The technology effect is the smaller of the two; solar PV and onshore wind face broadly similar financing costs, while offshore wind and geothermal carry a technology premium. Revenue certainty is the more significant variable: the difference in financing costs is greatest when future revenue is least certain, with the WACC for merchant projects roughly double that of projects backed by long-term contracts (BNEF, 2026c). Revenue certainty is primarily determined by contract structure. Long-term instruments, such as feed-in tariffs, CfDs and power purchase agreements, stabilise cash flows by reducing exposure to wholesale price volatility, improving debt capacity and lowering financing costs. Projects operating on a merchant basis face substantially higher cash-flow risk, which lenders price into borrowing costs and leverage ratios. Recent empirical analysis finds that well-designed long-term contracts can reduce the LCOE by 30–40% due to better financing conditions alone (Sánchez Canales and Hirth, 2026).

Policy and market design are reshaping revenue certainty

Stable revenue mechanisms, such as auctions, CfDs, and long-term power purchase agreements (PPAs) – lower risk premiums and reduce the cost of capital, directly influencing global investment flows.

In this regard, three policy developments were particularly significant in 2025:

- In the United States, the One Big Beautiful Bill Act restricted eligibility criteria for clean energy tax incentives and accelerated the timeline for phasing out wind and solar projects.
- In China, the transition from guaranteed feed-in tariffs (FiTs) to market-based pricing structures subjected projects to market price determination – although provincial CfDs offered a partial risk-mitigation mechanism (BNEF, 2026e). China also revoked provincial storage co-location mandates, replacing them with a strategic plan to deploy 180 GW of energy storage by 2027 (BNEF, 2026d).
- In the European Union (EU), regulatory initiatives aimed at expediting permitting procedures began to reduce project lead times, though structural bottlenecks persisted.

1.6 THE COST OUTLOOK: FURTHER DECLINES, BUT AT A SLOWER PACE

This section outlines potential short-term pathways for the TICs of solar PV and onshore wind technologies up to 2035, based on the two-stage approach described in Box 2. This method leverages the detailed, project-level IRENA Renewable Cost Database to develop possible cost trajectories specific to each technology and region. These modelled results are then complemented by external evidence that helps explain why costs vary across regions and why their decline is expected to slow. This section then extends to energy storage, covering possible future cost trajectories for both short-duration battery storage and long-duration energy storage, informed by recent published assessments.

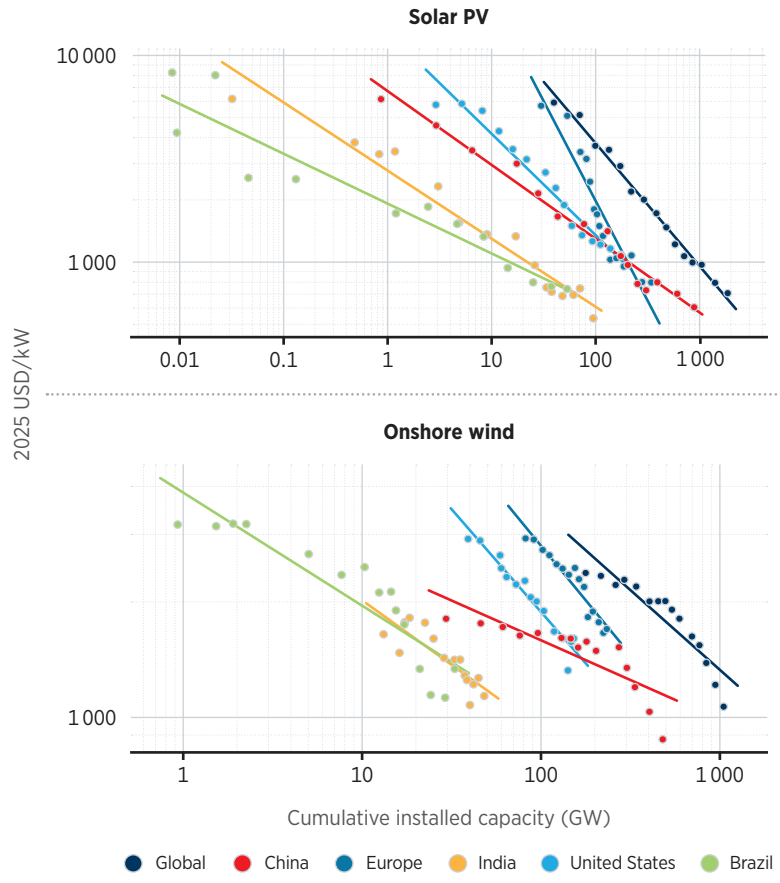
Box 1.1 A two-stage approach to projecting TIC trajectories

Cost trajectories for the period 2025–2035 were developed in two distinct stages.

STAGE 1: Learning-curve modelling

In the first stage, a learning-curve model was estimated from historical project data. The unit cost of each technology declined as cumulative installed capacity grew, while annual deployment responded to falling costs through a price elasticity of demand, creating a reinforcing feedback loop between cost reductions and capacity growth. The learning rate (the cost reduction for each doubling of cumulative capacity) and the elasticity were estimated separately for each region and technology. Solar PV had the higher global learning rate, at about 34%, compared to roughly 25% for onshore wind.

Figure B1.1 Solar PV and onshore wind learning curves per region



Region	Learning rate	Epsilon*
Brazil	15%	3.97
China	22%	2.17
Europe	49%	0.51
Global	34%	1.34
India	20%	2.30
United States	29%	1.47

Region	Learning rate	Epsilon*
Brazil	18%	1.96
China	13%	2.37
Europe	33%	0.43
Global	25%	1.49
India	21%	0.13
United States	31%	0.87

Notes: * Epsilon is the price elasticity of demand, reflecting how responsive deployment is to cost reductions; GW = gigawatt; kW = kilowatt; USD = United States dollar.

STAGE 2: Structural adjustments for market maturity

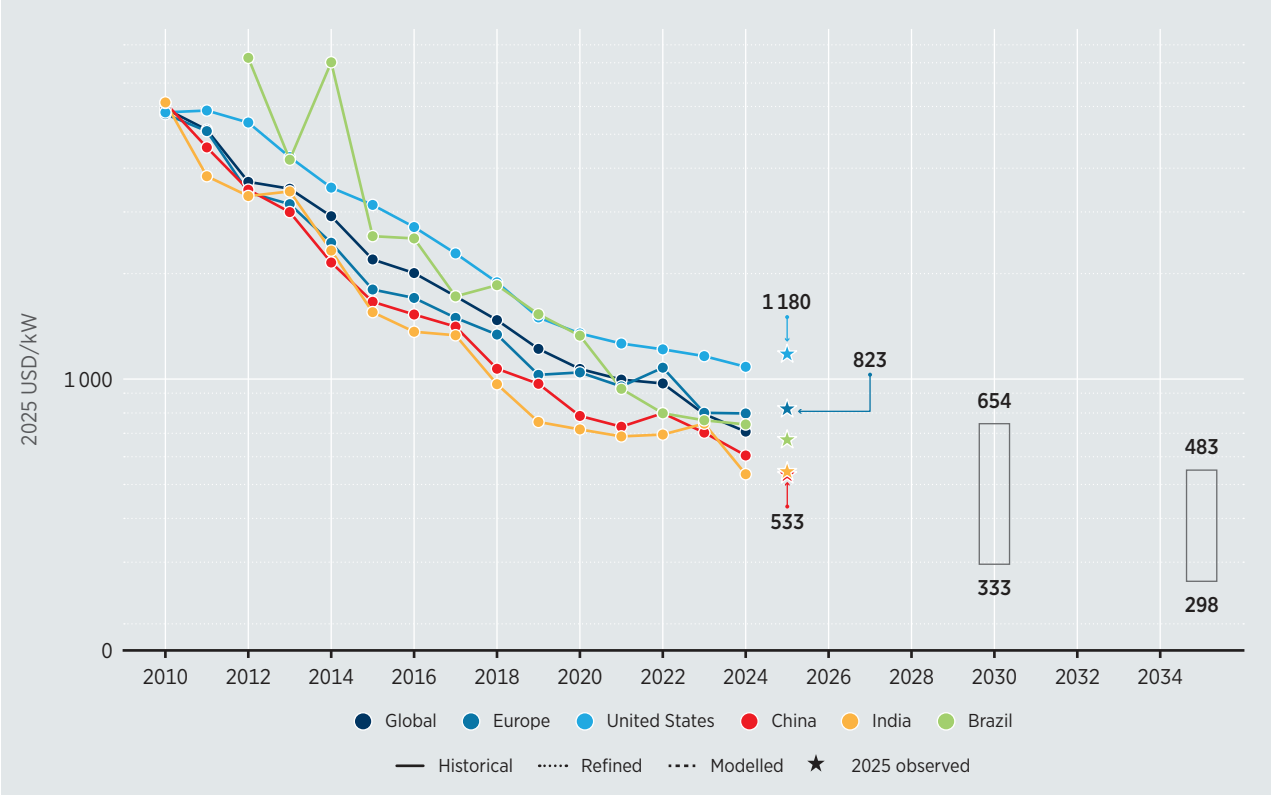
In the second stage, these learning curve-based estimates were adjusted to reflect persistent regional cost drivers. These included labour costs, permitting regimes, grid-connection complexity and localisation requirements. The adjustment established China as the global cost floor. This level is projected to decline at a more moderate pace over time as manufacturing capacity and market demand rebalance.

The resulting trajectories are indicative, rather than predictive. They assume stable macroeconomic and deployment conditions, constant learning rates and elasticities, and do not account for unanticipated shifts in international trade or industrial policy.

Solar PV: Lower costs, led by China

IRENA analysis suggests that the global weighted-average TIC of solar PV systems could decline from USD 667/kW in 2025 to USD 407/kW by 2030, before reaching USD 351/kW by 2035. This represents a decline of about 39% over the next five years, but only a further 14% between 2030 and 2035, illustrating the slower pace of cost reduction now expected.

Figure 1.6 Weighted-average TICs of solar PV systems by selected country and region, 2010–2035



Notes: kW = kilowatt; USD = United States dollar.

China continues to establish the global cost floor, with its regional baseline decreasing from USD 533/kW in 2025 to USD 298/kW by 2035. This position is supported by an established manufacturing sector that holds more than 90% of global solar PV manufacturing capacity – as opposed to around 2% in the United States and 1% in the EU (Bjerkan-Wade *et al.*, 2026). Intense competition between Chinese manufacturers cut solar module prices by around two thirds between 2022 and 2024, so that emerging markets importing this equipment at near-frontier prices remained close to the floor (Bjerkan-Wade *et al.*, 2026). Saudi Arabia, for instance, recently recorded one of the world's lowest solar PV tender prices, at USD 12.9/MWh (IEA PVPS, 2026).

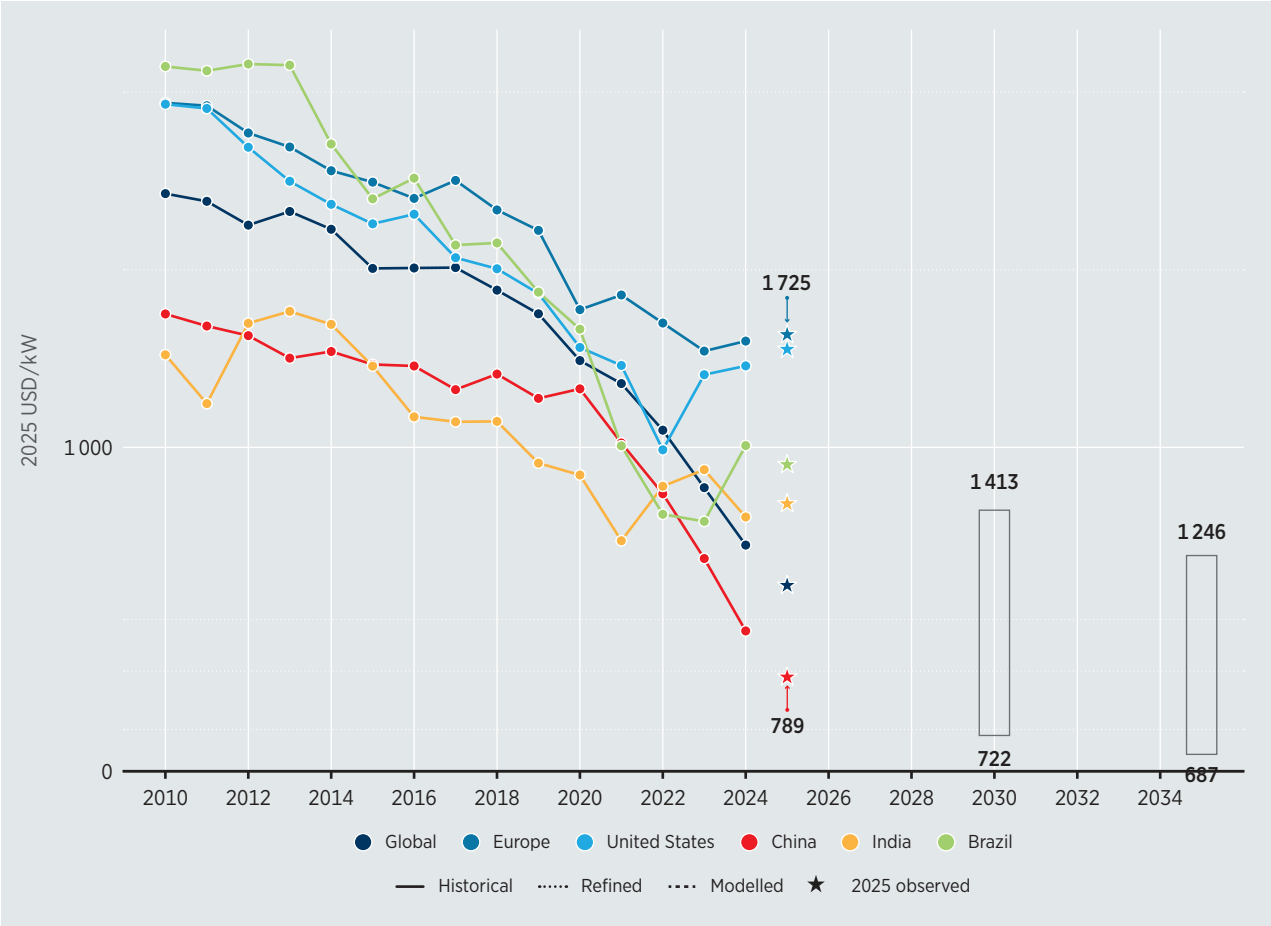
In contrast, Western markets face a persistent cost premium that has been revised upwards from earlier estimates. The simulations demonstrate that the United States remains the most expensive market throughout the forecast period, with TICs dropping from USD 1180/kW in 2025 to USD 483/kW by 2035. Europe also faces higher structural costs, with its 2035 figure adjusted upwards from previous outlooks to USD 371/kW.

Onshore wind: Costs decline gradually as the regional order shifts

IRENA modelling suggests that global weighted-average TICs for onshore wind could fall from USD 976/kW in 2025 to USD 869/kW by 2030, and to USD 792/kW by 2035. This represents a decrease of around 19% over the decade – a figure well below the roughly 47% decline projected for solar PV over the same period.

This gradual decline is heavily influenced by China, where large deployment volumes pull the global average down. China accounted for approximately 113 GW of the 150 GW of total onshore wind capacity added globally in 2025, or nearly three quarters of the global total (IRENA, 2026a).

Figure 1.7 Weighted-average TICs of onshore wind systems by selected country and region, 2010–2035



Notes: kW = kilowatt; USD = United States dollar.

The ranking of regions differs from that shown by solar PV, as indicated in Figure 1.5. Europe, rather than the United States, is the most expensive region, at about USD 1725/kW in 2025. This is roughly 2.2 times China's level, with Europe remaining the most costly market throughout the forecast period, reaching around USD 1246/kW by 2035. European financiers and insurers remain cautious about Chinese turbines, citing limited familiarity with manufacturers' track records and the need for independent certification and technical performance data. As a result, the low-cost import route available to other markets remains restricted in Europe.

In the onshore wind market, the global average cost sits below the individual costs of emerging markets that import this technology, such as India and Brazil. This divergence occurs because Chinese turbines sold abroad cost roughly double their domestic price, although even so, they remain markedly cheaper than Western turbines. This is why importing markets such as India and Brazil sit above China's floor, but well below Europe and the United States (BNEF, 2025a). In 2025, TICs are estimated at USD 1172/kW for India and USD 1282/kW for Brazil, compared to USD 789/kW for China. Because China dominates global deployment, its low domestic prices pull the global average firmly downward.

Large regional disparities in TICs do not automatically result in equally large gaps in the LCOE. The final cost of energy depends not only on upfront capital expenditure and operational costs, but also on financing conditions and local wind resources. For instance, when combined with lower maintenance expenses and favourable financing conditions, higher capacity factors – achieved through larger rotors, taller towers and turbines optimised for low wind speeds – can significantly improve the business case in high-cost regions.

Short-duration battery storage: Decline resumes after a brief interruption

The cost outlook for short-duration battery storage indicates a continued downward trend. Relative to 2025 turnkey levels, four-hour battery storage costs are projected to decrease by 2035. This decline will be substantial in China, where such costs will fall to approximately one-third of the current global average. However, the decline will be only moderate in Europe and the United States, which remain significantly above the Chinese cost floor (BNEF, 2025b).

Overall, these cost reductions are being driven not only by declining lithium-ion cell prices, but also by longer battery lifetimes, higher round-trip efficiencies and lower financing costs. This downward trajectory faces near-term constraints, however, as Chinese battery prices – which set the global benchmark – are expected to remain elevated throughout the first half of 2026 at least. This is due to higher metal costs and the phasing out of export tax rebates (BNEF, 2026f).

Long-duration energy storage: The path to competitiveness

LDES systems are projected to experience gradual cost declines at low, single-digit annual rates through to 2035. Benchmarking against current levels, however, highlights significant reductions by 2030. For instance, intraday electrochemical systems are expected to reach USD 244–358/kWh by 2030, while 100-hour multi-day systems are projected to decline to USD 26–38/kWh by the same date. Substantial uncertainty bands remain, however (LDES Council, 2026).

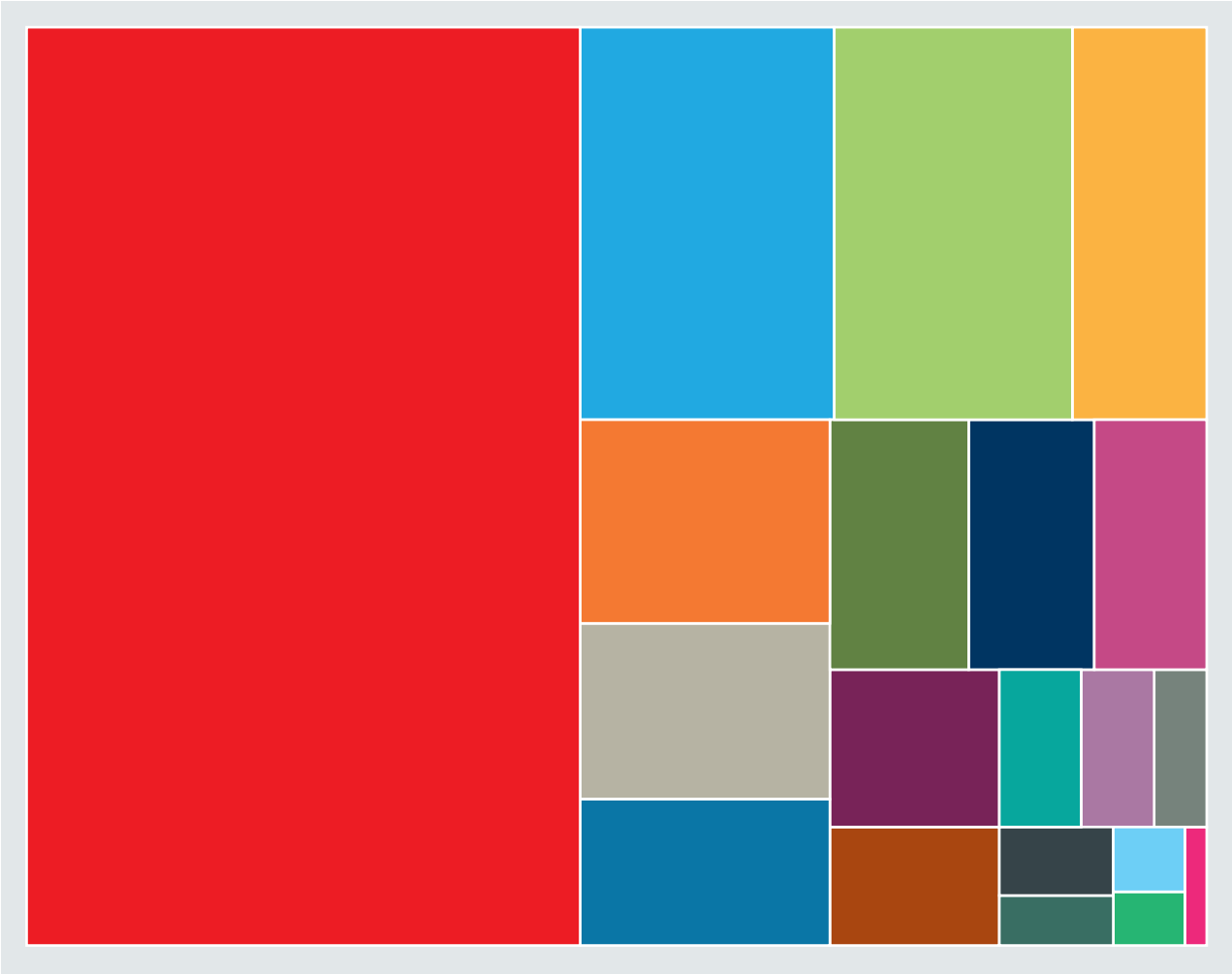
As capital costs decrease, LDES is expected to become increasingly competitive with gas-fired peaking plants. In China, for example, adiabatic compressed-air energy storage in natural caverns is expected to become more cost-effective than unabated, open-cycle gas turbines, with significantly lower operating thresholds evident by 2030 (BNEF, 2026g).

1.7 BEYOND COST: AVOIDED FUEL USE, EMISSIONS AND ENERGY SECURITY

The value of renewable power extends well beyond its generation cost. Because renewables produce electricity without fuel, they displace the coal and gas that would otherwise have been burned. This avoids both the cost of that fuel and the emissions it releases. To quantify these benefits, IRENA compared actual renewable generation in 2025 with a counterfactual in which each country meets the same demand by scaling up its existing coal and gas-fired fleet, according to its current proportions.[2]

Across the 20 major economies assessed, renewable power avoided an estimated USD 377 billion (2025 USD) in fossil-fuel purchases and around 6.6 gigatonnes (Gt) of carbon dioxide (CO_2) emissions in 2025. The 20 economies assessed account for about four-fifths of world renewable generation; scaling the same method to all countries gives an estimated global total of approximately USD 480 billion and 8.4 Gt of CO_2.

Figure 1.8 Avoided fossil fuel costs in 2025 across 20 major economies



Notes: (1) Mexico 2.9; (2) Indonesia 2.6; (3) Malaysia 2.0; (4) Argentina 1.6; (5) Philippines 1.4; (6) South Africa 0.8.

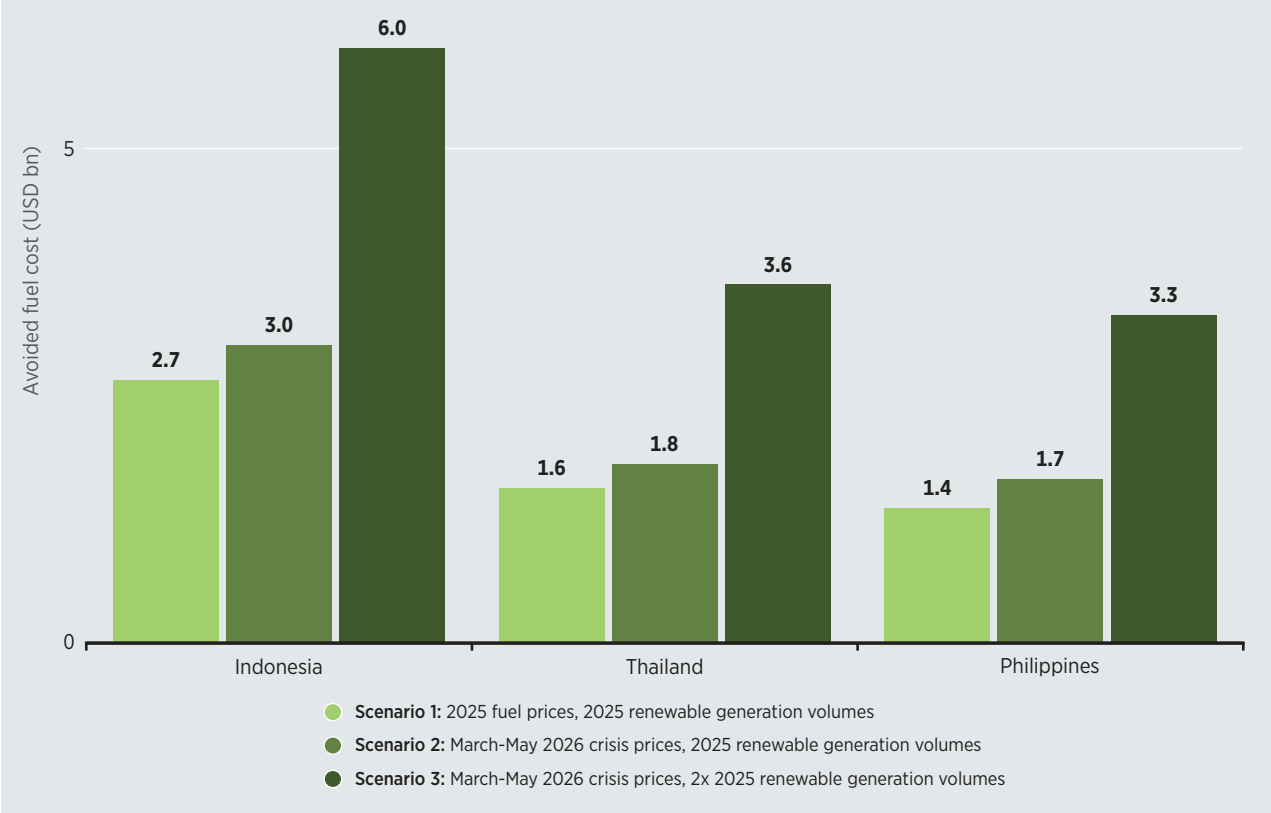
[2] *Generation and power-sector emissions data are sourced from Ember Energy's Global Electricity Data, with country-specific fuel prices and emissions factors derived from nationally reported figures. Avoided fuel is valued at average annual price levels, rather than short-term market spikes.*

The geographical distribution of these economic and environmental benefits closely mirrors the concentration of global renewable power generation. China alone accounted for about USD 177 billion – or around 47% – of the total avoided cost and roughly 3.4 gigatonnes (Gt) – or around 52% – of the avoided carbon dioxide (CO_2). These numbers reflect both the scale of China's renewable fleet and the predominantly coal-based generation it displaces. Avoided costs and emissions in the United States were next, standing at around USD 35 billion and 761 million tonnes (Mt) of CO_2, followed by Brazil, with USD 32 billion and 432 Mt,[3] India, with USD 18 billion and 451 Mt, Germany, with USD 18 billion and 215 Mt, and Japan, with USD 15 billion and 166 Mt.

These figures represent gross estimates: they do not deduct the capital costs of the renewable capacity itself, nor do they monetise avoided local air pollutants, such as sulphur dioxide (SO_2), nitrogen oxides (NO_x) and fine particulate matter. Reducing these delivers further, well-documented public health benefits beyond the scope of this calculation.

In 2025, the renewable generation of three, import-exposed Southeast Asian economies – Indonesia, Thailand and the Philippines – displaced an estimated USD 5.7 billion of coal and gas that would otherwise have been bought, much of it imported. Because renewable energy facilities require no fuel once operational, this saving is counter-cyclical: their value increases with rising global fossil-fuel prices – and they do so without any new investment, since the capacity is already in place.

Figure 1.9 Avoided fossil fuel costs for Indonesia, Thailand and the Philippines



[3] *The high placement of Brazil reflects the counterfactual, rather than a large fossil fleet. The country's substantial hydropower output is valued against the gas and coal that would otherwise have run, even though little fossil generation remains on its system today.*


Akhmad Dody Firmansyah © Shutterstock.com

When the Strait of Hormuz closed in early 2026, causing oil and gas import prices to spike across Asia and Europe, existing renewable electricity generation provided a crucial financial buffer. The three Southeast Asian economies looked at here are amongst the most exposed in the region: the Philippines sources over 95% of its crude oil imports from the Persian Gulf, while Thailand relies on natural gas for around two-thirds of its power output – a significant share of which arrives as liquefied natural gas through Middle East shipping routes. Meanwhile, Indonesia, now a net oil importer, imports roughly 60% of its fuel supply. Re-pricing the same 2025 renewable generation at March–May 2026 crisis levels increases the annual savings from USD 5.7 billion to USD 6.5 billion.

For countries that still rely heavily on fossil fuels, adding renewable capacity further strengthens economic protection. As shown in Figure 1.9, doubling renewable generation in Indonesia, Thailand and the Philippines would have raised avoided fuel costs to USD 12.9 billion – more than twice the baseline saving.[4]

[4] *The 2026 price shock has also accelerated near-term policy responses in the region. The Philippines fast-tracked grid connection for 1 471 megawatts (MW) of approved renewable power projects. Indonesia accelerated its 100 GW electrification programme, while Thailand restarted coal capacity whilst exploring expanded hydropower output.*

02 ONSHORE WIND



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HIGHLIGHTS

Onshore wind recorded lower total installed costs and higher capacity factors, driving a further decline in global weighted average LCOE.*

LCOE − 4%** ↓

Capacity factor + 2%*** ↑

in 2025 vs. 2024



TOTAL INSTALLED COSTS

Global total installed costs for onshore wind in China fell to a record low of USD 789/kW in 2025; in Brazil, costs fell by 4%; in the United States, India and Germany costs rose by 3-7% compared to 2024.



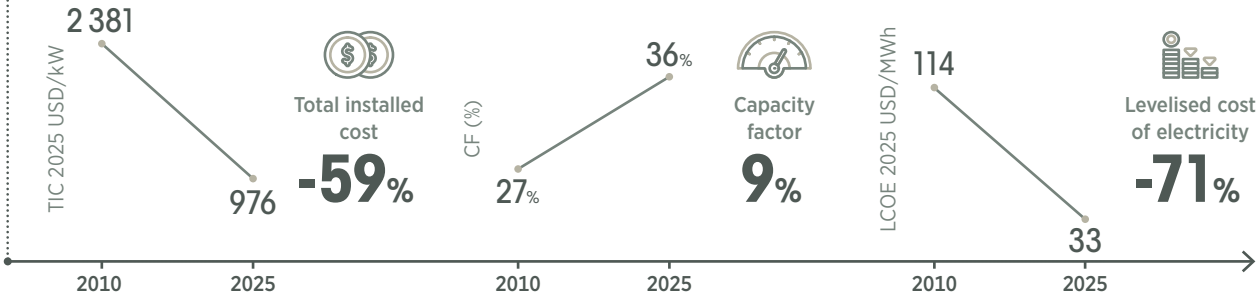
USD 976/kW



-8%

in 2025 vs. 2024

KEY PARAMETERS**



TOP MARKETS

Capacity additions (GW) in 2025



Outlook

The pace of future cost declines depends on market reforms, trade and permitting friction, stable policy frameworks, long-term revenue visibility and thebuild-out of grid infrastructure.



* Levelised cost of electricity; ** All values are weighted averages; *** All changes in capacity factor are expressed in percentage points.

2.1 INTRODUCTION

Now an integral component of modern electricity systems, new annual installations of onshore wind surpassed 100 GW for the third year running in 2025, with 150 GW of onshore wind installed worldwide, bringing total global capacity to 1200 GW – 6.7 times the installed capacity in 2010 – and representing year-on-year capacity addition growth of 41% (IRENA, 2026a).

China accounted for three-quarters of the global onshore wind capacity additions in 2025, with 113 GW. India and the United States followed as the second and third largest markets, each adding capacity at similar levels – 6.3 GW and 6.2 GW respectively.

Onshore wind deployment is influenced by a range of enabling conditions. These include cost competitiveness, clear and stable policy frameworks, predictable project pipelines, efficient permitting processes, grid access certainty, strong domestic supply chains, and energy security considerations. The extent to which these factors are present varies across markets.

Sustaining onshore wind momentum requires reinforcing the foundations that have driven deployment to date, while addressing emerging challenges and strengthening business cases. Permitting remains one of the most significant constraints and grid infrastructure has not kept pace with deployment ambitions. Supportive policy instruments are also essential in providing revenue certainty and attracting investment, as the continued growth of industrial capacity and domestic supply chains facilitates deployment and broadens local economic benefits. In addition, the repowering of existing sites is projected to increase and become an important source of new capacity, with advances in turbine technology enabling output to triple or quadruple relative to the turbines being repowered (WWEA, 2026).

2.2 TECHNOLOGICAL TRENDS

Onshore wind has been undergoing a transformation supported by a wave of innovation aimed at improving performance, reducing costs, and enhancing system integration. These developments reflect a broader shift towards optimising how capacity interacts within an increasingly complex energy system.

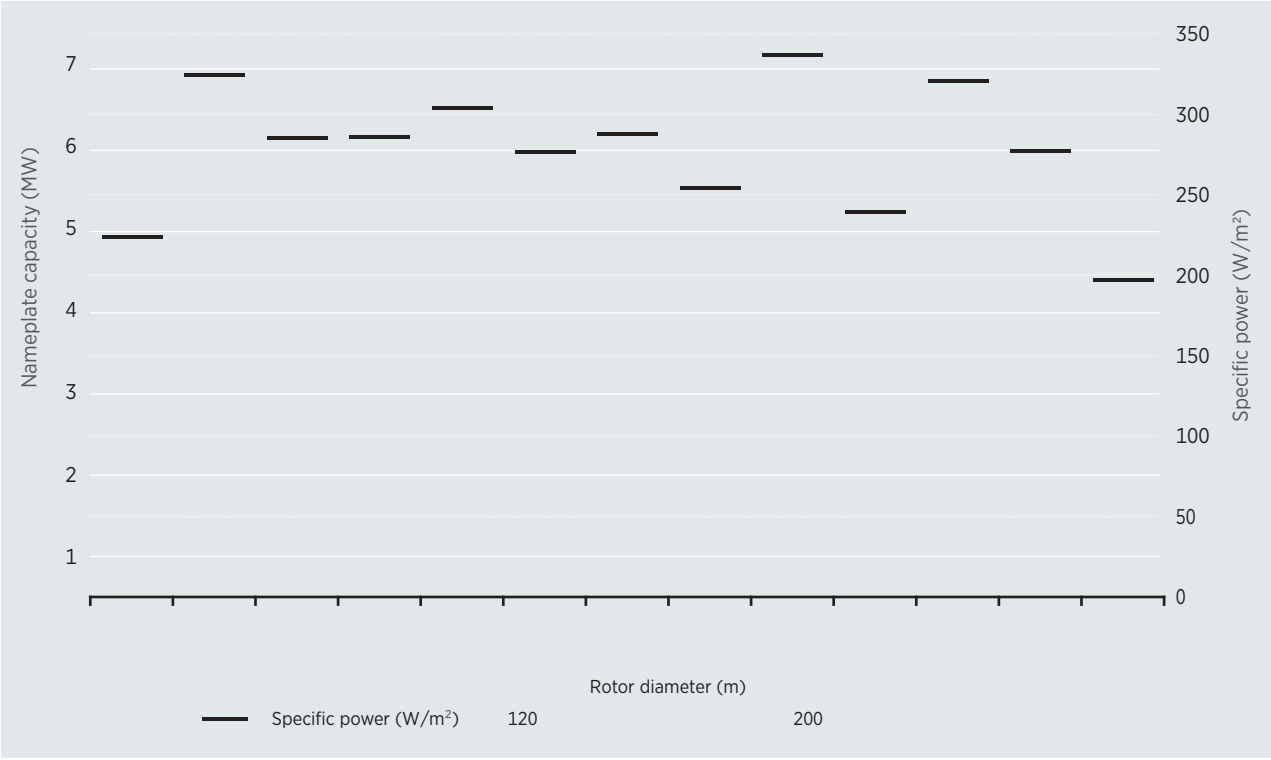
Technological advances have long been key drivers in the expansion of the onshore wind sector. Larger rotor diameters, taller towers and higher turbine nameplate capacities have all been improving project economics, increasing capacity factors and expanding viable deployment areas. Differences in turbine design have also reflected trends in technology, as well as optimisation for local wind regimes, terrain characteristics, and grid infrastructure.

One metric that can provide insight into the turbine design choices and deployment conditions is known as “specific power”. A lower specific power generally indicates larger rotor areas relative to generator capacity. This enables greater energy capture at lower wind speeds and increasing capacity factors. Conversely, higher specific power values are often associated with sites characterised by stronger wind resources, where smaller rotor areas can achieve similar energy yields.

Figure 2.1 presents the weighted-average nameplate capacity, rotor diameter and specific power of turbines installed in 2025 for selected countries.

China stands out with the highest weighted-average nameplate capacity and rotor diameter, reaching 7 MW and 200 metres, respectively. Lithuania follows, with a weighted-average nameplate capacity of 6.6 MW and a rotor diameter of 161 metres. Two broader clusters are then visible: one groups countries in the 5-6 MW range and another in the 3.5-4.5 MW range. India and France are at the lower end of weighted-average nameplate capacity, at 3.6 MW, with France also recording the smallest weighted-average rotor diameter, at 129 metres.[5] Across the countries represented, specific power ranged from around 200 watts per square metre (W/m^2) in India to approximately 340 W/m^2 in Ireland.

Figure 2.1 Weighted-average onshore wind rotor diameter, nameplate capacity and specific power, 2025



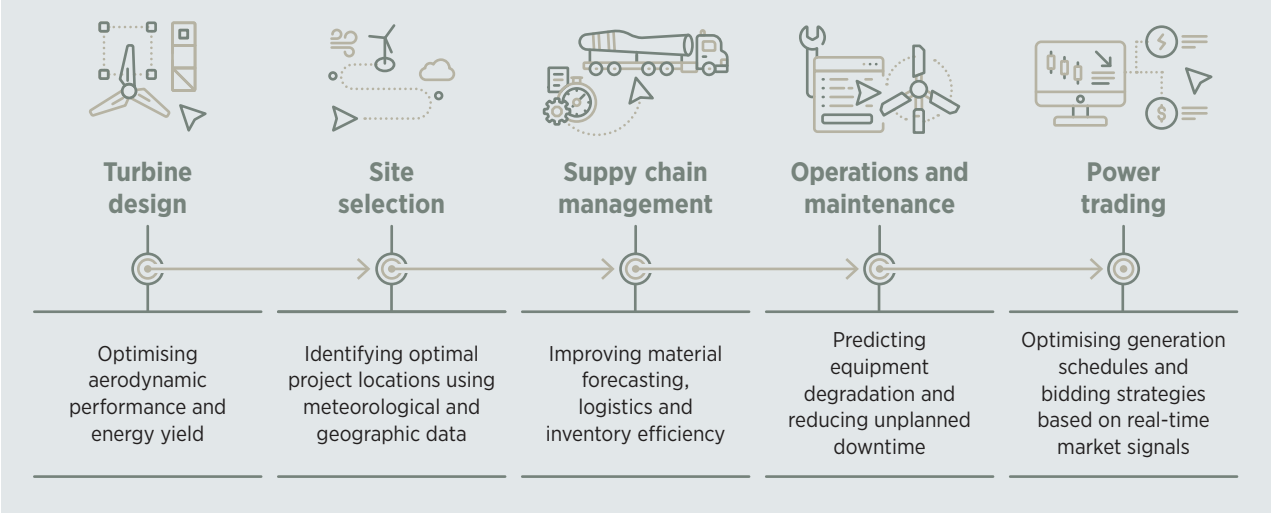
Notes: m = metre; MW = megawatt, W = watt.

In recent years, the industry's strategic focus has shifted towards improving operational efficiency and strengthening profitability. European manufacturers have shifted their emphasis from further turbine model upsizing to shortening project execution times, and supporting a resilient and sustainable supply chain (Vestas, 2023). Chinese manufacturers are pursuing similar priorities, focusing on improving reliability, competing in increasingly liberalised power markets and integrating AI into operations (BNEF, 2025c; Wood Mackenzie, 2025b).

[5] *These characteristics should not be interpreted as indicators of technological advances; rather, they reflect turbine design choices optimised for local wind resource conditions and project requirements.*

Indeed, digitalisation is reshaping operations across the wind power sector (see Figure 2.2). AI applications are increasingly improving project development processes and easing downward pressure on costs. In power trading, for example, Goldwind is introducing market-responsive turbines capable of adjusting output based on real-time electricity prices (BNEF, 2025c). More broadly, AI-driven strategies are helping streamline processes, optimise revenues and reduce operational risks.

Figure 2.2 AI applications in onshore wind development and operation



Based on: (BNEF, 2025c).

In addition, materials innovation is supporting the next phase of wind technology development. Lighter and more durable composite materials can reduce manufacturing and transportation costs, while advances in components and testing methods are improving turbine durability, blade design and maintenance performance (Firoozi *et al.*, 2024).

At the system level, hybrid configurations combining wind, solar, and storage are emerging as a powerful model to smooth variability, maximise grid connections, and optimise how capacity interacts within an increasingly complex energy system. In several major economies, co-located wind-plus-storage has already crossed a further threshold, with costs below coal and gas plants (IRENA, 2026b).



2.3 TOTAL INSTALLED COST

For onshore wind projects commissioned in 2025, the global weighted-average TIC was USD 976/kW. This represented a 59% decline on 2010 (see Figure 2.3). Between 2024 and 2025, the global weighted-average TIC fell by 8%, largely driven by the high share of installations in China, where TICs continue to decline and remain the lowest globally (see Table 2.1). In 2025, onshore wind TICs ranged from USD 632/kW to USD 2 208/kW, between the 5th and 95th percentiles.

Figure 2.3 TICs of onshore wind projects and global weighted-average, 2010–2025

Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.

Table 2.1 presents the weighted-average TICs for onshore wind projects at regional and country levels. Between 2015 and 2025, all regions and countries included in the table recorded declines in weighted-average TICs for newly commissioned projects. In 2025, regional costs ranged from USD 1 810/kW in Other North America to USD 1 314/kW in Other South America, with Oceania, Europe, Other Asia, Africa and Eurasia falling in-between.

Table 2.1 TIC ranges and weighted-averages for onshore wind projects by country/region, 2015 and 2025



	2015			2025		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2025 USD/kW)					
Africa	1 720	**2 636**	3 344	1 391	**1 550**	1 897
Eurasia	2 095	**2 503**	3 276	845	**1 397**	1 982
Europe	1 997	**2 446**	3 475	1 244	**1725**	2 380
Oceania	2 164	**2 891**	4 296	1 787	**1 787**	1 787
Other Asia	2 471	**3 115**	3 633	844	**1 713**	2 881
Other North America	1 925	**2 958**	4 145	1 623	**1 810**	2 250
Other South America	2 351	**2 663**	3 014	1 095	**1 314**	2 252
Brazil	1 611	**2 352**	2 736	1 016	**1 282**	1 516
China	1 590	**1 611**	1 976	553	**789**	1 163
India	1 073	**1 554**	1 971	782	**1 172**	1 301
Unitad States	1 915	**2 221**	2 926	1 014	**1 668**	2 672

Notes: "Other Asia" includes all Asian countries except China and India; "Other North America" includes Canada and Mexico; and "Other South America" includes all South American countries except Brazil; kW = kilowatt; USD = United States dollar.

Figure 2.4 presents the weighted-average TICs in 2024 and 2025 for the top 30 countries by onshore wind capacity additions, highlighting diverging market trends. In 2025, China recorded the lowest weighted-average TIC, at USD 789/kW. This was down 10% on 2024 and was underpinned by a uniquely enabling market structure (see Box 2.1). Brazil was the only other top-five market to record a decline, with costs falling 4%. In contrast, India, the United States and Germany saw cost increases of between 3% and 7%, reflecting differing supply chain pressures and market conditions.

In 2025, market-specific factors continued to shape the economics of onshore wind deployment. In Germany, higher TICs reflected structural pressures across the project development value chain. In particular, these included rising investment costs related to planning, grid connection and other project-related expenses (Deutsche WindGuard, 2025). In the United States, policy volatility, trade measures and permitting constraints continued to weigh on investment confidence and project development (Wood Mackenzie, 2026b).

Figure 2.4 Onshore wind weighted-average TICs in selected markets, 2024–2025

Notes: The data file available for download includes the historical data for all markets from 2010 to 2025; kW = kilowatt; Lao PDR = Lao People's Democratic Republic; USD = United States dollar.

Box 2.1 China's onshore wind market: An enabling model under transition

China's onshore wind deployment reflects an enabling market environment characterised by a co-ordinated industrial policy, long-term planning, large-scale infrastructure investment and regulatory certainty. These conditions have supported predictable project pipelines, accelerated deployment and facilitated the expansion of domestic manufacturing capacity and grid infrastructure.

In 2025, three ultra-high-voltage (UHV) transmission lines entered operation, strengthening the delivery of electricity from resource-rich northern regions to major demand centres (Wood Mackenzie, 2025b). The competitiveness of China's onshore wind sector also benefits from the industry itself, including large-scale manufacturing, low commodity costs, automation and integrated supply chains.

China's integrated approach has translated into strong deployment, industrial leadership and continued cost reductions. Wind power now supplies 10.7% of China's electricity, up from 3.2% in 2015 (Ember, 2026a). In terms of MWs of wind turbine order intake, in 2025, manufacturers from China occupied the top five positions worldwide, accounting for 63% of total global orders (Wood Mackenzie, 2026c). At the same time, installed costs declined by 10% between 2024 and 2025, reaching a record low of USD 789/kW and further strengthening the competitiveness of onshore wind.

The policy framework that has enabled the rapid expansion of China's onshore wind sector is now undergoing a transition, however. As the technology and the industry has matured, feed-in tariffs have been removed and guaranteed on-grid tariffs are to be phased out by 2030, moving the sector toward full market participation. As subsidies decline, investment is shifting towards load-oriented strategies, with energy-intensive industries moving west to access lower-cost renewable power, while developers focus on higher-quality wind resources to offset falling capture prices (Wood Mackenzie, 2025b).

Wind turbines are the largest cost component of onshore wind projects, typically accounting for around half of TICs – although the share varies across markets and project configurations. In the United States, for example, turbines represent 55% of total project costs, compared to 30% for balance-of-system expenditures and 15% for soft costs (NREL, 2024). In Germany, turbine costs account for 47% of the TIC (Deutsche WindGuard, 2025). Differences in project scale, turbine size, site conditions, financing costs, grid connection requirements and local supply chain maturity can all significantly influence overall project economics.

Indeed, the overall cost of a wind turbine reflects the contribution of multiple components (see Figure 2.5) with the costs of these structural, mechanical and electrical. Together, these components highlight the complexity of wind turbine manufacturing and the wide range of material, engineering and supply chain inputs that shape overall turbine costs. Among wind turbine components, towers and blades represent halt of the cost. Other parts, such as the nacelle, gearbox, generator and hub and pitch system, contribute smaller – though still notable – portions.

Figure 2.5 Indicative cost breakdown of a wind turbine

Based on: Global Wind Energy Council (GWEC) inputs and (Wood Mackenzie, 2021).



As wind turbines account for the largest share of TICs in onshore wind projects, turbine pricing remains a key indicator of cost dynamics across global markets. Figure 2.6 presents wind turbine price indices (WTPI) and pricing trends for the period 2010–2025.

Figure 2.6 Wind turbine price indices and price trends, 2010–2025

Source: (BNEF, 2025a; Vestas, 2026; Wiser *et al.*, 2025).
Notes: kW = kilowatt; USD = United States dollar; WTPI = Wind Turbine Price Index.

Prices for onshore wind turbines installed outside mainland China increased during the first half of 2025, as manufacturers looked to recover from slim or negative margins through higher-priced contracts (BNEF, 2025d). This trend is reflected in the BNEF WTPI, which rose 14% between 2024 and 2025. Meanwhile, price differentials between turbine classes narrowed considerably. Class I, II, III and S turbines converged around an average price of USD 1104/kW in the first half of 2026.[6]

[6] *The classifications given here are International Electrical Commission (IEC) wind turbine classifications. Class I wind turbines are designed for the best wind speed sites and typically have shorter rotors, while Class II wind turbines are designed for medium wind speed conditions and Class III turbines for poorer wind conditions with larger rotor diameters and lower specific power. Class S wind turbines are designed to meet specific site conditions and requirements that fall outside the standard classification.*

From 2021 onwards, pricing trends in China[7] diverged from those observed in other markets. Globally, rapid market growth and supply chain disruptions associated with the COVID-19 pandemic placed upward pressure on wind turbine prices. In China, however, average turbine prices fall, reflecting excess manufacturing capacity and intensifying competition following the phase-out of support schemes (IRENA, 2022a). This downward trend began to moderate in 2025, when turbine prices stabilised and showed signs of rising. Indeed, they increased by 2% between 2024 and 2025, and by 3% between the fourth quarter (Q4) of 2024 and Q4 2025, reaching USD 199/kW by the latter date. This shift partly reflected changes in procurement practices, with an industry agreement signed in October 2024 by 12 leading Chinese turbine manufacturers discouraging unfair pricing practices (BNEF, 2025d).

The price gap between China and other regions has encouraged Chinese manufacturers to expand international sales in pursuit of higher margins. Overseas turbine orders from Chinese original equipment manufacturers (OEMs) grew by 64% year-on-year in 2025 (Wood Mackenzie, 2026d), with India, Saudi Arabia and Kazakhstan accounting for the three largest export markets (Wood Mackenzie, 2026c). Although export prices for Chinese turbines are roughly double domestic levels, due to market dynamics and competitive conditions within China, they remain below those offered by most European and US manufacturers (BNEF, 2025a).

Among leading Western suppliers, pricing trends diverged in 2025. Vestas, for example, recorded lower average prices, due in part to orders excluding installation services. The company has, however, indicated that it does not intend to pursue further price reductions in order to preserve investment capacity for future technologies (BNEF, 2025a). Meanwhile, in 2025, pricing trends diverged between Siemens Gamesa and Nordex. Average turbine prices from the latter manufacturer increased by 4% year-on-year, to USD 993/kW, while prices at Siemens Gamesa declined by 4% to USD 889/kW (Wiser *et al*., 2025).

[7] *In China, turbine contracts often exclude delivery, installation and towers, making comparisons with international markets difficult.*

2.4 CAPACITY FACTOR

Between 2010 and 2025, the global weighted-average capacity factor for newly-commissioned onshore wind projects increased 9 percentage points, from 27% to 36% (see Figure 2.7). In 2025, the global weighted-average capacity factor increased by 2 percentage points, year-on-year, while between the 5th and 95th percentiles, capacity factors ranged from 28% to 50%.

Figure 2.7 Capacity factors of onshore wind projects and global weighted-average, 2010–2025

Note: MW = megawatt.

Table 2.2 presents weighted-average capacity factors for onshore wind projects at the regional level. Between 2015 and 2025, all regions recorded increases in the weighted-average capacity factors for newly-commissioned projects. In 2025, Africa achieved the highest regional weighted-average capacity factor, at 43%, while Europe and Oceania recorded the lowest values, with both at 34%. This variation likely reflects differences in wind resources, as well as the characteristics of projects commissioned within each region. For example, Africa's high regional average is influenced by the commissioning of projects in areas with exceptionally strong wind resources, such as Egypt's Gulf of Suez, while regional averages in Europe reflect a broader mix of projects across sites with varying resource conditions.

Table 2.2 Capacity factor ranges and weighted-averages for onshore wind projects by region, 2015 and 2025

	2015			2025		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	Capacity factor (%)					
Africa	22	**34**	44	32	**43**	49
Eurasia	29	**33**	42	30	**36**	46
Europe	24	**28**	36	25	**34**	40
Oceania	33	**36**	43	34	**34**	34
Other Asia	24	**30**	42	30	**35**	44
Other North America	31	**36**	43	37	**39**	40
Other South America	31	**41**	50	28	**37**	53
Brazil	43	**46**	52	43	**50**	56
China	22	**24**	24	30	**35**	45
India	19	**23**	25	28	**31**	33
United States	27	**39**	52	35	**42**	48

Notes: "Other Asia" includes all Asian countries except China and India; "Other North America" includes Canada and Mexico; and "Other South America" includes all South American countries except Brazil.



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Figure 2.8 presents weighted-average capacity factors in 2024 and 2025 for the top 30 countries by onshore wind capacity additions. Compared to 2024, most leading markets recorded increases. This growth was supported by continued advances in turbine technology, as well as differences in the characteristics and siting of newly commissioned projects. Brazil and the United States were the only exceptions to the broader upward trend, although they nevertheless maintained high average capacity factors of 50% and 42%, respectively.

Capacity factor differences can also reflect infrastructure and deployment dynamics. In China, for example, the commissioning of three ultra-high-voltage transmission lines in 2025 strengthened the delivery ofelectricity from high wind-resource areas (Wood Mackenzie, 2025b). Meanwhile, the decrease in the United States' capacity factor reflects a deployment trend in which projects are becoming more geographically distributed (Wood Mackenzie, 2026b).

Figure 2.8 Onshore wind weighted-average capacity factors in selected markets, 2024–2025

Notes: The data file available for download includes the historical data for all markets from 2010 to 2025; percentage values reported in the chart represent the percentage change between 2024 and 2025; Lao PDR = Lao People's Democratic Republic.

2.5 OPERATION AND MAINTENANCE COSTS

Operation and maintenance (O&M) costs represent one of the largest lifetime expenditures for onshore wind assets. They also remain a critical lever in optimising project economics. A standard O&M package typically covers inspections, consumables, labour, transportation and insurance, while major component repairs and technical upgrades are contracted separately (BNEF, 2026h).

For onshore wind, the O&M market has evolved into a mature landscape consisting of turbine manufacturers, independent service providers, speciality service providers, and asset owners with in-house servicing capabilities. While turbine manufacturers have traditionally dominated the market through warranty-linked service agreements, owners often reassess their strategy once these contracts expire, opting to extend agreements, internalise operations, or switch to independent providers (BNEF, 2026h).

Figure 2.9 presents country-level O&M costs alongside BNEF's O&M price indexes. Over the 2010–2025 period, there was an observable downward trend in O&M costs, reflecting the maturity and competitiveness of the market. Initial full-service contracts fell 76% between 2010 and 2025. At the country level, O&M costs for onshore wind in 2025 ranged from USD 15/kW/year in India to USD 91/kW/year in Japan.

Figure 2.9 Initial full-service O&M pricing indices and average O&M costs in selected countries, 2010–2025

Source: (BNEF, 2025e; IEA Wind, 2023; Wood Mackenzie, 2026e).
Notes: kW = kilowatt; USD = United States dollar.

Annualised lifetime average O&M costs per kW are expected to remain relatively stable over the next few years. Variations across markets, turbine platforms and turbine age will persist, with gradual reliability improvements preventing rapid cost increases (Wood Mackenzie, 2026e).

2.6 LEVELISED COST OF ELECTRICITY

For onshore wind projects commissioned in 2025, the global weighted-average LCOE was USD 33/MWh. This represented a 71% decline on 2010 (see Figure 2.10). Between 2024 and 2025, the global weighted-average LCOE fell by 4%. Over the past four years, the weighted average LCOE has remained relatively stable, however, fluctuating within a narrow range of USD 33/MWh to USD 34/MWh. In 2025, LCOE values between the 5th and 95th percentiles ranged from USD 21/MWh to USD 80/MWh. The large share of new capacity additions in China, combined with continued cost reductions, moderated the impact of higher costs observed in other regions. Excluding China, the global weighted-average LCOE was higher, at USD 51/MWh, marking a 55% increase.[8]

Figure 2.10 LCOEs of onshore wind projects and global weighted-average, 2010–2025

Notes: MW = megawatt; MWh = megawatt hour; USD = United States dollar.

[8] *The percentage shows the increase in the global weighted-average when China is excluded.*

Table 2.3 presents weighted-average LCOEs for onshore wind projects at regional and country levels. Between 2015 and 2025, all regions and countries included in the table recorded declines in the weighted-average LCOE for newly commissioned projects. In 2025, regional LCOEs ranged from USD 83/MWh in Other Asia to USD 46/MWh in Other North America.

Table 2.3 LCOE ranges and weighted-averages for onshore wind by country/region, 2010 and 2025

	2015			2025		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2025 USD/MWh)					
Africa	69	**97**	144	49	**59**	113
Eurasia	79	**94**	140	41	**63**	86
Europe	65	**94**	125	40	**54**	83
Oceania	65	**82**	103	48	**48**	48
Other Asia	83	**128**	165	42	**83**	117
Other North America	62	**85**	130	39	**46**	67
Other South America	61	**83**	106	34	**51**	101
Brazil	45	**62**	75	27	**31**	37
China	70	**71**	90	19	**27**	38
India	69	**87**	136	32	**43**	46
United States	45	**61**	92	29	**40**	59

Notes: "Other Asia" includes all Asian countries except China and India; "Other North America" includes Canada and Mexico; and "Other South America" includes all South American countries except Brazil; MWh = megawatt hour; USD = United States dollar.



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Figure 2.11 presents the weighted-average LCOEs for 2024 and 2025 for the top 30 countries by onshore wind capacity additions. In 2025, China recorded the lowest weighted-average LCOE, at USD 27/MWh. This represented a 7% decline from 2024. India was the only other top-five market to register a decrease, with costs falling by 11% to USD 43/MWh. By contrast, the United States, Germany and Brazil experienced cost increases that ranged from 3% to 9%. Despite this increase, Brazil remained the world's second most competitive market for onshore wind, with a weighted-average LCOE of USD 31/MWh.

Figure 2.11 Onshore wind weighted-average LCOE in selected markets, 2024–2025

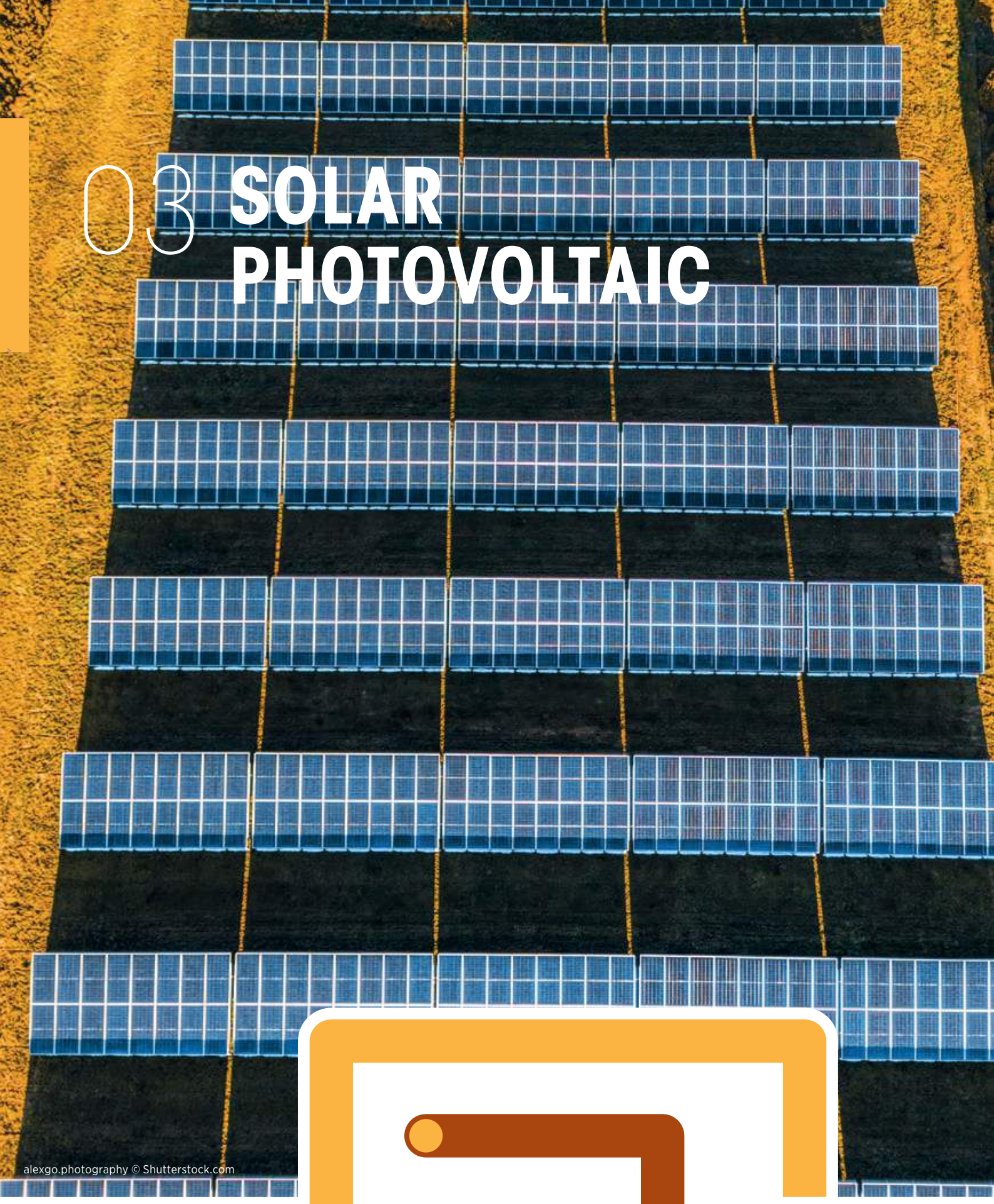
Notes: The data file available for download includes historical data for the selected markets from 2010 to 2025; Lao PDR = Lao People's Democratic Republic; MWh = megawatt hour; USD = United States dollar.

The LCOE of an onshore wind project is determined by a combination of factors, including TICs, capacity factors, O&M costs, project lifetime and the cost of capital. The relative contribution of these factors varies across markets, but their interaction ultimately determines project economics.

LCOE trends in China and Germany illustrate the different drivers. In China, the decline in LCOE has been supported historically by reductions in TICs and improvements in capacity factors. In Germany, by contrast, the LCOE has increased as higher installed costs – particularly planning, grid connection and other project development expenditures – have offset higher capacity factors.

While reductions in TICs have been a key driver of lower LCOEs, their importance varies by market. In markets with higher financing costs, the cost of capital can play an equally important – or even dominant – role in determining project economics. In such instances, financing conditions become a more significant driver of LCOE than technology costs alone.

03 SOLAR PHOTOVOLTAIC



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HIGHLIGHTS

Global average solar PV costs appeared stable, marking two structural shifts: growing regional divergence and a rapid rise in co-location with battery storage.

LCOE ⊕ 1%** ↑

Capacity factor ⊖ 1%*** ↓

in 2025 vs. 2024



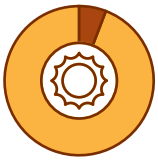
TOTAL INSTALLED COSTS

Projects commissioned in China and India saw the lowest weighted average TICs, at USD 533/kW and USD 545/kW, respectively.





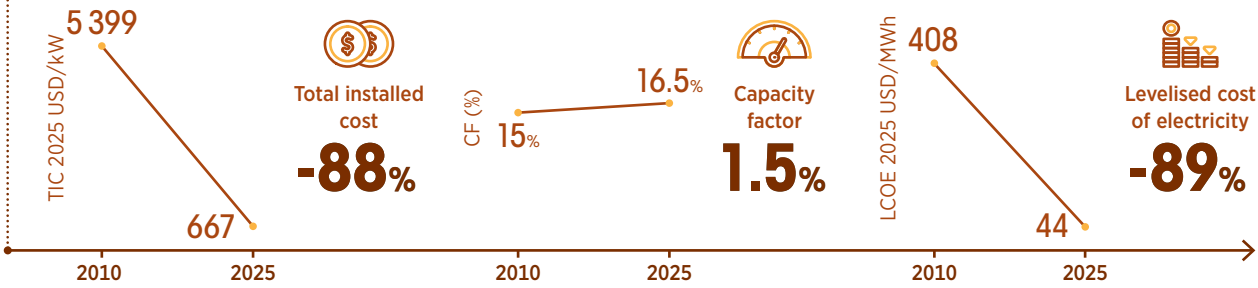
USD 667/kW



-6%

in 2025 vs. 2024

KEY PARAMETERS**



TOP MARKETS

Capacity additions (GW) in 2025



Outlook

In China, the removal of the 9% VAT refund on exported products in April 2026 has increased solar module prices outside the country. Additional cost pressures – including higher silver, polymer, aluminum, and copper prices, as well as rising shipping costs – may further increase the prices of solar modules, mounting systems, cables, and overall installation costs.

* Levelised cost of electricity; ** All values are weighted averages; *** All changes in capacity factor are expressed in percentage points.

3.1 INTRODUCTION

In 2025, of all renewable energy technologies, solar PV saw the greatest total capacity additions, worldwide. Breaking installation records year after year, by the end of 2025 over 2 393 GW[9] of solar PV systems had been installed, with around 511 GW of newly-installed systems being commissioned in 2025 alone (IRENA, 2025a). The capacity added was 4% more than in 2024, despite predictions that the year might see a decline due to Chinese policy changes.

Also in 2025, 295 GW, or 58% of total new capacity installed, was in the form of utility-scale projects.[10] The top three markets for all new additions were China, India and the United States. China led in new additions, accounting for approximately 62% of global utility-scale installations.

Meanwhile, along with an increase in grid constrains, curtailment and cannibalisation, the co-location of solar with battery energy storage systems (BESS) is also becoming a market trend. Indeed, new utility-scale solar PV installations paired with battery storage represented 25% of the capacity additions in 2025, globally (BNEF, 2025f). This growing synergy reflects a broader move toward hybrid energy systems. These are especially relevant in optimising the use of constrained grid connections, shifting electricity production to higher-value hours and reducing exposure to price volatility. A 2026 study of 24/7 renewables by IRENA shows that the firm LCOE[11] of solar–plus–BESS at 95% reliability[12] has now reached values below USD 85/MWh at high quality sites (IRENA, 2026b).

3.2 TECHNOLOGICAL TRENDS

In 2025, rolling-average module efficiency was 24.14% for bifacial heterojunction (HJT) modules. For bifacial tunnel oxide passivated contact (TOPCon) it was 24.43% and for bifacial extended back contact (XBC), 24.80% (CRU, 2026a). Passivated emitter and rear cell (PERC) technology continued to be phased out, with TOPCon now dominant, accounting for 88% of the market (CRU, 2026b).

Tandem technologies incorporating perovskite are also a major focus of solar PV industry research and development (R&D) for all major Chinese and non-Chinese manufacturers. When combined with silicon, perovskite cells have efficiency rates of up to 34.85% (LONGi, 2025). Crystaline silicon (c-Si)/perovskite tandems show promising market potential, supported by proven high efficiency in small-scale modules, while the performance of large-scale modules is currently undergoing testing. Ongoing research and development efforts have focused on enhancing stability and durability – alongside increasing investment in pilot and small-scale production facilities – as the industry moves toward full commercial deployment within the next two years. At the same time, outdoor field testing is underway to evaluate real-world performance, stability and long-term durability.

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[9] The capacity tracked by IRENA is in alternating current (AC).

[10] This chapter covers only cost data for utility-scale solar PV additions. Utility scale solar PV projects are grid connected power plants with a capacity above 1 MW.

[11] The "firm" LCOE is a project-level benchmark for assessing the economics of flat, firm round-the-clock renewable power. Unlike the conventional LCOE – which captures only plant-level generation costs – the firm LCOE accounts for the additional capital required to achieve a specified reliability target via storage, generation overbuild and complementary renewables.

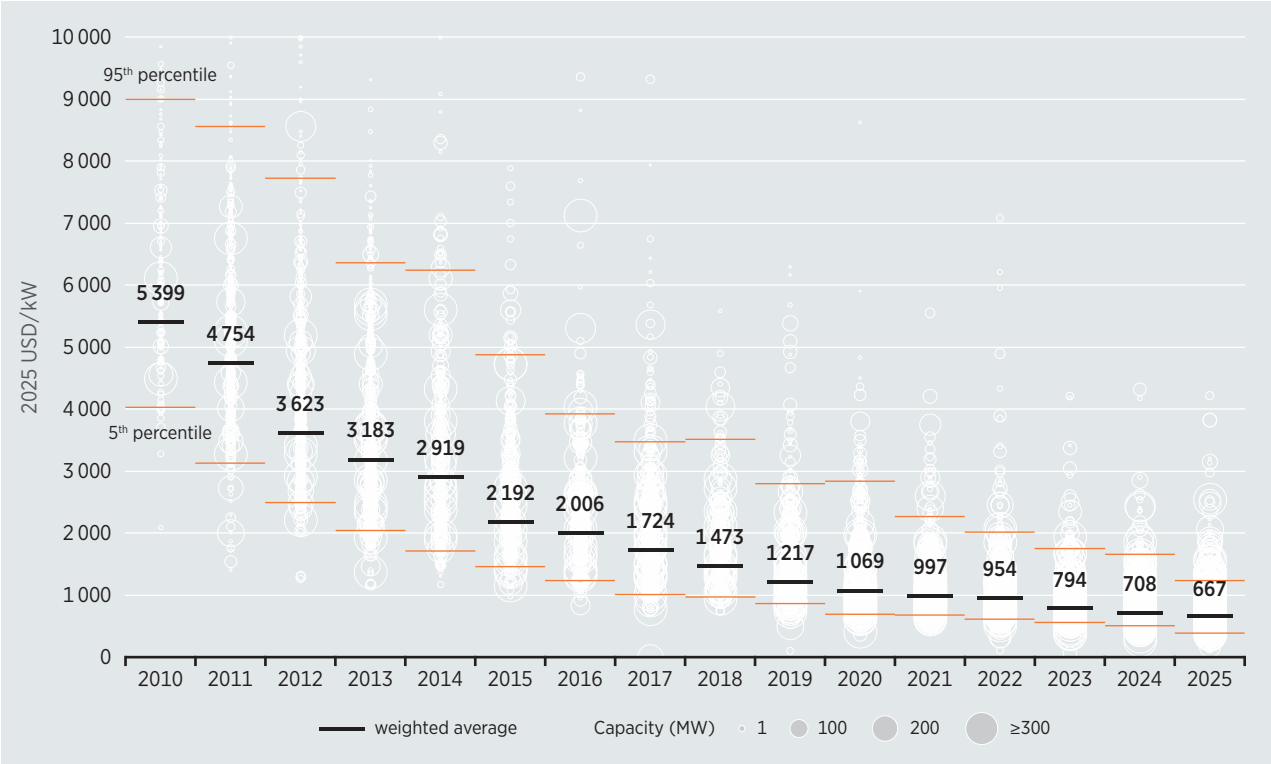
[12] The reliability metric used here describes the delivery certainty of the hybrid configuration.

Automation in the solar industry has evolved from an enabler in panel manufacturing into a core component of on-site construction and operations. In module production, robotics and process automation have long been used for wafer and cell handling, stringing, layup, framing and end-of-line testing. This has driven higher throughput, lower labour intensity and more consistent quality (Cerexio, 2025). That same logic has now migrated to construction and installation, where utility-scale projects are deploying AI-driven robotics to enhance installation efficiency. The 350 MW Culcairn Solar Farm in Australia, for example, used module-mounting robots to install 10 000 modules in under 10 weeks, achieving a 25% reduction in installation time and a 30% reduction in installation costs (pv magazine Australia, 2025).

3.3 TOTAL INSTALLED COST

The global weighted-average TIC[13] of utility-scale solar PV projects has decreased for 15 straight years. For projects commissioned in 2025, the TIC fell 6%, year-on-year, to USD 667/kW. This value was also 88% lower than in 2010. During 2025, the 5th and 95th percentile for all newly-commissioned projects fell within a range of USD 383/kW to USD 1 211/kW. The 95th percentile value was 27% lower than in 2024, while the 5th percentile value declined by 24%. The gap between the 5th and 95th percentiles was the smallest in 2025. This long-term reduction in the cost range points towards continued cost reductions and a competitive supply chain in an increasing number of markets. Compared to 2010, the 5th and 95th percentile values were 90% and 87% lower, respectively (see Figure 3.1).

Figure 3.1 TICs of utility-scale solar PV projects and global weighted-average, 2010–2025



Notes: MW = megawatt; kW = kilowatt; USD = United States dollar.

[13] *TIC data in this report are expressed as per kW of direct current (DC) for solar PV only.*

In 2025, the lowest weighted-average TIC for commissioned projects by region occurred in Europe and was USD 823/kW (see Table 3.1). Eurasia, meanwhile, registered the highest TIC, at USD 998/kW. Between 2015 and 2025, Africa had the highest regional TIC reduction at 76%. The continent saw TICs fall from USD 3 520/kW to USD 837/kW, registering a 25% year-on-year decrease.

Table 3.1 TIC ranges and weighted-averages for utility-scale solar PV projects by country/region, 2015 and 2025

	2015			2025		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2025 USD/kW)					
Africa	1 630	**3 520**	5 215	593	**837**	1 139
Central America and the Caribbean	2 091	**2 675**	4 052	649	**931**	1 016
Eurasia	2 541	**3 521**	4 619	764	**998**	1 256
Europe	1 372	**1 801**	3 638	518	**823**	1 501
Oceania	2 212	**2 728**	2 855	612	**921**	1 785
Other Asia	1 863	**2 716**	5 049	488	**882**	2 020
Other North America	2 035	**2 706**	6 153	702	**887**	1 777
Other South America	2 289	**3 280**	5 573	488	**867**	1 538
Brazil	2 139	**2 558**	2 697	503	**672**	1 138
China	1 560	**1 662**	2 834	374	**533**	785
India	1 116	**1 585**	2 576	397	**545**	656
United States	1 979	**3 137**	4 953	679	**1 180**	1 767

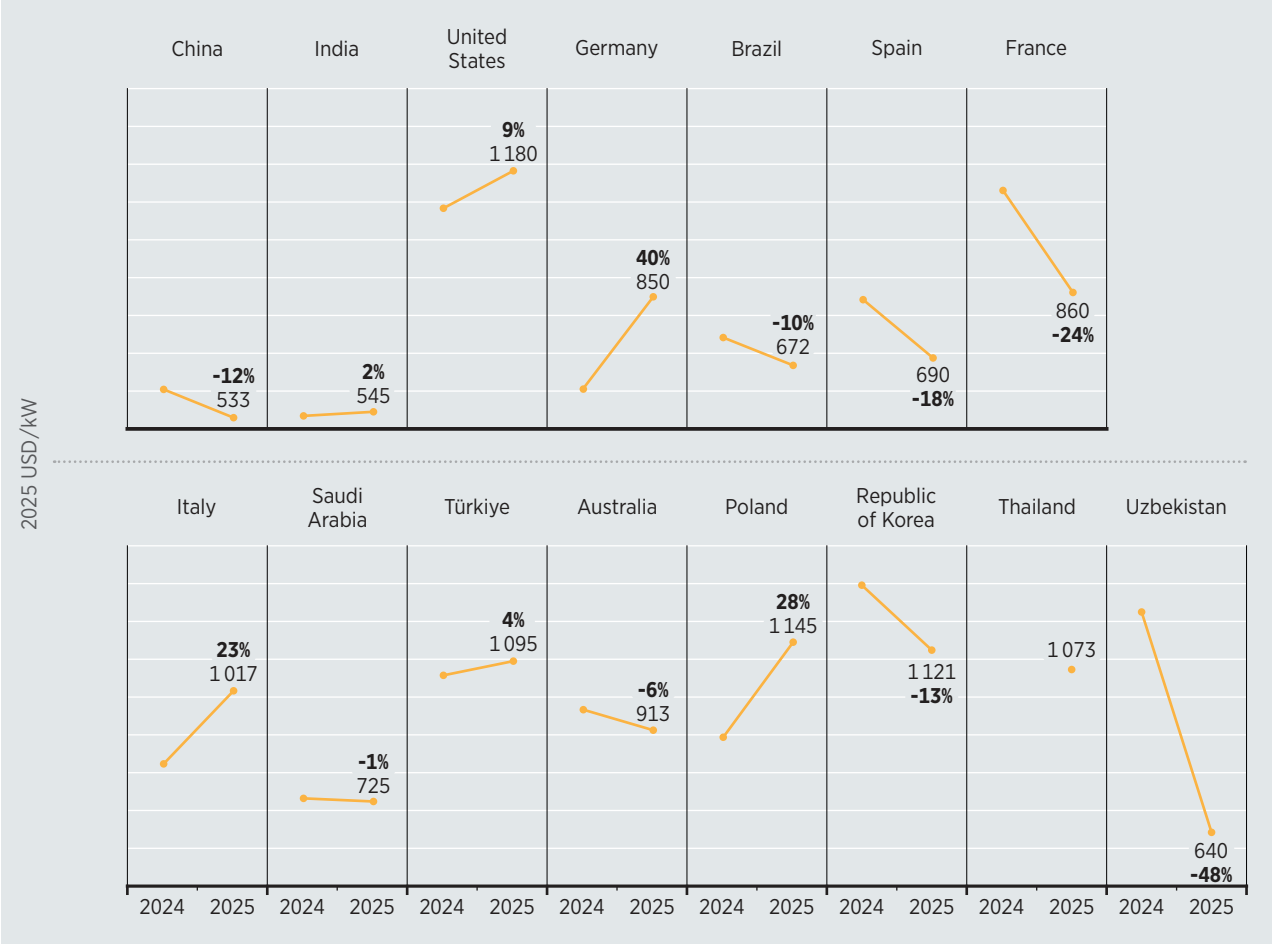
Notes: "Other Asia" includes all Asian countries except China and India; "Other North America" includes Canada and Mexico; and "Other South America" includes all South American countries except Brazil; kW = kilowatt; USD = United States dollar.

At the country level, projects commissioned in China and India saw the lowest weighted-average TICs, at USD 533/kW and USD 545/kW, respectively. China registered a 12% year-on-year decrease, which was driven primarily by low module prices. Manufacturing overcapacity, weak external demand and intense market competition pushed Chinese companies to sell solar modules at prices often close to, or even below, manufacturing cost. Among the top four country markets, the United States had the highest TIC in 2025, at USD 1180/kW – an increase of 9% compared to 2024. This was explained by higher import tariffs and supply chain pressures.

Between 2015 and 2025, at the country level, Brazil registered the highest TIC reduction, with a fall of 74%, from USD 2 558/kW to USD 672/kW. China, India and the United States saw reductions of 68%, 66% and 62%, respectively, over the same period.

Figure 3.2 shows the top 15 countries for solar added-capacity recorded in 2025. Between 2024 and 2025, TICs fell in 6 out of the top 15 markets surveyed. The reduction ranged from a 48% drop in Uzbekistan to 10% in Brazil. The market in Uzbekistan saw deployment growth of more than 50% during 2025, along with a broader range of project sizes and increasing participation by international developers. These factors likely intensified competition, improved economies of scale and increased market maturity.

Figure 3.2 Year-on-year changes in the top 15 markets in utility-scale solar PV TICs, 2024–2025

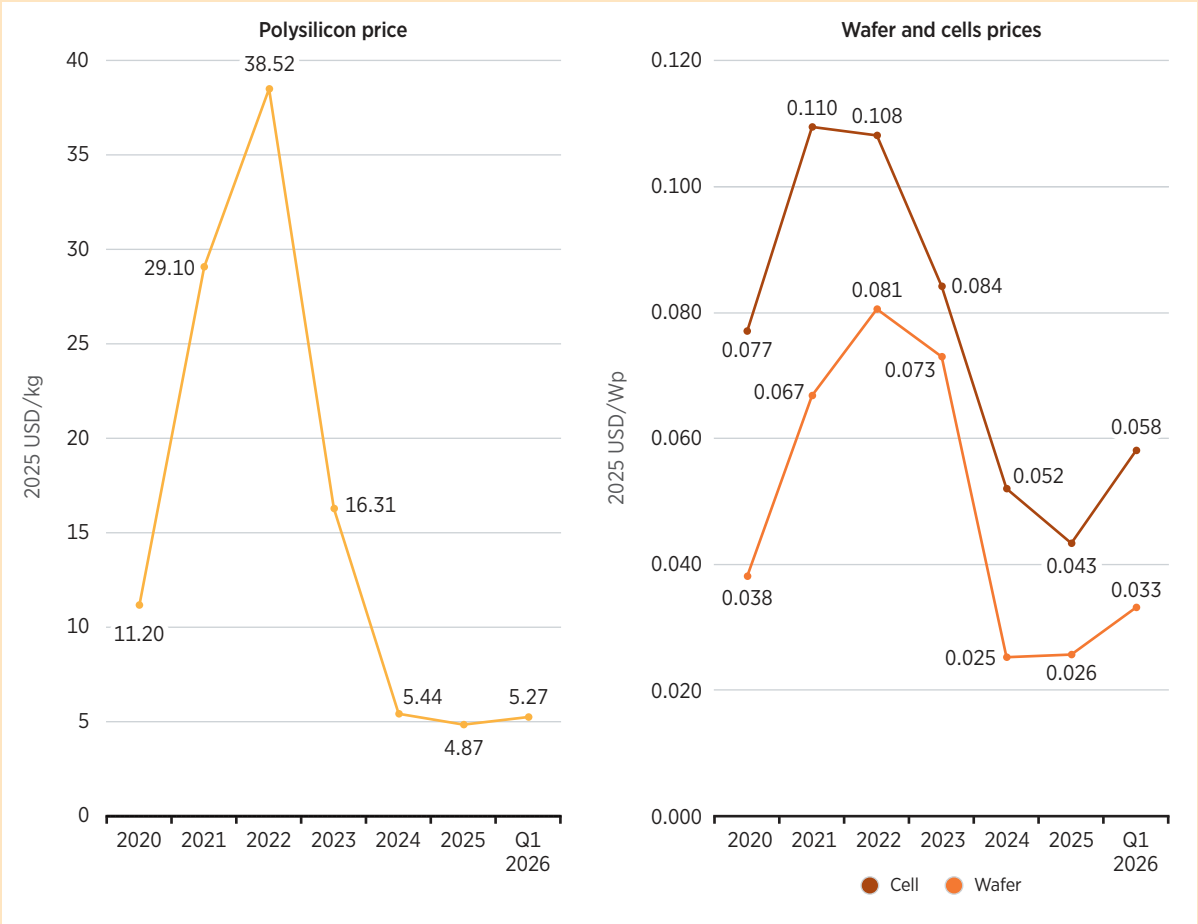


Notes: The data file available for download includes the historical data for all markets from 2010 to 2025; kW = kilowatt; USD = United States dollar.

The highest year-on-year increase was in Germany, where costs rose 40% to USD 850/kW. This was, however, still close to the European average, which was USD 823/kW. Despite the decline in module prices across the continent, higher balance-of-system (BoS) costs in Germany led to an increase in overall TICs. Other European countries, such as Poland and Italy, had cost increases of 28% and 23%, respectively. In contrast, however, France and Spain saw decreases of 24% and 18%, respectively, with costs in France reaching USD 860/kW and in Spain, USD 690/kW.

Box 3.1 Solar PV supply chain cost components

Figure B3.1 Average yearly polysilicon, wafer and cell prices between 2020 and Q1 2026



Based on: (Bernreuter, 2026; Wood Mackenzie, 2026a).
Notes: Wp = watt-peak; kg = kilogramme; Q1 = first quarter; USD = United States dollar.

Polysilicon prices decreased during 2025, reaching an annual average of USD 4.87/kg. This represented a decline of 11% on the average price of polysilicon in 2024, which had been USD 5.44/kg.

Preliminary data show prices rising in January 2026 to USD 6.13/kg. This helped push up the average for Q1 2026 overall by 8%, compared to the 2025 average, to USD 5.27/kg. By April 2026, however, prices were already falling again, reaching a monthly average of USD 4.08/kg (Bernreuter, 2026).

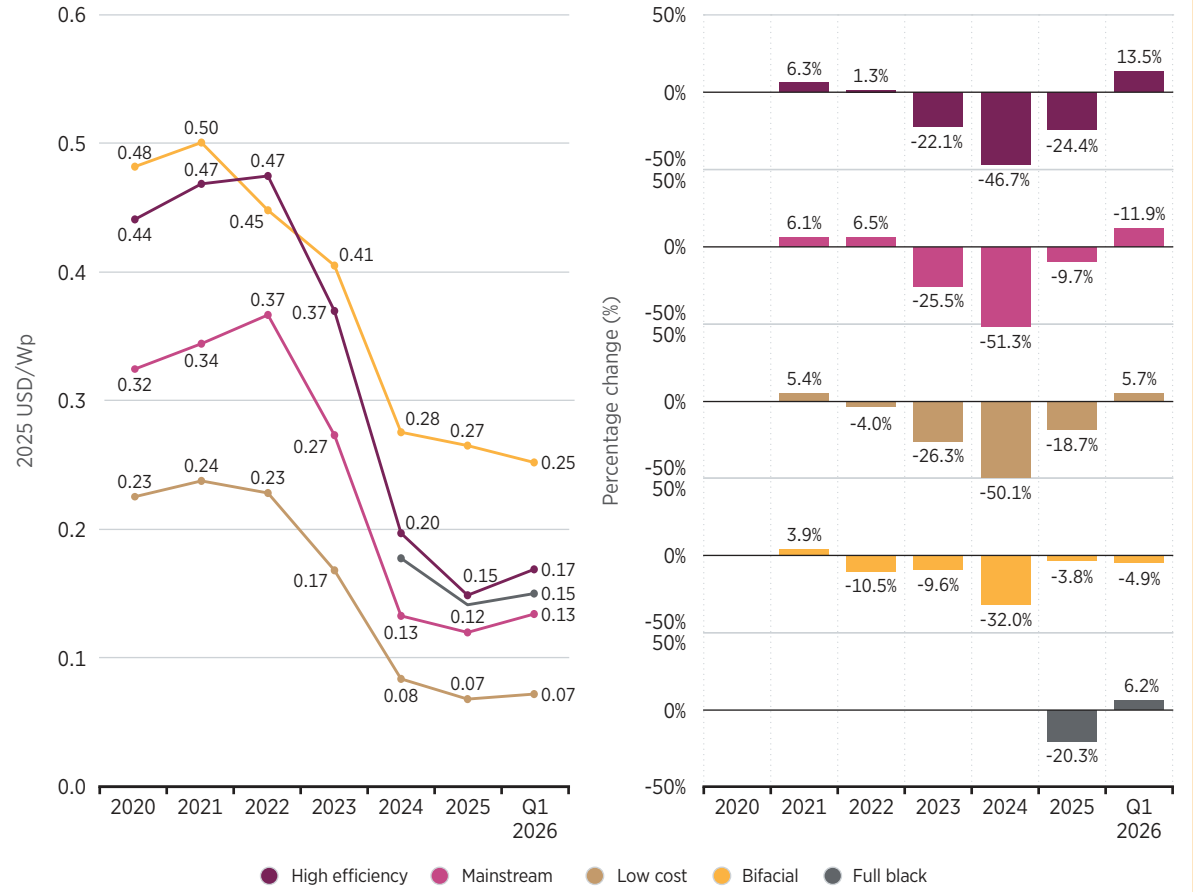
The polysilicon industry's spot price is primarily driven by supply and demand, resulting in fluctuations caused by periods of oversupply and subsequent production adjustments.

Wafer prices have also been following an upwards trend since 2024. In 2025, the average annual price was USD 0.026/Wp, with this value 2% higher than in 2024.

Preliminary data from Q1 2026 confirm the trend, with an average price of USD 0.033/Wp recorded. This was 29% higher compared to the 2025 average.

In contrast, cell prices fell in 2025, reaching their lowest annual average since 2020, at USD 0.043/Wp. Q1 2026 ended, however, with the price at USD 0.058/Wp – a higher level than the 2025 annual average. This increase reflected a rise in silver prices, with silver one of the main material components in cell manufacturing.

Figure B3.2 Average yearly solar PV module prices by technology sold in Europe, 2020 to Q1 2026; average (left) and percentage increase/decrease (right)



Source: (pvXchange, 2026).
Notes: Wp = watt-peak; USD = United States dollar.

Module prices sold in Europe reached their lowest levels ever in 2025 – yet, year-on-year the decrease was lower and less significant compared to 2024. The "high efficiency" category experienced the greatest year-on-year decline, falling 24% to reach a value of USD 0.15/Wp. This variety was followed by "low cost" modules. The smallest decrease was for bifacial modules, which registered a price of USD 0.27/Wp. This value was 3.8% lower than in 2024.

In Q1 2026, cost varied widely between the different types of module technology, ranging from as low as USD 0.07/Wp for the "low cost" category to as high as USD 0.25/Wp for bifacial modules – the market leaders. Bifacial modules have also registered continuous growth in their market share, rising from 50% in 2023 (ITRPV, 2024) to 68% in 2025 (ITRPV, 2026).

The decline in prices during 2025 was driven by continued oversupply, excess inventory and ongoing price competition across the solar supply chain. By the end of 2025, module prices had reached a floor with little room for further cost reduction. Although manufacturers reduced production volumes, accumulated inventories continued to weigh heavily on prices, forcing companies to prioritise cost-cutting measures that often-limited product quality improvements (Schachinger, 2025). There was also a reduction in output from the Chinese solar manufacturing industry as a result of government intervention. This was aimed at preventing a price race to the bottom and at curbing disorderly production after years of aggressive capacity expansion (Wood Mackenzie, 2026g).

At the same time, findings from recent manufacturing audits and quality inspections indicate that ongoing cost pressures and rapid production expansion are contributing to reduced quality across the solar PV industry.

Kiwa's 2025 manufacturing quality report highlights higher rates of major non-conformities in newer manufacturing hubs compared with more established regions. This was mainly due to weaker process controls and lower operational maturity. Factory audits, pre-shipment inspections and defect analysis also revealed recurring issues in critical production stages, including lamination defects, junction box failures, and compliance violations. These faults demonstrated that aggressive cost optimisation and scaling efforts can increase risks to reliability and safety (Kiwa, 2026). These findings reinforce the importance of quality assurance and compliance in supporting technology performance and long-term reliability in the solar PV industry.[14]

Meanwhile, global demand for solar and energy storage strengthened during Q1 2026, driven by energy security concerns and growing interest in energy independence. Preliminary data for Q1 2026 show that module market prices shifted toward a gradual increase, with rises ranging from 5% to 14% across all categories. In that quarter, made-to-order supply models and lower inventories contributed to longer lead times and exerted stronger upwards pricing pressure across the industry. In China, module supply was tighter amid production cuts and lower operating rates.



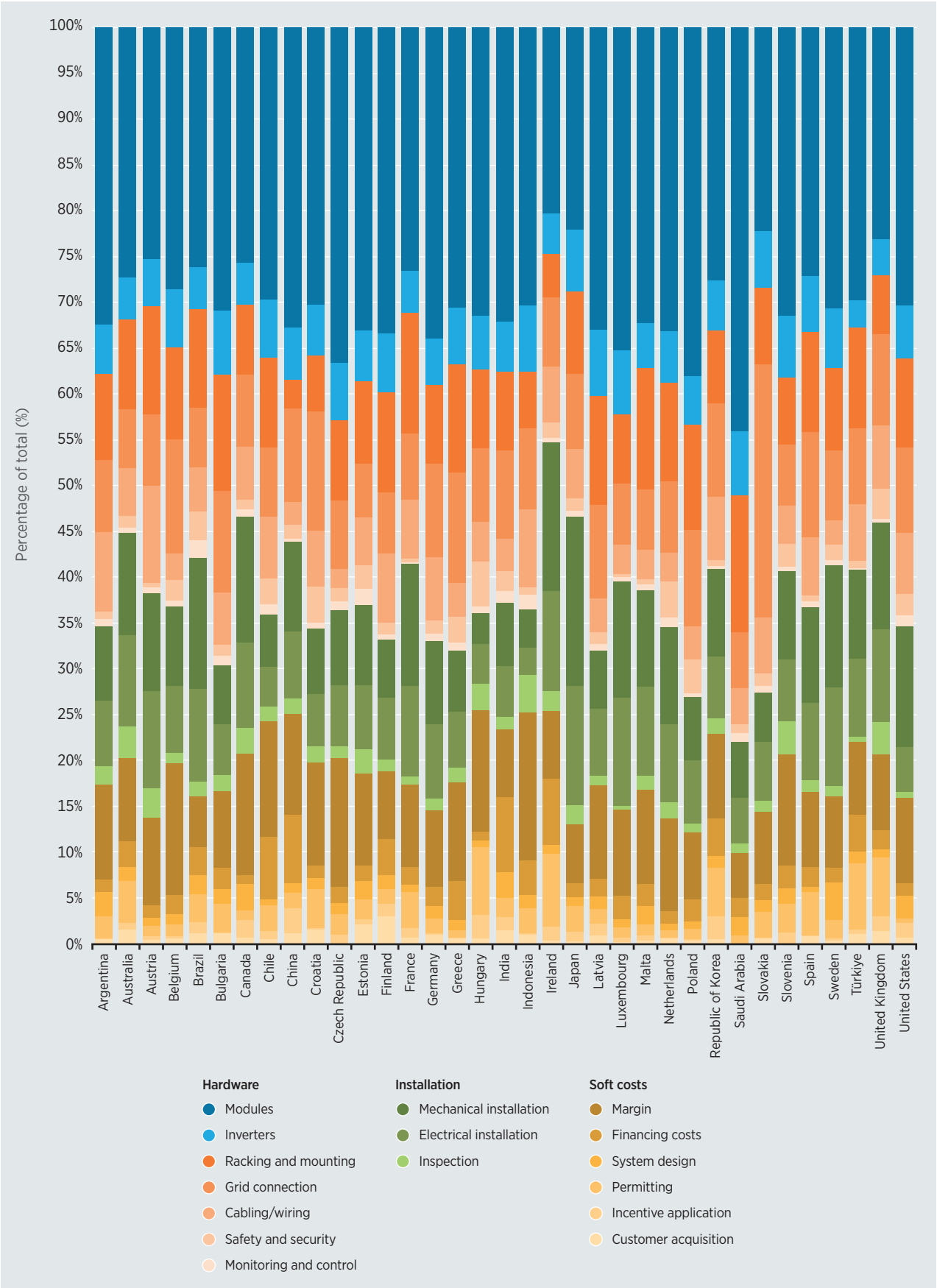
While solar PV has become a mature technology, regional cost variations persist. Understanding the contribution of each cost component to TIC costs is crucial for identifying cost drivers across individual markets.

On average, in the markets assessed in Figure 3.3, 2025 saw BoS costs (excluding inverters) make up around 64% of TICs. This percentage ranged from a low of 49% in Saudi Arabia to a high of 75% in Ireland. Overall, soft cost[15] categories for the countries evaluated made up an average of 18% of TICs during 2025, ranging from 10% in Saudi Arabia to 26% in Hungary. Modules and inverters together (non-BoS costs) ranged from USD 176/kW to USD 368/kW, a share that ranged from 25% to 51% around an average share of 35%. BoS hardware components made up between 18% and 44% of TICs during 2025, with an average share of 27% (equivalent to USD 196/kW). Installation costs ranged between 10% and 34% of TICs, giving an average of 18%, or USD 145/kW.

[14] *See the IRENA report,* Solar PV supply chain cost tool: Methodology, results and analysis*. This provides an understanding of how policy, cost factors and technological progress propagate across the value chain and influence manufacturing competitiveness (IRENA, 2026b).*

[15] *Soft costs are the non-hardware expenses associated with installing, financing and operating a project.*

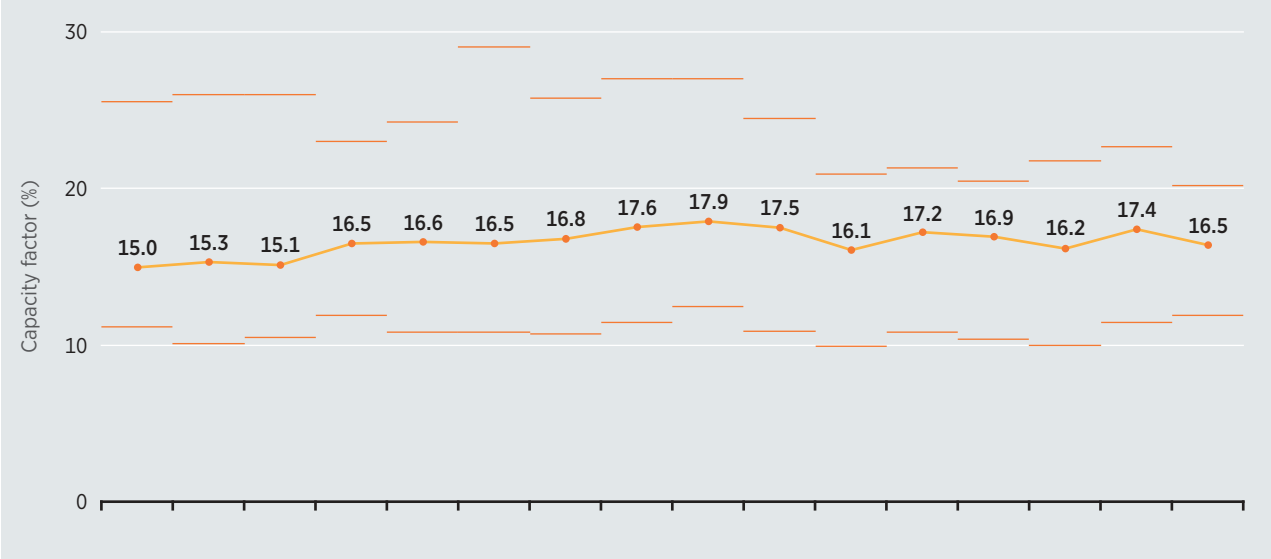
Figure 3.3 TICs by component in selected countries, 2025



3.4 CAPACITY FACTOR

The global weighted-average capacity factor[16] for new, utility-scale solar PV increased from 15% in 2010 to 16.5% in 2025. In comparison to 2024, however, the 2025 figure was almost 1 percentage point less (see Figure 3.4). In 2024, the global weighted-average capacity factor was 17.4%. Over the whole 2010–2025 period, the highest value recorded was 17.9%, which was achieved in 2018.

Figure 3.4 Capacity factors of utility-scale solar PV projects and global weighted-averages, 2010–2025



Over the period 2010–2025, capacity factors increased because of several concurrent drivers. These included: greater adoption of tracking systems; improved project locations in regions with stronger solar resources; the growing market share taken by bifacial modules; and changes in inverter loading ratios. Since 2013, however, this upward trend has stagnated, with global average capacity factors now at around 16–17% as continued technological improvements are increasingly offset by project expansion into less sunny regions.

At the same time, while capacity factors are falling at the global level, this trend is not uniform across markets. Between 2024 and 2025, Brazil saw capacity factors rise from 19.8% to 21.5%, while Germany saw them increase from 10.6% to 13.0%. At the same time, however, China saw them decline, from 17.3% to 15.6%. These changes are large enough to materially affect LCOE. The variation likely reflects differences in siting quality, technology mix and weather conditions each year.

In 2025, the 5th and 95th percentiles for all projects were 11.9% and 20.1%, respectively. The 95th percentile value was 2.5 percentage points lower than in 2024, while the 5th percentile value was 0.4 percentage point higher.

[16] *The capacity factor for solar PV in this chapter is reported as an AC-DC value, given that installed cost data in this report are expressed as per kW DC for solar PV only. This reflects the capacity of the solar modules. For other technologies in this report, the capacity factors are expressed in AC-to-AC terms. A more detailed explanation of this can be found in (Bolinger and Weaver, 2014; Bolinger et al., 2015).*

3.5 OPERATION AND MAINTENANCE COSTS

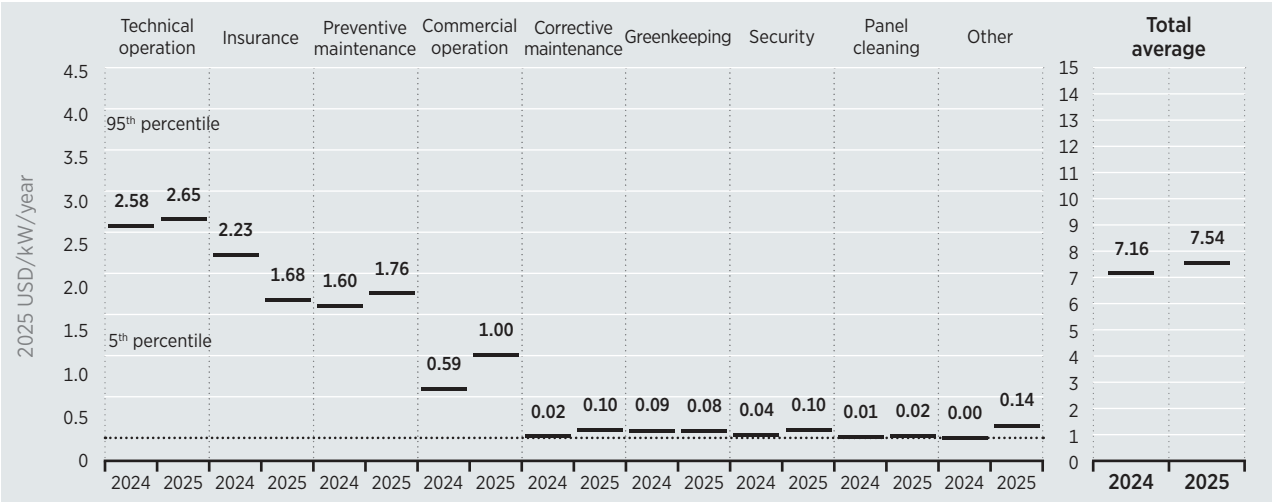
For 2025, data from projects in the IRENA renewable costs database registered a weighted-average utility-scale O&M cost of USD 12.2/kW per year, at the global level. This was a decline of 55% compared to 2010, when the figure was USD 27/kW/year. The LCOE calculations for 2025 considered O&M values of USD 21.26/kW/year for Organisation for Economic Co-operation and Development (OECD) countries and USD 11.23/kW/year for non-OECD countries. These estimated figures represent total, all-in O&M costs, which include items such as insurance and asset management – costs that are sometimes not reported in O&M surveys.

It is important to note that the scope of O&M contracts varies according to regulatory frameworks and market conditions. These influence system reliability, operational efficiency, risk mitigation and compliance requirements across different countries. As a result, O&M contributes to the overall competitiveness of solar PV beyond the absolute cost figures, as effective O&M can enhance project attractiveness to investors and strengthen long-term profitability.

Average total O&M costs show a wide divergence across markets. In 2025, IRENA assessed a sample of 141 surveyed projects, adding up to a total capacity of 29 GW (see Figure 3.5). The lowest value O&M was in China, at USD 3.59/kW/year, despite this being a 7% increase on 2024. The highest O&M average was in Japan, at USD 13.73/kW/year. Aggregating all countries, the average for the sample was USD 7.54/kW/year, a value 5% higher than in 2024.

Looking at the individual cost categories, three of these – technical operation, insurance and preventive maintenance – made up about 80% of total O&M costs. Between 2024 and 2025, costs increased slightly – by 3% – for technical operations, while commercial operation and security registered a significant, 69% increase. Commercial operations have become increasingly complex, as many projects must now actively market their electricity, rather than relying on feed-in-tariffs. Higher security costs are primarily driven by more stringent IT security requirements, particularly for large-scale projects.

Figure 3.5 Survey results for the average, all-in O&M costs for utility-scale solar PV by cost category, 2024–2025

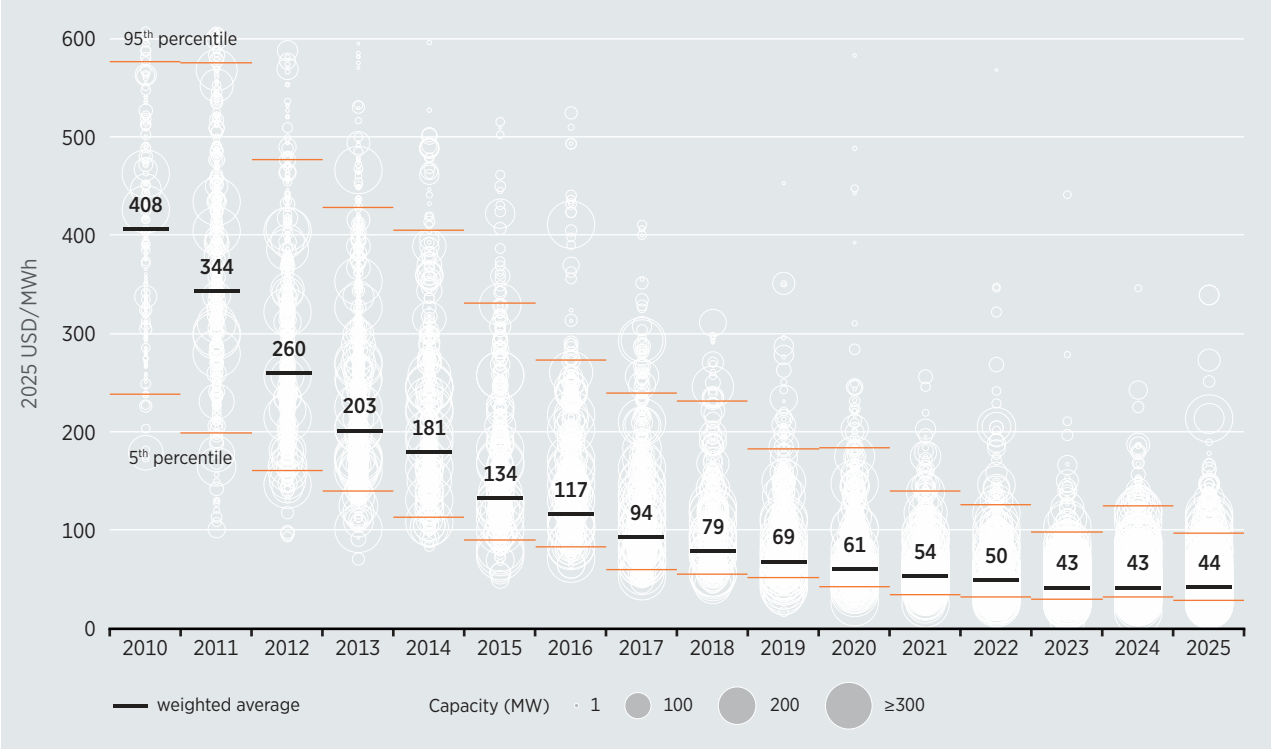


Notes: kW = kilowatt; USD = United States dollar.

3.6 LEVELISED COST OF ELECTRICITY

The global weighted-average LCOE[17] of utility-scale solar PV remained flat in 2025, registering a value of USD 44/MWh for projects commissioned that year (see Figure 3.6). This value was 1% higher than in 2024 and 89% lower than in 2010. This trend reflects the impact of higher financing costs in China due to market reforms – a pattern not observed globally, as financing costs declined across other major markets. Global figures are, however, influenced by China, which accounted for the largest share of deployments. Excluding China, the global weighted-average LCOE was USD 55/MWh, or 23% higher than the level when China was included.

Figure 3.6 LCOE of utility-scale solar PV projects and global weighted-averages, 2010–2025



Notes: MW = megawatt; MWh = megawatt hour; USD = United States dollar.

During 2025, the 5th and 95th percentiles for all the projects surveyed were USD 28/MWh and USD 97/MWh, respectively. The 95th percentile value was 22% lower than in 2024, while the 5th percentile was 13% lower. Compared to 2010, the 5th and 95th percentile values were 88% and 83% lower, respectively.

[17] *The LCOE value is for stand-alone, utility-scale solar PV plants.*

In 2025, the highest weighted-average LCOE for commissioned projects by region was USD 95/MWh, which was recorded in Central America and the Caribbean (see Table 3.2). Oceania, meanwhile, registered the lowest regional LCOE, at USD 41/MWh. Between 2015 and 2025, Africa recorded the largest regional reduction, at 77%, with the LCOE falling from USD 222/MWh to USD 52/MWh. This was followed by Eurasia, where a 74% reduction gave an LCOE of USD 91/MWh.

Table 3.2 LCOE ranges and weighted-averages for utility-scale solar PV projects by country/region, 2015 and 2025

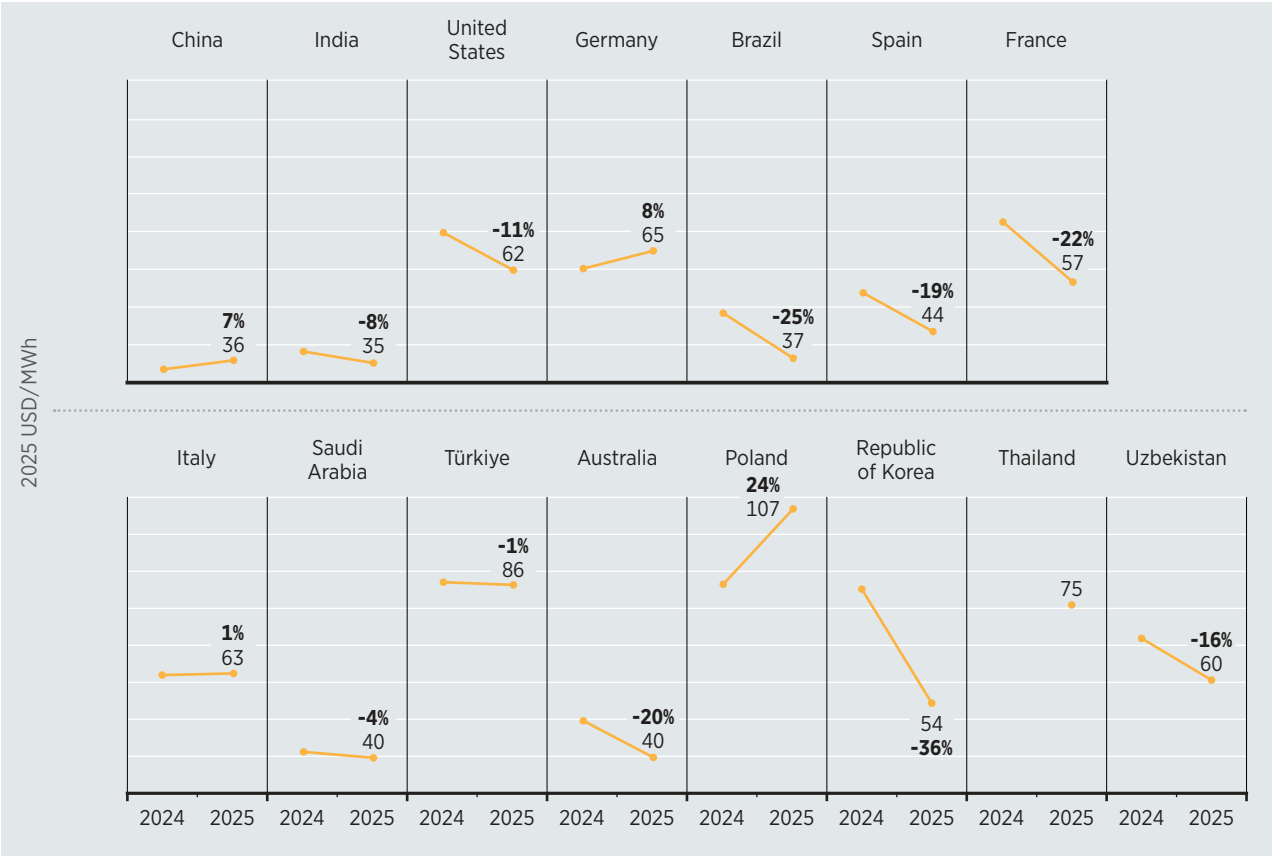
	2015			2025		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	2025 USD/MWh					
Africa	103	**222**	365	36	**52**	107
Central America and the Caribbean	119	**155**	264	45	**95**	137
Eurasia	252	**347**	449	74	**91**	101
Europe	83	**147**	186	40	**59**	126
Oceania	108	**122**	125	27	**41**	96
Other Asia	103	**181**	387	35	**57**	127
Other North America	93	**143**	435	34	**46**	108
Other South America	93	**119**	197	31	**61**	147
Brazil	147	**184**	197	26	**37**	53
China	106	**97**	190	28	**36**	55
India	75	**94**	182	29	**35**	41
United States	95	**159**	309	41	**62**	93

Notes: "Other Asia" includes all Asian countries except China and India; "Other North America" includes Canada and Mexico; and "Other South America" includes all South American countries except Brazil; MWh = megawatt hour; USD = United States dollar.

Figure 3.7 shows cost trends in the LCOEs of utility-scale solar PV in the largest 15 markets, worldwide. Between 2024 and 2025, the weighted-average LCOE decreased in 10 out of the 15 markets shown. These declines ranged from 1% in Türkiye to 36% in the Republic of Korea. A significant reduction in LCOE in the latter reflects lower TICs and lower WACCs, with both falling between 2024 and 2025.

Looking at the top-country markets, projects commissioned in India in 2025 saw the lowest weighted-average LCOE, at USD 35/MWh. This was an 8% year-on-year decrease. China registered the second lowest weighted-average LCOE, at USD 36/MWh, although in contrast, this figure represented a 7% increase, driven by higher financing costs. In Brazil, the LCOE fell 25%, year-on-year, reaching USD 37/kWh. This was driven by lower TICs and a reduced WACC. The United States had the highest weighted-average LCOE in 2025, at USD 62/MWh. This represented a decrease of 11% on 2024. However, this decline was achieved despite higher TICs, as these were offset by lower financing costs recorded in 2025.

Figure 3.7 Year-on-year changes in the top 15 markets in utility-scale solar PV LCOEs, 2024–2025



Notes: The data file available for download includes the historical data for all markets from 2010 to 2025; MWh = megawatt hour; USD = United States dollar.

Costs were up 24% in Poland – the highest year-on-year increase among the markets surveyed due to higher TIC. Reaching USD 107/MWh, the Polish figure was also higher than the European average of USD 59/MWh. Other European countries, such as Germany, had an increase of 8% with a weighted-average LCOE of USD 63/MWh, explained by higher financing costs. France and Spain registered decreases of 22% and 19%, with their LCOE values at USD 57/MWh and USD 44/MWh, respectively. This was mainly due to lower TICs.

Box 3.2 Floating photovoltaics

Floating photovoltaics (FPV) are solar PV systems installed on floating structures anchored to the bottom of a body of water. This helps avoid land-use constraints while enabling the expansion of solar generation. With a strong global potential across reservoirs and hydropower sites, the integration of FPV systems also demonstrates the potential that there is for increasing renewable energy generation by utilising existing hydropower infrastructure (Ramanan and *et al.*, 2024). Estimates suggest that installing FPV on just 10% of the world's inland reservoirs could yield up to 22 terawatts (TW) of capacity (Rodríguez-Gallegos and *et al.*, 2024).

FPV is thus a niche segment of solar and an emerging renewable energy technology. Indeed, by 2023, installed capacity for FPV had already reached 7.7 GW globally, with most of this deployed in Asia (Selj *et al.*, 2025). IRENA estimates that in 2025, total installed capacity of FPV surpassed 10 GW, worldwide. Further capacity additions are also expected, with Thailand planning to deploy more than 2.7 GW of FPV by 2037. This will be deployed across reservoirs operated by the Electricity Generation Authority of Thailand (EGAT) and supported by the launch of dedicated tenders for project development (Jacobo, 2025).

Currently, there are no clear, updated country-level FPV-specific targets or structured deployment programmes for the technology, however. Instead, most countries promote FPV indirectly through broader renewable energy targets, reservoir hybridisation strategies and project-level auction schemes.

FPV can be attractive where land is constrained or expensive. Yet it remains more expensive than ground-mounted PV because of the extra floats, anchoring, mooring and water-resistant designs it requires. Project economics can improve, however, when it is paired with hydropower reservoirs, or when projects benefit from supportive policy frameworks and scale (Ramanan *et al.*, 2024). An IRENA analysis of FPV projects commissioned in 2025 – a total of 728 MW – shows a global weighted-average TIC of USD 748/kW. For the same sample, the LCOE was USD 53/MWh – a figure within the range of solar PV LCOEs from 2021.

While the FPV sector is therefore gaining momentum, deployment remains limited due to policy and technical barriers.

A key limitation is the lack of policy frameworks, incentives and subsidy mechanisms specifically designed to support FPV deployment. A further challenge is the lack of standardised guidelines for system design, installation and operation, which can hinder large-scale adoption. Safety considerations also play a significant role, as combining electrical infrastructure with water introduces risks that require careful management, particularly for transmission systems nearby. In addition, the growth potential of FPV is partly restricted by the limited availability of suitable bodies of water that meet technical and regulatory requirements. The long-term durability of systems exposed to such diverse environmental conditions, including risks of corrosion, material degradation and mechanical stress, also present technical uncertainties.

The industry could move forward, however, by improving policy support, publishing more performance data and standardising technical requirements. It could also advance by building projects in lower-risk settings, such as sheltered reservoirs and ponds, before scaling to more complex sites (Ramanan *et al.*, 2024).



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04 OFFSHORE WIND



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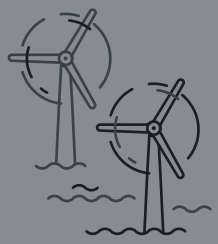
HIGHLIGHTS

Global total installed costs and capacity factors remained stable, while LCOE* declined, driven by improved financing conditions.

LCOE – 3%** ↓

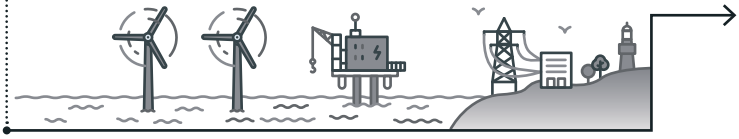
Capacity factor – 1%*** ↓

in 2025 vs. 2024



TOTAL INSTALLED COSTS

Asia had the lowest costs, led by China at USD 1 542/kW, followed by Europe and North America. Differences reflect market maturity, supply-chain development and project characteristics.

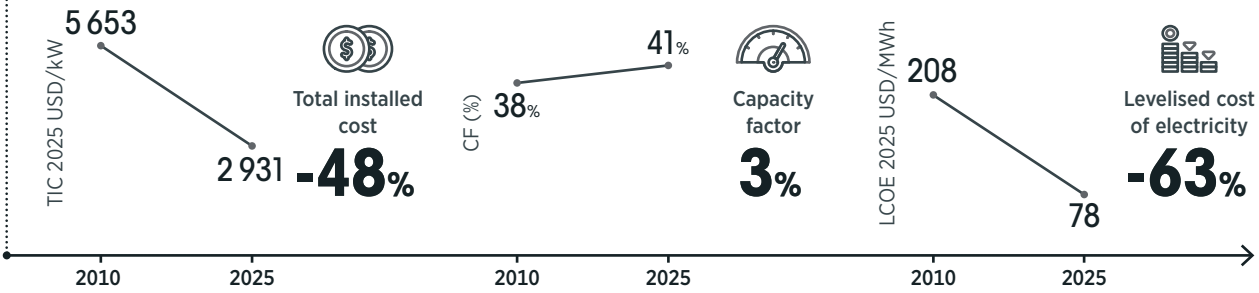


USD 2 931/kW

-0.3%

in 2025 vs. 2024

KEY PARAMETERS**



TOP MARKETS

Capacity additions (GW) in 2025



Outlook

Offshore wind is evolving to strengthen competitiveness and resilience. Auctions are transforming from price-focused procurement tools into frameworks that support market stability, investment certainty, and industrial development. At the same time, deployment is expanding into interconnected regional systems, new deep-water markets, and operational innovation.

* Levelised cost of electricity; ** All values are weighted averages; *** All changes in capacity factor are expressed in percentage points.

4.1 INTRODUCTION

Globally, the installed capacity of offshore wind expanded by almost 30 times between 2010 and 2025, rising from 3.1 GW to 91.4 GW. Between 2024 and 2025, annual new installations rose 3.6%, from 8.3 GW to 8.6 GW (IRENA, 2026a).

Due to its long deployment history and established regulatory and industrial framework, Europe remains the world's most mature offshore wind market. Meanwhile, China has rapidly emerged as the global leader in annual installations, developing substantial industrial capabilities and deployment expertise. Indeed, in 2022, China surpassed Europe in total installed offshore wind capacity, with this reaching 47.4 GW by 2025. This was approximately 23% higher than Europe's 38.6 GW (IRENA, 2026a). In 2025, China alone accounted for 78% of newly-installed offshore wind capacity (IRENA, 2026a).

Within Europe, the United Kingdom and Germany continue to lead deployment, while France and Poland are emerging as major future markets. In other regions, markets such as Colombia, Brazil and countries across the Asia-Pacific region have been incorporating offshore wind into their energy planning. In the United States, however, investor confidence has been affected by policy risks following a Presidential Memorandum in 2025 that withdrew offshore wind leasing areas (GCC, 2026). After preliminary injunctions, offshore wind projects in the United States that had already reached the final investment decision (FID) stage and entered the construction phase were allowed to continue, although legal and regulatory uncertainty remains (Beaubouef, 2026).

Worldwide, offshore wind expansion has been closely linked to competitive auctions and market-based support mechanisms. In 2025, several countries continued to support offshore wind deployment using these instruments. In Europe, 5.8 GW were awarded through two-sided Contracts for Difference (CfDs) in Poland, France and Ireland, and via a negative-bidding model in Germany (WindEurope, 2026). In addition, the United Kingdom awarded 8.4 GW through its Allocation Round 7 in January 2026 (GOV UK, 2026a). In Asia, the Republic of Korea has targeted 7-8 GW of offshore wind awards, of which 2.6 GW had already been awarded by 2025 (BNEF, 2025g).

Despite deployment support and capacity awards in some markets, rising costs, supply-chain constraints, faulty action design and financing challenges have led to several unsuccessful auction rounds in several European countries – among them, Denmark, Germany and France. These trends highlight a broader shift in offshore wind policy. This has seen movement beyond merchant tenders with concession payments and a focus on minimising bid prices towards frameworks that provide greater market stability, investment certainty and stronger industrial development.

4.2 TECHNOLOGICAL TRENDS

Offshore wind energy faces structural constraints that are slowing deployment despite strong global growth ambitions. Projects remain highly capital-intensive and depend on stable regulatory frameworks, predictable auction systems, and bankable long-term revenue mechanisms. Financing conditions have become one of the main challenges for new offshore wind investments.

Grid infrastructure has emerged as one of the sector's most critical bottlenecks, with this challenge currently evolving. Offshore deployment is expanding toward interconnected regional systems. Examples of this include the agreement announced between Denmark and Germany on Energy Island Bornholm (Danish Energy Agency, 2024) and the Hamburg Investment Pact, which outlines 100 GW of regional projects (BMWE, 2026). Major investments in transmission networks, subsea cables and cross-border coordination are therefore increasingly required. At the same time, complexity in permitting continues to delay projects, as offshore wind developments often involve lengthy environmental assessments and multi-level regulatory approvals (WindEurope, 2026).

Supply chains remain a major challenge for the offshore wind sector. The limited availability of installation vessels, port infrastructure and critical components has increased lead times and project costs. The supply chain ramp-up requires improved margins for suppliers, which strains already challenged project economics (Wood Mackenzie, 2025c).

Geopolitical and security concerns have been adding further complexity to offshore wind deployment. Offshore infrastructure is increasingly viewed as critical strategic infrastructure, raising concerns related to cybersecurity, supply-chain dependencies and the protection of subsea assets. Together, these factors have been increasing pressure on governments and industry to balance rapid deployment with long-term system reliability and industrial competitiveness.

Innovation has also been opening new pathways for offshore wind deployment and performance improvements. Floating offshore wind (FLOW), for example, has been expanding access to deeper-water resources and new markets (see Box 4.1). At the same time, digitalisation has been reshaping operations through AI-driven predictive maintenance, autonomous inspection systems and digital twins that improve performance and reduce downtime.



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Box 4.1 Floating offshore wind outlook

Floating offshore wind (FLOW) technology expands offshore wind deployment into deep waters. Around 70% of the world's technically available offshore wind resources are in waters better suited to floating technology than to fixed-bottom foundations, with capacity factors in the former exceeding 60%. FLOW is therefore key to expanding offshore wind deployment, particularly in countries with steep continental shelves, limited land availability and growing electricity demand (Carbon Trust and GOWA, 2026).

In 2025, around 278 MW of FLOW capacity was operational, globally, across more than 15 projects (Carbon Trust and GOWA, 2026). Yet, notably, 2025 was the first year since 2015 when there was no newly-commissioned floating capacity (GWEC, 2026). Deployment did resume in the first months of 2026, however, with 16.8 MW commissioned in Japan (TODA Corporation, 2026), 16 MW in China (Buljan, 2026), and 60 MW in France (Ocean Winds, 2026; TGS, 2026).

FLOW deployment faces a broad structural challenge due to the lack of a sufficiently large and visible project pipeline to mobilise investment and drive learning effects. Allocation Round 7 in the United Kingdom highlights this gap: under the round, two, early-stage 100 MW floating projects were cleared at USD 285/MWh – a figure substantially higher than the USD 120/MWh achieved by fixed-bottom offshore wind (GOV UK, 2026b).

Larger project pipelines are essential to achieve economies of scale. In this, the delivery of projects such as the 560 MW GreenVolt project in the United Kingdom will be pivotal in keeping FLOW's momentum (Carbon Trust and GOWA, 2026).

Recent setbacks, however, underline the importance of improved auction design and permitting frameworks (GWEC, 2026). Such setbacks include Equinor's withdrawal from the 750 MW Firefly project in the Republic of Korea (Equinor, 2026). Meanwhile, in June 2026, France launched a new a process to award development rights for offshore wind projects totalling 10GW, including 4.9 GW floating wind. The projects will be located across Normandy and Brittany, in the South Atlantic and in the Mediterranean Sea (EU, 2026)

In a recent white paper, the Carbon Trust and the Global Offshore Wind Alliance (GOWA) argued that FLOW costs remained high because projects were still small, dispersed and infrequent. These factors limited economies of scale and slowed learning effects, while policy uncertainty, supply-chain immaturity and limited experience with standardised project execution had further increased risks for developers and suppliers.

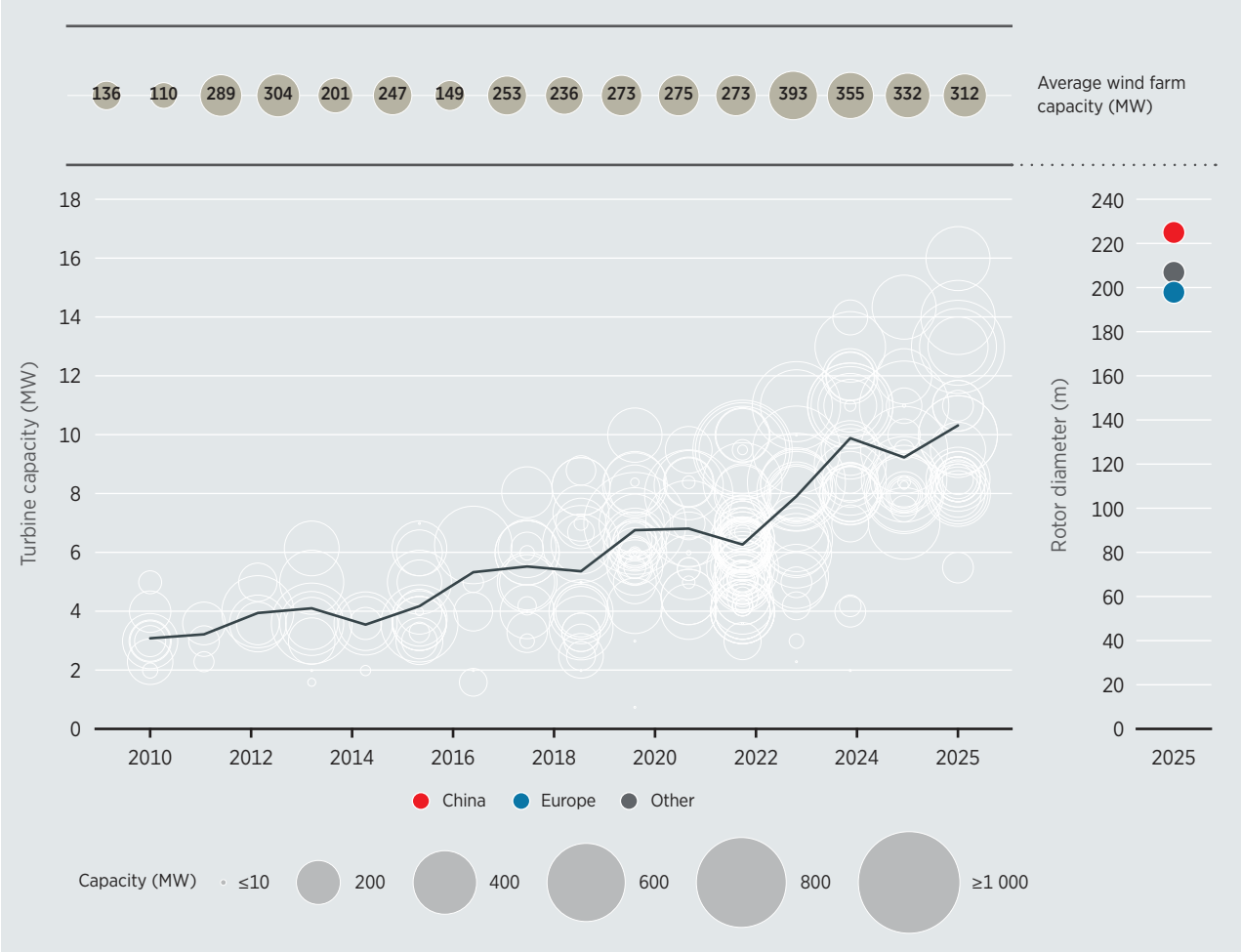
To accelerate cost reductions, the white paper highlighted the importance of scaling deployment, fostering learning-by-doing and promoting greater standardisation and industrialised installation approaches. The report suggested that governments could support this process through clear deployment targets, predictable auction schedules and tailored revenue mechanisms that reflected FLOW's maturity stage and its higher costs relative to fixed-bottom offshore wind (Carbon Trust and GOWA, 2026).

Between 2010 and 2025, average offshore wind project sizes increased significantly, rising from 136 MW to 312 MW (see Figure 4.1). Between 2022 and 2025, average project size also consistently exceeded 300 MW, with several projects surpassing 1 GW in capacity. In 2025, Europe recorded the largest average project size, at 394 MW, compared to 284 MW in China.

The weighted-average turbine capacity for offshore wind increased from 3.1 MW to 10.3 MW (see Figure 4.1), reflecting the continued deployment of larger turbines. In China, rapid innovation led to the deployment of offshore turbines of up to 16 MW, although turbines in the 8–10 MW range also continued to be installed. This resulted in a weighted-average turbine capacity of 10 MW in 2025. In Europe, the weighted-average turbine rating reached 10.9 MW, with the United Kingdom commissioning 13 MW turbines for the Dogger Bank project (Dogger Bank, 2026).

China uses larger rotor diameters primarily to enable cost-effective wind development in its central and eastern load centres, where wind speeds are lower than in its northern, resource-rich regions. In 2025, the weighted-average rotor diameter in China reached 225 metres, compared to 198 metres in Europe (see Figure 4.1). Chinese turbine exports have generally used smaller rotor diameters than those deployed domestically; however, markets with lower wind speeds, such as India, Indonesia and Saudi Arabia, could provide opportunities for larger-rotor Chinese turbines to gain market share (BNEF, 2026i).

Figure 4.1 Average wind farm capacity, project turbine size, global weighted-average turbine size and rotor diameter for offshore wind, 2010–2025



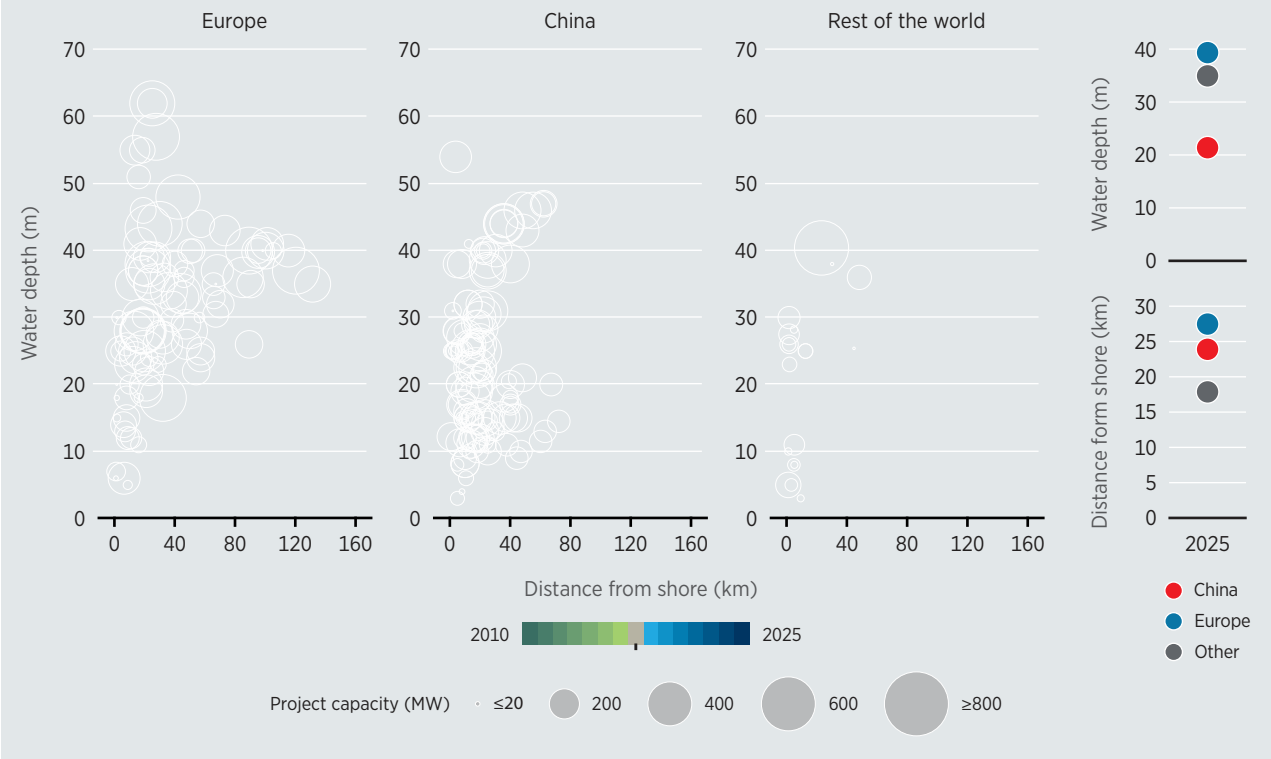
Source: (Wood Mackenzie, 2026h).
Note: m = metre; MW = megawatt.

The scaling-up trend requires systemic upgrades across the supply chain. Increases in the size of components and wind farm capacity require new generations of installation vessels, larger foundations and enhanced port infrastructure. In 2025, the focus shifted from size toward reliability, operational performance and digital intelligence (BNEF, 2025c).

Offshore wind project costs are strongly influenced by water depth and distance from shore. Projects located farther offshore require longer installation and maintenance transit times, while deeper waters often require more complex foundation designs. Site selection is also shaped by seabed conditions, environmental restrictions, maritime boundaries and competition for marine space from activities such as shipping and fisheries.

Figure 4.2 shows the trends in distance from shore and water depth for offshore wind projects in Europe, China and the rest of the world for the 2010-2025 period. The shift towards deeper waters and sites farther from shore was most evident in Europe, the most mature offshore wind market. In 2025, Europe recorded a weighted-average water depth of 39 metres and a distance from shore of 27 kilometres.

Figure 4.2 Distance from shore and water depth for offshore wind in Europe, China and the rest of the world, 2010–2025



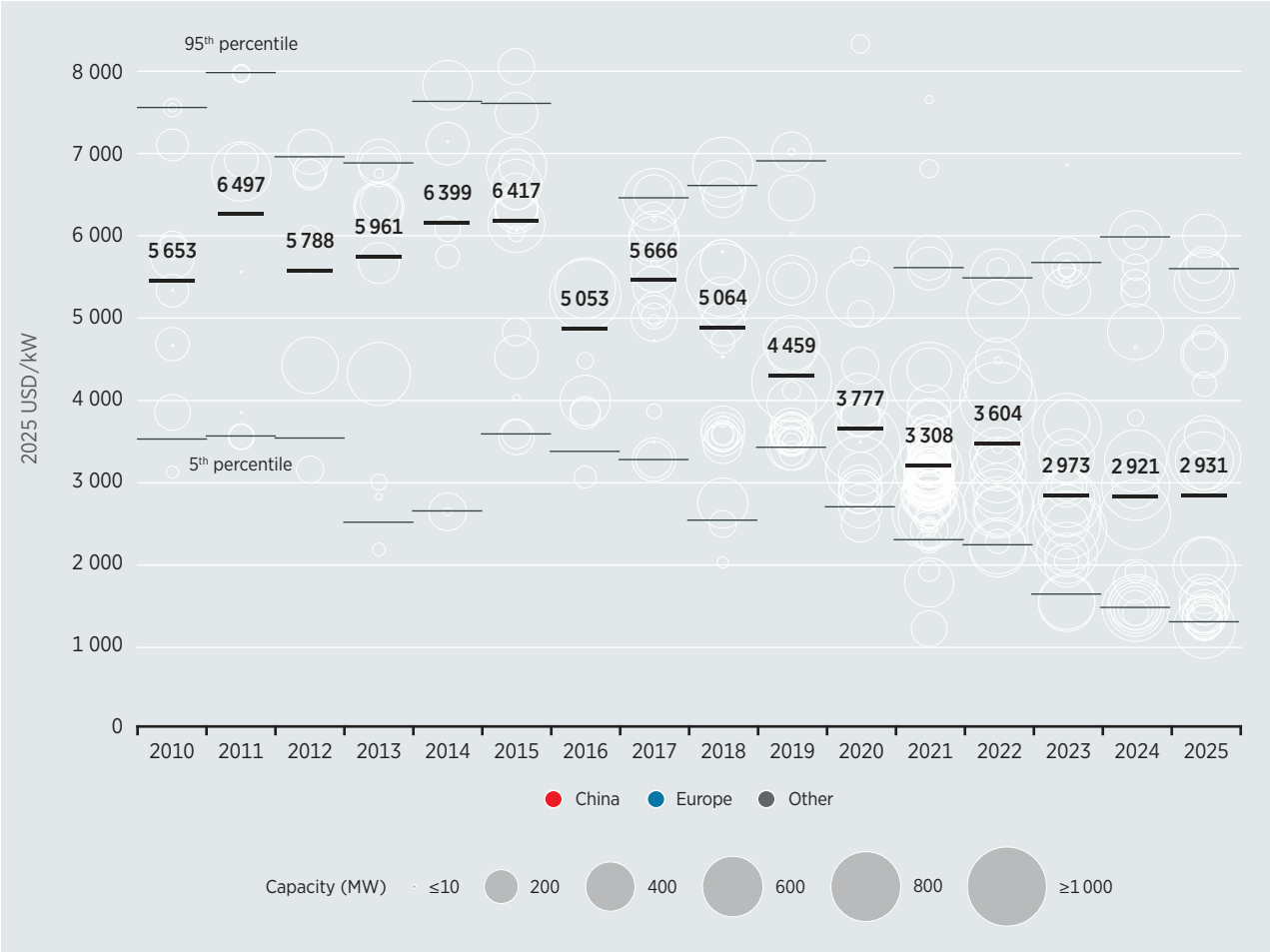
Source: (Wood Mackenzie, 2026h).
Notes: km = kilometre; m = metre; MW = megawatt.

Projects in China and the rest of the world generally remained closer to shore and in waters shallower than 40 metres over the period. In 2025, China recorded the lowest weighted-average water depth, at 21 metres, while projects in the rest of the world had the shortest average distance from shore, at 18 kilometres. China is seeking to expand offshore wind deployment into deeper waters and sites farther from shore through the “Single 30” regulation, introduced in 2023. This requires projects to be located at least 30 kilometres offshore and in waters deeper than 30 metres (Liu and Dong, 2026). While this is expected to increase costs, development is likely to focus first on areas with stronger wind resources (BNEF, 2026e).

4.3 TOTAL INSTALLED COST

For offshore wind projects commissioned in 2025, the global weighted-average TIC was USD 2 931/kW. This represented a 48% decline on 2010 (see Figure 4.3). Between 2024 and 2025, the global weighted-average TIC fell by 0.3%. In 2025, between the 5th and 95th percentiles, TICs ranged from USD 1 321/kW to USD 5 800/kW. Over the last three years, the weighted-average TIC of offshore wind has remained relatively stable, without significant variability.

Figure 4.3 TICs of offshore wind projects and global weighted-average, 2010–2025



Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.

Offshore wind projects face additional technical and logistical challenges that arise from the marine environment, which contributes to higher costs for this technology than for onshore wind. Site assessments must consider seabed conditions and weather patterns; in addition, greater distances from shore, deeper waters and specialised installation requirements increase the complexity of construction, grid connection, commissioning and ongoing O&M.

Figure 4.4 presents weighted-average TICs for offshore wind projects at both the regional and country levels. In 2025, North America recorded the highest weighted-average TIC, at USD 5 625/kW, remaining broadly stable, when compared to 2024. Europe followed, at USD 4 179/kW, continuing an upward trend observed since 2023. Asia had the lowest regional average, at USD 2 316/kW, reflecting a recent continued decline in costs.

At the country level, TICs in 2025 varied considerably, although most countries clustered within a narrower range than the regional averages suggest. China recorded the lowest weighted-average TIC by far, at USD 1 542/kW. At the other end of the range, France had the highest weighted-average TIC among the countries presented, at USD 5 721/kW. The United States had a weighted-average TIC of USD 5 625/kW in 2025 a level broadly unchanged from the previous year. Other countries presented recorded weighted-average TICs within an intermediate range.

Figure 4.4 Weighted-average TICs for offshore wind by country/region, 2020–2025 and 2024–2025

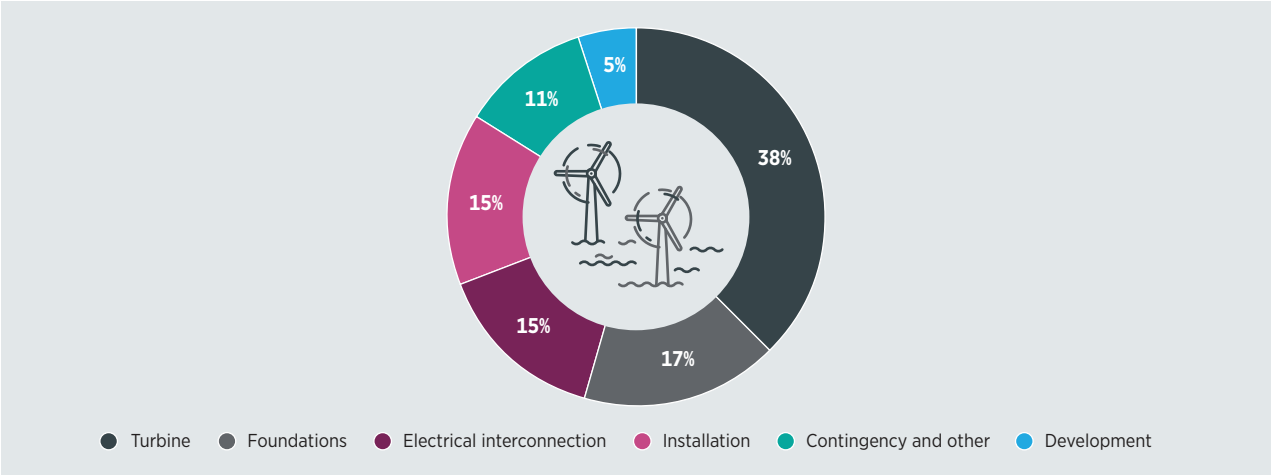


Notes: kW = kilowatt; USD = United States dollar; only countries with commissioned offshore wind capacity in 2025 are presented at the country level; however, regional weighted-averages for earlier years include additional markets.

Regional differences reflect variations in market maturity, supply-chain development and project characteristics. Asia's comparatively low costs are largely driven by China's extensive and competitive offshore wind sector, where large project pipelines, strong domestic manufacturing capacity and economies of scale have reduced equipment and installation costs. Europe's higher costs reflect newer project characteristics and markets, alongside rising turbine, financing and grid connection costs. In North America, particularly the United States, offshore wind costs remain the highest due to the sector's earlier stage of development, more limited supply-chain and installation infrastructure, its permitting complexity and reliance on specialised vessels and imported components (BNEF, 2026j).

Figure 4.5 presents an average[18] breakdown of offshore wind TICs based on selected market studies. Offshore wind turbines, including towers, account for the largest share of TICs, at 38%, while development costs represent the smallest share, at 5%. Foundations, electrical interconnection, installation, contingency and other costs also make significant contributions to overall project expense.

Figure 4.5 Indicative TIC breakdown for offshore wind from selected market studies



Source: (Alsubal *et al.*, 2021; BVG Associates, 2025; IRENA, 2016; Lacal-Arántegui *et al.*, 2018; MAKE Consulting, 2017; Musial, 2018; Smart *et al.*, 2016; Stehly Noonan *et al.*, 2020; Stehly Beiter *et al.*, 2020).

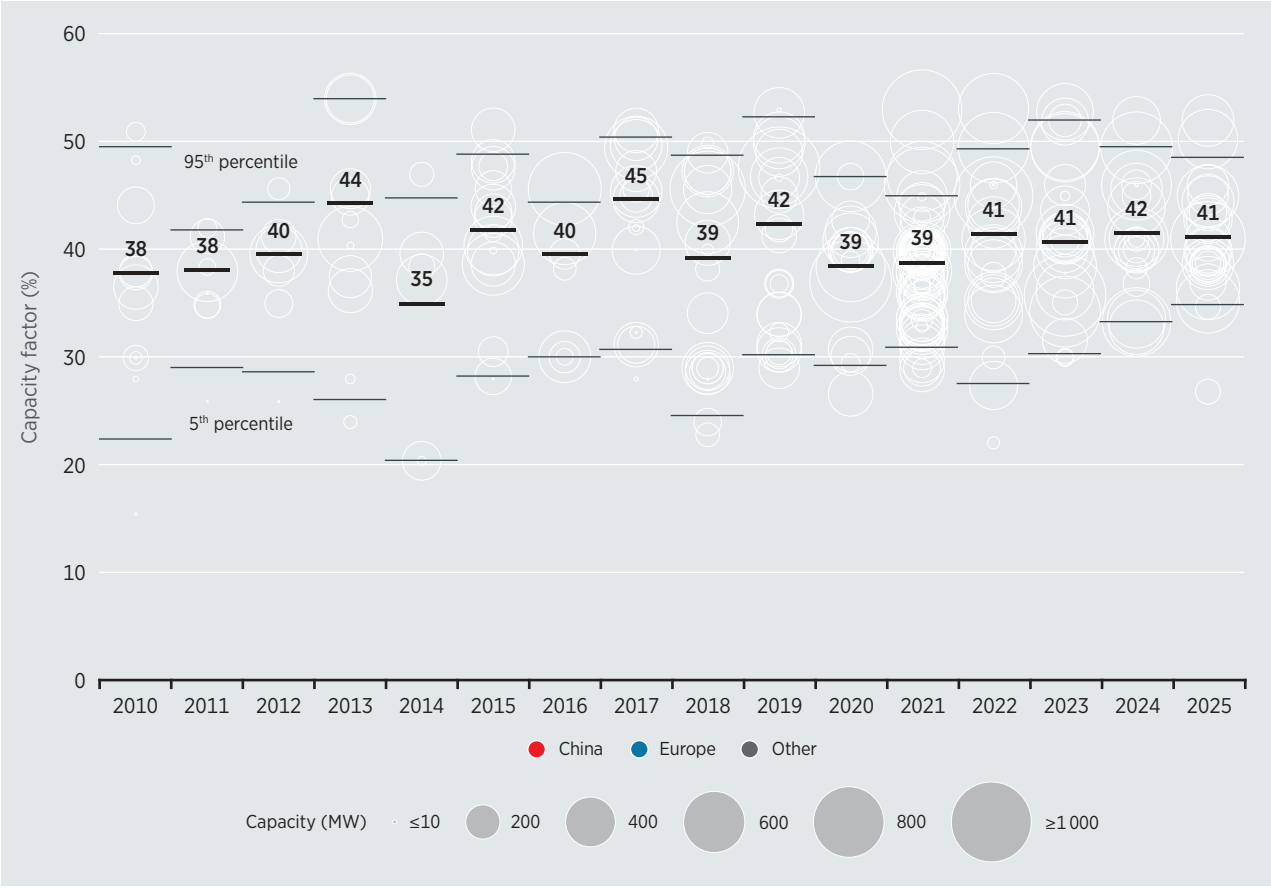
TIC structures also vary depending on who is responsible for the transmission assets between the wind farm and the shore. In some countries, these assets are developed and owned by the transmission network operator, while in others they are the responsibility of the project developer. For example, in the Netherlands, transmission assets are typically owned by the network operator, whereas in China they may be developed either by project owners or the transmission network operator. As a result, cost comparisons should be considered on a country-by-country basis.

[18] *The figure presents the average percentage shares of TICs. A broader range of offshore wind cost breakdowns is available in IRENA Renewable power generation costs in 2024 report (IRENA, 2025b).*

4.4 CAPACITY FACTOR

Between 2010 and 2025, the global weighted-average capacity factor of newly commissioned offshore wind farms increased by 3 percentage points, from 38% to 41% (see Figure 4.6). In 2025, the global weighted-average capacity factor fell 1 percentage point, year-on-year, while the capacity factor ranged between 35% and 49% (5th to 95th percentiles). Over the past four years, the global weighted-average capacity factor has remained relatively stable, at around 41–42%.

Figure 4.6 Capacity factors of offshore wind projects and global weighted-average, 2010–2025



Note: MW = megawatt.

Changes in the global weighted-average capacity factor reflect shifts in the regional composition of offshore wind deployment. Chinese projects, shown in red, generally exhibit lower capacity factors than those in Europe due to differences in wind resource conditions and project characteristics. Nevertheless, capacity factors in China have improved in recent years, supported by larger turbines and ongoing technological advances. European projects, shown in blue, continue to achieve comparatively higher capacity factors, with several projects at around 50%. This level is supported by strong offshore wind resources, larger turbine deployments and projects located farther offshore.

Figure 4.7 presents regional and country weighted-average capacity factors for newly commissioned offshore wind projects. In 2025, North America and Europe recorded the highest regional weighted-average capacity factors, at 45% and 43%, respectively. Asia remained lower, at 40%, although the region did show a gradual increase over the period. Since 2020, Europe has consistently achieved the highest regional averages, peaking at almost 50% in 2023 before declining in 2024 and 2025. In North America, a relatively high and stable capacity factor, at 45%, reflects favourable wind conditions.

At the country level, weighted-average capacity factors in 2025 ranged from 31% in the Republic of Korea to 46% in Germany. China recorded a weighted-average capacity factor of 39% in 2025, up from 37% in 2024. Germany remained among the highest-performing markets, at 46%, while France and the United States both recorded stable averages of 44-45%. The United Kingdom also achieved a relatively high capacity factor in 2025, at 42%.

Figure 4.7 Weighted-average capacity factors for offshore wind by country/region, 2020–2025 and 2024–2025.



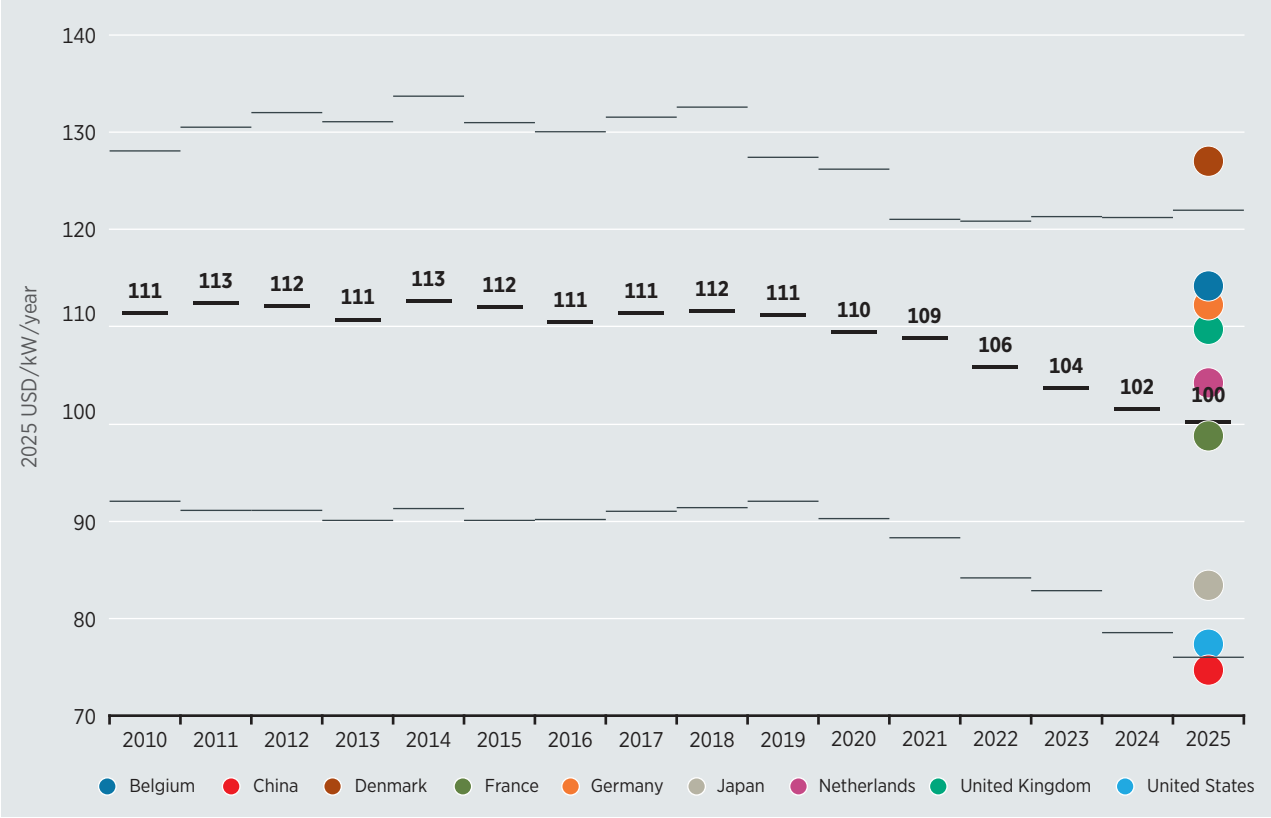
Notes: Only countries with commissioned offshore wind capacity in 2025 are presented at the country level; however, regional weighted-averages for earlier years include additional markets ; percentage values reported in the chart represent the percentage change between 2024 and 2025.

4.5 OPERATION AND MAINTENANCE COSTS

O&M in offshore wind is inherently complex, driven by the combined demands of a harsh marine environment, restricted site accessibility and the need for specialised vessels, equipment, and personnel. Weather windows constrain both routine servicing and unplanned interventions, while subsea cabling and the remoteness of offshore wind projects increase logistical and technical difficulty.

Figure 4.8 presents the average fixed O&M cost for selected countries between 2010 and 2025, weighted by cumulative installed capacity. Over the period, the weighted average declined from USD 111/kW/year in 2010 to USD 100/kW/year in 2025. Although this reduction was relatively modest, decreases in both the 5th and 95th percentiles reflected broader improvements in operational experience and efficiency across the sector. In 2025, costs ranged from USD 76/kW/year at the 5th percentile to USD 122/kW/year at the 95th, illustrating the considerable variation that persists across markets at different stages of deployment.

Figure 4.8 Average fixed O&M costs for offshore wind in selected countries, 2010–2025



Source: (Wood Mackenzie, 2024).
Notes: kW = kilowatt; USD = United States dollar.

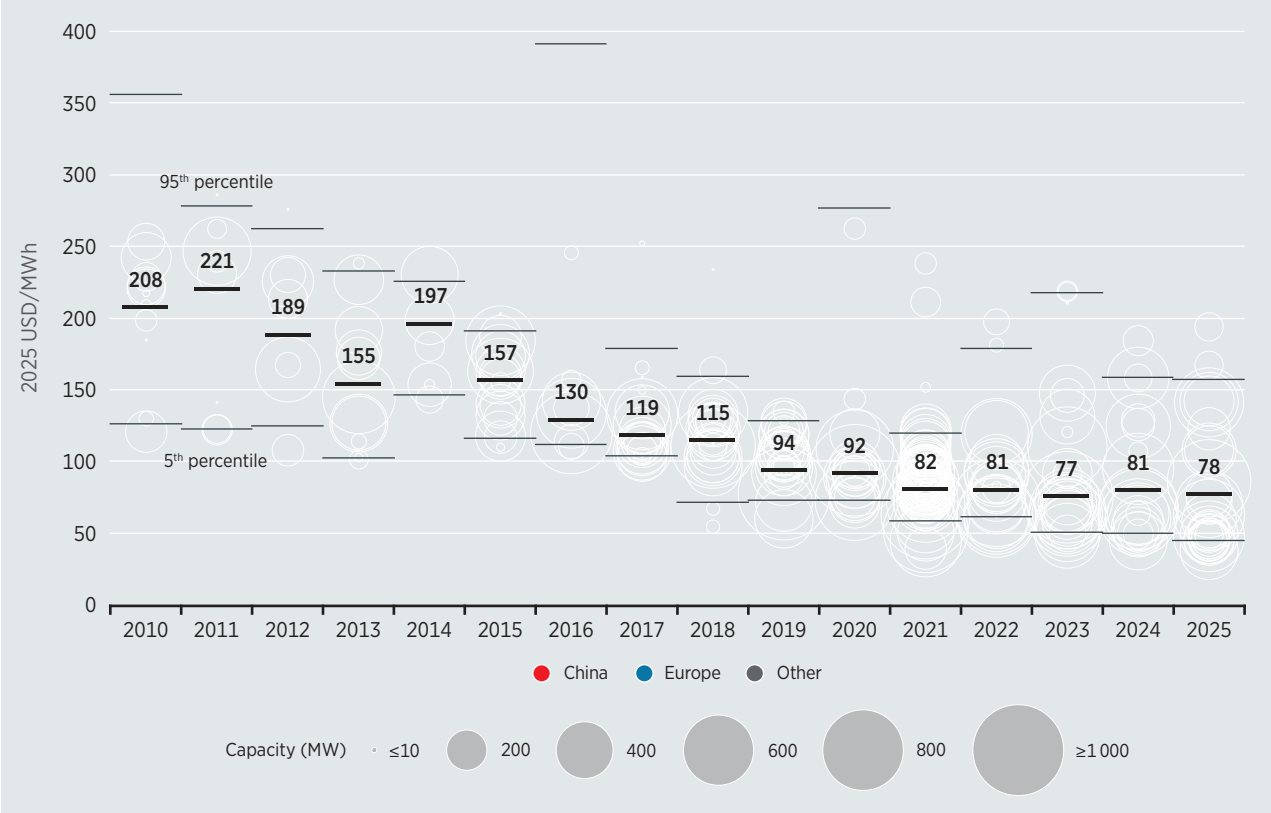
Offshore wind O&M costs comprise several categories of expenditure. Turbine maintenance represents the largest share, accounting for around 60% of total O&M costs. Operational support is the second-largest component, at 19%, followed by insurance costs, at 11%. Balance of plant maintenance – which includes marine operations, labour, spare parts, consumables, proactive and reactive maintenance, and offshore substation O&M – accounts for around 7%, while the remaining 3% relates to other operational and contingency costs (Wood Mackenzie, 2024).

4.6 LEVELISED COST OF ELECTRICITY

For offshore wind projects commissioned in 2025, the global weighted-average LCOE was USD 78/MWh. This represented a 63% decline on 2010 (see Figure 4.9). Between 2024 and 2025, the global weighted-average LCOE fell by 3%. In 2025, LCOE values ranged between USD 46/MWh and USD 144/MWh (5th to 95th percentiles).

Regional market dynamics continue to play an important role in shaping the global weighted-average LCOE. However, although significant changes did occur across markets during the 2020-2025 period, the weighted-average LCOE was relatively stable. This was because declining costs in China were partly offset by rising costs in Europe and North America.

Figure 4.9 LCOE of offshore wind projects and global weighted-average, 2010–2025



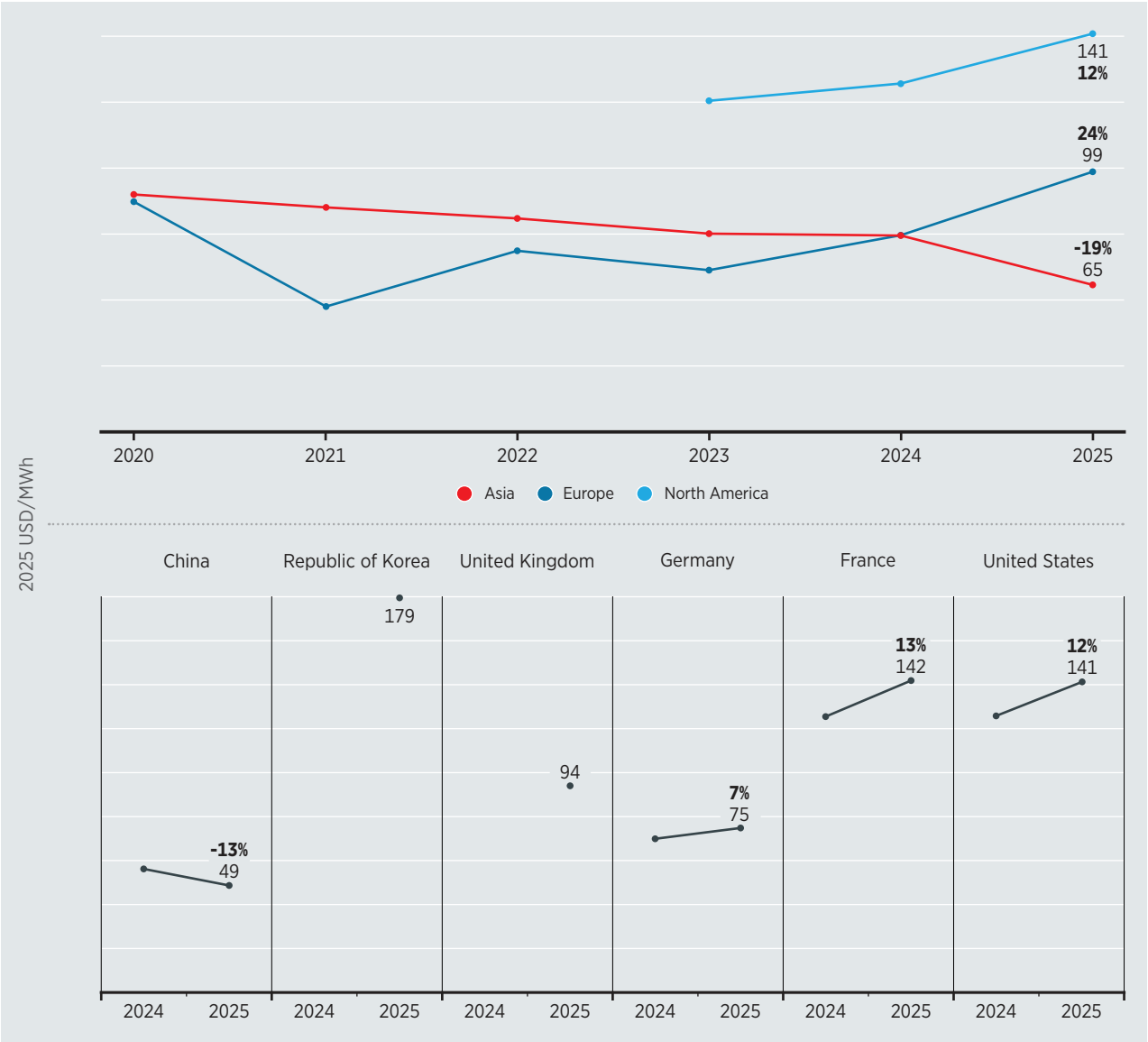
Notes: MWh = megawatt hour; MW = megawatt; USD = United States dollar.


Michael Dechev © Shutterstock.com

Figure 4.10 presents the weighted-average LCOE for offshore wind projects at both the regional and country levels. Between 2024 and 2025, Asia's weighted-average LCOE declined by 19%, from USD 80/MWh to USD 65/MWh, driven primarily by further cost reductions in China. There, the LCOE fell by 13%, year-on-year, to USD 49/MWh. In contrast, Europe's weighted-average LCOE increased by 24%, from USD 80/MWh to USD 99/MWh, reflecting higher project and financing costs. In North America, offshore wind projects commissioned in 2025 recorded an LCOE of USD 141/MWh.

Financing conditions are a key driver of offshore wind LCOE, given the capital-intensive nature of the technology. Even where TICs and capacity factors remain relatively stable, financing costs can significantly affect project economics. This highlights the importance of stable investment conditions and access to affordable capital in sustaining offshore wind cost reductions.

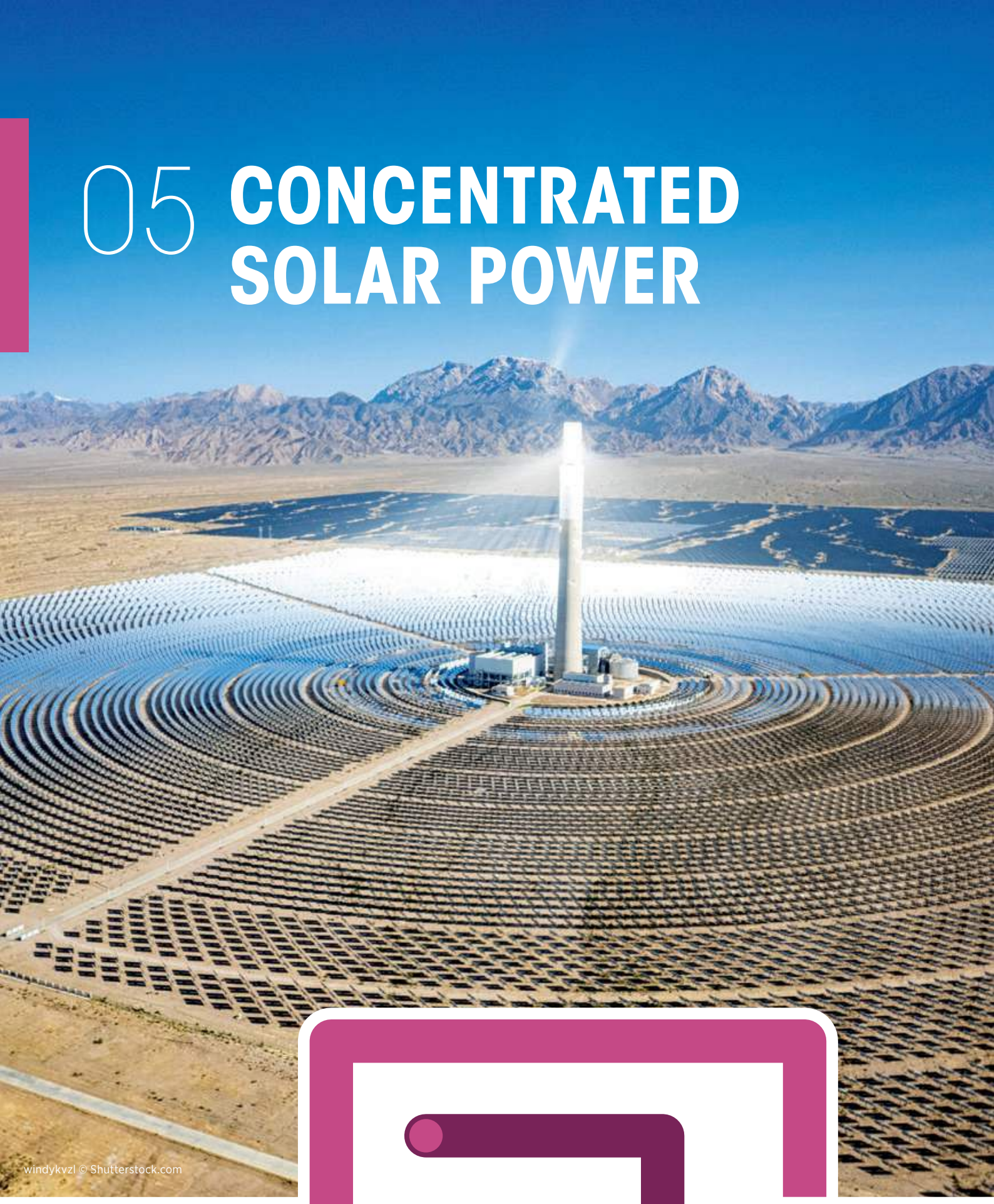
Figure 4.10 Weighted-average LCOE for offshore wind by country/region, 2020–2025 and 2024–2025



Notes: MWh = megawatt hour; USD = United States dollar; only countries with commissioned offshore wind capacity in 2025 are presented at the country level; however, regional weighted-averages for earlier years include additional markets.


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05 CONCENTRATED SOLAR POWER



windykvzl © Shutterstock.com

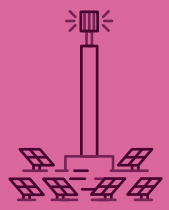
HIGHLIGHTS

Despite modest deployment, CSP remains an important complement to variable renewable energy owing to it's long-duration storage capabilities.

LCOE ⊕ 9%** ↑

Capacity factor ⊖ 19%*** ↓

in 2025 vs. 2024



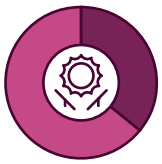
TOTAL INSTALLED COSTS

Installed costs for CSP reached a low of USD 2 418/kW in 2025; they exclusively represent costs in China - the only market with deployment in 2025.



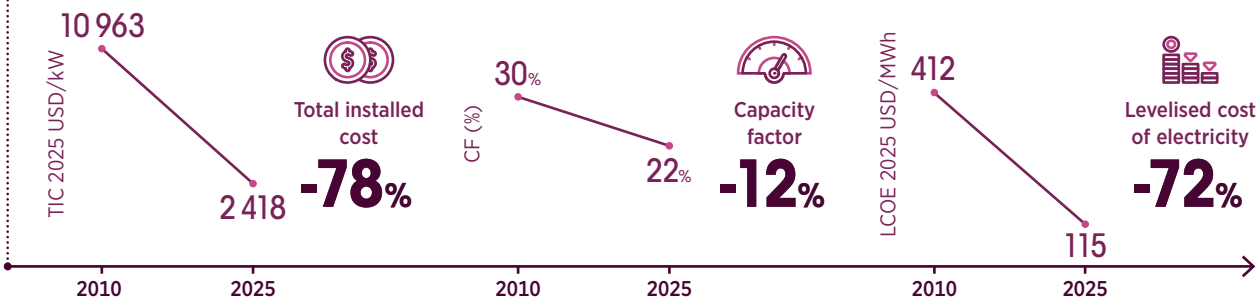


USD 2 418/kW



-36%
in 2025 vs. 2024

KEY PARAMETERS**



TOP MARKETS

Capacity additions (GW) in 2025

0.9

Outlook

China's 7 GW pipeline points to continued momentum toward its 15 GW by 2030 target, with hybrid configurations the dominant model. Whether CSP holds its competitive position will depend on market frameworks rewarding dispatchability, and on how fast battery storage costs continue to fall.



* Levelised cost of electricity; ** All values are weighted averages; *** All changes in capacity factor are expressed in percentage points.

5.1 INTRODUCTION

The global installed capacity of CSP reached 8.4 GW in 2025, marking the highest annual deployment of this technology since 2013. Added capacity almost tripled, year-on-year, driven by nine, newly-deployed projects – all in China – which added a total of 900 MW and comprised eight solar tower (ST) plants and one linear Fresnel plant.

In recent years, global deployment has remained limited, but more new projects are expected to be deployed in the near future. China currently has 1.7 GW of operational capacity, making it the leading market. The country also has ambitious plans for further CSP project development, with an additional 2.75 GW currently under construction across 22 projects. Meanwhile, 33 projects totalling 4.2 GW remain in the planning or pre-construction stage, further expanding the development pipeline. For China to achieve its target of 15 GW of installed capacity by 2030, however, a further 6.3 GW of CSP capacity must still be developed and brought online (CNSTE, 2026).

Deployed in China in 2024, the world's first, supercritical carbon dioxide (sCO_2) solar power system went into operation for a total of 3 174 minutes in 2025. This demonstrated the performance of the system's power generation unit – the outcome of multiple development stages, including fundamental research, advanced equipment engineering and full system integration (CNSTE, 2026).

5.2 TECHNOLOGICAL TRENDS

Currently, in China's CSP R&D portfolio there are 13 key national programmes focused on larger-scale, lower-cost, more grid-supportive technologies. These include long-duration thermal energy storage, high-parameter CSP systems and CSP-wind-PV hybrid operation. Technological improvements have focused on higher-efficiency CSP systems, new thermal energy storage technologies, smarter resource evaluation and dispatch/control, and multi-scenario applications, such as combined heat and power and industrial heat use (CNSTE, 2026).

In addition, regulatory changes in China have shifted CSP development to hybrid wind–solar projects, in which CSP serves as an add-on to meet renewable targets without central government subsidies.

CSP plants in China are being integrated into large-scale wind and solar assets in order to comply with capacity and storage mandates. Their configurations are being optimised to cut initial costs, despite having a higher LCOE compared to standalone PV or wind. This reflects the state's push to position CSP as a supporting, rather than primary technology. The CSP market is thus expanding through co-located projects and long-duration storage use-cases (CNSTE, 2026).

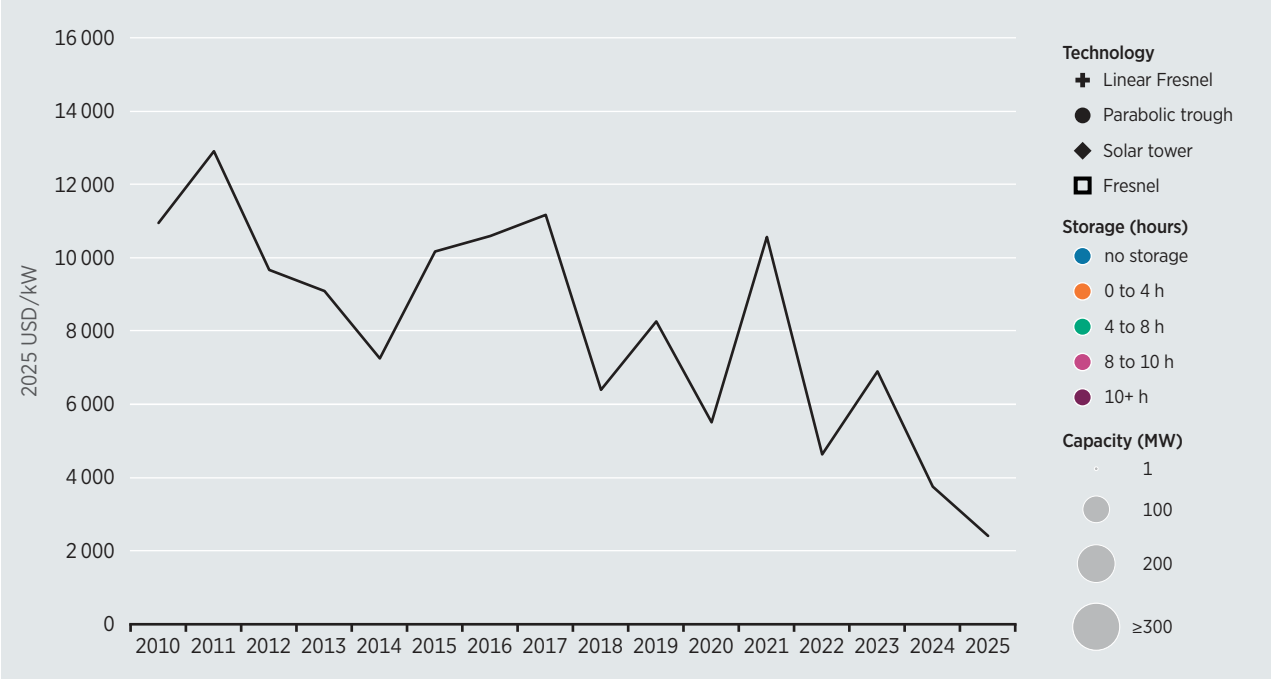
Globally, R&D is also advancing, with different countries focusing on complementary areas. The United States, China and Germany are leading research in thermal energy storage, solar fuels, grid integration and sCO_2 power cycles, while Spain, the United Arab Emirates, Morocco, South Africa and India have focused on utility-scale CSP deployment and molten salt thermal storage. Countries such as Australia, Switzerland, Israel and Germany are making advances in solar thermochemistry, solar fuels and industrial decarbonisation. France, Austria, Italy, the Republic of Korea and Brazil have been exploring hybrid solar thermal systems and industrial process heat, while Chile is looking at applications for CSP in the mining sector.

Worldwide, CSP operations are now increasingly AI-driven, with performance optimised by predictive maintenance and smart heliostat tracking. AI-enhanced operation systems show strong potential for improving CSP reliability and increasing thermal output. At the same time, equipment constraints are being honoured through AI-based forecasting and dual-parameter optimisation of mirror angles and fluid flow rates (Gul *et al.*, 2025). New modular and hybrid designs (especially CSP+PV) improve reliability and expand CSP beyond large utilities. Linear-Fresnel technology has also advanced, with projects demonstrating fully-automated mirror production, 550 degree centigrade (°C) molten-salt operation and CSP+PV hybrid control with sub-second frequency regulation (SolarPaces, 2025).

5.3 TOTAL INSTALLED COST

CSP facilities now commonly include low-cost and long-duration thermal energy storage, typically using molten salts. This gives CSP greater flexibility in dispatch and thus the ability to target output to periods of high cost in the electricity market.

Figure 5.1 TICs for CSP by project size, collector type and amount of storage, 2010–2025



Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.

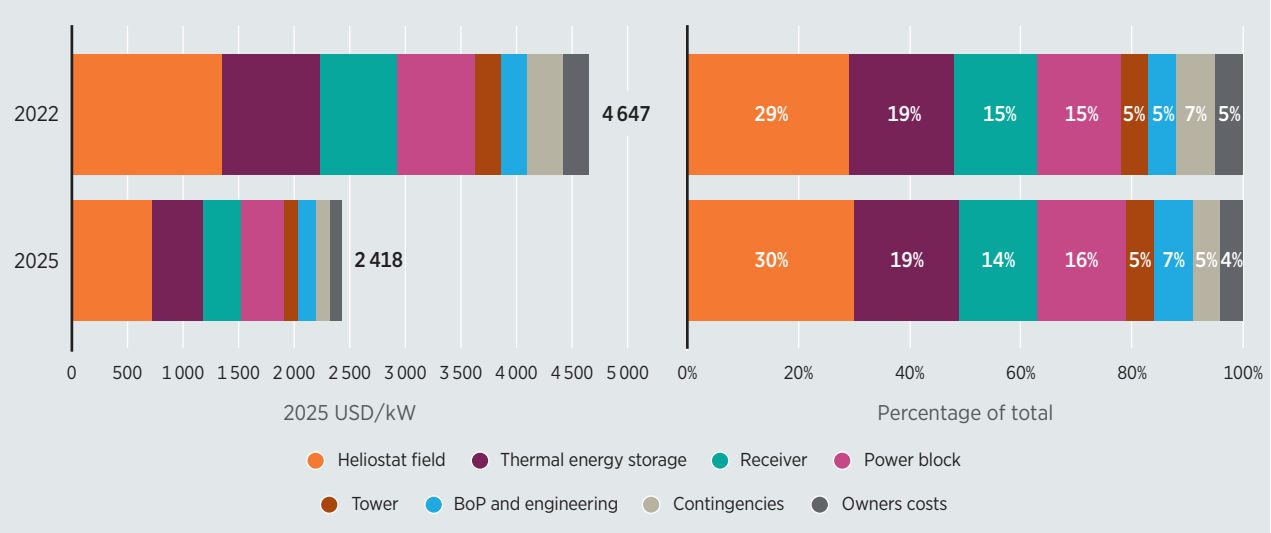
Figure 5.1 shows year-on-year fluctuation in the TICs for CSP between 2010 and 2025. Over that period, the weighted-average TIC for CSP plants in the IRENA renewable costs database fell by 78%, reaching a low for the period in 2025, of USD 2 418/kW. That cost also represented the TIC in China alone, since that was the only market with deployment that year.

Historically, fluctuations in CSP costs have mainly been due to small market deployment and cost differences across markets. The years 2022, 2024 and 2025 saw the lowest costs, since deployment was mainly in China, where the cost structure was lower. This was different from 2021, when there was also a project in Latin America, and 2023, when there was a project in the United Arab Emirates.

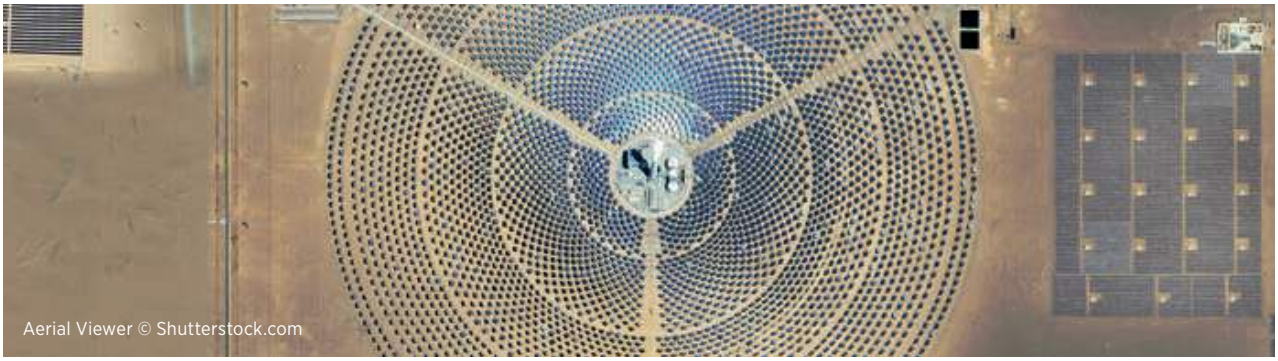
Comparing costs in China in recent years, there was a decrease of 48% between 2022 and 2025. This was largely driven by the hybridisation of CSP with solar PV and wind, which helped reduce overall system costs (see Figure 5.2).

In terms of cost breakdown, the main change in 2025 was the lower share of contingency and owner's costs. Balance of plant was slightly higher, however, reflecting the increased complexity of grid integration and additional BoS requirements.

Figure 5.2 TIC breakdown for ST projects in China, 2022 and 2025



Notes: kW = kilowatt; USD = United States dollar.


Aerial Viewer © Shutterstock.com

5.4 CAPACITY FACTORS

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

The highest global average capacity factor ever attained by CSP was in 2021, when it reached 80%. This was due to the excellent solar resource provided by the Atacama Desert in Chile – the location of the Cerro Dominador CSP project. In 2023, the global capacity factor decreased to 55%. This was due to the Noor 1/DEWA IV CSP project – an ST and parabolic trough deployed in the United Arab Emirates.

CSP can generate electricity in a stable and continuous manner; however, declining capacity factors have been observed in China. This is largely due to the structure of the Chinese market, where CSP plants are primarily operated as storage-oriented assets, rather than as standalone generators, meaning they are not dispatched at full capacity continuously. In hybrid configurations, CSP with molten-salt storage is treated as a dispatchable resource used for peak shaving and grid balancing. The technology can charge thermal storage with solar heat and then generate electricity during evening peaks or low-sun periods, improving reliability. CSP acts as the flexible regulator, which inherently lowers its own annual output share (Hu and *et al.*, 2024).

In 2022, the weighted average capacity factor in China was 36%, while in 2025 – driven by a mix of hybrid plants – this figure declined to around 22%. This was based on the announced generation output reflecting a shift towards smaller solar fields. This decrease should be interpreted with care, however, since CSP plants in operation in China have demonstrated improved performance over time. An analysis of five projects that have been operating for more than five years shows current capacity factors ranging from 28% to 34%, with several plants reaching their highest levels to date. Indeed, compared to their first year of operation, these projects have experienced a noticeable increase – almost doubling their capacity factors overall, while in some projects, they more than doubled.

Table 5.1 Electricity generation and capacity factors of CSP plants in China: Comparison between the first year of operation and 2025

Plant	MW	MWh in the first full year of operation	Capacity factor	MWh in 2025	Capacity factor
CGN 50 MW trough-type CSP plant in Delingha	50	110 400	25%	146 380	33%
Shouhang High-Tech 100 MW ST-type CSP plant in Dunhuang	100	86 471.7	10%	244 820	28%
Qinghai Zhongkong Delingha 50 MW ST-type CSP	50	106 600	24%	143 000	33%
CSN New Energy 100 MW trough-type CSP plant	100	229 000	26%	301 000	34%
Lunan Golmud Multi-Energy Complementary Project	50	69 498.6	16%	148 232.7	34%

Source: Based on (CNSTE, 2026).
Notes: MW = megawatt; MWh = megawatt hour.

The average thermal storage capacity for solar thermal plants in the IRENA renewable costs database increased from 3.5 hours to 10.3 hours between 2010 and 2025. The storage duration of CSP projects deployed in 2025 ranged between 8 hours and 12 hours.

Figure 5.3 Average project size and average storage hours of CSP projects, 2010–2025



Note: MW = megawatt

5.5 OPERATION AND MAINTENANCE COSTS

Advanced CSP designs reduce long-term O&M costs through single-axis tracking systems, fewer components and more durable receiver technologies. Innovations such as molten salt, which is used for both heat transfer and storage, eliminate costly equipment. At the same time, enclosed receivers and optimised aiming strategies extend component lifetimes. Digital tools – including robotics automation, drone inspections, and data analytics – enable predictive maintenance and early error detection (Khan and *et al.*, 2024).

Industry trends indicate further cost reductions through standardisation, improved materials and automation. Enhanced durability, increased redundancy and digitalisation are extending maintenance intervals and lifetimes. While ongoing technological advances and best practices are expected to reduce O&M costs for future CSP plants, O&M will likely continue to represent a relatively large share of LCOE compared to other renewable power technologies (Khan *et al.*, 2024). For projects in the IRENA renewable costs database, O&M accounts for 23% of the LCOE, on average.

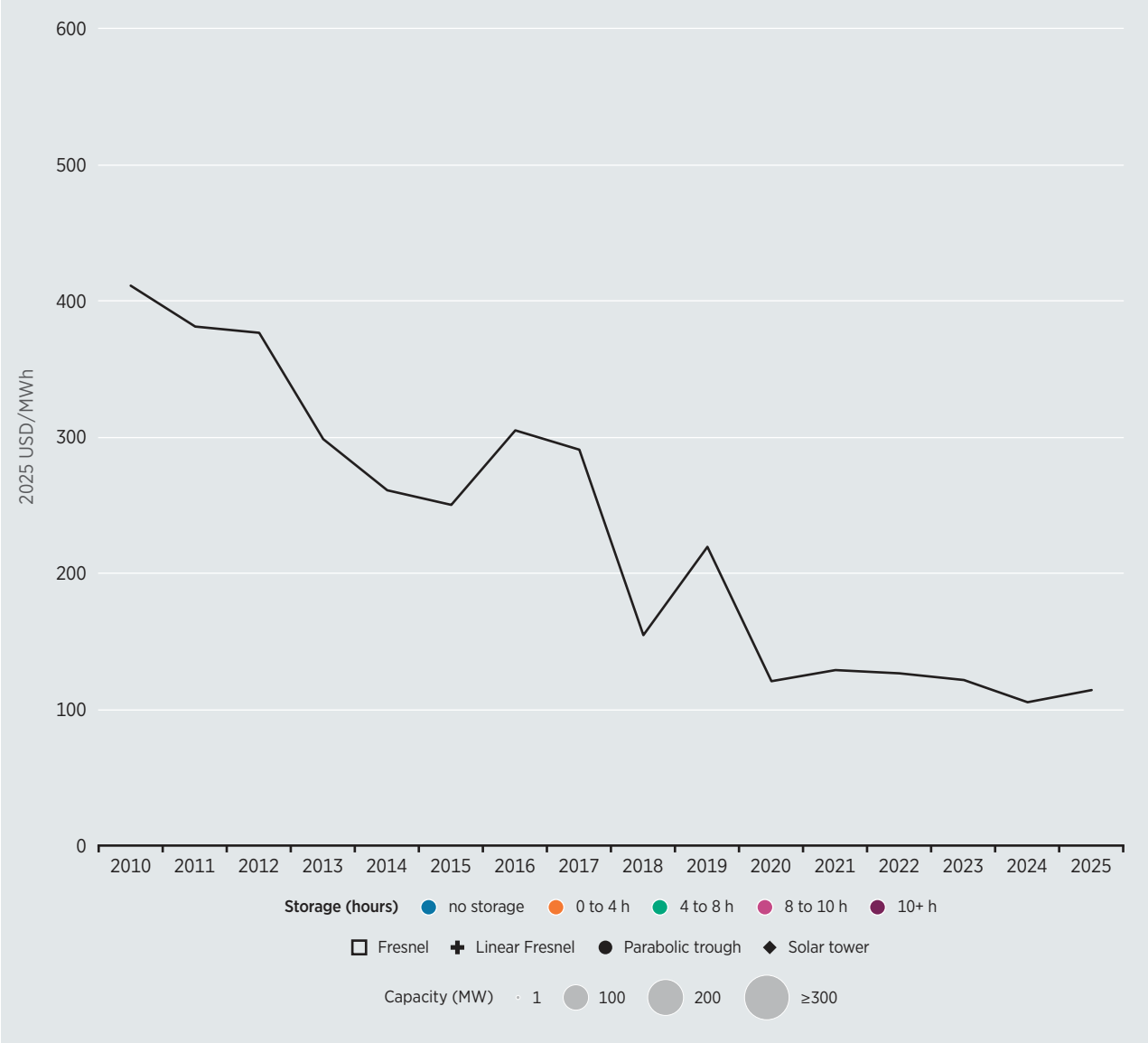
5.6 LEVELISED COST OF ELECTRICITY

Between 2010 and 2025, the global weighted-average LCOE of newly-commissioned CSP plants fell by 72%, from USD 412/MWh to USD 115/MWh (see Figure 5.4).

Between 2020 and 2023, the LCOE for CSP ranged between USD 121/MWh and USD 122/MWh. These values were based on a very thin market, however, as there was only one project commissioned each year during the period that had a capacity between 50 MW and 200 MW. In 2024, the low capital costs of projects occurring in China pushed down the weighted-average LCOE to USD 106/MWh.

In 2025, global deployment reached 900 MW – the highest level since 2013. However, the LCOE registered an increase of 9%, year-on-year, mainly driven by lower capacity factors in China.

Figure 5.4 LCOE for CSP projects by technology and storage duration, 2010–2025



Notes: MWh = megawatt hour ; MW = megawatt; USD = United States dollar.

Despite the historical decrease, however, financing costs continued to be a significant factor contributing to LCOE and project viability. For projects commissioned in 2025, financing costs represented on average 34% of the LCOE. This was largely due to the conservative assumptions made by lenders and investors – a factor requiring further attention from policy makers. For CSP projects, higher perceived risks and elevated debt interest rates make financing more challenging. This contributes to delays in project development, thus slowing commercial project deployment.

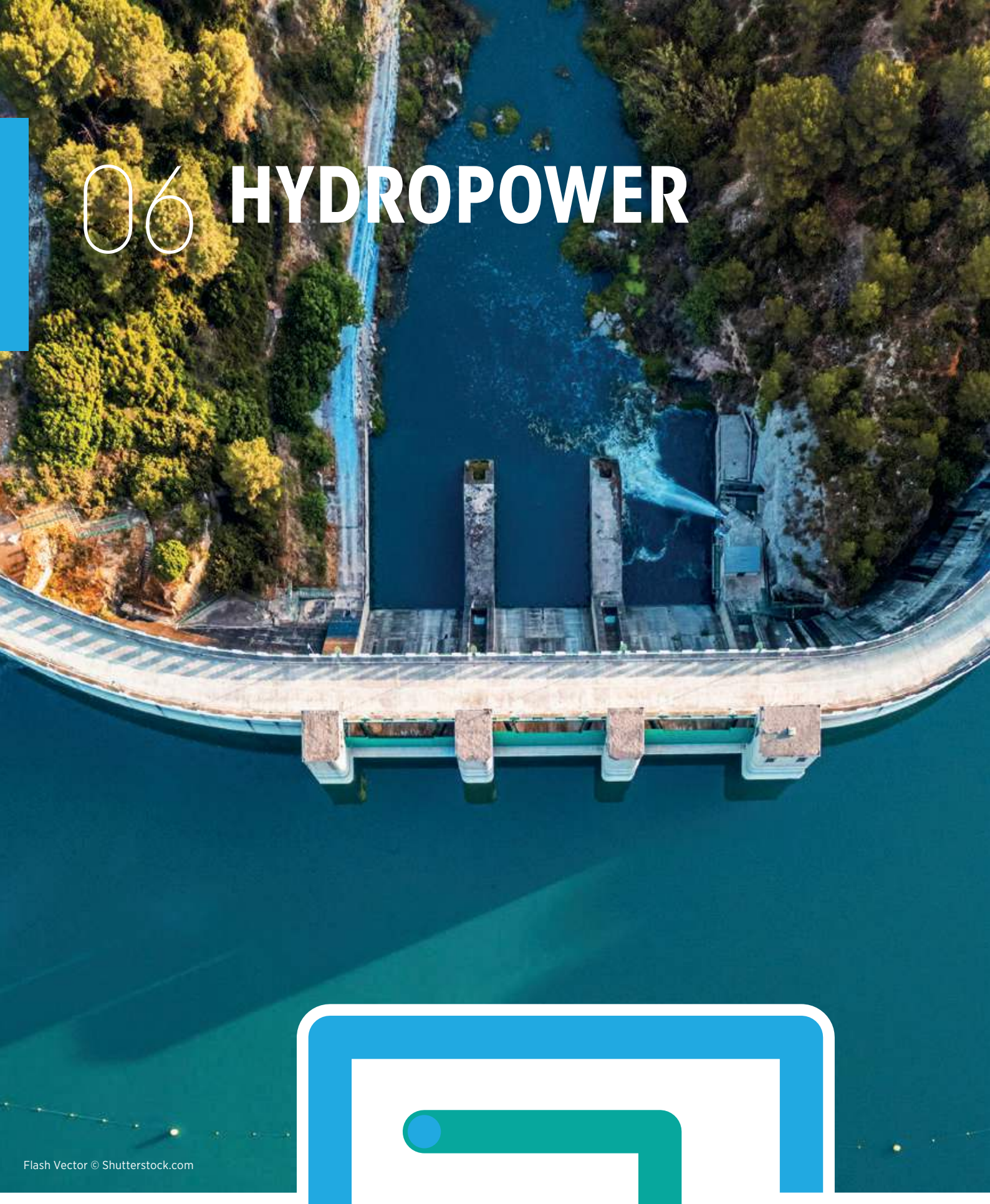
Although there has been significant success in reducing costs since 2010, the CSP market remains small, with a limited number of new projects in the pipeline. As of the end of 2025, China remained the leading market, with 12 tenders completed for the selection of contractors for CSP and molten-salt thermal storage projects that are expected to come online in the near term (Kraemer, 2026).

A key advantage of CSP is its ability to provide dispatchable and renewable power to the grid. In many countries, however, current regulations and market structures do not adequately reward the value of dispatchable generation. To enable CSP to compete on a level playing field, electricity markets must evolve to recognise and incentivise this technology's unique capabilities (Schöniger *et al.*, 2021).

Policy makers should implement protective measures, such as electricity pricing mechanisms, ancillary service rules and electricity market participation guidelines for new energy sources. This should be done alongside case-by-case sustainable price settlements and a dedicated capacity compensation mechanism to ensure operational stability amid competition. Subsidy support should target R&D and engineering applications in high-parameter, large-capacity CSP plants, gradually enhancing the technology, system regulation capabilities, safety and reliability of this renewable energy solution (CNSTE, 2026).


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06 HYDROPOWER



Flash Vector © Shutterstock.com

HIGHLIGHTS

Hydropower reported a higher LCOE*, as lower total installed costs were offset by lower capacity factors resulting from operational design choices.

LCOE + 9%** ↑

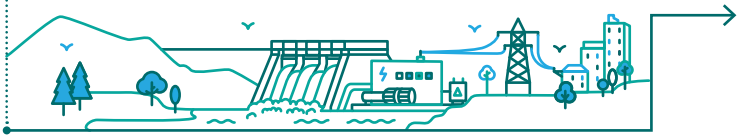
Capacity factor − 5%*** ↓

in 2025 vs. 2024



TOTAL INSTALLED COSTS

Global total installed costs reached their lowest level since 2018. Trends diverged between large and small hydropower, with costs falling by 11% and rising by 40%, respectively.

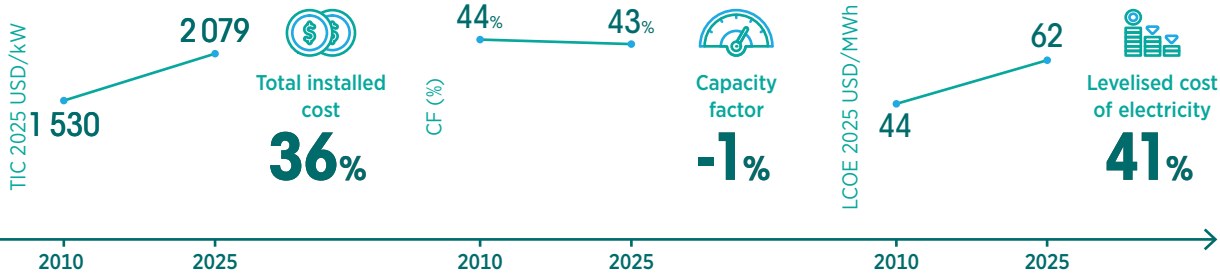


USD 2 079/kW

-10%

in 2025 vs. 2024

KEY PARAMETERS**



TOP MARKETS

Capacity additions (GW) in 2025



Outlook

Hydropower provides renewable electricity alongside flexibility, storage and broader system support services. Its role is becoming increasingly important as variable renewables expand. Modernization of ageing fleets, hybridisation with solar, and digitalized operations are key trends to watch.



* Levelised cost of electricity; ** All values are weighted averages; *** All changes in capacity factor are expressed in percentage points.

6.1 INTRODUCTION

After two years of low deployment, annual capacity additions of renewable hydropower[19] increased sharply in 2025, jumping 150% year-on-year to reach 18.4 GW. This was a return to levels comparable to those seen before 2023 (IRENA, 2026a) and helped total global capacity reach 1 296 GW.

Mostly concentrated in China, Ethiopia and India, hydropower accounted for 2.6% of total global renewable capacity additions in 2025 (IRENA, 2026a). Each of these three countries commissioned more than 1.5 GW of new capacity that year, together accounting for 56% of global hydropower additions. China remained the global leader, commissioning 4.8 GW. In India, policy support strengthened, particularly for small hydropower projects and pumped storage (Forum of Regulators, 2025; PIB, 2026). In Ethiopia, hydropower remained central to the national energy strategy and to the country's ambitions of becoming a regional electricity export hub by 2030 (IHA, 2025a).

In the global energy transition, hydropower occupies a unique position due to its scale, flexibility and technological maturity. As countries increase the share of variable renewable energy sources in their power systems, hydropower is also playing an increasingly strategic role in maintaining grid stability and reliability. Beyond electricity generation, hydropower can also deliver broader socio-economic benefits, including water management services, employment opportunities and affordable, reliable renewable energy supply.

6.2 TECHNOLOGICAL TRENDS

As a mature, dispatchable[20] and generally low-carbon technology, hydropower bridges the gap between conventional power systems and increasing shares of variable renewable energy. Hydropower offers ancillary services, such as frequency regulation, spinning reserves and black-start capability, helping to maintain grid stability and reduce electricity price volatility. Supportive policies and regulatory frameworks that recognise the full range of services provided by hydropower can help unlock further investment in the sector.

Modernisation efforts are becoming increasingly important across the hydropower sector. Upgrades, such as digitalisation, turbine modernisation and hybridisation with solar, wind and battery storage systems, can improve operational efficiency and increase system flexibility (IHA, 2025a). At the same time, AI-driven water management systems, digital twins and ecological restoration measures are being integrated to optimise performance, strengthen asset management and reduce environmental impacts (Ember, 2025; IRENA, 2023; Vattenfall, 2026).

[19] *This chapter focuses on reservoir and run-of-river systems, excluding pumped storage.*

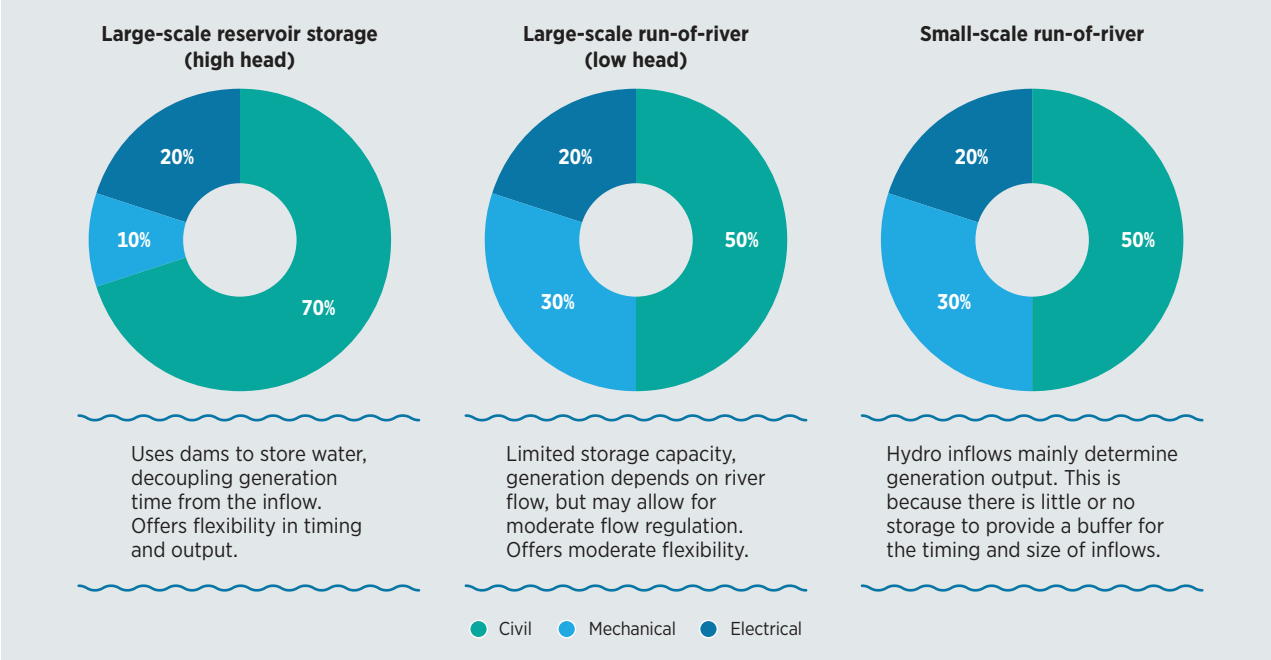
[20] *This is especially so when the plant includes reservoir storage.*

6.3 TOTAL INSTALLED COST

Hydropower project construction is influenced by factors such as project size, location and technical specifications. These determine turbine selection, plant design and overall cost structure. Reservoir and run-of-river projects, as well as large and small installations, have distinct technical and cost characteristics.

Figure 6.1 presents the hydropower projects covered in this chapter and provides an overview of the estimated shares of civil, mechanical and electrical cost components for a sample of projects. Projects in this chapter are categorised by size, with small hydropower referring to installations of 10 MW or less and large hydropower to those above 10 MW.

Figure 6.1 Hydropower plant type and TIC breakdown by component and weighted-averages for a sample of hydropower projects in Europe, 2021



Source: International Hydropower Association (IHA).

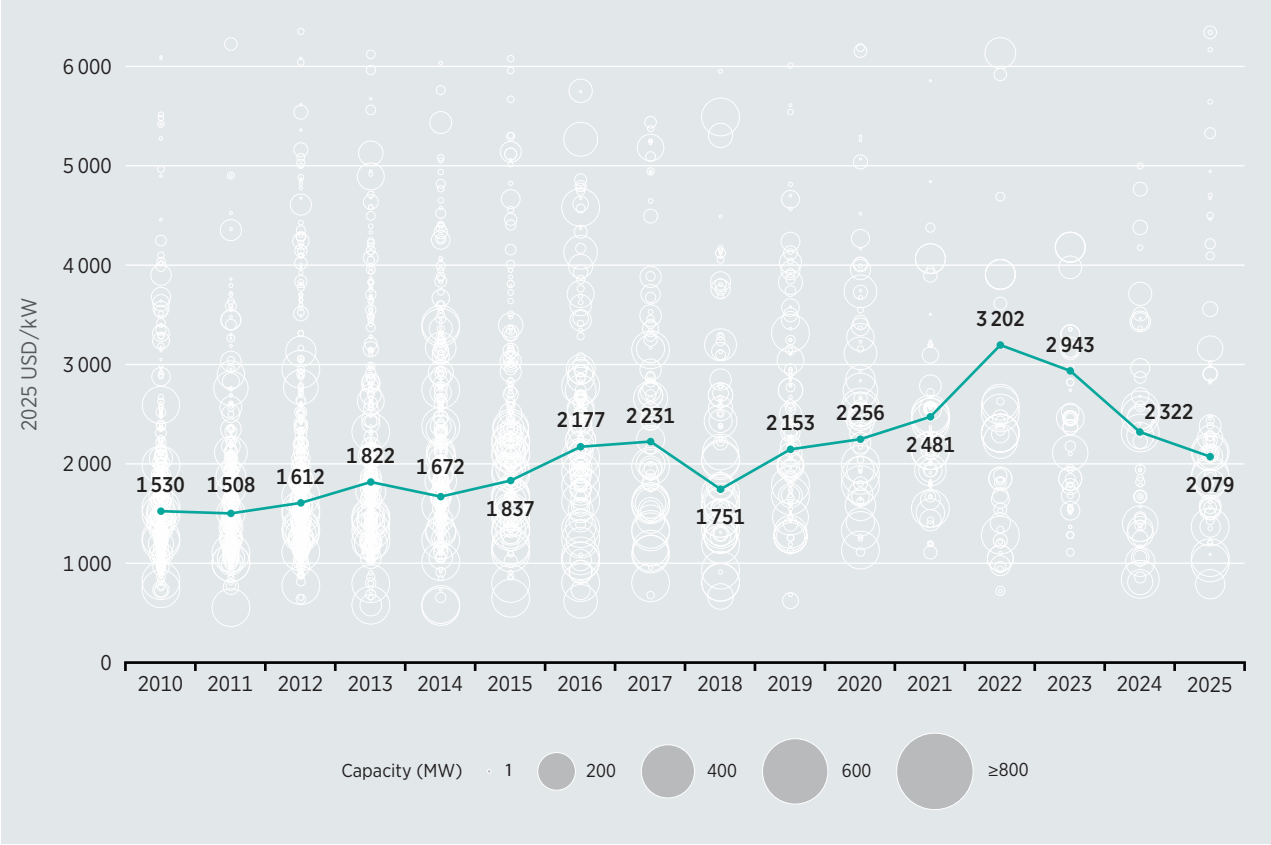
Hydropower is a capital-intensive technology with long lead times and high upfront investment requirements. Civil works, such as dams, tunnels and powerhouses,[21] typically account for 50–70% of TICs – the largest share. This is followed by the cost of mechanical and electrical equipment. Projects that expand or use existing infrastructure, however, can reduce civil construction costs and increase the share of electro-mechanical components.

Additional costs may arise from feasibility studies, stakeholder engagement, environmental measures and land acquisition. For large-scale projects, long development timelines can also make owner and financing costs a significant share of total project expenditures.

[21] *Structures that house turbines, generators and other electromechanical equipment*

For hydropower projects commissioned in 2025, the global weighted-average TIC reached its lowest level since 2018, at USD 2 079/kW, representing a 36% increase on 2010 (see Figure 6.2). Between 2024 and 2025, the global weighted-average TIC fell by 10%. In 2025, the weighted-average TIC ranged between USD 1153/kW and USD 7 346/kW (5th to 95th percentiles).

Figure 6.2 TICs of hydropower projects and global weighted-average, 2010–2025



Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.

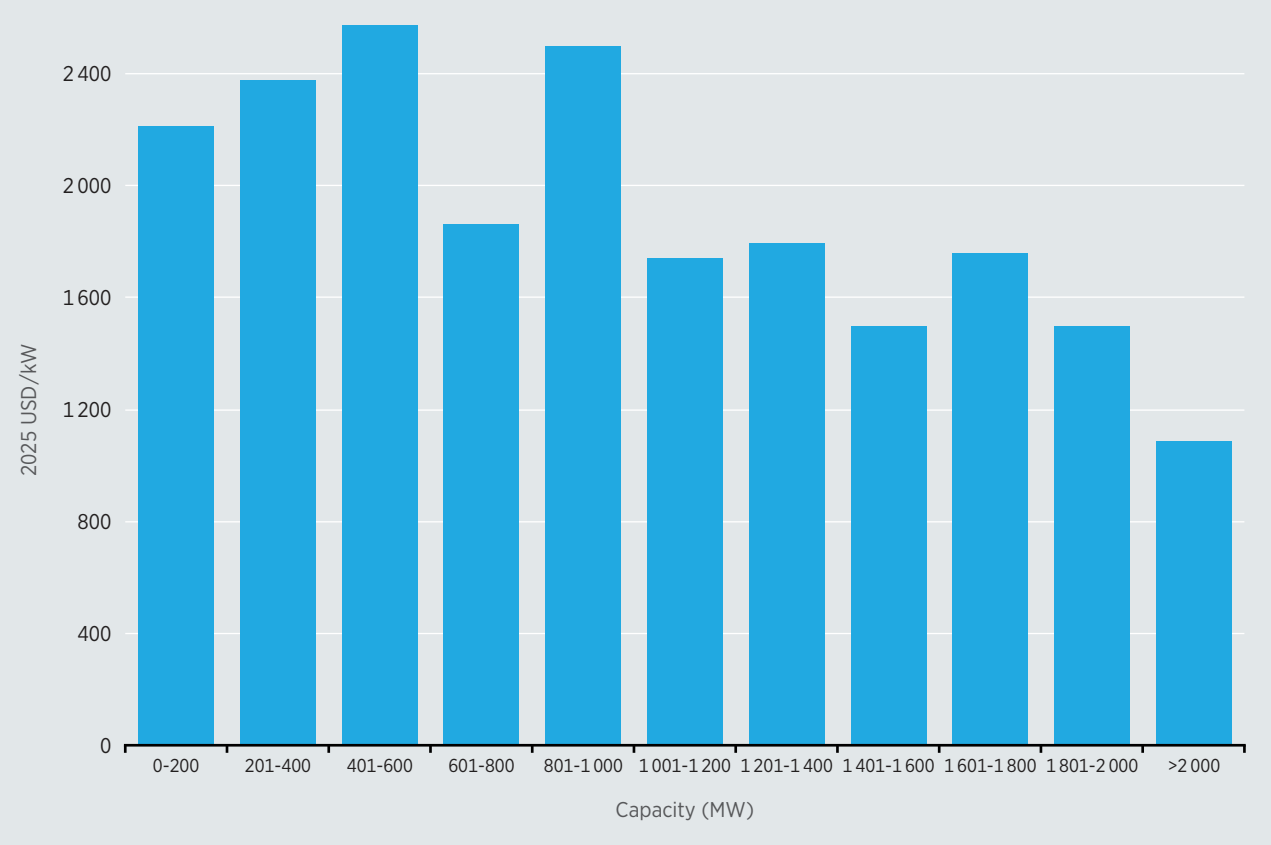
Figure 6.3 shows the weighted-average TICs of hydropower projects commissioned between 2010 and 2025 by project capacity range. Capacities are divided at 200 MW-intervals, with a final category for projects larger than 2 000 MW.

Overall, the data does not indicate strong economies of scale for hydropower projects below 1000 MW, as weighted-average installed costs remained relatively similar across most capacity ranges. While some categories show lower average costs – projects between 600 MW and 800 MW, for example, averaged USD 1864/kW – the differences across capacity ranges are generally limited.

The weighted average total installed costs observed between 2010 and 2025 suggest the presence of economies of scale for projects above 1 GW (see Figure 6.3), with costs averaging USD 2306/kW for 0–1 GW capacity projects compared to USD 1609/kW for 1–2 GW capacity projects. For projects exceeding 2 GW, the weighted-average TIC declined further, to USD 1087/kW. Overall, these lower costs were influenced by several lower-cost projects commissioned before 2019.

At the same time, the number of projects differs considerably across capacity ranges, while project designs, geographical conditions and the range of services provided vary significantly between developments. These factors make it difficult to draw definitive global conclusions regarding the extent of economies of scale in hydropower development.

Figure 6.3 TICs for hydropower projects by weighted-average and capacity range, 2010–2025

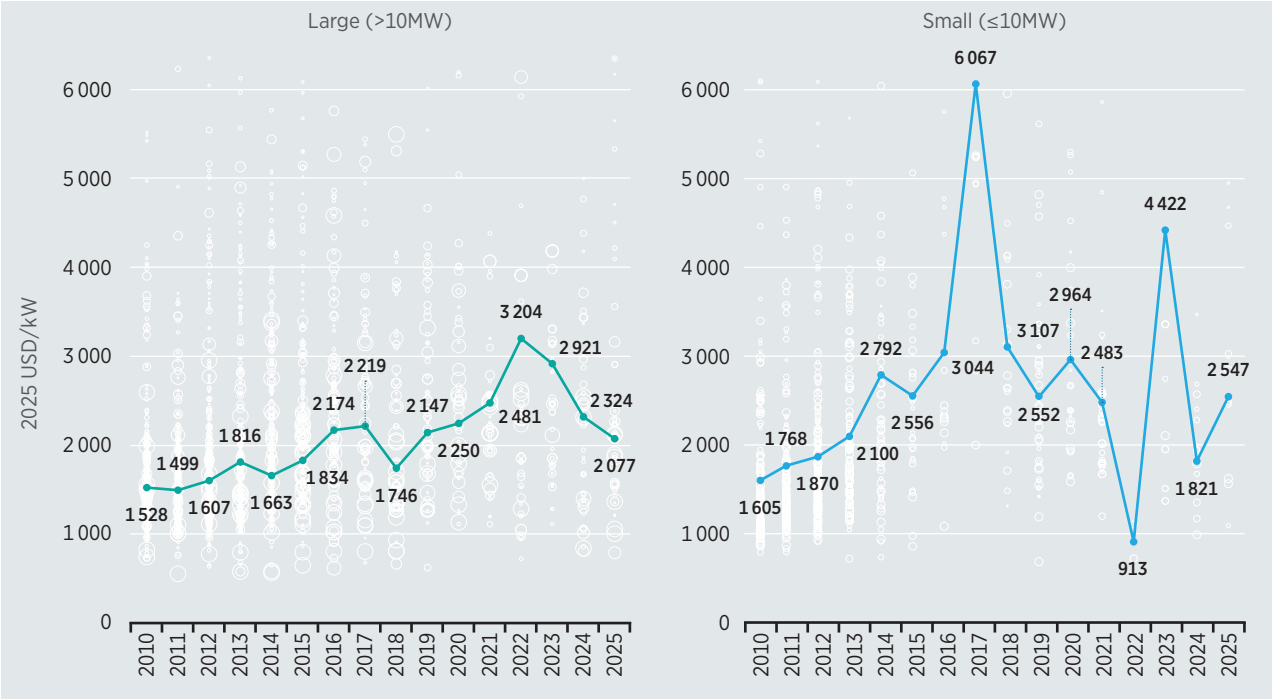


Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.


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Figure 6.4 shows the distribution of TICs by capacity for small and large hydropower projects in the IRENA renewable costs database. In 2025, for large hydropower, the weighted-average TIC decreased 11% year-on-year, reaching USD 2 077/kW. In contrast, small hydropower projects – which tend to exhibit significant variability, due to the limited number of projects commissioned annually – recorded a 40% increase over 2024, reaching USD 2 547/kW. This increase was not driven by a specific country or region, but rather reflected the diverse mix of projects commissioned across South America, Africa and Asia. As such, the long-term trend for small hydro remains to be confirmed.

Figure 6.4 TICs for small and large hydropower projects and global weighted-average, 2010–2025



Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.

Between 2010 and 2025, hydropower saw two periods of increasing global weighted-average TICs (see Figure 6.2). The first occurred between 2010 and 2017 and was followed by a notable decline in 2018. A second period of rising costs then began after 2019 and continued through 2022, before costs declined again in 2023 and 2024. Given these shifts, the following analysis focuses on the 2018–2025[22] period in order to better understand recent cost dynamics at the global and regional levels.

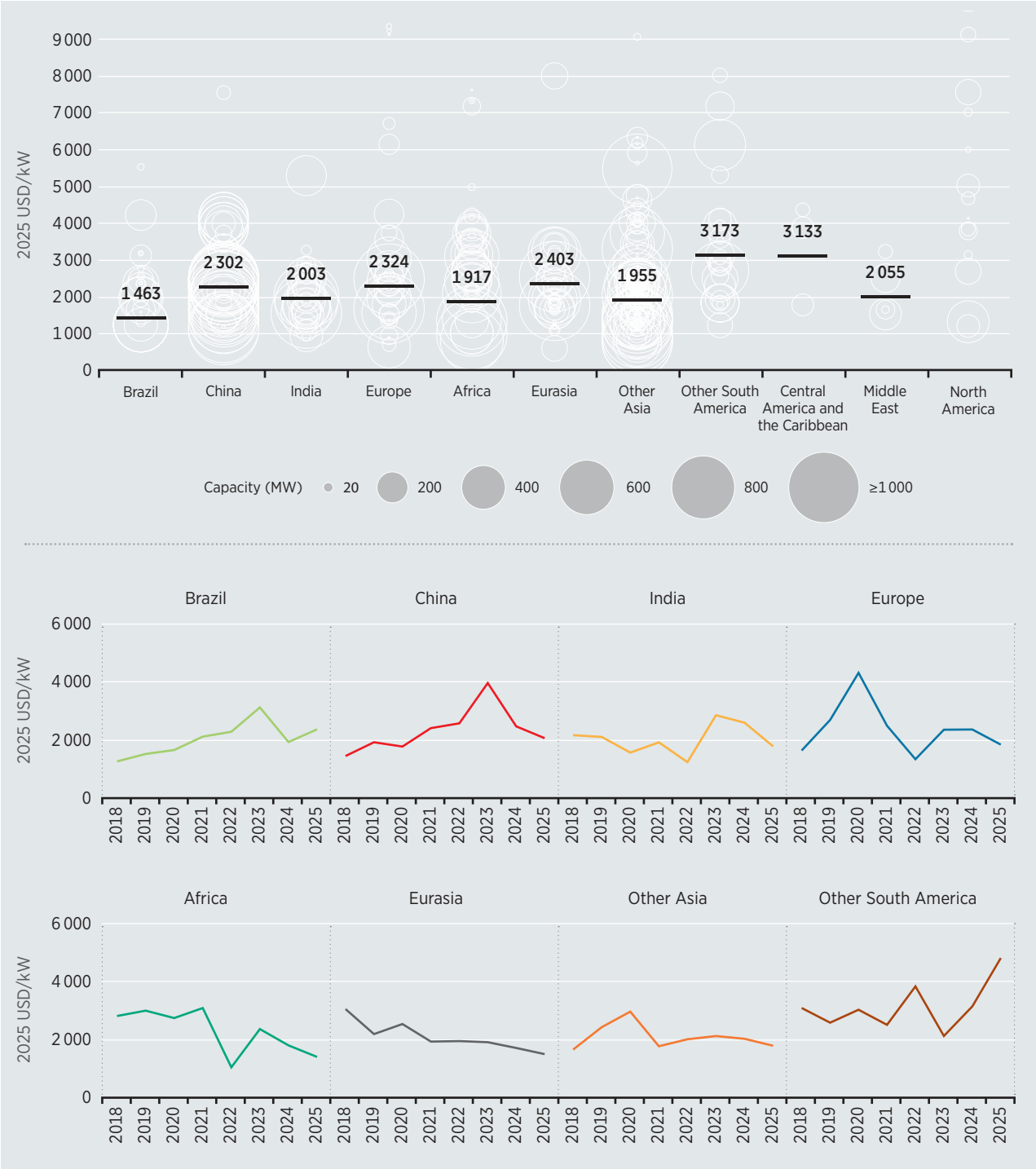
Figure 6.5 presents the TIC and weighted-average TIC of large hydropower projects by region and selected countries between 2018 and 2025. During this period, the weighted-average TIC ranged from USD 1 463/kW in Brazil to USD 3 133/kW in Central America and the Caribbean. Most regions, however, remained within a relatively similar cost range.

Between 2024 and 2025, weighted-average TICs declined across most selected regions and countries. This was despite considerable annual variability, driven by the limited number and diverse characteristics of projects commissioned each year. Brazil and Other South America were notable exceptions, with both showing an upward cost trend over this period.

[22] *A regional analysis for the period 2010–2017 can be found in the* IRENA Renewable Power Generation Cost in 2024 *report (IRENA, 2025b).*

In 2025, Africa recorded the lowest weighted-average TIC, at USD 1 414/kW. This was influenced by the commissioning of the Grand Ethiopian Renaissance Dam – Africa's largest hydroelectric project and one of the continent's largest sources of renewable electricity generation (IHA, 2025a; The Guardian, 2025). In contrast, Other South America recorded the highest weighted-average installed cost, at USD 4 829/kW.

Figure 6.5 TICs by project and weighted-averages for large hydropower projects by selected country/region, 2018–2025



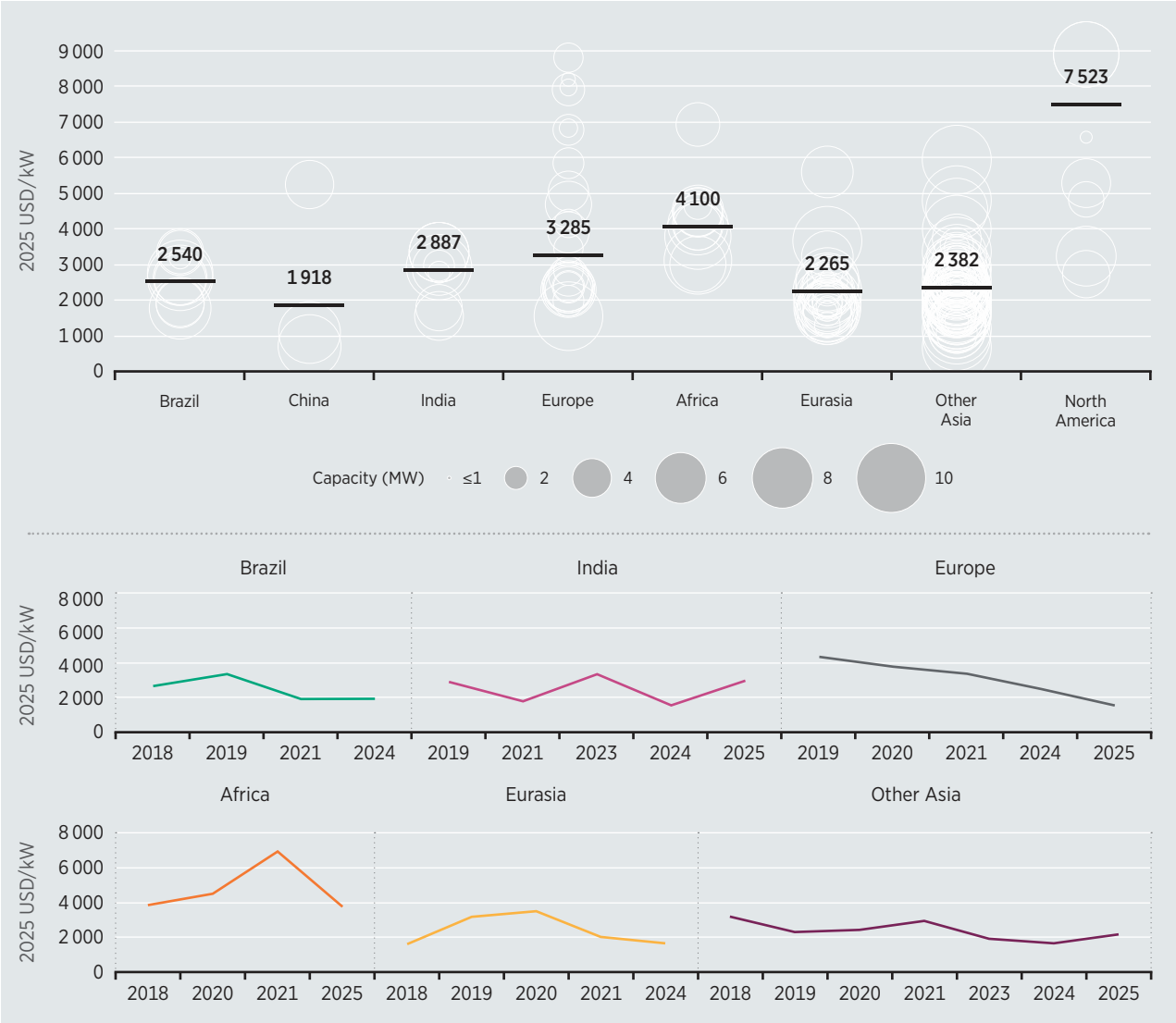
Notes: "Other Asia" includes all Asian countries except China and India; "Other South America" includes all South American countries except Brazil; ; kW = kilowatt; MW = megawatt; USD = United States dollar; trend lines are shown only for regions and countries with sufficient annual project data over the period analysed.

Figure 6.6 presents the TICs and weighted-average TICs of small hydropower projects by region and selected countries between 2018 and 2025. During this period, weighted-average TICs ranged from USD 1 918/kW in China to USD 7 523/kW in North America.

For the 2018–2025 period, the number of newly-commissioned small hydropower projects in the database for Other South America, and Central America and the Caribbean, was limited. As a result, the weighted-average TICs for these regions are not considered representative.

On a regional level, small hydropower exhibits significantly greater cost variability and no clear year-on-year cost trend. This reflects the smaller number of projects commissioned annually and the wide diversity of characteristics. Project capacities also vary considerably, ranging from small installations to projects approaching the upper threshold of small hydropower classification. Together, these factors contribute to the variability observed across the dataset.

Figure 6.6 TICs by project and weighted-averages for small hydropower projects by country/region, 2018–2025

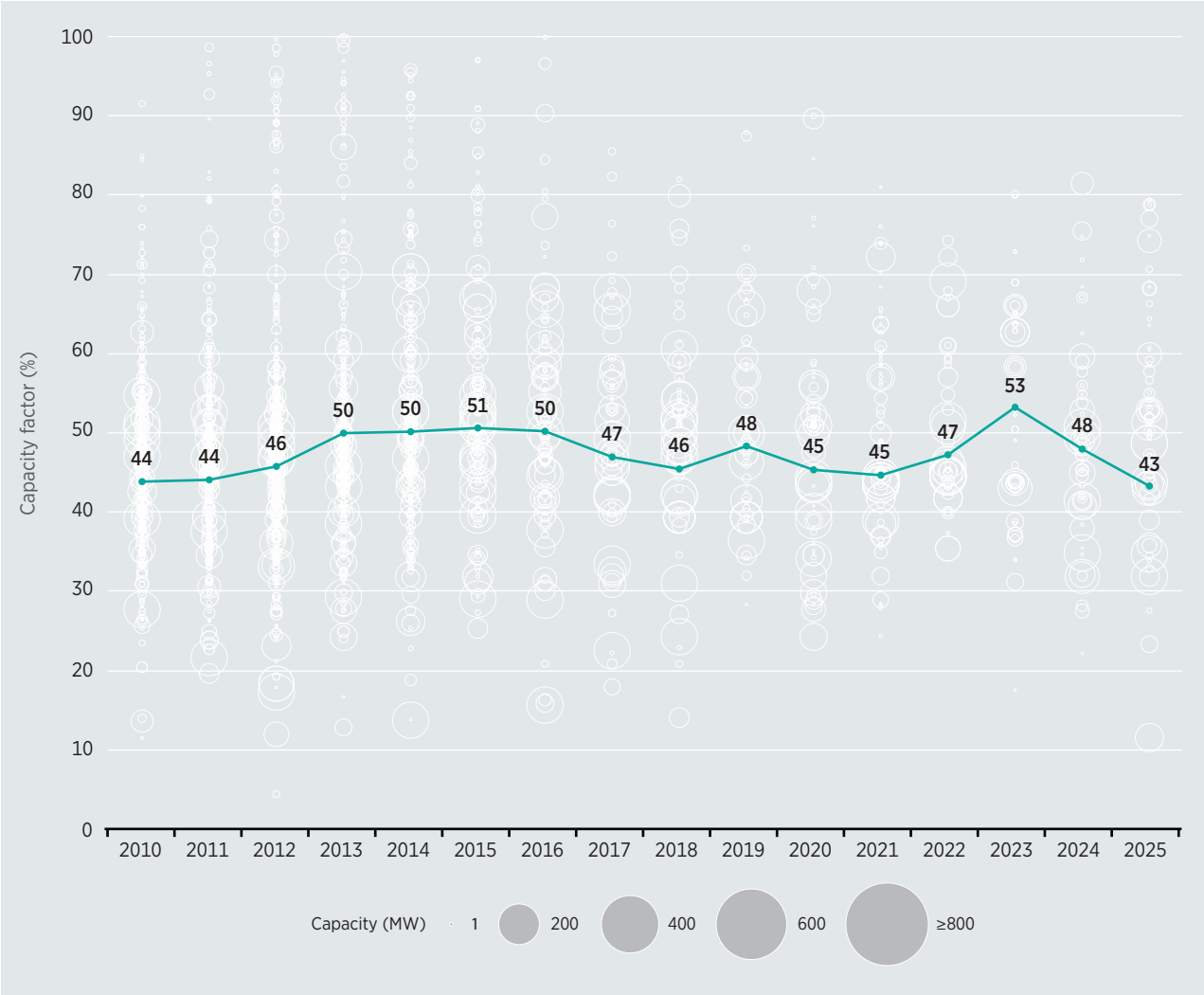


Notes: "Other Asia" includes all Asian countries except China and India; kW = kilowatt; MW = megawatt; USD = United States dollar; trend lines are shown only for regions and countries with sufficient annual project data over the period analysed.

6.4 CAPACITY FACTOR

Between 2010 and 2025, the global weighted-average capacity factor of commissioned hydropower projects of all sizes declined from 44% to 43% (see Figure 6.7). This relative stability was despite a peak of 53% in 2023. Over the period, the 5th and 95th percentiles ranged between 24% and 80%, reflecting the diversity in hydropower project design, site characteristics and operating conditions. In 2025, there was a 5 percentage point decrease in the global weighted-average capacity factor, year-on-year, from 48% to 43%.

Figure 6.7 Capacity factors of hydropower projects and global weighted-average, 2010–2025



Notes: MW = megawatt.

Figure 6.8 presents the weighted-average capacity factors of large and small hydropower projects. Between 2010 and 2025, the annual global weighted-average capacity factor of newly commissioned large hydropower projects declined slightly, from 44% to 43%, largely shaping the overall global trend. In contrast, over the same period, the weighted-average capacity factor of newly-commissioned small hydropower projects increased from 48% to 53%.

Small hydropower projects in the IRENA renewable cost database generally exhibit higher weighted-average capacity factors than large hydropower projects. However, differences in capacity factors often reflect project design and operational objectives, rather than technical performance alone. Some projects are designed to operate more continuously, resulting in higher average capacity factors, while others are built with larger installed capacity to provide peak-load generation, system flexibility or ancillary grid services – a design that can result in lower average utilisation rates.

Figure 6.8 Global weighted-average capacity factor, 5th and 95th percentiles for small and large hydropower, 2010–2025

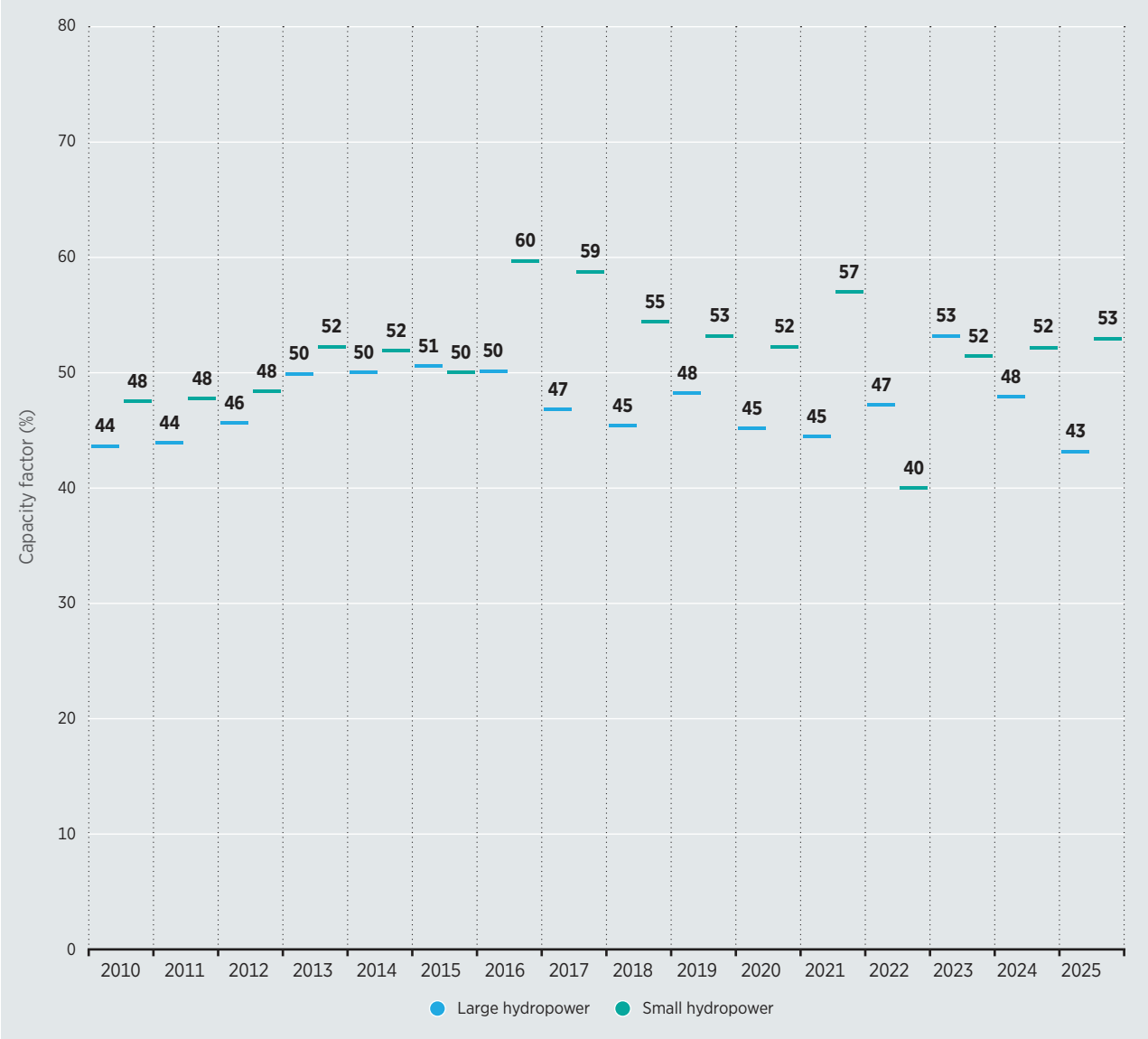


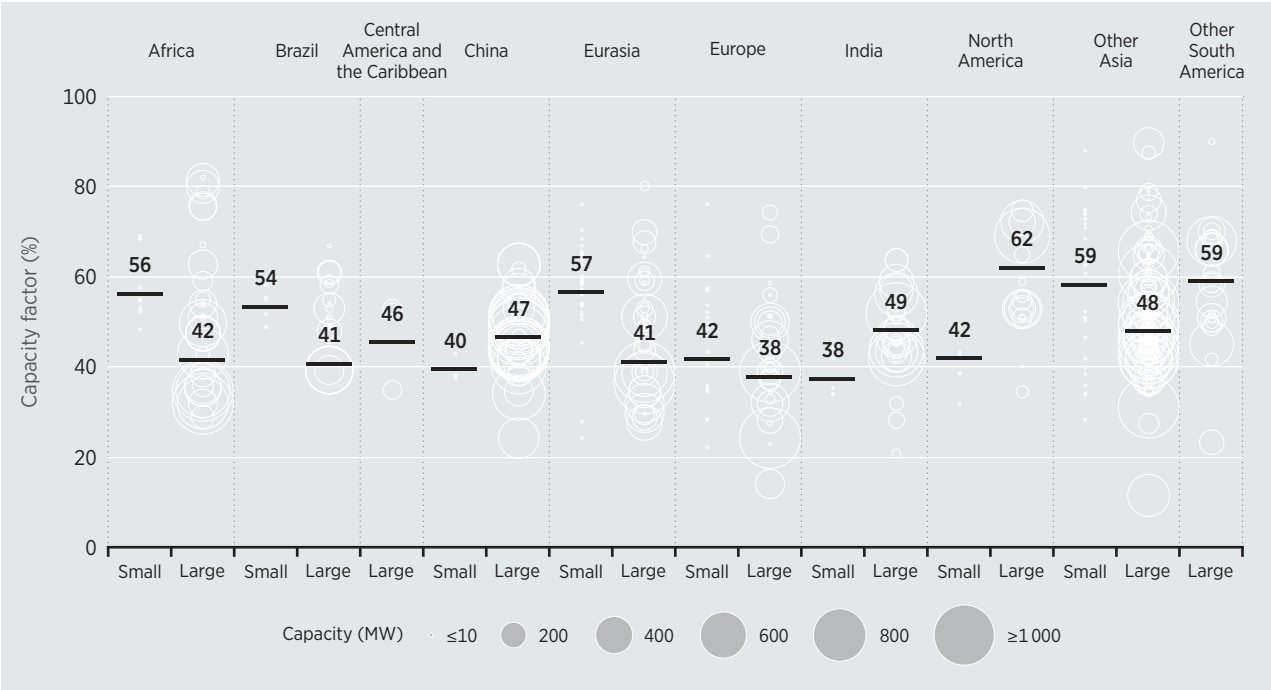
Figure 6.9 shows the regional differences in weighted-average capacity factors for both large and small hydropower projects for the 2018–2025 period. During this period, a limited number of newly-commissioned small hydropower projects appeared in the database for two regions – Other South America and Central America and the Caribbean. As a result, the weighted-average capacity factors for these regions are not considered representative.

Regional comparisons showed differences between large and small hydropower projects. In China, India, North America and Other South America, large hydropower projects generally recorded higher weighted-average capacity factors than small hydropower projects. In contrast, small hydropower projects exhibited higher weighted-average capacity factors in Africa, Brazil, Eurasia and Other Asia.

For large hydropower projects, weighted-average capacity factors ranged from around 38% in Europe to 62% in North America. For small hydropower projects, weighted-average capacity factors ranged from 38% in India to 59% in Other Asia. These regional differences reflect variations in hydrological conditions, reservoir storage capacity, plant design and operational strategies across hydropower systems.

Differences in operational strategies are also an important driver of regional variation in capacity factors. In Europe, hydropower is increasingly operated as a flexible resource to balance growing shares of wind and solar generation, resulting in lower capacity factors. In contrast, in some other regions, such as Other South America, hydropower plants operate closer to their technical capacity to meet baseload demand, leading to higher capacity factors (IHA, 2025a).

Figure 6.9 Capacity factors and weighted-averages for large and small hydropower projects by country/region, 2018–2025



Notes: "Other Asia" includes all Asian countries except China and India; "Other South America" includes all South American countries except Brazil; MW = megawatt.

6.5 OPERATION AND MAINTENANCE COSTS

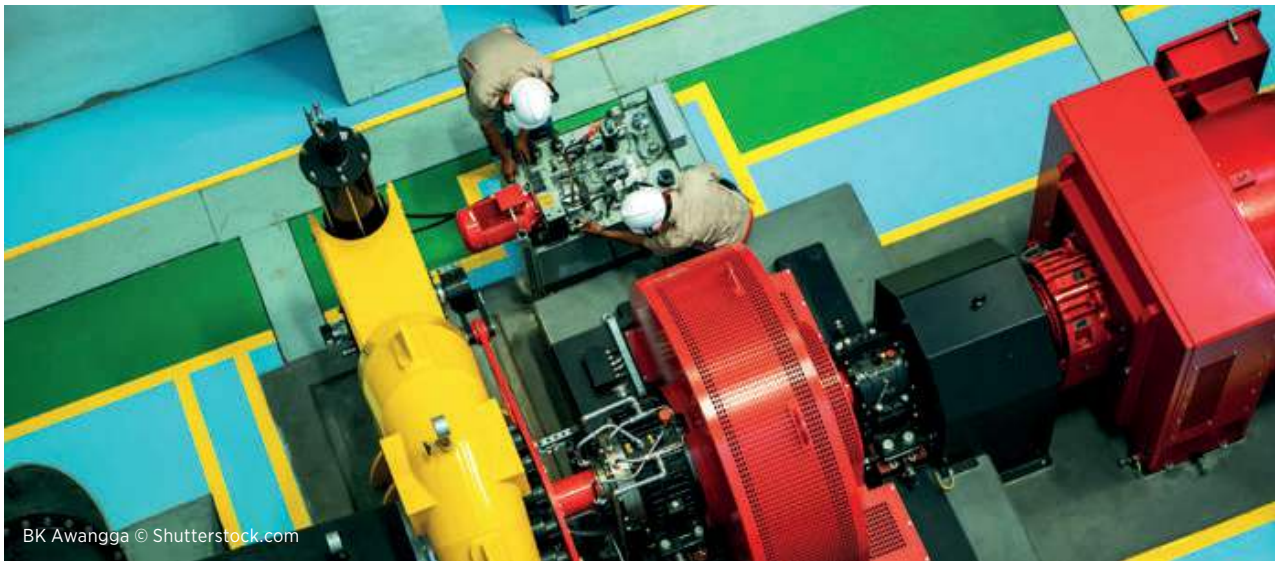
Annual O&M costs for hydropower are commonly expressed as a percentage of TICs per year, with typical values ranging between 1% and 4%. For the hydropower projects in the IRENA Renewable Cost Database, a value of 2% is used for large hydropower projects and 3% for small hydropower projects. This range is broadly consistent with the values reported in other studies (Greenpeace *et al.*, 2015; IPCC, 2011).

O&M costs are distributed across a range of activities. Previously, IRENA had collected O&M data on 25 projects commissioned between 2010 and 2016 (IRENA, 2018). Table 6.1 presents the cost distribution of individual O&M items in that sample. On average, operations accounted for 46% of hydropower O&M expenditure, salaries for 35%, other expenses for 15% and materials for 4%.

Table 6.1 Hydropower O&M costs by category from a sample of 25 projects

Project component	Share of total O&M costs (%)		
	Minimum	Weighted average	Maximum
Operational costs	20	**46**	61
Salary	13	**35**	74
Other	5	**15**	28
Material	3	**4**	4

These costs typically include routine maintenance and periodic refurbishment of mechanical and electrical equipment – such as turbine overhauls, generator rewinding and upgrades to communication and control systems. These costs, however, generally exclude major refurbishment or replacement of long-lived infrastructure components. These components include electro-mechanical equipment, penstocks, tailraces and civil works, which often have design lives ranging from several decades to more than a century.

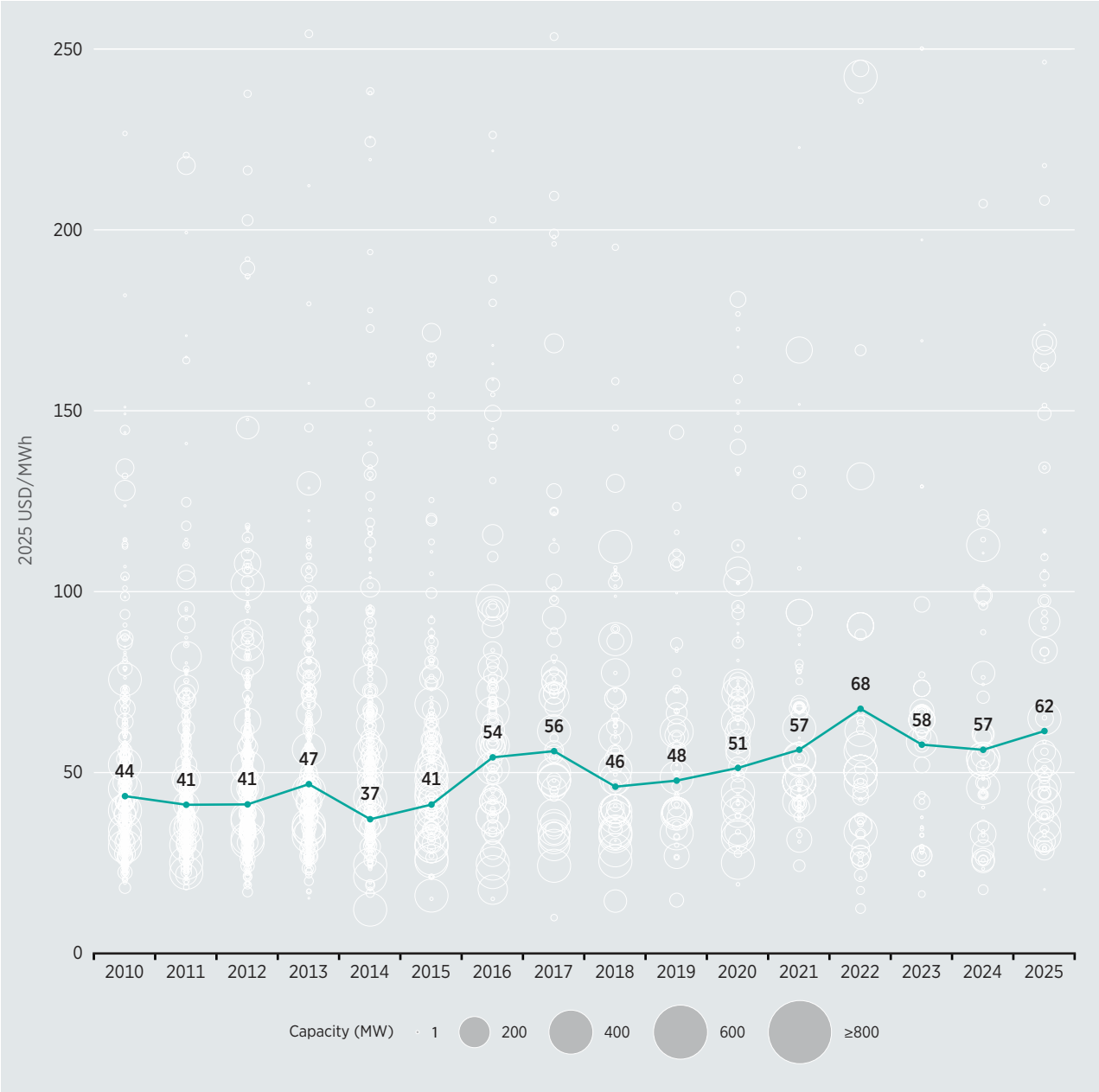


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6.6 LEVELISED COST OF ELECTRICITY

For hydropower projects commissioned in 2025, the global weighted-average LCOE[23] was USD 62/MWh, representing a 41% increase on 2010 (see Figure 6.10). Excluding China, the global weighted-average LCOE was USD 70/MWh, or 13% higher than the level when China was included. Between 2024 and 2025, the global weighted-average LCOE rose by 9%. In 2025, LCOE values ranged between USD 35/MWh and USD 227/MWh.

Figure 6.10 LCOE of hydropower projects and global weighted-average, 2010–2025



Notes: MWh = megawatt hour; USD = United States dollar.

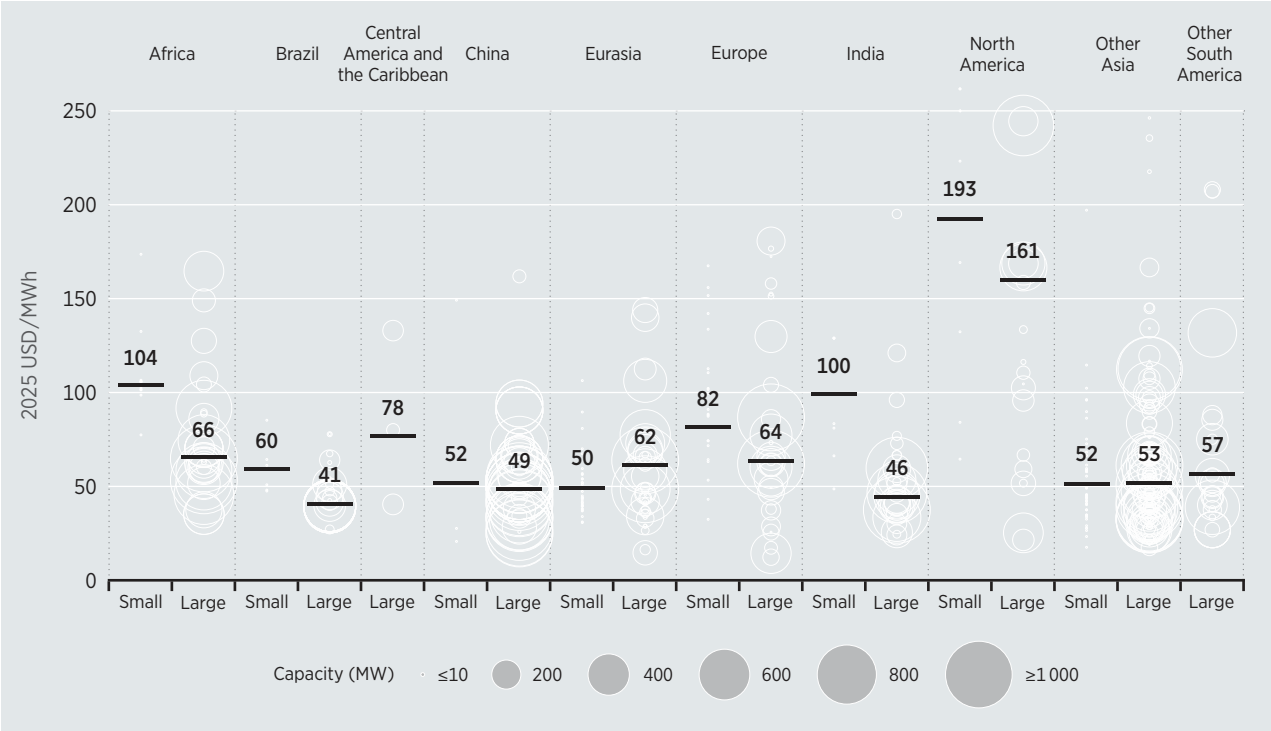
[23] *The LCOE assessment presented in this chapter assumes a conservative economic life of 30 years. The original investment is fully amortised by the time any significant re-investment is needed. Consequently, re-investment cost is not considered. Nevertheless, hydropower plants usually have longer lifetimes, which, depending on the components, are in the range 30 to 80 years.*

Figure 6.11 presents regional differences in weighted-average LCOE values for both large and small hydropower projects over the 2018–2025 period. During this period, the number of newly-commissioned small hydropower projects in the database for Other South America, and Central America and the Caribbean, was limited. As a result, the weighted-average LCOEs for these regions are not considered representative.

Large and small hydropower projects showed differences across regions. Large hydropower projects generally recorded lower weighted-average LCOE values than small hydropower projects in Africa, Brazil, China, Europe, India and North America. In contrast, small hydropower projects exhibited lower weighted-average LCOE values in Eurasia and Other Asia.

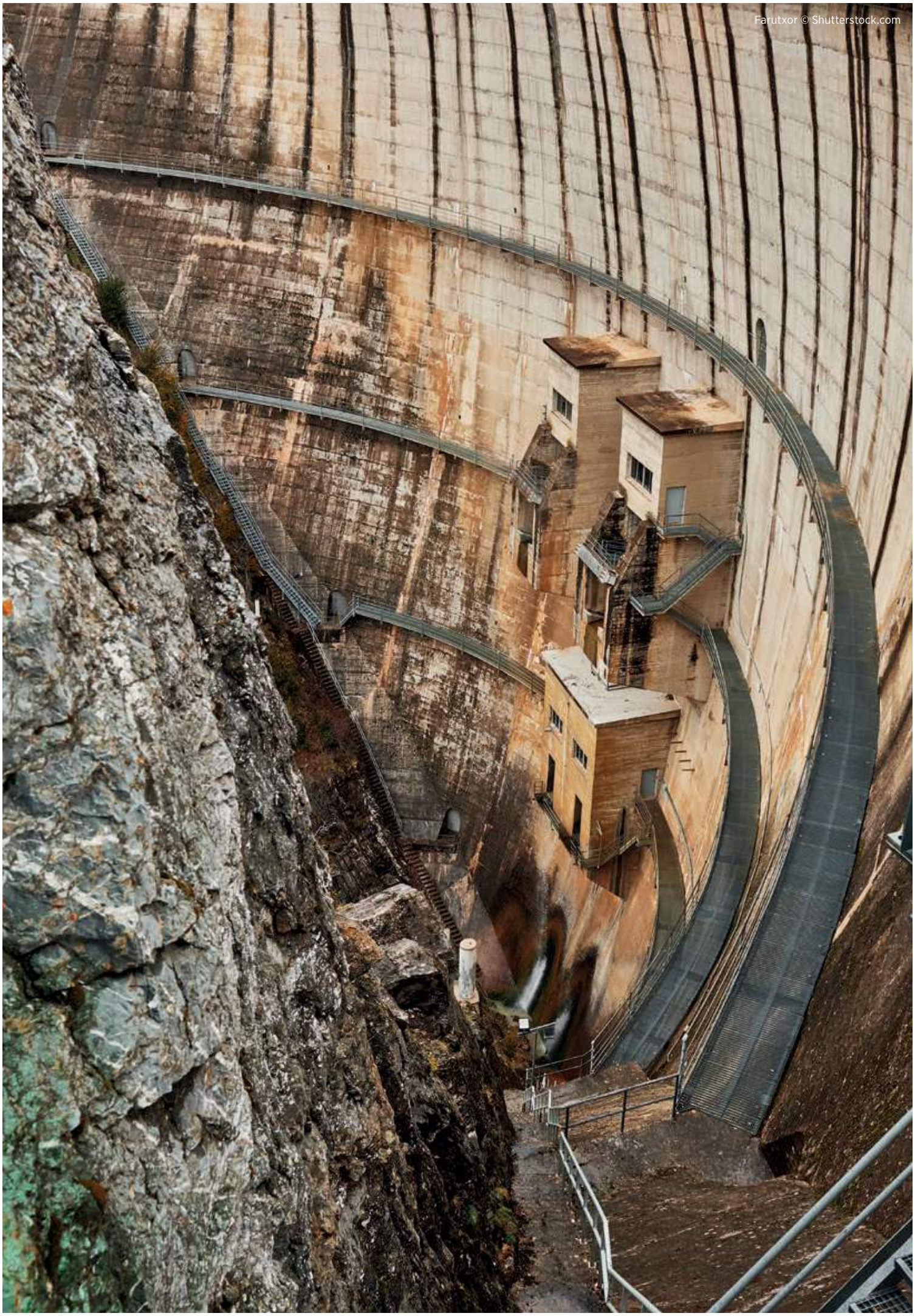
For large hydropower projects, weighted-average LCOE values ranged from around USD 41/MWh in Brazil to USD 161/MWh in North America. For small hydropower projects, weighted-average LCOE values ranged from USD 50/MWh in Eurasia to USD 193/MWh in North America. The latter value was influenced by projects in Canada that experienced very large cost overruns. These regional differences also reflected variations in hydrological conditions, project scale, financing structures, construction costs and operational strategies across hydropower systems.

Figure 6.11 LCOE and weighted-averages for large and small hydropower projects by country/region, 2018–2025



Notes: "Other Asia" includes all Asian countries except China and India; "Other South America" includes all South American countries except Brazil; MWh = megawatt hour; MW = megawatt; USD = United States dollar.

Beyond electricity generation, hydropower is a multi-purpose asset that provides additional services not captured in LCOE metrics, including system flexibility, energy storage and water management functions. Although the costs associated with these services are often included in overall project expenditure, their economic value is not reflected in the LCOE calculations presented in this chapter.


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07 GEOTHERMAL



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HIGHLIGHTS

Innovation in drilling, reservoir engineering and digital technologies is accelerating the transition from conventional to next-generation geothermal systems.

LCOE ⊕ 53%** ↑

Capacity factor ⊖ 3%*** ↓

in 2025 vs. 2024



TOTAL INSTALLED COSTS

For projects deployed in 2025, total installed costs ranged from a high of USD 8 141/kW to a low of USD 2 741/kW. The global weighted average total installed cost was USD 5 997/kW.





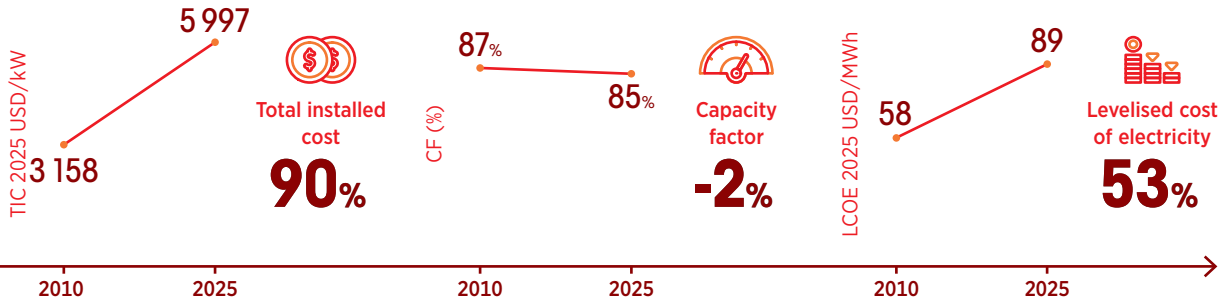
USD 5 997/kW



46%

in 2025 vs. 2024

KEY PARAMETERS**



TOP MARKETS

Capacity additions (GW) in 2025



Outlook

In the Unites States, the pipeline of new geothermal plants is robust (1 640 MW of PPAs) and indicates future cost declines. With WACC driving nearly half of LCOE, financing conditions will move geothermal economics more than any other renewable.



* Levelised cost of electricity; ** All values are weighted averages; *** All changes in capacity factor are expressed in percentage points.

7.1 INTRODUCTION

Cumulative installed capacity at the end of 2025 reached around 15.7 GW, this was 13% higher than in 2020 (IRENA, 2026a). In 2025, 273 MW of geothermal power generation have been commissioned, 20% less additions compared to 2024.

New projects were mainly deployed in Indonesia (a total of 105 MW) – the market leader in cumulative capacity – and in the Philippines (a total of 106 MW). In the same year, a strategic partnership between institutions from both countries was established to develop geothermal projects with an estimated 440 MW capacity across multiple sites in Indonesia. The country holds around 40% of the world's geothermal reserves (Nasruddin *et al.*, 2016) but only a small portion has been developed. This partnership reflects growing regional investment aimed at expanding clean, reliable power generation and supporting long-term energy security (FirstGen, 2025).

The United States is the second largest market by cumulative installed capacity, representing 17% of the global total. The country has 54 projects under development and over 1640 MW of new capacity to be deployed based on signed PPAs, of which 60% are for next-generation geothermal plants (Akindipe *et al.*, 2026). The recent growth in the geothermal industry is being driven in large part by rising demand for reliable electricity from data centres. Major technology companies are already investing in geothermal energy to secure constant, reliable electricity for their operations. In 2025, XGS Energy and Meta announced an agreement for up to 150 MW of next-generation geothermal power to support the operation of a data centre in New Mexico, with deployment planned by 2030 (GeoEnergy and Cariaga, 2025).

In Europe, the geothermal project pipeline currently includes around 50 geothermal power plants at various stages of development, ranging from early exploration and drilling activities to grid connection readiness (EGEC, 2025).

Historically, geothermal power generation depended on hydrothermal resources where underground rock formations were both naturally hot and permeable, allowing water to circulate through fractures and transport heat to the surface. These geological conditions exist in only a limited number of locations, rendering geothermal energy a niche source of electricity globally, despite offering reliable, low-emission baseload power.

However, advances in next-generation geothermal technologies have significantly expanded the potential for geothermal development. New approaches can now create or enhance subsurface flow pathways artificially, removing the need for naturally occurring permeability. Combined with improvements in deep drilling techniques and more efficient power-conversion systems capable of generating electricity from lower-temperature resources, these innovations are opening a much broader range of geological settings for geothermal deployment (EMBER, 2026b). While these technologies are still in pilot or early commercial stages, developers are increasingly moving beyond traditional hydrothermal systems and exploring enhanced geothermal, super rock and closed-loop geothermal systems aimed at unlocking geothermal resources at much larger scale.

7.2 TECHNOLOGICAL TRENDS

Recent innovation in the geothermal sector is focused on improving exploration accuracy, reducing drilling costs, and expanding deployment beyond conventional hydrothermal resources. Advances in drilling technologies include hybrid high-pressure water jet and percussion systems for faster penetration through hard rock; new well designs, such as deep multilateral closed loops; and autonomous robotic drilling systems like Switzerland's "Grabowski" robot for shallow geothermal projects. Artificial intelligence and digitalization are also playing an increasingly important role across the geothermal value chain, with AI-enabled tools being used to analyse seismic and subsurface data in real time; improve drilling success rates; optimise reservoir modelling; and support operational decision-making through digital twins. Exploration campaigns are also becoming more sophisticated, employing 3D seismic surveys, fibre optic sensing, airborne geophysical surveys and advanced forward modelling techniques to better identify viable geothermal reservoirs and reduce development risk (EGEC, 2025).

Together, these innovations are accelerating the commercialisation of next-generation geothermal systems and creating new opportunities for geothermal deployment across a much wider range of geological settings. With the resurgence of global interest in reliable, low-carbon baseload power, the growth of next-generation geothermal will depend on attracting new investment, scaling emerging technologies, and overcoming regulatory and permitting barriers. Government support is also playing an important role, particularly in the United States, where a growing number of state-level incentive and regulatory frameworks are helping to encourage geothermal development. Continued technological innovation and supportive policies will be critical to unlocking the sector's full potential.

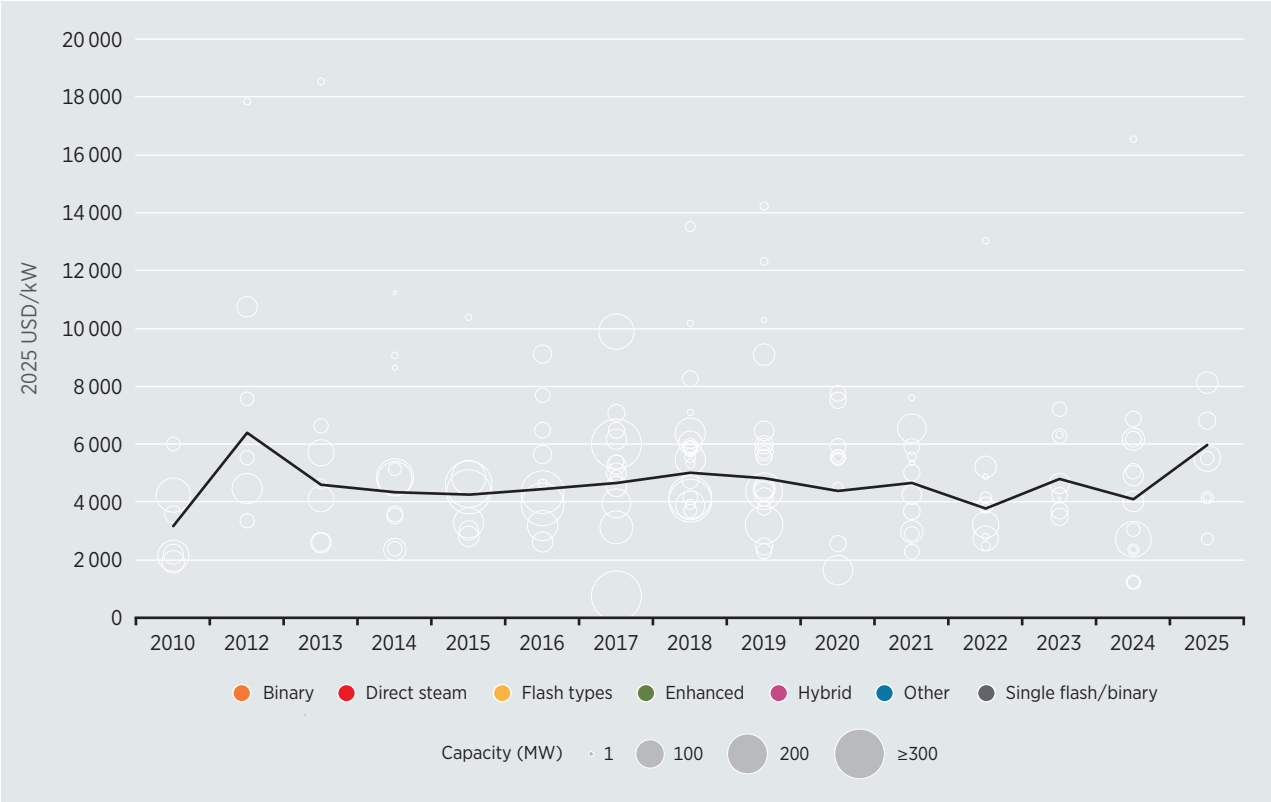


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7.3 TOTAL INSTALLED COST

For projects deployed in 2025, TIC ranged from a high of USD 8 141/kW to a low of USD 2 741/kW (see Figure 7.1). TICs reflect the specific costs of the geothermal generation plant, which includes factors such as the cost of exploration, plant equipment and construction, as well as balance-of-system and financial costs.

Figure 7.1 TICs of geothermal power projects by technology and project size, 2010–2025



Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.

In 2025, the global weighted-average TIC was USD 5 997/kW. Since 2010, this has fluctuated annually – owing to the limited number of new geothermal plants – with cost trends largely influenced by the specific locations where projects are commissioned.

Project development, field preparation, production and reinjection wells, the power plant and associated civil engineering works entail significant upfront costs for geothermal projects. These are also subject to variations in drilling costs, which have a direct impact on the costs of engineering, procurement and construction (EPC) and are in turn often influenced by the business cycle in the oil and gas industry.

In particular, geothermal power project costs are heavily influenced by reservoir quality, *i.e.* temperature, flow rates and permeability. This is because reservoir quality influences both the type of power plant and the number of wells required to achieve a given capacity. The nature and extent of the reservoir, its thermal properties and its fluids (and at what depths they lie) 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 a hybrid approach to providing the steam that drives the turbine to 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. This is because extracting the electricity from lower temperature resources is more capital intensive.

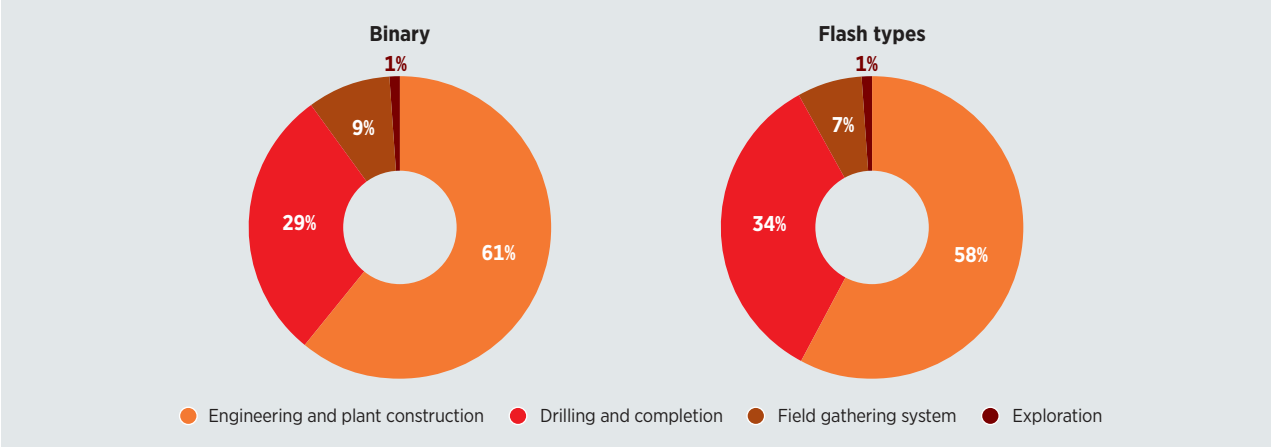
The TIC of geothermal power plants also include the cost of exploration and resource assessment, such as for seismic surveys and test wells. This cost category also applies to solar and wind resources, but resource assessment with weather stations costs much less than that for geothermal power plants.

Considering the cost breakdown for binary and flash type technologies (see Figure 7.2), aside from engineering and plant construction that represent from 58% to 61% of the plant cost, drilling is one of the major drivers, typically accounting for between 29% and 34% of the total. Indeed, drilling costs can be even higher, reaching up to 57% of the TICs for deep EGS binary technology (Akindipe *et al.*, 2026).

As a result, improving drilling efficiency is critical. Recently, major gains have been achieved in this area by developers, cutting drilling times by over 60% across horizontal development wells in high temperature and deep granite contexts (Fervo Energy, 2024). This has occurred in both pilot and commercial-scale projects (Adie, 2025).

Furthermore, 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.

Figure 7.2 Cost breakdown of geothermal power plants by technology



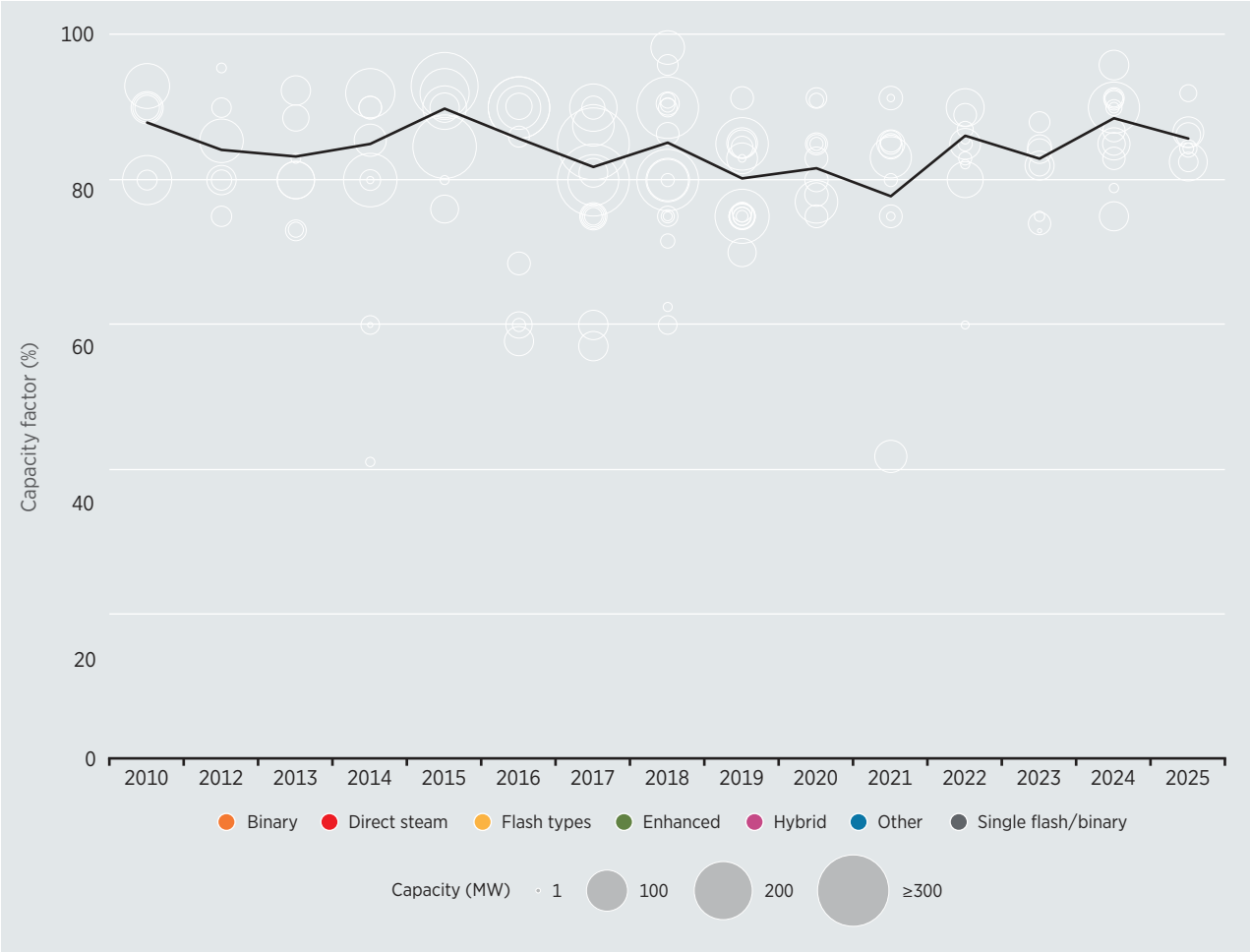
Source: (Akindipe *et al.* 2026)

7.4 CAPACITY FACTOR

By accessing steam or heated water near the Earth's surface, geothermal plants have a continuous source of energy and tend to operate during most times of the year. For projects commissioned between 2010 and 2025, geothermal power plants typically have capacity factors that range from 60% to 96%, albeit with some exceptions. There were, however, significant variations by project and – to a lesser extent – by country.

For the 2010–2025 period, Figure 7.3 presents the capacity factors of geothermal power projects in the IRENA renewable costs database by year, project size and technology. Where available, the capacity factors used here were taken from project data, while national averages were used if no specific project information was available.

Figure 7.3 Capacity factors of geothermal power projects by technology and project size, 2010–2025



Notes: MW = megawatt

In 2025, the global weighted-average capacity factor for newly-commissioned geothermal projects was 85%. Looking at the different technologies, flash type plants had a capacity factor of 86%, while the weighted-average for binary plants was 90%.

7.5 OPERATION AND MAINTENANCE COSTS

Geothermal power projects require continuous optimisation throughout their lifetime. The sophisticated reservoir and production well-management required to ensure output meets expectations also lead to higher O&M costs.

Once geothermal plants are commissioned, the management of the plant and its reservoir becomes a dynamic and evolving process. Geothermal operations require ongoing adjustment as reservoir fluid is extracted and reinjected throughout the life of the project. To maintain production at the designed capacity factor, the reservoir and production profile of the geothermal power plant therefore require agile management. Over time the reservoir pressure around the production well can decline, leading to poorer flow rates. The performance of individual production wells is influenced by the natural change in fluid migration patterns, and productivity deteriorates over time. Typically, additional complementary wells will be required over the lifetime of the plant as productivity at existing wells declines. 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.

As operational experience grows, however, operators' understanding of a reservoir's behaviour improves, enabling more effective management of the plant over time.

The O&M cost applied for all projects deployed in 2025 was USD 128/kW/year, a value that includes two sets of wells for makeup and reinjection – necessary to maintain performance over the 25-year life of the project.

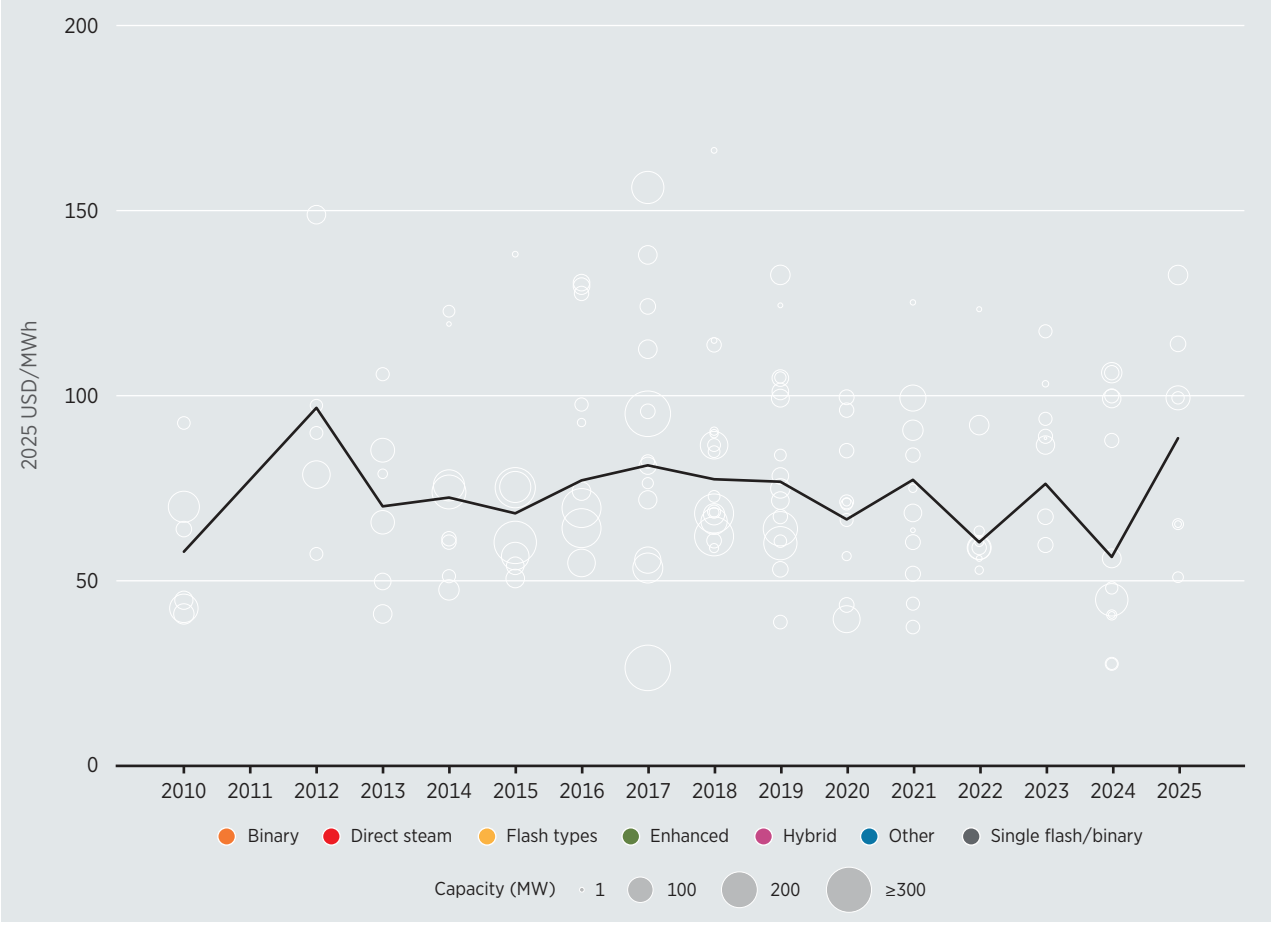

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7.6 LEVELISED COST OF ELECTRICITY

The LCOE of geothermal power projects tends to follow the trend in TICs, with typically little variation in capacity factor, considering the diversity of geothermal technologies. Geothermal power plants have higher TIC, O&M costs and capacity factors than other renewable energy technologies. The higher capacity factors help to offset the higher capital and operating costs, and plants run during most hours of the day. Financial costs continue to remain a significant factor in relation to LCOE. For projects commissioned in 2025, the average share of WACC in total LCOE was 45%, followed by TIC at 33% and O&M at 22%.

Figure 7.4 presents the LCOE of geothermal power projects by technology and size for the period 2010–2025. During 2025, the LCOE varied from as low as USD 45/MWh to as high as USD 110/MWh.

Figure 7.4 LCOE of geothermal power projects by technology and project size, 2010–2025



Notes: MW = megawatt; MWh = megawatt hour; USD = United States dollar.

In 2025, the global weighted-average LCOE was USD 89/MWh. Year-on-year variations should be interpreted with caution, however, owing to the lower deployment levels of geothermal power compared with other technologies, as well as the fact that project pipelines vary significantly from year to year. The cost trend in 2025 reflects the deployment of projects in Indonesia (+105 MW) and the Philippines (+106 MW), while in 2024, deployment was mainly in New Zealand (+225 MW) (IRENA, 2026a).


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08 BIOENERGY



Flash Vector © Shutterstock.com

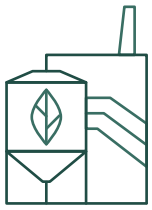
HIGHLIGHTS

Bioenergy recorded higher total installed costs and capacity factors, driving a slight decline in the global weighted average LCOE.*

LCOE − 2%** ↓

Capacity factor + 5%*** ↑

in 2025 vs. 2024



TOTAL INSTALLED COSTS

Total installed costs increased due to shifts in the geographic and technology mix of new projects. India reported the lowest costs at USD 1 687/kW, and North America the highest at USD 4 945/kW.

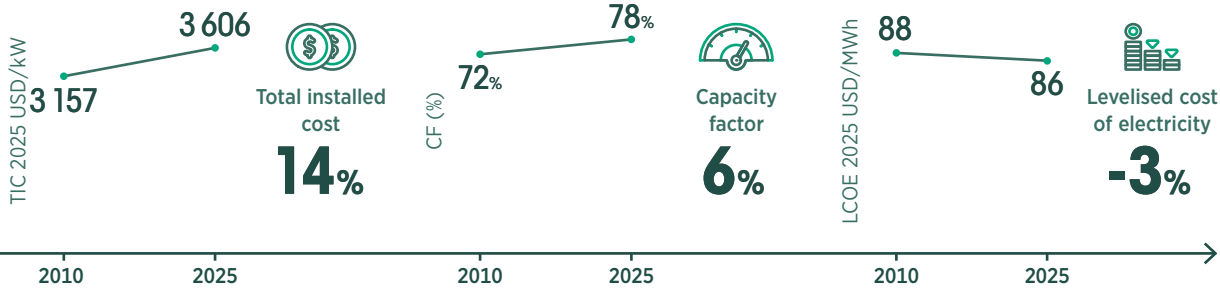


USD 3 606/kW

9%

in 2025 vs. 2024

KEY PARAMETERS**



TOP MARKETS

Capacity additions (GW) in 2025



Outlook

Bioenergy delivers renewable power alongside waste management, emissions reduction and system flexibility. Key trends to watch include feedstock stability, decarbonisation, plant optimisation, and the increasing value of its dispatchable and waste-management benefits.



* Levelised cost of electricity; ** All values are weighted averages; *** All changes in capacity factor are expressed in percentage points.

8.1 INTRODUCTION

Bioenergy is the fourth-largest renewable technology in terms of cumulative installed capacity, having expanded by 3.4 GW in 2025 to reach 154 GW. Bioenergy capacity additions fell by 14% compared with 2024 and accounted for 0.5% of total annual renewable capacity additions in 2025 (IRENA, 2026a).

Bioenergy encompasses solid, liquid and gaseous biofuels, as well as renewable municipal and industrial waste. In 2025, solid biofuels, such as woodchips, pellets and bagasse, remained dominant, representing around 70% of total installed capacity. Renewable municipal waste followed, accounting for 28% of capacity additions (IRENA, 2026a). Feedstock composition varies across regions, depending on resource availability, infrastructure and policy frameworks.

In 2025, Japan, China and Brazil accounted for 71% of global additions. In Japan, growth has been driven by feed-in tariff (FIT) and feed-in premium (FIP) schemes, highlighting the importance of stable and predictable revenue frameworks (METI, 2025). China benefits from abundant feedstock availability combined with supportive policies, and is building infrastructure and feedstock supply chains for future acceleration (IEA, 2024b; SCIO, 2025). In Brazil, strong policy, combined with abundant agricultural residues, expanding regulation and growing demand driven by blending mandates, has supported bioenergy expansion (Navarro, 2025). These trends reflect the role of policy frameworks, resource availability and industrial capacity in shaping bioenergy deployment.

8.2 TECHNOLOGICAL TRENDS

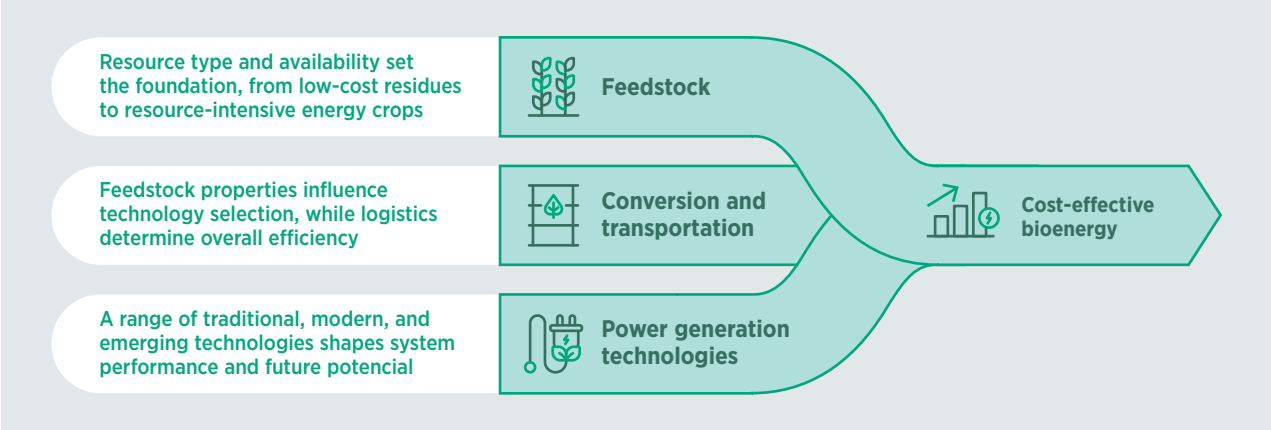
Bioenergy is becoming smarter, more flexible and more integrated into modern energy systems. Innovations in the sector are expanding its role in decarbonisation and optimising plant performance. Bioenergy with carbon capture and storage (BECCS) can deliver net-negative emissions and represents a strategic option for achieving long-term climate goals (IRENA, 2022b). Digital twins for bioenergy plant management allow operators to simulate different scenarios and optimise energy production in real time – advancements that enhance economic viability and make bioenergy systems smarter, more adaptable and efficient (IRENA, 2025c). At the same time, bioenergy's dispatchable generation supports grid stability alongside variable renewables.

8.3 TOTAL INSTALLED COST

Electricity generation from bioenergy is shaped by three fundamental factors: the type and availability of feedstock; the conversion and transportation processes; and the power generation technologies employed (see Figure 8.1). These elements collectively determine the performance, cost-effectiveness and sustainability of bioenergy systems.

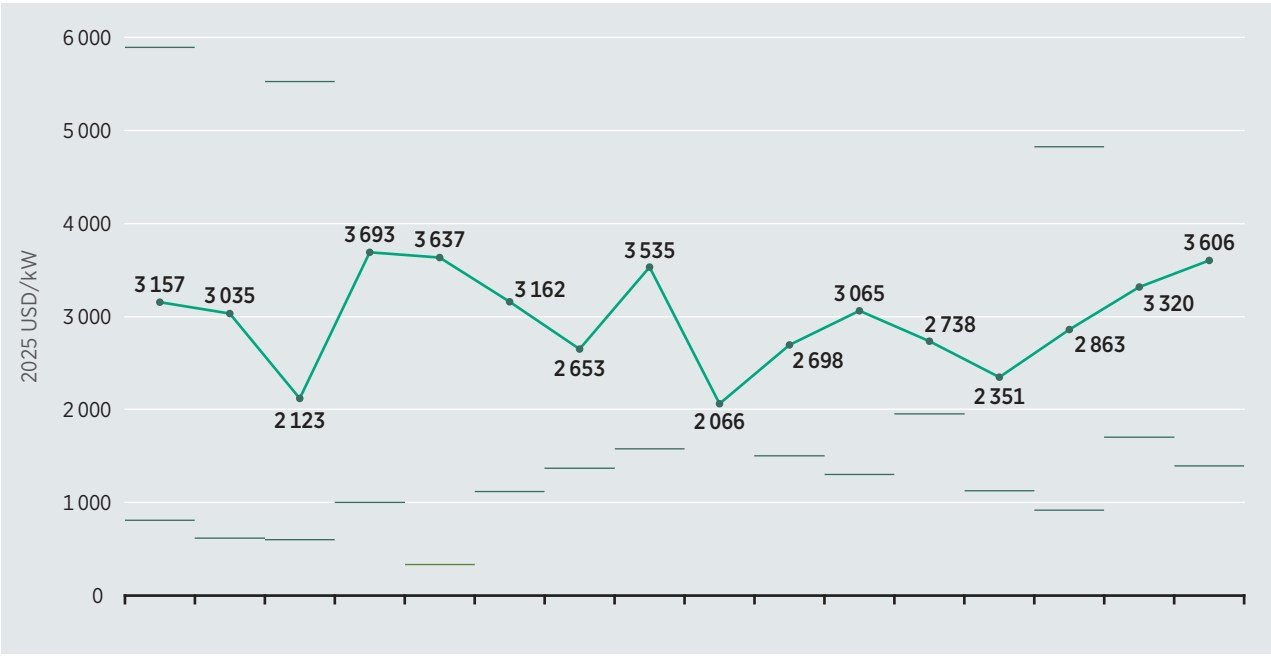
Equipment typically represents the largest share of TICs, while infrastructure and logistics become increasingly significant in remote or off-grid locations. Although combined heat and power biomass systems involve higher upfront investment, their high efficiency (80–85%) and ability to supply heat and steam for industrial processes or district heating can substantially improve overall project viability.

Figure 8.1 Factors shaping TIC from bioenergy



For bioenergy projects commissioned in 2025, the global weighted-average TIC was USD 3 606/kW, representing a 14% increase since 2010 (see Figure 8.2). TICs have fluctuated considerably since 2010, reflecting differences in technology maturity, project characteristics and deployment patterns across markets. In 2025, TICs ranged between USD 1 396/kW and USD 10 273/kW (5th to 95th percentiles), and rose by 9% compared to 2024.

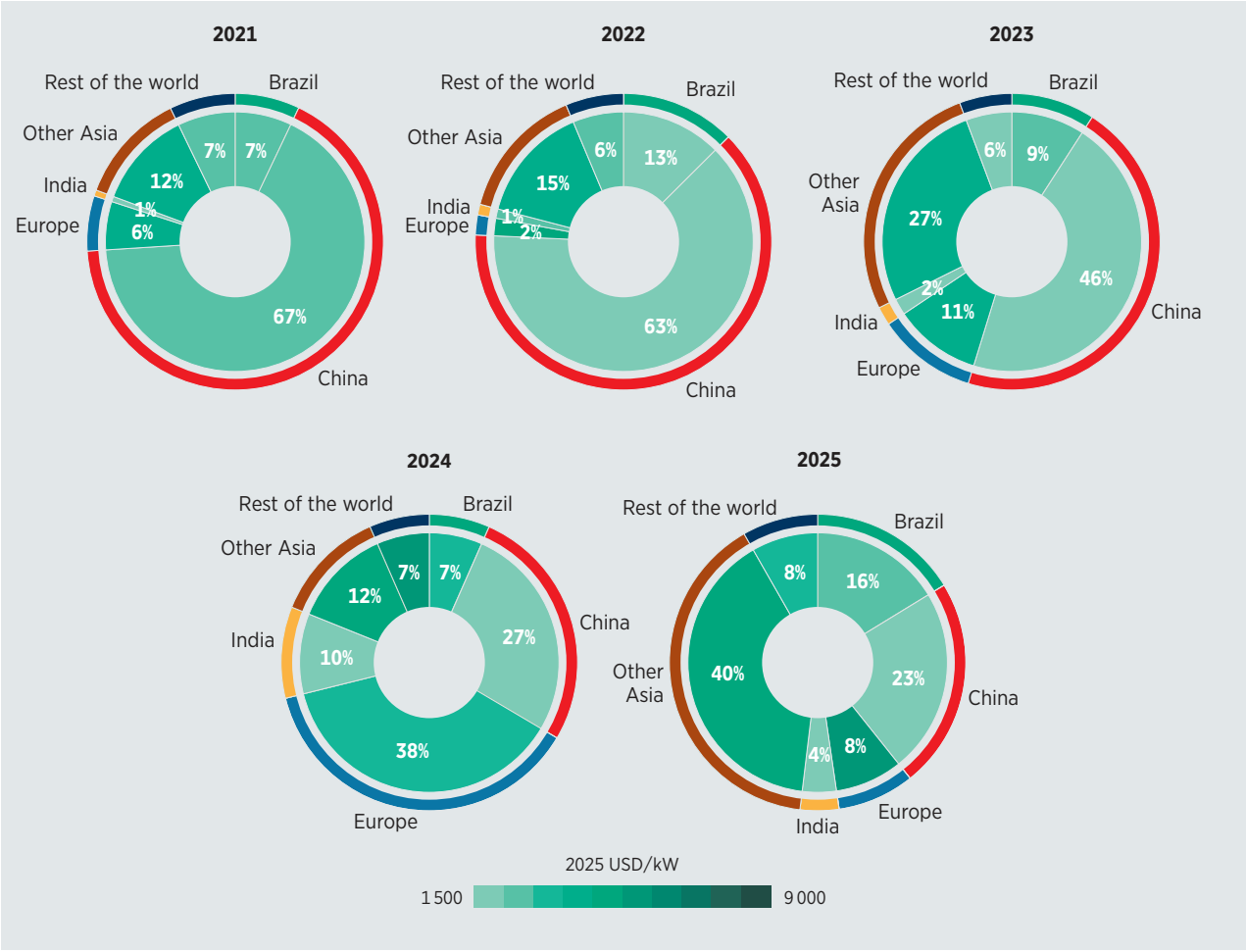
Figure 8.2 TICs of bioenergy projects and global weighted-average, 2010–2025



Notes: kW = kilowatt; USD = United States dollar.

Bioenergy TIC is sensitive to changes in the geographic and technological mix of new projects commissioned each year. Regional costs have remained stable. As illustrated in Figure 8.3, the rise in TIC in 2025 is not a result of technology becoming intrinsically more expensive, but rather a shift in the geographic composition of new capacity toward higher-cost contexts. Over the past five years, weighted-average TICs across regions have remained within a broadly similar range, with China and India consistently recording the lowest values.

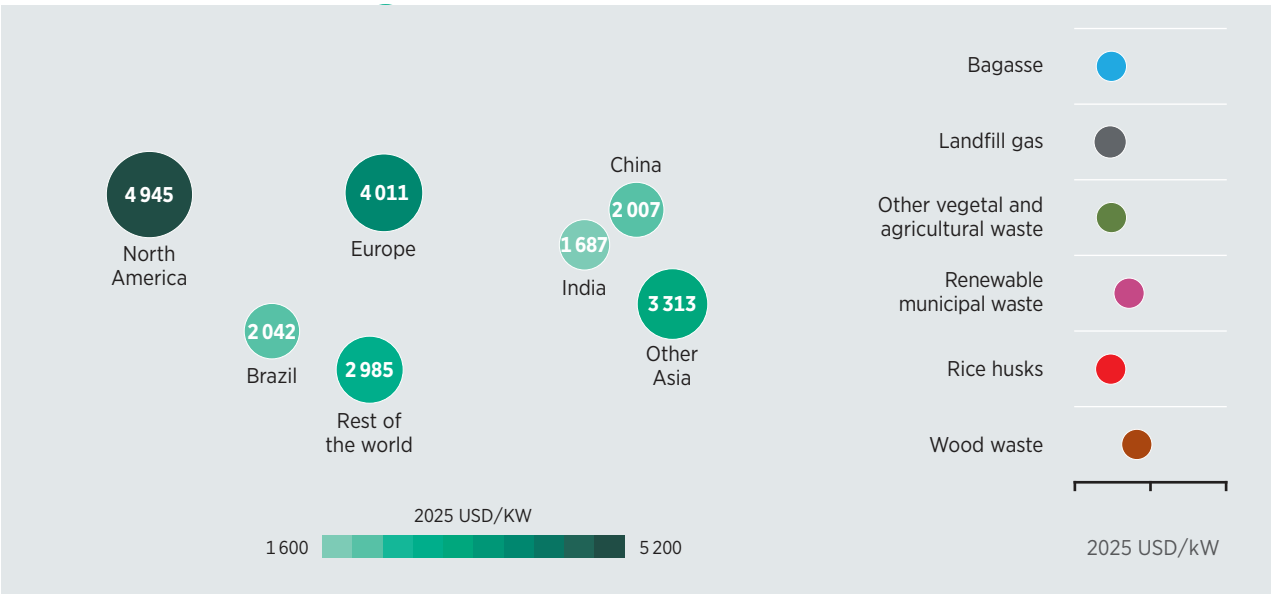
Figure 8.3 Bioenergy capacity additions share and weighted-average TIC, 2021–2025



Notes: kW = kilowatt; USD = United States dollar.

Figure 8.4 presents weighted-average TICs by region/country and feedstock type in the 2010–2025 period. TICs tend to be higher in North America and Europe across all feedstock categories, with values reaching USD 4 945/kW in North America and USD 4 011/kW in Europe. In contrast, China and India record significantly lower TICs, with India showing the lowest weighted-average TIC at USD 1 687/kW, reflecting the concentration of lower-cost project types and the availability of lower-cost feedstocks. Regarding feedstock type, bagasse, landfill gas, other vegetal and agricultural waste, and rice husk projects form a lower-cost cluster, with weighted-average TIC of around USD 2 300/kW. By contrast, projects using renewable municipal waste and wood waste generally exhibit higher TICs, exceeding USD 3 500/kW.

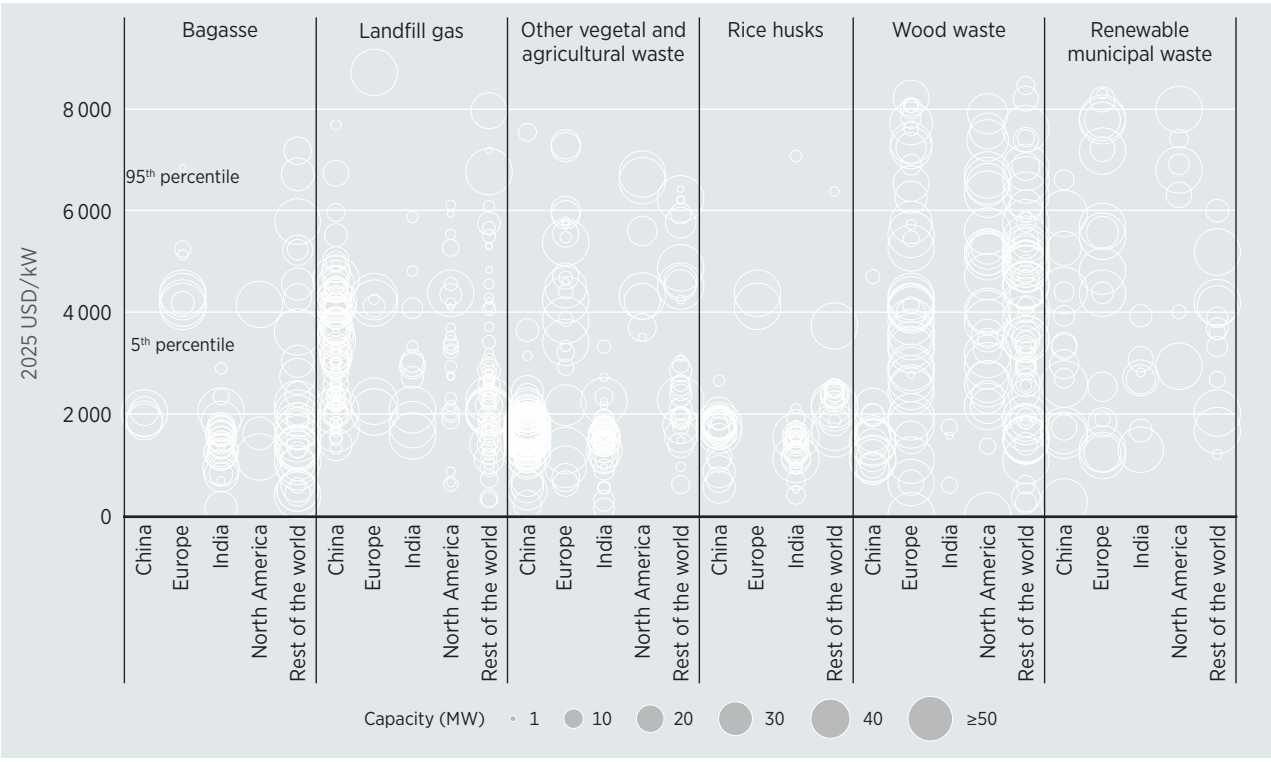
Figure 8.4 Weighted-average TICs of bioenergy projects by country/region and selected feedstocks, 2010–2025



Notes: kW = kilowatt; USD = United States dollar.

More detailed country and feedstock-level analyses (see Figure 8.5) highlight this variation. The highest weighted-average TIC is observed for renewable municipal waste projects in Europe, at USD 6 474/kW, while the lowest is for rice husk projects in India, at USD 1275/kW.[24]

Figure 8.5 TICs of bioenergy projects by selected feedstocks and country/region, 2010–2025



Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.

[24] *These figures exclude the TICs for wood waste, which are not representative given the small sample available.*

8.4 CAPACITY FACTOR

For bioenergy, the availability of feedstock over time influences generation potential. Plants with stable year-round feedstock availability can achieve capacity factors of 85–95%, while those reliant on seasonal agricultural cycles often operate at lower capacity factors. Climate change may increasingly affect biomass feedstock availability, as changing precipitation patterns, droughts and seasonal variability can influence both biomass supply and plant capacity factors. This highlights the importance of climate-resilient supply chains and long-term resource planning (IRENA, 2025d).

Figure 8.6 presents the weighted-average annual capacity factor for bioenergy power projects commissioned between 2010 and 2025. Over this period, values have remained in the range of 67–86%. In 2025, the global weighted-average capacity factor stood at 78%, an increase of five percentage points compared to 2024, and ranged between 71% and 90% (5th to 95th percentiles).

Figure 8.6 Capacity factor of bioenergy projects and global weighted-average, 2010–2025

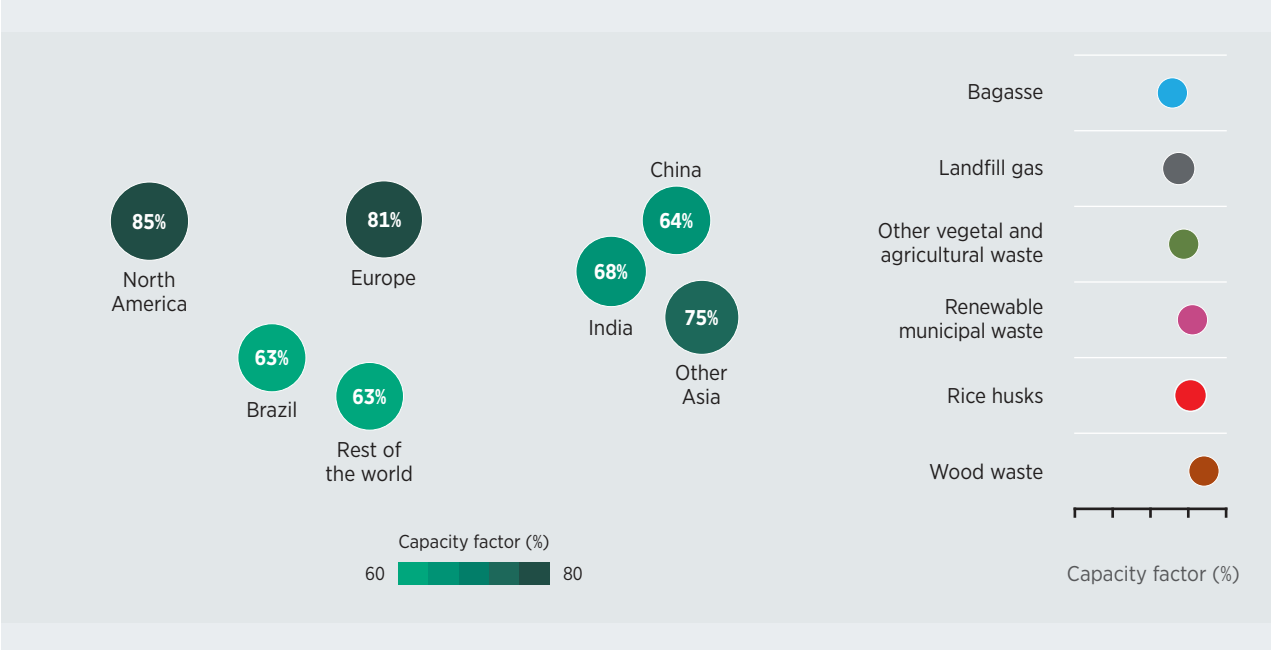


The global weighted-average capacity factor is also influenced by the geographic distribution of newly commissioned projects. The five-percentage point increase observed in 2025 reflects a growing share of capacity in Other Asia, where in some markets biomass plants tend to use imported feedstocks such as wood pellets and palm kernel shells (USDA, 2023). The use of long-term procurement contracts reduces reliance on seasonal agricultural residues, enabling more stable and continuous operation. Reinforcing this, policy frameworks such as feed-in tariff schemes, create strong financial incentives to maximise output and operate continuously, further driving capacity factors upward.

Capacity factors also vary considerably across regions and feedstocks. According to the IRENA renewable cost database, North America recorded the highest weighted-average capacity factor over the 2010–2025 period at 85%, followed closely by Europe at 81% (see Figure 8.7). In contrast, Brazil and the rest of the world recorded the lowest weighted-average capacity factors, both at 63%.

Feedstock type is an equally significant driver of variation. Between 2010 and 2025, bioenergy plants relying on bagasse operated at lower weighted-average capacity factors (62%), reflecting the seasonal nature of sugarcane harvests, which limits fuel availability to certain months of the year. In contrast, plants using renewable municipal solid waste achieved higher weighted-average capacity factors (82%), benefiting from more consistent and year-round feedstock availability.

Figure 8.7 Weighted-average capacity factors of bioenergy projects by country/region and selected feedstocks, 2010–2025



8.5 OPERATION AND MAINTENANCE COSTS

Fixed O&M costs encompass labour, insurance, scheduled maintenance and the routine replacement of key plant components – including boilers, gasifiers and feedstock handling equipment. Across the bioenergy power sector, these costs typically represent between 2% and 6% of TICs annually, with larger plants generally achieving lower per-kW fixed O&M costs because of economies of scale.

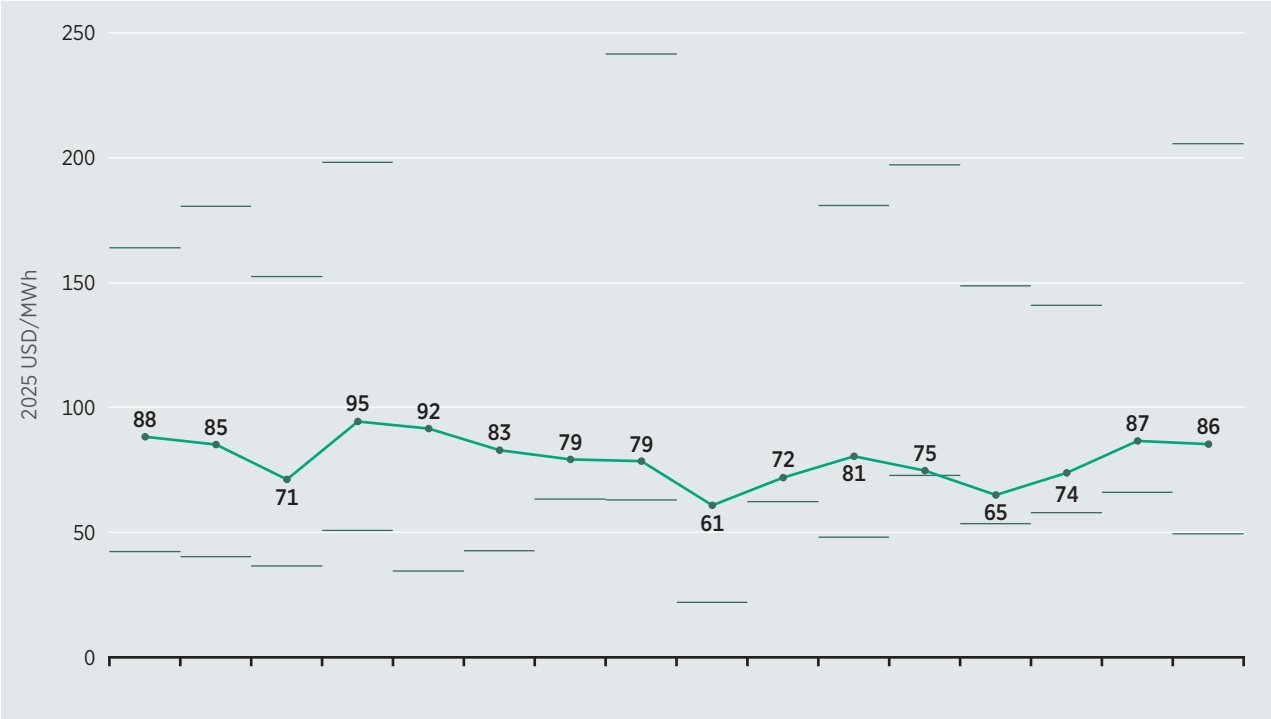
Variable O&M costs tend to be lower than their fixed counterparts, averaging approximately USD 0.004/kWh. These costs are primarily driven by replacement parts, incremental servicing requirements and non-biomass operational expenses such as ash disposal. Given the project-specific nature of these cost components and the limited availability of disaggregated data, this report presents fixed and variable O&M costs on a combined basis.

8.6 LEVELISED COST OF ELECTRICITY

The LCOE of bioenergy reflects the diversity of the sector. Variations in TICs, capacity factors, feedstocks and technology pathways give rise to a wide range of observed LCOEs, making bioenergy one of the most context-dependent of all renewable energy sources.

For bioenergy projects commissioned in 2025, the global weighted-average LCOE was USD 86/MWh, representing a 3% decrease since 2010 (see Figure 8.8). Between 2024 and 2025, LCOE fell by 2%. In 2025, LCOE values ranged between USD 49/MWh and USD 206/MWh (5th to 95th percentiles).

Figure 8.8 LCOE of bioenergy projects and global weighted-average, 2010–2025



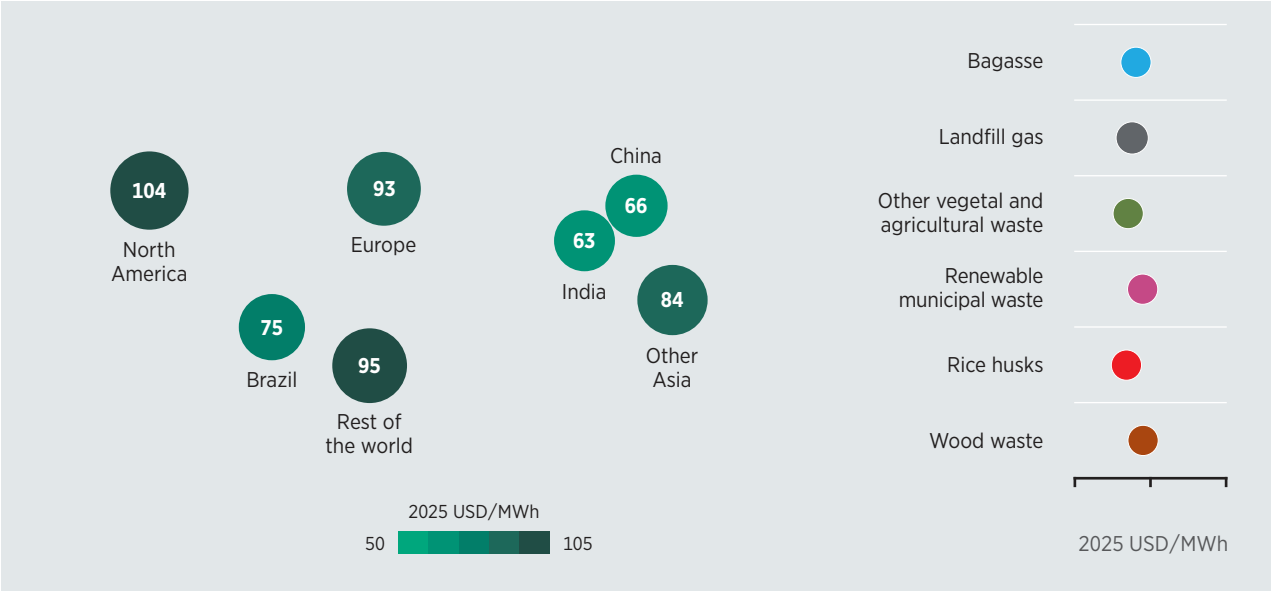
Notes: MWh = megawatt hour; USD = United States dollar.

Figure 8.9 presents the LCOE for bioenergy projects by country, region and feedstock, based on data from the IRENA renewable cost database, and where sufficient data exists to provide meaningful insights.

Over the 2010–2025 period, weighted-average LCOEs ranged from USD 63/MWh in India to USD 104/MWh in North America. As discussed above, the low values recorded in India and China reflect a combination of lower capital costs and the widespread availability of low-cost feedstocks in these markets.

Across feedstock types, rice husk-based projects recorded the lowest weighted-average LCOE at USD 68/MWh, consistent with their comparatively low TICs and the abundance of this residue in key producing markets. In contrast, wood waste projects recorded the highest weighted-average LCOE at USD 91/MWh. While wood waste benefits from relatively stable capacity factors, its comparatively elevated TICs result in a higher LCOE than other feedstock categories.

Figure 8.9 Weighted-average LCOE of bioenergy projects by country/ region and selected feedstocks, 2010–2025



Notes: MWh = megawatt hour; USD = United States dollar.



09 ENERGY STORAGE



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HIGHLIGHTS

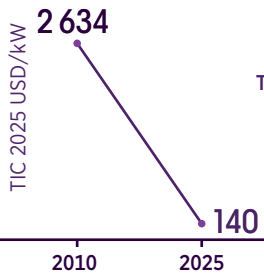
The expansion of energy storage is accelerating the transition towards more dynamic and responsive electricity systems.



KEY PARAMETERS FOR SHORT DURATION BESS

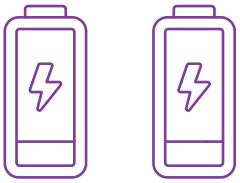
New annual capacity additions reached 307 GWh of gross capacity in 2025, this is 67% higher than in 2024

Total installed cost

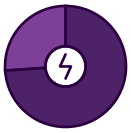


Total installed cost
95%

Chemistry - LFP* share



Application - energy shifting



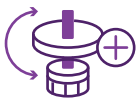
Share in 2025
74%

Capacity added
83 GW
241 GWh

KEY PARAMETERS FOR LONG DURATION STORAGE

Pumped storage hydropower

Pumped storage hydropower dominated the LDES lanscape with a total installed capacity of 160 GW in 2025. This is a 7% increase compared to 2024.



Additions PSH
200 GWh



TIC 2025 USD/kWh
153

Emerging LDES

The global total installed capacity for emerging LDES reached 5.1 GW in 2025, representing a cumulative energy capacity of 25.6 GWh.



Additions emerging LDES
9.6 GWh

Outlook

Battery storage is expected to continue its rapid growth as renewable energy assets are increasingly paired with BESS and AI-driven data center growth increases demand for reliable backup power. The viability and performance of LDES for extended storage needs are expected to improve as technology advances and practical experience grows.



* lithium iron phosphate.

9.1 INTRODUCTION

With a growing share of variable renewable power generation worldwide, energy storage plays a crucial role in ensuring the successful delivery of reliable electricity systems. Energy storage technologies, such as chemical batteries or pumped storage, have fast-response capabilities and can stabilise frequency, bolster resilience during outages and provide backup power, thereby ensuring grid security.

Today, there are a wide variety of energy storage solutions available, including: electrochemical storage (notably lithium-ion batteries, but also flow batteries and those using 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 such as in pumped storage hydropower); and chemical storage (storing energy in chemical bonds, such as hydrogen or its derivatives).

By capturing surplus electricity and releasing it when needed, battery energy storage systems (BESS) can enhance system flexibility – with the appropriate market framework and strategic deployment – as well as cut transmission losses and relieve grid congestion. BESS also deliver significant economic value to both grid operators and end users by deferring costly transmission and distribution upgrades, and enabling market arbitrage opportunities in power systems with high shares of variable renewables. It is important to note, however, that power system flexibility is required over time scales that range from seconds to entire seasons. BESS serve electricity storage needs at daily time scales and cannot solve, for example, the mismatch between PV production in summer and maximum energy demand in winter for space heating in many northern countries.

Unlike short-duration batteries, long-duration energy storage (LDES) can support a broader range of grid services – from supplying short-term reserves to addressing extended energy shortfalls, whilst more generally underpinning the clean energy transition by reducing dependence on fossil-fuels and lowering overall emissions.

Storage can be coupled directly with solar PV or wind, or function as a standalone asset, optimising distribution and transmission systems. Other hybrid system configurations also exist, with a growing number of solar PV (ground-mounted and floating) and wind projects being co-located with pumped storage and hydropower facilities. Hybrid systems deliver more predictable, dispatchable power profiles, helping to mitigate the impacts of grid connection delays, curtailment risks and network congestion by absorbing excess generation and smoothing demand peaks. As grid modernisation efforts advance, co-locating storage with renewables is proving to be a key enabler for accelerating renewable deployment.

9.2 TECHNOLOGICAL TRENDS

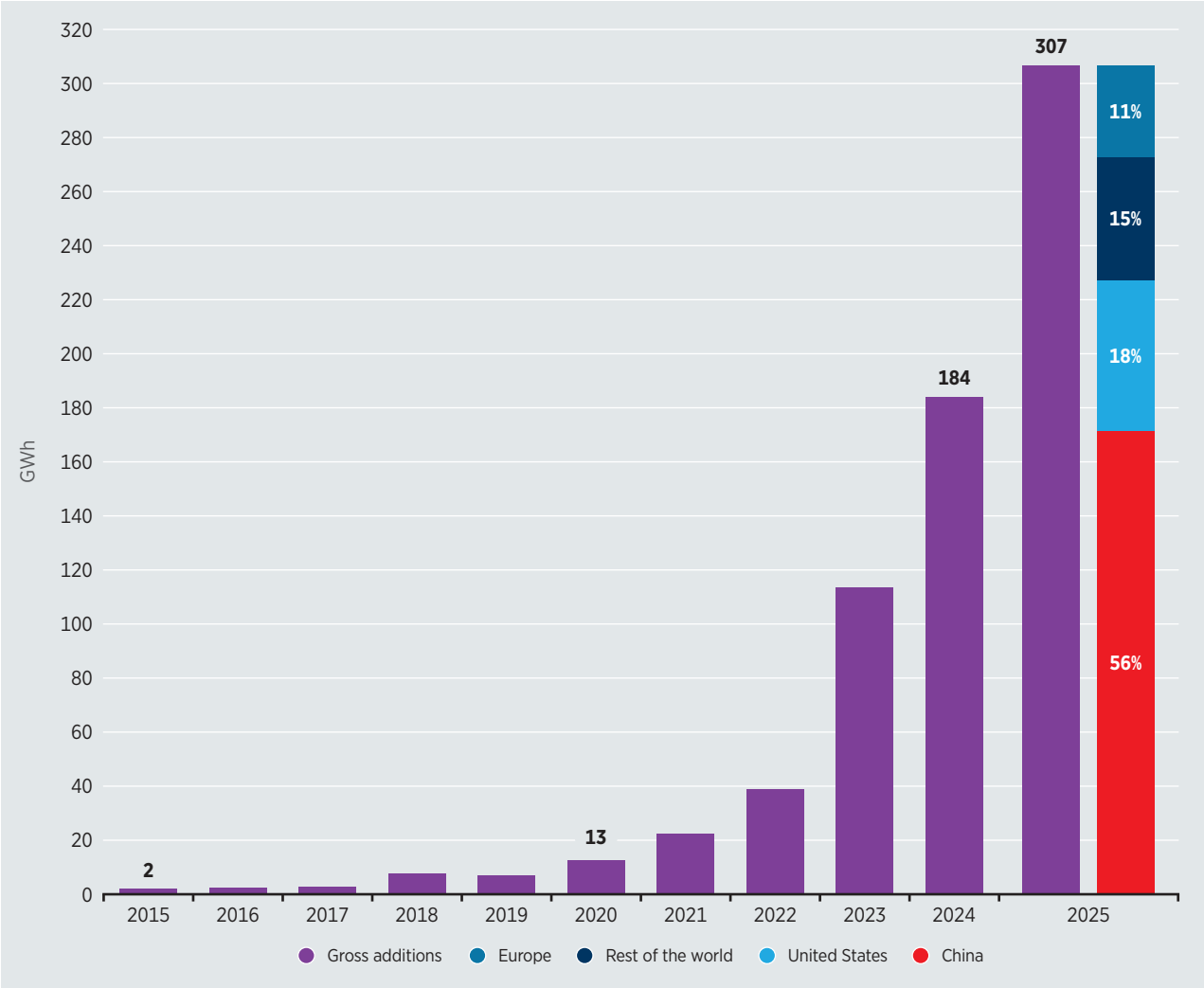
Battery innovation over the past decade has been driven by advances in lithium-ion materials and the large-scale manufacturing of battery cells, enabling rapid growth in the energy storage sector. Improvements in cathode chemistries, particularly higher-nickel and higher-voltage designs, have played a major role in boosting performance and reducing costs, while future gains are expected from innovations in anodes and solid-state electrolytes (BNEF, 2025h).

Battery providers for stationary storage continue to pursue lower costs, improved performance, and reduced dependence on materials that are expensive or difficult to source. Sodium-ion batteries – which replace lithium – are under consideration as a promising alternative for lowering raw material costs. Battery recycling is also becoming increasingly important in addressing raw material supply constraints and supporting a more sustainable battery value chain. In parallel, manufacturers are increasing cell sizes to improve energy density and lower per-unit costs, moving beyond standard 280–320 Ah prismatic cells toward larger formats that enable higher-capacity storage systems, although these new designs also require changes in pack and rack integration (BNEF, 2025i).

9.3 UTILITY-SCALE BESS DEPLOYMENT COST TRENDS

BESS are scaling up rapidly; new annual capacity additions increased from 2 GWh of gross capacity in 2015 to 307 GWh in 2025 (see Figure 9.1), and representing a 67% increase over the 184 GWh in 2024.

Figure 9.1 Global gross BESS capacity additions by year and deployment share by country/region, 2015–2025



Based on: (BNEF, 2026k).
Notes: GWh = gigawatt hour.

China and United States are leading the global expansion. China installed the most capacity in 2025, at 173 GWh (61 GW) – representing an increase of 74% compared over the annual addition in 2024 and accounting for 56% of total global additions in 2025. The United States was the second largest market, adding 55 GWh (18 GW), representing 18% of total new added capacity worldwide.

In China, the utility-scale energy storage market was driven by a target to deploy more than 180 GW of new energy storage by 2027. The country is focusing on making storage a core part of the power system, especially to support renewable integration and grid stability. China's National Energy Administration identified key priorities for the sector, including planning, market mechanisms, core technology R&D, power-system functionality, and strengthening storage industry (CNESA, 2025).

In the United States, deployment growth was supported by expanding state-level commitments to renewable energy and energy storage, with 13 states now having established energy storage targets, alongside favourable market conditions that created opportunities to compete in balancing markets. At the federal level, the passage of the One Big Beautiful Bill Act preserved key storage tax credits, providing continued policy support for the sector. Utility-scale projects dominated deployments in 2025, accounting for 86% of new additions, with developers foreseeing continued growth in capacity markets, energy arbitrage and long-term contracts. By project configuration, standalone systems represented 47% of deployments (26 GWh), while 52% were co-located with solar (29 GWh) and 1% were co-located with wind (1 GWh) (SEIA and Benchmark Minerals Intelligence, 2026).

Europe registered 32 GWh of new additions, representing 11% of total deployment, supported by stronger policy frameworks, renewable energy expansion, and growing opportunities in energy arbitrage and ancillary services. This was the first year that utility-scale storage led deployment. Co-located solar and storage increased, reaching 15% of new grid-scale BESS installations compared to less than 10% in 2024 (SolarPower Europe, 2026). The United Kingdom, Germany and Italy led the annual utility-scale storage deployment on the continent, collectively accounting for 59% of total capacity additions in 2025. The United Kingdom continued to play a leading role through strong government support, and ambitious renewable and storage targets. In Germany, growth was driven by rising flexibility needs from renewable generation, favourable power market conditions and regulatory reforms recognising storage as critical energy infrastructure. In Italy, rapid renewable deployment, a 50 GWh storage target by 2030 and strong participation in the MACSE auction further accelerated market growth and investor interest (SolarPower Europe, 2026).

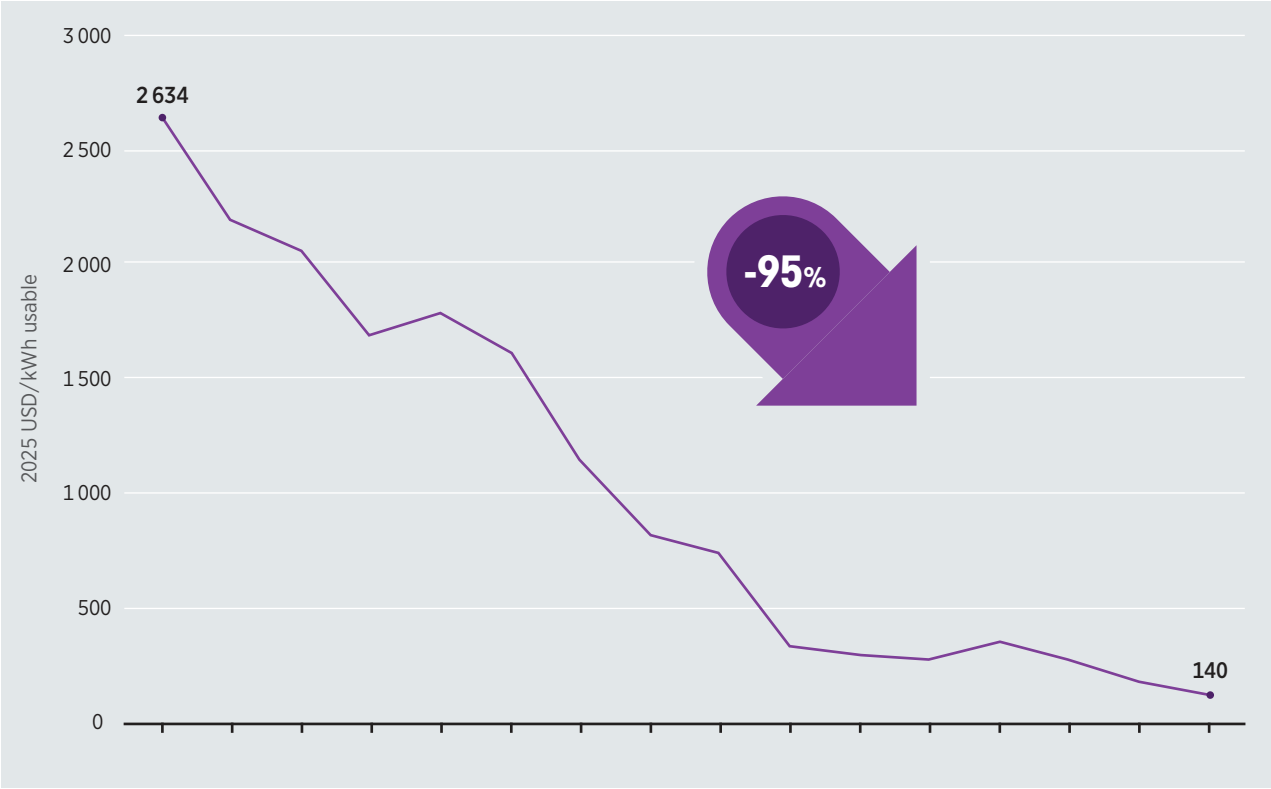
Meanwhile, in the Middle East and North Africa, countries such as Saudi Arabia and the United Arab Emirates are leading investments in giga-scale energy storage projects. Saudi Arabia has a target to deploy 48 GWh of BESS by 2030, according to announcements from the Saudi Power Procurement company (Maisch, 2026). In Abu Dhabi, United Arab Emirates, the Al Dhafra complex will pair 5.2 gigawatts (GW) of solar PV capacity with 19 gigawatt hours (GWh) of BESS to deliver a steady 1 GW of uninterrupted output (Masdar, 2025).

Globally, TICs of BESS declined by 95% between 2010 and 2025, from USD 2 634/kWh to USD 140/kWh (BNEF, 2025b). This was almost a 30% year-on-year decrease. 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 and the transition toward higher-energy-density LFP battery design (see Figure 9.2).

China is the largest BESS market, with a mature and robust manufacturing supply chain driven by strong domestic demand, while the industry also remains strongly export oriented. During Q1 2026, exports totalled 27.3 GWh of battery storage, representing 32.4% of all Chinese battery exports (Xiao, 2026).

The energy storage supply chain is diversifying, while the United States continues to expand its manufacturing capacity and strengthen its ability to meet domestic demand (SEIA *et al.*, 2026). Similar industry trends have been observed in 2025, with cost declines driven by oversupply and intensified competition among manufacturers.

Figure 9.2 TICs of battery energy storage project, 2010–2025



Source: (BNEF, 2025b; Schmidt and Staffell, 2023).

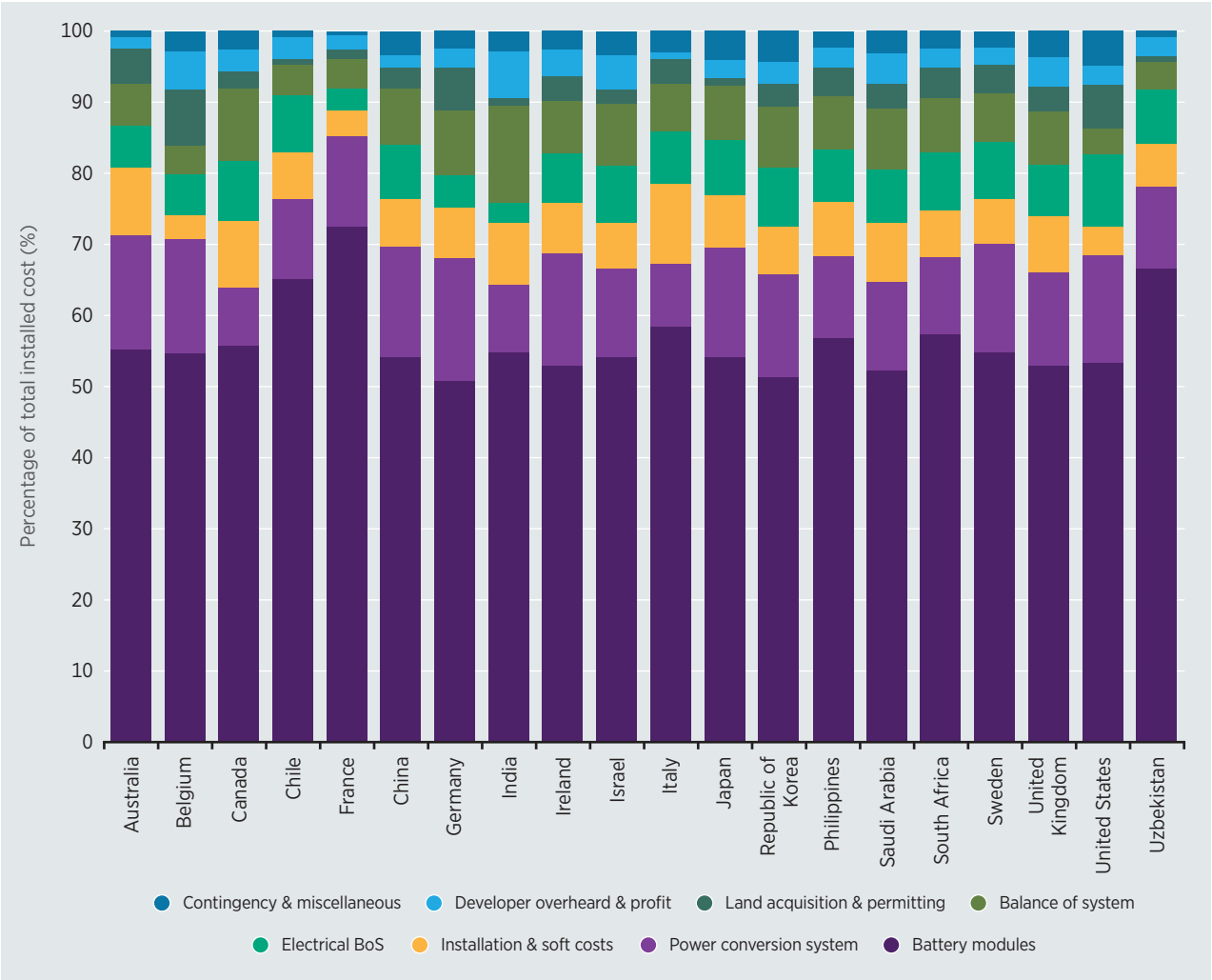
Notes: Cost data from 2010 to 2015 was calculated based on the capacity, price and experience curve regression data for electrical energy storage technologies model developed by Oliver Schmidt and Iain Staffell; kWh = kilowatt hour; USD = United States dollar.

While battery technology is increasingly standardised, driven largely by the dominance of LFP chemistry, BESS total installed costs are not yet fully convergent. Significant regional disparities persist, reflecting differences in project configuration, operational requirements, supply chains, regulatory environments and market dynamics.

Figure 9.3 shows the cost breakdown of TICs BESS projects in selected markets. In the markets assessed, 2025 saw – on average – the share of battery modules accounted for around 56% of TICs at a value of USD 240/kWh, ranging from a low of 51% in both Germany and South Korea to a high of 73% in China. Power conversion systems accounted for 13% of TICs during 2025, on average, ranging from 8% in Canada to 17% in Germany.

Soft costs and system integration play a more significant role in determining TICs than is often assumed. The global average share for installation and soft costs, and electrical BoS, was 7% for each, with only small variations across markets. While battery modules dominate the cost structure, non-hardware components (including installation, permitting and overheads) represent a substantial and often under-optimised share. Balance of system costs accounted for between 4% and 14% of TICs. Other categories – such as land acquisition and permitting, developer overheads and profit, and contingency and miscellaneous – each accounted for 3% of TICs, on average. Land acquisition costs represent a relatively higher share of TICs in Belgium, accounting for approximately 8%. India records the highest proportion of developer overhead and profit, at around 7% of TICs.

Figure 9.3 Cost breakdown of BESS total installed costs



Notes: BoS = balance of system; kWh = kilowatt hour; USD = United States dollar.

The economics of BESS are primarily influenced by battery modules, project scale, storage duration and region-specific factors such as labour expenses, regulatory requirements and permitting procedures. Looking ahead, further cost reductions are expected to result not only from continued declines in battery prices but also from improvements in system integration, streamlined permitting processes and standardisation across project development. As the BESS market becomes mature, opportunities for cost competitiveness will shift from hardware improvements toward reducing soft costs and enhancing project execution. Consequently, competitive advantage will depend less on access to technology and more on the ability to efficiently design, construct and integrate BESS within the broader energy infrastructure.

Figure 9.4 presents turnkey[25] BESS prices by market and duration between 2021 and 2025. turnkey BESS prices continue to fall, reaching USD 117/kWh in 2025 – 31% lower than in 2024. Further price reductions are expected in the future, driven by technological and performance improvements, including higher energy-density cells and more efficient rack designs. Additional reductions are likely to come from better system integration and continued improvements in manufacturing efficiency (BNEF, 2025b).

Turnkey BESS prices are available for major markets, with these providing a sense of the price variation between regions. These prices include the price of battery providers and system integrators but exclude EPC, grid connection and development costs. In 2025, global weighted-average turnkey BESS price ranged between USD 125/kWh for 2-hour projects and USD 111/kWh for 4-hour projects. The 4-hour turnkey BESS projects were, on average, 11% cheaper than 2-hour projects. Turnkey BESS prices decreased by 26% for a 2-hour system and 27% for a 4-hour system, compared to 2024.

Battery cell prices, which are closely linked to the cost of key raw materials such as lithium, nickel and cobalt, remained stable in 2025. Raw materials are concentrated in the cathode and anode components of the battery cell (Schmidt *et al.*, 2023), which together account for about 50% of the total cost (McKinsey, 2024).

However, preliminary data from Q1 2026 registered an increase in battery metal prices, which pushed up energy storage cell prices. The future evolution of battery cell costs remains uncertain, as it will be dominated by these material costs, the volatility of which is increasing with demand in the renewables sector but also from AI and data centres (BNEF, 2026f).

[25] *Turnkey BESS costs include project equipment based on usable capacity, excluding EPC and grid connection costs.*

Figure 9.4 Turnkey BESS prices by market and duration, 2021–2025



Source: (BNEF, 2025c).

Notes: In the lower half of the chart, the reference line represents the cost ratio compared to the global average showing whether costs are higher or lower than the global benchmark; kWh = kilowatt hour; USD = United States dollar.

China saw turnkey BESS prices below USD 100/kWh, averaging 41% less than the global benchmark. In 2025, electricity storage in China saw price decreases ranging from 26% (for a 2-hour system) to 28% (for a 4-hour system). Lower prices in China are mainly due to its well-established supply chain and large manufacturing capacity, which creates strong domestic market competition, therefore maintaining downward pricing pressure.

Europe saw the highest percentage price decrease between 2024 and 2025, of between 35% (for a 4-hour system) and 37% (for a 2-hour system). Having been higher in 2024, the price decline in 2025 pushed European turnkey BESS prices below US levels. The cost ratio compared to global prices was 1.45 for 2-hour and 1.55 for 4-hour battery systems.

The United States saw the lowest percentage price decrease between 2024 and 2025, ranging from 10% (for a 2-hour system) to 11% (for a 4-hour system). The cost ratio compared to global prices of was 1.83 for 2-hour and 1.93 for 4-hour turnkey BESS. While supply conditions and manufacturing capacity improved during 2025, structural factors continue to keep prices elevated in the United States compared to other regions. These include tariff-related input costs and uncertainty around eligibility for incentives such as the 45X tax credit,[26] which together prevent costs from converging toward lower international benchmarks (SEIA *et al.*, 2026).

9.4 UTILITY-SCALE BESS TECHNOLOGY MARKET SHARE

A wide range of battery technologies has emerged to meet various performance, cost and sustainability requirements. Key chemistries include: lithium iron phosphate (LFP), nickel manganese cobalt (NMC), nickel cobalt aluminium (NCA) and sodium-ion (Na-ion) batteries, among others.

Figure 9.5 illustrates the evolving market share of utility-scale BESS technologies from 2021 to 2025. A clear trend toward the increasing dominance of LFP batteries is seen globally. The market share of LFP batteries grew from 49% in 2021 to an estimated 91% by 2025, thanks to their relatively lower cost and higher cycle life. In the United States, for example, lithium ion batteries accounted for 98% of the deployment of BESS (SEIA *et al.*, 2026).

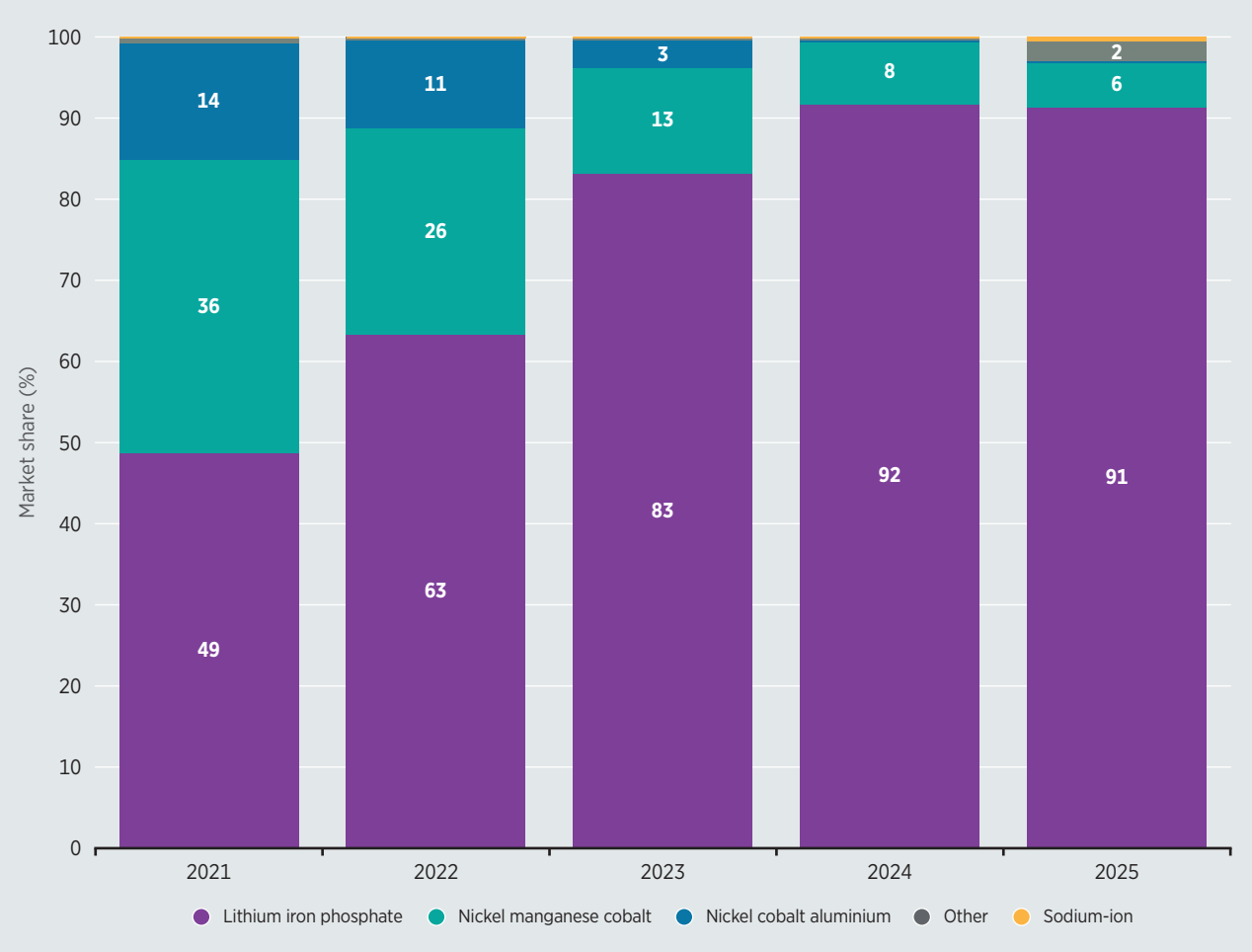
NMC batteries declined from 36% to 6% over the same period and NCA batteries continued to be phased out as LFP batteries reached competitive energy densities while maintaining lower costs. A small but growing share of other batteries[27] emerged in 2025 at 2%, reflecting the early stages of market entry for these alternative chemistries. The sodium-ion category remained minimal throughout the year, at less than 1% in 2025.

Advances in alternative battery technologies are progressing rapidly. Sodium-ion and flow batteries are alternative technologies enabling large-scale stationary storage. The future success of sodium-ion batteries is also tied to ongoing research and development efforts to improve their performance and address their limitations. Innovations are expected to significantly improve energy density, alongside ongoing development of hybrid battery configurations that combine different technologies to enhance overall performance of sodium-ion batteries (IRENA, 2025f).

[26] *Section 45X Advanced Manufacturing Production Credit, under the Inflation Reduction Act 2022, provides direct financial support for domestic manufacturing of eligible clean energy components.*

[27] *'Other' refers to technologies for LDES, the commercialisation of which remains uncertain.*

Figure 9.5 Global market share trends of utility-scale BESS technologies, 2021–2025



Based on: (BNEF, 2026a).

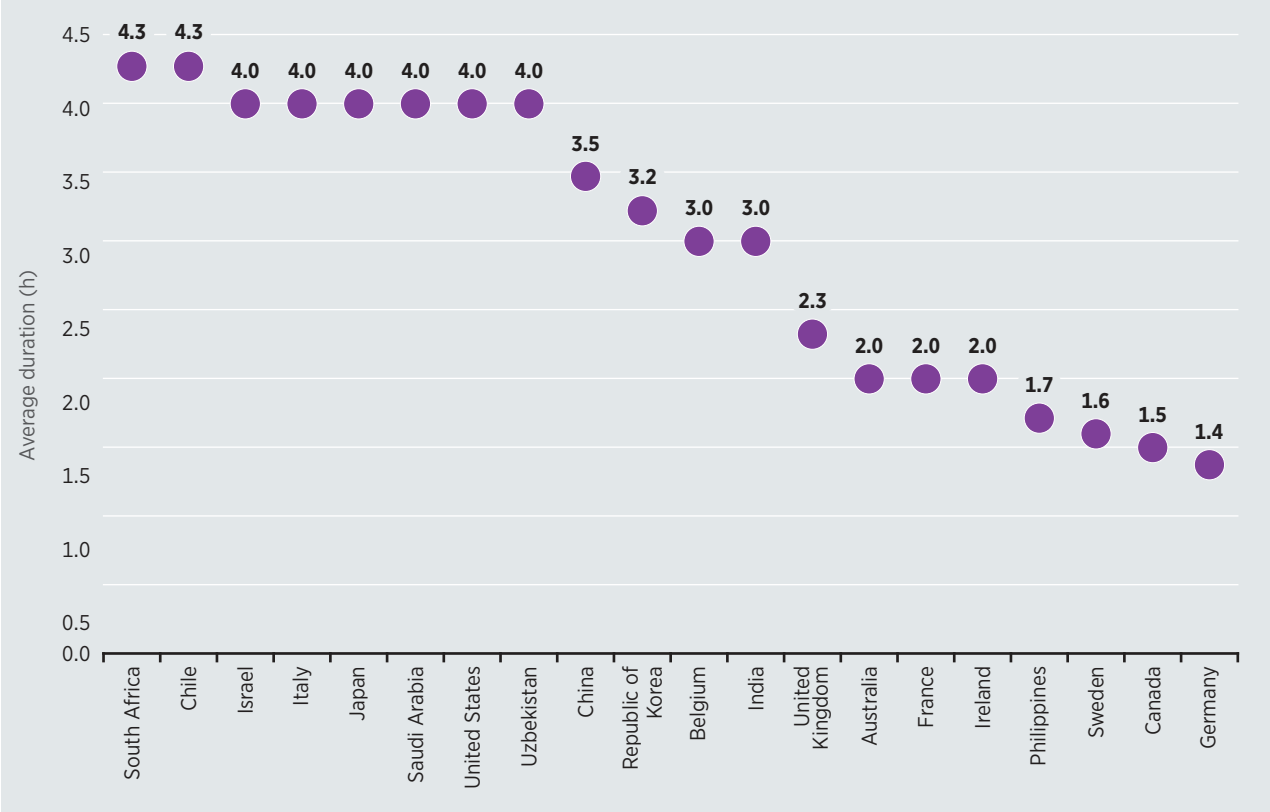


9.5 UTILITY-SCALE BESS DURATION

Discharge duration of the LFP battery varies, based on a sample of BESS projects in operation across 20 markets. For those deployed in the markets shown in Figure 9.6, the discharge duration ranges from as high as 4.3 hours in South Africa and Chile to 1.4 hours in Germany.

For projects with a discharge duration of around four hours, applications vary across markets. In South Africa, BESS deployments are predominantly focused on improving grid resilience and reducing peak demand. In Chile, BESS projects enable renewable energy integration and load shifting, whereas in Germany they are mainly utilised for frequency regulation. BESS projects with discharge durations of two to three hours support a wider range of use cases, including backup power, capacity replacement and the integration of renewable energy resources.

Figure 9.6 Discharge duration of LFP batteries across different markets



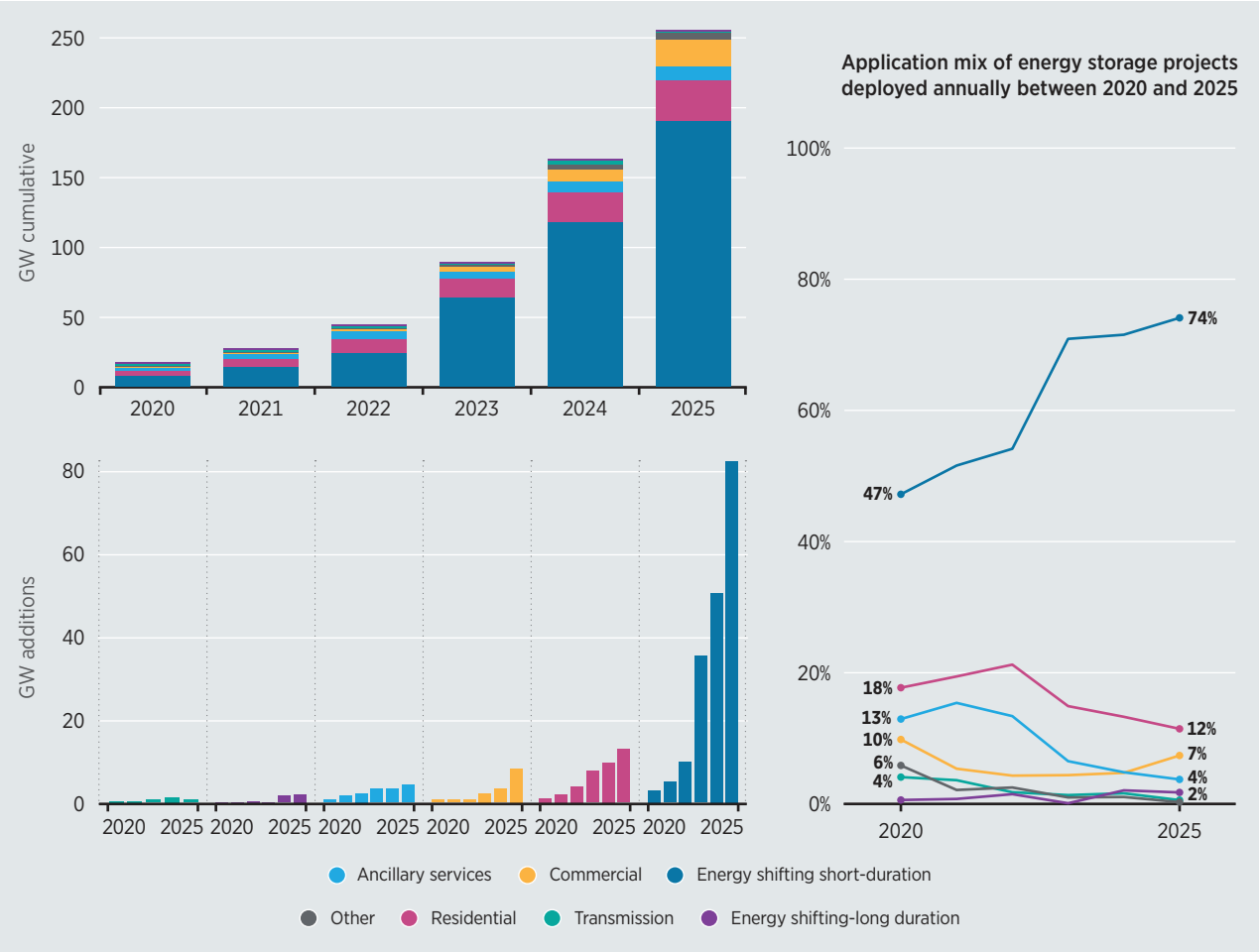
9.6 UTILITY-SCALE ENERGY STORAGE APPLICATIONS

Currently, the primary use of electricity storage is for energy shifting (see Figure 9.7), which accounts for 74% of the total additions of energy storage capacity in 2025. Energy shifting balances the power system by storing renewable energy production at times of low market prices (leading to low/null revenue or even negative prices) or low demand (leading to curtailments). These circumstances encourage energy storage for later use at times of peak electricity demand or prices, resulting in improved project economics.

The increase in the use of BESS for energy shifting shows that falling electricity storage costs have led to economic opportunities for time shifting, especially as solar PV penetration has risen in certain markets. Additionally, as grid constraints and curtailment increase, storage is becoming an important solution for developers because it can reduce project risk and improve revenue predictability. By pairing storage with intermittent energy, developers can better manage network congestion and capture more value from their assets (DNV, 2025).

BESS capacity for energy shifting added in 2025 was almost 83 GW/241 GWh; this value was 63% higher than the added capacity in 2024 and accounted for almost 74% of the total new BESS capacity additions in 2025. In the residential segment, the capacity added reached 13 GW, but its share of the energy storage application mix fell from 13% in 2024 to 12% in 2025, as deployment in the utility-scale sector accelerated. Ancillary services also saw their share of the application mix decrease to 4% of all energy storage projects deployed annually in 2025, with an added capacity of 4.3 GW/5.3 GWh compared to 3.5 GW in 2024. Energy shifting for long duration reached 2% of the application mix, with an added capacity of 2 GW/9.9 MWh in 2025 compared to 1.5 GW in 2024. Transmission and distribution were marginal applications, despite the increase in year-on-year added capacity.

Figure 9.7 Energy storage deployment by application in GW



Based on: (BNEF, 2026k).
Note: GW = gigawatt.

9.7 LONG-DURATION ENERGY STORAGE

As the energy transition accelerates to 2030, the system will need 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 thanks to their capacity to discharge over long periods of time, especially in a system relying on more variable renewable sources. LDES offers durations of at least eight hours and can complement short duration applications, such as lithium-ion batteries.

The LDES landscape is dominated by pumped storage hydropower (PSH), with a cumulative capacity of around 160 GW in 2025 (IRENA, 2026a). This is a 7% increase in total capacity compared to 2024. In 2025, market leaders were China (with 7 GW of new installed capacity) followed by India (4 GW), totalling more than 200 GWh in new storage capacity combined. Continued additions are expected in both countries in the future. In China, 136 GW of pumped storage capacity is expected to be deployed by 2035 (IHA, 2025) while India set a target to deploy 100 GW of pumped storage by 2036 (CEA, 2026).

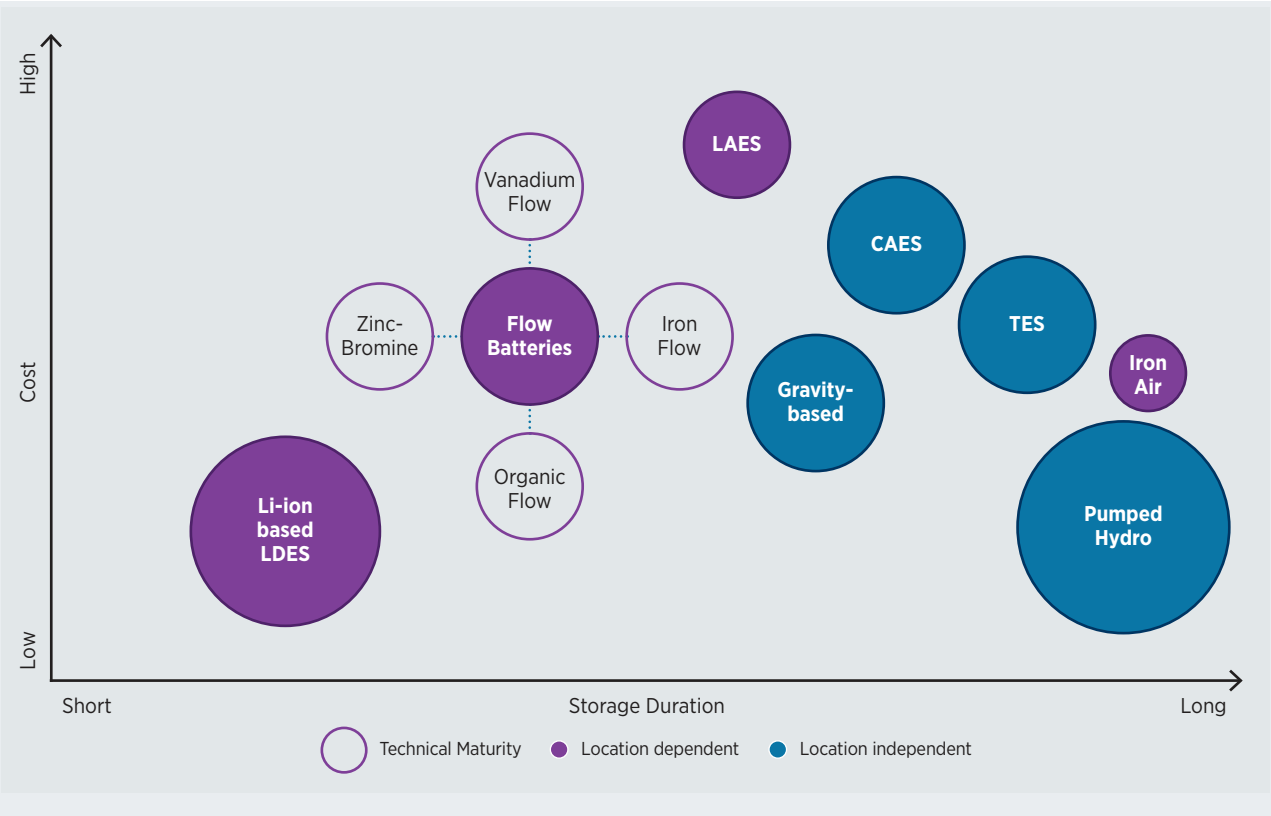
Retrofitting existing hydropower plants with reversible pump-turbine systems offers significant potential to expand PSH capacity by utilising existing reservoirs and civil infrastructure. Such conversions can be technically feasible for both single and cascade hydropower schemes, enabling them to operate as storage assets that shift between generation and pumping modes depending on system needs and provide flexibility to the power system (Dagsvik and Storli, 2021; Toufani *et al.*, 2022).

Apart from PSH, a variety of LDES technologies are emerging, including chemical, electro-chemical, thermal and mechanical. New added capacity in 2025 was 2 GW/9.6 GWh. The global total installed capacity for emerging LDES reached 5.1 GW in 2025, representing a cumulative energy capacity of 25.6 GWh. China and the United States are the market leaders. China represents 73% of total operating capacity, while United States accounts for 12% (BNEF, 2026l).

The technology landscape for operating novel LDES technologies includes compressed-air energy storage (CAES), liquid-air energy storage (LAES) and flow batteries. As the deployment evolves in the coming years, the technology focus is expected to vary across major markets. In China, efforts are focused on scaling commercial CAES solutions, while the United States has the most diverse technology pipeline, including LAES, gravity, and thermal storage, alongside advanced battery chemistries such as flow batteries (vanadium, zinc-bromine), metal-air systems and sodium-sulphur batteries.

Figure 9.8 illustrates the storage duration across different LDES technologies. Each technology is at a different stage of maturity, which influences both its cost structure and deployment potential. Storage duration varies significantly across technologies, with typical discharge durations reaching up to 10 hours for lithium-ion batteries, while most other LDES technologies – including PSH, thermal storage, CAES, hydrogen-based systems, flow batteries and gravity-based solutions – operate at approximately 20 hours or more.

Figure 9.8 LDES discharge duration



Source: (Carbon Limiting Technologies, 2025).

Notes: CAES = compressed-air energy storage; LAES = liquid–air energy storage; LDES = long-duration energy storage; Na-ion = lithium-ion; TES = thermal energy storage.

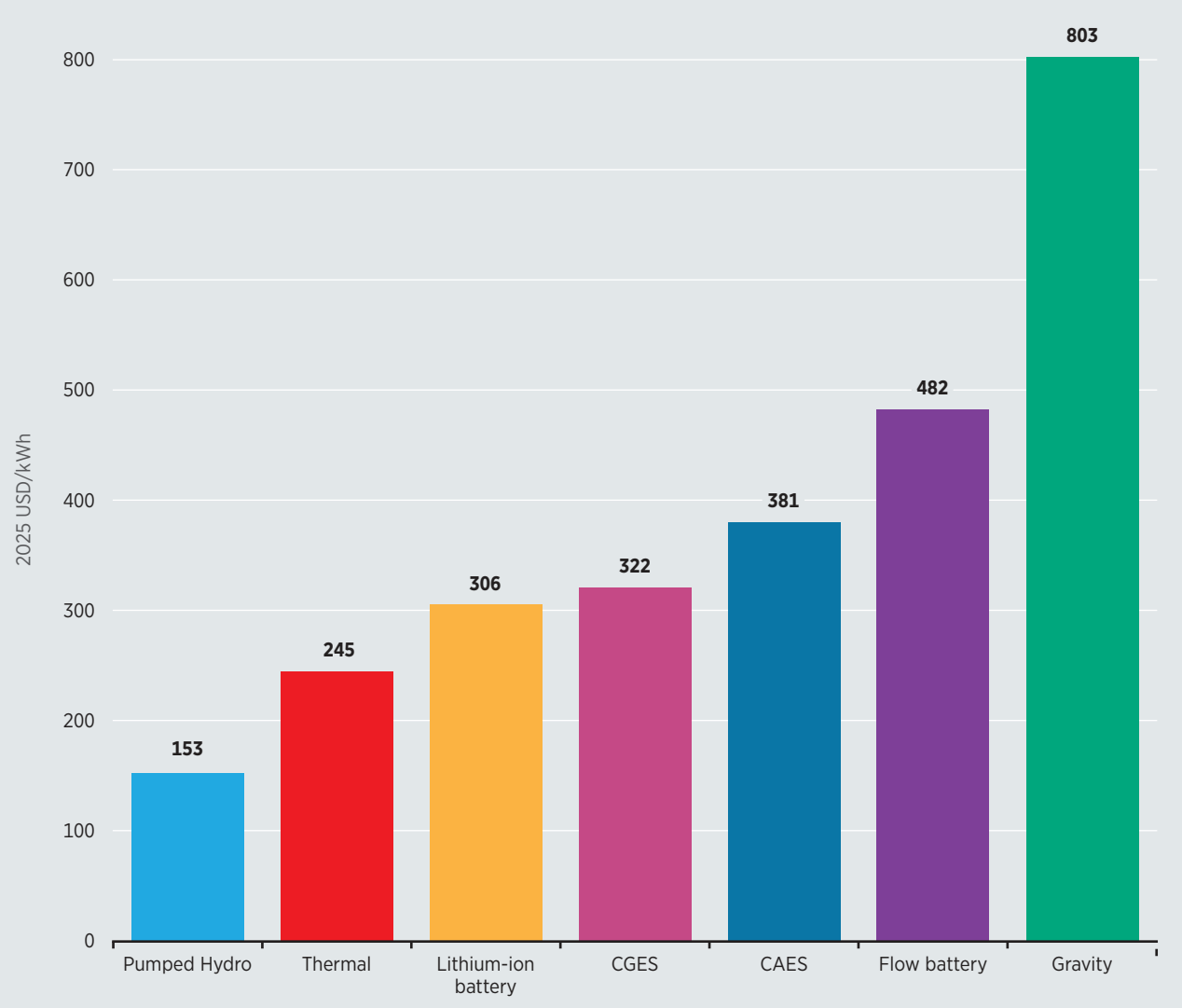
Pumped storage hydropower is a well-established and mature technology, while thermal energy storage (TES) is commercially deployed in industrial processes and CSP plants. TES is a cost-competitive option in certain heat-sector applications, particularly where low-cost renewable electricity can be utilised for industrial heat or district energy systems. In contrast, flow batteries, CAES, LAES, gravity-based systems and chemical storage technologies are at different stages of technological and commercial maturity. For such emerging LDES technologies, the sector is facing growing challenges due to declining investment and increasing competition from lithium-ion batteries (Wood Mackenzie, 2026i), which makes policy support and R&D funding critical to bridge the cost gap and enable LDES to reach commercial viability.

Major markets are implementing policies, market mechanisms and financial incentives to promote LDES deployment. Targets for LDES have been established in Australia, Canada, China and the United States. Revenue certainty is strongest in the United Kingdom, which introduced a cap-and-floor mechanism that stabilises returns for long-duration storage (CEPA and ESP Consulting, 2025). LDES auctions and procurement are also emerging in Europe. Germany has launched dedicated LDES tenders (200 MW in 2025, 300 MW in 2026) requiring 72-hour discharge and CAPEX support (Colthorpe, 2024).

Using the available cost data for LDES from 211 projects with storage durations above eight hours – combined secondary data sources – the average price per technology can be seen in Figure 9.9 below. Despite presenting the global weighted-average, costs depend on the technology, project size, storage duration and location.

Pumped storage hydropower is still the most competitive technology, with a global average TIC of USD 153/kWh; thermal storage, such as molten salt and solid state, has a global average TIC of USD 245/kWh. For emerging technologies, TICs range from USD 381/kWh for CAES to USD 803/kWh for gravity energy storage (see Figure 9.9). The viability and performance of LDES for extended storage needs are expected to improve as technology advances and practical experience grows. Early adoption and faster commercialisation may also depend heavily on favourable regulatory and policy frameworks.

Figure 9.9 LDES global average TICs per technology in USD/kWh



Source: (AURORA, 2022, 2023; BNEF, 2026c; DESNZ, 2023; LDES Council and EPRI, 2026).

Notes: Typical discharge duration is above eight hours for lithium-ion batteries and around 20 hours for pumped storage, thermal, CAES, GGES, flow batteries and gravity; CAES = compressed air energy storage; CGES = compressed gas energy storage; kWh = kilowatt hour; USD = United States dollar.

10 EMERGING TECHNOLOGIES



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This chapter covers technologies that are not yet deployed at scale, the costs of which are still derived mainly from developer surveys and engineering models rather than large samples of commissioned projects. For this reason, they sit outside the main technology chapters. The data provided below are best read as indicative ranges, as opposed to the project-based weighted-averages reported in the previous sections of the report.

10.1 OCEAN ENERGY

Ocean energy - mainly wave energy and tidal stream - currently sits between the pilot and pre-commercial stages of development. This section reviews the resource and its system value; the present state of deployment; current and likely cost trajectories; the drivers behind expected cost reductions; and the market and policy conditions that shape competitiveness.

Resource potential and system value

The global resource is substantial. Wave and tidal stream together have an estimated generation potential of around 3 910 TWh per year – equivalent to roughly 13% of present-day electricity demand and close to the amount generated by hydropower today (Ocean Energy Europe, Forthcoming). Beyond its scale, the resource has characteristics that can add system value. Tides are governed by the moon and the sun, so tidal output is highly predictable; tidal turbines can generate for at least 20 hours per day and, when combined with short-duration battery storage, can provide round-the-clock renewable generation. Wave energy, although primarily driven by wind, can also generate power for several hours after the wind has dropped. These attributes matter to any economic assessment, since the value of generation depends not only on its cost but also on its timing and predictability.

Deployment to date

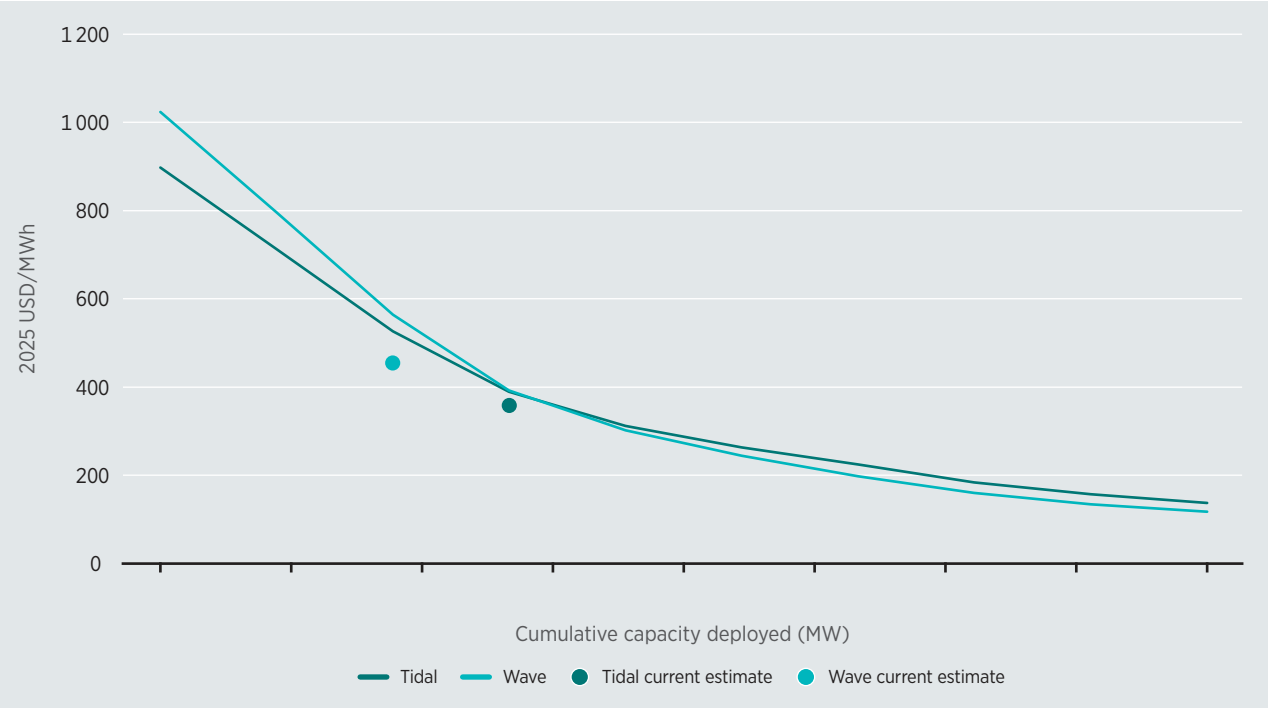
Wave and tidal stream are innovative technologies and have not yet been deployed at large scale. Since 2010, 43 MW of tidal stream and 27 MW of wave capacity have been deployed worldwide (Ocean Energy Europe, 2025). More than half of this capacity – 32 MW of tidal and 14 MW of wave – was deployed in Europe, where the market is most advanced. The remaining capacity has been deployed mostly in the United States, China, Canada, Japan and Australia. Deployments are set to increase rapidly, as the sector passes from single devices or small arrays to larger farm developments. In Europe, there is now a pipeline of 16 tidal and wave farms supported by grant funding and the first revenue-support schemes. This means 196 MW of new capacity and 200 devices are set to be deployed by 2030, kick-starting the industrial rollout of the technology. Beyond this pipeline, national targets and market mechanisms in Europe foresee 650 MW of capacity being awarded by 2030. China, the United States and Canada are also increasing their ocean energy ambitions with targets and funding schemes, with China in 2025 setting a 400 MW ocean energy target by 2030.

Cost levels and trajectory

The LCOE of current wave and tidal stream projects is higher than that of mature technologies such as wind and solar, which have benefited from decades of scale and experience. The cost of capital is also higher, reflecting the risk premium that investors attach to an early-stage technology with a limited operating track record. Compared at an equivalent stage of development, however, the present costs of wave and tidal are reported to be lower than those of other renewable technologies recorded at the same early point in their own development and deployment. LCOEs are reported to have fallen sharply since the first prototypes and are currently estimated at approximately USD 358/MWh (2025) for tidal stream and USD 454/MWh (2025) for wave. They are projected to decline further, to about USD 140/MWh for tidal stream and USD 120/MWh for wave at 2 GW of deployment – an estimate based on aggregated learning across several technologies, with reductions for any single technology potentially greater at the same installed capacity (IRENA and OEE, 2023).[28]

[28] *This estimate presents a forecast for Europe and is based on European data.*

Figure 10.1 Levelised cost of electricity against cumulative deployment in 2025 USD/MWh



Notes: MW = megawatt; MWh = megawatt hour; USD = United States dollar.

These cost figures reflect a full project system boundary – *i.e.* they include the device; its support structure and moorings; subsea and onshore electrical infrastructure; and grid connection, installation, consenting, insurance, contingency and decommissioning (Table 10.1).

Drivers of cost reduction

The business model and cost drivers of wave and tidal are similar to those of offshore wind: they rely on similar supply chains, materials, power electronics, offshore operations and staff. As a result, wave and tidal are set to follow a similar cost-reduction pathway through learning, innovation and scale. The most important drivers are:

- Improved operations: more efficient installation; retrieval and maintenance; and decommissioning.
- Farm-level economies of scale due to larger machines and projects:
  - exponentially higher yield of larger devices;
  - lower CAPEX/unit – shared grid connection, licensing and maintenance facilities; and
  - lower OPEX/unit – shared resources and operations (maintenance teams/admin).
- Industry-level economies of scale: mass production, standardisation, dedicated supply chains, higher competition among suppliers, specialised services.
- Lower capital costs: cheaper equity and debt driven by proven operations, certification, insurance and warranties.

Table 10.1 Project system boundary associated with tidal stream and wave





Tidal stream	Wave
The tidal stream system boundary includes the turbine device (rotor; drivetrain or direct-drive generator; power take-off; nacelle; and control systems); the support structure (fixed-bottom foundations or floating hull with moorings and anchors); subsea inter-array and export cables; offshore and onshore electrical infrastructure and grid connection; marine transportation, installation and commissioning; construction insurance; project development; consenting and environmental compliance, EPC and developer margins; contingency; and decommissioning provisions.	The wave energy system boundary includes the wave energy converter (primary structure or hull, prime mover and power take-off, with control systems); the station-keeping system (moorings and anchors for floating devices or foundations and civil works for fixed and shoreline devices); subsea inter-array and export cables; offshore and onshore electrical infrastructure and grid connection; marine transportation, installation and commissioning; construction insurance; project development; consenting and environmental compliance, EPC and developer margins; contingency; and decommissioning provisions.

Outlook and policy considerations

As highlighted in the previous section, ocean energy is at an early but advancing stage, with a credible route to lower costs if deployment is scaled. Two policy levers can significantly speed up the roll-out of ocean energy worldwide. The first is revenue support: experience with wind and solar suggests that ring-fenced mechanisms such as contracts for difference (CfDs) or feed-in tariffs can provide the predictable returns and market visibility that attract private investment. The United Kingdom has auctioned CfDs for tidal stream since 2022, building the largest project pipeline. Early public grant support can also lower capital costs and help unlock the first farms in a country. The second policy lever is regulatory: most countries still lack dedicated frameworks – standardised permitting, grid-connection procedures and designated deployment zones – and the uncertainty this creates can slow projects and raise capital costs. Whether ocean energy follows the cost trajectory seen across other renewables will depend substantially on whether such market and regulatory conditions are put in place.[29]

[29] *For further details on how to scale up ocean energy deployment within a given jurisdiction, please consult the joint OEE/IRENA report Scaling up Investment in Ocean Energy, IRENA, 2023. www.irena.org/Publications/2023/Mar/Scaling-up-investments-in-ocean-energy-technologies*

10.2 LONG-DURATION ENERGY STORAGE

As variable renewables grow, the power system needs storage that can discharge for longer periods. BloombergNEF projects that the average discharge duration of grid batteries will rise from around four hours today to over six hours by 2030, reaching close to ten hours by 2050, as solar and wind increase their share in global generation. LDES - defined here as systems able to discharge for at least eight hours at rated power - is the response to this shift. Pumped storage hydropower remains the deployed long-duration incumbent (discussed in the energy storage chapter); this section focuses on the emerging alternatives that are not yet built at scale.

Compressed air leads on cost, but the geology matters

Compressed-air energy storage (CAES) emerges as the most cost-competitive long-duration option currently available. The LDES Council survey estimates the TIC for intraday compressed gas systems (100 MW, ten-hour design) in 2025 in the range of USD 160 –470/kWh (the lowest entry point of any intraday category), falling to USD 120–445/kWh by 2030 (LDES Council, 2026).[30] BloombergNEF's parallel analysis finds that adiabatic CAES (A-CAES) paired with a natural cavern in China achieves a levelised cost of storage (LCOS) below USD 30/MWh at mid-cost estimates (BNEF, 2024).

The economics depend heavily on geology. Energy-related capital costs for natural-cavern A-CAES in China are roughly one-ninth those of lithium-ion at 2024 prices – a striking gap, but one that closes substantially when purpose-built caverns are required. Purpose-built capital costs are more than eight times those of natural-cavern, and broadly comparable to lithium-ion. Suitable natural caverns are scarce and may face competing demand from large-scale hydrogen and CO_2 storage. For multi-day storage of 36 hours or more outside China, BloombergNEF identifies CAES as the clear cost winner, and concludes it is the only technology in its survey on track to meet the US Department of Energy's LDES Shot target – a 90% cost reduction and an LCOS at or below USD 50/MWh by 2030 (US DOE, 2024).

Flow batteries and thermal storage are closing the gap

The LDES Council's intraday electrochemical category, which encompasses flow batteries alongside other emerging chemistries, shows 2025 TICs of roughly USD 220–570/kWh for a 100 MW, ten-hour design, falling to USD 245–360/kWh by 2030 – an average reduction of around one-third, with the range narrowing as technologies converge.

[30] *TIC is reported as total plant cost (TPC) by LDES Council.*

Vanadium redox flow batteries (VRBs), classified separately in BloombergNEF's survey as a flow chemistry, are improving but remain more expensive than lithium-ion across most durations. Energy-related capital expenditure stands roughly one-fifth above lithium-ion today, with BloombergNEF projecting declines of around 6% to 7% a year through 2030. Even so, the lowest-cost VRB in China is forecast only to rival the most expensive lithium-ion equivalent at durations of 14 hours or more by 2030. Zinc-bromine flow batteries record the highest LCOS of any LDES technology in the BloombergNEF survey, and are projected to remain at more than twice the cost of oversized lithium-ion for 120-hour storage in 2030 (BNEF, 2026l).

The LDES Council's thermal energy storage category – covering primarily power-to-heat applications – shows 2025 TICs of USD 24–132/kWh$_{th}$, falling to USD 20–82/kWh$_{th}$ by 2030, with reductions ranging from roughly one-sixth to just under half across the category. Round-trip efficiencies (measured as thermal energy out per electrical energy in) are reported in the range of 95–97%, although these costs exclude any new power cycle required for grid discharge. Molten salt thermal storage occupies a middle position in the power-to-power comparison, with capital costs in China projected to fall by about 3% a year through 2030, at which point the lowest-cost Chinese systems may undercut the most expensive lithium-ion equivalents at around 18 hours of storage. Round-trip efficiency for these power-to-power systems is more modest (40–80%), and operational challenges – high temperatures, corrosive salts, leaks and material degradation – are well documented.

The LDES Council also reports a multi-day storage category, with 2030 TICs of USD 26–38/kWh for a 100-hour design – far lower on a per-kWh basis than other categories, and reflecting the longer duration over which fixed costs are spread. Overall, projected cost declines for most non-CAES technologies close the gap with lithium-ion equivalents; but the marginal cost of adding duration is expected to be substantially lower for LDES than for lithium-ion, where doubling or tripling duration nearly doubles or triples capital costs.

10.3 LOOKING FORWARD

The technologies in this chapter share a common feature: their costs are shaped less by incremental learning than by the conditions for first deployment at scale. For LDES, the evidence supports a measured version of the industry's narrative – CAES with natural caverns is already the most cost-competitive option and the only one on track to meet the US LDES Shot, but its scalability is constrained by geology, and the cost declines projected for other technologies mostly close the gap with lithium-ion. Crucially, much of the remaining gap is in financing rather than equipment, so instruments that lower the cost of capital for unproven assets will matter as much as manufacturing scale.

For ocean energy, the picture is one of a pre-commercial sector on the cusp of industrial rollout, with a visible European pipeline to 2030 and growing ambition in Asia and North America. Here, too, policy is the key variable: revenue-support schemes and dedicated regulatory frameworks are the instruments that can convert resource potential into deployed capacity and falling costs. In both cases, the years to 2027 will be less about technology breakthroughs than about whether policy and finance respond to match the engineering.



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