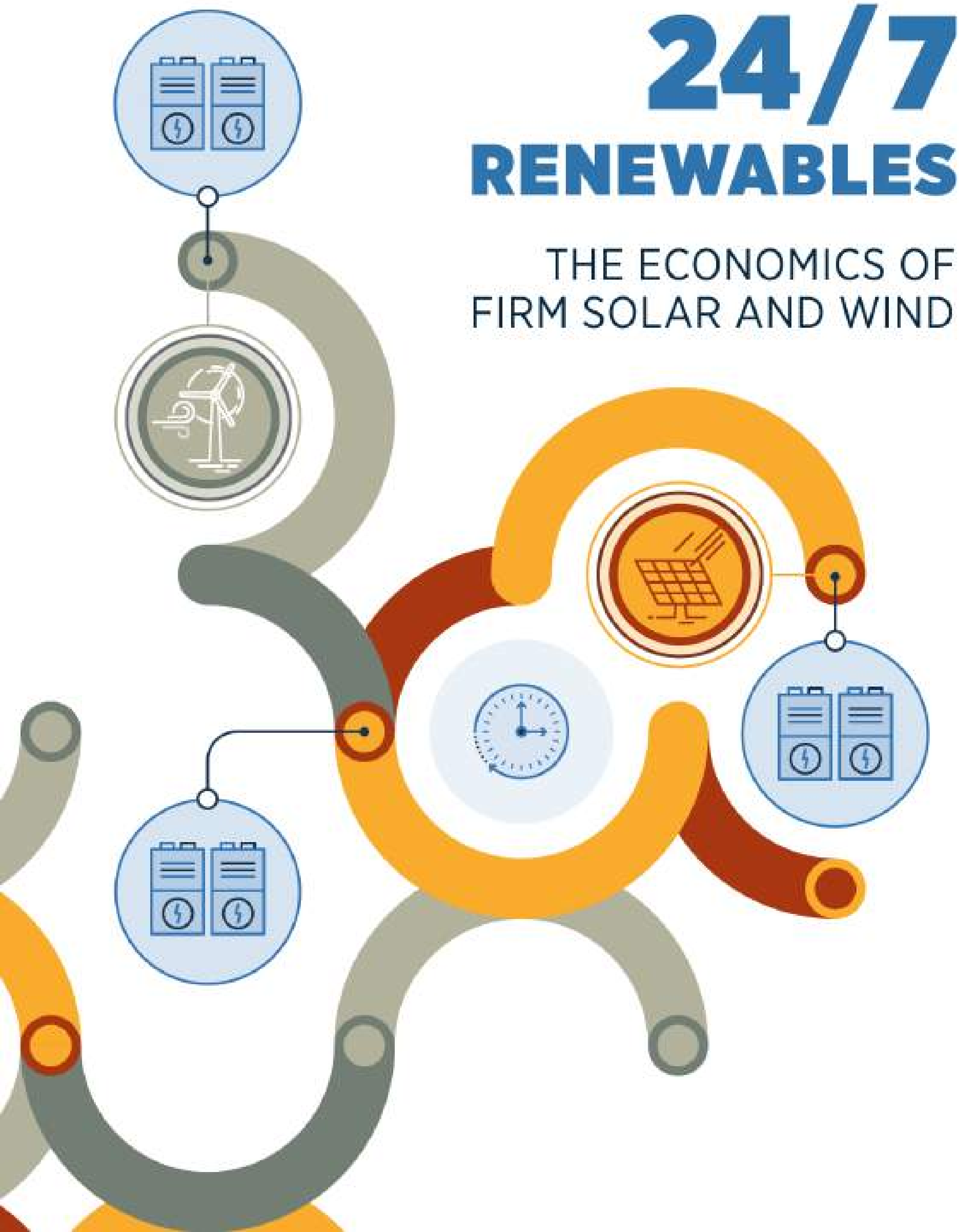
IRENA
International Renewable Energy Agency

24/7 RENEWABLES

THE ECONOMICS OF FIRM SOLAR AND WIND



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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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ABBREVIATIONS

AC	alternating current
AI	artificial intelligence
BESS	battery energy storage system
BNEF	BloombergNEF
BOS	balance-of-system
CAPEX	capital expenditure
DC	direct current
ELCC	effective load carrying capability
EMS	energy management system
EPC	engineering, procurement and construction
EU	European Union
F-LCOE	firm levelised cost of electricity
GHG	greenhouse gas
GW	gigawatt
GWh	gigawatt hour
HJT	heterojunction technology
IEA	International Energy Agency
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
LNG	liquefied natural gas
MWh	megawatt hour
MW	megawatt
NCA	nickel cobalt aluminium oxide
Net CONE	net cost of new entry
NMC	nickel manganese cobalt oxide
OECD	Organisation for Economic Co-operation and Development
O&M	operation and maintenance
PCS	power conversion system
PV	photovoltaics
TOPCon	tunnel oxide passivated contact
TWh	terawatt hour
USD	United States dollar
VPP	virtual power plant
VRE	variable renewable energy
WACC	weighted average cost of capital

EXECUTIVE SUMMARY

Solar and wind have become the cheapest sources of new electricity generation worldwide, reliably delivering large volumes of clean energy over time. As renewable penetration rises, however, the central challenge of the energy transition is increasingly one of adequacy and flexibility: ensuring that clean electricity is available whenever and wherever it is needed, not only when conditions are favourable. Because solar and wind output varies with weather and time of day, delivering power around the clock requires additional investments in storage, generation overbuild and system flexibility. Understanding the cost of this "firming" – *i.e.* transforming variable renewable output into a continuous, dependable supply[1] – is therefore critical for assessing the full economics of renewables in current and future electricity systems.

This report approaches that question from the "bottom up", assessing firming costs at the asset level rather than through system-wide models of flexibility needs and their cost implications. It indicates that co-located solar photovoltaics (PV) and onshore wind systems with battery energy storage systems (BESS) can reliably and cost-effectively provide round-the-clock electricity in favourable resource conditions. In high-quality solar and wind zones, optimally configured systems can already deliver round-the-clock electricity at costs below typical fossil fuel benchmarks – and at prices that, once the plant is built, are largely insulated from the fuel cost volatility and supply disruptions, such as the most recent shocks to global fossil fuel markets caused by disruptions to shipping in the Strait of Hormuz.

The interpretation of these results is subject to two important caveats. First, this report does not advocate firm, continuous supply as a universal objective. Reliability is achieved through diverse resources – storage, dispatchable generation, transmission and demand-side flexibility – and no power system needs every generator to be firm. Second, the flat output profile underpinning this cost metric is a modelling assumption chosen for comparability and transparency – not a prescription for how renewable projects should be designed or how power systems should be operated.

[1] *Inthisreport,"firmrenewablepower"referstoelectricitydeliveredbyacombinationofrenewablegenerationandstoragethatmeets a specified share of demand on a continuous, hourly basis.*

HYBRID SOLAR, WIND AND BESS AS AN EMERGING ASSET CLASS

Solar and wind are increasingly paired with BESS in co-located hybrid configurations.[2] These systems optimise the use of constrained grid connections, shift electricity production to higher-value hours and reduce exposure to price volatility. Co-located solar PV, wind and BESS are also well positioned to serve the most demanding electricity users – including data centres, artificial intelligence workloads and advanced manufacturing – that require uninterrupted, high-quality power and for which a continuous, firm supply is often the relevant commercial benchmark.

Large projects are already demonstrating the technical and commercial feasibility of this approach. The United Arab Emirates' Al Dhafra complex, for example, will combine 5.2 gigawatts (GW) of solar PV with 19 gigawatt hours (GWh) of battery storage to deliver a firm 1 GW of clean electricity – equivalent to a large thermal power plant – at an estimated firm cost of USD 70/megawatt hour (MWh).[3] Across the United States, co-located solar-plus-storage has shifted from an exception to an increasingly standard project configuration, with the paired share of new utility-scale solar growing rapidly and projected to represent the majority of additions within this decade, according to industry analysts. Projects of this kind illustrate how hybrid renewable systems are now able to provide services once associated exclusively with conventional generation.

This deployment momentum is being reinforced by a parallel transformation in how clean electricity is measured and valued. Annual matching – long the standard for corporate clean energy claims – is increasingly recognised as inadequate, as it allows companies to report near-zero electricity emissions regardless of when or where generation occurred. The ongoing revision of the GHG Protocol Scope 2 Guidance proposes hourly and location-matched certificates as the basis for market-based emissions claims, a shift already reflected in the European Union's renewable hydrogen certification rules and Carbon Border Adjustment Mechanism, as well as Granular Certificate frameworks emerging across other markets.[4] These developments are creating price signals that reward reliability and flexibility, strengthening the investment case for storage, hybrid portfolios and round-the-clock clean electricity supply.

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[2] *Throughoutthisreport,"solar"referstoutility-scalesolarPVtechnology."Wind"referstoutility-scaleonshorewind."Storage" refers to utility-scale battery energy storage systems (BESS). Battery storage is modelled as a four-hour lithium-ion system to reflect prevailing utility-scale deployment and to ensure comparability across projects and regions. "Hybrid systems" refers to co-located combinations of solar PV, onshore wind and storage. These conventions apply throughout unless explicitly stated otherwise.*

[3] *IRENAestimatebasedonkeyassumptions:USD5.94billioncapitalexpenditure(CAPEX),a5%discountrateanda20-yearlifetime.*

[4] *Thisconvergencetowardstemporalandlocationalmatchingextendsbeyondcorporateaccountingframeworks.UnderArticle6.4of the Paris Agreement, internationally transferred mitigation outcomes are also subject to corresponding adjustment requirements that similarly reward the verifiable, time-specific delivery of clean energy.*

A PROJECT-LEVEL METRIC FOR FIRM RENEWABLE ELECTRICITY: FIRM LCOE

This report introduces the firm levelised cost of electricity (F-LCOE) as 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 (Figure 1) via storage, generation overbuild and complementary renewables.

Figure 1 Conceptual framework of firm LCOE

Note: Variable solar PV and wind generation (left) is transformed into a flat, firm output (right) through a combination of generation overbuild, complementary renewable generation and BESS. The flat output profile is calibrated to conserve the total annual generation volume of the original variable asset, ensuring that the firm LCOE reflects only the additional cost of reshaping the output profile, not of increasing total energy production. The firm LCOE is the sum of the standalone LCOE and the firming premium, accounting for the additional expenditure associated with the firming option required to achieve a specified reliability target (set by default to 95%, unless otherwise stated).

In this study, reliability is defined at the asset level in simplified, energy-based terms as the share of annual electricity demand that can be met by renewable generation and storage within the modelled configuration. This definition differs from standard concepts of power system reliability. In power system engineering, reliability typically covers adequacy – the ability to meet peak demand – and security, which refers to resilience against sudden disturbances such as generator outages or transmission failures.

The reliability metric used here therefore describes the delivery certainty of an individual renewable asset or hybrid configuration, rather than the adequacy or security of the power system. In the context of hourly clean energy accounting, this metric is closely related to "clean matching score" or "hourly matching rate" – the share of demand met by clean sources in each hour – although applied here to project economics rather than to emissions accounting.

The modelling framework assumes a flat hourly output profile over the year. This assumption should be understood as a proxy for round-the-clock supply commitments – such as those used by data centres or round-the-clock industrial off-takers – where a constant and continuous supply is the relevant commercial benchmark. It does not represent an optimal dispatch pattern for real-world electricity systems, which typically rely on a combination of flexible generation, transmission, storage and demand response to balance supply and demand. Firm LCOE should therefore be interpreted as a conservative, project-level backstop cost for delivering reliable renewable electricity in grid-constrained or islanded contexts.

Because system-level integration – through aggregation across multiple resources, transmission networks and flexibility measures – typically reduces the cost of achieving comparable reliability, the firm LCOE should be viewed as an upper bound on the profile costs associated with variable renewables. Used in this way, it complements system-wide power sector models by offering investors and developers a transparent, replicable benchmark for assessing the economics of hybrid renewable assets at the project level.

While this analysis focuses on solar PV, onshore wind, and lithium-ion battery storage, the findings do not imply that these are the only – or necessarily the optimal – pathways to firm renewable power in all contexts. Long-duration energy storage, concentrated solar power, geothermal energy and cross-border interconnection are all viable contributors to system reliability, although they fall outside the scope of the current modelling framework. Further deployment of these options is expected to put additional downward pressure on the cost of firm renewable electricity through learning curve effects and economies of scale.

COST COMPETITIVENESS OF ROUND-THE-CLOCK RENEWABLE ELECTRICITY

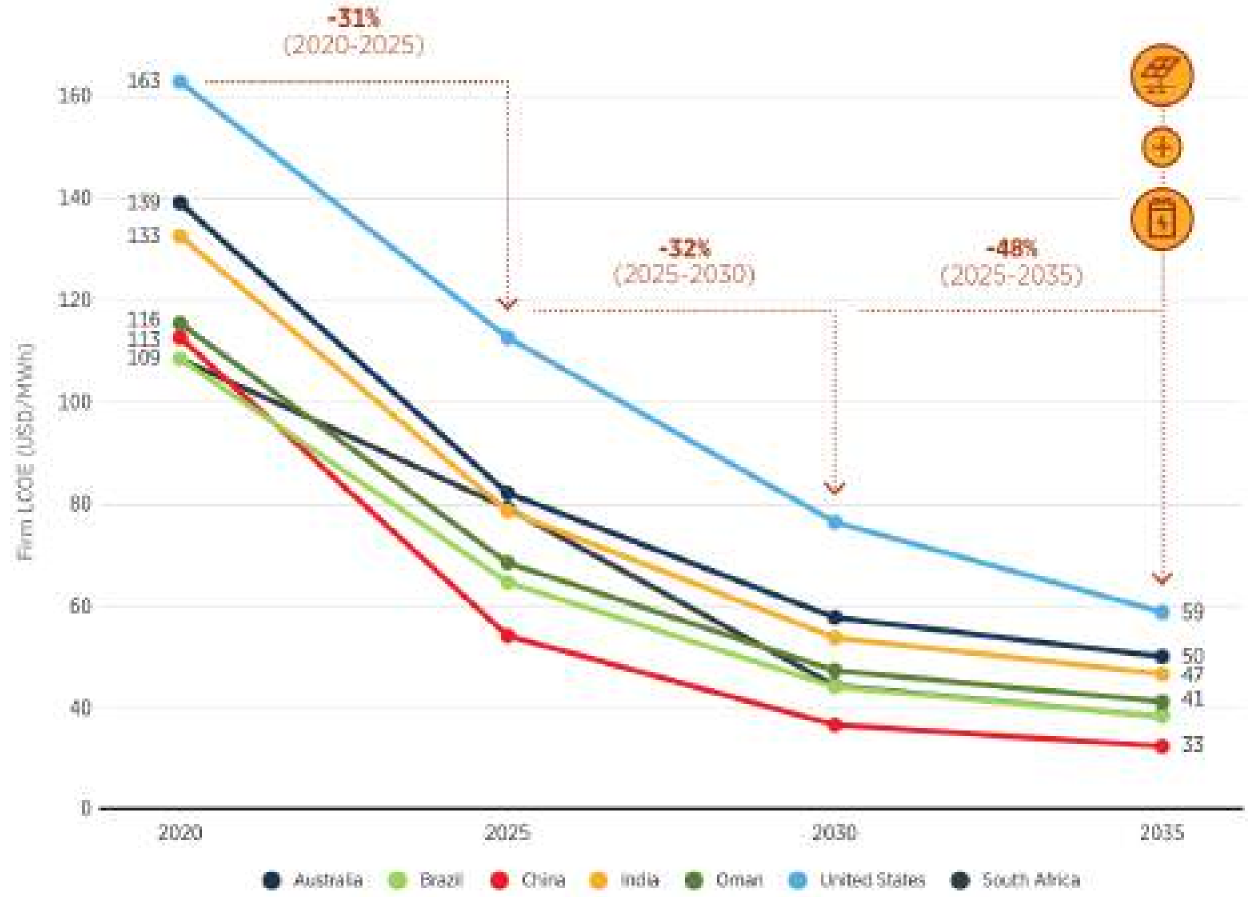
IRENA modelling shows that the cost of delivering firm renewable electricity has declined rapidly, driven by falling costs for solar PV, wind power and BESS.[5] Between 2010 and 2024, total installed costs declined by 87% for solar PV – reaching USD 708/kilowatt (kW)[6] – and by 55% for onshore wind, reaching USD 1066/kW. BESS costs fell even more sharply, declining by 93% from USD 2 634 per kilowatt hour (kWh) in 2010 to USD 197/kWh in 2024. Recent industry surveys indicate that this decline accelerated further in 2025, with turnkey system prices falling by around 30% in a single year, reaching their lowest recorded level. Continued technology learning, manufacturing scale and supply chain maturation are expected to drive further cost reductions across all three technologies over the next five to ten years.

[5] *Allcosttrajectoriespresentedinthisreportshouldbeinterpretedasscenario-basedestimatesunderstatedtechnology, financing, and deployment assumptions, rather than as forecasts of future market outcomes.*

[6] *Unlessotherwisestated, allcostfiguresinthisreportareexpressedinrealUnitedStatesdollarsat2025prices (USD2025). Where a price year is shown explicitly – for example, USD_{2024} – the figure is expressed in the prices of that reference year, as reported in the original source, and has not been deflated or adjusted to 2025 prices.*

The impact on firming costs has been substantial. Analysis by IRENA of solar-plus-battery configurations across multiple countries shows that firm LCOEs have fallen from above USD 100/MWh in 2020 to around USD 54-82/MWh by 2025 in high-irradiance solar regions and strong wind corridors.[7] Further cost reductions of roughly 30% by 2030 and around 40% by 2035 are projected under current technology and cost assumptions, bringing firm LCOEs below USD 50/MWh at the best-performing sites by 2035. Figure 2 illustrates this trend. The simulations assumed a reliability target of 95%.

Figure 2 Firm LCOE trajectory for solar PV and BESS at 95% reliability, 2020-2035



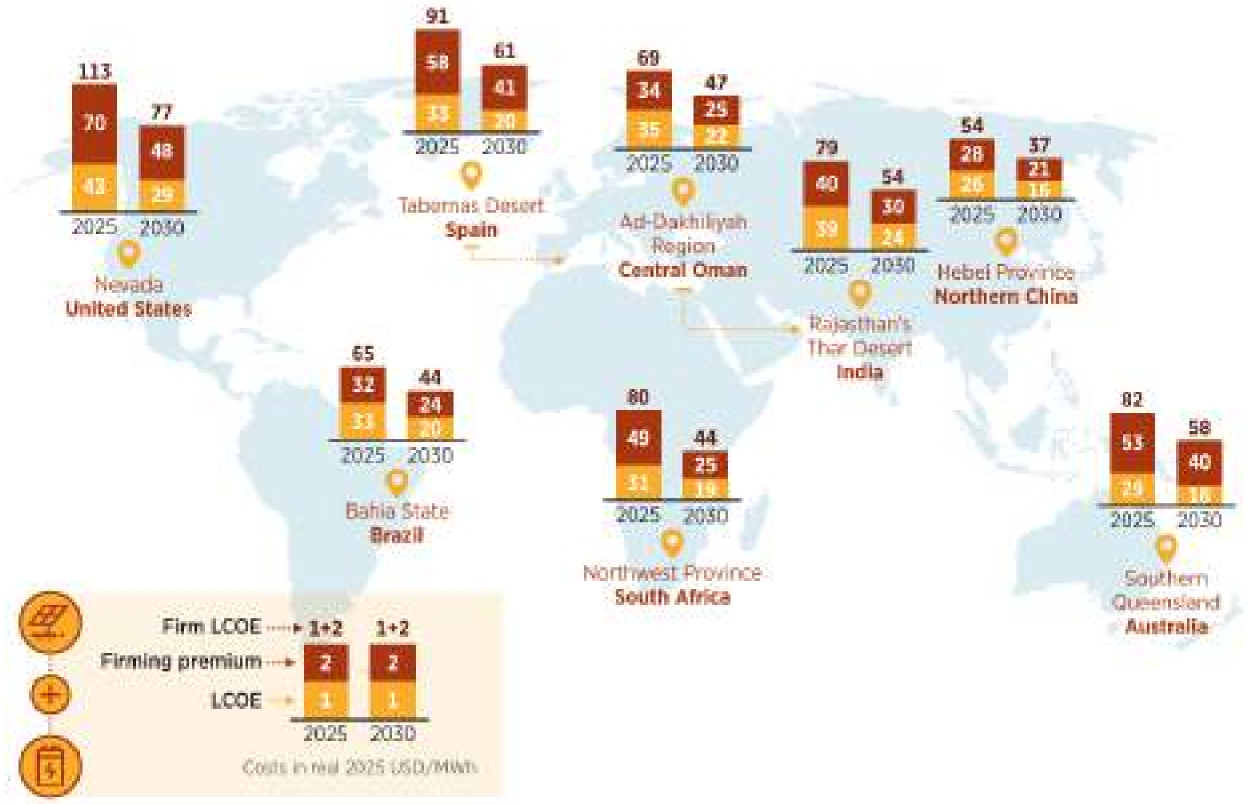
[7] *Thesetrajectories,basedonalearningcurveapproachtotechnologycostprojections,shouldbeinterpretedasscenariosratherthan deterministic forecasts. In contexts where costs have plateaued or, in some cases, risen – as in the United States in recent years – these trajectories reflect technical potential rather than near-term delivery expectations.*

China currently defines the global cost floor for firm solar-plus-storage. Simulations applied to 252 utility-scale solar PV projects commissioned in 2024 show that a significant majority can deliver firm electricity below USD 100/MWh (Figure 3). The minimum firm LCOEs observed in the project sample are as low as USD 30/MWh at a 90% reliability level, rising only modestly to around USD 46/MWh at 99% reliability, with more than half of the sample remaining below the USD 100/MWh benchmark even at the highest reliability tier considered.

Figure 3 Share of solar PV projects in China with firm LCOE below USD 100/MWh (modelled)

Globally, firm LCOEs for solar-plus-storage remain higher than in China but are declining rapidly. Across a range of high-quality sites – from Bahia State in Brazil and the Thar Desert in India to Southern Queensland in Australia and the Northwest Province in South Africa – firm LCOEs in 2025 ranged from around USD 65 to USD 82/MWh, with unfirmed LCOEs as low as USD 29 to USD 39/MWh. By 2030, firm costs are projected to fall to between USD 44 and USD 58/MWh at most of these sites, reflecting continued declines in both solar PV and BESS total installed costs (Figure 4). The United States is an exception: higher financing costs, interconnection charges and permitting complexity have kept costs elevated, and firm solar-plus-storage LCOEs remain higher than in other regions. Across all locations, the firming premium is narrowing, highlighting the growing competitiveness of round-the-clock solar power in high-resource regions worldwide. The majority of the world's population lives within these high-irradiance and strong wind zones, making the declining cost of firm renewable power a development opportunity of global significance.

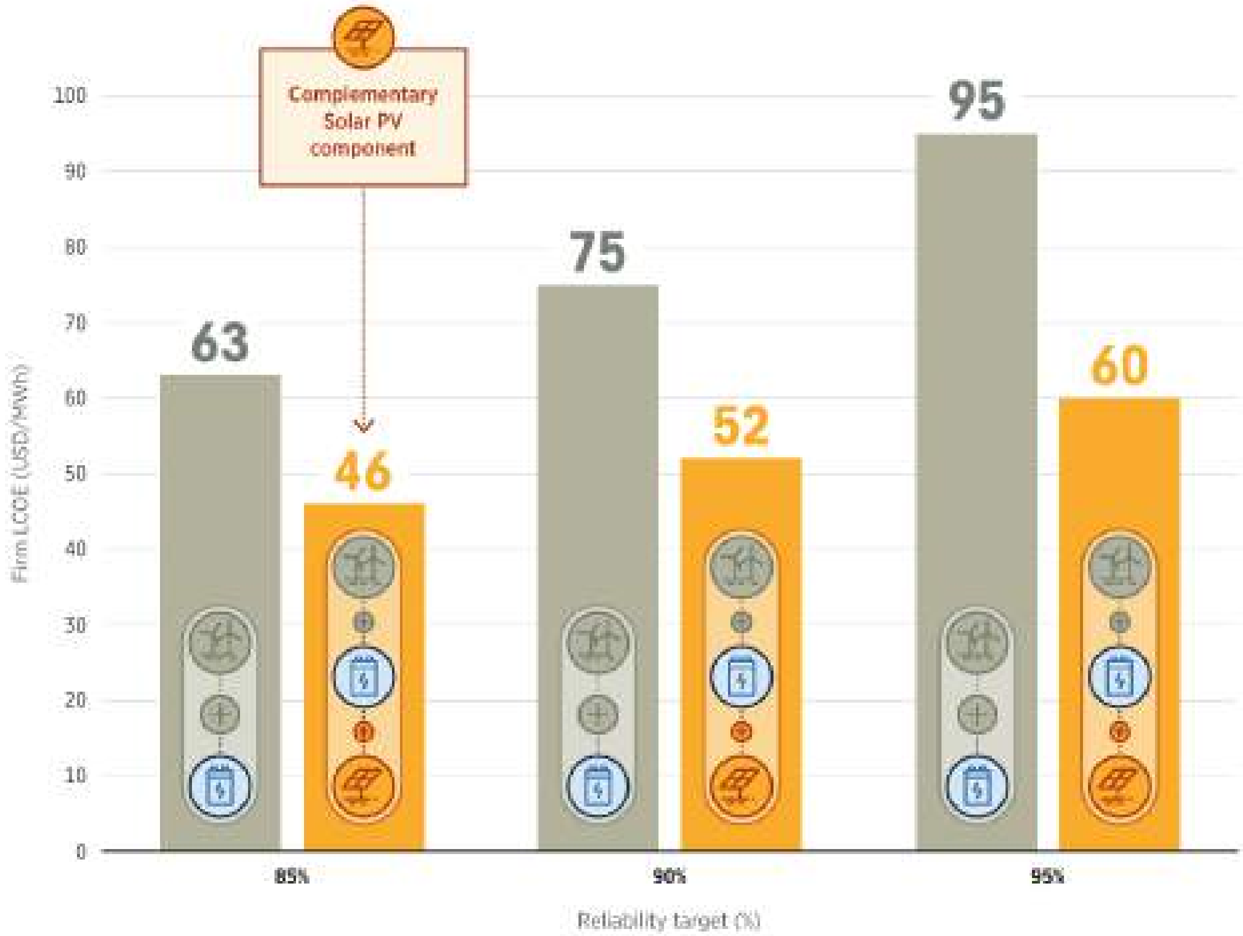
Figure 4 LCOE and firm LCOE at 95% reliability for selected solar PV sites, 2025 and 2030



Firm LCOEs for wind-plus-storage are generally higher than for solar-plus-storage at equivalent reliability targets, despite onshore wind being typically cheaper than solar PV on an unfirmed LCOE basis. The difference is due to variable generation profiles. Solar PV follows a predictable diurnal cycle, and firming primarily requires intra-day storage to shift daytime output to evening demand. Wind output, by contrast, can be affected by multi-day low-generation events even in high-resource regions, requiring larger storage or back-up capacity, which drives up the firm LCOE. IRENA estimates for 2025 show that firm wind-plus-storage LCOEs ranged from around USD 59/MWh in China to around USD 88 to USD 94/MWh across Brazil, Germany, and Australia, with costs projected to fall to roughly USD 49 to USD 75/MWh across these markets by 2030 (USD 46 to USD 67/MWh in 2035).

At the system level, however, this distinction largely disappears: the complementary nature of solar and wind generation profiles reduces the duration and depth of energy shortfalls, lowering the overall firming requirement and reducing costs substantially compared with either technology firmed in isolation (Figure 5). In practice, the most cost-effective firm renewable systems combine solar and wind, leveraging their natural complementarity.

Figure 5 Impact of hybridisation strategies on the firm LCOE of onshore wind with BESS



Note: Results are shown for an onshore wind and battery storage configuration under two hybridisation strategies – wind overbuild (grey columns) and a complementary solar PV component (orange columns) – across reliability targets of 85%, 90% and 95%. The analysis is based on 2025 technology cost assumptions and a high-quality wind site in the Elizabeth Bay corridor in Namibia.

These cost trajectories point to a fundamental shift in the competitive landscape for electricity generation. In China, firm solar-plus-storage already falls well below the cost of new coal-fired generation – which typically ranges between USD 70 and USD 85/MWh – and well below new gas-fired plants, which generally exceed USD 100/MWh.[8] In the United States, new combined-cycle gas turbines have reached a record USD 102/MWh – broadly in line with firm solar and wind costs at 90-95% reliability in high-resource regions. In Saudi Arabia, solar-plus-storage systems can approach near-continuous supply at a firm LCOE of around USD 70/MWh, competitive with combined-cycle gas generation even where fossil fuels are domestically cheap.

[8] *This figure reflects the estimated LCOE of new coal-fired capacity in China and should not be conflated with the average cost of existing operational plants. The benchmark LCOE for coal generation in China is typically in the range of USD 50 to USD 65/MWh, levels at which plants with higher costs would struggle to remain profitable. The new-build benchmark is used throughout this report for consistency with cross-country comparisons, where the relevant policy and investment question concerns the cost of capacity that has yet to be built.*

In several major economies, co-located wind-plus-storage has already crossed a further threshold: its cost now falls below the operating costs of existing coal and gas plants – meaning that the economics of already-built fossil assets are being challenged, not only by new renewable capacity, but by the marginal cost of keeping the existing fleet running. Globally, the dramatic decline in generation and storage costs observed in recent years has brought firm renewables to a point where they maintain a cost advantage relative to new fossil generation across prime solar and wind resource regions – an advantage whose implications extend well beyond the power sector itself.

Electricity is the dominant cost driver in green hydrogen and other power-to-X processes, typically accounting for two-thirds or more of the levelised cost of production. These processes are sensitive not only to the price of electricity but also to the capacity factor at which electrolysers operate: higher utilisation rates spread construction costs over more output, lowering the cost per unit of hydrogen or synthetic fuel produced. Firm renewable electricity – delivered continuously at stable, declining cost – directly addresses both parameters. As a result, the economics of green hydrogen and derivative clean fuels are set to improve, reinforcing the strategic value of round-the-clock clean power well beyond electricity markets. The same logic applies to energy-intensive industries more broadly, for which access to firm, low-cost electricity is a structural competitiveness advantage.

KEY DRIVERS OF FIRM RENEWABLE ELECTRICITY COSTS

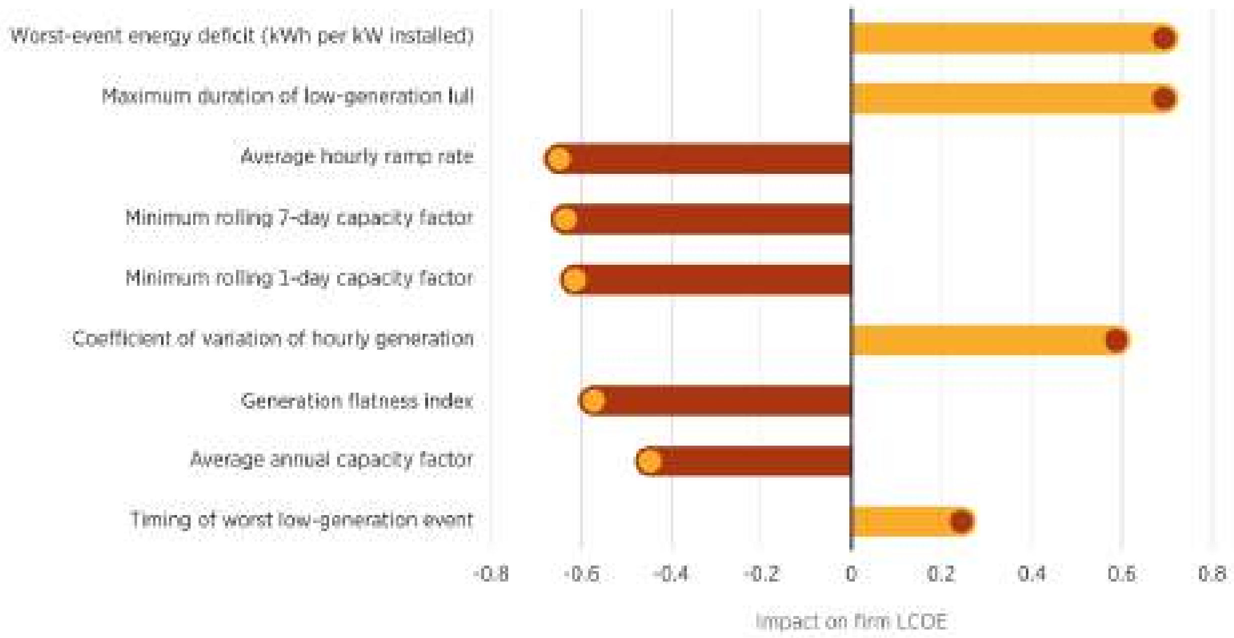
The cost of delivering firm renewable electricity varies across technologies, locations and reliability targets. Understanding these drivers is essential to identifying where round-the-clock renewable power is already competitive and where further progress is required.

The starting point is geography. Resource quality and local weather patterns are the primary determinants of whether a site can support cost-competitive firm renewable power at all.[3] High-irradiance solar regions and wind corridors with persistent, stable generation profiles experience fewer and shallower supply shortfalls, reducing the storage capacity and generation overbuild required to maintain a reliable supply. In areas with weaker or more variable resources, the cost of firm power is structurally higher across all reliability levels, and project-level firming alone may not be the most economic route to reliable supply. Without favourable resource conditions, no combination of storage, overbuild or system design can fully compensate – although in such contexts, other options such as geothermal energy, long-duration energy storage and regional interconnection become particularly relevant.

[3] *The generation profiles adopted in this analysis are based on a single representative historical weather year, which ensures consistent comparison across locations and technologies and supports the narrative on cost trends. Using multiple weather years would be a more rigorous approach, particularly to stress-test for prolonged low-generation events, and should be conducted whenever a specific site is assessed.*

At well-resourced sites, however, prolonged low-generation events – periods of simultaneously weak solar irradiance and low wind speeds lasting several consecutive days, known as "dark doldrums" or, in the energy literature, as *Dunkelflaute* – can still occur, with a negative impact on firm LCOE. IRENA's analysis shows that the depth and duration of such events exert a far stronger influence than average capacity factors or short-term output variability (Figure 6).

Figure 6 Resource-related drivers of the firming premium for solar PV

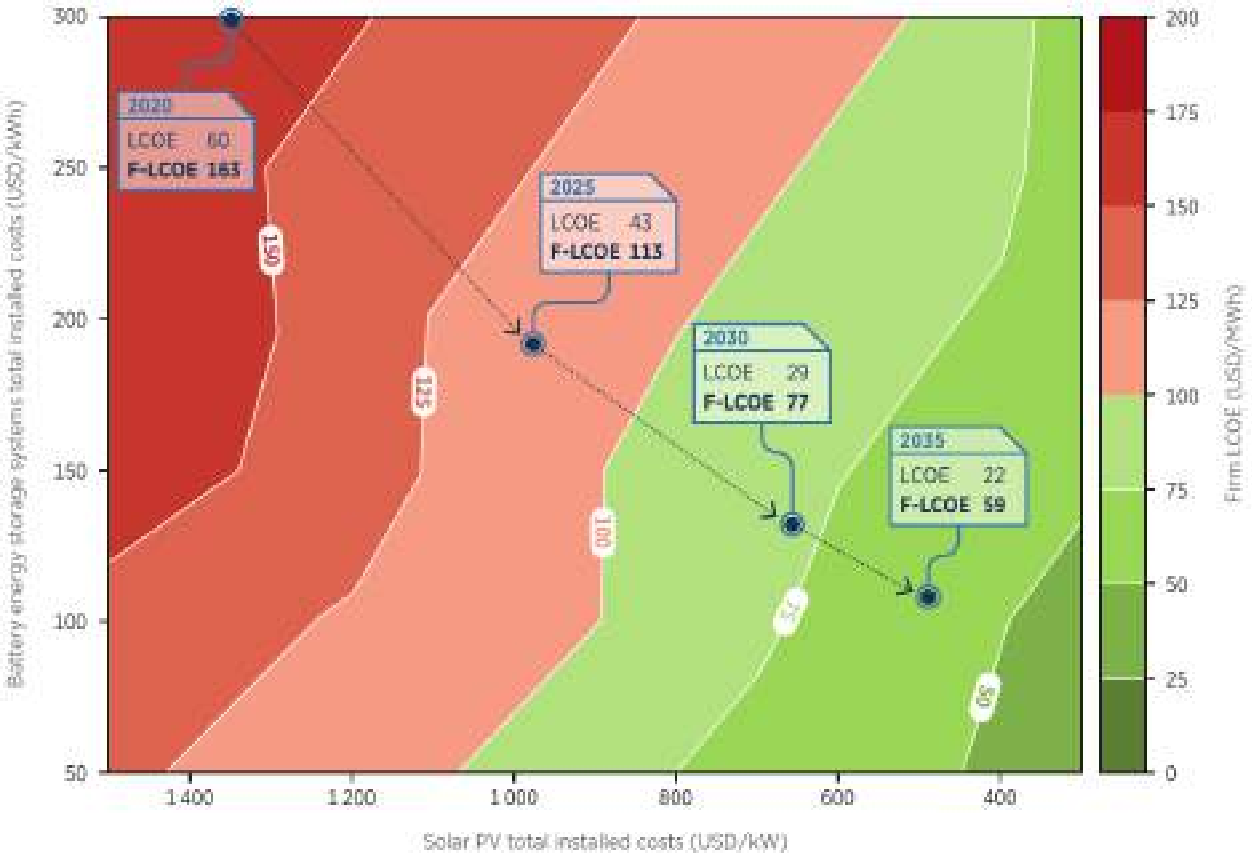


Note: The tornado diagram's bars show Pearson correlation coefficients between project-level firming premium and several indicators of resource quality, ranked by absolute magnitude. A positive coefficient indicates that the indicator and the firming premium move in the same direction – for example, longer low-generation events are associated with a higher firming premium. A negative coefficient indicates that they move in opposite directions. All projects are modelled under identical techno-economic assumptions – any differences in firming premiums therefore reflect resource characteristics alone.

Lithium-ion batteries handle daily fluctuations effectively, but bridging multi-day or seasonal gaps requires moving beyond short-duration storage. The most powerful tool is portfolio diversification: where resource conditions are favourable, combining solar PV and wind generation can reduce the supply shortfalls. In the United Kingdom, for instance, Ember suggests that days with simultaneously low wind and low solar generation occur only 2% of the time (Mayo, 2025). Where gaps remain, the system's ability to bridge multi-day shortfalls can be extended through long-duration storage technologies – including pumped storage hydropower, flow batteries, compressed-air systems and thermal storage – as well as dispatchable renewable sources such as hydropower, bioenergy and geothermal power.

Once a site and its hybrid configuration are defined, technology costs and the chosen reliability target together determine the final cost. As solar PV, wind and BESS become cheaper, the system moves from higher-cost to lower-cost territory – independent of the reliability level targeted – although the trajectory is shaped by the site's resource quality and financing conditions (Figure 7).

Figure 7 Impact of declining technology costs on the firm LCOE of solar PV and BESS



Note: Hypothetical solar PV site in Las Vegas, Nevada, United States. Each isoline of the contour plot represents a firm LCOE level (in USD/MWh) – estimated at a 95% reliability target – as a function of the total installed costs of solar PV (horizontal axis) and BESS (vertical axis). As technology costs decline, the system moves from the high-cost red zone towards the low-cost green zone along the dashed trajectory. The shape and position of the contours reflect the site's resource quality and financing conditions.

A final cost driver is the chosen reliability target – Figure 5 illustrates its impact on the firm LCOE of a wind-plus-storage configuration. At moderate levels – 80% to 90% in high-quality resource regions – hybrid renewable systems can meet demand cost-effectively using manageable volumes of storage and generation overbuild. Beyond this threshold, costs rise non-linearly: each additional percentage point of reliability requires disproportionately more storage or overbuild. For most commercial and industrial applications, the 80-90% range therefore represents the most cost-effective balance between affordability and delivery certainty. Users with the most demanding supply requirements – including data centres, hospitals and precision manufacturing facilities – typically require higher availability standards and will need dedicated back-up strategies, such as renewable dispatchable generation or explicit grid redundancy.

BEYOND COST: RELIABILITY, RESILIENCE AND DEPLOYMENT SPEED

In high-quality resource regions, co-located solar PV, onshore wind and BESS can already deliver reliable, round-the-clock electricity at costs competitive with – and in many cases below – those of new fossil fuel generation. This represents a fundamental shift in what renewable electricity can deliver and the price at which it can be delivered.

Firm solar and wind represent, however, only one of several pathways to reliable power systems. High shares of variable renewables can be integrated without requiring every generator to be firm, provided that sufficient flexibility exists across transmission networks, storage, demand response and complementary dispatchable capacity. Project-level firming is most relevant where grid access is constrained, where customers require a continuous, firm supply, or where new capacity is needed rapidly and conventional alternatives face extended lead times.

As electricity demand from data centres, artificial intelligence and energy-intensive industries accelerates, deployment speed – not just cost – is emerging as a competitive advantage of hybrid renewable systems. Co-located solar PV, wind and BESS can typically be built and commissioned within one to two years, once permitting and grid connection have been secured – considerably faster than new gas-fired generation in many markets.[10] Furthermore, the addition of battery storage enables more variable renewable capacity to connect behind existing grid connection points, reducing deployment timelines and deferring costly transmission upgrades.[11]

The strategic value of these advantages extends well beyond project economics. Electricity demand is rising fast – driven by electrification across transport, industry, and the digital economy, and by the broader shift away from fossil fuels. At the same time, recent geopolitical shocks have highlighted that dependence on imported fossil fuels exposes economies to price volatility and supply disruptions beyond their control. In this evolving context, renewable electricity – and round-the-clock hybrid systems in particular – offers a structurally different proposition: the resource is local, the marginal cost of generation is low, long-run prices are largely decoupled from global commodity markets, and firm, flexible supply can be delivered at predictable, declining cost – offering a natural hedge against fossil fuel price volatility for any large electricity consumer.

As technologies mature and costs continue to fall, realising their potential is increasingly a question of enabling policies and strategies. In many countries, electricity markets, grid infrastructure and procurement frameworks do not yet adequately reward the value that hybrid renewable systems can provide. Closing these gaps – through market design reforms that explicitly value flexibility and firmness – will determine the pace at which the cost reductions documented in this report translate into deployed firm renewable capacity and reduced reliance on fossil fuels.

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[10] *Inmanymarkets,totalprojectdevelopmenttimelines–includingpermitting,interconnectionapprovalsandgridconnection–extend well beyond the construction period alone. In countries affected by grid connection delays, permitting constraints, or supply chain pressures, development timelines may be longer and cost reductions slower to materialise. The trajectories presented in this report should therefore be understood as reflecting technical potential rather than actual deployment outcomes – which will vary across countries and regulatory environments.*

[11] *AnalysisbyEmbersuggeststhatBESScanenableuptofivetimesmoresolarcapacitytoconnectthroughexistinggridinfrastructure (Ember, 2025).*

01

THE RISE OF ROUND-THE-CLOCK RENEWABLE POWER

Over the past decade, the cost of renewable electricity has fallen sharply – solar photovoltaics (PV) and onshore wind have become the most cost-competitive sources of new electricity generation globally, as tracked by the Renewable Cost Database of IRENA (IRENA, 2025). This cost decline has driven record deployment: renewable capacity additions have consistently outpaced those of any other technology in recent years.

However, as the share of variable renewables increases, two challenges emerge. The first is physical: ensuring that power is available when and where it is needed. While system operators have become increasingly adept at managing real-time balancing, grid connection constraints are emerging as a binding limitation. The second challenge is economic: high renewable shares depress wholesale prices during periods of peak generation, eroding the revenues – and the business case – for project developers.

In response, a new generation of hybrid assets combining solar PV, wind and battery energy storage systems (BESS) is taking shape (Box 1). These systems enable more generation capacity to connect through existing grid infrastructure, shift output to higher-value hours, improve capture rates[12] and deliver reliable, round-the-clock renewable electricity.

[12] *Hirth(2026)definesthecapturerateas"theper-MWhwholesalerevenuerelativetotheaverage(base)electricitypriceofthesameyear".*

BOX 1 PROJECT-LEVEL FIRMING IS ALREADY TAKING SHAPE IN PRACTICE

- 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).
- India's round-the-clock renewable tenders require developers to guarantee minimum utilisation thresholds across hybrid solar, wind and storage portfolios – enabling firm clean power to be procured competitively through standard commercial mechanisms (Andreae *et al.*, 2022). Recent auctions demonstrate that such configurations can deliver near-continuous clean power at high availability (around 95%) and at costs below USD 60-65/MWh (Chojkiewicz *et al.*, 2025).
- Across the United States, co-located solar-plus-storage has shifted from an exception to an increasingly standard project configuration, with about a quarter of utility-scale solar additions in 2025 paired with storage – a share projected to exceed half of all new capacity within this decade (BNEF, 2025).
- In high-irradiance markets such as Saudi Arabia, solar-plus-storage configurations are approaching near-continuous availability at costs competitive with combined-cycle gas generation – broadly in line with the USD 70-80/MWh estimated for the Al Dhafra project in the United Arab Emirates – even where fossil fuels are domestically produced (BNEF, 2026a).
- In Australia and Portugal, developers are similarly coupling solar with BESS and complementary wind generation to maximise output within fixed grid limits (Ember, 2025).

This deployment momentum is being reinforced – and accelerated – by two additional drivers: a surge in electricity demand from data centres, artificial intelligence workloads and advanced manufacturing that is stretching lead times and driving up the capital expenditure (CAPEX) for conventional generation (Box 2); and a fundamental shift in how renewable electricity is measured and valued, driven by policy reform and evolving accounting standards (Box 3).

BOX 2 THE CAPACITY RACE: SPEED AND RELIABILITY AS THE NEW DIFFERENTIATORS

Co-located solar and storage assets are becoming increasingly critical as electricity demand rises rapidly,* driven by data centres, artificial intelligence workloads and advanced manufacturing.** These sectors require not only large volumes of power but also a continuous, high-quality supply with almost zero tolerance for disruption. As demand accelerates, the speed at which new capacity can be deployed is becoming a decisive factor. In this context, hybrid renewable systems – combining solar, wind and storage – offer a modular and scalable solution. They can typically be developed and commissioned within one to two years, once permitting and grid connection have been secured, allowing firm capacity to be brought online quickly and expanded progressively as needs grow.

In contrast, conventional gas-fired generation faces growing constraints due to supply chain bottlenecks and rising costs. According to S&P Global, strong worldwide demand for gas turbines has extended lead times to between five and seven years for many models (Anderson, 2025). Simultaneously, the CAPEX of new combined-cycle gas plants has dramatically increased, exceeding USD 2 000/kW in some markets – more than double the cost of comparable projects built just a few years ago. These delays and cost escalations limit the ability of gas generation to respond to near-term capacity needs, particularly in power systems experiencing rapid growth.

* *The International Energy Agency (IEA) projects that around 80% of global energy demand growth to 2035 will occur in regions with high-quality solar irradiation. This marks a decisive shift in the geography of energy consumption and helps explain the accelerating deployment of solar-based firm power solutions, particularly in emerging and developing economies (IEA, 2025a).*

** *According to the IEA, global electricity demand from data centres is growing at around 12% per year and is set to more than double by 2030, with particularly strong impacts on power systems in advanced economies. The IEA's recent report, Energy and AI (IEA, 2025b), highlights the importance of renewables supported by storage in delivering reliable, uninterrupted electricity at scale, while noting that long lead times for conventional generation technologies – including gas-fired power plants – could constrain the speed at which new capacity can be delivered.*

BOX 3 ACCOUNTING REFORM MEETS MARKET REALITY

The regulatory and market environment is converging on a common principle: clean electricity should be measured and valued not just by volume, but by when and where it is delivered.

In the European Union, binding rules for the certification of renewable hydrogen require geographical correlation and phase in hourly matching from 2030, encouraging the development of more granular certificate infrastructure. In the United States, federal tax legislation has established a differentiated credit structure for co-located projects, with credits for the storage component extending beyond those for standalone solar – effectively shifting project economics in favour of co-located and firm designs. In China, provincial mandates requiring battery co-location as a condition of grid connection approval drove a rapid scale-up of co-located capacity between 2023 and 2025 – establishing a domestic industry that continued to grow even after the mandates were removed in early 2025. At the corporate level, large buyers are increasingly pairing variable renewables with co-located solar-plus-storage, hydropower and other low-carbon power sources – including nuclear – signalling a measurable shift from volume maximisation towards reliability optimisation in clean energy procurement.

These policy signals are meeting a commercial reality that reinforces the case for firm hybrid renewable systems. In Europe, the rapid increase in zero- and negative-priced hours in solar-saturated markets has exposed the limits of annual matching in practice. Standalone solar projects face growing revenue erosion during periods of peak generation, while hybrid solar-plus-storage assets can shift output to higher-value hours, commanding a price premium that the market is increasingly recognising. Project lenders and investors are responding accordingly, with hybridised portfolios and storage integration becoming conditions for revenue stability, rather than optional enhancements (Radoia *et al.*, 2026).

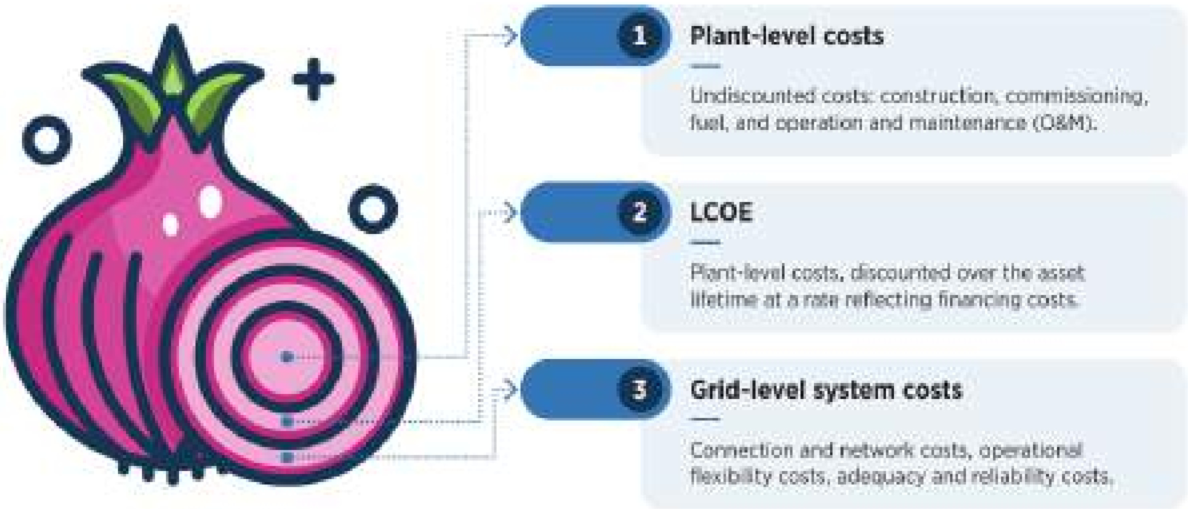
The accounting framework is catching up with this market reality. Hourly Guarantees of Origin – now mandated in the European Union – and equivalent Granular Certificate frameworks emerging in other markets are designed to link clean energy claims to the specific hour and location of delivery, creating price signals that reward reliability and flexibility. The ongoing revision of the GHG Protocol Scope 2 Guidance proposes to extend this logic globally, requiring hourly and location-matched certificates as the basis for market-based emissions claims; this prospect is already influencing procurement strategy, with buyers exploring firm and dispatchable clean energy options in anticipation of tighter Scope 2 obligations.

1.1 BEYOND LCOE: WHY A SYSTEM PERSPECTIVE MATTERS

In 2024, new utility-scale onshore wind projects had the lowest global weighted average levelised cost of electricity (LCOE) at USD 35/MWh, followed by solar PV (USD 44/MWh) and hydropower (USD 58/MWh). Notably, 91% of newly commissioned utility-scale renewable capacity delivered power at a lower LCOE than the cheapest fossil fuel-fired alternative (IRENA, 2025). By 2025, costs had converged further, with fixed-axis solar and onshore wind both averaging around USD 40/MWh globally (BNEF, 2026b). Renewables are now the least-cost option – on an LCOE basis – for new power generation capacity in most regions.

The LCOE metric, however, captures only project-level costs – essentially the construction and operation expenditures incurred within the boundaries of the plant (Figure 8). In particular, it does not account for the wider costs of integrating the generation asset into the power system.[13] These include balancing supply and demand in real time, providing grid flexibility and reinforcing transmission networks to connect new capacity. As the share of variable renewable generation grows, these system costs are expected to increase.

Figure 8 LCOE captures plant-level costs - but not the full system picture



With a record 670 GW of solar and wind capacity added globally in 2025 alone (IRENA, 2026b), a further consideration emerges: the value associated with each unit of energy, not just the generation cost, which depends critically on when it is produced. When solar or wind generation is high, and the demand is low, variable generation tends to depress wholesale market prices, reducing per-MWh revenues. This effect on the capture rate becomes more pronounced as penetration rises. In Germany,[14] the average per-MWh wholesale revenue of solar assets had fallen to roughly half the annual average market price, while the capture rate for onshore wind had declined to around 0.8 (Hirth, 2026). This "cannibalisation effect" reduces the ability of renewable generators to recover their costs and can contribute to increased curtailment,[15] ultimately hindering the development and deployment of renewable energy projects. LCOE, by definition, does not account for when generation occurs - and therefore cannot reflect the value of a MWh.[16]

[13] *Integration costs are not unique to renewables – all generation technologies impose costs on the wider power system, including grid connection, frequency control and the maintenance of adequate reserve capacity.*

[14] *This pattern is not confined to Germany. Data for 2025 shows solar capture rates of around 54-58% across Spain, France and Greece, reflecting rising solar penetration across European markets (Jamaux, 2025).*

[15] *For example, in Brazil, electricity prices were historically driven by hydropower, with limited volatility. With the recent growth of solar and wind, curtailment has increased sharply, reaching around 14% for wind and 21% for solar in the first half of 2025, up from near zero in 2022, according to BloombergNEF (BNEF, 2025a).*

[16] *Two alternatives to LCOE have been developed to capture the value of electricity: the Levelised Avoided Cost of Electricity (LACE), which reflects the value of displaced generation (US EIA, 2013), and the Value-Adjusted LCOE (VALCOE), which incorporates energy, capacity and flexibility components into the assessment of generation technologies (IEA, 2018).*

Moving beyond plant-level costs requires a system-level perspective – one that captures not only the cost of generating electricity, but also the measures needed to maintain reliable, secure and affordable supply. As the share of variable renewable energy (VRE) – solar PV and wind – increases, power system operators must ensure that demand can be met during periods of low renewable availability – when solar irradiance and wind speeds simultaneously fall – and that electricity grids can accommodate new capacity.

At low shares of VRE, these needs can generally be met within existing system capabilities without inducing significant costs. As the share of VRE increases, however, additional investment and operational changes are required to maintain reliable, secure and affordable system operation. These can be provided through a portfolio of "clean flexibility" tools (Rangelova *et al.*, 2024), including short- and long-duration energy storage, demand-side flexibility, grid expansion and interconnection, and more flexible operation of both renewable and fossil generation.

Earlier studies, including (Hirth *et al.*, 2015), provided a useful conceptual framework to classify system integration costs, distinguishing three main categories:

- Profile costs – arising from the mismatch between variable renewable generation and electricity demand over time.
- Balancing costs – linked to short-term output variability and forecast errors.
- Grid-related costs – associated with expanding and reinforcing transmission to connect renewables located far from consumption centres.

Over the past decade, the magnitude and composition of these effects have evolved significantly, reflecting increased deployment, declining storage costs, improved system operation, and the growing role of demand-side flexibility and interconnections.

Recent analyses emphasise that integrating higher shares of renewables is not governed by a single cost component, but by the optimisation of a portfolio of flexibility solutions tailored to different time scales (IRENA, 2026a). In many systems, these options are already delivering multiple system-wide benefits: lowering overall system costs, reducing exposure to price volatility, improving reliability and resilience, and unlocking wider economic impacts, including growth, job creation and enhanced energy security (Arup, 2026).

Plant-level metrics such as LCOE must therefore be complemented by system-level analyses – accounting for the costs of flexibility and reliability and the value of resource diversity – and by macroeconomic impact assessments that quantify the broader benefits to society at large.

1.2 FROM SYSTEM MODELS TO PROJECT-LEVEL BENCHMARKS

A system-wide approach remains essential for planning reliable, low-carbon power systems and assessing the flexibility needed for higher shares of renewables. However, the complexity and data intensity of large-scale models often make them practically inaccessible to investors, developers and policy makers as they seek clear, replicable benchmarks.

Complementing the system view, a growing body of work is adopting simpler, project-level approaches to quantify the economics of hybrid renewable assets. The 2025 edition of Lazard's Levelised Cost of Energy Plus introduced an estimate of the "cost of firming intermittency", based on the Effective Load Carrying Capability (ELCC) of variable renewables and the Net Cost of New Entry (Net CONE) of firm resources (Lazard, 2025). Ember developed a project-level framework for firm solar, showing that high reliability can be achieved through solar overbuild combined with short-duration storage, while providing a transparent and replicable benchmark for investors and policy makers (Ember, 2025). BloombergNEF has similarly expanded its analytical framework to include co-located renewable and storage assets, applying project-level cost modelling to assess the economics of hybrid configurations (BNEF, 2026b). The two perspectives are increasingly converging as markets mature.

Building on these developments, this report introduces a transparent and replicable framework to assess the economics of firm renewable electricity at the project level. IRENA has tracked renewable energy costs globally for over a decade, assembling one of the most comprehensive datasets on utility-scale solar PV, onshore wind and BESS across markets and regions. This report leverages that foundation – combining project-level cost data with location-specific resource profiles, characterised by local wind speeds, solar irradiance and generation patterns – to assess what it actually costs to deliver firm, round-the-clock electricity from a hybrid renewable system at a given site, under realistic technology and financing assumptions. The result is a consistent, globally comparable benchmark: the firm levelised cost of electricity. Chapter 2 presents the framework, its findings across a wide range of markets and resource conditions, and the key drivers that determine where and when firm renewable electricity becomes cost competitive.

02

THE ECONOMICS OF FIRM RENEWABLE POWER

2.1 MEASURING THE COST OF FIRM RENEWABLE POWER: THE FIRM LCOE

As established in chapter 1, the levelised cost of electricity (LCOE) does not capture the additional investment needed to make renewable output continuous and dependable. Transforming variable generation into a firm supply requires battery energy storage systems (BESS) to shift generation across hours and, in many cases, additional generation capacity to cover periods when the resource is insufficient – costs that conventional LCOE does not reflect.

To address this gap, this report introduces the firm levelised cost of electricity (F-LCOE) as a project-level benchmark for assessing the economics of continuous renewable power. The firm LCOE represents the total cost per MWh of electricity supplied reliably by a combination of renewable generation and battery storage, providing a consistent basis for comparing the cost of firm solar and wind not only with other dispatchable renewable technologies such as hydropower, bioenergy, geothermal power, and concentrated solar power, but also with conventional generation, including coal- and gas-fired plants.

The proposed approach is conceptually related to the Levelised Cost of Load Coverage (LCOLC) framework proposed by Grimm *et al.*, which shifts the focus from generation costs to the cost of meeting a specified electricity demand with an optimised mix of generation and storage technologies (Grimm *et al.*, 2024). LCOLC typically assumes full load coverage as a deterministic constraint. The methodology adopted here relaxes this assumption by introducing an explicit reliability parameter, allowing the model to find the least-cost configuration for any given delivery certainty level rather than requiring complete demand coverage at all times.

The framework rests on two important conventions. First, the firm LCOE is calculated against a flat, constant hourly demand profile throughout the year – a modelling choice that ensures consistent, apples-to-apples comparison of firm renewable costs across technologies, locations, and time, rather than a claim about how power systems operate in practice. Second, the approach seeks to achieve a specified reliability target – defined as the share of that flat annual demand that the modelled configuration can cover – which should not be confused with the broader concept of power system reliability.

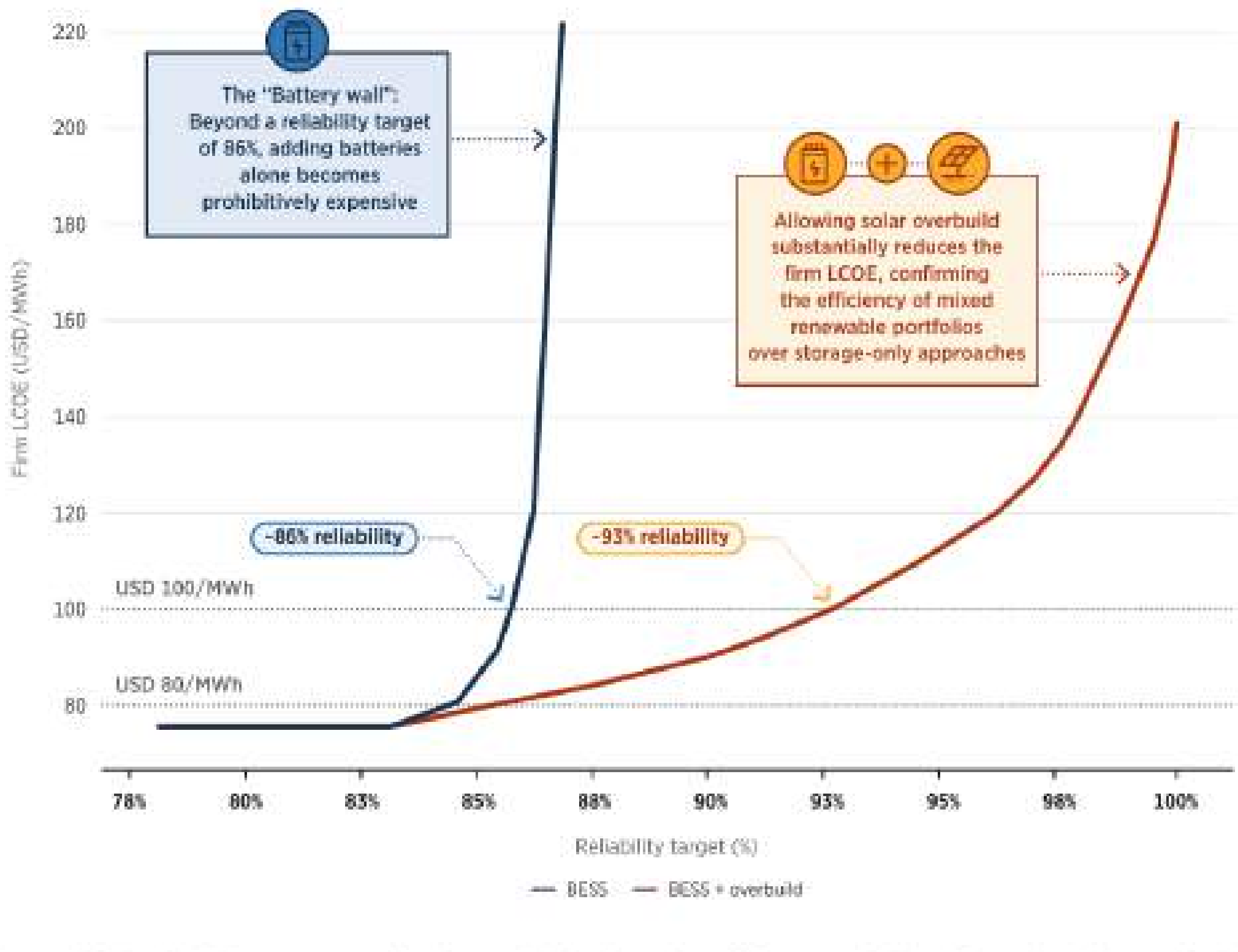
The methodology – including the modelling framework, data sources and cost allocation approach – is described in full in the technical annexes of this report. The remainder of this section illustrates how the framework operates in practice through a reference case.

Illustrative case: solar PV and BESS in Las Vegas, United States

To demonstrate how the firm LCOE framework operates, a reference simulation was conducted for a hypothetical 100 MW solar PV plant in Las Vegas – one of the most favourable locations in the United States for solar-plus-storage.

The standalone LCOE for this plant, based on 2025 cost assumptions (as described in the technical annexes), is around USD 43/MWh. The firm LCOE depends both on the firming option and the reliability target, as illustrated in Figure 9.

Figure 9 Firm LCOE versus reliability target for a solar PV project with BESS (Las Vegas, United States)



At an 80% reliability target, a four-hour BESS alone is sufficient to deliver firm electricity at below USD 80/MWh (blue curve in Figure 9). Beyond 85%, however, the cost of relying on battery storage alone rises sharply. Each additional percentage point of reliability requires disproportionately more storage capacity to cover increasingly rare but demanding low-generation events.

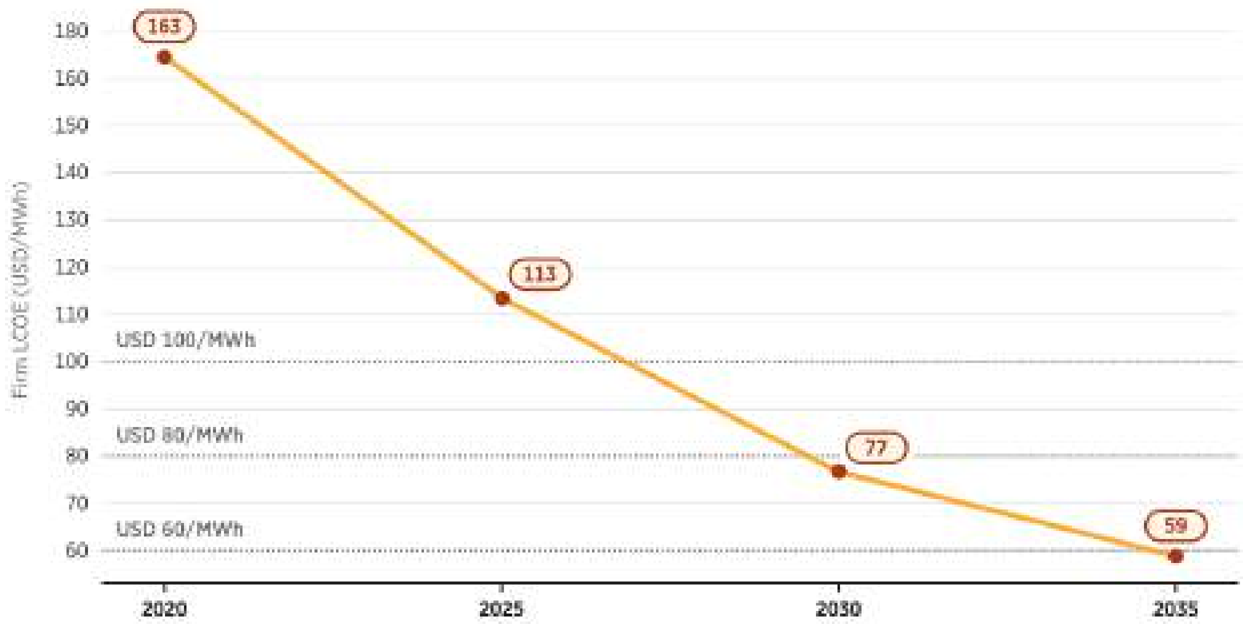
Allowing solar overbuild significantly reduces the costs induced by firming (Brown in Figure 9). The calculations associated with this option (BESS plus solar overbuild) suggest that a 95% reliability target can be achieved at around USD 113/MWh with 592 MWh of BESS and 62 MW of additional solar capacity (Table 1). In this configuration, the firming premium relative to the base LCOE is around USD 70/MWh, with roughly 40 USD/MWh allocated to BESS[17] and the remainder to solar overbuild.

Table 1 Firm LCOE breakdown for a solar PV project with BESS (Las Vegas, United States)

Parameter	Value
BESS	591.8 MWh
Solar overbuild	61.9 MW
Firm LCOE	**113.2 USD/MWh**
LCOE	**43.5 USD/MWh**
Firming premium	**69.7 USD/MWh**
Firming premium attributed to BESS	40.4 USD/MWh
Firming premium attributed to solar overbuild	29.3 USD/MWh

Looking ahead, declining technology costs – for both solar and batteries – are projected to reduce the firm LCOE substantially over time. Under the cost trajectories described in the technical annexes, the firm LCOE for this configuration is projected to fall below USD 80/MWh by 2030 and below USD 60/MWh by 2035 (Figure 10).

Figure 10 Projected decline in firm LCOE for solar PV and BESS (Las Vegas, United States)



[17] The storage-related component of this firming premium can be interpreted as a proxy for the levelised cost of storage (LCOS) within a co-located firming system, as explained in the technical annexes of this report.

2.2 HOW FIRM RENEWABLE COSTS COMPARE ACROSS MARKETS

Using IRENA's Renewable Cost Database, firm LCOEs were estimated for a large sample of utility-scale solar PV and onshore wind projects commissioned in 2024 in China, the United States and other selected sites across the world. The analysis combines project-level cost data with location-specific hourly generation profiles to assess how technology costs, resource conditions and reliability requirements interact across different market environments.

In these simulations, solar and wind projects are treated consistently. For each project, additional capacity is sized as needed to deliver round-the-clock power supply at a specified reliability target. Solar projects are configured with both BESS and additional solar capacity, and wind projects are configured with BESS and additional wind capacity. No cross-technology complementarity between solar and wind is included at this stage – an assumption that makes these estimates conservative relative to hybrid configurations, as explained in section 2.4.

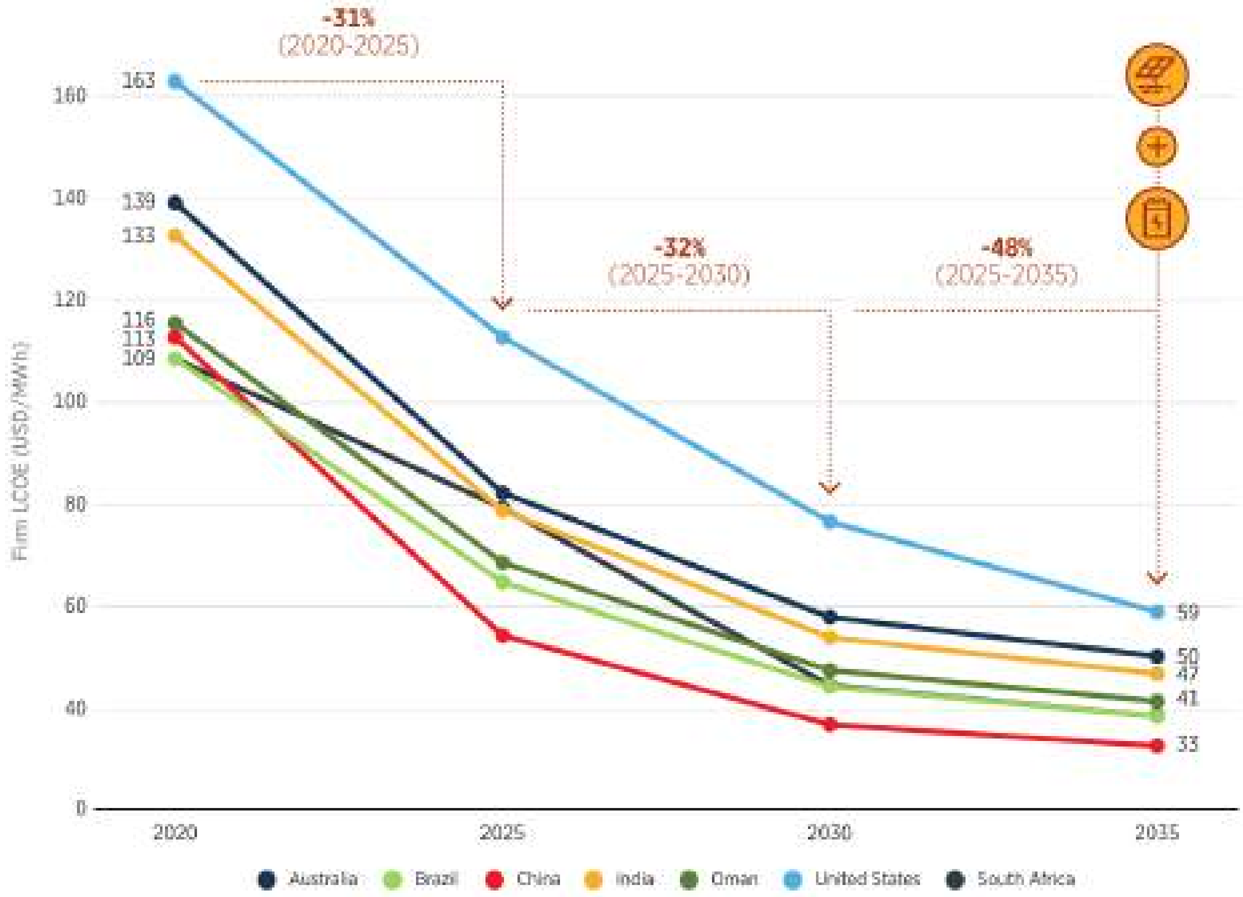
The evidence is presented in three parts. Global cost trajectories for solar PV and onshore wind are described first, followed by a detailed analysis of China – where firm renewables have already crossed the fossil fuel cost threshold – and a discussion of the structural factors that explain why costs in the United States and other markets remain higher.

Global trajectories

Solar PV

Across the high-quality solar PV sites assessed in this study, firm LCOEs at a 95% reliability target have fallen sharply since 2020 and are projected to continue declining through 2035. In 2020, firm solar LCOEs ranged from just above USD 100/MWh at the lowest-cost sites to more than USD 160/MWh at the highest. By 2025, costs had declined substantially across all locations, with reductions of around 30% at representative sites. The downward trend is projected to continue, with firm solar LCOEs converging into a narrower band by 2035 – ranging from around USD 33/MWh at the lowest-cost sites in China to around USD 59/MWh in the United States (Figure 11).

Figure 11 Firm LCOE trajectory for selected solar PV sites, 2020-2035

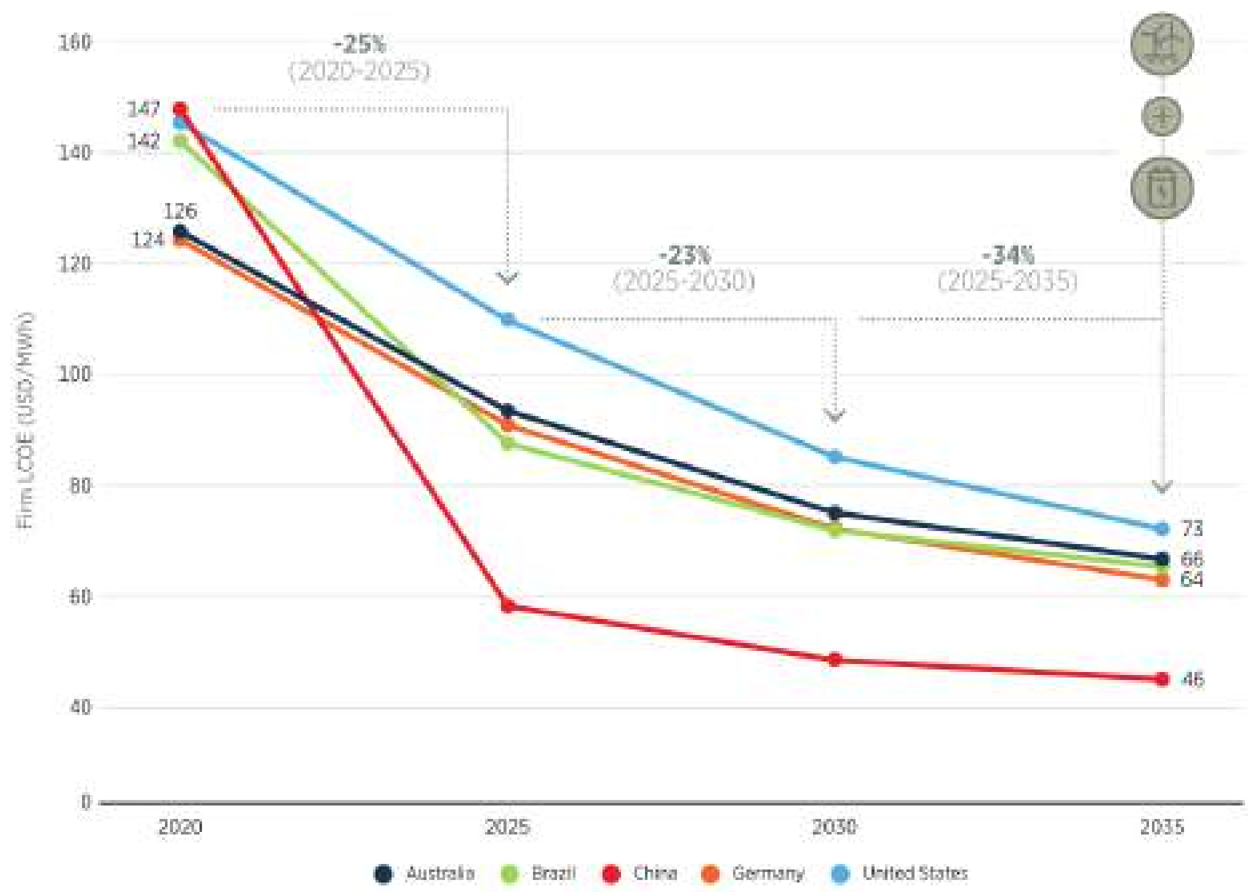


Two structural observations emerge from these trajectories. First, the firming premium is narrowing over time across all locations, as declining BESS costs reduce the incremental investment required to achieve a given reliability target. Second, geographic divergence persists even as absolute costs fall: the advantage of high-quality resource locations is durable, and sites with strong, stable resources continue to achieve firm LCOEs well below those of less favourable locations as the global cost frontier moves downward.

Onshore wind

For onshore wind, the overall trend is similar in direction but reflects the distinct firming characteristics of wind generation. In 2025, firm wind LCOEs at a 95% reliability target range from around USD 59/MWh in Inner Mongolia (China) to USD 110/MWh in Oliver County (United States) (Figure 12) – a wider spread than for solar PV, reflecting greater geographic variation in both resource quality and firming requirements. By 2030, this range narrows significantly, with firm LCOEs falling to between roughly USD 49/MWh in Inner Mongolia and USD 85/MWh in Oliver County. By 2035, costs decline further to USD 46-73/MWh across the sites assessed (Figure 12).

Figure 12 Firm LCOE trajectory for selected onshore wind sites, 2020-2035



The country profiles that follow examine these trajectories in detail, using a consistent analytical framework applied to representative high-quality sites across nine countries.

China: firm renewables now below fossil fuel costs

China currently defines the global cost floor for firm renewable electricity, and by a substantial margin. A combination of vertically integrated manufacturing, low financing costs and co-ordinated infrastructure development has compressed firm LCOEs to levels that are competitive with new fossil fuel generation.

Solar PV

IRENA analysis of 252 utility-scale solar PV projects commissioned in China in 2024 reveals that a large majority can deliver firm electricity below the USD 100/MWh fossil benchmark across a wide range of reliability targets (Figure 13). At a 90% reliability level, almost the entire sample remains competitive, with minimum firm LCOEs as low as USD 30/MWh. As reliability requirements increase, the share of competitive projects declines gradually but remains substantial – more than half of the sample delivers firm electricity below the fossil benchmark even at a 99% reliability target, with minimum firm LCOEs rising only modestly to around USD 46/MWh at the highest reliability level considered.

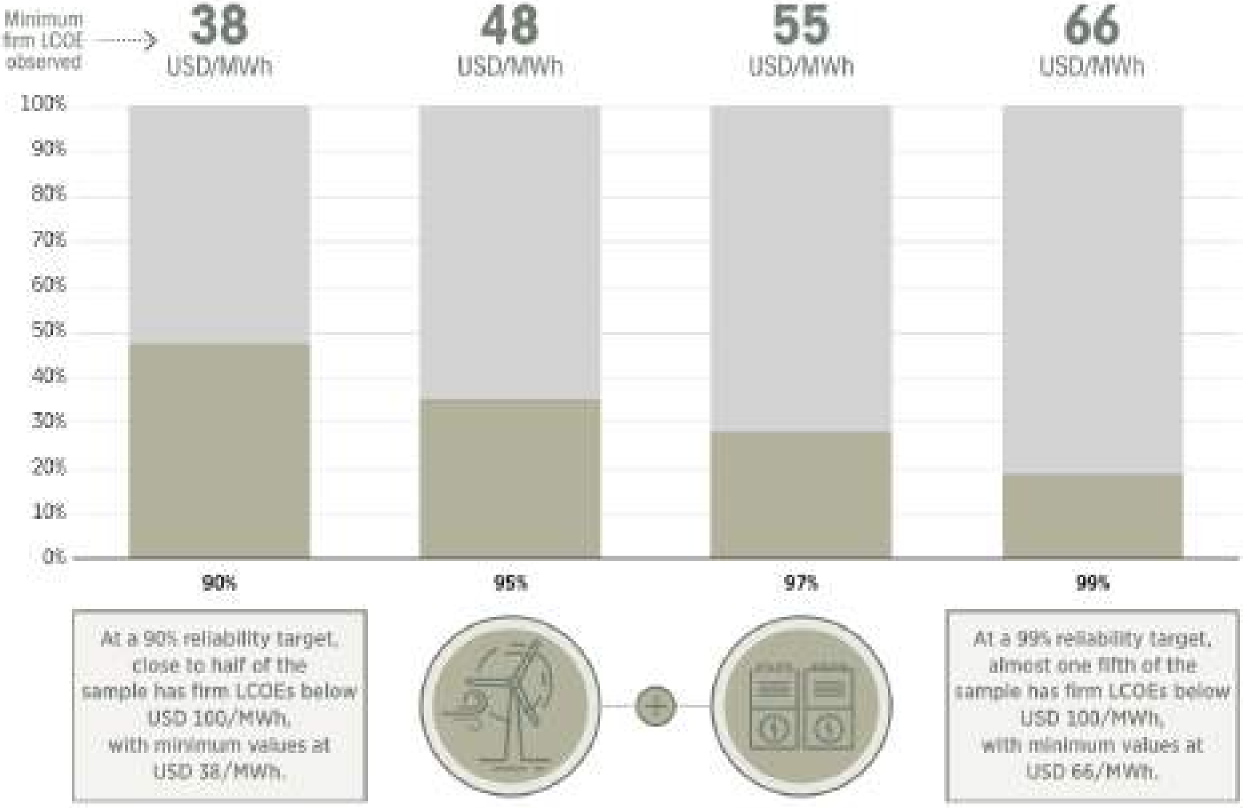
Figure 13 Share of solar PV projects delivering firm electricity below USD 100/MWh – China

The most competitive sites are distributed across Hebei, Ningxia, Qinghai, Xinjiang, Gansu, Inner Mongolia and Yunnan, where strong irradiance and stable output profiles reduce storage requirements.

Onshore wind

The same analytical framework was applied to 201 onshore wind projects commissioned in China in 2024. Inland wind resources are also moving towards firm power competitiveness, although across a more selective set of projects than for solar PV. At a 90% reliability target, close to half of the sample delivers firm electricity below the USD 100/MWh fossil benchmark, with minimum firm LCOEs of around USD 38/MWh. As reliability requirements increase, the share of competitive projects declines more rapidly than for solar PV. Nevertheless, a meaningful subset remains cost competitive even at high reliability levels, with minimum firm LCOEs rising to around USD 66/MWh at a 99% reliability target (Figure 14).

Figure 14 Share of onshore wind projects delivering firm electricity below USD 100/MWh – China



The most competitive projects are concentrated in Inner Mongolia, Jilin, Gansu and Shaanxi – regions characterised by strong, steady inland winds and comparatively low development costs.

Geography, finance and infrastructure: what shapes costs across markets

Firm renewable costs outside China are declining rapidly, but remain higher across most markets, reflecting a combination of resource conditions, financing environments and infrastructure constraints rather than any fundamental technological limitation.

Across high-quality solar sites in Brazil, India, Oman, South Africa, and Australia, firm LCOEs in 2025 range from around USD 65 to USD 82/MWh – competitive with or approaching new fossil fuel benchmarks in most of these markets, and on a trajectory towards USD 37 to USD 58/MWh by 2035 (Figure 15). These markets benefit from strong solar resources and access to internationally traded equipment at close to global cost levels, even where financing conditions and balance-of-system costs remain above Chinese levels.

Figure 15 LCOE and firm LCOE for selected solar PV sites, 2025 and 2030

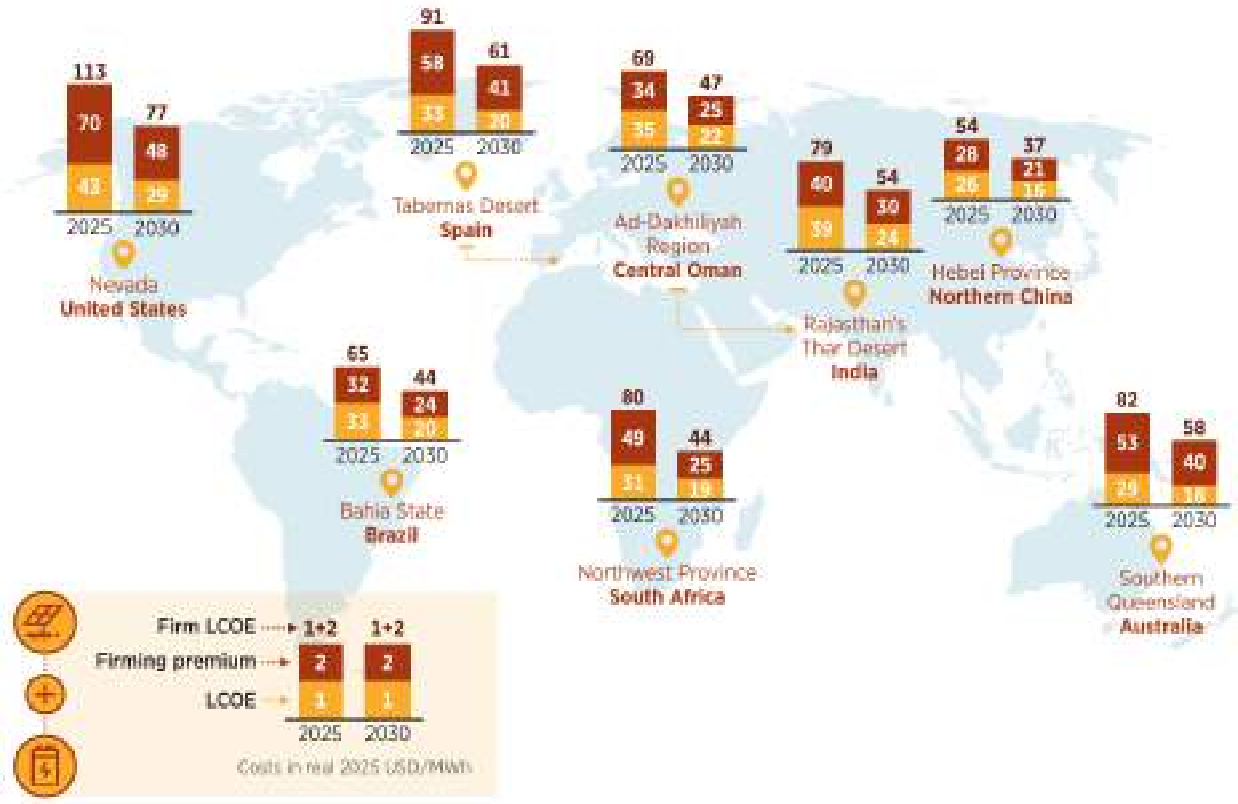
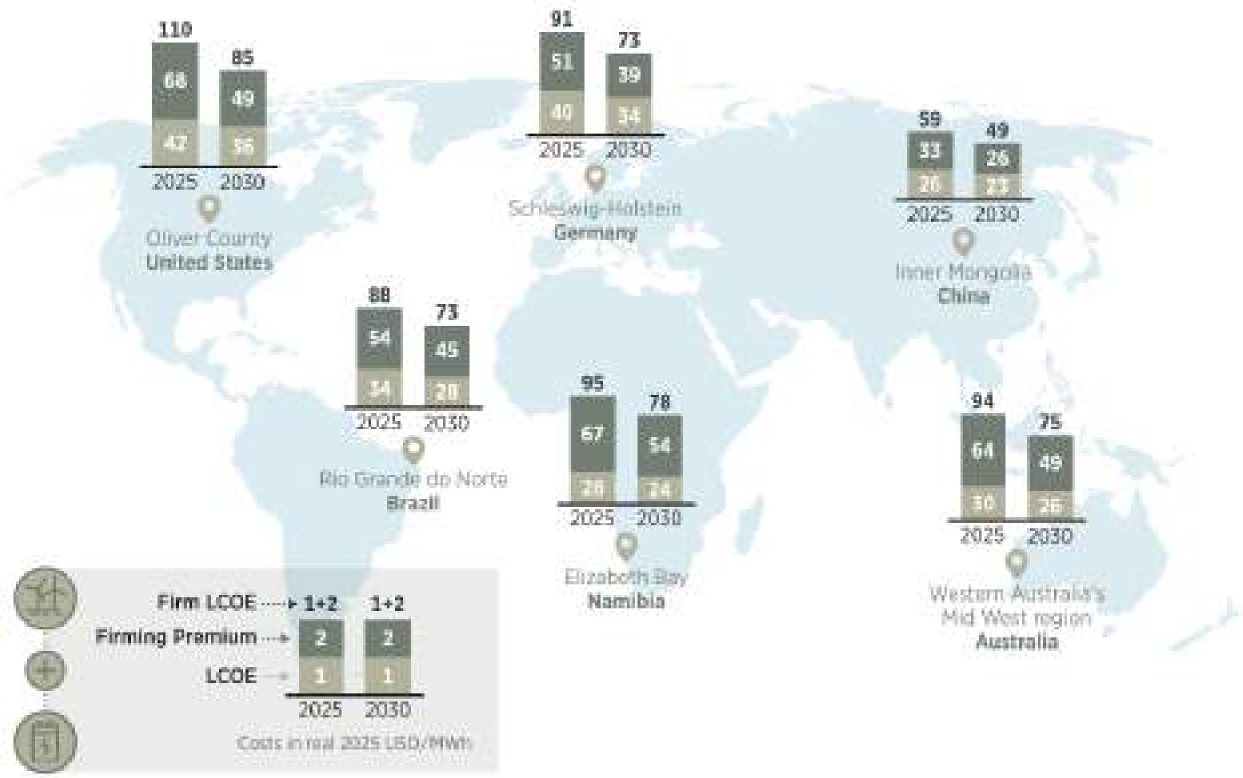


Figure 16 LCOE and firm LCOE for selected onshore wind sites, 2025 and 2030



Onshore wind follows a similar pattern. At high-quality sites in Brazil, Germany, Namibia, Australia, and the United States, firm LCOEs decline from USD 88-110/MWh in 2025 to USD 49-85/MWh by 2030 (Figure 16). Inner Mongolia stands apart, with firm costs already below USD 60/MWh - closer to the Chinese solar floor than to international wind benchmarks.

In the United States, abundant solar and wind resources place many sites within reach of fossil fuel cost parity at 90-95% reliability, with minimum firm LCOEs as low as USD 63/MWh for solar PV at the best-resourced locations. However, these figures reflect technical cost potential at long-run cost assumptions rather than typical near-term project outcomes. Solar PV total installed costs have largely stalled since 2020, and LCOEs have risen in recent years due to higher financing costs. In many United States electricity markets, interconnection charges are borne directly by project developers rather than socialised across the broader system – a cost not captured in the modelled estimates presented here. Permitting and total development timelines also extend considerably beyond construction periods alone. Results for the United States should therefore be interpreted as indicative of what is achievable at well-resourced sites under favourable conditions, rather than as a characterisation of typical market outcomes.

Across all markets, four structural factors consistently explain the gap with China. First, financing costs exceed China's by three to five percentage points in real terms, reflecting higher perceived investment risk and more limited access to long-term, low-cost capital. Second, balance-of-system and infrastructure costs remain above Chinese levels even where hardware is sourced internationally, due to higher labour costs, more complex permitting regimes, and grid-connection requirements. Third, the pace of grid expansion and interconnection in many markets constrains deployment and adds project-level cost in ways that system-wide planning in China largely avoids. Fourth, policy uncertainty in some markets elevates risk premiums beyond what financing cost figures alone capture. As industrial scale-up proceeds, grid investment accelerates, and policy frameworks stabilise, these structural gaps will narrow – and the cost trajectory that China demonstrates today will become progressively more accessible across a wider range of markets.

2.3 COMPETITIVENESS WITH FOSSIL-FUEL GENERATION

The cost trajectories presented in this chapter reflect a broader and accelerating shift in the competitive landscape for electricity generation. Over the past decade, the economics of new power capacity have been transformed: solar PV and onshore wind have become the cheapest sources of new generation in most markets (IRENA, 2025), while the cost of new fossil fuel generation has risen sharply.

In 2025, utility-scale solar PV and onshore wind both cost around USD 40/MWh globally – less than half the benchmark cost of new combined-cycle gas turbines, which exceeded USD 100/MWh, driven by a surge in turbine demand that caused orders to outpace manufacturing capacity (BNEF, 2026b). Gas prices, which account for a large share of the cost of gas-fired generation, have added further upward pressure following supply disruptions that recently affected global liquefied natural gas (LNG) trade and sent European gas benchmarks to multi-year highs. The competitive advantage of renewables over fossil generation has therefore widened in both directions simultaneously – through falling renewable costs and rising fossil costs.

Hybrid solar-plus-storage systems follow the same trajectory. Close to 90 GW of co-located solar and storage was commissioned worldwide in 2025 at average combined costs of under USD 60/MWh – below the benchmark for new gas-fired generation and, in high-quality resource regions, below the cost of new coal (BNEF, 2026b). In China, firm LCOEs across the solar project sample analysed here fall well below both fossil-fuel benchmarks – new coal-fired generation, which typically costs around USD 80/MWh; and well below new gas-fired plants, which generally exceed USD 100/MWh (IEA, 2025a). Beyond China, firm solar LCOEs of USD 65-80/MWh in Brazil and South Africa are at or approaching fossil fuel benchmarks, with trajectories pointing to USD 38-44/MWh by 2035. In Oman and the wider Gulf region, firm solar at around USD 69-80/MWh is competitive with combined-cycle gas even where fossil fuels are domestically produced – a finding corroborated by independent industry analysis showing that solar-plus-storage configurations in Saudi Arabia can approach near-continuous availability at broadly comparable costs (BNEF, 2026a).

Wind-plus-storage firm LCOEs are higher than solar equivalents – ranging from around USD 59/MWh in China to USD 88–94/MWh across Brazil, Germany and Australia in 2025 – yet fall at, or below, the cost of new gas-fired generation across most markets analysed. This advantage extends to the existing fleet in China, Egypt, Germany, Spain and the United Kingdom, where co-located wind-plus-storage has already fallen below the operating costs of existing coal and gas plants (BNEF, 2026a), meaning that the economics of already-depreciated fossil assets are being challenged not only by new renewable capacity, but by the marginal cost of keeping them running.

The cost case is reinforced by an energy security argument that the current geopolitical environment makes impossible to ignore. In liberalised electricity markets where gas sets the marginal price, fuel price shocks translate directly into electricity price spikes regardless of the generation source – a vulnerability that has been repeatedly exposed, most recently with severity. Countries with higher shares of renewable generation have demonstrably experienced smaller price impacts during such episodes, while those most dependent on fossil fuel imports face simultaneous pressure on inflation, fiscal balances and economic stability. Firm renewable electricity is priced at the cost of capital and technology rather than the cost of fuel: once built, it is structurally insulated from the commodity price volatility and supply disruptions that have repeatedly driven fossil costs sharply upward. In a growing number of markets, it is not only the most economic option for new firm generation capacity – it is also the most secure.

2.4 WHAT DRIVES THE COST OF FIRM RENEWABLE ELECTRICITY?

The Las Vegas case shows that delivery certainty has a price – the firming premium – and that this cost increases non-linearly as higher reliability targets are pursued (Figure 9). It also reveals that the most cost-effective configurations combine storage with generation overbuild, rather than relying on storage alone. More broadly, the cost of firm renewable electricity is shaped by three interacting factors: the performance and cost of the underlying technologies; the quality and variability of the renewable resource; and the extent of diversification across generation sources and storage assets.

Technology performance and costs

Over the past decade, sustained reductions in the technology cost of solar PV, onshore wind and BESS have transformed the economics of renewable power. As both generation and storage costs decline, the additional investment required to achieve a given level of reliability falls accordingly. These trends provide the essential foundation for understanding how firm renewable electricity is becoming increasingly cost competitive across a growing range of markets and resource environments.

Solar PV

Solar PV remains the fastest-advancing renewable power technology. Between 2010 and 2024, global weighted average total installed costs fell by 87%, reaching USD 708/kW, while the global weighted average LCOE declined by 90% to USD 44/MWh. These gains were driven by advances across the full value chain: higher-efficiency module designs, lower-cost inverters, improved mounting structures, and more efficient engineering, procurement and construction (EPC) processes (Table 2).

Table 2 Technology trends, cost trends and cost drivers – solar PV

Technology trends	Cost trends	Cost drivers
• Bifacial modules, single-axis trackers and higher inverter load ratios drive higher output and smoother generation. • Global module efficiencies reached 21.7% to 23.8% in 2024, with N-type TOPCon and heterojunction technology (HJT) cells now standard. • Bifacial modules accounted for around 90% of global shipments, reflecting strong yield and cost advantages. • Improved inverter loading ratios and tracker deployment lifted global capacity factors from 15% in 2010 to 17.4% in 2024.	• Total installed costs fell 87% between 2010 and 2024, reaching USD 708/kW. • Crystalline silicon module prices dropped 97% to USD 0.28 per watt by late 2024. • Global weighted average LCOE declined 90%, from USD 427/MWh in 2010 to USD 44/MWh in 2024. • China and India achieved the lowest LCOEs globally, at USD 34-39/MWh.	• Module and inverter advances delivered around 60% of total installed cost reductions. • Balance-of-system components contributed a further 30% through lower mounting, racking and EPC costs. • The remaining 10% came from reduced O&M costs, improved financing, and larger project and manufacturing scale.

Onshore wind

Between 2010 and 2024, global weighted average total installed costs for onshore wind fell by 55% to around USD 1066/kW, while the global weighted average LCOE declined by 70% to USD 35/MWh. These reductions have been driven primarily by scaling in turbine design, with larger rotors capturing more energy at lower wind speeds and raising global weighted-average capacity factors, as well as by the maturity of supply chains in leading markets and advances in predictive maintenance and data analytics (Table 3).

Table 3 Technology trends, cost trends and cost drivers – onshore wind

Technology trends	Cost trends	Cost drivers
• Average global turbine rating reached 4.7 MW in 2024, with leading markets deploying units above 6 MW. • Rotor diameters averaged 160 metres, and hub heights ranged from 120 to 140 metres, boosting energy capture and site performance. • Modular nacelles, advanced blade materials and smart control systems enhanced reliability and reduced downtime. • Global capacity factors rose from 27% in 2010 to 34% in 2024, surpassing 40% in top-performing regions such as South America and Northern Europe.	• Total installed costs declined 55% between 2010 and 2024, reaching USD 1 066/kW. • Weighted average LCOE dropped 70%, from USD 116/MWh in 2010 to USD 35/MWh in 2024. • China and Brazil recorded the lowest global LCOEs at USD 30/MWh and USD 31/MWh, supported by mature supply chains and favourable financing.	• Larger rotors, higher hub heights and optimised turbine design improved energy yield and reduced per-MWh costs. • Standardised turbine platforms, larger project scales and competitive auctions lowered manufacturing and financing costs. • Mature local supply chains in China, India and Brazil reduced capital and O&M costs by up to 20%. • Predictive maintenance and data analytics cut O&M costs by 10-15% over the past decade, further enhancing competitiveness.

Battery energy storage systems (BESS)

BESS has become a central source of flexibility in modern power systems. By 2025, BloombergNEF reports that global volume-weighted average turnkey energy storage system prices had fallen below USD 120/kilowatt hour (kWh) (BNEF, 2025b), the lowest level recorded in its annual survey, driven by persistent cost declines in lithium-ion batteries, manufacturing oversupply, intensified competition, and a shift towards larger, higher-energy-density lithium iron phosphate cells and containerised system designs (Table 4). China continues to set the global cost floor through scale and vertically integrated supply chains, while costs in Europe and the United States remain higher due to localisation requirements and trade policies. Ongoing improvements in system integration, cell size and manufacturing efficiency are expected to further reduce costs and enhance the performance and reliability of utility-scale storage systems.

Table 4 Technology trends, cost trends and cost drivers – BESS

Technology trends	Cost trends	Cost drivers
• Lithium-ion batteries dominate utility-scale storage, with lithium iron phosphate (LFP) accounting for around 94% of surveyed systems in 2025, reflecting its cost advantage and longer cycle life. • Nickel-based chemistries (NMC/NCA) have largely retreated from stationary storage due to higher costs and lower durability, rather than being displaced by alternative chemistries. • Larger-format LFP cells (≥300 amp-hours, increasingly ≥500 amp-hours) are becoming standard, materially reducing system costs through higher energy density and simplified system architecture. • Higher-capacity containers (≥4 MWh, moving towards 5-8 MWh) are increasingly deployed. • System integration is increasing, including more integrated direct current (DC) blocks, alternating current (AC) blocks and liquid-cooled designs, reducing balance-of-system complexity.	• Global volume-weighted average turnkey energy storage system prices fell to below USD 120/kWh in 2025, a 31% year-on-year decline and the lowest level in BNEF's cost survey (BNEF, 2025b). • China remained the lowest-cost market by a substantial margin, with average prices approaching USD 75/kWh and the most competitive configurations falling below USD 65/kWh. • Costs in Europe and the United States were roughly two and a half to three times higher than in China, reflecting localisation requirements, tariff exposure, and supply-chain constraints. • Larger battery cells and higher-density container designs materially reduced costs: systems using larger-format cells were around half the price of smaller configurations on a DC-side basis, and higher-capacity containers delivered cost reductions of roughly one third compared with smaller units.	• Persistent oversupply and intense competition in lithium-ion manufacturing, particularly in China, remain the primary drivers of cost declines. • Scale, vertical integration and manufacturing efficiency in China continue to underpin the lowest global system costs. • Cell and system design improvements, including larger cells, denser racks and higher-capacity containers, deliver structural reductions in CAPEX. • Automation, standardisation and improved yields are reducing manufacturing scrap rates and unit costs across the value chain. • Falling battery prices outweigh rising lithium prices, with margin compression absorbed by manufacturers rather than passed through to system costs. • Logistics, EPC and non-hardware costs are declining, aided by standardised designs and simpler system integration. • Policy and trade measures increasingly shape regional cost divergence, with tariffs, localisation rules and domestic content incentives raising costs in the United States and Europe relative to China, even as global benchmarks fall.

The integration of renewable generation with BESS is increasingly reshaping power system operations, particularly through the rapid growth of co-located solar-plus-storage projects. By pairing BESS with renewables, developers can improve utilisation of grid connections, shift generation to higher-value hours and provide greater operational flexibility to the power system.[18] Digital control platforms and energy management systems support these assets by co-ordinating charging and dispatch and managing degradation, although their role remains primarily operational rather than transformational.

[18] *Marketevidenceshowsthat BESSisdeployedprimarilyforenergyshiftingratherthanancillaryservices. BloombergNEFestimates that short-duration energy shifting accounts for nearly 80% of global storage deployments in GWh through 2028, while ancillary services decline to a marginal share as these markets become saturated (BNEF, 2025b). This reinforces the view that the economic value of storage lies in arbitrage, renewable integration and capacity provision, rather than frequency response alone.*

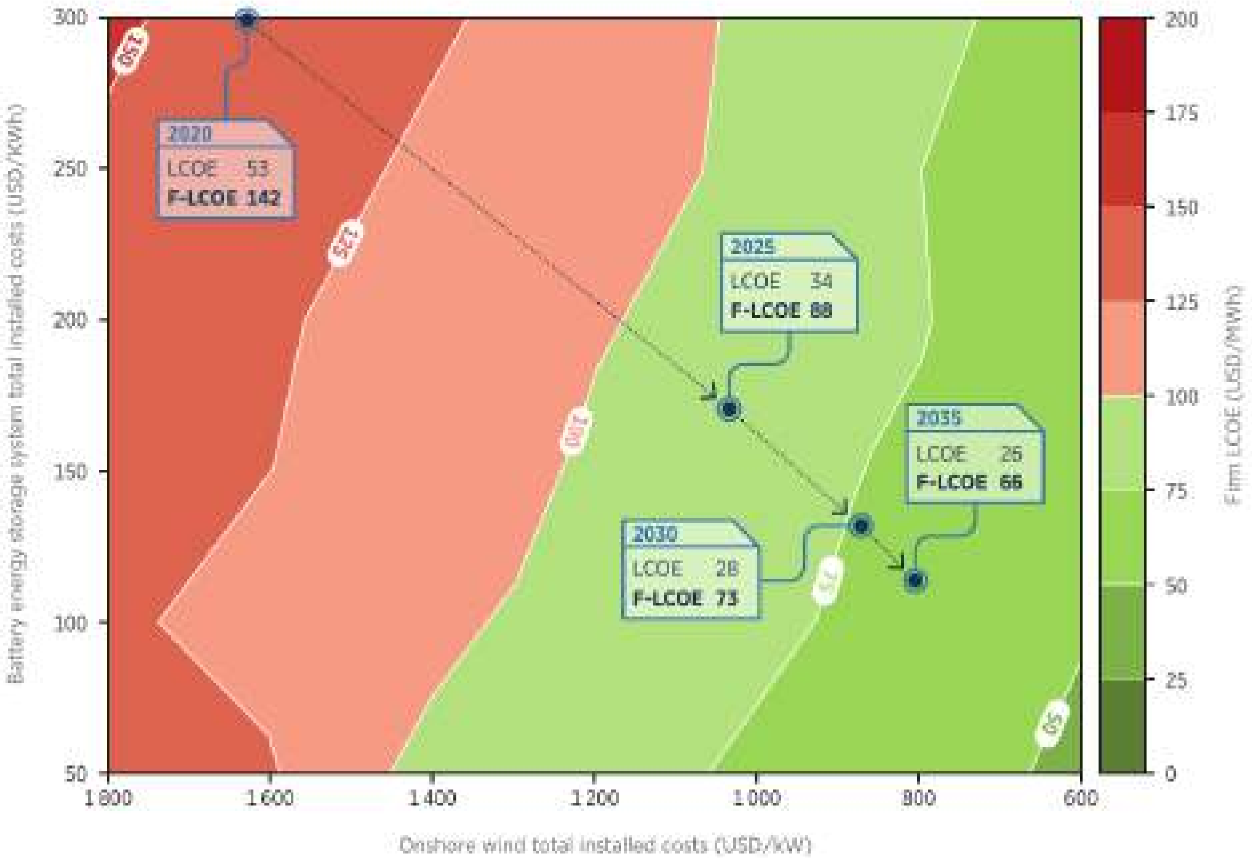
Impact of declining technology costs on the firm LCOE

Falling costs for solar, wind and BESS are driving a rapid decline in the cost of firm renewable power across all major markets.

Figure 17 illustrates this dynamic for a representative onshore wind site in Rio Grande do Norte State, Brazil, characterised by strong and persistent easterly winds with typical wind speeds of 8-10 metres per second at hub height. The firm LCOE falls from USD 142/MWh under 2020 cost conditions to USD 88/MWh by 2025, before declining further to USD 73/MWh by 2030 and USD 66/MWh by 2035.

The contour plot maps firm LCOE levels as a function of BESS total installed costs (vertical axis) and generation technology total installed costs (horizontal axis), revealing where round-the-clock clean power is already competitive and where further cost reductions are still required. The colour gradient – shaped by local resource quality and country-specific financing conditions – traces a clear pattern: as technology and financing costs decline, countries progressively move from higher-cost red zones towards the lower-cost green zones of competitiveness.

Figure 17 Impact of declining CAPEX on the firm LCOE of onshore wind and BESS



Note: Hypothetical onshore wind site in Rio Grande do Norte State, Brazil. Each isoline of the contour plot represents a firm LCOE level (in USD/MWh) – estimated at a 95% reliability target – as a function of the total installed costs of onshore wind (horizontal axis) and BESS (vertical axis). As technology costs decline, the system moves from the high-cost red zone towards the low-cost green zone along the dashed trajectory. The shape and position of the contours reflect the site's resource quality and financing conditions.

Resource quality and variability

Even when technology costs, financing conditions and reliability targets are held constant, firm LCOEs vary widely across projects. This variation is driven primarily by geography: the meteorological conditions that determine how solar and wind output evolves over time.

To isolate the effect of resource characteristics on firming costs, IRENA conducted a large-scale numerical experiment across solar PV and onshore wind projects in China and the United States, applying identical techno-economic assumptions to all projects and varying only the hourly generation profile derived from local weather conditions. Differences in firm LCOEs across projects in this experiment can therefore be attributed directly to resource characteristics.

To interpret these differences, generation profiles are characterised along two complementary dimensions: short-term variability and long-duration energy scarcity.

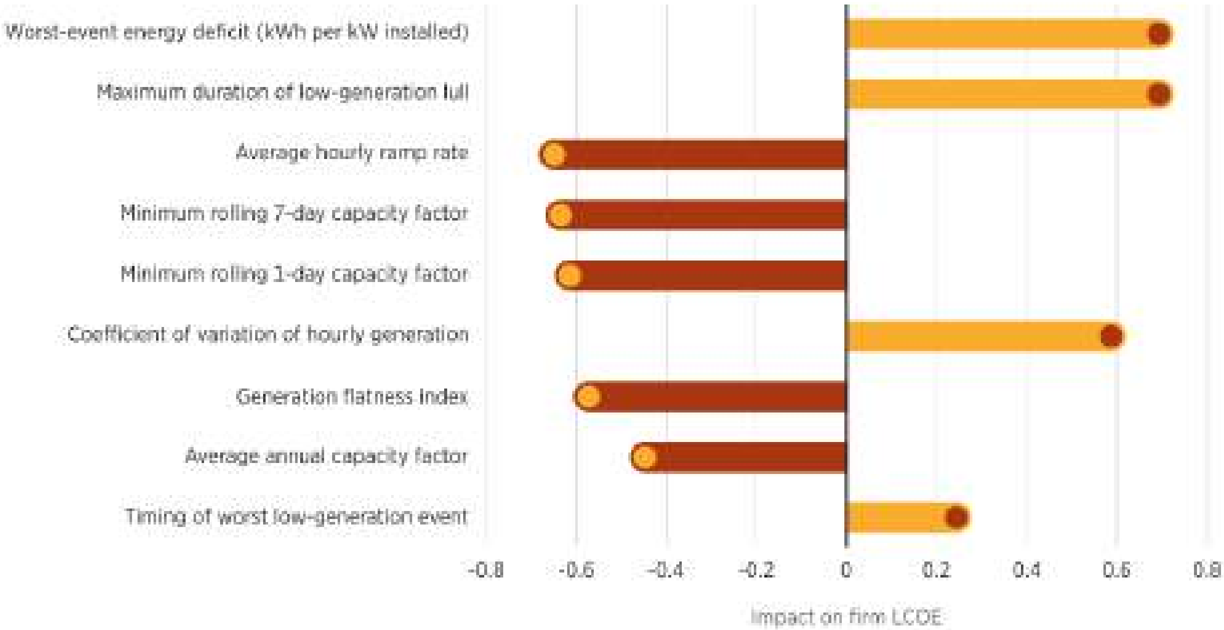
- Variability indicators – they describe the magnitude and speed of short-term fluctuations in generation:
  - Average annual capacity factor.
  - Coefficient of variation: standard deviation of hourly output divided by the mean, measuring overall dispersion.
  - Flatness index: degree to which generation approaches a constant profile at the same mean output.
  - Ramp rate: average absolute hour-to-hour change in output, normalised by the installed capacity.
- *Dunkelflaute* indicators – they capture the persistence and severity of sustained low-generation events:
  - Minimum rolling 1-day and 7-day capacity factors: lowest sustained output over 24-hour and multi-day windows, filtering out short-term noise.
  - Maximum lull duration: longest continuous period during which generation remains below 10% of installed capacity.
  - Worst-event energy gap: total energy deficit accumulated during the most severe low-generation event, expressed per kW installed.

Together, these indicators reflect the minimum energy volumes that storage or back-up resources must supply to maintain a given reliability level.

Solar PV

Figure 18 summarises the relative influence of different resource characteristics on the solar PV firming premium, based on Pearson correlation coefficients between project-level firming cost and different types of indicators. The coefficients are ranked by absolute magnitude and presented as a tornado diagram, highlighting the dominant resource-driven determinants of firming cost across sites.

Figure 18 Resource-related drivers of the firming premium – solar PV



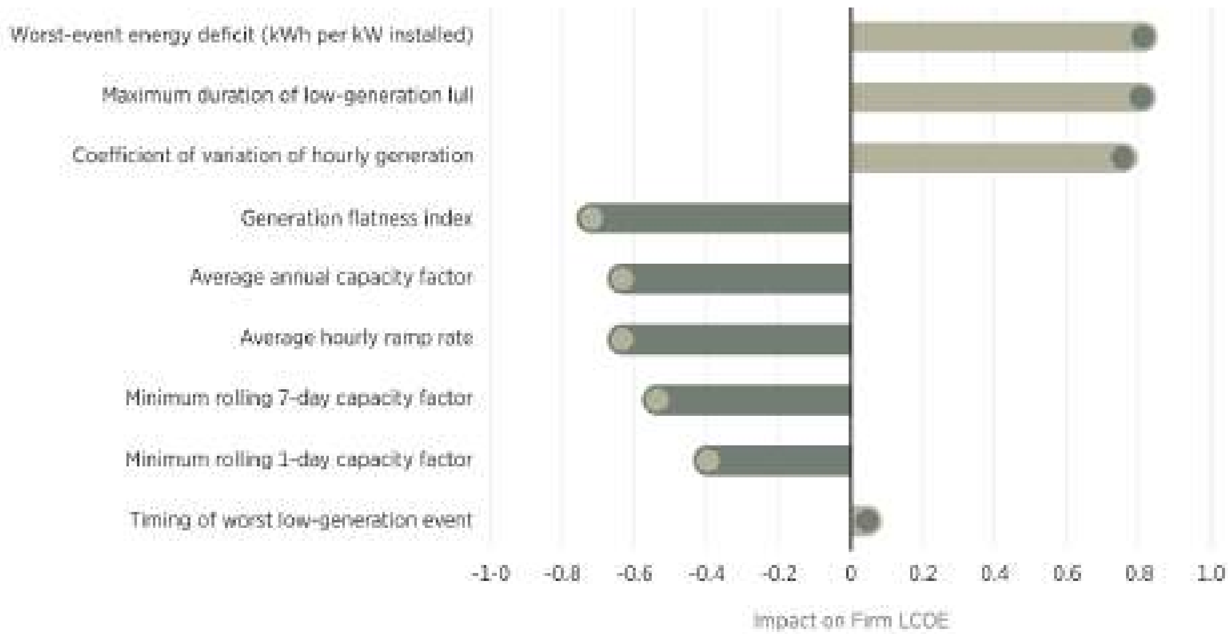
Note: The tornado diagram's bars show Pearson correlation coefficients between project-level firming premium and several indicators of resource quality, ranked by absolute magnitude. A positive coefficient indicates that the indicator and the firming premium move in the same direction – for example, longer low-generation events are associated with a higher firming premium. A negative coefficient indicates that they move in opposite directions. All projects are modelled under identical techno-economic assumptions – any differences in firming premiums therefore reflect resource characteristics alone.

For solar PV, firming costs are driven mainly by the severity of sustained low-irradiance periods. The strongest correlations with the firming premium are observed for the worst-event energy gap – the total energy deficit accumulated during the most severe low-irradiance episode of the year – and the maximum lull duration. Sites experiencing deep, multi-day depressions in solar output require substantially larger storage volumes and generation overbuild to maintain a given reliability level. Short-term variability plays a secondary role, while mean annual capacity factor has limited explanatory power once long-duration scarcity is accounted for.

Onshore wind

For onshore wind, the correlation structure is even more concentrated. Firm LCOEs are dominated by the worst-event energy gap and maximum lull duration, confirming that rare but prolonged wind drought events are the primary cost driver (Figure 19). These are the events for which systems must be sized, and they represent the defining challenge for wind firming irrespective of average resource quality.

Figure 19 Resource-related drivers of the firming premium – onshore wind



The key implication is that average annual capacity factor is an insufficient indicator of firm renewable competitiveness. Firming costs are determined instead by the depth and persistence of low-generation events. Strengthening resource assessment tools to capture these dynamics – including high-resolution meteorological data, *Dunkelflaute*-aware metrics and multi-year datasets – can unlock cost reductions that exceed those achievable through incremental technology improvements alone. In this sense, improved site characterisation is as critical as continued technological learning.

System configuration and diversification

Lithium-ion batteries have become indispensable for managing daily variability in solar and wind generation. Four-hour systems can smooth fluctuations, shift solar output into evening demand periods and bridge short intra-day shortfalls at rapidly declining cost. However, as the analysis of the previous paragraph demonstrates, the most demanding reliability challenges arise from events that extend well beyond the duration that short-term storage can address. Achieving cost-effective firm renewable power at high reliability levels therefore requires a broader approach, combining short- and long-duration energy storage, diversified portfolios and digital flexibility.

Beyond lithium: the rise of long-duration energy storage

Global investment and innovation are expanding the role of energy storage beyond short-duration applications. According to BloombergNEF, costs for long-duration energy storage (LDES) technologies are expected to decline significantly by 2030 as commercialisation accelerates, with several technologies – including compressed-air energy storage, flow batteries and thermal storage – projected to approach or outperform lithium-ion battery costs for longer discharge durations (Zhou *et al.*, 2025). A parallel cost benchmarking study by the Electric Power Research Institute (EPRI) and the LDES Council, drawing on survey data from technology developers, confirms that substantial cost reductions are expected across all major LDES categories between 2025 and 2030, driven by improved performance, economies of scale and expanded manufacturing capacity (EPRI, 2026).

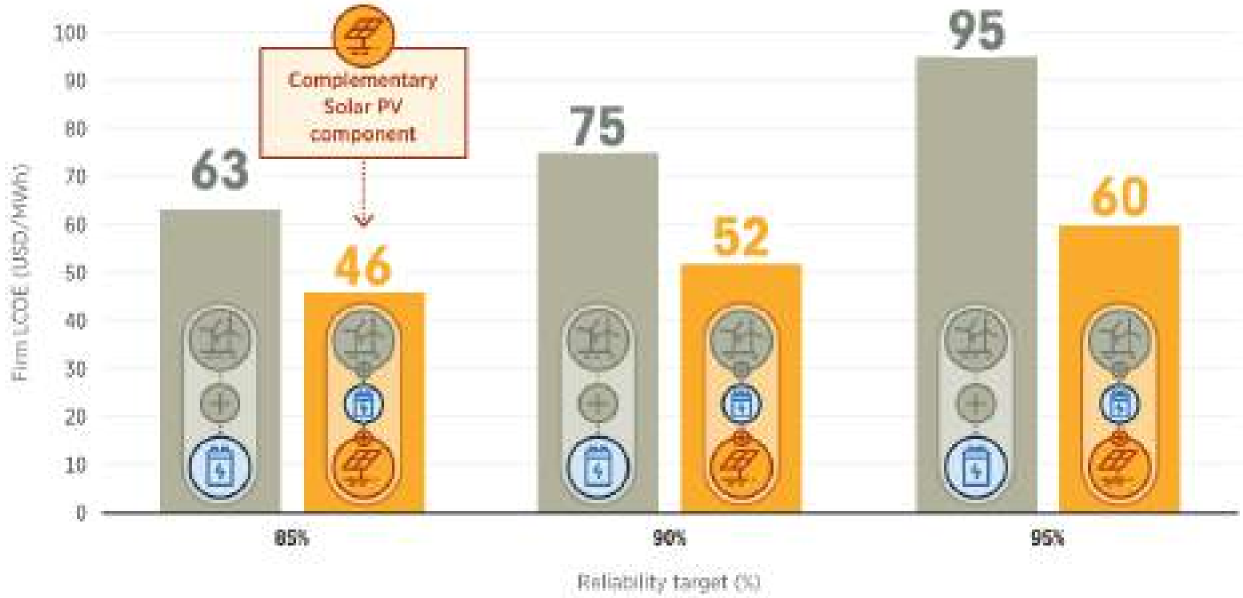
LDES complements lithium-ion systems by providing flexibility over longer time horizons, helping to meet demand during extended periods of low renewable output. While costs remain higher than lithium-ion today across most technologies and markets, this gap is narrowing – and for some technologies and applications, cost parity is within reach by 2030.

For short-duration energy storage, the cost outlook is also improving. The US National Laboratory of the Rockies projects that utility-scale four-hour lithium-ion battery costs will decline by 16-56% by 2035 relative to 2024 levels under its mid and low scenarios, reaching USD 147-243/kWh – continuing the downward trajectory that has already compressed firming premiums significantly (Cole *et al.*, 2025). These parallel cost reductions across both short- and long-duration storage are reinforcing the economics of firm renewable electricity across an expanding range of reliability targets and market contexts.

The value of diversified portfolios

IRENA modelling shows that introducing a modest share of complementary solar generation significantly reduces firming costs at the same reliability level, demonstrating the efficiency gains from portfolio diversification (Figure 20). At a 95% reliability target, a wind-plus-storage configuration achieves a firm LCOE of USD 95/MWh. Adding a complementary solar component reduces this to USD 60/MWh – a firming cost saving of USD 35/MWh, or roughly one-third, attributable entirely to the natural offset between wind and solar generation profiles.

Figure 20 Impact of hybridisation strategies on the firm LCOE of onshore wind with BESS



Note: Results are shown for an onshore wind and BESS configuration under two hybridisation strategies – wind overbuild (grey columns) and a complementary solar PV component (orange columns) – across reliability targets of 85%, 90% and 95%. The analysis is based on 2025 technology cost assumptions and a high-quality wind site in the Elizabeth Bay corridor in Namibia.

Combining complementary renewable resources reduces the frequency and depth of supply shortfalls, as mixed portfolios produce more consistent output than individual technologies operating alone. In the United Kingdom, for instance, days with simultaneously low wind and low solar generation occur only 2% of the time (Mayo, 2025), illustrating the strong natural complementarity between these resources. Where shortfalls persist, LDES and demand-side flexibility can bridge them at declining cost. As these options mature and scale, diversified hybrid systems will play an increasingly central role in delivering reliable, round-the-clock renewable power.

From storage to systems: Virtual power plants and digital flexibility

Reliability is not only about hardware; it also depends on co-ordination. Virtual power plants (VPPs) – networks of digitally connected distributed resources such as rooftop PV, small batteries, electric vehicle chargers and demand response assets – are emerging as powerful enablers of system flexibility.

In leading markets such as the United States, Germany, and Australia, VPPs already aggregate thousands of distributed devices to provide frequency regulation, peak shaving and local balancing services. By unlocking flexible capacity on the demand side, they reduce the need for costly centralised back-up and enable higher renewable integration at lower overall system cost.

Digitalisation, artificial intelligence and advanced forecasting are turning VPPs into virtual reliability assets capable of providing services once delivered only by conventional power plants. Their rise signals a broader shift from expanding physical capacity to using existing assets more intelligently – transforming flexibility into the new frontier of reliable, affordable clean power.

03

FROM COST COMPETITIVENESS TO DEPLOYMENT AT SCALE

The analysis in Chapter 2 establishes that, in high-quality resource regions, firm renewable electricity has crossed the threshold of cost competitiveness with new fossil fuel generation. The central question is no longer whether firm renewables can compete on cost, but how quickly the structural conditions needed to realise their potential can be put in place across the diversity of markets and institutional contexts prevailing globally.

3.1 TECHNOLOGY LEARNING: A SELF-REINFORCING COST REDUCTION DYNAMIC

The cost reductions documented in chapter 2 reflect technology learning – a structural dynamic in which unit costs decline systematically as cumulative deployment grows, driven by manufacturing scale and accumulated engineering and operational experience.

Solar PV, onshore wind and BESS are all on this trajectory, with learning rates of around 34%, 25% and 18% per doubling of cumulative installed capacity, respectively.[19] For firm renewable electricity, these effects compound: as generation costs fall, the baseline LCOE declines; as storage costs fall, the firming premium narrows; and the two effects together drive down the firm LCOE faster than either technology alone would suggest.

This dynamic creates a self-reinforcing cycle in which falling costs and growing deployment mutually reinforce one another, progressively narrowing the firming premium and widening the range of locations where firm renewable electricity is competitive. Industrial scale compounds the effect: as deployment volumes grow, supply chains develop while improving their processes, and project costs – permitting, grid connection, engineering and financing – fall as experience accumulates and risk perceptions adjust. Countries and regions that move early to build domestic industrial capacity will further compress this cycle, capturing both the cost and the energy security benefits that firm renewable deployment delivers.

[19] *ThelearningratesforsolarPVandonshorewindareIRENAestimatesbasedonglobalcostanddeploymentdatacoveringthe 2010-2024 period. For BESS, the 18% learning rate is associated with battery rack costs (BNEF, 2025b).*

3.2 MATCHING TECHNOLOGY TO CONTEXT

While technology learning defines the cost trajectory, geography determines how that trajectory translates into deployment. Three broad system archetypes emerge from the evidence presented in this report, each with its own resource logic, cost structure and strategic implications.

In sun-rich regions – across the Arabian Peninsula, sub-Saharan Africa, north-eastern Brazil, the Thar Desert in India and inland Australia – large-scale solar PV combined with battery storage is the natural backbone of continuous clean power. High annual irradiance, low cloud cover and stable seasonal output profiles minimise the depth and duration of low-generation events, reducing storage requirements and generation overbuild. In the most favourable locations, firm solar LCOEs are projected to fall below USD 60/MWh by 2030, decreasing to less than USD 50/MWh by 2035. Where land is available and not subject to competing agricultural, conservation, or other uses, this cost potential is realisable at scale. Solar-plus-storage in these environments is not a transitional technology awaiting a better alternative: it is the most economic route to firm, continuous clean power available today, and its competitive position will strengthen further as costs decline.

In wind-rich temperate and continental regions – across the Great Plains of North America, northern Europe, Patagonia and the wind corridors of East Africa – the most cost-effective strategy is resource complementarity. Combining wind with solar PV and short-duration storage extracts the full benefit of the partial offset between the two generation profiles, reducing the frequency and depth of supply shortfalls without requiring large volumes of storage or excessive generation overbuild. Because this complementarity operates at the portfolio level rather than the plant level, procurement frameworks that reward portfolio-level reliability – rather than requiring individual assets to be fully firm – will generally deliver lower overall costs.

For markets with limited domestic renewable resources – small island economies, land-constrained or densely populated regions, and countries where resource quality is insufficient to achieve competitive firm LCOEs at the project level – regional interconnection is potentially the primary pathway to reliable clean electricity at competitive cost. Interconnection substitutes geographic diversity for storage depth: linking power systems across diverse weather zones smooths variability, reduces the depth of simultaneous supply shortfalls, and lowers system-wide firming costs without requiring additional investment at individual project sites.

Singapore's context highlights why this approach is necessary: clean solar imports via a planned 1 GW interconnection with Indonesia's Batam Island raise the grid's baseline carbon-free electricity score from 2.7% to 10%, displace 6 terawatt hours (TWh) of gas-fired generation annually, save around USD 440 million in fuel costs, and avoid 2.8 million tonnes of carbon dioxide ($MtCO_2$) emissions – demonstrating the system-wide value of clean interconnection for resource-constrained economies (Puspitarini and Suarez, 2025). The European experience demonstrates this dynamic at continental scale. Emerging regional power pools in South-East Asia, sub-Saharan Africa, the Middle East and Latin America offer similar opportunities for rapidly growing electricity systems in these regions.

Across all three archetypes, the guiding principle is the same: align technology choices with local resource conditions, grid architecture and demand characteristics. Land availability, cost and competing uses are a further structural factor shaping deployment choices in all three contexts: where land is scarce, expensive, or subject to competing demands, technology configurations, siting strategies and ownership models will need to adapt accordingly – for instance, through agrivoltaic designs, offshore deployment or the prioritisation of rooftop and buildings and urban infrastructure.

3.3 ENABLING DEPLOYMENT: THE DECISIVE ROLE OF POLICY

Cost competitiveness alone does not guarantee deployment. In many markets, electricity markets and regulatory frameworks were designed around conventional generation and do not yet adequately reward the reliability and flexibility that hybrid renewable systems provide. Four policy levers – administrative mandates, fiscal incentives, auction and procurement design, and demand-side regulation – are proving decisive in closing this gap.

Administrative mandates accelerate early deployment by requiring storage or firm supply as a condition of grid connection or market participation. China's provincial storage attachment requirements – which made co-located battery storage a condition of grid connection approval for new renewable projects – triggered the growth of a domestic manufacturing and project development industry that now accounts for most of the global co-located capacity. Once the domestic industry had reached the scale needed to sustain deployment without regulatory compulsion, these mandates were completely removed at the national level in March 2025. This experience suggests that well-designed mandates are most effective when the objective is to create an industrial ecosystem that does not yet exist, and that they should evolve towards market-based mechanisms as that ecosystem matures.

Fiscal incentives can steer investment towards hybrid and firm configurations by making co-located projects more financially attractive than standalone ones. In the United States, federal legislation has established tax credits that treat the solar and storage components of co-located projects differently: the solar component qualifies for investment tax credits through 2030, while the storage component retains eligibility through 2035 – provided that components are not sourced from Foreign Entities of Concern. This difference in treatment effectively makes co-located configurations more attractive than standalone solar, since developers can benefit from storage credits for longer. The One Big Beautiful Act further strengthens incentives for paired solar PV and storage within this framework.

The impact on investment is already visible: around 20% of utility-scale solar additions in the United States in the first half of 2025 were paired with storage, a share BloombergNEF projects to exceed 50% by 2031. Near-term momentum has nonetheless been slowed by uncertainty over tariffs and restrictions on Chinese-manufactured components, which has stalled corporate procurement. The underlying logic extends beyond the United States: tax credit structures that make co-located and hybrid configurations more financially attractive than standalone variable generation can encourage investment in firm renewables, without policy makers having to require it explicitly.

Auction and procurement design can convert reliability from an abstract system need into a competitively priced market product, allowing markets – rather than policy makers – to discover the least-cost route to firm renewable supply. India's round-the-clock renewable tenders require developers to meet minimum utilisation thresholds across hybrid solar, wind, and storage portfolios, leaving developers free to find the most cost-effective combination of technologies while ensuring that firm supply is the contractual outcome. Germany's Renewable Energy Sources Act Innovation Auctions provide a dedicated market channel for co-located and hybrid renewable assets, and have attracted strong developer interest, with clearing prices declining materially in recent years – demonstrating the cost-reducing effect of competitive procurement. In Germany, hybrid solar PV and battery storage power purchase agreements now command a 30-40% price premium over standalone solar PV contracts, as buyers increasingly price in the value of reliable, shifted generation (Radoia *et al.*, 2026). The key design principle is the same: specify the output – a reliability target or a minimum utilisation threshold – and allow competition to find the least-cost configuration.

Demand-side regulation creates structural demand for firm renewable electricity by requiring consumers to source power from verified, time-matched clean generation. The European Union's framework for renewable hydrogen certification – requiring additionality, locational deliverability and hourly temporal matching as conditions for regulatory eligibility – effectively mandates firm renewable electricity as the power source of the emerging clean hydrogen economy. The ongoing revision of the GHG Protocol Scope 2 Guidance proposes to extend this logic globally, requiring hourly and location-matched certificates as the basis for corporate market-based emissions claims. When adopted, this shift will transform demand for firm renewable electricity from a voluntary commitment by leading buyers into a mainstream feature of corporate energy procurement worldwide.

Realising the full potential of these policy levers also depends on three physical and institutional enablers. Diversified and resilient supply chains are essential to ensure that cost reductions translate into secure, affordable deployment across a wide range of markets. Grid infrastructure linking resource-rich regions to demand centres – and regional interconnection pooling diverse weather zones – determines whether firm renewable capacity can be efficiently integrated and its output reliably delivered. And digital technologies, including artificial intelligence, are increasingly transforming hybrid renewable assets from passive generators into intelligent grid resources capable of providing the full range of services that modern power systems require.

3.4 LOOKING AHEAD

Four developments, already taking shape across leading markets, will extend the reach of firm renewable electricity further in the decade ahead.

Long-duration energy storage technologies – including flow batteries, compressed-air systems, pumped heat energy storage and thermal storage – are maturing and declining in cost, progressively addressing the multi-day and seasonal supply gaps that short-duration lithium-ion battery storage cannot bridge cost-effectively. Across all technology categories surveyed, developers expect substantially lower costs by 2030, driven by research and development progress and manufacturing scale-up, although multi-day storage technologies remain at an earlier stage of commercial readiness (EPRI, 2026). These technologies are not interchangeable: each has distinct cost structures, geographic requirements and operational characteristics suited to different time scales. The most cost-effective firm renewable systems of the next decade will draw on a portfolio of storage durations rather than a single solution.

Advanced digitalisation – including artificial intelligence-driven forecasting, predictive maintenance and grid-forming inverter technology – is helping hybrid renewable systems provide an expanding set of grid-support services, including voltage and frequency regulation, inertia-like response and, in some cases, black start and restoration capabilities. While these capabilities do not fully replace all functions of synchronous generation, they are increasingly narrowing the gap.

Expanding interconnection is reshaping the geography of competitive firm renewables, enabling land- and resource-constrained markets to access reliable clean electricity from neighbouring regions and reducing the storage and overbuild required to maintain reliability across wider system footprints. Emerging regional power pools – in South East Asia, sub-Saharan Africa, the Middle East and Latin America – are at an early but accelerating stage of this process, with the potential to replicate at regional scale the diversity and cost benefits that continental interconnection has delivered in Europe.

Finally, the maturation of **time-matched energy accounting** – through Hourly Guarantees of Origin and Granular Certificate frameworks now being rolled out across multiple markets – is making reliability visible, verifiable and commercially valuable at a global scale. Extending this logic to corporate emissions accounting – shifting from annual to hourly and location-matched reporting – would, if adopted, broaden this demand signal further – from pioneering corporate buyers to the full population of electricity consumers, reinforcing the investment case for storage, hybrid portfolios and round-the-clock clean supply across all markets.

The technologies are maturing, the costs are falling, the policy frameworks are developing and the commercial demand is growing. The projects, markets and examples described in this report are not isolated experiments: they signal a structural transformation in how electricity is generated, delivered and valued. The pace at which that transformation proceeds will determine the outcome of the global energy transition in the decade ahead.

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ANNEXES

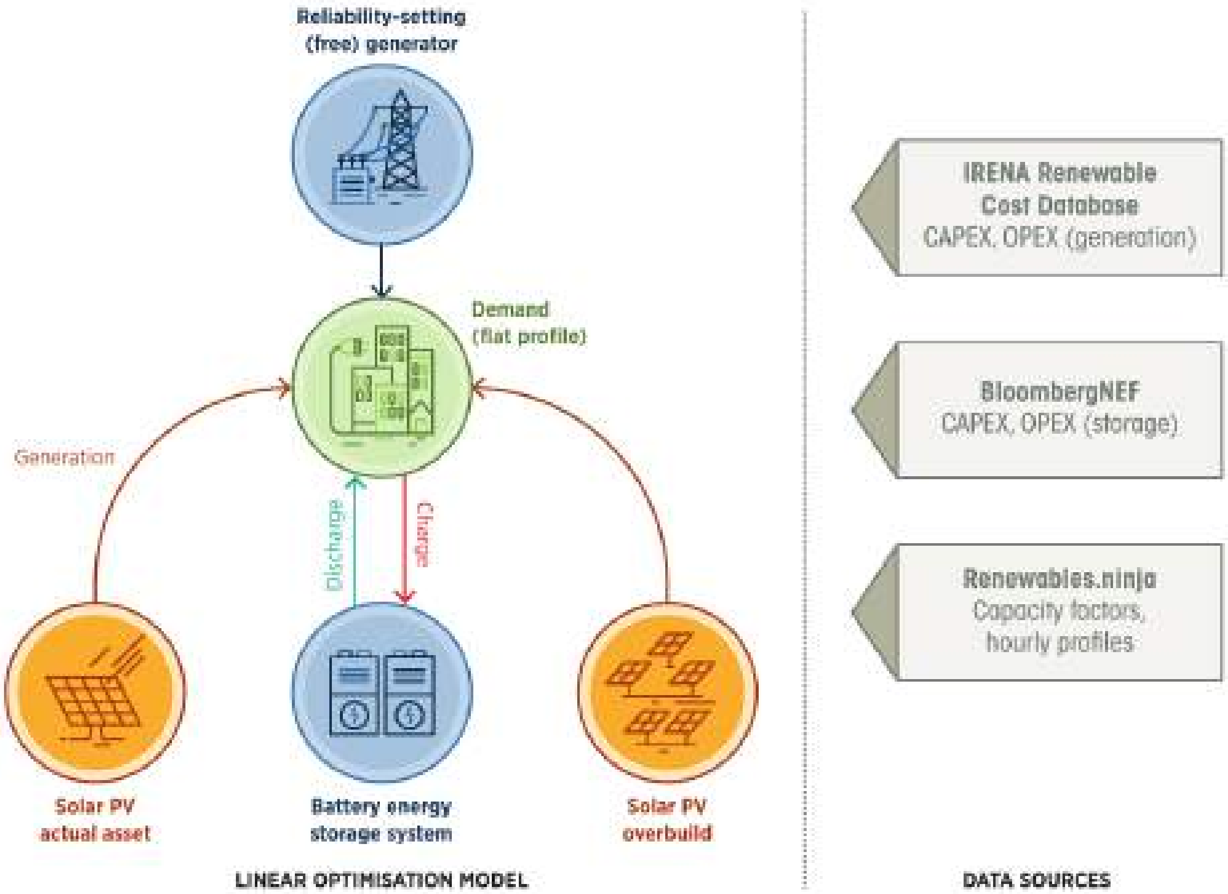
A METHODOLOGICAL FRAMEWORK FOR ESTIMATING FIRM LCOE

This annex outlines the modelling architecture, data flows and cost accounting principles at the basis of the firm levelised cost of electricity (F-LCOE) framework introduced in section 2.1. It documents the components of the linear optimisation model, the treatment of solar and wind resource data, and the post-processing methods used to derive firm LCOE estimates and the levelised cost of storage (LCOS).

A.1 Overview of the modelling framework

The firm LCOE framework is implemented using the open-source Integrated Energy Systems Optimiser (IESO) (Gréoux Research, 2024) based on the Google OR-Tools linear optimisation framework (Google, 2024). For this study, IESO is configured as a project-level firming tool rather than as a power system model. Figure 21 describes building blocks and data flows of the project-level firming optimisation model.

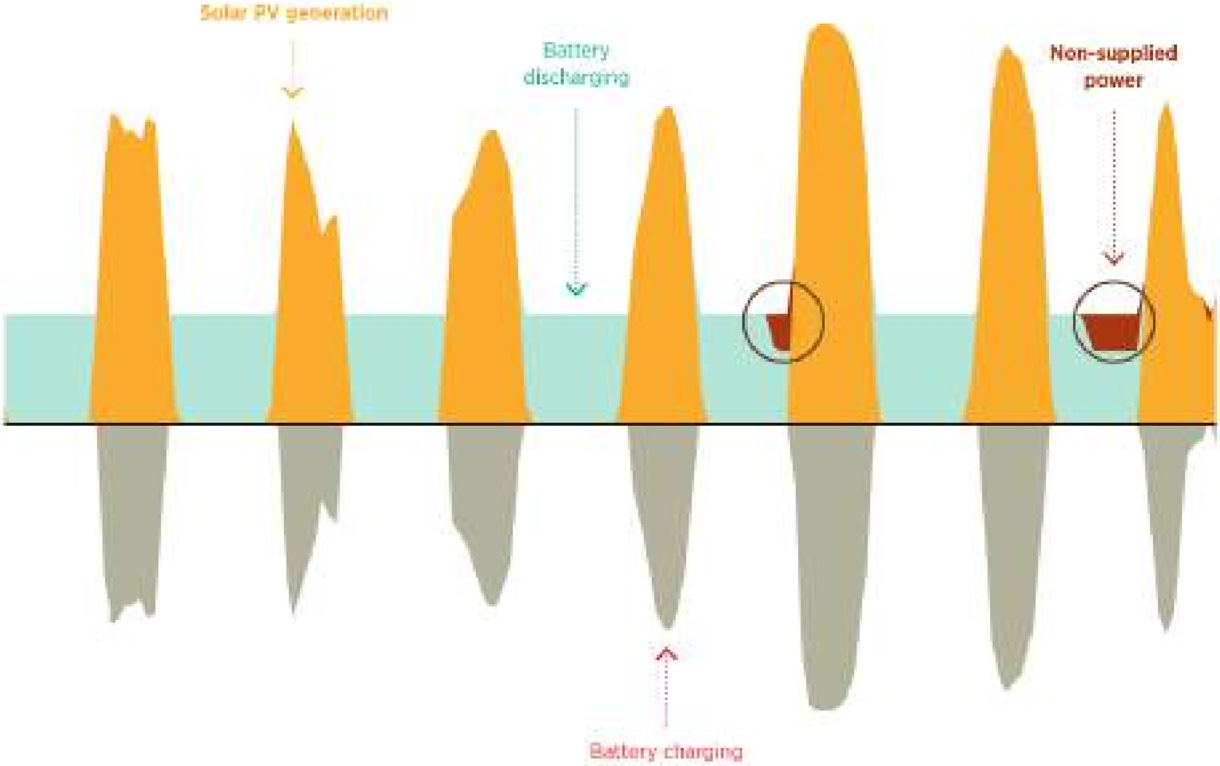
Figure 21 Building blocks and data flows of the project-level firming optimisation model



For any given project – characterised by location, technology (*e.g.* solar PV) and installed capacity – the model identifies the least-cost combination of co-located renewable overbuild and storage capacity required to deliver a flat hourly electricity output over a full year, subject to a specified reliability target. The cost metrics – Firm LCOE and LCOS – are calculated post-optimisation based on the capacity of the firming assets determined by the optimiser.

In this study, reliability is defined at the asset level in simplified, energy-based terms as the ratio of annual energy delivered (by renewable generation and storage) to total annual demand (Figure 22). This definition differs from standard power system reliability concepts, which typically focus on adequacy (the continuous ability to meet peak demand) and security (resilience against sudden disturbances) – properties that are inherently shaped by the broader grid and generation mix, not by individual assets in isolation.

Figure 22 Illustrative example of hourly dispatch calculations



Note: The reliability target is the share of total annual demand that the modelled renewable and storage configuration is required to cover. Hours in which generation and storage fall short of the flat demand profile – shown in red – represent non-supplied power and determine the gap between the chosen reliability target and 100%.

A.2 Demand and generation logic

The hourly electricity demand – assumed constant across the 8 760 hours of the year – is calculated to conserve the annual energy volume of the original reference project.

For example, a 100 MW solar PV plant with a 20% capacity factor yields an annual energy volume of 175 200 MWh (20% × 100 MW × 8 760 hours) and a constant hourly demand of 20 MWh.

The flat output profile serves as a proxy for continuous delivery obligations – such as those serving data centres or industrial off-takers – where a constant, reliable supply is the relevant commercial standard. It should be read as a conservative and transparent benchmark for the economics of firm renewable power, not as a claim about real-world system operation or a system optimisation outcome.

This constant load is met by three supply components:

1. Existing renewable asset: The original solar PV or wind capacity (*i.e.* the standalone power generation system).
2. Firming asset (overbuild): An additional asset of the same technology, with an identical hourly generation profile and cost structure. Its capacity is endogenously determined by the optimiser.
3. Reliability-setting generator: A fictitious dispatchable unit with zero fixed costs, used as a modelling construct to enforce the desired reliability target (*e.g.* 95%).

A.3 Storage modelling

Energy storage is modelled as a flexibility asset.[20] The optimiser determines the required storage capacity (in MWh) accounting for the asset's key techno-economic characteristics: fixed costs, round-trip efficiency (assumed at 90% for a four-hour battery energy storage system [BESS]) and discharge duration (four hours).[21]

A.4 Data inputs and resource assumptions

Exogenous inputs – including project characteristics from the IRENA Renewable Cost Database (IRENA, 2025), battery storage cost data from BloombergNEF (BNEF, 2025b) and hourly generation profiles from Renewables.ninja (Pfenninger and Staffell, 2016) – are channelled into the model to populate the endogenous optimisation variables, as illustrated in Figure 21.

[20] *This study focuses specifically on lithium-ion battery energy storage systems (BESS) with a four-hour discharge duration, reflecting the dominant technology in current utility-scale deployments. Other storage technologies – including pumped storage hydropower, long-duration electrochemical storage, thermal storage, compressed-air systems and power-to-hydrogen pathways – are not modelled here.*

[21] *Battery discharge duration is fixed at four hours across all modelled cases. This assumption reflects current market practice for utility-scale lithium-ion systems and enables consistent comparison across projects and regions.*

Hourly generation profiles are generated via the application programming interface (API) of Renewables.ninja, applying the assumptions summarised in Table 5 to reflect modern utility-scale projects. In this analysis, generation profiles are derived from 2019 weather data from the MERRA-2 dataset. The use of a single weather year provides a consistent basis for comparing locations and technologies.[22]

Table 5 Renewables.ninja API inputs

Solar PV	Onshore wind
• Generic modern utility-scale solar PV with single-axis tracking (horizontal, north-south aligned). • Profiles are normalised to 1 kW and use MERRA-2 weather data with explicit system losses of 9%.	• Modern utility-scale onshore wind using a low-specific-power turbine (Vestas V162-7.2 MW). • Profiles are normalised to 1 kW and assume a hub height of 120 metres, reflecting recent utility-scale deployments.

A.5 Cost calculation and allocation

The firm LCOE is estimated as:

- The sum of the annualised CAPEX and fixed O&M costs for all assets contributing to firm supply (baseline generation, firming overbuild and storage).
- Divided by the total annual electricity delivered.

This calculation fully accounts for the energy losses within the BESS.

The difference between the resulting firm LCOE and the LCOE of the standalone renewable project is referred to as the firming premium. The term draws on an established analogy in finance – the price paid for a guarantee – and clearly signals an incremental cost above a baseline. It also pairs naturally with the concepts of firm LCOE and firm electricity used throughout this study.

To derive the levelised cost of storage (LCOS), the total firming premium is allocated to individual firming components (renewable overbuild and battery storage) in proportion to their share of the firming infrastructure's annualised fixed costs.

Unlike conventional LCOS calculations, which typically require an exogenous assumption regarding the purchase price of charging electricity, the approach applied here endogenously captures charging costs within the system optimisation. This approach ensures internal consistency between the LCOS and Firm LCOE metrics and avoids distortions arising from externally assumed prices. As a result, the LCOS figures reported in this study should be interpreted only as the cost of storage within a co-located renewable firming system, rather than the standalone cost of operating a battery in isolation.

[22] *Theobjectiveoftheanalysisistoexaminetheeconomicsandcosttrendsoffirmrenewablepower, ratherthantomodelworst-case meteorological conditions such as prolonged Dunkelflaute events, which are typically assessed using multi-year weather datasets in detailed system reliability studies.*

B CAPITAL EXPENDITURE ASSUMPTIONS

BloombergNEF suggests that the turnkey CAPEX of a co-located solar and BESS can be estimated by applying standalone turnkey CAPEX to the solar component, while assuming co-located BESS CAPEX of around 70% of standalone to reflect the benefits of co-location[23] (BNEF, 2025c).

In line with this approach, the co-located system CAPEX is calculated as follows:

$$\text{CAPEX}_{\text{co-located}} = \text{CAPEX}_{\text{solar, standalone, turnkey}} + 0.7 \times \text{CAPEX}_{\text{BESS, standalone, turnkey}}$$

where:

- $\text{CAPEX}_{\text{solar, standalone, turnkey}}$ is the full standalone turnkey solar CAPEX, which is typically not affected by co-location.
- $\text{CAPEX}_{\text{BESS, standalone, turnkey}}$ is the standalone turnkey BESS CAPEX.
- The 0.7 factor reflects avoided engineering, procurement, construction, permitting and grid-connection costs due to co-location.[24]

This calculation scheme is applied consistently across solar and wind projects, assuming an AC-coupled co-location configuration in which the renewable asset and BESS share grid connection and balance-of-plant infrastructure but retain separate inverters.

B.1 Solar PV and onshore wind costs

The primary source of historical cost data for variable renewable technologies is IRENA's Renewable Power Generation Costs database, which includes country- and region-specific information on total installed costs.

Cost trajectories for the period 2025-2035 are developed using a two-stage approach. First, a learning curve model is applied to historical data to derive short-term cost projections (IRENA, 2025). Second, these projections are adjusted using explicit structural assumptions to reflect persistent regional cost drivers, including labour costs, permitting regimes, grid-connection complexity and localisation requirements. Historical and projected costs are reported in Table 6 (for solar PV) and Table 7 (for onshore wind).

[23] *BloombergNEFsuggeststhatinco-locatedprojects,theBESScomponentcanusethesolarplant'sexistinggridconnectionand construction crew, meaning that grid-related electrical works, overheads and other EPC items are already captured within the solar balance-of-plant rather than duplicated for storage (BNEF, 2025c).*

[24] *Thisassumptionappliestofour-hoursystemsoutsideChina.InChina,thisfigureisratherconservative,asBloombergNEFindicates that co-located four-hour battery systems typically cost closer to 65% of standalone storage CAPEX (BNEF, 2025c).*

Table 6 Assumed solar PV total installed costs curves

Year	China	Europe	Global	United States
2020	784	1 048	1 069	1 349
2025	530	683	658	978
2030	338	424	412	657
2035	305	379	359	489

Table 7 Assumed onshore wind total installed costs curves

Year	China	Europe	Global	United States
2020	1 524	1 864	1 626	1 675
2025	844	1 616	1 034	1 552
2030	730	1 361	872	1 334
2035	701	1 177	806	1 168

All costs are expressed in real USD (2025) and represent turnkey, overnight construction and commissioning costs, reported per kW of installed capacity. System boundaries for solar PV and onshore wind are summarised in Table 8.

Table 8 System boundaries for solar PV and onshore wind

Solar PV	Onshore wind
• The solar PV system boundary includes PV modules and inverters, mounting structures (fixed-tilt or tracking, reflecting prevailing market practice), balance-of-system hardware, electrical works, grid connection, installation, project development, permitting, commissioning, and EPC and developer margins.	• The onshore wind system boundary includes turbines (nacelle, rotor, blades and tower), foundations and civil works, electrical infrastructure and sub-stations, transport, installation, commissioning, project development, permitting and environmental compliance, and EPC and developer margins.

The key assumptions used to develop regional cost trajectories are presented in Table 9.

Table 9 Key assumptions underlying cost trajectories for variable renewable technologies

Solar PV	Onshore wind
• China is treated as the global cost floor due to its abundant manufacturing capacity and structurally low balance-of-system costs. • Global markets converge asymptotically towards Chinese cost levels, reflecting access to low-cost hardware combined with relatively low non-hardware costs, while remaining above China. • Europe converges gradually but remains structurally above China, reflecting full pass-through of global module price declines and competitive EPC markets, offset by higher labour, permitting and grid-connection costs. • The United States remains the highest-cost region, with partial convergence constrained by domestic content requirements, higher labour and construction costs, and more complex permitting and interconnection processes.	• China is treated as the global cost floor, reflecting very low turbine prices, strong domestic competition and highly standardised large-scale projects. • Global markets converge asymptotically towards Chinese cost levels, benefiting from access to low-cost turbines and favourable local cost conditions, while remaining above China due to residual non-hardware cost components. • Europe is considered the highest-cost region, due to high labour costs, constrained siting opportunities, persistent grid-connection bottlenecks and lengthy permitting processes. • Cost levels in the United States – lower than in Europe but higher than in China and the global average – reflect domestic manufacturing requirements, labour costs, logistics and permitting complexity.

B.2 Battery costs

Battery costs refer to the overnight CAPEX expenditure associated with a utility-scale four-hour lithium-ion BESS delivered as a turnkey project. The four-hour configuration is applied consistently across regions to ensure comparability. The cost figures, compiled in Table 10, are expressed in real USD (2025) per kWh of installed energy storage capacity. They assume lithium iron phosphate (LFP) chemistry, reflecting prevailing utility-scale deployment trends.

Table 10 Assumed BESS total installed costs curves

Year	China	Europe	Global	United States
2020	300*	300*	300*	300*
2025	62	172	171	192
2030	48	125	132	132
2035	41	101	114	108

Notes: * Values marked with an asterisk are IRENA assumptions for 2020. All other values are from BloombergNEF's 2025 Energy Storage System Cost Survey (BNEF, 2025b). The BloombergNEF "Global" category is split into "Global – high"and "Global – low", reflecting differences in import tariffs, transport and logistics costs, local construction labour costs, and balance-of-system and EPC requirements. The column "Global" in this table is the average of "Global – high" and "Global – low".

The BESS scope includes battery racks, balance-of-system, energy management system (EMS), power conversion system (PCS), transformer, and associated installation and commissioning expenses.[25]

The cost figures in Table 10 are IRENA estimates derived from analysis of market data, including BloombergNEF's 2025 Energy Storage System Cost Survey (BNEF, 2025b). The underlying market data confirm that four-hour energy storage costs have declined rapidly in recent years, driven by falling lithium-ion battery prices and abundant supply from China, which remains the lowest-cost market due to economies of scale, vertical integration and rapid adoption of higher-energy-density cell and container designs. Costs in Europe and the United States remain materially higher, reflecting localisation requirements, tariff exposure, and higher balance-of-system and EPC costs. Looking ahead, BloombergNEF expects further cost declines through 2035, supported by larger cell formats, more energy-dense containers, and improved system integration, with China continuing to set the global cost floor.

B.3 Regional coverage

Total installed cost curves are defined for four regions:

- China
- Europe
- United States
- Global (rest of world) – applied to all countries outside the United States, Europe and China.

For countries not explicitly represented by a dedicated regional cost curve, the Global trajectory is used as the default proxy, reflecting access to internationally traded equipment combined with country-specific balance-of-system and construction costs.

C OPERATING EXPENDITURE ASSUMPTIONS

To maintain simplicity while reflecting technology-specific cost differences, annual operating and maintenance costs are assumed as a fixed percentage of the total installed costs (TIC). Solar PV systems are assumed at 2% of TIC per year, reflecting relatively low and predictable O&M costs, while wind-based systems are assumed at 3% of TIC per year, due to the presence of mechanical components and a higher exposure to corrective maintenance. For batteries, O&M costs are systematically set to 2.5% of CAPEX per year.

[25] *ConsistentwithBloombergNEF'sdefinition,theturnkeytotalinstalledcostsincludesthesystemintegratormarginbutexcludes broader project-level costs such as engineering, procurement and construction (EPC), grid connection infrastructure, developer overheads and developer margins.*

D PROJECT TIMELINE AND FINANCING ASSUMPTIONS

This annex summarises the assumptions regarding project timing, the cost of capital and the time value of money used in the analysis of co-located projects.

D.1 Project timeline

Co-located solar-plus-storage and wind-plus-storage projects are assumed to have a construction period of one year, consistent with typical utility-scale project delivery timelines.[26] Battery systems are installed in parallel and do not extend the critical path.

The economic lifetime of such systems is assumed to be 20 years (Rangelova and Jones, 2025), reflecting the design life of modern lithium iron phosphate battery systems, which represent the limiting component in firm generation configurations. No explicit repowering, battery replacement or residual value is modelled.

D.2 Cost of capital (WACC)

The cost of capital for renewable energy projects is highly project- and context-specific, reflecting the perceived risk of future revenue streams and the broader macroeconomic environment in which investments take place.

Compared with standalone solar or wind, co-located assets are more flexible, enabling load shifting, peak shaving, and reduced curtailment, which improve capture prices and stabilise revenues. This improved revenue certainty can support lower financing costs where storage revenues are embedded in contracted or auction-based structures, although the cost of capital remains highly project- and context-dependent.

In this study, the weighted average cost of capital (WACC) is treated as a scenario assumption rather than as a forecast and is held constant in real terms over the 2021-2035 period, reflecting long-run financing conditions rather than short-term macroeconomic fluctuations. A high-level classification of countries that are members of the Organisation for Economic Co-operation and Development (OECD) versus non-OECD countries is applied, with a real WACC of 5.0% for OECD countries and 7.5% for non-OECD countries. For China, the real WACC applied is 5.0%.

These values should therefore be interpreted as simplified financing assumptions used to enable cross-country comparability, rather than as representations of prevailing financing conditions or projections of future financing costs.

D.3 Time value of money

Capital expenditures are incurred during construction and annualised over the assumed economic lifetime using the applicable real WACC. Operating expenditures are treated as annual costs. All values are expressed in real terms.

[26] *Notethatinseveralmarkets–includingtheUnitedStatesandpartsofEurope–totalprojectdevelopmenttimelinesmaybemuch longer due to permitting procedures, interconnection queues and supply chain constraints.*

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