

Electricity Market Design

Building on strengths, addressing gaps

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Abstract

Electricity markets play a central role in balancing supply and demand, guiding operational decisions and shaping investment outcomes. As systems change with higher shares of variable generation, greater decentralisation and evolving patterns of electricity use, the ability of market designs to deliver secure and affordable electricity has never been more critical. If market arrangements do not keep pace with these developments, the functioning of electricity systems could become more uncertain and more costly.

This report provides a cross-regional assessment of how wholesale electricity markets and their complementary policy mechanisms are performing today. We find that short-term markets have continued to operate reliably and efficiently, translating real-time conditions into meaningful price signals even as system complexity grows. Medium- and long-term markets, however, face persistent gaps in liquidity and accessibility, which can make it harder for participants to manage risk and invest with confidence. Complementary mechanisms have become structural features of many systems, helping to support resource adequacy and decarbonisation objectives, but their effectiveness and cost efficiency depends on designs that work in concert with market signals.

The analysis highlights that coherent evolution across market layers and mechanisms is essential to maintain secure, affordable and sustainable electricity systems. The report concludes with insights to guide policy makers as they refine market arrangements and ensure that markets remain resilient, efficient and responsive as system needs continue to change.

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Executive summary

Electricity systems are changing fast, and market design must evolve with them

Electricity systems are undergoing rapid structural change, increasing the need for market frameworks that keep pace with evolving operational and investment requirements and possibilities. Electricity is central to modern economies, and its role is expanding as consumption patterns shift, digitalisation accelerates, energy systems decentralise, and variable resources grow. Across major regions, these trends are increasing the complexity of real-time operations and reshaping investment dynamics. Short-term and seasonal flexibility needs are projected to grow faster than demand over the next decade, while electrification in many sectors is strengthening the dependence of households, businesses and industry on the reliable performance of electricity systems. These developments reinforce the importance of market arrangements that ensure efficient resource co-ordination while supporting stable long-term investment.

Recent system stresses have underscored the importance of durable market design that can withstand a wide range of system conditions. Higher financing costs, supply chain constraints, network development delays and broader geopolitical pressures have all contributed to a more uncertain operating environment. Since 2019, many jurisdictions have seen annual wholesale market price volatility at five to nine times 2019 levels. In Europe in 2021, triggered by the sudden and drastic reduction in Russian pipeline gas deliveries to Europe, wholesale electricity prices increased over four times compared with levels in 2019. These increases were largely the result of volatile and rising gas prices, prompting over 400 emergency measures to mitigate impacts on consumers. These experiences have heightened public and political scrutiny of electricity markets and underlined the importance of ensuring that market frameworks remain resilient, efficient and practical as system pressures grow.

Short-term markets remain effective for operations, but long-term markets need strengthening to support investment and risk management

Short-term markets have been broadly effective in maintaining reliable and efficient operations even as systems become more complex. In the markets analysed across parts of Europe, the United States, Australia and Japan, electricity has been securely supplied more than 99.9% of the time over the past five years. Short-term markets have enabled efficient scheduling, transparent

price formation and broad participation across a diverse set of resources and actors. In Europe, the day-ahead market processes more than 400 000 bids every hour across thousands of registered actors. As variability and decentralisation have increased, these markets continued to translate real-time conditions into meaningful price signals that align operational behaviour with system needs.

Growing variability and decentralisation require refinements that unlock flexibility and strengthen the co-ordination role of short-term markets. As more resources operate at the distribution level or behind the meter, and as weather-dependent generation expands, short-term markets must capture system conditions with finer temporal and locational granularity. This includes reducing day-ahead market time intervals to 15 minutes or less where this has not yet been implemented, and dividing large bidding zones into smaller areas where needed to better reflect real network conditions. Further refinements, including improved access for distributed resources and more flexible participation frameworks can help unlock the full range of demand- and supply-side flexibility needed in modern electricity systems. These enhancements support the continued effectiveness of short-term markets as the central co-ordination mechanism for electricity systems.

Long-term markets have not kept pace with rising investment needs and growing exposure to uncertainty, leaving participants with limited tools to manage risk. While the generation mix is shifting toward a higher share of capital-intensive technologies, the vast majority of forward and futures markets suffer from low liquidity, limiting how easily market participants can buy or sell contracts. In addition, these markets remain shallow across all regions analysed in this report, with most trading concentrated within the first two years of delivery. This restricts participants' ability to hedge revenue and cost risks over longer periods. Heightened exposure to wholesale price volatility can raise financing costs and weaken investment confidence in new generation, storage and in electrification projects that depend on predictable long-term prices, a challenge that grows as more sectors rely on electricity as a core input.. Strengthening long-term markets is therefore essential to support timely investment in both supply and demand-side resources.

Power Purchase Agreements (PPAs) help many market participants manage price risk, but they cannot substitute for deep and liquid long-term markets accessible to all. Corporate and utility PPAs have expanded where long-term markets are thin, providing tailored risk-management options. However, access is uneven: in Australia, Japan, Europe and the United States, between half and three-quarters of corporate PPAs have been signed by companies with revenues above USD 1 billion, with limited uptake among smaller actors. Pay-as-produced PPAs can also induce misalignments with short-term signals, affecting how

participants react to real-time system conditions. While PPAs will remain an important tool, they cannot alone fulfil the role of well-functioning long-term markets.

Complementary mechanisms are now structural and must align with market signals through co-ordinated reform

Complementary mechanisms, such as capacity remuneration mechanisms and renewable support schemes, now play a major role in delivering investment and policy objectives across many jurisdictions. These and other investment tools have expanded as governments pursue objectives such as ensuring resource adequacy, supporting domestic industry and advancing low-carbon generation. In Australia, for example, 98.8% of capacity additions in the National Electricity Market over the last decade has relied on some form of government support. Similar dynamics are visible across Europe, Japan and several US markets: they have become a structural feature of electricity systems, supporting the entry of new large-scale, low-emission generation and the continued operation of existing dispatchable and flexible plants that remain essential while operating at declining capacity factors.

The design of these mechanisms must be carefully co-ordinated with short- and long-term markets to avoid unintended consequences. Poorly aligned mechanisms can weaken price signals, increase system costs and create uncertainty, while well-designed mechanisms can reinforce market efficiency and mobilise timely investment. For example, support schemes that remunerate output at a fixed price irrespective of market conditions can prompt generation even when low prices indicate abundant supply, reducing the responsiveness of generators and flexibility providers to market conditions. Recent reforms illustrate approaches to improve alignment, such as two-sided contracts for difference with safeguards during negative price periods. Ensuring that complementary mechanisms support, rather than hinder, the functioning of existing markets is essential for maintaining investor confidence and efficient system operation.

Effective market design requires co-ordinating complementary mechanisms with market signals across all time horizons to support efficient investment and system operation. Secure and affordable electricity depends on the interaction of short-term markets, long-term contracting tools, complementary mechanisms and broader system governance. While complementary mechanisms play an important role, they can add to overall system costs and can expose investors to policy instability. This underscores the need to strengthen long-term markets and refine short-term arrangements, ensuring that complementary

mechanisms are well co-ordinated within a coherent investment framework that supports efficient outcomes and sustains confidence among investors and consumers.

Predictable and well-co-ordinated reforms are crucial for maintaining confidence, enabling timely investment and ensuring electricity systems keep pace with growing needs. As electricity systems evolve, market design must be treated as a regular, iterative process rather than a one-off exercise, with periodic reviews built in to keep frameworks aligned with changing conditions. Clear objectives, transparent consultation and well-signalled implementation timelines provide the stability participants need to plan and invest effectively. Abrupt or retrospective changes risk undermining trust and increasing system costs. Clear, co-ordinated action on market design is essential to deliver the reliable, affordable electricity paving the way in the Age of Electricity.

Introduction

Coherent market design requires co-ordination across markets, policy and regulation

Electricity underpins modern life. Every second, electricity systems must keep supply and demand tightly balanced across networks that stretch thousands of kilometres. In many countries, electricity markets provide the architecture that helps match generation with consumption while allocating responsibility and risk among a wide range of actors. As grids decentralise, technologies advance and end-use sectors electrify, the ability of market designs to deliver secure and affordable electricity has never been more critical. Market design also plays a powerful role in shaping how systems evolve to meet broader policy and social objectives. Ensuring market designs remain fit for purpose is therefore essential for electricity security, affordability and sustainability.

Markets do not operate in isolation. They are shaped by, and operate alongside, policy and regulation. Together, these elements can be used to support an increasing number of electricity system objectives linked to security, affordability and sustainability. Electricity market design also encompasses multiple layers, ranging from real-time markets through to forward markets and long-term complementary investment support mechanisms. Each layer serves a distinct function, yet all interact within the broader market framework. Hence, coherent market design requires co-ordination and alignment across market layers, policy and regulation to deliver overall objectives.

Market optimisation and reform require insights into how markets are performing

Markets have always been designed to evolve in response to changing system needs and shifting policy objectives. Yet today, the increased pace and scale of change shaped by evolving technologies, shifting demand patterns and greater system complexity are raising new questions and uncertainties for market design. Understanding how wholesale markets are performing is critical to ensuring that market design can continue to support electricity system objectives as conditions change. This report aims to provide timely and accessible insights that can inform this evolution and contribute to the many market design reviews and reforms currently under way.

The report examines the current state of major liberalised wholesale electricity markets in Europe (Spain, France and Germany), Great Britain, the United States (the California Independent System Operator [CAISO], Electric Reliability Council

of Texas [ERCOT] and PJM Interconnection [PJM] regions), Japan and Australia (the National Electricity Market [NEM]). These markets have some of the most established designs, are experiencing profound system changes and together offer diverse examples that provide opportunities for sharing lessons across regions.

Liberalised wholesale markets – hereafter referred to as “wholesale markets” in this report – are not the only mechanism through which electricity system objectives can be delivered. In many parts of the world, highly regulated or administratively priced systems without free price formation continue to play a central role in shaping electricity system outcomes. As the context and institutional underpinnings of these models differ substantially from wholesale markets, they have not been included in the scope of this analysis. This should not be interpreted as suggesting that one approach is inherently more or less effective than another. The focus on wholesale markets allows the report to draw lessons that are transferable and practical across similar institutional contexts.

The analysis considers wholesale electricity markets across all time horizons, from real-time balancing to long-term contracts. Complementary mechanisms, such as capacity remuneration markets and generation support schemes, are also included in the scope. The analysis highlights which design features are working well, what common challenges are emerging and what lessons can inform future market reform. Although the scope does not extend to retail markets, network tariffs or system planning, their interactions with wholesale market design are discussed where relevant. Examining these areas in full would significantly expand the scope beyond practical limits and reduce the depth of analysis on core wholesale market designs.

The report provides a high-level assessment of how wholesale market designs are performing today. It does not aim to present new primary research or detailed technical analysis of individual markets. Instead, it offers a holistic, cross-regional overview of the current state of major wholesale markets. The purpose is to establish a shared understanding, accessible to both technical and non-technical audiences, of where these markets stand today. This common baseline is intended to support informed discussions on the direction of market design, identify areas where further analysis would be most valuable and highlight issues that may require closer attention in future reforms.

Overall, despite the differences among market designs, the analysis identifies several clear common threads and emerging trends. Across the markets examined, short-term markets have generally been effective in supporting electricity system objectives, though they will need to continue evolving to reflect changing system conditions. In contrast, medium- and long-term markets have been less effective in supporting investment and hedging needs, revealing several

gaps that require attention. Finally, complementary mechanisms are assuming a growing role in achieving various policy objectives. When deployed correctly, they can accelerate and expand market outcomes, but they must be carefully designed to reinforce rather than undermine efficient market outcomes and maintain affordability.

The report is structured in five chapters as follows:

Chapter 1 (Context) sets out the role of wholesale market designs in electricity systems. The chapter explains how markets provide the framework for delivering secure and affordable electricity while also working alongside complementary mechanisms to achieve wider policy and social objectives. It describes how market frameworks span multiple layers, from short-term markets to long-term contracts, and how their designs vary across jurisdictions. The chapter also explores the ongoing transformation of electricity systems across supply, demand, infrastructure, digitalisation and flexibility, and discusses how market design must evolve in response. Finally, it highlights that while reforms are widespread, they are often lengthy and complex, underscoring the importance of effective implementation when considering market design changes.

Chapter 2 (Short-term markets) outlines the central role short-term markets have in wholesale market design. The chapter covers day-ahead, intraday, real-time, balancing and ancillary markets. It discusses the differences between these markets and services, as well as the variations in design elements across jurisdictions. The chapter also reviews the performance of wholesale energy markets and ancillary markets, noting the growing operational complexity that comes with higher shares of variable generation sources. Finally, it considers how short-term market designs must continue evolving to meet changing system needs.

Chapter 3 (Medium and long-term markets) explores the growing importance of medium- and long-term markets as electricity systems shift toward more capital-intensive investments. The chapter reviews the role of forwards, futures and power purchase agreements in supporting investment and hedging needs, before assessing the current liquidity limitations and related challenges. These challenges include mismatches between the hedging needs of buyers and sellers, participation barriers for certain market actors, outdated contract structures and the limited evolution of medium- and long-term products across markets and regions.

Chapter 4 (Complementary mechanisms) describes how markets are designed to deliver efficient operations and investment signals, but in isolation, cannot ensure the delivery of broader policy objectives, such as resource adequacy and decarbonisation targets. The chapter reviews complementary mechanisms, structured around resource adequacy mechanisms and decarbonisation

mechanisms. It considers how these have been designed, highlighting examples of where they have successfully supported policy goals as well as cases where they have distorted market signals, operational practices and investment incentives.

Chapter 5 (Recommendations) summarises the main lessons and proposes recommendations to guide the evolution of market designs in line with system needs. While recognising that each country context is unique, the recommendations focus on common challenges identified across the wholesale electricity markets analysed. They are organised around three major areas: short-term markets, medium- and long-term markets, and co-ordination across market and policy frameworks. The chapter stresses the importance of practical reform, noting the negative implications of unnecessary complexity and uncertainty for market participants.

Chapter 1: Context

Electricity market design determines how the electricity system balances supply and demand, how prices reflect scarcity and how investment signals are formed. It provides the framework that links physical operation and investment signals with policy objectives that typically include security, affordability and sustainability. When well co-ordinated, short- and long-term markets can provide the economic signals that allow electricity systems to operate efficiently while supporting investment in future capacity.

Electricity systems are changing rapidly as dispatchable generation is increasingly replaced by weather-dependent resources, demand becomes more flexible and digital technologies create new forms of participation. The electrification of transport, heating and industry is deepening the role of electricity in the wider economy, while transmission and distribution networks are adapting to more decentralised patterns of supply. These developments are increasing the importance of clear market signals. Markets remain effective tools for delivering electricity system objectives, but they must evolve to address emerging patterns of variability, risk and investment.

Market structures have evolved differently across regions, reflecting distinct policy goals, institutional structures and system characteristics. Some jurisdictions employ energy-only designs that emphasise wholesale price signals, while others envisage a larger role for targeted instruments to meet reliability standards. Despite these differences, all systems face similar pressures to effectively integrate new sources of generation, maintain reliability amid increasing variability and adapt regulation and infrastructure quickly enough to keep pace with technological and structural change. Continued refinement and reform are therefore central to effective electricity market design.

Experiences across jurisdictions show that while designs differ, the underlying mechanisms of efficient co-ordination remain consistent. The ongoing transformation of electricity systems calls for reinforcing those principles rather than replacing them. Achieving this balance requires markets that work together across timeframes and align with policy and regulatory frameworks to maintain reliability, minimise costs and adapt to evolving system needs and policy objectives.

Market design overview

Wholesale electricity markets are central to many modern electricity systems, providing a framework for efficiently balancing supply and demand, co-ordinating operational decisions and signalling investment needs. They operate in a policy

and regulatory environment where complementary mechanisms support security, affordability, and sustainability. Although designs vary among wholesale markets, each seeks to reflect the physical realities of electricity systems, including grid constraints, and meet demand with the least-cost mix of resources.

The [majority of global electricity demand](#) occurs in countries with market-based electricity systems. Reviewing the performance of major wholesale electricity markets can offer useful insights for jurisdictions that already operate wholesale market designs as well as those moving toward such designs. This report focuses on established wholesale markets, with lessons that may be informative elsewhere, while recognising that institutional, regulatory and policy contexts differ across electricity systems.

Wholesale markets can be powerful tools for supporting secure, affordable and sustainable electricity systems

As the foundation of many electricity systems, well-designed wholesale markets enable the efficient use of resources today while signalling investment needed for efficient operations in the future. Wholesale electricity markets encourage private sector participation to deliver efficient outcomes by promoting competition, driving innovation and allocating operational and investment risks to those best placed to manage them. By mobilising capital and unlocking diverse business models, market designs play a key role in supporting secure, affordable and sustainable electricity systems.

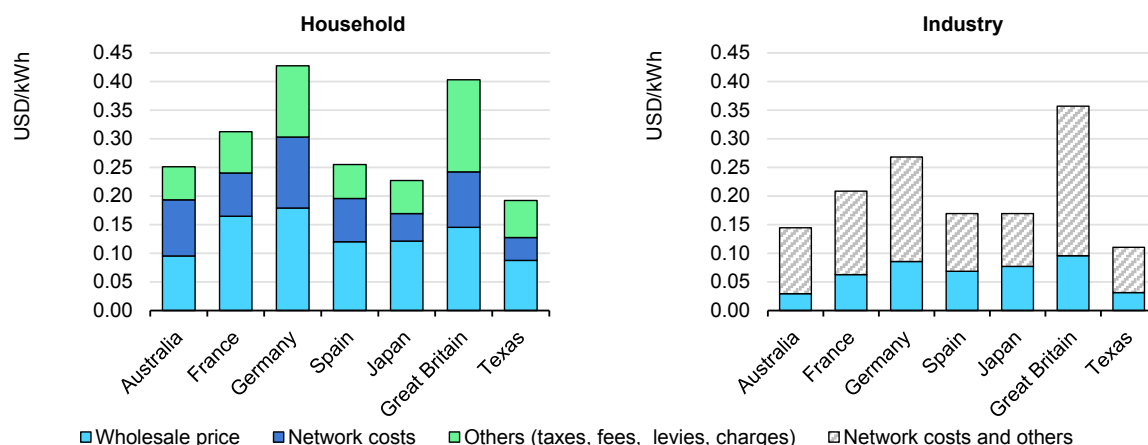
Wholesale markets alone, however, are not designed to deliver all electricity system objectives. While they are effective in driving efficient operations and investment signals, they are not always fit-for-purpose to deliver at the pace and scale that governments and societies desire, particularly when it comes to meeting reliability and decarbonisation targets. Market design should therefore be viewed as one element within a broader policy and regulatory toolkit. Alignment between markets and policies is essential to maintaining market efficiency and delivering electricity system objectives.

In terms of affordability, efficient wholesale markets help reduce system costs, which in turn lower consumer bills. Wholesale electricity costs represent a significant share of these bills. For instance, the wholesale component of household retail bill ranges between 35% and 55% across the markets analysed. Clearly, market design has important role to drive efficient outcomes in wholesale markets. However, affordability is also shaped by other components of retail bills, including network charges, taxes and levies.

From industrial consumers' perspective, market design is also particularly important for keeping electricity sourcing costs affordable and supporting competitiveness. Industrial users tend to engage more closely with wholesale markets, both through active participation and tailored contracting. This provides

industrial consumers with more flexibility to negotiate supply terms, manage price risk and shape their procurement strategies. Effective market design is therefore important for enabling them to make full use of these options.

Electricity price components for households and industry in selected regions, 2024



IEA. CC BY 4.0.

Notes: For Japan, the figure is based on a household electricity bill in Tokyo. Australian industry prices are based on an estimation.

Sources: IEA analysis based on IEA (2025), [Energy Prices](#); IEA (2025), [Real Time Electricity Tracker](#); Eurostat (2025), [Electricity Price Statistics](#); EIA (2025), [Electric Power Monthly](#); ACCC (2024), [Inquiry into the National Electricity Market](#); TXU Energy (2025), [Understanding your Bill](#); Ofgem (2025), [Energy Price Cap \(Default Tariff\) Levels](#); METI (2024), [Surcharge Rate for FY2024](#); Selectra (2024), [Understand Your Electricity Bill in Japan](#).

A range of markets work in tandem to deliver electricity across time horizons, complemented by mechanisms that meet broader policy goals

Market designs consist of a series of interlinked markets, each serving a distinct purpose across different time horizons. Central to each market is the fundamental role of bringing together buyers and sellers to exchange electricity, capacity, system services or financial contracts. Generally, sellers include independent power producers, generators and developers. On the buyers' side, retail suppliers and large consumers purchase electricity directly from the wholesale market, while most commercial and household customers buy electricity through the retail market. Wholesale transactions may occur via centrally co-ordinated platforms or, increasingly, through private bilateral agreements.

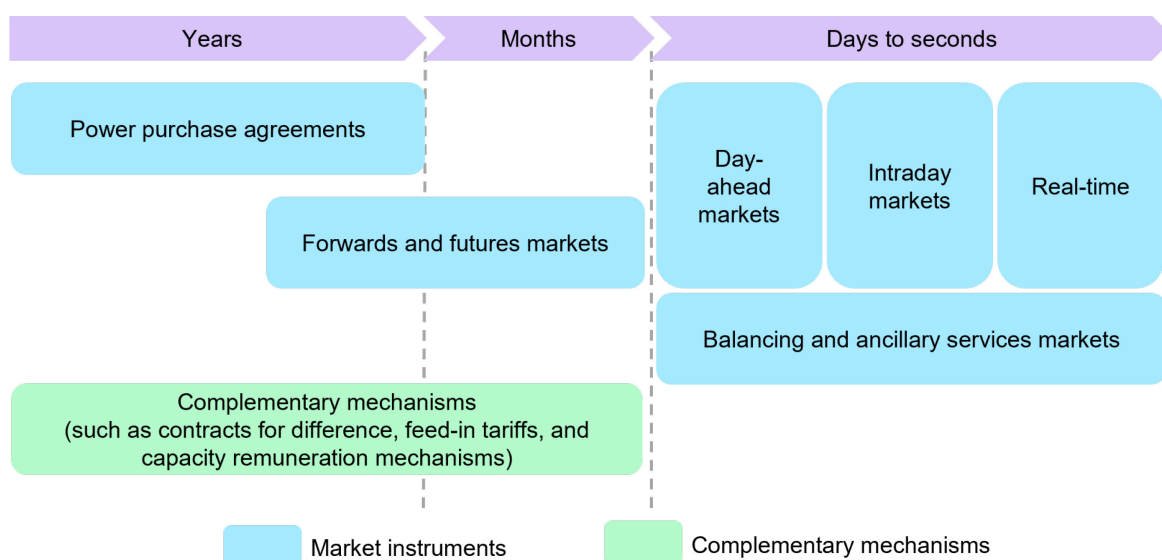
Short-term markets are designed to optimise the real-time and near-term balance of supply and demand, supporting the secure and efficient delivery of electricity under prevailing system conditions. Price signals guide participants' operational decisions, enabling the dispatch of the least-cost mix of available resources satisfying system constraints. At the same time, short-term prices provide a benchmark for forward contracting and a reference point for investment decisions, signalling the value of flexibility and resource adequacy over time. Short-term markets are typically composed of several distinct markets including day-ahead

markets to offer early visibility to actors, intraday markets to adjust position based on new information, real-time markets to create dispatch schedules, balancing markets to ensure supply-demand balance near real-time and ancillary services markets to maintain secure operations.

Medium- and long-term markets play an essential role by providing risk management tools and price stability for buyers and sellers. Forward and futures markets allow participants to hedge against price volatility over months or years. This reduces exposure to short-term price fluctuations, while also reflecting expectations of future short-term market conditions. Futures products are standardised, traded on exchanges and centrally cleared, while forward contracts are typically bilateral, negotiated over the counter and offer greater flexibility and complexity in their terms. In addition, power purchase agreements are tailor-made bilateral contracts that can be physical or financial and vary widely depending on the terms agreed between parties.

Complementary mechanisms are widely used alongside wholesale markets to support investment, contribute to resource adequacy and advance policy objectives. Examples include capacity remuneration mechanisms, renewable energy support schemes and targeted support for capital-intensive or emerging technologies. Because they interact closely with wholesale markets and influence investment and operational signals, aligning them with market frameworks is a key element of electricity market design.

Overview of common market instruments and complementary mechanisms



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Notes: This graph provides an overview for illustrative purposes only, as market arrangements could differ in specific jurisdictions. For instance, balancing or ancillary services are sometimes procured further in advance. In addition, some complementary mechanisms also operate on a day-ahead basis, such as emissions trading schemes.

Market designs share common features but diverge in implementation across regions

Wholesale electricity markets share a set of core features, as each layer serves a distinct role in supporting system operation and investment. In all jurisdictions, some form of medium- to long-term contracting and forward or futures markets exists to manage risk and provide investment certainty. Likewise, all designs feature short-term markets, including some form of day-ahead markets to provide visibility and scheduling certainty, intraday, balancing or real-time markets to adjust positions as conditions change, as well as ancillary service markets to maintain secure operation of the system.

Overview of different market layers in selected regions, 2025

	Day-ahead market	Ancillary markets	Intraday market	Balancing market	Real-time market	PPAs	Forward and future markets	Capacity remuneration mechanism	Decarbonisation mechanism
NEM	●	●	●	●	●	●	●	●	●
France	●	●	●	●	●	●	●	●	●
Germany	●	●	●	●	●	●	●	●	●
Spain	●	●	●	●	●	●	●	●	●
Japan	●	●	●	●	●	●	●	●	●
Great Britain	●	●	●	●	●	●	●	●	●
United States - CAISO	●	●	●	●	●	●	●	●	●
United States - ERCOT	●	●	●	●	●	●	●	●	●
United States - PJM	●	●	●	●	●	●	●	●	●

Legend: ● Yes ● No ● Partially/under implementation

Notes: CAISO = California Independent System Operator; ERCOT = Electric Reliability Council of Texas; NEM = National Electricity Market; PJM = PJM Interconnection; PPA = power purchase agreement. Exact terminology of markets can vary across jurisdictions, especially for balancing and ancillary services markets. Here, balancing markets refer to markets designed to balance system-wide demand and supply, while ancillary markets refer to markets where the system operator procures other services for the security of the system. Spain is currently implementing a capacity market, which is expected to be operational in 2026. Australia's NEM does not have a day-ahead market; however, participants are required to submit generation forecasts and bids the day ahead of dispatch, which provides similar visibility as day-ahead scheduling.

A major point of divergence is the approach to capacity and resource adequacy. Some markets, such as many in Europe, Japan and PJM in the United States, rely on capacity remuneration mechanisms, while others, including Australia's NEM and ERCOT, depend on scarcity pricing within real-time markets to provide investment signals. The price caps set in these energy-only markets are typically much higher than in designs with capacity remuneration mechanisms, allowing price signals to better reflect the value of lost load and encourage investment.

Both approaches can deliver efficient investment outcomes and secure electricity systems when well designed. In systems with capacity mechanisms, governments typically emphasise reliability while aiming to limit price volatility and price spikes. In contrast, energy-only markets rely to a larger extent on market signals, including scarcity pricing. In practice, however, almost all jurisdictions complement market-based signals with additional regulatory or policy measures to ensure resource adequacy and system reliability.

Price caps and price floors in selected regions, 2025

Market	Price floor (per MWh)		Price cap (per MWh)	
	Local currency	USD	Local currency	USD
Australia (NEM)	AUD -1 000	-660	AUD 20 300	13 392
Europe	Day-ahead	EUR -500	EUR 4 000	4 328
	Intraday	EUR -9 999	EUR 9 999	10 819
Great Britain	GBP -500	-639	GBP 4 000	5 112
Japan	JPY 10	0.066	JPY 200 000	1 321
United States - CAISO	USD -150	-150	USD 2 000	2 000
United States - ERCOT	USD -250	-250	USD 5 000	5 000
United States - PJM	None	None	USD 2 000	2 000

Notes: AUD = Australian dollar; JPY = Japanese yen. For US markets, the Federal Energy Regulatory Commission requires independent system operators to verify the cost of assets bidding above USD 1 000/MWh. US price caps refer to the energy offer cap for bids; locational marginal pricing can be locally higher. Australia's price cap is revised every year, and the value is for fiscal year 2025/26; it is a spot price cap, but other mechanisms exist to prevent prolonged times of high prices. Japan has no formal wholesale price cap; the listed value represents METI's upper limit on imbalance settlement prices applied only under tight supply-demand conditions. Europe "Intraday" floor and cap refer to the intraday continuous market. Great Britain floor and cap refer to the Nord Pool N2EX day-ahead auction.

Sources: [ACER](#) (2023); [ACER](#) (2023); [AEMC](#) (2025); [AER](#) (2025); [State of the market 2025](#); [YesEnergy](#); [ERCOT](#); [PUCT](#); [CAISO](#) (2024); [FERC](#) (2013); [PJM](#) (2025); [Nord Pool](#) (2025).

Another major structural difference between electricity markets lies in how physical dispatch is carried out. Some systems rely on a central dispatch model, in which the system operator determines, nearly in real time, the optimal generation schedule based on market bids and grid constraints. Others follow a self-dispatch model, where individual generators decide their output based on market outcomes, within technical and regulatory limits.

This distinction significantly affects the role of the final market stage before delivery. In central dispatch systems, the real-time market determines not only prices but also the physical dispatch of generation. In self-dispatch systems, the intraday or balancing markets mainly aim to allow participants to adjust their positions in response to forecast errors or system needs, while dispatch decisions remain decentralised. As a result, central dispatch models can benefit from co-optimisation across markets but require stronger system operator oversight and detailed market co-ordination. Self-dispatch models, by contrast, place greater emphasis on participants' forecasting capability, flexibility and responsibility for balancing their own positions.

Finally, electricity markets differ in how they organise the trading of electricity between generators and consumers, shaping both transparency and risk management. In a gross pool electricity market, all generation and consumption must be traded through a central market, with its clearing prices applying to all physical transactions. In contrast, a net pool allows participants to trade and physically settle electricity directly with each other, with the residual volumes traded in the short-term market. Neither model is inherently better – rather, they reflect different frameworks, each with its own benefits. Gross pools centralise all physical trading, maximising transparency and dispatch efficiency, whereas net pools introduce greater contracting flexibility, allowing participants to manage risks through long-term physical or financial agreements.

Overview of market dispatch and pool structures in selected markets, 2025

Market	Dispatch mode	Net/gross pool
Australia (NEM)	Central dispatch	Gross
Europe	Self-dispatch	Net
Great Britain	Self-dispatch	Net
Japan	Self-dispatch	Net
United States (CAISO, ERCOT, PJM)	Central dispatch	Net

Note: Europe excludes Ireland, Greece and Italy, which have central dispatching and a gross pool structure. Japan is currently reviewing integrating wholesale and balancing markets to get closer to a central dispatch, co-optimised model.

Market designs operate across electricity systems with different physical realities and needs

Electricity systems differ significantly in their physical characteristics, shaping the needs and functions of market design. Differences in resource endowment, generation mix, demand patterns, network configuration, interconnection levels as well as existing policy and regulatory arrangements mean that market designs must be tailored to the specific characteristics and operational needs of each system.

Across the electricity market designs analysed in this report, the physical realities vary greatly, requiring context-specific design choices. For instance, Australia's NEM covers a vast geographical area compared with the number of customers it serves and has limited domestic interconnections. Japan's electricity system is divided into eastern and western zones operating on different frequencies (50 Hz and 60 Hz), with limited interconnecting capacity. In contrast, Europe operates a highly meshed and interconnected grid, enabling extensive cross-border trade and regional balancing. Great Britain is an island, but its electricity system benefits from international interconnections with Ireland and continental Europe.

In the United States, both ERCOT and CAISO have large natural gas generation fleets but increasingly seeing significant amounts of solar and wind coming online, contributing to swings in daily supply and demand profiles. In addition, ERCOT experiences the additional challenge of seasonal demand swings in a largely self-contained system. PJM oversees one of the largest electricity markets globally.

Market designs are inherently a product of their context. As a result, while design choices in one jurisdiction may be beneficial, they may lead to significant challenges if adopted elsewhere without careful consideration of the system-wide interactions.

Wholesale electricity market factsheet for selected regions, 2024

	Regions covered	Market liberalisation	People served (million)	Peak demand (GW)	Largest generation (GWh)	VRE generation (GWh)	Length of HV grid (km)	Interconnected
NEM	Six states and territories	1998	23	34	Coal, 56%	32%	40 000	No
France	Whole country	2000	69	86	Nuclear, 67%	12%	105 000	Yes
Germany	Four control areas of Germany	1998	84	75	Wind, 27%	42%	35 000	Yes
Spain	Whole country	1998	49	38	Wind, 22%	40%	46 000	Yes
Japan	10 TSO areas	1995	125	161	Coal, 30%	11%	40 000	No
Great Britain	England, Wales and Scotland	1990	67	45	Wind, 30%	35%	19 000	Yes
United States - CAISO	California, Nevada	1996	32	48	Gas, 35%	31%	42 000	Yes

	Regions covered	Market liberalisation	People served (million)	Peak demand (GW)	Largest generation (GWh)	VRE generation (GWh)	Length of HV grid (km)	Interconnected
United States - ERCOT	Texas	1996	27	85	Gas, 44%	35%	87 000	Yes
United States - PJM	13 eastern states and DC	1996	67	153	Gas, 28%	3.5%	142 000	Yes

Notes: DC = District of Columbia; HV = high voltage; VRE = variable renewable energy; TSO = transmission system operator. Largest generation refers to the largest source of electricity generation. VRE generation indicates the share of VRE in total electricity production.

Sources: IEA based on IEA (2025), [Electricity Information](#); IEA (2025), [Country Profile](#); Parliament of Australia (2017), [Powering Our future](#); Australian Energy Market Operator (2024), [Energy Markets and Systems](#); RTE (2025), [About RTE](#); RTE (2025), [Electricity Consumption](#); Bundesnetzagentur (2025), [Electricity Market Data](#); Federal Ministry for Economic Affairs and Energy (2025), [Grids and Infrastructure](#); Red Eléctrica (2023), [The Spanish Electricity System](#); Red Eléctrica (2023), [Electricity Transmission Grid Facilities](#); ISEP (2025), [2024 Share of Electricity from Renewable Energy Sources in Japan](#); TEPCO (2025), [Power Transmission Lines](#); NESO (2025), [Britain's Electricity Explained](#); National Grid (2025), [Network and Infrastructure](#); CAISO (2024), [Key Statistics](#); ERCOT (2024), [Advancing Reliability](#); Texas Comptroller (2023), [ERCOT Overview](#); PJM (2025), [PJM – At a Glance](#).

Market design evolution

Electricity systems are undergoing a fundamental transformation, driven by a range of factors including market dynamics, technology improvements and policy changes. Generation is becoming increasingly variable, distributed and characterised by low marginal cost, while demand is rising and becoming more flexible through electrification and digitalisation. Networks must now manage bidirectional flows, congestion and growing flexibility needs as a result of conditions that differ significantly from those for which most markets were originally designed. Electricity markets are evolving in tandem with system changes, both responding to emerging challenges and shaping the long-term trajectory of the electricity sector. This is reflected by market design reforms taking place across many countries. Ensuring these reforms balance timely adaptation with predictability and coherence is critical to delivering reliability, efficiency and investment confidence in this new, more complex electricity system.

Transformations in electricity systems are reshaping how markets are designed and operated

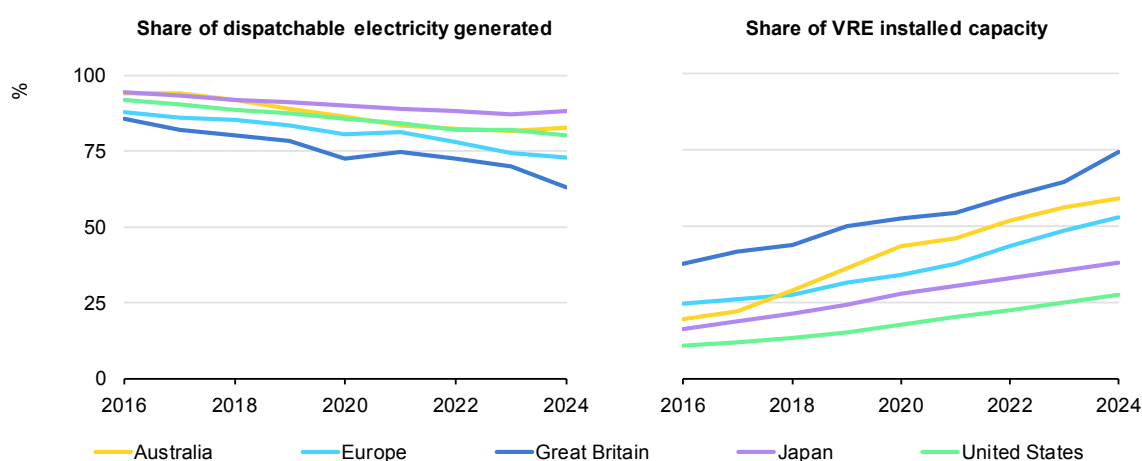
Electricity market design and the physical electricity system are interdependent. The rules and mechanisms embedded in market design influence how the physical system develops over the long term. At the same time, market design must also adapt to the evolving characteristics of the physical system, such as changes in generation mix, demand patterns and network constraints, to ensure secure and efficient operations.

Understanding how market design responds to system change requires examining the main dimensions through which those changes occur. The physical and operational features of electricity systems shape how prices form and how participants interact, while ongoing technological, behavioural and infrastructure shifts influence the effectiveness of existing arrangements and the refinements they may require. The main dimensions of change include demand, supply, networks, flexibility and digitalisation, which together define the structure and dynamics of the electricity system. Considering how these dimensions are evolving helps clarify how electricity market design can adapt to the systems it serves as they continue to transform.

Supply

Across many systems with wholesale market designs, electricity supply is undergoing a fundamental structural shift, driven by technological innovation, system economics, and policy objectives. Ageing thermal power plants, particularly coal and gas, are retiring and wind and solar PV continue to expand rapidly. This transition marks a move away from dispatchable, fuel-based generation toward capital-intensive, low-marginal-cost technologies that are increasingly decentralised and weather dependent.

Share of dispatchable generation in total generation and installed variable renewable energy capacity in selected regions, 2016-2024



IEA. CC BY 4.0.

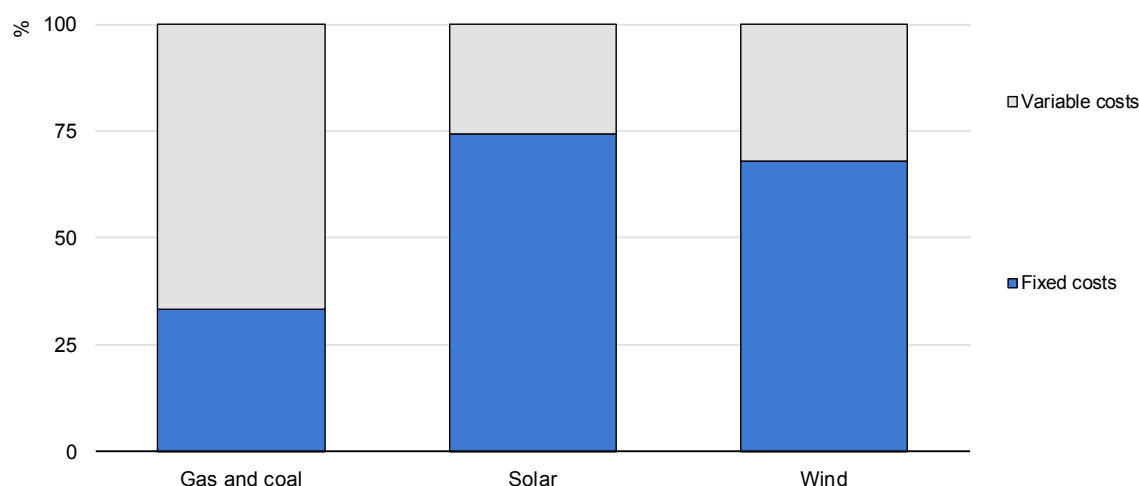
Notes: Australia refers to the NEM. Dispatchable generation includes coal, natural gas, hydro, nuclear, oil and others. Dispatchable electricity generated is expressed as the share of total generation (GWh) while VRE installed capacity refers to the share of total installed capacity (GW).

Sources: IEA (2025), [Electricity Information](#); IEA (2025), [Real-Time Electricity Tracker](#); IEA (2025), [Renewable Energy Progress Tracker](#); ENTSO-E (multiple years), [Statistical Factsheet](#); AEMO (2024), [2024 Integrated System Plan \(ISP\)](#); JEPIC (multiple years), [The Electric Power Industry in Japan](#); EIA (multiple years), [Electric Power Annual](#); United Kingdom Government (2025), [Digest of UK Energy Statistics \(DUKES\): electricity](#).

This transition toward technologies with high upfront capital costs but minimal running expenses is fundamentally reshaping the economics of electricity systems. Over a 20-year lifetime, capital costs account for about 41% of total project costs for coal and 25% for gas on average in Europe and the United States,

compared with over 67% for solar PV and wind. Fossil fuel generation bears most lifetime costs through fuel, so short-term market revenues have historically tracked operating costs. By contrast, technologies such as solar PV, hydro and nuclear incur most costs before producing electricity, altering short-term market dynamics.

Cost composition of generation technologies in Europe and the United States, 2025



IEA. CC BY 4.0.

Notes: O&M = operations and maintenance. The cost composition refers to the average per technology in the United States and Europe, assuming the asset is constructed in 2024 under the Current Policies Scenario. Variable cost, i.e. fuel, CO₂ and O&M between 2024 and the end of the assumed economic lifetime were linearly interpolated. While these assets have ranging lifetimes, the economic lifetime is set at 20 years, based on a typical maximum PPA duration, reflecting a long-term investment decision horizon. The cost structure of coal-fired generation differs across countries, partly due to differences in variable cost levels.

Source: IEA (2025), [World Energy Outlook 2025](#).

As a result, electricity systems are becoming more spatially distributed and technologically diverse, with a growing number of market participants and resource types. This evolving supply mix introduces new operational complexities as well as investment challenges, particularly in securing sufficient capacity and system services to maintain electricity security. Trends across key regions show a marked decline in dispatchable generation, highlighting the scale of the transition and the need for adaptable market frameworks.

This transformation heightens the importance of aligning short-term markets that manage operational efficiency with long-term mechanisms that underpin investment and security of supply. Capacity remuneration mechanisms are increasingly employed to complement short-term markets by rewarding availability and responsiveness while long-term markets help bridge the gap between volatile spot prices and investors' need for stable revenue streams.

Demand

After more than a decade of stagnation, electricity demand in advanced economies is [returning to sustained growth](#). This resurgence is being propelled by the electrification of transport, heating and industry, alongside the rapid expansion of new demand sources, such as data centres. These emerging loads can differ from traditional consumption: they can be more concentrated geographically or located in new areas, more sensitive to price signals and, in some cases, more flexible in how they operate. As a result, electricity demand is not only growing but also changing in nature, characterised by greater temporal variability and a broader diversity of customer needs and risk profiles.

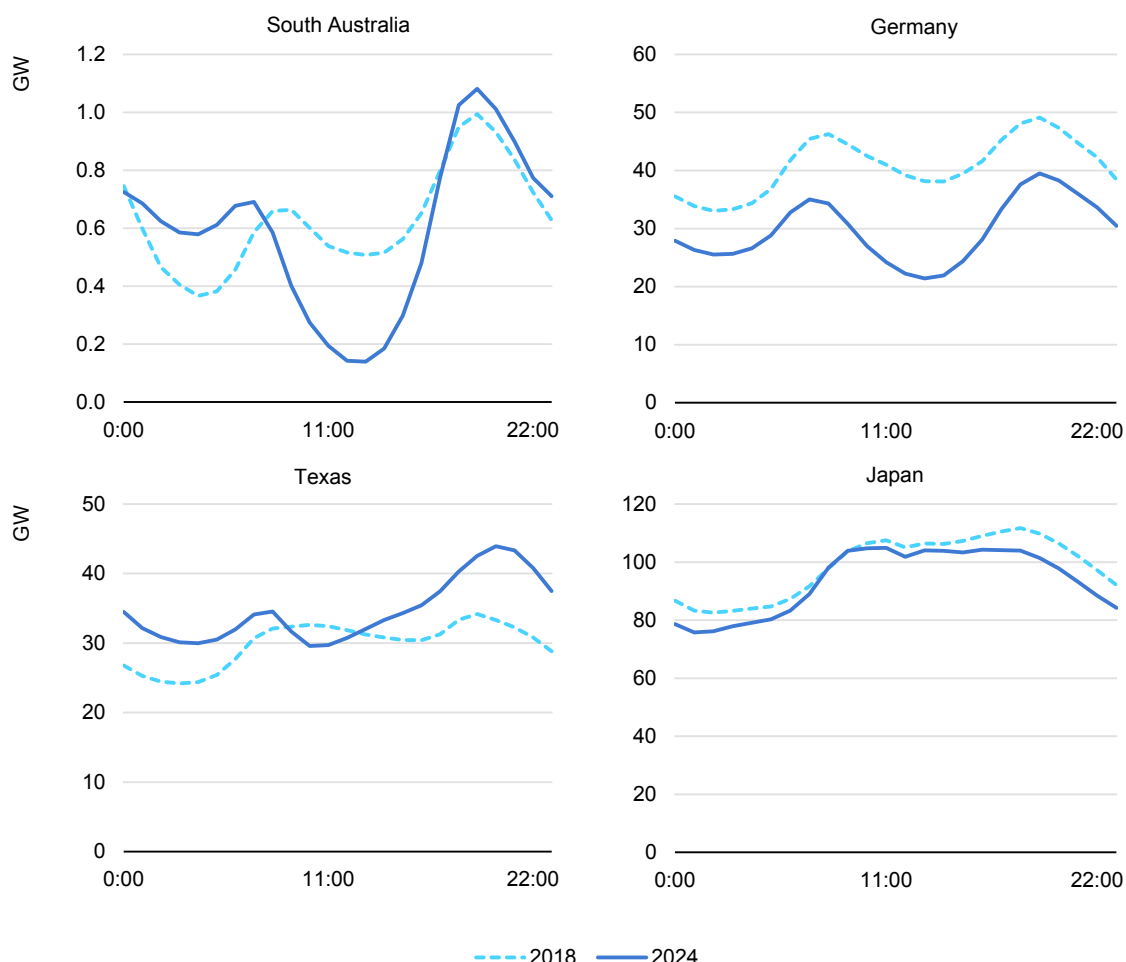
These evolutions on the demand side combined with the changes on the supply-side raise important questions for market design. More flexible demand can help make the system more efficient, but markets need to provide clear price signals and integrate demand-side resources in short-term markets and other arrangements. At the same time, new demand can be highly concentrated geographically, for which market signals can help guide where it is best located. Electrification of end-uses such as industrial processes often implies significant consumer investments which reinforces the importance of long-term stability and visibility of electricity prices. Finally, the overall rise in demand means substantial supply-side investment is needed, highlighting the role of long-term markets and complementary mechanisms in unlocking adequate resources over time.

Flexibility

Flexibility is a cornerstone of reliable electricity systems, ensuring that supply is able to meet demand across seconds, hours and seasons. Traditionally, large dispatchable power plants, particularly thermal and hydropower, have provided most of this flexibility by adjusting their output to follow fluctuations in demand. However, as electricity systems transition toward higher shares of variable renewable energy and greater electrification of end uses, the scale, timing, and sources of flexibility needs are changing profoundly. By 2030, flexibility requirements in the European Union alone are expected to grow [more rapidly than electricity demand on all timescales](#) and to reach around a [quarter of total demand](#), with interconnections, storage and dispatchable generation all playing vital roles.

At the same time, the expansion of solar PV and wind generation is reshaping system dynamics, shifting the focus from total electricity demand to net demand. This represents the residual electricity demand that must be met by dispatchable resources after variable renewable output is taken into account. In many markets, the expansion of wind and especially solar has led to deeper midday troughs in net demand and steeper evening ramps, most notably in systems such as CAISO, South Australia and Germany.

Average net demand daily profile in South Australia, Germany, Texas and Japan, 2018 and 2024



IEA. CC BY 4.0.

Note: Net demand refers to the demand addressed by dispatchable assets; it is the gross demand (consumers' need) minus the non-dispatchable generation (mainly solar and wind).

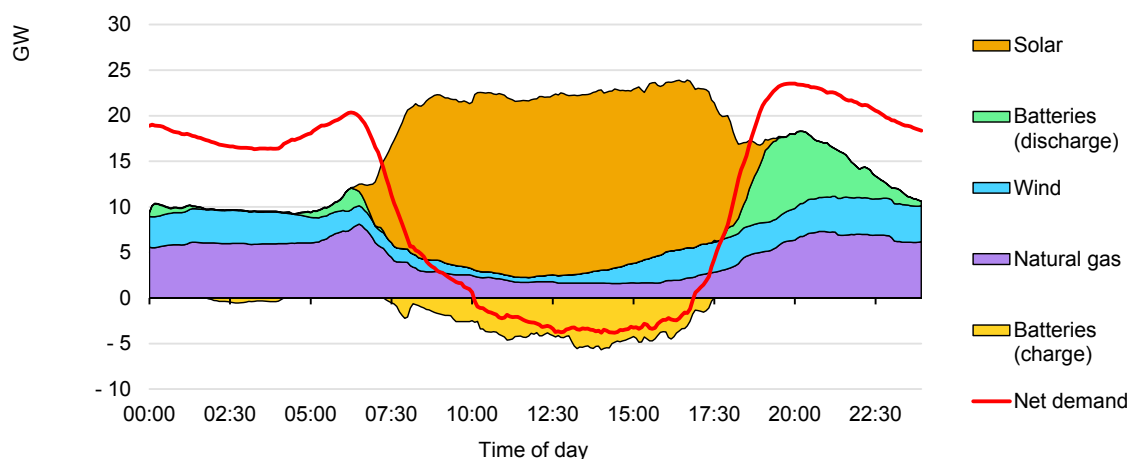
Sources: IEA (2025), [Electricity Information](#); IEA (2025), [Real-Time Electricity Tracker](#); IEA (2025), [Renewable Energy Progress Tracker](#).

In today's electricity systems, new forms of flexibility are emerging to complement traditional sources. Batteries are already being deployed to manage daily variability in solar and wind output, especially in markets such as CAISO, ERCOT and Australia. Battery systems, demand-response and electric vehicles are also beginning to contribute to ancillary services. Cross-border electricity trade plays an important role in enhancing system flexibility, particularly in interconnected regions such as Europe. At the same time, thermal and hydropower plants continue to provide critical seasonal and long-duration flexibility that newer technologies cannot yet fully replicate.

These shifts have significant implications for market design. Short-term markets may need to integrate fast, decentralised resources with adequate price granularity, sufficiently short settlement intervals and enhanced ancillary service

frameworks that reflect the value of real-time flexibility. At the same time, delivering long-duration and [seasonal flexibility](#), may require complementary mechanisms, such as capacity remuneration schemes or flexibility-specific incentives, to ensure sufficient investment.

Generation profile in CAISO for selected technologies, 21 April 2025



IEA. CC BY 4.0.

Notes: Net load refers to the difference between total electricity demand and generation by wind and solar. Negative generation refers to batteries charging at times of excess supply, mainly driven by solar generation.

Sources: IEA based on CAISO (2025), [Today's Outlook](#).

Digitalisation

Digitalisation is transforming how electricity is produced, delivered and consumed, with far-reaching implications for market design. The growing deployment of smart meters, connected devices, real-time data platforms and cloud-based systems is making electricity systems more flexible, responsive and efficient. For market design, these technologies can enable smaller resources to participate in the market directly or via aggregation. This can support more active participation in short-term markets by unlocking the value of small-scale resources. Realising these benefits requires regulatory frameworks that enable secure data access, interoperability and standardised reporting while ensuring cybersecurity and data privacy.

Artificial intelligence (AI) further extends these opportunities by enabling predictive, real-time decision-making across system operations and market participation. It is widely [used by market participants](#) to improve power plant operations in response to market conditions. Yet, AI also introduces market design challenges around data governance, transparency and accountability of decision-making in electricity markets. For instance, the rise of AI-driven algorithmic bidding can introduce risks of market manipulation and instability, requiring updated market safeguards.

Algorithmic bidding and evolving market risks

An increasing number of market participants are adopting AI-driven bidding strategies. These algorithms can enhance market efficiency by responding rapidly to changing conditions, optimising dispatch and supporting more accurate price formation. In some cases, they may also contribute to greater market liquidity by enabling more frequent and responsive participation.

However, algorithmic trading also presents risks, including the following:

- **Collusion:** AI systems may independently learn to align bidding patterns in ways that increase prices without explicit communication, making detection and enforcement challenging.
- **Reinforcing errors:** Similar algorithms drawing on common data sources increase the risk that faulty inputs or model errors spread quickly across participants.
- **Amplified volatility:** Feedback loops between competing algorithms can magnify short-term price swings and distort price signals.
- **Market complexity:** Higher rebidding frequency adds operational complexity for managing system security and investigating incidents and anti-competitive practices.

Together, these risks can lead to non-competitive outcomes, higher costs and greater challenges in managing operational security, highlighting the need for updated regulatory frameworks. In Australia's NEM, the number of bids per day has increased fourfold since 2021 and now exceeds 230 000 bids per day. This has prompted [recommendations](#) for regulatory responses to address risks created by excessive algorithmic bidding. In the European Union, an [amendment](#) to the REMIT Regulation aims to protect against market manipulation in the wholesale energy market and introduces additional requirements for participants using algorithmic trading.

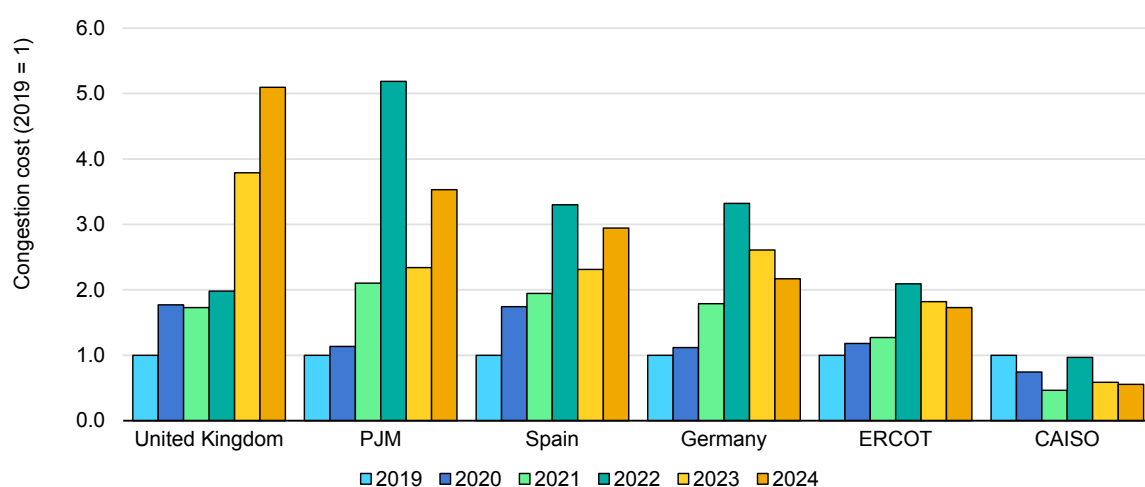
Networks

Electricity networks are also evolving, where they were historically designed for centralised generation and relatively stable demand, today's grids face new pressures from changing supply and demand dynamics. Although these changing dynamics put additional pressure on grids and necessitate further investment, grid expansion has not kept pace in recent years. While global grid investment is expected to surpass [USD 400 billion in 2025](#), a 20% increase compared to a decade ago, the ratio of grid investment to generation investment has worsened. In 2016, about USD 0.60 was spent on grid infrastructure for every dollar spent on

new generation capacity. This decreased to USD 0.40 in 2025 despite declining renewable costs and increasing costs for transformers and cables.

This growing mismatch in investment is leading to rising congestion and operational constraints, adding additional costs. This is exacerbated by the [different development timelines](#) for generation and demand assets compared with network infrastructure. Market design plays an important role in managing congestion through operational and investment signals. By enhancing locational signals for demand and supply, market design can guide efficient network use and contribute to reducing congestion.

Transmission congestion costs in selected markets, 2019-2024



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Note: US wholesale markets measure congestion as the locational price spread between congested nodes and calculate congestion rents based on this, which are partially returned to consumers. European congestion refers to physical redispatch and curtailment costs that are passed through to consumers via network tariffs.

Sources: IEA based on Bundesnetzagentur (2025), [Netzengpassmanagement 2024](#); NESO (2025), [Daily Balancing Services Use of System Cost Data](#); Red Eléctrica (2025), [Cost of the Solution of Technical Constraints](#); CAISO (multiple years), [Annual Report on Market Issues and Performance](#); Potomac Economics (multiple years), [State of the Market Report](#); PJM (multiple years), [State of the Market](#).

As market transformation accelerates, the complexity and time required to implement reforms present major challenges

Markets designs are not intended to be unchangeable. Rather, wholesale electricity markets necessitate regular reviews and enhancements as systems and objectives evolve. Striking the right balance between adapting to evolving conditions and maintaining a coherent, stable framework is a key design challenge. The process through which markets evolve, however, differs markedly across jurisdictions. In some systems, such as in the United States, continuous stakeholder engagement and decentralised governance enable gradual, evolutionary adjustments to market rules. In others, like the European Union, change typically occurs through formal, policy-driven reform cycles that require

specific triggers and consultations. These institutional differences influence how quickly and flexibly markets can respond to emerging challenges.

As systems evolve, reform processes are becoming more important to address the complexity of the challenges and lengthy reform implementation timelines. The current scale and pace of system transformations have increased the complexity and breadth of market design reforms. Major reforms and reviews are now under way across many jurisdictions, including Great Britain's [Review of Electricity Market Arrangements](#), Australia's [Review of Wholesale Market Settings](#) in the NEM, Japan's METI-led [Review of Electricity Market Reform](#) and ongoing reviews following the European Union's Reform of the [Electricity Market Design](#), adopted in 2024. While each reflects local contexts, cross-cutting themes and similarities appear across the reviews, linked to topics such as resource adequacy, system flexibility and locational signals. The breadth of topics covered by the various reforms and reviews in each studied jurisdiction are increasingly broad.

Overview of wholesale market reviews and reforms in selected regions, 2022-2025

Market	Resource adequacy	Ancillary services	System flexibility	Locational signals	DERs	Funding mechanism
NEM	●	●	●	●	●	●
EU-wide	●	●	●	●	●	●
Europe	●	●	●	●	●	●
France	●	●	●	●	●	●
Germany	●	●	●	●	●	●
Spain	●	●	●	●	●	●
Japan	●	●	●	●	●	●
Great Britain	●	●	●	●	●	●
United States	●	●	●	●	●	●
CAISO	●	●	●	●	●	●
ERCOT	●	●	●	●	●	●
PJM	●	●	●	●	●	●

Legend: ● Reform ● Review ● None

Notes: DER = distributed energy resource; EU = European Union. Wholesale electricity market review refers to the process of examining and assessing how the wholesale electricity market is operating, involving monitoring of market rules, structures, performance and pricing mechanisms, after which a determination is made whether the market should be reformed or not. Wholesale electricity market reform refers to the action process of implementing changes or enhancements based on market review results or policy targets, such as updating market rules, introducing new market mechanisms and improving transparency.

The time needed to implement market reforms has consistently posed challenges. This is particularly relevant for reforms involving extensive stakeholder co-ordination, new institutional arrangements, legislative changes or complex software updates. For instance, in Australia's NEM, it took six years (2015-21) to [implement the shift from 30-minute to 5-minute](#) settlement following the initial rule change request. The European Union has experienced similar timelines for

reducing the market time unit to 15 minutes, with [regulations adopted in 2019](#) and implementation taking place on [1 October 2025](#), after originally being scheduled for 1 January 2025. In the European Union, multi-year delays are also common for legislation that requires national governments to update their legislation.

Despite these challenges, many electricity markets have evolved substantially over the past two decades, achieving major milestones such as market coupling, the introduction of new ancillary service markets and the establishment of capacity mechanisms. Reforms that are fragmented, poorly timed or developed without meaningful stakeholder engagement can create uncertainty and elevate perceived risks for market participants. Therefore, maintaining predictability, transparency and coherence across reforms can facilitate their delivery as well as minimise uncertainty, strengthen investor confidence and enabling timely investment in needed resources.

Chapter 2: Short-term markets

Short-term markets play a central role in wholesale market design. Operating from one day ahead up to real-time delivery, they co-ordinate the balance between supply and demand, enabling electricity to flow where and when it is most valued through price signals that reflect system needs. These signals guide operating decisions by indicating the value of electricity and system services at specific times and locations. Beyond operations, market signals can also inform investment needs. As electricity systems become increasingly variable, interconnected and decentralised, short-term market designs must continue to evolve to incentivise the efficient use of resources needed to deliver secure electricity.

Short-term markets have proven highly effective at delivering secure and efficient dispatch, even under increasingly complex system conditions. As electricity systems evolve, the challenge is to preserve these proven strengths while adapting market design to reflect the needs of more dynamic and decentralised systems. While reforms to market designs can deliver meaningful benefits, they can also be complex to implement. The central objective is therefore to refine short-term market designs so that they continue to provide clear and efficient price signals, enabling technologies and market participants to deliver their full system value. The following sections provide analysis of short-term market strengths and areas for refinement to inform future design considerations and market design priorities.

The role of short-term markets

The design of wholesale electricity markets largely rests on short-term markets. As the last step before electricity delivery, they are crucial for managing systems and extracting the most value from them. By translating physical conditions into transparent prices, short-term markets can incentivise generators, consumers and storage units to adjust their behaviour in line with system needs, while also providing longer-term information for investment decisions. Their design underpins effective co-ordination across geographies, efficient scheduling and dispatch, and transparent price formation, all while supporting the secure operation of electricity systems.

Effective co-ordination of supply and demand across systems and geographies

Short-term markets provide a non-discriminatory framework capable of operating across systems of different sizes and technological mixes. They offer a common

platform where participants submit offers to produce or consume electricity. By applying the same rules and price signals to all participants, short-term markets create an open framework that can allow participation from emerging technologies and services. In addition, because they function, by design, in the same way regardless of system size, short-term markets provide a scalable framework that can operate across regional, national and international levels.

Beyond their system-wide benefits, short-term markets enable participation from a broad range of actors. They provide a transparent and competitive framework that allows engagement from generators to retailers and consumers. This helps markets make more efficient use of resources across large regions and contributes to overall system security. In Europe, for instance, the day-ahead market, the largest in the world, processes on average more than [400 000 bids every hour](#) to serve [over 500 million consumers](#). In the United States, the California Independent System Operator (CAISO), Electric Reliability Council of Texas (ERCOT) and PJM Interconnection (PJM) markets collectively manage about 50 000 pricing points¹ for over 125 million consumers². Across the studied markets in Australia, Europe, Japan and the United States, short-term markets deliver electricity to more than 700 million people³ every day.

Efficient scheduling and dispatch

A key function of short-term markets is to determine and update a sequence of scheduling and dispatch processes to co-ordinate the system. These include day-ahead, intraday, real-time, balancing and ancillary service markets. Each market design includes a combination of these markets to deliver electricity safely. While market terminology may vary across designs, in general, day-ahead mechanisms – whether through a dedicated market or a mandatory bid submission for a later market – provide early visibility of supply and demand, allowing participants to plan their positions in advance. Closer to delivery, intraday, balancing and real-time markets update these schedules at frequent intervals, incorporating the latest forecasts and responding to unexpected events. Finally, ancillary service markets facilitate the delivery of essential system services, most notably frequency and voltage regulation, which are needed to maintain secure operations.

¹ Sources: CAISO (2025), [CAISO OASIS](#); [ERCOT](#) (2025); PJM (2025), [PJM Data Miner 2](#).

² Sources: [CAISO](#) (2025), [ERCOT](#) (2025), [PJM](#) (2025).

³ Sources: Australian Energy Council (2018), [The National Electricity Market](#); [CAISO](#) (2025); [ERCOT](#) (2025); [PJM](#) (2025); [World Bank](#) (2025); ENTSO-E (2015), [ENTSO-E at a glance](#).

Main characteristics of typical short-term markets

Market	Objective	Timeline	Existing in
Day-ahead	Provide early visibility on demand, supply availability and prices	Clearing the day before delivery, typically between 10:00 and 14:00	Europe, Japan, Great Britain, United States (CAISO, ERCOT, PJM)
Intraday	Adjust position compared to day-ahead schedules	During the day of delivery, up to a few minutes before delivery	Europe, Japan, Great Britain
Real-time	Create dispatch schedule based on real-time conditions	Clearing very close to delivery	Australia's NEM, United States (CAISO, ERCOT, PJM)
Balancing	Adjust dispatch schedule to very short-term conditions of the system	Very close to delivery, usually after the other markets	Europe, Great Britain, United States (CAISO)
Ancillary services	Provide needed system services (frequency and voltage control, black start), operated by system operators	Varying	Europe, Japan, Great Britain, United States (CAISO, ERCOT, PJM)

Notes: Exact terminology of markets can vary across jurisdictions, especially for balancing and ancillary services markets. Here, balancing markets refer to markets designed to balance system-wide demand and supply, while ancillary markets refer to markets where the system operator procures other services for the security of the system. Black start service is the ability to restart the system after a blackout. The timeline for ancillary services varies from prior contracting for some services (such as black start) to near real-time clearing for others (frequency and voltage regulation).

Transparent price signals

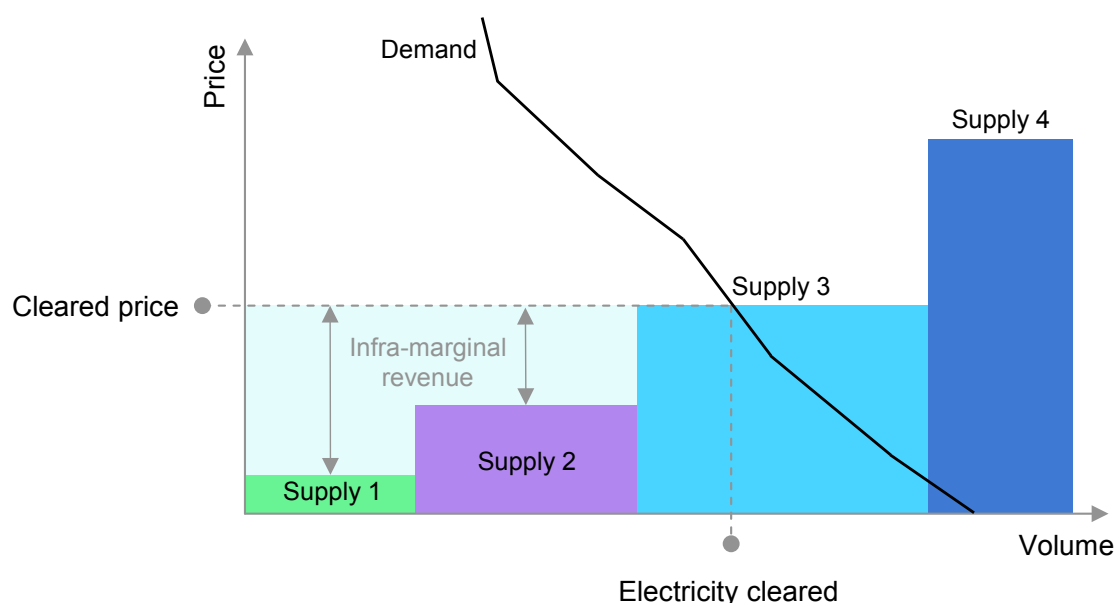
A core feature of many short-term markets is the way they set prices for electricity through an auction-based system called marginal pricing. This pricing mechanism is consistent with many other competitive markets with frequent transactions, such as oil markets. In electricity markets, generators and consumers submit offers to sell or buy electricity. These bids are ranked from lowest to highest until demand is met. The price of the last unit needed to balance supply and demand, the marginal unit, sets the market price for all participants. Because of this pricing mechanism, these auctions are also referred to as pay-as-cleared auctions.

Marginal pricing auctions provide a mechanism for using the lowest-cost resources first, while higher-cost plants operate only when needed to meet demand. They produce clear price signals received by both sides of the market: generators are encouraged, or even mandated, to bid close to their actual short-run or opportunity costs in order to be dispatched, while price-exposed consumers

adjust their usage in response to price levels. The result is a transparent process that reflects system conditions and balances supply and demand by prioritising low-cost resources.

While pay-as-cleared auctions remain the dominant design for short-term markets, alternative mechanisms also exist. In some markets, such as the intraday markets in Europe and Japan, a pay-as-bid mechanism is used, where each trade is executed at the price proposed by the buyer and the seller once their offers align. This enables continuous trading close to real time, helping participants adjust their positions as new information becomes available. However, compared with pay-as-cleared auctions, pay-as-bid designs may be less cost-efficient, as resulting prices do not necessarily reflect the marginal price of electricity at each moment.

Simplified supply-demand curve with marginal pricing auction



IEA. CC BY 4.0.

Note: Infra-marginal revenue indicates the revenue earned by suppliers that bid at a lower price than the marginal unit setting the clearing price.

Effectiveness of short-term markets

Short-term markets have continued to effectively manage evolving electricity systems. Core design features, such as marginal pricing, have allowed market prices to broadly reflect the physical state of the system and inform operational and investment decisions. Competitive market arrangements have also created incentives for operational improvements and innovation, supporting cost-effective system operation over time.

Price signals have continuously adapted to changing conditions. As generation and demand have become more variable and decentralised, as consumption

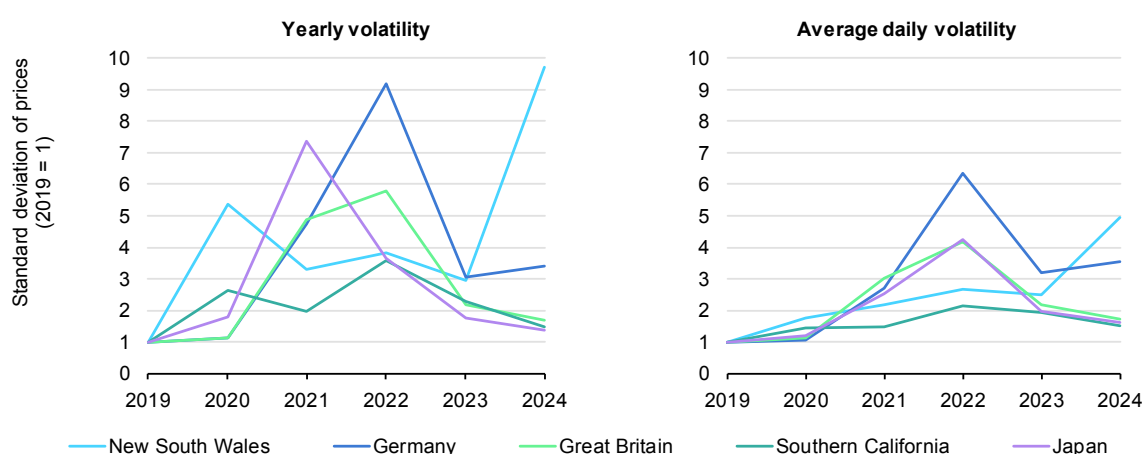
patterns have shifted, and as new technologies and participants have entered the system, price dynamics have evolved accordingly and continued to guide the efficient use of assets. In some regions, this has induced more frequent price extremes and greater variability across days and seasons. Although such volatility has not always been politically acceptable, it has generally reflected underlying system conditions and provided signals that incentivise participants to respond to system needs.

Short-term markets have also played an important role in maintaining secure electricity system operations, alongside policy, regulatory oversight and system operator actions. Despite increasing system complexity, market arrangements have continued to provide a reliable framework for balancing supply and demand under most conditions. This has been achieved by maintaining core design features while refining specific elements as needed.

Price signals effectively co-ordinate resources in changing system conditions

Short-term markets were originally designed for systems dominated by dispatchable generation and relatively predictable demand. As electricity systems have become more complex with increasing variable and distributed generation and evolving demand patterns, short-term markets have continued to effectively balance supply and demand. Evidence from Europe shows that despite increasing variable generation, wholesale markets have continued to operate effectively, with the amount of energy used in balancing markets [remaining fairly stable from 2019 to 2023](#).

Evolution of wholesale electricity price volatility



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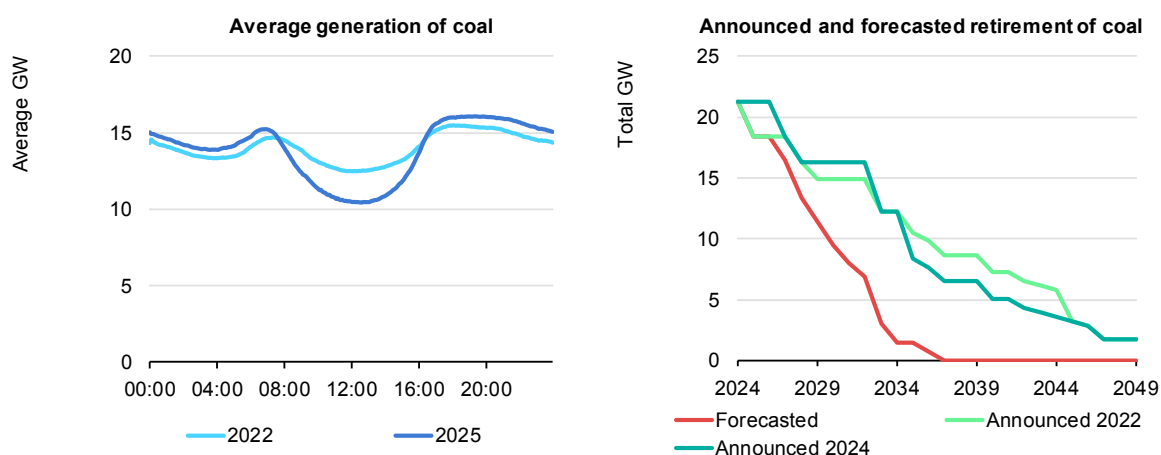
Notes: Volatility is defined as the standard deviation of prices, calculated for each day and then averaged across the year for the daily volatility graph. Wholesale prices refer to the day-ahead for Europe, Great Britain and Japan and the spot for Australia. Southern California corresponds to area SP15 in the state's zonal regions.

Sources: IEA (2025) [Electricity Information](#); IEA (2025) [Real-Time Electricity Tracker](#).

The effectiveness of short-term markets largely comes from price signals that reflect system conditions. With the growth of variable renewable generation, supply has become more weather-dependent, and systems have become more variable. As markets reflect this physical reality, price signals have become more volatile, fluctuating across hours, days and seasons as conditions change. Such volatility plays an important role in signalling when flexibility is most valuable, guiding day-to-day operations, demand-side actions and longer-term investment decisions. Rather than indicating inefficiency, increased price volatility in response to system conditions is a normal and expected feature of well-functioning short-term markets, helping align participant behaviour with evolving system needs.

Short-term markets help align the economic interests of participants with system needs. By translating system conditions into price signals, they encourage flexible operation and efficient electricity use, rewarding participants that adjust output or consumption in response to high, low or negative prices. Evidence of these responses is already visible in practice. In Australia, coal-fired plants have adapted within a few years to increasing price volatility, adjusting daily output profiles in response to changing market conditions. However, increasing volatility has also affected the profitability of these plants, as technical constraints limit their ability to reduce output during periods of low or negative prices. This has accelerated retirement timelines and strengthened investment signals for new flexible capacity. As a result, more than [6 GW of battery storage capacity](#) is expected to be added in the coming years, more than twice the current level.

Coal average generation in a day and retirement forecast in the Australian National Electricity Market



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Notes: Generation data are the average of April to June for both years. The announced and forecast retirement of coal are from the 2024 Integrated System Plan. "Forecasted" corresponds to the "step change" scenario of the Australian Energy Market Operator (AEMO).

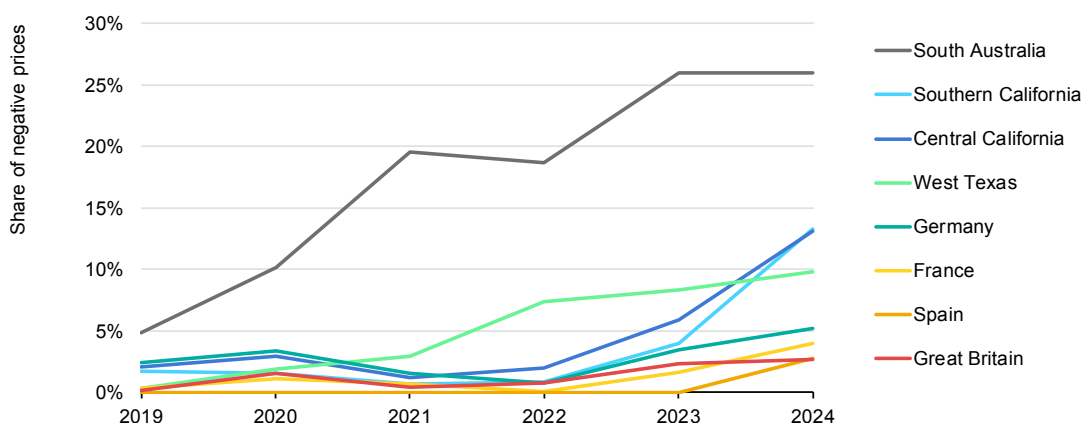
Source: IEA analysis based on AEMO (2025), [Quarterly Energy Dynamics Q2 2025](#); AEMO (2024), [2024 Integrated System Plan \(ISP\)](#).

While volatility can be politically sensitive, it plays an important role in signalling system conditions to both suppliers and consumers. High prices reflect tight

supply-demand conditions and incentivise flexible generation and demand reduction. Low or negative prices indicate surplus supply or inflexibilities and support time-of-use load shifting and storage charging to balance the system. From a consumer perspective, the key issue is not the presence of price spikes but whether elevated prices persist over time and how volatility ultimately affects retail bills. In practice, retail tariff design, hedging mechanisms and demand-response options play an important role in shaping how wholesale price variability affects consumers, while still enabling operational and investment signals within the system.

Alongside greater volatility, many markets are seeing an increase in the occurrence of negative wholesale prices. These can stem from [technical, regulatory or contractual factors](#) and typically occur during periods of low electricity demand and high generation, especially from non-flexible assets that cannot, or do not, react to prices. Although negative prices still account for a small share of time in most markets, their increasing frequency suggests the growing need for flexibility. Flexible assets can more easily adapt to changing prices, and some, as storage or demand response, can even take advantage of negative prices. While negative prices contribute to sending signals for more flexibility, they may not be sufficient alone to ensure it in some markets, as regulatory frameworks and other tariff structures also play an important role.

Share of negative wholesale price occurrence in selected countries and regions, 2019-2024



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Note: Wholesale prices refer to the day-ahead prices for the United States, Europe and Great Britain and the spot prices for NEM. For South Australia, five-minute interval prices were converted to hourly averages to enable comparison. Southern California corresponds to area SP15 in the state's zonal regions, Central California to area ZP26 and Northern California to area NP15.

Sources: IEA (2025) [Electricity Information](#); IEA (2025) [Real-Time Electricity Tracker](#).

Finally, despite the changing generation mix, the link between wholesale electricity prices and fuel cost, particularly gas, remains strong, reflecting the underlying

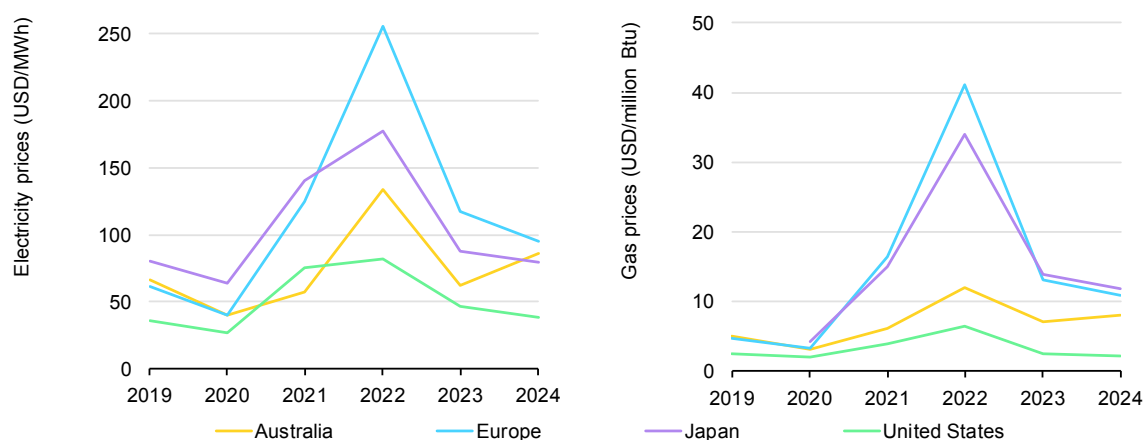
structure of electricity systems. While gas may account for a relatively small share of total electricity generation in many systems, it often sets the market price due to its role as a flexible, dispatchable resource that can be used to balance supply and demand. These prices are, once again, signals sent by markets to inform participants about the current conditions under which the system is operating, consistent with the principles of marginal pricing, and aim to reflect the cost of delivering the last unit of electricity required to meet demand.

Competitive bidding promotes efficient use of resources and cost-efficient outcomes

Short-term markets deliver efficiency gains by co-ordinating supply and demand through competitive bidding. This mechanism enables the optimal operation of a wide range of participants and helps minimise overall system costs. In the United States, a 2022 study estimated that wholesale short-term markets reduced operational costs by [USD 3-5 billion](#). Markets can also deliver scaling benefits. In Europe, ACER estimated that cross-border trading resulted in gains of up to [USD 35.8 billion annually](#). Similarly, the Western Energy Imbalance partial market in the United States has delivered [more than USD 7 billion](#) in benefits since 2014.

Even during the 2022 energy crisis, short-term markets remained efficient, delivered meaningful price signals and helped lower operational costs. The crisis highlighted the link between fuels and electricity systems: as gas prices surged, wholesale electricity market prices followed. Producers and consumers faced high prices that triggered market interventions by governments to mitigate the effects on consumers, especially in Europe. Despite the intense political attention, markets continued to deliver operational schedules and coherent price signals that informed participants of system conditions. High prices sent scarcity signals that incentivised energy efficiency improvements and demand reductions, contributing to a [3% decline in electricity demand](#) across Europe from 2021 to 2022. Although the retail electricity prices faced by consumers depend on multiple factors, including fuel prices, short-term markets nonetheless played an essential role in efficiently minimising operational costs and delivering savings for consumers.

Average wholesale electricity and gas prices in studied countries and regions, 2019-2024



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Notes: Electricity prices refer to the average of day-ahead markets for the United States (CAISO, ERCOT, PJM, MISO, NYISO, ISO-NE and SPP), Europe (European Union, Switzerland and Norway) and Japan and to the NEM for Australia. Gas prices refer to the Dutch TTF for Europe, JKM Asia for Japan, Henry Hub for the United States and Wallumbilla for Australia.

Sources: IEA analysis based on EIA (multiple years), [Short-Term Energy Outlook](#); EIA (2025); IEA (2025) [Electricity Information](#); IEA (2025) [Real-Time Electricity Tracker](#); AER (2025); ACER (2025), [2025 Monitoring Report](#); International Gas Union (multiple years), [World LNG Report](#); IEA (2021).

The European Union's response to the energy crisis

The 2022 energy crisis led to a significant increase in gas prices, which passed through to electricity prices, especially in Europe. This was politically not acceptable for many European countries, prompting the implementation of a wide set of mitigation measures. In the European Union, [more than 400 measures were applied](#), ranging from direct support for final consumers to interventions in wholesale markets. Overall, these measures succeeded in reducing prices for consumers. ACER estimated that without them, prices could have been [more than 40% higher](#). Even so, the crisis still led to a [33% increase in household electricity prices](#) by the end of 2022 compared with levels at the beginning of 2020.

While most measures succeeded in protecting consumers – directly or indirectly – some created large market distortions. In particular, interventions in wholesale markets reduced energy efficiency, demand response and investment incentives in some cases. For instance, [caps on inframarginal revenues](#) for producers, designed to reduce the windfall profits of some generators, weakened incentives for generators to reflect their true costs in bids. The extended duration of these interventions also led to [industry bodies](#) calling for their removal, citing negative impacts on investor certainty and market confidence. Finally, government revenues from the caps were sometimes lower than expected, as some

producers had already sold their production on longer-term markets and were therefore less exposed, or not exposed, to wholesale prices.

Some measures also led to unintended short-term consequences. For instance, Spain and Portugal implemented a gas price cap by paying gas power plants to lower their variable costs and thus limit wholesale electricity prices. As the Iberian Peninsula is not highly connected to the rest of the continent, this measure was approved by the European Union. While it is [estimated to have succeeded in lowering consumers' bills](#), it also prevented prices from reflecting the true cost of gas and ultimately increased gas consumption and exports to France, at the expense of the Spanish government.

Many EU countries implemented direct support for end-use consumers – mainly households and small companies – which accounted for [46% of all measures](#). This was mainly in the form of financial support through direct payments to consumers by governments or lowered taxes on electricity. Direct support is usually the most efficient way to assist consumers as it reduces their electricity expenses without affecting markets or dispatch. However, it was very costly for countries, amounting to [more than 2% of the European Union's GDP](#). This burden was compounded by the fact that many countries overestimated revenues from other mechanisms, such as the infra-marginal cap. For instance, France initially estimated revenues [1.5 times higher](#) than what was ultimately collected, mainly because wholesale prices got lower.

Overall, the interventions provided important consumer protection during an exceptional crisis. Some measures, such as direct support to consumers, led to clear benefits with limited drawbacks. Others, such as direct market interventions, created distortions in markets and in some cases led to unwanted consequences. The crisis highlights the importance of preparing crisis response plans in advance with industry input, co-ordinating measures across jurisdictions and defining clear entry and exit conditions to avoid prolonged market interventions.

Short-term markets continue to support secure operations

Despite increasing system complexity, short-term markets have continued to support secure operations. This has been enabled through several design features of short-term markets that work alongside system operator actions to support system security. For instance, broad and transparent market access allows a diverse range of resources to participate, enhancing operational resilience. Day-ahead markets set schedules and provide early visibility of expected demand, generation availability and prices, enabling participants and system operators to plan ahead. Intraday, balancing and real-time markets allow

positions to be adjusted as conditions evolve closer to delivery, supporting the system in managing forecast uncertainty. Finally, ancillary service markets deliver essential frequency and reserve services, ensuring the system can respond rapidly to disturbances and unforeseen events. Together, these mechanisms balance supply and demand, respond to unexpected events and efficiently mobilise system resources to safeguard system security.

System performance in recent years demonstrates the continued effectiveness of these arrangements. Across the regions examined in this report, electricity has been reliably delivered more than 99.9% of the time over the past five years. In the rare instances where supply was disrupted, markets were generally not the cause. For instance, the 2025 Iberian blackout was mainly [caused by technical issues](#). Market-related incidents have been uncommon and have typically resulted from IT issues or human error rather than design flaws. Although cyber threats are a growing concern, no major outages have yet been linked to cyberattacks in the studied markets. In all reported cases, emergency procedures were successfully activated, ensuring that secure electricity delivery was maintained.

Recent reported incidents in short-term wholesale markets since 2022 in Europe and Australia's NEM

Market	Year	Incident	Cause	Total share of year affected
Europe intraday continuous	2025	Market down for 10 minutes	Human error	0.002%
	2024	Market down for 64 minutes	IT issue	0.012%
	2023	Market down for 52 minutes	IT issue	0.01%
	2022	Market down for 46 minutes	IT issue	0.01%
Europe day-ahead	2024	Partial decoupling	IT issue	0.55%
		Partial decoupling	IT issue	
	2023	Partial decoupling	IT issue	0.27%
	2022	Partial decoupling	IT issue	0.27%
Australia (NEM)	2024	Suspension for 75 minutes	IT issue	0.014%
	2023	Suspension in Victoria for 1 day	IT issue	0.29%
		Suspension in New South Wales for 55 minutes	IT issue	
	2022	Suspension for 9 days	Various	2.56%
		Suspension in Tasmania for 6 hours 40 minutes	IT issue	
		Suspension in South Australia for 110 minutes	IT issue	

Notes: The incidents in this table refer to those reported; some smaller incidents can happen that are not reported. The incidents regarding the intraday auctions in Europe were not included. Decoupling refers to the separation of the European market into zones without a shared order book; this decreases overall efficiency without stopping the market completely. "Total share of year affected" refers to the fraction of time that the reported incidents sum up to during the year.

Australia's NEM 2022 market suspension

Australia's NEM wholesale market features two main price caps:

- Market price cap (MPC): the maximum price that can be reached on the spot market during a trading interval.
- Administered price cap (APC): a price cap that applies if the cumulative price threshold is exceeded. The threshold limits the total value of prices that can occur over seven consecutive days of trading.

In June 2022, the [NEM was operating under extreme conditions](#) with high fuel prices, plant outages, low renewable output and strong winter demand. Sustained price spikes led to the cumulative price threshold being reached and activation of the administered price cap. This subsequently led to the withdrawal of generation bids and a decline in available supply. To manage supply and avoid load shedding, the Australian Energy Market Operator (AEMO) was forced to direct generators online. After two days, AEMO stated that managing supply through the market had become unworkable and suspended the market for nine days.

[Investigations found several contributing factors](#), including that the administered price cap was set too low to cover the operating costs of most thermal generators. At the time, the administered price cap was set at AUD 300 (Australian dollars)/MWh and had not been updated since 2008. Following reviews, [market settings were updated](#), including doubling the administered price cap to AUD 600/MWh. The incident underscores the importance of regularly reviewing market design settings to ensure they evolve and remain fit for purpose. It also highlights how price caps can affect market operation, as high prices usually reflect physical system conditions.

Market design refinements

As Chapter 1 highlighted, market designs have never been static and have undergone several revisions to adapt to changing electricity systems. Across the markets included in this report, several reviews and reforms are under way to refine short-term market arrangements, including those related to ancillary services, system flexibility, locational signals and the integration of distributed energy resources.

While short-term markets have largely continued to support efficient operations, evolving system needs create opportunities for further refinement and improvement. Increasing temporal and locational price granularity can help better reflect system conditions and signal where flexibility is most needed. Frameworks for enhanced participation can unlock greater value from existing and emerging

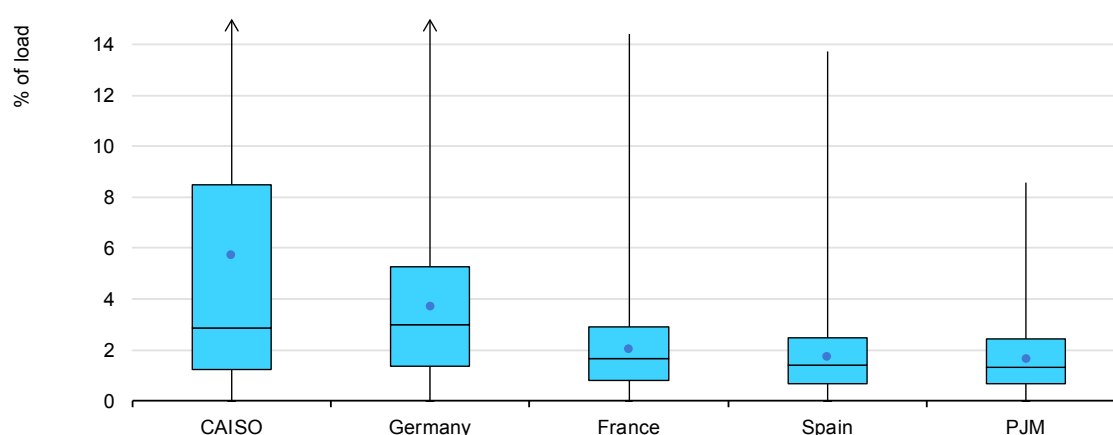
resources by enabling fair access and remuneration for assets of different sizes and technologies on both the supply and demand sides. In addition, strengthening co-ordination across short-term market segments can improve operational efficiency.

Low temporal resolution limits optimisation based on system conditions

Electricity systems could deliver greater value through price signals that more accurately reflect changes in system conditions. As technologies advance with digitalisation and IT systems become more powerful, electricity assets can be more precisely and quickly managed to add greater value. To fully unlock this potential, price signals must be detailed enough to reflect system variability. This can be done through increased temporal granularity in markets by trading shorter-duration products and enabling transactions closer to the time of physical delivery.

Low temporal granularity reduces market participants' visibility of system conditions. Markets that offer shorter products can better represent system dynamics, especially as solar and wind generation or electricity demand can change substantially within minutes. In addition, the need for, and benefits of, dispatching closer to real time – by narrowing the interval between the last bid and physical dispatch – has grown significantly, since variable generation and demand remain difficult to forecast accurately several hours ahead of delivery. In 2024, for example, [demand in Australia's NEM](#) shifted by over 1 GW within an hour on average – more than the largest gas plant's maximum output – and typically by 200 MW within 15 minutes, about 1% of average demand.

Difference between day-ahead forecast and actual system load in different jurisdictions as a share of load, 2024



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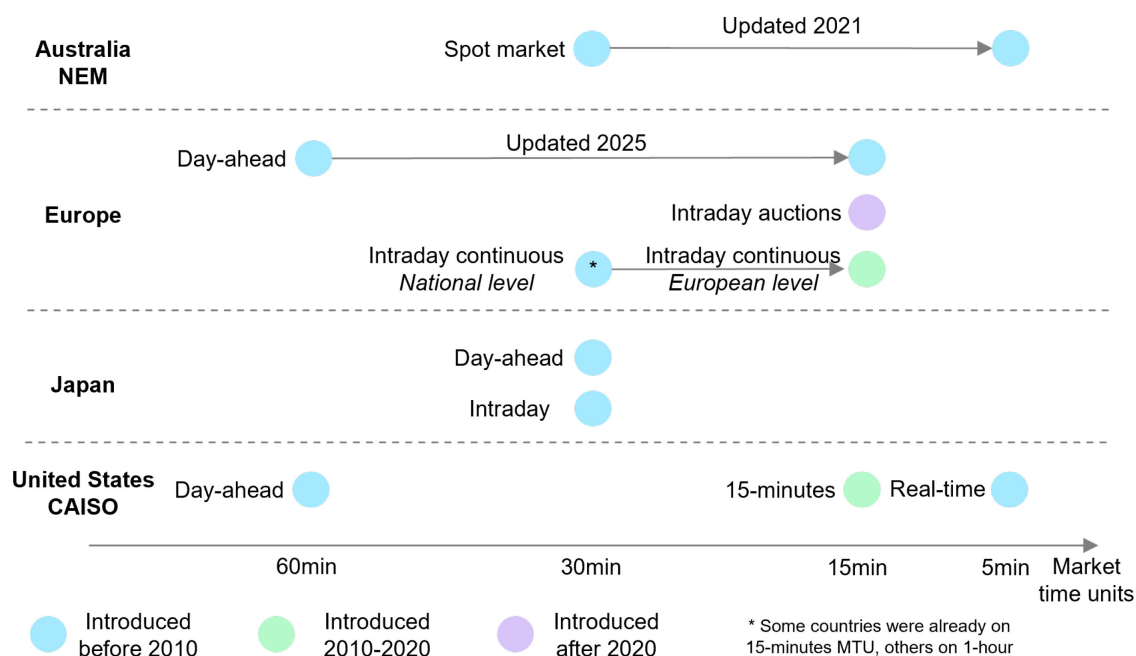
Notes: The blue dots indicate the average error in forecast. The boxes range from 25% to 75% with the median shown by the horizontal lines. The vertical lines stretch from the minimum to the maximum errors (outside of graph for CAISO with 34% and Germany with 21%).

Source: IEA analysis based on ENTSO-E (2025), [Transparency Platform](#); CAISO (2025), [CAISO OASIS](#); PJM (2025), [PJM Data Miner 2](#).

Several options exist to increase the temporal granularity of price signals. A common method across jurisdictions is to shorten the duration of products being traded. For instance, the NEM switched to [5-minute products in 2021](#), while the European day-ahead market adopted [15-minute products in 2025](#). Another method is to create new markets that operate closer to real time, enabling participants to adjust their physical and financial positions in line with updated forecasts, such as the intraday markets in Europe or CAISO's 15-minute market. Similarly, most US jurisdictions operate a 5-minute real-time market for dispatching alongside a 1-hour day-ahead financial market.

Adding markets and reducing time units has generally been successful, as market actors increasingly seek near-real-time opportunities. In Europe, for instance, intraday trading volumes rose from around [150 TWh in 2019 to over 310 TWh in 2024](#), exceeding 17% of the total volume across both day-ahead and intraday markets. A similar trend is visible in Japan, where intraday trading has expanded from [less than 1% of total volume in 2019 to nearly 3% today](#). Finally, shortening the interval between last market operation (gate closure) and physical dispatch is another way of offering greater temporal granularity. ACER, for example, is [shortening the gate-closure-to-delivery time](#) for cross-border intraday trading in Europe from 60 minutes to 30 minutes by 2026.

Evolution of market time units in short-term electricity markets across selected jurisdictions

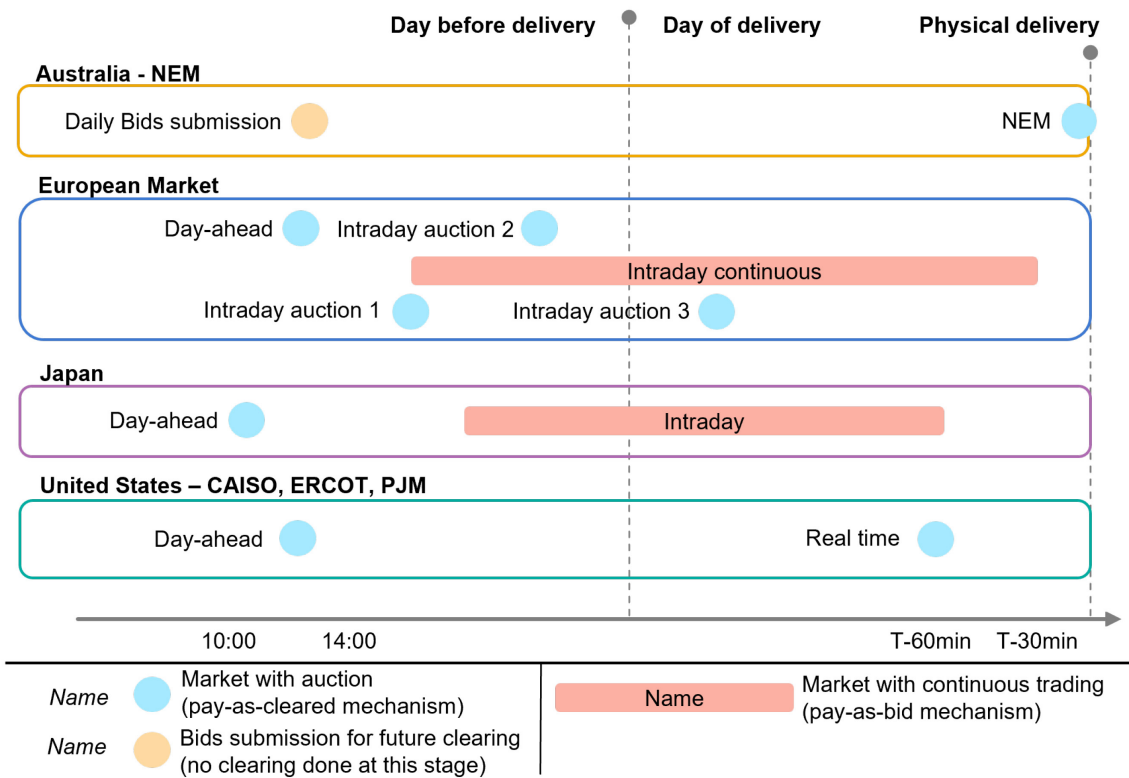


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Yet even highly granular markets cannot fully eliminate last-minute imbalances. Systems follow different approaches to managing these residual errors. Some

jurisdictions have added dedicated markets operating very close to delivery and used directly by system operators, such as some ancillary services markets, while others rely on direct transmission system operator intervention. Designs with real-time markets, such as those in the United States and Australia’s NEM, place less emphasis on separate intraday or balancing markets, as real-time price formation is designed to provide the flexibility and operational signals needed for system balancing. The choices are also often influenced by dispatch models: for example, self-dispatch systems may require longer operating buffers, as they cannot co-optimize all assets in real time.

Overview of sequence of main markets in selected jurisdictions, 2025



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Notes: In Australia’s NEM, generators submit their bids by 12:30 pm ahead of the following trading day. The price bands are then fixed for that day, yet generators can still adjust the MW volumes linked to each band.

Increasing temporal granularity comes with challenges and requires careful implementation. For instance, [some European transmission system operators have received derogations](#) from ACER’s decisions and delayed their introduction dates due to implementation challenges, including technical issues, IT complexity and high implementation costs. In addition, higher time resolution with many very granular markets can increase complexity for actors, especially smaller ones, and multiply trading costs. This aspect is crucial, as some participants may not be able to adapt easily to greater operational complexity.

Geographical resolution helps represent the system more accurately

Enhancing the geographical detail of price signals can unlock greater value from electricity systems. As systems become increasingly decentralised, transmission and distribution networks face physical limits that can restrict power flows. When these limits are reached, congestion arises, and in markets where prices reflect local conditions, price differences emerge that encourage participants to adjust their behaviour accordingly.

Higher geographical resolution allows prices to more accurately reflect the physical state of the network close to where assets operate. Geographical resolution refers to size and shape of the area covered by a single price: smaller geographical area means more granularity. More detail enables resources to adjust their behaviour in line with local conditions, reducing the need for costly redispatch or reserves by system operators. By providing more precise locational signals, it also guides investment toward areas where additional capacity or flexibility is most needed. While greater geographical resolution cannot eliminate the need for operator intervention, it can reduce overall system costs by better aligning market signals with network realities.

The level of detail of geographical resolution varies widely across jurisdictions. Very different choices were made across market designs, ranging from broad zonal pricing, where one price applies across an entire country to highly detailed systems, where prices are set at the transmission network level (nodal pricing). For instance, Europe has opted for large pricing zones, mainly following country boundaries, while the United States has largely adopted nodal pricing.

Geographical price granularity in studied markets

Market	Granularity	Number of price points	Average area covered per price point
Australia (NEM)	Zonal with corrections	5	> 500 000 km ²
Europe	Zonal	> 40	> 100 000 km ²
Great Britain	Zonal	1	240 000 km ²
Japan	Zonal	10	> 30 000 km ²
United States (CAISO)	Nodal	> 20 000	15 km ²
United States (ERCOT)	Nodal	> 18 000	28 km ²
United States (PJM)	Nodal	> 13 000	46 km ²

Notes: The number of price points and area covered are indicative. Australia's NEM has some scaling factors applied to zonal prices, which reflect losses from delivery of electricity, and depend on the location of the seller or buyer.

Sources: [CAISO](#) (2025), [ERCOT](#) (2025), [PJM](#) (2025), [ENTSO-E](#) (2025), [AEMO](#) (2025), [OCCTO](#) (2025).

Within zonal market designs, a key design choice is how many zones to define and where to place their borders. These decisions determine the extent to which

price signals reflect underlying physical system conditions. Although there can be several zones within a region or country, many designs opt for only a limited number, which can result in less granular signals and a weaker reflection of system conditions. For instance, in Germany, there is a [clear divide between the north and the south](#) of the country that is not reflected in its single zone. Over the past decades, [numerous studies on European bidding zones](#) have highlighted the benefits of greater granularity, but only four changes have been implemented.

Latest bidding zone boundaries and pricing system revisions

Market		Year of the revision	Revision
Australia (NEM)		2008	Removal of the Snowy region zone
Europe	Italy	2021	Reshaping of the existing internal bidding zones
	Austria-Germany-Luxembourg	2018	Divide the single bidding zone into Austria and Germany-Luxembourg
	Norway	2011	Split Norway into five bidding zones
	Sweden	2011	Split Sweden into four bidding zones
	Rest of Europe	1998	No revision since the first introduction
Japan		1995	No revision since the first introduction
United States	CAISO	2009	Switch to nodal pricing
	ERCOT	2010	Switch to nodal pricing
	PJM	1998	No revision since the first introduction

Note: The date for the introduction of “Rest of Europe” zones corresponds to the First Energy Package of the European Union, depending on the date of accession to the European electricity market, some countries may have different dates. Zones in Italy were originally only on the generator’s side, and buyers had only one price; this mechanism is being phased out in 2025.

Sources: [AEMC](#) (2007), [Terna](#) (2021), [Transnet BW](#) (2018), [Nordpool](#) (2011), [CAISO](#) (2009), [Public Utility Commission of Texas](#) (2010).

Implementing changes can be challenging, as highlighted by the limited number of reforms. Adapting designs requires updates to IT infrastructure to account for all transmission constraints, and actors need to adapt to the changes that follow. For example, in Great Britain, a review found that introducing new zones within the country [would take around seven years](#). In addition, such changes can affect revenues for existing assets, since earlier investment decisions were based on the previous framework. This highlights the need for carefully planned implementation.

Despite locational granularity being a change to short-term market design, its implications need to be considered within the broader market design framework. In systems with many small zones, fewer participants in each area can reduce opportunities for trading and hedging, creating a need for complementary financial instruments, such as Financial Transmission Rights, to hedge price differences arising from network congestion. Smaller zones can also amplify the market power of large actors, reinforcing the need for robust market monitoring.

More granular price signals typically increase short-term price variability. While this can improve asset utilisation, flexibility and investment efficiency, it may also raise risk management challenges for some participants. Introducing additional zones can also be politically sensitive, as greater regional price differentiation may raise concerns about fairness and distributional impacts, even if it enhances overall system efficiency.

There are, however, examples of successful implementation. CAISO and ERCOT in the United States switched to nodal pricing, while in Europe, Norway and Sweden split into nine zones in total in 2011. Analyses have shown that when carefully designed and implemented, these reforms can deliver benefits, demonstrating that the challenges can be overcome. Nevertheless, the previously mentioned risks can reduce policymakers' incentives to increase resolution and, in some cases, depending on the exact system, may outweigh the forecasted benefits. For instance, a recent review in Great Britain led to the decision [not to implement multi-zonal pricing](#) and to keep a single zone.

The switch from zonal to nodal pricing in ERCOT

ERCOT's wholesale market was originally structured around four price zones. These zones were very large (above 200 000 km² on average), which [resulted in low price transparency and high congestion costs](#). In response, in 2003, the Public Utility Commission of Texas [decided to switch to nodal pricing](#). The change was planned to take effect three years later, in 2006, but was ultimately delayed to December 2010.

The switch to nodal pricing required substantial adaptation for all actors. First, the IT challenge was significant: ERCOT needed a precise network model of [over 18 000 nodes](#) and an algorithm able of creating a dispatch schedule that optimised power flow for each 5-minute interval in a reasonable time across thousands of bids. Next, it required market participants to understand the new framework and adapt their operations to the additional complexity. Overall, this required ERCOT to perform [extensive system-wide testing](#) for months, with over 150 hours of testing.

The one-time implementation cost is estimated to have exceeded [USD 500 million for ERCOT](#). Nonetheless, nodal pricing delivered significant benefits of [over USD 300 million in the first year alone](#), mainly through reduced redispatching costs and enhanced operations. The reform also changed how plants were operated and ultimately decreased operational costs by a few percentage points while providing more detailed price signals.

To help actors hedge against the risk of congestion and the resulting price volatility, ERCOT introduced new financial products, including [Congestion Revenue Rights](#). These products allow buyer – whether suppliers, consumers or

retailers – to receive revenues when congestion arises between two defined nodes. Congestion Revenue Rights are typically used to hedge congestion risk between an actor's location and the long-term trading hub (usually an aggregation of nodes) chosen for regular hedging. This mechanism also helps avoid liquidity issues for other long-term products by concentrating trading in a few hubs.

Ultimately, ERCOT's reform led to prices that better reflect system conditions and enabled a more efficient use of assets. The complexity and risk associated with the reform were assessed, and mechanisms were introduced to ensure that benefits were realised. This example highlights both the complexity and good practices when implementing such changes.

Further integration of distributed energy resources in markets could unlock benefits

Distributed energy resources (DERs) encompass small-scale generation, storage and demand response, usually spread across market regions and often connected to the distribution network. DERs can enhance flexibility and security by supporting supply-demand balancing, providing peak shaving and reducing reliance on costly grid-scale investments. For instance, it is estimated that, without market barriers, DERs in Japan could contribute up to 27 GW to the balancing market annually by 2030, more than 15% of nationwide peak demand.⁴ However, many barriers prevent DERs from delivering these benefits, as they are often not well integrated into markets. Many DERs are not visible to markets and therefore may not react to market signals, resulting in less optimal dispatch overall.

Market frameworks are adapting to unlock the potential of DERs. A key enabler is lowering the minimum asset size required for market participation. Reforms to wholesale markets have improved access. [Several European countries](#), [some US markets](#) and [Japan](#) already allow entry from 100 kW, while [Great Britain](#) has reduced requirements to 100 kW for wholesale access and 50 kW for local services. These thresholds are usually low enough to allow participation by many DERs while remaining high enough to limit the number of assets that distribution system operators have to account for. Nonetheless, despite expanded access to wholesale markets, DERs still do not widely participate in them due to barriers such as high bid steps – the minimum amount that can be bid – and high trading costs for smaller actors.

⁴ Nomura Research Institute (2022), Progress Report on the Estimation of DSR and DER Potential.

As the installed capacity of DERs grows, co-ordination becomes increasingly important to ensure they deliver their full value. Poorly co-ordinated operation can create inefficiencies and raise system costs. In Australia's NEM, which has high DER penetration, AEMO estimates that without better co-ordination of consumer batteries, more than [AUD 4 billion of additional investment](#) would be required. This highlights the need to appropriately integrate DERs into markets so they can be optimised like any other system asset.

Aggregators play a crucial role in enabling smaller assets to participate in markets. By pooling assets on both the supply and demand sides, aggregators can more easily participate in markets as bigger players while facilitating the co-ordination of resources. On the DER side, aggregation offers the possibility to overcome entry barriers and share trading costs. In the United States, [FERC Order No. 2222](#) requires wholesale market access for aggregated DERs, while [France](#) and [Great Britain](#) allow independent aggregators in wholesale and balancing markets. [Japan](#) is progressively opening balancing markets to low-voltage DERs, and [Australia](#) has updated its regulation to allow more aggregators and DER participation. However, aggregators still have limited access to markets in some jurisdictions, [such as Germany](#).

Market rules for the integration of distributed energy resources

Market	Allowance of aggregation for retailers	Wholesale market access for independent aggregators	Minimum bidding steps, wholesale	Minimum bidding steps, ancillary services
Australia - NEM	●	●	1 MW	1 MW
Europe - France	●	●	0.1 MW	1 MW
Europe - Germany	●	●	0.1 MW	1 MW
Europe - Spain	●	●	0.1 MW	1 MW
Japan	●	●	0.1 MW	1 MW
Great Britain	●	●	0.1 MW	1 MW
United States - CAISO	●	●	0.1 MW	0.1 MW
United States - ERCOT	●	●	0.1 MW	0.1 MW
United States - PJM	●	●	0.1 MW	0.1 MW

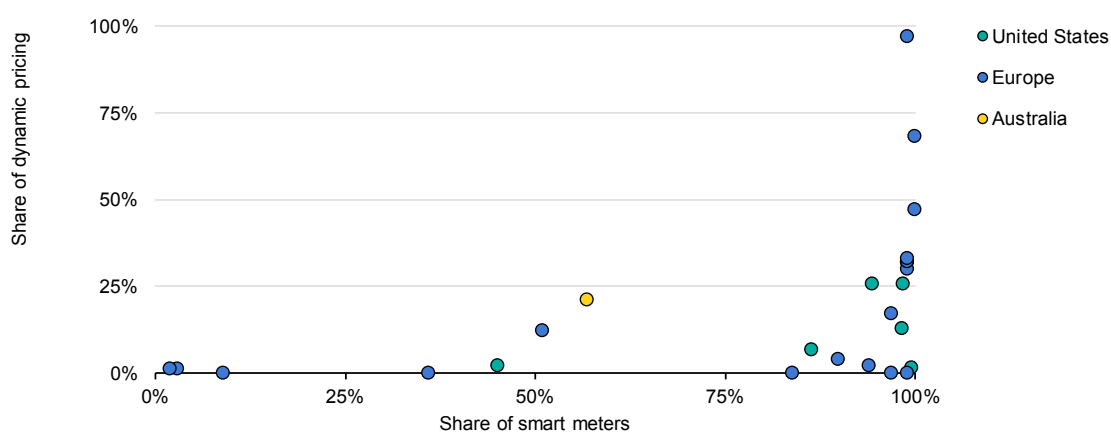
Legend: ● Yes ● Ongoing ● Limited

Notes: Ongoing means that revisions are being made to facilitate access and are expected to be completed within a few years at most. Allowance of aggregation lets retailers pool smaller resources into a single portfolio. Independent aggregators provide an alternative by participating directly in wholesale markets as market participants without prior permission of the retailer. Access for independent aggregators improves competition and helps unlock the potential of flexible resources.

Sources: IEA (2025), [Product Policy Framework for Demand Side Flexibility: Case Studies](#); Smart Energy Europe (2024), [2024 smartEn Map on Wholesale Markets](#); [European Business Council in Japan](#) (2025); FERC (2021), [FERC Order No. 2222](#); PJM (2025), [DER Aggregator Participation Model](#); ERCOT (2025).

Consumers have an increasingly direct role to play in electricity systems and markets through demand response. Demand-side flexibility can have important effects on prices levels, since even a small reduction in demand may avoid the use of costly peak generation and sharply lower wholesale prices. For example, in [Spain in January 2023](#), a demand drop of just 0.03% could have cut wholesale prices by around 9%. In addition, as electricity systems become increasingly variable, the need for flexibility is increasing, and demand-side participation holds considerable potential to provide it. While demand response has grown – for instance, in Texas it doubled [from 2 GW in 2010 to 4 GW in 2020](#) – it remains underutilised, constrained by regulatory fragmentation and technological barriers that continue to limit participation.

Smart meter uptake and dynamic pricing share for household consumers in selected jurisdictions, 2024



IEA. CC BY 4.0.

Notes: Dynamic pricing refers to retail offers where prices are time dependant or market based, through market exposure or regulated varying tariffs. The dots for the United States are the main wholesale markets (CAISO, PJM, ERCOT, MISO, NYISO, SPP, ISO-NE); Australia is the NEM; and Europe shows a selection of countries (Austria, Belgium, Czechia, Finland, France, Germany, Hungary, Ireland, Italy, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovenia, Spain and Sweden).

Sources: IEA analysis based on ACER (2025), [Electricity Country Sheets](#); ACER (2024), [2024 Market Monitoring Report](#); AEMC (2024); ACCC (2024), [Inquiry into the National Electricity Market](#); EIA (2024), [Annual Electric Power Industry Report](#).

Many options exist to unlock the full value of demand response. With increasing digitalisation and technical improvements, it has become easier to measure consumption and send signals to reduce demand or price electricity differently. One approach is through peak-shaving products that can reduce demand during periods of system stress, whether caused by high demand or low generation capacity. However, careful implementation is essential. In 2025, [ACER warned](#) that some peak-shaving products activated outside of markets – for instance, after the market clearing – risk generating higher costs than benefits. Another way is to incentivise consumers, especially households, to change their demand through time-varying tariffs. For household consumers, progress has been made across many regions to remove technical barriers through advancements in smart meter rollouts. This enables retailers to offer different tariffs that can incentivise varying

levels of demand response. Unfortunately, in many cases, consumers do not engage with these options and continue to remain on flat tariffs. In [the Netherlands](#) and [Texas](#), for example, more than 95% of households remain on flat tariffs.

Growing and changing ancillary services needs are not always met by up-to-date frameworks

Beyond electricity balancing, operators must also manage the technical requirements of the electricity system through ancillary services, including frequency and voltage stability, reserves and the ability to restore the system after extreme events (such as black start capacity after blackouts). Traditional sources of generation, such as coal, gas, large hydro and nuclear, have typically provided inertia – the ability of the system to resist frequency changes – and frequency control as by-products of their generation. As the share of such generation declines, operators must ensure that these services continue to be delivered. Technically, many other assets can provide ancillary services, including solar PV, wind, batteries and hydro assets. However, as these services were once freely provided by traditional generation sources, remuneration frameworks are not always in place. In response, many countries are making changes to offer a wider range of ancillary services and markets.

For many years, most countries have been procuring frequency control through market-based mechanisms. This can be delivered efficiently through markets because frequency is a system-wide characteristic that helps to promote competition. In recent years, some market designs have introduced fast frequency response markets, with reactions of less than a second. For example, ERCOT in the United States introduced [Responsive Reserve Services](#), while Australia's NEM a suite of fast [Frequency Control Ancillary Services products](#). Adding markets for some services has proven efficient in promoting competition and reducing costs, and has led to a reduction in ancillary service prices in several countries. This decline in prices is particularly evident in Australia's NEM, where the cost of frequency ancillary services [fell by over 50% from 2019 to 2024](#), reflecting intensified competition driven by growing battery capacity.

Other ancillary services, such as inertia and voltage control, are mostly remunerated through cost recovery, if at all, as they are challenging to value adequately. The absence of remuneration for these services can lower incentives for the needed investments. Some jurisdictions are therefore exploring how they could be delivered through market-based approaches to better account for emerging needs. [Germany](#), for instance, is adding mandatory [market-based tenders](#) for voltage regulation procurement from 2025 onwards, and [inertia services](#) will also be compensated starting in 2026, encouraging grid-forming technologies. [Great Britain](#) is developing a voltage control market and trialling [inertia contracts](#), primarily awarded to synchronous condensers, with some

awarded to batteries providing virtual inertia. However, implementation barriers remain, and benefits are not always easy to evaluate. For instance, [Australia](#) considered a potential market for inertia, but the expected benefits were not enough to justify implementation at present. Likewise, voltage, as a local characteristic of electricity systems, may face limited competition, reducing the benefits of a market-based approach in some jurisdictions.

Overview of procurement and remuneration mechanisms of ancillary services

Market	Fast frequency control	Primary frequency control	Secondary /tertiary frequency control	Voltage control	Black start
Australia - NEM	●	●	●	●	●
Europe - France	●	●	●	●	●
Europe - Germany	●	●	●	●	●
Europe - Spain	●	●	●	●	●
Japan	●	●	●	●	●
Great Britain	●	●	●	●	●
United States - CAISO	●	●	●	●	●
United States - ERCOT	●	●	●	●	●
United States - PJM	●	●	●	●	●

Legend: ● Market based ● Partially market-based ● Regulated prices or cost recovery ● Mandatory and not remunerated ● Not available

Notes: Frequency services are categorised mainly based on their response time. The typical response time are: fast, frequency control is expected to react in less than a second; primary, in a few seconds; secondary, in up to a few minutes; and tertiary, in less than 15 minutes. Black start service is the ability to restart the system after a blackout. Voltage control in CAISO and PJM can be remunerated through cost recovery in case of exceptional deviation.

Sources: [AEMO](#); IEA (2021), [Conditions and Requirements for the Technical Feasibility of a Power System with a High Share of Renewables in France Towards 2050](#); [Modo Energy](#) (2023); PJM (2025), [PJM Data Miner 2](#); AEMO (2025), [Guide to Ancillary Services in the National Electricity Market](#); [ENTSO-E](#); [Pexapark](#) (2025), [SkippingStone](#) (2024), [Japan Energy Market Update](#); [NESO](#); [CAISO](#); [Monitoring Analytics](#) (2025), [2024 State of the Market Report for PJM](#); [Modo Energy](#) (2024); [ACER](#) (2023), [2023 Market Monitoring Report](#); [RTE](#); [ENTSO-E](#) (2025), [Survey on Ancillary services 2024](#); IEA (2024), [Reactive Power Management with Distributed Energy Resources](#); [NESO](#); [CAISO](#) (2025); [PJM](#) (2024); [ERCOT](#) (2015); [Netztransparenz](#); [NESO](#); [CAISO](#) (2020); [PJM](#) (2025); [ERCOT](#) (2025).

Limited co-ordination between energy and ancillary services markets constrains efficient use of assets

Electricity markets must ensure both the procurement of energy, so that generation meets demand, and the provision of ancillary services, which represent a smaller share of electricity but are crucial for secure operation. In most jurisdictions, assets can stack their revenue streams by bidding in multiple markets – including ancillary services and energy markets – or by contracting

capacity with system operators. For some assets, such as batteries, revenue stacking can even be a necessity to secure sufficient remuneration. However, because it is usually not possible to procure both energy and ancillary services simultaneously, when energy and ancillary services markets are independent and cleared separately, assets must split their bids between the two, risking missed opportunities. For some assets, especially smaller ones, this adds operational [complexity, uncertainty](#) and higher trading costs.

To increase efficiency and help reduce complexity, some markets have adopted real-time co-optimisation. When splitting energy and ancillary services between two distinct markets, system operators risk not producing the least-cost dispatch across the range of required services. Real-time co-optimisation allows the market operator to optimise both energy and ancillary services procurement in real time and manage the whole system at once by co-ordinating energy and ancillary services markets, leading to cost reductions. This results in price signals that more accurately reflect the cost of providing services, including the lost opportunity cost of providing one service instead of another.

In real-time co-optimisation, assets submit their bids, technical constraints and costs for each service they can provide, including energy. While they still need to split their bids between services, the optimisation made by the operator creates a framework that can facilitate the choices assets have to make and reduce incentives for strategic bidding.

Although real time co-optimisation can increase efficiency, it comes with challenges and risks. To be able to implement co-optimisation, the system must be run through a central dispatch model to allow a market operator to produce a dispatch schedule. This means that markets with self-dispatch designs would require extensive reforms to introduce co-optimisation. Nonetheless, reform is possible. In Japan, for instance, discussions are progressing towards establishing a market for the simultaneous procurement of energy and system services despite the current self-dispatch model.

Current state of co-optimisation of ancillary services and wholesale markets

Market	Real-time co-optimisation
Australia - NEM	
Europe - France	
Europe – Germany	
Europe - Spain	
Japan	
Great Britain	

Market	Real-time co-optimisation
United States - CAISO	
United States - ERCOT	
United States - PJM	
Legend:  Yes  No  Transitioning  Under review, not implemented	

Chapter 3: Medium- and long-term markets

Medium- and long-term electricity markets (referred to collectively in this chapter as long-term markets) manage revenue and price risk over horizons ranging from several months to decades. Their role is to convert uncertain future prices into more predictable revenue and cost streams, giving investors and electricity buyers greater confidence in planning decisions. These markets serve all technologies in the electricity system by allowing buyers and sellers to agree on future prices or delivery conditions that reduce exposure to short-term volatility and distribute risk among participants with different risk appetites.

As technologies such as solar PV, hydro and nuclear expand, electricity systems are shifting toward more capital-intensive investment structures, where upfront costs dominate and operating costs are lower. This transformation heightens the importance of long-term markets, since accessing low-cost finance for these assets depends on predictable revenues over many years. Effective long-term contracting has therefore become a key pillar of system reliability and cost efficiency in modern electricity systems.

While Chapter 2 examined short-term markets that co-ordinate the efficient real-time operation of electricity systems, this chapter explains how long-term contracting mechanisms provide financial certainty for investors and electricity buyers. Together, short- and long-term markets form the backbone of a well-functioning electricity market design: the former reveal efficient price signals, while the latter convert those signals into investable certainty. Long-term markets can therefore play a stabilising role in systems characterised by growing price variability, capital-intensive assets and rising demand for predictable returns.

These markets encompass a wide spectrum of contracts and products. Futures and forwards are standardised products, traded either on organised exchanges or bilaterally, that enable participants to fix electricity prices in advance. Power purchase agreements (PPAs) are bespoke bilateral contracts tailored to the characteristics of specific projects or buyer needs. Although these contracts and products differ, they share a common purpose: to provide stable revenues and predictable costs that support investment and consumption decisions.

Long-term electricity markets face three main challenges: liquidity, accessibility and system alignment. While short-term markets have matured to deliver operational efficiency, long-term markets remain less developed across all three dimensions. Liquidity provides market participants with sufficient trading

opportunities and stable price signals, yet long-term markets are relatively illiquid, leading to higher trading costs, weaker investment signals and limited risk management options. Accessibility ensures that a broad range of participants can hedge their price exposure. However, participation in long-term markets is often uneven, restricting access for smaller players and reducing overall market depth. Finally, system alignment requires market products to evolve in step with changes in the electricity system and remain co-ordinated with short-term markets. In practice, long-term markets have not always kept pace with shifting technologies, risks and system needs. By addressing these challenges, long-term markets can be more effective in serving market participants' risk management and hedging needs.

The scope of this chapter is limited to private-sector, market-based arrangements. Government-backed or policy-driven mechanisms, such as contracts for difference or capacity remuneration mechanisms, are analysed separately in Chapter 4, which considers how complementary interventions can address residual investment and resource adequacy challenges.

The role of long-term markets

Long-term markets reduce participants' exposure to short-term market volatility by securing predictable prices and volumes over extended periods. They serve the diverse needs of market participants through a mix of contracts and products that differ in flexibility, risk allocation and timeframes. For investors, these contracts and products help provide stable revenues that support financing, particularly for capital-intensive technologies with high upfront capital costs and low operating costs. For electricity buyers, such as consumers and retailers, they also help protect from price shocks and mitigate risks to industrial competitiveness.

Long-term markets support the development of capital-intensive assets

Long-term markets provide the stable and predictable revenue streams that facilitate the financing of new generation and storage assets and the continued operation of existing plants. Without forward revenue commitments, generators are more exposed to wholesale market volatility, which can deter investment, raise financing costs and ultimately threaten resource adequacy in the system.

The importance of long-term markets is growing as the electricity system shifts toward capital-intensive technologies. Initially, wholesale markets were designed at a time when dispatchable thermal power plants represented a large share of the generation mix. Short-term markets could track variable fuel costs relatively closely, which comprised most of the variable and much of the lifetime costs of these plants. However, capital-intensive technologies like solar PV, wind, nuclear

and hydro require predictable long-term cash flows to recover their high fixed costs and attract investment. At the same time, rising shares of variable renewables have made short-term prices more volatile and less predictable. Together, these system transformations have increased exposure to risk and heightened the importance of well-functioning long-term markets to support both hedging and investment.

To invest in new capital-intensive projects, developers and financial actors require confidence that electricity sales will cover capital costs and deliver adequate returns. Long-term markets help by reducing the risk premium demanded by lenders and investors, lowering overall financing costs. Projects are often financed with a [large share of debt](#), making steady cash flow essential for meeting ongoing interest payments. Predictable income streams are therefore essential to unlock financing and keep its costs low.

Evidence from several markets shows how revenue certainty lowers price risk and financing costs for investors. A [2022 survey](#) in Australia found that expected equity returns for renewable projects fell from 12.25% for projects exposed only to spot markets, to 8% under corporate PPAs, and to 6.25% under government-backed contracts for difference. Similarly, in [Germany](#), long-term contracts reduced the levelised cost of electricity by USD 10.7/MWh for onshore wind, USD 13/MWh for solar PV, and USD 21.6/MWh for offshore wind, cutting costs by more than 20%.

Long-term markets help protect wholesale electricity buyers from price volatility

Electricity buyers can use long-term markets to manage or limit their exposure to short-term price variability, depending on how much of their demand they choose to hedge in advance. Buyers include retail suppliers, large electricity consumers that purchase directly from the wholesale market, and public procurement bodies.

By stabilising prices over multiple years, long-term contracts offer predictability and help shield buyers from market turbulence. Hedging gives retailers the ability to offer more stable and predictable tariffs, reducing the risk of sudden bill increases for households and small businesses that are less able to absorb price shocks. Long-term price visibility is also increasingly important for electrification, as predictable electricity costs support investment decisions to switch to electric technologies. However, while these markets help hedge against short-term price variation, they do not guarantee lower prices, since short-term prices may rise or fall relative to the long-term contract price.

The 2022 energy crisis highlighted the risks of inadequate hedging. In Australia, Europe and Japan, exposure to short-term wholesale prices led to the collapse of several retail suppliers and forced some electro-intensive consumers to curtail production or close operations. In Great Britain, [27 retail suppliers](#), including the

[seventh largest](#), went bankrupt between 2021 and 2022. In Australia's National Electricity Market (NEM), [seven retail suppliers failed](#) in 2022. In response to the crisis, the European Union introduced a [new regulation](#) requiring retail suppliers to have in place or implement appropriate hedging strategies to limit exposure to changes in wholesale electricity prices.

Overview of long-term markets

Long-term electricity markets are mainly composed of forwards, futures and PPAs. These contracts play a critical role in hedging price risks, supporting investment and providing revenue stability. However, most forwards, futures and PPA markets remain relatively illiquid. This limits their effectiveness in providing long-term price signals and opportunities for risk management.

Long-term markets encompass a range of contracts and markets

Electricity market participants use a variety of contracts and products to manage exposure to wholesale price volatility and to align commercial strategies with operational and investment decisions. Forwards and futures contracts allow participants to agree on electricity prices for delivery typically one month to several years ahead, while PPAs provide long-term, often project-specific agreements that ensure stable revenues for generators and predictable costs for buyers.

Together, these contracts and products form the foundation of long-term market activity, linking short-term price formation with longer-term system investment needs. Retailers typically hedge against price volatility on behalf of their customer portfolios using a basket of futures and forwards, while large industrial buyers often use longer-term, [tailored PPA contracts](#). On the supply side, [different types of contracts](#) are needed to cover different technology and project risk profiles. Larger market participants with sophisticated risk management capabilities may be better placed to negotiate bespoke bilateral arrangements, such as PPAs. In contrast, smaller participants may rely on standardised products that provide hedging support with lower trading costs and complexity.

Contracts traded in long-term markets can be structured as financial contracts, where differences between the contract price and the market price are settled financially, or as physical contracts, where electricity is delivered to the buyer. Forwards and PPAs are typically bespoke bilateral agreements, while futures are standardised products traded on exchanges.

Main characteristics of power purchase agreements, forwards and futures contracts

Contract	Forward contract	Futures contract	Power purchase agreement
Description	Bilateral deal to buy or sell electricity at a set price for future delivery, not tied to a project	Standardised deal for future delivery, traded on an exchange, backed by a clearing house	Bilateral deal between producer and buyer, usually tied to a single or multiple projects from a producer's fleet
Uses	Hedge price risk; customise delivery terms	Hedge price risk; access transparent prices	Finance projects; hedge price risk; support corporate decarbonisation targets
Typical duration	1 month to 5 years	1 month to 5 years	1-20 years
Trading platform	Over the counter, often via brokers	Centralised exchanges	Usually negotiated directly between parties
Product	Financial or physical	Financial	Financial or physical
Standardisation	Medium	High	Low
Transparency	Medium to low	High	Low

Notes: This table summarises the main contract types used in advanced electricity markets. Other contracts, such as tolling agreements, are also used but fall outside the scope of this report.

Forwards and futures markets

Forwards and futures contracts allow electricity market participants to buy or sell power at a predetermined price for delivery at a future date, providing a way to manage exposure to wholesale price fluctuations. Participants typically use these contracts to secure positions from one month up to around five years ahead of delivery.

Forwards and futures differ in their degree of standardisation and trading structure. Forward contracts are bilateral deals to buy or sell electricity at a set price for future delivery and are traded over the counter, often through brokers. They can be financial or physical, and while there is a degree of standardisation in contract design, their terms can be customised to suit the needs of the buyer and seller. Futures contracts, by contrast, are fully standardised products traded on centralised exchanges such as the European Energy Exchange or the Japan Electric Power Exchange. They are purely financial products, settled through clearing houses that guarantee settlement and take on counterparty risk.

Both types of contracts serve a similar purpose: to hedge against short-term price fluctuations. Generators use them to stabilise revenues for expected production, retail suppliers to lock in electricity procurement costs, and large industrial

consumers to predictably manage the cost of future consumption. Financial institutions and traders also participate to facilitate risk transfer and enhance price discovery. The standardisation of these contracts, particularly for futures, allows them to be easily traded and re-traded, making them well-suited for risk management. The use of intermediaries, such as centralised exchanges for futures and brokers for forwards, further facilitates trading. However, due to their shorter timeframes, neither forwards nor futures alone typically provide the long-term revenue certainty needed to unlock investment in new capacity.

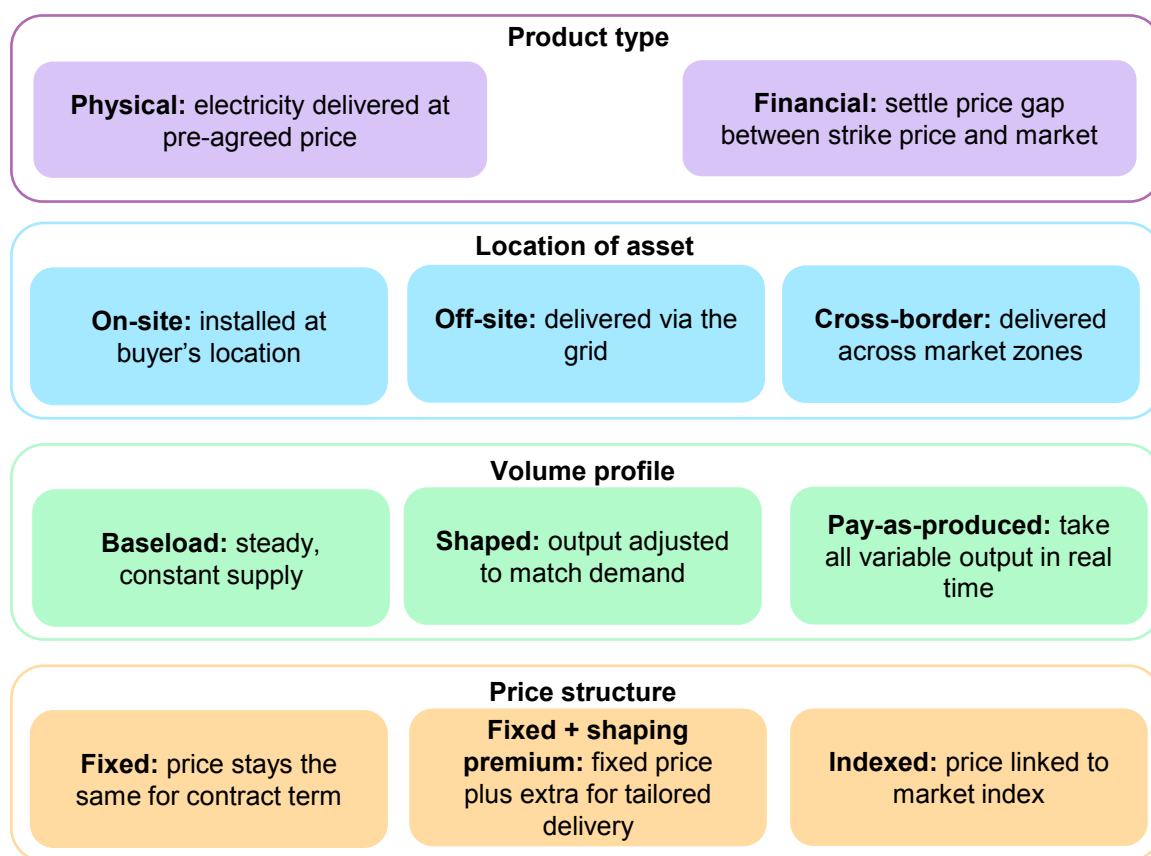
Power purchase agreements

PPAs are long-term contracts between electricity buyers and sellers, including utilities, corporations and public entities. They are highly customised to reflect the needs of the contracting parties, whether to finance new capacity, hedge price exposure or meet decarbonisation targets. By providing revenue certainty for sellers and predictable costs for buyers, PPAs have become an important [driver of new capacity](#) additions, especially for renewables. Their bespoke nature and long timeframes mean they are typically used by large, creditworthy buyers.

A key advantage of PPAs lies in their ability to be fully tailored to project or buyer needs, including contract length, pricing structure, volume flexibility and allocation of market or operational risks. This flexibility allows PPAs to offer long-term price stability alongside opportunities to comply with policy obligations or corporate social responsibility goals. However, this bespoke nature also makes PPAs complex and resource-intensive to negotiate, limiting their accessibility, liquidity and scalability.

Similarly to forwards, PPAs can be structured as physical or financial contracts, influencing their interaction with electricity markets. In markets such as most of Europe, Japan and the United States, buyers and sellers can trade physical electricity outside of short-term electricity markets, including through physical PPAs. In other markets, such as Australia's NEM, all physical electricity volumes must be bid through short-term markets, affecting how physical contracts are organised. In the NEM, only [on-site PPAs are possible](#). Financial PPAs, however, can be used across all types of market systems.

Types of power purchase agreements and their characteristics



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Long-term markets often suffer from limited liquidity

The effectiveness of long-term electricity markets in managing price risk depends on their liquidity, or how easily participants can buy or sell contracts. A common benchmark for sufficient liquidity in energy markets is a ratio of traded to physical volumes, also known as the “churn rate”, of [at least 10 to 1](#). This indicates traded volumes that are ten times higher than electricity physically consumed. Below this level, hedging becomes more difficult and price discovery less reliable.

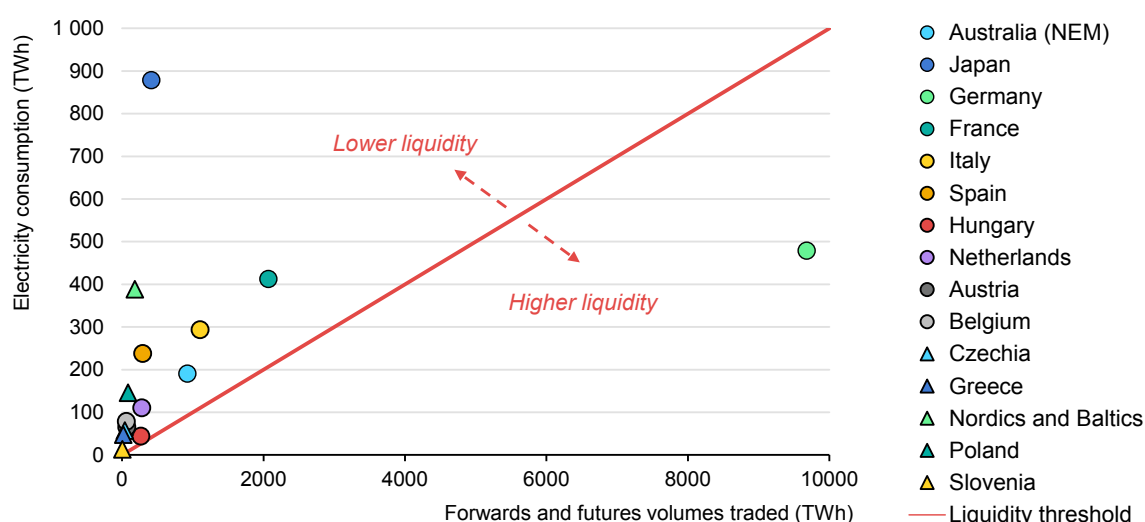
Across major electricity markets, liquidity in forwards and futures trading varies widely. In Germany, traded volumes in 2024 were [over 20 times annual demand](#), indicating a relatively high degree of liquidity. In contrast, many southern and eastern European countries and the Nordics [have limited liquidity](#), with churn rates between 1 to 1 and 6 to 1. As a result, many European market participants rely on [Germany's market for hedging](#). Since Japan [launched a futures market in 2019](#), volumes have grown rapidly, increasing [tenfold between 2021 and 2024](#), yet liquidity there also remains limited.

Electricity's limited storability and the need for dedicated infrastructure to move it across long distances mean that trade is confined to specific grids or bidding

zones. These structural constraints can partly explain why electricity markets continue to exhibit low liquidity, as they restrict the pool of participants and the scope of traded volumes.

Although the nature of electricity, gas and oil markets differ, even the most liquid electricity forwards and futures markets are far less liquid than other energy commodities. The Dutch TTF gas hub reached a trading level more than [100 times its physical market](#) in 2024, while the Henry Hub for gas trading in the United States [rose to 55 times](#). Oil markets are also deeper in comparison to electricity: daily trading in petroleum futures is around [50 times world consumption](#), with West Texas Intermediate and Brent futures alone trading at 20 to 25 times global daily oil consumption.

Forwards and futures traded volumes and electricity consumption in selected markets, 2024



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Notes: The diagonal line represents a churn rate of 10; in other words, when the volumes traded on forward markets are ten times higher than the actual consumption in the market. [According to ACER](#), a market is considered liquid when the churn rate (liquidity rate) exceeds 10, while a value above 40 indicates a highly liquid market. Australia's NEM only accounts for futures, as forwards data are not publicly available.

Sources: ACER (2025), [Electricity Markets Indicators](#); EEX (2025), [EEX Group Annual Volumes 2024](#); Nasdaq (2025), [Nasdaq Commodities Market Report January 2025](#); Shulman Advisory (2024), [TOCOM's Power Futures Trading Volume Jumps Sharply in Q2, Lags EEX](#); METI (2025), [Monitoring Report of Voluntary Efforts and Competitive Status October to December 2024 Period](#).

Market makers are a potential lever to develop liquidity in forwards and futures markets

Market-making functions are an option to help resolve liquidity issues in forwards and futures markets. A market maker in electricity markets is an entity that regularly offers to buy and sell a minimum amount of power products at prices that are not too far apart, often in exchange for a fee. This helps keep prices available at all times and makes trading cheaper and easier for other market participants.

Several examples from Australia, Europe and Japan show that market making is increasingly viewed as a potential lever to develop liquidity. The [Australian NEM review](#) is currently considering reinforcing its market-making obligation for futures, drawing on international experience from Great Britain and New Zealand. Market-making roles have also been identified as viable options to [help drive liquidity in the European Union](#), among other tools. In Japan, a market-making scheme is [in place](#) to support liquidity in its recently established futures market, with the Japan Electric Power Exchange providing financial incentives to participants in exchange for their market-making role.

While market marking can increase liquidity by strengthening trading opportunities, it cannot address fundamental imbalances between sellers and buyers. As a result, its effectiveness may be limited in markets with [structural surpluses or shortages](#).

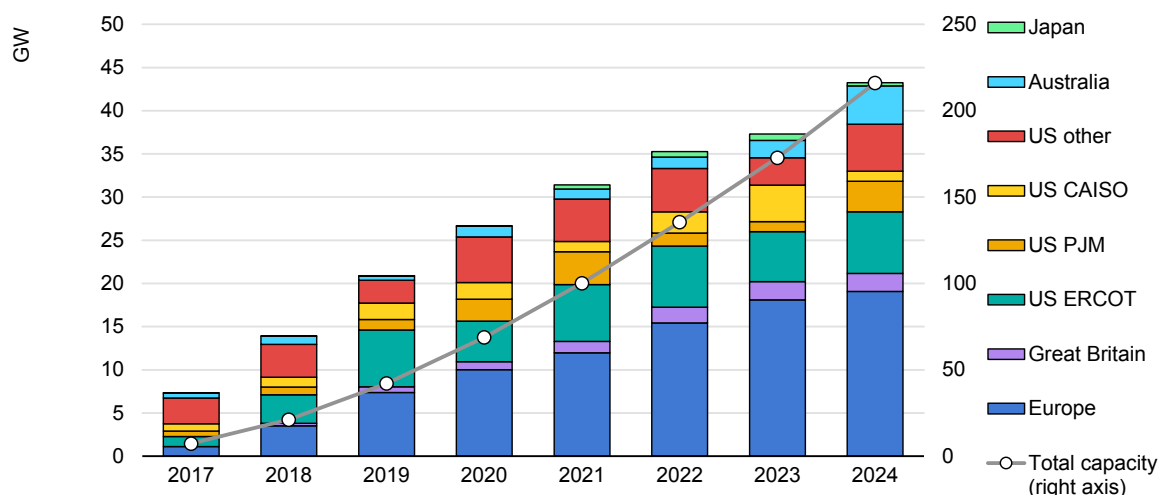
While forwards and futures are typically exchanged multiple times, traded volumes are more limited for PPAs as their bespoke nature makes them harder to resell. However, traded volumes are only one aspect of market liquidity. The contracted capacity in relation to installed capacity also indicates the size of PPA markets, highlighting the role they play in supporting investment and bringing new capacity online, or keeping existing plants running.

The size of the PPA market remains modest across regions when compared with total installed capacity. In Europe, renewable and storage PPAs signed in 2024 covered only 3% of installed capacity for the relevant technologies, with similarly low levels in Great Britain (4%) and Japan (0.4%). In the United States' wholesale markets and Australia, capacity under PPAs represents around 10% and 12% of total installed capacity, respectively.⁵ However, PPAs are playing an increasingly important role in supporting investment and the operation of low-carbon

⁵ S&P Global (2025), Market Intelligence.

generation and storage assets. For instance, within the United States' wholesale markets, PPAs cover a range of assets and technologies, covering around one-third of solar and wind assets and one-fifth of batteries.

Renewable utility and corporate power purchase agreements signed annually and total capacity in selected regions, 2017-2024



IEA. CC BY 4.0.

Notes: Renewables include solar, wind, hybrid projects, storage, biomass and others. Australia refers only to the NEM and US other to Southwest Power Pool (SPP), independent system operator New England (ISO-NE), New York Independent System Operator (NYISO) and Midcontinent Independent System Operator (MISO). Data are based on reported deals and may not capture unreported contracts.

Sources: IEA analysis based on S&P Global Energy (2025), S&P Global Market Intelligence (2025), and Pexapark (2025)..

Long-term market challenges

Liquidity in long-term electricity markets remains limited, reflecting deeper challenges. Many buyers are reluctant to hedge far into the future, while barriers to entry can prevent participants from accessing long-term contracts. In some cases, long-term market design has not kept pace with evolving system needs, leaving products misaligned with current hedging needs. Moreover, long-term markets can be inadequately co-ordinated with short-term markets, neighbouring regions and complementary mechanisms, weakening their role in providing hedging opportunities and supporting efficient, co-ordinated outcomes.

Structural mismatches between buyers' and sellers' hedging needs constrain liquidity across longer timeframes

Limited liquidity in forwards and futures markets can be partially explained by the lack of incentives or willingness among electricity buyers to hedge over longer periods compared to sellers. This mismatch is particularly visible in forwards and

futures markets. While PPAs have longer durations, their total volumes remain small relative to the size of the market and decline as contract length increases.

The “tenor gap”

Developers and investors typically require long-duration contracts to support financing for capital-intensive assets and secure predictable revenue streams. By contrast, many buyers prefer shorter commitments because their future electricity demand is uncertain. This misalignment, known as the “tenor gap”, limits opportunities for long-term hedging and investment.

Retail suppliers often lack visibility of future consumption, particularly in regions where more customers generate or store their own power, and in competitive retail markets where consumers can switch providers freely with little notice. As a result, retailers face risks if they engage in long-term markets beyond the timeframe for which they are reasonably confident of their consumer portfolio demand.

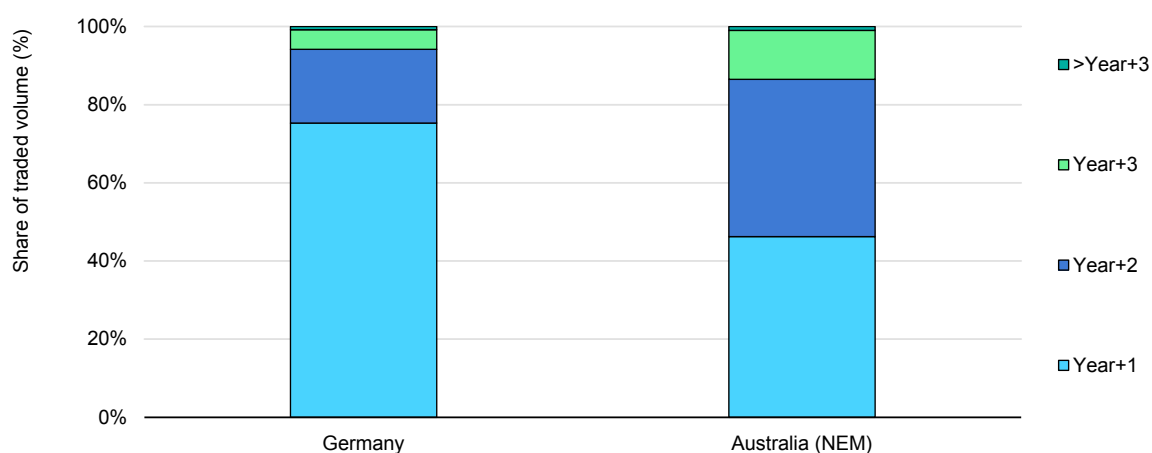
Examples from Australia, Europe and Japan show that most retailer contracts rarely extend beyond three years, leaving little visibility beyond this horizon. In competitive retail markets such as [France](#) or [Sweden](#), contracts usually last 1-3 years and consumers can switch providers with minimal or no penalties. In [Germany](#), the regulatory framework does not allow retail contracts lasting beyond 2 years, although contract prolongations are possible after this date. In Japan, over [55% of retail suppliers'](#) volumes are procured within a year of delivery, while in Australia, contracting typically occurs [4-16 months ahead](#) because of [demand uncertainty and price expectations](#). This uncertainty makes it difficult for suppliers, particularly new entrants or those with growing portfolios, to commit to long-term contracts that [may not align](#) with future demand.

Additionally, some buyers may rely on the [expectation of government intervention](#) during price spikes, as seen during [Europe's energy crisis](#). This perceived safety net can weaken incentives to hedge through long-term markets.

Forwards and futures market timeframes

Forwards and futures markets are particularly affected by the tenor gap. In these markets, there is limited liquidity for contracts that are set to be fulfilled more than 3 years in the future, even in otherwise liquid markets. For instance, in Germany, the country with the highest liquidity in the European Union, trading activity is concentrated within the [first 2 years ahead of delivery](#). In Australia's NEM, around [70% of traded volumes](#) are for delivery within an 18-month horizon. This is in part due to limited hedging needs or incentives on the demand side. As a result, market participants typically lack opportunities to hedge against price fluctuations more than 2-3 years in advance using forwards or futures.

Traded volumes of forwards and futures by the length of time before the contract is set to be fulfilled, 2021-2023



IEA. CC BY 4.0.

Notes: Shares are calculated as an average over 2021-23. For Australia, the metric shows Australian Securities Exchange base futures.

Sources: ACER (2024), [2024 Market Monitoring Report](#); AER (2024), [Wholesale Electricity Market Performance Report 2024](#).

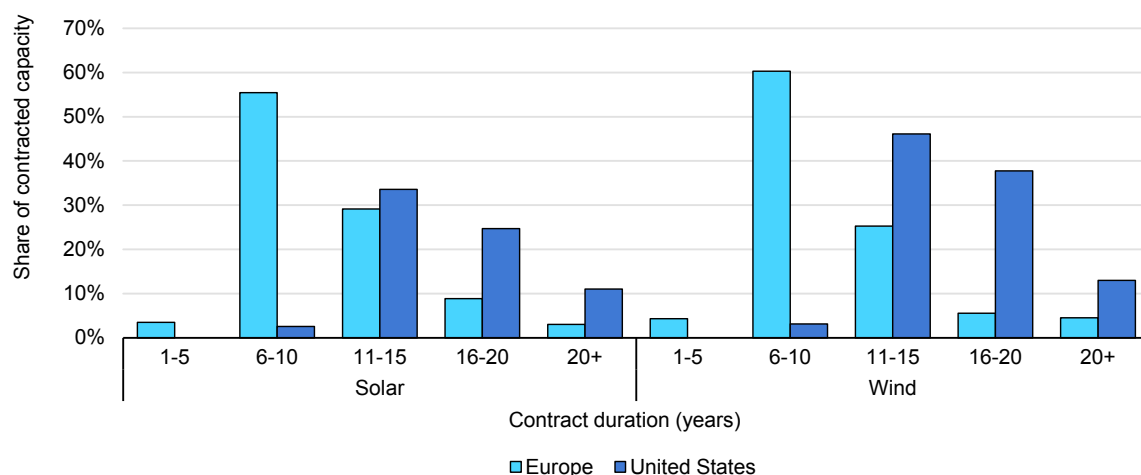
Power purchase agreement market timeframes

PPAs have a longer-term perspective than forwards and futures, often lasting 10 years or more, allowing them to meet different hedging needs. Their duration reflects the needs of the contracting parties to have stable revenues or electricity prices over time. Contract length can depend on a variety of factors, including the technology type, the availability of alternative options to de-risk investments over the long term, as well as whether the PPA aims to finance a new asset or stabilise revenues for an existing one.

Since 2017, the contract duration of solar and wind PPAs has generally exceeded 5 years in Europe, while in the United States they tend to last for at least 10-15 years. The main reason for this difference is that US markets rely more on bilateral trading and renewable certifications, while European markets have a mix of consumer protection schemes and renewable support mechanisms that limit the need for long-term PPA agreements.

When considering long-term markets altogether, hedging opportunities remain limited over longer timeframes. Although PPAs enable trading over longer durations and extend the hedging horizon, absolute volumes remain low. In addition, the longer the PPA term, the fewer contracts are signed, particularly after 10-15 years, as seen in Europe and the United States. As such, the collective liquidity of long-term markets over longer timeframes remains modest.

Share of solar and wind power purchase agreements in Europe and the United States by contract duration, 2017-2025



IEA. CC BY 4.0.

Notes: US data include only the independent system operators: CAISO, ERCOT, PJM, MISO, NYISO, SPP and ISO-NE. Data are based on reported deals and may not capture unreported contracts. Shares are calculated based on the capacity of PPAs signed between 2017 and 2025; data until end of September 2025.

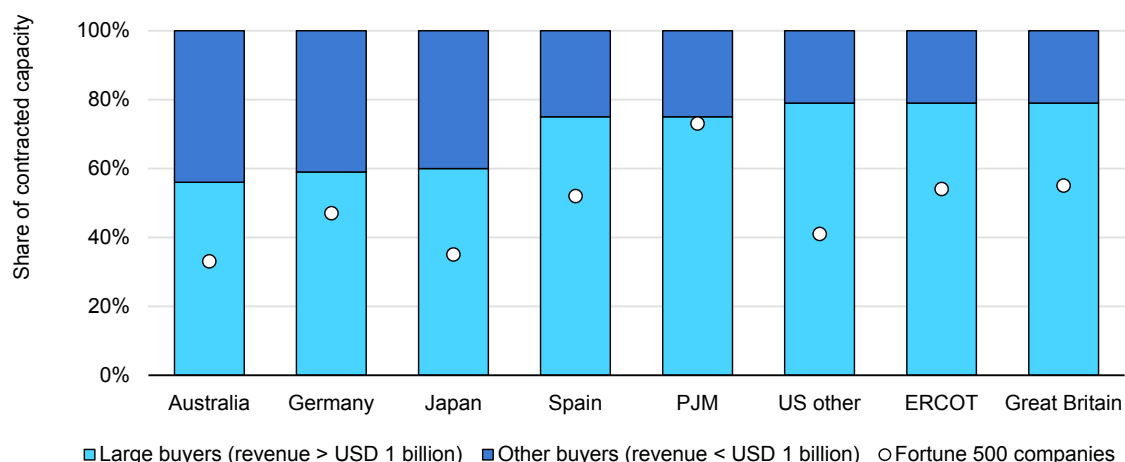
Sources: IEA analysis based on S&P Global Market Intelligence (2025) and Pexapark (2025).

Long-term markets are not always accessible to all market participants

Access to long-term markets is often constrained for certain participants, particularly small and medium-sized entities or those with limited financial reserves. While not all market participants seek to hedge electricity costs over the long term, others may wish to do so but face barriers deterring or preventing their participation. These barriers include high collateral and creditworthiness requirements, as well as the complexity of bespoke contracts.

The lack of access of smaller participants is particularly apparent for PPAs, where large buyers dominate. Across Australia, Japan, and several European and US markets, between half and three-quarters of corporate PPAs have been signed by companies with annual revenues above USD 1 billion. In some markets, concentration is even higher, with Fortune 500 companies accounting for almost three-quarters of corporate PPAs in the PJM Interconnection (PJM) market and around half in the Electric Reliability Council of Texas (ERCOT) market and Great Britain.

Average share of renewable corporate power purchase agreement buyers by company size and market, 2017-2024



IEA. CC BY 4.0.

Notes: Renewables include solar, wind, storage, biomass, and hybrid projects. Australia refers to the NEM, US other to SPP, ISO-NE, NYISO and MISO. Large buyers are defined as companies with revenue above USD 1 billion in 2024; other buyers have revenue below this level. Fortune 500 companies are classified according to the 2025 global ranking.

Sources: IEA analysis based on S&P Global Market Intelligence (2025) and S&P Global Energy (2025).

Collateral and creditworthiness requirements

In long-term electricity markets, buyers and sellers need reasonable confidence that their counterparties will honour financial commitments. Two key safeguards can help ensure this: collateral and creditworthiness. Collateral involves posting money or assets to secure a contract, while creditworthiness reflects a party's ability to meet financial obligations. These measures protect against default but can restrict access for smaller participants with limited financial reserves.

Small or medium-sized participants may struggle to meet collateral demands, especially when electricity prices rise and additional payments are required at short notice. This can [limit their ability to hedge](#) over longer periods. In [Australia's NEM](#), for instance, small retailers contract only about 10% of their forward volumes on the Australian Securities Exchange, compared to over 80% for large retailers. In Europe, [high collateral costs](#) restrict access to longer-term contracts. Reforms such as the [European Union's 2022](#) expansion of acceptable collateral types, and ongoing work to improve the [transparency and predictability](#) of margin calls, aim at lower entry barriers without negatively impacting necessary market safeguards.

Creditworthiness requirements also act as a barrier, as sellers often prefer buyers with strong financial ratings. This can exclude many smaller firms, even when they are willing to engage in long-term contracts. If prices fall below the agreed level, buyers with weaker financial positions may face losses, making sellers cautious about whom they contract with. To shield themselves, sellers often require strong creditworthiness. This severely limits the pool of buyers, as less than [5% of global](#)

[corporates](#) meet investment-grade thresholds, compared with around [80% of European utilities](#). The lack of creditworthy counterparties has been flagged as a major factor [limiting credible PPA](#) demand across Europe.

Complexity of tailored contracts

Long-term contracts face a key trade-off between two needs: adaptability to match specific buyer and seller hedging needs, and ease of trading. Standardised products, such as futures, are simple, transparent and reduce the costs of trading, but often fail to reflect the diversity of market participants' hedging needs. Tailored contracts like PPAs can address these needs and include additional services, yet they bring higher complexity and legal and commercial costs and are harder to resell.

PPA negotiations are typically resource-intensive, requiring months of preparation, specialist advisers and close co-ordination across legal, commercial and procurement teams. The bespoke nature of PPAs also limits the ability to resell them on secondary markets, meaning market participants must bear the full cost of negotiating new contracts rather than acquiring existing ones. This lack of secondary trading opportunities also contributes to lower liquidity in the PPA market, as contracts do not change hands easily, unlike standardised products.

Efforts are underway in [Europe](#) to provide voluntary standard PPA contracts to streamline negotiations. This standardisation aims to reduce the time and costs needed to sign a PPA. It could also provide opportunities for a secondary market, helping avoid locking in contracting parties for the entire term of the PPA. However, full standardisation could erode the bespoke benefits that make PPAs distinct from standardised forward or future contracts. In a recent [ACER review](#), stakeholders cited this customisation as a key benefit of PPAs. In addition, the liquidity and pool of participants in the secondary market may remain limited, given the growing but still-modest volumes of PPAs across markets.

Policy makers have implemented schemes to incentivise PPA uptake and broaden buyer diversity

While PPA volumes have grown across several regions, participation in many markets remains concentrated among large, creditworthy buyers. In response, several jurisdictions have introduced measures to broaden access and support wider uptake. These include the following:

- **Guarantee schemes:** In [Spain](#) and [Norway](#), guarantee schemes have been introduced to underwrite corporate credit risk, enabling smaller or non-rated firms to sign PPAs. The European Union's 2025 [Action Plan for Affordable](#)

[Energy](#) reinforces this approach, tasking the European Investment Bank with developing guarantee instruments for PPAs. These measures aim to lower the counterparty risks that often block broader participation and reflect a growing EU policy focus on expanding PPA access to a wider range of buyers.

- **Renewable portfolio mandates:** Certain US states, like California and Texas, have adopted renewable portfolio standards that incentivise buyers to meet renewable procurement targets through PPAs or other **contracts**. In most states this is driven by corporations, while California stands out as an exception where utility buyers represent four-fifths of the PPA market. This reflects California's utility-specific [renewable portfolio standards](#), adequacy requirements and the strong role of [community choice aggregators](#).
- **Procurement mandates:** Spain requires large electro-intensive consumers to [procure at least 10% of their consumption](#) from renewables using long-term contracts of at least 5 years, such as PPAs.

Long-term markets have not kept pace with evolving system needs

The physical electricity system is evolving, but the design of forwards and futures products in long-term markets has not always kept pace. Forwards and futures markets first emerged when electricity mostly came from large thermal plants that could adjust output on demand. Standard contracts assumed predictable generation and stable demand, using fixed-volume products such as flat blocks and simple time splits like peak, off-peak, weekday and weekend periods. Market design relied on the ability to plan production to match these rigid structures.

Today, more electricity comes from variable renewables like wind and solar, with their weather-dependent output rarely matching fixed contract blocks. Flat-volume contracts expose these generators to shortfalls or surpluses, leaving them vulnerable to costs and risks in short-term markets. Peak products also reflect outdated supply and demand patterns, as solar peaks at midday, while net demand now often peaks in the evening. This mismatch between contract design and physical system conditions raises risks and costs while limiting participation.

Some regions have begun to introduce new market products that better reflect evolving hedging needs. For instance, in Spain, the market operator Operador do Mercado Ibérico de Energia (OMIP), the Iberian Energy Market Operator, launched [solar-shape futures](#) that align with solar generation patterns rather than flat blocks. In June 2025, Australia's NEM central exchange, the Australian Securities Exchange, [introduced morning and evening peak futures](#) to adapt to

the changing generation mix and demand profiles. More broadly, innovation in over-the-counter forward contracts can provide further opportunities to hedge against specific generation profiles and time periods, such [as seen in Australia's NEM](#).

Overview of available futures products on selected organised trading platforms in Europe, Japan, Australia's NEM and selected US markets by type, 2025

Market	Base	Peak	Off peak	Weekday/ weekend peak	Weekend off peak	Morning/ evening peak	Solar
Australia - NEM	●	●	●	●	●	●	●
France	●	●	●	●	●	●	●
Germany	●	●	●	●	●	●	●
Great Britain	●	●	●	●	●	●	●
Spain	●	●	●	●	●	●	●
Japan	●	●	●	●	●	●	●
US CAISO	●	●	●	●	●	●	●
US ERCOT	●	●	●	●	●	●	●
US PJM	●	●	●	●	●	●	●

Legend: ● Available ● Not available

Notes: Availability of the products is based on product listings. Base refers to flat product for all hours of all days. Peak definition varies throughout markets but generally refers to the weekday (08:00 to 20:00 in Europe and Japan, 07:00 to 22:00 for NEM, ERCOT and CAISO, and 08:00 to 23:00 for PJM); off peak is the rest of the day. CAISO also offers 09:00 to 16:00 peak and weekday peak products. Weekend refers to Saturday and Sunday for all except CAISO, where only Sunday is separated. Weekday refers to Monday to Friday, except for CAISO, where Saturday is also included. Morning peak refers to 06:00 to 09:00 in Australia. Evening peak refers to 16:00 to 21:00 in Australia. and 18:00 to 22:00 in ERCOT. Japanese futures availability corresponds to the Tokyo area only.

Source: IEA based on Intercontinental Exchange (ICE) (2025), [Products - Futures & Options](#); European Energy Exchange (EEX) (2025) [Power Futures](#); European Energy Exchange (EEX) (2025) [EEX Japanese Power Futures Overview](#); Australian Securities Exchange (ASX) (2025) [ASX Australian Electricity Derivatives Product fact Sheet June 2025](#); Operador do Mercado Ibérico de Energia (OMIP) (2025) [Power Derivatives Portfolio](#); Japan Exchange Group (JPX) (2025) [Electricity Futures](#).

Long-term markets are not always well aligned with other markets and regions

Long-term markets are a key building block of market design, but they do not operate in isolation. To function effectively, they must be coherently integrated with short-term markets, neighbouring regions and complementary mechanisms. Transparency is also important, as limited visibility of long-term contract prices and volumes can weaken investment signals and disconnect long-term decisions from broader market dynamics. Today, long-term markets face growing

challenges in achieving this alignment, underscoring the need for better co-ordination with the rest of market design.

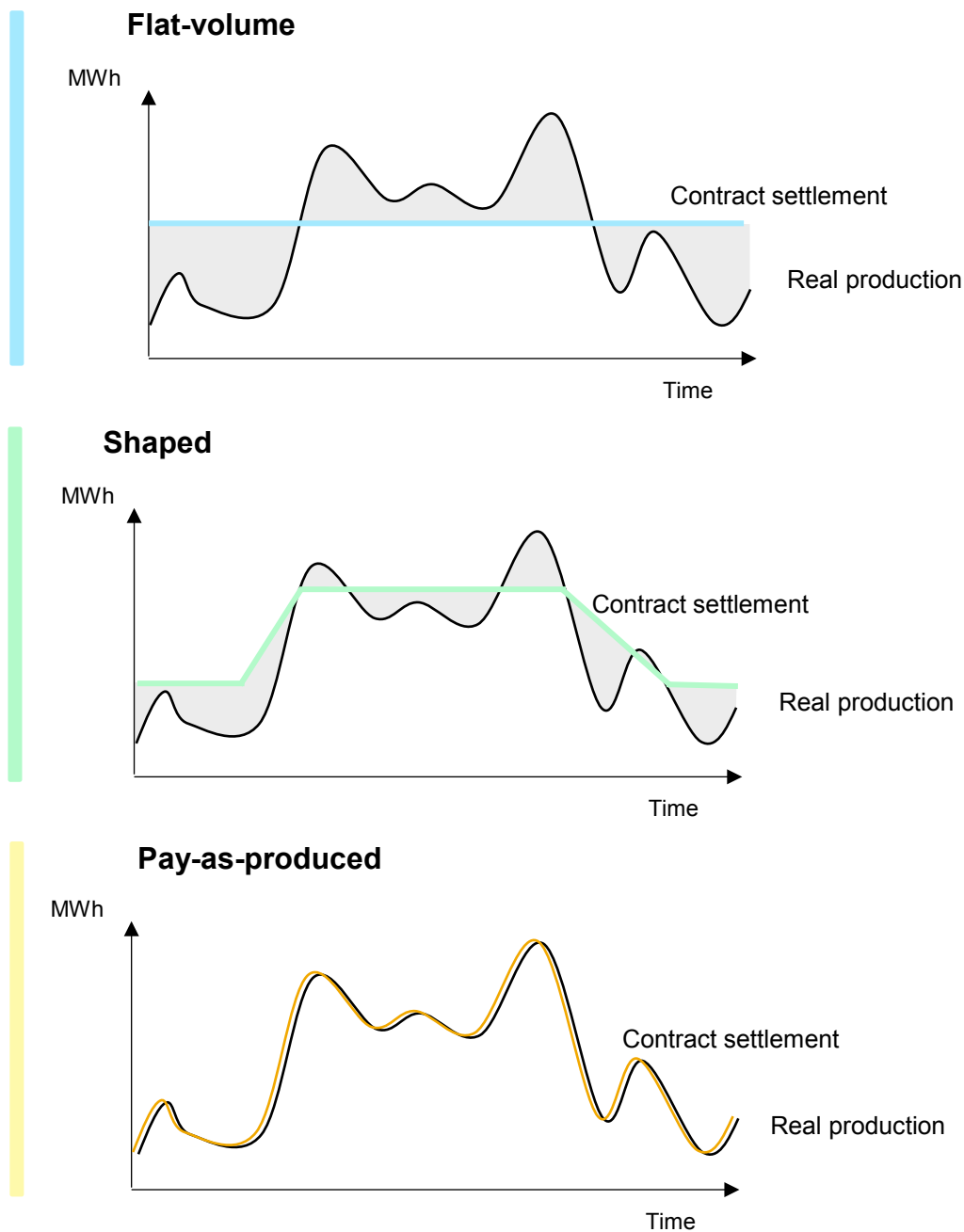
Alignment with short-term markets

Long-term contracts reduce exposure to short-term market volatility, but depending on their design, can also affect how participants react to short-term market signals. This is particularly true for long-term contracts that are settled based on the electricity actually produced or consumed and not on a fixed amount or schedule. Generators operating under pay-as-produced PPAs receive a fixed price for each unit of electricity they produce. Under these contracts, the [generators are generally not incentivised](#) to optimise the timing of their production based on short-term market prices because their remuneration is not directly tied to real-time system conditions.

In contrast, contracts that specify a different volume profile from the asset's actual production can still support short-term market responsiveness. Payments under these contracts are not linked to the real-time behaviour of the asset, allowing market participants to react to short-term price signals without affecting their long-term contract settlement. This is the case for [forwards and futures](#), as well as PPAs based on flat-volume or shaped profiles.

However, pay-as-produced PPAs can still include clauses that expose producers to some short-term signals, such as [temporary suspensions](#) during periods of negative prices. In addition, long-term contracts covering only part of the production or consumption of a market participant leave the remaining volumes exposed to short-term prices, encouraging behaviours that support system efficiency.

Illustration of long-term contract volumes subject to short-term price signals in flat-volume, shaped and pay-as-produced contracts



- Volumes of electricity exposed to short-term prices

IEA. CC BY 4.0.

Note: In flat-volume or shaped long-term contracts, the settlement of the long-term contract is carried out on a volume of electricity that can differ from the electricity produced by the seller. The real production of the asset is sold in the short-term market, and so is exposed to short-term price signals, independently of the settlement of the long-term contract. If short-term prices are negative, incentives are sent to reduce production to zero and avoid a loss. Overall, the seller is exposed to short-term prices within the grey zone shown in the figure, which represents the difference between the real production and the long-term contract volume profile.

Further, corporate renewable targets tied to PPAs and requiring green certificates can create misaligned incentives for low-carbon generators. Corporations often use PPAs to meet sustainability goals and demonstrate low-carbon consumption through certificates. However, this can encourage generators to prioritise production to meet certificate targets rather than respond to system signals.

While emerging 24/7 clean energy frameworks that match consumption with hourly low-carbon generation aim to reinforce system decarbonisation, they can also introduce new challenges if applied narrowly. In particular, strict hourly matching under voluntary [24/7 clean energy goals](#) may lead generators to tailor production to follow the associated consumer load profile rather than to respond to real-time system conditions. This can create [a siloed approach](#), where generation aligns only with buyer demand rather than broader system needs. Effective trading of time-based green certificates offers a way to [aggregate load and renewable](#) generation profiles within the system and, in doing so, help realign generation behaviours with overall system conditions.

Regional long-term market integration

Limited liquidity in long-term markets may not always be an issue if participants can trade in neighbouring, more active markets. This can help them bypass liquidity issues in their own area and manage price risks more effectively. In Europe, for example, many participants hedge in the German market, where higher liquidity provides more reliable price signals and lower risk than in less liquid zones. However, relying on another market's prices does not fully protect against differences in local electricity prices that may arise due to network constraints or regional characteristics, whether at the nodal or zonal level. This residual exposure means additional instruments are needed to complement long-term markets and allow market participants to hedge effectively.

Across jurisdictions, various mechanisms are employed to address these risks. Financial instruments are commonly used to hedge against price differentials between areas, such as between market zones in Australia, Japan or most of the [European internal energy market](#), or between nodes such as in the ERCOT, PJM and California Independent System Operator (CAISO) markets. These instruments have different names and parameters but are generally equivalent in principle. In Denmark, Finland, Norway and Sweden, [electricity price area differentials](#) cover the [price difference](#) between a central reference “hub” price, which aggregates all market zones, and specific zones across the four countries. In the European Union, while these instruments are usually financial in nature, [physical transmission rights](#) are also used for some borders, allowing participants to nominate [physical electricity flows on interconnectors](#).

For hedging to be effective, their design and allocation of these instruments should align with long-term electricity markets. This includes matching how long trading can occur in advance, the shape of delivery profiles and the timing of auctions. Without such alignment, market participants face gaps in risk coverage, reducing their protection against price variations. Across Australia, Europe, Japan and the United States, the allocation of cross-market hedging instruments is not always possible far in advance, and products often have short durations of up to a year.

Cross-market hedging instruments by jurisdiction and maximum trading term ahead of time, 2025

Market	Instrument name	Hedging type	Maximum trading time ahead (years)	Maximum contract length (years)
Australia - NEM	Inter-regional settlement residue	Zone-to-zone	3	<1
European Union (except Nordics)	Financial and physical transmission rights	Zone-to-zone	1	1
Europe - Nordics	Electricity price area differentials	Zone-to-hub	4	1
Japan	Indirect transmission rights	Zone-to-zone	<1	<1
US CAISO	Congestion revenue rights	Node-to-node	1	10
US ERCOT	Congestion revenue rights	Node-to-node	3	<1
US PJM	Financial transmission rights	Node-to-node	3	1

Notes: In CAISO, long-term congestion revenue rights have a term of 10 years. The maximum trading time ahead captures the number of years ahead at which the procurement occurs. For instance, an annual transmission right starting on 1 January can be bought by market participants up to 1 year ahead in the EU internal market. The Nordics include Denmark, Finland, Norway and Sweden.

Sources: IEA based on data from AEMO (2019) [Guide to the Settlements Residue Auction](#); Euronext (2025) [Contract Specifications Power Derivatives](#); JPX (2024) [Japan Electric Power Exchange \(JEPX\) Overview](#); ERCOT (2025) [ERCOT CRR Market Overview](#); PJM (2025) [PJM ARR FTR Markets Overview](#); CAISO (2025) [Congestion Revenue Rights Enhancements working group presentations](#); CAISO (2024) [Section 36 - Congestion Revenue Rights as of Aug 3, 2024](#); ACER (2024) [Transmission capacities for cross-zonal trade of electricity and congestion management in the EU](#).

Transparency of price signals

Forwards and PPA contracts can reduce the transparency of price signals that guide decisions in electricity markets. Unlike exchange-traded futures, which provide public data on prices and volumes, forwards and PPA contracts are mostly private. As prices and volumes are often not publicly disclosed for these contracts due to commercial sensitivity, transparency is reduced, which can hinder long-term investment signals.

Jurisdictions take different approaches to managing transparency and confidentiality, but PPA information is generally only publicly available when participants choose to disclose it. For instance, in the United States, there is no mandatory disclosure of PPAs in wholesale markets, including CAISO, ERCOT and PJM. In Europe, [PPA data are sent to ACER](#) under the Regulation on Wholesale Energy Market Integrity and Transparency, but [only aggregated assessments are published](#), and not individual contract details. Australia and [Japan](#) also have no legal requirement to publish PPA information, and while regulators may collect data, [they are treated confidentially](#).

Moreover, even if PPA or forward prices were published, the customised nature of these contracts means that the information alone would be less meaningful. Prices would not be fully comparable without further information on the specific terms of each agreement. As these markets expand, improving both the availability and interpretability of data, while protecting commercially sensitive information, will become increasingly important.

In markets that allow trading of physical forwards and PPAs, as is often the case in [Europe and Japan](#), transparency can be further limited. With these contracts, physical electricity volumes can be sold in long-term markets and so are not sold in the spot market. As such, this can shrink the size of short-term markets, making prices more volatile and representing a smaller share of physical electricity flows. In contrast, under market designs where long-term contracting is usually limited to financial contracts, such as [Australia's NEM](#), the short-term market price reflects all physical electricity volumes.

Power purchase agreement alignment with renewable support cost recovery

The interaction between PPAs and complementary mechanisms, in particular the cost recovery of decarbonisation mechanisms discussed in Chapter 4, can influence the participation of buyers in the PPA market. Buyers who sign long-term PPAs with low-carbon assets may help bring additional capacity to the system. In many countries, however, these buyers are also subject to policy charges to cover the costs of complementary mechanisms supporting low-carbon capacity development. These policy charges come on top of the fixed PPA price, reducing the overall value of the contract.

This raises the key question of whether buyers directly contributing to renewable deployment through PPAs should also bear the cost of complementary mechanisms. Not applying such charges would help recognise the contribution of PPAs to policy objectives, encourage greater market participation from buyers and reduce reliance on public funding.

Several jurisdictions have such charges in place. For example, in Great Britain, buyers that have signed corporate PPAs are still subject to [renewable levies](#), such as contract-for-difference charges. In Japan, [buyers of off-site PPAs](#) must also pay policy charges linked to renewable support schemes. Spain temporarily offered some relief in 2021-22 by [excluding long-term PPAs](#) from a retroactive revenue “clawback” mechanism.

Chapter 4: Complementary mechanisms

Complementary mechanisms in electricity markets provide targeted interventions to address gaps in market signals, ensuring that system operation and investment are aligned with public policy objectives. In the short run, their function is to provide incentives for efficient operation, addressing potential market failures such as pollution or undersupply of reliability. In the long run, they address investment gaps that even well-designed energy-only markets may not fully supply on their own. When carefully implemented, these instruments can reinforce reliability and affordability while supporting jurisdictional energy and climate objectives.

Electricity markets are undergoing profound structural change. Growing shares of variable generation, early retirement of firm capacity, rising demand and changing demand patterns are all affecting revenue streams and increasing investment risk. In this context, complementary mechanisms have become essential for supporting market efficiency, maintaining reliability and mobilising investment in technologies that markets alone struggle to support, particularly those that are capital-intensive, low-carbon or strategically important for system adequacy.

Where Chapters 2 and 3 examined how short- and long-term markets form the foundation of wholesale electricity markets, this chapter considers how governments and regulators can use complementary mechanisms to strengthen that foundation. When properly designed, these instruments enhance rather than replace market signals, translating policy objectives into stable investment conditions while preserving market efficiency.

This chapter focuses on three areas where complementary mechanisms have become most relevant: maintaining resource adequacy and reliability, delivering decarbonisation objectives and mobilising investment in strategic capital-intensive technologies such as nuclear and large hydro. Examples of complementary mechanisms include capacity remuneration mechanisms, such as strategic reserves and capacity markets, and decarbonisation mechanisms, such as emissions trading schemes and contracts for difference (CfDs). These mechanisms interact with existing market arrangements and influence investment signals, system reliability and long-term cost efficiency.

Complementary mechanisms have become essential features of modern electricity market design. However, they cannot substitute for well-functioning markets. While they are critical to achieving desired public policy outcomes, there is a risk they may be treated as primary drivers rather than supporting instruments.

When introduced without regard for interactions with short- and long-term price signals, they can unintentionally undermine efficiency. The central task for policymakers is therefore to close market and investment gaps without eroding what already works, designing interventions that integrate smoothly into existing markets rather than operate outside them.

The role of complementary mechanisms

Electricity markets have not always managed to attract investment at the pace and scale needed to meet policy goals. As demand expands and new forms of generation and storage are deployed at scale, these pressures are intensifying. This is further exacerbated by the mismatch between entry and exit timelines for generation, particularly as large thermal plants retire. Other issues stem from the physical characteristics of electricity itself, as the system must remain balanced at all times, offer enough flexibility and provide system services that maintain grid stability. Furthermore, some policy objectives, such as reliability or emissions reduction, cannot always be achieved through markets alone. Investment is also often considered too risky, either because the electricity technologies involved are long-lived or capital-intensive, or because market conditions are expected to continue evolving in unpredictable ways.

To close these gaps, one approach is to change how prices are set in wholesale markets, for example by removing or raising price caps, introducing administrative scarcity pricing or expanding demand response. In principle, such measures should allow prices to reflect the true value of electricity during scarcity and encourage investment. In practice, however, sharp price spikes are politically and socially contentious, can create opportunities for market power abuse and still fail to address the underlying investment risks that deter new capacity.

Consequently, governments in many jurisdictions have introduced complementary mechanisms such as capacity markets, government-backed long-term contracts and other support schemes. When well designed, these measures can provide revenue certainty, reduce investment risk and mobilise capital for low-carbon and capital-intensive technologies. Yet they also involve trade-offs. They may lead to muted price signals, introduce additional costs for electricity buyers or taxpayers and impact market behaviour in ways that limit the ability of electricity markets to perform effectively. For this reason, careful design is needed to ensure that complementary mechanisms support rather than weaken efficient market outcomes and do not undermine affordability.

Although such mechanisms have become the preferred solution in many jurisdictions, they cannot solve all challenges on their own. Just as markets can underdeliver or even fail in certain circumstances, so too can policy. Shifts in political priorities can undermine investment signals, reinforcing the need for careful market design and a balanced mix of market and out-of-market

interventions. Investment may also be constrained by non-market factors, for which complementary mechanisms may be less effective. Bottlenecks can occur due to non-integrated planning, local and environmental permitting, and supply chain delays. These are important considerations that, while outside the scope of this report, should be addressed alongside market design.

Electricity markets alone cannot deliver the reliability standards society demands

Electricity has become an essential service that underpins modern life and economic activity. Because of this, policymakers and the public expect a level of reliability that exceeds what markets would naturally deliver. While markets aim to balance supply and demand efficiently, society's tolerance for blackouts is extremely low, and the consequences of outages are often deemed unacceptable. As a result, governments set reliability standards that reflect this preference for higher security, even when doing so comes at a higher cost than a purely market-driven outcome.

Reliability standards set clear targets for electricity security, such as acceptable probabilities or durations of interruptions, and guide investment planning. While specific metrics vary across jurisdictions, the principle remains the same: to ensure sufficient capacity is available to meet demand under a wide range of conditions. Commonly used indicators include the loss of load expectation, which measures how often available generation might fall short of demand; expected unserved energy, which estimates the total volume of energy likely to go unmet over time; and the reserve margin, which expresses the percentage of available capacity above expected peak demand. Together, these metrics quantify reliability from different perspectives, i.e., frequency, magnitude and capacity, providing complementary ways to assess resource adequacy.

Comparison of yearly reliability standards across selected jurisdictions

Metric	Unit	Explanation	Example market	Reliability value
Loss of load expectation	Hours per year	Number of hours in a year where the full load cannot be covered by available supply	France	2 h/year
			Germany	2.77 h/year
			Great Britain	3 h/year
	Days per year	Number of days with at least one period where the full load cannot be covered by available supply	US PJM	0.1 days/year
			US CAISO	
	Number of events	Frequency of lost load events in a specified period	US ERCOT	0.1/year

Metric	Unit	Explanation	Example market	Reliability value
Maximum expected unserved energy	% of total yearly energy	Percentage of total load not supplied during a year	Australian NEM	0.0020%
	kWh/kW per year	Load not supplied during a year, expressed as a proportion of demand capacity	Japan	0.018 kWh/kW/year
Reserve margin	% of peak demand	Surplus of capacity available compared to the maximum forecasted load	Spain	10%

Notes: CAISO = California Independent System Operator; ERCOT = Electric Reliability Council of Texas; NEM = National Electricity Market; PJM = PJM Interconnection; US = United States. The value for Japan is set annually; the 2025 value is shown here. ERCOT is introducing an [approach using three criteria](#), with the first triennial assessment planned for 2025.

These standards provide policy-driven certainty about the level of reliability expected, but they also create expectations that markets alone [may not always be able to fulfil](#). Revenues from electricity markets may not fully recover capital costs, particularly when [price caps suppress scarcity value](#). This so-called “[missing money](#)” problem means that even during periods of high demand, [prices do not rise enough](#) to incentivise new investment or retain existing capacity. This issue is further [exacerbated by the increasing penetration](#) of technologies with near-zero marginal costs, such as solar PV and wind, which tend to depress average wholesale energy prices. Uptake of these technologies can erode conventional plant capacity factors to the point where they require other forms of compensation to remain in the market. As a result, relying solely on electricity market signals can lead to underinvestment and heightened reliability risks.

To bridge this gap, capacity remuneration mechanisms (CRMs) are being increasingly incorporated into electricity market design. [By providing a stable revenue stream alongside market earnings](#), CRMs can help prevent the premature retirement of existing resources and support timely investment in new capacity. For example, a CRM can drive investment in thermal generation, such as a gas plant, that can provide both adequacy and flexibility. The plant can be remunerated more for its availability than its electricity sales, especially as capacity factors decrease with increasing renewables penetration.

Beyond resource adequacy, electricity systems are facing growing flexibility needs to maintain security of supply as variable sources of generation expand. These needs span multiple timeframes, from daily balancing to seasonal and even yearly variations. For example, Europe's flexibility requirements are [projected to double by 2033](#), while markets such as [California](#) and [Australia](#) anticipate several-fold increases in storage capacity requirements to manage variability. Meeting these needs will require a diverse mix of solutions, including demand-side response, storage, interconnection and flexible generation. Solutions can be related to market design or outside of it – together, they aim to ensure systems can adapt to rapid and prolonged changes in supply and demand.

Targeted interventions are essential to achieve decarbonisation objectives in the electricity industry

Many jurisdictions have adopted clear policy targets to reduce emissions and expand the share of low-carbon technologies in electricity generation. These goals are often embedded in national or regional energy strategies and expressed as target shares for renewables, nuclear or storage capacity. For example, Great Britain has set a goal of [95% clean electricity by 2030](#), while Australia targets [82% renewable generation](#) by the same year. Similar objectives exist across Europe, Japan and the United States, where renewable support schemes and long-term targets guide investment planning. These commitments create a policy need for the evolution of the generation mix towards low-carbon technologies.

To achieve these targets on time, additional mechanisms are often needed to support low-carbon technologies. Such schemes can accelerate investment by providing revenue stability and reducing exposure to market volatility. They have driven a substantial share of renewable capacity additions over the past decade and are expected to remain central in the future. The IEA projects that more than 80% of global utility-scale renewable growth to 2030 [will depend on policy support](#). Well-designed schemes can help deliver policy objectives while maintaining market efficiency.

Long-term certainty is crucial to enable investment in strategic capital-intensive technologies

Technologies such as nuclear and large hydropower can play an important role in achieving long-term policy objectives for reliable, low-carbon electricity systems. They provide firm, dispatchable capacity that enhances reliability while delivering low-emission generation. As synchronous technologies, they also contribute essential system services such as inertia, voltage support and frequency stability, benefitting the entire system.

However, their investment characteristics often create significant challenges. Very high upfront costs and long construction periods, often exceeding a decade, mean that delays can significantly increase compounding interest payments, harming project economics. For example, the cost of a 1.6 GW nuclear unit in France [reached USD 26 billion](#), while nuclear units totalling 2.5 GW in the United States [exceeded USD 30 billion](#), both at the time of commissioning. Similar challenges exist for large hydropower, where capital costs can account for up to [90% of total costs](#). Long payback periods over asset [lifetimes that can surpass 60 years](#) likewise expose projects to price and policy volatility, making it difficult to attract private capital without additional support. Securing private financing beyond 20 years is particularly challenging, especially as counterparty risk typically grows

over such extended timeframes. Complementary mechanisms such as government-backed funding or regulatory frameworks are therefore critical. These tools help reduce investment risk, improve bankability and lower financing costs, which represent a [major share of total project costs](#). By providing predictable revenues and mitigating uncertainty, these mechanisms enable timely delivery of infrastructure essential for maintaining electricity security.

Capacity remuneration mechanisms

As previously mentioned, revenues from electricity sales alone are not always sufficient to maintain the capacity needed to meet peak demand or manage extreme conditions. To address these challenges, many jurisdictions have introduced CRMs, which provide an additional, predictable revenue stream to generators and other resources in exchange for committing to be available when needed. By supplementing volatile wholesale market revenues, CRMs help ensure resource adequacy, reduce the risk of supply shortages and encourage investment in capacity that might otherwise retire early or not be built at all. Their effectiveness, however, depends critically on design choices that balance cost, efficiency and long-term system needs while maintaining alignment with market signals.

Capacity remuneration mechanisms support resource adequacy but can face challenges with additionality, availability and cost

CRMs, while widely used, can face several challenges in practice. First, additionality can be difficult to demonstrate. The purpose of a CRM is to bring forward or retain capacity that would not exist without the mechanism. Yet in reality, it is often hard to determine whether payments are supporting genuinely additional capacity or simply rewarding assets that would have been in operation regardless.

Second, CRMs procure capacity months or even years in advance of delivery, but procured capacity may not always be available when needed most. During Winter Storm Elliott in PJM in December 2022, [around 23% of the system's capacity failed to deliver](#) when called upon, leading to emergency conditions and significant penalties for non-performance. Such events highlight the gap between contracted capacity and real system reliability, showing that financial availability does not always translate into physical performance, especially during stress events.

Third, CRMs can be costly. According to the [European Union Agency for the Cooperation of Energy Regulators](#), the total cost of CRMs across the European Union was around USD 3.0 billion in 2020, which more than doubled to USD 7.0 billion in 2024. In PJM, the cost of capacity payments was

[USD 16.1 billion for the 2026/27 delivery year](#), up from [USD 7.0 billion in 2020/21](#). While such mechanisms can reduce reliability risk, they can also encourage overinvestment or lock in inefficient technologies. Because many CRMs reward availability rather than efficiency, they can favour assets with low capital costs but high fuel consumption.

Finally, translating reliability standards into effective market mechanisms remains a core design challenge for CRMs. Unlike energy, which is directly consumed and easily measured, capacity is an administrative construct, with its demand defined by policymakers, along with how it is valued and how non-performance is penalised. Designing these mechanisms requires careful calibration of how much capacity is needed, how it should be procured and how resources should be incentivised to perform when required. At the same time, uncertainty in system conditions and evolving reliability needs make it difficult to ensure that today's mechanisms remain effective in the future. As systems transition from being capacity-constrained to energy- and flexibility-constrained, CRMs must increasingly account for storage, ramping, inertia, locational adequacy and cross-border effects, all while remaining compatible with decarbonisation goals. Well-calibrated mechanisms can support system adequacy at least cost, while poorly designed ones can hamper investment incentives, raise consumer costs and undermine the effectiveness of wholesale electricity markets.

It is important to note that jurisdictions with energy-only structures, including Australia's National Electricity Market (NEM) and the Electric Reliability Council of Texas (ERCOT), are not "pure energy-only" markets in practice. Even where there is no formal CRM, policymakers and regulators often introduce complementary interventions to maintain reliability. These designs use scarcity pricing to drive capacity investments, while resource adequacy is ensured through other market, policy and regulatory features. For example, in Australia's NEM, multiple mechanisms fill the resource adequacy gap without a formal CRM. These include the [Capacity Investment Scheme](#), the [Reliability and Emergency Reserve Trader](#), the [Retailer Reliability Obligation](#) and [state-level support schemes](#). Likewise, ERCOT is not entirely unassisted, with administrative backstops including [out-of-market procurements](#) and [demand response programmes](#).

The design of capacity remuneration mechanisms varies widely in practice across jurisdictions

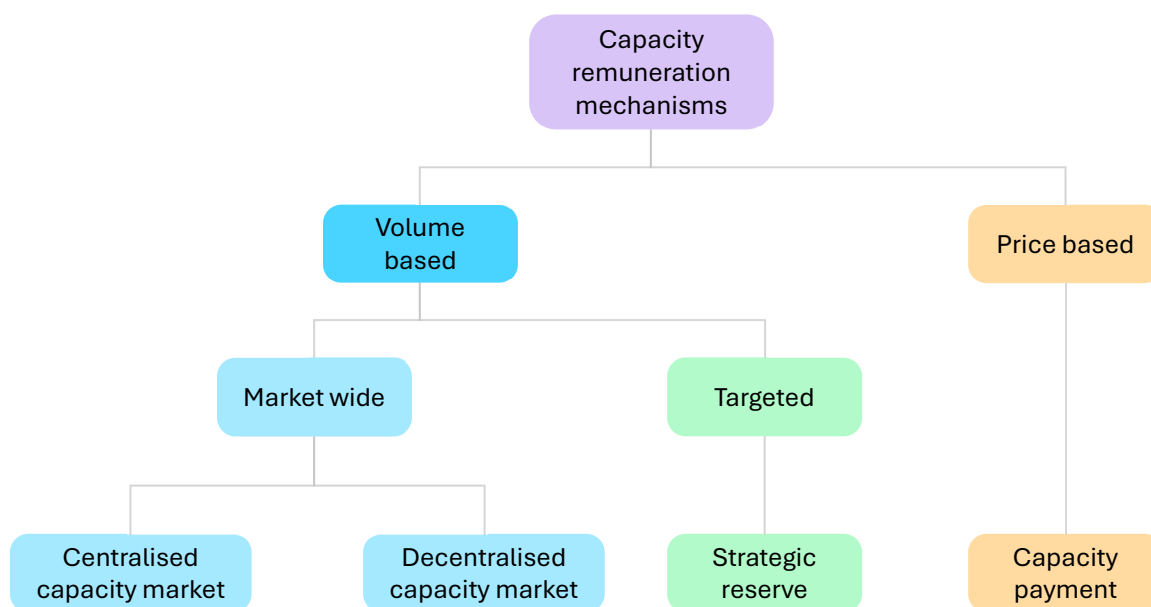
The implementation of CRMs varies widely by design, reflecting different policy priorities and system needs. CRMs can be classified as volume-based or price-based, each with distinct advantages and drawbacks.

In a price-based CRM, the payment level for capacity is set administratively, while the volume is determined by the market. These capacity payments are simple,

administratively stable and reduce capacity price volatility. However, they may not deliver the correct volume if the payment level is set too high or low, and they can lead to inefficient investment if payments do not reflect actual reliability needs.

In a volume-based CRM, the quantity of capacity required to meet a reliability standard is set in advance by a central authority, typically the system operator or regulator. The market then determines the price needed to procure the necessary capacity. Capacity can be contracted through market or non-market mechanisms. Centralised capacity markets involve auctions run by the central authority, such as in [Great Britain](#), [PJM](#) or [Japan](#), while decentralised models place obligations on market participants to contract with capacity providers, such as in [France](#) or [CAISO](#). Strategic reserves, as used in [Germany](#), contract capacity outside the market to be scheduled during scarcity events. Volume-based mechanisms ensure that a reliability standard is met, promote competition among generators and help guide investment by revealing the cost of reliability. However, their drawbacks include the need for accurate demand and reliability forecasts and the risk of over-procurement if these forecasts are too conservative.

High-level capacity remuneration mechanism taxonomy



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Notes: In volume-based mechanisms, the quantity is set administratively, while the price is determined through a market or bilateral contracting. In price-based mechanisms, it is the reverse, where prices are set administratively, and quantities are determined through the market.

Sources: IEA based on Florence School of Regulation (2019), [The EU Clean Energy Package](#); Institute for Policy Integrity (2021), [Resource Adequacy in a Decarbonized Future](#).

Beyond their overall structure, CRMs differ across several key design dimensions, including the eligibility criteria for participation, the timing and frequency of auctions, the duration of contracts awarded and the extent to which cross-border participation is permitted. These parameters have important implications for

efficiency, investment, system reliability and market integration and should be carefully considered in the context of meeting policy objectives and regional co-ordination.

Overview of selected capacity remuneration mechanisms across Europe, the United States, Australia and Japan, 2025

Market	Type	Market mechanism	Technology neutral	Participation		Performance penalties
				Cross-border	DSR	
Australian NEM	-	-	-	-	-	
France	CM	Decentralised	✓	Interconnector only	✓	✓
Germany	SR	Centralised	✓	No	✓	✓
Spain	-	-	-	-	-	
Great Britain	CM	Centralised	✓	Interconnector only	✓	✓
Japan	CM	Centralised	✓	N/A	✓	✓
US CAISO	CM	Decentralised	✓	✓	✓	✓
US PJM	CM	Centralised	✓	✓	✓	✓
US ERCOT	-	-	-	-	-	

Notes: CM = capacity market; SR = strategic reserve. The CAISO mechanism serves to compensate any shortfall [following primary capacity procurement](#) at the local deliverability area level.

Sources: IEA based on European Union Agency for the Cooperation of Energy Regulators (2023), [Security of EU electricity supply](#); Low Carbon Contracts Company (2025), [Overview of the latest capacity market auction results](#); California Public Utilities Commission (2025), [2023 Resource adequacy report](#); Japan Energy Hub (2025), [FY2028 capacity auction clears 166.2GW at 11,134 yen/kW average](#); BESS bids triple year-on-year; PJM (2025), [PJM Manual 18: PJM Capacity Market](#); European Commission (2018), [Commission Decision of 7.2.2018 on the Aid Scheme](#).

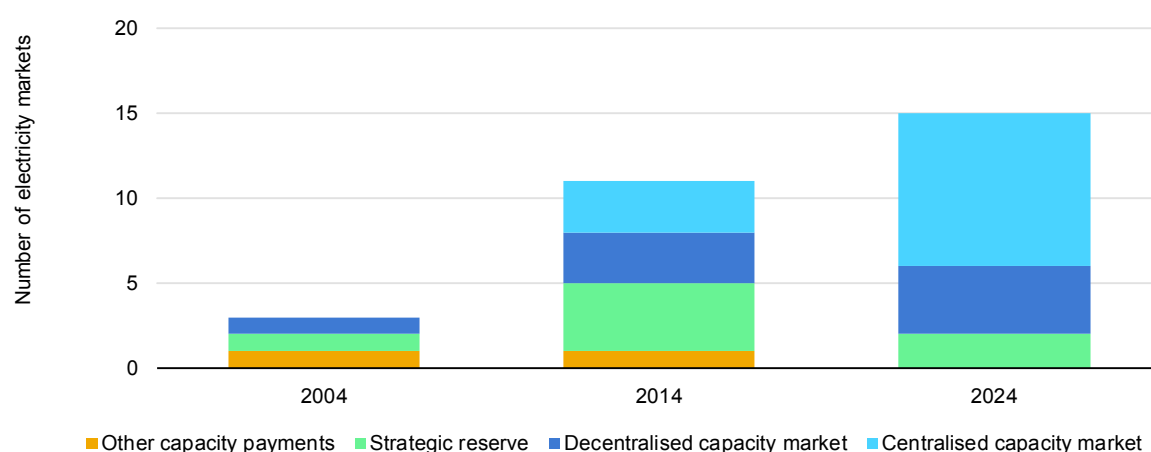
A growing number of regions are introducing capacity remuneration mechanisms

The prevalence of CRMs, mainly in the form of capacity markets, has been steadily increasing over the past two decades. US electricity markets led the way with the introduction of these mechanisms in the 2000s. European countries began implementing them in the 2010s, followed by other regions in the 2020s, including Japan. Overall, there has been a gradual shift from [strategic reserves towards capacity markets](#) in many jurisdictions, driven by the need to encourage new investments in capacity.

As of November 2025, several additional countries are also considering implementing capacity mechanisms. These include [Spain](#), which has limited interconnection with its neighbours, and [Germany](#) which has historically relied on

a strategic reserve mechanism. The growing interest in capacity markets has been reinforced by experiences from the recent European energy crisis, when prolonged periods of high and volatile electricity prices [faced pushback from societies](#). If policymakers intervene to mitigate such price spikes and volatility, for example by capping or attenuating spot prices, electricity markets require alternative mechanisms, such as CRMs, to provide the necessary long-term investment signals for resource adequacy.

Number of electricity markets with capacity remuneration mechanisms in Europe, the United States, Australia and Japan by type, 2004, 2014 and 2024



IEA. CC BY 4.0.

Note: Other capacity payments refer to capacity payments administratively determined.

New mechanisms are emerging to meet growing flexibility needs

Complementary mechanisms that only target adequacy do not necessarily guarantee the flexibility needed in the system to ensure security of supply. Some adequacy mechanisms allow demand response participation, seeking to avoid over-procurement of capacity by enabling direct cost competition between supplying electricity and reducing demand. However, many adequacy mechanisms are not designed to deliver the full range of flexibility services required beyond adequacy, nor to do so in the most cost-effective manner. Complementary mechanisms, whether as adaptations of adequacy mechanisms, dedicated flexibility support schemes or flexibility-focused ancillary services, can help incentivise investments in assets capable of providing short-term and seasonal flexibility.

Trends in mechanisms to support flexibility

In recent years, policymakers have introduced a growing number of schemes aimed at unlocking timely investments in resources needed to ensure security of

supply and reduce price volatility. As of 2025, 15 electricity markets across Europe, Japan, Australia's NEM and the United States are complemented by schemes to support the development of flexibility, 13 of which have been implemented since 2022.⁶ Most of these schemes cover electricity storage technologies, such as in Australia's NEM, Japan, CAISO and Great Britain, while several also include demand-side response support mechanisms, [as seen in France](#).

Mechanisms to support flexible supply vary widely across jurisdictions, largely depending on the extent to which policymakers are willing to assume risks that would otherwise fall on investors or developers. These mechanisms address investment challenges such as high capital costs and volatile market prices. Common approaches include investment grants that help cover upfront costs, as in [Spain](#); “cap and floor” mechanisms, as in [Great Britain](#); and “floor and share” models, as in [Australia](#). Other markets feature hybrid models that combine grants with contracts for difference to support flexible technologies.

Articulation with resource adequacy mechanisms

As mechanisms targeting flexibility become more widespread, policymakers should ensure their design is aligned with existing market arrangements, particularly CRMs. Many resources contribute simultaneously to system reliability and flexibility, and without clear co-ordination, overlapping incentives may lead to inefficiencies such as double remuneration for some technologies. A coherent approach to articulating these mechanisms helps ensure that each one reinforces the other, rather than creating conflicting signals.

Where both capacity adequacy and flexibility needs exist, complementary mechanisms can be designed either combined within a joint mechanism or as separate instruments. In a joint mechanism, [as seen in CAISO's CRM](#), two main options exist. One approach is to procure a single product that reflects both the adequacy and flexibility contributions of capacities procured, integrating requirements such as ramping capability into the design. Alternatively, firm and

⁶ CRU (2024), [DSO Demand Flexibility Product Procurement](#); European Commission (2022), [Greece - Financial support in favour of electricity storage facilities](#); European Commission (2023), [Spain: Support for innovative electricity storage projects](#); European Commission (2024), [France : mesure de soutien aux flexibilités décarbonées de court terme en France par appels d'offres](#); European Commission (2024), [Italy Support for the development of a centralised electricity storage system in Italy](#); European Commission (2022), [Lithuania – Electricity storage under the RRF](#); ; European Commission (2023), [Hungary TCTF – RRF: Aid for energy storage facilities for the integration of weather variable renewable energy sources](#); ; European Commission (2023), [Slovakia TCTF - RRF - Slovakia: Investment support for electricity storage](#); ACER (2024) [Security of EU electricity supply](#); DCCEEW (2025) [Capacity Investment Scheme](#); Ofgem (2025) [Long Duration Electricity Storage technical document](#); CAISO (2025) [2023 Resource Adequacy Report](#); METI (2025) [Ensuring a stable supply of battery storage](#); Atsumi & Sakai (2023) [Battery storage subsidy in Japan](#); Modo Energy (2023) [CfD batteries: co-location of storage in the Contracts for Difference scheme](#); California Public Utilities Commission (2025) [Self-Generation Incentive Program \(SGIP\)](#).

flexible capacity can be treated as distinct products, each with its own technical criteria, as is the case with CAISO's [resource adequacy products](#).

Where mechanisms remain separate, careful alignment is still needed to avoid inefficiencies and ensure that both adequacy and flexibility needs are met in a cost-effective manner. For instance, the demand-side response contract for difference implemented in France [is settled against capacity market revenues](#), directly linking the two mechanisms together.

Decarbonisation mechanisms

To reach electricity decarbonisation objectives, policymakers often introduce complementary mechanisms designed to help meet emission reduction goals. These mechanisms can vary widely in design. Some act directly on emissions, while others work indirectly through support for low-carbon technologies. In recent years, they have also been undergoing an evolution, where competitive procurement is preferred to fixed price support. Moreover, governments have been moving to secure investment in high-capital-cost technologies through significant taxpayer backing. Even with these changes, decarbonisation mechanisms are not always well integrated with broader market arrangements, and their effectiveness depends ultimately on design. It is important that they work in concert with wholesale electricity market signals for operation and investment, ensuring that affected assets remain responsive to system needs.

Decarbonisation mechanisms support the energy transition but face efficiency, additionality and market integration challenges

Wholesale electricity prices typically do not reflect the social cost of carbon, meaning that the environmental cost of emissions is not included in electricity prices. To correct this, policymakers have introduced a range of complementary instruments to shift operation and investment towards low-carbon technologies. These mechanisms work by penalising carbon-intensive production, rewarding low-carbon generation or both. By putting a value on carbon or supporting low-carbon alternatives, they can make cleaner technologies more financially attractive. When well designed, they complement short-term market signals and help ensure that clean energy is deployed at the pace and scale required to meet policy targets.

In practice, design and co-ordination challenges can limit their effectiveness. First, if not carefully designed, decarbonisation mechanisms can misalign incentives and create dispatch inefficiency in wholesale electricity markets. Instruments that reward production without regard for market conditions can lead to inflexible

generation behaviour. Typically, such mechanisms can encourage overproduction during periods of low prices, raising system balancing and congestion costs.

Second, similar to CRMs, decarbonisation mechanisms can suffer from additional concerns. Their aim is to encourage increased investment in, and more frequent operation of, low-carbon technologies. However, these instruments sometimes reward projects that would have been built or operated anyway, reducing cost-effectiveness and increasing the burden on consumers or taxpayers.

Finally, overlapping or poorly co-ordinated decarbonisation mechanisms can weaken price signals and adversely impact competition. When several instruments operate at once, they can send conflicting incentives to investors or lead to double payments for the same activity. Differences in jurisdictional designs can also fragment investment signals and hinder efficient cross-border trade in integrated markets. Clear policy co-ordination and consistent price signals are therefore important to ensure these mechanisms work in unison.

Ultimately, decarbonisation mechanisms play an important role in achieving national climate objectives, but they must be stable, transparent and aligned with electricity market signals. Poorly designed interventions risk undermining operational efficiency and investor confidence, the very conditions they are meant to improve. The challenge for policymakers is to use these tools in a way that delivers deep emissions reductions without compromising reliability or affordability.

A wide variety of decarbonisation mechanisms exist in practice

Policymakers use a diverse mix of instruments to accelerate the shift toward low-carbon electricity. Carbon pricing mechanisms directly internalise the cost of pollution, allowing markets to find the least-cost pathway to decarbonisation. Price-based mechanisms help overcome investment barriers linked to high upfront costs, price volatility and uncertain long-term revenues by offering predictable income for low-carbon generation. Quantity-based policies create guaranteed demand for technologies that might not otherwise emerge through market forces alone. Tax credits and fiscal incentives, such as production and investment tax credits, further support decarbonisation by lowering the cost of eligible technologies, reducing financing costs and accelerating project development. Together, these instruments increase the cost of emissions, create stable revenue streams for clean producers and guide the power system toward a low-carbon mix.

Comparison of selected decarbonisation mechanisms in place across Europe, the United States, Australia and Japan

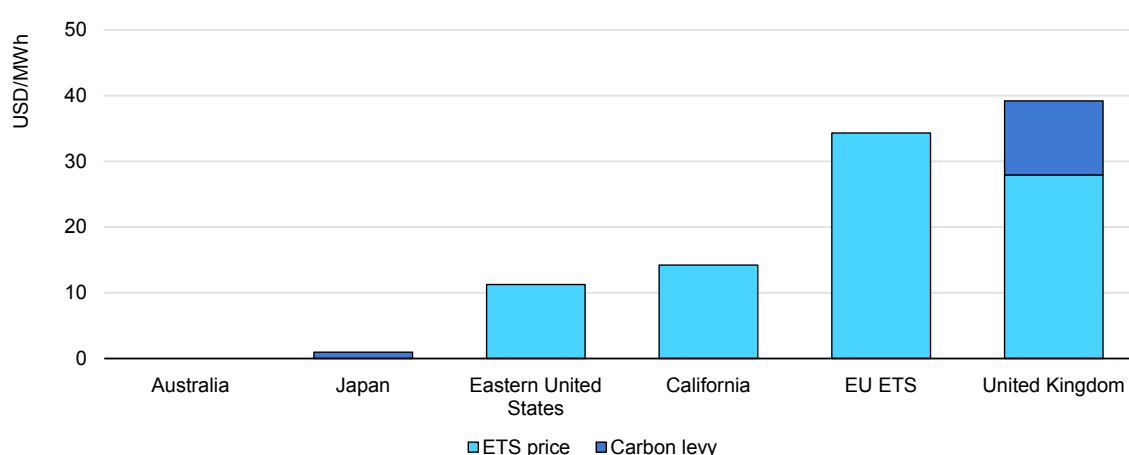
Mechanism type	Unit of remuneration	Measure	Revenue support	Example
Price based	MWh of energy generated	One-way CfD (sliding feed-in premium)	Any shortfall between the market price and the guaranteed ("strike") price is paid to generators	Germany
		Feed-in tariff	Generators receive a guaranteed total price instead of the market price	France
		Fixed feed-in premium	Generators receive a guaranteed supplementary fixed payment as well as the market price	Spain (1998-2004)
	MWh of energy generated; MWh of generation capability	Two-way CfD	As one-way CfD, but any surplus received from the market above the strike price is paid back by generators	Great Britain
Tax/fiscal incentive	MWh of energy generated	Tax credit	Generators receive a tax credit for eligible generation	United States - federal
Quantity based	MWh of energy generated; units of CO ₂ eq avoided	Renewable guarantees of origin/certificates	Generators receive certificates for qualifying generation; in voluntary schemes, generators can sell certificates separately to generated energy	European Union
	MWh of energy generated	Renewable portfolio standards	Suppliers must source a minimum proportion of energy they supply from qualifying facilities	US CAISO
Carbon pricing	Units of CO ₂ -eq	Emission trading scheme	Generators must surrender emission permits equivalent to their eligible emissions; permits are often allocated primarily through auctions	EU Emissions Trading System
		Carbon levy	Generators or suppliers must pay a levy for each unit of CO ₂ -eq	Great Britain (Carbon Price Support)

Carbon pricing

[Carbon pricing mechanisms](#), such as emissions trading schemes and carbon levies, are used in many regions to incentivise least-cost emission reductions by [increasing the cost of carbon-intensive generation](#) and improving the competitiveness of low-carbon alternatives. They are often considered [a first-best approach](#) to reducing emissions because they directly target carbon emissions through the least-cost abatement path. While effective at reducing emissions, they have often been priced too low, applied inconsistently across jurisdictions or been too volatile to provide [a strong and predictable investment signal](#). Unpredictable policy and regulatory changes, such as adjustments to market design or allowance allocation, [can contribute to this uncertainty](#). In addition, as low-carbon generation expands, the impact of [carbon pricing on electricity prices diminishes](#), reducing its ability to incentivise new investment.

Several examples illustrate how policy or regulatory changes affect carbon prices. For instance, the EU Emissions Trading System has undergone [major reforms](#) impacting aspects such as its scope, geographical coverage, emission allowances, caps and penalties. These changes have affected carbon [prices in Europe](#), which ranged from below USD 6/tCO₂ in 2016 to over USD 108/tCO₂ in 2023, before falling again. The Regional Greenhouse Gas Initiative in the United States has seen [three major reviews since its 2009 launch](#), in 2012, 2017 and in 2021-25, with the next review [planned for 2028](#). These reviews include [revisions to emissions caps](#), as well as [minimum auction prices](#), directly influencing the [resulting carbon price](#).

Emissions Trading System price and carbon levies for an average combined cycle gas plant in Europe, the United States, Australia and Japan, April 2025



IEA. CC BY 4.0.

Notes: Prices are as of 1 April 2025, or latest available. Some jurisdictions have multiple instruments in place. For example, Sweden has a carbon tax but is also covered by the EU ETS. Eastern United States refers to the Regional Greenhouse Gas Initiative, which is the common carbon market for Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont. [Carbon intensity](#) for combined cycle gas plant of 490 gCO₂-eq/kWh.

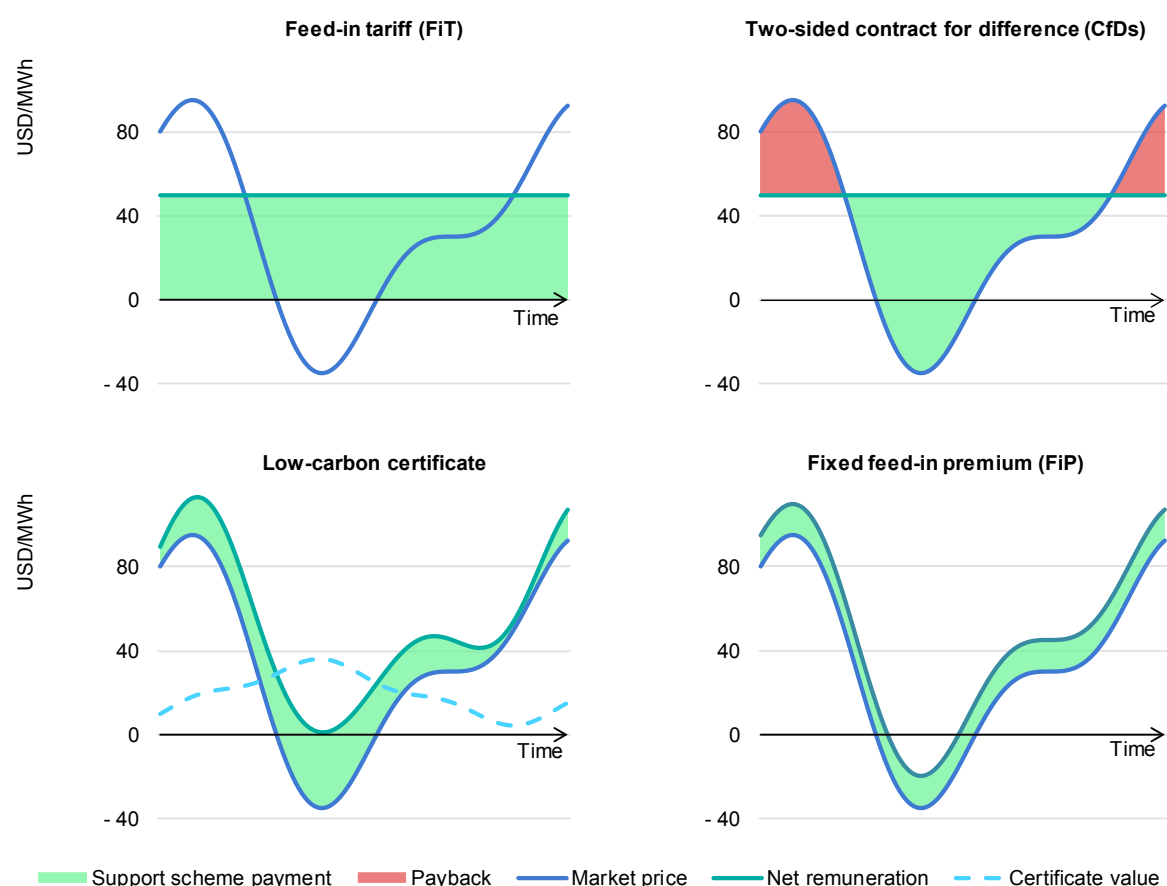
Source: IEA based on data from the World Bank (2025), [State and Trends of Carbon Pricing Dashboard](#).

The application of carbon pricing mechanisms has not always provided sufficient clarity or strength to induce the desired levels of low-carbon investment. To help address this, many jurisdictions have introduced other complementary mechanisms aiming to improve revenue certainty and reduce financial risk for low-carbon projects. These instruments differ in design and scope but share the objective of reinforcing investment signals and supporting deployment in line with decarbonisation policy objectives.

Price-based mechanisms

Price-based mechanisms, such as feed-in tariffs (FiTs), feed-in premiums (FiPs) and contracts for difference (CfDs), guarantee revenue for low-carbon generators. They reduce exposure to market volatility and revenue risk, thereby enabling investment in capital-intensive projects that might not otherwise have been viable. They do so by either providing additional revenues (FiPs) or guaranteeing prices (FiTs and CfDs). These mechanisms indirectly encourage decarbonisation by incentivising investment in, and operation of, low-carbon technologies.

Illustrative examples of low-carbon generation support schemes



IEA. CC BY 4.0.

Notes: These diagrams are illustrative only. The FiT and CfD strike prices are set to USD 50/MWh. The FiP is set to USD 15/MWh. Two-sided CfDs are also referred to as two-sided sliding FiPs. One-sided CfDs (or sliding FiPs), where no payback is due in the case of high market prices, also exist.

In a FiT scheme, generators receive a fixed payment per unit of electricity produced, regardless of wholesale electricity prices. This guarantees stable revenues but disconnects generation from market signals, potentially encouraging production even when prices are low or negative. Similarly, two-sided CfDs provide full revenue stabilisation, where the generator receives payments when market prices are below the strike price and returns excess revenue when prices are above it. This symmetric design limits windfall gains and ensures cost predictability for consumers while maintaining long-term investment certainty for low-carbon plants. A fixed FiP, in contrast, adds a premium on top of the market price, partially restoring exposure to market dynamics.

Quantity-based mechanisms

Quantity-based mechanisms generate demand for low-carbon electricity production that might not otherwise arise through market forces alone. Renewable portfolio standards guarantee demand through a mandate for low-carbon generation. Low-carbon certificates create additional revenue streams by assigning value to the environmental attributes of low-carbon generation. They are used across different jurisdictions, such as renewable energy certificates or zero-emission certificates in the United States or guarantees of origin in Europe. These revenue streams are additional to, and independent from, market revenues. Similar to price-based mechanisms, certificate-based mechanisms indirectly encourage decarbonisation by supporting investment in, and operation of, low-carbon technologies.

Voluntary certificate-based mechanisms allow consumers to choose electricity backed by renewable sources, helping stimulate demand for low-carbon generation. Mandatory mechanisms, typically backed by renewable portfolio standards in markets like [CAISO, ERCOT and PJM](#), or the [Non-Fossil Certificate system in Japan](#), require retailers or utilities to source a defined share of their electricity from low-carbon generation. The approach has also expanded beyond renewables: zero-emission certificates now provide similar support to existing nuclear plants, ensuring the continued contribution of non-emitting generation to system decarbonisation.

While these mechanisms can help drive investment and support power purchase agreements, they may also introduce inefficiencies. For example, they may encourage generation in areas or periods already rich in low-carbon sources, leading to grid congestion or curtailment. Despite these challenges, quantity-based mechanisms remain an important part of the policy toolkit for encouraging electricity sector decarbonisation. By creating additional revenue streams for low-carbon generation, they help decrease investment risk and broaden participation in clean energy markets.

III-designed decarbonisation mechanisms can lead to unintended consequences

Complementary mechanisms can distort both dispatch and investment by insulating revenues from market signals, encouraging generation during surpluses and misaligned maintenance or siting. This is particularly evident in fixed FiTs and conventional CfDs, which can fully shield generators from market price signals. Reforms such as negative-price clauses, strike price adjustments and monthly settlements aim to reduce distortions, while new CfD models seek to preserve price signals with revenue certainty.

Mechanisms based on production, such as fixed FiTs and conventional CfDs, provide generators with predictable revenues that are largely independent of market prices. Since payments are guaranteed for each unit of output, [generators have limited incentive](#) to adjust production in response to short-term price signals. As a result, they may continue generating during periods of low or negative market prices, when [electricity is already in surplus](#). Fixed FiP and renewable energy certificate schemes expose producers more directly to wholesale price movements and, therefore, cause fewer dispatch distortions. However, since revenues are still partially insulated from market outcomes, these mechanisms can weaken incentives to respond efficiently to short-term price fluctuations.

Many CfDs are linked to the day-ahead market price as the benchmark for payments. This means generators [base their decisions on day-ahead outcomes](#), even if prices later change in the intraday or real-time markets. In practice, generators may [adjust production to maximise revenue](#) rather than respond to real-time system needs. This misalignment can reduce efficiency and make balancing the system more difficult.

Furthermore, FiTs and CfDs reduce incentives for generators to align maintenance with market conditions, weakening market signals to avoid outages during periods of tight supply. This also reduces incentives for system-friendly asset design. Developers may choose sites, configurations or technologies based solely on resource potential rather than on their contribution to system balance or flexibility. Similarly, decisions on repowering or retrofitting may be distorted, leading to either overinvestment or underinvestment relative to system needs. Ensuring that support mechanisms maintain a sufficient link to market outcomes is critical to promote efficient investment and reliable system operation.

Decarbonisation mechanism designs are evolving

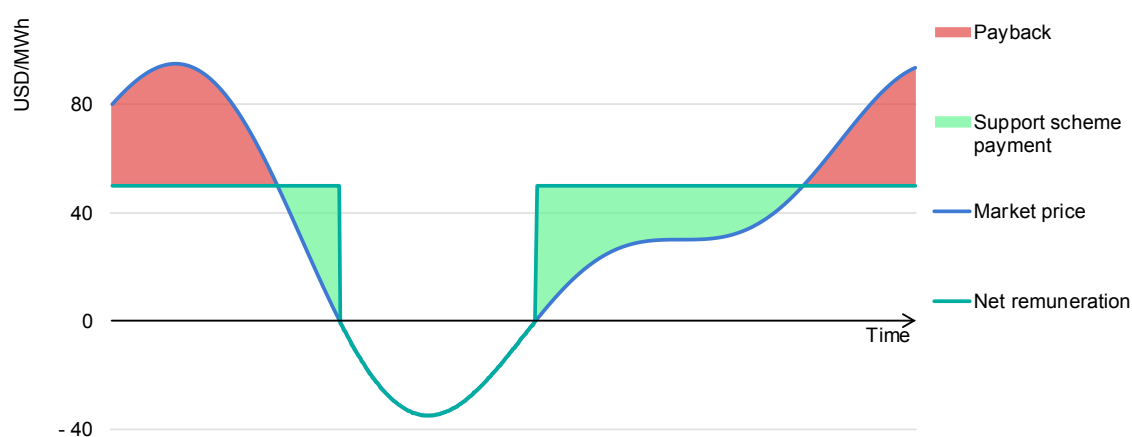
As power systems transition toward higher shares of variable renewables and new low-carbon technologies, decarbonisation mechanisms are adapting to maintain investment while minimising market distortions. Policymakers are refining these instruments to better align with evolving market dynamics: combining competitive

allocation, adaptive revenue designs and more targeted support for capital-intensive projects. This evolution reflects a broader shift from static, output-based incentives toward flexible, risk-sharing frameworks that preserve market efficiency while delivering long-term investment certainty.

Refining mechanisms to minimise market distortions

Policymakers in several jurisdictions have implemented adjustments to conventional CfDs to [better align incentives](#) with short-term price signals. First, negative-price suspension clauses have often been added to remove incentives to produce during times of electricity generation surplus. In Europe, [most markets with two-sided CfDs](#) include suspension clauses in times of negative prices, as required by [EU guidelines](#). Second, incentives to respond to market prices can be embedded in the strike price of CfDs. In Spain, for instance, the payment received under the CfD is [subject to an adjustment](#) depending on market prices and the technology. Third, [averaging reference prices over longer periods](#), such as on a monthly basis, exposes generators to short-term price signals over the averaging period.

Illustrative example of a two-sided contract for difference with suspensions during negative price hours



IEA. CC BY 4.0.

Notes: This diagram is illustrative only. The CfD strike price is set to USD 50/MWh.

In Europe, [alternative approaches](#) for renewable CfD designs are also under consideration to better align with system requirements. These include [financial CfDs](#) and [yardstick CfDs](#), which decouple payments from physical output to reduce dispatch distortions and mitigate volume risk. A design using capability-based rather than generation-based remuneration was selected for offshore wind [tenders in Denmark](#) in 2025. Although not yet implemented in practice, these models aim to preserve market signals while providing revenue certainty and encouraging investment decisions that reflect system value.

Beyond Europe, emerging policy designs also aim to address specific market gaps that conventional CfDs do not fully cover. In Australia's NEM, two new approaches illustrate this evolution. The proposed [Enhanced System Efficiency Mechanism](#) is intended to provide long-term investment certainty. It addresses only the risks not already managed by the market, using derivative markets to manage spot-price risks by establishing a link between short-, medium- and long-term economic signals. Similarly, the [Capacity Investment Scheme](#) introduces a revenue-underwriting model that establishes both a revenue floor and cap over an agreed period, balancing risk between investors and consumers. These mechanisms represent a shift towards more adaptive, risk-sharing frameworks that maintain investment confidence while preserving short-term market efficiency.

Despite these innovations, legacy schemes, even if phased out or replaced with new schemes designed to better interact with markets, will continue to influence market behaviour for years. This legacy effect complicates efforts to improve market signals for these assets. Policymakers must account for these residual impacts when designing new support mechanisms and co-ordinating market reforms. At the same time, retroactive changes to existing agreements, such as the transition from fixed support to a CfD for early [offshore wind farms in Belgium](#), should be carefully considered, as they may undermine investor confidence and raise the cost of capital for future projects.

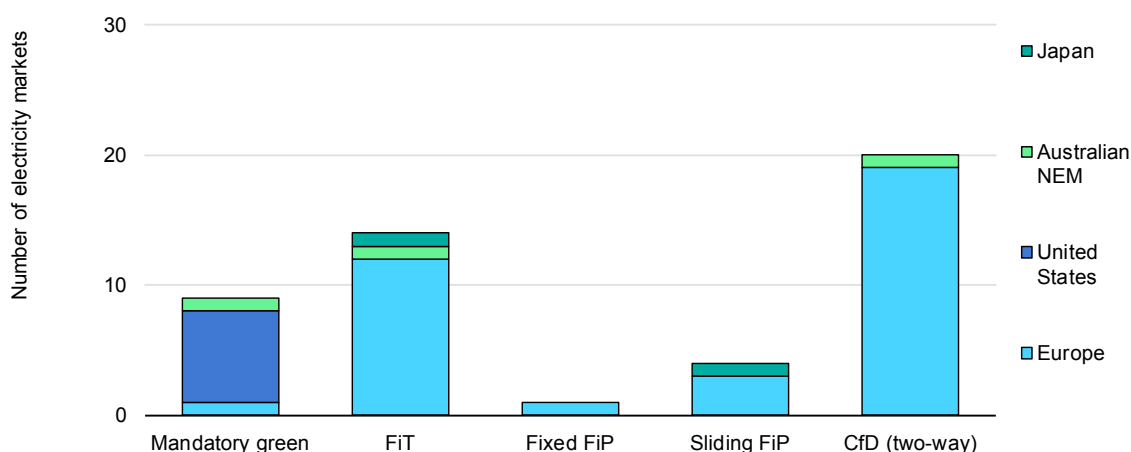
Transitioning from fixed-price incentives to competitive auctions

Decarbonisation mechanisms have evolved significantly over the past two decades, especially in how remuneration is determined, whether through fixed, administratively set rates or through competitive allocation. Fixed-price mechanisms, such as FiTs or fixed FiPs, offer investors predictable long-term revenues but can lead to higher system costs if support levels are set above market prices. Competitive auctions, in contrast, introduce market discipline by awarding contracts to projects offering the lowest price for a defined capacity or production volume.

Two-way CfDs and other auction-based mechanisms have become increasingly prominent, especially across Europe. These schemes enable governments to manage new capacity while containing costs through competition. In Europe, most utility-scale projects have transitioned from [20-year fixed-price FiTs to auction-based two-way CfDs](#), reflecting a broader shift toward market-based support. Even so, FiTs continue to be important for small-scale and distributed generation. In many jurisdictions, including France and Germany, [FiTs remain available](#) for new residential and commercial solar PV systems, where administrative simplicity and investment certainty outweigh the benefits of competitive procurement. The move toward competitive allocation, mainly across Europe, has improved cost

efficiency and policy control, while the continued use of fixed-price mechanisms for smaller systems can help maintain broad participation and diversity in low-carbon supply.

Number of electricity markets with renewable support schemes across Europe, the United States, Australia and Japan by type, 2025



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Note: Sliding FiPs are also known as one-way contracts for difference. Europe refers to the EU markets, with the addition of the United Kingdom, Norway and Luxembourg.

Adapting support for high-capital-cost technologies

Few new large-scale, high-capital-cost projects, such as nuclear and large-scale hydro, are being developed today without dedicated, government-backed support. Their high upfront costs, long construction periods and uncertain revenue outlooks make them difficult to finance under purely market-based conditions. CfDs are emerging as a key form of support for these projects and are planned or already operational for nuclear in five European countries. The 2024 EU electricity market design reform established [two-sided CfDs as the default](#) form of support for all new capacity investments, including nuclear. [Design options vary significantly](#), reflecting differences in market structure and policy objectives.

While CfDs are being used for high-capital-cost technologies, more bespoke support is often necessary. The [regulated asset base model](#), expected to be implemented in the United Kingdom for the [Sizewell C nuclear project](#), combines a revenue guarantee with cost recovery during construction. This reduces financing risk for long-lead projects by allowing partial recovery of efficient costs before commissioning. The model [allocates risk differently](#) to CfDs, shifting some of the construction risk to electricity buyers under strict regulatory oversight. State ownership [covers the bulk](#) of nuclear capacity in Europe, while private operation is more common in the United States.

Overview of support and de-risking mechanisms in place and planned for high-capital-cost technology in Europe, the United States, Australia and Japan, 2025

Market	Capital-intensive technology supported	Type of support	Status and capacity
Australia (NEM)	Pumped hydro storage	State equity financing	Construction underway , 2.2 GW
France	Nuclear	State-subsidised loan	Planned, 10 GW Penly , Gravelines , Bugey
Germany	Hydrogen-ready gas and combined heat and power	Central capacity remuneration mechanism	Planned
United Kingdom	Nuclear	Regulated asset base; CfD (investment contract)	Planned and approved, ~6.5 GW
Japan	Renewables, nuclear, decarbonised thermal power, long-duration energy storage, liquified natural gas	Long-term decarbonised capacity auction	In place
United States (federal)	Hydro	Ex-post feed-in premium	In place
United States (PJM and others)	Nuclear	Zero-emission certificate	In place
United States (federal)	Nuclear	Production tax credit	In place

Chapter 5: Recommendations

Overall, this analysis has shown the importance of taking a holistic and contextualised view of wholesale electricity market design. Each component, from short-term markets to medium- and long-term markets, together with complementary policy mechanisms, plays a unique and necessary role in supporting secure, affordable and sustainable electricity systems.

Chapter 2 demonstrated that short-term markets have proven effective in delivering secure and efficient dispatch, even in highly complex systems. However, as electricity systems become more decentralised and weather-dependent, these markets need to evolve to better reflect system conditions and the capabilities of all technologies.

Chapter 3 highlighted the increasing role of medium- and long-term markets in supporting investment confidence and managing risk, particularly as short-term markets become more volatile and investments increasingly capital intensive. Yet, structural challenges remain, particularly in terms of market depth, liquidity, transparency and participation.

Chapter 4 explored the role of complementary mechanisms, such as capacity remuneration and decarbonisation mechanisms, in supporting electricity system objectives. When well designed, these instruments enhance rather than replace market signals, translating policy objectives into stable investment conditions while preserving market efficiency. However, when poorly designed, these mechanisms can have unintended consequences, including market distortions that lead to system inefficiencies and higher costs.

Together, these insights point to three central reform priorities for wholesale electricity markets. While the specific design choices will vary by context – reflecting the unique characteristics of each market, such as its existing arrangements, system needs, resource endowment and institutional framework – the following three priorities are widely applicable across designs:

1. Maintain the effectiveness of short-term markets while adapting them to more dynamic and decentralised systems.
2. Reform and strengthen medium- and long-term markets to manage risk and support a capital-intensive transition.
3. Enhance co-ordination across markets and policy frameworks to deliver broader electricity system objectives.

In addition, as electricity becomes increasingly variable, flexibility has become an important consideration in electricity market design. A flexible electricity system cannot be secured through a single product or isolated reform. Instead, it should be treated as a cross-cutting guiding principal across market design and areas of reform. This means ensuring that short-term markets, medium- and long-term markets, and complementary mechanisms integrate flexibility in ways suited to the needs of each electricity system. Doing so will be critical to maintaining resilient, secure and efficient electricity systems.

Finally, market design should be viewed as one element within the broader evolution of electricity systems. Market reform alone cannot deliver all objectives. Parallel progress in energy efficiency, grid modernisation and expansion, and accelerated permitting and connection processes is equally important to enable secure, affordable and sustainable electricity systems. It is essential that these different reforms progress in predictable ways and evolve in step with one another to provide stability and coherent signals for system development and investment confidence.

Principles for executing market reform

Experience shows that the success of electricity market reforms depends not only on *what* changes are introduced but also on *how* they are carried out. The following principles highlight practical considerations that can help ensure reforms are effective in practice, trusted by stakeholders and aligned with system needs.

- **Tailored and context-specific:** Market reforms should reflect local market structures, institutional arrangements and legacy commitments. Drawing on international experience while grounding design in the local context helps ensure reforms reinforce rather than disrupt market functioning and investment signals.
- **Transparent and predictable:** Effective reforms depend on clarity in both process and implementation. This may include publishing and clearly communicating implementation timelines, conducting consultation through well-defined channels and setting out decision-making processes in a clear and consistent manner. Such transparency can reduce uncertainty, support investor confidence and strengthen long-term decision-making.
- **Pragmatic and deliverable:** Successful reforms are not only well designed in theory but workable in practice. This may involve prioritising the most critical reforms, tailoring design to local market conditions and institutional capacity, simplifying rules where added complexity brings little value and phasing implementation in line with available resources. Such pragmatism

increase the likelihood that reforms are delivered on time and clearly understood by stakeholders.

- **Holistic and adaptable:** Market reforms should be considered within the overall market framework, not in isolation. This requires recognising interactions across different markets, assessing how new measures affect existing arrangements and aligning reforms with broader policy and regulatory objectives. At the same time, reforms should be adaptable, with mechanisms for periodic review and adjustment, ensuring they evolve predictably alongside changing system needs.

Maintain the effectiveness of short-term markets while refining them for more dynamic and decentralised systems

Short-term electricity markets have proven effective in delivering secure and efficient dispatch. As systems evolve with rising shares of variable generation, increasing decentralisation and the emergence of new technologies, the challenge is to preserve these proven strengths while refining market design to reflect more dynamic system conditions. Some reforms are complex to implement because they may require extensive IT upgrades and difficult rule changes, or be perceived to disadvantage existing participants or negatively affect investor confidence. This creates tension between maintaining the clarity and reliability of established market functions and introducing new features that support flexibility and decentralised participation. Our analysis points to the following recommendations for preserving and refining short-term markets, recognising that the specific design choices will need to reflect the local context.

Preserve the core features that underpin effective short-term markets. The effectiveness of short-term markets stems from a set of well-established design features, with each serving an important function. In the main wholesale market, marginal pricing and pay-as-cleared auctions ensure that resources are dispatched in order of cost and that all cleared resources receive the same price, creating transparent signals, rewarding efficiency and encouraging innovation. Day-ahead markets or equivalent mechanisms play a critical role in co-ordinating the system, enabling resources to be scheduled efficiently, ensuring that capacity is available to meet expected demand and providing a reliable reference price for longer-term contracts. Equally important are markets that remain open close to real time, particularly as variable sources of generation expand. These markets allow for continuous adjustment to forecast errors, incentivise flexible resources and support secure balancing of demand and supply. Preserving these features

is essential for short-term markets to continue delivering efficient, reliable and transparent outcomes as electricity systems become more dynamic and decentralised.

Enhance temporal price signals to better reflect system dynamics and flexibility needs. Increasing the temporal granularity of market signals, for example, through shorter settlement intervals or later gate closures, can provide more dynamic pricing that better reflects system conditions. This can reward resources that are able to adjust flexibly, improve incentives for demand-side participation, and strengthen the role of fast-responding technologies. However, reducing time intervals can be costly to implement, add complexity for market participants and may increase exposure to price volatility for buyers. While this can create challenges for some participants, sharper price signals also better reflect real system conditions, helping to support more efficient operational and investment decisions across both demand and supply. In some markets, such as Australia's National Electricity Market (NEM), reforms have already increased temporal resolution, meaning additional changes may not deliver significant benefits over the short term. Reform efforts should therefore carefully weigh the potential efficiency gains of sharper temporal signals against the costs and complexity of implementation.

Strengthen locational price signals to reflect network realities and manage congestion. Greater locational granularity in price signals can better reflect grid constraints, the value of flexibility in different parts of the system and the costs of congestion. It can also guide the efficient siting of generation, storage and demand response, while reducing the need for costly redispatch. Some market designs, notably in the United States, have already increased the granularity of their price signals through nodal designs. In contrast, zonal systems show wide variation in how closely price signals reflect grid conditions, and in some cases, limited locational granularity has contributed to inefficiencies and higher system costs. However, enhancing granularity can be complex. Concerns often arise over impacts on legacy assets, where revenue outcomes may shift relative to expectations at the time of investment, raising questions of fairness and regulatory stability. More granular zones may also result in uneven regional price outcomes, creating distributional impacts, while financial market liquidity can fragment as trading volumes spread across more pricing areas. Reform efforts should therefore balance the efficiency gains from sharper locational signals against these wider implementation challenges. Establishing regular and transparent review cycles for zonal boundaries can help price signals evolve with system needs while providing a predictable change management process for market participants.

Enable broader participation across all resource types. Market designs should ensure that any resource capable of providing system value can participate and

be fairly remunerated, regardless of size or technology. While designs have evolved to broaden access through measures such as reducing minimum bid size requirements and enabling aggregation, other barriers continue to limit participation. In many markets, minimum bid steps remain above the scale of typical distributed or aggregated resources, and trading costs can be disproportionately high for smaller actors, meaning that formal access does not always translate into effective participation. In addition, while value stacking has been made easier in many central dispatch market designs, barriers remain in some self-dispatch markets where energy and ancillary services are procured separately, limiting the ability of some technologies, such as batteries, to capture the full range of services they can provide. Addressing these gaps, without introducing market distortions, is essential to ensure all resources can compete fairly and contribute fully to system needs.

Ensure government interventions are exceptional, transparent and temporary. Market interventions should never be the first port of call, but governments may consider them as part of a broader toolkit for use in exceptional circumstances. In many cases, targeted support for vulnerable consumers and industry can be provided outside the market. Where market interventions are deemed necessary, they must be transparent, maintain clarity and consistency in regulatory frameworks, and avoid undermining market signals and investor confidence. Experience and lessons learned from the 2021-22 global energy crisis underscores these principles. Good practice includes clearly defining the conditions under which interventions may be triggered, preparing response measures with industry in advance and establishing clear exit conditions at the time of implementation.

Reform and strengthen medium- and long-term markets to manage risk and support a capital-intensive transition

Medium- and long-term markets – encompassing forwards, futures and power purchase agreements, and collectively referred to as “long-term markets” – play a central role in electricity market design. They support the development of capital-intensive assets and protect market participants from short-term price volatility. However, long-term markets often offer limited hedging opportunities and provide inadequate accessibility for small and medium-sized market participants. As a result, strengthening long-term markets is necessary in many jurisdictions to ensure they fulfil their role effectively. They must evolve to reflect the changing physical realities of the electricity system, better reflect market participants’ hedging needs and integrate more effectively with wider market arrangements. Our analysis points to the following recommendations to reform and strengthen long-term markets.

Ensure the availability of a range of well-functioning long-term market options to serve different needs. Long-term markets are essential to manage price risks and provide revenue certainty for investors. Well-functioning market designs should offer a mix of instruments that reflect the diverse needs of participants, such as varying hedging timeframes, production and demand patterns, as well as provide different options to access these markets. While physical electricity systems have evolved, long-term markets have not kept pace. Where gaps in hedging needs exist, the market design framework should be reviewed to enable the emergence of the necessary long-term contracts, particularly in futures markets. Policymakers should therefore conduct regular market monitoring and assessments, investigating elements such as the availability of products across timeframes and contract types. While bilateral contracts remain at the discretion of market participants, policymakers should work with stakeholders and power exchanges to identify and address barriers to the evolution and addition of futures products that reflect emerging system needs.

Lower barriers to entry to enable wider participation. Barriers to entry, such as high collateral requirements, creditworthiness thresholds and contract complexity continue to limit participation in long-term markets, especially for small and medium-sized participants. Broader access would enable more market participants to hedge price risks more effectively, especially in forwards and futures markets where a wide variety of buyers seek to hedge. Policymakers could explore public credit guarantees, reviews of collateral and margin call requirements, and measures to reduce the complexity of signing bilateral contracts. Although not every market option needs to be available to all stakeholders, each market participant should have access to contracts suited to their needs.

Explore options to bridge the tenor gap and support long-term hedging in electricity markets. The tenor gap – the mismatch between developers' need for long-duration contracts and buyers' preferences for short-term commitments – limits liquidity in markets with contract durations longer than 3 years and can hinder investment in capital-intensive assets. To address this, a potential option is to consider establishing a central entity that contracts long term and resells shorter-term contracts to buyers, a model currently explored in the [Australian NEM Review](#). Another option is to consider reinforcing incentives for buyers to hedge over longer timeframes. However, while retail frameworks play a key role in shaping retailers' ability and incentives to manage long-term risks, retail market design is beyond the scope of this report.

Consider implementing market-making schemes to drive liquidity in long-term markets where needed. Liquidity is critical for enabling access to hedging opportunities. Market-making schemes, where an entity commits to buying and selling electricity products within a narrow price range, support liquidity by

providing consistent offers. These schemes, under consideration in Australia's NEM and Japan, make trading cheaper and easier for market participants. However, the cost of remunerating market makers should be assessed, along with their likely effectiveness in markets with persistent imbalances between buyers and sellers.

Ensure that long-term market participants remain responsive to short-term market signals. While long-term contracts are essential for managing investment and price risks, some designs can inadvertently weaken incentives for market participants to respond to real-time system needs. For example, contracts settled purely on output can reduce the incentive to adjust generation in response to short-term price signals, particularly during periods of oversupply or negative prices. Likewise, the use of green certificates to meet sustainability goals should be carefully co-ordinated with market operations to avoid discouraging flexibility. Policymakers can strengthen alignment between long-term investment frameworks and system needs by promoting contract structures and certificate schemes that preserve exposure to real-time price signals and encourage behaviour that supports efficient and reliable system operation.

Improve transparency in long-term contracting while protecting commercial confidentiality. Limited visibility of prices, volumes and contract terms in bilateral arrangements such as power purchase agreements or forwards reduces the ability of market participants and policymakers to assess market conditions and weakens long-term price signals. It can also obscure the impact that low-carbon technologies have on market prices, leading to misconceptions about their role in keeping electricity affordable. Enhancing transparency, such as through aggregated or anonymised data, can strengthen confidence in market outcomes, as well as improve investment decisions and system needs assessments. Policymakers should explore approaches such as regular publication of aggregated contract information, reporting requirements for standardised products and voluntary disclosure frameworks developed with industry to improve price discovery while safeguarding sensitive commercial details.

Enhance co-ordination across market and policy frameworks to deliver electricity system objectives

While market signals are essential for guiding where and when resources are most valuable, they do not guarantee that investment will occur at the scale or speed required. Market imperfections, policy choices and investor risk appetite can all contribute to gaps in market outcomes, system needs and policy targets. Complementary mechanisms play an important role in bridging these gaps, but their design must be carefully co-ordinated with short- and long-term markets. Poorly designed mechanisms can distort short-term signals, crowd out long-term markets and increase policy risk, while well-designed ones can reinforce markets

and mobilise timely investment. Our analysis points to the following recommendations, which highlight the importance of targeting complementary mechanisms to specific needs and integrating them coherently and predictably within market frameworks.

Design complementary mechanisms to target specific objectives.

Policymakers should design complementary mechanisms with clear objectives and a defined purpose, targeting specific gaps that markets cannot address alone. These may be related to resource adequacy, flexibility, decarbonisation or the development of strategic technologies. A wide range of design options is available to accommodate the type, level and duration of support, and eligibility of technologies. Hence, policymakers should be explicit on mechanism objectives. By tailoring designs to clearly defined purposes, mechanisms can mobilise timely investment while preserving the efficiency benefits that markets can deliver.

Align complementary mechanisms with market frameworks and signals.

Once introduced, complementary mechanisms must operate coherently with the wider market framework. Poorly designed schemes can decouple remuneration from system conditions, weaken incentives for efficiency and flexibility, or limit the role of long-term markets. To be effective, they should reinforce short-term price signals while complementing existing long-term markets. A key design challenge is balancing stable revenues for investors with sufficient exposure to market signals to ensure resources respond efficiently to system needs. As the share of resources operating under complementary schemes increases, often across extended time horizons, designs must consider interactions across market layers and time horizons to maintain the efficient delivery of electricity system objectives.

Support investment outcomes through stable and predictable frameworks.

As a growing share of investments rely on complementary mechanisms, their effectiveness in mobilising capital depends on stability and predictability over time. Existing mechanisms should remain stable, since sudden or retroactive adjustments can undermine confidence, raise the cost of capital and slow the pace of investment. However, the design of new mechanisms should evolve as system needs change and collective learning on their implementation progresses internationally. An example is the evolution of contracts for difference, which have changed over time to better balance investor risk with market efficiency. The challenge for policymakers is therefore to provide clear and credible commitments for existing schemes while ensuring that new mechanisms are updated over time to reflect changing system needs and insights gained from past designs.

Refine capacity remuneration mechanisms to improve efficiency and system integration.

Capacity remuneration mechanisms have been instrumental in maintaining reliability standards and ensuring secure electricity supply where market signals alone are insufficient. However, as electricity systems evolve, their

design must continue to improve to reflect changing system needs. Policymakers should ensure capacity remuneration mechanisms are inclusive of important technologies, such as flexible technologies, and demand-side resources. Alignment with energy and ancillary service markets, along with regional co-ordination, can enhance efficiency and reduce overall adequacy costs. At the same time, stable and transparent frameworks remain essential to sustain investor confidence as capacity remuneration mechanisms adapt to new technologies, flexibility requirements and deeper market integration.

Use decarbonisation mechanisms strategically to achieve emissions goals while preserving market efficiency. In the absence of broad and consistent carbon pricing, complementary decarbonisation mechanisms remain important to drive emissions reductions and accelerate the deployment of low-carbon technologies. Policymakers should design these mechanisms to address specific barriers, such as high capital costs and revenue uncertainty, while avoiding adverse impacts on market signals. To ensure cost-effective outcomes, designs should promote competition, maintain exposure to market prices where possible and be regularly reviewed to adapt to evolving system conditions and technological progress.

Annex

Abbreviations and acronyms

ACCC	Australian Competition and Consumer Commission
ACER	European Union Agency for the Cooperation of Energy Regulators
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFRY	ÅF Pöyry
AI	Artificial Intelligence
APC	Administered Price Cap
ASX	Australian Securities Exchange
BESS	Battery Energy Storage System
CAISO	California Independent System Operator
CfD	Contracts for Difference
CM	Capacity Market
CRM	Capacity Remuneration Mechanisms
CRU	An Coimisiún um Rialáil Fóntais (Commission for Regulation of Utilities)
DC	District of Columbia
DCCEEW	Department of Climate Change, Energy, the Environment and Water (Australian Government)
DER	Distributed Energy Resource
DESNZ	Department for Energy Security and Net Zero
DSO	Distribution System Operator
DSR	Demand Side Response
EDF	Électricité de France
EDP	Energias de Portugal
EEX	European Energy Exchange
EIA	Energy Information Administration of the U.S. Government.
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ETS	Emissions Trading System
EU	European Union
FERC	Federal Energy Regulatory Commission
FiP	feed-in premium

FiT	feed-in tariff
HV	High Voltage
ICE	Intercontinental Exchange
IEA	International Energy Agency
IEEJ	The Institute of Energy Economics, Japan
ISEP	Institute for Sustainable Energy Policies
ISO-NE	Independent System Operator New England
ISP	Integrated System Plan
IT	Information Technology
JEPIC	Japan Electric Power Information Center
JEPX	Japan Electric Power Exchange
JPX	Japan Exchange Group
LNG	Liquified Natural Gas
METI	Ministry of Economy, Trade and Industry of Japan
MISO	Midcontinent Independent System Operator
MPC	Market Price Cap
N2EX	Joint venture between Nord Pool Spot and Nasdaq OMX Commodities AS
NEM	National Electricity Market
NESO	National Energy System Operator
NG	Natural Gas
NYISO	New York Independent System Operator
O&M	Operations and Maintenance
OCCTO	Organization for Cross-Regional Coordination of Transmission Operators
Ofgem	Office of Gas and Electricity Markets
OMIP	Operador do Mercado Ibérico de Energia (Iberian Energy Market Operator)
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PPA	Power Purchase Agreement
PUCT	Public Utility Commission of Texas
PV	Photovoltaic
RAP	Regulatory Assistance Project
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
RRF	Recovery and Resilience Facility
RTE	Réseau de Transport d'Électricité (Electricity Transmission Network)
RWE	Rheinisch-Westfälisches Elektrizitätswerk
Solar PV	Solar Photovoltaics
SR	Strategic Reserve
SSP	Southwest Power Pool
S&P	Standard & Poor's
TCTF	Temporary Crisis and Transition Framework

TEPCO	Tokyo Electric Power Company
TransnetBW	Transmission System Operator for Baden-Württemberg
TSO	Transmission System Operator
TXU	Texas Utilities
TTF	Title Transfer Facility
US	United States of America
VRE	Variable Renewable Energy

Units of measure

AUD	Australian dollar
CO ₂ -eq	Carbon dioxide equivalent
EUR	Euro
GBP	British Pound Sterling
gCO ₂ -eq/kWh	grams of CO ₂ equivalent per kilowatt-hour
GW	Gigawatt
GWh	Gigawatt-hour
Hz	Hertz
JPY	Japanese yen
km	kilometre
km ²	square kilometre
kW	Kilowatt
kWh	Kilowatt-hour
kWh/kW/year	kilowatt-hour per kilowatt per year
MTU	Market Time Unit
MW	Megawatt
MWh	Megawatt-hour
tCO ₂	tonnes of CO ₂
USD	United States Dollar

Throughout the report currency exchange rates have been used from the following source: Federal Reserve (2025), [Foreign Exchange Rates](#).

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