Integrating Distributed Energy Resources in China

Lessons from international experience

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Abstract

Like no other country in the world, the People's Republic of China (hereafter, "China") is witnessing rapid growth in distributed energy resources (DERs), including rooftop solar photovoltaics, battery storage and electric vehicle (EV) chargers. As China advances towards its carbon peaking and neutrality goals, these resources offer a unique opportunity to support a more flexible, efficient and resilient power system, provided their integration is well-managed.

This report analyses recent trends in DER deployment across China and highlights the emerging challenges their growth poses for power system planning and operation, calling for renewed attention to distribution grids. It puts China's development of DERs in international perspective by drawing on experiences from jurisdictions that are further along in their DER integration journey, such as Australia, Europe, Japan and the United States. Through cross-country comparison, the analysis identifies lessons and best practices that are relevant to China's evolving power sector and regulatory landscape. It offers insights into the role of policy, regulation, market design, digital infrastructure and institutional frameworks in unlocking the full potential of DERs.

The report provides tailored policy guidance to support Chinese decision makers in designing effective strategies for DER integration through 2030 and beyond. At the same time, it can serve as a valuable reference for Chinese and international experts working to develop coherent, forward-looking approaches to DER integration.

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Executive summary

Rapid DER expansion creates new considerations for China's distribution networks

China is experiencing an unprecedented boom in distributed energy resources (DERs), including rooftop solar photovoltaics, battery storage, electric vehicles (EVs) and flexible electric loads. Typically located behind-the-meter, these small assets can deliver significant benefits to China's power system if efficiently integrated, including enhanced flexibility, strengthened electricity security and lower system costs. Driven by declining technology costs and supportive national programmes, DER deployment has accelerated across rural communities and commercial and industrial buildings. By 2024, distributed photovoltaics (DPV) accounted for 40% of the country's total solar capacity, up from 30% four years earlier, while the stock of electric cars grew by more than 650% over the same period. This rapid deployment is reshaping China's power system and placing increasing pressure on distribution networks to adapt.

The speed of DER uptake has outpaced the readiness of the grid in several provinces. While China has succeeded in reducing and maintaining low curtailment rates over the past decade, localised grid constraints have emerged. In 2024, congestion and connection restrictions were reported in 11 provinces, where low demand or limited investment in distribution networks resulted in DPV injection exceeding local hosting capacity. Limited system flexibility, mismatches between supply and demand across time and location and a lack of operational visibility into behind-the-meter assets have further exacerbated these constraints. Other DERs, such as battery storage and demand response, could help alleviate them, but China's market and regulatory conditions have so far constrained their full participation as system assets.

Policy responses have begun to emerge, signalling a turning point in integrating DER into power grids and markets. National regulations introduced in 2025 cancelled the profitable and widely implemented guaranteed purchase option for the largest DPV installations, requiring instead self-consumption models. At the same time, high-level policy documents are promoting market access for distributed generation and aggregators. Grid companies have announced record levels of investment and are assessing how much additional capacity the grid can safely accommodate to better guide DER deployment. But the challenges ahead require more systemic reforms.

The IEA's three-pillar strategy, centred on modernising system operations, enabling progressive market integration and advancing regulatory reform,

provides a pathway for China to integrate DERs securely and at scale by 2030, while also laying the foundations for longer-term system transformation. Informed by international experience from countries at the forefront of DER deployment, this approach can help China harness the full benefits of DERs and support its broader goal of a secure, affordable and low-carbon power system.

Pillar 1: Enhancing distribution-level operations through visibility and local flexibility

As DER capacity grows, secure system operations increasingly depend on improved forecasting, visibility and control of decentralised assets. While simplified connection procedures and minimal technical requirements have supported China's rapid DER deployment, they have also created operational blind spots in some regions. Grid operators lack real-time visibility and control of DERs, limiting their ability to forecast demand, ensure reliability or proactively address congestion. Additionally, the lack of flexibility of distribution networks reduces their capacity to absorb excess generation, especially during midday hours when solar output peaks and demand is relatively low.

To address these challenges before they become more widespread across networks, China can benefit from building on its smart grid advancements and centralised planning strengths through targeted improvements in distribution operations, by adopting more data-driven practices and improving local flexibility. Key recommendations for grid operators and regulatory authorities include:

- **Enhance DER visibility and controllability** by implementing monitoring, control and real-time forecasting requirements for new DER installations, leveraging China's digital infrastructure investments and proven IoT capabilities at low-voltage levels.
- **Strengthen technical standards and grid connection rules** to ensure new DERs contribute to system reliability and demand responsiveness, including requirements for smart inverters and standardised communication protocols.
- **Implement mechanisms for grid congestion relief and for guiding the siting of new projects,** such as transparent grid hosting capacity assessments – building on National Energy Administration (NEA)'s pilot programme – and locational signals in network tariffs. For the most congested areas, experiment with flexible connection agreements, while pilots for local flexibility procurement can be considered in provinces with more advanced power markets.
- **Invest in workforce training, institutional capacity and promote interprovincial and international experience sharing** to equip grid

operators, planners and regulators with the skills and tools needed to manage a more decentralised and dynamic power system.

Pillar 2: Unlocking DER value through progressive market integration and new business models

Unlocking the full value of DERs requires integrating them into both the grid and power markets – either directly, through aggregators, or by exposure to market prices – so their flexibility can be harnessed in response to system needs. In China, policymakers are increasingly turning to market mechanisms to mobilise flexibility and support renewable integration, but progress on power market reform has been uneven across provinces. Even where power markets are in place, most DERs still operate outside these frameworks, shielded from real-time price signals that reflect system conditions, and often without proper remuneration for the services they can provide.

Expanding viable DER business models is needed to support China's shift toward self-consumption and market-based participation, while harnessing flexibility from virtual power plants (VPPs), EVs and demand response. To accelerate this transition, key recommendations for national and provincial regulatory authorities include:

- **Facilitate DER and aggregator access to wholesale and ancillary service markets** where they operate, by removing practical entry barriers and adapting bidding rules and market products. As provincial markets develop and trial rules, ensure they enable DERs to provide multiple services and stack revenues without compromising system reliability.
- **Encourage demand-side flexibility from smaller consumers** by expanding the use of time-of-use and dynamic pricing schemes. This can be facilitated by leveraging China's extensive rollout of smart meters and by introducing those schemes on an opt-out basis, focusing on consumers with flexible loads such as EVs and heat pumps.
- **Promote self-consumption through targeted operational and remuneration models,** particularly in areas with limited grid capacity. This includes pairing distributed generation with flexible loads, storage, as well as setting minimum self-consumption thresholds for new installations. In rural areas, accelerating electrification and using smart demand management can help absorb DPV production.
- **Pilot and scale up innovative DER business models**, such as VPPs, co-location, peer-to-peer trading and local energy communities, supported by adequate regulatory frameworks and informed by experiences from provinces and countries that have advanced further in this field.

Pillar 3: Advancing regulatory reforms for fair grid access, cost-reflective tariffs and integrated planning

China's current regulatory framework is not yet fully aligned with the needs of a power system with high shares of DERs. Structural inefficiencies such as limited grid access for incremental distribution networks, uneven allocation of grid costs, weak incentives for grid companies to adopt cost-effective alternatives and fragmented planning between transmission and distribution can hinder efficient and equitable DER integration.

Adjusting regulatory frameworks is essential to ensure that DERs contribute to a system that is economically efficient, socially equitable and supported by clear institutional responsibilities. Key recommendations for national and provincial regulatory authorities include:

- **Ensure fair grid access and cost allocation** by mandating non-discriminatory access rights for DERs, microgrids and privately invested incremental distribution networks, in line with the newly enforced Energy Law, and by establishing transparent and equitable mechanisms for sharing transmission and distribution costs.
- **Optimise transmission and distribution pricing mechanisms to reflect system costs and encourage efficient use**. This includes refining the current voltage-based pricing to further encourage local consumption and introducing dynamic elements to network tariffs, drawing on provinces' experience with incorporating grid costs into time-varying tariff components.
- **Strengthen incentives for grid companies to support DERs by linking their performance to system outcomes** under NEA guidance and supervision, encouraging the adoption of DERs and smart grids as alternatives to traditional grid expansion. Network tariff methodologies can gradually integrate performance-based elements to reward efficiency and reliability.
- **Improve co-ordination between transmission and distribution networks in system planning,** ensuring that local DER deployment and integration is reflected in provincial and national grid planning. This includes using shared forecasting tools, joint cost-benefit analysis and clear performance metrics.
- **Clarify operational responsibilities for DER management at the distribution level**, particularly for managing hosting capacity, procuring local flexibility services and collecting data.

Introduction

DER growth is placing distribution grids at the centre of clean energy transitions

Distributed Energy Resources (DERs) are playing an increasingly important role in power systems worldwide. Typically located close to the point of consumption and behind-the-meter (BTM), these modular, small-scale resources are reshaping electricity supply and demand dynamics.

This report focuses on the integration into China's electricity system of non-fossil DERs such as distributed solar PV, battery storage systems and demand response.[1] It excludes technologies such as diesel generators or small gas turbines due to their marginal role in clean energy transitions and their distinct integration issues. While China's policy documents have formalised the concept of distributed generation, there is currently no official definition of DER as a broader category. In practice, the term is commonly understood to refer to installations connected to the distribution grid at voltage levels ranging from 220/380 V for residential users to 35 kV for commercial and industrial users, extending up to 110 kV for the largest installations. Distributed generation typically refers to systems with a capacity below 50 MW.

In recent years, several countries – including China – have witnessed rapid growth in the deployment of DERs. This expansion is driven by a combination of falling technology costs, supportive policies and broader energy system trends, such as electrification and decarbonisation. For example, the levelised cost of solar PV power fell by 90% from 2010 to 2023, making it more accessible to households and businesses. The increasing adoption of electrified end uses such as EVs, air conditioners and heat pumps is also accelerating demand-side electrification, contributing to rising electricity consumption at the distribution level. This trend is especially pronounced in China, which is set to make up over 45% of the global electricity growth by 2030 in the IEA's Stated Policies Scenario, due to surging electricity use in the building and road transport sectors, as well as accelerated electrification in industries.

This growth is placing renewed attention on distribution networks, which have traditionally been planned and operated for one-way power flows, with a clear separation between generation, transmission and distribution. The increasing

[1] Some organisations, such as the US Federal Energy Regulatory Commission, also include energy efficiency in their definition of DER. While this report mainly focuses on resources relevant to system integration, energy efficiency remains important for planning and long-term, structural demand reduction.

deployment is blurring these boundaries, introducing two-way power flows and requiring more dynamic, data-driven and flexible distribution system planning and operations. This shift is particularly relevant for China, where two parallel dynamics in grid development are observed: the traditional approach of large-scale transmission infrastructure to transport electricity from energy bases in the northern and western provinces[2] to demand centres in the east and a more recent trend towards localised DER development in densely populated regions where distribution grids were not initially designed to accommodate such capacity growth.

Efficient integration is essential to unlock the full value of DERs

DER can offer a wide range of benefits to both the power system and consumers. When efficiently integrated, DERs can support emission reductions and help meet electricity demand growth by enabling the deployment of clean electricity close to consumers, enhance energy security by improving resilience and contribute to greater affordability – three priorities high on the agenda of Chinese authorities.

For end users, DERs offer opportunities to access new revenue streams and reduce electricity bills either through self-consumption or participation in demand response programmes. Decentralising electricity supply also increases resilience for users during natural disasters or supply disruptions, which is particularly valuable for communities more frequently affected by outages, such as those in rural areas.

At the system level, DERs can enhance flexibility by providing services such as voltage support, frequency regulation and peak shaving. In some cases, they may also help avoid costly infrastructure investments by deferring the need for additional generation, transmission or distribution capacity. DERs also contribute to overall system resilience by reducing reliance on imported fossil fuels.

Realising these benefits depends on the timely integration of DERs, namely, their effective connection, management and utilisation within the power system, aiming to extract as much value as possible from new and existing technologies. While some advantages, such as clean electricity from rooftop solar, can be accessed immediately, unlocking the full system-wide benefits of DERs requires a co-ordinated approach that addresses technical, regulatory and market-related barriers.

[2] In this report, the term “provinces” is used to refer to China’s provincial-level divisions, including provinces, autonomous regions and municipalities under the central government.

Examples of benefits unlocked from DER integration

DER benefits	Concrete examples
Meeting growing electricity demand	Rooftop solar generated over 12% of Australia's total electricity in 2024, in a year when overall electricity demand rose by 3.2%.
Emissions reduction	In the Netherlands, where rooftop solar PV accounts for 55% of total installed renewable capacity, solar energy avoided an estimated 10 Mt of CO_2 emissions in 2024 – equivalent to 10% of the country's 2030 carbon budget.
Resilience	In 2023, Puerto Rico (US) launched a national fund to increase grid resilience against frequent hurricanes, incentivising residential rooftop solar and battery storage installations for low-income households.
System-level cost savings	In Texas, the value of T&D grid investment deferral by integrating DERs was estimated at 8.5% of total transmission and distribution infrastructure costs annually.
Flexibility provision	In Great Britain, as of June 2025, 113 flexibility providers were registered on UK Power Networks' flexibility platform, representing 188 000 distributed assets with 1.2 GW of upward and 1.5 GW of downward flexibility capacity.
Additional revenue streams	In Shanghai, EV owners who charge at home overnight and discharge at their workplace's vehicle-to-grid stations during peak hours can earn an estimated average of RMB 500 (USD 70) per month.

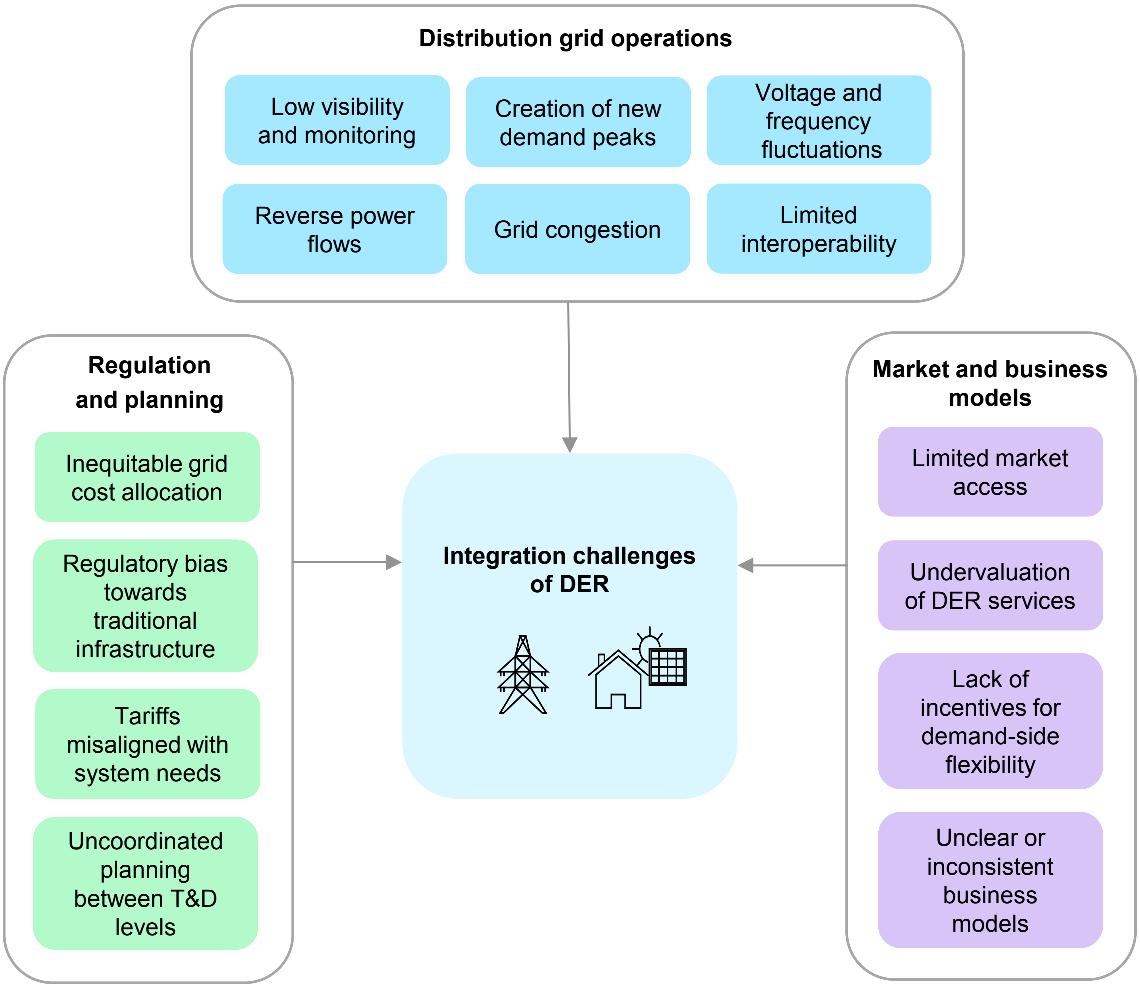
Integration challenges span technical, economic and regulatory dimensions

The nature of DERs – small-scale, BTM, often rapidly deployed – poses new challenges for grid operations and raises questions about current economic and regulatory frameworks, which are often inherited from power systems designed and planned around centralised assets. Given that its pace of DER uptake in recent years has been the fastest in the world, China is no exception and has experienced these challenges acutely.

On the technical side, distribution grids are increasingly exposed to bi-directional power flows, voltage fluctuations and congestion, particularly during hours of high solar PV production. In areas with high rooftop solar penetration, this can lead to thermal overloading of grid components or automatic curtailment of clean electricity. Moreover, the growing use of EVs and other electrified end uses is shifting load profiles and creating new demand peaks, which if not actively managed, could necessitate costly grid upgrades.

Limited visibility and controllability over distributed assets remain key barriers. Many system operators lack real-time data on DER behaviour, complicating load forecasting and system operations. In addition, interoperability and standardised communication protocols are not widespread, limiting the ability of DERs to achieve a seamless integration into broader system operations.

Integration challenges of DERs



On the economic and regulatory side, a number of structural issues have emerged. In systems where grid operations and electricity retail are still strongly linked, [3] and where grid tariffs are primarily charged based on electricity consumption – as is the case in China – utilities face declining revenues as more consumers adopt rooftop solar while still needing to maintain and operate the grid.

[3] In 2024, 37% of China's total electricity consumption was transacted through retail markets, while the rest was supplied through grid company purchases, direct transactions between generators and consumers, and non-market segments such as residential and agricultural loads, as well as consumption from local grids not operated by the main grid companies.

When this self-consumption is net-metered, [4] non-DER users bear a disproportionate share of the fixed costs, raising concerns about fair cost allocation.

At the same time, current regulatory frameworks often undervalue the services that DERs can provide. For example, distributed resources that help defer or avoid infrastructure investments may not be recognised or compensated for appropriately, weakening their business case. In many jurisdictions, regulatory incentives were designed around centralised energy systems and continue to favour traditional infrastructure investments over DER-based solutions. Additionally, DERs may face limited eligibility to participate in various power markets, with existing bidding thresholds or the lack of aggregation pathways preventing them from accessing additional revenue streams.

Tariff structures and market mechanisms also remain misaligned with evolving system needs. Flat tariffs and net metering schemes, which are still widespread globally, fail to reflect the real-time value of electricity and grid services, thereby distorting price signals. This can lead to inefficient DER operation and limit the potential for these resources to contribute to system optimisation.

Finally, uncoordinated planning between T&D levels can lead to inefficient investment decisions, missed opportunities to proactively integrate DERs cost-effectively and increased risks to system reliability. These issues are further compounded by limited technical tools and methodologies to support integrated planning and to quantify the system-wide and societal benefits of better co-ordination.

Addressing these challenges will be critical in China to ensure that DERs are not only deployed at scale but also used efficiently to deliver maximum benefit to the system and to consumers.

Lessons from international experience can inform China in its own DER integration journey

International experience offers a valuable reference for China as it scales up its integration efforts. Leading markets have developed tools and frameworks that can inform China's efforts to maximise the value of distributed resources, from dynamic tariffs and flexibility markets to advanced forecasting and cost-sharing mechanisms. This report focuses particularly on systems with a high share of DER, with special attention to those that have extensively deployed distributed solar PV, such as Australia, Brazil, California, Germany and Japan, as well as

[4] Net metering is a billing mechanism by which prosumers receive credit for the electricity they export to the grid at the same rate as their consumption. This can result in little or no electricity charges, even though they continue to use and rely on the grid, potentially reducing their contribution to fixed grid costs.

those with advanced market mechanisms to harness DER flexibility, such as the United Kingdom. These cases were selected based on their relevance to China's own priorities and the specific challenges it faces in scaling up clean DER.

After examining recent DER development trends in China (Chapter 1), this report provides an overview of global best practices in DER integration (Chapter 2) and identifies which measures should be prioritised in the Chinese context within the 2030 timeframe (Chapter 3) which is a key milestone for the country's energy transition, aligned with its carbon peaking target and the 15th Five-Year Plan. By drawing on these experiences and tailoring them to China's unique institutional, regulatory and system conditions, China can avoid costly pitfalls and accelerate the development of a secure, affordable and sustainable power system.

Chapter 1. Status of DERs in China

DER development trends

DERs have become a major component of China's power system, with distributed solar photovoltaic (DPV) systems leading the way. In recent years, rapid expansion of DPV has been driven by supportive national programmes, local incentives and sharply declining technology costs. In regions with high electricity consumption, commercial and industrial (C&I) users dominate DPV adoption, with large industrial parks emerging as a key adopter of clean energy systems combining distributed generation, storage and demand response. Meanwhile, in rural areas, rooftop solar installations by households, small businesses and public institutions are being actively promoted as part of the broader rural revitalisation strategy. However, future growth of distributed solar may face headwinds: new national policy measures are expected to slow the pace of installations, as they shift away from the previously guaranteed full grid purchase model towards more self-consumption and market-oriented uptake conditions for large installations.

Although distributed wind power currently plays a minor role, recently introduced development targets suggest it could see increased uptake, albeit limited by its comparatively higher costs relative to solar PV. At the same time, the widespread adoption of electric devices, such as EVs, air conditioners and heat pumps, has significantly accelerated the electrification of China's economy, where electricity accounted for 29% of final energy consumption in 2023, well above the global average of 20%.

BTM battery storage remains primarily concentrated among large C&I users who seek to optimise their electricity costs through time-of-use (TOU) pricing.

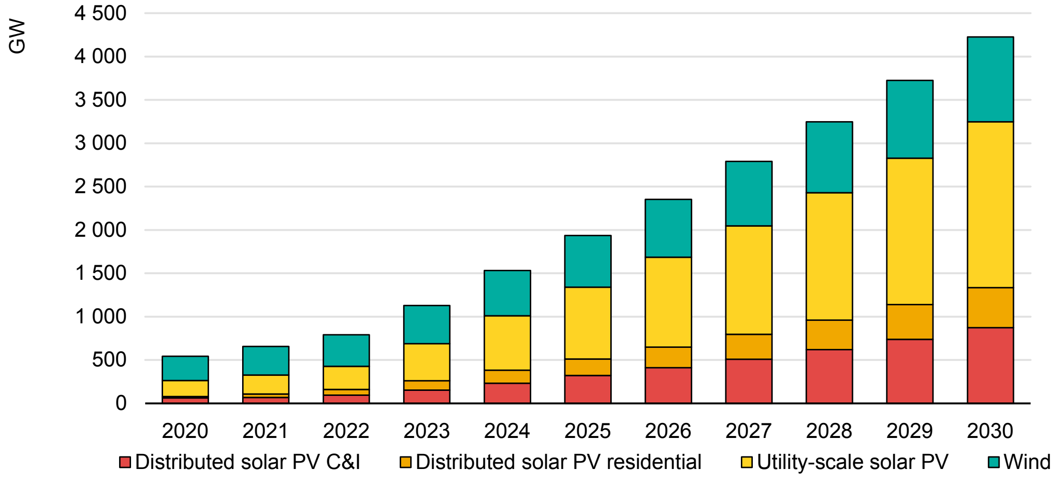
Distributed solar growth accelerates, while distributed wind starts gaining traction

DPV systems have experienced remarkable growth in recent years, becoming a major component of China's solar capacity. In 2020, DPV accounted for 30% of the country's total installed solar capacity. By the end of 2024, this share had grown to around 40%, underscoring the decentralisation trend of solar deployment across the country.

This expansion has been underpinned by several key drivers. First, China's national decarbonisation objectives and a series of supportive policy measures have laid a strong foundation for DPV development. These include historically generous feed-in tariffs and, since 2021, the implementation of a full grid purchase model that guaranteed the purchase of distributed solar output by grid operators, profitable conditions which have attracted large amounts of private capital. In addition, national initiatives such as the Whole County DPV Development Programme, primarily targeting rural areas, have played a major role by mandating installation targets across public institutions, commercial users and residential rooftops in participating counties. From an administrative point of view, the DPV project registration and grid connection processes have also been relatively straightforward, with few permitting or restrictive requirements, making DPV assets quick and easy to deploy.

Another critical factor contributing to DPV growth is the sharp decline in system costs. Between 2020 and 2024, the average price of PV modules fell from 1.57 RMB (USD 0.23)/W to just 0.68 RMB (USD 0.09) /W,[5] making distributed solar increasingly more affordable and attractive to both businesses and households. In addition, some investors have turned to DPV over utility-scale projects, which face greater exposure to markets and TOU tariffs, leading to less predictable returns.

Installed capacity of solar PV and wind power plants in China in the Renewables 2024 main case, 2020-2030



Source: IEA (2024), Renewables 2024.

C&I consumers are the primary adopters of DPV, accounting for 61% of total DPV capacity in 2024. While most of these installations are under 6 MW, China classifies larger systems – up to 50 MW – as distributed so long as they are connected to the distribution network (typically under 110 kV). This broad definition has enabled significant uptake among large energy consumers, especially in

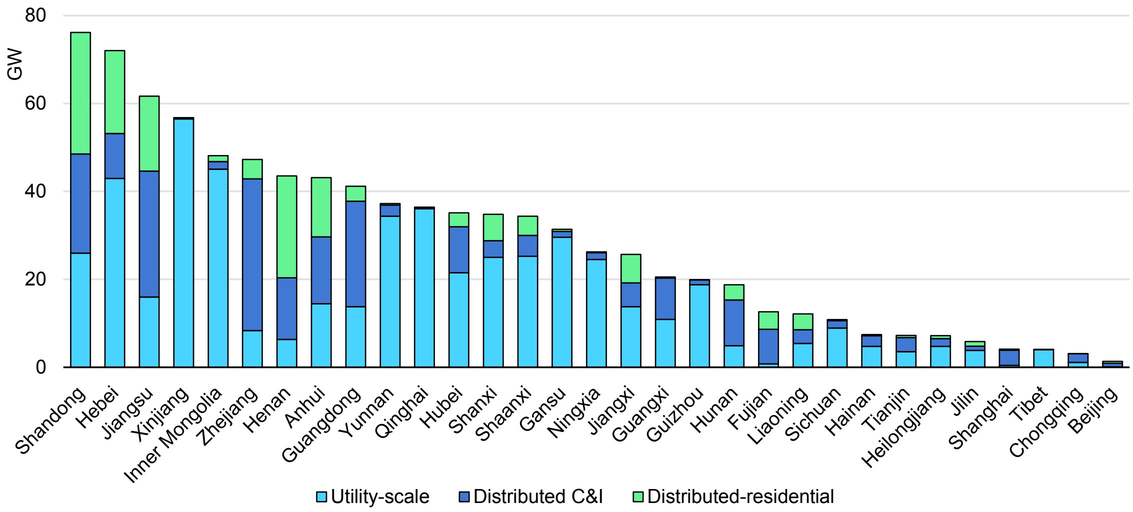
[5] In this report, exchange rates are based on the annual average for each given year.

coastal provinces such as Shandong, Hebei, Jiangsu and Zhejiang, where high industrial activity and power demand provide a strong economic rationale for self-generation.

At the same time, central and northern rural provinces such as Henan and Hebei have seen rapid DPV growth, driven by the government's rural revitalisation agenda. The recently introduced Sunshine for Every Home Action Plan further reinforces the national commitment to expanding residential solar in rural communities.

In contrast, the provinces in China's Northeast, North and Northwest regions – characterised by lower local energy demand and abundant land and solar resources – continue to prioritise large-scale, centralised solar PV projects over distributed systems.

Installed capacity of solar PV systems across China, 2024



Source: IEA based on data from the National Energy Administration.

While the overall outlook for DPV remains positive towards 2030, a near-term adjustment is anticipated, particularly for large-scale C&I installations. The new Management Measures for DPV Projects, released by the National Energy Administration (NEA) in January 2025, introduced new criteria that shift the focus of policy support towards small-scale, low-voltage systems. General and large-scale C&I systems are no longer eligible for the previous full grid purchase model.

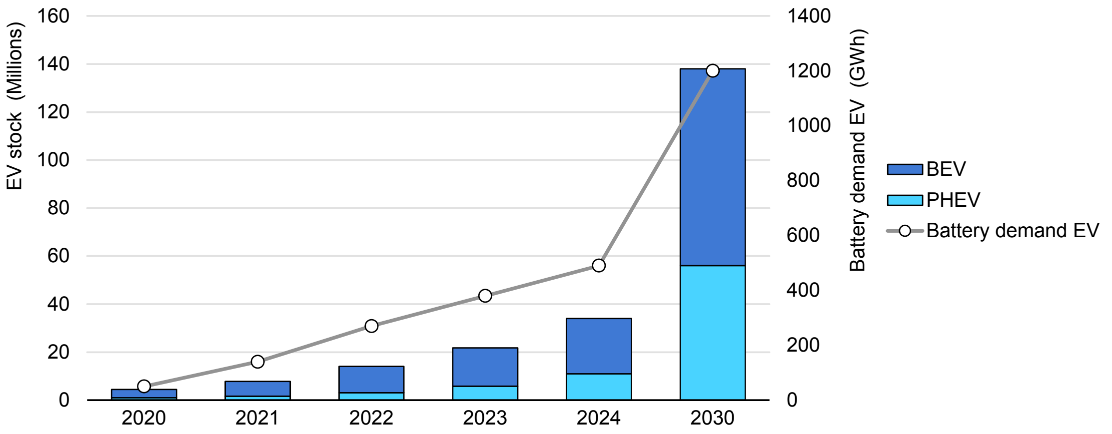
In comparison, distributed wind power (defined as projects under 50 MW) has remained marginal within China's energy mix. As of 2024, only 3.7% of the country's total wind capacity of 520 GW was classified as distributed. This limited uptake has been largely due to complex permitting processes. However, this trend may begin to shift. The Thousand Towns and Villages Distributed Wind Power Initiative, introduced in 2024, aims to promote village-level wind development by 2025. In addition, the larger number of utilisation hours of distributed wind, compared to solar, could enhance its attractiveness as permitting and policy frameworks evolve.

New electrified end-use technologies are reshaping the demand side

In recent years, China has witnessed a rapid uptake of electrified end-use technologies, driven by robust policy support and steadily declining costs. This electrification trend spans various sectors such as transport, buildings, industry and agriculture, and is playing an increasingly important role in the transformation of the whole energy system.

EVs are at the forefront of this shift. As of 2024, electric cars accounted for almost half of all new car sales, positioning China as a global leader in clean mobility adoption. By 2030, the national electric car stock is projected to reach close to 140 million vehicles, supported by continuous advancements in vehicle technology and widespread charging infrastructure. Notably, the number of publicly and privately connected charging points reached 12.8 million in 2024, surpassing the 2025 national target of 12 million.

Stock of electric cars and corresponding battery demand in China in the Announced Pledges Scenario, 2020-2030



Notes: BEV = battery electric vehicles. PHEV = plug-in hybrid electric vehicles.
Source: IEA (2025), Global EV Outlook 2025.

Electrification of heating and cooling across sectors is also advancing rapidly. In 2024, air conditioner ownership reached 1.5 units per household and is set to rise to 1.7 by 2030 under the Announced Pledges Scenario (APS) (in comparison, ownership by 2030 is set to reach 0.5 in the European Union, and 2.5 in the United States and Japan). Heat pumps also represent a growing share of the heating solutions: their contribution to meeting heating demand was only 4% in 2022, but is projected to increase to 13% by 2030 in the APS, with heat pumps surpassing resistance heaters in the space heating stock. In April 2025, China released its first-ever National Action Plan on Heat Pump Development, signalling strong government support for their deployment across multiple sectors, including buildings, industries, agriculture and transport.

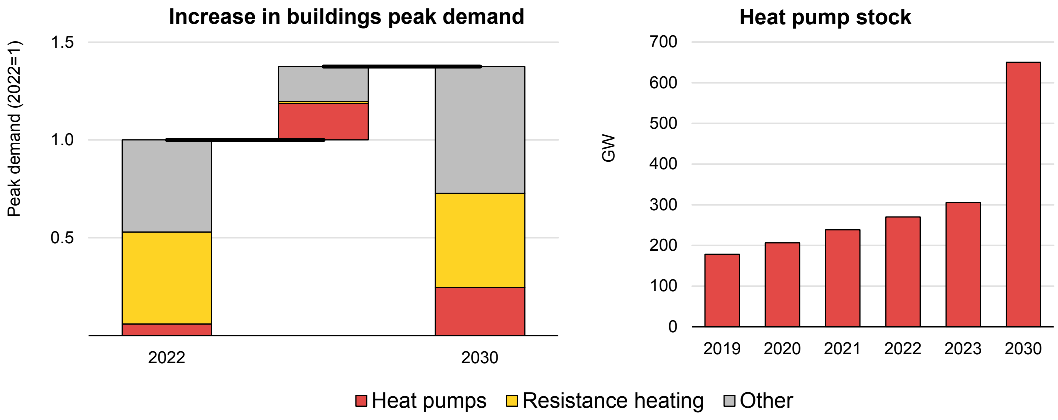
Battery storage is likewise evolving. While most of China's energy storage capacity remains front-of-the-meter and utility-scale, battery systems are increasingly being installed BTM, particularly in C&I buildings, though many of these are relatively large and comparable in size and cost to utility-scale projects in other countries. Distributed projects are set to grow significantly, reaching nearly 40% of total storage capacity by 2030, driven by large consumers seeking to benefit from dynamic pricing and to pair with VRE generation for more continuous supply.

Unlike countries like Australia, where residential storage in individual houses is common, the adoption of home batteries in China remains limited. This is largely due to the country's high population density and the prevalence of large apartment complexes, which raise safety concerns and regulatory restrictions. In addition, electricity tariffs are designed to keep residential prices low, reducing incentives for households to invest in batteries. In 2024, battery systems under 5 MW or connected at 220/380 V levels represented only 1% of the total battery capacity deployed.

In parallel, the growing adoption of EVs, heat pumps and other electrified end-use equipment has introduced new dynamics to grid operations. On one hand, they increase the variability of electricity demand and peaks, posing challenges to the stability and security of power system operations. On the other hand, they present substantial opportunities for load flexibility and grid support.

For instance, in 2024, EV charging loads in Guangdong province accounted for more than 2% of total peak electricity consumption and rose above 9% during night peak charging hours. Similarly, in Zhejiang province, air conditioners accounted for 40% of summer peak demand, of which 46% was from residential air-conditioning load in July 2024. In winter, the uptake of electric heating in buildings drives peak electricity demand, which is projected to rise by over a third between 2022 and 2030 in the APS. These patterns highlight the scale and impact of flexible consumer-side loads.

Contribution to winter peak electricity demand in buildings by technology (left), and heat pump stock (right) in China in the Announced Pledges Scenario, 2022-2030



Notes: Peak electricity demand here is the average demand for the 125 highest load hours in winter, before activation of demand response. Heat pumps and resistance heating cover space heating consumption. Charging of electric passenger cars and two/three-wheelers is included in other end uses. Reduced heat pump efficiency at lower outdoor temperatures is captured.
Sources: IEA (2022), The Future of Heat Pumps in China and IEA (2024), Clean Energy Market Monitor.

Recognising both the challenges and opportunities, China is actively promoting the integration of DERs through aggregation and development of virtual power plants (VPPs). These systems aggregate and co-ordinate the output and consumption of consumer-side resources along with other DERs, enabling them to participate in power markets and provide grid services. In April 2025, the National Development and Reform Commission (NDRC) and the NEA jointly issued a policy document to accelerate the deployment of VPPs. The plan sets ambitious targets, aiming to achieve 20 GW of dispatchable capacity by 2027 and 50 GW by 2030.

Industrial parks are increasingly driving the adoption of DERs

Industrial parks are one of the fastest expanding use cases for DERs among C&I users. The Chinese concept of “generation-grid-load-storage integration” (“源网荷储”) projects, implemented at the park level, has emerged as a key approach to leveraging larger-scale DERs and the flexibility of large consumers. The projects consist of smart microgrids combining local supply, grid, load and storage components along with advanced digital and AI technologies to mobilise demand-side capabilities.

While these projects are generally connected to the public grid, the government has recently clarified the conditions under which direct connection lines can be established between captive renewable power plants and large users, bypassing the main grid.

In February 2021, the NDRC and the NEA issued a policy encouraging the development of integrated projects in industrial parks. By the end of 2024, over 450 integrated projects had been launched nationwide, with total installed power generation capacity exceeding 100 GW. Such projects have been listed and announced by local governments, especially those with robust industrial bases. For example, Henan province announced 253 integration projects by 2024 for a total capacity exceeding 5 GW, of which 180 projects were located in industrial sites.

Several drivers fuel the development of these clean industrial parks. China's dual carbon goals place direct pressure on the industrial sector, which accounts for over 25% of the country's energy-related emissions. Notably, since 2025, provincial-level renewable electricity consumption binding targets have been extended to cover additional energy-intensive industries such as steel, cement, polysilicon and data centres. In mid-2025, a notice on the construction of zero-carbon parks further encourages local consumption and renewable integration into the local distribution grid. At the same time, industrial electricity prices in China are generally higher than those for residential and agricultural users, creating strong economic incentives to reduce electricity costs and offset peak prices. Energy security has also become a growing concern for industrial clusters that require uninterrupted power. On-site renewables are seen as a way to enhance resilience and reduce dependency on centralised grids. In addition, for export-oriented industrial clusters, DER development is viewed as a strategic response to anticipate the potential impact of carbon tariffs under initiatives such as the European Union's Carbon Border Adjustment Mechanism.

In this context, and to boost industrial competitiveness, local governments have actively supported DER development and innovation in industrial parks by facilitating permitting processes, providing financial incentives and integrating DERs into local industrial planning. Notable examples of these projects include the Changzhou Industrial Park, whose microgrid is the largest of its kind in Jiangsu province. The microgrid, spanning an area of 370 000 square meters, combines 1.61 MW of distributed solar PV, 6 MW of energy storage and a smart management platform. The latter can forecast demand and optimise energy use by analysing weather conditions, traffic flows and historical electricity usage data.

In Inner Mongolia, Envision Group is building a net zero industrial park in Ordos, with "source-grid-load-storage-hydrogen" end-to-end solutions. The park combines the manufacturing supply chains of several electricity-intensive industries, such as EV and batteries, with an integrated energy system entirely relying on wind, solar PV, energy storage and green hydrogen, of which the outputs are forecasted and optimised through the smart microgrid platform. The park will also integrate an electric truck transportation system.

Case study: Suzhou Industrial Park's strategy to integrate DPV and micro-grid systems

Suzhou Industrial Park has become a national benchmark for integrating DPV with local micro-grids, thanks to a combination of clear development targets, targeted financial incentives and innovative trading models. The project has achieved an estimated annual CO_2 reduction of 9 000 tons and has been cited as a replicable model for many cities across China.

In 2022, the park released Several Measures to Promote Distributed PV Development, aiming to add 70 MW of solar capacity each year until 2025. This was followed by the Action Plan for Green and Low-Carbon Development in 2025, which sets the goal of reaching 480 MW of DPV and a rooftop coverage rate of at least 50% in 2025. The action plan also calls for promoting integrated PV-storage-charging systems and microgrids.

Financial incentives have played a key role in supporting these targets. Since 2022, distributed solar PV projects located in the park are eligible for a one-year subsidy of 0.1 RMB/kWh, while battery projects receive a three-year discharging subsidy of 0.3 RMB/kWh. Suzhou's broader land renewal and energy efficiency policies have also supported project deployment through density bonuses and project-level incentives.

In addition, the park has experimented with an innovative market-based distributed generation trading model. This peer-to-peer (P2P) trading approach uses AI to dynamically match solar generation with industrial demand. Excess solar power is stored in batteries and will be sold directly to nearby users in the same grid tier under contract during high-tariff periods, reducing transmission losses and improving price realisation.

Emerging challenges

Many countries face issues such as grid connection requests exceeding hosting capacity, resulting in congestion, and a lack of visibility and control over BTM assets that complicates grid operations. However, in China, the rapid pace of DER deployment, combined with specific market and regulatory conditions, has intensified these challenges. This has hindered the cost-effective integration of DERs, limited their ability to serve as system assets and raised concerns about the financial viability of future grid investments.

Distribution network limitations have led to restrictions in new DPV projects' connections

The rapid expansion of DPV systems in China, while being a major contributor to the country's decarbonisation goals, has exposed critical limitations in the distribution network. China's DPV development model has long predominantly favoured the full export of electricity generated by solar systems to the grid, with grid companies purchasing this output at fixed prices. This model has been widely implemented even in areas with low local electricity demand, such as rural regions, leading to a mismatch between production and consumption.

By 2023, 80% of residential PV systems were operating under the so-called "full purchase mode", where all solar electricity was injected into the grid. As residential electricity tariffs in China remain relatively low, they offer little economic rationale for households to consume their own solar power. In rural areas, a common business model has involved residents leasing their rooftops to third-party developers, who install PV systems and sell the generated power directly to the grid. This model, while financially attractive for developers and supported by rural economic development policies, has raised concerns about land use and grid congestion and is facing growing regulatory challenges.

Grid congestion and lack of flexibility

As solar PV production began to outpace local demand in many regions, grid congestion emerged as a widespread issue, particularly in rural areas with limited load and underinvested distribution infrastructure. With approximately 75% of DPV systems connected at low-voltage levels, issues such as voltage stability, reverse power flows and local overloads have become increasingly frequent. For instance, in the Jibei power grid (in northern Hebei province), the number of distribution transformers affected by reverse overloading from DPV increased by 75% year-on-year, while overvoltage violations rose by 66% in the first ten months of 2024.

These challenges have been compounded by the limited flexibility of distribution networks. Most were designed for one-way power flows and are not equipped to accommodate high shares of variable, distributed generation. Storage and regulation capacities remain insufficient, especially during midday hours when solar output peaks and demand is relatively low. Without advanced controls or flexible demand to absorb this surplus generation, the system struggles to maintain stable operation.

To better understand and tackle these issues, an NEA pilot programme in 2023 evaluated the grid hosting capacity of DPV systems across six representative provinces (Shandong, Heilongjiang, Henan, Zhejiang, Guangdong and Fujian). The results revealed that, except for Zhejiang, widespread grid connection constraints have been experienced in many areas.

Since then, several local governments have designated areas with saturated grid capacity as “yellow” or “red” zones, in which new DPV project connections are either discouraged or outright restricted. While initial restrictions primarily targeted residential systems, beginning in 2024 larger C&I building projects in provinces such as Guangdong, Hunan and Hubei have also come under connection constraints. More than 450 “red” zones were reported across 11 provinces at the end of 2024. In addition, in several congested areas, local authorities have taken measures to adjust the remuneration of solar PV generation, such as reducing guaranteed purchase hours and adjusting on-grid price bands, directly affecting the revenue streams of operators.

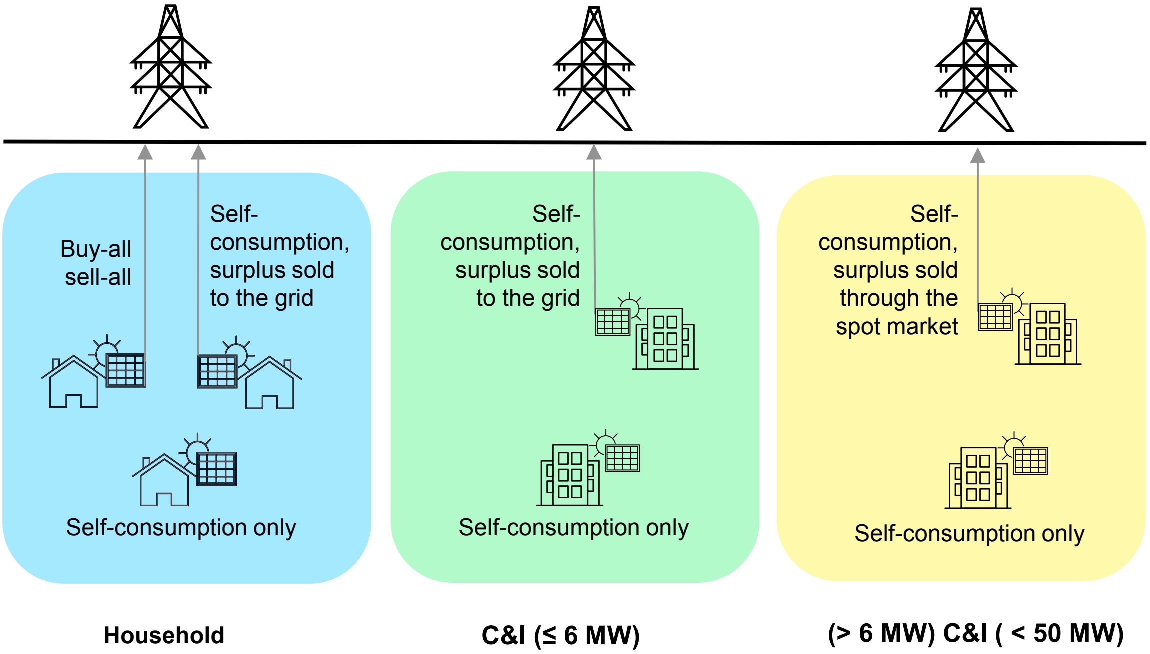
Assessment of DPV hosting capacity in six provinces under the NEA pilot programme

Province	Assessment results of DPV hosting capacity
Guangdong	25 counties or districts across the province have been designated as red zones (DPV connection is restricted and applications for DPV connection are temporarily suspended).
Fujian	4 out of 10 pivot counties across the province have no available connection capacity.
Shandong	53 out of 136 counties and districts across the province have been designated as red zones.
Henan	More than half of the counties or districts across the province have been designated as red zones.
Zhejiang	No counties or districts across the province have been designated as red zones.
Heilongjiang	86 counties or districts across the province have been designated as red zones.

Source: Provincial NDRC or NEA in Guangdong, Fujian, Shandong, Henan, Zhejiang and Heilongjiang.

To ease pressure on distribution networks, China is shifting towards a more consumption-oriented model for DPV. The new Management Measures for DPV, in effect since May 2025, explicitly prioritise increasing self-consumption and local use of distributed generation. C&I projects can no longer sell all their output to the grid at a fixed price – they must either self-consume entirely or sell only the surplus. For installations over 6 MW, surplus electricity can be sold only through spot markets where continuous operation has been established. Some parts of the country, which have abundant renewable energy but face grid constraints, have gone further when implementing this new policy. Inner Mongolia and Jilin, for example, require self-consumption thresholds of 90% and 80%, respectively, for projects up to 6 MW. While this policy may ease grid congestion and drive investment in storage, it also brings economic uncertainty for developers, prompting a rush in grid connections ahead of enforcement.

Operation models of DPV systems in China after the 2025 Management Measures



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Notes: Under the "Buy-all, sell-all" model, all the production is guaranteed to be bought by the grid company at a fixed price, also known in China as "full grid purchase".
Under the "self-consumption, surplus sold to the grid" model, the production of DPV is consumed with any surplus sold to the grid in proportions determined by the provincial authorities. There is no net metering scheme in China, meaning that the self-consumption part is not deducted from the surplus part in the calculation of the remuneration. For the largest installations, production surplus can be sold through the spot market in areas where it has achieved continuous operation.
Under the "self-consumption only" model, all the DPV production is self-consumed locally.

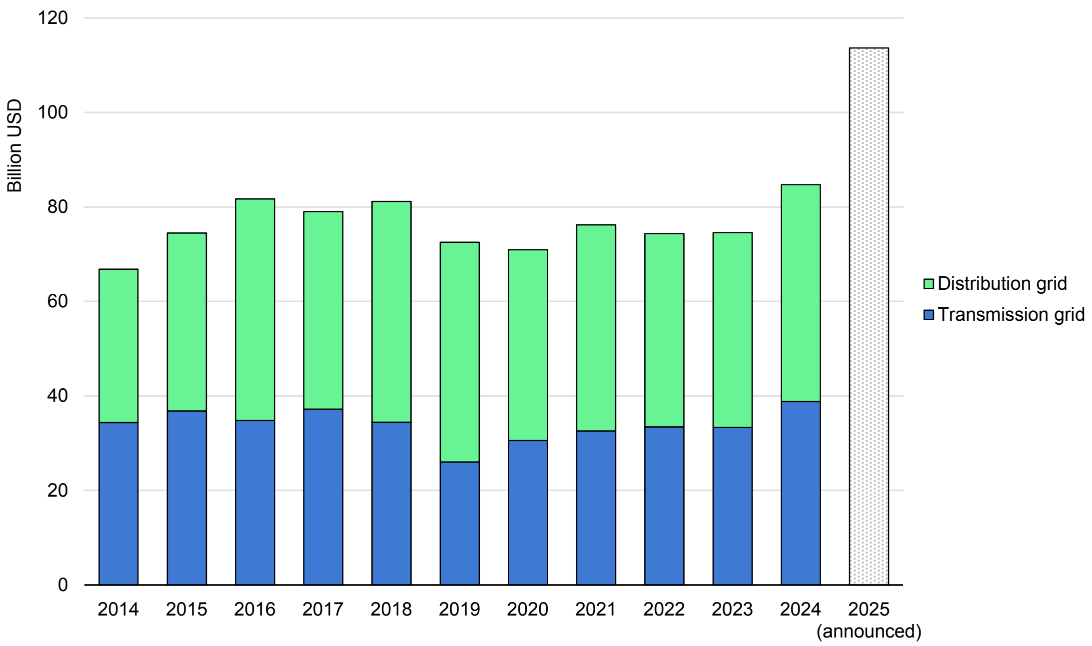
Lagging investments

China has a distribution grid of about 8 million km, of which 30% has been added in the last decade. The responsibility for investment and operation of distribution networks lies primarily with state-owned grid companies, the two major ones being the State Grid Corporation of China and China Southern Power Grid. Historically, investment in China's power grid has consistently lagged behind the rapid expansion of generation capacity, especially as renewables have expanded quickly due to their faster deployment compared to grid projects. This, combined with limited power system flexibility and poor co-ordination between generation and grid infrastructure development, has been a major contributor to the persistent issue of renewable energy curtailment. Investment in power generation has accelerated in recent years, especially since the announcement of the dual carbon goals in 2020. By the end of 2023, generation investment had exceeded grid investment by an estimated RMB 440 billion (USD 62.2 billion).

In response to the need to accommodate a large capacity of renewables and meet rising electricity demand, grid companies have scaled up their investment efforts. Both the State Grid Corporation of China and China Southern Power Grid have announced ambitious investment plans for 2025, totalling RMB 825 billion (USD 113.7 billion), a substantial year-on-year increase of 36%.

Compared to most other countries, China's grid operators have historically allocated a larger share of investment to transmission over distribution. Although total grid investments have increased, the share dedicated to distribution levels has remained steady at around 55%.[6] A more balanced ratio may appear in the coming years, as provinces respond to an unprecedented government push to expand distribution networks. For instance, China has set ambitious targets to strengthen the distribution grid's capacity to accommodate 500 GW of distributed renewable energy and 12 million EV charging stations by the end of 2025, alongside goals to improve grid flexibility, digitalisation and co-ordination with the transmission system.

Transmission and distribution grid investments in China, 2014-2025



Sources: IEA based on data from the China Electricity Council (2014-2024) and public announcements from the State Grid Corporation of China and China Southern Grid (2025).

Historically, distribution grid investments in China have been concentrated in urban and industrialised areas, where electricity demand is dense and the need for supply reliability is paramount. These regions have naturally received priority for network reinforcement and modernisation, as they are critical to economic

[6] In comparison, between 2016 and 2022, advanced economies allocated an average of 65% of grid investment to distribution networks, while emerging markets and developing economies allocated 61%.

activity and social stability. In contrast, rural areas – with significantly lower electricity consumption and sparse populations – have traditionally seen limited grid development. The distribution infrastructure in these areas was designed primarily to serve basic household and agricultural loads, with no anticipation of hosting large-scale power injections. As a result, the rapid growth of DPV in rural China is increasingly constrained by insufficient grid capacity.

While upgrading rural distribution networks is a high priority for the government and grid companies are obligated to do so, these types of investments may be less profitable due to limited use of rural grids and their high maintenance costs. Besides, the scale of investment required has made it difficult to keep pace with the increasingly complex needs of distribution networks. Attempts to introduce investment from non-state actors, such as through the 2016 incremental distribution grid reform, have had limited success to date due to regulatory uncertainty, weak revenue prospects and barriers posed by incumbent grid companies.

In addition, several structural factors have contributed to this lag in investment. The current cost-plus remuneration model for grid companies, while allowing for some moderate profits, remains focused on capital-intensive infrastructure (CAPEX-based), with limited incentives to pursue more cost-effective alternatives such as procuring flexibility from DERs. Historically, the performance of grid companies has been assessed mainly through individual evaluations for grid company managers, rather than based on system-wide performance, an approach that risks inefficient outcomes and higher costs for the system and consumers. Encouragingly, some regions have already piloted reliability-linked incentives and the 2023 Electricity Demand Side Management Measures mandate a minimum annual electricity saving of 0.3% supported by an evaluation and assessment indicator system.

Moreover, cost allocation mechanisms are not well aligned with the evolving system needs. For example, DPV installations often do not contribute to grid balancing costs. Meanwhile, the main grid continues to bear the cost of interconnection, backup supply and regulation services for connected DERs, without a clear recovery pathway.

The lack of requirements for visibility and controllability has created blind spots for grid operators

Part of the modernisation effort for distribution grids is expected to go into improving the visibility and controllability of DERs. Most DERs, particularly those installed BTM, remain invisible and uncontrollable from the perspective of grid operators. This complicates real-time grid management and raises concerns around operational security.

Some provinces have taken proactive steps to address these challenges. Shandong province, which leads in installed DPV capacity, has implemented advanced requirements since 2021. These mandate full monitoring and remote-control capabilities for all DPV systems connected at 10 kV and above, as well as voltage ride-through capabilities.[7] However, such advanced functionalities are still not widely adopted elsewhere and many lower-voltage systems continue to operate without intelligent control equipment, creating "blind spots" in the distribution grid.

To improve visibility and oversight of new installations, national authorities have tightened registration requirements. Since 2024, all renewable energy projects connected to the grid must be registered within one month of connection. This is a prerequisite for green certificates eligibility. For residential PV systems, the local grid company is responsible for completing registration on behalf of the project owner. The January 2025 Management Measures further require that all new DPV systems must include functions for visibility, measurement and control. In practice, the large majority of consumers with DPV are already equipped with bi-directional smart meters that measure both consumption and PV infeed and enable their automatic connection and disconnection from the grid. However, not all of them allow for adjustable, flexible control of PV production.

These new technical requirements are expected to increase the upfront cost of DPV installations. However, it remains unclear whether these additional costs will be borne by end users or subsidised through the grid tariff or public funding.

DERs are operated mainly outside the market, limiting their responsiveness to system needs

Distributed generation

Historically, solar PV and wind in China have operated largely outside power markets. Their production was typically guaranteed through fixed-price agreements or feed-in tariffs, regardless of real-time system conditions or market prices. Although market reforms in China have gradually progressed, with market-based transactions covering over 62% of total electricity consumption in 2024, many generators, particularly renewables, still have their dispatch governed by administrative planning rather than being driven by real-time price signals. In particular, DPV under a guaranteed purchase agreement is totally inflexible and does not bear peak regulation nor system balancing obligations, whereas centralised plants can be curtailed.

[7] These capabilities reflect the ability of a generator or other electrical equipment to withstand temporary voltage fluctuations and continue operating without tripping offline.

The February 2025 reform (Document 136) aims at better matching non-hydro renewable generators with market conditions, by introducing a two-way contract-for-difference (CFD) mechanism. Provinces are responsible for organising auctions and deciding how much wind and solar capacity qualifies under this scheme.

Under the new policy, all wind and solar PV projects built from June 2025 that have obtained an auction quota must sell their electricity on the wholesale market. The CFD is settled based on the difference between a reference price – set by the highest accepted bid in the auction – and the average monthly market price for similar technology projects. If the market price falls below the reference price, generators receive compensation; if it exceeds the reference price, they must pay back the difference.

This mechanism incentivises generators to respond to market signals and to adopt a more flexible operation to be profitable, for example by selling at times of high demand, storing electricity during low-prices hours, or participating in ancillary services. While it offers stable revenues for qualified projects, the new price regime introduces less favourable conditions for generators: in several provinces, spot prices are already below the coal benchmark, and there is uncertainty around how provinces will implement the scheme. As a result, many wind and solar PV projects have rushed to connect to the grid before the policy takes effect.

In particular, DPV projects, which are also affected by the policy, saw a 113% increase in installed capacity in the first half of 2025 due to shorter installation timelines. However, the pathway for smaller DPV installations to participate in the market remains unclear. Where aggregators are available, they may facilitate access to the market; otherwise, these installations are expected to act as price takers, which could significantly reduce their profitability.

Evolution of new wind and solar PV projects on-grid pricing in China and related major policies, 2005-2025

Phase I (2006-2015): Fixed feed-in-tariff mechanism

- Administratively set fixed feed-in tariff, generally higher than coal power, with subsidies funded via renewable energy surcharge on energy bills
- Full purchase of VRE production is guaranteed at the feed-in-tariff rate

Phase II (2016-2020): Link with coal-fired power benchmark price

- New VRE projects' grid tariffs match the local coal-fired power benchmark price, implementing grid parity
- Progressive phase down of benchmark feed-in tariffs
- Guaranteed full purchase of VRE in grid constrained areas determined based on grid transmission and absorption capacity
- Promotion of VRE market entry beyond guaranteed purchase quotas
- Pilot green certificates trading scheme

Phase III (2021-2024): Guaranteed purchase + Partial market pricing

- Phase out of all national subsidies for new wind and solar PV projects
- Guaranteed purchase volume + market transactions volume for on-grid renewable electricity
- Green certificates replace direct subsidies as the main VRE support policy
- Enforcement of a renewable energy portfolio standard, with annual provincial targets and compliance encouraged through green certificates

Phase IV (2025-): Full market-based pricing + Contract for difference guarantee

- Full market entry for VRE on-grid projects (Document 136)
- Introduction of a contract-for-difference settlement mechanism between grid companies and projects owner

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Other DERs

Despite this progress on the generation side, the market integration of other DER technologies remains limited. For instance, effective storage participation requires access to time-differentiated price signals and multiple revenue streams, including arbitrage opportunities and the provision of ancillary services such as frequency regulation or voltage support. Yet, in many provinces, barriers persist. Most battery storage projects are still excluded from participating in local wholesale power or ancillary service markets, even as national-level policy encourages their treatment as independent market actors.

Previous regulations requiring storage systems to be co-located with wind and solar projects further hindered efficiency and economic viability. In many cases, these batteries were under-utilised due to a lack of accessible revenue streams. Recognising the inefficiencies, Document 136 cancelled these mandatory pairing requirements in February 2025. Looking forward, as more provinces open their markets to standalone storage systems and clarify market rules, developers are expected to pursue more diverse and market-based business models, unlocking the full potential of batteries for load shifting, peak shaving, frequency regulation and more.

In parallel, VPPs are emerging as a promising pathway for aggregating and co-ordinating DERs to provide grid services. Several pilot programmes, notably in Shandong, Guangdong and other leading provinces, are demonstrating the ability of VPPs to deliver demand response, load balancing and energy arbitrage. However, industry participants have raised concerns over the high market entry thresholds currently imposed on VPP operators. While VPPs require frequent, efficient and reliable data exchange with system operators and trading platforms, China has yet to establish a comprehensive regulatory framework to support such interactions. Moreover, the absence of national technical standards and operational protocols continues to impede scalability and interoperability, undermining the potential of VPPs to become mainstream flexibility providers on markets.

Beyond generation and storage, small consumers equipped with DERs are in most cases not exposed to dynamic prices reflecting market conditions, with low flat tariffs or the TOU price difference not constituting a strong economic incentive for demand response. Although nearly 100% of residential consumers in China are equipped with advanced smart meters capable of supporting demand response (including response to price signals and remote load disconnection), the lack of supporting regulatory framework and incentives make them an under-utilised asset for the efficient operation of distribution grids. Users connected at voltages below 10kV can participate in demand response mechanisms through load aggregators or virtual power plants. However, in practice, widespread demand response implementation is still in demonstration stages in provinces such as Jiangsu and Guangdong.

Chapter 2. International experiences

While the pace and context of deployment vary, many jurisdictions have experienced similar challenges to those China now faces. This chapter draws on international experiences to explore how frontrunner systems are responding to these challenges through operational, market and regulatory innovation. The objective is not to prescribe solutions for China, but to present a set of practical examples worth considering. The chapter is structured around three core themes:

- adapting distribution system operations to better integrate DERs
- developing market and business model innovations to unlock their value
- aligning regulation and planning with the needs of a more decentralised power system.

These experiences can help inform China's approach to the integration of DERs as it enters a new phase of deployment.

Evolving practices in distribution operations

With DER expansion, distribution system operations are undergoing a major transformation. Utilities and system operators around the world are beginning to invest in new tools to improve the visibility, real-time monitoring and forecasting accuracy of DERs; these are critical measures for maintaining grid stability and reliability. Practices such as national DER registries, smart metering, smart inverters and submetering are becoming more widespread, while new connection schemes and hosting capacity maps are helping manage local grid constraints. At the same time, the role of distribution system operators (DSOs) is evolving towards more active system management, requiring clear responsibilities and closer co-ordination with transmission system operations.

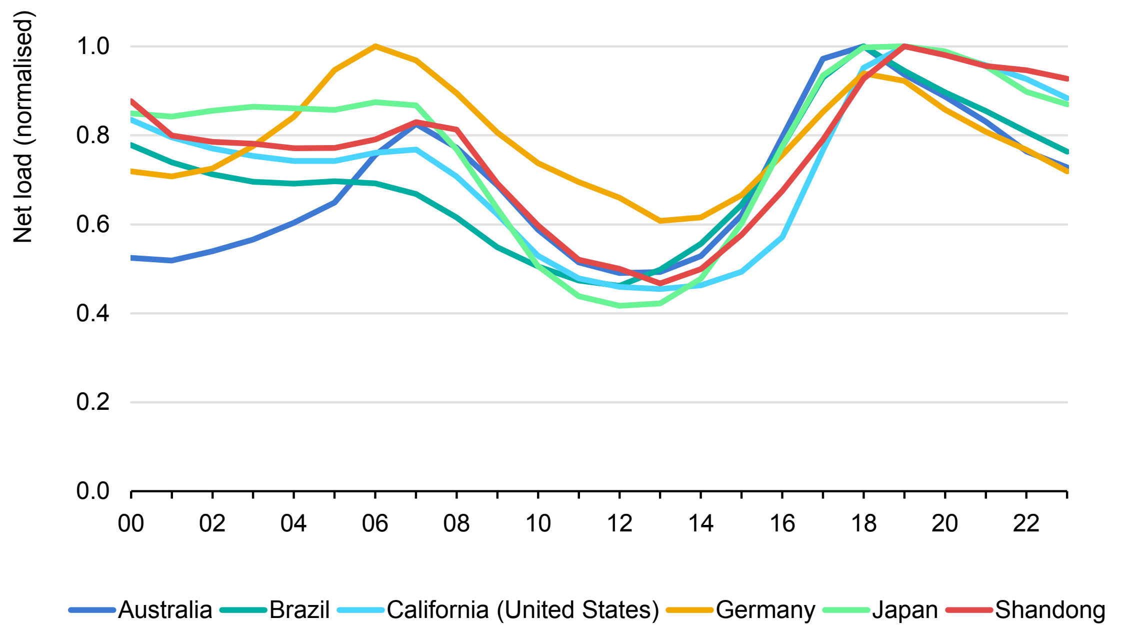
In China, the operational challenges emerging in several provinces increasingly resemble those faced by early adopters of solar PV and other DERs. In Shandong province, for instance, the rapid uptake of DPV has significantly reshaped net load[8] profiles. The province's net load curve exhibits a pronounced midday dip and steep evening ramp, features that are characteristic of the "duck curve" observed in solar-rich systems like Australia.

[8] The net load corresponds to the load minus the wind and solar PV generation.

While such patterns, including the duck curve and the need for high ramping capabilities, can emerge in systems with high shares of either utility-scale or distributed solar, DPV tends to amplify the operational challenges. BTM generation is often neither visible nor controllable by the system operator, leading to a deduction in observed demand during midday hours. This is compounded by limited forecasting accuracy and lack of co-ordinated dispatch.

The duck curve is however only one manifestation of the broader system-wide operational challenges associated with high shares of DERs. Grid operators must address localised impacts, such as voltage regulation, system strength and reverse power flows, which necessitate tailored, location-specific solutions.

Net load curves for selected solar-dominated systems, 2023



Notes: All selected systems have a higher share of DPV compared to utility scale, except for California where the shares of utility scale and distributed solar PV are equivalent. For each system, an extreme day with low demand and high solar PV output was selected. Values are normalised based on the system's hourly peak net load on that day.

Measures to increase DER visibility and improve forecasting are supporting secure grid operations

One of the most pressing challenges for system operators is the insufficient visibility of DERs, particularly at low voltages of distribution networks. Without accurate information on the location, capacity and operation of DERs, system operators may provide inaccurate forecasts and face increased risks of voltage violations, overloading of transformers and conductors and congestion of distribution lines.

In the United States, utilities estimate that they currently have visibility of only one-third of DERs connected to their networks, while three-quarters report that this has already led to operational issues. In Great Britain, the electricity system operator reported that about 25% of generation connected to the grid was not readily visible to inform its forecasts.

For the grid operator, a lack of visibility and controllability over DERs can complicate real-time system operations and emergency response, particularly during disturbances or extreme events. In Chile, initial findings suggest that the widespread blackout in February 2025, which affected 99% of the population, may have been exacerbated by an underestimation of the drop in DPV generation. This occurred when distribution-level nodes were disconnected during load shedding, worsening the grid imbalance. Another major blackout event was that which occurred on the Iberian Peninsula in April 2025, affecting almost the entire population of Spain and Portugal. The Spanish government's report, which investigated the causes of the blackout, highlighted the lack of real-time visibility and control over DERs and their behaviour during voltage disturbances as a key operational challenge. Although DERs were not identified as the primary cause of the event, the report noted that disconnections of distributed units triggered by overvoltage conditions, non-compliance with regulations and other factors may have further exacerbated the situation, contributing to a cascading failure.

Advanced practices for more accurate forecasting and granular control

A number of measures to improve DER visibility are now considered foundational and are being implemented across many jurisdictions, including China. They range from establishing a national registry for connecting assets and equipping end users with smart meters, to including minimum requirements for DER visibility grid codes.

However, as the penetration of DERs increases, it becomes necessary for system operators to have a clear overview of their behaviour closer to real time. Operational metering requirements are a key enabler of DER participation in system operations and flexibility markets, offering real-time data on their performance and availability. For example, in Spain, DPV above 1 MW must be visible to the system operator and those above 5 MW must be controllable. The threshold for installing a control device is as low as 7 kW in Germany.

For smaller assets, the relevant data are generally requested at the aggregated level, to avoid imposing heavy technical or cost burdens on individual DERs. In the Great Britain, where real-time metering requirements are in place for DERs to provide balancing services, a revision is being discussed to ensure that they do not constitute a barrier to entry for smaller assets.

To further enhance the visibility and co-ordination of DERs, several European countries are developing or piloting flexibility registers, which enable system operators to access up-to-date information on the location, capacity and operational status of DERs. Another initiative is submetering,[9] which can be considered in systems where smart meters are not yet widely deployed or where more detailed data is needed. Recent reforms to the European Union electricity market design now formally allow system operators and aggregators to use submeter data for observability and settlement of demand response and flexibility services.

Data on BTM assets come directly with improved forecasting, since having a better overview of underlying demand and generation leads to more precise forecasts and adequacy margins. While a national register can already assist system operators in forecasting rooftop solar PV generation, advanced analytics, such as machine learning algorithms and real-time processing of smart meter data, are increasingly used to predict the behaviour of BTM devices and distribution system flows. In California, the system operator provides short-term forecasts up to five minutes ahead in real time, incorporating weather data and real-time inverter outputs to predict the contribution of distributed solar and storage systems.

Beyond enhancing operational security, measures to enhance DER visibility and forecasting can lead to direct consumer savings. In Great Britain, NESO estimates that improving DER forecasting, enhancing data sharing and incorporating DERs into operational decision-making could deliver up to GBP 150 (USD 192) million per year in consumer benefits.

[9] Installation of meters on individual DER assets, which allows for the application of specific tariffs and demand response contracts, independently from household level consumption.

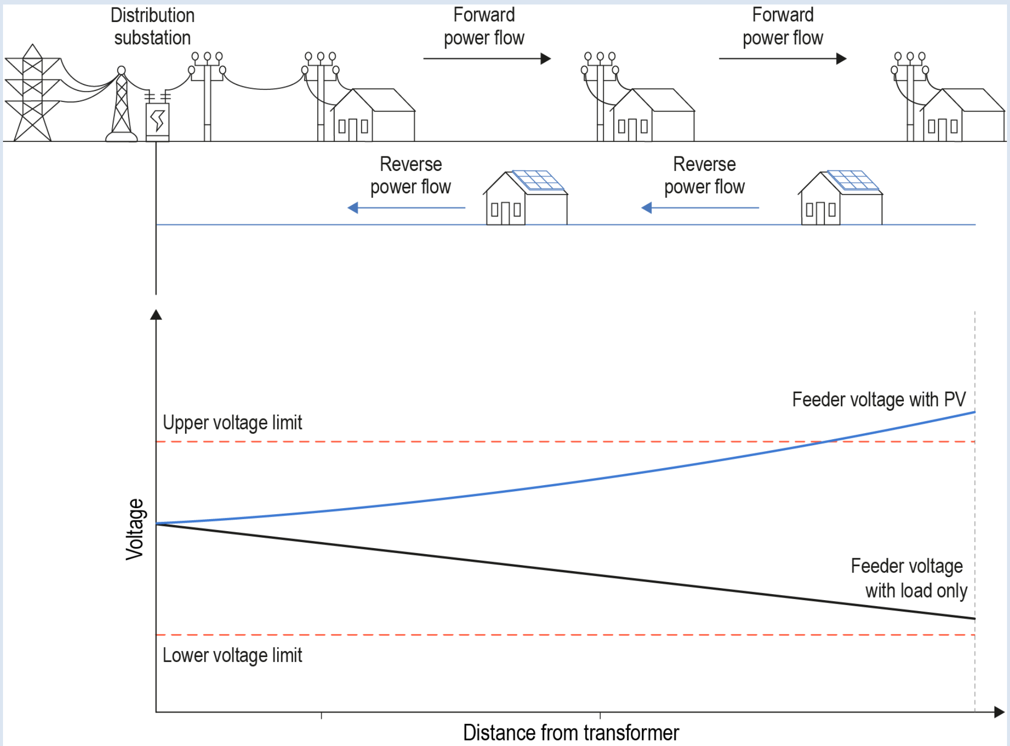
Managing reverse power flows and risks of overvoltage

When rooftop solar PV systems generate more electricity than local demand, the excess power flows in reverse, from customers back towards the substation. This can cause a voltage rise along the feeder, especially towards the end of the line where PV systems are concentrated.

Distribution networks are typically designed for one-way power flow, with voltage naturally dropping from the substation to the last customer. Reverse flows can invert this gradient, and if injected power exceeds the feeder's hosting capacity, it may lead to overvoltage, potentially damaging equipment, reducing power quality and triggering protective devices to disconnect DERs. Operators also aim to avoid back feeding into the transmission grid. To manage this, they can take actions to curtail solar output or store excess energy in distributed batteries.

Ensuring safe and stable grid conditions requires real-time monitoring tools like SCADA (supervisory control and data acquisition) systems, voltage control measures such as smart inverters (with dynamic injection or absorption of dynamic power capability), on-load tap changers and voltage regulators.

Illustration of reverse power flows in distribution networks



Source: Kwang-Hoon Yoon et al. (2022), Operation Method of On-Load Tap Changer on Main Transformer Considering Reverse Power Flow in Distribution System Connected with High Penetration on Photovoltaic System, as modified by the IEA.

Minimum technical requirements become more stringent as DER penetration increases

Grid integration of DERs is increasingly supported by the adoption of more stringent technical requirements and standards designed to ensure system-friendly operation. These requirements aim to maintain electricity security by ensuring that DERs continue to operate and contribute to the system during disturbances, rather than disconnecting abruptly.

In Australia, the decision to revise DER technical standards in 2020 was partly driven by an analysis of grid disturbances which revealed critical vulnerabilities. Notably, the Australian Energy Market Operator (AEMO) estimated that up to 40% of DPV generation disconnected in several regions during disturbance due to inadequate ride-through requirements. In the context of rapid DPV growth, AEMO warned that sudden losses of even larger amounts of generation could severely impact power system security if nothing was done. In response, the new connection standards require renewable generators and DERs to actively support grid stability during faults. This includes voltage and frequency ride-through capabilities and minimum performance expectations during abnormal grid conditions.

Similarly, Germany updated its outdated technical standards, which had required DPV systems to automatically disconnect when grid frequency rose to 50.2 Hz. When DPV capacity reached several gigawatts, this disconnection threshold became problematic, as the potential for large-scale generation losses posed a risk of cascading failures. Subsequently, new requirements were introduced in 2012, mandating a gradual reduction in power output at increased frequency levels instead of sudden disconnection, and large-scale retrofits of existing installations.

While robust technical standards are essential for system reliability, they must also be balanced to avoid placing undue financial or administrative burdens on DER owners. For instance, during the energy crisis in 2022, the European Union introduced a "positive administrative silence" mechanism: systems under 50 kW are automatically granted grid connection approval if no response is received within four weeks. This measure helped accelerate DPV deployment while still allowing grid operators to review applications within a reasonable timeframe.

Smart inverters and demand response readiness requirements

A growing number of jurisdictions now require that DPV and storage systems incorporate smart inverters.[10] In the United States, several states have implemented this requirement, with utilities financing upgrades to smart inverters to enhance voltage control at the distribution level. In Germany, all new PV systems (> 7 kW) must be able to provide voltage and frequency regulation, fault ride-through and remote controllability, with the cost associated with the necessary inverters, control systems and certification falling on the project developer. In China, the revision currently underway of the technical standards for grid connection of distributed generation includes more stringent requirements such as dynamic voltage control and enhanced fault ride-through capabilities, which would in practice require the use of advanced inverters to access the grid. Revisions of grid codes are often accompanied by grid modernisation measures, with grid operators increasingly investing in technologies for remote voltage control in distribution transformers and in power electronic devices (e.g. static synchronous compensator or STATCOM) that provide fast reactive power support.

Minimum requirements for demand response capabilities are also beginning to emerge, particularly in the residential sector, reflecting a growing awareness of the potential for appliance-level flexibility. In Germany, since 2024, all new residential appliances above 4.2 kW – such as EVs, water heaters and space heaters – must be capable of adjusting demand in response to grid signals during network stress events. Similar requirements have been proposed in Great Britain, with mandatory enforcement phases in 2026 and 2028. At the subnational level, South Australia has mandated demand-response capabilities for air conditioners, while California has introduced equivalent rules for pool pumps.

Interoperability

Ensuring interoperability and standardised communication protocols is essential to enable the seamless integration of DERs into broader system operations. Without common standards, DERs cannot effectively interface with aggregators, retailers, system operators and other connected devices. This limits co-ordinated control and market participation. In practice, the lack of interoperable standards, particularly for domestic appliances, remains a key barrier to unlocking residential controlled load. While awareness of this issue is growing, few jurisdictions have fully implemented robust frameworks to address it.

[10] Smart inverters are advanced inverters used in solar and wind systems: beyond converting DC to AC power, they also support the grid by providing services such as voltage regulation, frequency response, reactive power support and ride-through during disturbances, enabling decentralised resources to act more like conventional power plants.

In the European Union, the Commission developed a voluntary Code of Conduct for manufacturers to promote interoperability of energy-smart appliances. However, a harmonised framework for data exchange, covering system-level, service-level and device-level communication, is still lacking. This limits both data interoperability and consumer participation and remains a barrier to the full activation of DER flexibility potential. As countries continue to define technical standards for DER integration – for example, China is expected to establish standards for vehicle-to-grid interactions by 2025 – international collaboration is also gaining momentum. Initiatives such as the IEA Technology Collaboration Programme's Task 53 on Bidirectional Charging provide a platform for knowledge sharing and alignment with emerging international practices.

Hosting capacity maps, innovative grid tariffs and flexible connection schemes are helping to manage local grid constraints

As distribution grids become increasingly saturated in some areas, traditional connection processes – based on guaranteed, unrestricted grid access – can lead to delays, refusals or inefficient use of infrastructure. Hosting capacity maps offer a way to identify where grid capacity is available for new connections. To address congestion, countries are implementing complementary solutions: network tariffs with time-based or locational signals, flexible connection agreements and local flexibility markets.

The choice between these approaches depends on local conditions and the urgency of the situation. Flexible connection agreements are often relatively quick to implement and can constitute a temporary solution, whereas reforming network tariffs or establishing market-based procurement schemes for flexibility typically require more time. The decision also involves how the cost of flexibility is allocated: either socialised through centrally procured explicit flexibility or primarily borne by the connecting asset under a tariff-based approach.

Hosting capacity maps

Hosting capacity maps, by indicating how much additional generation or load a section of the grid can accommodate without triggering upgrades or reliability issues, can guide investment decisions and accelerate project planning.

Scale and temporal resolution matter and these maps are increasingly detailed and technology specific. In France, a dedicated map provides visibility into grid availability for battery storage projects. In Australia and the United States, public maps support the siting of EV charging infrastructure, while in Japan, the "Welcome Zone Map" guides the siting of new demand, such as data centre projects. In the Netherlands, the energy association Netbeheer Nederland publishes integrated maps covering both T&D networks, showing available capacity for both injection and offtake.

China is also making progress in this area, providing developers and local authorities with clearer signals about where new systems can most effectively connect. Beginning in 2025, grid companies have had to co-operate with provincial energy authorities to assess grid capacity, publish capacity data with early warning mechanisms and guide siting of solar PV installations.

Transparency on distribution grid capacity can be mandated by regulation, as in the case of the EU Directive requiring DSOs to publish and update capacity availability data at least quarterly. While the level of detail, temporal resolution and geographic coverage varies across countries, the overall trend is towards more regular, standardised and transparent information-sharing.

Network tariffs

Innovative network tariff structures, incorporating temporal and/or locational differentiation, can be used to encourage network users to shift consumption to off-peak periods or to connect in less congested areas.

TOU network charges are one such approach, where the price paid per kW or kWh is higher when network utilisation approaches technical limits and lower during off-peak periods. In Europe, 78% of countries apply TOU charges at the distribution level. This type of tariff can help reduce system-wide or local peak demand, as demonstrated by impact assessments in Belgium.

Locational signals can also be incorporated into network tariffs to guide the siting of new generation or load, thereby avoiding network congestion. These can take the form of differentiated connection charges or use-of-system charges. This is particularly relevant in systems with zonal pricing models, where wholesale market prices do not reflect local grid constraints. For example, Denmark applies differentiated injection and connection charges for generators connecting to grids above 10 kV, with higher charges in regions with excess generation.

Another approach is to incentivise self-consumption through tariff design, exempting consumers who consume energy locally from paying for the use of higher voltage network levels. In Portugal, for instance, a 2022 reform introduced a more favourable tariff regime for prosumers, exempting them from certain grid costs associated with higher voltage infrastructure.

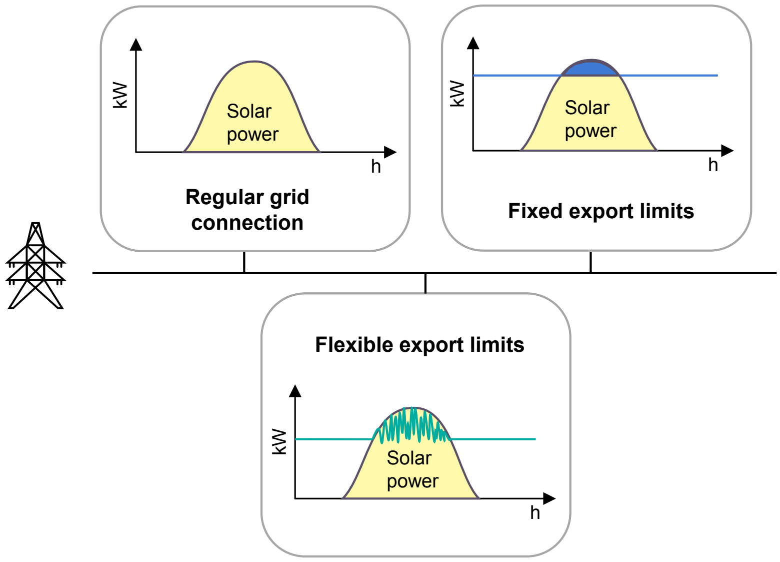
Flexible connection agreements

Flexible connection agreements (FCA) allow DERs to connect to the grid under certain conditions, typically by limiting the power they can export during times of local network congestion. Rather than rejecting new applications outright, these arrangements provide a compromise that helps accelerate the pace of connection and optimises the use of existing grid infrastructure. For the connecting asset, it involves weighing the impact of operational limitations on the business case against the benefit of gaining earlier access to the grid.

Under such schemes, grid operators may define static export or import limits (e.g. capped feed-in during peak solar hours) or dynamic limits, which vary based on real-time grid conditions. In both cases, a prerequisite is that the network be sufficiently digitalised to enable the communication of these limit signals. The extent of curtailment, eligibility criteria and whether or not compensation is provided for reduced output vary significantly across jurisdictions. In the European Union, the 2024 electricity market design reform gave grid users the right to benefit from flexible connections in congested areas. Several member states soon adopted such schemes. In Germany, participation is mandatory for certain users. In the Netherlands, where grid congestion is frequent, FCA have been in place since 2024 and new minimal availability and timeslots agreements were introduced in 2025 for users to gain at least partial access to the T&D networks.

Outside Europe, flexible connection options have emerged, for example in California where solar and battery system owners can manage export limits to align with local grid conditions. In South Australia, dynamic operating envelopes – where import and export limits can vary over time and location – are now the standard connection arrangement for new rooftop PV installations. Updated at short intervals, these envelopes reflect local grid availability and enable consumers to export significantly more electricity than would be possible under fixed limits. On average, solar households under this offer have been able to export up to twice as much compared with static export caps, without requiring major network reinforcements, while costs of implementing such a solution for the grid operator are relatively low – less than 1% of South Australia Power Network's revenue over the fiscal years 2020-25.

Illustration of three types of grid connection agreements for a building equipped with rooftop solar panels



IEA. CC BY 4.0.

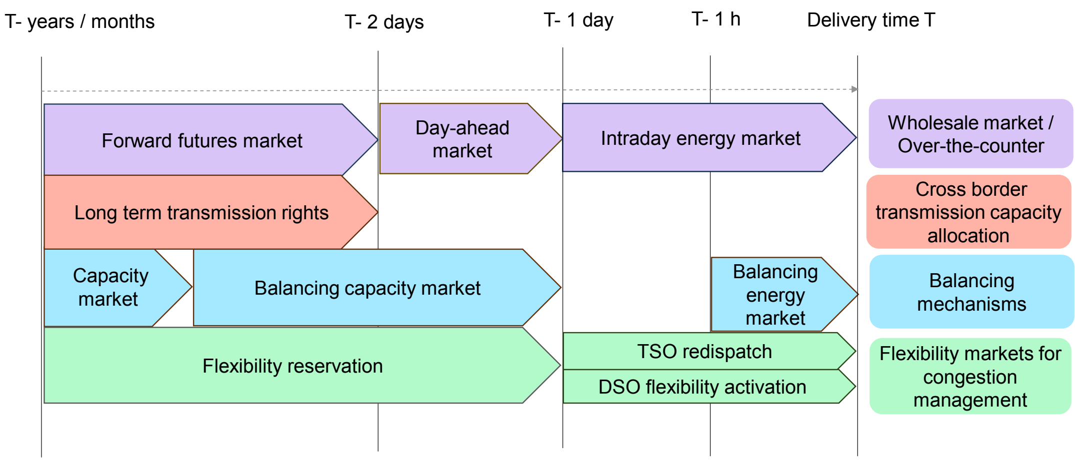
Local flexibility markets reduce the need for network reinforcement in congested areas

Local flexibility markets allow system operators to buy flexibility from DERs and other flexible resources within a specific area, using local price signals to manage congestion and reduce the need for network upgrades. They have been introduced in jurisdictions facing severe local grid constraints and rising balancing costs. This is the case in the Netherlands, where grid congestion is becoming a major bottleneck for energy transition and affordability. Similarly, in the United Kingdom, system operators faced a 75% increase in congestion management costs between 2010 and 2017.

While these markets can be powerful tools for grid congestion relief, their effectiveness heavily depends on sufficient liquidity and participation. They should not be seen as substitutes for simpler, more readily implementable measures, such as hosting capacity assessments or flexible connection agreements, which can often deliver faster or lower-cost solutions.

Where they operate, local flexibility markets also constitute more opportunities for DER value creation, offering additional revenue streams for participating assets. Assets can participate in multiple markets and stack value, with aggregators optimising prices and asset output across timeframes. In Europe, typically, once day-ahead flexibility reservations are submitted, asset operations are adjusted in the intraday continuous energy and balancing markets taking into account their committed services.

European electricity markets structure and time frames



Notes: The last gate closure of continuous intraday energy markets in Europe is gradually approaching real-time delivery. Capacity markets are available in a limited number of EU countries.
Source: EPEX Spot, as modified by the IEA.

Local flexibility markets in Europe

The European Union has led the development of local flexibility markets, underpinned by clear regulatory mandates. EU regulation 2019/943 calls for the most cost-effective operation of the distribution networks, including flexibility services and facilitation of demand-side flexibility market access. The directive 2019/944 incentives DSOs to procure flexibility and congestion management for distribution networks in a transparent, non-discriminatory and market-based manner, and member states must ensure that their regulatory framework allows for it.

Outside Europe, uptake has been more limited with local flexibility procurement hindered by vertically integrated utilities (i.e. no independent DSOs), alternative approaches to system balancing, or regulatory environments that still prioritise traditional grid investments over non-wire alternatives.

Across Europe, flexibility services are typically orchestrated by an aggregator or provided directly by larger users to address two types of needs: structural congestion, where flexibility is used regularly to manage persistent grid constraints, and incidental congestion, in response to short-term or unexpected events. These requests from the system operator can cover pre-contracted commitments (long-term reservation) where flexible resources commit to be available during specific time windows and can be activated with a day's notice. Alternatively, assets can respond to day-ahead or intraday requests without prior reservation, typically issued by DSOs at the distribution level. TSOs may also issue a flexibility request for redispatch, where local generation or consumption is adjusted to relieve congestion and is offset by adjustments elsewhere in the system.

Effective co-ordination between TSOs and DSOs is essential to ensure that flexibility activated at the distribution level does not create problems at the transmission level and vice versa. Greater co-ordination helps align market timeframes and procurement processes, enabling flexible resources to be used when they deliver the most system value and reducing barriers to participation. However, co-ordination remains a challenge in practice, as data sharing and operational protocols are not yet harmonised across Europe. Only some jurisdictions have implemented data-sharing schemes for demand and generation forecasting and for power generation facilities with a 15-minute granularity.

System and consumers cost savings

Local flexibility markets can offer multiple benefits. For system operators, they help manage grid balancing more effectively, reducing balancing costs and deferring costly grid reinforcements. For consumers, these cost savings can translate into lower electricity bills and also lead to potential additional revenue streams if they monetise their flexibility.

There have been promising results from local flexibility markets, especially in the United Kingdom where DSOs have procured various flexibility services through competitive tenders since 2018. The largest DSO, UK Power Networks, has been particularly active, launching regular day-ahead auctions on the EPEX Spot platform since 2024. UKPN estimates that using flexibility instead of building new infrastructure could save customers up to GBP 410 (USD 553) million between 2023 and 2028.

While the potential for system-wide cost savings is significant, there are several barriers to unlocking this value. One major challenge is risk aversion from system operators, who have limited control over the delivery of flexibility services, raising concerns about operational security. Market entry barriers also hinder liquidity development, including complex qualification requirements, the need to install monitoring devices and a lack of visibility on market value. Notably, a key issue hindering participation is the lack of sufficient economic incentives and consumer awareness to offer flexibility. For aggregators, whose achievable revenues per asset are relatively low, building a viable business model depends on enrolling a large enough pool of flexible assets, which in turn requires greater end-user participation.

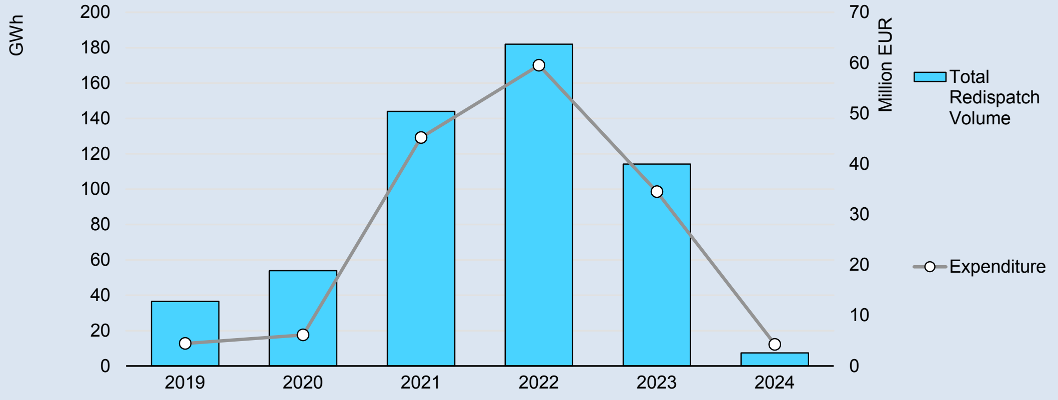
Several approaches can scale up asset participation, including consumers' awareness campaigns, smart appliance integration, interoperable DSO standards and simplified registration. In Great Britain, flexibility platforms allow individual devices to participate even without a smart household meter, and the Flexibility Market Asset Registration streamlines access with a one-time registration process for multiple markets. Besides, greater transparency from system operators in terms of expected flexibility needs and early publication of congested areas allow participants to prepare for participation and assess their business case.

Selected marketplaces for grid congestion relief procurement

Flexibility marketplaces are platforms that link providers of flexibility services with system operators' requests. Depending on the platform, services may include asset prequalification, flexibility request notification, request matching, price formation and dispatch instructions.

- **NODES** operates in constrained areas in Norway, Belgium, Canada and Sweden with aggregators and large flexibility providers. It has facilitated more than 3 TWh in reservations and 6 GWh in activations since 2021, both covering short- and long-term needs. For DSOs, NODES manages auctions, clears transactions and settles payments, while for TSOs, it only acts as a market intermediary.
- **Piclo** has registered over 30 GW flexible capacity, with 3 GW procured since 2019. In Great Britain, Piclo now serves all six DSOs and the TSO and is expanding to Ireland, Italy, Portugal, Australia and the United States. Piclo Flex focuses on long-term flexibility reservations and is increasingly offering short-term flexibility services. In 2023, the TSO introduced a Local Constraint Market on Piclo, enabling day-ahead DER bidding. In 2024, Piclo Max was introduced to unify access to wholesale, balancing and capacity markets.
- **GOPACS** is a congestion management platform primarily used for intraday TSO redispatch and has been operated by Dutch grid operators since 2019. Participation is either voluntary or mandatory depending on the contract for assets above 100 kW of capacity, with initiatives to target smaller flexible resources. However, GOPACS has not been sufficient to fully alleviate grid congestion, with one issue being the lack of long-term investment signals found in UK-style flexibility markets, where local and system-level services can be pre-contracted and delivered by VPPs.

Redispatch volume and expenditure on the GOPACS platform, 2019-2024



Note: The decrease in the redispatch volume can be partially explained by the increase in flexible connection agreements for day-ahead congestion management which reduces the need for intraday redispatch congestion management.

Source: IEA analysis based on data from GOPACS.

DER integration measures in selected power markets

Integration measures	National registry	Real-time metering data to SO requirement	Smart inverter requirement	Public hosting capacity maps	Flexible connection agreements
China	🟢	🔴	🔴	🟡	🔴
Australia	🟢	🟢	🟢	🟡	🟢
Denmark	🟢	🟢	🟢	🟢	🟢
France	🟢	🔴	🟢	🟢	🟢
Germany	🟢	🟢	🟢	🟡	🟢
Great Britain	🟢	🟢	🟢	🟡	🟢
Italy	🟢	🟢	🟢	🟢	🔴
Japan	🟢	🟢	🔴	🔴	🟢
The Netherlands	🟢	🟢	🟢	🟢	🟢
Norway	🔴	🟢	🟢	🟢	🟢
Singapore	🟡	🟡	🔴	🔴	🔴
Spain	🟢	🟡	🟢	🟢	🔴
Sweden	🟢	🟢	🟢	🔴	🟢
United States	🟡	🟢	🟢	🟡	🟡

🟢 Implemented 🟡 Partially implemented 🔴 Not implemented

Notes: The countries presented here were selected based on the maturity of their power market and their openness to DERs, with additional consideration given to ensuring broad geographical representation. The requirement for real-time metering data to SO (system operator) assesses whether live metering is required to participate in certain ancillary services.

"Partially implemented" for hosting capacity maps means the map does not cover the entire country.

Sources: JDLK renewable; IEA (2023), Efficient Grid-Interactive Buildings; Energistryrelsen; ODRE; Marktstammdatenregister; SSEN, Embedded capacity register; ARERA; METI; Energieleveren; SP group (2022), Solar PV – User Guide for Residential Consumers; Metico; IEA PVPS (2023); New York State; Basic Rules of the Electric Power Auxiliary Services Market; DNV (2025) Operational Metering Requirements; Prequalification Process for Balancing Service Providers (FCR, aFRR, mFRR) in Germany; ARERA (2025); METI (2025); Stattnett (2023); SP group (2022), Solar PV – User Guide for Residential Consumers; Red Electrica; Svenska kraftnät; IEA (2024), Meeting Power System Flexibility Needs in China by 2030; IEA (2022), Unlocking the potential of DER; Scupower (2025) Introduction to Energy Storage Certification EN50549; Scupower (2025), Comprehensive Guide to German Grid Compliance Meteocontrol; Baidu (2025), Distributed photovoltaic access is restricted in more than half of Henan Province; New South Wales; Kapacitetskort for elnettet; RTE Services Portal; Stromnetz; SSEN; E-Distribuzione; OCCTO; Tennet grid capacity map; WattApp; EMA; Iberdrola; New York State; AEMO (2023), Dynamic Operating Envelopes; ACER (2025), Getting the signals right: Electricity network tariff methodologies in Europe; Solar Power Europe (2024), Electricity Market Design Reform; IREC (2024), Milestone Decision by California Regulators Approves the Use of DER Schedules to Avoid Interconnection Upgrades.

Roles and responsibilities of DSOs in a high DER system

In liberalised electricity systems, DSOs were introduced to separate monopoly network operations from competitive activities like electricity generation and retail. This structural unbundling was essential to ensure neutrality and foster competition, while creating opportunities for innovation.

Different TSO-DSO co-ordination models, for example total DSO, hybrid DSO and total TSO, exist. As DERs are expanding rapidly, the role of DSOs is shifting from passive network management to active system co-ordination. Depending on the local context, DSOs are increasingly taking on new responsibilities, including managing local flexibility needs by procuring services such as demand response or storage for congestion management, maintaining grid stability through real-time monitoring, DER forecasting and voltage control, and co-ordinating with TSOs by sharing operational data and aligning system operations, as DER behaviour have system-wide implications.

Some examples from international experience highlight the diversity of DSO functions and their recent evolution:

- **Great Britain**: The transition from distribution network operators (DNOs) to DSOs is driven primarily by increasing local flexibility needs.
- **Australia**: The creation of both DSOs and DMOs (distribution market operators) is being considered to facilitate DER integration and to address grid stability challenges.
- **California (CAISO)**: Hybrid models are under discussion, to deal with complex co-ordination issues in a context of market integration of DER.
- **European Union**: The DSO concept across EU member states is not uniform and depends on country needs. However, the EU DSO Entity focuses on harmonising rules across jurisdictions and projects like SmartNet. It aims at enhancing co-ordination between DSOs and TSOs for information exchange and procurement of ancillary services from DERs.

For China, where the DSO function is not yet clearly defined, clarifying the roles and responsibilities of actors at the distribution level will be critical to support the next phase of DER integration.

Market and business models to unlock the value of DERs

While system operators are rethinking distribution practices to better integrate DERs into the grid, market operators and regulators in many countries are also revisiting market rules to enable their participation. This shift reflects a growing recognition that, when properly integrated, DERs can enhance system flexibility and resilience. Meanwhile, traditional remuneration schemes such as full grid purchase and net metering, which were instrumental in early DER deployment, are being re-evaluated due to their limited ability to capture system value and incentivise system-friendly behaviour. In several parts of the world, this evolution is fostering new business models focused on self-consumption and enabling DER owners to monetise grid services, thereby promoting more diversified and sustainable value streams.

Market rules are being adjusted to allow DER participation and value stacking

Market access

Power systems with growing shares of DERs are advancing market reforms to enable their active participation, allowing them to provide system services while creating value for their owners. A key step in this transition is the revision of rules for market participation, with eligibility criteria such as minimum capacity thresholds, availability duration and response times. Participation also requires technical capabilities for measurement and settlement, typically including real-time metering, baseline measurement methods, remote control and dispatchability. Since individual DERs may be too small to participate directly, aggregators bundle multiple assets to meet market entry requirements. While a typical entry threshold has historically been around 1 MW, some jurisdictions are now lowering these requirements to enable wider participation.

In the European Union, minimum bidding thresholds can be as low as 100 kW for wholesale markets and several member states are enabling aggregators to participate independently of retail suppliers. However, the European Union Agency for the Cooperation of Energy Regulators (ACER) has pointed out that fragmented implementation and limited market access across member states remain key barriers to the deployment of demand response.

In the United Kingdom, recent modifications to industry codes now allow aggregators to participate in most electricity markets. Current participation thresholds stand at 100 kW for wholesale markets and 50 kW for flexibility markets. Since the end of 2024, asset owners can select aggregators or optimisers to trade their flexibility independently of their electricity suppliers, further opening the door for decentralised participation. To address potential revenue loss for suppliers caused by downward demand response actions from aggregators, a mutualised compensation mechanism has been introduced. Under this arrangement, suppliers are reimbursed from a common pool funded collectively by market participants, with compensation based on average sourcing costs. This mechanism is considered a leading approach in enabling explicit demand response while maintaining fairness across suppliers.

In the United States, the Federal Energy Regulatory Commission (FERC) has implemented a series of landmark reforms. Order No. 841 requires system operators to accommodate energy storage in wholesale markets, while Order No. 2222 mandates market access for aggregated DERs, with system operators required to design participation models that reflect their operational characteristics. Implementation is ongoing across regional markets, with notable progress in CAISO and NYISO.

The National Electricity Market (NEM) in Australia has also introduced reforms to facilitate DER market integration, including the “Integrating Energy Storage Systems” rule change to enable participation of bi-directional assets. Project EDGE, a large-scale trial, has tested wholesale bidding models for aggregated DERs under these new frameworks.

DER participation in selected power markets

Market	Wholesale	Ancillary services	Capacity market	Strategic reserve	Local flexibility	Peer-to-peer trading
China	Partially eligible	Partially eligible	Not available	Not eligible	Not available	Eligible
Australia	Eligible	Eligible	Not available	Eligible	Eligible	Eligible
Denmark	Eligible	Partially eligible	Not available	Not available	Not available	Eligible
France	Eligible	Eligible	Eligible	Not available	Eligible	Eligible
Germany	Eligible	Partially eligible	Not available	Partially eligible	Eligible	Eligible
Great Britain	Eligible	Eligible	Eligible	Not available	Eligible	Eligible
Italy	Eligible	Partially eligible	Eligible	Not available	Eligible	Eligible
Japan	Eligible	Eligible	Eligible	Not eligible	Not available	Eligible
The Netherlands	Eligible	Eligible	Not available	Not available	Eligible	Eligible
Norway	Eligible	Partially eligible	Not available	Not available	Eligible	Not available
Singapore	Eligible	Partially eligible	Not available	Not available	Not available	Eligible
Spain	Eligible	Eligible	Not available	Not available	Not available	Eligible
Sweden	Eligible	Partially eligible	Not available	Eligible	Eligible	Eligible
United States	Eligible	Partially eligible	Partially eligible	Not available	Partially eligible	Eligible

Eligible Not eligible Partially eligible Not available

Notes: The countries are selected based on the maturity of their power market and their openness to DERs, with additional consideration given to ensuring broad geographical representation.

"Eligible" means DERs can participate in the market individually or through an aggregator. DERs are considered eligible to participate in ancillary services markets if they can participate in all of the following selected services: primary, secondary, tertiary and restoration reserves. Countries with local flexibility markets and peer-to-peer trading initiatives (even at pilot stage) are marked green.

"Partially eligible" means that DER participation is restrictive or not available everywhere in the country.

"Not available" means the market is not available in the country.

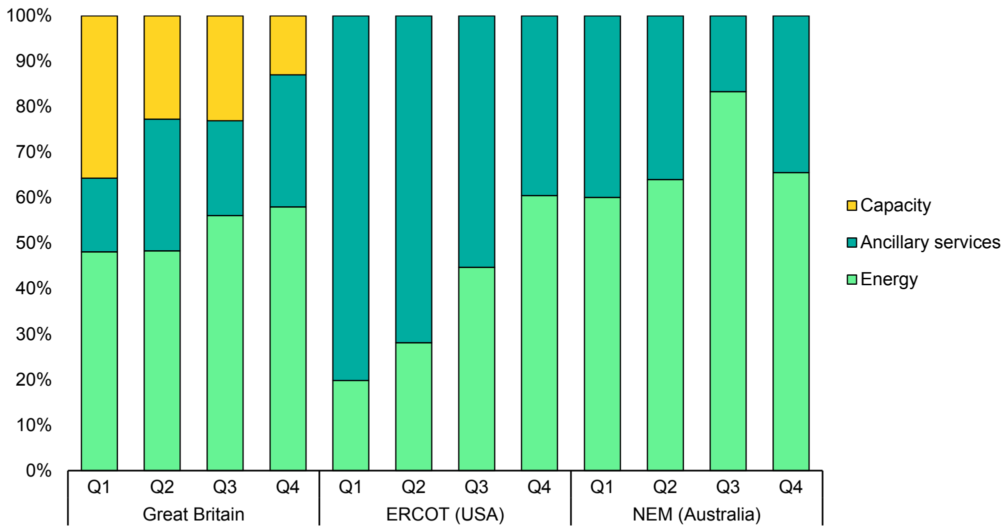
Sources: IEA (2023), Building a Unified National Power Market System in China; Institute for Sustainable Futures (2025), Product Policy Framework for Demand Side Flexibility: Case Studies; EPEX Spot (2024), Trading at EPEX SPOT; ACER (2023), Demand response and other distributed energy resources; Institute for Sustainable Futures (2025), Product Policy Framework for Demand Side Flexibility: Case Studies; International Bar Association (2024), Initiatives and challenges for the introduction of distributed energy systems; IEA (2023), Efficient Grid-Interactive Buildings ; NARUC 2024, Aggregated Distributed Energy Resources in 2024; Shanxi energy regulatory office (2022); SkippingStone 2024, Japan Energy Market Update; EMA 2024, Harnessing Distributed Energy Resources via Virtual Power Plants to Provide Energy and Ancillary Services; IEA (2024), Meeting Power System Flexibility Needs in China by 2030; AEMO, Reserve Capacity Mechanism; Aurora (2025), Capacity remuneration mechanisms in Europe; Aurora (2025), Capacity remuneration mechanisms in Europe; METI (2021), Japanese Energy Market; EMA 2023, Centralised Process to Ensure Sufficient Generation Capacity; Piclo; Fingrid (2020), Local Flexibility Markets in the Nordics; JRC (2022), Local electricity flexibility markets in Europe; Accenture (2024), Benchmark on local flexibilities for DSO; Piclo (2025); Progetto EDGE; Gopacs (2025); REEFLEX (2025); Piclo; Energy Policy Research Group (2021), International experience in local electricity markets for the procurement of flexibility services; PV magazine (2024), China issues new rules to support peer-to-peer energy trading; Irena (2020), peer-to-peer electricity trading; EPRI; Powerledger (2024), The Future of Decentralised Energy: Powerledger's Research in Blockchain and P2P Trading; IEA Clean technology guide (2025); F&S Energy Limited (2022), Peer to Peer Matching Platform; Open Research Europe (2022), Peer-to-peer energy communities: regulatory barriers in the EU context; Irena (2020), peer-to-peer electricity trading; Coordinet (2022), Final Report of the Swedish Demonstration.

Value stacking

By opening access to multiple markets, DERs and aggregators can stack value across different revenue streams, bidding into energy, ancillary services and where available, capacity markets. In Great Britain, Texas (ERCOT) and Australia, batteries are already active across several markets. Over time, a commonly observed trend is for ancillary services markets to get saturated, hence the importance of allowing batteries to get access to other revenue streams such as capacity markets or strategic reserves. For instance, Japan has allowed DERs to enter its newly established capacity market, with the ability to provide 1 MW or more of dispatchable capacity through aggregation. During the heatwaves of summer 2024, demand response-based dispatchable resources were instrumental in maintaining grid stability.

Aggregators play a central role in this ecosystem by managing portfolios of small-scale assets and optimising them across customers and markets. They are typically best positioned to co-ordinate dispatch across different services while navigating potential conflicts between overlapping obligations.

Average revenues of 1- and 2-hour battery systems in Great Britain, ERCOT (United States) and the NEM (Australia) in 2024



IEA. CC BY 4.0.

Notes: In this chart, “ancillary services” for Great Britain combine the revenues from frequency response and reserve, while “Energy” combines the revenues from the wholesale market and balancing mechanism.
In ERCOT, “energy” combines the day-ahead energy market and the real-time market.
In Australia’s NEM, “ancillary services” include lower regulation, lower contingency, raise regulation and raise contingency. There are no capacity markets in ERCOT and Australia’s NEM.
Source: IEA analysis based on data from Modo Energy.

Remuneration schemes are evolving to better align DER behaviour with system needs but there is a risk of deterring investments

Traditional remuneration schemes, such as net metering and buy-all, sell-all models, have played a central role in driving the uptake of DPV across many markets. An analysis of the top countries with the highest shares of DPV generation in 2023 confirms that these models, either still in place or already phased out, have been instrumental in enabling early deployment by offering strong financial incentives to investors and a simple programme design.

DPV remuneration schemes in countries with high DPV penetration

Remuneration schemes	Buy-all, sell-all	Net metering	Real-time, self-consumption
China	🟢	🔴	🟢
Hungary	🔴	⚫	🟢
Greece	🔴	⚫	🟢
The Netherlands	🔴	⚫	🔴
Australia	🔴	🟢	🟢
Italy	⚫	⚫	🟢
Germany	🟢	🔴	🟢
Austria	🟢	🔴	🟢
Belgium	🔴	⚫	🟢
Switzerland	🔴	🔴	🟢
Japan	⚫	🔴	🟢
Brazil	🔴	🟢	🔴
Poland	🔴	⚫	🟢
Portugal	🔴	🔴	🟢

🟢 Implemented 🔴 Not implemented ⚫ Phasing/Phased out

Notes: The countries selected had the highest global share of DPV generation in their total electricity generation in 2023. The countries (except from China) are listed in descending order, with Hungary having the highest share. Remuneration schemes' availability may differ between residential and C&I consumers, with typically more favourable conditions for residential installations.

"Buy-all, sell-all": All PV generation is sold to the utility at a fixed price, which can be above, equal to or lower than the retail rate. PV owners buy all the electricity they consume from the grid at the retail price. This model is often implemented in the form of a feed-in tariff.

"Net metering": PV owners can self-consume the electricity they generate, which reduces their consumption from the grid. They receive an energy credit for any excess generation exported to the network during a specific time, which can be deducted from the electricity bought from the grid on future bills at another time.

"Real-time, self-consumption models": Unlike net metering, energy accounting is done in real-time and PV owners are paid for each unit of electricity exported, rather than earning energy credits towards future bills. The price paid for exported electricity varies by jurisdiction and can be from zero to above the retail price. This model incentivises PV owners to better interact with the grid, by self-consuming their production or injecting electricity when grid prices are high and buying electricity from the grid when prices are low.

Sources: PV magazine (2025), China to switch from FITs to market-oriented renewables pricing; Solar Power Europe (2024), EU Market Outlook for Solar Power 2024-28; IEA (2019), Renewables 2019; IEA-PVPS (2023), National Survey Report of PV Power Applications in Italy 2023; Germany: PV magazine (2025), Germany introduces new rules for solar remuneration during negative price; IEA-PVPS (2023), National Survey Report of PV Power Applications in Austria 2023; IEA-PVPS (2023), National Survey Report of PV Power Applications in Switzerland 2023; IEA-PVPS (2022), National Survey Report of PV Power Applications in Japan 2022; PV magazine (2022), Brazil introduces new rules for distributed generation, net metering; European Commission (2019); IEA-PVPS (2023), National Survey Report of PV Power Applications in Spain 2023.

Net metering, in particular, has proven effective in promoting residential and small-scale solar adoption by allowing PV owners to offset their electricity consumption with on-site generation, often at retail prices. However, these schemes are overly generous and typically do not reflect the true value or system costs of DER exports, especially when generation coincides with periods of low demand or system congestion. In addition, they can create equity concerns: by enabling PV users to rely on the grid while reducing their proportional contribution to its upkeep, costs may be shifted onto non-DPV generating consumers, who are often lower-income households.

In response, a growing number of jurisdictions are reforming remuneration schemes to better align DER behaviour with system needs and incentivise self-consumption. Adjustments to traditional net metering schemes have been introduced, although these changes do not address the schemes' core structural issues. For example, in an attempt to deal with the rapid DPV growth and to ensure fairer cost sharing, Brazil updated its net metering policy in 2023, introducing grid fees for connecting assets which will increase until 2045.

Another pathway has been the transition to real-time self-consumption models, including net billing schemes. While more cost-reflective, such models tend to offer less favourable economics for PV owners and have, in several cases, led to a slowdown in deployment. This trend is evident in multiple regions.

In the United States, the federal investment tax credit along with state- and utility-level incentives for net metering have been the main drivers for DPV adoption. However, recent shifts from net metering to net billing in some states (e.g. California and Hawaii) have contributed to a slowdown in new rooftop solar installations, along with increased battery adoption. Across Europe, a similar transition is underway. Since the Netherlands announced in 2024 the phase-out of the net metering scheme from 2027, a notable decline in new residential installations was observed due to uncertainty regarding future policy. At the end of 2024, the authorities confirmed that the scheme will be replaced with a new compensation mechanism, through which energy suppliers will set the compensation rate for excess electricity fed into the grid. The export prices are expected to fall close to zero, which encourages maximising self-consumption rather than maximising generation. Other countries, including Greece, Poland and Hungary, have adopted similar reforms in recent years, transitioning to net billing systems that better reflect system value but have also been associated with slower growth in the residential PV segment. Great Britain replaced its feed-in tariff with the Smart Export Guarantee in 2020, a government-backed scheme for surplus electricity exports. However, the policy has so far proven insufficient to sustain strong DPV growth.

Time-differentiated retail electricity prices as a primary tool to unlock consumers' flexibility

Time-differentiated electricity prices can incentivise consumers to shift their consumption to low-demand or high production periods. Tariffs can be static TOU with fixed peak and off-peak hours, or dynamic, linked to wholesale prices. Globally, TOU tariffs are significantly more widespread among smaller consumers, as they still offer predictability. Dynamic tariffs, although potentially offering greater savings for flexible users, have seen limited adoption so far, as they also expose consumers to the risk of high price spikes.

In China, since 2022, C&I consumers are required to procure electricity through the retail or wholesale markets and are subject to mandatory TOU tariffs. Fixed-price packages, typically including TOU pricing, remain the preferred option to avoid market volatility, even though they come with a premium. Residential consumers have very limited exposure to variable pricing, although initiatives for optional TOU pricing for households and EV charging exist in some provinces.

In the European Union and Norway, the availability of time-differentiated retail contracts for households and C&I customers varies across countries. Despite the increase in offers and increased number of hours with low wholesale prices in 2024, 15 member states still heavily rely on fixed-price and/or regulated contracts, indicating untapped potential for demand-side flexibility. Barriers to adopting more dynamic pricing include the lack of smart meters and limited consumer awareness of potential savings.

Norway stands out, with 97% of households choosing dynamic tariff contracts. This is due to the hydro-dominated electricity mix mitigating exposure to price volatility, full smart meter coverage and a high share of technologically engaged consumers using their heat pumps or EVs flexibly. In California (United States), TOU tariffs are widespread, and legislation requires utilities to introduce optional dynamic tariffs for all consumer classes by 2030, as part of the state's strategy to increase its load-shifting goal to 7GW at this horizon.

While reforming residential retail price structures remains sensitive and complex in China, leveraging EV flexibility through dedicated smart charging tariffs appears more practical and attainable. In Shandong province, the growing number of EVs has created a peak in charging demand in the evening after users come back home and plug in their cars. Consumers can voluntarily choose a TOU charging tariff, with peak, valley and flat rates, adjusted seasonally. Outside of China, the UK retailer Octopus offers specific tariffs under which cars are charged at the cheapest time automatically. In Amsterdam, several public charging points schedule EVs' recharges based on expected departure times.

New business models are emerging to unlock behind-the-meter (BTM) flexibility and encourage self-consumption

As remuneration schemes evolve to better reflect the system value of DER, new business models are emerging to monetise this value and promote a smarter use of BTM assets. These models are driven by dual revenue streams: customer bill savings through optimised self-consumption and compensation for providing grid services. Beyond market access rules, their development often relies on enabling conditions, including the deployment of smart meters, time-varying tariffs and the establishment of a clear regulatory framework for aggregators. Demand response mechanisms, either implicit by using price signals to incentivise consumers to shift consumption or explicit by making direct payments to enrolled consumers, have also been commonly implemented in many jurisdictions to leverage end users' flexibility.

Demand-side flexibility enablers in advanced power markets

	Smart meter penetration	Aggregator framework	Implicit demand response		Explicit demand response	
			Household	C&I	Household	C&I
China	100%	Implemented	Partially implemented	Implemented	Partially implemented	Implemented
Australia	56%	Implemented	Implemented	Implemented	Not implemented	Implemented
Denmark	100%	Implemented	Implemented	Implemented	Implemented	Implemented
France	94%	Implemented	Partially implemented	Implemented	Implemented	Implemented
Germany	2%	Implemented	Partially implemented	Implemented	Not implemented	Implemented
Great Britain	54%	Implemented	Partially implemented	Implemented	Implemented	Implemented
Italy	100%	Implemented	Implemented	Implemented	Partially implemented	Implemented
Japan	100%	Implemented	Partially implemented	Implemented	Implemented	Implemented
Netherlands	90%	Partially implemented	Partially implemented	Implemented	Implemented	Implemented
Norway	99%	Not implemented	Implemented	Implemented	Implemented	Implemented
Singapore	-	Partially implemented	Partially implemented	Partially implemented	Implemented	Implemented
Spain	99%	Not implemented	Implemented	Implemented	Not implemented	Implemented
Sweden	100%	Not implemented	Implemented	Implemented	Implemented	Implemented
United States	73%	Partially implemented	Partially implemented	Implemented	Implemented	Implemented

Implemented   Not implemented   Partially implemented

Notes: The countries are selected based on their high eligibility for DERs to participate in various power markets.

The smart meter penetration is given for households for the latest year available. The penetration rate for Australia corresponds to the coverage in the National Electricity Market as of 2025. This data was not available for Singapore.

"Aggregator framework" tracks if countries have defined roles and responsibilities for aggregators.

Implementation of implicit demand response is assessed based on the share of consumers exposed to time-of-use/dynamic tariffs (fewer than 10% corresponds to "partially implemented").

C&I = commercial and industrial users.

Sources: Asian Power; NEM (2025), Smart meter rollout turned on for 2025; ACER (2024); GOV.UK (2024); METI (2024), Progress of full liberalization of electricity and gas retail sales; Open electricity market (2025); Smart Energy International (2024), Residential smart meters penetration surpasses 70% in US; Australian Government; NDRC (2025), Guiding Opinions on Accelerating the Development of Virtual Power Plants; ACER (2025) No-regret actions to remove barriers to demand response; JRC (2022), Local electricity flexibility markets in Europe; Ofgem (2023), Facilitating Access to Wholesale Markets for Flexibility Dispatched by VLPs; E-GOV; Energy Market Company; FERC (2021); IEA (2024), Meeting Power System Flexibility Needs in China by 2030; ARENA (2024), Flexible Demand State of Play in Australia ; dayaheadmarket; BMWE (2023); Ofgem (2025) State of the energy market report; METI, List of Demand Response (DR) businesses; Deloitte (2024), Households transforming the grid: Distributed energy resources are key to affordable clean power; Institute for Sustainable Futures (2025), Product Policy Framework for Demand Side Flexibility: Case Studies; Energinet; RTE (2024), demand response call for tenders; Agora Energy China (2025), How is Germany increasing flexibility in the power system?; PWC (2021) Unlocking Industrial Demand Side Response; NESO; JRC 2022 Explicit Demand Response for small end-users and independent aggregators; METI, List of Demand Response (DR) businesses; Enel X Japan; SEDC (2017), Explicit Demand Response in Europe; EMA residential, EMA non-residential ; Smart Energy International (2022), Red Eléctrica completes first demand response auction; red electrica; DR4EU (2023); PJM (2024); CAISO (2024).

Residential virtual power plants

Residential VPPs aggregate rooftop PV, battery storage and flexible loads across households to operate as a single dispatchable unit. By co-ordinating these assets, VPPs can increase local self-consumption, reduce system peak demand and deliver ancillary services.

In California, Tesla's VPP connects home batteries from thousands of participants to provide emergency demand response. Battery owners are compensated at a rate of USD 2 per kWh exported to the grid during emergency load reduction events. In 2024, total compensation reached nearly USD 10 million, demonstrating the growing value of residential flexibility in stressed system conditions. Similarly, members of the sonnenCommunity, a network of residential VPPs operating across several countries, have their battery usage optimised across all members, balancing supply and demand in real time. Members can receive direct financial rewards for contributing to system stability.

In Australia, Project EDGE in 2023 launched a trial to show how DERs could be integrated into the wholesale market and provide local network services. The pilot included over 400 DER devices across 300 households and commercial sites, which together provided 3.5 MW of flexible capacity. The project demonstrated the technical feasibility of co-ordinating DERs through an aggregator model and tested mechanisms to reward participating consumers for the flexibility offered. Beyond this trial, several commercial VPPs are currently operating in the country.

Co-location strategies for commercial and industrial sites

C&I consumers are also adopting innovative models to increase self-consumption and decarbonise their electricity supply. Co-location of on-site renewables, storage and flexible demand, often connected via private wire networks, is gaining traction. These systems are designed to optimise internal energy flows and to provide services to the grid when conditions and regulations allow. Drivers behind their development include corporate decarbonisation strategies, combined with the need to circumvent long grid connection queues and have access to reliable energy supply.

One prominent example is Google's development of clean energy parks, consisting of large-scale microgrids designed to power data centres with co-located renewable generation and storage. China has advanced further in this area, with hundreds of government-supported clean industrial park projects that combine localised generation, storage and flexible loads.

In Brazil, delays in connection are encouraging developers to shift towards on-site contracts with C&I users, rather than remote generation sites, which require grid usage. In addition, the new net metering scheme introduced in 2023, which makes prosumers subject to grid fees, further incentivises alternative business models based on self-consumption.

However, these projects raise important regulatory questions: how to categorise co-located assets as generation, load, or storage – each with different tariff and regulatory implications. There are also concerns about cost allocation for network infrastructure and potential undesirable consequences, such as new load clusters diverting output from existing grid-connected generation intended for wider system use.

Collective self-consumption and peer-to-peer trading

Concurrently, emerging models like collective self-consumption through community microgrids and peer-to-peer (P2P) trading are enabling consumers to share electricity within local networks, often without a central utility intermediary. These arrangements allow individuals to set their own buy and sell prices and trade electricity directly, potentially lowering costs and boosting local self-sufficiency.

In Uttar Pradesh, India, Powerledger implemented a blockchain-enabled P2P trading platform that led to a buying price 43% lower than retail rates, prompting regulatory reforms mandating utilities to accommodate such trading. In Portugal, an energy sharing project around a football stadium equipped with 645 kW of rooftop solar allows local residents to access electricity at prices below those offered by market suppliers.

P2P trading remains in its early stages in most markets, with yet limited evidence of its effectiveness in supporting renewable energy integration beyond trial settings. Notably, significant regulatory challenges remain. Questions persist around licensing for participants who sell power, potential competition with incumbent suppliers and the integration of such models into formal market operations.

Several countries are taking steps to provide legal clarity and support for energy communities. At the EU level, Directive 2024/1711 sets a maximum system size of 6 MW for energy sharing schemes to ensure that larger installations remain integrated into the wider electricity market which is not bypassed entirely. While only Portugal and France have fully implemented functional collective self-consumption frameworks, this model is increasingly emerging as a relevant route to market for rooftop PV in a growing number of countries.

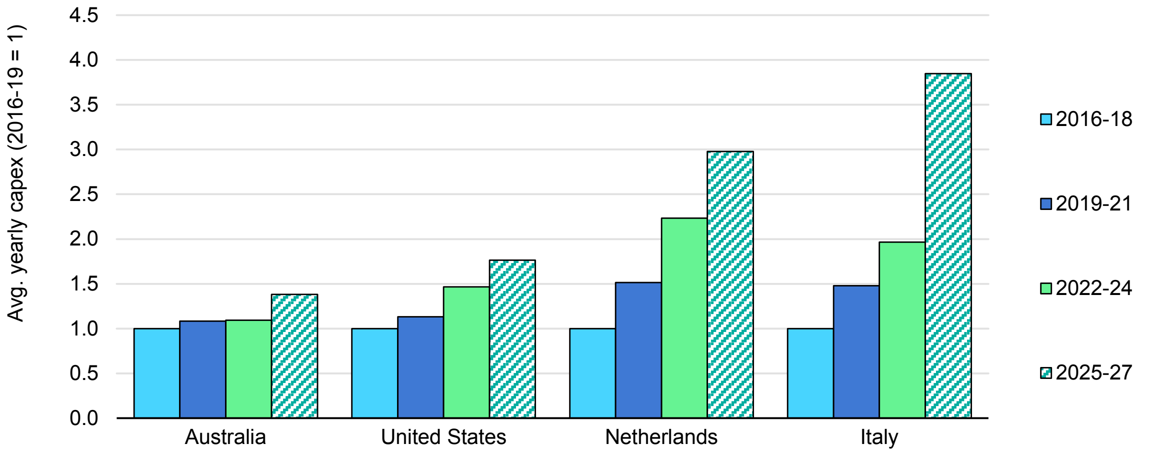
Economic regulation and planning for distribution networks

The rapid growth of DERs is reshaping how distribution networks are planned and financed. This shift puts pressure on traditional regulatory frameworks, calling for new approaches that reflect the evolving role of the grid. Economic regulation plays a pivotal role in ensuring that the costs of T&D are fairly allocated among stakeholders, particularly between grid operators and end users. Well-designed regulatory frameworks safeguard against unfair cost burdens while creating the right investment signals for grid modernisation, resilience and expansion. Effective planning and pricing are essential to ensure that distribution grids can evolve to accommodate increasing shares of DERs while maintaining affordability and economic efficiency. This section explores how regulatory approaches across different countries have tried to balance these imperatives, ensuring that investment and cost-sharing mechanisms align with long-term system needs.

Performance-based regulations are incentivising grid companies to integrate DERs

Upgrades and expansion to distribution networks are essential to the efficient integration of DERs. As more solar PV, EVs or flexible demand connect at the local level, DSOs need to invest in modernising infrastructure to manage bi-directional power flows, enhance visibility and control, and maintain reliability. This includes physical assets, digitalisation and enabling greater system flexibility. In response to growing electrification, DER uptake and ageing infrastructure, annual distribution capital expenditure (CAPEX) has risen steadily in many countries.

Average annual capital expenditures on distribution infrastructure for selected countries, 2016-2027



Notes: Data for the three years 2025-27 are based on investment plans from the DSOs. They include only 2025-26 data for the United States and the Netherlands. In Australia, past overinvestment in the early 2010s may reduce the need for future large additional investments.

Sources: IEA analysis based on S&P Global Market Intelligence (2025); AER (2024), Determininations; Edison Electric Institute (2024), Industry Capital Expenditures; Enel (2024), Strategic Plan 2025-2027; Enexis (2024), Investeringsplan 2024; Liander (2024), Investeringsplan 2024 Elektriciteit en Gas; Stedin (2024), Investeringsplan 2024.

For example, Italy is facing rapid expansion of its renewable capacity – both large-scale and decentralised generation, as well as rising electricity demand driven by the electrification of the transport and heating sectors. These trends are increasing the need for significant upgrades to both T&D infrastructure. As a result, average CAPEX in distribution infrastructure doubled in the three years 2022 to 2024 compared to 2016-18 and is projected to reach nearly four times that level from 2025- to 27. A similar scenario is seen in the Netherlands, where rising CAPEX in electricity distribution infrastructure is largely driven by growing grid congestion due to high levels of generation from renewable forms of energy and electrification from EVs, heat pumps, data centres and industry.

Regulatory frameworks are critical to ensure that these infrastructure investments are timely, efficient and aligned with policy goals. Traditional cost-of-service regulation, however, creates limited incentives for utilities to adopt DERs or other innovative alternatives. Because utility revenues are tied to capital investments (CAPEX), they naturally favour grid expansion over operational or digital solutions even when the latter may be more efficient. Performance-based regulation (PBR) addresses this misalignment by decoupling revenues from electricity sales. It incentivises specific outcomes such as reliability, customer engagement or DER hosting capacity, encourages innovation or supports non-wires alternatives by allowing utilities to earn returns on DER-based solutions that defer or avoid significant infrastructure upgrades.

For instance, the Great Britain’s RIIO model (Revenue = Incentives + Innovation + Outputs) introduced PBR principles across electricity distribution. RIIO includes output-based incentives for reliability, customer satisfaction and network efficiency. It encourages DSOs to procure flexibility services from DERs and supports trials for DER integration and flexibility services through innovation funding. Additionally, RIIO minimises the traditional bias towards capital-intensive projects by evaluating both capital and operational expenditure collectively (Total Expenditure or TOTEX model), which has proven effective in driving investments towards more flexible, grid-efficient solutions. During the first RIIO price control exercise (RIIO-ED1), covering the regulatory period 2015-23, the regulator Ofgem disallowed GBP 1.4 billion in proposed spending and DNOs identified an additional GBP 700 million in savings, including through the deployment of smart grids. In parallel, service quality improved, with significant reductions in the average duration and frequency of power outages. Customer interruptions fell by 23% across the DNOs and the average duration of interruptions decreased by 18% from 2015-16 to 2021-22.

Building on RIIO-ED1's successes, RIIO-ED2 (from 2023 to 2028) has introduced enhancements including an incentive structure with a wider range of rewards and penalties, and a new mechanism to protect both consumers and companies against significant deviations in performance from expectations set at the start of the price control.

Similarly, Italy’s Regolazione per Obiettivi di Spesa e di Servizio (ROSS) framework, introduced by the regulator ARERA, represents a shift towards performance-based regulation for both TSOs and DSOs. Like Great Britain’s RIIO, it uses a TOTEX model, encouraging cost-effective and innovative grid management strategies rather than solely relying on large infrastructure projects. To address the bias of traditional CAPEX-focused models, the Z-factor mechanism allows utilities to request upfront increases to their operational budget for energy transition activities, such as digitalisation or DER integration. However, in its current form, ROSS still treats CAPEX conventionally, with ex-post evaluation and no standard cost benchmarking, limiting neutrality between grid expansion and DER-based alternatives. The framework is in an early phase and designed to evolve, with key features like output-based incentives and forward-looking planning baselines (ROSS-integrale) still in development. Its full impact will depend on improved data collection and monitoring.

In the United States, PBR has been used to address the limitations of traditional utility models that favoured capital investment over innovation and demand-side solutions. In New York, the Reforming the Energy Vision initiative introduced Earning Adjustment Mechanisms to incentivise utilities to support DER deployment, energy efficiency and demand response. This led to significant outcomes, including 52 MW of peak load reduction, 110 GWh in annual energy savings and the installation of 12 000 new solar systems, generating USD 42.9 million in earnings for the utility Con Edison. Similarly, Hawaii's PBR framework aimed to align utility incentives with customer interests and policy goals, encouraging DER integration and cost control. Hawaiian Electric earned performance incentives for delivering 5.6 MW of load reduction through its Grid Services Performance Incentive Mechanism, though broader mechanisms are still being developed. These cases demonstrate how PBR can shift utility behaviour towards more flexible, efficient and customer-focused grid management.

Cost-benefit analyses are being used to assess the full system contribution of DERs

Complementing PBR approaches, cost-benefit analysis (CBA) can also be a useful tool for assessing the cost-effectiveness of DERs by systematically comparing their economic, environmental and system-wide impacts. Unlike traditional assessments focused narrowly on energy savings or capital costs, CBA captures the broader economic, environmental and system-level impacts of DERs. It accounts for costs such as installation, operation and potential grid upgrades, while also considering benefits like avoided energy and infrastructure costs, reduced peak demand, improved reliability and lower emissions. By monetising these factors, CBA helps determine whether DER investments deliver net positive value and align with long-term policy goals, especially in the context of electrification and evolving technology costs. Importantly, CBA enables a fair comparison between DERs and conventional infrastructure by incorporating long-term and societal benefits, such as deferred grid investments, reduced congestion and public health improvements from lower emissions. This approach supports more informed, efficient and forward-looking investment decisions.

Real-world case studies provide compelling evidence of how CBA frameworks can help measure DER benefits. In India, a techno-commercial solution, the Energy Storage India Tool, developed by NITI Aayog and the India Smart Grid Forum, was used to evaluate the impact of battery storage on an overloaded feeder in Kolkata. Quantifying benefits such as deferred infrastructure upgrades, improved reliability and enhanced power quality, the analysis informed national strategies on energy storage deployment. The CBA framework has since been used to guide national policy, including phased energy storage targets and investment strategies in India.

In the United States, several states have adopted the National Standard Practice Manual (NSPM) to develop consistent and comprehensive CBA methodologies. Colorado uses NSPM to evaluate non-wires alternatives in distribution planning, while Hawaii applies it to model DER value streams and avoided costs. Rhode Island embedded a tailored CBA test into its procurement standards to support broader energy policy goals, and Maryland is developing a unified framework to address inconsistencies in DER valuation. These cases highlight how structured CBA approaches can support more balanced, forward-looking investment decisions that reflect the full value of DERs across the power system.

Connection charge designs are evolving in response to cost-recovery concerns

With the growth of grid-connected DERs, ensuring that the costs associated with these resources are recovered in a fair, efficient and transparent manner has emerged as a growing concern. Key questions include how to allocate the costs of new infrastructure, who should pay for grid upgrades triggered by new connections and how to balance investment signals with broader decarbonisation and affordability goals. In this context, connection charging frameworks are evolving to better reflect system needs and support the efficient integration of DERs.

Shallow, deep and hybrid models

Connection charges determine how the costs of connecting to the distribution network are allocated between DER owners and the broader energy system. Two primary approaches – shallow and deep connection charges – are used to distribute these costs, each with distinct implications for DER deployment and grid expansion.

Connection charge approaches at the distribution level

Aspect	Shallow	Deep	Hybrid / Moderate shallow
Definition	Developer pays only for direct connection assets (e.g. to nearest substation)	Developer pays for direct connection plus all upstream reinforcement	Developer pays direct connection assets; some deeper costs shared via tariffs
Cost allocation	Deeper reinforcement costs socialised via tariffs paid by all users	All connection-related costs charged to connecting party	Cost split between developer and general user base, depending on rules
Incentive for DER/VRE development	Strongly encourages growth by lowering entry barriers	May discourage DER in weak or remote areas with high costs	Encourages DERs in a wider range of areas while controlling tariff impact
Equity among users	High equity: costs spread broadly; avoids penalising remote projects	High cost-reflectivity; avoids cross-subsidies	Seeks a balance between equity and cost-reflectivity

Aspect	Shallow	Deep	Hybrid / Moderate shallow
Impact on distribution planning	Supports centralised distribution planning; enhances DER uptake	Promotes market-based grid expansion, risks inefficient siting and under-utilisation of networks	Supports targeted grid planning and efficient DER integration
Ease of implementation	Relatively easy to implement in systems with robust planning and tariff mechanisms	Simpler in cost-recovery terms, but less supportive of transition	Moderate complexity; needs clear cost-sharing rules and planning
Policy priorities	DER development, rapid VRE integration, fairness in access	Avoid cross-subsidisation, cost recovery, developer-pays principle	Balance investment signals, system optimisation, DER access
Country examples	UK, Germany (for VRE), Spain, Denmark, China	USA (many states), Ontario (Canada), India (some states), Australia (WA/QLD)	Italy, New York (USA), Australia (Victoria), France (partly)

In practice, countries are adapting these models based on national circumstances, evolving policy goals and emerging system challenges. For example, in Germany, where a shallow connection regime applies at the distribution level, the broader network reinforcement costs are socialised and recovered from all network users via use-of-system charges. However, Germany's energy regulator is formally reviewing the electricity grid fee structure, with proposals that could shift some grid costs from consumers alone to renewable energy producers. This includes considering flat or capacity-based fees (instead of consumption-based), dynamic pricing to encourage efficient usage and rules to better integrate batteries and storage. These changes would directly affect the way DERs are charged for connecting to and using the grid and the overall distribution of network expansion and maintenance costs.

The Netherlands, recognised for its ongoing support for distributed generation and renewables, also applies a shallow connection charge regime with grid costs being socialised across all users. This approach is further supported by the broader policy context, where the regulator sets grid fees based on cost-of-service methodologies, while costs for grid expansion and maintenance are largely borne by all grid users rather than individual connecting parties.

While most countries applying shallow or deep connection charges at the transmission level have clearer rules, at the distribution level, the applied regime can be hybrid or mixed.

France, Sweden and Norway are among those with hybrid connection charge regimes at the distribution level, reflecting a balance among economic efficiency, equity and support for the energy transition. By generally socialising network costs (shallow approach), they lower barriers for small-scale generators and prosumers. At the same time, they require projects that cause significant local upgrades to bear those specific costs (deep approach), ensuring that users who impose extra burdens on the grid pay accordingly. This flexible, hybrid strategy also helps manage grid congestion, encourages innovation and aligns with EU regulatory requirements.

Ultimately, the choice of connection charge regimes by regulators reflects a balancing act among economic efficiency, equity and the promotion of DERs or prosumers. While shallow or standardised charges can encourage rapid deployment by lowering the upfront costs for new entrants, they may also raise concerns about cross-subsidisation and long-term cost recovery, with all users collectively sharing the burden of grid upgrades and expansions. Conversely, deep or location-specific charges can send more accurate investment signals under a developer-pays principle, but risk discouraging adoption.

Fair cost recovery

Beyond connection charges, DER integration raises important questions about how to fairly recover the ongoing costs of maintaining shared T&D infrastructure. While connection charges determine upfront investments in grid access, additional cost-recovery mechanisms are needed to address ongoing access and system usage, especially when DER owners remain physically connected but reduce their reliance on grid-supplied electricity.

This issue is especially relevant in the case of microgrids and self-generating customers who still require backup services or seek to export surplus electricity. In such cases, their partial use of the network may not reflect the full costs of maintaining system capacity and reliability. Without targeted cost-recovery mechanisms, utilities risk under-recovering fixed costs, potentially shifting the financial burden onto customers who rely more heavily on grid-supplied power.

In some jurisdictions, regulators have addressed this issue through mechanisms such as standby charges or departing load charges, to uphold the financial sustainability of the utility and prevent cost shifting to remaining customers. For instance, in California, microgrids and distributed generation systems that remain grid-connected are required to pay standby fees, reflecting the cost of maintaining grid services available when needed (e.g. for backup or exporting excess power). In cases where customers reduce or eliminate their consumption from the utility entirely, departing load charges are applied to recover stranded costs from prior infrastructure investments made to serve them.

Integrated system planning anticipates DER deployment while minimising costly network upgrades

Integrated system planning is being used for anticipating DER deployment while minimising costly network upgrades. By combining DER forecasts, network capacity assessments and evolving system service needs, integrated planning supports more forward-looking grid development. Historically, distribution networks were treated as passive loads, but this approach seemed no longer viable amid rising electrification, variable generation and sectoral interdependencies. While planning practices are evolving to reflect the dynamic role of DERs and flexibility services, progress has been slow. For example, only 47% of EU DSOs consider flexibility in their network development plans, which can be done by incorporating flexibility scenarios based on historical procurement and future capabilities, developed in collaboration with flexibility service providers.

A leading example is the Common Evaluation Methodology developed in Great Britain, which enables planners to assess grid investments against the potential of flexibility to meet system needs. Integrated planning also requires improved co-ordination between T&D networks, with clear roles and robust data frameworks to ensure visibility of DERs at the T&D interface.

California offers another strong case of the value of integrated system planning in enhancing effective integration of DERs into the grid. Through the Distributed Resource Plan and Integrated Distributed Energy Resources proceedings, launched by the California Public Utilities Commission, the state connects distribution, transmission and resource planning to align DER deployment with system needs and climate goals. Tools like the Grid Needs Assessment, Locational Net Benefits Assessment and Integration Capacity Analysis help identify grid constraints, value DERs by location and map hosting capacity. Utilities are also required to assess and report on non-wire alternatives, enabling DERs to be competitively procured in place of traditional grid upgrades.

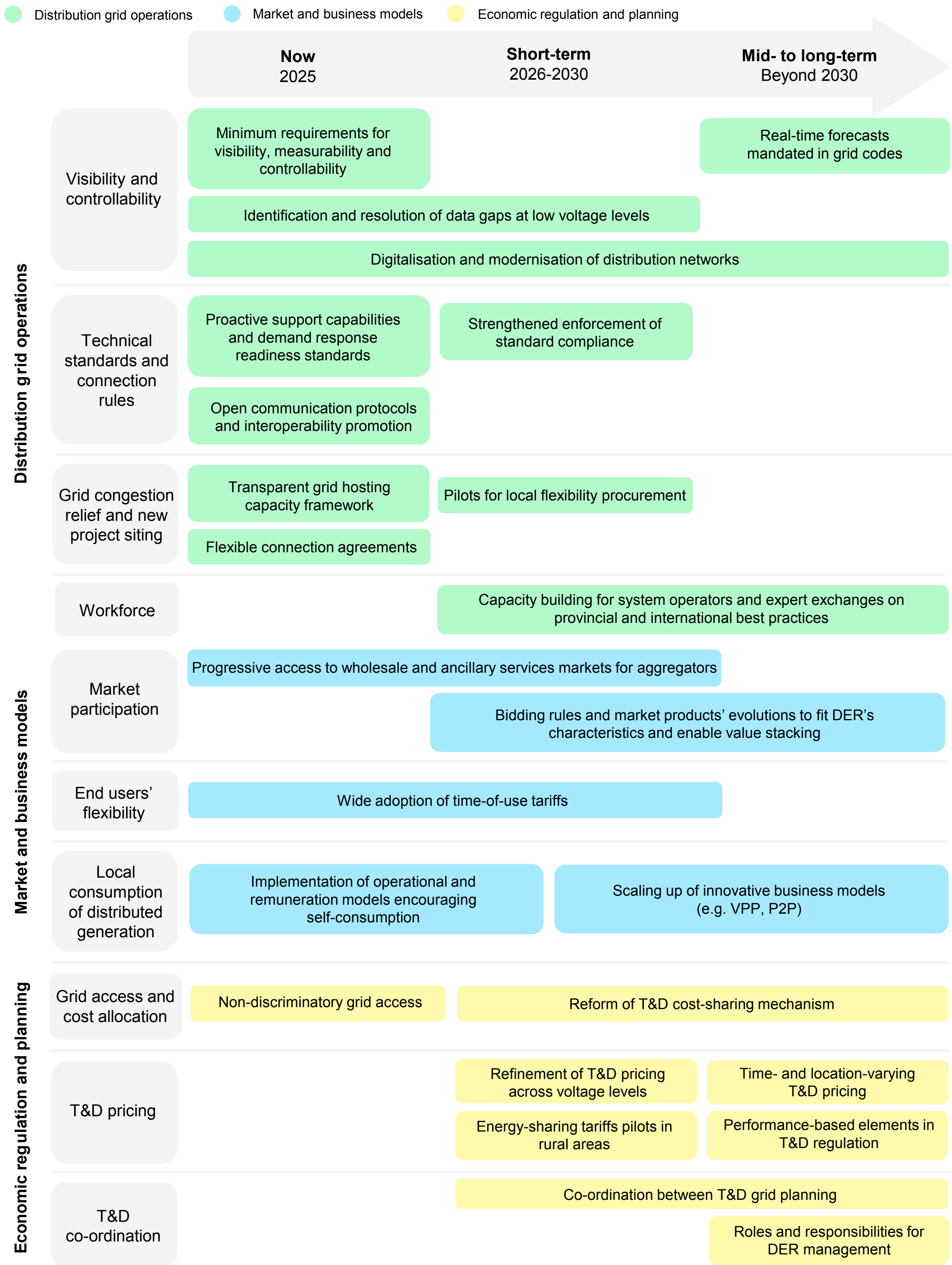
Chapter 3. Policy insights for China

This chapter provides policy insights tailored to facilitate DER integration in China's power system. Drawing from international experiences presented in the previous chapter, the recommendations are adapted to the Chinese context and structured around three pillars: grid operations, market integration and business models, and regulatory framework and planning. They target national and provincial regulatory authorities, as well as grid operators.

The actions are prioritised by time of action:

- Now (within the year): to address immediate integration challenges.
- Short-term (by 2030): to tackle emerging structural issues.
- Mid-to-long term (beyond 2030): to support the creation of a long-term enabling environment for DER integration.

Taken together, these recommendations address the technical, economic and institutional dimensions of DER integration. While large-scale transmission projects will continue to play a critical role in delivering electricity from resource-rich western regions to demand centres in the east, the growing adoption of DERs highlights the importance of data and digitalisation, market access and value recognition, fair cost allocation and institutional reforms. These measures will be essential to enable co-ordinated development between DERs and distribution networks, as well as between distribution and transmission systems. They will ultimately support a more flexible and integrated power system for China.


Distribution grid operations
Market and business models
Economic regulation and planning
Now
2025
Short-term
2026-2030
Mid- to long-term
Beyond 2030
Distribution grid operations
Visibility and controllability
Minimum requirements for visibility, measurability and controllability
Real-time forecasts mandated in grid codes
Identification and resolution of data gaps at low voltage levels
Digitalisation and modernisation of distribution networks
Technical standards and connection rules
Proactive support capabilities and demand response readiness standards
Strengthened enforcement of standard compliance
Open communication protocols and interoperability promotion
Grid congestion relief and new project siting
Transparent grid hosting capacity framework
Pilots for local flexibility procurement
Flexible connection agreements
Workforce
Capacity building for system operators and expert exchanges on provincial and international best practices
Market and business models
Market participation
Progressive access to wholesale and ancillary services markets for aggregators
Bidding rules and market products' evolutions to fit DER's characteristics and enable value stacking
End users' flexibility
Wide adoption of time-of-use tariffs
Local consumption of distributed generation
Implementation of operational and remuneration models encouraging self-consumption
Scaling up of innovative business models (e.g. VPP, P2P)
Economic regulation and planning
Grid access and cost allocation
Non-discriminatory grid access
Reform of T&D cost-sharing mechanism
T&D pricing
Refinement of T&D pricing across voltage levels
Time- and location-varying T&D pricing
Energy-sharing tariffs pilots in rural areas
Performance-based elements in T&D regulation
T&D co-ordination
Co-ordination between T&D grid planning
Roles and responsibilities for DER management

Distribution grid operations

In China, grid connection for small-scale assets has generally been straightforward, with minimal technical requirements and favourable conditions that have supported the rapid uptake of distributed generation. While these conditions have helped accelerate deployment, they have also introduced new challenges for system operations.

In the absence of adequate visibility and metering requirements, grid companies struggle to monitor BTM generation and consumption. This limits their ability to accurately forecast demand and maintain system balance. In areas facing localised grid congestion, some authorities have resorted to restricting or even banning new distributed energy connections. These measures actually risk deterring further investment.

Managing a grid with high shares of DERs introduces operational complexities that require new tools, practices and capabilities to modernise distribution network operations. China can benefit from building on its smart grid advancements and centralised planning strengths to improve DER visibility and control, establish clear and consistent technical standards for DER connection and enable smarter, more flexible grid management.

Workforce training and upskilling will also be essential to ensure that all actors, from local planners to grid companies, are equipped to manage a more decentralised and dynamic power system. These reforms will help ensure electricity security, enhance system flexibility and prevent future congestion as DER deployment continues to grow.

Enhance visibility and controllability at low-voltage levels

- **Implement minimum requirements for visibility, measurability and controllability of DERs.** Newly installed DERs should, to the best extent, be deployed with minimum communication and control infrastructure, as it is much more expensive to retrofit them once installed. The 2025 Management Measures for DPV introduce such provisions by requiring new connecting assets to be visible and measurable, with grid companies responsible for installing metering devices at no cost. Further guidance should clarify what types of data must be collected at various voltage levels and how to account for already-connected assets lacking such features, including DERs other than DPV.

- **Identify and address data gaps in distribution networks, especially at low-voltage levels**. Based on this assessment, targeted investments should be deployed in priority zones, including real-time sensors, feeder monitors and substation automation. Going further, the goal should be to establish a unified, integrated platform that collects, stores, manages and shares all distribution network data, ensuring standardisation and interoperability for different grid actors.

- **Amend grid codes to require the use of real-time forecasts and more accurate forecasting models,** to support better grid operation. This would enable grid operators to make more accurate projections of DER behaviour.
- **Continue advancing the digitalisation and modernisation of distribution networks** by leveraging China's existing digital infrastructure and IoT capabilities at low-voltage levels. This includes the use of intelligent monitoring, remote diagnostics and automated operation and maintenance. These technologies contribute to enhancing the flexible, efficient and reliable operation of the grid.

Strengthen technical standards and connection rules

- **Update distribution network codes to include minimum performance standards,** ensuring that DERs contribute to system reliability with proactive support capabilities (e.g. through grid disturbance response). This can be done by mandating smart inverters for specific asset classes**.**
- **Mandate minimum demand-response capabilities in appliance standards,** to ensure that new devices entering the market are ready to contribute to system flexibility. Support schemes aimed at replacing older appliances should prioritise the most energy-efficient and demand-responsive technologies in line with these standards, such as the current consumer goods trade-in programme which promotes energy-efficient air conditioners.
- **Strengthen standard compliance enforcement**, for example by making asset owners responsible for providing documentation demonstrating grid code compliance. Compatibility with network code can also be improved by engaging equipment manufacturers.
- **Promote open communication protocols to ensure interoperability among DERs.** This will ensure that DER equipment and platforms support recognised, standardised protocols to enable seamless integration, real-time co-ordination and effective participation in power markets. In addition, this will avoid vendor lock-in and reduce overall integration costs.

Implement mechanisms for grid congestion relief and for guiding the siting of new projects

- **Allow flexible connection agreements for new DER projects in congested areas**, as an alternative to blanket bans. More advanced solutions like dynamic export limits can be piloted in selected areas in the longer term.

- **Establish a transparent evaluation framework for grid hosting capacity** in all provinces and make it available to project developers to improve transparency and steer siting of new projects where the grid can accommodate them. This can build on NEA's pilot programme and be extended across provinces through the release of public hosting capacity maps. In the longer run, introducing locational signals into network tariffs can also help guide new projects toward less congested areas.

- **Pilot market-based procurement of flexibility services at the distribution level in provinces where congestion is most acute and power markets are more advanced**. In the longer run, consider broader deployment of local flexibility markets where needed.

Invest in capacity building and workforce upskill

- **Invest in training for grid operators to handle new technologies and active management of distributed resources**. This includes developing comprehensive training programmes in digital technologies and cybersecurity and providing certifications to support international standards.

- **Support expert exchanges on provincial and international best practices**. Given the rapid pace of innovation in distribution networks, regular engagement is crucial to keep pace with policy and technology developments. Within China, interprovincial/regional policy exchanges can be leveraged to share lessons from pilot projects and recent implementation outcomes of critical policies for DER integration, such as market access and self-consumption requirements.

Market and business models

Unlocking the full value of DERs requires not only technical integration into the grid, but also their integration to power markets, through aggregators or by prices reflecting market conditions. When appropriately incentivised, DERs can provide valuable flexibility services and contribute to system efficiency and reliability. In

China, policymakers are increasingly turning to market mechanisms to mobilise flexibility and support renewable integration, but progress on power market reform has been uneven across provinces, requiring dedicated solutions to accompany this transition and establish viable business models.

Distributed generation – particularly rooftop solar PV – has historically benefited from favourable conditions, including full purchase guarantees and limited exposure to market signals. This has allowed for rapid deployment, but often decoupled generation from real-time system needs and prices. Similarly, other distributed assets such as EVs and home appliances typically operate outside of market frameworks, with limited incentives to adjust consumption in response to system conditions.

Recent reforms signal a shift in direction. Policies increasingly promote self-consumption and aim to encourage market participation, especially from larger distributed installations.

Measures to support this evolution include enabling the participation of aggregators, allowing for revenue stacking across multiple services and promoting the local use of distributed generation. Such steps will strengthen DER business cases and help unlock the wide flexibility potential of their systems.

Facilitate DERs' market participation and provision of flexibility

- **Improve access for DER and aggregators to wholesale and ancillary services markets** where they operate. Recent 2024 reforms – updating power market basic rules and the concept on new business entities in the power sector – are a positive step, recognising aggregators, encouraging their market participation and exempting them in principle from retail licenses. However, implementation has been uneven and in practice, aggregators are still excluded in many parts of the country.

- **Ensure that bidding rules and market products do not pose barriers to the integration of DERs** and are adapted to assets like storage to maximise participation of smaller resources on a level playing field. As provincial markets develop and trial rules, this includes tailoring technical requirements and procurement schemes to accommodate different user categories and technology profiles, while allowing for smaller minimum bid sizes. However, a good practice is to design products to address system needs rather than creating specific asset revenues. For example, fast frequency response can be added to ancillary markets if aligned with system needs, not just to support battery value stacking. In the longer term, improvements to market design such as higher bidding frequency and product resolution can greatly facilitate DER integration in the most advanced markets.

- **Enable DERs to maximise value across multiple services at local and system levels through revenue stacking**. Regulation should clearly define which services can be combined (e.g. capacity and reserves) without compromising reliability.
- **Encourage demand-side flexibility by smaller end users,** through wider adoption of time-of-use tariffs or dynamic pricing in the residential and commercial sectors. This can be facilitated by leveraging China's extensive rollout of smart meters and by introducing those schemes on an opt-out basis, focusing on consumers with flexible loads such as EVs and heat pumps. It is important that the economic benefits at the system level of tapping into this flexibility potential are reflected in the end users' cost savings.

Promote local consumption of distributed generation

- **Implement operational and remuneration models that promote self-consumption**, particularly in areas with limited grid absorption capacity such as rural regions. This can be done by acting on the local demand, for example, pairing solar PV with heat pumps, storage and/or EV charging stations and by promoting the development of integrated projects, combined generation, load and storage. This also involves continuing the transition from full grid purchase remuneration models to schemes encouraging self-consumption, even for smaller consumers, while more stringent self-consumption requirements can be more widely implemented for larger installations on C&I sites. Minimum self-consumption thresholds already adopted in some provinces could be replicated in other regions experiencing rapid DPV uptake.
- **Pilot and scale up innovative DER business models**, such as VPPs, co-location and local energy communities with P2P trading. These models can be trialled and expanded where they deliver the most benefits, supported by adequate regulatory frameworks. For example, provinces like Guangdong have recently released market participation rules for VPPs, indicating strong potential for these models to expand in the coming years.

Economic regulation and planning

Beyond market reforms, adapting the broader regulatory framework is also important for ensuring fair access, efficient pricing and system-wide optimisation.

In China, certain structural inefficiencies persist, such as limited grid access for incremental distribution networks, uneven cost allocation due to the exemption of most distributed assets from grid fees and a T&D pricing structure that does not encourage local consumption. Additionally, grid companies may lack incentives within current remuneration models to prioritise efficient alternatives over traditional infrastructure investments.

Addressing these issues may involve reforms to grid tariff design, clearer definition of roles and responsibilities for emerging actors at the distribution level and improved co-ordination between T&D system planning and operations.

Ensure fair grid access and cost allocation

- **Guarantee non-discriminatory grid access for DERs, microgrids and privately invested incremental distribution networks,** in line with the newly enforced Energy Law. This includes preventing unfair practices by grid companies and guaranteeing that multi-investor microgrids can connect to and rely on the public grid for secure and reliable electricity supply.
- **Establish a transparent and equitable cost-sharing mechanism for transmission and distribution services**. DERs and microgrids should contribute fairly to T&D fees based on their use of the public grid, without being overcharged or subsidised, to reflect their actual impact on system costs. Adjustment of connection charges can be piloted first in regions with high penetration (e.g., areas with large-scale DPV deployment), in order to avoid slowing down DER development where penetration is still low.

Optimise the transmission and distribution pricing mechanism

- **Adjust the T&D pricing mechanism, to reflect the true cost of electricity.** In the short-term, this can be done by reasonably widening the tariffs gap across voltage levels, to further encourage local consumption of renewable energy. In addition, the varying capacity component of tariffs according to voltage levels – first introduced in 2023 – can be further refined to reflect user profiles. Going further, introducing time-varying or dynamic elements into T&D pricing can encourage smarter electricity use. This may be based, in part, on signals from the spot market, or by allowing grid companies greater flexibility to adjust charges based on real-time grid conditions. Currently, only a few provinces such as Anhui, Henan, Guangdong, Sichuan and Zhejiang include T&D costs in the floating basis of their TOU electricity tariffs.

- **Pilot local energy sharing tariffs in rural areas,** where consumers and producers pay lower tariffs for intra-community energy flows, aiming at rewarding local consumption and reducing voltage-level network load. While residential and agricultural electricity prices remain regulated under catalogue pricing, pilots could focus on commercial or collective users where regulatory flexibility allows.

- **Reform the incentive structure for grid operators to align with performance-based regulation**, linking revenues to a range of system-wide outcomes such as reliability, efficiency and flexibility. This would make DERs and smart grid solutions viable alternatives to traditional grid expansion while providing new revenue streams to grid companies. The 2026-2030 T&D pricing cycle offers an opportunity to introduce a nationwide performance-based incentive mechanism by gradually integrating performance-based elements to tariffs methodologies, ensuring grid companies are rewarded for enhancing system performance. Performance assessments should be based on system-level metrics rather than individual manager evaluations. For example, this could take the form of a specific set of targets and associated incentives for grid companies to implement demand response and efficiency solutions, building on the targets of the 2023 Electricity Demand Side Management Measures.

Strengthen co-ordination between the transmission and distribution levels

- **Improve co-ordination between T&D networks in system planning**, ensuring that local DER deployment and integration is reflected in provincial and national grid planning. The flexibility solutions provided by DERs, including storage, microgrids and other non-wire options, can serve as cost-and time- effective alternatives to transmission grid reinforcement. Better co-ordination of T&D planning will ensure that all potential solutions are considered in a technology-neutral way. Given the varying levels of DER deployment across provinces and over time, different co-ordination models may be appropriate at different stages. In the early stages, simple information exchange may suffice, while higher DER penetration may require integrated, co-optimised planning processes, shared forecasting and co-ordinated investment decisions. Cost-benefit analysis should be used to evaluate all options, with monitoring based on DER integration success metrics.

- **Clarify operational responsibilities for DER management at the distribution level.** While there are no independent DSOs established in China, provincial branches of grid companies play DSO-like functions. However, with new actors (e.g. aggregators, clean industrial park operators) and new flexibility needs at the distribution level, formalising the role of the DSO can be considered, including hosting capacity assessment, DER integration and active grid management. This would require a clear framework for TSO-DSO co-ordination, particularly regarding the responsibility for procurement of system services such as congestion management and reserves and for data collection and sharing. However, given China's five-layer grid structure (national-regional-province-city-county), further analysis is needed to determine whether a single DSO level or differentiated DSO functions across administrative levels (provincial/regional vs. city/county) would best support local flexibility and DER integration.

Annex

Abbreviations and acronyms

ACER	European Union Agency for the Cooperation of Energy Regulators
AEMO	Australian Energy Market Operator
APS	Announced Pledges Scenario
ARERA	Italian Regulatory Authority for Energy, Networks and Environment
BEV	battery electric vehicle
BTM	behind-the-meter
C&I	commercial and industrial
CAPEX	capital expenditure
CBA	cost-benefit analysis
DER	distributed energy resources
CFD	contract-for-difference
DPV	distributed photovoltaics
DMO	distribution market operator
DNO	distribution network operator
DSO	distribution system operator
EV	electric vehicle
FCA	flexible connection agreement
FERC	Federal Energy Regulatory Commission
GBP	British Pound Sterling
NDRC	National Development and Reform Commission
NEA	National Energy Administration
NEM	National Electricity Market
NSPM	National Standard Practice Manual
P2P	peer-to-peer
PHEV	plug-in electric vehicle
PBR	performance-based regulation
RIIO	Revenue=Incentives+Innovation+Outputs
RMB	Renminbi (Chinese Yuan)
ROSS	Regolazione per Obiettivi di Spesa e di Servizio (Regulation for Expenditure and Service targets)
STATCOM	Static Synchronous Compensator
T&D	transmission and distribution
TOTEX	total expenditure
TOU	time-of-use
TSO	transmission system operator
UKPN	UK Power Networks
USD	United States Dollar
VPP	virtual power plant
VRE	variable renewable energy

Units of measurement

GW	gigawatt
kW	kilowatt
MW	megawatt
Mt	millions of tonnes

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