2025 China Power Market Outlook: 10 Key Trends for Market Players

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About RMI

Rocky Mountain Institute (RMI) is an independent, nonpartisan nonprofit founded in 1982 that transforms global energy systems through market-driven solutions to secure a prosperous, resilient, clean energy future for all. In collaboration with businesses, policymakers, funders, communities, and other partners, RMI drives investment to scale clean energy solutions, reduce energy waste, and boost access to affordable clean energy in ways that enhance security, strengthen the economy, and improve people's livelihoods. RMI is active in over 60 countries.

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Executive Summary

In 2025, China marks the tenth anniversary of its latest round of power market reforms. Since 2020, with the announcement of the dual carbon target and the New Power System,[i] the pace of power market development continues to accelerate. A series of market designs and pricing mechanisms covering various power sources, industrial and commercial users, and emerging entities have been introduced to support the momentum (see Exhibit ES1).

Exhibit ES1 **Key power market and electricity pricing policies since 2021**

Date	Name	Abstract
October 2021	*Notice on Further Deepening the Market-based Reform of Coal Power Generation On-Grid Prices (Document #1439)*	**Promote the inclusion of all coal power generation and 10 kV+ industrial and commercial (I&C) users in the power market,** expanding the price fluctuation range for market transactions.
January 2022	*Guiding Opinions on Accelerating the Construction of a National Unified Power Market System (Document #118)*	**Establish clear objectives and timelines for the national unified power market,** aiming to create a multilayered, unified market system adapted to the New Power System.
May 2023	*Notice on Provincial Grid Transmission and Distribution Prices for the Third Regulatory Period and Related Matters (Document #526)*	**Define and clarify I&C users' electricity pricing,** comprising generation on-grid prices, line losses, transmission and distribution tariffs, system operating fees, and government fees.
October 2023	*Notice on Further Accelerating the Construction of the Power Spot Market (Document #813)*	**Expand the scope of spot market construction and operation** and clarify the criteria for spot market operation.
November 2023	*Notice on Establishing a Coal Power Capacity Pricing Mechanism (Document #1501)*	**Establish a coal power capacity pricing mechanism** to support the transition of coal plants into a flexible and backup source role.
February 2024	*Notice on Establishing and Improving the Power Ancillary Services Market Pricing Mechanism (Document #196)*	**Regulate ancillary services trading and pricing mechanisms,** clarify cost share, and improve system-wide resource allocation.
January 2025	*Notice on Deepening the Market-Based Reform of Renewable Energy On-Grid Pricing to Promote High-Quality Development of Renewables (Document #136)*	**Establish the mechanism pricing for renewables** to support the smooth entry of renewables into the power market.

RMI Graphic. Source: NDRC, RMI

Over the past year, significant progress has been made in policies and practices related to the power spot market, capacity pricing, and mechanism pricing, further advancing the development of a market structure and pricing system that supports the transition to the New Power System and facilitates high levels of renewable energy integration.

i The dual carbon target calls for China to peak carbon dioxide emissions before 2030 and achieve carbon neutrality before 2060. The New Power System has renewable energy as the mainstay.

The power spot market has reached initial maturity, with expanded coverage and an enhanced role in price discovery. Twenty-nine provincial power grids have implemented trials or full spot market operations. In addition to serving a settlement role in the spot market, spot prices also influence medium- to long-term (M2L) transactions, and the time-of-use (TOU) electricity pricing policies based on intraday price fluctuations.

The full implementation of coal power capacity pricing has laid the groundwork for the transformation of the coal power sector. This pricing mechanism restructures the revenue model for coal power operators, reducing reliance on energy sales and demand for a higher capacity factor, thereby providing room for further reduction in coal power operating hours as part of the transition to the New Power System.

The introduction of renewable energy mechanism pricing promotes the market entry and sustained development of renewables. Renewable energy power is now largely included in the power market, with post-market settlement of price differences through a sustainable development pricing mechanism. This approach optimizes resource allocation and enhances the certainty of investment returns for renewable energy projects.

RMI has been closely monitoring the power market momentum since 2015. In past research, we focused on market design, analyzing and discussing how the power market should be improved, while also adopting the market participant perspective in our annual reports, presented in our annual series: *Power Market Outlook: Key Trends for Market Players*. These reports aim to provide both in-depth and broad insights for power generators and users.

For the report this year, extending our **2024** and **2023** Power Market Outlook reports, we systematically review key developments and market dynamics for the period from early 2024 to present in power market construction and pricing system development. We also offer analysis of future trends. Unlike previous reports, which were primarily organized by market components, this year's edition provides more targeted analysis by focusing on different types of market participants (see Exhibit ES2). For detailed information on the progress of power market reform and pricing systems from 2023 to early 2024, as well as background on the 2015–2022 period, readers can refer to the corresponding sections in the 2024 and 2023 annual reports. Also, please be reminded that this version is a version tailored for English language readers.[1] If you are interested, please check out our **extended version in Chinese** for more details. In the context of accelerating the construction of the New Power System and a unified national power market, we hope this report will help market participants better understand the current and future electricity pricing system, and gain insights into market development trends to better support the clean and low-carbon energy transition.

Exhibit ES2 **Ten key trends for power market players**

By market	Spot markets	1. Twenty-nine provincial grids are (trial) operating the power spot markets, with spot prices falling due to lower coal price, more renewables, and looser supply-demand balance.
	M2L transactions	2. Buyers now have greater flexibility in allocating shares across M2L transactions, whose prices closely follow thermal coal and spot market trends.
By market participant	Conventional generators	3. Capacity pricing restructures the revenue stream of conventional power plants; a new capacity tariff adjustment could further lower thermal power's capacity factor.
	Renewables	4. Renewable generation is fully entering the market, with over-the-counter pricing mechanisms playing a key transitional role.
	Distributed energy	5. Grid connection challenge requires that distributed photovoltaic (PV) prioritize on-site consumption, leading to uncertainty in returns.
	Stand-alone storage	6. Stand-alone energy storage is seeing core revenue from energy market arbitrage, with frequency regulation and capacity earnings sensitive to market and policy shifts.
	Virtual power plants (VPPs)	7. VPPs are still in the demonstration stage and entering power spot markets may be a breakthrough for commercialization.
	Retail market buyers	8. Enhanced coordination is visible between retail and wholesale market pricing mechanisms with fair and effective market competition.
	Green power users	9. The green power and certificate trading system is improving, with trading volume influenced by mechanism ratios, certificate ownership, and usage.
	EV charging	10. Several provinces have adopted pricing for residential EV charging, on a voluntary basis, following existing residential pricing structures.

RMI Graphic. Source: RMI

Spot Markets

1 Twenty-nine provincial grids are (trial) operating power spot markets, with spot prices falling due to lower coal price, more renewables, and looser supply-demand balance

By the end of 2025, China will "achieve basic full coverage of provincial spot markets"

Since the end of 2023, development of the power spot market has accelerated significantly, with trial or official operations now underway in 29 provincial grid regions nationwide (see Exhibit 1). After Shanxi and Guangdong took the lead in transitioning from spot market trial operation to official operation at the end of 2023, Shandong, Gansu, and West Inner Mongolia followed and started official operation in June 2024, September 2024, and February 2025, respectively. In addition, Hubei, Zhejiang, Anhui, and Shaanxi all transitioned from short-/long- term trial operation to continuous trial operation in 2024. At the regional and national levels, the State Grid Interprovincial Spot Market officially launched on October 15, 2024, after more than two years of continuous trial operation — marking a key milestone in the maturity of China's unified multi-level market model in the State Grid region. In November 2024, the China Southern Power Grid Regional Spot Market — covering Guangdong, Guangxi, Yunnan, Guizhou, and Hainan — completed its first full-month trial. It remains the fastest-advancing regional power market in China.

According to the Key Points of Energy Regulation in 2025 by the National Energy Administration (NEA), China will "achieve basic full coverage of provincial spot markets" by the end of this year. Of the six provincial spot markets in continuous trial operation, Hubei and Zhejiang are expected to move to official operation after one year,[ii] while the other four will remain status quo. Fujian, Jiangsu, Hunan, and Ningxia are set to advance into continuous trial operation. The China Southern Power Grid Regional Spot Market is expected to begin continuous trials in the second quarter, and the Beijing-Tianjin-Hebei Regional Spot Market may launch its first trial operation.

ii Hubei has moved to official operation on June 6th.

Exhibit 1 Overview of spot market development at the subnational level as of March 2025

Trial operation without settlement	Short-term trial operation	Long-term trial operation	Continuous trial operation	Official operation
• Heilongjiang • East Inner Mongolia • Jilin • Qinghai • Hunan • Xinjiang • Shanghai	• Jiangxi • Qinghai • Jilin • Shanghai • Xinjiang • Heilongjiang • East Inner Mongolia • Henan • Ningxia • Chongqing • Shaanxi • China Southern Power Grid Regional Spot Market	• Fujian • Sichuan • Jiangsu • Henan • Hunan • Ningxia • Chongqing • China Southern Power Grid Regional Spot Market • Zhejiang • Anhui • Hubei	• Hubei • Zhejiang • Anhui • Shaanxi • Liaoning • South Hebei • Shandong • Gansu • State Grid Interprovincial Spot Market • West Inner Mongolia	• Shanxi • Guangdong • Shandong • Gansu • State Grid Interprovincial Spot Market • West Inner Mongolia

Blue names = Provincial-level spot markets without stage changes
Red names = Regional and national-level spot markets
Green names = Spot markets with stage changes compared to January 2024
Gray names = Spot markets and their stages as of January 2024

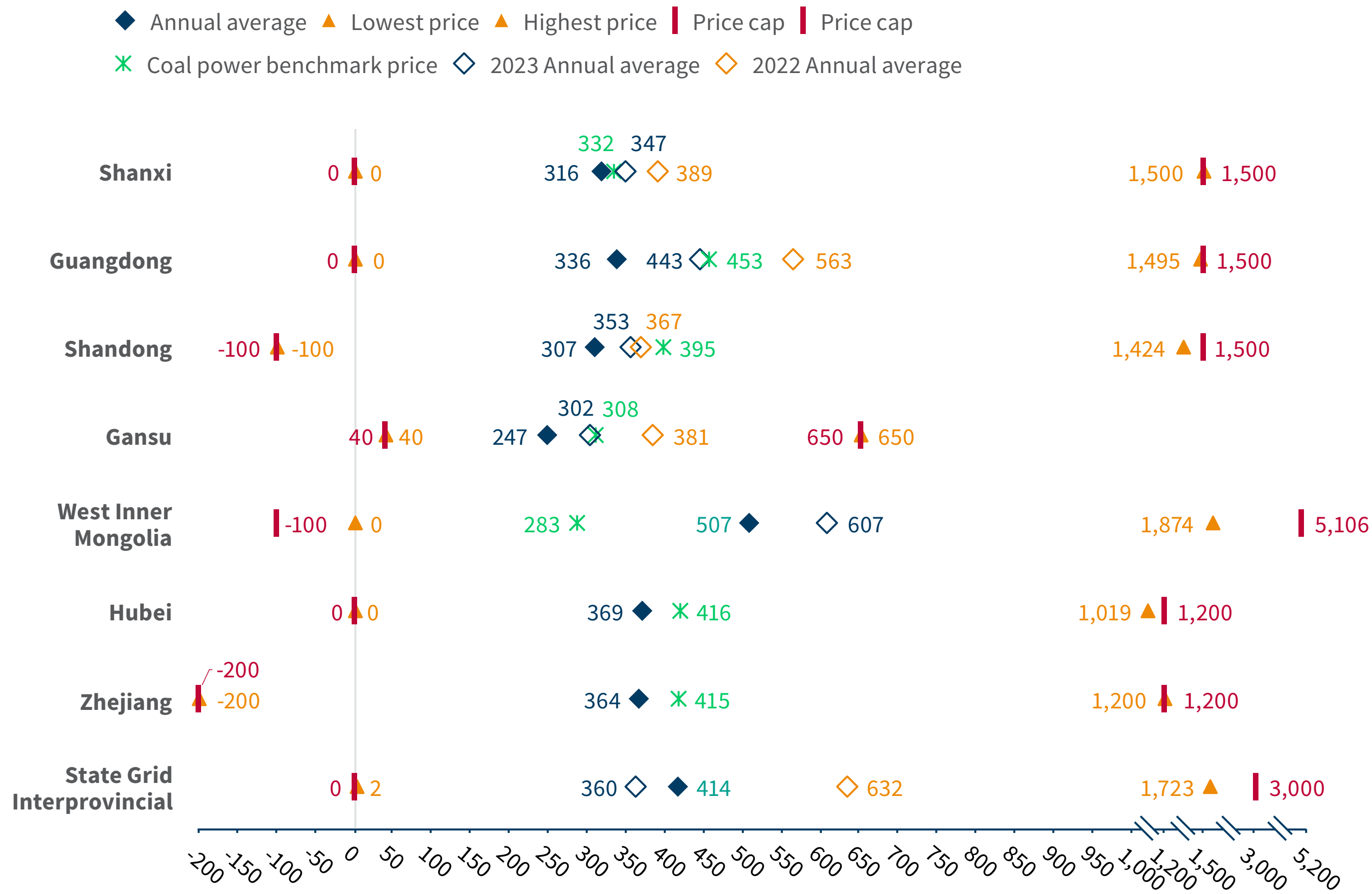
RMI Graphic. Source: Provincial and regional power trading centers, government websites, official media, etc., compiled by RMI

Spot prices in most provinces dropped in 2024, and the downward trend is expected to persist in 2025

Except for the State Grid Interprovincial Spot Market, provincial spot markets with continuous (trial) operations saw further price declines in 2024, driven by lower thermal coal prices, a higher share of renewables, and a relatively loose supply-demand balance (Exhibit 2). Average spot prices fell year-on-year by 31 RMB/MWh (8.9%) in Shanxi, 108 RMB/MWh (24.3%) in Guangdong, 46 RMB/MWh (13.0%) in Shandong, 55 RMB/MWh (18.2%) in Gansu, and 100 RMB/MWh (16.5%) in West Inner Mongolia. Hubei and Zhejiang, which began continuous trials in April and May 2024, saw average prices drop 11.3% and 12.2% below their coal power benchmark prices, respectively.

In the interprovincial market, average temperatures during the flood season (April 1–October 23) rose by 2.06°C year-on-year, with frequent heatwaves and autumn droughts in the eastern part of Southwest China and the middle reaches of the Yangtze River.[2] From August to November, spot prices reversed earlier declines, with the clearing prices in August and September more than doubled year-on-year — pushing the annual average up by 15.2%.

Exhibit 2 **Overview of key spot price data in 2024**



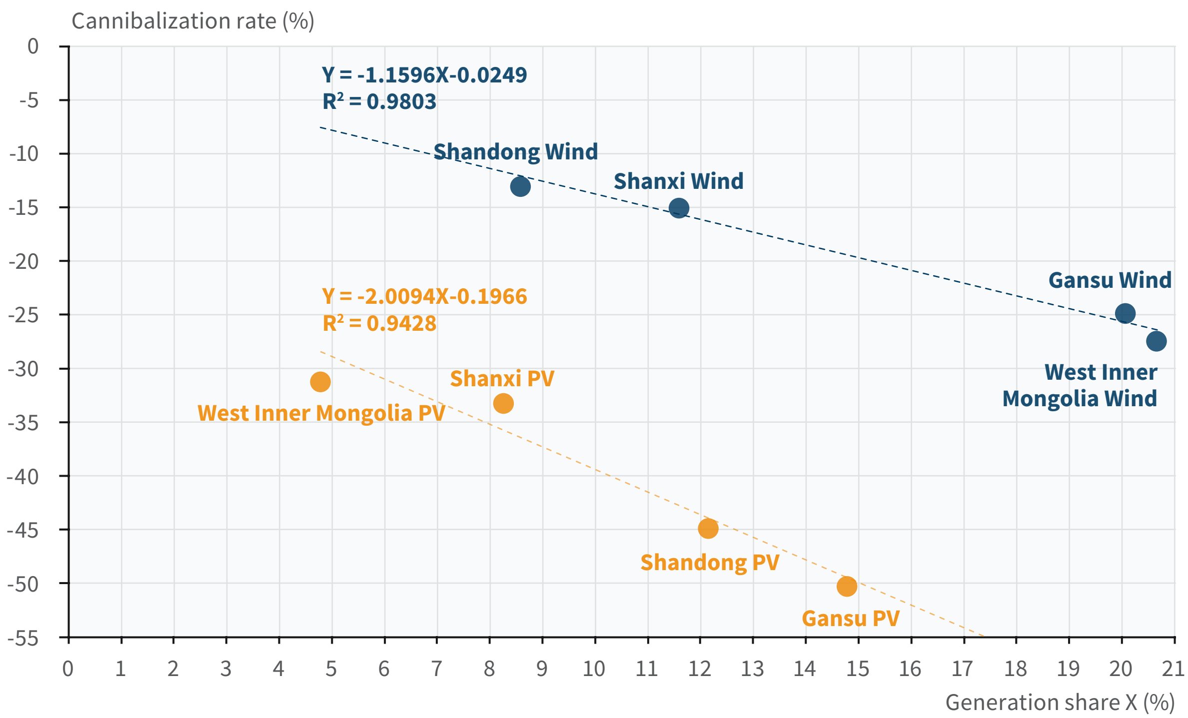
RMI Graphic. Source: Lambda Power Spot, RMI

Three main factors contributed to spot price trends:

First, the price of thermal coal continues to decline. In most provinces, coal power typically sets the marginal price in spot market clearing. For reference, the average 2024 spot price of 5,500 kcal thermal coal at Qinhuangdao Port was 860 RMB/ton — down 105 RMB/ton (10.9%) from 2023. With a coal consumption rate of 300 g/kWh, this translates to a 32 RMB/MWh drop in fuel costs, directly contributing to lower spot prices. Additionally, the coal power capacity price mechanism, officially implemented in 2024, helped generators recover part of their fixed costs (see Section 3). The introduction of capacity price allowed coal power plants to bid prices closer to fuel costs in the power spot market, which also contributes to the decline in spot prices in 2024. **Since early 2025, thermal coal prices have continued to fall.** The long-term contract price for 5,500 kcal coal at Qinhuangdao Port dropped from 693 RMB/ton in January to 679 RMB/ton in April, while the spot price fell from around 770 RMB/ton to 670 RMB/ton — now on par with the long-term contract price. With stable coal supply-demand conditions, many institutions expect this downward trend to persist through 2025, along with a decline in electricity spot prices.[3]

Second, the share of renewables in the power system continues to increase. Exhibit 3 shows that in all four provinces analyzed — Shandong, Shanxi, Gansu, West Inner Mongolia — the annual average capture prices of wind and solar PV projects were lower than the overall market average, highlighting the cannibalization effect of renewables in spot markets. This effect is strongly correlated with generation share: each 1% increase in the share of wind power leads to a ~1.16% drop in its capture price relative to the market average; for solar PV, the price drop is even steeper at 2.0%. In 2025, as the share of renewables continues to grow and with all renewables fully participating the market (see Section 4), the spot prices in the above-mentioned provinces will be more volatile and the cannibalization effect of renewables will be more significant.

Exhibit 3 **Correlation between the cannibalization rate of wind power or solar PV and its share of total generation in 2024**



Notes: Cannibalization rate Y = (Provincial wind power or solar PV average capture price – provincial spot market average price) / Provincial spot market average price; Generation share X = Provincial wind power or solar PV generation / Total provincial power generation

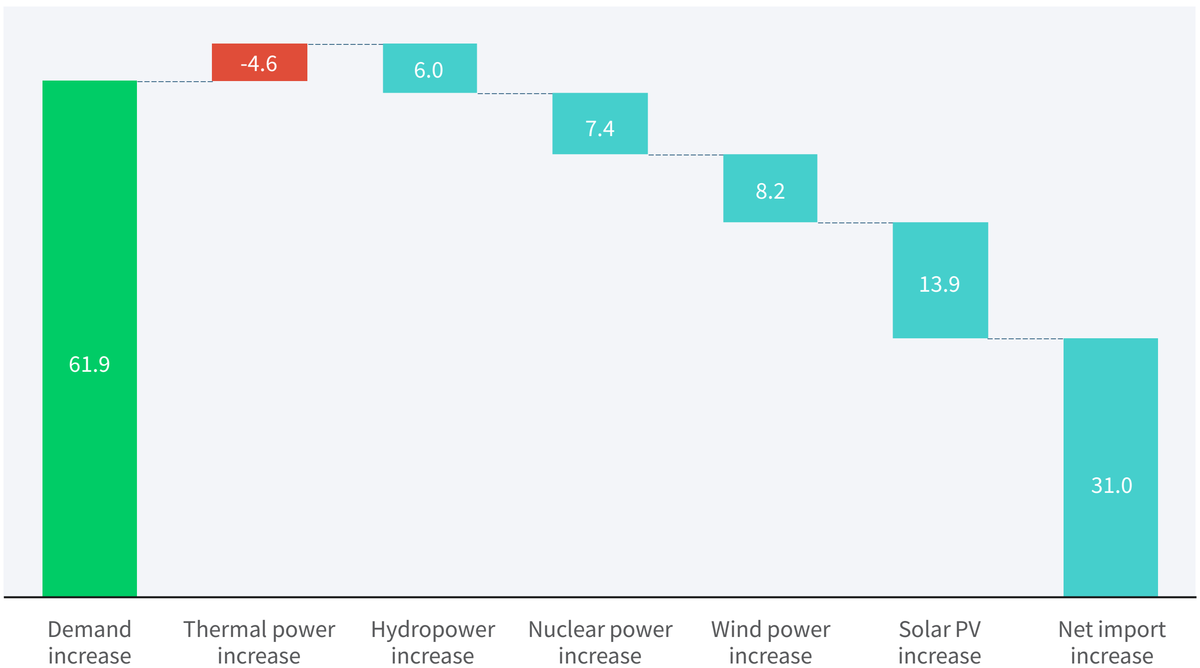
The annual average spot price used here does not represent the final settlement price in the energy market but is only its capture price in the spot market. The final settlement price is also significantly affected by M2L transactions.

RMI Graphic. Source: Lambda Power Spot; and China Electricity Council, *Statistical Bulletin of the National Electric Power Industry in 2024*, RMI

Third, the supply-demand tension of electricity loosens. The commissioning of numerous coal and gas plants approved after the 2021 power shortages, combined with strong hydropower output in 2024 and slower demand growth in some regions, has loosened the supply-demand balance and pushed spot prices down. In Guangdong, the average thermal power utilization hours in 2024 dropped sharply by 398 hours year-on-year, driven primarily by a capacity surge. Between 2023 and 2024, the province added 20.91 GW of new thermal power — more than double the 9.32 GW added in 2021–2022. However, the additional demand was largely met by non-fossil sources. As shown in Exhibit 4, most of the incremental electricity consumption in 2024 was supplied by hydropower (including imported power from Yunnan and Guizhou Provinces), solar PV, and wind. In contrast, thermal power generation declined by 4.6 TWh year-on-year. This shift reflects the market dispatch order: imported electricity governed by intergovernmental agreements, along with renewables and hydropower, are cleared first due to their lower marginal costs. As a result, thermal power plants are competing for a smaller residual demand, which suppresses their utilization rates and lowers the spot market clearing prices. According to data from Global Energy Monitor and China Electricity Council, an additional 56–87 GW of coal power plants is projected to go online nationwide in 2025, potentially exceeding the total addition of 65.37 GW in 2023–2024.[4]

Meanwhile, new renewables capacity is expected to exceed 300 GW (360 GW in 2024), while the growth rate of electricity consumption is expected to remain at around 6% (6.8% in 2024). **Therefore, competition on the power generation side in the spot market may be more intense.** Guangdong expects to have another 10 GW of coal power plants, and another 10 GW of gas power plants come into operation in 2025 — ranking first among China's provinces. However, on the demand side, Guangdong's electricity consumption grew by only 2.2% in the first three months of 2025 (7.3% for the whole year of 2024). **It is expected that the supply-demand balance will continue to be loose, and spot prices in Guangdong will be under great downward pressure.**

Exhibit 4 **Overview of year-on-year changes in electricity supply and demand in Guangdong Province in 2024 (TWh)**



RMI Graphic. Source: China Electricity Council, RMI

Medium- to Long-Term Transactions

2 Buyers now have greater flexibility in allocating shares across M2L transactions, whose prices closely follow thermal coal and spot market trends

M2L transactions remain the dominant component of China's power market, with steady growth in recent years. In 2024, bilateral M2L volumes reached 4,650 terawatt hours (TWh) — up 5% year-on-year — representing 47% of total electricity consumption, 98% of which transacted within provincial markets.[5] Participation has broadened beyond coal and renewables to include stand-alone storage, VPPs, pumped hydro, and nuclear, reflecting a more diverse and dynamic market.

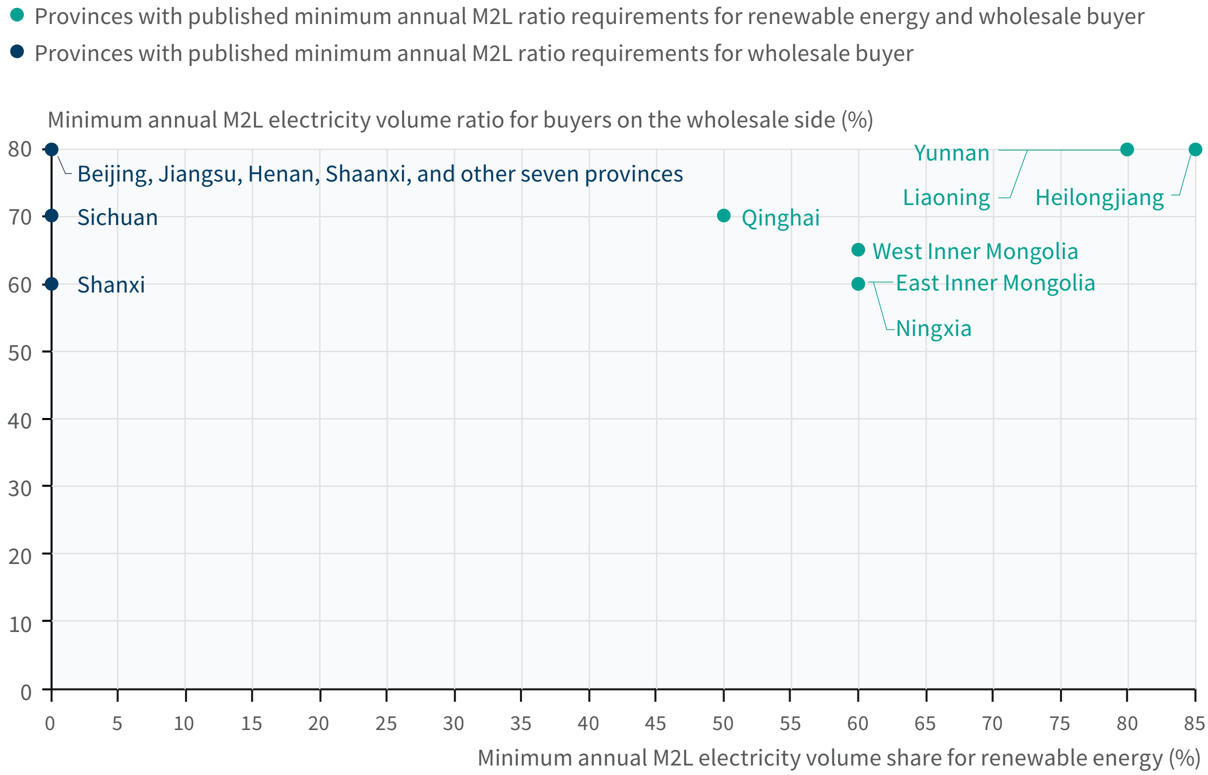
Several provinces start to relax limits on annual contract shares for wholesale buyers

The 2025 M2L transactions highlight varying provincial annual contract shares for wholesale buyers, with several regions easing shares limit (Exhibit 5). Fourteen provinces continue to mandate annual contract shares of 80% or more,[iii] while six regions — Qinghai, Sichuan, East and West Inner Mongolia, Shanxi, and Ningxia — have reduced the minimum to 60%–70%. Nationally, the "*2025 M2L Contract Execution Notice*" by NDRC and the National Energy Administration (NEA) allows provinces where renewables and hydropower exceed 40% of generation mix to relax annual contract shares limit: from above 80% to above 60%. These adjustments are subject to regulatory approval and comprehensive assessment.[6]

The relaxed annual contract shares limit reflects the inapplicability of applying coal benchmark price to an energy market with growing renewable penetration. Coal power generators are typically required to secure at least 80% of their coal supply through long-term contracts.[7] Aligning this with an equivalent proportion of M2L electricity contracts minimizes exposure to market risk. In contrast, the inherent variability of renewable output makes long-term contracting less predictable. As a result, provinces generally apply more flexible contracting requirements for renewable generators compared to coal plants. In addition, **with the continued growth of renewables, we expect to see more relaxed limits on annual contract shares and more sub-annual transactions, such as monthly, intramonthly, and multiday transactions.**

iii The 14 provinces are Yunnan, Liaoning, Heilongjiang, Beijing, Tianjin, South Hebei, North Hebei, Jilin, Shanghai, Jiangsu, Anhui, Henan, Hainan, and Shaanxi.

Exhibit 5 **Provincial minimum M2L annual electricity ratio for wholesale buyers**



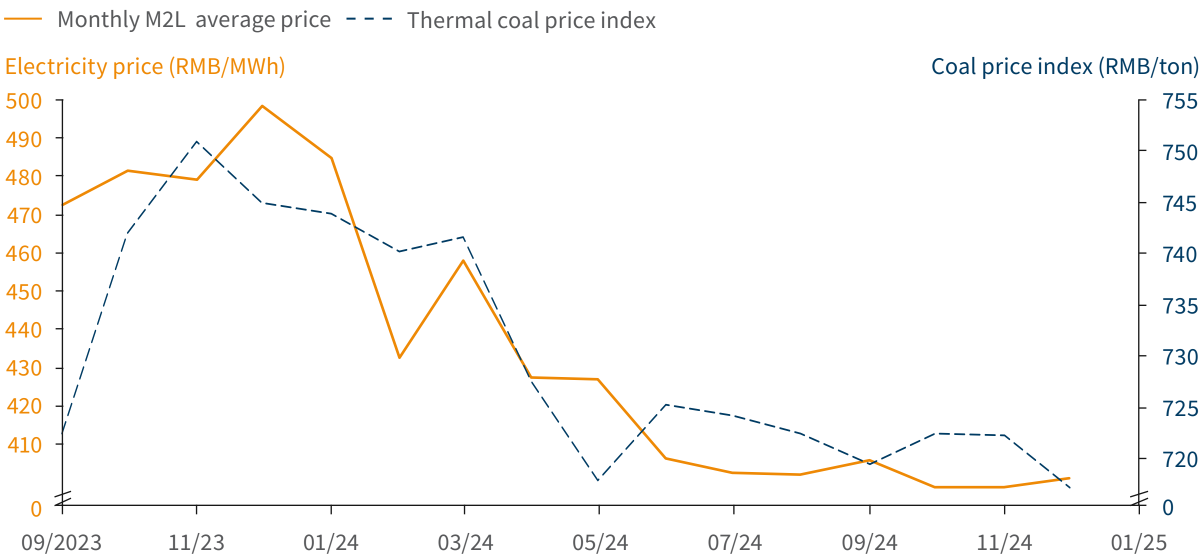
RMI Graphic. Source: Provincial Development and Reform Commissions, Provincial Power Exchange Centers, RMI

Prices for monthly M2L transactions follow thermal coal price trends

Coal power is the pricing anchor of China's M2L transactions given its large proportion of the total. In 2024, coal power accounted for 54.8% of the country's total electricity generation. All coal power generation is mandated to be in the power market and 90% of this generation needs to be settled through M2L contracts.[8] This means coal power generation alone contributed approximately 80% of the 6,180 TWh traded through power exchange centers, firmly establishing it as the core price setter in M2L transactions.

Fuel costs represent the largest portion — about 70% — of coal power's levelized cost of electricity. To stable operational costs from fuel price fluctuations, coal plants typically incorporate thermal coal price trends into their bidding strategies. As a result, monthly M2L transaction prices often move in tandem with thermal coal price indices. In Guangdong, for instance (Exhibit 6), both the thermal coal price index and monthly M2L prices showed aligned downward trend from September 2023 to December 2024.

Exhibit 6 **Monthly M2L transaction prices vs. coal prices in Guangdong Province (September 2023–December 2024)**



RMI Graphic. Source: Guangdong Power Exchange Center, China Coal Transportation and Distribution Association, China National Coal Exchange Center, China Electricity Council, RMI

Time-segmented M2L transactions continue to evolve, increasingly reflecting spot market price signals

Since the launch of time-segmented M2L transactions in Shanxi in 2021,[iv] 28 provinces, including Guangdong, Gansu, and Zhejiang, have adopted similar practices. For transactions not yet using time-segmented pricing, curve-based pricing is available as an alternative. Both mechanisms distinguish the value of electricity across different time periods.[v]

Based on whether time segmentation is applied and whether price caps/floors are referenced, current time-segmented M2L pricing can be categorized into four types:

- Uniform pricing: Some regions still use a flat-rate settlement for generation regardless of time value. For example, Shandong (optional for renewables), Fujian (generation side), and Hainan (generation side) apply a single price across all time periods.
- Referencing industrial and commercial (I&C) TOU pricing and coal power floating price: Xinjiang, Beijing, etc.
- Segment definitions and floating ratios that differ from TOU pricing: Qinghai.
- Aligned with spot market, sharing the same pricing cap as spot market: Guangdong, Shanxi, Shandong (user side), Gansu, and Zhejiang.

iv M2L time-segmented transaction refers to dividing each day into different time periods — such as peak, off-peak, and super off-peak hours or hourly intervals — with the electricity volume in each period treated as a separate trading product.

v Curve-based TOU trading is a mechanism by which the electricity load profile is explicitly defined in the contract between supply and demand parties in 15-minute increments.

Looking ahead, as market participants improve their trading capabilities and spot market development progresses, the integration between spot and M2L markets will deepen. For shorter-cycle M2L products (e.g., intramonth or multiday trades), the closer proximity between trading and delivery dates provides more accurate forecasting inputs, making price and volume predictions easier. These products are expected to align more quickly with spot market price limits.

Conventional Generators

3 Capacity pricing restructures the revenue stream of conventional power plants; a new capacity tariff adjustment could further lower thermal power's capacity factor

The NDRC and the NEA jointly published the *Notice on Establishing a Coal Power Capacity Pricing Mechanism* (Document #1501), introducing a capacity tariff for public utilities' conventional coal power plants, effective from January 2024. Qualified coal power plants currently receive a capacity tariff of 100 RMB/kW per year or 165 RMB/kW per year depending on their location. The expense is shared among industrial and commercial users as part of the system operation fee.

In the first year of coal power capacity pricing implementation, both the generation-side revenue model and the user-side price structure transitioned smoothly

2024 marked the first year of coal power capacity pricing.[vi] On the generation side, the capacity tariff reconstructed the revenue model of coal power plants to adapt to the energy transition. On the electricity user side, the coal power capacity fee embedded in the system operation fee began to become an important part of the electricity cost, though it has not yet significantly affected the users' electricity bills.

For coal power generators, the capacity tariff shifted the revenue model from purely energy-based to a two-part structure, combining energy and capacity revenues. In 2024, it is estimated that the introduction of coal power **capacity tariff converted on average about 6.4% of the generator's revenue into capacity revenue.**[vii] In areas where the capacity tariff is 100 RMB/kW per year, the proportion of capacity revenue in the total revenue (i.e., energy revenue and capacity revenue) is mostly in the range of 3% to 7%, with an average of about 5%; in areas where the capacity tariff is 165 RMB/kW per year, this proportion is 6% to 16%, with an average of about 10%.

From a regional perspective, **coal power operators in the southwest, northwest, and northeast regions are currently more dependent on capacity revenue,** but the reasons for the high dependence in the three regions are different. **The southwest region is mainly affected by the level of capacity tariff setting:** the capacity tariff in Sichuan, Chongqing, Yunnan, and Guangxi is priced at 165 RMB/kW per year, resulting in the capacity income share generally approaching or exceeding 10%. **The northwest region is mainly affected by the energy market price.** Due to the relatively low price in the energy market, the total revenue is relatively low compared to other provinces, making capacity income a larger share by

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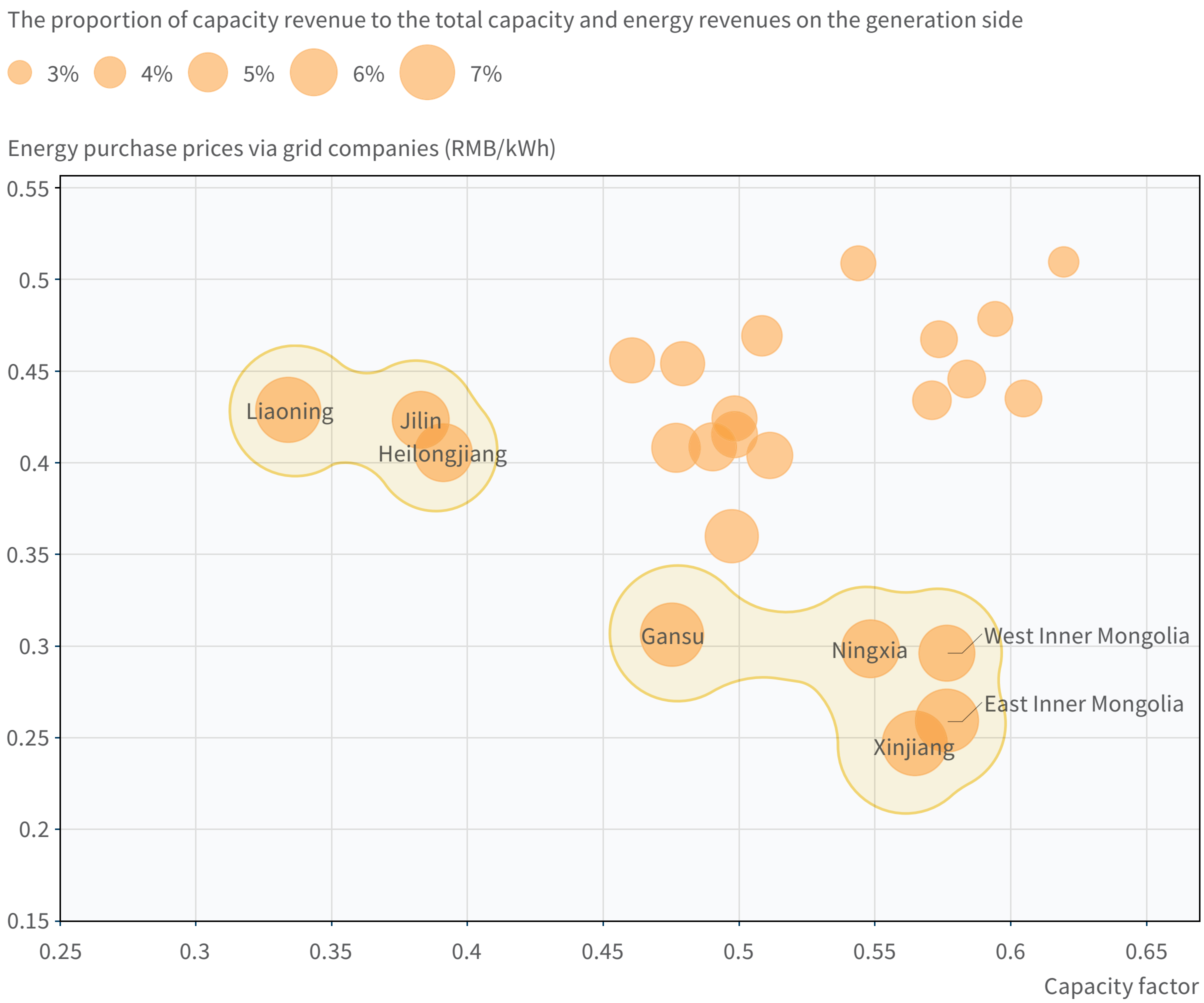
vi We differentiated power capacity prices into two categories related to their corresponding entity, where "tariff" would be applied to generators and "fee" to consumers.

vii The total revenue of energy and capacity in each region is estimated based on information such as the energy price, line loss rate (price), utilization hours, and coal power capacity tariff. This estimation is also regarded as the income level under the traditional energy only revenue model. Some regions (e.g., Beijing, Tibet, Hong Kong, Macao, and Taiwan) are not included in the estimation due to data availability.

comparison (Exhibit 7). **The northeast region is mainly affected by the capacity factor.** The relatively low-capacity factor reduces the income from selling energy, thereby increasing the proportion of capacity income in the total income.

Exhibit 7 **Estimated ratio of capacity revenue to capacity and energy revenue by region (for regions with capacity tariff of 100 RMB/kW per year)**



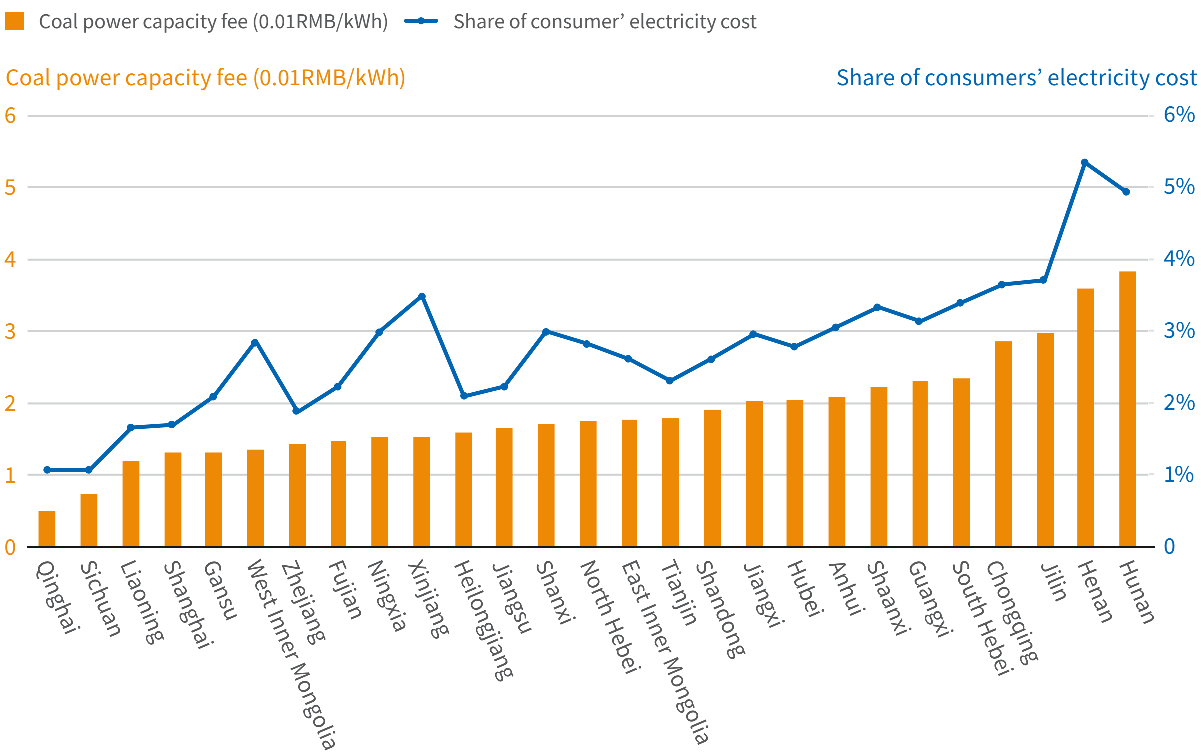
Note: The content shown in this chart is an estimate of the capacity revenue ratio, not the actual value. For a brief description of the methodology, please refer to footnote vii. The calculation process refers to price and utilization duration.

RMI Graphic. Source: NDRC, provincial power grid companies, China Electricity Council, bjx.com.cn, RMI

For electricity users, the coal power capacity fee is generally 0.010–0.030 RMB/kWh,[viii] with an average level of about 0.019 RMB/kWh. This capacity fee now accounts for about 2.8% of the total electricity bill, where most provinces fall into the range of 2%–3.7% (Exhibit 8).

A further look into the total electricity price paid by consumers reveals that the introduction of coal power capacity tariff has not increased the consumer's electricity cost. The energy price in consumers' electricity bills dropped by about 0.028 RMB/kWh on average in 2024 compared with 2023, due to both the downward trend in coal prices and the introduction of coal power capacity tariff. Considering that the coal power capacity fee is around 0.019 RMB/kWh, the total cost in 2024 saw a net decrease compared with the previous year.

Exhibit 8 Coal power capacity fee and its share of consumers' electricity costs (average level in 2024)



Note: The information in this chart refers to the monthly energy retail price (via provincial power grids), coal power capacity fees, and other information, and takes 1–10 kV energy-only (I&C) users as an example; the mean calculation adopts the arithmetic average of each month and does not take into account differences in monthly electricity consumption.

RMB Graphic. Source: Provincial power grid companies, RMI

viii The analysis and calculation on electricity consumption in this section considers only the provinces noted in Exhibit 8.

The capacity tariff is expected to adjust in 2026, making more room for the reduction of coal power capacity factor

Based on the requirements of Document #1501 and its annexes, it is expected that the coal power capacity tariff in most provinces will increase starting in 2026. Most provinces with the current tariff level at 100 RMB/kW per year are expected to rise to 165 RMB/kW per year. Some provinces with the current tariff level at 165 RMB/kW per year, such as Yunnan and Sichuan, may increase to about 230 RMB/kW per year.

For coal power operators, the tariff adjustment will further enhance the role of the capacity income in their total revenue stream and allow further reduction in capacity factor. Without considering the fluctuations of electricity energy prices, coal prices, and utilization hours, the expected capacity tariff adjustment is expected to increase generators' reliance on the capacity income by about 3 percentage points. If assuming a constant income level for a generator before and after the tariff change,[ix] it can be estimated that the expected capacity tariff adjustments **could support a 150-hour decrease in utilization in most places,** and a reduction of 200–250 hours or more in some places.

For electricity consumers, the capacity tariff adjustment may result in an uptick in the system operation expenses in the short term. Calculations show that after the adjustment of coal power capacity tariff, the average coal power capacity fee paid by users is expected to change **from the current approximately 0.02 RMB/kWh to approximately 0.03 RMB/kWh in the short term.** However, considering the declining price of fuel (coal price) in the short term, it is expected that the energy price in the electricity bill may cause total electricity cost to remain stable or to decline slightly, so **the impact of the capacity tariff adjustment on electricity consumers is relatively limited.**

ix The estimation also assumes that the energy price remains unchanged (the same as the historical price).

Renewables

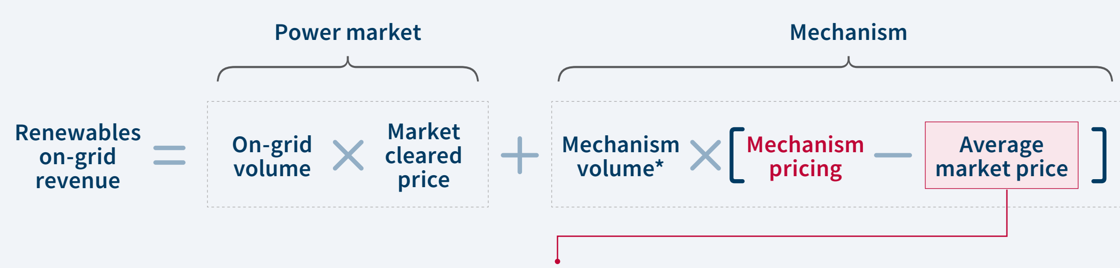
4 Renewable generation fully entering the market, with over-the-counter pricing mechanisms playing a key transitional role

On-grid renewable generation is moving into a new market phase

In February 2025, the NDRC and the NEA jointly issued the *Notice on Deepening the Market-Based Reform of Renewable Energy On-Grid Pricing to Promote High-Quality Development of Renewables* (Document #136). In addition to proposing a set of "renewable sustainable development pricing mechanisms" — also known as "mechanism pricing" — to improve the return visibility and stability of wind and solar projects, the document mandates that all on-grid generation from wind and solar should, in theory, be included in the energy market. It effectively encourages the switch from the old "guaranteed purchase + partial market pricing" approach to the "full market pricing + partial over-the-counter guarantee" strategy for pricing renewable generation. Furthermore, the agreement makes clear that this mechanism will be promptly assessed, improved, and withdrawn as necessary. This suggests that China's objective of introducing all renewables into the power market by 2030 will benefit greatly from this new settlement mechanism.

After participating in the energy market transaction, renewables included in this mechanism can also settle the price difference, which could be in negative value, over-the-counter, as shown in Exhibit 9. This is effectively the two-way contract-for-difference with the benchmark adjusted monthly.

Exhibit 9 **Renewables revenue under the new mechanism**



- **Regions with operating spot market:** determined based on the weighted average monthly price of similar projects in the real-time generation-side spot market
- **Regions without continuous operation of the spot market:** determined based on the weighted average of similar generation-side M2L transactions during the most active trading periods

* On-grid volume × mechanism ration

RMI Graphic.

The scope, cost, and duration of this pricing system will be decided at the provincial level. National guidelines, however, set different requirements for existing and new renewable projects. Projects that connected to the grid before June 1, 2025, are expected to transition gradually to market pricing, ensuring continuity with the current system. Projects connected from June 1, 2025 onward will be subject to the new pricing structure from the start of commission — resulting in greater exposure to market uncertainty (Exhibit 10).

Exhibit 10 **Key characteristics and differences of renewable energy pricing policies**

<table>
<tr><th rowspan="2">Portion</th><th rowspan="2">Transactions</th><th rowspan="2">Current practice
(Feed-in tariff)</th><th colspan="2">Mechanism pricing</th></tr>
<tr><th>Existing project (online before June 1, 2025)</th><th>New projects
(online after June 1, 2025)</th></tr>
<tr><td rowspan="2">Guaranteed purchase by the grid</td><td>Guaranteed volume and price (in some provinces)</td><td>Volume: Set by the government, with a yearly decline in some provinces
Price: Based on the local coal benchmark price (except in major hydropower provinces)
Term: Update each year</td><td rowspan="4">Volume: Aligns with existing policies; full volume must enter the market

Price: Per current pricing policies
Term: Per current term policies</td><td rowspan="4">Volume: At provincial level, annual total determined by factors like non-hydro renewables portfolio standards; sets upper limit for generation participating in mechanism pricing
At project level: Each project decides the volume within limit, but it cannot exceed the previous year's volume

Price: Set at the highest qualified bid; settlement price adjusted monthly based on average market price for the same technology
Term: Generally covers the average initial investment payback period</td></tr>
<tr><td>Guaranteed volume with lower price (in some provinces)</td><td>Volume: Set by the government, with a yearly decline in some provinces
Price: Lower than local coal benchmark price
Term: Update each year</td></tr>
<tr><td rowspan="2">Traded in the market</td><td>M2L market</td><td>Volume/price: Negotiated between generators and users
Term: One year in most cases</td></tr>
<tr><td>Spot market</td><td>Depending on the trade</td></tr>
</table>

RMI Graphic.

In China, renewable projects currently have two main paths to participate in the power market:

1. Sell electricity through the spot or M2L market, with Green Electricity Certificates (GECs) traded separately; or

2. Trade green power bundled with GECs in M2L market

However, once mechanism pricing takes effect, generation covered by the mechanism can no longer engage in bundled green power transactions — and likely cannot participate in the energy-only M2L transaction either. This means such projects may be limited to the spot market, where they receive benchmark prices for difference settlement. At the same time, the associated GECs are barred from market trading. Provinces have yet to clarify the procedures for GEC cancellation or transfer. One possible outcome is that these GECs are directly transferred to provincial green certificate accounts to help meet local renewable portfolio standards. They may then be allocated to local users through non-market channels.

By the end of 2025, all provinces must establish and execute customized mechanism pricing in accordance with the national guidelines. It is anticipated that every province would reflect their own values and factors in their policies. Shanxi, Guangdong, Shandong, Gansu, and West Inner Mongolia are currently leading the way in the spot market's official operation and they are expected to be the front-runners in releasing provincial guidelines.

In the short term, Document #136 has a greater impact on fostering the interaction between user-side renewables and storage than it does on the generation side

On the user side, any on-grid generation from distributed renewables (mainly solar PV) that is not covered by mechanism pricing must be settled at market prices. Since most of these projects are smaller, they are more likely to participate in M2L transactions (including energy-only and bundled transactions) through aggregation or act as price takers in the spot market (see Section 5 for more detail). The spot price curve will become the baseline for the rest of the power market. As a result, these projects will face similar price curves, regardless of the transactions or settlement method. To increase income, the key solution for these projects is to integrate energy storage. Currently, most distributed PV projects send excess generation to the grid rather than charging energy storage. This is because they have a feed-in-tariff (FIT) matching the local coal power benchmark prices, which are relatively high. However, once the FIT fades, on-grid prices will likely drop significantly, encouraging owners to invest in storage to utilize generation as much as possible to save on electricity costs.

On the supply side, In the past five years, over 30% of novel energy storage installations in China built by renewables developers have been required to pair energy storage with renewables for less curtailment. However, Document #136 removed the mandatory requirement for energy storage to be paired with renewables, raising questions about whether investors will continue to develop energy storage alongside renewable projects. On one hand, the current intraday price gaps in the spot market remain too small to incentivize significant investment in energy storage. On the other hand, from the perspective of industry leaders and strategic planning, there are still many compelling reasons to continue co-locating energy storage with renewable projects. Based on our research:

- We assume that energy storage charges at lowest price and discharges at the highest price of the day, and according to the data displayed in Exhibit 11, the current spot market price spread in Shanxi and Shandong are insufficient to fully support 2-hour lithium battery storage investments. There are four main reasons for this:

    1. Given the current cost conditions and without considering ancillary services or capacity mechanism, energy storage requires a price gap of at least 600 RMB/MWh every day within the year (assuming one cycle per day) to earn enough return. In both provinces, in over 70% of the days the intraday price gap does not reach the mentioned level. Although policies have called for a wider spot price spread, we believe that most provinces will not see significant improvement in the near future. This is mainly due to projections of a loose supply-demand balance and the declining thermal coal costs of peak generation units in the spot market.

2. In practice, energy storage systems often cannot capture the highest intraday price differences each day for charging and discharging, meaning actual profits are typically lower than projected.

3. Even if renewables paired with storage use advanced price forecasting technologies to capture high-price periods, the increasing number of storage assets and intensified competition in the market generally lead to a downward trend in the highest prices over time.

4. Even with revenues from ancillary services and the capacity mechanism, achieving optimal joint operation and clearing across multiple markets is required. The actual revenue is not simply the sum of the three independent market revenues. Moreover, capacity fees are currently only available to stand-alone storage in some provinces, and renewables-paired storage generally cannot access them.

- At the same time, we believe a significant number of investors in well-positioned renewable energy projects will continue to voluntarily pair with storage. The main reasons are:

1. Storage can help reduce curtailment and increase total power output, thereby raising the share of electricity covered by guaranteed feed-in tariffs.

2. As renewables move fully into the market, storage greatly enhances flexibility and helps mitigate price troughs. With Document #136 indicating the eventual phase-out of feed-in tariffs, relying on the policy for price protection is unsustainable. Investors should build price-risk resilience while the policy still offers support.

3. Global experience shows that early movers in storage often enjoy first-mover advantages and higher initial profits, which tend to erode as more projects enter the market.

4. China's regulatory and market frameworks for storage are still evolving. Continued improvement in project economics will depend on early industry participants demonstrating scalable, real-world value.

Exhibit 11 Spot market intraday price gap distribution by month in 2024 in Shanxi (top) and Shandong (bottom)

Shanxi spot market intraday price gap in 2024 (RMB/MWh)	0–99	100–199	200–299	300–399	400–499	500–599	600–699	700–799	800–899	900–999	1,000–1,099	1,100–1,199	1,200–1,299	1,300–1,399	1,400–1,500
Jan	0	0	0	16	3	1	1	0	0	1	1	2	3	0	1
Feb	0	0	2	10	2	1	2	2	0	1	1	3	2	0	0
Mar	0	3	1	10	5	1	1	1	1	1	0	0	2	2	0
Apr	0	4	0	13	2	0	0	1	0	0	0	2	2	0	0
May	2	2	0	4	4	3	0	0	1	2	1	2	0	3	0
Jun	11	7	1	7	1	1	0	0	0	0	1	0	1	0	0
Jul	11	10	3	5	1	1	0	0	0	0	0	0	0	0	0
Aug	8	10	4	8	1	0	0	0	0	0	0	0	0	0	0
Sep	5	6	3	4	4	2	0	0	1	0	0	0	5	0	0
Oct	1	3	3	11	7	1	0	0	0	0	0	1	2	1	0
Nov	2	3	3	7	1	2	3	0	2	1	0	1	3	0	2
Dec	0	1	2	14	2	2	1	2	0	2	0	0	1	1	1
% in 2024	11%	13%	6%	30%	9%	4%	2%	2%	1%	2%	1%	3%	6%	2%	1%

Shandong spot market intraday price gap in 2024 (RMB/MWh)	0–99	100–199	200–299	300–399	400–499	500–599	600–699	700–799	800–899	900–999	1,000–1,099	1,100–1,199	1,200–1,299	1,300–1,399	1,400–1,500
Jan	0	1	2	1	12	5	4	2	1	2	1	0	0	0	0
Feb	0	1	3	3	8	5	3	3	1	1	1	0	0	0	0
Mar	0	1	1	2	6	13	4	2	0	0	1	1	0	0	0
Apr	0	2	1	4	14	7	0	1	0	1	0	0	0	0	0
May	0	3	1	3	0	6	6	3	3	5	1	0	0	0	0
Jun	0	2	2	3	3	7	8	3	2	0	0	0	0	0	0
Jul	0	7	5	2	4	3	6	2	1	1	0	0	0	0	0
Aug	0	8	9	7	1	3	2	1	0	0	0	0	0	0	0
Sep	0	4	1	9	7	2	4	1	2	0	0	0	0	0	0
Oct	0	4	5	3	3	5	9	0	0	0	0	0	0	0	0
Nov	0	4	3	3	4	10	4	0	1	1	0	0	0	0	0
Dec	0	3	5	2	9	5	3	3	1	0	0	0	0	0	0
% in 2024	0%	11%	10%	11%	19%	19%	14%	6%	3%	3%	1%	0%	0%	0%	0%

Note: Exhibit may be missing some dates for which data is not publicly available

RMI Graphic. Source: Shanxi Power Exchange Center, Shandong Power Exchange Center, RMI

Distributed Energy

5 Grid connection challenge requires that distributed PV prioritize on-site consumption, leading to uncertainty in returns

Distributed PV sees expansion across coastal provinces with high electricity demand, with sharp drop in residential installations

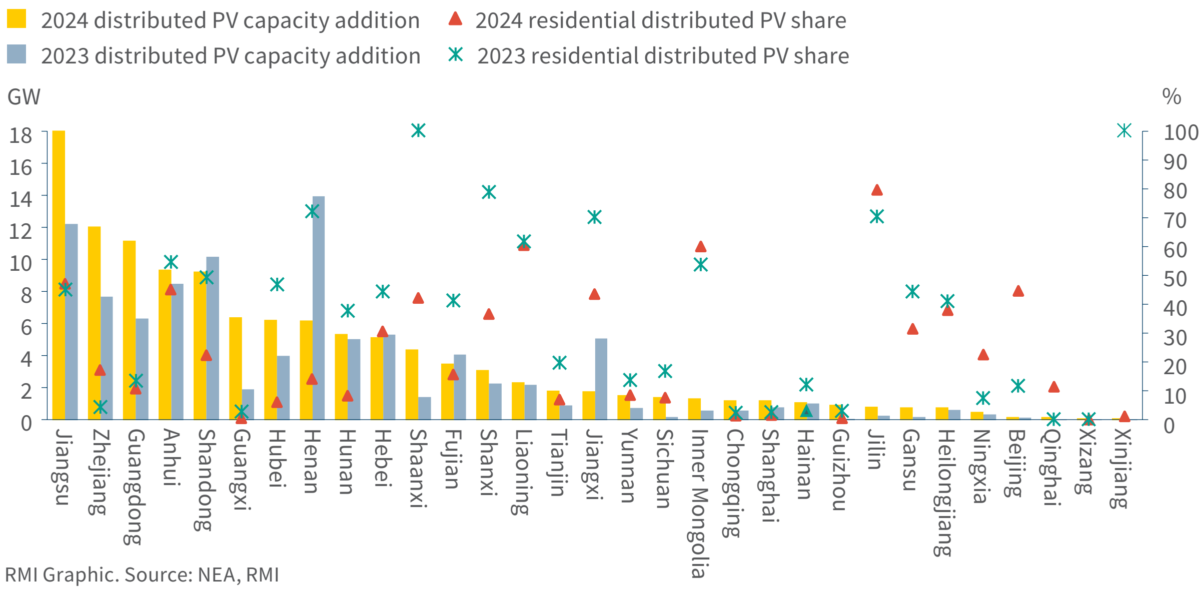
In 2024, the installed capacity of distributed PV systems continued to grow steadily, but the proportion of residential distributed PV declined. Distributed PV added 118.18 GW in 2024, with a year-on-year 23% increase. Due to grid constraints and rising risks in project returns, the residential PV capacity additions in 2024 dropped to 29.55 GW, down 32% year-on-year. Its share in total incremental capacity of distributed PV fell from 45% in 2023 to 25% in 2024.[9]

Distributed PV capacity additions were mainly concentrated in coastal provinces with high electricity demand. The top five provinces — Jiangsu, Zhejiang, Guangdong, Anhui, and Shandong — accounted for 50.5% of the national incremental capacity (see Exhibit 12). Guangdong, Jiangsu, Shandong, and Zhejiang are China's largest electricity consuming provinces.

Jiangsu led the nation in distributed PV additions from 2023 to 2024, with a 48% year-on-year growth in 2024. This rapid expansion can be attributed to Jiangsu's solid support for the PV industry, increasing demand for green power, and sufficient distribution grid capacity.

Henan province, despite ranking first in distributed PV additions nationwide in 2023, saw a significant downturn in performance in 2024 due to grid constraints in many counties, as exposed by grid assessments. The province saw a drop of more than 50% in new distributed PV installations, with residential additions plummeting by over 90%.

Exhibit 12 **Incremental distributed PV capacity by province, 2023–2024**



RMI Graphic. Source: NEA, RMI

China releases tighter regulation for distributed PV with emphasis on on-site consumption

In January 2025, the NEA issued the revised *Administrative Measures for the Development and Construction of Distributed Photovoltaic Power Generation* (hereafter referred to as the *Administrative Measures*), which applies to projects connected to the grid from May 1, 2025.[10] The revision standardizes the development and construction of distributed PV projects at the national level, categorizing them into specific types and introducing tailored management approaches for each category (see Exhibit 13).

Exhibit 13 **Overview of administrative measures for the development and construction of distributed PV power generation**

Category	Residential distributed PV		I&C distributed PV	
	Residential (Individual)	Residential (non-individual)	General I&C	Large-scale I&C
Construction site	Residential houses or courtyards	Public institutions, industrial/commercial buildings, and affiliated sites	Buildings and affiliated sites	
Investment and filing entity	Individuals owning the site	Investors		
Project scale (at grid connection point)	≤380 V	≤10 kV (20 kV), ≤6 MW		35 kV, ≤20 MW Or 110 kV (66 kV), ≤50 MW
Grid connection mode	All feed-in All on-site consumption On-site consumption first, with surplus feed-in		All on-site consumption On-site consumption first, with surplus feed-in (local governments set the minimal self-consumption ratio)	All on-site consumption
Type of power market to participate for on-grid energy	M2L market, green power market, spot market			Spot market

Source: NEA, RMI

Provinces have set varying on-site consumption ratio restrictions for general I&C distributed PV, based on local grid capacity and development needs. Several provinces have already issued draft or finalized provincial-level *Administrative Measures*, which diverge into two regulatory approaches for general I&C distributed PV but may undergo dynamic adjustments going forward:

- In coastal, load-intensive provinces like Jiangsu and Guangdong, no limitations are currently proposed for the on-site consumption ratio of general I&C distributed PV.

- In provinces with abundant renewable resources but grid constraints, on-site consumption requirements are being implemented. For example, Ningxia's proposed policy mandates 30%–50% on-site consumption by sites.

The *Administrative Measures* are expected to recalibrate market behavior toward more sustainable development patterns for distributed PV. By prioritizing on-site consumption, particularly through stringent on-site consumption requirements, the policy will encourage more cautious investments that better match with end-users' load profiles. Moreover, the mandated quarterly publication of distribution grid capacity assessments for renewable interconnection enables investors to properly evaluate project viability and make informed investment decisions.

Accelerated market integration of distributed PV increases uncertainty around returns

In accordance with Document #136, all on-grid energy from renewables are required to fully participate in the energy market. This marks the end of FITs for distributed PV and the beginning of a transition to market mechanisms.

Distributed PV has already begun participating in green power markets (see Section 9) in regions like Guangdong, Jiangsu, and Zhejiang, with planned expansion into M2L transactions and spot market trading. Their participation in spot markets will depend on development in the provincial power market. In the short term, distributed PV will act as price takers in the market. However, aggregated trading models like VPPs are poised to lead development in the long run, offering better bargaining power and operational convenience.

As distributed PV enters spot markets, uncertainty around returns will increase. Historically, some of their on-grid energy was settled at local coal power benchmark prices, ensuring stable and predictable returns. However, spot market prices — subject to significant fluctuations from supply-demand dynamics — introduce significant volatility, making it difficult to guarantee stable revenue streams. To maximize market returns, distributed PV will need to enhance forecasting and optimize the management of both energy production and consumption.

Stand-alone Storage

6 Stand-alone energy storage: core revenue from energy market arbitrage, with frequency regulation and capacity earnings sensitive to market and policy shifts

In 2024, China's novel energy storage capacity (mainly battery energy storage systems) reached 73.76 GW, representing a year-on-year growth of over 130%. In China, energy storage is typically divided by application into three categories: variable renewable energy (VRE)-paired storage,[x] stand-alone storage,[xi] and demand-side storage.[xii] Stand-alone storage led growth, comprising 56% of total installed capacity by year end. This surge was largely driven by supportive national and provincial policies.

On February 9, 2025, the NDRC and the NEA issued Document #136,[xiii] which explicitly states that "the allocation of energy storage shall not be set as a prerequisite for the approval, grid connection, or market entry of new renewable projects." As a result, VRE-paired storage installations are expected to decline sharply in the short term, with new capacity shifting primarily toward stand-alone storage.

Diversified revenue for stand-alone storage is driven by ancillary services and capacity mechanisms, while energy market arbitrage still leads

As market rules for ancillary services evolve across regions, the business model for stand-alone energy storage is taking shape. In some provinces, a combined revenue model of "energy market + ancillary services + capacity mechanism" has been established, enabling more diversified, market-driven income streams. As shown in Exhibit 14, spot market revenues still account for the largest share, but ancillary services and capacity payments now play a critical role in the overall revenue mix.

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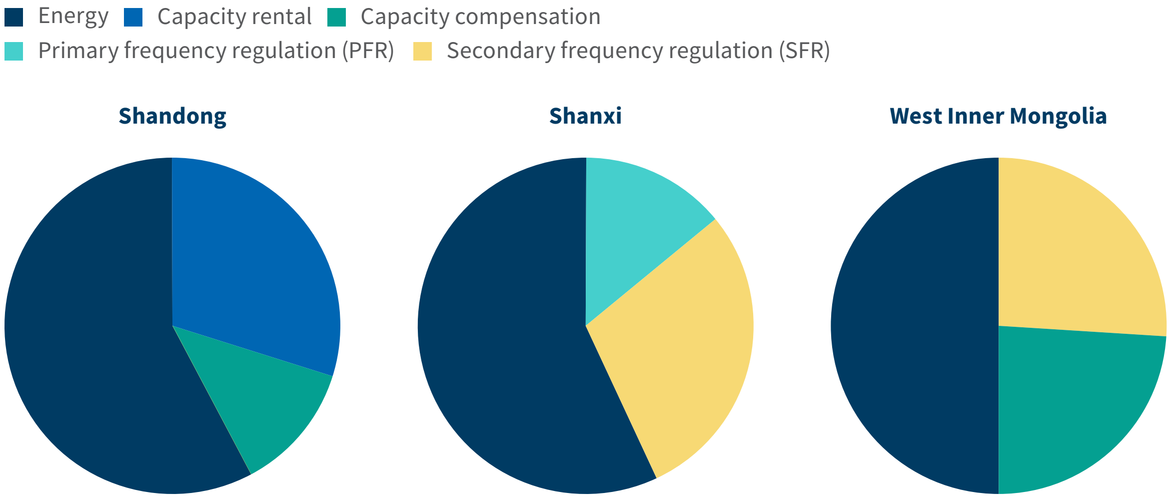
x Energy storage systems built alongside new energy projects to reduce the curtailment of wind and solar power or to meet policy requirements.

xi Energy storage systems installed on the grid side, mainly used to balance grid loads and provide ancillary services such as peak shaving and frequency regulation. These systems operate as independent market entities and can participate in power market transactions.

xii Installed by electricity users, such as industrial, commercial, and residential users, mainly to shift peak loads, maximize the self-consumption of solar power, and reduce electricity costs.

xiii For a discussion on the impact of Document #136 on VRE-paired storage and demand-side storage, see Section 4.

Exhibit 14 **Power market revenue breakdown in select provinces, 2024**

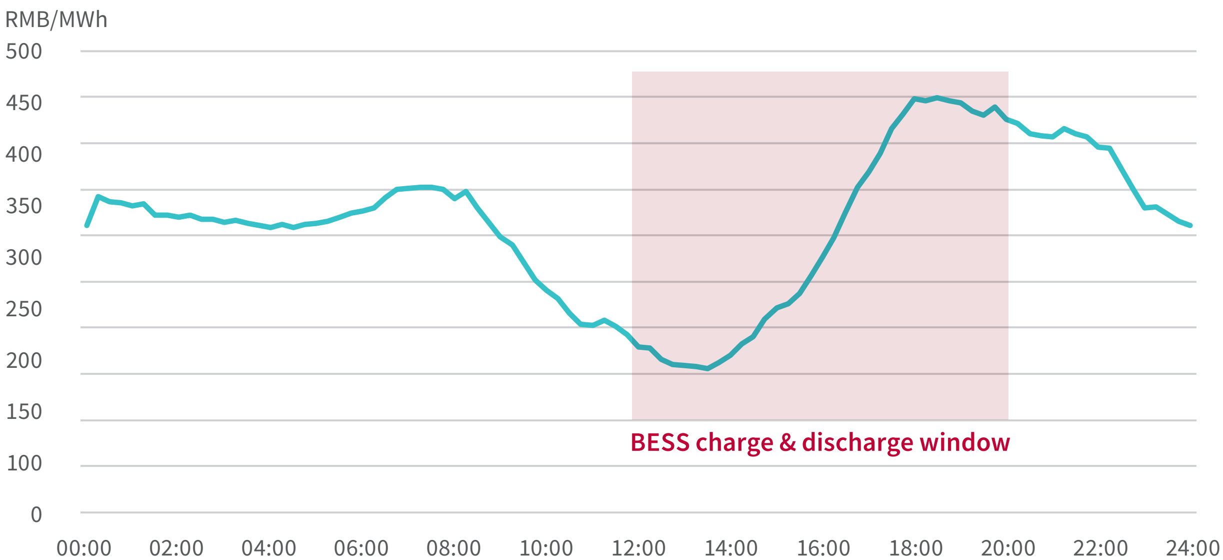


Note: Revenue is derived from a calculation that assumes continuous operation across various markets.

RMI Graphic. Source: RMI

The mainstream trading strategy for stand-alone storage in the spot market is one-cycle operation per day: charging during the price dip created by midday solar power generation and discharging during the evening peak (Exhibit 15). Opportunities for two-cycle operation exist when wind output at night is high enough, but the occurrence is limited over the course of a year. Therefore, when assessing stand-alone energy storage's potential spot market earnings, we recommend focusing on the one-cycle strategy, with limited consideration for the two-cycle operation.

Exhibit 15 **Fifteen-minute interval day-ahead spot price annual average in Shanxi, 2024**



Note: BESS stands for battery energy storage system, the main type of stand-alone storage.

RMI Graphic. Source: Shanxi Power Exchange Center, RMI

Stand-alone energy storage revenue is sensitive to evolving ancillary service and capacity mechanism rules

China's provincial power markets are evolving rapidly, with frequent updates to pricing policies and trading rules aimed at better reflecting the value of stand-alone energy storage. However, revenue from ancillary services and capacity mechanisms remains highly sensitive to policy and market shifts. As such, any earnings forecast must carefully account for potential regulatory changes and market volatility.

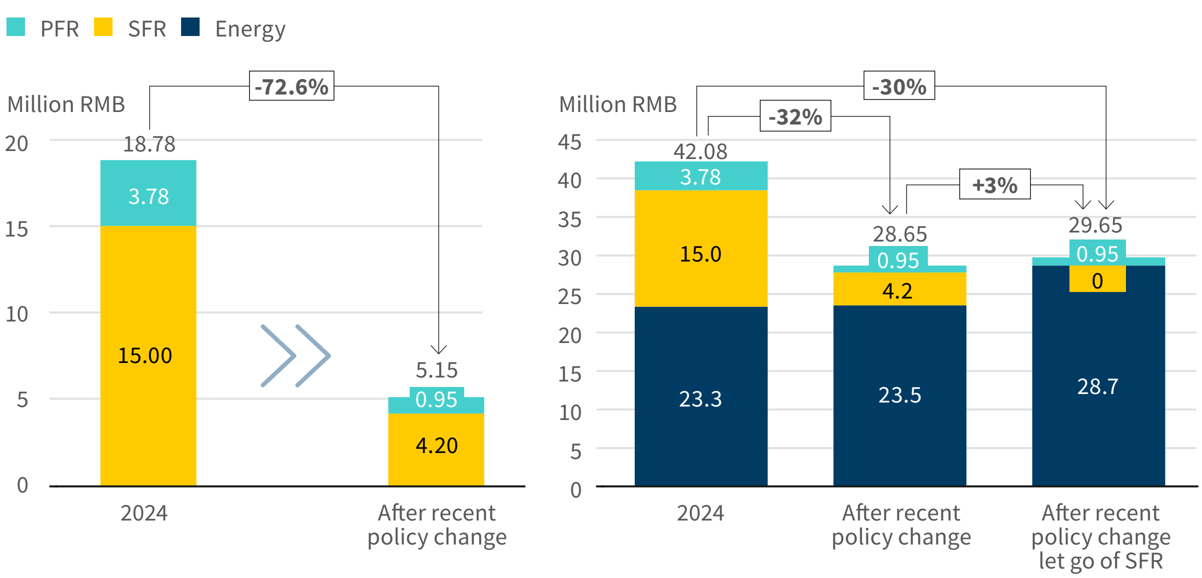
Adjustment of frequency regulation market settlement rules may significantly impact short-term revenue

Frequency regulation is the major product currently being traded in the ancillary services market in China. In the frequency regulation market, earnings are determined by the product of three factors: the cleared regulation mileage, settlement performance index,[xiv] and declared prices. Changes in trading rules and pricing can significantly affect the earnings level.

Shanxi has been at the forefront of integrating stand-alone energy storage into the ancillary services market. Recently, the province adjusted its power market trading rules, directly impacting the frequency regulation earnings for stand-alone energy storage. Under the new policy, the theoretical maximum for primary and secondary frequency regulation performance index has been adjusted from eight to two, which will drastically reduce revenue under otherwise unchanged conditions.

We calculated the revenue for a 100 MW/200 MWh stand-alone energy storage project in Shanxi, comparing the earnings before and after the policy change (see Exhibit 16).

Exhibit 16 **Stand-alone storage revenue change in Shanxi before and after recent policy change**



Note: the frequency regulation mileage and storage performance index are based on the average levels; the revenue is a calculation derived from the assumption of continuous operation across various markets.

RMI Graphic. Source: RMI

xiv The settlement performance index for frequency regulation is determined by the product of the response time, the regulating rate, and the response accuracy.

The revenue from frequency regulation services has plummeted by 72.6%. Even with the new regulations allowing stand-alone energy storage to participate in both the spot and ancillary services markets, the increase in spot market revenue is offset by the reduction in ancillary service earnings, resulting in a 32% decrease in overall revenue. In contrast, if the energy storage project chooses not to participate in secondary frequency regulation and instead allocates all capacity to the spot market, revenues may increase by about 3%. However, this still represents a 30% reduction compared to pre-policy adjustment earnings.

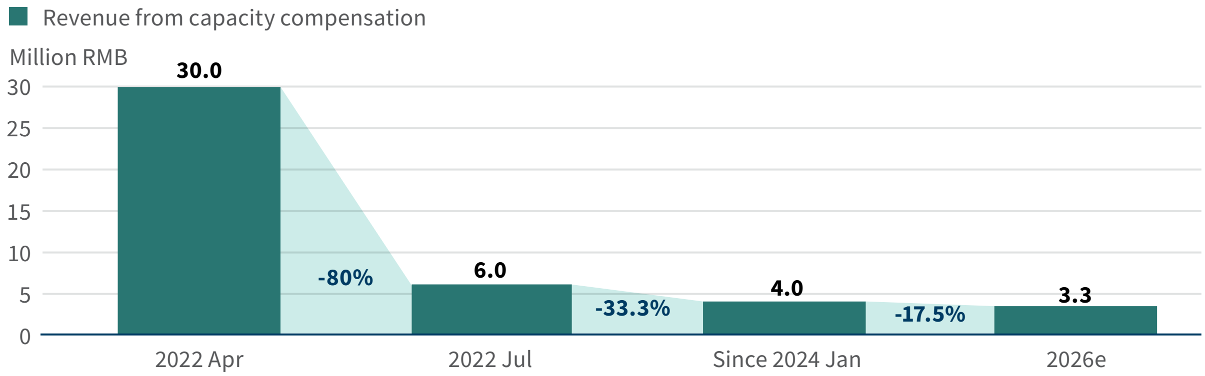
The demand for frequency regulation services depends on the penetration rate of renewables. Given that energy storage projects have shorter construction cycles than renewable projects, the supply of frequency regulation services may soon exceed demand. Therefore, a more competitive frequency regulation market and the entry of future higher-performing storage systems introduce uncertainties, potentially leading to a decline in or even the complete loss of frequency regulation revenue. Taking these factors into account, our calculations suggest that the revenue from frequency regulation services for stand-alone energy storage in Shanxi will account for approximately 10%–15% of overall revenue in the future.

Capacity compensation is linked to market, with levels determined by market conditions

In recent years, only a few provinces have announced a capacity compensation mechanism, with representative provinces including Xinjiang, Inner Mongolia, Shandong, Hebei, and Guangdong. Of these, Shandong's capacity compensation mechanism is most closely integrated with the spot market, offering a higher degree of marketization compared to the fixed compensation policies in other provinces. The compensation level in Shandong considers the supply-demand balance in the market: the total capacity compensation is determined by $\sum \mathbf{Demand}_t \times \mathbf{Capacity\ Compensation} \times \mathbf{TOU\ Coefficient}_t$, where "t" denotes to the time of usage. The total compensation is then allocated among all supply side market entities, with each entity receiving compensation proportional to its effective capacity.

Since its introduction in 2022, the capacity compensation available to stand-alone energy storage in Shandong has undergone several significant changes. Exhibit 17 illustrates the potential capacity compensation for a 100 MW/200 MWh stand-alone energy storage project in Shandong at different points in time.

Exhibit 17 Shandong storage capacity compensation revenue trend (100 MW/200 MWh BESS)



Revenue from capacity compensation	0.0991 RMB/MWh	0.0991 RMB/MWh	0.0705 RMB/MWh	Expect to drop
Capacity credit definition	Nameplate capacity	Nameplate capacity ×K/24×2	Nameplate capacity ×K/24×2	Expect to stay the same

Note: K denotes to the maximum continuous discharge hours at nameplate capacity of the storage.

RMI Graphic. Source: RMI

It is evident that changes in the capacity accounting and compensation standards significantly impact the revenue from capacity compensation for stand-alone energy storage. Considering the potential for a slight increase in coal power plant capacity prices starting in 2026 (see Section 3), the current market-based capacity compensation rate of 0.0705 RMB/kWh may continue to decline in the short term (one to three years). As a result, the revenue from capacity compensation is expected to decrease further and is unlikely to become a major revenue source for energy storage in the future. However, considering the exit of capacity leasing, the share of capacity compensation in overall revenue may remain at around 15%.

Post-document #136: Capacity leasing will fade from the market

In addition to capacity compensation, capacity leasing is also part of the capacity mechanism. Since 2022, provinces such as Ningxia, Gansu, Jiangsu, Henan, Shandong, Hebei, and Xinjiang have issued guidelines for implementing capacity leasing. This mechanism emerged as a more flexible approach to meet the energy storage allocation requirements tied to renewable projects. However, following the release of Document #136, new renewable projects are no longer required to allocate energy storage for grid connection. For stand-alone energy storage, this means that the capacity leasing will no longer be viable in the market.

Based on our analysis of various revenue sources, the spot market remains the core revenue stream for stand-alone energy storage. The ancillary services market is unlikely to generate additional profits for stand-alone energy storage. Capacity compensation will become more closely linked with the energy market, while the capacity leasing model will fade from the market.

Virtual Power Plants

7 VPPs are still in the demonstration stage and entering power spot markets may be a breakthrough for commercialization

In November 2024, the NEA issued the *Guiding Opinions on Supporting the Innovative Development of New Business Entities in the Power Sector*, designating VPPs as resource aggregators eligible to participate in power system optimization and market trading. In March 2025, the NDRC and NEA released the *Guiding Opinions on Accelerating the Development of VPPs*, specifically allowing VPPs to participate in the M2L, spot, and ancillary service markets as independent entities.

The policy established the development goals of VPPs at the national level for the first time, proposing that “by 2027, VPP construction, operation, and management should be standardized, with robust market participation mechanisms and over 20 GW of flexible capacity,” which corresponds to approximately 1% of the national peak load; “By 2030, VPP applications are expected to broaden, with innovative business models and flexible capacity exceeding 50 GW,” roughly 2% of the national peak load, according to the policy.

Most operational VPP platforms are based on provincial power grids, but the revenue models remain unclear

At present, most operational VPP platforms in China are led by the provincial power grid operators or local governments with participation from market-oriented resource aggregators. Exhibit 18 highlights four such platforms, each shaped by local grid characteristics. Shenzhen and Shanghai are typical megacity power grids reliant on imported electricity. They focus their VPP platforms on demand-side load management. The goal is to ease supply-demand imbalances, relieve distribution grid congestion during peak periods, and reduce land use for grid expansion. On the other hand, North Hebei and Shanxi are major power exporters with high renewable penetration. Their VPP platforms aim to better leverage demand-side flexibility to integrate more intermittent renewable generation.

Exhibit 18 **Typical VPP platforms currently in operation in China**

Case	Aggregate scale	Aggregate resources	Revenue	Current situation / typical cases
Shenzhen VPP	As of April 2025, 61 VPPs operators were participating with 60,000+ flexible resources aggregated, and a maximum flexible capacity of ~1 GW was achieved.	Charging and swapping stations, building air conditioning, energy storage, 5G base station energy storage, thermal ice storage, etc.	**Provincial grid demand response mechanism:** Guangdong Market-Based Demand Response Mechanism	In 2023 and 2024, the supply-demand balance was relatively loose, and no demand response trading was carried out
			Precise demand response at the city level: Shenzhen Precise Demand Respond subsidies, allocated from government funds	Three-year subsidy plan from 2023 to 2025, with a subsidy of 4.5 million RMB, 15 million RMB, and 15 million RMB per year, respectively, and a price cap for demand response bidding of 3.5 RMB/kWh; From 2023 to April 2025, the precise demand response was carried out more than 100 times, generating earnings of about 18.2 million RMB to the VPP operators and reducing carbon emissions by about 4,681 tons.
			Power market: China Southern Power Grid Regional Ancillary Services	Test verification stage
Shanghai VPP	As of February 2025, 31 VPPs operators were participating and a declared maximum flexible capacity of 1.15 GW was achieved	Charging and swapping stations, building air conditioners, distributed trigeneration, large industrial users, 5G base station energy storage, data centers, etc.	**Provincial grid demand response mechanism:** Shanghai Market-Based Demand Response compensations, allocated from user-side sharp peak price funds	The bidding price cap is 3 RMB/kWh for peak shaving and 1.2 RMB/kWh for valley filling. The subsidy coefficient needs to be determined according to the actual demand response rate. In 2024, the demand response was carried out 49 times, with a maximum demand response level of 704.3 MW, an increase of 117% year-on-year.
			Precise demand response at the city level: The Lin-gang Special Area will organize its own demand response energy and capacity subsidies, precise demand response energy and capacity incentives, allocated from the special funds of the local management committee.	Trial operation in 2024 , not yet officially operational
			Power market: Mutual-Aid Trading of Surplus Demand-Side Flexible Resources in the Yangtze River Delta Regional Power Market	In two instances on July 22 and 23, 2024, a total of 47 demand-side market players participated, with a maximum transaction volume of 360 MW, supporting the peak load of 130 MW, 100 MW, 100 MW, and 30 MW to Shanghai, Jiangsu, Zhejiang, Anhui, respectively

Case	Aggregate scale	Aggregate resources	Revenue	Current situation / typical cases
North Hebei VPP	As of February 2025, the thermal storage electric boiler VPP aggregated 16 users with a maximum flexible capacity of 330 MW, and the electric heavy truck VPP achieved a flexible capacity of 105.6 MW.	Electric heavy trucks, electric boilers with thermal storage, large industrial users, etc.	**Power market:** North China Peak Regulation Ancillary Service Market	From 2019 to 2022, the peak regulation revenue was 0.183 RMB/kWh, and the cumulative increase in the renewables consumption was 34.12 GWh. The total revenue for VPPs operators and aggregated users was 6.24 million RMB, of which the VPPs operators' revenue was 3.96 million RMB. No public information for 2023–2024.
Shanxi VPP	As of January 2025, four batches of 24 VPP operator pilot enterprises have been approved. The aggregated capacity reached 2.01 GW, and the maximum flexible capacity reached 256.3 MW.	Large industrial users, charging and swapping stations, buildings, electric heating, electric boilers with thermal storage, etc.	**Power market:** Shanxi Power Spot Market	From September 2023 to January 2025, the five VPPs that have been put into operation had 384 million kWh of electricity settled in the market, generating a total profit of 2.59 million RMB.
			Power market: Shanxi Peak-Shaving and Valley-Filling Market (Draft for comments)	Not operating yet. The bidding price range is 10–100 RMB/MWh for valley filling and is 10–200 RMB/MWh for peak shaving

RMI Graphic. Source: Shenzhen Development and Reform Commission, Shenzhen Special Zone News, Shanghai Development and Reform Commission, Shanghai Economic and Information Commission, Grid News, Liangbao, Jibei Electric Power Research Institute, Shanxi Provincial Energy Administration, State Grid Shanxi Electric Power, RMI

In summary, VPP operators in Shenzhen and Shanghai mainly rely on demand response mechanisms, but their revenue streams remain narrow and uncertain. In Shenzhen and the Lin-gang Special Area of Shanghai, demand response subsidies are funded by local government budgets, with amounts and durations determined annually. These subsidies typically last only 1–3 years, limiting the frequency, scale, and reliability of DR events and making it hard to build a sustainable business model. For instance, Guangdong Province conducted nine day-ahead demand response transactions in 2022, achieving a peak demand response of 2.77 GW and generating 160 million RMB in user income. However, no demand response trading occurred in 2023 or 2024.[11]

In the future, VPP operators must actively participate in power market trading, including spot and ancillary services markets to earn stable returns. The above-mentioned VPP platforms in North Hebei and Shanxi have provided valuable demonstrations. From 2019 to 2022, VPP operators in North Hebei earned 6.2 million RMB through the North China Peak Regulation Ancillary Service Market. However, this market may be phased out if the electricity spot market in the Beijing-Tianjin-Hebei region begins official operation. In Shanxi, VPP operators earned 2.6 million RMB in the spot market between September 2023 and January 2025, though only five pilot projects have officially joined the market so far. Therefore, the regular and large-scale participation of VPPs in the power market needs further development.

Load-type VPP can bid both volume and price in the power spot market to manage load and optimize electricity costs for aggregated users

Considering the current progress of various power markets, the regular and large-scale participation in the power spot markets may be the first step for VPP operators. Provinces like Shanxi, Shandong, Guangdong, Gansu, Anhui, and Hubei already allow load-type VPPs to bid both volume and price in the spot market, enabling VPPs to respond to price signals, reshape aggregated load curves, lower electricity costs, and share savings with users. In contrast, ancillary service markets — such as frequency regulation and capacity reserve — and capacity pricing mechanisms are not yet ready for VPPs to participate.

Following the release of the updated *Management Measures for the Development and Construction of Distributed Solar PV* (see Section 5) and Document #136 (see Section 4), there is a clear trend of surplus power from distributed renewables — in excess of self-consumption — to enter the power market. This shift opens up a new business model for VPPs. Operators can now serve as aggregators for distributed renewables, acting as agents in power market trading. In doing so, they transition into generation-type VPPs, expanding their role beyond demand-side management to include renewable generation aggregation and market trading.

Retail Market Buyers

8 Enhanced coordination between retail and wholesale market pricing mechanisms with fair and effective market competition

Since the NDRC proposed the orderly full market access for I&C users in 2021, most 10 kV and above I&C users have entered the power market, primarily through retail transactions. In 2024, the State Grid's service areas recorded 2.87 TWh of retail market transaction volume, marking a 7.2% year-on-year increase.[12] Meanwhile, in Southern Grid service areas, Guangdong Province alone reached 0.39 TWh in retail transactions, representing an impressive 26% annual growth.[13]

Optimized time-of-use retail pricing strengthens end-user cost-behavior linkages

Various regions in China are actively optimizing retail electricity package designs, with a focus on enhancing TOU price signals for end-users. Most provinces now require fixed-price packages for large I&C users to include mandatory peak/off-peak pricing coefficients. In provinces with official operational spot markets, retail packages tied to wholesale prices are encouraged to pass real-time price signals directly to end-users.

Fixed-price packages — typically incorporating TOU pricing — remain the dominant packages in China's retail power market. For instance, in Shandong, TOU-based packages constitute 62% of the 265 standardized retail packages for 2025 listed on the Shandong Power Exchange Center's website. Similarly, in Guangdong, fixed-price contracts with TOU pricing account for 88.4% of the total signed electricity volume.[14]

Provinces with advanced spot market development have taken the lead in promoting price-linked retail packages, significantly enhancing the alignment between retail and wholesale electricity prices. Shandong's 2025 market plan encourages flexible-demand users to adopt price-linked packages. Shanxi's 2025 framework goes further, eliminating fixed-price models under its "base price + premium/discount" structure and requiring all base prices to float with wholesale market rates. While both provinces integrate spot and M2L market linkages, their implementation strategies differ (see Exhibit 19).

Exhibit 19 **Price-linked approaches in Shandong and Shanxi**

Province	Price-linked benchmark options
Shandong	Option 1 User-side day-ahead settlement price or user-side real-time settlement price
	Option 2 Base price: Weighted average price of provincial annual and monthly centralized bidding, and annual and monthly bilateral contracts Peak/off-peak prices: Adjusted according to peak/off-peak coefficients
	Option 3 The combination of options 1 and 2 divided by electricity volume
Shanxi	Option 1 90% M2L market price (weighted average of annual, monthly, and decadal TOU centralized trading prices) + 10% spot market price (user-side day-ahead settlement price)
	Option 2 60% annual TOU M2L trading price + 40% monthly and decadal TOU centralized trading price

Source: Shandong Power Exchange Center, Shanxi Power Exchange Center, RMI

While price-linked retail packages currently represent a modest proportion of both contracted volumes and total electricity coverage, their adoption is expected to grow as more regions launch spot markets. The broader trend points toward embedding wholesale market signals into retail pricing to better convey supply-demand dynamics to end-users.

As retail packages increasingly incorporate TOU and strengthen their alignment with wholesale markets, end-users will face greater exposure to market price volatility. However, flexible load management can mitigate this risk. Under TOU pricing, users can lower electricity costs by shifting consumption away from peak periods. With price-linked packages, users can select pricing benchmarks (annual, monthly, or spot-based) that best match their demand response capabilities to optimize cost control across different timescales.

Regulation curbs generator-retailers' advantage to ensure fair and effective competition in the power market

China's electricity retail market has transitioned from its initial rapid-growth phase to a new stage focused on standardization and transparency. Local governments are continuously optimizing retail package designs while providing standardized contract templates to help users better understand terms. Moreover, provinces are accelerating the rollout of online retail platforms, where companies must disclose detailed pricing mechanisms — greatly enhancing transparency and enabling more informed consumer choices.

However, this evolving market landscape faces significant challenges, particularly from generator-retailers that dominate the supply side. These vertically integrated players enjoy substantial competitive advantages, including preferential access to generation resources and lower procurement costs, allowing them to offer more attractive pricing packages and gain large market share. In Guangdong, for instance, such companies made up only 8% of retail providers but accounted for 59% of total retail transaction volume in 2024. This imbalance highlights the need for targeted policy measures to preserve market competitiveness while curbing excessive concentration of power.

To address market concentration, electricity regulators at both national and local levels have introduced targeted measures to promote fair competition and efficient resource allocation. The NEA's *Notice on Further Standardizing Power Market Trading Practices* set clear mandates: prohibiting generator-retailers from exploiting their structural advantages, ensuring equal access for all retail companies and major consumers, and safeguarding a unified, open, and orderly market.[15] In response, regional 2025 trading plans have adopted differentiated strategies. Hubei and South Hebei implemented indirect controls by capping generator-retailers' market share, while Shaanxi applied direct limits on bilateral transaction volumes secured by generator-retailers. These localized interventions strengthen market transparency and foster healthier competition.

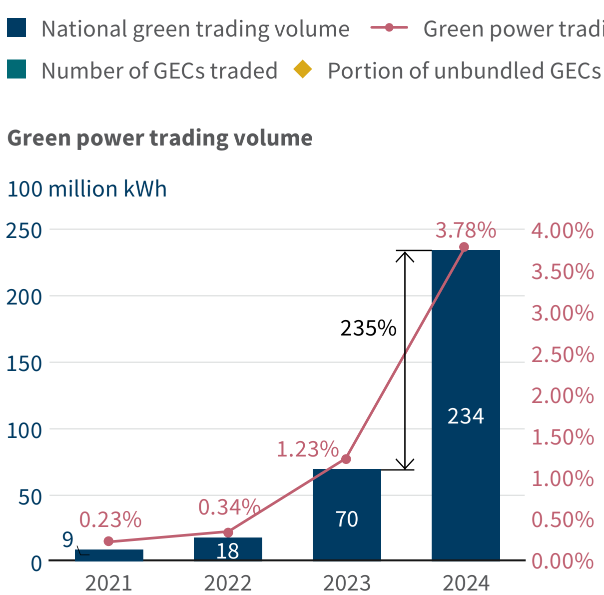
Future market share restrictions on generator-retailers across more provinces would boost the competitiveness of independent retailers, improve market transparency and competition, and offer end-users greater choice.

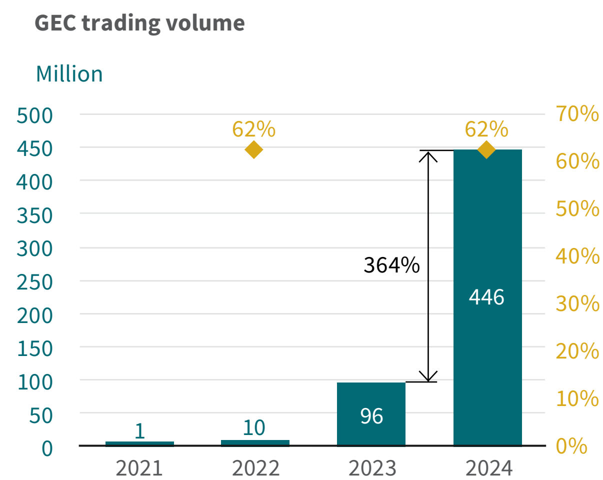
Green Power Users

9 The green power and GEC trading system is improving, with trading volume influenced by mechanism ratios, certificate ownership, and usage

In 2024, green power trading and GEC markets expanded rapidly as prices fell.[xv] Green power trading volume reached 233.6 TWh in 2024,[16] and its share of the power market continues to grow year over year (Exhibit 20). GEC trading volume in 2024 totaled 446 million,[17] and it shifted to predominantly unbundled GEC trading from volume dominated by green power bundled trades in 2022. In terms of pricing, 2024 data from the State Grid region shows that the average prices were 417.09 RMB/MWh for green power and 9.6 RMB per GEC.[18] In the China Southern Power Grid region, the average environmental value of green power traded in the first half of 2024 was 9 RMB/MWh.[xvi, 19] The average GEC price was 3.51 RMB.[20] Both green power and GEC prices declined compared to 2023.

Exhibit 20 **Green power trading and GEC trading volume, 2021–24**





RMI Graphic. Source: Beijing Power Exchange Center, China Electricity Council, NEA, China Renewable Energy Engineering Institute (CREEI), RMI

xv Each certificate corresponds to 1 MWh of green power.
xvi The price of green power is composed of two elements: the energy price and the environmental value, the latter representing the price associated with the environmental attributes of green power.

The green power and GEC trading system is largely in place, with ongoing rule refinement supporting users claiming their green power consumption

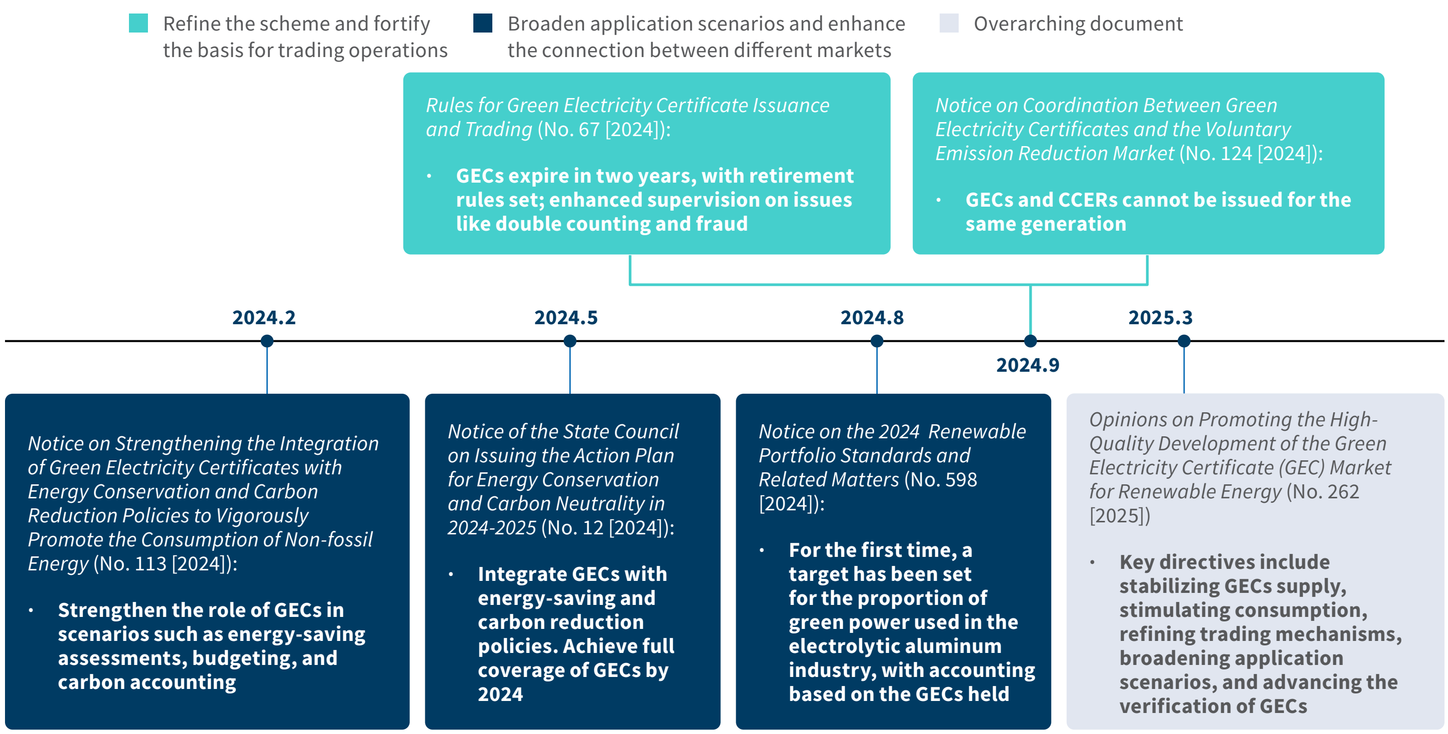
The national green power trading scheme has become more standardized and continues to improve. Guidance now covers multi-year power purchase agreements (PPAs), distributed projects, and direct user-generator transactions. Building on this framework, regional policies have introduced key innovations including:

- More trading modes: Rules now allow direct contracts between users and generators. In Shanghai, retail users can sign wholesale PPAs with developers, and with affiliated retailers handling execution.[21] This ensures stable supply, better traceability, and a simpler process.

- Expanded market coverage: More provinces permit distributed projects to join green power trading via aggregation. By the end of 2025, this is expected to become standard. These projects follow similar procedures as utility-scale projects, requiring only an agreement with the aggregator. For end users, the trading process remains largely unchanged.

The GEC scheme has been rapidly refined, firmly establishing GECs as the sole representation of green power's environmental attributes. As shown in Exhibit 21, 2024 policies eliminated the overlap of GECs with International Renewable Energy Certificates and China Certified Emissions Reductions (CCERs), reinforcing GECs' uniqueness and clarifying retirement and oversight rules. This has bolstered international recognition, with some multinationals shifting from international certificates to Chinese GECs. GECs are also now eligible for offsetting energy consumption in provincial and stakeholder energy-saving assessments, further boosting demand.

Exhibit 21 **Overview of 2024 GEC policy evolution**



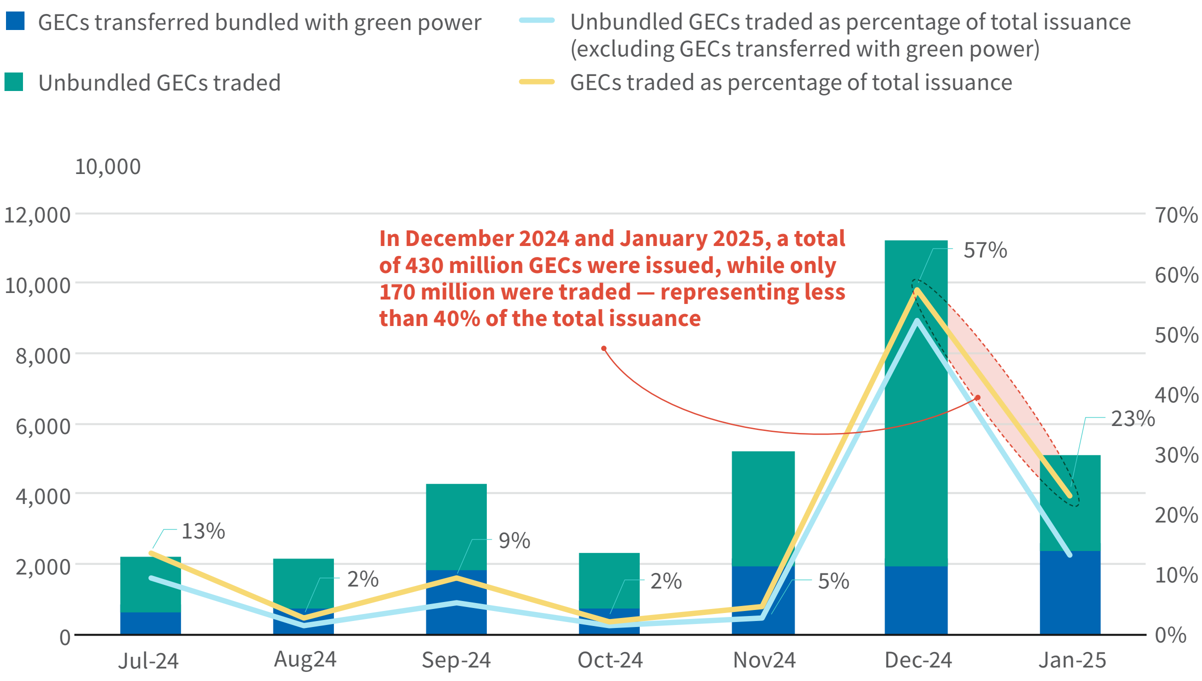
RMI Graphic.

New mechanism reshapes supply–demand dynamics of green power and GECs; environmental attributes are emerging as a stand-alone element in retail package

The mechanism may affect the future scale of the green power trading market, depending on the share of electricity covered and provincial implementation. In February 2025, Document #136 introduced the mechanism pricing (see Section 4), requiring the inclusion of environmental attributes in mechanism pricing and prohibiting their monetization through other markets. This means mechanism pricing reflects both the energy and environmental value of green power. Accordingly, electricity under the mechanism is excluded from green power trading. Generators must choose between participating in the mechanism or the green power market for the same output — a choice that directly impacts green power supply.

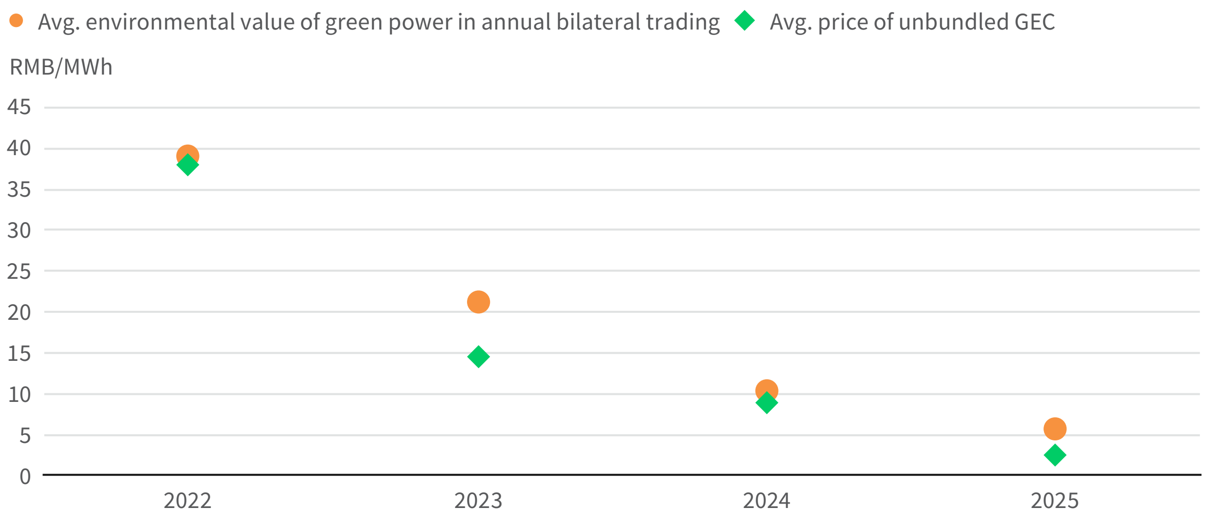
The price of unbundled GECs and the environmental value of green power are expected to remain low in the short term. A large influx of newly issued GECs, along with the bulk sale of GECs nearing expiration, has contributed to the oversupply. While supply has increased significantly, demand remains relatively weak. As shown in Exhibit 22, trading volumes typically rise between the end of one year and early the following year due to compliance reporting requirements. However, even during this peak period, supply continues to far exceed demand. This oversupply is expected to persist in the near term, keeping prices depressed. As the environmental value of green power is largely tied to the price of unbundled GECs, 2025 transaction outcomes also reflect declining environmental value. Exhibit 23 illustrates this downward trend using Guangdong as an example.

Exhibit 22 **Monthly GEC trading volume, 2024–2025**



RMI Graphic. Source: NEA, CREEI, RMI

Exhibit 23 **Comparison between the average price of unbundled GECs and the average environmental value of green power in Guangdong's annual bilateral trade, 2022–25**



Note: The average GEC trading prices for each year are defined as follows:

- 2022: National average trading price for GECs from unsubsidized projects
- 2023: Average trading price of China Southern Power Grid (CSG) region
- 2024: First-quarter average trading price within the CSG region
- 2025: Average listed transaction price from January 1 to March 31, 2025

RMI Graphic. Source: Guangzhou Power Exchange Center, NEA, CREEI, China Green Electricity Certificate Trading Platform, Inengyuan, RMI

In the medium to long term, tradable GEC prices will be shaped by the mechanism and renewable portfolio standards. Under Document #136, electricity volumes covered by the mechanism are not eligible for reselling GECs for additional revenue. This means that the more generation is covered by the mechanism, the fewer tradable GECs remain on the market, resulting in a tightened supply. Non-tradable GECs may be allocated within the provinces, though the method for doing so is still unclear (see Section 4).

At the same time, boosting GEC use is becoming a key focus. The market will shift toward a new structure — with supply mainly from power outside the mechanism, and demand driven by both voluntary purchases and growing mandatory targets. This evolving dynamic will influence GEC prices accordingly.

Green power retail packages are increasingly shifting toward separately specifying environmental value. In 2024, multiple provinces revised their retail transaction rules, requiring the electric energy part of green power to follow conventional thermal power in pricing and settlement, with environmental attributes to be specified separately. For example, Fujian, Zhejiang, Guangdong, and Guangxi now require the energy portion to follow the standard thermal power rules, with green power retail contracts highlighting only the environmental value. Separating the environmental value in transactions allows the market to better reflect the environmental attributes of green power. More provinces are expected to adopt this model, distinguishing green power through its environmental attributes while treating its energy component as functionally identical to thermal power.

EV Charging

10 Several provinces have adopted TOU pricing for residential EV charging, on a voluntary basis, following existing residential pricing structures

In early 2024, the *Opinions on Strengthening the Integration of New Energy Vehicles and the Power Grid* was issued and called for independent TOU pricing for flexible loads like residential EV charging, with full rollout targeted by end of 2025.[22] It mandates distinct rates from household use and guides provincial TOU policy design. Since 2023, multiple provinces have progressively rolled out TOU pricing schemes for residential EV charging, with variations in implementation across provinces.

TOU pricing for residential EV charging, mainly voluntary participation, is in place in 22 provinces, using residential rates as a benchmark

As of the end of 2024, 22 provincial-level regions in China had implemented TOU pricing for residential EV charging (Exhibit 24), mostly on a voluntary basis. Four provinces — Jiangsu, Hainan, Guangdong, and Gansu — have made TOU the default option.

Most provinces use a two-period (peak-valley) structure, while others adopt more detailed schemes. For example:

- 13 provinces use two periods (peak and valley)
- 5 provinces use three periods (peak, shoulder, valley)
- 4 provinces use four periods (sharp, peak, shoulder, valley)

EV charging TOU period definition typically follows residential TOU periods, though some provinces reference I&C TOU pricing or create custom periods for EV charging. TOU pricing levels are generally based on residential levels, with adjustments made within defined ranges.

According to the Hubei Electric Power Marketing Service Center, EV charging TOU implementation led to an 11.04% drop in residential charging peak load, with a 9.4 MW peak reduction. Participating users saw an 86.7% drop in their individual peak demand.

Exhibit 24 **Implementation status of TOU pricing for residential charging by province (as of end-2024)**

Province / municipality	TOU Implemented	Mandatory or not	Number of TOU periods	TOU period reference	Pricing benchmark
Beijing	No	-	-	-	Residential tariff (non-TOU)
Tianjin	No	-	-	-	Residential tariff (non-TOU)
Hebei	Yes	Voluntary	2	Residential TOU	Residential TOU tariff
Shanxi	Yes	Voluntary	2	Residential TOU	Residential TOU tariff
Inner Mongolia	No	-	-	-	Residential tariff (non-TOU)
Liaoning	No	-	-	-	Residential tariff (non-TOU)
Jilin	Yes	Voluntary	2	Residential TOU	Residential TOU tariff
Heilongjiang	Yes	Voluntary	4	Residential TOU	Residential TOU tariff
Shanghai	Yes	Voluntary	2	Residential TOU	Weighted average based on residential TOU pricing
Jiangsu	Yes	Default	2	Customized	Based on residential TOU tariff
Zhejiang	Yes	Voluntary	2	Residential TOU	Residential TOU tariff
Anhui	Yes	Voluntary	2	Residential TOU	Based on residential TOU tariff
Fujian	Yes	Voluntary	2	Residential TOU	Based on residential TOU tariff
Jiangxi	Yes	Voluntary	2	Residential TOU	Residential TOU tariff
Shandong	Yes	Voluntary	5 (Summer: 4)	Custom (partial Industrial & commercial reference)	Residential TOU tariff
Henan	Yes	Voluntary	2	Residential TOU	Residential TOU tariff
Hubei	Yes	Voluntary	4	Customized	Based on residential TOU tariff
Hunan	Yes	Voluntary	3	Customized	Based on residential TOU tariff
Guangdong	Yes	Default	3 (Summer: 4)	Industrial & commercial TOU	Industrial and commercial electricity tariff
Guangxi	No	-	-	-	Residential tariff (non-TOU)
Hainan	Yes	Default	3	Residential TOU	Residential TOU tariff
Chongqing	Yes	Voluntary	3	Residential TOU	Based on residential TOU tariff
Sichuan	Yes	Voluntary	3	Residential TOU	Based on residential TOU tariff
Guizhou	No	-	-	-	Residential tariff (non-TOU)
Yunnan	Yes	Voluntary	2	Customized	Based on residential TOU tariff
Tibet	Not applicable (shared meter)	-	-	-	Shared household meter (no separate EV meter)
Shaanxi	Yes	Voluntary	2	Customized	Based on residential TOU tariff
Gansu	Yes	Default	3	Customized	Based on residential TOU tariff
Qinghai	No	-	-	-	Residential tariff (non-TOU)
Ningxia	Yes	Voluntary	2	Residential TOU	Residential TOU tariff
Xinjiang	No	-	-	-	Residential electricity tariff

RMI Graphic. Source: Power supply service centers of provincial power companies, RMI

The implementation of TOU pricing for residential EV charging will be further expanded, featuring more granular time periods and more detailed pricing structures

Based on policy goals and current provincial practices, TOU pricing for residential private EV charging is expected to advance in several key ways including:

Broader provincial rollout: With the goal of full implementation by the end of 2025, provinces that haven't adopted TOU pricing are expected to do so soon.

Increased user participation: Currently user participation has been relatively low due to voluntary models and limited awareness. User enrollment is expected to rise as policy clarity, cost benefits, and public understanding improve.

More granular time periods: Drawing on the experience of provinces that have adopted multiperiod systems, more regions are expected to refine their TOU periods to better guide charging behavior and enhance load-shifting potential.

More flexible period adjustments: To alleviate grid pressure caused by EV charging, local governments are actively exploring dynamic adjustments. Building on insights from I&C TOU pricing adjustments, residential TOU policies are expected to become more responsive and regularly updated.

More distinct EV tariffs: Most current TOU schemes still reference general residential rates. Moving forward, more provinces are expected to implement separate EV-specific TOU periods and pricing, in line with the policy target of shifting over 80% of private EV charging to off-peak hours by the end of 2025.

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