2024 China Power Market Outlook: 10 Key Trends for Market Players

Report / June 2024

About RMI

RMI is an independent nonprofit founded in 1982 that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut climate pollution at least 50 percent by 2030. RMI has offices in Basalt and Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; Abuja, Nigeria; and Beijing, People's Republic of China.

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Executive Summary

Launched in 2015, the second round of power market reform in China has been underway for more than nine years. Since 2020, with the announcement of the dual carbon target and the New Power System,[i] the power market system has also been designed to support accelerated renewable power development, promote the low-carbon transformation, and support New Power System construction.

Over the past year, power market reform has made comprehensive progress, and the electricity pricing system has been further refined and improved. At the national level, multiple components in the electricity market and pricing system, including transmission and distribution (T&D) tariffs, the power spot market, power capacity price, and ancillary services markets, have all undergone important updates, favoring New Power System construction and renewable energy access. These updates profoundly influence the composition of industrial and commercial (I&C) electricity prices and set a refined price formation mechanism (see Exhibit 1):

- T&D tariff: The tariff for the 2023–25 period was released. Unlike the bundled T&D tariff in the past, the transmission loss and system operation fees are separated from the new T&D tariff effective in June 2023.
- Power spot market: The first national-level basic rule for the power spot market was released in late September 2023, which standardizes the market construction path, rule design, and market operation requirements across provinces. In December 2023, after five years of trial operation, the Guangdong and Shanxi power spot markets were the first to enter formal operation, opening a new chapter in the construction and operation of the power spot market.
- Power capacity price: In November 2023, the coal power capacity price mechanism was established. Starting in 2024, the revenue of coal-fired units transformed from energy price only to a two-part mechanism of energy price + capacity price.
- Ancillary services markets: The National Development and Reform Commission (NDRC) and the National Energy Administration (NEA) issued a notice on electricity ancillary services markets in February 2024, standardizing the service types, market design, and price ceiling setting for ancillary services markets across the country.

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

Exhibit 1 **Electricity price structure for I&C users in China in 2024**

Price component		Price formation method
Feed-in price (on-grid price)		*Based on market transactions between generators and consumers*
+		
Transmission and distribution loss (line loss) fee		*Loss rate verified by government*
+		
Transmission and distribution (T&D) tariff		*Regulated by government*
+		
System operation fee Pumped hydro storage capacity fee Coal power capacity fee Ancillary services fee		*Regulated by government or based on market, total expenses shared by consumers*
+		
Governmental funds and surcharges		*Set by government*
=		
Sales price		*Determined by all components above*

RMI Graphic. Source: RMI analysis

RMI has been tracking the process of electricity market reform in China. Last year, with the publication of the ***2023 China Power Outlook: 20 Key Trends for Power Market Players*** report, we commenced an annual report series for electricity market participants, aiming to provide phased insights that are both in-depth and comprehensive.[1] This year, based on the 2023 report, we systematically reviewed the important progress and trade dynamics over the past year, and looked forward to market development trends in the next one to three years. Similar to last year's report, this report also discusses key market trends by market components.

Additionally, this year we also add trends focusing on specific market participants and specific transaction types (see Exhibit 2). For background information on the power sector reform and electricity price system from 2015 to 2022, readers can refer to the corresponding content in the 2023 report. In the context of accelerating the construction of the New Power System and building a national unified electricity market system, we hope this report can help market participants better understand the current and future electricity price system in China, grasp market development trends, and enhance their ability to participate in electricity market transactions.

Exhibit 2 Ten key trends for power market players

By market component	Energy	1. Twenty-three provinces have initiated the (trial) operation of the power spot market, and the renewables output shapes the peak-valley pattern of spot prices.
		2. Time-of-use electricity pricing policy iterates frequently, with spot prices playing a guiding role.
		3. The power retail market has made improvements in expanding user coverage, diversifying retail companies, and communicating wholesale market signals to retail market.
	Transmission and distribution	4. T&D tariffs better reflect the costs of grid operations; transmission losses and system operation fees are now listed explicitly on electricity bills.
	Capacity pricing	5. The coal power capacity pricing mechanism is introduced, reconstructing the electricity price structure of both power generators and consumers, and supporting the transformation of coal power's role.
	Ancillary services	6. The ancillary services market pricing mechanism is improved and standardized; renewables and energy storage owners may need market strategy adjustments.
By market participants or transaction type	Renewables	7. The market-oriented transactions of renewables are scaling up, bringing challenges to project profitability in the long run due to price fluctuations.
	Distributed energy	8. As distributed photovoltaics grow rapidly in China, developers should closely monitor grid access and feed-in price policies.
	Independent energy storage	9. Independent energy storage expands market participation; the energy market is still their primary revenue source.
	Green power trading	10. The green power and green electricity certificate markets continue to expand, with a relatively relaxed supply–demand relationship in the short term.

RMI Graphic. Source: RMI analysis

Energy

1. Twenty-three provinces have initiated the (trial) operation of the power spot market, and the renewables output shapes the peak-valley pattern of spot prices.

In the third quarter of 2023, the NDRC and the NEA jointly issued the “Basic Rules for the Power Spot Market (Trial)” and the “Notice on Further Accelerating the Construction of the Power Spot Market” to further support the implementation and expansion of the power spot market in China.[2] This signifies that the spot market progress in China has moved from subnational pilot trials to a new stage of nationwide implementation. All provinces and regions in China would now establish or operate the power spot market following the national rules and guidelines.

Exhibit 3 summarizes the progress of provincial and regional spot markets as of January 2024. At the provincial level, the Shanxi and Guangdong spot markets had transitioned from trial to official operation by the end of 2023. Prior to the transition, both provinces’ spot markets had been in continuous trial operation for more than two years. Additionally, the Shandong, Gansu, and western Inner Mongolia spot markets had all been in continuous trial operation for more than one year. At the regional and national levels, the State Grid Interprovincial Spot Market began continuous trial operation from July 1, 2022; and on December 15, 2023, the China Southern Power Grid Regional Spot Market achieved the first full-region short-term trial operation with dispatch and settlement covering Guangdong, Guangxi, Yunnan, Guizhou, and Hainan provinces, making it the fastest progressing regional electricity market in China (compared with the Yangtze River Delta Electricity Market and Beijing-Tianjin-Hebei Electricity Market).

Looking forward to 2024, the Shandong spot market is expected to start official operation, and the spot markets in provinces and areas such as Jiangsu, Jiangxi, Southern Hebei, and Hubei are expected to start continuous trial operation. The China Southern Power Grid Regional Spot Market will carry out trial operations of various durations.

Exhibit 3

Progress overview of spot markets at subnational level across China as of January 2024

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

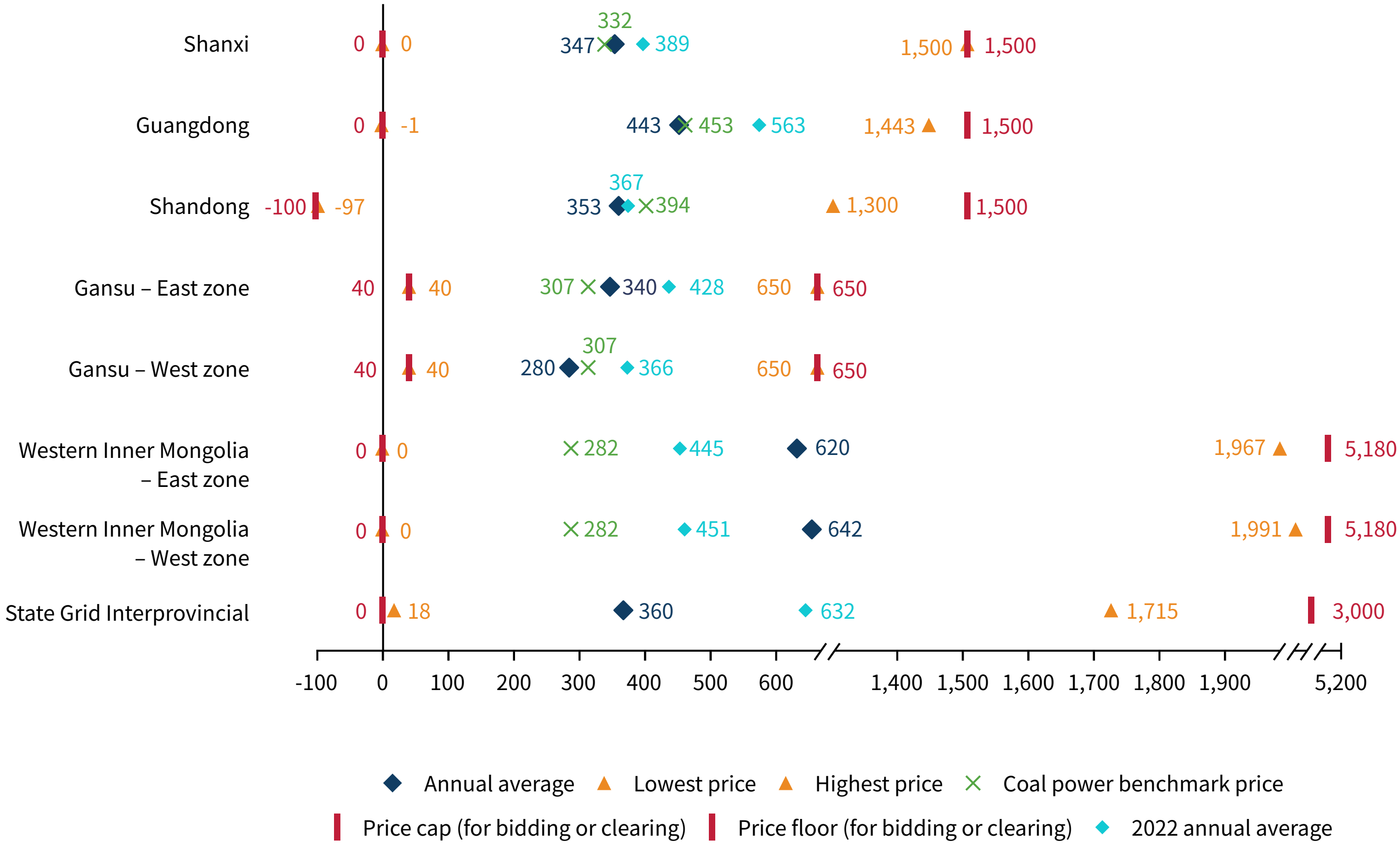
Note: The construction of the spot market generally goes through six stages: simulation trial without dispatch or settlement, trial operation with dispatch but without settlement, short-term trial operation with dispatch and settlement (generally lasts less than a week), long-term trial operation (generally lasts from two weeks to one month), continuous trial operation (generally lasts more than one year), and official operation. The blue names are provincial-level spot markets, and the red names are regional and national-level spot markets. Some subnational spot markets are not considered. Unlike other spot market designs, Sichuan has designed a hydropower spot market during the wet season and a thermal power spot market during the flat and dry season. Both spot markets have achieved long-term trial operation.

RMI Graphic. Source: Provincial and regional power exchange centers

Six subnational spot markets had continuous trial operation throughout the year, with the renewables output shaping the spot price curve. Throughout 2023, Shanxi, Guangdong, Shandong, Gansu, western Inner Mongolia, and the State Grid Interprovincial spot markets all had continuous settlement, with the average clearing prices falling in most provinces and regions compared with 2022. As Exhibit 4 reveals, with the reduction in thermal coal prices, the annual average spot prices in all markets except for western Inner Mongolia fell compared with 2022, with declines ranging from 3.7% to 23.7%. Western Inner Mongolia saw its average spot price more than double compared with 2022 because the medium- to long-term (M2L) market settled at lower prices and the generation side wanted to recover costs in the spot market. However, due to the risk prevention compensation mechanisms on the demand side, the final settlement price would still fall within a certain range of the average M2L transaction price.

As for the State Grid Interprovincial Spot Market, the bidding price cap was adjusted from RMB 10/kilowatt-hour (kWh) in 2022 to RMB 3/kWh in 2023. In addition, the daily average settlement price of the export node was capped at RMB 1.5/kWh to reduce the pressure of cost allocation on the import side in extreme situations.[3] Thanks to better rainfall conditions in summer and the year-over-year increase in hydropower generation, there was less stress on supply–demand balance across the country in 2023, resulting in the average spot price of the State Grid Interprovincial Spot Market dropping significantly by 43.1% compared with 2022.

Exhibit 4 **Overview of key spot price data at the annual level in 2023**



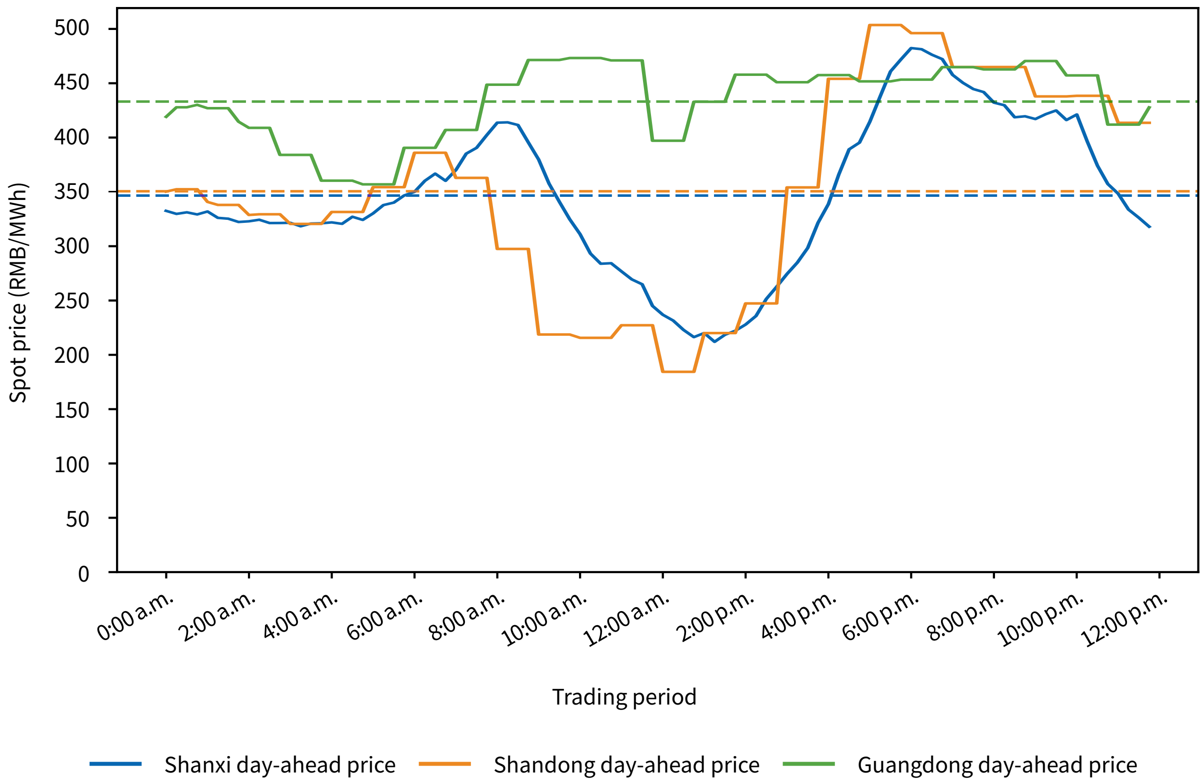
RMI Graphic. Source: Lambda

Specifically, at the intraday level, the peak-valley spot price pattern in each province was highly correlated with the renewables output. As shown in Exhibit 5, the spot price patterns in Shanxi and Shandong both showed a duck curve. The morning peak occurred before sunrise from 6 to 9 a.m., and the higher evening peak occurred before and after sunset from 5 to 7 p.m. In between, the spot prices were significantly lower than the annual average, with the lowest value occurring at the highest photovoltaic (PV) output from 12 to 2 p.m.

In contrast, the lowest price in Guangdong occurred from 4 to 6 a.m. when the load was lowest for the entire the day. Except for a price valley from 12 to 1 p.m., the daytime electricity price remained above the annual average. This phenomenon was related to the PV penetration: in 2023, the share of PV in total generation was only 3.1% in Guangdong, while it was 6.2% and 9.7% in Shanxi and Shandong, respectively. Comparing the three provinces, Shandong had the highest PV penetration rate, which also led to the largest valley depth. The average valley price coefficient (average lowest price/annual average price) was as low as 0.5, and the average peak-valley ratio (average highest price/average lowest price) was as high as 2.7. With the continued growing PV penetration, the spot price during daytime is expected to further fall.

Exhibit 5

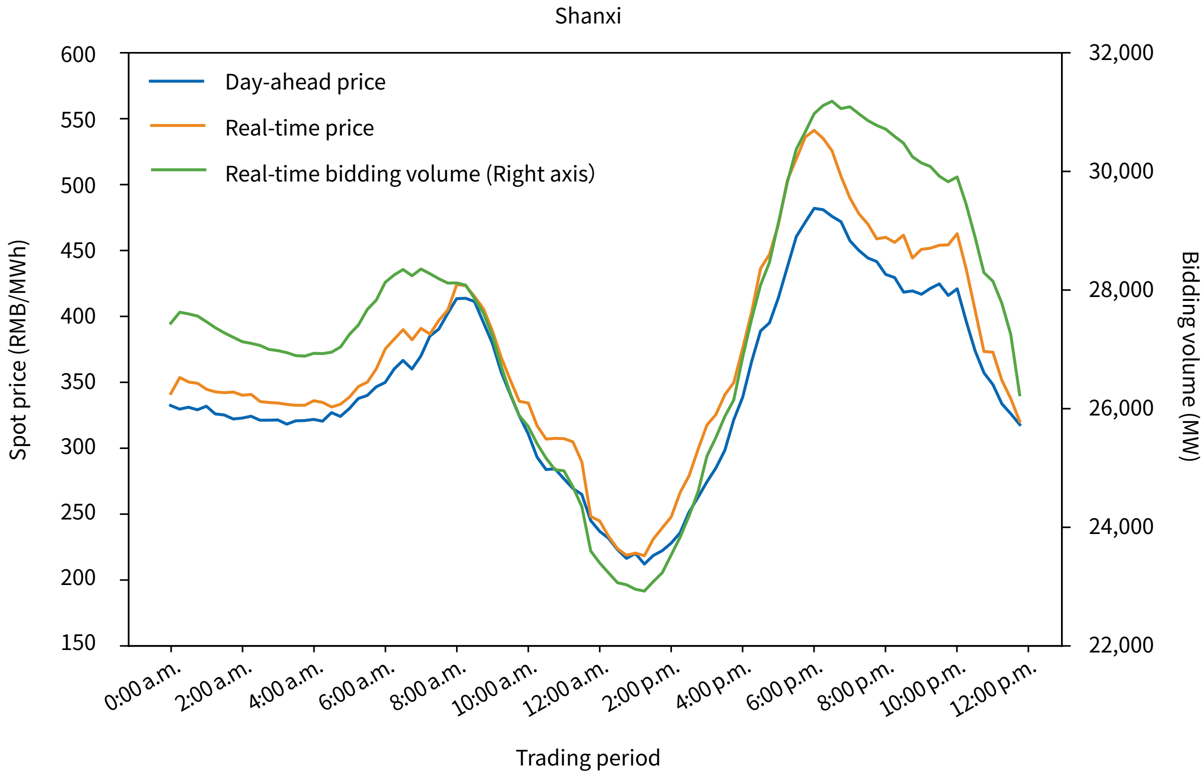
Average spot prices per 15 minutes in Shanxi, Shandong, and Guangdong's day-ahead markets in 2023 (dotted line is the annual average)

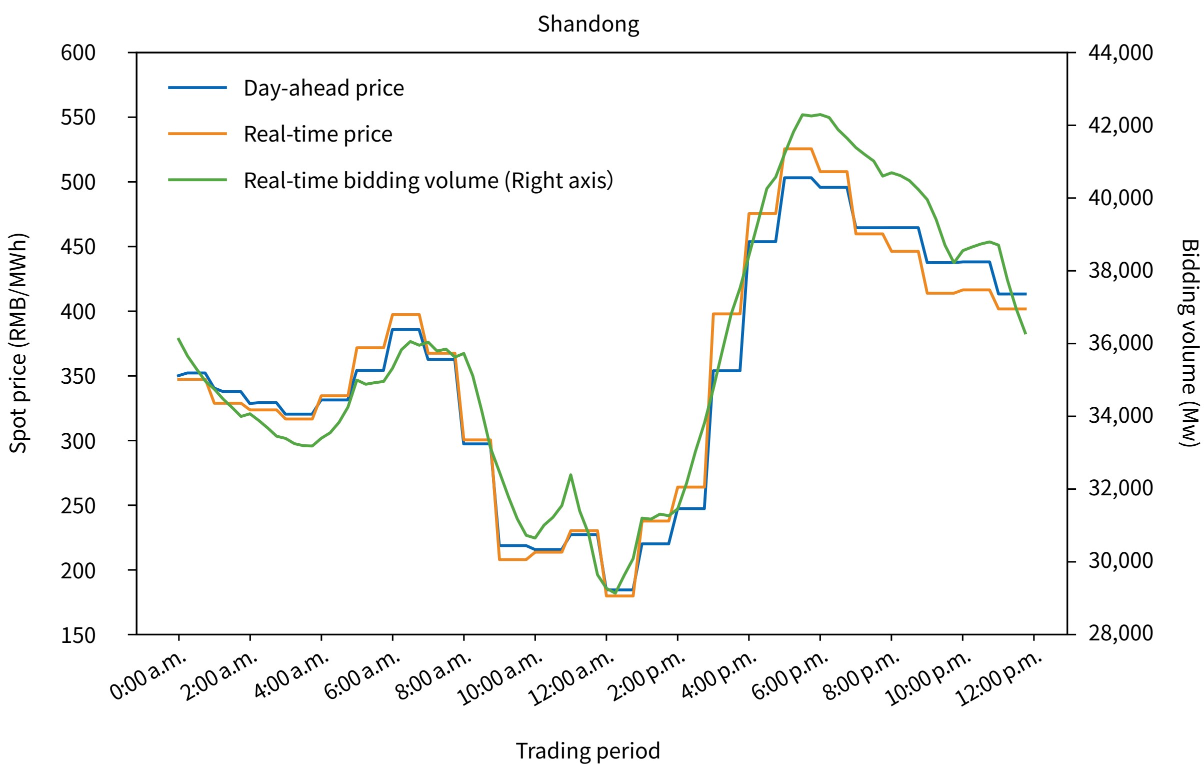


RMI Graphic. Source: Dianchacha

We also found that the spot price and bidding volume were strongly correlated (see Exhibit 6). Compared with the day-ahead price, the real-time price had a similar peak-valley pattern but at a higher range. The real-time price curve and the real-time bidding volume curve showed a close and positive correlation, which aligned with the spot market design. When the load is low or the output of prioritized dispatched units (e.g., interconnection) and zero marginal cost (e.g., renewables) units is high, the bidding volume for dispatchable units is lower. Because the demand side currently bids only volume without price, dispatchable units (mainly thermal power) with lower price bids will be cleared first, and the marginal clearing price of the spot market will decrease accordingly, and vice versa.

Exhibit 6 **Average spot prices and average real-time bidding volume per 15 minutes in Shanxi and Shandong's day-ahead and real-time markets in 2023**





Note: In this report, the bidding volume for supply-side participation is approximately defined as bidding volume = provincial grid load – interprovincial import – wind power output – solar PV output.
RMI Graphic. Source: Dianchacha

More renewables and more emerging entities will participate in the spot market, and bilateral volume and price bidding will be further piloted and promoted. Utility-scale renewables, independent energy storage, virtual power plants, nuclear power, and other entities have made progress in participating in the spot market. In western Inner Mongolia and Gansu, except for distributed PV and poverty alleviation PV projects, all other PV and onshore wind have all their generation participated in the M2L transaction and spot market. In contrast, renewables in Shandong and Shanxi entered the market on a voluntary basis, and the renewables that entered the market also participated in the spot market with all the generation. Shandong's renewables that did not enter the power market (with guaranteed purchase by the grid at fixed feed-in price) need to have 10% of the generation settle at the spot prices (the 2023 standard). In Guangdong, all PV and wind power with grid connection at the 220-plus kilovolt (kV) voltage level participate in the spot market (for details on renewables entering the market, see Trend 7).

Shandong was the first to include independent energy storage stations to bid only volume without price in the spot market, in February 2022. Other provinces followed Shandong to include independent energy storage stations in the spot market and ancillary services market (e.g., frequency regulation). In 2023, Shanxi and Guangdong successfully piloted independent energy storage to participate in the spot market in a bid volume and price manner (for details on independent energy storage entering the market, see Trend 9). In addition, virtual power plants and nuclear power also made breakthroughs in participating in the spot market in Shanxi and Shandong, respectively.[4]

Looking forward, more utility-scale renewables are expected to enter the power market in more provinces to participate in the spot market with all the generation. Independent energy storage, virtual power plants, load aggregators, and other emerging market entities will be further promoted to participate in the spot market with bidding both volume and price. In 2024, it is expected that provinces with more renewables such as Shandong will take the lead in piloting the participation of distributed renewables in spot markets to trade their surplus generation.

Spot markets at all administrative levels and various types of electricity markets are better aligned. In terms of aligning electricity markets at all administrative levels, the State Grid region and the China Southern Power Grid region have adopted different approaches. During the trial operation of the China Southern Power Grid Regional Spot Market, the five provinces in the region have a unified market clearing. Meanwhile, the provincial (e.g., Guangdong) spot market clearing results are used as a backup reference. The centralized auction and unified clearing approach helps achieve optimal resource allocation across the entire region. In contrast, the State Grid Interprovincial Spot Market and the provincial spot markets within the region are complementary. In this approach, the interprovincial spot market clearing results serve as the boundary conditions for clearing the provincial spot markets, which optimize the remaining interprovincial transmission capacity and the allocation of available energy across provinces.

In terms of aligning various types of electricity markets, the ability of price discovery in the spot market is increasingly recognized by market participants and the spot price serves as the price anchor for M2L transactions. Regulation clearly states that in areas where the spot market operates continuously, an M2L transaction needs to operate continuously from D − 7 days to D − 2 days (D is the execution day); ancillary services costs can be attributed to the demand side; and the price cap of the spot market in all regions should be in line with the demand response compensations. From the perspective of trading strategy, the buyers and sellers of annual M2L transactions will consider not only the price level of thermal coal, but also the price level of the recent spot market.

For example, in Guangdong Province, the price of thermal coal was high in 2022, and the average spot price reached RMB 562.9/megawatt-hour (MWh), which also led to the average price of the 2023 annual M2L transaction being RMB 553.9/MWh, basically reaching the upper limit of 20% of the coal power benchmark price (regulated by NDRC).[5] In comparison, the annual average spot price in 2023 in Guangdong was only RMB 443.1/MWh, significantly lower than the annual M2L transaction price. The average (real-time) spot price in November was RMB 469.5/MWh, and the corresponding average price of the 2024 annual M2L transaction launched in December fell to RMB 465.6/MWh, higher than the coal power benchmark price by less than 1%.[6] In the monthly and intra-month M2L transactions, the spot price levels of the previous month and the current month are expected to have a more prominent anchoring effect on M2L transaction prices.

Energy

2. Time-of-use electricity pricing policy iterates frequently, with spot prices playing a guiding role.

The time-of-use (TOU) electricity pricing better matches between power supply and demand and promotes the consumption of renewable energy.[7] **The TOU pricing policy sets the power grid companies' TOU electricity purchase prices,[ii] indirectly affecting the TOU prices of M2L transactions and further influencing the retail market TOU electricity prices**. Currently, 33 provincial power grids have implemented I&C TOU electricity pricing policies, and 16 of these grids had policy updates within the past year.

Key updates include:

- **Sharp peak period extended** (see Exhibit 8a). Shandong added 184 hours to its sharp peak periods, increased deep valley periods by 62 hours, reduced peak periods by 182 hours, and reduced valley periods by 180 hours. In Anhui, for I&C users with power demand above 315 kilovolt-amperes (kVA), an additional 248 hours were added to the sharp peak periods.
- **More precise segmentation, with 30-minute intervals** (see Exhibit 8b). In Liaoning, the peak period in morning is from 7:30 to 10:30 a.m., and the peak period in midday is from 11:30 a.m. to 12:00 p.m. Six regions, including Liaoning, have improved their time interval to 30 minutes.
- **Exploring deep valley policies on major holidays** (see Exhibit 8c). Zhejiang and Jiangsu have pioneered the implementation of midday deep valley pricing during major holidays such as the Spring Festival, Labor Day, and National Day. In Zhejiang, the deep valley period during holidays is from 10:00 a.m. to 2:00 p.m., encompassing the original sharp peak, peak, flat, and valley flat periods. Meanwhile, in Jiangsu, the deep valley period is from 11:00 a.m. to 3:00 p.m., covering the original flat periods.
- **Unified floating mechanism for TOU electricity pricing.** A national unified method for calculating peak and valley prices has been established. Prices now float based on time segment ratios, using the base price during flat periods as a reference (see Exhibit 8d). In January 2024, Zhejiang updated its TOU electricity pricing policy by specifying floating ratios for large industrial users, transitioning away from the method of using a fixed absolute value for floating ratio. Following these updates, the floating ratio method was implemented nationwide to determine peak and valley prices.
- **More flexible time segmentation for TOU pricing.** In Guangxi, during the peak periods of summer and winter, power grid companies can flexibly adjust the time segmentation based on power supply and demand for users' voltage levels above 35 kV, following filing and public disclosure.

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ii TOU electricity pricing policy divides the 24 hours of the day into five time periods: sharp peak, peak, flat, valley, and deep valley. Power grid companies purchase electricity on behalf of I&C users who do not directly participate in the power market through a power market transaction.

Exhibit 8 Time segmentation and floating ratios of TOU electricity pricing policy for I&C users in five provinces

(a)

Policy	Season/Month	User	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21	21-22	22-23	23-24
Shandong Provincial Development and Reform Commission Notice on Matters Related to Time-of-Use Electricity Pricing Policy for Industrial and Commercial Users (Effective from January 1, 2024)	Winter (December, January, February)	Industrial and commercial users	1	1	1	1	1	1	1	1	1	1	0.3	0.1	0.1	0.1	0.3	1	2	2	2	1.7	1.7	1	1	1
	Spring (March to May)	Industrial and commercial users	1	1	1	1	1	1	1	1	1	1	0.3	0.1	0.1	0.1	0.3	1	1	2	2	2	1.7	1.7	1	1
	Summer (June to August)	Industrial and commercial users	0.3	0.3	0.3	0.3	0.3	0.3	1	1	1	1	1	1	1	1	1	1	1.7	2	2	2	2	2	1	1
	Autumn (September to November)	Industrial and commercial users	1	1	1	1	1	1	1	1	1	1	0.3	0.1	0.1	0.1	0.3	1	1.7	2	2	1.7	1.7	1	1	1
Shandong Provincial Development and Reform Commission Notice on Further Optimizing the Time-of-Use Electricity Pricing Policy for Industrial and Commercial Users (Effective from January 2023 to December 2023)	Winter (December, January)	Industrial and commercial users	1	1	1	1	1	1	1	1	1	1	0.3	0.3	0.1	0.1	0.3	0.3	2	2	2	1.7	1.7	1.7	1	1
	Spring (February to May)	Industrial and commercial users	1	1	1	1	1	1	1	1	1	1	0.3	0.1	0.1	0.1	0.3	1	1	1.7	2	2	1.7	1.7	1	1
	Summer (June to August)	Industrial and commercial users	1	1	0.3	0.3	0.3	0.3	0.3	0.3	1	1	1	1	1	1	1	1	1	1.7	2	2	2	2	1	1
	Autumn (September to November)	Industrial and commercial users	1	1	1	1	1	1	1	1	1	1	0.3	0.1	0.1	0.1	0.3	1	1.7	2	2	1.7	1.7	1	1	1

Deep Valley | Valley | Flat | Peak | Sharp Peak

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<tr><th></th><th>Policy</th><th>Season/Month</th><th>User</th><th>0-1</th><th>1-2</th><th>2-3</th><th>3-4</th><th>4-5</th><th>5-6</th><th>6-7</th><th>7-8</th><th>8-9</th><th>9-10</th><th>10-11</th><th>11-12</th><th>12-13</th><th>13-14</th><th>14-15</th><th>15-16</th><th>16-17</th><th>17-18</th><th>18-19</th><th>19-20</th><th>20-21</th><th>21-22</th><th>22-23</th><th>23-24</th></tr>
<tr><td rowspan="9">(a)</td><td rowspan="7">Anhui Provincial Development and Reform Commission and Anhui Energy Administration Notice on Further Optimization of Peak-Valley Time-of-Use Electricity Pricing Policy and Related Matters (Effective from April 2024)</td><td>July, August, September</td><td>Industrial and commercial users of 100 kVA and above</td><td colspan="9">0.382</td><td colspan="7">1</td><td colspan="8">1.843</td></tr>
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Deep Valley | Valley | Flat | Peak | Sharp Peak

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	Policy	Season/Month	User	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21	21-22	22-23	23-24
(b)	Liaoning Provincial Development and Reform Commission Notice on Further Improving the Time-of-Use Electricity Pricing Mechanism (Effective from September 2023)	Other seasons	Industrial and commercial users of 100 kVA and above			0.5				1		1.5		1	0.5		1					1.5			1	0.5	
		Summer and Winter(December, January, July, August)								1		1.5		1	0.5		1			1.5	1.875		1.5		1	0.5	
(c)	Jiangsu Provincial Development and Reform Commission Notice on Further Improving the Time-of-Use Electricity Pricing Policy (Effective from July 2023).	All months	Single-part pricing mechanism, large industrial users below 315 kVA and general industrial users of 100 kVA and above					Single-part Pricing Mechanism, Large Industrial Users Below 315 kVA And General Industrial Users Of 100 kVA And Above					1.6719				1						1.6719			1	
		All months	Two-part pricing mechanism, large industrial users below 315 kVA and general industrial users of 100 kVA and above					Two-part Pricing Mechanism, Large Industrial Users Below 315 kVA And General Industrial Users Of 100 kVA And Above					1.7196				1						1.7196			1	
		Summer (July and August, when daily maximum temperatures reach or exceed 35°C)	Large industrial users of 315 kVA and above					Large Industrial Users Of 315 kVA And Above					1.7196			1		2.06352		1		1.7196		2.06352	1.7196	1	
		Winter (December and January,, when minimum temperatures reach or fall below -3°C)	Large Industrial Users Of 315 kVA And Above					Large Industrial Users Of 315 kVA And Above				1.7196	2.06352				1				1.7196	2.06352		1.7196		1	
		Major holidays (during Chinese New Year, International Labor Day on May 1st, and National Day	Large industrial users of 315 kVA and above													0.65608											

Deep Valley	Valley	Flat	Peak	Sharp Peak

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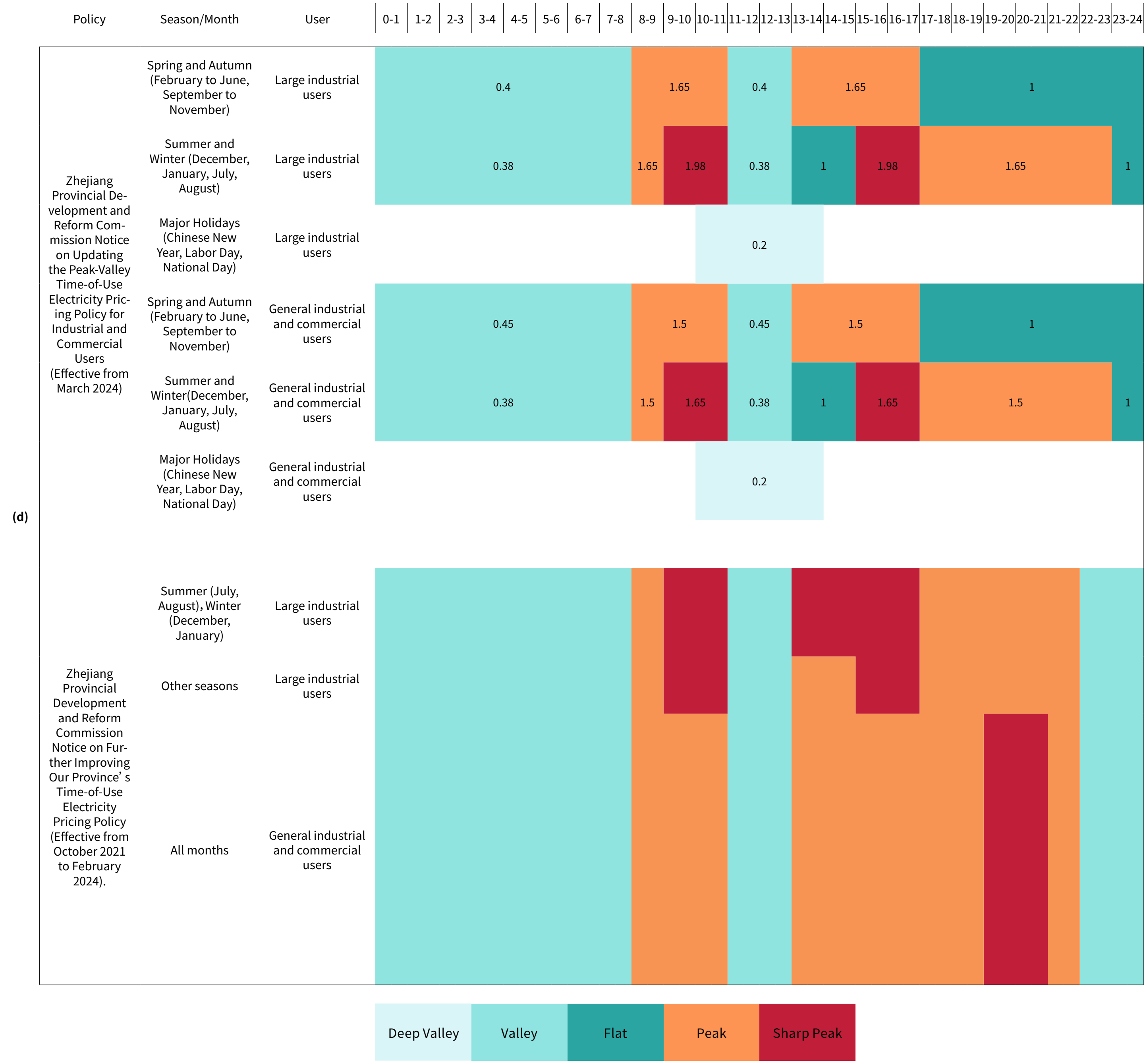


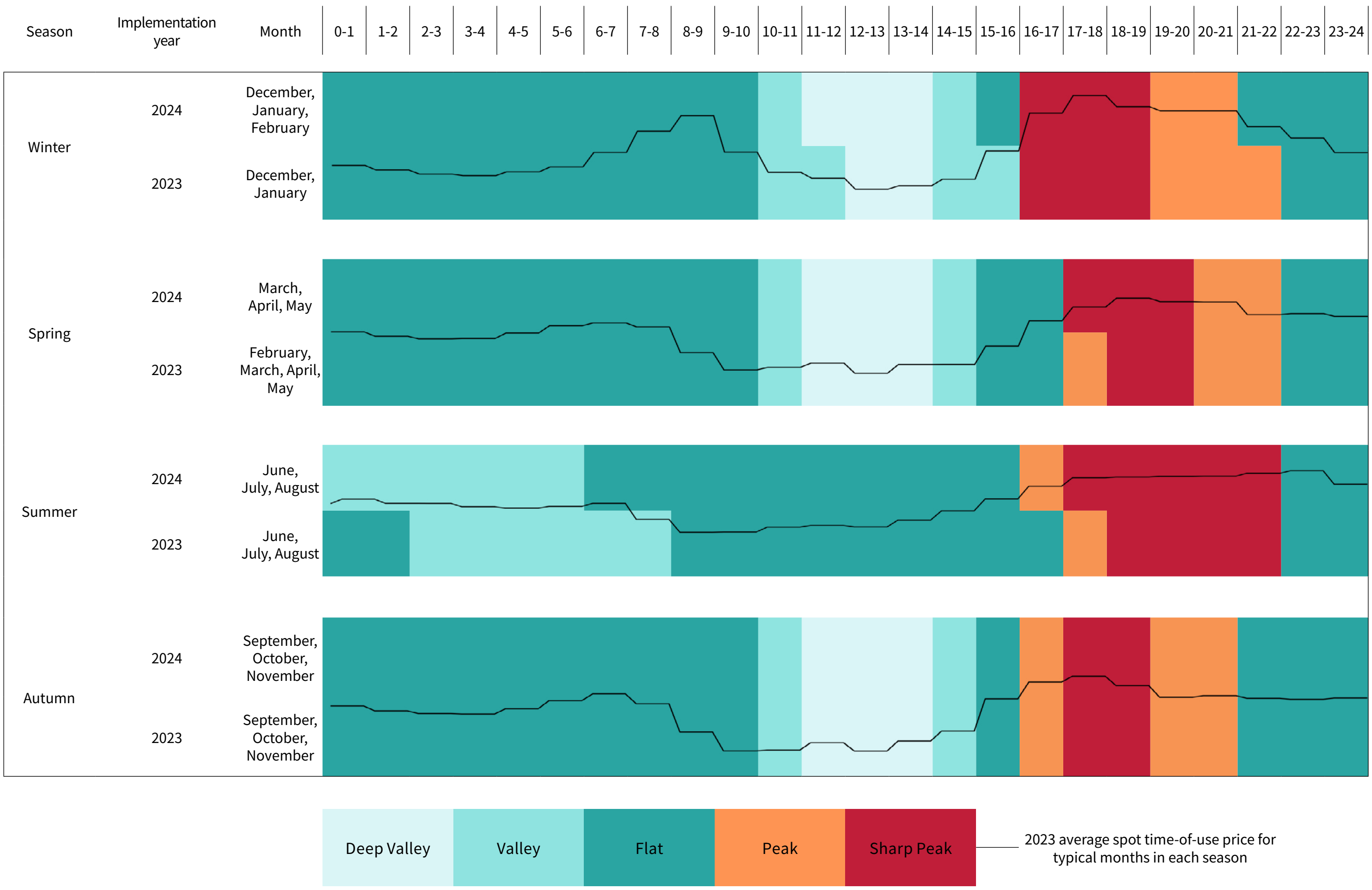
RMI Graphic. Source: Provincial Development and Reform Commissions

In provinces where the spot market has a continuous trial operational, the intraday spot price fluctuations have become an important reference for updating the TOU electricity pricing policy for the following year. The TOU electricity pricing policy dynamically integrates price signals from the spot market, thereby better informing users of the value of power within the day. Taking Shandong as an example (see Exhibit 9), the TOU electricity pricing policy for 2024 has adjusted the peak and valley periods for winter, spring, and summer based on the period distribution in 2023. The adjustments in the deep valley and sharp peak periods clearly reflect the fluctuation in the spot price curve:

- For deep valley adjustment, in the winter of 2024, the 11:00 a.m. to 12:00 p.m. time slot will be adjusted from valley to deep valley. This update aligns with the intraday fluctuations of the winter 2023 spot prices and their trend compared with the previous year. In the January 2023 spot market, the average price between 11:00 a.m. and 12:00 p.m. was 14% lower than during the 10:00 to 11:00 a.m. slot, setting the intraday lowest price at 0.56 times the month's average price (the lowest average spot price for any time slot in January was 0.4 times the monthly average).

- For the sharp peak adjustment, the 5:00 to 6:00 p.m. time slot in the spring and summer of 2024 will be shifted from peak to sharp peak. The spot transaction prices from July 2023 indicate that the average spot price between 5:00 and 6:00 p.m. was 9.7% higher than from 4:00 to 5:00 p.m., reaching a peak. The price was 93% of the highest price recorded for any intraday time slot, thus falling into the sharp peak price category.

Exhibit 9 TOU electricity pricing time segment for Shandong Province in 2023 and 2024 and spot prices for 2023

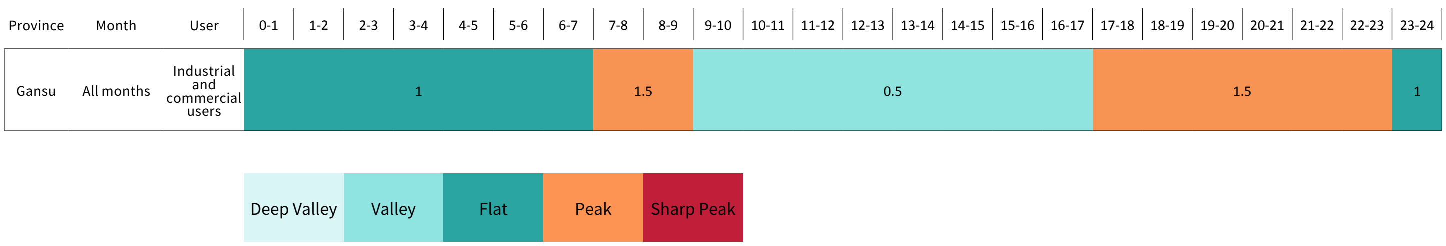


Note: Spot prices for 2023 represent typical monthly spot prices for each season, with January for winter, April for spring, July for autumn, and October for fall.
RMI Graphic. Source: Shandong Provincial Development and Reform Commission, Dianchacha

However, **periods within certain regions exhibit inconsistencies between fluctuations in spot prices and TOU pricing policy.** For example, in Shandong during the summer (see Exhibit 9), the 12:00 to 6:00 a.m. period is designated as valley, yet the average hourly spot prices during this time were higher than those during the flat period of 8:00 a.m. to 1:00 p.m. Furthermore, Exhibits 10 and 11 show that spot prices in Gansu-East zone display strong seasonal variations, which are not yet reflected in the current TOU electricity pricing policy.

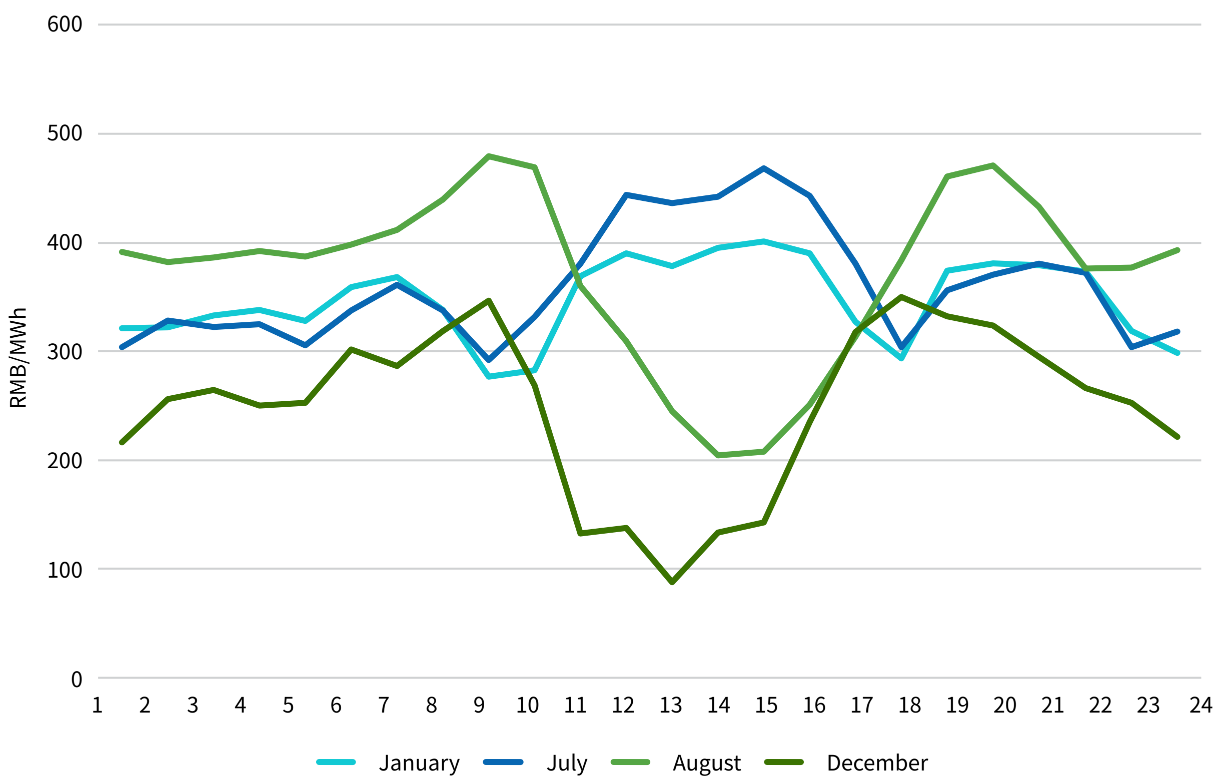
For instance, during the summer months of July and August in Gansu-East zonal spot market, peak prices typically occurred in the afternoon (12:00–5:00 p.m.) and evening (6:00–11:00 p.m.), whereas in winter peak prices were concentrated in the early morning (7:00–9:00 a.m.) and evening (5:00–11:00 p.m.). The implemented TOU pricing policy closely aligns with the winter spot price trends but deviates notably during the summer. **Power users should closely monitor such discrepancies between TOU policy pricing and spot prices because these periods are likely to become focal points for future updates in TOU electricity pricing policies.**

Exhibit 10 Time segmentation and floating ratios for TOU electricity pricing in Gansu Province



RMI Graphic. Source: Gansu Provincial Development and Reform Commission

Exhibit 11 Average spot TOU prices in Gansu-East for 2023



RMI Graphic. Source: Lambda

There are significant differences in defining the basis price for TOU floating across provinces. A unified guidance for the basis price definition is expected to be announced. Currently, the definition for the basis price for TOU pricing varies across provinces. In the pilot provinces with continuous operation of spot markets, as illustrated in Exhibit 12, the basis for floating TOU electricity price includes more than just market purchase prices by grid companies. In Anhui, Henan, Guangdong, Sichuan, Zhejiang, Jiangsu, and Liaoning, the T&D tariffs are included in price floating. In Zhejiang and Jiangsu, government funds and surcharges are included in the floating. In addition, there is no unified definition regarding whether the costs of transmission losses and system operations should be included or not.

As a result, power users should pay attention not only to the peak and valley ratios set by the TOU policy but also to the boundary of the TOU price floating basis within their respective provinces. **When the floating ratio of user-side electricity prices is at a similar level, a smaller floating basis allows for a greater range in price fluctuations, which benefits storage players looking to capitalize on peak and valley price differences and recoup investment costs. With the goal of building a unified national power market, normative guidance concerning the basis price for TOU floating may be issued at the national level to clarify the boundary and further standardize the electricity pricing system.**

Exhibit 12 **TOU electricity price floating basis in pilot provinces for spot markets**

	Basis for TOU electricity price floating				
Province	Market transaction price/grid agency purchase price	Cost of transmission losses	Transmission and distribution tariffs	System operation costs	Governmental funds and surcharges
Anhui	✓		✓[Excluding basic power fees]		
Guangdong	✓	✓	✓[Excluding basic power fees]	✓	
Henan (Draft for Comments)	✓		✓[Excluding basic power fees]		
Hubei	✓	✓			
Jiangsu	✓	✓	✓[Excluding basic power fees]	✓	✓
Liaoning	✓	✓	✓[Excluding basic power fees]		
Mengxi	✓				
Shandong	✓	✓		✓	
Shanxi	✓(Historical deviation electricity fee discounts do not fluctuate)				
Sichuan	✓		✓[Excluding basic power fees]		
Zhejiang	✓	✓	✓[Excluding basic power fees]	✓	✓

Note: Shandong's unique capacity compensation electricity pricing is also included in the floating basis, whereas Shanghai, Fujian, and Gansu have not made clear regulations on the composition.
RMI Graphic. Source: Provincial Development and Reform Commissions, Polaris Power Grid

3. The power retail market has made improvements in expanding user coverage, diversifying retail companies, and conveying wholesale market signals to retail market.

Market-based electricity transaction volume continued to grow in 2023, with 30% of the volume purchased by grid companies.[iii] According to the NEA, the national market-based electricity transaction volume reached 5,700 terawatt-hours (TWh), a 7.9% year-over-year increase.[8] The volume of power purchased by grid companies accounted for about 30.6% of total volume, and almost all I&C users whose voltage level is below 10 kV are purchasing electricity from grid companies.

In October 2023, Guangdong Province issued the "Implementation Plan for the Pilot of Market-based Trading Participation by Low-Voltage Industrial and Commercial Users in the Guangdong Electricity Market," initiating a pilot in Shenzhen that allows low-voltage I&C users to directly purchase electricity from the wholesale market or through power retail companies other than grid companies.[9] This pilot lays the foundation for more open options to I&C users, which promotes healthy development of the retail market.

Participating in the retail market, instead of the wholesale market, is the main way for I&C users to engage in market-based electricity transactions for the remaining 70% of total volume not purchased by grid companies. Taking Guangdong Province, which ranked first in electricity consumption in 2023, as an example, a total of 39,243 users directly participated in the Guangdong power market in 2023, but only four users participated in the wholesale market.[10] During Guangdong's 2024 annual electricity transaction, only one user participated.[11]

Provinces took opposite actions on user access to power in the wholesale market in 2023. Several provinces have set entry criteria: Guangdong and Qinghai set 10 gigawatt-hours (GWh) and Fujian sets 5 GWh annual electricity consumption as the criteria for users to enter the wholesale market. However, Sichuan and Xinjiang provinces have removed the thresholds in their 2024 power market trading schemes, reducing the restrictions on power users to directly trade in the wholesale market.

The provincial power retail markets were improved in 2023, and 17 provinces and cities (Guangdong, Jiangsu, Zhejiang, Hebei, Xinjiang, Sichuan, Anhui, Fujian, Shanxi, Yunnan, Shaanxi, Hunan, Gansu, Tianjin, Qinghai, Jilin, and Hainan) issued or updated managing regulations related to retail markets or retail companies in 2023. These documents clarified the rights and obligations of users and retail companies, as well as the trading process of the retail transaction organization. Templates for retail contracts and retail packages were standardized and provided by officials. Moreover, governments developed online retail transaction platforms for users to keep records and proceed with contracts efficiently.

iii Grid companies act as purchasing agents on behalf of users (all residential and agricultural users and some I&C users) to purchase electricity from wholesale markets. The purchase volume is accounted for in the market-based electricity transaction.

Power retail packages include fixed-price, price-linkage, price pass-through, and proportional-split packages. Fixed-price packages set a fixed settlement price, which effectively eliminates price risk for customers. Price-linkage packages directly link package price to the average market price (either based on the wholesale market price or the grid companies' purchase price). Price pass-through packages have prices linked to a retail company's average settlement price from wholesale market transactions. Proportional-split packages enable retail companies and users to share profits and risks. Moreover, some provinces have proposed specific retail packages for green power, including the green power volume and relevant green premium.

- Fixed-price packages are currently the primary choice of users because they mitigate the risk of electricity price fluctuations. For example, in Guangdong Province, more than 98% of power users, which also covered over 98% of electricity volume, opted for a fixed + market-linked price retail contract type in the 2023 and 2024 power retail markets.[12] The electricity traded based on market-linked price in 2023 and 2024 constituted 10.6% and 10.8% of total electricity traded in the retail market, where the required minimal portion was 10%, indicating that users had no desire to buy electricity based on market-linked price beyond government regulation.

- The reference prices in price-linkage packages include annual and monthly M2L prices, average spot market price, and monthly grid companies' purchased price. Both price-linkage packages and price pass-through packages normally include a service fee to cover the retail company's costs besides electricity energy price.

- Some provinces, such as Guangdong and Shanghai, provide options for users to link the retail contract price to the coal price. However, from the results of Guangdong's retail contract transactions, few users opted for coal price linkage (no users in 2023 and 0.03% of users in 2024), indicating that most power users still preferred fixed electricity prices.

- **To reduce the fluctuation risk of electricity purchase prices for users in the retail market, two mechanisms were established, including price limits and price risk alerts.** Guangdong Province directly set upper and lower price limits for the fixed-price portion in the power retail market in 2023, aligning these limits with those in the annual transaction of the power wholesale market. Moreover, Yunnan Province chose to use 1.2 times the benchmark electricity price for coal-fired power as the upper price limit, and Zhejiang Province set the optional price cap based on 80% of the annual average wholesale transaction price + 20% of the monthly average wholesale transaction price. Furthermore, Jiangsu Province is an example of setting risk warning thresholds for key price parameters in retail packages.

- **Deviation assessments were usually optional in retail contracts, and some provinces encouraged retail companies to exempt low-voltage retail users.** For example, Zhejiang Province encourages retail companies not to perform deviation assessments for retail users below 35 kV. This province also stipulates that the deviation assessment fees retail companies collected from users should not exceed the deviation costs of retail companies in the wholesale market.

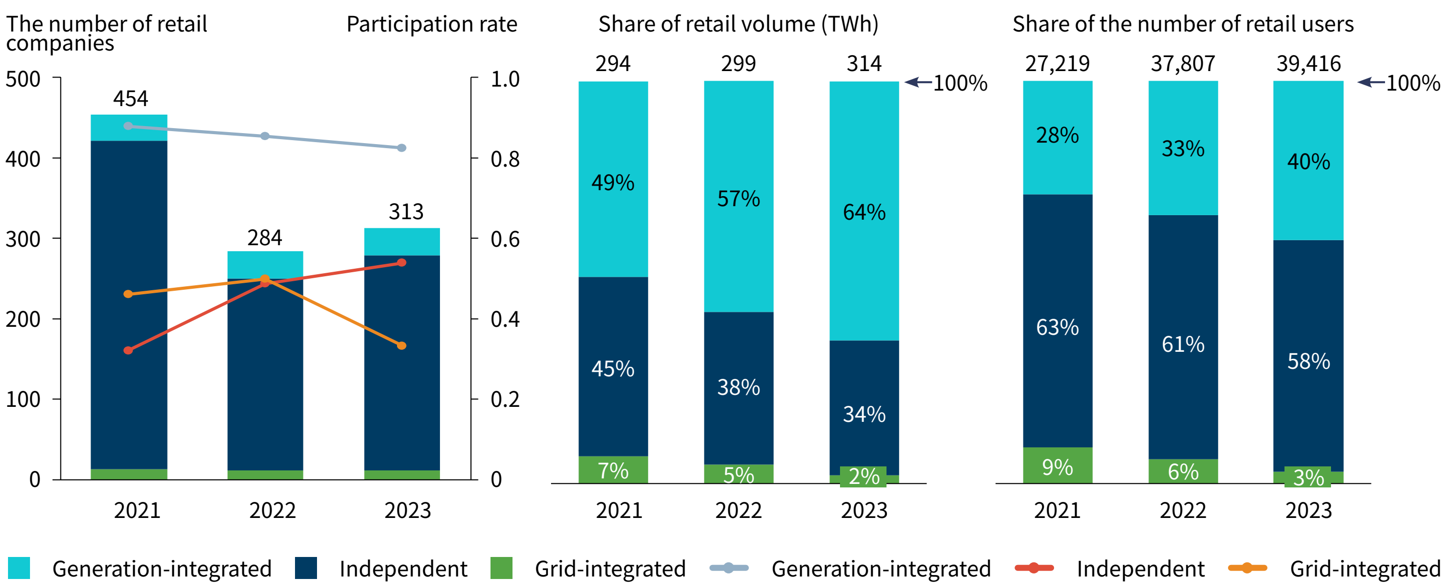
- Retail packages apply TOU electricity pricing by two methods: one is to directly agree on flat period prices, with other periods floating according to specified peak-to-valley ratios (such as Guangdong Province); the other is to agree on prices for different periods separately (such as Shaanxi Province).

Independent retail companies were the majority, accounting for about 85%. However, generation-integrated retail companies had the highest participation rate compared with independent retail companies and grid-integrated retail companies.[iv] With the phase out of companies not engaged in substantive business, the participation rate of independent retail companies increased from 32% in 2021 to 54% in 2023.[13] Exhibits 13 and 14 display power retail transaction in the Guangdong electricity market:

- Generation-integrated retail companies covered around 60% of retail electricity volume with only about 30% of retail users. **Generation-integrated companies have the advantage of power supply, which enables them to offer lower electricity prices and more stable power supply to power users.** As a result, the share of retail electricity by generation-integrated retail companies continuously increased in 2021–23. Moreover, the retail transaction results in Guangdong showed that generation-integrated retail companies offered the lowest electricity prices to their users, with the prices in 2022 and 2023 being RMB 19/MWh and RMB 8/MWh lower than the market average, respectively. With the lowest management costs because of the economies of scale from servicing large users, generation-integrated retail companies also had the lowest per-unit profits among all types, with the profits in 2022 and 2023 being RMB 7/MWh and RMB 4/MWh lower than the market average, respectively.

- **Independent retail companies cater to about 60% of retail power users, especially small and medium-sized users, enhancing the diversity of the retail market.** The per-unit electricity prices and profits of independent retail companies are higher than the market average, with per-unit prices in 2022 and 2023 being RMB 26/MWh and RMB 14/MWh higher than the market average, respectively, and profits being RMB 11/MWh and RMB 7/MWh higher, respectively. Independent retail companies emphasize developing their core competencies in trading capabilities or service abilities, and usually require higher returns than generation-integrated retail companies.

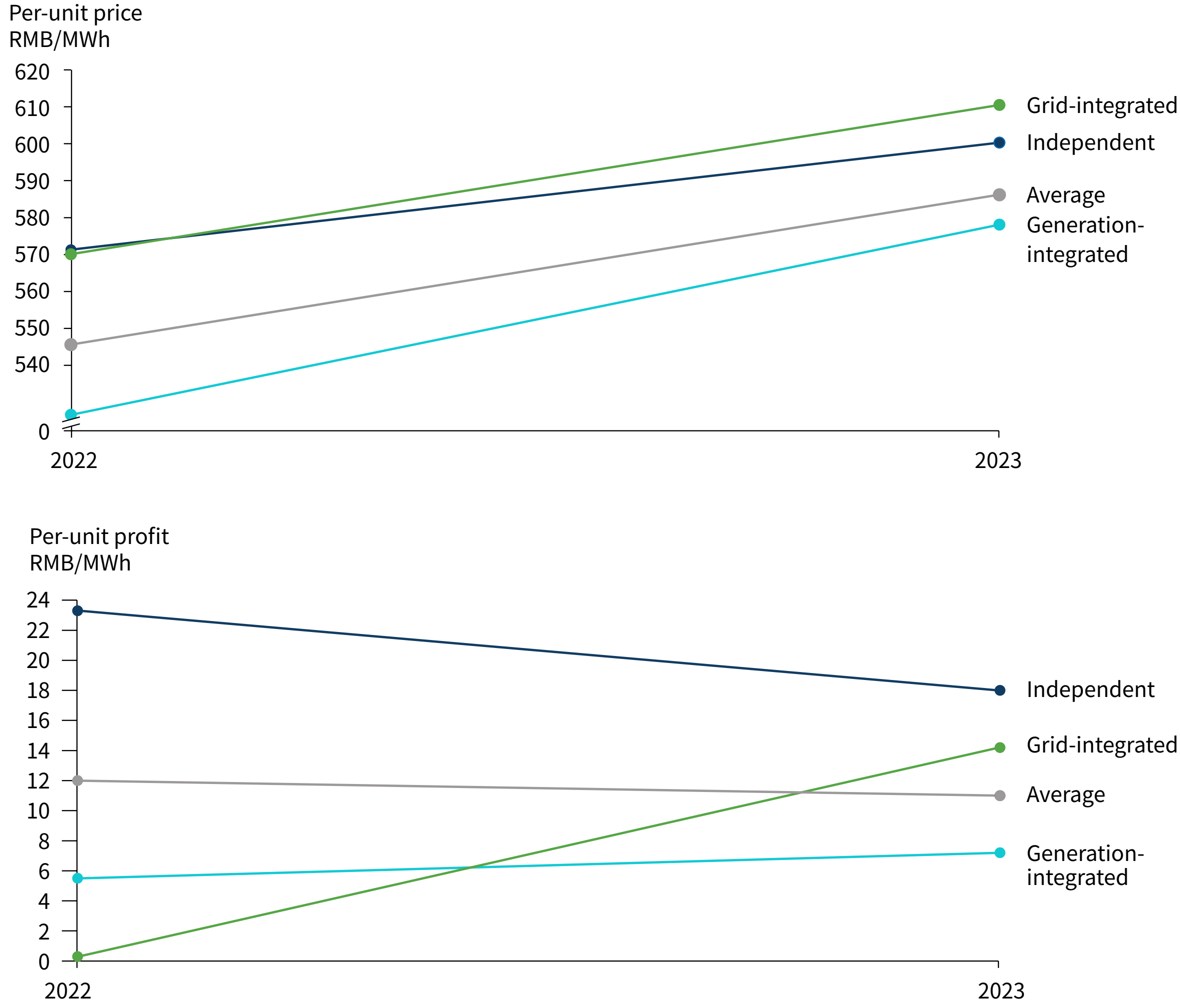
Exhibit 13 **Market share of different types of retail companies in the Guangdong electricity market**



RMI Graphic. Source: Guangdong Power Exchange Center

iv Participation rate: the number of retail companies that participate in power market divided by the total number of retail companies.

Exhibit 14 **Per-unit prices and profits of different types of retail companies in the Guangdong electricity market**



RMI Graphic. Source: Guangdong Power Exchange Center

Based on the pilot of low-voltage I&C users participating in electricity market transactions in Guangdong Province, **it is expected that more pilots will be conducted in various regions to expand the coverage of I&C users to participate in the power market.** The scope of grid companies' purchased electricity will therefore be expected to narrow down.

Participation in the retail market will remain the primary method for users to engage in the power market. The diversification trend of retail companies will remain, but all types of retail companies need to provide more specialized, refined services, as well as expanding value-added services to generate more revenue streams.

In terms of the user selection of retail packages, it is expected that the proportion of market-linked pricing will gradually increase. Fluctuations in wholesale market prices will effectively transmit to end-users, guiding their electricity usage behaviors. Moreover, as the construction of spot markets progresses, spot market trading prices will be more frequently considered in price-linkage packages, better leveraging the price discovery function of the spot market.

Transmission and Distribution

4. T&D tariffs better reflect the costs of grid operations; transmission losses and system operation fees are now listed explicitly on electricity bills.

The T&D tariffs are revised to align more closely with price-following mechanisms, refine power user classifications, and introduce a voltage-level basic power fee for the first time.[v] On May 15, 2023, the NDRC issued the “Notice on the Third Supervision Cycle of Provincial Power Grid T&D Tariffs” (Third Cycle Notice) for the 2023–25 period.[14] The tariff adjustments better reflect grid operation costs and more effectively distribute those costs to end-users.

In previous cycles, I&C electricity pricing comprised only feed-in price and T&D tariffs, with the latter category lacking a detailed breakdown of the electricity bills, and was perceived as accounting for transmission losses and system operation fees. The Third Cycle Notice clarifies that T&D tariffs should only reflect the cost of T&D services. I&C electricity pricing now includes feed-in price, transmission losses, T&D tariffs, system operation fees, government-related funds, and surcharges. For the first time, transmission losses and system operation fees are explicitly itemized on electricity bills. Transmission losses represent the monetary value of energy lost during power transmission, whereas system operation fees cover various costs such as pumped storage capacity prices, coal power capacity prices, and ancillary services cost.

The power user categories are reclassified from the previous four categories (residential, agricultural production, large industry, and general I&C) into three categories: residential, agricultural production, and I&C. I&C users of the same voltage level will now be subject to the same pricing scheme. Previously, general I&C users and large industrial users had differing cross subsidies embedded in their T&D tariffs, leading to price discrepancies for users within the same voltage level. The new standards consolidate general I&C and large industrial users into a single I&C category with unified cross subsidies, significantly enhancing transparency and fairness within the pricing structure.

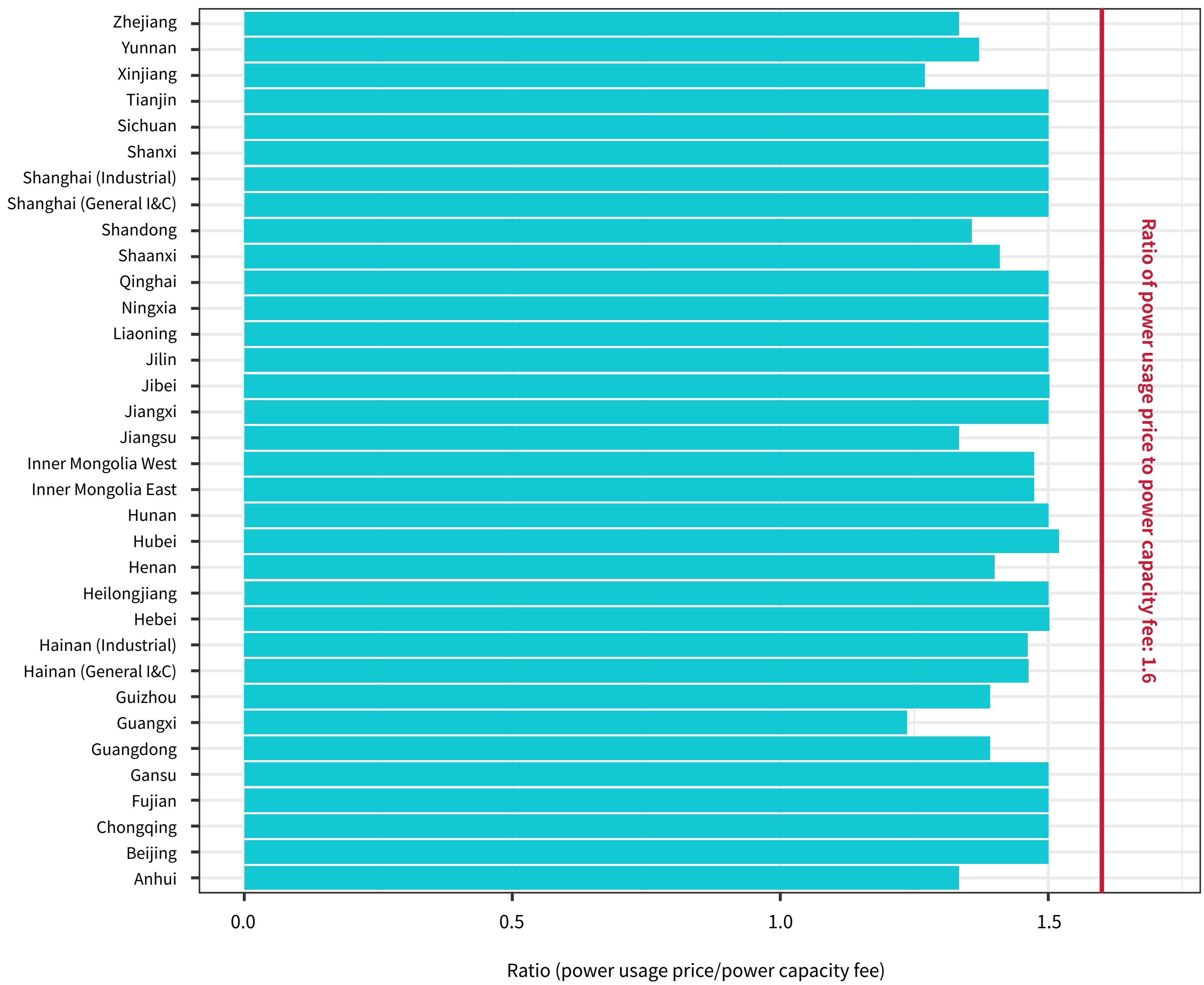
I&C users can choose to implement the fixed or the two-part electricity price,[vi] according to their voltage level and power demand. The Third Cycle Notice stipulates that users with a power demand of 100 kVA and below shall implement the fixed price; those with a power demand between 100 and 315 kVA can choose the fixed price or the two-part electricity price; and those with a power demand of 315 kVA and above shall implement the two-part electricity price.

v The basic power fee is exclusively applicable to industrial users. It is a capacity charge of the transformer capacity claimed by the industrial users.

vi With the fixed electricity price, users pay a fixed price (RMB/kWh) based on their electricity consumption. The price is generally higher than the same category in the two-part pricing because it takes into account the basic power fee. With the two-part electricity price, users pay the electricity price (RMB/kWh) and the basic power fee. The basic power fee can be either the power capacity fee or the power usage price, per the user’s choice. The power capacity fee (RMB/kW/month) measures the maximum rated capacity of the transformer the user requests. The power usage price (RMB/kVA/month) measures the actual power usage of the user.

Within the basic power fee of the two-part electricity price, the power usage fee is uniformly set at 1.6 times the power capacity fee in the current adjustment cycle. This marks a notable increase in the ratio of power usage fee to power capacity fee across all provincial power grids when compared with the second cycle (see Exhibit 15). This adjustment widens the price difference between power usage fee and power capacity fees, providing a direct incentive for users to make rational choices on either plan. It is also beneficial to the grid's existing and future planning for transformer capacity because the users' choice would better match their production schedules and power load curves.

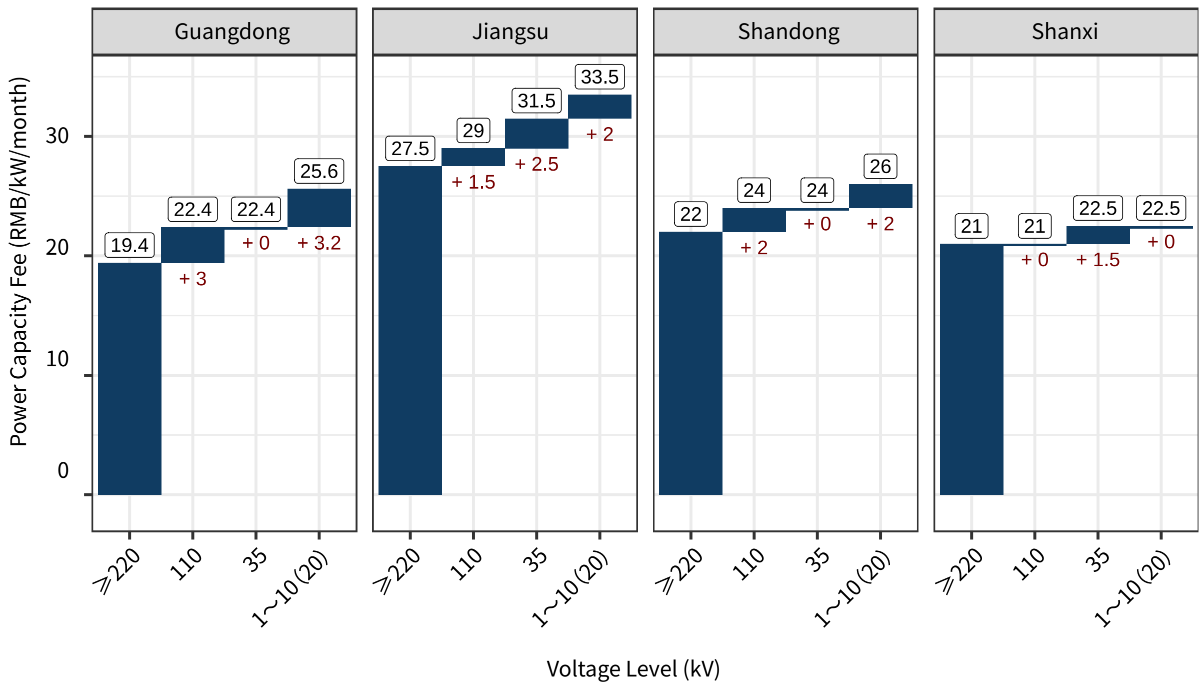
Exhibit 15 **Ratio of power usage price to power capacity fee in the second cycle**



RMI Graphic. Source: NDRC

In the previous cycles, the basic power fee was not distinguished by voltage level. Users below 10 kV or above 220 kV paid the same rate, which limited the fee's ability to reflect the varying costs of T&D services at different voltage levels. Now, the basic power fee is differentiated according to the voltage level. On average, basic power fees for lower voltage levels are roughly 14% higher than those for high voltage levels (see Exhibit 16). This adjustment enables emerging market players such as distribution grid expanders and load aggregators to utilize the price gap among different voltage levels in both the electricity prices and the basic power fee, which encourages private capital to enter the distribution businesses.

Exhibit 16 **Power capacity fee overview in selected provinces**



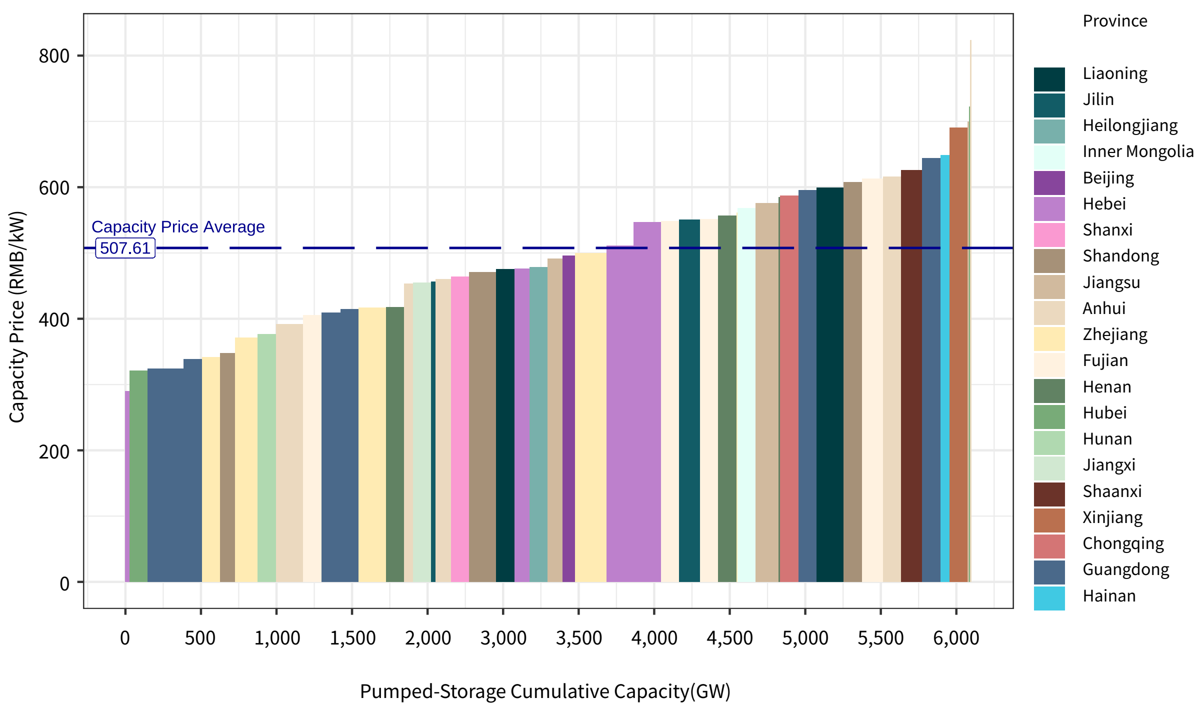
RMI Graphic. Source: NDRC

In addition, the two-part electricity price introduces an incentive mechanism for I&C users: users who efficiently utilize their requested transformer capacity (when their monthly electricity consumption per kVA reaches 260 kWh or more) are rewarded with a 10% discount on their monthly power usage price. Such a mechanism better distributes the transformer capacity costs to users of different voltage levels and of different utilization. The change will affect I&C users' strategy for choosing the power capacity fee or the power usage price to set the basic power fee. Users who previously found it more cost-effective to choose the power capacity fee may find the power usage price a better option now.

Listing system operation costs as a separate category is one of the highlights of the third cycle adjustment, bringing enhanced transparency to the pricing structure. Within the system operation costs, the capacity fee of pumped storage power stations is a key focus. The NDRC released the annual capacity fees for each operational pumped storage power stations during 2023–25.[15] The cost recovery mechanism for pumped storage power stations becomes clear: fixed costs (e.g., construction) are recovered through the capacity fee, whereas operating costs and profits are derived from the price difference between charging and discharging.

The average capacity fee for the 48 pumped storage power stations (see Exhibit 17) that are currently operational or planned for operation by the end of 2025 is RMB 507.61/kW. The average installed capacity of these stations is 1.14 gigawatts (GW). Twenty-two stations have a capacity fee above the average. The Xianghongdian Station in Anhui Province has the highest capacity fee at RMB 823.34/kW with an installed capacity of 80 megawatts (MW). Conversely, the Panjiakou Power Station in Hebei Province has the lowest capacity electricity fee at RMB 289.73/kW with an installed capacity of 270 MW. Among these 48 stations, the most common installed capacity is 1.2 GW, with 21 stations falling into this category.

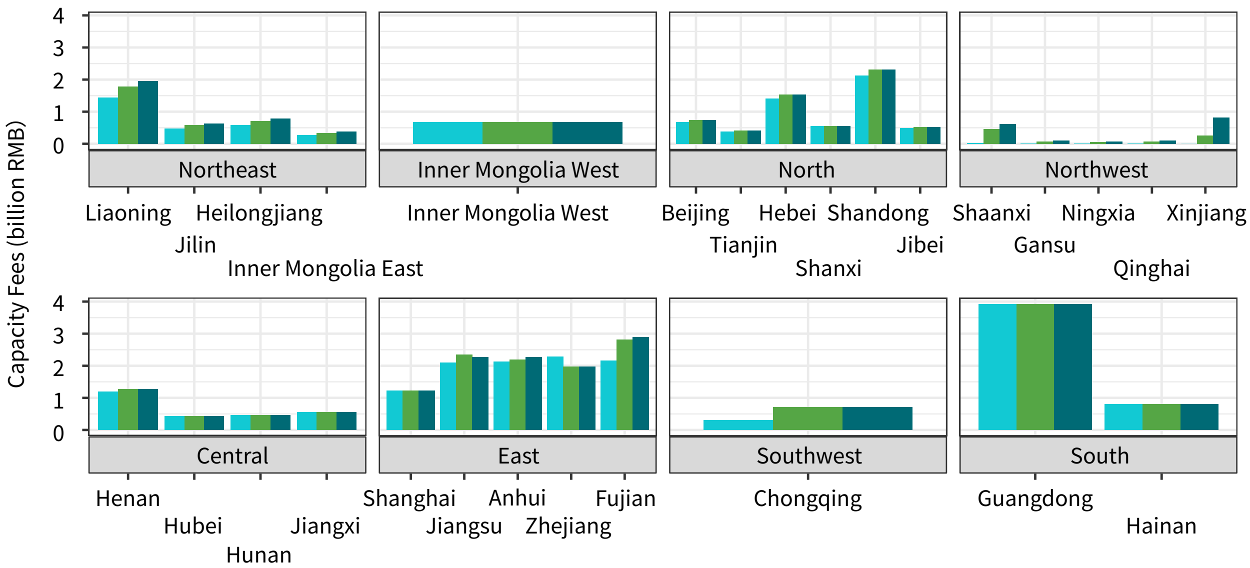
Exhibit 17 **Provincial Pumped-Storage capacity and capacity fees overview**



RMI Graphic. Source: NDRC

Looking at each province and region (except Jiangsu and Zhejiang), the total annual capacity fee for pumped storage power stations is expected to remain flat or increase between 2023 and 2025 (see Exhibit 18). By 2025, we estimate that the pumped storage capacity fee passed on to I&C users within system operation fees will range between RMB 0.03/kWh and RMB 0.04/kWh. Within the State Grid's operating area, provinces in Northeast and East China tend to have higher pumped storage capacity fees. As a result, the passed-through cost to I&C users in these regions is expected to be around RMB 0.008–0.01/kWh.

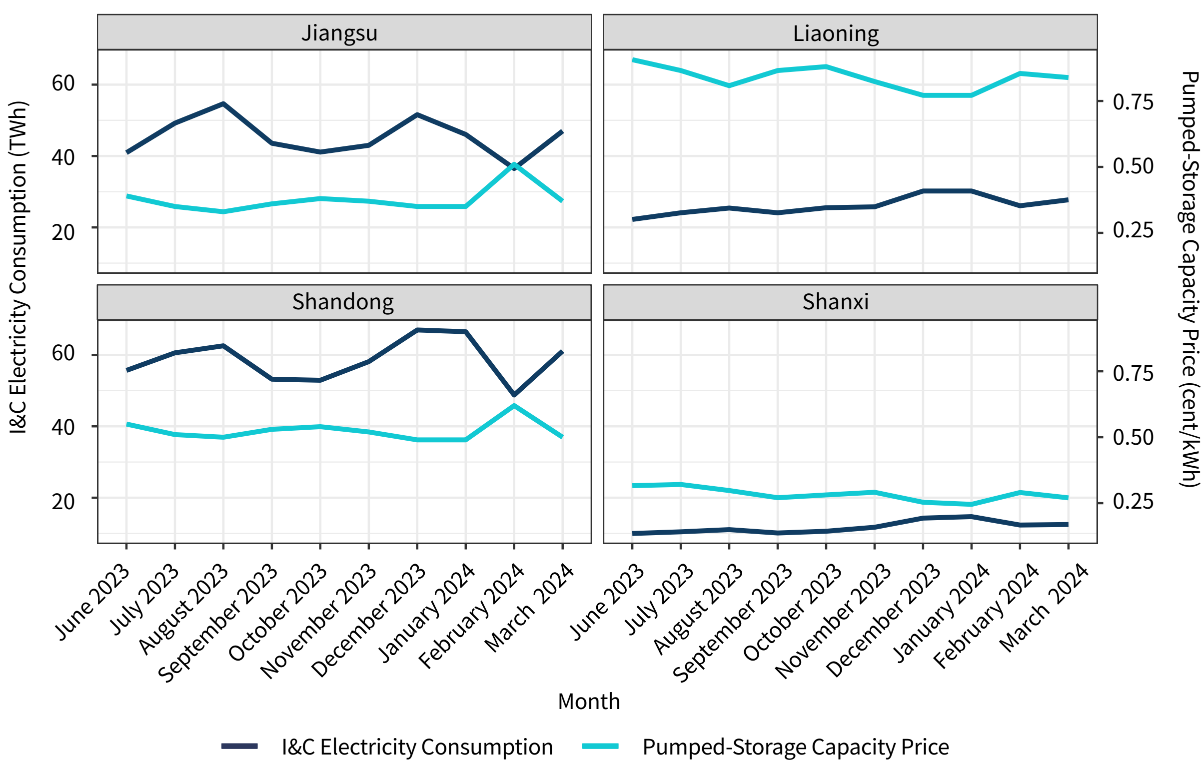
Exhibit 18 Annual capacity fees for pumped storage



RMI Graphic. Source: NDRC

The pumped storage capacity fee paid by I&C users also fluctuates monthly. This monthly price exhibits an inverse relationship with the overall level of I&C electricity consumption (see Exhibit 19). In other words, when the monthly I&C electricity consumption is high, the pumped storage capacity fee tends to be lower, and vice versa.

Exhibit 19 Monthly I&C electricity consumption vs. pumped storage capacity fee in selected provinces



RMI Graphic. Source: State Grid, China Electricity Council (CEC)

Capacity Pricing

5. The coal power capacity pricing mechanism is introduced, reconstructing the electricity price structure of both power generators and consumers, and supporting the transformation of coal power's role.

On November 8, 2023, the NDRC and the NEA jointly issued the "Notice on Establishing a Coal Power Capacity Pricing Mechanism," stating that **starting on January 1, 2024, a capacity fee mechanism is effective for utilities' coal-fired electricity-generating units (EGUs)**, and the resulting coal power capacity fee will be included in the system operating expenses and will be shared by I&C users based on the monthly electricity consumption.[16]

The coal power capacity fee mechanism ensures coal power assets a guaranteed income that is independent of utilization hours, and aims to support the transformation of coal power's role. The current coal power capacity tariff is cost-oriented, determined by the fixed cost of the coal power unit and the cost recovery ratio set by the province.[vii] The fixed cost adopts a standardized value at RMB 330/kW/year (y). The cost recovery ratio is determined based on the renewable energy and power system transformation progress in provincial power grids. For 2024–25 (see Exhibit 20), this ratio is generally set at 30% (i.e., RMB 100/kW/y) in most provinces, and some provinces and regions with a higher proportion of renewable energy are set at 50% (i.e., RMB 165/kW/y).[17]

The coal power capacity tariff level, or the fixed cost recovery ratio, is related to the production and consumption of renewable energy in the provincial grid. Six of the seven provincial grids with the tariff at RMB 165/kW/y are also among the top seven provinces with the highest renewable power consumption weight responsibility.[viii] Sichuan, Yunnan, and Qinghai need to reach 70%, while Hunan, Guangxi, and Chongqing all exceed 40% (see Exhibit 21a). The only exception is Henan: although its consumption responsibility is not among the top, its coal power fleet has been transformed rapidly. Data shows that Henan's thermal power utilization hour is only higher than those of Xizang and the three northeastern provinces (see Exhibit 21c) and is about 20% lower than the national average.

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

viii The provincial renewable power consumption weight responsibility is set by the NDRC to assign each province a target percentage of its electricity consumption that must come from renewable sources based on the renewable resource status quo in each province.

Exhibit 20 **Coal power capacity tariff and coal power capacity fee in each province**

	Paid to generators	Charged to consumers	Charged to consumers
Provincial grid	2024–25 coal power capacity tariff (RMB/kW/y)	January 2024 coal power capacity fee (RMB/kWh)	February 2024 coal power capacity fee (RMB/kWh)
Beijing	100	0.009581	0.013798
Tianjin	100	0.0123	0.0172
Hebei North	100	0.0147	0.0221
Hebei South	100	0.0195	0.0271
Shanxi	100	0.014274	0.015273
Shandong	100	0.0190	0.0225
Western Inner Mongolia	100	0.0139	0.0137
Eastern Inner Mongolia	100	0.011651	0.012280
Liaoning	100	0.011421	0.003450
Jilin	100	0.02176	0.032494
Heilongjiang	100	0.016000	0.016000
Shanghai	100	0.0142	0.0173
Jiangsu	100	0.0158	0.0225
Zhejiang	100	0.0140	0.0255
Anhui	100	0.0210	0.0205
Fujian	100	0.0161	0.0212
Jiangxi	100	0.01608	0.01881
Henan	165	0.036775	0.037298
Hubei	100	0.0180	0.0254
Hunan	165	0.03708	0.04862
Chongqing	165	0.028621	0.034697
Sichuan	165	0.0075	0.0090
Shaanxi	100	0.0197	0.0216
Xinjiang	100	0.015108	0.017263
Qinghai	165	0.004676	0.004634
Ningxia	100	0.0124	0.0137
Gansu	100	0.012279	0.013358
Shenzhen	100	—	—
Guangdong	100	—	—
Yunnan	165	—	0.006006
Hainan	100	—	—
Guizhou	100	—	—
Guangxi	165	0.0230	0.028021

RMI Graphic. Source: NDRC, provincial power grid companies, BJX.com.cn

Exhibit 21 Coal power capacity fee and related influencing factors

RMI Graphic. Source: NDRC, CEC, provincial power grid companies, BJX.com.cn

On the consumption side, starting in 2024, the coal power capacity fee will be part of the system operating fee and will be paid per kWh. All I&C users jointly share the coal power capacity fees of the provincial grid by month based on their monthly electricity consumption (see Exhibit 20).

At least 28 provincial grids have disclosed the coal power capacity fee for January 2024. **The nationwide average level is RMB 0.017/kWh.** Hunan, Henan, Chongqing, Jilin, and Guangxi are among the highest, with Hunan and Henan exceeding twice the national average. Qinghai, Sichuan, Beijing, Liaoning, and eastern Inner Mongolia are among the lowest, with Qinghai and Sichuan below 50% of the average.

The ratio of the coal power capacity fee to the energy price generally falls into the range of 3.0%–5.0%. Out of the 28 provincial grids, 16 fall into this range. There are four provincial grids that fall into the range of 2.0%–3.0%, and four that fall into the range of 5.0%–6.0%. For the rest, Henan and Hunan are above 8.0%, while Qinghai and Sichuan are only roughly 1.6%.

The coal power capacity fee level charged to the user is related to the coal power capacity tariff paid to the generator. Among the seven provinces with a higher coal power capacity tariff, Hunan, Henan, Chongqing, and Guangxi also have a significantly higher capacity fee level on the user side. However, other provinces with a higher tariff (i.e., Qinghai, Sichuan, and Yunnan) yield the lowest fee level (see Exhibits 21d and e). The power generation mix of a provincial grid can explain this phenomenon: among the 33 provincial grids that implement coal power capacity tariffs, the proportion of thermal power generation in total power generation is generally close to or higher than 50%, except for Qinghai, Sichuan, and Yunnan. In fact, the proportion of these three provinces is only about 10% to 20% (see Exhibit 21b). The low proportion of the generation mix also means that installed coal power capacity accounts for a significantly low share in these three provinces. Therefore, even if the tariff per kW capacity on the power generation side is relatively high, the coal power capacity fee charged per kWh to power users is still at the lowest level in the country.

The current coal power capacity pricing mechanism has had a spillover effect on the capacity pricing for other market members such as natural gas units and energy storage. In terms of natural gas units, Guangdong Province, which previously adopted a per-kWh price, also introduced a natural gas power capacity tariff in January 2024. The tariff level is the same as that of coal power, both at RMB 100/kW/y. In terms of energy storage, Hebei Province established a temporary support policy in 2024, and independent energy storage power stations can receive a capacity price of up to RMB 100/kW/y.

For the coal power capacity tariff and pumped hydro storage capacity tariff, as well as the gas power capacity tariff that had been implemented in some provinces in 2023 (such as Shanghai and Jiangsu), the calculation is based on fixed costs. The tariff level either reflects a partial or full recovery of either a standard fixed cost (e.g., coal power) or the unit-specific fixed cost (e.g., pumped hydro storage). However, both the aforementioned Guangdong gas power and Hebei energy storage capacity tariff are clearly benchmarking to the coal power capacity price level. **This shows a new practice for capacity tariff: technologies with similar capability in providing system adequacy will have similar capacity price structure and revenue model.**

For the price outlook, in the short term (one to two years), the coal power capacity tariff will remain at the current level. In the medium term (three to five years), in accordance with the policy, the tariff will likely increase by RMB 65/kW/y. In terms of the fee charged to end-users, because the growth of I&C electricity consumption is likely to be less than the tariff adjustment, the coal power capacity fee paid in RMB/kWh may slightly increase in the medium term. In the long term, because the purpose of the capacity pricing mechanism is to ensure system adequacy, the capacity pricing mechanism is likely to cover more types of power generation and energy storage technologies. At the same time, similar to the ancillary services markets, **integrating various power supply-side capacity pricing mechanisms and achieving market-oriented development will be a long-term trend.**

Ancillary Services

6. The ancillary services market pricing mechanism is improved and standardized; renewables and energy storage owners may need market strategy adjustments.

To support the increasing renewables penetration, solving challenges of reduced synchronous inertia, reduced frequency stability, and increased fluctuations in renewables output has become more urgent. In the past few years, China has been promoting ancillary service varieties that are crucial to the power grid, expanding the participant pool of the ancillary services market, and establishing a more equitable cost-sharing and compensation mechanism. On February 8, 2024, the NDRC and the NEA issued the "Notice on Establishing and Improving the Electric Power Ancillary Services Market Price Mechanism" (Ancillary Services Notice), unifying the ancillary services market at the national level for the first time.[18] The notable changes and improvements include the following.

The Ancillary Services Notice clarifies the connection between peak regulation service and the spot market. Since the late 2010s, peak regulation service has gradually become the most mature and most widely adopted ancillary service in China; in fact, many provinces only have the peak regulation service in their ancillary services markets. Its function is to measure the price difference of electricity in different time periods when the spot market is not in place. The Ancillary Services Notice proposed that in areas where the power spot market operates continuously, the peak regulation market or markets for similar functions will no longer be applicable; in areas where the power spot market does not operate continuously, when the spot market does not operate, the units providing the peak regulation service (excluding wind and PV; hydropower units are encouraged to participate) bid the volume and price in the peak regulation market.

The Ancillary Services Notice outlines the pricing calculation methods and price ceilings for three major ancillary services:

- **Peak regulation:** Coal power has been the major flexibility provider in China, significantly lowering output to make way for renewable power generation, and receives compensation payment from the renewables. As more renewables have entered the grid in recent years, many provinces have continued to increase the compensation standards, with the price ceiling sitting in the range of RMB 0.1–3.5/kWh and the higher end surpassing the renewables' per-kWh revenue. This means renewables are seeing negative revenue to avoid curtailment in some provinces. The Ancillary Services Notice stipulates that the peak regulation price should not be higher than the feed-in price of local nonsubsidized renewable projects.

- **Frequency regulation:** For many years, the lack of technological neutrality and inconsistent pricing standards was widely observed in different provinces' ancillary services market design. The Ancillary Services Notice clarifies that the calculation for the frequency regulation fee should be consistent across all technologies and defines how the reference unit should be selected and how the parameters are calculated. In principle, the upper limit of the frequency regulation clearing price does not exceed RMB 0.015/kW, which is not much different from the price ceiling currently implemented in most provinces.

- **Reserve:** Compared with peak regulation and frequency regulation, which have already been operated in many provinces, reserve started later in China's power market reforms. The Ancillary Services Notice plays more of a role in unifying and standardizing the market price mechanism in advance. It clarifies that the reserve fee is the product of the clearing price, the bid-winning capacity, and the bid-winning time. The price limit shall not exceed the local energy market price. Currently, Hunan, Zhejiang, and the Northeast region have price ceilings in the range of RMB 0.04–0.2/kWh, which are all lower than the local energy market price.

The Ancillary Services Notice also clarifies the service cost-sharing mechanism. In areas where the spot market does not operate continuously, the ancillary services costs will continue to be shared among the EGUs, especially the non-dispatchable ones. In areas where the spot market operates continuously, the cost will be shared by both the consumption side and part of the supply side (EGUs that are not participating in the power market) and the sharing ratio is determined by provincial governments. At the same time, the Ancillary Services Notice also clarifies that the clearing price, bid-winning unit, and bid-winning capacity need to be determined through market competition, and no subsequent adjustment will be allowed.

Looking forward, the Ancillary Services Notice marks that the ancillary services market will gradually transition from a regulated compensation mechanism to a market-based pricing mechanism. The overall cost scale will be reduced, and the market entities' burden on ancillary services costs will be fairer and more reasonable. We expect two types of market entities to face the greatest impacts from the Ancillary Services Notice in the short term:

- **On-grid renewables will pay less in the ancillary market in some provinces.** The Ancillary Services Notice clearly stipulates that the theoretical price ceiling of peak regulation services is the feed-in price of the parity renewable projects, which benchmarks to the coal power reference price in most provinces. In this case, renewables' cost to avoid curtailment will no longer be higher than what they can receive from selling generation to the grid. But at the same time, renewables will face higher price uncertainties in the energy market (see the next trend about renewables participating in the energy market).

- **Energy storage income in the ancillary services market could be reduced and should be prepared for the spot market.** Where the spot market is continually operating and the regulated price range is further released to reflect the time value of electricity, energy storage assets are ready to secure such revenues. Where the spot market is not yet in continual operation, energy storage will earn less in peak regulation services in some provinces. In addition, according to international experience, the supply of frequency regulation services usually grows faster than demand, mostly due to the rapid growth of energy storage and dispatchable generators. Therefore, the frequency regulation service market could be saturated soon, causing prices to fall.

Renewables and Energy Storage

7. The market-oriented transactions of renewables are scaling up, bringing challenges to project profitability in the long run due to price fluctuations.

The market-oriented transaction volume and share of renewable generation continued to expand, reaching 684.5 TWh and 47.3% in 2023.[19] The volume of market-oriented transactions of renewable generation was 346.5 TWh in 2022, accounting for 38.4% of total renewable generation.[20]

The types of power market that renewable projects usually participate in are intra-provincial M2L market, intra-provincial spot market, and interprovincial market; the intra-provincial M2L market is the major one. Because the progress of the power spot market varies among regions, renewable projects are mainly engaging in the intra-provincial spot market in regions where the spot market is in official operation or continuous trial operation, such as Shanxi, Guangdong, Shandong, Inner Mongolia, and Gansu. The surplus generation of renewable projects in the intra-provincial market can participate in the interprovincial market, mainly through M2L transactions instead of spot transactions due to the immaturity of the interprovincial spot market.

Some regions have imposed restrictions on the market transaction volume of renewable projects. As with coal-fired projects, renewable projects should comply with the minimum proportion of a signed M2L contract, which is usually 80% of generation the previous year. However, provinces like Jiangsu have imposed upper limits on the annual and monthly transaction volumes for renewable projects, considering the uncertainty in generation. In terms of interprovincial transactions, provinces with rich renewable resources, like western Inner Mongolia, require that the share of interprovincial transactions for renewable projects should not exceed a certain level, which is the central government's requirement for local renewable consumption share.

In March 2024, the NDRC revised the full guarantee purchase system for renewable projects, clarifying the two parts of renewable projects' generation: **guarantee purchase volume and market transaction volume.** For the guarantee purchase part, renewable projects could guarantee the selling price and volume, which are uncertain and depend on the market transaction results for the market transaction part.

In 2023 and 2024, the guarantee purchase part of renewable projects kept narrowing down, and a greater share of renewable generation had to participate in power market, bringing uncertainty to the revenue of renewable projects. For example, in western Inner Mongolia, the government's announced equivalent utilization hours of wind and solar PV projects continued to decrease in 2022–24. The utilization hours of the guarantee purchase part of wind projects in western Inner Mongolia were 1,100 in 2022, 550 in 2023, and 300 in 2022; and of solar PV projects they were 900 in 2022, 450 in 2023, and 250 in 2022.

While promoting renewables participating in the power market, some provinces still provide subsidy mechanisms for the renewable generation excess to the guarantee purchase portion. These mechanisms ensure reasonable returns for renewable projects by enabling part of renewable generation to be purchased at a fixed price, which is usually the coal power benchmark price or below. For example, to incentivize the construction and operation of renewable projects, Yunnan provided subsidies for certain parts of wind and solar PV generation, which could be purchased at the coal power benchmark price in Yunnan. However, the proportion of subsidized generation continues to decrease (see Exhibit 22).

Exhibit 22 **The proportion of subsidized renewable generation in Yunnan**

Full capacity grid-connected time	January 1, 2021, through July 31, 2023	August 1 through December 31, 2023	January 1 through June 30, 2024	July 1 through December 31, 2024
Solar PV	100%	80%	65%	55%
Wind	60%		50%	45%

RMI Graphic. Source: Yunnan Development and Reform Commission

Renewable projects should adhere to TOU policy while participating in the power market; however, **some provinces released separate peak-valley floating ratios for renewable projects to reduce the impact on project revenue.** For example, Qinghai and Ningxia, two provinces with a high penetration of renewables, provided a lower downward adjustment ratio during valley hours for renewable projects compared with other types of power projects (see Exhibit 23). Qinghai's off-peak period is from 11:00 a.m. to 4:00 p.m., and Ningxia's off-peak period is from 9:00 a.m. to 5:00 p.m. The separate TOU policy avoids excessively low electricity prices for renewable projects in the daytime, thus safeguarding project revenue.

Exhibit 23 **TOU policies for power projects in Qinghai and Ningxia in 2024**

Qinghai	Solar PV: Peak-upward ≥63% Valley-downward ≥20%	Others: Peak-upward ≥63% Valley-downward ≥65%
Ningxia	Renewable projects: Peak-upward ≥30% Valley-downward ≥30%	Coal power projects: Peak-upward ≥50% Valley-downward ≥50%

RMI Graphic. Source: Qinghai Energy Administration, Ningxia Development and Reform Commission

With the power spot market moving forward, the rules for renewable projects participating in it have been refined. In most regions, renewable projects should bid both volume and price in the spot market. In terms of participation scope, western Inner Mongolia and Gansu require all utility-scale wind and solar projects to participate in the spot market. However, in Shanxi and Shandong, participation is voluntary. In Guangdong, all wind and solar projects that connect to the grid at 220 kV or above should participate in the spot market.

Looking ahead, **the proportion of renewables participating in the power market is expected to further increase**, and the guarantee purchased part will decline. Although the M2L market is the main market for renewable projects, the rules and pilot tests for renewable projects in the spot market and interprovincial market will continue to be enhanced.

With deeper engagement in the power spot market, **renewable projects will be expected to face more price fluctuations, increasing the risk for project revenue.** However, reasonable project returns are necessary to develop renewable projects and achieve higher penetration of renewables in the power system. Therefore, it is important that a supporting mechanism is created to ensure renewable project profitability in the power market. The M2L contract will continue to play a significant role in guaranteeing the revenue from renewable projects in the short term.

8. As distributed PV grows rapidly in China, developers should closely monitor grid access and feed-in price policies.

Distributed PV systems are gaining popularity due to their proximity to end-users and the higher revenue potential of the self-generation and self-consumption model.[ix] Also, distributed PV projects offer advantages such as ease of installation and simplified registration procedures, contributing to their rapid growth in recent years. In 2023, newly installed distributed PV capacity reached 96.3 GW, accounting for 44.5% of the total newly installed PV capacity for the year.[21] Cumulative installed capacity exceeded 250 GW, representing 41.8% of the total cumulative PV installed capacity.

Nationwide, three provinces — Henan, Jiangsu, and Shandong — saw newly installed distributed PV capacity surpass 10 GW in 2023, while five other provinces and regions recorded newly installed capacity exceeding 5 GW (see Exhibit 24). However, large-scale integration of distributed PV systems into the grid can pose significant challenges; various regions have begun implementing measures to regulate their development. Market investors should closely monitor policy changes related to distributed PV systems in different regions and carefully assess the investment risks associated with these projects.

Exhibit 24 **Overview of PV projects by province in 2023**

Province	Cumulative installed capacity in 2023 (GW)			Newly added capacity in 2023 (GW)				
	Utility scale	Distributed	Total	Utility scale	Growth compared with 2022	Distributed	Growth compared with 2022	Total
Henan	6.37	30.94	37.31	0.09	1.37%	13.89	81.53%	13.98
Jiangsu	11.56	27.72	39.28	2.03	21.24%	12.17	78.26%	14.20
Shandong	15.94	40.99	56.93	3.44	27.53%	10.79	35.71%	14.23
Anhui	12.86	19.37	32.23	2.22	20.88%	8.47	77.67%	10.69
Zhejiang	6.67	26.90	33.57	0.54	8.75%	7.64	39.68%	8.18
Hebei	30.24	23.93	54.16	10.30	51.64%	5.31	28.55%	15.61
Jiangxi	9.81	10.12	19.93	2.86	41.14%	5.05	99.74%	7.91
Hunan	3.99	8.53	12.52	1.13	39.54%	5.03	143.72%	6.16
Fujian	0.44	8.30	8.75	0.05	12.65%	4.05	95.01%	4.10
Hubei	17.49	7.38	24.87	7.74	79.29%	3.98	117.02%	11.72
Shanxi	18.24	6.66	24.90	5.67	45.11%	2.28	51.90%	7.95
Liaoning	5.21	4.36	9.58	1.40	36.76%	2.17	98.90%	3.57

Continued on next page

ix The self-generation and self-consumption model avoids T&D tariffs for distributed renewable owners given the power flow is off grid, and therefore has higher revenue potential.

Continued from previous page

Shaanxi	18.26	4.66	22.92	6.32	52.94%	1.44	44.61%	7.76
Tianjin	2.99	1.90	4.90	1.77	145.83%	0.91	92.49%	2.69
Shanghai	0.40	2.50	2.89	0.16	65.79%	0.79	46.07%	0.95
Heilongjiang	3.96	1.69	5.65	0.29	7.96%	0.60	55. 72%	0.90
Chongqing	0.88	0.72	1.60	0.34	62.08%	0.57	375.50%	0.90
Ningxia	20.12	1.25	21.37	5.20	34.86%	0.33	35.61%	5.53
Jilin	3.40	1.20	4.60	0.46	15.45%	0.28	30.05%	0.73
Gansu	24.15	1.04	25.19	11.04	84.21%	0.18	21.61%	11.22
Sichuan	5.23	0.51	5.74	3.50	202.21%	0.18	52.86%	3.67
Beijing	0.05	1.03	1.08	0.00	0. 00%	0.13	14.53%	0.13
Qinghai	25.21	0.19	25.40	7.15	39.63%	0.04	22.48%	7.19
Tibet	2.52	0.05	2.57	0.76	42.98%	0.03	131.36%	0.79
Xinjiang	28.78	0.18	28.96	14.37	99.79%	−0.09	−33.16%	14.28

RMI Graphic. Source: NEA

The rapid expansion of distributed PV is significantly altering the net load curve. Due to the inherent intermittency of solar power generation and the self-generation and self-consumption model offsetting net load, distributed PV systems can cause a steep decline in net load during morning and midday when demand is typically lower. This trend is particularly evident in regions like Shandong, Hebei, and Henan, where the rapid development of these systems is transforming the net load curve from a duck curve (evening peak, daytime trough) to a more extreme canyon curve with even deeper daytime troughs. This shift poses significant challenges to the flexibility of the power system because it needs to adapt to these substantial fluctuations in supply.

Furthermore, if a high proportion of distributed PV systems feeds all generated power back into the grid, the power flow direction on the distribution side may reverse, posing significant challenges to the stability of the grid.

To address the challenges raised by more distributed PV connecting to the grid, various regions are gradually implementing policies to regulate their development. These measures include restricting the rapid expansion of distributed PV systems in areas with connection constraints and adjusting the range for peak and valley electricity prices to optimize distributed PV development using price mechanisms.

Distributed PV should be regulated according to the grid's capability in managing power flow fluctuations. In June 2023, Shandong, Heilongjiang, Henan, Zhejiang, Guangdong, and Fujian conducted pilot programs to assess the grid capacity for accommodating distributed PV access.[22] According to the assessment results, except for Zhejiang, the five other provinces have certain constraints in accommodating distributed PV. Among the five provinces with constraints, Henan, Shandong, and Heilongjiang have all suspended or restricted new distributed PVs' access to grid. In addition, more and more regions and counties are reporting that the grid's capability for new distributed PV is very limited. Besides the aforementioned six provinces, Liaoning, Guangxi, Hebei, and Hubei have also released assessments of their grid capacity for accommodating distributed PVs. Statistics show that over 200 areas (including counties, cities, and districts) nationwide have no space for accommodating new distributed PVs.

Therefore, the development of distributed PV systems faces significant uncertainty. Some PV investors are shifting from a positive outlook to a more cautious stance. To improve PV grid integration capabilities, many regions are asking PV projects to bundle with energy storage, with increasing requirements for storage capacity and durations. Although requiring distributed PV to be equipped with energy storage opens additional space for the domestic energy storage market, it also increases the up-front burden for distributed PV projects.

Peak and valley electricity price adjustments are unfavorable to distributed PV development. The growth of distributed PV has exacerbated the duck curve. Traditional peak and valley pricing structures no longer accurately reflect the power balancing costs. In response, PV-abundant provinces like Shandong and Hubei have begun adjusting peak and valley electricity pricing using price mechanisms to guide distributed PV development.

Shandong is progressively adjusting its peak and valley pricing periods according to spot market prices. The latest pricing structure assigns the 10:00 a.m. to 4:00 p.m. period as the valley or deep valley period, matching the time when PV generation peaks. This change significantly reduces the revenue of distributed PV. Other provinces with spot markets are likely to adopt similar adjustments or directly implement spot market prices on the retail side. Investors should closely monitor the risks associated with distributed PV as pricing structure changes.

At the same time, Henan, Hebei, and Shandong have introduced policies requiring distributed PV to participate in peak regulation services and be included as a market entity in the ancillary services market. In May 2022, the NEA's Henan Supervision Office required on-grid distributed wind power and distributed PV systems with the voltage level of 10 (or 6 kV depending on the model) kV or above in the province to be included as market entities and participate in the peak regulation ancillary services market.[23] The ancillary service fee is shared among all market entities. In Hebei and Shandong, to cope with insufficient peaking capacity during the Spring Festival, distributed PV systems would be requested to participate in peak regulation services. It is expected that, in the future, non-spot market provinces and regions will have more stringent requirements for distributed PV to share ancillary services costs and/or participate in peak regulation services.

Market-based mechanisms are deemed essential to break through the barriers hindering the development of distributed PV systems. In line with this strategy, Hunan Province has taken the lead in issuing the "Notice on Further Standardizing the Development and Construction of Distributed Photovoltaics" in June 2023, requiring all distributed PV systems with 10 kV or above to enter the power market by the end of 2023.[24] The goal is to have all on-grid distributed PV across all voltage levels included in the power market by the end of the 14th Five-Year Plan period.

I&C distributed PV systems typically operate under a self-generation, self-consumption, and surplus on-grid model.[x] Currently, most distributed PV systems do not directly participate in the power market, but their actual settlement prices are already affected by it. For the self-generation portion of electricity, one of the common pricing methods is users getting a discount on the price of electricity purchased through the grid agent. Therefore, after I&C users enter the power market, especially in the spot market, the spot price curve affects the grid agent's purchase price of electricity, which in turn affects the actual settlement price of the self-generated portion of electricity. For the portion of surplus on-grid, the local coal-based benchmark price is usually used for settlement. However, looking forward, with the accelerated development of distributed PV (including residential and I&C) in recent years and the rapid increase in the amount of surplus on-grid, it is expected that the on-grid portion will be settled according to the spot market price curve or directly by the market.

x I&C distributed PV systems refer to systems owned by I&C users that provide power generation to the owners first, and then any surplus power is traded in the power market. Surplus on-grid refers to any surplus energy generated by the distributed PV system that will go through the grid to the power market for sale.

9. Independent energy storage expands market participation; the energy market is still their primary revenue source.

In recent years, more novel energy storage systems have emerged as independent entities instead of being integrated into wind or solar projects or owned and operated by the grid.[xi] Many provinces are exploring rules and mechanisms for independent energy storage to participate in the local power market. Inner Mongolia, Shanxi, Shandong, Xinjiang, and other provinces and regions are exploring diversified approaches for independent energy storage.

Inner Mongolia: Energy Market + Capacity Compensation

Inner Mongolia issued the "Inner Mongolia Autonomous Region Independent Novel Energy Storage Project Implementation Rules (Interim)" (Implementation Rules) in 2023, which clarified details of entering the power market for grid-side and independent energy storage systems.[25] The main sources of income for market entities include energy market trading and capacity fee.

Independent energy storage systems participate in the energy market and ancillary services market as both buyers and sellers. During discharge, they are like power plants (sellers), and during charging, they are users (buyers). The Inner Mongolia power grid is divided into two parts, and the progress of its power market is inconsistent. The western Inner Mongolia grid has established a spot market, and independent energy storage systems can obtain income by participating in the spot market and the ancillary services market. The eastern Inner Mongolia grid has not yet established a spot market. Independent energy storage obtains income by utilizing the price gap between peak and valley prices during the day, and providing peaking, frequency regulation, and rotating inertia services according to the relevant requirements of the Northeastern Regional Power Ancillary Services Management Regulation.

The Implementation Rules establish capacity fee for independent energy storage in Inner Mongolia. Grid-side independent energy storage systems that are part of the pilot projects can earn capacity compensation based on discharged energy for up to 10 years, with a temporary price cap of RMB 0.35/kWh. This compensation can change if a capacity market or capacity-related pricing policies are introduced. Power-side independent energy storage can generate income through capacity sales or leasing agreements with renewable enterprises, with rental prices guided by the compensation standard for grid-side projects.

xi Independent energy storage can be a stand-alone power source or on the grid side, as long as it is registered independently in the market.

Shanxi: Spot Market + Frequency Regulation Services

Shanxi is one of the most progressive provinces in spot market operation, and has spot market rules allowing independent energy storage to participate through bidding on both quantity and price or just quantity. Only day-ahead market participation is permitted for now, with real-time market access planned. And because the peak regulation services are merging in the spot market, there would not be a separate market for them.

In response to the rapid growth of renewable energy, Shanxi has established the country's first paid primary frequency regulation market. Independent energy storage can participate in this market to obtain compensation by providing primary frequency regulation capabilities beyond their basic market obligations. The market demand is set at 10% of the predicted maximum output of renewables plants within the day. Market participants submit bids for both quantity and price, with a price range of RMB 5–10/MW.[26] Prices are merit ordered based on comprehensive performance indicators (e.g., response time, response rate, and response accuracy). Frequency regulation revenue is calculated based on the regulation mileage.[xii] Storage systems' charge and discharge losses associated with the primary frequency regulation are compensated at the real-time spot average price for the current month.

Although Shanxi does not mandate compulsory energy storage for renewables projects, the province has yet to establish clear policies regarding the leasing of novel energy storage. However, the Shanxi Provincial Power Market Trading Guidelines in 2023 proposed exploring and implementing a capacity leasing or capacity compensation mechanism for novel energy storage, indicating a potential trend toward these approaches.[27]

Guangdong: M2L Market + Spot Market + Ancillary Services Market

To facilitate the growth of novel energy storage, in 2023, the Guangdong Provincial Development and Reform Commission and Energy Administration implemented a variety of measures, including encouraging participation in power market trading and mandating compulsory storage for renewables projects. As per the phased mandates, offshore wind power projects added after 2022 and utility-scale PV and onshore utility-scale wind projects added after July 1, 2023, must be equipped with novel energy storage with a capacity of no less than 10% of the generation capacity and a minimum discharging duration at rated capacity of one hour.

Like Inner Mongolia and Shaanxi, independent energy storage systems in Guangdong engage in the M2L, spot, and ancillary services markets. In the spot market, they submit bids with quantity and charging/discharging prices linked to TOU pricing at the corresponding node. Following the Southern Regional Ancillary Service Market Rules, they also submit quantity and price bids to partake in ancillary services markets to provide regional frequency regulation and cross-provincial reserve services.

Power-side energy storage systems, jointly with power generation enterprises, participate in the energy and ancillary services markets. Their trading mode is similar to that of grid-side energy storage. User-side energy storage systems, jointly with power users, participate in the electricity energy and demand response markets. They engage in wholesale (M2L, spot) or retail electricity energy trading, aiming to reduce electricity costs by utilizing peak-valley price differences to flatten the peak and fill the valley. Additionally, user-side energy storage, jointly with power users, participates in trading products such as day-ahead demand response, receiving demand response revenue based on the market clearing price and effective response capacity.

xii Defined as the absolute change in automated generation control set points between four-second intervals.

Xinjiang: Energy Market + Capacity Compensation + Peak Regulation Services Market

In May 2023, the Xinjiang Development and Reform Commission issued the “Notice on Establishing a Supporting Policy Suite for the Development of Novel Energy Storage,” establishing market participation guidelines for novel energy storage in the energy market, capacity compensation (or capacity leasing), and peak regulation services. Independent novel energy storage in Xinjiang can participate in all or a portion of its capacity in the M2L energy market or ancillary services markets. When discharging to the grid, independent energy storage acts as a power generation market entity and executes TOU on-grid prices; when charging, it is treated as a power user and executes peak and valley prices in M2L TOU market contracts with power generation enterprises. After the spot market is established, the charging and discharging prices of independent energy storage will be settled according to the spot market prices.

Xinjiang implements a capacity compensation policy for on-grid independent energy storaage. However, the compensation is less than that in Inner Mongolia and decreases rapidly each year. Before the end of 2025, the compensation standard will be calculated based on the cumulative discharge energy. In 2023, it was temporarily set at RMB 0.2/kWh, and it will decrease by 20% each year starting in 2024 (i.e., the compensation standard for 2024 is RMB 0.16/kWh and for 2025 it is RMB 0.128/kWh). The compensation funds will be temporarily shared by all I&C users.

Independent energy storage systems are supported to recover their construction costs by selling or leasing their capacity for peaking and other shared services in Xinjiang. However, the corresponding capacity will no longer receive capacity compensation. The NDRC releases an annual reference price for capacity leasing (the provisional reference price for 2023 is RMB 300/kW/y). Renewable enterprises and shared energy storage project enterprises sign long-term leasing agreements or contracts of not less than 10 years based on the annual reference price.

In Xinjiang, if independent energy storage systems charge according to dispatching instructions to avoid or reduce grid-wide wind and solar curtailment, they will receive compensation for their peak regulation service. The compensation standard is RMB 0.55/kWh per their charged energy during the peak regulation service. This energy can then be discharged to the grid if needed at RMB 0.25/kWh. The energy storage will no longer receive capacity compensation if participating in peak regulation service. Grid companies will prioritize energy storage facilities to provide the peak regulation service given the same performance rating among all available sources.

The energy market will be the most important revenue source for independent energy storage, while the ancillary services market and capacity compensation hold uncertainties. Independent energy storage generates revenue primarily through participation in energy markets (M2L and spot), capacity leasing to renewables or receiving capacity compensation, and providing ancillary services. We expect the trend to be as follows:

1. The importance of the energy market is growing. As the spot market expands rapidly and price caps are relaxed, independent energy storage participation in the spot market to capture price gap gains is becoming more certain. Consequently, the spot market is set to become the most crucial revenue source for independent energy storage.

2. The revenue from the ancillary services market will be limited. On February 8, 2024, the NDRC and NEA issued the “Notice on Establishing Market Price Mechanisms for Power Ancillary Services,” which requests provinces or regions with continuous spot market operation to delist peak regulation service

in the ancillary services market. For places that still have peak regulation services, the service price should not exceed the on-grid price of price parity renewables projects. For frequency regulation services, the maximum price for cleared frequency regulation mileage is capped at RMB 0.015/kW. The revenue from the peak regulation service and the frequency regulation service is expected to gradually decline.

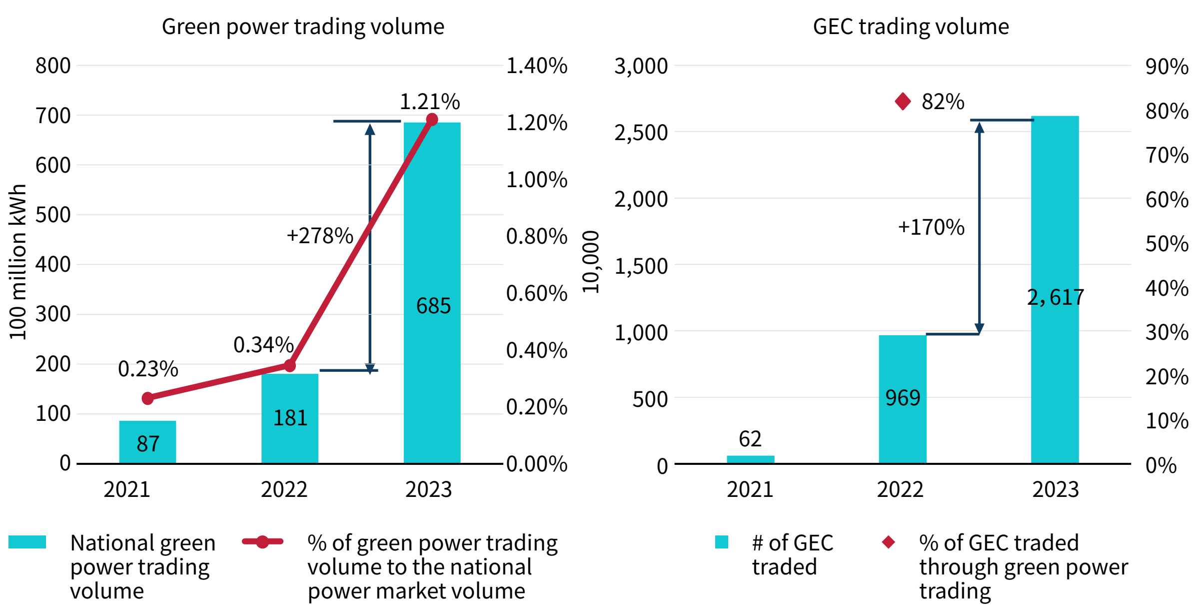
3. Capacity compensation has yet to be established nationally. Although current provincial policies recognize the value of independent energy storage through capacity compensation or renewable leasing capacity arrangements, a specific capacity fee mechanism tailored to novel energy storage has yet to be established. This is partly due to concerns regarding the inherent safety of lithium-ion batteries, the dominant technology in novel energy storage. Additionally, the prevalent two-hour system configuration falls short of meeting the capacity requirements of the power system, and issues such as lithium battery capacity degradation and relatively shorter lifespan have raised concerns. However, the overarching framework outlined in the "Notice on Establishing a Coal Power Capacity Pricing Mechanism" emphasizes the gradual implementation of a two-part pricing mechanism that effectively reflects the value of both electricity and capacity from various sources. Given the advantages of novel energy storage in terms of response performance and zero-carbon attributes compared with coal power, it is anticipated that a capacity pricing mechanism will be introduced to cover novel energy storage systems once a standardized safety protocol emerges and the systems exhibit stable long-duration capability. This transition, however, will necessitate time for technological breakthrough.

Renewables and Energy Storage

10. The green power and green electricity certificate markets continue to expand, with a relatively relaxed supply–demand relationship in the short term.

In 2023, the green power trading and green electricity certificate (GEC) markets maintained rapid expansion. The national green power trading volume reached 68.5 billion kWh in 2023, marking a 278% year-over-year increase. Specifically, the State Grid region recorded a trading volume of 61.1 billion kWh, showing a 327% year-over-year growth.[28] From January to July 2023, 26.17 million GECs were traded, marking a 170% increase over with 2022 (see Exhibit 25).[29] In terms of price, the average green premium of green power in the State Grid region was RMB 0.065/kWh in 2023; in the Southern Grid region, green power prices were RMB 0.0185/kWh higher than the average price of coal power.[30] The average price for nonsubsidized GECs from January to July 2023 was RMB 42.4, slightly up from the RMB 38 average in 2022.[31] However, starting in August 2023, the price of nonsubsidized GECs decreased by RMB 9–10 compared with the preceding seven months.[32]

Exhibit 25 **Green power trading and GEC trading volume, 2021–23**



RMI Graphic. Source: CEC, China Renewable Energy Engineering Institute

The updated green power trading rules further clarify the pricing mechanism for green power. In August 2023, the Beijing Power Exchange Center released the "Implementation Rules for Green Power Trading of Beijing Power Exchange Center (Revised Draft)" (the Revised Draft).[33] The Revised Draft requires that "market participants should separately list the energy price and the green premium of green power."[xiii] Under the bilateral negotiation and listed trading methods, market participants need to specify both the energy price and the green premium as well as the overall transaction price of green power. In the centralized auction mode, market participants declare the overall transaction price, and the green premium is determined based on the average price of GECs, with the remaining part being the energy price. Additionally, the Revised Draft for the first time clarifies that the electric energy and the environmental value need to be settled separately.

The significance of GECs has been further enhanced, solidifying their role as the exclusive embodiment of the environmental value of green power. In August 2023, the NDRC, the Ministry of Finance, and the NEA jointly issued the "Notice on Fully Covering Green Electricity Certificates to Promote Renewable Energy Electricity Consumption" (Document No. 1044).[34] Document No. 1044 expands the eligible technology for GEC issuance from onshore wind power and utility-scale solar PV to all wind power (including distributed wind and offshore wind), solar power (including distributed solar PV and solar thermal power), conventional hydropower, biomass power, geothermal power, and ocean energy, among other documented renewable energy generation projects. It introduces a centralized auction method, strengthens the role and status of GECs, and clarifies that GECs are the sole proof of the environmental attributes of green power and the only validation for the production and consumption of green power. In September 2023, the "Notice on Matters Related to the Issuance of Green Electricity Certificates" specified that the issuing agency of GECs would be changed to the Power Business Qualification Management Center of the NEA, further enhancing the authority of GECs.[35]

The latest provincial green power trading schemes generally reflect the new requirements set out in the Revised Draft. Currently, bilateral negotiation is the main mode of green power trading, with regions such as North Hebei, Shaanxi, Sichuan, Jiangsu, Fujian, and Guangxi currently only conducting bilateral negotiations. Some areas (such as Tianjin, Zhejiang, Anhui, Guangdong, and Guizhou) also conduct listed trading and centralized auction. In the Beijing Power Exchange Center region (State Grid territory), for example, Tianjin, Shaanxi, Jiangsu, and Anhui all require that the bilateral negotiation mode must separately specify the overall transaction price, the energy price, and the green premium.

Unlike the requirements in the State Grid territory, the latest trading schemes in the Southern Grid territory primarily focus on declaring the green premium. For example, Guangdong requires that only the green premium needs to be declared in both bilateral negotiation and centralized auction, and the energy price can be executed according to the agreed price or according to the respective existing pricing mechanisms; in Guangxi, both buyers and sellers in bilateral negotiations only need to declare the green premium, and the energy price in principle is the weighted average price of monthly (weekly) trading plans for each time segment of coal-fired power plants (excluding contract power transfer transactions).

Besides the wholesale market, power users can also participate in green power trading through the retail market or subscription-based transactions. Regardless of the method of participation, **under the current rules, the overall transaction price of green power trading generally consists of two parts: the energy price and the green premium. These are commonly referenced against the price of coal power and the price of GECs, respectively.**

xiii The overall transaction price of green power = energy price (embodies the value of electric energy) + green premium (embodies the value of environmental value).

In the retail market, power users purchase green power through retailers. The retailer purchases green power in the same way as the wholesale market's power users, as explained earlier. However, the retail prices may vary from the prices the retailer obtained in the wholesale market, depending on the regional rules and the retail packages. For example, Zhejiang requires that the green premium sold by retailers must be consistent with that in the wholesale market, but there is flexibility in the agreement on the energy price; whereas in Guangdong, power users can choose different retail packages and negotiate separately with retailers on the energy price and green premium.

Subscription-based transactions are currently only conducted in the Southern Grid territory. In this mode, nonmarket power users can negotiate the green premium with the renewables owners, while the energy price is defaulted to the grid companies' purchase price.

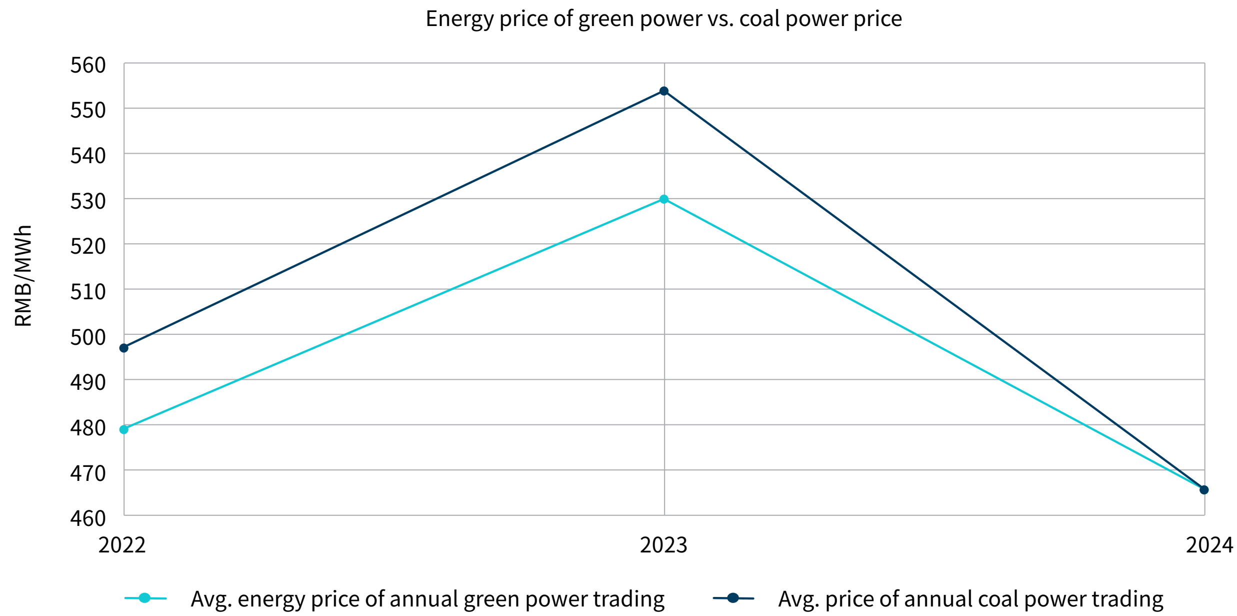
In 2023, a series of green power trading and GEC policies and rules were iterated, establishing the foundation for the development of the green power market for the foreseeable future. Considering the current trends in both energy price and green premium, **the overall transaction price of green power trading is expected to remain stable with a slight downward trend in the short term.**

The energy price is expected to decrease to some extent in the short term, primarily due to the decline in coal power trading prices and the separation of coal power capacity compensation. Currently, coal power still dominates the market, and green power energy prices are primarily anchored to coal power trading prices. Guangdong (see Exhibit 26) illustrates how green power energy prices fluctuate with thermal power trading prices, showing parallel trends from 2022 to 2024. As the thermal power trading prices approach the coal power benchmark price in 2024, the price gap between green power and thermal power trading narrowed in 2024.

Against the backdrop of declining thermal coal prices nationally, the results of 2024 annual M2L trading in multiple regions show a trend of decreasing prices for coal power. Consequently, we anticipate a corresponding decline in green power energy prices.

Additionally, after incorporating the capacity compensation into the system operation costs, the coal power price settled in the market reflects only the price of electric energy. Thus, the coal power price will decrease compared with when capacity compensation was not separated. This decline will drive down the energy price of green power.

Exhibit 26 Comparison of average annual trading price in Guangdong from 2022 to 2024



RMI Graphic. Source: Guangdong Power Exchange Center

The green premium is expected to fluctuate within a relatively stable range. Due to the linkage of the green premium with carbon markets and energy consumption assessment, regulatory authorities anticipate a reasonable fluctuation range. Maintaining the green premium within a stable range also facilitates the integration of various markets and reflects consistency in environmental attributes. Some provinces with a strong demand for green power, such as Zhejiang and Guangdong (see Exhibit 27), have set limits on the range of the green premium:

Exhibit 27 Setting limits on environmental values in selected provinces for 2024

	Document	Limits on green premium
Guangdong	"Notice on Relevant Matters of Power Market Transactions in 2024 by the Guangdong Energy Administration and South China Energy Regulatory Bureau of National Energy Administration"	0 ≤ green premium ≤ RMB 50/MWh
Guangxi	"2024 Guangxi Green Power Trading Implementation Plan"	Green premium ≥ 0
Zhejiang	"Operational Rules for Market-based Trading of Green Power and Green Electricity Certificates in Zhejiang (Trial)"	RMB 10/MWh ≤ green premium ≤ RMB 30/MWh
Tianjin	"Tianjin Green Power Trading Work Plan (2024 Revised Edition)"	Green premium ≤ RMB 50/MWh, and ≠ 0
Anhui	"Anhui 2024 Green Power Trading Implementation Plan"	Green premium > 0

RMI Graphic. Source: Guangdong Energy Administration, South China Energy Regulatory Bureau of NEA, provincial power exchange centers

Within the fluctuation range, power users' bargaining power regarding the green premium is expected to increase. While the fluctuation direction of the green premium currently lacks a clear indication, a significant short-term increase in supply will bolster power users' bargaining power regarding the green premium. This surge in supply stems from both the increase in green power and GECs, which serve as the benchmark for pricing the green premium of green power.

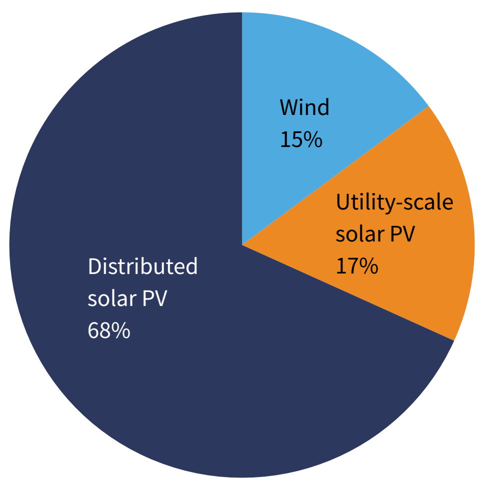
- Green power supply: The southeastern coastal provinces with a high demand for green power are expanding their green power supply by promoting interprovincial transactions and the entry of distributed projects into the market.

- Interprovincial transactions: In the absence of local nonsubsidized solar and wind projects, Shanghai relies solely on interprovincial transactions to meet its green power demand. With the increase in interprovincial supply, Shanghai's 2024 green power trading volume has already doubled that of the entire year of 2023.[36] Similarly, Jiangsu's green power supply is also in an abundant state in 2024. Relevant retailers believe that interprovincial transactions have greatly supplemented Jiangsu's green power supply.

- Distributed projects market entry: Guangdong, Jiangsu, and Zhejiang all issued documents to guide distributed projects participating in green power trading.[xiv] Zhejiang, which had already aggregated distributed projects to participate in green power trading in 2022, greatly alleviated the limited supply of green power from the local utility-scale projects (see Exhibit 28). The increase in green power supply will alleviate the previously tight balance between supply and demand, shifting the market from a state of supply shortage to a more balanced state in the short term. The change in the supply–demand relationship will enhance the bargaining power of power users over the green premium.

Exhibit 28

Proportion of solar PV and wind power installed capacity in Zhejiang as of the end of 2023



Note: The majority of wind in this exhibit is utility-scale wind projects.

RMI Graphic. Source: NEA, Xinhua News Agency

xiv Guangdong issued the "Guangdong Province Renewable Energy Trading Rules (Trial)" in 2023, allowing distributed projects to participate in green power trading as individuals. Jiangsu's "Guidelines on Market Registration and Entry Work for Distributed Wind and Solar PV" was the first to provide clear guidance for distributed projects to participate in intra-month green power trading. Zhejiang clarified in the "Zhejiang Green Power Trading and Transmission and Distribution Service Contract (Model Text, 2024 Edition)" that distributed power projects could be represented by retailers to participate in the wholesale market.

- In terms of the supply of GECs: Influenced by the Revised Draft and documents from some provinces, market participants often reference the price of GECs when setting the green premium. Following the issuance of Document No. 1044 in August 2023, the scope of GEC issuance was expanded beyond onshore wind and utility-scale solar PV to include offshore wind, distributed solar PV, biomass, and other documented renewable energy generation projects. Based on the cumulative installed capacity of renewable energy by the end of 2023, the installable capacity eligible for GECs in just wind and solar PV increased from 760 million kW to 1.05 billion kW. This policy iteration led to market expectations of an increase in GEC supply, and the anticipated change in the supply–demand relationship caused a significant drop in GEC prices in August 2023.

- Subsequently, in February 2024, the "Notice on Strengthening the Integration of Green Electricity Certificates with Energy Conservation and Carbon Reduction Policies to Promote Non-Fossil Energy Consumption" was issued.[37] It mandates that by the end of June 2024, all utility-scale renewable energy generation projects in the country should be fully documented, and the scale of documented distributed projects should be further increased. It also stipulates that "Interprovincial trading of GECs should not be restricted." These requirements are expected to greatly accelerate the mass issuance of GECs and increase the willingness of interprovincial GEC trading, significantly increasing the GEC supply in the short term. With the further increase in supply, GEC prices may correspondingly decrease. Because the green premium is pegged to GEC prices, the decline in GEC prices will enhance the bargaining power of power users when negotiating the green premium.

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