Capacity payments for coal-fired power plants in China

January 2026

Report Team

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About the Project

This report was produced by the Electricity Market Tracker project, an initiative to generate independent analytical capabilities to respond to the myriad debates over power market designs occurring in provinces throughout China. Through collection of market and grid data, development of modeling simulation tools, and analysis of international experiences, the project aims to address policy-relevant research questions and disseminate results to a wide range of stakeholders.

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Summary

China has implemented a capacity payment mechanism for coal-fired power plants since January 2024, but it remains unclear whether current levels of capacity payments are sufficiently high or low. As the country operates the world's largest coal fleet, the design and implementation of this mechanism will have far-reaching implications for power sector decarbonization and low-carbon energy integration. We evaluate the profitability of coal-fired power plants across provinces and find that pre-tax profit margins range from -33% to 26% with capacity payments in 2024, with regional disparities expected to widen by 2035. The results suggest that capacity payments should be tailored to each grid region's capacity needs and operational patterns. In the longer term, China's capacity payment mechanism should evolve from its current administrative approach to a market-based framework to enhance efficiency and align with broader power market reforms.

Introduction

China has begun implementing capacity payment mechanisms in recent years for coal-fired power plants to improve cost recovery and maintain grid reliability. In 2022, the Nation Development and Reform Commission (NDRC) and the National Energy Administration (NEA) issued the "Guiding Opinions on Accelerating the Establishment of a National Unified Electricity Market System", referred to as Document No. 118, which mandates that all regions with electricity spot markets should "establish a market-based mechanism for recovering power generation capacity costs" (NDRC, 2022). Subsequently, in November 2023, the NDRC and NEA jointly issued the "Notice on Establishing a Coal Power Capacity Pricing Mechanism", which took effect in January 2024 (NDRC, 2023a). Under this framework, the fixed costs of coal units are standardized nationwide at 330 RMB/kW-yr, with roughly 30% of these costs recoverable through capacity payments in most regions during 2024-2025. In areas undergoing faster coal transitions, the recovery ratio can reach 50% (NDRC, 2023b). Beginning in 2026, the proportion of fixed costs recovered through capacity payments will increase to at least 50% across all regions. Given that China operates the largest coal fleet in the world, the design and implementation of such a capacity payment mechanism will play a critical role in shaping the country's transition towards a low-carbon energy system.

The rationale for introducing capacity payment mechanisms is two-fold. First, China's electric power system is expected to have more coal power online, and a growing challenge lies in ensuring cost recovery for these units. While renewable capacity has been growing at an unprecedented rate of over 300 GW/yr since 2023, new coal-fired projects continue to advance, with a total estimated capacity of 94.5 GW, representing 93% of the global new coal capacity in 2024 (CarbonBrief, 2025). However, rising fuel costs, limited cost pass-through, and decreasing capacity factors when renewable energy is abundant have contributed to significant losses for coal-fired power plants. In 2021 alone, over 80% of coal units failed to cover their operating costs, leading to nationwide financial losses exceeding 300 million RMB (Chen, 2022). In provinces like Gansu, coal-fired power plants represent a large share of outstanding loans and face higher fuel costs than other provinces (Wang et al., 2022). As renewable energy continues to displace coal generation, the reduced utilization of coal units may increase the risk of loan defaults, potentially destabilizing local banking systems.

Second, China's efforts to reduce the carbon intensity of its coal fleet remain financially challenging. Under its 2030 Nationally Determined Contributions (NDCs), China targets a 65% reduction in carbon intensity from 2005 levels by 2030, while the latest 2035 NDCs call for economy-wide greenhouse gas emissions to decline by 7-10% below peak levels by 2035

(United Nations Climate Summit, 2025). To reduce emissions from coal power, China unveiled the Coal Action Plan in 2024, promoting the adoption of technologies such as biomass or green ammonia co-firing and carbon capture and storage (CCS) (ARE, 2024). However, it remains uncertain whether these financially constrained units have sufficient financial incentives to undergo capital-intensive retrofits. Moreover, recent studies show that retrofitted coal power may operate at even lower capacity factors, as their value propositions shift toward providing flexibility services and supporting renewable integration (PKU, 2025).

This policy context gives rise to two central research questions:

(1) Which regions experience the most cost recovery pressure (i.e., least profitable) under the current capacity payment mechanism?
(2) How should capacity payment mechanisms evolve to align with ongoing decarbonization and power market reforms?

Overcompensating coal units exclusively could incentivize additional coal investment and create fossil fuel infrastructure lock-in. The answers to these questions become crucial when China's new coal capacity reaches its highest level in a decade. To the best of our knowledge, no existing study has examined how capacity payment mechanisms affect the financial viability and transitional risks of China's coal-fired power plants.

Findings

To address these gaps, we adopt the following methodology. First, we analytically solve for the pre-tax profit margin for coal-fired power plants in each province, incorporating key factors such as electricity benchmark tariffs, contract prices for coal on-grid power, annual run hours, fuel costs, and capacity payment revenues. In this process, we estimate capital recovery factors (CRF) for each coal unit using the 5-year loan prime rates from the People's Bank of China and calculate capacity-weighted CRF in each province. This approach allows us to capture the spatial heterogeneity in investment timing and financing conditions. Second, we use a forward-looking approach, where we obtain capacity and generation mix at the provincial level for 2035 based on the least-cost decarbonization pathways for China's power sector (Z. Zhang et al., 2025). We update the profit margin calculations accordingly to estimate the distribution of future coal power profitability in 2035, considering future electricity demand, renewable cost, and policy uncertainties. Finally, we provide policy recommendations to inform China's ongoing capacity market design, drawing on our analytical findings and international experiences with capacity payment mechanisms.

Figure 1 shows the pre-tax profit margins for coal-fired power plants across Chinese provinces in 2024, using operation and cost data from the same year. Three scenarios are analyzed: (1) no capacity payments, (2) capacity payments with an unadjusted electricity tariff ceiling, and (3) capacity payments with an adjusted electricity tariff ceiling. The ceiling price for coal on-grid power is set at 120% of the benchmark tariff in each province (NDRC, 2021). The adjusted ceiling reflects current market practice, in which capacity payments are converted to an energy-equivalent value using annual run hours and then deducted from the tariff ceiling.

Regions with low electricity benchmark tariffs, low run hours, and high fuel costs generally see low coal power profitability. The Northwest grid region has both the least profitable (e.g., Ningxia, Gansu, and Qinghai) and most profitable coal units (e.g., Inner Mongolia), primarily driven by differences in fuel costs and annual run hours. The dominant factors driving low coal profitability vary by region. For example, Central China has the highest fuel costs nationwide, whereas Northeast China has the lowest level of annual run hours, albeit above-average electricity benchmark tariffs.

Introducing capacity payments significantly improves profitability, raising pre-tax profit margins by an absolute amount of 4%-20% before tariff ceiling adjustments. The largest gains occur in provinces with the lowest baseline profitability (e.g., Qinghai, Gansu, and Yunnan). Higher capacity prices increase profit margins by an additional 3%-5% in provinces such as Sichuan and Guangxi, assuming comparable levels of coal run hours and electricity benchmark tariffs. However, once tariff ceiling adjustments are implemented, capacity payments have minimal impacts on profitability in provinces where mid-to-long-term (MLT) electricity contract prices are already close to the tariff ceiling (e.g., Ningxia, Guizhou, and Hainan). Detailed results showing different capacity payment levels are provided in **Supplementary Information**.

Figure 2 shows the distribution of pre-tax profit margins with capacity payments (unadjusted tariff ceiling) and installed coal capacity in 2035 in each province, alongside the outstanding loans for coal-fired power plants as of 2022 (Wang et al., 2022). The results are derived from least-cost decarbonization pathways of China's power sector consistent with a 2ºC global temperature rise target, which provide a set of plausible future coal capacity and annual run hours. According to these pathways, total installed coal capacity will drop from around 1,400 GW in 2024 to 880-1,050 GW in 2035 nationwide, and electricity generation from coal-fired power plants will decrease from 6,940 TWh in 2024 to 3,070-3,450 TWh in 2035. Correspondingly, average coal run hours will decrease from around 5,000 hours in 2024 to 3,100-3,900 in 2035 nationwide.

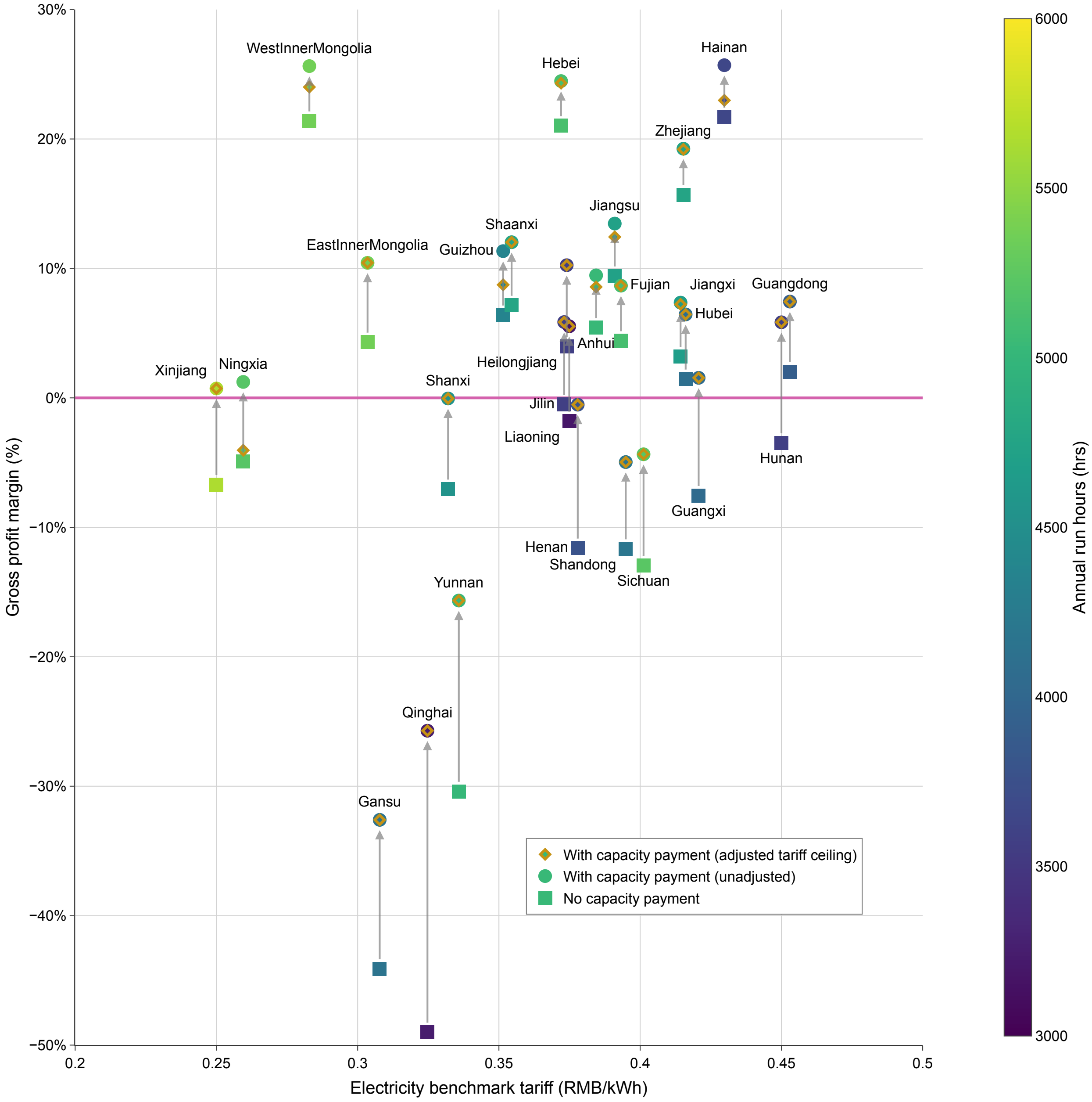

Figure 1. Pre-tax profit margins for coal-fired power plants in each province in 2024. The color scale shows the annual run hours of coal-fired power plants, and arrows indicate the changes in coal profitability with capacity payments.

As coal utilization declines, pre-tax profit margins will change by an absolute amount of -25% to 5% from 2024 to 2035 nationwide, where the profit increases are attributable to higher capacity payment levels. Regions that have lower-quality renewable resources may experience moderate gains in coal profitability of up to 8% (e.g., Jiangxi). In comparison, the largest reductions are observed in Inner Mongolia and Jilin, driven by sharp declines in coal generation and large-scale renewable deployment.

Two distinct patterns of financial risks may emerge by 2035. First, regions with persistently low coal profitability and moderate levels of outstanding coal loans, such as Gansu and Ningxia, face elevated risks of cost recovery shortfalls and stranded assets. Second, regions with highly uncertain coal profitability and large outstanding coal loans, such as Inner Mongolia and Shandong, experience systemic financial vulnerability as the energy transition accelerates.

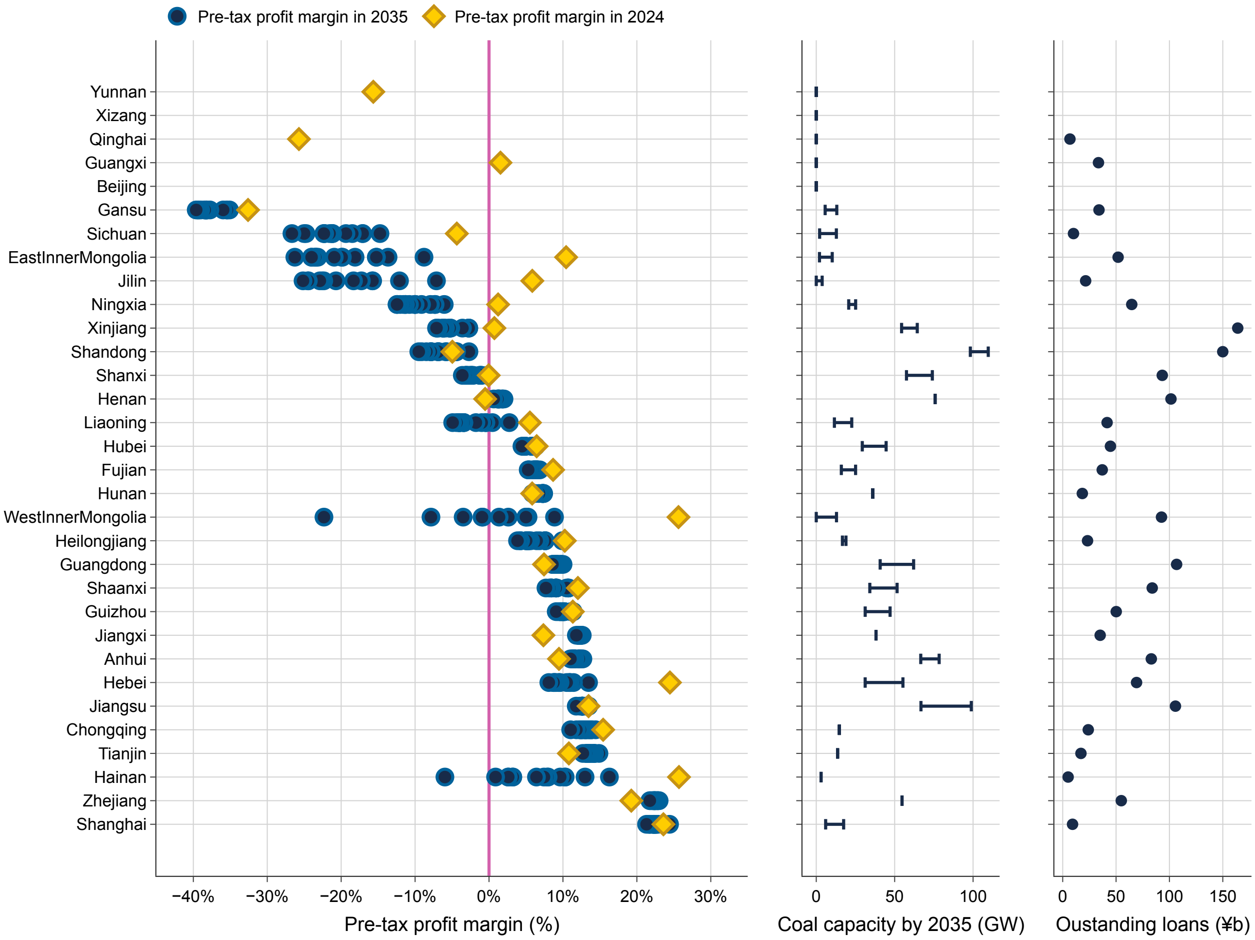

Figure 2. Pre-tax profit margins for coal-fired power plants in each province in 2035. The left panel shows the pre-tax profit margin, where circle-shaped icons indicate 2035 pre-tax profit margins in each scenario, and diamond-shaped icons indicate the 2024 levels with capacity payment (unadjusted tariff ceiling). The middle panel shows the range of installed coal power capacity in each province in 2035. The right panel shows the outstanding loans for coal-fired power plants as of 2022, obtained from Wang et al., 2022.

Our analysis has several limitations. First, we calculate coal run hours by dividing monthly electricity generation by the installed coal capacity at the provincial level, due to the limited availability of provincial-level statistics on actual coal run hours. We use the annual statistics from NEA to verify that our run hour estimates are reasonable at the national level (i.e., the average nationwide run hours are around 4,417 hours from 2013 to 2023). Second, actual electricity prices for on-grid coal power in each province can fluctuate by up to 20% relative to the benchmark tariffs. We obtain average annual contract prices from industry reports and trading websites, but detailed data at the firm level are limited. Lastly, for our analysis of coal profitability in 2035, we assume capacity payment prices rise to 50% of the standardized fixed cost. We do not consider coal transition pathways such as CCS retrofits, early retirement, and flexibility retrofits. While other studies have done detailed assessments on coal transition pathways using power system models with unit-level engineering details, integrating such analyses into future capacity market modeling will be an important next step.

Policy Implications

This work has important implications for enhancing the capacity payment mechanism in China. We show that coal power profitability ranges from -33% to 26% across provinces in 2024 with capacity payments, and this disparity is expected to widen further by 2035. Such heterogeneity suggests capacity payment should vary by province at the very least, if the policy objective is to partially recover the fixed costs of coal-fired units. China's NDRC currently excludes certain coal-fired power plants from receiving capacity payments, specifically those that do not meet requirements for energy consumption, environmental protection, and flexible adjustment capabilities. However, among the eligible plants, the existing framework does not differentiate payment levels according to other key drivers of profitability, such as unit age, fuel efficiency, and fuel costs (Hui, 2023). Incorporating these factors into the payment structure could make the mechanism more targeted and cost-effective, ensuring support is directed toward units that are both financially vulnerable and essential for grid reliability.

Second, China should explore a broader suite of capacity payment design options to improve efficiency and adaptability. Our analysis shows that coal profitability can decrease by up to 15% in 2035 in provinces with great potential for high-quality renewable resources, but increase by up to 8% in provinces with relatively lower-quality resources. Although nationwide coal run hours are expected to decline each year, the resource adequacy needs and operational patterns will continue to differ across grid regions and over time. This suggests that capacity payment mechanisms should be sufficiently dynamic to adapt to those grid changes, yet not overly volatile to undermine investment confidence. For example, annual fixed capacity payments may affect spot market bidding behaviors more than quarterly or monthly payments, and can be less effective without non-performance penalties. Key design dimensions, including update frequency, interannual variability, and the look-back period for assessing historical performance, should be carefully determined next. Moreover, assessing the capacity value of coal capacity could adopt a reliability-based approach, such as the Effective Load Carrying Capability (ELCC), given reliability standards, to ensure resources are compensated according to their actual contribution to resource adequacy.

In the longer timeframe, China's capacity payment mechanism should evolve from its current administrative approach to a more market-based framework. A market-based approach can be more effective in revealing efficient price signals to ensure resource adequacy (Joskow, 2008). As resources other than coal power can also help meet the system's capacity needs, the mechanism should be inclusive to all resource types, while reflecting their distinct technical-economic characteristics (Kahrl et al., 2021), such as asymmetric risk exposure (Mays et al., 2019). While there is no consensus on the optimal mechanism design, it is essential to systematically evaluate the available options, such as resource eligibility, reliability-based or performance-based, class-based or unit-specific, and average or marginal capacity value (Byers et al., 2018; Prete et al., 2024). Future capacity market design should adhere to key principles: competitive, non-discriminatory, enforcing non-performance penalty, and minimizing spot market distortions (Ming et al., 2023; RAP, 2023).

Finally, as China aims to reach carbon neutrality by 2060, it remains nebulous whether and how the expanding coal fleet will be efficiently utilized to support this transition. Coal-fired power plants, especially the retrofitted units that are less carbon-intensive, will play a critical role in contributing to resource adequacy and grid resilience, as renewable penetration rises. However, the policy framework for incentivizing coal retrofit decisions is still unclear. Going forward, the design of capacity payment mechanisms should consider the interaction with decarbonization policies, spot market reforms, and the national emission trading scheme, to ensure coal's evolving role aligns with the long-term climate targets.

Methods

To evaluate coal power profitability, we take the following analytical approach. We consider revenues from electricity generation and capacity payment, and costs from annualized fixed costs, fuel costs, and other variable costs. Then, we obtain electricity benchmark tariffs, average MLT prices, run hours, fuel costs, and capacity payment prices at the provincial level. Lastly, we calculate the pre-tax profit margin for coal-fired power plants in each province.

For a coal-fired power plant, annual revenues in each province are calculated as,

$$\gamma_i Cap_i + \sum_t \lambda_i E_{i,t}$$

where Cap_i is the installed coal power capacity in kW in province i, $E_{i,t}$ is the annual electricity generation in kWh in province i in month t, λ_i is the average MLT price for coal on-grid power in RMB/kWh in province i, and γ_i is the capacity payment price in RMB/kW-yr in province i. We do not consider other revenue streams, such as ancillary services.

Annual costs in each province are calculated as,

$$\alpha Cap_i + \sum_t (\beta_{i,t} E_{i,t} + \eta E_{i,t})$$

where α is the annualized capital cost in RMB/kW, $\beta_{i,t}$ is the fuel price in RMB/kWh in province i in month t, and η is the other variable cost in RMB/kWh.

Thus, the pre-tax profit margin of coal-fired power plants in each province is,

$$\frac{\gamma_i Cap_i + \sum_t \lambda_i E_{i,t} - \left(\alpha Cap_i + \sum_t (\beta_{i,t} E_{i,t} + \eta E_{i,t})\right)}{\gamma_i Cap_i + \sum_t \lambda_i E_{i,t}}$$

Substitute $E_{i,t}$ with $R_{i,t} \times Cap_i$, where $R_{i,t}$ is the monthly run hours in province i in month t, we have the pre-tax profit margin as,

$$ProfitMargin_i = 1 - \frac{\alpha + \sum_t (\beta_{i,t} + \eta) R_{i,t}}{\gamma_i + \sum_t \lambda_i R_{i,t}}$$

To obtain the distribution of plausible future coal power profitability in each province in 2035, we use the capacity and generation mix for 2035 according to least-cost decarbonization pathways for China's power sector that comply with a 2^{o}C global temperature rise target and update the pre-tax profit margin calculations (**Supplementary Note 4**). The pathways are obtained from running the Renewable Energy Siting and Power-system Optimization (RESPO) model, which optimizes for renewable deployment and other power system variables at high spatial and temporal resolutions (D. Zhang et al., 2024). We consider decarbonization pathways across 15 scenarios, with varying levels of electricity demand, CO_2 emission targets for the power sector, and renewable cost trajectories.

Data sources used in this study are summarized below. We obtain electricity generation and run hours from the website of NEA (**Supplementary Note 2**), and electricity benchmark tariffs and capacity payment prices from the website of NDRC (**Supplementary Note 1**). We use the fuel cost estimates from An et al. to calculate operational costs for coal-fired power plants in 2024 (An et al., 2025). In their study, a regression analysis was first conducted on provincial coal price indexes (CTCI) and the national coal price index (CTCI) from 2014 to 2020. Then, the national coal price index (CECI Caofeidian index) in 2023 was used to predict provincial fuel costs in 2023 (**Supplementary Note 3**). While there are other coal price indexes available, the CECI Caofeidian index reflects well the actual fuel costs for coal power generation. We use the historical loan prime rates from the People's Bank of China to estimate the capital recovery factors (CRF) and annualized fixed costs across provinces (**Supplementary Note 5**). For the 2035 coal profitability analysis, we assume capacity payment prices remain at 165 RMB/kW-yr across provinces, consistent with existing policy requirements. Detailed data descriptions and assumptions are provided in **Supplementary Information**.

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Supplemental Information

Supplementary Note 1 Electricity prices, benchmark tariff, and capacity payment

The electricity price for on-grid coal-fired power has been implemented based on a market-based price mechanism of “benchmark tariff + floating range” since January 1, 2020. The benchmark tariff is determined according to the local existing electricity benchmark tariff for on-grid coal-fired power generation, which includes prices for desulfurization, denitrification, and dust removal (NDRC, 2019). The floating range for coal electricity benchmark tariff was expanded from a maximum 10% increase and a maximum 15% decrease to a maximum 20% increase or decrease starting October 15, 2021. Electricity spot market prices are not subject to the above limitations (NDRC, 2021).

In November 2023, the NDRC and NEA jointly issued the “Notice on Establishing a Coal Power Capacity Pricing Mechanism”, which establishes a coal power capacity pricing mechanism to be implemented starting January 2024 (NDRC, 2023a). The fixed costs of coal power units follow a nationwide unified standard of 330 RMB/kW-yr. The proportion of fixed costs recovered through capacity pricing is set at approximately 30% in most regions for 2024 and 2025, with some areas undergoing faster coal power transformation reaching around 50% (NDRC, 2023b). From 2026 onward, the proportion of fixed costs recovered through capacity pricing in all regions will be increased to no less than 50%.

Table 1 shows the electricity benchmark tariff and capacity payment prices in each province used in this study. Due to limited data availability, we ignore the floating range component for on-grid electricity prices for coal power generation in our calculations. We assume capacity payment prices from 2026 onward remain at 165 RMB/kW-yr, which is 50% of the standardized annualized fixed costs of coal-fired power plants.

Supplementary Table 1. Provincial electricity benchmark tariff and capacity payment prices

Province	Electricity benchmark tariff (RMB/MWh)	Capacity payment price in 2024 and 2025 (RMB/kW-yr)	Capacity payment price in 2035 (RMB/kW-yr)
Beijing	0.3598	100	165
Tianjin	0.3655	100	165
Hebei	0.372	100	165
Shanxi	0.332	100	165
Shandong	0.3949	100	165
West Inner Mongolia	0.2829	100	165
East Inner Mongolia	0.3035	100	165
Liaoning	0.3749	100	165
Jilin	0.3731	100	165
Heilongjiang	0.374	100	165
Shanghai	0.4155	100	165
Jiangsu	0.391	100	165
Zhejiang	0.4153	100	165
Anhui	0.3844	100	165
Fujian	0.3932	100	165
Jiangxi	0.4143	100	165
Henan	0.3779	165	165
Hubei	0.4161	100	165
Hunan	0.45	165	165
Chongqing	0.3964	165	165
Sichuan	0.4012	165	165
Shaanxi	0.3555	100	165
Xinjiang	0.25	100	165
Qinghai	0.3247	165	165
Ningxia	0.2595	100	165
Gansu	0.3078	100	165
Guangdong	0.463	100	165
Yunnan	0.3358	165	165
Hainan	0.4298	100	165
Guizhou	0.3515	100	165
Guangxi	0.4207	165	165
Xizang	0.4993	N/A	N/A

Supplementary Note 2 Coal capacity, electricity generation, and run hours

Table 2.1 shows the installed coal capacity, annual electricity generation, and annual run hours in each province in 2024. Annual run hours are obtained by dividing annual electricity generation by the installed coal capacity in each province. The electricity generation in Inner Mongolia is split into West Inner Mongolia and East Inner Mongolia based on installed coal capacity.

Table 2.2 shows the detailed monthly breakdowns of electricity generation from coal-fired power plants.

Supplementary Table 2.1 Coal capacity, electricity generation, and run hours in 2024

Province	Coal capacity (GW)	Annual electricity generation (10^8 kWh)	Annual run hours (hours)
Beijing	11.53	420.2	3645
Tianjin	18.94	763.6	4032
Hebei	56.47	2887.6	5113
Shanxi	80.93	3660.8	4524
Shandong	121.02	5048.5	4172
West Inner Mongolia	73.71	3938.5	5343
East Inner Mongolia	41.33	2208.5	5343
Liaoning	39.61	1254.9	3168
Jilin	18.91	674.5	3567
Heilongjiang	25.77	913.6	3545
Shanghai	25.42	983.9	3870
Jiangsu	108.25	5084.7	4697
Zhejiang	71.48	3396.4	4751
Anhui	63.07	3160.2	5010
Fujian	38.49	1907.0	4954
Jiangxi	31.61	1395.7	4415
Henan	74.21	2797.1	3769
Hubei	40.78	1665.7	4085
Hunan	28.97	1032.7	3565
Chongqing	17.20	924.3	5372
Sichuan	21.47	967.0	4504
Shaanxi	61.30	2754.8	4494
Xinjiang	68.69	3862.9	5623
Qinghai	4.12	133.1	3227
Ningxia	33.30	1726.4	5184

Gansu	25.85	1075.1	4159
Guangdong	117.41	4891.0	4166
Yunnan	11.36	598.9	5272
Hainan	8.53	310.2	3637
Guizhou	37.40	1624.6	4344
Guangxi	29.24	1193.4	4081
Xizang	0.43	3.9	912

Supplementary Table 2.2 Monthly electricity generation in each province in 2024

Province (10^8 kWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Beijing	46.3	46.3	35.0	23.3	22.8	33.4	42.4	36.9	23.8	22.6	38.7	48.7
Tianjin	72.1	72.1	61.7	53.8	49.2	62.7	75.8	76.8	58.3	50.1	57.3	73.8
Hebei	268.7	268.7	227.5	208.4	212.3	249.4	262.9	267.1	225.5	208.4	227.0	261.8
Shanxi	332.1	332.1	291.8	252.0	256.7	300.4	349.7	332.3	277.0	269.0	312.8	354.9
Shandong	438.0	438.0	387.5	371.4	371.0	420.9	446.4	515.4	431.7	383.7	403.2	441.4
West Inner Mongolia	330.8	330.8	310.3	286.6	295.1	324.8	388.8	376.5	315.7	307.0	322.8	349.2
East Inner Mongolia	185.5	185.5	174.0	160.7	165.5	182.2	218.0	211.1	177.0	172.2	181.0	195.8
Liaoning	118.5	118.5	101.7	81.1	75.8	91.8	122.7	132.0	91.3	91.3	108.6	121.7
Jilin	68.0	68.0	60.7	44.4	39.9	42.1	62.3	63.1	41.7	50.8	63.4	70.1
Heilongjiang	86.6	86.6	81.3	64.7	58.6	63.8	81.0	77.4	59.3	72.7	85.9	95.8
Shanghai	87.5	87.5	84.9	66.8	61.4	55.2	100.4	116.1	98.0	64.8	69.2	92.1
Jiangsu	393.0	393.0	408.6	383.7	404.6	404.5	486.6	545.9	450.9	377.8	391.3	444.8
Zhejiang	224.2	224.2	290.0	264.3	257.1	222.1	346.3	363.3	328.7	277.0	275.0	324.3
Anhui	273.2	273.2	242.7	218.3	227.0	260.7	306.3	334.0	268.0	221.3	248.2	287.3
Fujian	132.3	132.3	167.3	129.0	142.9	145.6	197.8	203.4	191.5	151.9	146.3	166.7
Jiangxi	119.1	119.1	109.0	95.8	96.8	96.4	124.6	135.7	133.4	106.1	117.9	141.9
Henan	257.4	257.4	199.0	179.1	197.8	251.2	260.0	309.8	230.2	197.0	199.2	259.0
Hubei	140.3	140.3	117.4	102.2	111.7	136.7	116.2	169.1	179.1	134.3	143.9	174.6
Hunan	99.5	99.5	74.8	48.1	54.7	49.5	93.2	110.4	113.6	77.5	96.0	115.9
Chongqing	80.6	80.6	77.5	62.8	62.5	56.9	70.6	96.0	103.7	71.7	73.9	87.5
Sichuan	91.7	91.7	106.6	82.6	66.7	46.4	50.9	86.7	104.1	70.5	74.1	95.0
Shaanxi	252.3	252.3	218.5	180.9	180.0	224.6	243.4	258.8	231.1	199.3	227.4	286.2
Xinjiang	359.0	359.0	342.2	286.6	277.8	291.6	312.9	319.6	279.3	296.6	338.2	400.1
Qinghai	15.7	15.7	14.5	10.1	8.3	5.2	5.2	3.4	11.6	11.8	13.9	17.8
Ningxia	147.5	147.5	144.2	121.8	128.3	140.2	155.4	150.7	135.7	121.0	161.7	172.5
Gansu	114.1	114.1	97.2	66.6	53.4	69.9	90.4	85.2	77.8	83.3	100.2	122.9
Guangdong	333.6	333.6	420.3	412.0	375.5	389.4	485.0	470.4	481.6	387.9	392.7	409.1
Yunnan	53.1	53.1	63.0	56.5	58.4	43.9	34.3	27.6	43.1	54.1	54.8	57.1
Hainan	21.4	21.4	26.4	29.0	25.5	26.9	28.1	29.9	28.3	25.9	22.9	24.6
Guizhou	144.9	144.9	147.2	124.9	107.9	98.2	102.7	153.3	158.2	130.2	136.0	176.2
Guangxi	114.4	114.4	117.6	110.9	92.8	82.9	88.6	90.5	102.0	82.8	90.8	105.7
Xizang	0.2	0.2	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3

Supplementary Note 3 Coal fuel efficiency and fuel costs

Table 3 shows the national statistics on fuel efficiency and annual run hours from 2013 to 2023 obtained from the websites of NEA and NDRC. Fuel efficiency refers to the amount of standard coal consumption for each unit of electricity generation for coal-fired power plants with a capacity of 6,000 kW or above. Annual run hours refer to the utilization hours of coal-fired power plants with a capacity of 6,000 kW or above. In our analysis, we assume all the coal-fired power plants have a fuel efficiency of 300 g/kWh.

Table 4 shows the provincial-level fuel costs for coal-fired power plants. We obtain the original values in $/GJ reported in An et al. In their study, a regression analysis was conducted on provincial coal price indexes (CTCI) and the national coal price index (CTCI) from 2014 to 2020. The regression results were then used to predict provincial coal prices in 2023 using the available national coal price index (CECI Caofeidian index Q5000) in 2023. In our analysis, we use an exchange rate of 1 USD = 7.1 RMB. We assume each tonne of coal has a heat value of 21 GJ, and future fuel costs remain at the 2023 level.

Supplementary Table 3. Historical data on fuel efficiency and annual run hours

Year	Fuel efficiency (g/kWh)	Annual run hours (hours)
2013	N/A	5012
2014	318	4706
2015	315	4329
2016	312	4165
2017	309	4209
2018	308	4361
2019	307	4293
2020	305.5	4216
2021	302.5	4448
2022	301.5	4379
2023	303	4466
Average	308	4417

Supplementary Table 4. Coal fuel costs in each province. Original values in $/GJ are obtained from (An et al., 2025)

Province	Fuel costs ($/GJ)	Fuel costs (RMB/tonne)
Beijing	5.51	821.54
Tianjin	5.51	821.54
Hebei	4.4	656.04
Shanxi	4.03	600.87
Shandong	5.93	884.16
West Inner Mongolia	2.49	371.26
East Inner Mongolia	2.63	392.13
Liaoning	5.36	799.18
Jilin	5.58	831.98
Heilongjiang	5.09	758.92
Shanghai	5.44	811.10
Jiangsu	5.81	866.27
Zhejiang	5.63	839.43
Anhui	6.11	911.00
Fujian	5.71	851.36
Jiangxi	6.89	1027.30
Henan	6.01	896.09
Hubei	6.6	984.06
Hunan	6.93	1033.26
Chongqing	6.09	908.02
Sichuan	6.49	967.66
Shaanxi	4.44	662.00
Xinjiang	2.4	357.84
Qinghai	4.85	723.14
Ningxia	3.92	584.47
Gansu	5.29	788.74
Guangdong	5.93	884.16
Yunnan	4.23	630.69
Hainan	4.8	715.68
Guizhou	4.95	738.05
Guangxi	6.85	1021.34
Xizang	N/A	N/A

Supplementary Note 4 Future coal capacity and run hours in 2035

We use the Renewable Energy Siting and Power-system Optimization (RESPO) model to obtain the least-cost decarbonization pathways for China's power sector that comply with a 2°C global temperature rise target. We consider decarbonization pathways across 15 scenarios, with varying levels of electricity demand, CO_2 emission targets for the power sector, and renewable cost trajectories. **Table 4.1** summarizes the modeling scenarios, and **Table 4.2** shows the capacity expansion results at the national level.

Table 4.3 and **Table 4.4** show the provincial-level coal capacity and run hours in 2035 across different scenarios.

Supplementary Table 4.1 Summary of modeling scenarios

Group	Electricity demand and emission targets	Scenario ID	Key variations
Moderate Growth	● 12.5 PWh in 2030, 13.5 PWh in 2035 ● 2°C emission trajectory (4,200 $MtCO_2$/yr in 2030 and 3,300 $MtCO_2$/yr in 2035)	A1	Reference renewable costs
		A2	Conservative renewable costs
		A3	Low wind costs
		A4	Low battery costs
		A5	2035 demand uncertainty (14.85 PWh)
Rapid Electrification	● 13.5 PWh in 2030, 15 PWh in 2035 ● 2°C emission trajectory (4,200 $MtCO_2$/yr in 2030 and 3,300 $MtCO_2$/yr in 2035)	B1	Reference renewable costs
		B2	Conservative renewable costs
		B3	Low wind costs
		B4	Low battery costs
		B5	2035 demand uncertainty (14.5 PWh)
Ambitious Decarbonization	● 12.5 PWh in 2030, 13.5 PWh in 2035 ● More ambitious 2°C emission trajectory (5% lower emissions in 2030 and 10% lower emissions in 2035 than 2°C)	C1	Reference renewable costs
		C2	Conservative renewable costs
		C3	Low wind costs
		C4	Low battery costs
		C5	2035 demand uncertainty (14.85 PWh)

Supplementary Table 4.2 Nationwide renewable deployment, coal capacity, and coal power generation in 2035 across different scenarios

Scenario ID	Renewable capacities (GW)	Storage capacities (GW)	Total transmission capacities (GW)	Renewable generation shares (%)	Coal capacities (GW)	Coal power generation (TWh)
A1	2976	240	1228	49.64%	934	3431
A2	2913	240	1279	49.60%	931	3438
A3	2921	240	1199	49.68%	911	3420
A4	2976	240	1228	49.64%	934	3431
A5	3612	258	1403	54.40%	1040	3437
B1	3686	267	1417	54.89%	1047	3437
B2	3615	264	1462	54.87%	1043	3441
B3	3616	240	1410	54.89%	1137	3429
B4	3686	267	1417	54.89%	1047	3437
B5	3440	245	1358	53.25%	1025	3435
C1	3141	242	1284	52.36%	941	3080
C2	3072	240	1338	52.33%	910	3087
C3	3089	240	1260	52.39%	887	3071
C4	3141	242	1285	52.36%	914	3080
C5	3801	303	1448	56.97%	973	3084

Supplementary Table 4.3 Coal capacity in each province in 2035

Province (GW)	A1	A2	A3	A4	A5	B1	B2	B3	B4	B5	C1	C2	C3	C4	C5
Anhui	73.0	78.4	66.6	73.0	78.4	78.4	78.4	72.7	78.4	78.1	73.6	78.4	66.7	73.7	78.4
Beijing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fujian	16.8	16.9	16.0	16.8	23.8	24.5	25.1	22.7	24.5	21.6	16.5	16.9	16.0	16.4	22.4
Gansu	10.7	11.1	9.2	10.7	13.1	11.6	11.2	10.4	11.6	11.3	8.0	8.8	5.7	8.3	9.9
Guangdong	48.9	49.6	43.2	48.9	60.4	61.1	62.1	57.6	61.1	57.3	45.0	45.7	40.8	44.9	55.9
Guangxi	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Guizhou	34.8	35.1	31.2	34.8	46.5	47.0	47.1	41.4	47.0	42.3	35.5	35.9	31.4	35.5	43.6
Hainan	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Hebei	39.4	34.2	43.3	39.4	52.7	54.8	52.3	55.3	54.8	49.8	32.8	31.2	35.5	32.8	41.3
Heilongjiang	19.0	19.0	17.0	19.0	19.0	18.0	17.6	17.8	18.0	19.0	19.0	19.0	17.3	19.0	16.7
Henan	75.8	75.8	75.8	75.8	75.8	75.8	75.8	75.8	75.8	75.8	75.8	75.8	75.8	75.8	75.8
Hubei	38.0	39.1	31.0	38.0	44.6	44.6	44.6	44.6	44.6	44.6	37.7	40.0	29.4	37.9	44.6
Hunan	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
Jiangsu	78.1	81.4	66.8	78.1	98.9	98.9	98.9	98.9	98.9	98.9	83.6	87.8	74.4	83.4	98.9
Jiangxi	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1
Jilin	1.7	0.7	3.8	1.7	0.1	0.0	0.2	2.3	0.0	0.0	0.3	0.0	1.6	0.3	0.0
Liaoning	13.4	14.5	17.1	13.4	18.4	18.8	18.3	22.6	18.8	20.5	14.2	14.4	16.2	14.1	11.6
Ningxia	22.8	22.8	21.8	22.8	24.6	24.3	24.3	25.1	24.3	24.8	22.4	21.7	20.8	22.4	20.7
Qinghai	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shaanxi	38.7	40.2	34.2	38.7	47.5	48.9	51.6	43.8	48.9	44.4	40.4	42.2	36.5	40.3	46.1
Shandong	109.7	109.6	109.7	109.7	109.7	109.7	109.7	109.7	109.7	109.7	106.1	98.3	109.7	106.2	105.3
Shanghai	7.7	6.4	16.6	7.7	14.5	15.5	16.4	17.5	15.5	10.6	6.4	6.0	10.8	6.4	10.8
Shanxi	64.0	65.0	57.5	64.0	72.6	74.0	74.0	70.4	74.0	71.7	66.7	65.9	60.6	66.6	69.1
Tianjin	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6
Xinjiang	56.8	54.9	54.4	56.8	63.6	64.4	63.3	61.4	64.4	62.1	55.9	56.0	54.6	55.9	58.0
Xizang	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Yunnan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Zhejiang	54.7	54.7	54.7	54.7	54.7	54.7	54.7	54.7	54.7	54.7	54.7	54.7	54.7	54.7	54.7
Chongqing	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Sichuan	11.7	7.5	12.8	11.7	8.5	8.4	7.2	12.8	8.4	11.4	6.4	2.2	8.3	6.2	2.2
East Inner Mongolia	8.7	7.9	10.2	8.7	7.2	7.7	5.4	7.4	7.7	9.2	7.6	4.0	7.9	7.4	2.1
West Inner Mongolia	4.5	0.5	12.9	4.5	0.0	0.0	0.0	6.8	0.0	1.7	0.0	0.0	7.3	0.0	0.0

Supplementary Table 4.4 Coal run hours in each province in 2035

Province (hours)	A1	A2	A3	A4	A5	B1	B2	B3	B4	B5	C1	C2	C3	C4	C5
Anhui	5245	5542	5160	5245	4748	4763	5167	4601	4763	4718	4856	5446	4743	4856	4522
Beijing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fujian	3131	3156	3315	3131	3195	3206	3200	3228	3206	3146	2926	2968	3108	2932	3064
Gansu	2048	1985	2092	2048	1743	1744	1644	1668	1744	1718	1732	1613	1788	1721	1633
Guangdong	3551	3652	3579	3551	3353	3343	3399	3435	3343	3401	3212	3296	3305	3214	3204
Guangxi	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Guizhou	3454	3463	3385	3454	3122	3074	3062	3013	3074	3135	3178	3133	3187	3170	2960
Hainan	1407	1264	1813	1407	1069	1091	819	1069	1090	1010	1290	1218	1570	1285	1372
Hebei	1590	1576	1816	1590	1441	1428	1382	1554	1428	1447	1474	1423	1628	1476	1486
Heilongjiang	1946	1842	2360	1946	1630	1613	1489	1784	1613	1681	1646	1531	1949	1646	1531
Henan	4729	4763	4835	4729	4481	4472	4521	4667	4472	4567	4408	4433	4513	4409	4197
Hubei	2779	2756	2902	2779	2797	2832	2913	2576	2832	2733	2478	2459	2562	2488	2565
Hunan	4107	4116	4156	4107	4219	4208	4191	3929	4208	4189	3690	3638	3575	3695	3656
Jiangsu	3642	3624	3503	3642	3366	3344	3381	3358	3344	3340	3377	3268	3418	3373	3134
Jiangxi	6814	6995	6599	6814	6563	6519	6694	6408	6519	6653	6476	6635	6363	6477	6124
Jilin	791	648	1164	791	607	545	560	712	560	743	602	N/A	924	595	N/A
Liaoning	1477	1366	1805	1477	1214	1206	1152	1430	1206	1209	1247	1183	1559	1249	1244
Ningxia	2364	2294	2519	2364	2007	1959	1865	1935	1960	2076	2079	1899	2164	2077	1864
Qinghai	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Shaanxi	3373	3388	3327	3373	2901	2898	2844	2867	2897	3014	3027	3008	3009	3027	2766
Shandong	2913	2559	3444	2913	2192	2181	1993	2588	2181	2367	2354	2084	2892	2354	1936
Shanghai	2390	2341	3067	2390	2412	2380	2216	2541	2379	2454	2261	2154	2482	2257	2448
Shanxi	3147	3110	3317	3147	2800	2782	2764	2943	2782	2881	2905	2842	3106	2905	2699
Tianjin	4228	4109	4563	4228	3767	3736	3685	4021	3736	3922	3862	3756	4202	3860	3520
Xinjiang	3572	3570	3425	3572	3075	3032	2949	2917	3032	3176	3154	3155	3027	3156	2912
Xizang	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Yunnan	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Zhejiang	5682	5703	5843	5682	5447	5325	5322	5521	5325	5464	5179	5016	5373	5181	4957
Chongqing	4423	4243	4720	4423	3931	4059	3752	4053	4059	4263	3827	3578	3754	3828	3330
Sichuan	1773	1634	2050	1772	1338	1331	1081	1384	1331	1412	1413	1181	1557	1407	1167
East Inner Mongolia	1288	1168	1622	1288	982	967	901	1066	967	984	1104	984	1360	1101	993
West Inner Mongolia	1655	1524	1909	1655	N/A	1359	N/A	1461	1250	1354	1096	N/A	1672	734	N/A

Supplementary Note 5 Estimating capital recovery factors

To estimate the capital recovery factors and annualized fixed costs for coal-fired power plants in each province, we take the following approach. First, we use the 5-year loan prime rates (LPR) from 2001 to 2025, as reported by the People's Bank of China, to approximate the corresponding 20-year loan rates (People's Bank of China, 2025). Then, we calculate the capital recovery factor (CRF) for each coal-fired power plant g based on its construction start year i (Global Energy Monitor, 2025), as follows:

$$CRF_g = \frac{WACC_i \times (1 + WACC_i)^N}{(1 + WACC_i)^N - 1}$$

where N is the amortization period and $WACC_i$ is the weighted average cost of capital (WACC) in the construction year i. WACC is calculated as $WACC_i = LPR_i + \epsilon$, where LPR_i is the 5-year LPR in year i, and ϵ is the regional interest rate spread and risk premium.

Next, we calculate the capacity-weighted CRF and the corresponding annualized fixed cost in each province p as below:

$$CRF_p = \frac{\sum_{g \in G_p} CAP_g \times CRF_g}{\sum_{g \in G_p} CAP_g}$$

where G_p is the set of coal units in the province p, CAP_g is the installed capacity of each coal unit g, and CRF_g is the estimated capital recovery factor for that coal unit.

We assume a 20-year amortization period, full debt financing, and a capital cost of 4000 RMB/kW. For coal-fired units constructed before 2000, we assume zero remaining capital recovery costs. In this process, we adjust the provincial loan rates by adding basis points to the 5-year LPRs to reflect regional interest rate spreads and risk premiums, and ensure the nationwide average annualized fixed cost matches the benchmark level of 330 RMB/kW-yr. **Table 5.1** shows the capacity-weighted CRF in each province.

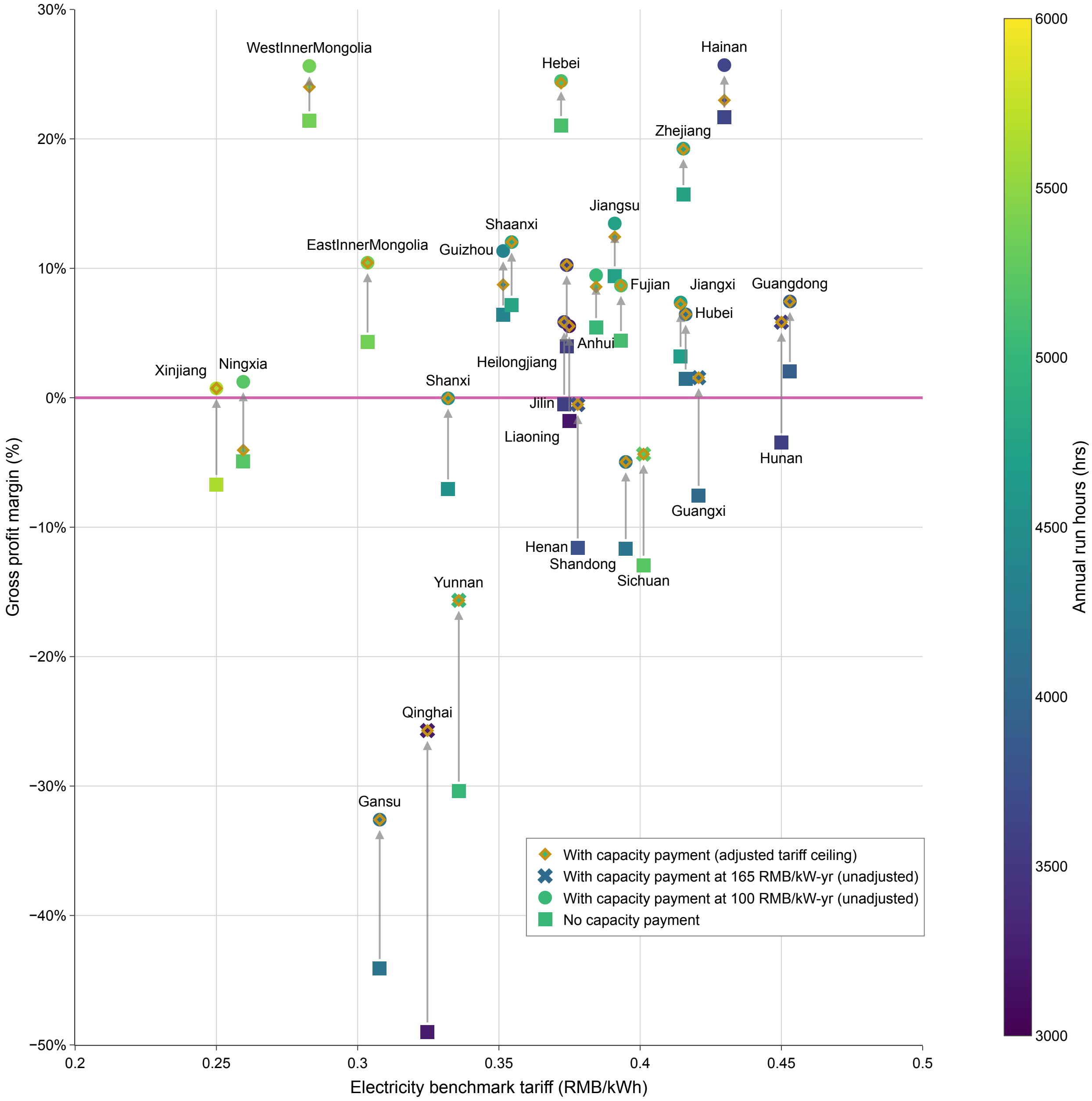
Supplementary Table 5.1 Capital recovery factor for coal-fired power plants

Province	CRF (%)
Beijing	N/A
Tianjin	7.44%
Hebei	7.81%
Shanxi	8.76%
Shandong	7.69%
West Inner Mongolia	8.90%

East Inner Mongolia	8.52%
Liaoning	7.35%
Jilin	7.74%
Heilongjiang	6.83%
Shanghai	6.26%
Jiangsu	8.35%
Zhejiang	8.42%
Anhui	8.59%
Fujian	8.51%
Jiangxi	8.53%
Henan	8.87%
Hubei	7.76%
Hunan	8.40%
Chongqing	8.38%
Sichuan	8.39%
Shaanxi	8.75%
Xinjiang	9.30%
Qinghai	9.22%
Ningxia	8.92%
Gansu	8.59%
Guangdong	8.29%
Yunnan	8.50%
Hainan	9.34%
Guizhou	9.11%
Guangxi	9.00%
Xizang	N/A

Supplementary Note 6 Pre-tax profit margins

Figure 6.1 shows the pre-tax profit margins for coal-fired power plants in each province in 2024. The color scale shows the annual run hours of coal-fired power plants, and icon shapes indicate the level of capacity payment that varies by province. The arrows indicate the changes in coal profitability with capacity payments.



Supplementary Figure 6.1 Pre-tax profit margins for coal-fired power plants in each province in 2024