

UC Berkeley

CUDARE Working Papers

Title

Electricity Sector Reform in China: Progress, Performance and Challenges

Permalink

<https://escholarship.org/uc/item/6nm5m57z>

Authors

Lin, Jiang

Feng, Yanbo

Song, Feng

et al.

Publication Date

2025-04-01

Electricity Sector Reform in China: Progress, Performance and Challenges

Yanbo Feng^a, Jiang Lin^{bc*}, Feng Song^{a*}, Mun Sing Ho^d

ARE Working Paper

Abstract

Since the 1980s, many countries have progressively implemented power market reforms to foster competition and enhance efficiency. China, which hosts the world's largest power sector, launched a comprehensive market-oriented reform initiative in 2015. In this review, we summarize the progress, achievements, and challenges of these reforms. Progress has been made in enhancing competition in wholesale and retail markets, strengthening regulation over grid costs and services, expanding inter-regional transmission, and promoting renewable electricity. Reform efforts have yielded several notable achievements: significantly improving generation efficiency, particularly among smaller-capacity units; substantially reducing industrial and commercial electricity prices, though primarily due to government intervention; effectively capturing market dynamics through spot market expansion, although their limited scale has constrained broader impacts; and improving efficiency and welfare through market integration but raising concerns about equity. Moving forward, two pivotal challenges remain: striking a balance between market mechanisms and government intervention to sustain reform momentum; and ensuring system flexibility and long-term resource adequacy, especially as China accelerates its transition to a low-carbon energy future.

^a School of Applied Economics, Renmin University of China, Beijing, China.

^b Energy Technologies Area, Lawrence Berkeley National Laboratory, Berkeley, CA, USA.

^c Department of Agricultural and Resources Economics, University of California, Berkeley, CA, USA.

^d Harvard-China Project on Energy, Economy and Environment, Harvard University, Cambridge, USA.

*Corresponding author: lin.jiang@berkeley.edu (Jiang Lin), songfeng@ruc.edu.cn (Feng Song)

1. Introduction

Historically, the great majority of electricity customers in most countries were served by a vertically integrated (and in some cases, government-owned) monopoly utility that provided generation, transmission, local distribution, and billing/collections. Since the 1980s, however, many countries have pursued power sector marketization and restructuring initiatives. Electricity market reforms seek to restructure vertically integrated power companies to improve their efficiency through market competition and encourage private sector participation in the power business¹.

China has the world's largest electricity sector, with 2.92 million megawatts (MW) of installed capacity and 9.22 billion megawatt-hours (MWh) of electricity consumption in 2023². In 2002, China initiated its first round of power sector reform, splitting the State Power Company and establishing two major power grid operators and five major power generation companies^{3,4}. The power grid operators would purchase electricity from power plants owned by the power generation companies at wholesale prices and then sell it to power users at government-guided retail prices⁵. Although the 2002 reforms yielded considerable achievements, China's power sector still faced critical challenges such as insufficient competition on the generation side, inadequate market-based pricing mechanisms, an underdeveloped regulatory system, and obstacles to renewable energy expansion.

To address these issues and advance power sector marketization, China launched a second round of reforms in 2015. These reforms fostered price competition in generation and retail, enhanced regulation of grid costs and services, expanded inter-regional transmission, and promoted renewable electricity⁶. To date, these reforms have achieved several impressive outcomes⁷. Notably, China's wholesale and retail electricity markets have been established, its transmission and distribution (T&D) pricing system has gradually formed, the role of the market in determining resource allocation has been significantly enhanced, and the proportion of electricity traded in the market has increased significantly.

Today, a decade after the 2015 reforms, China's power sector has reached a critical juncture. Conducting a comprehensive review of progress, identifying unresolved issues, and charting a course for the future are essential to ensuring continued success. This study combines qualitative and quantitative methods to evaluate the reform's achievements while identifying areas for improvement. Key conclusions include the following: the shift from "fairness-based" to market-based dispatch has significantly enhanced generation efficiency, with smaller-capacity units benefiting the most; industrial and commercial (I&C) electricity prices have seen notable declines, largely driven by enhanced regulatory supervision, especially in transmission and distribution; and spot markets have effectively captured market dynamics, but their limited scale restricts broader impact. Market integration has improved efficiency and welfare but

has also highlighted equity challenges. Looking ahead, China's electricity reform faces two major challenges. First, balancing the roles of government and the market remains a complex task, as state involvement is vital for regulation, planning, and addressing market failures. Second, ensuring system flexibility and long-term adequacy is increasingly critical, particularly with the growing share of renewable energy.

The remainder of this paper is organized as follows. In Section 2, we review international experience with electricity market reform. In Section 3, we summarize China's reform progress since 2015. In Section 4, we assess the 2015 reforms from the perspectives of efficiency, price, and integration. In Section 5, we summarize the challenges currently faced by market reform efforts, as well as potential solutions. We conclude by summarizing China's electricity market reform and offering a perspective on its future.

2. International experience with electricity market reform

The electricity industry has four main segments: generation, transmission, distribution, and retailing/billing. Historically, all segments were vertically integrated within monopoly utility companies who served customers under "cost-of-service" regulation. These utilities were subject to government regulation of prices, entry, investment, service quality, and other aspects of firm behavior^{8,9}. Since the 1980s, countries such as the U.S. and the UK began restructuring their power sectors to enable market competition and greater efficiency¹⁰. Several studies have summarized the experience of electricity reforms around the world and distilled a theoretical basis and common principles^{11,12,13}. Crucially, market rules must create economic incentives for actions by individual market participants that enhance, or at least do not detract from, real-time system reliability or long-term supply adequacy.

2.1 Market restructuring and ownership changes

The restructuring of the power industry includes both vertical unbundling and horizontal restructuring. Vertical unbundling separates generation and retailing activities from the natural monopoly transmission and distribution segments to limit monopoly power^{14,15}. Horizontal restructuring increases the number of participants in wholesale and retail markets¹⁶.

2.1.1 Vertical unbundling to separate functions

Structural or functional vertical separation of competitive segments (i.e., generation, marketing, and retail supply) from regulated segments (i.e., distribution, transmission, and system operations) is viewed as essential to electricity market restructuring for two reasons. First, each segment exhibits different cost structures and innovation characteristics, leading to distinct optimal scales, risk profiles, and

operational logics for each segment. Second, vertical unbundling can guard against the cross-subsidization of competitive businesses from regulated businesses, as well as discriminatory policies affecting competitive suppliers' access to distribution and transmission networks ¹⁰.

2.1.2 Horizontal restructuring to enhance competition

Horizontal restructuring increases the number of enterprises in competitive segments to mitigate market power and ensure reasonably competitive outcomes^{10,16}. In the generation segment, this typically involves breaking up existing firms and encouraging entry by new players. Both are done to avoid the establishment of dominant firms and ensure an economically efficient resource mix. Firms with an excessively large market share can use market power to raise prices, particularly during periods of scarcity⁷. On the retail side, restructuring relaxes utilities' monopoly franchise rights and promotes "customer choice" as a guiding principle. Consumers gain the flexibility to purchase electricity from competing suppliers, who either source power from wholesale markets or operate generation assets to fulfill retail supply obligations^{7,11}.

In horizontal unbundling, large amounts of generation capacity were converted from monopoly utility or government ownership to private, competitive ownership. Most electricity reform models attach considerable importance and expectations to market-oriented reforms based on competition among non-monopoly private sector entities. Where private ownership of generation assets is not possible, reform efforts require power companies to operate on commercial principles. These principles require that enterprises pay taxes and market-based interest rates, earn commercially competitive returns on equity capital, and manage their own budgets, borrowing, procurement, and labor ¹⁷.

2.2 Mechanisms to achieve real-time balance

Maintaining the stability of power systems requires real-time balancing of electricity supply and demand. Prior to restructuring, regulated utilities centrally managed supply-demand coordination. The advent of market-oriented reforms introduced the need for mechanisms to align market participants' actions with real-time balancing objectives. This need has become even more critical with the growth of variable renewable energy sources such as wind and solar, which require sophisticated solutions to ensure system reliability.

2.2.1 Short-term markets

Short-term markets reward generators for matching supply and demand in near real-time, which typically involves both day-ahead and intra-day (balancing) markets.

This gives incentives to generators (and to loads) to adjust their position based on the general condition of the system and their own operating situation. Prices in short-term markets are often determined by marginal costs, where the price of electricity reflects the cost of the last unit of generation dispatched to meet demand. Short-term prices can provide transparent and constantly updated information and serve as the basis for determining longer-term contract prices. They also signal to the demand side of the market the value of short-run actions to reduce (or increase) power demand.

2.2.2 Ancillary service markets

The key attributes of real-time supply-demand balancing in electricity, along with other physical characteristics of electricity, significantly influence whether and how competition can be introduced. Electricity demand varies greatly across hours of the day and days of the year, and despite advances in storage technologies, cost-effective electricity storage remains a persistent challenge for both consumers and distributors. Consequently, the generation and consumption of electricity must be continuously balanced to maintain grid frequency, voltage, and stability, avoiding sudden power losses. In vertically integrated markets, utility companies provide a bundled product of energy, reliability, and customer service, eliminating the need for explicit compensation for “ancillary services” provided by generation units to maintain system reliability.

However, with the unbundling of different segments in the electricity industry, ancillary services must be compensated to avoid compromising system reliability or power quality. For instance, with respect to reserve capacity, moving toward a liberalized market typically results in reductions to reserve capacity. If this leads to an unacceptably high risk of rolling blackouts in power systems, the creation of a market to reward capacity (separately from energy) may be justified⁷. Further, the growth of variable renewables has given rise to new flexibility services that maintain reliability. If markets or compensation mechanisms for these services are absent, the cost of maintaining reliability with an inappropriate generation mix will rise^{18,19,20}.

2.2.3 Demand-side resources

Unlocking demand-side potential is a crucial source for improving the efficiency and flexibility of electricity markets. By providing consumers with the ability and motivation to respond to electricity market prices—by adjusting or rescheduling their business activities and/or utilizing demand-side technologies that save, modulate, or generate electricity—market reform efforts can significantly lower power system costs, reduce the need for new centralized capacity additions, and facilitate the integration of customer-sited renewable resources²¹.

To enable the active participation of consumers and demand-side resources in electricity markets, two fundamental conditions must be met: (1) Provision of actionable information: Consumers need real-time information on when and how to

adjust their electricity usage, which necessitates the adoption of smart meters; (2) Economic incentives: Pricing mechanisms must be established to align consumer behavior with system needs by providing financial rewards for responsive actions, such as compensation for reducing peak demand^{22,23,24,25}.

2.3 Mechanisms to ensure long-term resource adequacy—and facilitate an energy transition

Ensuring long-term resource adequacy is critical for maintaining a reliable grid and stable electricity markets. Short-term markets often operate with price caps, which limit revenues during periods of electricity scarcity, leading to a “missing money” problem that discourages investment in generation capacity. The issue of insufficient long-term investment becomes even more pronounced with the increasing share of renewables. Traditional energy-only electricity markets were primarily designed for fossil fuel-based systems, with prices set based on system marginal costs. In contrast, renewable energy sources have much lower marginal costs, as nearly all expenses are incurred upfront as capital costs and no fuel costs are incurred for generation. Moreover, high renewable energy penetrations can drive prices very low or even negative, exacerbating the difficulty generators face in recovering costs through short-term markets²⁶.

To address these challenges, two main mechanisms have been proposed to induce adequate investment in generation capacity. The first is fixed-price forward contracts, whereby regulators require retailers to procure a certain percentage of their forecasted demand at different time intervals ahead of delivery through long-term contracts. These contracts provide generators with revenue certainty, hedge against price volatility, and facilitate financing for new generation to meet future demand. The second mechanism is capacity payments: generators receive fixed annual payments based on their available capacity, thereby incentivizing investment and covering fixed costs. This incentivizes long-term resource adequacy by providing financial support beyond energy market revenues²⁷.

2.4 Regulation to address market failures and safeguard equity

The restructuring and liberalization of the electricity sector do not equate to deregulation. The California electricity crisis and subsequent power shortages in other markets have raised concerns that, without careful design and regulation, liberalized electricity markets may be unsustainable¹⁶. Competitive segments must be carefully monitored to prevent the abuse of market power, especially during transitional reform phases. At the same time, the transmission segment, as a natural monopoly, continues to require government-regulated pricing. Additionally, regulatory oversight is essential to address energy equity concerns, ensuring access and affordability for vulnerable

populations.

2.4.1 Mitigating local market power

The need for real-time system balancing and the impracticality of storing large amounts of electricity make electricity markets vulnerable to the exercise of market power, even by firms with relatively small market shares¹⁶. Additionally, both wholesale and retail markets, as products of existing monopolies, exhibit natural tendencies toward re-consolidation. Therefore, restructuring is not and cannot be synonymous with deregulation, as markets continue to require regulatory oversight⁹. In short, without appropriate regulation, electricity prices could escalate sharply, undermining the goals of market restructuring.

Market power issues are typically addressed through measures such as price caps and requiring a certain proportion of transactions to be handled by fixed-price long-term contracts. For regulators, determining when and whether market outcomes cause sufficient harm to certain participants is needed to justify explicit regulatory intervention. If market outcomes become excessively harmful, regulators must have the authority to temporarily suspend market operations. This requires significant subjective judgment on the part of regulators and regulatory agencies, who may lack the experience and flexibility to effectively address the wide range of potential issues, particularly during the early years of market reforms.

2.4.2 Regulating the natural monopoly in transmission and distribution

The transmission and distribution (T&D) segment is the typical natural monopoly within the electricity sector. True competition would require companies to replicate each other's wired networks, which would be extraordinarily expensive and therefore inefficient. Therefore, regulation of the T&D segment is essential, particularly in setting T&D tariffs⁹. Tariffs for T&D companies, as natural monopolies, are set by regulators based on underlying costs. But tariffs must also be set to encourage efficient investment in and use of the network, while addressing any revenue shortfalls⁷. Consequently, network utility companies must, at least at times, set prices above efficient levels (such as those indicated by locational marginal price, LMP) to recover fixed costs. According to this principle, any T&D revenue gaps should be recovered from consumers rather than deducted from generators' net income. This ensures that producers face efficient wholesale market prices, guiding their decisions regarding location, scale, and type of generation²⁰.

Another critical regulatory task is ensuring equal access to transmission services for third parties. Regulated access to scarce transmission capacity and the efficient allocation of this resource are vital because transmission system investments are

significant and often face opposition from communities that do not directly benefit, complicating new transmission development. There are two main approaches to addressing these issues: (1) Regulatory pathway: Imposing rules on vertically integrated utility companies to facilitate third-party access to their networks; (2) Institutional pathway: Encouraging the creation of Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs). The operational independence of ISOs and RTOs from generators and retailers is crucial, as dispatch decisions directly affect the revenues of individual generators. Dispatch must align with the overall system's best interests rather than the narrow interests of a single entity or group ²⁸.

2.4.3 Balancing equity and efficiency

Balancing efficiency and equity is essential for market reforms, as electricity is both a commodity and a fundamental public service. Some studies point out that the pursuit of efficiency in market restructuring could come at the expense of equity, leaving low-income populations struggling to access affordable electricity absent appropriate regulatory oversight^{11,28}. In some cases, private sector entities may lack the incentive to extend services to “unprofitable” or low-usage consumers, highlighting the need for appropriate government intervention. To promote equity, carefully designed subsidies may be employed to ensure that the benefits of market reforms reach all social groups. These mechanisms commonly include government subsidies for specific user groups, cross-subsidies from I&C users to residential users, and even cross-subsidies within residential user groups. This is especially true in developing nations, where policy interventions are vital to mitigating inequality and securing access to basic electricity services for vulnerable populations^{29,30}.

3. Progress of China's electricity reform

China's electricity sector has long operated as a government-planned system. It was vertically integrated and essentially under governmental control until 2002, when the first attempt at market-oriented reform was initiated. The 2002 reform restructured the sector by separating generation from the grid and sought to improve efficiency by encouraging competition among electricity generators³¹. However, the reforms fell short of establishing market-based mechanisms, leaving the sector still largely governed by planning. New capacity investment needed approval from the central government, electricity production was allocated by the local government, and prices were predetermined by provincial governments.

In 2015, China inaugurated a new round of reform, which broadly focused on fostering price competition in generation and retail, enhancing regulation of grid costs and services, expanding inter-regional transmission, and promoting renewable electricity. The reform so far has achieved several impressive outcomes. The role of the

market in resource allocation has been significantly enhanced, wholesale and retail markets have been established, the T&D pricing system has been refined, and renewable energy has gradually entered the market. China's reform process illustrates a tailored approach to market rule design, reflecting unique national and regional circumstances. While some features align with international practices, significant distinctions remain, such as ongoing state involvement, limited trading activities, an emphasis on long-term contracts over spot markets, high market concentration, and a preponderance of state-owned entities^{32, 33}. China's electricity sector is currently entering a transitional phase where production quotas coexist with competitive market elements. Key milestones since the 2015 reform are depicted in Fig.1.

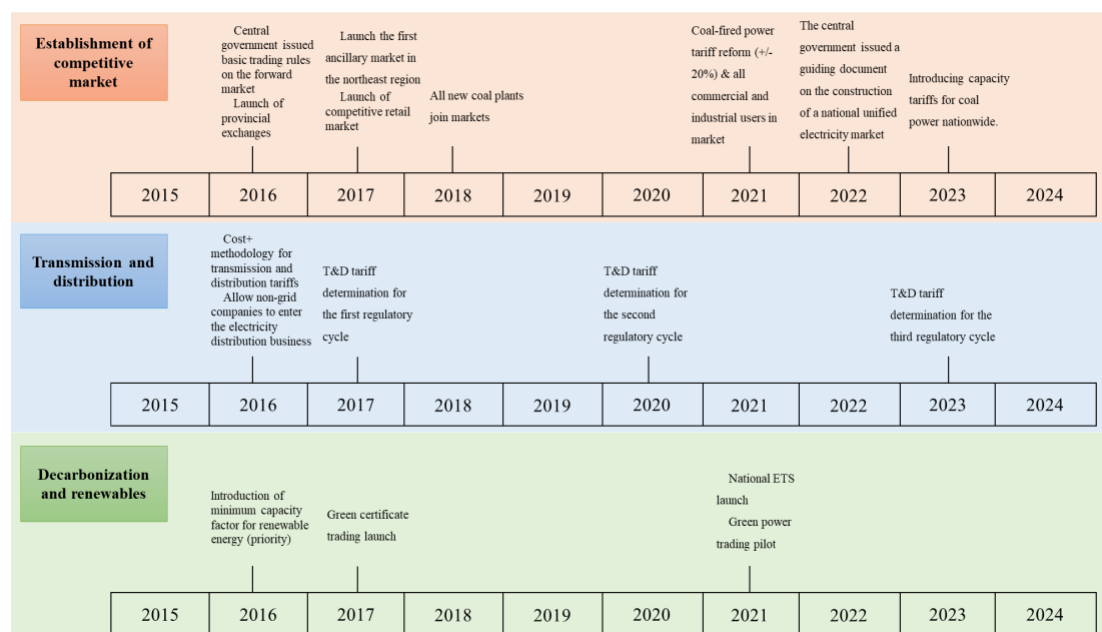


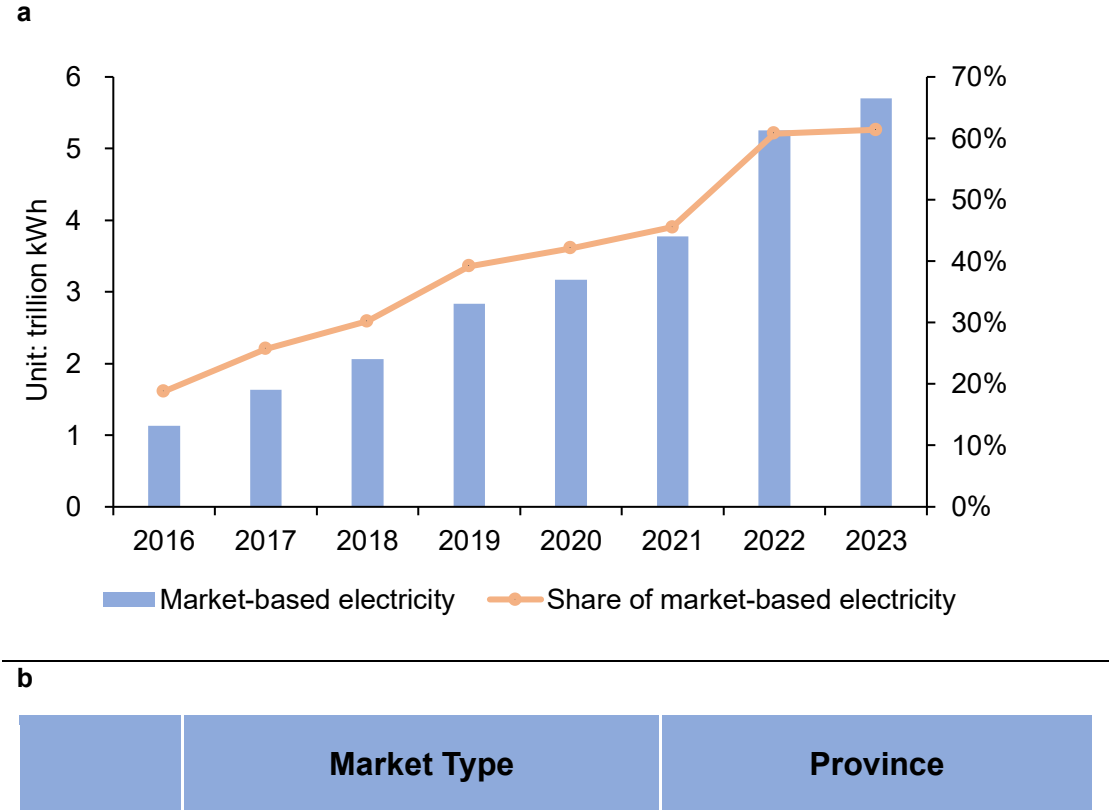
Fig.1 | China's power sector reform milestones since 2015

3.1 Wholesale Market Reform

The aspect of reform receiving the most attention was the establishment of wholesale electricity markets. Prior to these reforms, while the sector had undergone vertical unbundling and generation was divided horizontally among multiple producers, the system operated under a “single buyer” model. In this setup, vertically integrated T&D companies monopolized both the procurement of energy from generators and the supply to end users. Prices and generation volumes were strictly regulated by the government. Generator dispatch followed general principles of maintaining “equal shares” across generators and ensuring revenue sufficiency³⁴. Specifically, local governments forecasted electricity consumption for the next year and allocated a total generation amount to each power plant based on an approximately equal quota. Under this “fair dispatch” rule, thermal generating units of a similar type and capacity were assigned an equal amount of annual operating hours, to ensure the equity of power

generation^{35,36}. Provincial “benchmark tariffs” were fixed by the National Development and Reform Commission (NDRC) based on expected returns, inflation, and other socio-economic concerns³⁶. Since 2015, a diversified market structure has emerged, encompassing long-term, spot, and ancillary service markets. By the end of 2021, China’s central government required all coal-fired generation to be traded through market-based mechanisms. Accordingly, market-based electricity transactions increased from 13% of total consumption in 2015 to 61% in 2023 (Fig.2a).

China’s wholesale market reform can be described as an experimental governance process, where the central government provides a broad yet rudimentary framework while actively encouraging the implementation of pilot electricity markets at the local level. Consequently, the development of wholesale electricity markets varies significantly across provinces (Fig.2b). Even so, a typical reform path adopted by many provinces is as follows: (1) build a forward (physical) market, expand market access, increase the amount of market-based electricity trading, and cultivate participants’ market awareness; (2) build an ancillary service market (for frequency regulation, energy reserve, and others) and perhaps a peak regulation market, depending on the extent of renewable curtailment; (3) build a spot energy market closely integrated with the forward market, which could involve a mix of financial and physical contracts; (4) build a capacity market and financial forward markets involving futures and options^{7,37,38,39}, but so far, no provinces has achieved this step, and all provinces currently implement administrative capacity compensation mechanisms.



Stage 1	Medium- and long-term market	All except Tibet
Stage 2	Ancillary services market	All except Tibet
Stage 3	Spot market	Shanxi, Guangdong, Gansu, Shandong
Stage 4	Capacity market (capacity compensation mechanism currently)	Initially, Shandong and Guangdong; in 2024, all except Tibet

Fig.2 | Pathways and marketization share in China's electricity wholesale sector. a | Market-based electricity and share of market-based electricity. *Source:* China Electricity Council (CEC). **b |** Power market construction path in provinces.

3.1.1 Medium- and long-term market

China first built a medium- and long-term market rather than a spot market at the start of the 2015 reform. Spot markets for electricity are central to the development of wholesale markets, as they provide price signals for efficient dispatch and the efficient operation of medium- and long-term markets⁷. However, price volatility in spot markets is high, and the Chinese government, wary of volatile electricity prices or even electricity shortages, began the reform by establishing the medium- and long-term market. Most contracts in China's medium- and long-term market are on monthly or longer horizons and are physical contracts for energy specifying only a price and total amount, which must later be decomposed into power curves and implemented into actual power system dispatch³⁸. Since the 2015 reform, provinces have explored medium- and long-term electricity trading, with most provinces specifying that such trading must account for 90-95% of market-traded electricity⁴⁰. China's central government issued basic trading rules for the medium- and long-term market at the end of 2016, regulating trading behaviors across provincial markets nationwide and further promoting market development⁴¹. Except for Tibet, all provinces have established a medium- and long-term market. Notably, China has set an upper and lower price limit for its medium- and long-term electricity markets, with fluctuations allowed to range from 10-20% of the current benchmark price in each province.

3.1.2 Ancillary services market

Ancillary services refer to services beyond electricity production and transmission that ensure the safe and stable operation of the power system. These services include primary frequency regulation, reactive power regulation, reserves, and ramping, which

are closely tied to real-time power quality maintenance. Currently, the peak-shaving market is a unique ancillary service market in China and its most critical ancillary service product. Established on a transitional basis to address real-time power balance issues during the early stages of spot market development, the peak-shaving market will be phased out when the spot market becomes fully operational.

Fig.3a illustrates the evolution of ancillary services in China. Before the first round of electricity sector reform in 2002, these services were provided free of charge by generation units. At that time, almost all generation units were owned by the State Power Corporation, eliminating the need for specific units to be compensated. After electricity sector restructuring, generation units became affiliated with independent power companies with individual profit objectives. Since 2006, ancillary service providers have received compensation, albeit at a low rate. Generating companies providing these services were reimbursed under the principle of “cost compensation plus reasonable returns,” with costs distributed among units that do not participate in ancillary service provision^{42,43}.

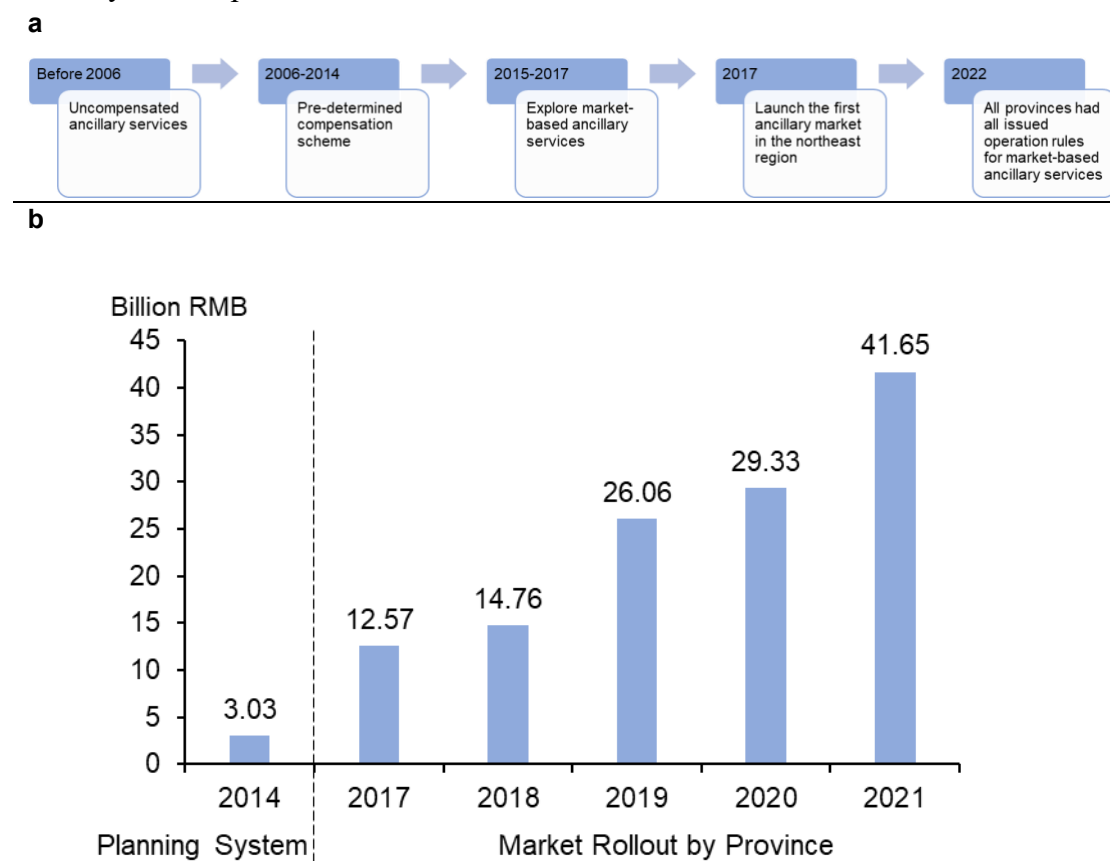


Fig.3 | Evolution of ancillary services market reform in China. a | China’s ancillary service market development. *Source:* National Energy Administration (NEA). **b |** China’s ancillary service costs by year⁴⁴.

As China’s share of renewable energy increased, demand for ancillary services rose. Low, non-market-based compensation rates failed to incentivize flexible generation units to provide sufficient ancillary services, creating an urgent need for market-based

price signals. Such signals must reflect both the grid value of ancillary services and the rising costs of provision to encourage retrofitting for flexibility among generators and to bridge service gaps. Against this backdrop, the ancillary services market was proposed in 2014 and became operational in northeast China (including Heilongjiang, Jilin, and Liaoning) in 2015, which primarily focused on peak-shaving service. It has since expanded to all provinces.

The ancillary services market typically operates in three steps: (1) Demand declaration: grid companies announce the demand for ancillary services. (2) Bidding process: market participants submit prices and capacities for the services they can provide, considering the opportunity cost between ancillary services and the spot market (as capacity allocated to ancillary services forgoes revenue opportunities in the spot market). In the early stages, only thermal and hydropower units could participate. By 2024, energy storage and virtual power plants were added as market participants, adding a new potential revenue stream for these resources⁴⁵. (3) Sorting and clearing: bids are ranked from lowest to highest price and cleared at the marginal price.

The allocation of ancillary service costs is a key challenge in developing this market. From a theoretical perspective, there are three cost-sharing models: (1) All costs borne by generators: this distorts the energy market, as generators must consider ancillary service costs when bidding in the spot market, thereby preventing marginal-cost bidding and reducing market efficiency. (2) Costs shared by generators and users: while still causing some distortion, this approach is more acceptable. (3) All costs borne by users: the ideal model, involving no market distortion, but may face initial consumer resistance due to electricity bill increases. In practice, regardless of who initially bears the ancillary service costs, these are eventually passed on to users, as generators adjust their bids in other markets to recover these costs.

The general compensation principle is “providers benefit,” and the cost-sharing principle is “beneficiaries bear costs.” However, fully implementing these principles remains difficult. Before 2009, ancillary service costs were borne primarily by coal-fired and hydropower units. After 2009, wind and photovoltaic units were gradually included. Since 2014, power plants exporting electricity to other provinces began sharing ancillary service responsibilities based on exported electricity. Since 2022, efforts have been made to include market-based consumers in cost-sharing, excluding residential, agricultural, institutional, and essential public service consumers. In 2024, new participants—such as energy storage plants and virtual power plants, which integrated generation and consumption—began sharing costs based on their electricity input (generation side) or output (user side). As shown in Fig.3b, ancillary service costs have increased more than tenfold since the market was established, rising from 3 billion yuan in 2014 to 41.6 billion yuan in 2021, accounting for approximately 1.5% of China’s electricity costs.

Cost-sharing mechanisms for ancillary services vary based on the status of

provincial spot markets. In provinces without continuously operating spot markets, all costs are borne by generators, while in provinces with continuously operating spot markets (i.e., Guangdong, Shanxi, Shandong, Gansu, Fujian, Western Inner Mongolia, Zhejiang, Hubei), costs are shared between generators and users⁴⁵. Typically, costs are divided equally (1:1) between generators and consumers, and then distributed proportionally within each group based on electricity production or consumption. Why does this cost-sharing mechanism differ between provinces with and without spot markets? A plausible explanation is that consumers in spot markets play a more active role in optimizing the power system compared to their counterparts in non-spot market regions. Real-time price signals in spot markets offer users both the flexibility and financial incentives to adjust their electricity consumption. Consequently, it makes economic sense that users in spot market provinces would take on ancillary service cost-sharing responsibilities ahead of users in non-spot market provinces.

3.1.3 Spot market

The core of electricity market development lies in the spot market. Before the operation of its spot market, China introduced a peak-shaving market as a partial substitute to incentivize generating companies to adjust resources and provide sufficient flexibility for the system, ensuring real-time supply-demand balance. The peak-shaving and spot markets differ in significant ways, with the pricing mechanism being the fundamental distinction. In the peak-shaving market, ancillary services are typically bid unilaterally by providers in the day-ahead or intra-day timeframe. The dispatching authority then ranks bids from low to high according to predetermined rules and utilizes the required capacity. As a result, market-based ancillary service prices are determined through competitive allocation driven solely by supply-side bids, with no participation from the demand side in pricing. In contrast, the spot market adopts a more integrated approach, enabling both buyers and sellers to participate actively in pricing through price and quantity bids. This dynamic interaction between supply and demand enhances market efficiency and transparency.

China's spot market started as a pilot in a few provinces. In 2017, the central government selected eight regions—Guangdong, western Inner Mongolia, Zhejiang, Shanxi, Shandong, Fujian, Sichuan, and Gansu—for the first batch of electricity spot market pilots. In 2021, spot market pilots expanded to Shanghai, Jiangsu, Anhui, Liaoning, Henan, and Hubei. In 2023, based on operational experience from pilot provinces, the central government issued basic rules of electricity spot market operation for the first time. As of year-end 2024, China's electricity spot market has achieved near-complete provincial coverage, with markets in Shanxi, Shandong, Gansu, and Guangdong now officially in operation. **Error! Reference source not found.** provides an overview of the status of each market in 2024. In provinces where the spot market is not yet fully operational, a trial spot market may coexist with a peak-shaving market.

Provinces such as Sichuan and Henan typically require thermal power units to bid 50% of their capacity into the spot market, with the remainder submitted to the peak-shaving market^{46,47}. The purpose is to provide stable compensation, allowing owners of thermal generation to gradually adapt to reforms and reducing their resistance to the changes.

Table 1 | Status of China’s spot power markets

Status	Province
Official operation	Shanxi, Guangdong, Gansu, Shandong
Continuous trial operation	Fujian, Western Inner Mongolia, Zhejiang, Hubei
Long-term trial operation (more than one month)	Sichuan, Jiangsu, Anhui, Liaoning, Henan, Shaanxi, Hebei
Short-term trial operation (less than one month)	Southern region (Guangdong, Guangxi, Yunnan, Guizhou, Hainan), Ningxia, Chongqing, Hunan, Jiangxi
Simulation test	Jilin, Tianjin, Qinghai, Heilongjiang, Xinjiang, Shanghai
No plan	Beijing, Tibet, Eastern Inner Mongolia

Source: IEA (2024)⁴⁸; Provincial Development and Reform Commissions.

On the supply side, thermal power generators primarily participate in spot market transactions by bidding on both volume and price. Notably, many regions have opened their electricity spot markets to broad range of participants. Entities such as centralized renewable energy facilities, independent energy storage systems, virtual power plants, pumped storage, and nuclear power plants have gradually joined the spot market, increasingly engaging in spot trading through volume-and-price bidding mechanisms. On the demand side, while Gansu has adopted volume-and-price bidding, volume-only bidding continues to dominate. Nonetheless, provinces like Guangdong and Shandong are actively experimenting with volume-and-price bidding models. Time-based price signals in the spot market are now steering users away from traditional “demand-driven electricity usage” toward “price-sensitive electricity usage,” enhancing resource allocation efficiency. For example, in Gansu, the daily peak load has shifted from the evening to midday (when photovoltaic generation surges), enabling “peak shaving” and “valley filling” of 2.4 GW, equivalent to 10% of its total load.^①

^① Source: <https://36kr.com/p/2937991283744128>

3.1.4 Capacity compensation mechanism

Due to the intermittent and volatile characteristics of renewable power generation, it is necessary for regulating units, primarily coal-fired power plants and energy storage units, to manage fluctuations and ensure sufficient power supply when the output of wind and photovoltaic units declines. However, as the proportion of renewable energy in the power mix increases, the profitability of coal-fired regulating units diminishes under traditional electricity pricing mechanisms, making it difficult for them to sustain normal operations, let alone make long-term investments to ensure future capacity adequacy. The main reasons are two-fold: first, renewable energy has near-zero marginal costs, which significantly depresses spot market electricity prices when introduced at scale; and second, large-scale renewable energy generation crowds out the economic dispatch space for other power sources. Additionally, due to price caps, generating units cannot earn substantial scarcity rents during periods of tight supply. To address this issue and support the flexible operations needed to integrate renewables, China has introduced a capacity compensation mechanism aimed at enabling coal-fired units to recover stranded costs and maintain stable operations⁴⁹.

In 2020, Shandong and Guangdong were the first provinces to trial capacity compensation for coal power units. By 2024, this mechanism had expanded nationwide, transitioning coal power pricing from a single-part tariff to a two-part tariff, with the capacity component set by the government at a rate of 100 to 165 yuan/kW annually. In seven provinces where coal power plants face greater financial losses, such as Yunnan and Sichuan, the proportion of fixed coal power costs recovered through capacity pricing is set at 50%, while in other regions it is set at 30%. According to Geng et al. (2024), current compensation standards can ensure cost recovery for coal-fired power units⁵⁰. However, the current mechanism does not differentiate between units that have already recovered their costs and those that have not, applying a uniform standard that may potentially reduce the effectiveness of targeted financial support. Moreover, the current mechanism solely targets coal-fired power enterprises. In practice, other adjustable power units could also be compensated, especially energy storage. New energy storage systems are characterized by flexible operation and strong regulation capabilities, but in the absence of a well-developed market mechanism, policy support is needed to encourage their development^{51,52}.

3.2 Reform on the consumer side

Historically, China's electricity sector has operated under a "single buyer" model, where grid companies purchase and resell all electricity (with government involvement through quota- and price-setting). The 2015 reform marked a significant shift on the consumption side, notably by easing the monopoly franchise rights previously held by utilities. By the end of 2021, the central government required, in principle, that all

industrial and commercial (I&C) consumers participate in market-based electricity trading. Today, grid companies no longer serve as the sole purchasing channel for consumers. I&C users can now access electricity through two primary pathways: direct transactions with generators via wholesale markets or indirect participation through long- or short-term contracts with retailers⁵³. Non-market consumers—primarily households, agriculture, and public service sectors—continue to rely on grid companies, purchasing electricity at regulated tariffs. In 2022, I&C consumers purchased about 4.8 billion MWh of electricity through the market, accounting for about 90% of their electricity consumption. With ongoing market development, innovative demand-side mechanisms such as virtual power plants have emerged, further enhancing demand-side efficiency and flexibility. Fig.4 shows China's electricity pricing mechanism.

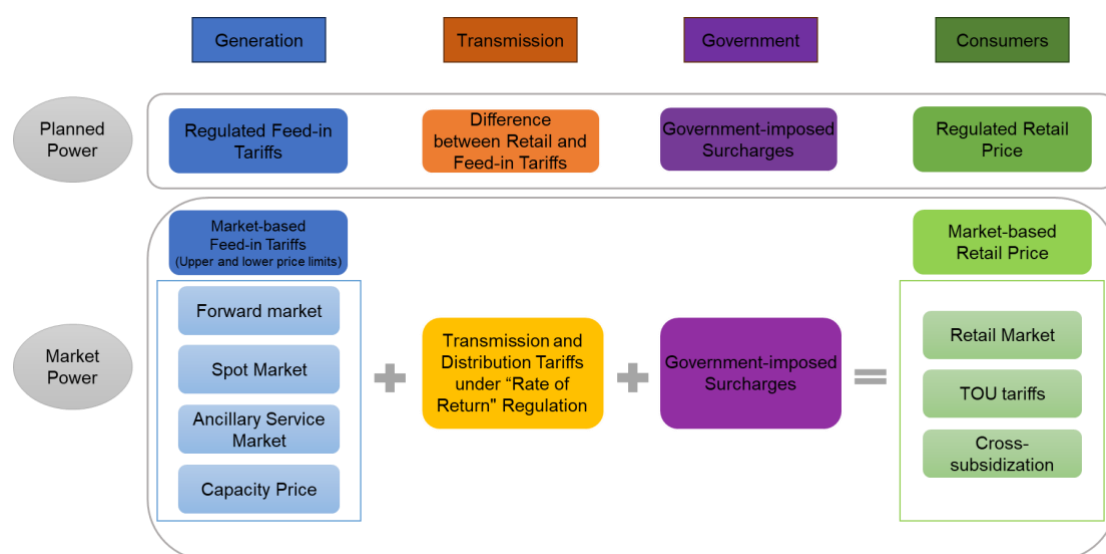


Fig.4 | China's electricity pricing mechanism

3.2.1 Retail market

Since the 2015 electricity reform, consumers have gained increasing access to the market through retail companies. The retail market aims to diminish the privileged position of monopoly suppliers by providing direct consumer access, fostering competition among retail suppliers for customer contracts. Consumers now have the option to participate in wholesale markets either directly or indirectly by signing long- or short-term contracts with retailers. The expansion of market-based electricity trading has driven growth in the number and activity of retail companies. By the end of 2022, there were 15,000 registered electricity retailers. In 2018 alone, retail companies facilitated transactions exceeding 200 million MWh, accounting for nearly 10% of electricity transactions. Ideally, retail electricity tariffs would be tied to wholesale market prices, particularly spot market prices, to encourage efficient consumption and provide accurate locational signals³⁷. In practice, however, retail prices often deviate from this principle. Retail contracts rarely link directly to wholesale price fluctuations;

instead, retailers and customers usually negotiate fixed tariffs for the upcoming year, which remain unchanged regardless of subsequent variations in wholesale prices. Retailers generate most of their income by capitalizing on this price differential, making it their primary source of revenue rather than relying on service fees.

3.2.2 Demand-side management

China began implementing demand-side management relatively early in its reform efforts, but progress has been slow. China's time-of-use (TOU) pricing policy dates to 2003, aiming to guide consumers to use more electricity during off-peak periods and less during peak periods. Following recent reforms, demand-side management has seen widespread adoption. By 2021, 29 out of 33 provincial grids had implemented TOU pricing. Initially, TOU pricing only differentiated between peak and off-peak periods; gradually it became more detailed, distinguishing among peak, shoulder, and off-peak periods. The price gap between peak and off-peak periods has been widening. For example, in Guangdong, the peak/shoulder/off-peak (PSO) price ratio expanded from 1.5:1:0.5 in 2022 to 1.7:1:0.38 the next year⁵⁴. The contracts will specify the price ratios that consumers must pay. Currently, TOU tariffs are predominantly applied to I&C sectors. One reason is that residential consumers are relatively insensitive to time-varying tariffs⁵⁵. In contrast, I&C customers are typically more responsive to price changes^{56,57}. Another reason is the relatively low share of electricity consumption by residential and agricultural sectors.

In 2012, Shanghai, Suzhou, Beijing, Tangshan, and Foshan were the first cities approved for demand-side management pilots and gradually explored market-based demand response. Market rules explicitly stipulated that demand response participants would be rewarded for reducing loads during peak periods⁵⁸. However, demand response, and especially virtual power plants, remain in their infancy. In summary, demand-side management and electricity market operations are currently not well integrated, and demand-side management remains largely reliant on administrative TOU pricing.

3.3 Reform in transmission and distribution

Reforms in the transmission and distribution segment have been notably more successful. A key objective has been to redefine the role of grid companies, which no longer function as single buyers in the wholesale market or single sellers in the retail market. Prior to these changes, T&D tariffs were embedded within retail electricity prices. The new reforms have established standalone T&D tariffs for intra-provincial, inter-provincial, and inter-regional transactions, transforming these tariffs into grid companies' primary revenue source and replacing the previous model of charging customers based on the buy-sell price differential. The tariff structure is regulated using a rate-of-return framework, aimed at curbing the profitability of grid companies. T&D

tariffs in China are typically reviewed and adjusted every three years. During these intervals, grid companies can achieve higher-than-allowed returns if they successfully lower costs, creating a built-in incentive for efficiency improvements. Three rounds of tariff regulation have been conducted since 2015. The first round resulted in a reduction of grid companies' permitted revenues by approximately 60 billion yuan and eliminated about 128.4 billion yuan in unrelated or unreasonable costs, averaging a 15.1% cost reduction. The average T&D price was lowered by 0.014 yuan/kWh compared to the previous price differential between feed-in tariff and retail tariff⁵⁹.

New reforms support private investment in electricity distribution, although the T&D system is still operated mainly by grid companies. The Incremental Power Distribution Reform Pilot has been launched since 2016, aiming to introduce competition to the distribution segment. By the end of 2022, the National Energy Administration issued distribution business licenses to 237 owners of private distribution projects. Although the number of private sector companies that actually operate electricity distribution businesses is quite limited, their emergence has prompted the two state-owned grid companies to improve their service levels⁶⁰.

3.4 Reform in market integration

The electricity sector in China has historically been fragmented, primarily due to two key factors. First, local protectionism has led provincial governments to prioritize local power generation while limiting competition from other regions to achieve economic and political objectives. Second, significant disparities in market rules and the pace of reforms across provinces have further deepened fragmentation, as reforms are often piloted in specific regions before being implemented nationally. China's energy transition has been likened to an iterative process of negotiation between central and provincial actors, involving complex, non-zero-sum dynamics. The spatial politics and accountability structures in China have played a critical role in guiding electricity market reforms. In the country's decentralized policy framework, provincial actors hold substantial influence⁶¹. While the central government provides overarching guidance, the specifics of reform initiatives are largely left to provincial authorities, leading to divergent reform trajectories across regions^{7,62}. The 2015 reform aimed to address this fragmentation by fostering market integration. Given the significant disparities in energy resources and economic development across regions, electricity supply and demand are unevenly distributed across China. A unified national market is therefore essential to optimizing electricity resource allocation on a broader scale.

In early 2022, China's central government issued a guidance document on the construction of a unified national electricity market, proposing its near-completion by 2030⁶³. Two power exchange centers have been established to support regional power

markets in the State Grid and South Grid regions^②. Attempts at market integration are occurring in China's medium- and long-term, spot, and ancillary services markets. In the long-term market, inter-provincial trading has been running continuously since March 2022, with the total trading volume reaching 1.04 billion MWh for the year⁶⁴. In the spot market, the Southern market was the first to begin trial operations in 2018, and entered the monthly trial operation phase in November 2024⁶⁵. Additionally, the State Grid's inter-provincial spot market launched its pilot phase in January 2022, achieving an annual trading volume of 27.8 million MWh and involving over 6,000 generators across 21 regions and buyers from 25 provinces. In the ancillary service market, pilot operations for reserve and peak-shaving markets in the Southern region began in 2021⁶⁶. In 2022, Sichuan and Chongqing merged their markets, enabling power plants to provide ancillary services across provincial boundaries.

3.5 Reform for integrating renewables

Transitioning to low-carbon resources is both a goal and guiding principle for the future development of China's electricity sector. As of 2023, China leads the world in renewable energy capacity, with wind and solar installations reaching 441 GW and 609 GW, respectively. Approximately 20% of renewable electricity is currently traded in wholesale electricity markets. Fig.5 illustrates the rapid growth in China's renewable energy installations. Historically, the country's low-carbon transition has been driven by fixed feed-in tariffs and guaranteed purchase policies, with minimal integration into competitive electricity markets.

As wind and solar continue to account for a growing share of generation, China is increasingly embracing market-based mechanisms for renewable energy trading. Beyond integrating renewables into long-term and spot markets, specialized "green electricity" trading platforms have been established, enabling environmentally conscious users to negotiate prices directly with generators, although trading volumes remain small. In the State Grid regions, the first year of green electricity trading (up to September 2022) resulted in cumulative transactions of 17.6 million MWh, with environmental value reflected in a 0.03-0.05yuan/kWh premium over local coal-fired benchmark tariffs⁶⁷. Additionally, China employs a distinctive form of generation rights trading, where renewable or cleaner generators replace quotas allocated to inefficient and polluting units^{68,69}. This unique mechanism differs from other contract substitution models seen in countries such as the United States, Australia, and the UK.

^② China's power transmission and distribution are divided among three major grid operators. The Southern Power Grid Corporation manages networks across Guangdong, Guangxi, Yunnan, Guizhou, and Hainan. The Inner Mongolia Power Grid Corporation oversees operations in western Inner Mongolia. The State Grid Corporation is responsible for all remaining provinces, excluding the Southern and western Inner Mongolia regions.

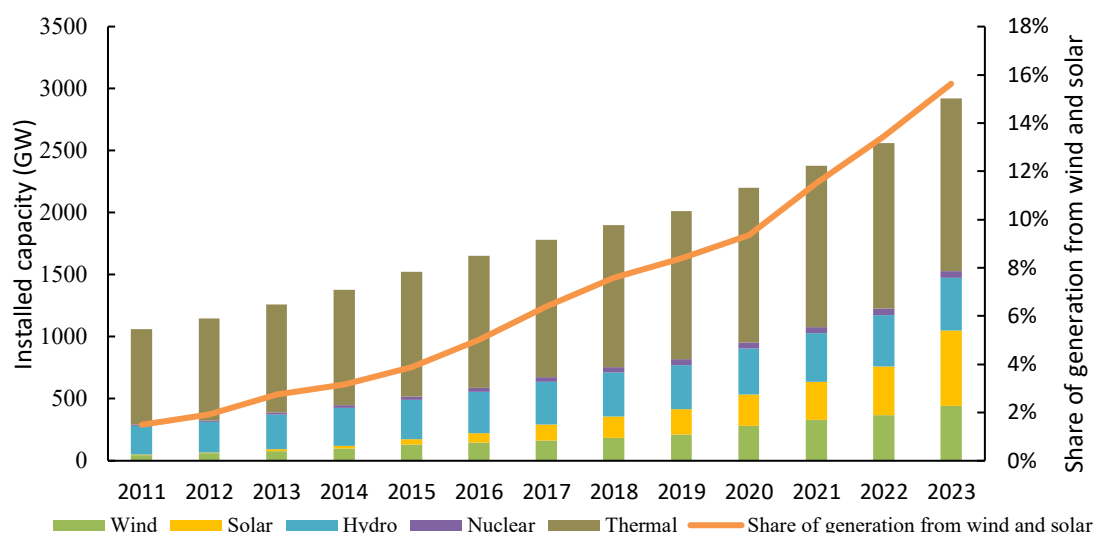


Fig.5 | China's installed generation capacity by type. *Source:* National Bureau of Statistics.

4. Electricity market performance since 2015 reforms

4.1 Enhancing efficiency in power generation

The 2015 market-oriented reform has widely been acknowledged to have improved operational efficiency on the generation side. Most studies simulate counterfactual scenarios post-reform, analyzing changes in coal consumption and production costs to evaluate efficiency gains. These studies estimate that the shift from fairness-based dispatch to economic dispatch has resulted in a 3-15% improvement in production efficiency^{4,70,71,72,73,74,75}. Dispatch reform represents a step toward market allocation, with value prioritized based on energy efficiency, incentivizing reduced fuel consumption and lower marginal costs. A smaller number of studies employ empirical analyses using power plant operational data from specific regions or provincial panel data before and after the reform. These analyses confirm that China's market reforms have enhanced efficiency in the power sector^{76,77,78}.

4.1.1 Smaller-capacity units see greater efficiency gains

We use national power plant data to further validate these efficiency improvements. Fig.6a shows the distribution of coal intensity (coal used per kilowatt of electricity) for all of China's coal-fired plants in 2012 and 2017.^③ It can be seen that the distribution of coal intensity of power plants has clearly shifted to the left.

To further test this relationship between coal intensity, reform, and installed capacity, we estimate the following regression on plant-level data for all coal power plants in the country from 2012 to 2017:

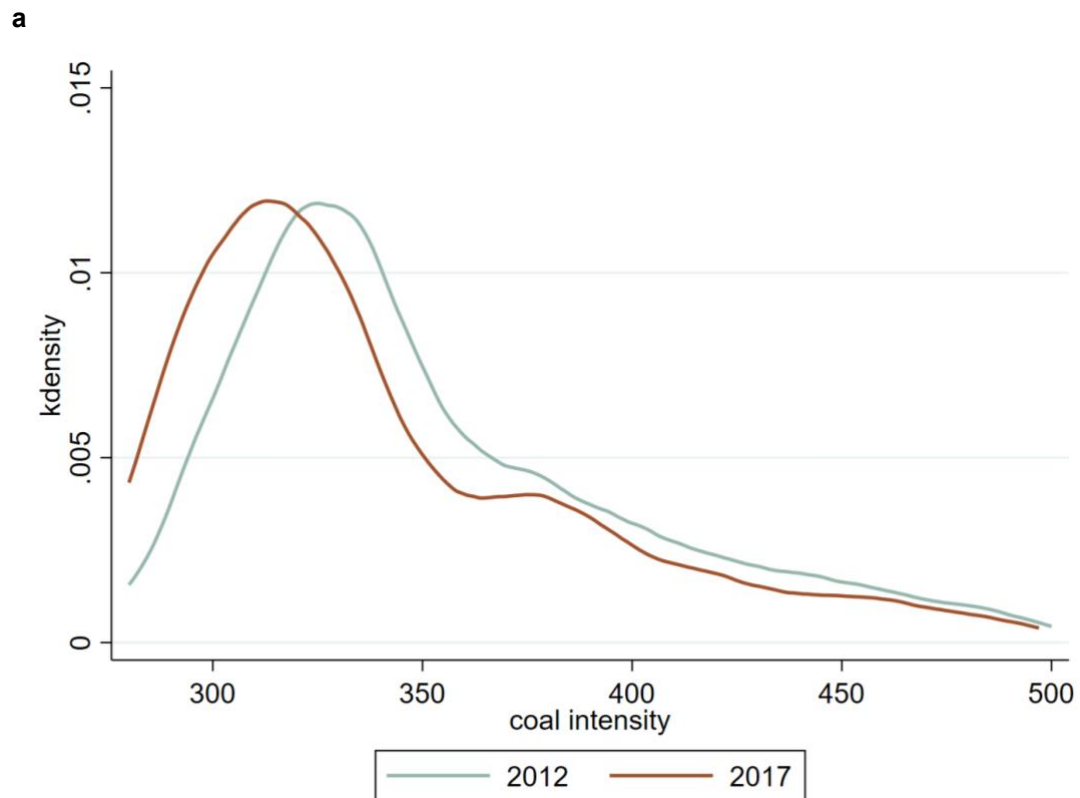
^③ Coal intensity represents the standard coal consumption per power generation (g/kWh).

$$Intensity_{it} = \beta_1 Reform_t + \beta_2 Capacity_{it} + \beta_3 Reform_t \times Capacity_{it} + \lambda_p + \lambda_y + \varepsilon_{it} (1)$$

Where $Intensity_{it}$ and $Capacity_{it}$ are the log coal intensity and log installed capacity of plant i in year t ; $Reform_t$ represents whether reforms are implemented at year t . We divided the whole sample into two periods: for 2015 and before, $Reform_t$ is 0, and after 2015, $Reform_t$ is 1; λ_y is the year effect that does not change among individual plants; λ_p is the provincial effect that does not change with time; and ε_{it} is the independent error term.

The dataset used in our empirical analysis is the power plant data collected by the China Electricity Council, which is the national association for the electricity industry founded with the approval of the State Council. Our dataset covers more than 10,000 power plants from 2012 to 2017, with detailed information on plant-level annual electricity generation, operating hours, generator capacities, coal intensity, coal consumption, and names of plants. All power plants with installed capacity of 6 MW or higher are covered by this dataset. Since this is quite a low threshold for coal-fired power plants, this dataset covers nearly all coal plants in China. For instance, in 2012, the total installed capacity for plants above 6 MW is 754 GW, accounting for 99.86% of the country's total 755 GW coal capacity⁷⁹.

The results of the regression in Equation 1 are reported in Fig.6b. The first column of Fig.6b suggests that the average coal intensity of coal-fired plants decreased by 4% after the reform. Columns 2 and 3 introduce the interaction term ($Reform \times Capacity$) to investigate whether unit capacity influences the reduction in coal intensity during the reform period. The results show that the positive coefficient of the interaction term is significant (at the 1% level) whether in a one-way fixed-effects model or in a two-way fixed-effects model. This implies that the larger the unit capacity, the less significant the reform's impact on reducing coal intensity, and that reform has mainly driven efficiency improvements in smaller-capacity units. This could be attributed to the substantial potential for efficiency enhancement in smaller-capacity units, which typically have higher marginal costs than larger units and must reduce fuel costs to compete more effectively in electricity markets.



b

Regression	(1)	(2)	(3)
Reform	-0.0405*** (0.00265)	-0.0715*** (0.0135)	-0.0896*** (0.0135)
Capacity	-0.00922* (0.00477)	-0.0137*** (0.00487)	-0.0121** (0.00482)
Reform* Capacity		0.00389*** (0.00107)	0.00393*** (0.00106)
Constant	5.969*** (0.0585)	6.010*** (0.0598)	6.005*** (0.0592)
Province fixed effect	YES	YES	YES
Year fixed effect	YES	NO	YES
Observations	6,074	6,074	6,074

c

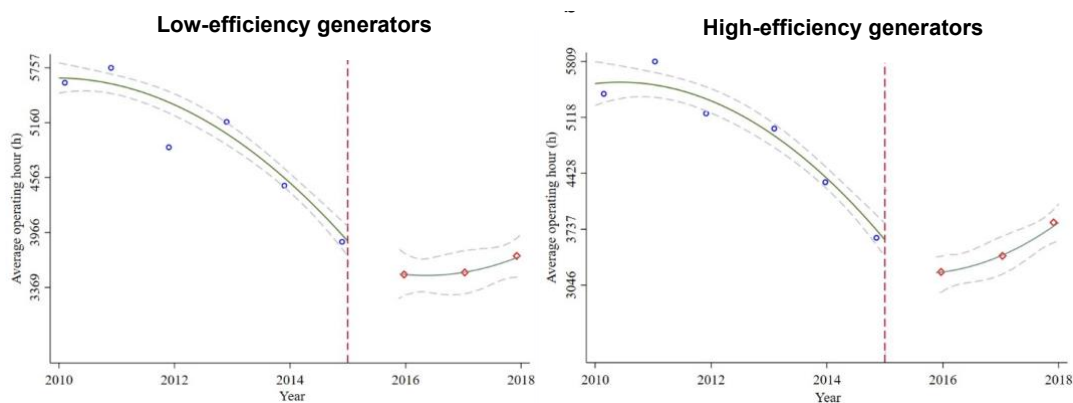


Fig.6 | Efficiency improvement in power generation since China's 2015 electricity reform. a | Coal intensity distribution in power plants. b | Regression results of coal intensity and reform. Standard errors in parentheses. * $p < 0.01$, ** $p < 0.05$, * $p < 0.1$. P values are for a two-sided test based on normal distribution. "Yes" denotes that the fixed effect is controlled in the model; "No" is vice-versa. c | Changes in average operating hours of low-efficiency and high-efficiency generators in Guangdong before and after reform. Source: Xiang et al. (2023a)⁷⁷.**

4.1.2 Efficiency improvements are largely attributed to dispatch reforms prioritizing high-efficiency units

Several studies have analyzed the reasons for the increased efficiency of power generation. The main reason for this increase is the shift from "equal share" dispatch to market-based dispatch, which increases the operating hours of efficient generators^{80,81}. Equal share dispatch has often been criticized for its inefficient use of polluting power plants^{7,82}. Market-based dispatch encourages more efficient generators with lower fuel costs to produce more electricity^{83,84,85,86}. As shown in Fig.6c, in Guangdong, the operating hours of high-efficiency power units have risen significantly since the 2015 reforms⁷⁷. Cui et al. (2025) construct a counterfactual market reform scenario based on micro-panel data of coal-fired units in five of China's southern provinces, finding that coal-fired power generation costs and carbon emissions both decrease by about 2.4% compared with the 2015 baseline scenario. Using the log mean divisia index (LMDI) decomposition methodology⁸⁷, they demonstrate that these savings are mostly due to improvements in allocation efficiency (about 45%), followed closely by fuel efficiency improvements (about 40%) and reductions in the self-consumption rate (about 14%)⁸¹.

4.1.3 Potential for efficiency gains is constrained by incomplete marketization

China's transition to market-based dispatch remains incomplete, and while efficiency has improved it has not been fully realized⁷⁸. The power system currently

operates under a “semi-planned and semi-market” dispatch approach in China, where “in-plan” generation is pre-allocated to generators by local governments and “out-of-plan” generation is determined through market competition, a dynamic that limits the potential of marketization. In addition, market reforms have faced certain political challenges, with local governments favoring local enterprises over central state-owned enterprises in their allocated generation quotas. This protects small coal-fired and natural gas generators, lessening their motivation to improve generation efficiency even after reforms. Using generator-level data of China’s Southern Power Grid region in 2019, Xiang et al. (2023b) found that only half of potential CO₂ emission reductions and social welfare gains have been realized due to politically allocated generation dispatch.⁸⁸

4.1.4 Transmission and distribution efficiency has not significantly improved

Beyond the generation sector, several studies have examined the impact of the 2015 reforms on transmission and distribution efficiency. Zheng et al. (2021) found that the impact of reforms on T&D efficiency was not statistically significant based on the line loss rate⁷⁶. One possible explanation for this is that China’s ongoing effort to upgrade its T&D infrastructure is largely independent of the 2015 reforms. Another possible explanation is that China’s T&D system was already relatively efficient, leaving limited scope for further improvement⁸⁹.

4.2 Incomplete marketization limits the effectiveness of electricity pricing reforms

The 2015 reform sought to transition pricing from administrative control to market-driven mechanisms. However, China’s pricing system remains largely regulated, with limited sensitivity to cost fluctuations or supply-demand dynamics. While the nascent spot market effectively captures market dynamics, including supply-demand fluctuations and coal price changes, and thereby offers a glimpse into the potential of market-driven mechanisms, the small size of this market limits its effect on overall prices. I&C electricity prices have decreased significantly since 2015, but this is mainly due to government-driven administrative interventions rather than improved market efficiency. China’s T&D tariff reforms, which focus on reducing grid costs and establishing rate-of-return regulation, have significantly contributed to price reductions⁹⁰. Additionally, TOU pricing reforms have shown promise in improving social welfare by optimizing resource allocation and reducing capacity investment costs. Despite these advancements, the incomplete marketization of China’s electricity sector continues to constrain potential benefits from efficiency gains and cost-reflective

pricing, as discussed in the following sections.

4.2.1 Electricity prices are mainly set by government regulation, with limited connection to costs or supply-demand dynamics

An important goal of the 2015 reform is to determine electricity prices through markets, not government action. Nevertheless, some studies find that China's electricity pricing is still largely dependent on government regulation, with costs and supply-demand dynamics having little impact. Feed-in tariffs are adjusted infrequently and inadequately, leaving coal-fired power producers exposed to coal price volatility. Regulatory lag has limited the profit margins of coal-fired power enterprises^{91,92,93}. If price regulation were relaxed, Liu et al. (2019) found that, assuming other conditions remained unchanged, it would result in higher electricity prices and lower coal prices⁹⁴.

With fuel costs accounting for about 70% of the total cost of coal-fired power generation, the degree to which electricity prices mirror fluctuations in coal prices serves as a key indicator of the effectiveness of market reforms. To test the relationship between coal prices, reform, and end-user prices, we estimate the following regression on province-level monthly changes in end-user prices and coal prices. Monthly coal prices for each province are obtained from the Price Monitoring Center of the NDRC, and electricity price data, from the same source, are monthly prices for industrial customers (35 kV and above) in 36 major cities.

$$\Delta Elec_{price_{it}} = \beta_1 Reform_{i,t} + \beta_2 \Delta Coal_price_{i,t} + \beta_3 Reform_{i,t} \times \Delta Coal_price_{i,t} + X_{it} + \varepsilon_{it} \quad (2)$$

Where $\Delta Elec_price_{it} = \ln(Elec_price_{i,t}) - \ln(Elec_price_{i,t-1})$ and $\Delta Coal_price_{it} = \ln(Coal_price_{i,t}) - \ln(Coal_price_{i,t-1})$ are the monthly changes in log province average electricity rates and log province coal prices, respectively. We use 2014 as our base year (to capture any changes during 2015) and compare it to 2020.

The results of Equation (2) are reported in Fig.7. As Fig.7 suggests, the reform resulted in a 0.5% reduction in end-user electricity prices from 2014 to 2020. Changes in local coal prices, however, had no statistically discernible effect on electricity prices, as shown in the second column, reflecting that electricity prices did not keep pace with underlying cost changes and remain strongly regulated by the government. The third column in Fig.7 shows that the government's price-setting mechanism did not change after 2015. When the change in coal price interacts with the reform, the result suggests that post-reform, coal costs still do not have a statistically significant effect on electricity prices.

Regression	(1)	(2)	(3)
Reform	-0.00464***	-0.00467***	-0.00480***
	(0.00144)	(0.00144)	(0.00145)
$\Delta Coal_price$		0.00172	0.0163

		(0.00611)	(0.0148)
Reform* Δ Coal_price			-0.0176
			(0.0162)
Observations	2,100	2,100	2,100

Fig.7 | Inadequate cost reflection in electricity pricing. The result of Equation 2. Standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1. P values are for a two-sided test based on normal distribution.

Additionally, dampened electricity price effects can be partly attributed to the fact that long-term contracts constitute the vast majority of market-based transactions. While these contracts do allow price fluctuations within a band near the government benchmark price, the upper and lower limits constrain the degree of fluctuation. Moreover, the benchmark price itself is slow to adjust to changes in coal prices. For example, Zheng et al. (2021) demonstrated that from 2003 to 2018, coal prices had no significant effect on provincial benchmark prices for thermal power. As a result, coal-fired generators cannot fully pass on fuel costs to end-users⁷⁶.

4.2.2 Spot market prices reflect market conditions

China's spot market—still in its infancy, with fewer pilot provinces and a relatively small share of electricity transactions—is working reasonably well, with prices that reflect supply and demand at different moments. Taking the Guangdong spot market as an example, we use data from November 2021 to October 2022 and sum 15-minute interval data to daily data for the regression as shown in Equation (3):

$$Spot_price_t = \beta_1 Coal_price_t + \beta_2 demand_t + \lambda_m + \varepsilon_t \quad (3)$$

Where $Spot_price_t$ is the log average spot price on day t ; $Coal_price_t$ represents the log coal price on day t , which is derived from the price of 5,500 kcal thermal coal in Qinhuangdao Port; $demand_t$ represents the log average electricity demand to participate in the spot market every 15 minutes on day t ; λ_m is the month fixed effect; and ε_t is the independent error term. Fig.8a shows the regression results, indicating that spot market prices are sensitive to both coal price and demand and suggesting they accurately capture supply-demand fluctuations.

With the growing share of wind and solar power, weather fluctuations (e.g., wind speed and solar radiation) can cause sudden surges in power supply that outpace demand adjustments, leading to negative spot market prices. For example, Shandong experienced 22 continuous hours of negative prices during the May Day holiday in 2023, drawing significant attention. Negative prices typically result when supply exceeds demand during periods of low consumption. On an hourly scale, they usually occur during the daytime (Fig.8b), while seasonally, they are more common in winter (Fig.8c). The occurrence of negative prices demonstrates the spot market's ability to

reflect real-time supply conditions. However, given China's relatively low share of wind and solar power generation, the frequent appearance of negative prices reveals a lack of flexibility in the power sector—both in terms of supply and demand. As shown in Fig.8d, Shandong's "duck curve"⁹⁵ remains relatively flat—particularly when compared to places like California, where wind and solar account for a much larger share of generation but negative prices are rare.^④

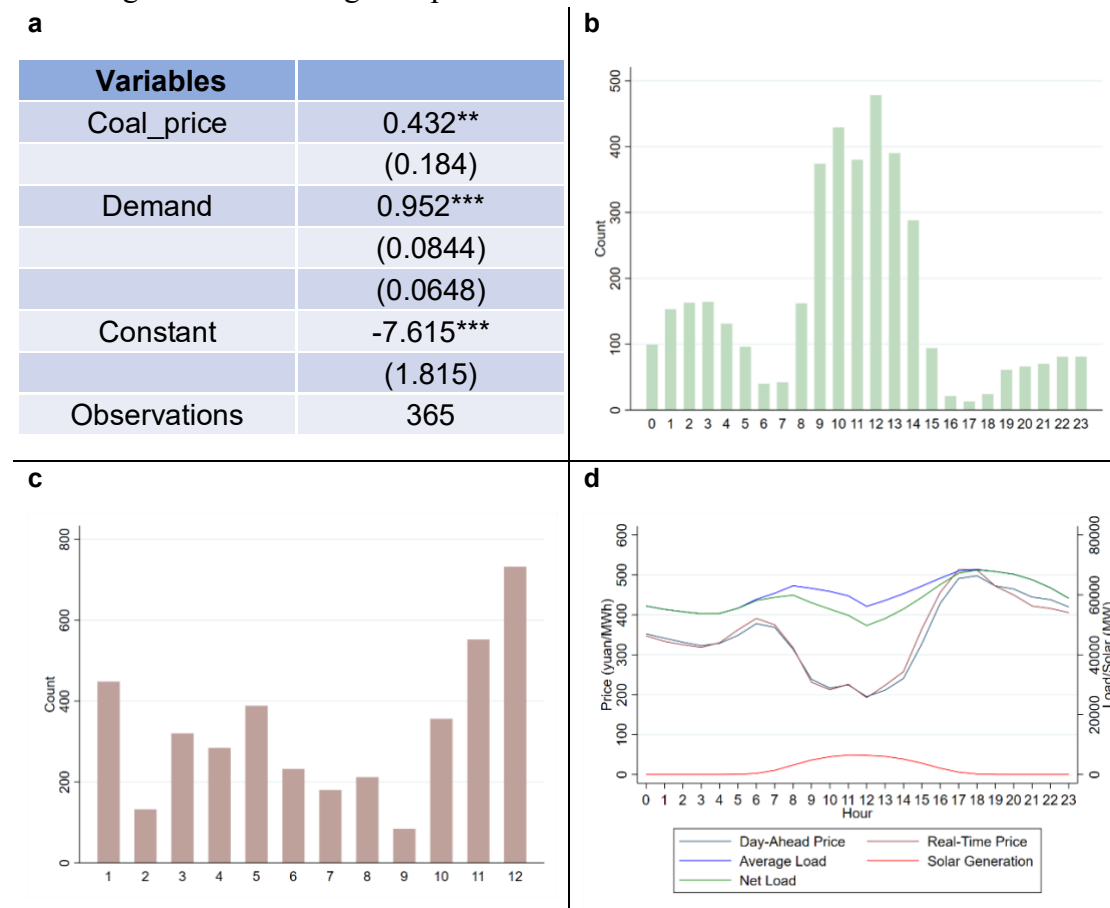


Fig.8 | Spot market electricity prices. a | Regression results of spot market price and coal price. Standard errors in parentheses. *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$. P values are for a two-sided test based on normal distribution. **b** | Instances of negative electricity prices in Shandong by hour (2023). **c** | Instances of negative electricity prices in Shandong by month (2023). **d** | Annual average load and spot prices in Shandong.

4.2.3 Reductions in I&C electricity prices primarily result from T&D efficiencies

Theoretically, market-oriented reforms are expected to enhance competition on the generation side and reduce electricity prices^{39,71}. Overall, I&C prices fell significantly while residential prices did not change much⁷⁶. That is, price reductions mostly

^④ The "Duck Curve" refers to the daily net load curve in power systems (total electricity load minus renewable generation), characterized by a midday dip (due to high solar generation) and a steep evening ramp-up in demand. It underscores the operational challenges posed by renewable energy intermittency.

benefited non-households, consistent with the Chinese government’s focus on reducing costs to businesses to foster economic growth³⁷. Some studies of electricity prices in Jiangsu, Guangdong, and Zhejiang found that nominal I&C electricity prices decreased by 20-30% since January 2012^{90,96}. Fig.9 illustrates the decline in industrial electricity prices in 36 major cities from 2012 to 2023. Most studies find these pricing decreases do not come primarily from improved market efficiency, increased competition, or cost reductions, but rather from the government’s use of administrative means to reduce electricity prices⁹⁰.

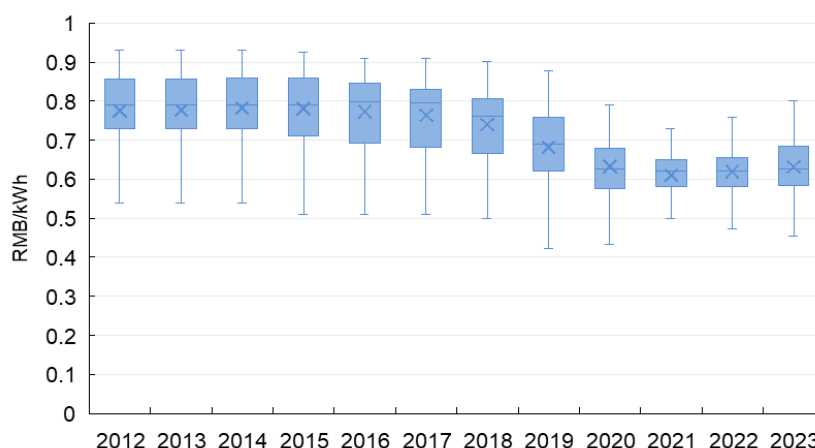


Fig.9 | Average tariff for general industrial electricity customers (35 kV and above) in 36 major cities. *Source:* Price Monitoring Center, NDRC.

Xie et al. (2020) conducted a study on Guangdong and Zhejiang provinces, the pioneers of electricity market reforms, finding that the majority of post-reform price reductions were driven by lower T&D tariffs⁹⁰. In fact, the Chinese government has explicitly identified the reduction of T&D prices as a primary strategy for lowering electricity costs⁹⁷. These price reductions have occurred mainly due to the regulation of T&D enterprises, as reform has transformed their “duopoly” as sole buyers and sellers. Prior to reform, grid company revenues came primarily through an energy (volumetric) tariff on the difference between selling and buying prices³⁴. Since reform, T&D tariffs are set based on “rate of return” regulation, aimed at establishing cost-of-service remuneration with some additional performance incentives. On a three-year cycle, expected costs are converted into tariffs based on expected demand³⁷. This shift has dramatically reduced T&D tariffs. Xie et al. (2022) analyzed the impact of the 2015 reform on 30 of China’s provincial grid companies, finding that T&D tariff reforms and other changes in regulatory mechanisms had a direct negative impact on profitability⁹⁸.

4.2.4 Time-of-use (TOU) pricing has improved social benefit

To optimize power resource allocation, China established TOU tariffs for I&C users in the 2015 reforms, encouraging market transactions to set peak/shoulder/off-peak (PSO) price ratios. Guo et al. (2023) examine the effectiveness of mandatory TOU

pricing for I&C users in Guangdong⁵⁴. They reveal that the social benefits of TOU tariffs can reach up to approximately 4.5% of wholesale electricity generation costs, with nearly 98% of these benefits arising from savings in capacity investment. However, the current PSO price ratio is not optimal. Widening the price gap between peak and off-peak periods can substantially enhance social benefits. The authors demonstrate that social benefits increase by approximately 70% at the optimal price ratio, indicating that social benefits of China's TOU tariffs could rise to 7.6% of wholesale electricity generation costs. This substantial improvement is driven by several factors. First, current off-peak demand remains underutilized; widening the price gap can incentivize users to shift production activities to off-peak hours, lowering their operating costs. Second, encouraging consumers to shift non-essential electricity use to low-load periods enhances resource utilization, reduces reliance on high-cost generators and ancillary services, and cuts fuel and maintenance expenses. Third, a larger peak-to-off-peak price difference helps alleviate peak demand, reducing the need for costly infrastructure investments designed to handle peak loads.

4.3 Market integration enhances efficiency and welfare but raises equity concerns

In January 2022, the central government issued an important document announcing its intention to establish a unified national electricity market by 2030⁶³. Since the 2015 reforms, inter-provincial electricity trading has gradually increased. Fig.10 depicts the scale of inter-provincial electricity transactions in China. While the total trading volume has remained relatively stable, the share of market-based transactions has gradually risen. However, current pricing mechanisms for cross-provincial and inter-regional electricity still rely more on government planning than market-driven processes.

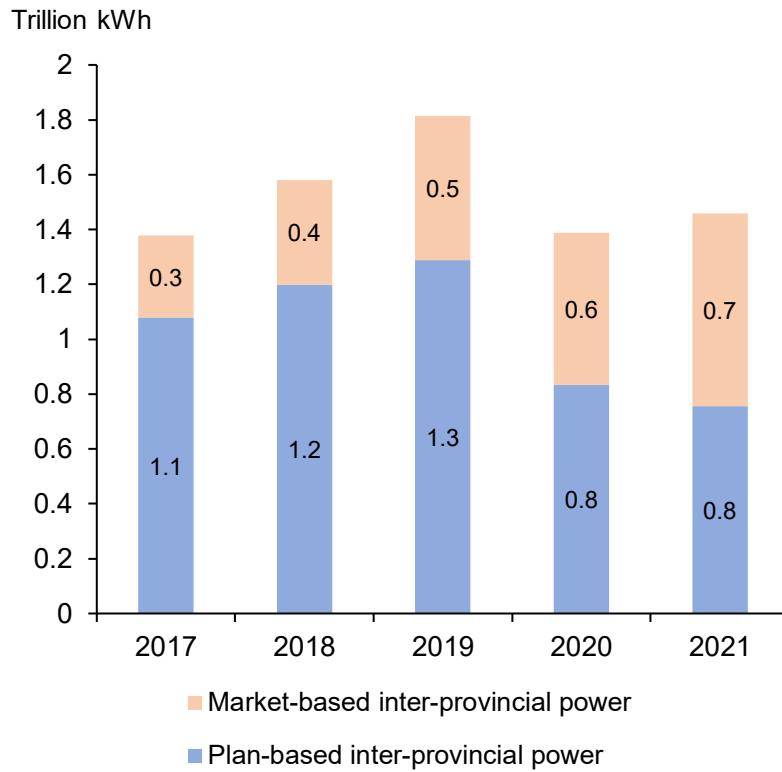


Fig.10 | Share of inter-provincial power based on markets and government plans

With the national electricity market yet to be fully unified, current research mainly uses scenario-based simulations to assess the potential effects of market integration. Research has predominantly focused on southern China, where integration among the five provinces has advanced more rapidly. Findings suggest that market integration can optimize generation capacity, boost production efficiency, lower wholesale electricity prices, and enhance social welfare. Chen et al. (2022) estimated that consolidating southern China's provincial markets into a regional market could reduce electricity prices, cut carbon emissions, and generate seven billion yuan in additional social benefits⁹⁹. Similarly, Abhyankar et al. (2020) estimated that market-based operations in the region led to a 35% reduction in wholesale electricity costs, with 40% of these savings achievable without transmission expansion⁷⁴.

Despite these benefits, societal gains from market integration are unevenly distributed across provinces and stakeholders, potentially leading to equity concerns among regions and between producers and consumers. In examining implications of establishing a unified national electricity market, Song et al. (2024) find that market integration can enhance inter-provincial electricity trade and drive price convergence across regions. This process could result in higher electricity prices in provinces that primarily export electricity, while reducing prices in those that rely on imports, thereby reshaping regional price dynamics. The resulting higher electricity prices in some exporting provinces could negatively affect local consumers, while generators in resource-poor eastern provinces may face losses as production shifts to resource-

abundant western regions. On the whole, China's north, northwest, and central regions are expected to experience greater welfare gains than others¹⁰⁰.

5. Future challenges of China's electricity market reform

5.1 Balancing the roles of government and markets

State control and marketization are not mutually exclusive but rather complementary processes³³. While advancing the role of the market is a key goal of China's electricity reform, that does not entail a simple withdrawal of the state. Over time, the state's role must evolve from direct control of operations and pricing to more strategic institutional responsibilities, such as incentivizing regulation, addressing market power, coordinating activities, and engaging in long-term planning^{8,11,30,101,102}. That markets and regulation are both imperfect necessitates finding an optimal balance between them¹⁰³. Achieving this balance is no easy task, as calibrating the extent of government involvement in market operations remains a delicate challenge. China is currently navigating this transitional phase, which has brought forth a range of complexities and challenges as discussed in this section.

5.1.1 How to balance cost recovery and price volatility in regulating electricity prices?

Electricity prices in China are not fully market-driven. Rather, China's power sector operates under a "dual-track" system, combining both planned and market-based mechanisms. In the planned track, the grid purchases electricity from priority generators and supplies it to priority users, with feed-in and sales prices determined by the government. Priority generating units include renewable energy units, units planned for inter-provincial power supply, and cogeneration units guaranteeing heat supply. Priority consumers include agriculture, residents, and important public entities. Even within the wholesale market, the government regulates prices through mechanisms like upper and lower price caps in both spot and long-term markets. These caps aim to mitigate excessive price volatility, shielding market participants while effectively constraining market forces.

Determining how best to adjust benchmark prices and price fluctuation ranges in line with cost changes poses a formidable challenge, one that demands a high degree of regulatory sophistication. Recent developments suggest that existing price benchmarks and fluctuation ranges might require recalibration. For instance, since 2019, the benchmark price for coal-fired power in the long-term market has been based on a coal price of 535 yuan/ton. Despite coal prices surpassing 800 yuan/ton since 2021, this benchmark remains unchanged. This disconnect has left coal-fired generators unable to

recover their costs, leading to substantial financial strain^{104,105}. Even so, eliminating price regulation is unlikely to be feasible in the foreseeable future. More frequent price adjustments to reflect changes in fuel costs as well as wider price bands could ease the transition to a fully market-based price formation mechanism over time. The key challenge lies in striking an appropriate balance—designing price caps and benchmarks that capture market dynamics while safeguarding economic efficiency and system security.

5.1.2 How to regulate market power on the generation side?

China's power generation sector remains highly concentrated. To date, its market structure is still primarily shaped by the horizontal unbundling reforms of 2002, with the 2015 reforms having little impact on market concentration. Most provincial markets exhibit considerable oligopoly dominance. In 2023, the concentration ratio of the top four companies (CR4) in State Grid provincial markets exceeded 30% in all provinces, with 18 provinces surpassing 50%, and the highest reaching 86.7% (see Fig.11a). Nationally, the market share of the five major state-owned power generation groups has been declining, dropping from 52% in 2013 to 43% in 2020, but it remains substantial (see Fig.11b).^⑤ In 2020, due to operational difficulties, coal-fired power plants owned by these five groups were re-integrated across five northwestern provinces (Gansu, Shaanxi, Xinjiang, Qinghai, and Ningxia). This restructuring left each province's coal power sector under the leadership of a single central enterprise. Other generation sources, including coal plants operated by local state-owned and private enterprises, continue to operate independently, preserving the overall competitive framework. Nevertheless, the integration has intensified market power concerns in these provinces.

The vertical unbundling of electric utilities, coupled with strict rate-of-return regulation, has successfully mitigated market power. Although explicit abuses have not been observed, expansion of the spot market is likely to heighten the risk of such behavior in the power generation sector. Moreover, the fragmentation of China's electricity market could intensify localized monopolistic tendencies. During peak demand periods, tight electricity supply creates opportunities for power generation companies to exert market power, and decisions by individual generators have a heightened impact on market outcomes during these times. Power generators may either directly bid higher prices or indirectly raise prices by reducing generation output¹⁰⁶. Such practices lead to higher electricity costs for consumers and a notable decline in overall consumer welfare^{107,108}. To mitigate these risks, both competitive and regulatory measures can be explored. From a competitive standpoint, several strategies can help mitigate market power. First, broadening market access for private generators stimulates competition²⁹. Second, advancing regional and national electricity market

^⑤ The “five major power generation groups” denote the leading central state-owned enterprises in power generation, formed during the 2002 restructuring.

integration counteracts localized monopolies. Third, implementing more refined trading mechanisms, such as locational marginal price (LMP), prevents generators from leveraging geographical advantages to exert market power¹¹. From a regulatory perspective, enhancing real-time market power surveillance, implementing reasonable price caps, reinforcing antitrust enforcement, and developing a credit rating system could serve as effective safeguards^{109,110,111}. Without adequate countermeasures, such risks could materialize as so-called “gray rhino” events, with predictable but consequential impacts.

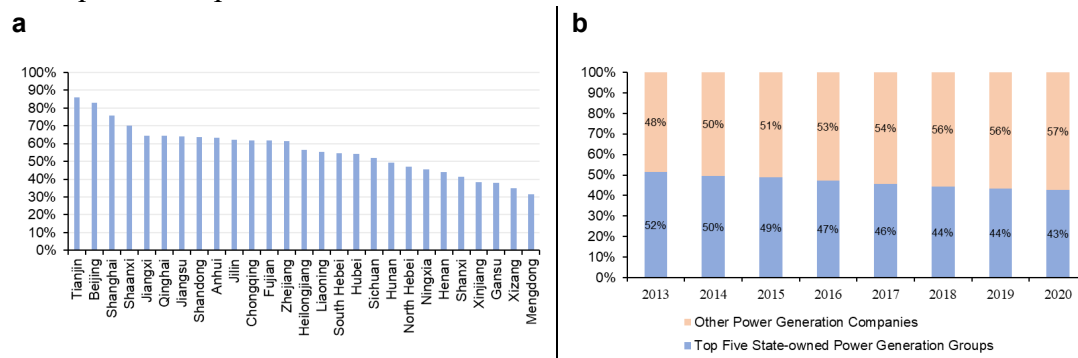


Fig.11 | Market structure and concentration in China's power generation sector. a | Concentration ratio of installed capacity owned by top four companies (CR4) in provincial markets within State Grid regions, 2023. *Source:* Data from provincial electricity trading centers. **b |** Market share of installed capacity held by the five major power generation groups. *Source:* Enterprises' corporate social responsibility reports and industry annual statistical compilations.

5.1.3 How to advance market integration?

The geographic mismatch between China's energy resources and electricity demand underscores the need to establish a unified national electricity market. However, two pressing challenges must be addressed. First, the rigidity of inter-provincial electricity trading agreements must be relaxed, as it limits market flexibility. Current inter-provincial agreements often set predetermined export schedules well in advance—sometimes more than a year—leaving little room for adjustments based on real-time demand. This inflexibility undermines the role of market price signals and often results in inefficient outcomes, such as regions with high generation costs exporting electricity at a loss or high-demand areas struggling to procure power economically. For instance, in the Southern Power Grid, Yunnan's hydropower exports to Guangdong have been strained by seasonal resource variability and evolving regional electricity needs. Similarly, Shandong's rapid solar expansion has resulted in frequent midday power surpluses, reducing its willingness to import electricity at those times. However, during evening peaks, Shandong often depends on imports, which can conflict with supply shortages in exporting regions, causing reluctance from exporting provinces to send power at previously agreed prices. Expediting the development of inter-provincial day-ahead and real-time electricity markets could significantly enhance

market flexibility and better align supply with demand⁴⁰.

Second, other inter-provincial barriers must be addressed¹¹². While the 2015 reforms encouraged the development of provincial electricity markets, differences in trading models, products, and regulatory frameworks across provinces have complicated efforts to integrate market operations. Moreover, local governments often exhibit protectionist tendencies. Market integration optimizes resource allocation on a broader scale but inevitably redistributes benefits. Some regions or enterprises may lose advantages under an integrated market, leading to resistance against reforms. Building a unified electricity market therefore depends on balancing the interests of different stakeholders, whether through market design or government intervention. In the short term, targeted fiscal transfers and capacity compensation may ease opposition from certain market players. However, in the long run, real-time dynamic pricing is expected to become the norm, benefitting all stakeholders¹¹³.

5.1.4 How to reform residential electricity pricing?

China's electricity reforms have historically focused on I&C users, with minimal attention given to residential consumers. Currently, residential and agricultural users benefit from cross-subsidies funded by higher electricity prices for I&C users, giving them relatively low rates¹¹⁴. While this approach treats electricity as a basic public good, research suggests that such subsidy mechanisms may impose excessive financial burdens on I&C users and distort market price signals¹¹⁵. Another question is whether electricity prices should be the same for the wealthy and the poor. To address this, China has implemented tiered electricity pricing for households, where higher consumption is charged at progressively higher rates. This policy aims to encourage energy conservation among residents through price incentives while maintaining fairness¹¹⁶.

Future reforms may need to place greater emphasis on residential consumers. From an equity standpoint, more refined pricing mechanisms may be necessary to consider disparities between rural and urban households, as well as the economic divide between China's developed eastern provinces and less-developed western regions¹¹⁴. From an efficiency perspective, residential users are likely to be increasingly integrated into electricity markets, and cross-subsidies from I&C users progressively reduced. This transition could raise electricity prices, posing the challenge of introducing market mechanisms while protecting vulnerable consumers. Moreover, integrating residential consumers into electricity markets may be constrained by the need for extensive smart meter deployment. To address this challenge, some studies propose that independent system operators (ISOs) could adopt statistical sampling techniques for aggregations of consumers, rather than relying on direct measurement of each individual load. This approach could facilitate residential market participation even in scenarios where smart meter penetration remains limited¹¹⁷.

5.2 Challenges in ensuring flexibility and adequacy in China's power system

The growing share of renewable energy poses significant challenges to China's electricity market design due to the inherent intermittency and variability of renewable resources. The primary concern lies in ensuring flexibility and long-term adequacy of electricity system. In theory, a well-structured electricity market can address these challenges effectively. However, in practice, additional policy objectives, such as climate goals and economic development, introduce complexities—particularly during the transitional phase of electricity market reforms.

5.2.1 How to ensure flexibility?

Ensuring power system flexibility is a critical issue in the energy transition. As renewable energy penetration increases, power systems become more vulnerable to natural variability, increasing the risk of supply shortages. This necessitates timely generation from flexible units like thermal power plants and energy storage systems to maintain system balance. Additionally, the variable nature of renewables places greater demands on grid stability, particularly for frequency and voltage control, emphasizing the critical role of ancillary services provided by flexible resources^{35,62,118}. Studies find that well-designed market mechanisms are highly effective in ensuring flexibility, primarily by providing incentives and equitable revenue distribution^{27,48,119}. However, China's market-oriented policies may require further refinement to fully unlock their potential. Key strategies include incentivizing energy storage participation in spot and ancillary service markets⁵²; encouraging demand-side flexibility through expanded TOU pricing differentials; reforming capacity payments to adopt technology-neutral and performance-based compensation frameworks that promote fair competition between traditional providers (e.g., coal-fired power plants) and emerging flexibility providers (e.g., battery storage and demand-side aggregators); and establishing a unified national market to enhance signals for energy availability and scarcity on a broader scale^{48,120}.

5.2.2 How to ensure adequacy?

Ensuring the long-term adequacy of power systems is another critical challenge. This issue is largely attributed to the “missing money” problem: revenues from energy and ancillary service markets are often insufficient to incentivize needed investment in new generation capacity¹²¹. Price caps further compound this challenge by limiting generators' ability to earn scarcity rents during supply shortages. High renewable penetrations exacerbate the missing money problem because increased entry of variable energy resources with near-zero marginal costs decreases the amount of thermal

generation cleared from the merit-order stack and induces lower capacity factors for thermal generators. In addition, energy prices tend to be lower (on average) and more volatile as a result of increasing renewable power participation¹²².

Traditional approaches to addressing the missing money problem include several key mechanisms. Scarcity pricing is one such solution, allowing peak prices to reflect capacity scarcity more accurately¹²³. Capacity mechanisms, including fixed payments or capacity markets, are another common approach. Contracts for difference (CFD) offer an additional solution, providing revenue stability for generators while incentivizing availability during scarcity conditions. These contracts also protect consumers from extreme price volatility, as system operators can procure electricity at pre-specified prices¹²⁴.

Several recent studies introduce novel measures for enhancing long-term adequacy in power systems. Prete et al. (2024) categorizes 11 such approaches into four areas¹²⁵. The first, aimed at capacity markets, introduces a joint procurement mechanism for forward capacity and clean energy attribute credits and represents the least radical departure from current market structures¹²⁶. The second area focuses on long-term contracts, aiming to ensure revenue certainty through fixed-price agreements^{127,128,129}. The third targets short-term markets, proposing the separation of renewable and non-renewable electricity markets, with operational rules tailored to the specific characteristics of different generation technologies¹³⁰. The fourth approach introduces a “swing-contract” market design and would require a comprehensive structural overhaul of China’s electricity market¹³¹. Whether relying on traditional mechanisms or adopting innovative approaches, significant theoretical and empirical exploration is still needed to evaluate their viability in addressing China’s long-term electricity adequacy challenges as it moves toward a carbon-neutral power system.

6. Conclusion and future perspective

China’s electricity sector reforms since 2015 mark a pivotal shift toward harnessing market-oriented mechanisms to balance efficiency, equity, and sustainability in the world’s largest power system. The reform agenda has centered on fostering competition in generation and retail, tightening regulatory oversight of grid costs and services, integrating regional electricity markets, and accelerating the transition to renewable energy. Significant progress has been made in multiple areas. First, a comprehensive wholesale market structure has been established, with medium- and long-term contracts forming the backbone, complemented by spot markets, ancillary service markets, and capacity compensation schemes. As a result, the share of market-based electricity transactions nearly quintupled in eight years, increasing from 13% in 2015 to over 61% in 2023. Second, on the consumer side, industrial and commercial (I&C) users now have the option to engage in direct power purchase agreements with generators or

access competitive pricing through retail markets. Third, enhanced regulation of transmission and distribution (T&D) networks has led to the introduction of a transparent pricing framework, significant cost reductions, and greater private sector participation. Fourth, progress has been made toward a unified national electricity market by harmonizing various market structures. Finally, wind and solar power have been gradually integrated into the market, supported by dedicated green electricity trading platforms to facilitate their expansion.

Empirical evidence suggests that shifting from fairness-based dispatch to economic dispatch has significantly enhanced operational efficiency, with coal-fired power plants achieving efficiency gains of 3-15%^{4,70,71,73,74,75,132}. This effect has been particularly pronounced for smaller-capacity generators, which face higher per-unit generation costs and thus stronger competitive pressure to improve efficiency.

However, China's electricity market transition remains incomplete. Despite the introduction of market-oriented mechanisms, electricity pricing continues to be heavily regulated, preventing cost-reflective pricing. The observed decline in I&C electricity prices is largely attributed to strict government regulation in T&D tariffs rather than increased market competition⁹⁰. While spot markets effectively capture supply and demand fluctuations, their limited trading volumes have restricted the extent to which costs and supply-demand conditions are reflected in electricity prices. Greater market integration has fostered inter-provincial electricity trade, boosting overall efficiency and social welfare. However, despite these benefits, the distribution of welfare gains from market integration has been uneven across provinces and stakeholders, potentially leading to regional disparities and equity concerns between producers and consumers¹⁰⁰.

Looking ahead, China's power market reform must navigate two fundamental challenges: balancing government intervention with market dynamics and ensuring both system flexibility and long-term adequacy. The first challenge lies in defining the government's role in an increasingly market-driven power sector. While marketization remains a core objective, government intervention is still crucial for managing market power and protecting vulnerable consumers. Currently, electricity prices are still subject to partial regulation, yet delayed adjustments in benchmark tariffs and restrictive price caps hinder cost-reflective pricing. The concentrated market power within the generation sector further complicates competition, underscoring the need to enhance market access and strengthen regulatory oversight. Furthermore, inter-provincial electricity trade remains constrained by rigid agreements and local protectionism, reducing market efficiency. Expanding flexible trading mechanisms and harmonizing market rules across provinces would be effective measures for market integration. Residential electricity pricing is another area requiring policy reform, with a key consideration being how to introduce market mechanisms while protecting the most vulnerable consumers. Achieving the right equilibrium between government regulation and market autonomy will be crucial for sustaining reform momentum.

The second challenge is ensuring system flexibility and long-term adequacy, particularly as renewable energy penetration increases. The inherent variability of renewables demands a more adaptive power grid, along with enhanced market mechanisms for ancillary services, energy storage, and demand-side flexibility. Meanwhile, the issue of “missing money” threatens investment in new generation capacity, as price caps and the low market-clearing prices induced by renewables undermine generators’ long-term profitability. Addressing these issues requires comprehensive market reforms, with potential measures including improved scarcity pricing, capacity mechanisms, long-term markets, and contracts for difference¹²⁵. However, substantial theoretical and empirical research is still needed to assess the feasibility of these measures in addressing China’s long-term power adequacy challenges.

Enhancing market efficiency, strengthening system reliability, and advancing renewable energy integration remain central to China’s electricity market reform, necessitating ongoing refinement and adaptation. Despite substantial achievements, market mechanisms are still evolving amid a pivotal energy transition. Further research and experimentation is essential for defining the optimal trajectory for China’s electricity market development. Ultimately, the success of these reforms will extend far beyond the power sector, influencing China’s economic growth, energy security, and carbon neutrality goals.

Acknowledgements

Authors acknowledge the National Natural Science Foundation of China (grant 72141308).

Author contributions

Y.F., J.L. and F.S. contributed to discussion and framework of the manuscript content. Y.F. designed the initial manuscript. J.L., F.S. and M.H. provided substantial feedback and revisions to improve the manuscript.

Declaration of interests

The authors declare no competing interests.

Reference

¹ Fabrizio, K. R., Rose, N. L. and Wolfram, C. D. Do Markets Reduce Costs?

Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency. *American Economic Review* 97, 1250 – 1277, doi:10.1257/aer.97.4.1250 (2007).

² China Electricity Council. Report on the Economic Performance of the Electricity Industry in 2023 (2024);
<http://lwzb.stats.gov.cn/pub/lwzb/bztt/202405/W020240527578179924981.pdf>.

³ Xu, S. and Chen, W. The reform of electricity power sector in the PR of China. *Energy Policy* 34, 2455-2465, doi:10.1016/j.enpol.2004.08.040 (2006).

⁴ Timilsina, G. R., Pang, J. and Yang, X. Macroeconomic impacts of power sector reforms in China. *Energy Policy* 157, doi:10.1016/j.enpol.2021.112509 (2021).

⁵ Wang, Q. and Chen, X. China's electricity market-oriented reform: From an absolute to a relative monopoly. *Energy Policy* 51, 143-148, doi:10.1016/j.enpol.2012.08.039 (2012).

⁶ State Council of the People's Republic of China. Opinions on Further Deepening the Reform of the Electricity System (2015)
<https://aimg8.dlssyht.cn/u/2028657/ueditor/file/1015/2028657/1625821355249405.pdf>

⁷ Pollitt, Michael G. 2020. "Reforming the Chinese Electricity Supply Sector: Lessons from Global Experience." Springer. doi.org/10.1007/978-3-030-39462-2

⁸ Joskow, P. L. Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector. *Journal of Economic Perspectives* 11, 119 – 138, doi:10.1257/jep.11.3.119 (1997).

⁹ Borenstein, S. and Bushnell, J. Electricity Restructuring: Deregulation or Reregulation? *Regulation* 23 (2000).

¹⁰ Joskow, P. L. Markets for Power in the United States: An Interim Assessment. *The Energy Journal* 27, 1-36, doi:10.5547/ISSN0195-6574-EJ-Vol27-No1-2 (2006).

¹¹ Joskow, P. L. Lessons Learned From Electricity Market Liberalization. *The Energy Journal* 29, 9-42, doi:10.5547/ISSN0195-6574-EJ-Vol29-NoSI2-3 (2008).

¹² Jamasb, T. and Pollitt, M. Incentive regulation of electricity distribution networks: Lessons of experience from Britain. *Energy Policy* 35, 6163-6187, doi:10.1016/j.enpol.2007.06.022 (2007).

¹³ Pollitt, M. G. The Future of Electricity (and Gas) Regulation in a Low-carbon Policy World. *The Energy Journal* 29, 63-94, doi:10.5547/ISSN0195-6574-EJ-Vol29-NoSI2-5 (2008).

¹⁴ Joskow, P. L. Electricity Sector Restructuring and Competition: Lessons Learned. *Cuadernos de economía* 40, doi:10.4067/s0717-68212003012100023 (2003).

¹⁵ Green, R. J. and Newbery, D. M. Competition in the British Electricity Spot Market. *Journal of Political Economy* 100, 929-953, doi:10.1086/261846 (1992).

¹⁶ Borenstein, S. The Trouble With Electricity Markets: Understanding California's Restructuring Disaster. *Journal of Economic Perspectives* 16, 191 – 211, doi:10.1257/0895330027175 (2002).

¹⁷ Bacon, R. W. and Besant-Jones, J. GLOBAL ELECTRIC POWER REFORM, PRIVATIZATION, AND LIBERALIZATION OF THE ELECTRIC POWER

INDUSTRY IN DEVELOPING COUNTRIES¹. Annual Review of Environment and Resources 26, 331-359, doi:<https://doi.org/10.1146/annurev.energy.26.1.331> (2001)

¹⁸ CEER (2016). Principles for valuation of flexibility, C16-FTF-09-03, at http://www.eurelectric.org/media/285609/c16-fft-09-03_principles-for-valuation-of-flexibility.pdf

¹⁹ Newbery, D. Missing money and missing markets: Reliability, capacity auctions and interconnectors. Energy Policy 94, 401-410, doi:10.1016/j.enpol.2015.10.028 (2016).

²⁰ Newbery, D. M. What Future(s) for Liberalized Electricity Markets: Efficient, Equitable or Innovative? The Energy Journal 39, 1-28, doi:10.5547/01956574.39.1.dnew (2018).

²¹ Weber C., Möst D. and Fichtner W. Economics of Power Systems: Fundamentals for Sustainable Energy. <https://doi.org/10.1007/978-3-030-97770-2> (Springer Cham, 2022).

²² Patrick, R. H. and Wolak, F. A. in Regulation Under Increasing Competition (ed Michael A. Crew) 155-182 (Springer US, 1999).

²³ Wolak, Frank A. (2006) “Residential Customer Response to Real-Time Pricing: The Anaheim Critical-Peak Pricing Experiment,” available from <http://www.stanford.edu/~wolak>. <https://escholarship.org/uc/item/3td3n1x1#main>

²⁴ Wolak, F. A. Do Residential Customers Respond to Hourly Prices? Evidence from a Dynamic Pricing Experiment. American Economic Review 101, 83-87, doi:10.1257/aer.101.3.83 (2011).

²⁵ Wolak, F. A. Handbook on Electricity Markets (Chapter 4: Wholesale electricity market design).(2021).

²⁶ Nepal, R., Sen, A. and Jamasb, T. in Revisiting Electricity Market Reforms: Lessons for ASEAN and East Asia (eds Han Phoumin et al.) 1-25 (Springer Nature Singapore, 2022).

²⁷ Borenstein, S., Bushnell, J. and Mansur, E. The Economics of Electricity Reliability. Journal of Economic Perspectives 37, 181-206, doi:10.1257/jep.37.4.181 (2023).

²⁸ Borenstein, S. and Bushnell, J. The US Electricity Industry After 20 Years of Restructuring. Annual Review of Economics 7, 437-463, doi:10.1146/annurev-economics-080614-115630 (2015).

²⁹ Newbery, D. M. Regulatory Challenges to European Electricity Liberalisation. (Faculty of Economics, University of Cambridge, 2002).

³⁰ Jamasb, T. Between the state and market: Electricity sector reform in developing countries. Utilities Policy 14, 14-30, doi:10.1016/j.jup.2004.11.001 (2006).

³¹ Alva, C.A.H., Li, X., 2018. Power Sector Reform in China: an International Perspective. International Energy Agency. https://iea.blob.core.windows.net/assets/95fa6240-a316-4b9e-b5fa-40d8d265150e/Insights_Series_2018_Power4Sector_Reform_in_China.pdf

³² Li, S., Zhang, S. and Andrews-Speed, P. Using diverse market-based approaches to integrate renewable energy: Experiences from China. *Energy Policy* 125, 330-337, doi:10.1016/j.enpol.2018.11.006 (2019).

³³ Yu, Z. Beyond the state/market dichotomy: Institutional innovations in China's electricity industry reform. *J Environ Manage* 264, 110306, doi:10.1016/j.jenvman.2020.110306 (2020).

³⁴ Ma, J. On-grid electricity tariffs in China: Development, reform and prospects. *Energy Policy* 39, 2633-2645, doi:10.1016/j.enpol.2011.02.032 (2011).

³⁵ Kahrl, F., Williams, J., Jianhua, D. and Junfeng, H. Challenges to China's transition to a low carbon electricity system. *Energy Policy* 39, 4032-4041, doi:10.1016/j.enpol.2011.01.031 (2011).

³⁶ Kahrl, F., Williams, J. H. and Hu, J. The political economy of electricity dispatch reform in China. *Energy Policy* 53, 361-369, doi:10.1016/j.enpol.2012.10.062 (2013).

³⁷ Davidson, M. R. and Pérez-Arriaga, I. Avoiding Pitfalls in China's Electricity Sector Reforms. *The Energy Journal* 41, 119-142, doi:10.5547/01956574.41.3.mdav (2020).

³⁸ Guo, H. et al. Power market reform in China: Motivations, progress, and recommendations. *Energy Policy* 145, doi:10.1016/j.enpol.2020.111717 (2020).

³⁹ Lin, J., Kahrl, F., Yuan, J., Liu, X. and Zhang, W. Challenges and strategies for electricity market transition in China. *Energy Policy* 133, doi:10.1016/j.enpol.2019.110899 (2019).

⁴⁰ IEA (2023), Building a Unified National Power Market System in China, IEA, Paris <https://www.iea.org/reports/building-a-unified-national-power-market-system-in-china>, Licence: CC BY 4.0

⁴¹ National Development and Reform Commission. Basic Rules for Medium- and Long-Term Trading of Electricity (2016). <https://zfxgk.ndrc.gov.cn/web/iteminfo.jsp?id=2698>

⁴² National Energy Administration. Regulations on the Grid Operation of Power Plants (2006). https://zfxgk.nea.gov.cn/auto79/201306/t20130628_1618.htm

⁴³ National Energy Administration. Regulations on the Grid Operation of Power Plants (2006). https://gzb.nea.gov.cn/dtyw/jgdt/202308/t20230822_9336.html

⁴⁴ Li H, Song F, Xia F. Speeding Up Renewable Energy Integration with Invisible Hands: Ancillary Service Market and the COVID-19 Natural Experiment[J]. *The Energy Journal*, 2024: 01956574241240025.

⁴⁵ National Energy Administration. Basic Rules for the Electricity Ancillary Services Market (2024); https://zfxgk.nea.gov.cn/2024-10/08/c_1212404033.htm

⁴⁶ Henan Energy Regulatory Office of National Energy Administration. Henan Electricity Auxiliary Service Market Trading Rules (2024) https://henb.nea.gov.cn/dtyw/tzgg/202408/t20240828_268514.html

⁴⁷ Sichuan Energy Regulatory Office₄₂ of National Energy Administration.

Implementation Rules for the Management of Electricity Auxiliary Services in Sichuan Province (2023). https://scb.nea.gov.cn/dtyw/tzgg/202401/t20240119_227883.html

⁴⁸ IEA (2024), Meeting Power System Flexibility Needs in China by 2030, IEA, Paris <https://www.iea.org/reports/meeting-power-system-flexibility-needs-in-china-by-2030>, Licence: CC BY 4.0

⁴⁹ National Development and Reform Commission. Notice on the Establishment of the Coal Capacity Tariff Mechanism (2023) https://www.ndrc.gov.cn/xxgk/zcfb/tz/202311/t20231110_1361897.html

⁵⁰ Geng, S. et al. in 2024 6th Asia Energy and Electrical Engineering Symposium (AEEES) 822-828 (2024).

⁵¹ Liu, J. et al. in 2023 IEEE 7th Conference on Energy Internet and Energy System Integration (EI2) 3271-3275 (2023).

⁵² Kahrl, F. and Lin, J. Changing economics of China's power system suggest that batteries and renewables may be a lower cost way to meet peak demand growth than coal. *iScience* 27, 108975, doi:<https://doi.org/10.1016/j.isci.2024.108975> (2024).

⁵³ Zeng, M., Yang, Y., Wang, L. and Sun, J. The power industry reform in China 2015: Policies, evaluations and solutions. *Renewable and Sustainable Energy Reviews* 57, 94-110, doi:10.1016/j.rser.2015.12.203 (2016).

⁵⁴ Guo, B., Sun, A. and Song, F. Time is Money: The Social Benefits of Time-of-Use Tariffs. *SSRN Electronic Journal*, doi:10.2139/ssrn.4560864 (August 31, 2023).

⁵⁵ Harding, M. and Sexton, S. Household Response to Time-Varying Electricity Prices. *Annual Review of Resource Economics* 9, 337-359, doi:10.1146/annurev-resource-100516-053437 (2017).

⁵⁶ Faruqui, A., Sergici, S., Lessem, N. and Mountain, D. Impact measurement of tariff changes when experimentation is not an option—A case study of Ontario, Canada. *Energy Economics* 52, 39-48, doi:10.1016/j.eneco.2015.09.011 (2015).

⁵⁷ Qiu, Y., Kirkeide, L. and Wang, Y. D. Effects of Voluntary Time-of-Use Pricing on Summer Electricity Usage of Business Customers. *Environmental and Resource Economics* 69, 417-440, doi:10.1007/s10640-016-0084-5 (2016).

⁵⁸ Zhang, S., Jiao, Y. and Chen, W. Demand-side management (DSM) in the context of China's on-going power sector reform. *Energy Policy* 100, 1-8, doi:10.1016/j.enpol.2016.09.057 (2017).

⁵⁹ National Development and Reform Commission. Promote Reform, Reduce Costs, Strengthen Regulation: The National Development and Reform Commission Deploys the Second Regulatory Cycle (2019) https://www.gov.cn/xinwen/2019-01/28/content_5361828.htm

⁶⁰ China Energy News. Seven years after the implementation of the incremental distribution of electricity, what is the crux of the problem? (2023) http://paper.people.com.cn/zgnyb/html/2023-04/03/content_25974909.htm

⁶¹ Wu, D. Accountability relations and market reform in China's electric power

sector. *Global Transitions* 1, 171-180, doi:10.1016/j.glt.2019.10.002 (2019).

⁶² Zhang, S., Andrews-Speed, P. and Li, S. To what extent will China's ongoing electricity market reforms assist the integration of renewable energy? *Energy Policy* 114, 165-172, doi:10.1016/j.enpol.2017.12.002 (2018).

⁶³ National Development and Reform Commission. Guiding Opinions on Accelerating the Construction of a Nationally Unified Electricity Market System (2022) https://www.gov.cn/zhengce/zhengceku/2022-01/30/content_5671296.htm.

⁶⁴ National Development and Reform Commission. Relevant Developments in China's Electricity Market in 2022 (2023b) https://www.ndrc.gov.cn/fggz/hjyzy/jnhnx/202302/t20230215_1348801.html

⁶⁵ China Southern Power Grid News. The Southern regional electricity market transitioned to a monthly settlement trial operation. (2024) https://www.csg.cn/xwzx/2024/gsyw/202411/t20241105_343390.html

⁶⁶ China Electric Power News. China's power market construction advances steadily.(2023) https://cpnn.com.cn/news/zngc/202303/t20230329_1593819_wap.html

⁶⁷ China Electric Power News. Give full play to the environmental value of green power.(2023) https://cpnn.com.cn/news/zngc/202308/t20230815_1626335_wap.html

⁶⁸ Banaei, M., Oloomi Buygi, M. and Raouf Sheybani, H. Supply function Nash equilibrium of joint day-ahead electricity markets and forward contracts. *International Journal of Electrical Power and Energy Systems* 113, 104-116, doi:10.1016/j.ijepes.2019.05.036 (2019).

⁶⁹ Zhao, W., Zhang, J., Li, R. and Zha, R. A transaction case analysis of the development of generation rights trading and existing shortages in China. *Energy Policy* 149, doi:10.1016/j.enpol.2020.112045 (2021).

⁷⁰ Wei, Y.-M. et al. Economic dispatch savings in the coal-fired power sector: An empirical study of China. *Energy Economics* 74, 330-342, doi:10.1016/j.eneco.2018.06.017 (2018).

⁷¹ Lin, J., Kahrl, F., Yuan, J., Chen, Q. and Liu, X. Economic and carbon emission impacts of electricity market transition in China: A case study of Guangdong Province. *Applied Energy* 238, 1093-1107, doi:10.1016/j.apenergy.2019.01.128 (2019a).

⁷² Chen, S., Liu, P. and Li, Z. Low carbon transition pathway of power sector with high penetration of renewable energy. *Renewable and Sustainable Energy Reviews* 130, doi:10.1016/j.rser.2020.109985 (2020).

⁷³ Ding, Q., Wang, J., Zhang, B. and Yu, Y. Economic burden of China's fairness regulations on power generation sector. *Energy* 278, doi:10.1016/j.energy.2023.127653 (2023).

⁷⁴ Abhyankar, N., Lin, J., Liu, X. and Sifuentes, F. Economic and environmental benefits of market-based power-system reform in China: A case study of the Southern grid system. *Resources, Conservation and Recycling* 153, doi:10.1016/j.resconrec.2019.104558 (2020)⁴⁴

⁷⁵ Luo, Q. et al. The Health and Climate Benefits of Economic Dispatch in China's Power System. *Environ Sci Technol* 57, 2898-2906, doi:10.1021/acs.est.2c05663 (2023).

⁷⁶ Zheng, X., Menezes, F. and Nepal, R. In between the state and the market: An empirical assessment of the early achievements of China's 2015 electricity reform. *Energy Economics* 93, doi:10.1016/j.eneco.2020.105003 (2021).

⁷⁷ Xiang, C., Zheng, X., Song, F., Lin, J. and Jiang, Z. Assessing the roles of efficient market versus regulatory capture in China's power market reform. *Nature Energy* 8, 747-757, doi:10.1038/s41560-023-01278-9 (2023a).

⁷⁸ Cao, J., Ho, M. S., Ma, R. and Zhang, Y. Transition from plan to market: Imperfect regulations in the electricity sector of China. *Journal of Comparative Economics* 52, 509-533, doi:10.1016/j.jce.2024.01.001 (2024).

⁷⁹ National Energy Administration. 2012 National Electric Reliability Annual Report. (2012) <https://prpq.nea.gov.cn/uploads/file1/20210716/60f13d915584a.pdf>

⁸⁰ Gallagher, K. S., Zhang, F., Orvis, R., Rissman, J. and Liu, Q. Assessing the Policy gaps for achieving China's climate targets in the Paris Agreement. *Nature Communications* 10, doi:10.1038/s41467-019-09159-0 (2019).

⁸¹ Cui, J., Song, F. and Jiang, Z. How market competition improves industrial efficiency: Empirical evidence from China's electricity market reform. Working Paper. (2025).

https://www.researchgate.net/publication/389143346_How_market_competition_improves_industrial_efficiency_Empirical_evidence_from_China's_electricity_market_reform

⁸² Dupuy, M. (2016). China power sector reform: Key issues for the world's largest power sector. The Regulatory Assistance Project (RAP), 1-8. <https://www.raponline.org/wp-content/uploads/2023/09/rap-dupuy-key-issues-china-power-sector-2016-march.pdf>

⁸³ Lynch, M. Á., Shortt, A., Tol, R. S. J. and O'Malley, M. J. Risk – return incentives in liberalised electricity markets. *Energy Economics* 40, 598-608, doi:10.1016/j.eneco.2013.08.015 (2013).

⁸⁴ Bistline, J. E. Electric sector capacity planning under uncertainty: Climate policy and natural gas in the US. *Energy Economics* 51, 236-251, doi:10.1016/j.eneco.2015.07.008 (2015).

⁸⁵ Hu, Y. and Cheng, H. Displacement efficiency of alternative energy and trans-provincial imported electricity in China. *Nature Communications* 8, doi:10.1038/ncomms14590 (2017).

⁸⁶ Duan, L., Petroski, R., Wood, L. and Caldeira, K. Stylized least-cost analysis of flexible nuclear power in deeply decarbonized electricity systems considering wind and solar resources worldwide. *Nature Energy* 7, 260-269, doi:10.1038/s41560-022-00979-x (2022).

-
- ⁸⁷ Ang, B. W. LMDI decomposition approach: A guide for implementation. *Energy Policy* 86, 233-238, doi:10.1016/j.enpol.2015.07.007 (2015).
- ⁸⁸ Xiang, C., Zheng, X. and Xie, L. How can China's power sector reform reduce carbon emissions? A long-term competition perspective. *China Economic Review* 80, doi:10.1016/j.chieco.2023.102000 (2023b).
- ⁸⁹ Menezes, F. M. and Zheng, X. Regulatory incentives for a low-carbon electricity sector in China. *Journal of Cleaner Production* 195, 919-931, doi:10.1016/j.jclepro.2018.05.256 (2018).
- ⁹⁰ Xie, B.-C., Xu, J. and Pollitt, M. What effect has the 2015 power market reform had on power prices in China? Evidence from Guangdong and Zhejiang. (Faculty of Economics, University of Cambridge, 2020).
- ⁹¹ Teng, F., Jotzo, F. and Wang, X. Interactions between Market Reform and a Carbon Price in China's Power Sector. *Economics of Energy and Environmental Policy* 6, doi:10.5547/2160-5890.6.1.ften (2017).
- ⁹² Hu, J. and Jiang, Y. in *Post-COVID Economic Revival, Volume II: Sectors, Institutions, and Policy* (ed Vladimir S. Osipov) 143-157 (Springer International Publishing, 2022).
- ⁹³ Liu, X. and Jin, Z. An analysis of the interactions between electricity, fossil fuel and carbon market prices in Guangdong, China. *Energy for Sustainable Development* 55, 82-94, doi:10.1016/j.esd.2020.01.008 (2020).
- ⁹⁴ Liu, H., Zhang, Z., Chen, Z.-M. and Dou, D. The impact of China's electricity price deregulation on coal and power industries: Two-stage game modeling. *Energy Policy* 134, doi:10.1016/j.enpol.2019.110957 (2019).
- ⁹⁵ CAISO (California Independent System Operator). What the duck curve tells us about managing a green grid. (2016) https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf
- ⁹⁶ Li, T., Gao, C., Pollitt, M. G., Chen, T. and Ming, H. Measuring the Effects of Power System Reform in Jiangsu Province, China from the Perspective of Social Cost Benefit Analysis. *The Energy Journal* (2025, forthcoming), 01956574241280817, doi:10.1177/01956574241280817.
- ⁹⁷ National Development and Reform Commission. Notice of the National Development and Reform Commission on Matters Relating to the Reduction of General Industrial and Commercial Electricity Prices (2018) https://www.gov.cn/zhengce/zhengceku/2018-12/31/content_5434123.htm
- ⁹⁸ Xie, B.-C., Duan, N., Ni, K.-K. and Zhang, T. Has the market-oriented reform of 2015 affected the performance of China's power grid firms? *Energy and Climate Change* 3, doi:10.1016/j.egycc.2022.100081 (2022).
- ⁹⁹ Chen, H., Cui, J., Song, F. and Jiang, Z. Evaluating the impacts of reforming and integrating China's electricity sector. *Energy Economics* 108, doi:10.1016/j.eneco.2022.105912 (2022).

¹⁰⁰ Song, F., Feng, Y., Huang, Y. and Cui, J. A Synergistic Ex-ante Evaluation Framework of the Unified National Market: An Application to the Electricity Market (in Chinese). Working Paper (2024).

¹⁰¹ Foster, Vivien; Rana, Anshul. 2020. Rethinking Power Sector Reform in the Developing World. Sustainable Infrastructure;. © Washington, DC: World Bank. <http://hdl.handle.net/10986/32335> License: [CC BY 3.0 IGO](#).

¹⁰² Nepal, R. and Jamasb, T. Caught between theory and practice: Government, market, and regulatory failure in electricity sector reforms. *Economic Analysis and Policy* 46, 16-24, doi:10.1016/j.eap.2015.03.001 (2015).

¹⁰³ Lin, K.-C. and Purra, M. M. Transforming China's electricity sector: Politics of institutional change and regulation. *Energy Policy* 124, 401-410, doi:10.1016/j.enpol.2018.07.041 (2019).

¹⁰⁴ Jia, Z., Lin, B. and Wen, S. Electricity market Reform: The perspective of price regulation and carbon neutrality. *Applied Energy* 328, 120164, doi:<https://doi.org/10.1016/j.apenergy.2022.120164> (2022).

¹⁰⁵ Zhang, K., Yao, Y.-F., Liang, Q.-M. and Saren, G. How should China prioritize the deregulation of electricity prices in the context of carbon pricing? A computable general equilibrium analysis. *Energy Economics* 96, 105187, doi:<https://doi.org/10.1016/j.eneco.2021.105187> (2021).

¹⁰⁶ Stoft, S. (2002). *Power system economics: designing markets for electricity* (Vol. 468): IEEE press Piscataway.

¹⁰⁷ García, J. A. and Reitzes, J. D. International Perspectives on Electricity Market Monitoring and Market Power Mitigation. *Review of Network Economics* 6, doi:10.2202/1446-9022.1127 (2007).

¹⁰⁸ Cho, Y., Lee, J. and Kim, T.-Y. The impact of ICT investment and energy price on industrial electricity demand: Dynamic growth model approach. *Energy Policy* 35, 4730-4738, doi:<https://doi.org/10.1016/j.enpol.2007.03.030> (2007).

¹⁰⁹ Pollitt, M. G. The role of policy in energy transitions: Lessons from the energy liberalisation era. *Energy Policy* 50, 128-137, doi:<https://doi.org/10.1016/j.enpol.2012.03.004> (2012).

¹¹⁰ Cramton, P. and Stoft, S. A Capacity Market that Makes Sense. *The Electricity Journal* 18, 43-54, doi:<https://doi.org/10.1016/j.tej.2005.07.003> (2005).

¹¹¹ Wolak, F. A. Diagnosing the California Electricity Crisis. *The Electricity Journal* 16, 11-37, doi:[https://doi.org/10.1016/S1040-6190\(03\)00099-X](https://doi.org/10.1016/S1040-6190(03)00099-X) (2003).

¹¹² Liu, S., Bie, Z., Lin, J. and Wang, X. Curtailment of renewable energy in Northwest China and market-based solutions. *Energy Policy* 123, 494-502, doi:10.1016/j.enpol.2018.09.007 (2018).

¹¹³ Matthes, F. C. Energy transition in Germany: a case study on a policy-driven structural change of the energy system. *Evolutionary and Institutional Economics Review* 14, 141-169, doi:10.1007/s40844-016-0066-x (2017).

-
- ¹¹⁴ Wang, X. and Lin, B. Impacts of residential electricity subsidy reform in China. *Energy Efficiency* 10, 499-511, doi:10.1007/s12053-016-9466-3 (2017).
- ¹¹⁵ Lin, B. and Jiang, Z. Estimates of energy subsidies in China and impact of energy subsidy reform. *Energy Economics* 33, 273-283, doi:https://doi.org/10.1016/j.eneco.2010.07.005 (2011).
- ¹¹⁶ Wang, M. and Yu, X. Impact of tiered pricing reform on China's residential electricity use. *China Economic Quarterly International* 1, 177-190, doi:https://doi.org/10.1016/j.ceqi.2021.08.001 (2021).
- ¹¹⁷ Energy Systems Integration Group. Gaps, Barriers, and Solutions to Demand Response Participation in Wholesale Markets. (2025). <https://www.esig.energy/download/demand-response-wholesale-markets-report/>
- ¹¹⁸ Cheung, K. Integration of Renewables. doi:doi:https://doi.org/10.1787/5kg9sr5xm632-en (2011).
- ¹¹⁹ Ruhang, X., Zixin, S., Qingfeng, T. and Zhuangzhuang, Y. The cost and marketability of renewable energy after power market reform in China: A review. *Journal of Cleaner Production* 204, 409-424, doi:10.1016/j.jclepro.2018.09.018 (2018).
- ¹²⁰ Wesseh, P. K., Benjamin, N. I. and Lin, B. The coordination of pumped hydro storage, electric vehicles, and climate policy in imperfect electricity markets: Insights from China. *Renewable and Sustainable Energy Reviews* 160, doi:10.1016/j.rser.2022.112275 (2022).
- ¹²¹ Cramton, P. and Ockenfels, A. Economics and Design of Capacity Markets for the Power Sector. *Zeitschrift für Energiewirtschaft* 36, 113-134, doi:10.1007/s12398-012-0084-2 (2012).
- ¹²² Mallapragada, D. S. et al. Electricity pricing challenges in future renewables-dominant power systems. *Energy Economics* 126, 106981, doi:https://doi.org/10.1016/j.eneco.2023.106981 (2023).
- ¹²³ Bublitz, A., Keles, D., Zimmermann, F., Fraunholz, C. and Fichtner, W. A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanisms. *Energy Economics* 80, 1059-1078, doi:https://doi.org/10.1016/j.eneco.2019.01.030 (2019).
- ¹²⁴ Bidwell, M. Reliability Options: A Market-Oriented Approach to Long-Term Adequacy. *The Electricity Journal* 18, 11-25, doi:https://doi.org/10.1016/j.tej.2005.03.010 (2005).
- ¹²⁵ Prete, C., Palmer, K. and Robertson, M. Time for a Market Upgrade? A Review of Wholesale Electricity Market Designs for the Future. (Resource for the Future, 2024)
- ¹²⁶ Spees, K. (2020). The Integrated Clean Capacity Market: A Design Option for New England's Grid Transition. Presentation to the New England Power Pool, October 1. https://www.brattle.com/wp-content/uploads/2021/05/20353_the_integrated_clean_capacity_market.pdf.

¹²⁷ Wolak, F. A. Long-Term Resource Adequacy in Wholesale Electricity Markets with Significant Intermittent Renewables. *Environmental and Energy Policy and the Economy* 3, 155-220, doi:10.1086/717221 (2022).

¹²⁸ Cramton, P., Brandkamp, S., Chao, H.-P., Dark, J., Hoy, D., Kyle, A.S., Malec, D., Ockenfels, A. and Wilkens, C. (2024). A Forward Energy Market to Improve Reliability and Resiliency. <https://www.cramton.umd.edu/papers2020-2024/cramton-et-al-forward-energymarket.pdf>.

¹²⁹ Pierpont, B. (2020). A Market Mechanism for Long-Term Energy Contracts to Support Electricity System Decarbonization. <https://media.rff.org/documents/pierpont-longterm-electricity-markets-paper-dec-2020-final.pdf>.

¹³⁰ Keay, M. and Robinson, D. (2017). The Decarbonised Electricity System of the Future: The “Two Market” Approach. *Energy Insight 14*. Oxford Institute for Energy Studies. <https://www.oxfordenergy.org/publications/decarbonised-electricity-system-future-twomarket-approach/>.

¹³¹ Tesfatsion, L. (2021). *A New Swing-Contract Design for Wholesale Power Markets*. Hoboken, NJ: Wiley-IEEE Press

¹³² Chen, H., Chyong, C. K., Mi, Z. and Wei, Y.-M. Reforming the Operation Mechanism of Chinese Electricity System: Benefits, Challenges and Possible Solutions. *The Energy Journal* 41, 219-246, doi:10.5547/01956574.41.2.hche (2020).