



Decoding the Coal Power Transition in China

Fact, Challenges, and Opportunities in Accelerating Power System Decarbonization



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Table of Contents

Introduction	6
Background — China reiterates its commitment to decarbonize the world’s largest power system with phased-in timelines	8
Process and objectives to establish a New Power System	8
Surging power demand and inadequate system flexibility are the biggest near-term challenges	10
Electricity-demand growth is on a fast track, with weather increasing the challenge of grid balancing	10
Strong demand growth brings expansion in all power-generation technologies	12
Higher penetration of weather-dependent renewables requires more flexible resources	14
Review and outlook — coal power development and transition	16
Past: coal power development in China has experienced different stages and improved pricing mechanisms and technologies	16
Power supply–demand balance is the dominating factor in different stages of coal power development	16
More pricing mechanisms are introduced for newly built coal power projects to recover revenue	18
Coal power plant technology improvement enables higher efficiency and better flexibility	19
Present: the coal power pipeline has increased sharply, driven by multiple factors	20
Where and why: the surge in the coal power pipeline is driven by multiple factors in different regions	20
Who and how: state-owned enterprises continue to dominate coal power investment with strong vertical integration	23
Future: upgrading on decarbonization, reliability, flexibility and intelligence are key focus areas for coal power	26
Discussion — three challenges to phase down coal power from its major roles as the electricity generator and flexibility provider.	30
Increasing uncertainties in the electricity-demand forecast are spurring the push for a larger and safer power system.	30
Decoupling of economic growth from electricity consumption has not yet been seen in China	30
New consumption drivers imply a longer electricity growth trajectory in China	32
The traditional electricity-demand forecast requires thorough improvements to support a bigger and cleaner power system	34

Rising flexibility demand lacks diversified clean resources 36

- China needs fast-growing power-system flexibility for all timescales 36
- Zero-carbon flexibility resources are growing fast but not enough 37
- Promoting DSF is low-hanging fruit in the 2020s 39
- Much more energy storage needs to be built and better used to position it as
a reliable replacement for coal power 40

China’s New Power System calls for revision of power-system planning practices 43

- Current power-system expansion planning is dominated by top-down approaches. 43
- Limitations in current system planning show significant path dependency and reliance on coal . . . 44
- Planning for a power system with increasing uncertainties through a zero-carbon portfolio is a
common challenge worldwide 45

Appendix46

Introduction

China reiterates its determination to decarbonize its fast-growing power sector, which has seen demand increase by 36% and installed capacity expand by 67% in the past five years.

China's rapid expansion of renewable energy capacity has significant implications for the world.

In the past five years (2020–2024), China accounted for roughly 58% of added global renewable capacity. This not only supports China's own decarbonization goals, but also helps drive down the cost of renewable technologies worldwide and expedites global progress in the energy transition.

However, China's success in renewables is complicated by its persistent reliance on coal in the power sector. A rapidly growing demand for power, a 20-year, record-low river flow and hydropower output, lack of power-system flexibility, and increasing concerns about energy security have led to an acceleration of new coal power approvals in China, with approvals during 2022 and 2023 increasing to 1.6 times the total for 2016–21. These new approvals serve different purposes in different provinces, but mostly are aimed at meeting surging power demand and accommodating intermittent renewables. This surge slowed in 2024 but was still at elevated historical levels, with about 45 gigawatts (GW) approved. However, it remains to be seen whether this slowdown is a temporary dip or a permanent change.

In August 2024, China reiterated its green transition ambitions, which are only achievable by accelerating the phasedown of coal power generation. New state-level guidelines were unveiled in early August 2024 and set the tone for a green transition within China's socioeconomic development, with strict control of coal-consumption growth during 2021–25 and an intent to decrease it in 2026–30. This goal can only be met by continual, rapid clean energy development, which is reshaping the traditional power-system structure but making it more complicated for the grid to dispatch and integrate more renewables.

The government acknowledges the challenges and in August 2024 also released a three-year action plan (2024–27) to accelerate construction of the New Power System. Actions include optimization of system flexibility, flexible transmission, and high-quality distribution. Coal power upgrading are also highlighted to improve coal power's long-term adaptability in the power system.

Decoupling coal from power-demand growth and supply-security concerns is critical to decarbonizing China's power sector and will require specific approaches based on the three roles of coal power in the country's energy system.

Coal power plays three major roles in China's energy system: providing power generation, supporting power-system flexibility and reliability, and generating district heating in the north. In the first two roles, which are behind the recent increase in coal power approvals, coal is the dominating contributor but trending toward becoming supplementary. This effectively means that if clean alternatives are growing fast enough, the demand for coal will peak and then decrease. Despite continual record growth of renewables and energy storage, this is still not easy, given the fast-growing need for power generation and power-system flexibility while ensuring that supply security is prioritized as the key performance indicator for multiple stakeholders in the power sector.

Replacing coal as the dominating power generator requires the addition of clean power generation, primarily from wind, solar, hydro, and nuclear, to outpace power-demand growth. Since 2020, despite the impressive expansion of zero-carbon generation, wind, solar, hydro, and nuclear have only supported 55% of power-demand growth, even with prioritized dispatch and minimal curtailment. Cumulative power-demand additions in the past five years were around 66% and 96% of annual power demand in 2023 in the United States and European Union, respectively, exceeding the expectations of major policymakers and power-system planners.

Although China continues its strong promotion of hydro and nuclear, construction takes a long time and they have failed to meet the ongoing power-demand surge. Wind and solar are growing faster but face challenges from low capacity factors and growing difficulties in grid integration. Energy efficiency and resource reservation are also important but not key issues in this report.

Replacing coal as the major power-system provider for flexibility and reliability requires diversified promotion of multiple clean technologies, including but not limited to pumped hydro, battery energy storage, and demand-side flexibility (DSF). The demand for power-system flexibility has been surging for all timescales, from milliseconds to months, to accommodate fluctuations in power demand and clean energy availability. In the recent surge, coal power was considered the most reliable and convenient option to ensure supply–demand balance for all timescales, revealing an urgent need for faster development and improved use of clean, flexible resources. Clean resources that can meet demand for shorter timescale flexibility are more economically mature, while technologies to meet longer timescales are too expensive or take too long to build.

Accelerating the adoption and use of clean technologies will require changes in power-system forecasting, planning, and market design. The existing electricity-demand forecast method is becoming increasingly ineffective, given new electricity-consumption behavior and weather conditions, meaning there is a bigger need for a “safety backup” in the planning process, which currently relies heavily on coal. China is making strong progress in power-market reforms aiming to further incentivize investments in clean generation and flexible resources, but progress differs significantly by province.

China’s coal power transition strategy is to keep considerable scale for supply continuity while adopting multiple approaches to decarbonize assets, including improving fuel efficiency, lowering generation, using cleaner fuel, and capturing emissions.

Coal power plant retrofits to improve plant efficiency and operational flexibility are the two most mature approaches. China continues to improve coal power fuel efficiency, and 350 GW coal plants are expected to be retrofitted for efficiency by 2025. China has rich experience in coal power flexibility retrofits, and all plants are required to complete these retrofits by 2027. Such retrofitted coal power plants can generate less during renewables-rich hours and ramp up faster when less clean energy is available. New coal power plants are also built to be more flexible, which is described as adding capacity but cutting generation, serving the purpose of supply security while restricting emissions.

China is also promoting multiple pilots for co-firing with lower carbon fuel and carbon capture, utilization, and storage (CCUS), with the next three years being an important development window. Biomass co-firing is relatively more mature, and provinces are encouraged to explore customized scale-up solutions based on local biofuel supply conditions. Green ammonia co-firing and CCUS are in a much earlier stage, although the national government has identified the next three years as a key window for technical verification and testing at selected pilots.

Background – China reiterates its commitment to decarbonize the world’s largest power system with phased-in timelines

Process and objectives to establish a New Power System

China’s New Power System is a comprehensive strategy designed to transform the country’s energy landscape by significantly increasing the use of renewable energy sources while ensuring grid stability and reliability. This initiative is central to China’s broader goals of peaking carbon emissions by 2030 and achieving carbon neutrality by 2060 (hereafter referred to as the Dual Carbon Goal). As one of the world’s largest and fastest growing economies, China faces the double challenges of meeting its growing energy demands while reducing the environmental impact of its energy infrastructure.

The power sector is responsible for approximately 40% of emissions within the entire energy landscape, making it the largest contributor. Tackling emissions from the power sector is essential for taking a leap toward the Dual Carbon Goal. The New Power System, therefore, is designed to address current and future challenges in decarbonizing the power sector by reshaping the nation’s approach to energy production, distribution, and consumption.

In 2022, China’s National Energy Agency (NEA) outlined a clear roadmap in its *New Power System Development Bluebook*, dividing its strategy into three phases extending to 2060, with specific objectives targeting the power system’s four key sectors (see Exhibit 1).

In 2024, the National Development and Reform Commission (NDRC) and NEA jointly released a work plan for 2024–27 to accelerate establishment of the New Power System. One goal in the work plan is upgrading coal power for better flexibility and lower emissions. Another goal is stronger grid construction, including developing distribution lines and interprovincial transmission lines for renewable-generated electricity. Power-system flexibility is the key working area identified for improvement, through incentivizing energy storage and demand-side resources, such as electric vehicles (EVs).

Exhibit 1 New power system establishing timeline

Phase Sector	Accelerated Phase (Present to 2030)	System Formation Phase (2030–45)	Final Completion Phase (2045–60)
Power Generation	<ul style="list-style-type: none"> Renewable energy becomes the main driver of growth in power generation Increase renewables' share of installed capacity to over 40%, share of generation to over 20% Coal power plays a role as a safeguard for grid stability 	<ul style="list-style-type: none"> Renewable energy gradually becomes the main source of installed capacity Coal power undergoes an accelerated clean transformation 	<ul style="list-style-type: none"> Renewable energy becomes the main source of power generation Integrate hydrogen and other clean secondary energy sources into the power system
Grid	<ul style="list-style-type: none"> Further expand the large-grid model to leverage optimized resource allocation The supporting role of distributed smart grids becomes increasingly prominent 	<ul style="list-style-type: none"> Grid moves toward being more flexible and intelligent Large-grid model and distributed smart-grid integration 	<ul style="list-style-type: none"> Breakthrough in flexible and integrated grid technology Deep coordination and integration of power systems with renewables
Demand Side	<ul style="list-style-type: none"> More diversified power usage pattern emerges DSF's capability increase to over 5% Accelerate and expand electricity substitution in key emitting sectors (industry, construction, transportation) Increase end-use electrification level to approximately 35% 	<ul style="list-style-type: none"> Demand side advances decarbonization and flexibility Continue electrification to cover more end-use applications 	<ul style="list-style-type: none"> Profound changes in electricity production and consumption Demand side and power system can flexibly interact at larger magnitude and higher frequency
Storage	<ul style="list-style-type: none"> Scale up the development of energy storage across multiple applications and technology pathways Explore intraday power-balancing capability through storage 	<ul style="list-style-type: none"> Large-scale and long-term energy storage achieves breakthroughs Explore cross-day, power-balancing capability through storage 	<ul style="list-style-type: none"> Enhance energy system flexibility through the coordinated operation of various energy storage types, including electricity, heat, gas, and hydrogen

RMI Graphic. Source: NEA

China's New Power System represents a significant shift in the nation's approach to energy. By focusing on renewable energy, advanced storage solutions, grid modernization, demand-side management, and digitalization, China is building a sustainable, efficient, and resilient energy system. This transformation is essential not only for meeting the country's environmental goals, but also for supporting its continued economic growth and enhancing its energy security in the long term.

Surging power demand and inadequate system flexibility are the biggest near-term challenges

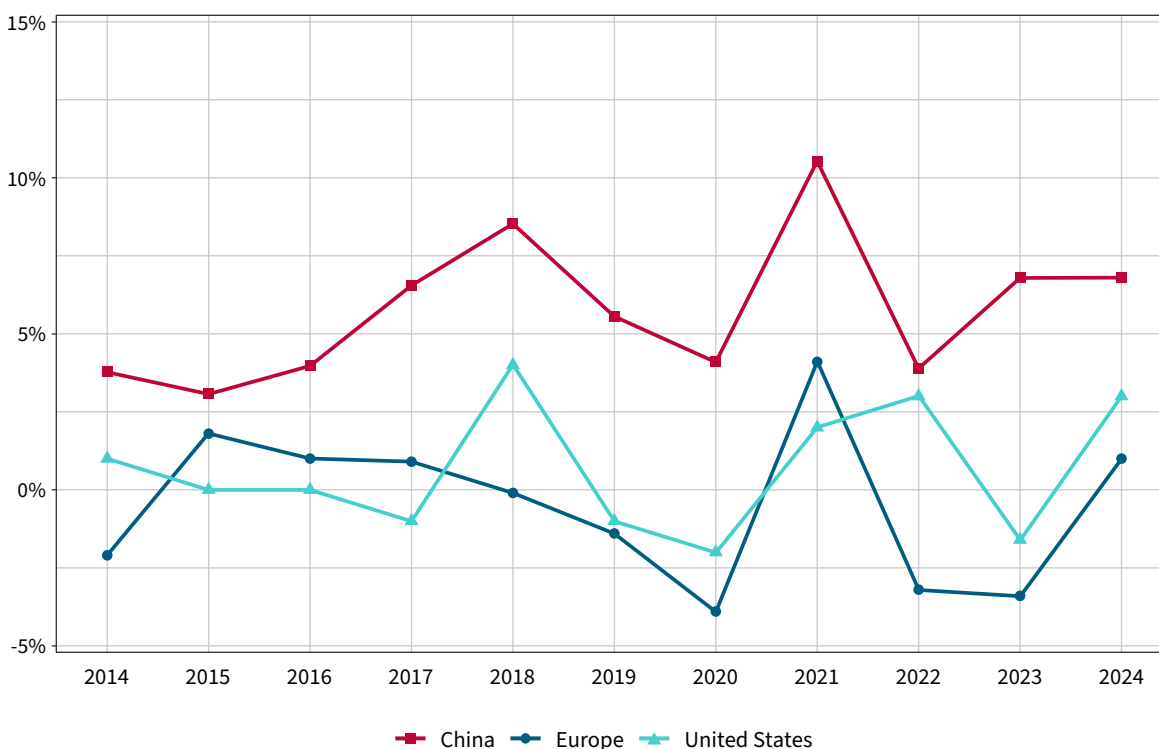
Electricity-demand growth is on a fast track, with weather increasing the challenge of grid balancing

China's economic rebound following the COVID-19 pandemic was swift and impressive, with electricity demand increasing significantly alongside economic growth. In 2021, China's gross domestic product (GDP) surged by 8.4%, partly fueled by government stimuli. These included substantial support for businesses and consumers, heavy spending on infrastructure projects, and a global export boom driven by supply chain disruptions elsewhere. Increase in demand for electricity was coupled with a post-pandemic economic rebound. The years 2021 and early 2022 saw significant increases in power demand, with growth rates of over 10% and over 5%, respectively, exceeding pre-pandemic levels. Meanwhile in Europe and the United States, all regions with legacies of economic strength, electricity demand had slow or even negative growth during the same period (see Exhibit 2).

In 2023 and 2024, demand for electricity continued to grow in China at the rate of 6.7% and 6.8%, respectively. The transition toward electricity as the primary energy source in sectors like transportation, with the rising popularity of EVs, for example, adds further strain on the grid. In contrast, other major economies in the world had a reduction in total electricity demand in 2023.

Exhibit 2 Electricity-demand growth in major economies from 2014 to 2024

Electricity Demand Growth Rate(%)



RMI Graphic. Source: China Electricity Council (CEC), International Energy Agency (IEA), Eurostat, RMI

China has faced unprecedented peak loads, intensifying the strain on the power grid and challenging its ability to balance supply and demand. In fact, every year since the post-pandemic recovery has set new records for peak load: in 2021 the peak load had a 10.8% increase compared with the previous year, 2022 had an 8.4% increase, 2023 had a 4% increase, and 2024 had an 8.2% increase. Such rapid growth in peak load escalates the tension on the grid even further.

This surge in peak load was driven primarily by the widespread use of cooling appliances, such as air conditioners, during an especially hot summer. Meteorological data confirms that temperatures across most of China have been significantly higher than usual, leading to a surge in electricity consumption as well as peak load when people seek respite from the heat. The China Electrical Engineering Research Institute estimates that cooling loads now constitute a substantial 30%–40% of most provinces' annual peak load, highlighting the significant impact of rising temperatures on power-system balancing.

Several provinces, including Guangdong and Fujian, have reported consecutive days of new peak load records. Guangdong had a historic high peak demand reaching a staggering 157 GW (equivalent to about two times the total installed capacity in California) in the summer of 2024, which was close to Guangdong's total dispatchable capacity, including all hydro, coal, and gas. Fujian's peak demand also had a historic high in the summer of 2024 at 54 GW that rose by 6.0% compared with the previous year.

Another challenge brought by the rapid influx of variable renewable energy (VRE) sources and the high volatility in river flow is the renowned duck curve effect on the net load for grid operators (GridCos). During peak solar generation hours, the net load, or the demand that must be met by dispatchable sources, plummets, creating a deep valley in the demand curve. This is followed by a sharp increase in the evening when solar output declines and residential and commercial electricity demand surges.

The challenge lies not only in the magnitude of this net load change but also in its speed, complicated by the increasing volatility of hydropower output. GridCos are often left scrambling to ramp up dispatchable power plants, typically fueled by coal or gas, to compensate for the setting sun and to meet the rising evening demand.

This challenge is further complicated by stable weather conditions that require a significant amount of dispatchable power source reserves. Stable weather conditions, characterized by low wind speeds and stagnant air, can have significant impacts on the power system, particularly when haze or air pollution occurs. During such periods, wind turbines may generate less electricity because of insufficient wind, while solar panels underperform because of reduced sunlight penetration. This reduction in renewable energy output can strain the power grid, necessitating increased reliance on conventional power sources, like coal or natural gas, to meet demand. Additionally, stable weather often coincides with temperature extremes, potentially leading to higher energy consumption for heating or cooling, further challenging the power system's capacity.

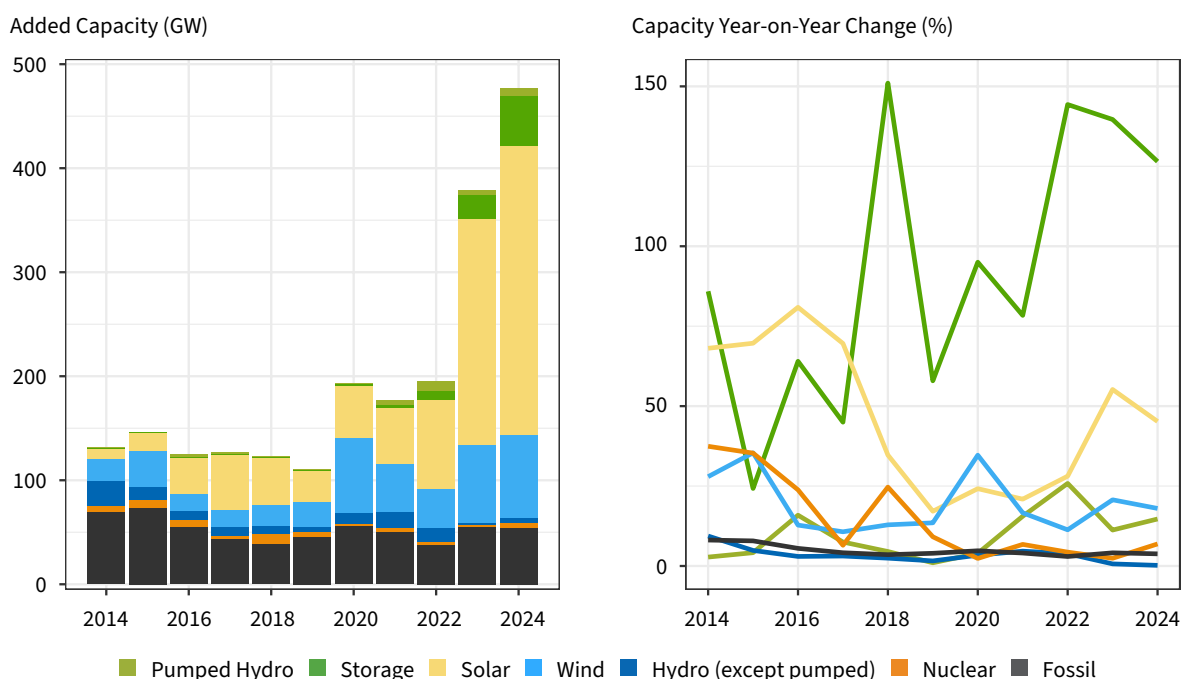
Strong demand growth brings expansion in all power-generation technologies

With the above-mentioned strong growth in both electricity and flexibility demand, China is expanding significantly across all power-generation technologies, with substantial investments in diverse energy sources to meet the needs.

Cost competitiveness and political determination have been significant drivers of wind and solar growth. China’s total installed capacity grew remarkably over the past decade, reaching a staggering 3,349 GW by the end of 2024. This represents a more than doubled (or roughly 1,970 GW) increase since 2014, with a particularly noteworthy shift toward renewable energy sources.

Leading this surge is the impressive contribution of non-fossil fuel generators, accounting for 379 GW of the newly added capacity. Notably, in 2024 alone, wind and solar power additions dominated with a combined 357 GW, constituting an exceptional 83% of the year’s total increase (see Exhibit 3). Battery storage has also seen consecutive and significant growth over the past decade. This focus on clean energy has culminated in a significant milestone — by the end of 2024, fossil generators took up less than half (43%) of the total installation, with coal representing 36%.

Exhibit 3 China’s added capacity and year-on-year change by technology from 2014 to 2024



RMI Graphic. Source: CEC, China Energy Storage Alliance (CNESA), RMI

This remarkable growth in renewable energy capacity, particularly in wind and solar power, is driven by unwavering political determination, as mentioned in the *Background* section (page 8), and the cost competitiveness that is making clean energy technologies more affordable and accessible, not only domestically but also globally. China has made significant strides in driving down the cost of renewable energy technologies through large-scale manufacturing, technological innovation, and the establishment of a robust domestic supply chain. As a result, the levelized cost of electricity (LCOE) of solar photovoltaic (PV) has plummeted by over 80% since 2010, and onshore wind fell by 69% — both are cheaper than fossil generation based on LCOE.

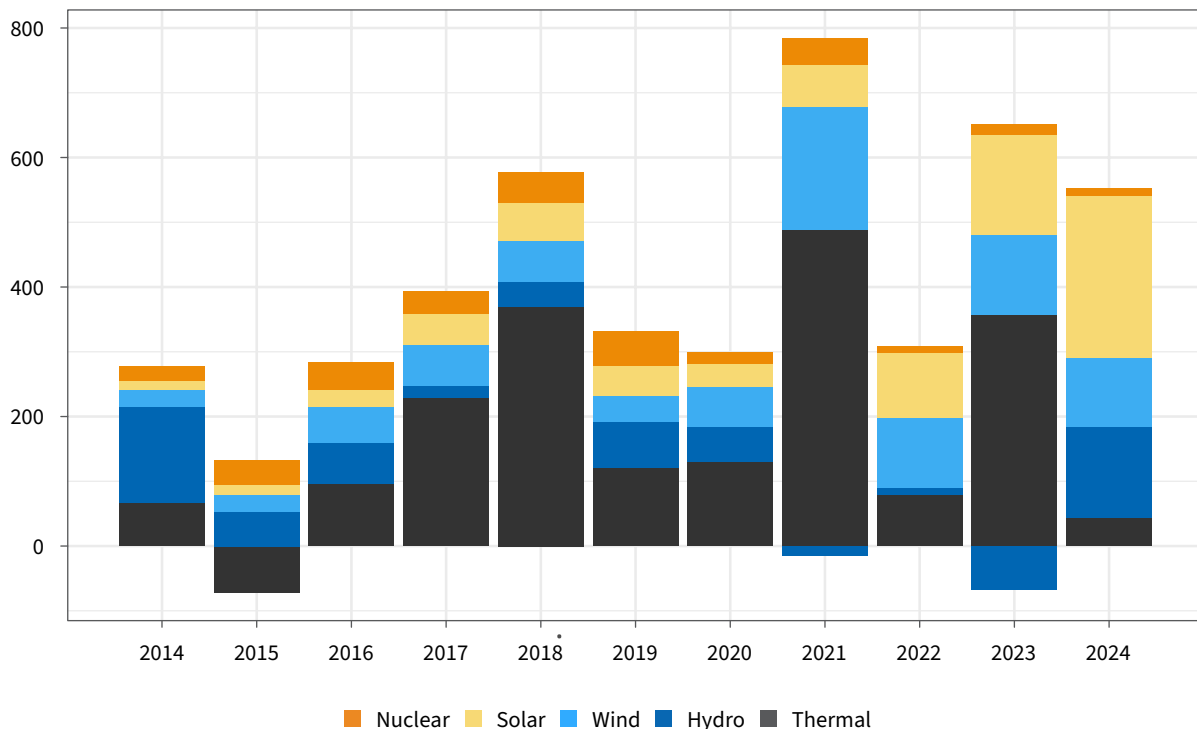
Nuclear is on track in capacity planning and showing an accelerating nuclear approval trend. China currently operates 58 nuclear power units (61 GW) and has 27 units (32 GW) under construction, ranking at the top globally. China’s nuclear power plants are primarily on the coast to ensure access to the large volumes of water needed for cooling purposes. Coastal locations also reduce the risk of water scarcity, which is more common inland, and help minimize the impact on densely populated or agriculturally important inland regions. As of 2020, nuclear plant approval has accelerated. China approved 10 units (about 11 GW) in 2022 and another 10 in 2023. And in 2024, China announced approval for 11 more units.

Hydropower development is on track with the country’s renewable energy strategy, playing a crucial role in its power-generation mix. As of 2024, the total installed hydropower capacity in China has reached approximately 377 GW, accounting for about 30% of global hydropower capacity. And a pipeline of 300 GW is planned, with most of it in Xizang and the rest in Sichuan and Yunnan.

Despite this fast growth, clean generation is still not enough to meet demand growth, and fossil generation needs to play a supplementary role (see Exhibit 4), even if clean generators are close to being fully utilized (see right chart of Exhibit 5). This is especially evident in the context of persistent electricity-demand growth and uncertainty in hydropower availability (see left chart of Exhibit 5). Hydropower, once a major driver of China’s clean energy push, has experienced a slowdown in generation growth — even a decrease in generation in 2021 and 2023 — because of persistent drought and the ensuing limited water flow.

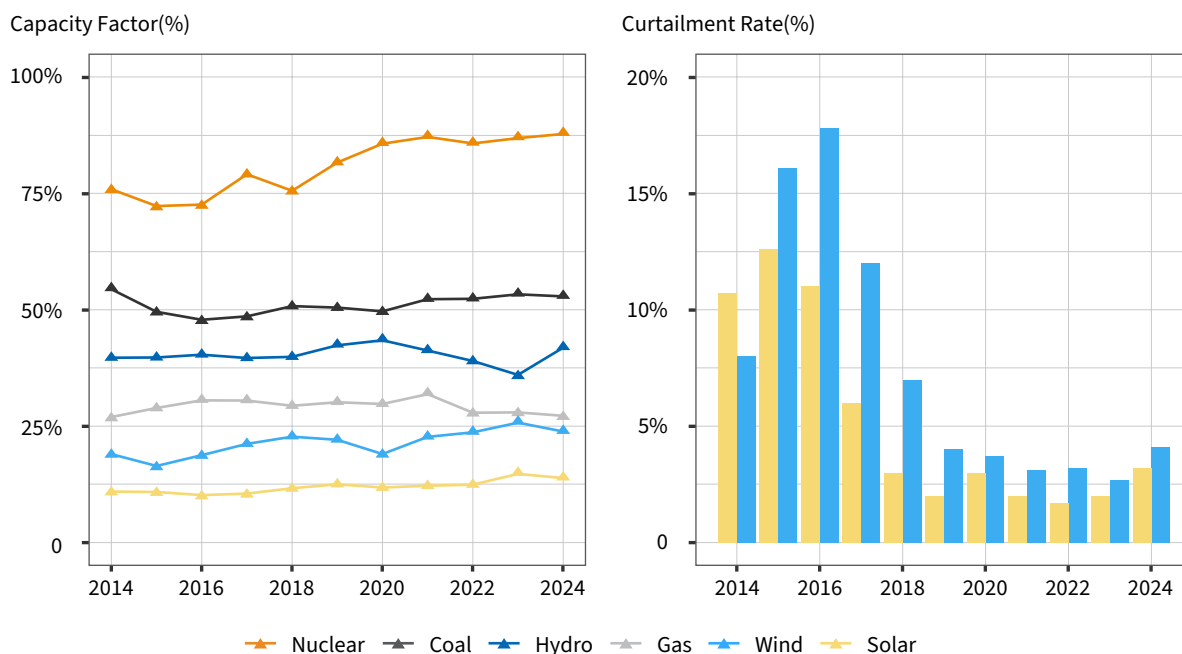
Exhibit 4 Year-on-Year Power-Generation Additions from 2014 to 2024

Generation Addition (TWh)



RMI Graphic. Source: CEC, NEA, RMI

Exhibit 5 Capacity factor by technology and renewables curtailment rate in China from 2014 to 2024



RMI Graphic. Source: CEC, RMI

Higher penetration of weather-dependent renewables requires more flexible resources

Rapid growth of VRE drives up flexibility demand at all timescales. The inability of wind and solar PV to provide system inertia leads to ultra-short-term flexibility demand, while their supply patterns shape the net load curve within a day, creating short-term flexibility needs. Moreover, medium-term and long-term flexibility demands caused by increasing VRE penetration are amplified by intensified climate change. Greater weekly, seasonal, and annual variations in weather conditions result in growing flexibility demand, attracting more attention to power supply safety. Details about different timescales' flexibility are discussed in the *China needs fast-growing power-system flexibility for all timescales* section (page 36).

Coal power is also the most versatile technology available for China's policymakers to supply flexibility. First, coal power technology occupies most of the flexibility niches. Because of abundant fuel resources and relatively cheap fuel cost, coal-fired power plants offer the most reliable and economic generation source. Moreover, the construction of coal power plants is not limited by geographical conditions and can be completed in two years, making them suitable to meet power supply gaps in any regions in the near term.

Other low-carbon flexibility technologies have also experienced rapid growth.

- By the end of 2024, the cumulative capacity of **pumped storage** in China reached 59 GW and ranked first in the world, accounting for around 30% of global capacity. Between 2021 and 2024, 22 GW of pumped storage was added to the operational grid. The pumped storage projects permitted during 2022–23 exceeded 60 GW per year and in 2024 reached 43 GW.

- For **novel energy storage**,ⁱ cumulative capacity in China reached 74 GW by 2024 and ranked first in the world. Annual capacity additions in 2024 in China reached 42 GW, which accounted for more than half of global addition, with an 87% year-on-year growth rate.
- In terms of **DSF**, China is increasingly leveraging pilots such as virtual power plants (VPPs) to aggregate demand-side resources and respond to power-system needs. Several provinces have already started pilot projects on VPPs. For example, in Shenzhen, VPP pilots can reduce peak load by 300 megawatts (MW), equivalent to the instantaneous electricity consumption of over 60,000 households.
- For **grid flexibility**, China has maintained stable interconnection investment since 2016, with around 500 billion renminbi (RMB) per year on transmission and around RMB 300 billion per year on distribution. According to the International Energy Agency (IEA), China accounts for more than one-third of total transmission addition in the past decade.

However, low-carbon flexibility technologies each have unique constraints on providing adequate supply to the system, bringing challenges to coal power replacement. Pumped storage takes a long time for construction and has geographical constraints. Safety concerns remain the major roadblock to full-scale adoption of battery storage. Emerging energy storage technologies lack competitive economics and have not achieved a commercial application stage. DSF lacks enough incentives and practices to unleash potential. Grid flexibility requires longer construction time than VRE development, resulting in a shortage of transmission capacity, especially in areas with abundant VRE projects. More comparisons about different flexibility technologies are discussed in the *Zero-carbon flexibility resources are growing fast but not enough* section (page 38).

i Novel energy storage refers to all energy storage technologies except pumped storage.

Review and outlook – coal power development and transition

Past: coal power development in China has experienced different stages and improved pricing mechanisms and technologies

Power supply–demand balance is the dominating factor in different stages of coal power development

Coal power has always served as the main source of power supply in China, although the growth rate has changed in the past 15 years. The reliance on coal power at the beginning of the first decade of the 21st century was at 74% of capacity share and 80% of generation share in the national power system. Although coal power's share in capacity and generation decreased because of the growth of other technologies, especially renewables, coal power still provided 55% of total generation and 36% of total capacity in 2024. More important, the growth rate of coal power generation is significantly aligned with the growth rate of electricity consumption, indicating coal power's significant role in securing power supply.

The development of coal power since 2007 can be divided into three stages based on the supply-demand balance in the power system, which is the key driver of coal power expansion. Because thermal power (mainly coal power) is the main supply in China's power system, the capacity factor of thermal power can be used as an indicator of the power supply and demand relationship, where a higher capacity factor usually reflects a tighter relationship and a lower capacity factor reflects a looser one. Moreover, the policy tones for coal power shift quickly according to the supply and demand relationship, signaling the need for additional coal power.

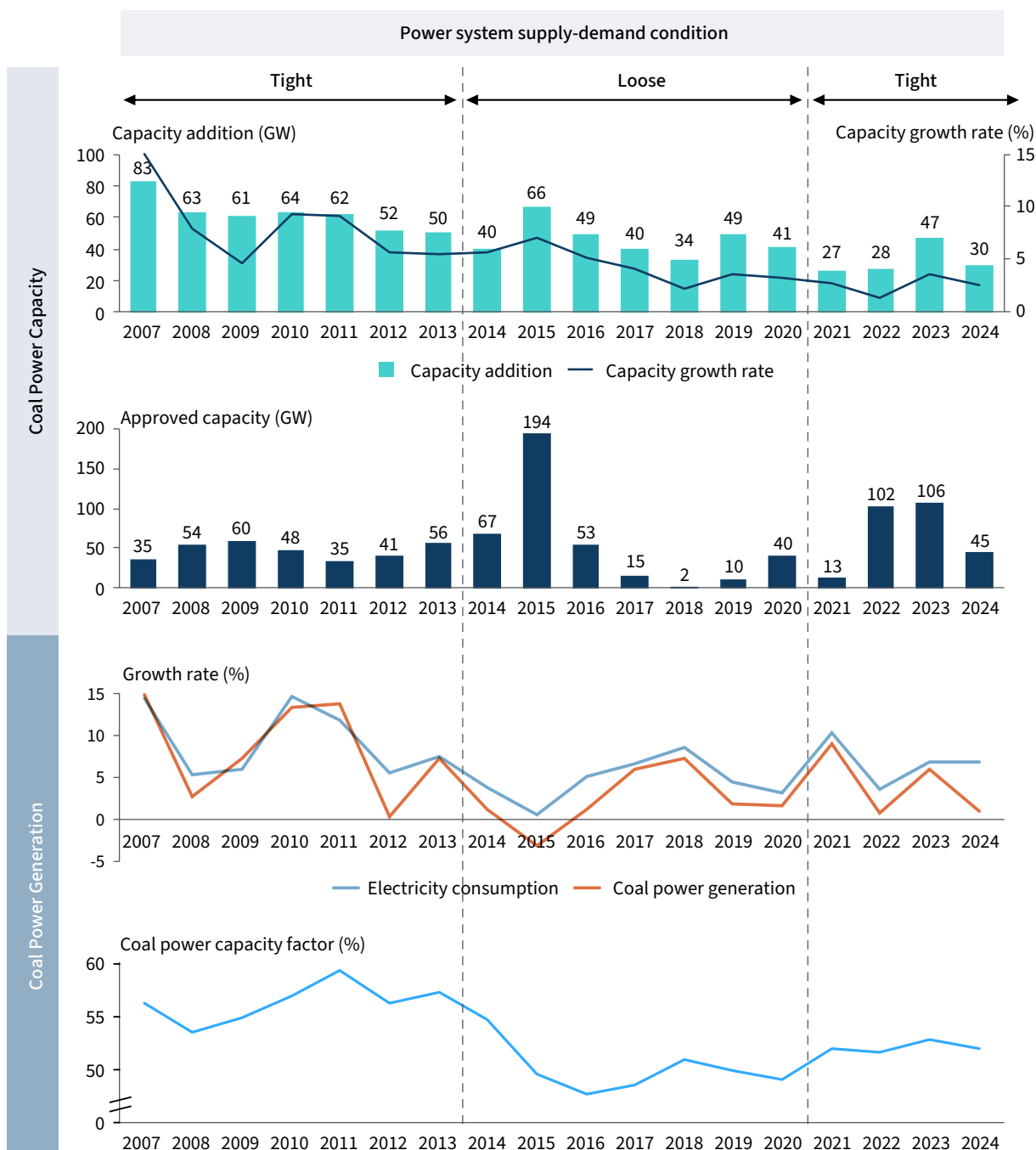
In 2007–2013, the annual capacity addition exceeded 50 GW and the annual approved capacity exceeded 35 GW. The high capacity factor of thermal power from 2007 to 2013 reflected a tight balance in the power system, particularly during the rapid growth in electricity consumption in 2010–11, leading to the growth of coal power capacity.

In 2014–2020, coal power experienced stringent control because of concerns about coal power overcapacity, resulting in a decrease in annual capacity addition and approvals. The capacity factor of coal power had a downward trend starting in 2014 and reached a historically low level in 2016. The low level lasted through the entire 13th Five-Year Plan (FYP) period (2016–20). This trend indicated a loose relationship between supply and demand, and the government was concerned about the risk of overcapacity of coal power.

As a result, the NDRC and NEA jointly released the *Notice on Promoting the Orderly Development of Coal Power* in 2016, which established a risk-control mechanism for coal power to manage the pace of coal power addition. Later, the NDRC and 15 other organizations jointly released *Opinions on Advancing Supply-Side Structural Reform and Prevent the Over-Capacity Risks of Coal Power* in 2017, which postponed over 150 GW of permitted coal power projects during the 13th FYP and set a limit for coal power capacity to stay under 1,100 GW by 2020. These policies significantly cut the addition of coal power and pipeline during the 13th FYP. In 2021 when China announced the Dual Carbon Goal, only 27 GW of coal power was added to the power system.

Recently, coal power experienced an approval and addition hike triggered by several power shortage events in 2021–22. The rebounded thermal power capacity factor during 2021–23 drew attention from the government and resulted in fine-tuning on coal power development. The top leadership has given multiple signals regarding establishment before abolition (*xian li hou po*) and the 14th FYP policy suite recognizes the continued importance of coal power in the near term. Furthermore, the 14th FYP policy suite highlights the role of existing and planned coal power plants in facilitating the integration of a larger share of renewable energy sources. As a result, previous control was eased, and approval of coal power reached more than 100 GW per year in 2022–23.

Exhibit 6 Three development stages of coal power (2007–24)



RMI Graphic. Source: CEC, BloombergNEF (BNEF), RMI

More pricing mechanisms are introduced for newly built coal power projects to recover revenue

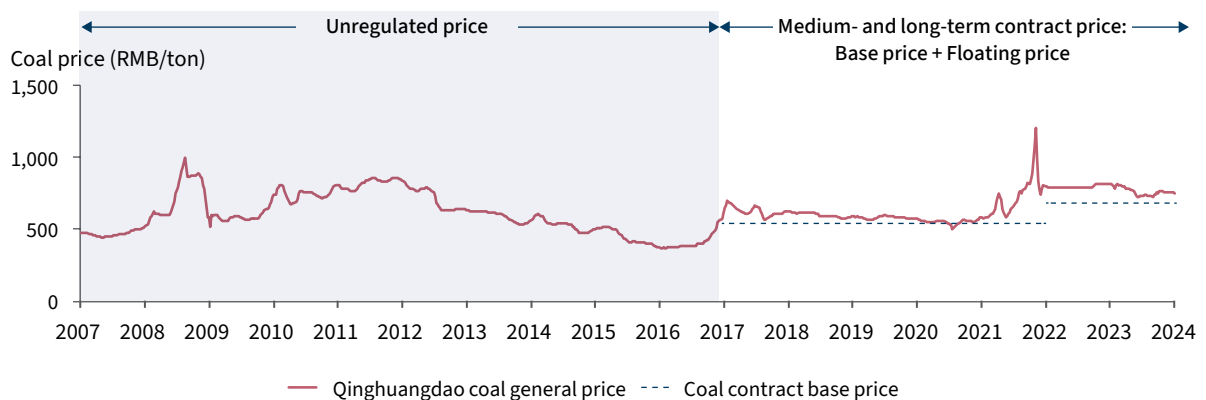
China's power-market reform introduced changes in the revenue mechanism of coal power. Historically, China used the coal benchmark price as the energy price for coal power, which was regulated by the government and changed irregularly. Since 2019, the NDRC has changed the energy price mechanism for coal power from the coal benchmark price to a base price + floating price mechanism. The floating range was -15% to 10%. This floating mechanism became the beginning of a market-oriented price mechanism, providing space to adjust the energy price of coal power based on generation cost and changes in supply and demand. However, a surge in the coal price in 2021 caused coal power companies to experience losses generating power even with the floating price, which led the government to expand the floating range to -20% to 20%, effective since the end of 2021.

With an expected decrease in the capacity factor of coal power with the process of power system decarbonization, the government established a capacity pricing mechanism for coal power starting in 2024. The resulting capacity fee will be included in system operating expenses and shared by industrial and commercial users based on monthly electricity consumption. The coal power capacity fee is cost-oriented, which is determined by the fixed operation cost of the coal power unit and the cost recovery ratio set by the province. The fixed cost is a standardized value of 330 RMB/kilowatt (kW)/year. The cost recovery ratio is determined based on the renewable energy and power-system transformation progress in provincial power grids, which is either 30% or 50% for 2024–25.

Besides changing the energy price and capacity price, China has worked to reduce the volatility of the coal price by promoting medium- and long-term fuel contracts, starting in December 2016, and by defining a reasonable price range in 2022 (see Exhibit 7). Long-term contracts provide a less undulatory price than spot prices. Considering thermal coal price at Qinghuangdao port, while the spot price rose to 1,024 RMB/ton on October 13, 2023, the general price, which consists of the long-term price and the spot price, was only 766 RMB/ton.

These policies are intended to guarantee the income of coal power projects, especially during power-market liberalization and power-system decarbonization, supporting the continued increase of coal power capacity.

Exhibit 7 Coal price in 2007–23 and relevant mechanisms for power generation



RMI Graphic. Source: China Coal Transportation and Distribution Association (CCTD), NDRC

Coal power plant technology improvement enables higher efficiency and better flexibility

China has worked to improve plant efficiency since the first decade of the century to reduce carbon intensity of coal power generation. Improving plant efficiency through equipment transformation and heat recovery directly reduces the fuel consumption required to generate 1 kilowatt-hour (kWh) of electricity. In September 2014, the NDRC, Ministry of Ecology and Environment (MEE), and NEA jointly released the *Action Plan for Retrofitting and Upgrading Coal Power Plants (2014–2020)*, which further reduced targets for carbon intensity. Average coal consumption was reduced by 2020, in the plan, to 300 grams (g)/kWh for new coal power plants and 310 g/kWh for existing coal power plants.

The plan also emphasized several working areas: (1) adding a stricter efficiency threshold for new coal power projects; (2) eliminating coal power with low efficiency and small capacity; (3) retrofitting existing coal plants' technology for higher efficiency; and (4) improving the dispatch of the power system and the operation of coal power to reduce coal consumption. By reducing the share of low-efficiency units and improving efficiency in coal power, China has successfully reduced coal consumption per kWh, reaching the international leading level of coal plant efficiency.

China has effectively improved plant efficiency, with 800 GW of coal power undergoing efficiency improvement by 2020. Coal consumption at thermal power plants decreased, on average, from 356 g/kWh in 2007 to 302 g/kWh (40% thermal efficiency) in 2022.ⁱⁱ That is more efficient than in the United States or Germany, although still less efficient than in Japan. For comparison, the average thermal efficiency of coal power in the United States was 32% in 2022. Carbon intensity has been successfully reduced from coal power through efficiency improvements in the past few years. According to the China Electricity Council (CEC), average carbon intensity of thermal power has decreased from around 1,000 g CO₂/kWh in 2007 to 824 g CO₂/kWh in 2022. For comparison, CO₂ emissions from coal power plants in the United States were 1,043 g/kWh in 2022.

In addition to plant efficiency improvements, another significant approach is repurposing coal plants to enhance operational flexibility. Coal power plants typically operate continuously at a steady output level constrained by minimum stable loads, usually at 80% of their nameplate capacity for combined-heat-and-power (CHP) plants during heating seasons and 50% of non-CHP units. These limitations hinder their ability to adjust generation to accommodate fluctuations in power demand or renewable energy availability. To address this challenge, NDRC and NEA jointly released the *National Implementation Plan for Coal Power Unit Retrofitting and Upgrading* in October 2021, mandating flexibility retrofits for both existing and newly constructed units. The minimum stable load requirement is set at ≤35% for non-CHP units under pure condensing condition and ≤40% for CHP units during heating seasons.

Through retrofits and equipment upgrades, China has made progress in flexibility retrofits, supporting intraday flexibility demand. It has finished flexibility retrofits on more than 300 GW of existing coal plants since 2021, leaving 200–400 GW to further retrofits in 2024–27 to achieve its target. With better flexibility performance, coal power can participate more in peak shaving, benefiting renewable consumption.

ii This is based on a calorific value of 7,000 kilocalorie/kg.

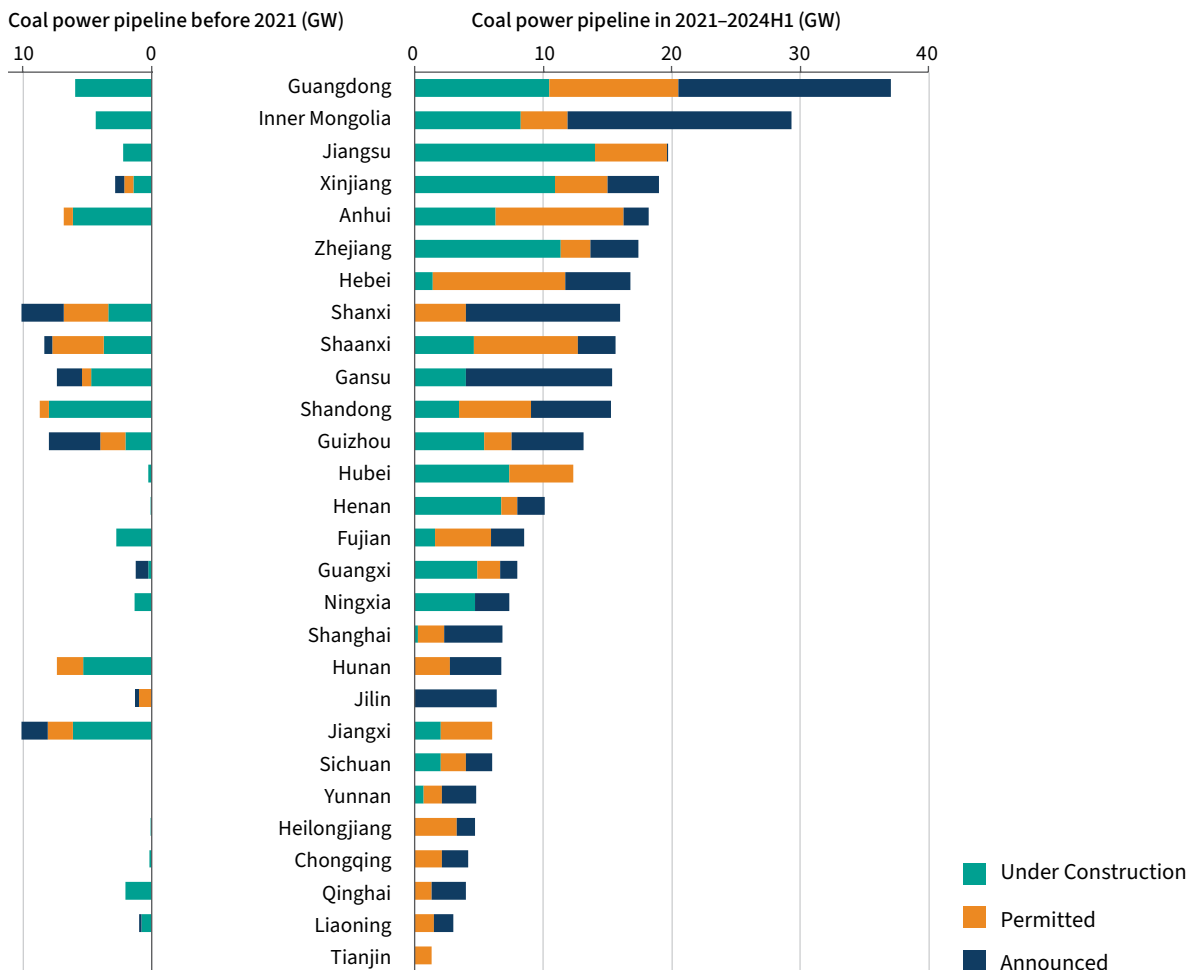
Present: the coal power pipeline has increased sharply, driven by multiple factors

Where and why: the surge in the coal power pipeline is driven by multiple factors in different regions

The coal power pipeline in China reached 425 GW by the first half of 2024, with 40% having started construction, 28% permitted, and the remaining in early stages. According to Global Energy Monitor's (GEM's) July 2024 data set, almost 80% of this total pipeline was added between 2021 and the first half of 2024.

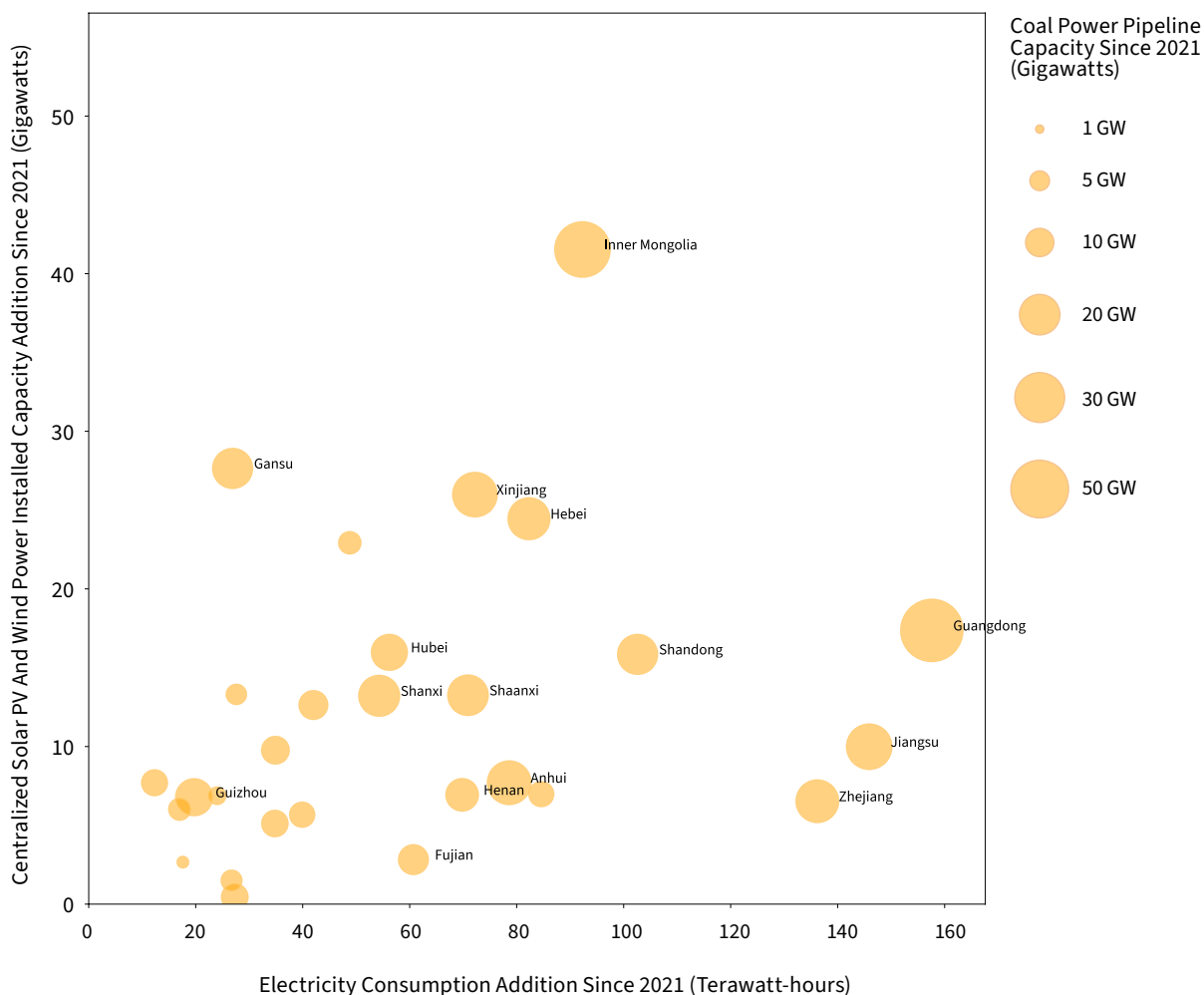
Between 2021 and the first half of 2024, half of the provinces with coal power pipelines had planned capacities exceeding 10 GW (see Exhibit 8). Notably, Guangdong and Inner Mongolia account for a significant 20% of the total pipeline capacity. Pipeline growth at the provincial level is driven by two main factors, electricity-consumption growth and VRE capacity growth (see Exhibit 9). Provinces with large increases in electricity consumption, such as Guangdong, require coal power to serve as a stable generation source to meet electricity demand. Provinces with rapid development of VRE projects, such as Inner Mongolia, are promoting coal power construction to support renewable electricity consumption within the province and its export to other provinces.

Exhibit 8 Coal power pipeline in China by province through June 2024



RMI Graphic. Source: GEM, RMI

Exhibit 9 Two drivers of coal power pipeline in provinces



Note: Named provinces are the top 15 with the most coal power pipeline.

RMI Graphic. Source: CEC, NEA, GEM

Three typical provinces (Guangdong, Anhui, and Inner Mongolia) were selected to discuss core reasons behind coal power pipeline growth, each representing one type of province. Details about the power systems in these three provinces are listed in Exhibit 10.

- East coastal load centers: **Guangdong**, Jiangsu, Zhejiang, and Shandong
- Inland resource deficiency provinces: **Anhui**, Henan, and Hubei
- North VRE export provinces: **Inner Mongolia**, Gansu, Xinjiang, and Hebei

Guangdong: strong electricity-demand growth + uncertain electricity import

Guangdong is one of the top load centers in China, experiencing rapid growth in annual electricity demand and peak load because of sustained economic growth and rising cooling load from extreme heat. Guangdong relies heavily on electricity imports from Yunnan and Guizhou. However, the shortage of hydropower in Yunnan in past years has drawn Guangdong's attention to improving electricity supply from local resources to prevent unexpected fluctuations in the import of electricity and to enhance local grid reliability. Coal is one of the power sources that Guangdong has been promoting to support its substantial demand.

Anhui: medium electricity demand growth + limited supply sources

Anhui’s electricity-consumption growth rate exceeds the national average level. However, Anhui lacks sufficient power sources to meet electricity-consumption growth. Necessary conditions for nuclear development are absent, and conventional hydropower resources have been almost fully exploited. Although Anhui is promoting transmission line construction to expand electricity imports, coal power is still the most feasible choice to meet electricity-demand growth in the near term.

Inner Mongolia: electricity-demand growth + renewable electricity export

With electricity consumption dominated by industry, the introduction of new industries has boosted quick growth in electricity consumption in Inner Mongolia. The province boasts abundant coal and renewable energy resources, and therefore both large coal power capacity and renewable capacity. With rich resources, Inner Mongolia is the province with the most exported electricity in China, mainly supporting the power supply in Northeast China and North China. Therefore, increased coal power in Inner Mongolia is used not only for meeting local electricity demand, but also for ensuring a stable power supply in other regions.

Exhibit 10 Core data of power system in typical provinces

Typical Provinces		Guangdong	Anhui	Inner Mongolia
Location		Southeast Coast	Central	Northwestern
Electricity Resources	Share of China’s total coal production in 2023	N/A	2%	26%
	Solar PV average capacity factor	11.3%	12.2%	18.9%
	Onshore wind average capacity factor	20.5%	23.3%	25.7%
	Offshore wind average capacity factor	30.3%	N/A	N/A
	Nuclear power availability	Yes	No	No
Electricity Demand	Electricity-consumption addition (terwatt-hours [TWh]) since 2021	158	79	92
	Electricity consumption (TWh) 2023	850	321	482
	Peak load 2023 (GW)	145	62	Eastern: 8.21 Western: 40
Interconnection	2018–22 average share of exported electricity in generation	3%	28%	39%
	2018–22 average share of imported electricity in consumption	25%	14%	8%
Evaluation of Power Supply and Demand Balance	2023	Slightly tight	Tense	Eastern: Basically balanced Western: Slightly tight
	2024	Slightly tight	Tense	Eastern: Basically balanced Western: Tense
	2025	Basically balanced	Slightly tight	Eastern: Basically balanced Western: Tense

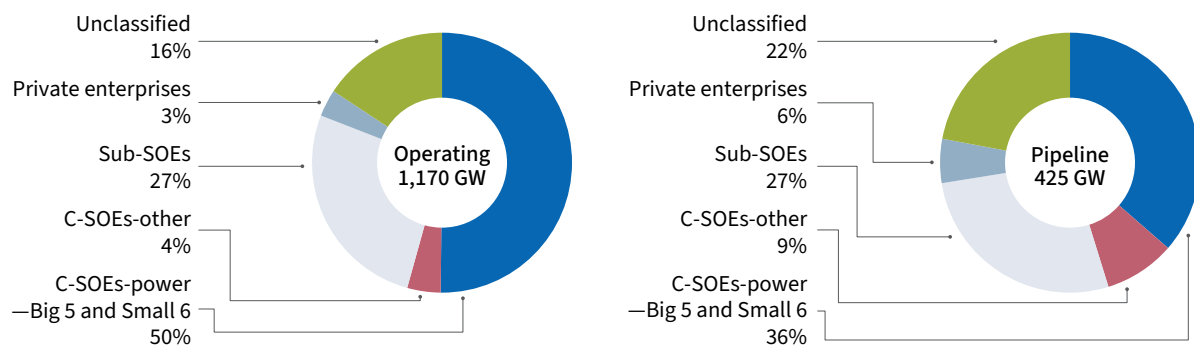
RMI Graphic. Source: CEC, NASA, NBS, Energy Bureau of Guangdong, Anhui Energy Administration, Inner Mongolia Electric Power Group, State Grid Inner Mongolia Eastern Electric Power Company

Who and how: state-owned enterprises continue to dominate coal power investment with strong vertical integration

Ownership of China’s coal power sector is highly concentrated, with 30% of asset owners controlling 80% of installed capacity. These dominating owners can be classified into the categories below, listed in descending order based on their operating coal power capacity (see Exhibit 11):

- **Central state-owned enterprises dominated by power-generation businesses (C-SOEs-power):** this category is mostly represented by the Big 5 and Small 6,ⁱⁱⁱ and these 11 companies own more than half of China’s total generation capacity, around 50% of total coal power capacity, and more than 30% of total wind and solar capacity.
- **Sub-national-level, state-owned enterprises (Sub-SOEs):** they are mostly responsible for ensuring local, usually provincial, power supply. For instance, Zhejiang Energy Group, which is majority-owned by the Zhejiang provincial government, controls 35% of the province’s power generation. The company’s coal power units account for approximately half of Zhejiang’s total coal power generation.
- **Central state-owned enterprises dominated by nonpower businesses (C-SOEs-other):** this category is emerging in coal power plant investment, with the majority from the coal mining industry. For example, China Coal, the biggest coal mining company in China and owner of 1.2% of the total operating coal power fleet, has expanded its coal power business through the construction and acquisition of projects that combine raw coal production with power generation at mine mouths, transportation hubs, and ports.
- **Private enterprises:** non-state-owned enterprises, including domestic and international investors, make decisions driven more by market signals, which depend on their own risk profiles and locations.

Exhibit 11 Coal power ownership mapping as of June 2024



RMI Graphic. Source: GEM’s Global Energy Ownership Tracker — July 2024, which covers around 90% of coal power capacity in GEM’s Global Coal Plant Tracker — July 2024

ⁱⁱⁱ Big 5 and Small 6 refer to China’s major state-owned power companies. Members of the Big 5 are the China Huaneng Group, China Datang Corporation, China Huadian Corporation, State Power Investment Corporation (SPIC), and China Energy Investment Corporation (formed from the merger of China Guodian Corporation and Shenhua Group). The Small 6 comprises the China National Nuclear Corporation, China General Nuclear Power Group, China Three Gorges Corporation, China Resources Power Holdings, SDIC Power Holdings, and China Power Investment Corporation (now part of SPIC).

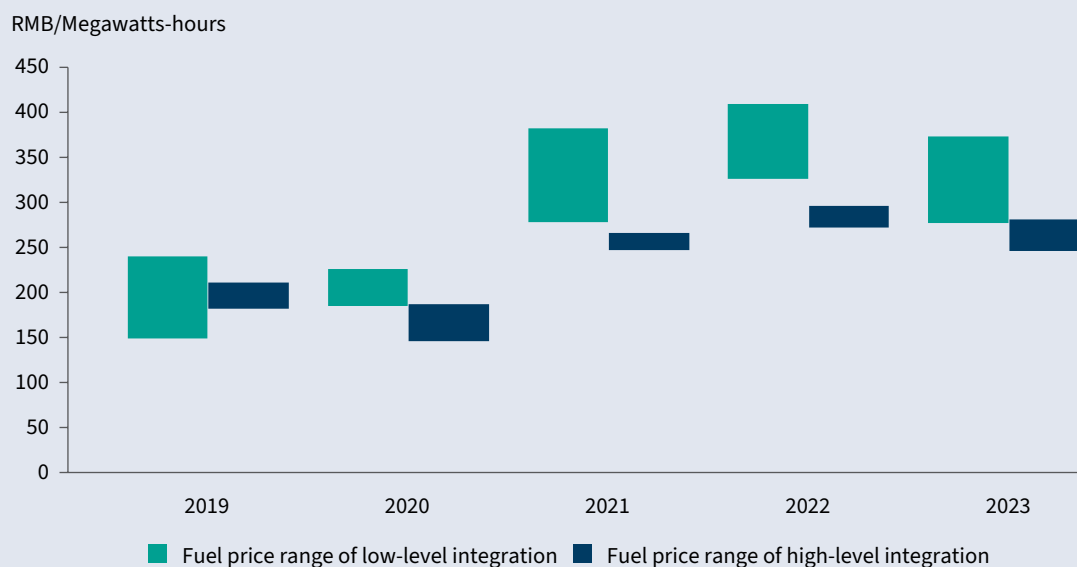
Key players in the coal power industry are encouraged by the national government to conduct vertical integration with coal mining and renewables development for the following reasons:

- **Mining-power integration:** Thermal coal purchases can only be conducted on an annual basis or shorter, weakening mining companies and coal power generators' ability to hedge fuel price risks. Mining-power integration establishes a risk-sharing mechanism to keep coal prices more stable, a major objective of regulators. Coal power plants can buy coal within their own companies or from their parent companies with coal mining assets. Coal plants can also obtain a relatively low coal price via long-term agreements with coal companies. All of the methods enhance resilience on fuel price changes.

Case study on mining-power integration

A sharp rise in the coal price in 2021–22 increased the fuel cost burden on coal power investors. Companies with a higher level of integration between coal power and coal mining proved to be more resilient and had a lower fuel price and a cost advantage. Exhibit 12 shows a high level of integration did not result in an absolute cost advantage during 2019–20 because the coal price was low. However, as coal prices rose to historically high levels in 2021–22, mining-power integration enabled coal power companies to get cheaper fuel. Companies with fewer or no coal mining assets needed to purchase fuel from the market, which resulted in higher fuel costs and wide variations. The average fuel cost of sampled high-level integration coal power companies was around 20% lower than that of low-level integration coal power companies in 2021–23, although the difference was only 4% in 2019.

Exhibit 12 Fuel price range of different levels of mining — power integration



RMI Graphic. Source: Zhongtai Securities

- **Coal-renewables integration:** From the financial perspective, renewables projects strengthen the profitability of the cooperation entity during power-system decarbonization. A diversified portfolio in the power sector supports a more sustainable financial return while shifting more investment to renewables. From the operation perspective, the joint operation of coal power and renewables makes it easier to address the flexibility challenge within the system itself, relieving pressure on the bulk grid system.

Such integration can be implemented in various ways and categorized as financial or operational integration. Financial integration is mostly implemented through equity investment or equity exchanges, while operational integration can be seen in a variety of practices, such as business expansion within the same company, establishing subsidiaries to manage new business, and signing long-term agreements for specific business partnerships. Examples of different types of integration are listed in Exhibit A1 in the *Appendix*.

To illustrate integrations adopted by the top 20 coal power owners, we calculated each company's share of coal power assets, renewable assets, and coal mining assets, taking equity proportion into account for existing assets and pipeline projects. Below are the key findings regarding the major state-owned enterprises' (SOEs') integrations; more details can be found in Exhibits A2 and A3 in the *Appendix*.

- **The Big 5** are pioneers in implementing both types of integration, owning 15% of national coal production capacity, 41% of coal power, and 30% of wind and solar. They also have considerable expansion plans in all three fields, contributing 25% of the national coal production pipeline, 12% of the coal power pipeline, and 18% of the wind and solar pipeline. In contrast, other C-SOEs-power, especially those with hydro or nuclear development as their major business, have significant investment in wind and solar but show minimal penetration in the coal mining and coal power sectors.
- **The Sub-SOEs** show greater interest in coal-renewables integration than mining-power integration to support their provincial targets on power generation. Among the top 20 entities by coal power pipeline capacity, more than 70% of Sub-SOEs have pipelines in both coal power and renewables. For those Sub-SOEs whose dominating business is coal mining, implementing two types of integration is a preferable development strategy.
- **Coal mining companies** are increasing investment in coal power, while penetration into renewables development is comparably limited. For example, China Coal Group, a C-SOE focusing on coal mining, has a 1.2% share in operating coal power and continues to hold a 1.8% share in the pipeline. Sub-SOEs with coal mining business can also strengthen integration with coal power business. For example, Shanxi Jinneng and Shandong Energy rank second and third in operating coal mining capacity, respectively, and both have coal power pipelines that rank in the top 20.

Future: upgrading on decarbonization, reliability, flexibility and intelligence are key focus areas for coal power

In China's latest action plan to establish the New Power System during 2024–27, technical upgrades are highlighted to improve coal power's long-term adaptability in the power system. Detailed upgrading measures are outlined in the *Implementation Plan for the Next-Generation Coal Power Upgrade Special Initiative (2025–2027)*, jointly issued by NDRC and NEA in March 2025. The plan reaffirms coal power's dual critical transition roles in the New Power System: ensuring power supply reliability and providing system flexibility, underscoring its ongoing importance. To align coal power with these objectives, the initiative targets upgrades across four key areas, tailored to three categories of plants: existing coal power, newly built coal power, and demonstration of next-generation coal power (see Exhibit 13).

The next-generation coal power demonstration projects will establish the benchmark for future coal power development, representing the most technically demanding category in Exhibit 13. Continuous R&D advancements will focus on overcoming operational challenges, particularly in meeting increasingly stringent flexibility requirements in the New Power System. To accelerate this transition, the NEA will prioritize next-generation coal power in its capacity expansion planning. Electricity market reforms—covering spot trading, ancillary services, and capacity pricing—should be enhanced to better recognize the value of coal power.



Exhibit 13 Metrics for coal power upgrading

Areas	Indicators	Existing Plants	Newly Built Plants	Demonstration of Next-Generation Plants
Decarbonization	CO ₂ Emission Reduction	Encouraged to adopt low-carbon retrofits	Reserve conditions for low-carbon retrofits; encouraged to adopt low-carbon retrofits where feasible	Carbon emission per kWh is 10%–20% lower than 2024 peer units
Reliability	Guaranteed Output Compliance Rate During Peak Demand Days	98%		99%
	Unplanned Outage Frequency During Peak Demand Days	0.3 times/(unit-year)		
Flexibility	Net Coal Consumption (g/kWh)	Comply with GB 21258 (≤ 291 for 600 MW ultra-supercritical units; ≤ 283 for 1,000 MW ultra-supercritical units)	Comply with GB 21258 (≤ 282 for 600 MW ultra-supercritical units; ≤ 276 for 1,000 MW ultra-supercritical units)	≤ 270 for ultra-supercritical units under wet-cooled conditions; other types may apply corrections but must achieve advanced levels
	Net Coal Consumption Increase Rate at 30% vs. 100% Load	≤ 25% (flexible adjustments allowed)	≤ 20% (flexible adjustments allowed)	≤ 15%
	Minimum Stable Loads (under pure condensing mode) (Pe)	35% (expect for circulating fluidized bed boiler)	25% for bituminous coal-fired units (flexible adjustment allowed)	20%
	Ramping Rates (Pe/min)	For pulverized coal (PC) boiler ≥ 50% load: 2.2%–2.5% 30%–50% load: 1%–1.2%	For pulverized coal (PC) boiler ≥ 50% load: 2.2% 30%–50% load: 1%	≥ 50% load: 4% 30%–50% load: 2%
	Primary Frequency Response	Encouraged performance improvement		
	Start-Stop Cycling Performance	Encouraged to possess safe and reliable start-stop peak shaving capability where feasible		Possess safe and reliable start-stop peak shaving capability
Intelligence	Intelligent Control	Automatic load regulation control above wet-dry transition point; ≥ 90% AGC compliance with no manual intervention	Encouraged to meet the technical standards for next-generation coal power demonstration projects	Full-range automatic load regulation control; ≥ 95% AGC compliance with no manual intervention
	Smart Operation	Enhance intelligent operation level; upgrade safety monitoring systems	Encouraged to meet the technical standards for next-generation coal power demonstration projects	Enhance intelligent operation level; upgrade safety monitoring systems; proactive adoption of condition-based maintenance; AI-powered lifetime consumption assessment
	Intelligent Decision-Making	Automatically analyze generation costs; provide AI-driven market participation strategies based on dispatch mechanisms and trading rules		

RMI Graphic. Source: NEA

- **Decarbonization**

Co-firing with low-carbon fuel and equipped CCUS are two options, encouraged since 2024, to reduce carbon intensity for coal power. In June 2024, the NDRC and NEA jointly issued the *Action Plan for Low-Carbon Retrofitting of Coal Power (2024–2027)*, proposing three decarbonization technologies: biomass co-firing, green ammonia co-firing, and CCUS. The first batch of low-carbon retrofitting coal power projects is set to begin construction by 2025, with a target to reduce carbon emissions by 20% by 2025 and 50% by 2027. These decarbonization technologies are not isolated and can be integrated to work together. China's ongoing technological exploration and demonstration projects aim to provide more flexible options for coal power decarbonization, tailored to the country's specific conditions.

Biomass and green ammonia co-firing with coal are two options for fuel decarbonization of coal power, requiring a co-firing ratio of more than 10% in the action plan. Co-firing can change the fuel composition of coal power plants by adding alternative fuel. Biomass co-firing is the more mature technology and will benefit more fully from burning and reducing nitrogen oxide emissions. The type and composition of biomass vary among regions; thus, operators of biomass co-firing with coal power are instructed according to local conditions.

Ammonia co-firing technology is less mature and will require more demonstration tests. China has already achieved successful ammonia co-firing in several coal power units. However, the impacts of ammonia co-firing on operation, safety, and emissions need more testing to prove feasibility. Furthermore, the 2024 action plan directs that green ammonia synthesis comes from green hydrogen, which not only supports carbon emissions reduction, but also boosts renewable consumption.

CCUS is an end-of-pipe control of carbon emissions instead of a source control via low-carbon fuel. Installing CCUS at coal power plants enables carbon emissions to be captured without escaping into the atmosphere. China is developing several demonstration projects of CCUS at coal power plants. However, because CCUS technique processes are not mature, scale application of CCUS and its best practices coordinated with coal power plants require more technological exploration.

- **Reliability**

Coal power plays a critical role in electricity generation during high-demand periods, particularly in summer and winter. Given the recent surge in peak loads, coal power remains essential for ensuring a reliable power supply. To enhance coal power reliability, two key performance indicators are emphasized in the implementation plan for 2025–2027: output compliance and unplanned outage rates. These requirements apply specifically to peak demand days rather than year-round operation, underscoring coal power's role as a vital backup during electricity shortages.

- **Flexibility**

Flexibility is the cornerstone of coal power upgrading in China, playing a pivotal role in the power system transition. Unlike reliability — which is primarily critical during peak demand periods — coal power's flexibility functions are required year-round. Moreover, enhancing flexibility is essential to transform coal power from a baseload provider into a flexible resource, which will ultimately define its long-term role in the power system.

The 2025–2027 Implementation Plan for coal power upgrading introduces, for the first time, coal consumption post-flexibility retrofit as a key performance indicator. While enhancing operational flexibility, coal power units experience higher carbon intensity due to increased coal consumption per unit of electricity generated — especially when operating at low capacities. This contradicts broader carbon reduction objectives. To address this challenge, the 2025–2027 Implementation Plan sets a specific coal consumption target under design conditions, aligning with existing policies. Additionally, it mandates that the increase in coal consumption between 30% and 100% rated capacity must not exceed type-specific thresholds. This measure aims to curb carbon emissions while ensuring coal power can sustainably provide system flexibility.

The latest policy significantly expands and strengthens technical requirements for coal power flexibility retrofits compared to previous standards. For minimum stable loads, the new targets require operating units to achieve 25%–35% (down from the previous 35% threshold under pure condensing mode), newly constructed units to reach $\leq 25\%$, and next-generation units to attain $\leq 20\%$. Beyond load requirements, the 2025–2027 Implementation Plan now comprehensively addresses additional critical flexibility parameters including ramp rate capabilities, primary frequency response, and start-stop cycling performance. These enhanced metrics better reflect the operational flexibility needed from coal plants to effectively accommodate high renewable energy penetration in the New Power System, marking a substantial advancement over prior policy frameworks.

- **Intelligence**

The advancement of intelligent technologies is set to significantly enhance the efficiency of coal-fired power operations, as emphasized in the 2025–2027 Implementation Plan. Intelligence will be applied across three critical areas: control systems, operational processes, and market trading strategies. In control systems, intelligent automation will ensure precise output regulation to execute AGC commands with at least 90% compliance (95% for next-generation coal power demonstration). For operational processes, smart solutions will optimize fuel management, safety monitoring, condition-based maintenance, and remaining useful life (RUL) assessment. Meanwhile, intelligent trading strategies will enable coal-fired plants to competitively participate in power markets by analyzing generation costs and dynamically adjusting bids to maximize revenue.

Discussion – three challenges to phase down coal power from its major roles as the electricity generator and flexibility provider

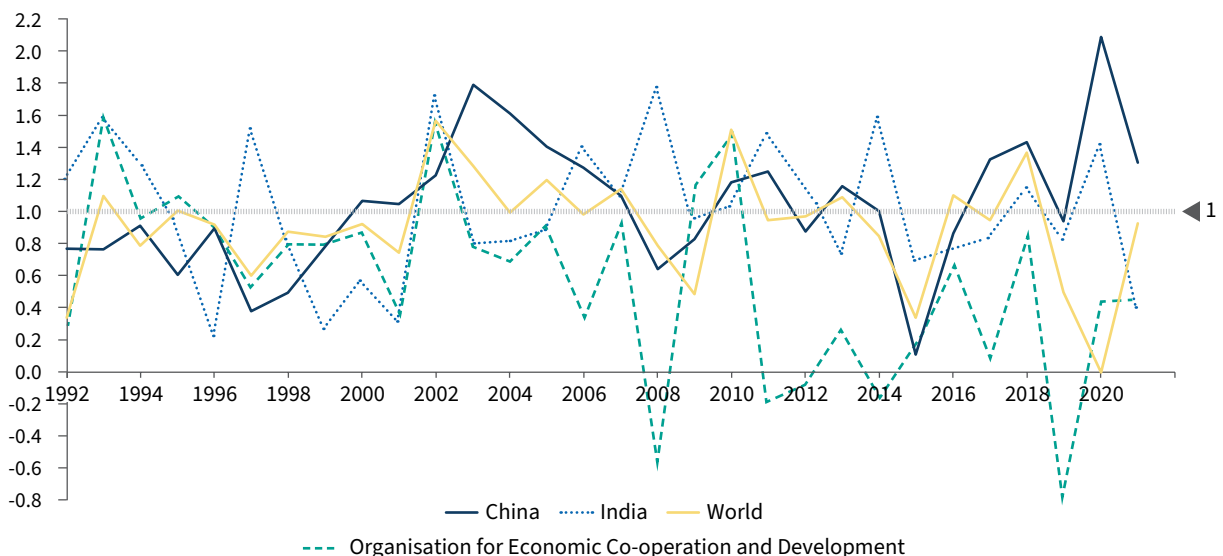
Besides repurposing coal power itself, China faces challenges in replacing coal power in providing generation and flexibility from the perspective of the whole power system. This section discusses three main challenges in the coal power phasedown: uncertainty in forecasting electricity consumption, lack of diversified flexibility resources, and reliance on coal power in resource planning.

Increasing uncertainties in the electricity-demand forecast are spurring the push for a larger and safer power system

Decoupling of economic growth from electricity consumption has not yet been seen in China

The trend of decoupling economic and electricity growth is commonly observed in developed countries but not yet in developing countries. The energy–environmental Kuznets curve (energy-EKC) model suggests that energy use will eventually reach a peak and then decrease as a country’s economy grows with the benefit of economic scale, technological development, and industrial structure change. Focusing on electricity consumption, stronger decoupling of economic growth has been observed in Organisation for Economic Co-operation and Development countries but not yet in China (see Exhibit 14). The electricity elasticity coefficient of China fluctuates around 1, indicating a strong relationship between electricity consumption and economic growth.

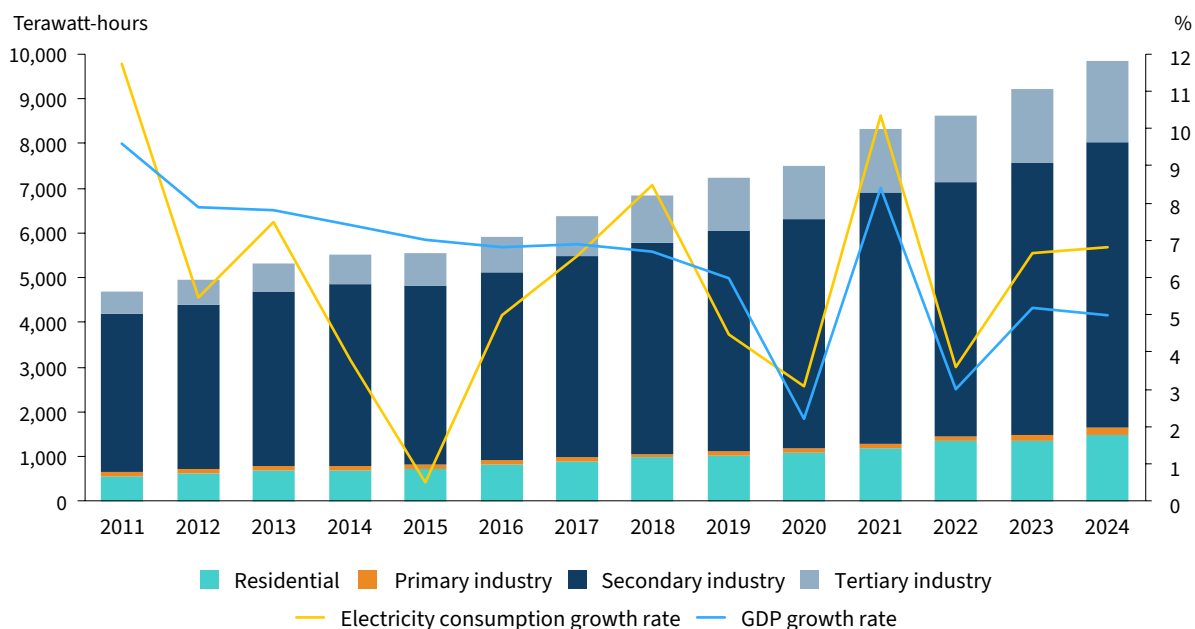
Exhibit 14 International comparison of electricity elasticity coefficient in 1992–2021



RMI Graphic. Source: IEA, World Bank, RMI

Continuous economic growth is the significant basis for power-demand growth in China. Even as the COVID-19 pandemic had a tremendous impact on the global economy landscape, it did not stop economic growth in China. The GDP in China grew at 5.5% per year during 2020–23, on average, while at the same time the global average growth rate was 4.0%. Growth in electricity consumption followed the GDP growth rate so closely in China that they were twins during 2020–23 (see Exhibit 15).

Exhibit 15 Electricity consumption by sector and growth rates and GDP growth rates in 2011–24



RMI Graphic. Source: CEC, National Bureau of Statistics

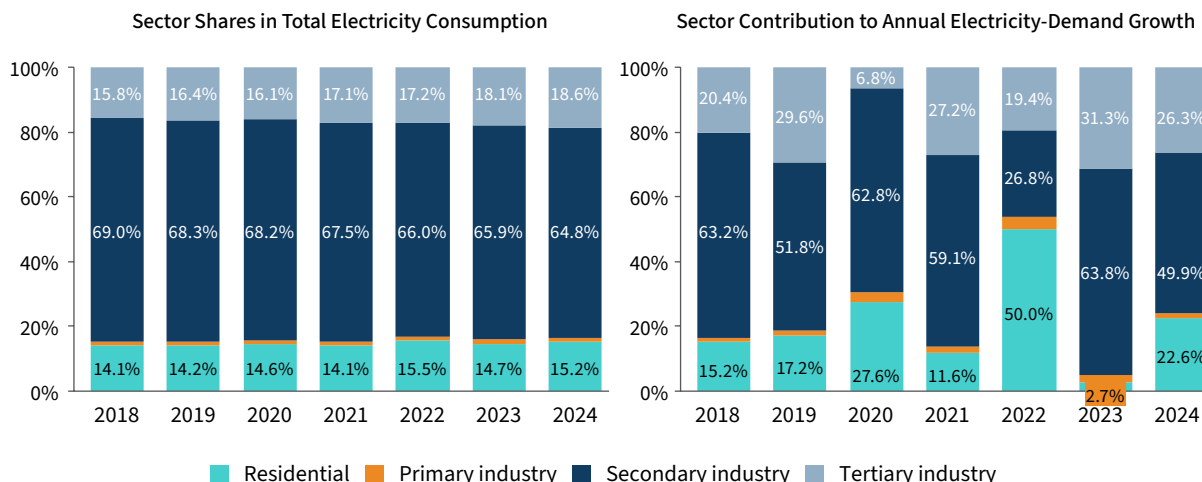
Looking at electricity consumption in different sectors, the secondary industry remains the largest share, although the share of the tertiary industry has grown in 2018–24 (see Exhibit 16).

- The **primary industry** represents only 1%–2% of total electricity consumption, and the share is quite stable.^{iv}
- The **secondary industry** continues to dominate electricity consumption. A lot of energy-intensive industries belong to the secondary industry, causing it to have the highest electricity consumption per GDP compared with the primary industry and the tertiary industry.^v Therefore, the growth of the secondary industry greatly determines the overall electricity-consumption growth pace.
- The **tertiary industry's** share of total electricity demand increased in 2018–24. The electricity consumption of the tertiary industry was affected by the lockdown policy during the pandemic but saw a large recovery in 2023 after reopening.
- The **residential sector** represents 14%–15% of total electricity consumption and shows a significant correlation with weather conditions. Notably, the residential sector contributed 50% of the electricity demand addition in 2022 because of extreme hot weather.

^{iv} The primary industry in China includes agriculture, forestry, livestock, and fishery.

^v The electricity consumption per GDP in 2023 is 0.134 kWh/RMB for the secondary industry, 0.026 kWh/RMB for the tertiary industry, and 0.014 kWh/RMB for the primary industry.

Exhibit 16 Electricity demand by sector in China in 2018–24



RMI Graphic. Source: CEC

New consumption drivers imply a longer electricity growth trajectory in China

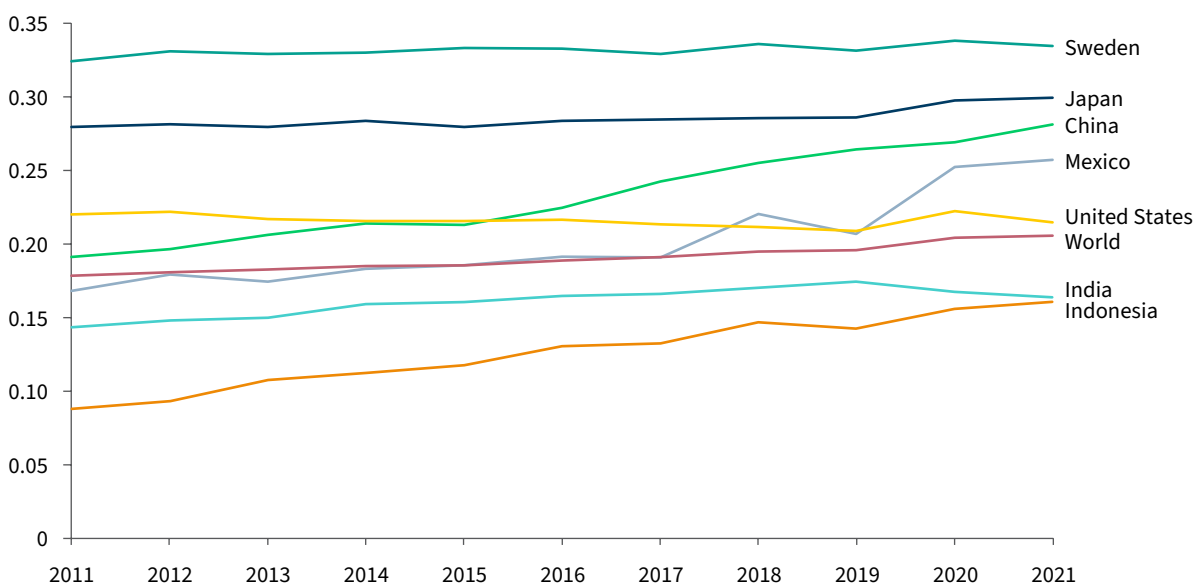
Rising electrification rates drive power-demand growth to outpace economic growth. The electricity elasticity coefficient has stayed above 1 since 2020, which means the electricity-consumption growth these years is faster than GDP growth. The national electrification rate increased from 25% in 2018 to 27% in 2022, although different sectors showed different trends.

- The **primary industry** has achieved a higher electrification level than the national average, increasing from 23% in 2018 to 31% in 2022. In the context of the continuous upgrading of rural power grids and the development of distributed energy, the electrification equipment of agricultural machinery has been widely promoted in rural areas, improving the level of primary industry electrification.
- The **secondary industry**, mainly manufacturing and mining, did not see big changes in its electrification rate after 2018, with the rate staying at around 26%.
- The **tertiary industry** has been the main electrified industry in recent years, especially in transportation. Increasing EV penetration in the public and private sectors raised electricity consumption in transportation from 5% in 2018 to 7% in 2022.
- The **residential sector** has experienced stepped-up growth in electrification as the number of electrified household appliances has increased, for instance for cooking and heating. Some electricity consumption for charging of electric bicycles and EVs is counted in the residential sector, which also contributes to the growing electrification level. The residential electrification rate increased from 29% in 2018 to 37% in 2022.

Electricity's share of total final energy consumption in China is in line with the global average. Developed countries, such as Sweden, Japan, and the United States, have maintained stable electrification rates for more than 10 years. However, in developing countries, such as China, Mexico, and Indonesia, electrification has increased in the past 10 years. China and Mexico had higher electrification rates than the United States in 2021 (see Exhibit 17). China still has potential for further electrification.

- In the **primary and secondary industries**, electricity substitution promoted by the government will drive the increase in electrification. Enhanced construction of distribution networks will provide the foundation for the electrification process.
- In the **tertiary industry**, leading and growing EV penetration in China will continue to drive the electrification rate higher.
- In the **residential sector**, China still has gaps compared with global leaders in electrification. For example, electrification rates for the residential sector in the United States and Japan in 2021 were 48% and 52%, respectively, according to IEA data. Adding electric appliances to close the gaps will increase China's electrification level in the residential sector.

Exhibit 17 International comparison of electrification rate



RMI Graphic. Source: IEA

The development of emerging industries in China will also lead to growth of electricity consumption. Although traditional energy-intensive industries may face a zero to negative electricity-demand growth trend, several emerging industries show sturdy growth potential and an increasing share of total electricity consumption.

Within the manufacturing industry, the electrical and electronics categories recently have experienced rapid growth of electricity consumption.^{vi} These two categories' electricity consumption grew by 91% between 2018 and 2023. The development of emerging industries, such as PV, EV battery, and smart devices, has led to a high growth rate of electricity consumption in these industries. For example, the electricity consumption of PV equipment manufacturing increased 77% in 2023 compared with 2022, and consumption in 2023 was 23 times that in 2018. These emerging industries are expected to become the new drivers for electricity-demand growth because of their expansion under decarbonization and digitalization.

^{vi} Under China's statistical classification, the electrical category includes manufacturing of PV equipment, batteries, and household devices, and the electronics category includes manufacturing of computers, communications equipment, smart devices, and electronic devices.

The tertiary industry also has experienced strong electricity-consumption growth from EV battery charging and swapping services and from internet data services. EV battery charging and swapping services' electricity consumption increased 78% in 2023 compared with 2022, and consumption in 2023 was 18 times that in 2018. Internet data services, which rely heavily on data centers, experienced a 28% year-on-year growth rate in 2023. Moreover, these two services are expected to grow even faster in the future. According to BNEF, the EV share of the passenger vehicle fleet in China is expected to grow from 7% in 2023 to over 30% in 2030. Thus, electricity demand for EV battery charging and swapping will continue its fast growth. IEA expects that global electricity demand for data centers will be over 1,000 terawatt-hours in 2026, more than double the demand in 2022. Data center development in China is expected to accelerate continuously, increasing potential electricity consumption.

The traditional electricity-demand forecast requires thorough improvements to support a bigger and cleaner power system

Accurately forecasting electricity demand is the priority for power-system planning and operation. However, current forecast practices may face challenges under new landscapes of electricity consumption, making it harder to reflect accurate expectations for the future. As a result, the recent surge of coal power is regarded as the most reliable and convenient option to meet uncertain electricity demand and guarantee reliable power supply. To support a bigger and cleaner power system, it is essential to improve traditional forecast methods to reduce reliance on coal power by enabling more effective and timely interventions.

Data collection and classification lack sufficient granularity

Although emerging industries are increasingly driving electricity-demand growth, the current statistics system for electricity consumption faces challenges in capturing high-quality data from these sectors to support accurate forecasting. Currently, major industries with significant shares are listed separately in statistics, providing a reliable data source for in-depth analysis. However, many emerging industries lack independent statistics, making it difficult to analyze their electricity-consumption patterns and increasing the challenges in forecasting accurately.

Moreover, more diversified electricity consumptions make tracking and gathering data more difficult. For instance, electricity consumption from EV charging is currently categorized based on different charging options. Charging at self-built stations is classified under the residential sector, without being separately listed, but charging at public stations is included in the tertiary industry and is listed separately. Therefore, it is hard to collect the total amount of electricity consumption from EV charging. Because charging choices can shift between self-built charging stations and public charging stations, the current data collection method of EV charging data complicates accurate forecasting, especially in the long run.

To better understand and forecast electricity demand, detailed data collection that aligns better with consumption behaviors is needed. More detailed data on emerging industries also is necessary. Categories such as the residential sector that encompass various electricity-consumption scenarios require data to be segmented by use type for more accurate classification.

Forecast methods are no longer applicable

The current forecast methods may no longer be applicable, given structural changes in electricity consumption. Traditionally, electricity consumption has relied heavily on GDP forecast and the analysis of its relationship with economic development. However, the recent observation that the electricity elasticity coefficient remains unexpectedly above 1 indicates a more complex electricity-consumption scenario. This reflects a shift, with a declining share of energy-intensive industries and a growing share of electricity-intensive industries.

Climate change is another factor that has affected the electricity elasticity coefficient, yet it remains hard to predict. For example, in 2022, China had a record number of days with a high daily temperature of $\geq 35.0^{\circ}\text{C}$ and the most extreme heat events, according to the China Meteorological Administration. As a result, the residential sector experienced 14% year-on-year growth in electricity consumption. It is also estimated that the growth rate of electricity consumption would be lower than the GDP growth rate if the impact of temperature were excluded. Therefore, only focusing on the relationship with GDP growth is not enough for electricity-demand forecasting.

In addition, energy-intensive industries traditionally have been emphasized in electricity consumption because of their large share. Extensive research has been conducted on the consumption patterns of these industries to improve forecasting accuracy. However, as emerging industries show greater importance, it is crucial to analyze their consumption characteristics and impact factors more thoroughly to achieve higher accuracy in forecasting total electricity consumption.

International reference is no longer available

China used to refer to the development trend of developed countries to predict GDP growth and electricity demand. However, as gaps in industrial development and technological progress among countries narrow, it has become increasingly difficult for China to rely on international benchmarks to serve as the expected development level. Furthermore, emerging industries, such as EVs and data centers, are new for all countries, with limited international experience regarding their development trends and consumption characteristics.

Therefore, with insufficient references available, an in-depth analysis of specific industries is needed to investigate electricity-consumption patterns for accurate forecasting. Using subdivided parameters by sectors and industries instead of using unified parameters can better reflect detailed changes. Furthermore, because emerging industries have become increasingly important in total electricity consumption but lack available references, the consumption characteristics and impact factors of these industries require more analysis to be better reflected in adapted forecast methodologies, improving forecast accuracy.

Rising flexibility demand lacks diversified clean resources

China needs fast-growing power-system flexibility for all timescales

Flexibility refers to the power system's ability to respond to supply and demand imbalance, manage the uncertainty of variable renewables, and maintain the power system's security and reliability within acceptable margins. Power-system flexibility can be classified into several categories by timescale (see Exhibit 18):

- **Ultra-short-term flexibility (shorter than one minute):** Flexibility demand under this timescale refers to the need to maintain system stability, such as frequency and voltage stability, which is increasingly challenged by high VRE penetration in China. For example, maintaining frequency stability becomes particularly problematic when large amounts of renewable energy are integrated into a weak power grid through power electronic devices. Under current technical conditions, few wind and photovoltaic power plants can provide frequency regulation and inertia support. But renewables have a crowding-out effect on traditional synchronous generators, leading to a shortfall in system flexibility supply. This results in problems such as rapid frequency changes, deeper frequency valleys, and insufficient backup during faults or emergencies.
- **Short-term flexibility (one minute to one day):** The flexibility demand under this timescale refers to the need to maintain power balance during the day, which is related to the net load change. Increasing VRE penetration, especially the large share of solar PV in total VRE installation capacity, boosts this flexibility demand. The duck curve caused by the large share of PV in the power system is the most typical example of short-term flexibility. The net load of the power system continues to decline during the noon period, with growing generation from solar PV, and then continues to increase as solar PV generation wanes until night. More ramp-down and ramp-up are required from the dispatchable units at noon and in the evening. In addition, the continuous decline in net load at noon requires some flexible power-generation units to maintain a low output level instead of shutting down, so that they can ramp up in time at night. Finally, weather uncertainty during the day can affect a wide range of renewable energy units in a short period of time, which places higher requirements on the system's ability to respond in a timely manner.
- **Medium-term flexibility (one day to one month):** Flexibility demand on this timescale refers to the system's ability to respond to changes in load and power generation over days to weeks because of specific events or weather conditions encompassing both foreseeable and unforeseeable fluctuations. Foreseeable flexibility demand includes the large-scale transfer and structural fluctuation of power load caused by holidays, such as the Spring Festival in China, and the prolonged low output of renewable energy caused by extreme heat and lack of wind, which often happens in summer in Beijing and surrounding provinces.

Unforeseeable flexibility demand includes rapid change in power demand over a short period caused by a sudden extreme high or low temperature, driven by more frequent extreme weather events in recent years. For example, extreme low temperatures caused power demand to rise in Texas from February 9 to 13, 2021. The daily load forecast by the Electric Reliability Council of Texas was less than the actual load value, which shows that the power grid underestimated the impact on the electrification rate of heating and extreme cold weather.

- **Long-term (or seasonal) flexibility (longer than a month):** This mainly refers to the flexibility demand caused by seasonal changes in power demand and generation from intermittent renewables such as wind, solar, and hydro. Multiple factors can trigger flexibility demand on this timescale, including increased electricity load due to economic growth, fluctuations of annual average output of renewable energy caused by climate conditions, and changes in fossil fuel generation availability due to fuel price volatility. Intensifying climate change further exacerbates the uncertainty of long-term flexibility needs.

Exhibit 18 Four timescales of flexibility – typical demand scenario and growth drivers

Timescale	Typical duration	Typical demand scenario	Growth drivers in China in recent years
Ultra-short-term	Shorter than one minute	Frequency and voltage change due to the volatility of wind and solar generation	Higher penetration of wind and solar
Short-term	One minute to one day	Low net load at noon	Higher penetration of wind and solar, especially large solar share
Medium-term	One day to one month	Extreme heat over several weeks	More frequent extreme weather events
Long-term	Longer than a month	Seasonal change of renewable generation	Intensified climate change, electrification improvement

RMI Graphic. Source: Tsinghua University, RMI

Zero-carbon flexibility resources are growing fast but not enough

Rising flexibility demand calls for various flexibility resources at different timescales (see Exhibit 19). Thermal power, including gas power and coal power, that implemented flexibility retrofits can provide system flexibility for all timescales. In China, coal power has advantages over gas power because of adequate fuel resources and lower costs, while it has the disadvantage of carbon emissions. Different types of hydropower can also provide flexibility at different timescales, although they typically require longer construction times. Zero-carbon resources from the storage and demand sides can contribute to flexibility, but their impact is generally limited to specific timescales.

A combination of different options can cover flexibility demands at different timescales and reduce reliance on coal power. Storage technologies and DSF are the main replacements for coal power offering flexibility supply. Clean alternatives to meet ultra-short-term and short-term flexibility demand are more economically mature, easier to deploy, and face fewer locational restrictions. Lithium batteries and demand flexibility are the lowest hanging fruits with considerable development potential. Other storage technologies, such as compressed-air energy storage, flow batteries, and flywheel storage, could also provide flexibility at these timescales, enriching alternative options, though these technologies are less mature and economical for now.

For medium-term flexible sources, pumped storage and flow batteries could provide flexibility beyond one day. Demand-side resources, from industry loads, air-conditioning loads, and EV loads, could also provide medium-term flexibility under different scenarios. However, few zero-carbon flexibility resources can cover long-term flexibility needs, which still require thermal power to serve as an important backup.

As mentioned in the *Higher penetration of weather-dependent renewables requires more flexible resources* section (page 14), China is actively promoting the development of various flexibility resources, including thermal power and zero-carbon options. However, development of zero-carbon flexibility resources has not been fast enough to fully substitute for coal power, and challenges remain in their efficient utilization, leading to the current reliance on coal power.

Exhibit 19 Comparison of flexibility technologies

Rating Dimension		Flexibility Dimension				Cost Dimension	Construction Dimension		Climate Dimension
Rating Contents		Ultra-short-term flexibility	Short-term flexibility	Medium-term flexibility	Long-term flexibility	Current economics	Construction speed	Potential addition in physical scale	Decarbonization level
Rating Scales		1–4: Higher grade refers to stronger flexibility ability under certain timescales				1–4: Higher grade refers to lower capex currently	1–4: Higher grade refers to faster construction speed	1–4: Higher grade refers to larger potential addition in physical scale	1–4: Higher grade refers to lower carbon emission under operation
Generation Side	Existing coal power after flexibility retrofits	2	3	4	4	3	3	2	1
	Newly built coal power	2	3	4	4	2	2	4	2
	Gas power	3	4	3	3	2	2	3	3
	Conventional adjustable hydropower*	4	4	2–4	1–4	1	1	2	4
	Concentrated solar power	2	3	2	1	1	2	1	4
Storage Side	Pumped storage	4	4	2	1	2	1	4	4
	Lithium-ion battery	4	3	1	1	3	3	3	4
	Compressed-air energy storage	3	4	1	1	2	2	1	4
	Vanadium redox battery	4	3	2	1	2	3	4	4
	Flywheel energy storage	4	1	1	1	1	3	4	4
Demand Side	Industrial load**	1–2	2–3	3	2	3–4	3	3	4
	HVAC load	2	3	2	1	4	4	2	4
	Vehicle-to-grid	3	2	2	1	4	4	3	4

* The conventional adjustable hydropower discussed includes multiyear adjustable hydropower stations, annual adjustable hydropower stations, seasonal adjustable hydropower stations, weekly adjustable hydropower stations, daily adjustable hydropower stations, and run-of-river hydropower stations. These types of adjustable hydropower stations have different flexibility abilities, and hydropower stations with larger regulating storage capacities offer flexibility over longer timescales.

** Variations exist in the flexibility ability of industrial load because of different production characteristics in different fields.

RMI Graphic. Source: Tsinghua University, RMI

Promoting DSF is low-hanging fruit in the 2020s

DSF is considered one of the most promising zero-carbon flexibility resources in the 2020s, given its multiple advantages illustrated in Exhibit 19. More important, with economic growth and electrification expansion across sectors, electricity demand in China will continue to rise, making the value of DSF increasingly critical.

China has recognized DSF as a critical measure to achieve power balance and increase renewables consumption. In September 2023, the NDRC revised and published the *Measures on Demand-Side Management of Electricity* (2023 edition), introducing a dedicated chapter on demand response for the first time. This update emphasizes the promotion of demand response through economic incentives to improve system flexibility. It clearly states that by 2025, each province’s demand-response capacity should reach 3%–5%, or even higher, of annual peak load, which directly translates to a potential peak demand cut of about 50–80 GW. By 2030, a large-scale, real-time, demand-response capability is expected, integrated with ancillary services and the energy markets to enable resource sharing and mutual support across provincial grids.

China’s DSF development is transitioning from regulated and planned measures to market-based operation mechanisms. In general, DSF development could be categorized into four phases (see Exhibit 20), showing a shift from regulation to market and an expanding pool of demand-side participants. Most provinces are in Phase II or III, although some (including Shanxi and Shandong) are entering Phase IV, when DSF sources can aggregate as VPPs and participate in spot markets and ancillary service markets. Additionally, megacities such as Shenzhen and Shanghai are building city-level VPP platforms to implement precise, distribution-level demand responses, aiming to alleviate grid congestion and reduce associated investment costs.

Exhibit 20 Four development phases of DSF in China

	Phase I: Regulated Load shaving	Phase II: Closed Demand Response	Phase III: Invitation-Based Demand Response	Phase IV: Regular Participation in the Electricity Market
DSF Sources	Planned industrial and commercial loads based on the severity level of the power shortage	Mainly commercial air-conditioning loads	Mainly industrial and commercial loads	Load sources, distributed energy sources, load aggregators, virtual power plants
Response Frequency	Only activated when there is a power shortage	Only activated when there is a power shortage/peak load (< 100 hours per year)	Uncertain, based on power supply–demand tightness and size of subsidy pool	Daily
Business Model	Regulated measures and nearly no subsidy	Self-financed construction by grid operators	Planned demand response subsidies from various sources	Market-based mechanism: demand response, spot market, ancillary services
Case	Orderly electricity consumption (under power shortage)	Provincial-level and city-level new load management platform	Provincial demand response mechanism	Currently, Shanxi and Shandong spot markets allow VPPs to participate

RMI Graphic. Source: RMI

However, gaps in knowledge, incentives, and practice are still blocking the scale-up of DSF. There is huge room to improve stakeholders' understanding of the importance and implementation of DSF, as well as to bridge misunderstandings between users and GridCos. Enterprises of different sectors and sizes have varying degrees of understanding of DSF. And some emerging high-growth industries, like data centers and residential EVs, lack mature DSF technical solutions.

Further, the current demand-response mechanism only operates for a few hours annually, and DSF resources do not have a level playing field with other participants in the energy and ancillary markets. Because of these gaps, business models to incentivize DSF development are not clear. Most practices today are still pilots without regular operations. To promote DSF, more efforts are needed in policymaking and market mechanism design, user-specific technical solutions, demand-response strategies, and pilot program expansion.

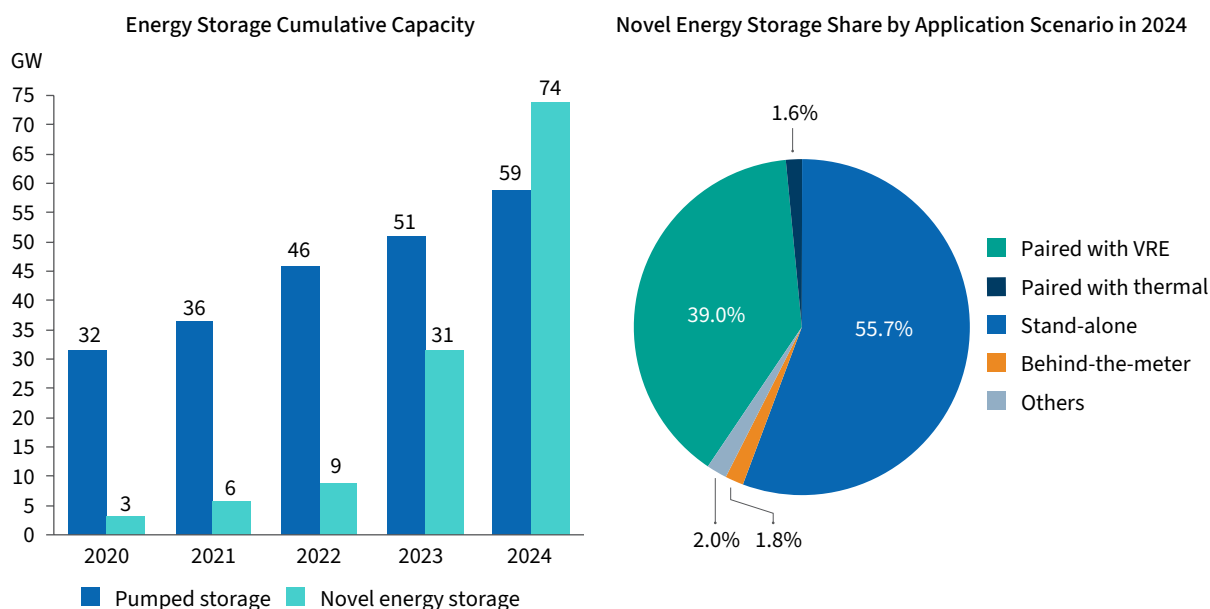
Much more energy storage needs to be built and better used to position it as a reliable replacement for coal power

The development of energy storage in China has sped up since 2015 and gained more momentum after 2020 (see Exhibit 21). During 2016–20, the policy priorities were technology development and standard setting. Since 2021, national development plans for pumped storage and novel energy storage have been released separately to promote their development and enhance power-system flexibility.

Pumped storage permits have accelerated since 2021 with strong policy promotion. The total installed capacity of pumped storage in China was 31 GW by the end of 2020 and was required to double every five years to reach 62 GW by 2025 and 120 GW by 2030 in the *Medium and Long-Term Development Plan for Pumped Storage (2021–2035)*, released by NEA in September 2021. These goals are likely to be surpassed, given the surging pipeline in the past few years, with a major driver from the capacity compensation mechanism for pumped storage launched in 2021.

Novel energy storage in China is on a high-speed growth rate, constituting around 85% of total energy storage growth in 2024. The NDRC and NEA jointly released the *Guidance on Accelerating the Development of Novel Energy Storage* in July 2021, aiming to reach large-scale development by 2025 and full commercial development by 2030. China's cumulative capacity for novel energy storage surpassed 44 GW by mid-2024, exceeding the 2025 national target of 40 GW. Among all technologies, lithium-ion batteries dominate, with a 97% share of total capacity.

Exhibit 21 Cumulative Energy Storage Capacity from 2020 to 2024



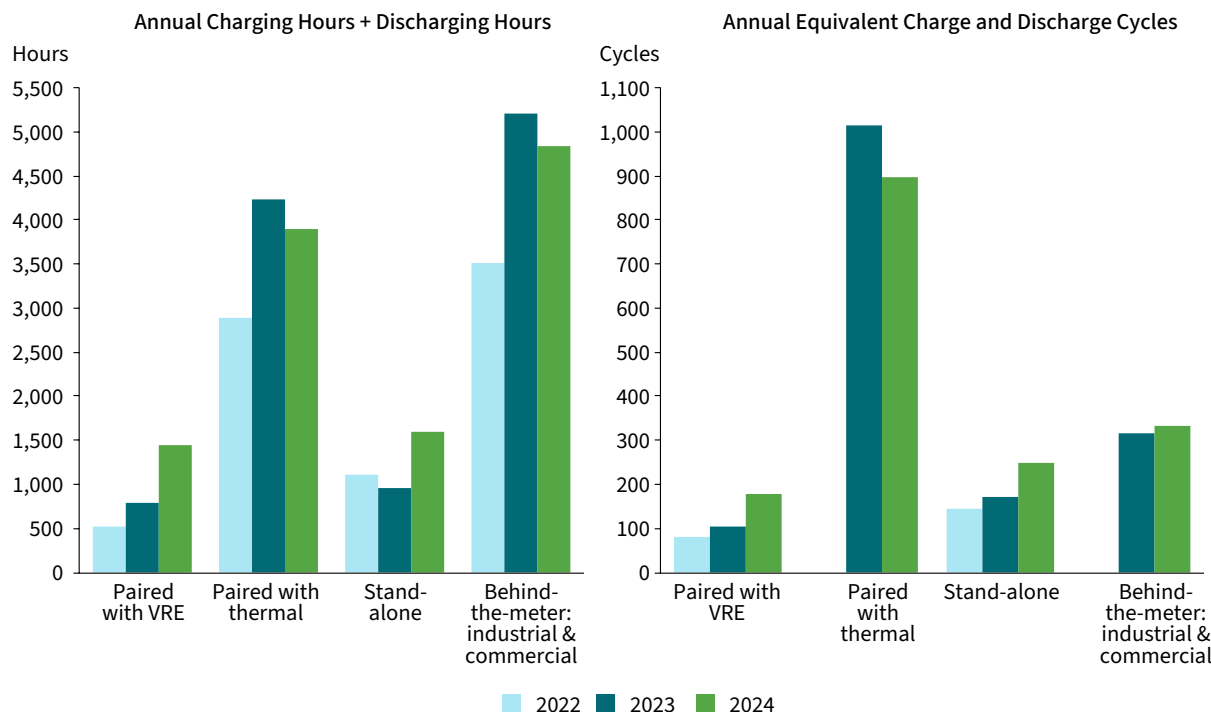
RMI Graphic. Source: NEA, CEC

Front-of-the-meter (FTM) novel energy storage contributed to around 90% of capacity addition from 2022 to 2024. FTM is the key alternative to replace coal power as a flexibility resource. More than 70% of provinces require VRE developers to colocate on-site novel energy storage with renewables, usually 10%–20% of renewables’ nameplate capacity with one- to four-hour duration to alleviate generation intermittency. Stand-alone storage, another form of FTM storage, is incentivized by expanded business models, which vary among provinces according to local policies.

Behind-the-meter (BTM) storage in China is growing at a slower pace than FTM storage but still plays a significant role in alleviating intraday fluctuation of electricity consumption. By 2024, BTM storage only constituted about 2% of total novel energy storage, mostly on the commercial and industrial sides. BTM storage plays a key role in demand-side management and is growing rapidly in eastern coastal provinces with high electricity demand and significant intraday change of load curves, such as Jiangsu and Guangdong. The recent accelerated development of BTM storage in China is stimulated by increasing intraday electricity price spreads under the time-of-use pricing mechanism that was established in 2021.

Despite the increase in installations, use of novel energy storage assets is limited, especially for FTM storage (see Exhibit 22). According to the CEC, FTM storage paired with VRE and stand-alone storage have the lowest utilization level among all types of novel energy storage. BTM storage has the highest utilization level and experienced significant improvement in 2023, with 5,203 utilization hours on average.

Exhibit 22 Comparison of utilization levels of novel energy storage in 2022–24



RMI Graphic. Source: CEC

Improvements in market mechanisms have boosted novel energy storage utilization. Besides promoting the construction of spot power markets to provide more obvious price signals, some provinces have also developed capacity mechanisms for energy storage. For example, Shandong provides two capacity mechanisms for novel energy storage: capacity leasing and capacity price. For capacity leasing, VRE facilities could lease capacity from stand-alone storage projects, the price of which was 200–300 RMB/kW in 2023. For capacity price, novel energy storage projects that participate in the power market will gain revenue from the energy price and the capacity price, with the capacity price regulated by the government. Providing capacity mechanisms for energy storage diversifies revenue streams for energy storage.

Considering the low utilization of VRE-paired storage, the trend is to shift to stand-alone storage through technical upgrades. In August 2023, Shandong initiated pilot projects to convert VRE-paired storage to stand-alone storage, with additional technical requirements for the transition. At the national level, the NEA released the *Notice on Promoting the Grid-Connected and Dispatching Application of Novel Energy Storage* in April 2024 to include VRE-paired storage that meets the technical requirements of stand-alone storage that can be separately dispatched by GridCos. The policy also encourages technological upgrades to enable existing storage projects to receive dispatch signals. As a result, the utilization level of energy storage is expected to improve.

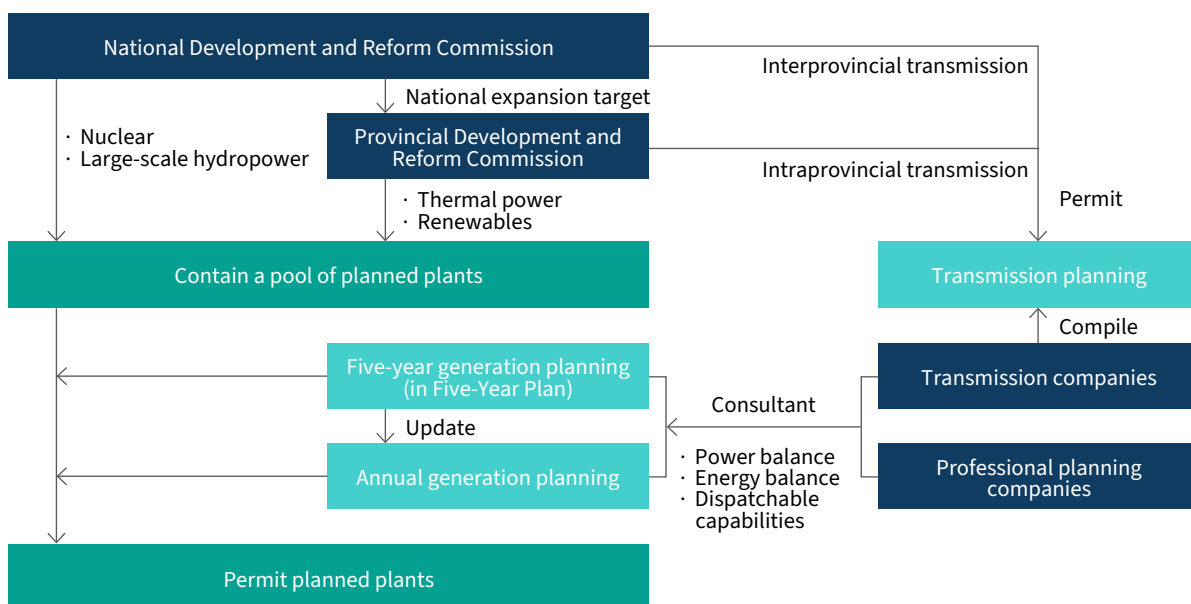
China's New Power System calls for revision of power-system planning practices

Current power-system expansion planning is dominated by top-down approaches

Generation companies (GenCos) and transmission companies (TransCos) in China initially belonged to a single entity. They were separated during the first round of power-market reform in 2002 to introduce more competition into the generation sector, although the grid sector is still a regulated monopoly. Since then, responsibilities for generation and transmission planning have been divided between these two groups, like the approach in the UK, the United States, and the EU. In these three regions, where wholesale markets are established, generation-expansion decisions are typically incentivized by price signals from the market, alongside government subsidies and development plans, such as contracts for difference (CFD) in the UK and feed-in premiums in Germany. In contrast, Chinese GenCos operate under more regulated wholesale prices, which provide less guidance for power-system expansion. Therefore, the central and local governments rely more on a top-down unified planning system to shape the generation mix in China.

Multiple stakeholders are involved in expansion of the power system (see Exhibit 23). The NDRC and the provincial Development and Reform Commission (DRC) are responsible for the planning and permitting of power plant projects. Large-scale hydropower and nuclear power plants are planned and permitted at the national level, while thermal power plants and renewable projects are handled at the provincial level. In addition to municipal entities, TransCos and professional planning companies and institutes, such as the China Electric Power Planning and Engineering Institute, offer crucial input to the government on matters like load forecasting and generation planning to ensure the power system grows along the correct trajectory. Finally, TransCos evaluate proposed generation plans in relation to grid capacity and proceed with grid planning accordingly.

Exhibit 23 The process of power-system expansion in China



RMI Graphic. Source: RMI

Limitations in current system planning show significant path dependency and reliance on coal

In its push to promote renewable energy, China has adopted different approaches for renewables and thermal power in generation-development planning. Typically, proposed capacity in DRC plans represents a lower bound for renewables but establishes an upper limit for fossil fuel power plants. As a result, we have seen faster-than-expected wind and solar expansion in recent years, causing flexibility and reliability issues alongside rising electricity demand.

The expansion of renewables beyond planned targets creates challenges for evaluating zero-carbon resources in generation planning and coordinating with transmission infrastructure. Underestimating the value of zero-carbon resources and slow transmission expansion have led to a continued reliance on coal power, which remains the easiest and most efficient way to ensure a stable power supply.

In generation planning, the capacity credit of wind and solar is roughly considered, but lacks granularity based on actual utilization. The capacity credit is used to identify the ability of generators to meet peak demand, usually represented by share of nameplate capacity, but does not fully capture the variability and real-world performance of renewable resources. Unlike thermal plants, where output is consistent and adjustable, renewables output is more spatially and temporally sensitive. Therefore, using one fixed number to represent renewables' capacity credit creates bias in generation planning as renewables penetration increases. Currently in China, capacity credits for wind and solar are in general less than 10%, lower than actual utilization level. This underestimation of the capacity value of wind and solar results in excessive capacity from other sources.

Moreover, the capacity credit for novel energy storage is largely neglected in China, hindering its development and perpetuating reliance on coal power. Evaluating the capacity credit for storage is more complicated than for generators because of factors such as discharge duration, dispatch strategy, and capacity mix. Because of these additional complexities specific to storage, most regions in China do not include novel energy storage when calculating capacity adequacy.

Therefore, although there is a surge in novel energy storage installations, power systems still require more dispatchable resources to meet rising electricity-demand growth. Even in Shandong Province, which has established a capacity credit for storage, the methodology is simplistic and yields lower credit compared with the usual method in the United States. In Shandong, capacity credit is determined by a straightforward formula: total available discharge hours divided by 24, resulting in a credit of 16.7% for four-hour storage. Companies in the United States usually use expected load-carrying capabilities through modeling to determine capacity credit for storage, which is 59% for the Pennsylvania-New Jersey-Maryland (PJM) Interconnection and 90% for the New York Independent System Operator for four-hour storage, much higher than that in Shandong.

For planning coordination, transmission expansion has traditionally been based on existing generation plans. However, this approach is no longer effective because renewables development increasingly exceeds planned targets. Transmission expansion is a far more complex process than generation, involving longer permitting processes, more studies, and land acquisition. Additionally, the construction timeline for transmission projects is often longer than that for wind and solar projects, causing TransCos to constantly lag wind and solar development. This has led to grid issues, such as interconnection queues and severe congestion, resulting in renewable energy curtailment. Grid congestion further restricts the ability to integrate generation resources over larger areas, forcing some regions to rely on local generation. Thus, in many cases, coal power remains the most reliable option for local energy supply.

Planning for a power system with increasing uncertainties through a zero-carbon portfolio is a common challenge worldwide

Traditional generation planning methods were designed for power systems dominated by thermal power, which faces less uncertainty and is easier to predict. However, transitioning to a decarbonized power system introduces more uncertainties and challenges to these traditional planning methods, a shared challenge globally. As zero-carbon resources play an increasingly important role, new planning methodologies are needed to accurately reflect their value within the power system and to develop scientifically sound expansion plans.

First, coordination among various stakeholders on planning decisions needs to be improved. A power system with high renewables penetration requires support from all sides, including generation, grid, demand, and storage. Unmatched transmission construction with renewables expansion leads to renewable energy curtailment and power-system instability. Additionally, the potential of demand-side and storage resources, which are emerging elements in the power system, remains underutilized without effective coordination. Therefore, proactive and synchronous planning on all sides is essential to optimize the construction and utilization of all resources.

Many studies have pointed out the benefit of coordinating transmission-generation-storage expansions, and transmission planning has been proactive in many established markets. Proactive transmission planning is a type of transmission planning practice in which transmission expansions are not only planned according to a forecast generation-expansion portfolio (e.g., by analyzing the interconnection queues), but also by anticipating how generation will respond to transmission planning. Many models are proposed in academic journals. Still, in reality (CAISO, for example), proactive transmission planning usually means adding another generation-expansion stage after a set of transmission candidates is selected.

Second, full understanding of the reliability of zero-carbon technologies is essential. Although zero-carbon technologies, especially storage, have developed rapidly in recent years, they still lack sufficient recognition. Knowledge gaps exist among stakeholders regarding the technical characteristics of these technologies, leading to distrust in their reliability and an underrating of their value in system planning. Therefore, fair evaluations of zero-carbon technologies should be encouraged to enhance stakeholders' view of emerging technologies.

Finally, it is important to recognize that a more redundant power system is inevitable under deep uncertainty. Capacity value becomes equally important to energy value for all subjects in the power system. Therefore, establishing a capacity mechanism is essential to incentivize capacity addition to achieve resource adequacy.

Capacity mechanisms have been implemented through various methods around the world, with two main types being scarcity pricing and capacity market. China has already implemented a capacity pricing mechanism, but it is limited to coal fleets and pumped storage projects at the national level, and to gas fleets and battery storage in some provinces. All these capacity pricing mechanisms in China are determined separately and driven by negotiations between the government and GenCos, without a unified capacity mechanism to fairly evaluate all technologies. Factors like duration and ramping rate are often overlooked, and scientific methods for calculating capacity credits have yet to be established. Therefore, introducing a technology-neutral capacity mechanism could be a useful approach for refining capacity remuneration in China in the long run.

Appendix

Exhibit A1 Types of integration in China and examples

Level	Form	Mining — Power Integration	Coal — Renewables Integration
Financial level	Equity participation/ cross holdings	Huaneng Power International Company, a subsidiary of Huaneng Group, has long held a 0.63% share in Shaanxi Coal Industry Company Limited, which primarily operates in the coal business.	Hebei Construction & Investment Group, operating coal power capacity that accounts for 1.12% of the national total, has 48.95% shareholding in China Suntien Green Energy, which manages wind power, PV, and natural gas businesses.
Operational level	Business expansion	In April 2024, Datang Group's Kongduigou Coal Mine project in Inner Mongolia received national approval. Upon completion, the project will increase the group's coal production capacity by 7 million tons/year.	Shandong Energy Group holds 0.2% of national, operating coal power plant capacity and 0.37% of pipeline capacity. The company is actively expanding its installed capacity in renewable energy, with its current operating renewable energy capacity accounting for only 0.1% of the national total, while the pipeline capacity has increased to 0.33%.
	Project company establishment	In August 2023, Jiangsu Guoxin and China Coal jointly invested in and established China Coal Jingjiang Power Generation Co. The company plans to invest in the construction of two 1,000 MW coal power units.	In April 2024, China Huadian Corporation's subsidiary Huadian New Energy Group Co. and Tongwei Co.'s subsidiary Sichuan Yongxiang Co. jointly established Inner Mongolia Huadian Huayong New Energy Co. The company is engaged in businesses such as wind power and solar power generation.
	Long-term agreement	In November 2018, China Coal signed a medium- to long-term strategic cooperation agreement with six power enterprises: China Huaneng, China Datang, China Huadian, SPIC, China Resources, and SDIC Power. Between 2019 and 2023, approximately 500 million tons of coal were supplied under this agreement.	N/A

RMI Graphic. Source: Sina Finance, Beijixing power network, China Electric Power News, Hunan Energy Regulatory Office of National Energy Administration of the People's Republic of China

Exhibit A2 Integration among China's top 20 entities, by operating coal power capacity

Type	Entities	Coal Power Share	VRE Share	Coal Mining Share
Top 20 Entities		61.25%	34.75%	28.41%
C-SOEs-Power	CEIC	13.37%	7.22%	10.54%
	Huaneng	9.65%	6.16%	2.13%
	Huadian	7.26%	4.40%	0.79%
	Datang	7.17%	4.01%	0.24%
	SPIC	3.95%	8.00%	0.93%
	China Resources	3.39%	2.26%	0.27%
	SDIC	0.77%	0.63%	—
C-SOEs-Other	China Coal	1.23%	0.01%	3.33%
Sub-SOEs	Zhejiang Energy Group	2.41%	0.20%	—
	Beijing Jingneng	1.77%	1.33%	—
	Jiangsu Guoxin	1.58%	0.11%	—
	Guangdong Energy Group	1.29%	0.03%	—
	Anhui Wenergy	1.17%	—	—
	Hebei Construction & Investment Group	1.12%	0.01%	0.11%
	Huaihe Energy	1.04%	0.00%	1.07%
	Shanxi Jinneng	0.95%	0.27%	5.12%
	Shaanxi Coal and Chemical Industry	0.94%	—	2.36%
	Henan Energy group	0.91%	—	1.28%
	Inner Mongolia Energy group	0.66%	0.12%	0.13%
	Guangdong Hanjian	0.63%	—	0.12%

RMI Graphic. Source: GEM, BNEF

Exhibit A3 Integration Among China's Top 20 Entities by Coal Power Pipeline Capacity

Type	Entities	Coal Power Share	VRE Share	Coal Mining Share
Top 20 Entities		21.48%	33.73%	26.73%
C-SOEs-Power	CEIC	4.56%	7.74%	5.85%
	Datang	2.01%	3.46%	5.55%
	SPIC	1.70%	4.04%	0.27%
	Huadian	1.68%	4.02%	1.42%
	Huaneng	1.46%	6.15%	2.99%
	China Resources	1.04%	2.04%	0.17%
	China Three Gorges Corp.	0.56%	3.43%	—
C-SOEs-Other	China Coal	1.81%	0.12%	2.18%
	China Power Engineering	0.65%	1.35%	—
	China Energy Engineering	0.44%	0.59%	—
Sub-SOEs	Shaanxi Coal and Chemical Industry	0.94%	0.06%	1.14%
	Shanxi Jinneng	0.71%	0.19%	4.74%
	Guangdong Baolihua	0.69%	0.05%	—
	Guangdong Energy Group	0.68%	0.07%	—
	Anhui Wenergy	0.56%	0.05%	—
	Zhejiang Energy Group	0.53%	0.02%	—
	Huaihe Energy	0.43%	0.02%	—
	Shandong Energy Group	0.37%	0.33%	2.42%
	Jiangsu Guoxin	0.34%	—	—
	Inner Mongolia Energy Group	0.33%	—	—

RMI Graphic. Source: GEM

Yujing Liu, Liyue Zhang et al., *Decoding the Coal Power Transition in China: Facts, Challenges, and Opportunities in Accelerating Power System Decarbonization*, RMI, 2025, <https://rmi.org/insight/decoding-the-coal-power-transition-in-china-facts-challenges-and-opportunities/>.

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