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Article

# Sustaining rapid growth of renewable power in the context of market liberalization

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## ABSTRACT

Achieving carbon neutrality necessitates uninterrupted renewable investment, yet market liberalization introduces systemic risks. Using causal loop mapping, we identify three key dampening feedback about sustaining variable renewable energy (VRE) investment, including merit order reduction, price volatility, and volume risk. Provincial empirical data in China was used to validate these challenges. Subsequently, we reviewed the historical evolution of policies in the UK that incentivize VRE investment, with a particular focus on the role of the Contracts for Difference (CfD) mechanism in breaking these dampening feedback loops. Finally, we compared the policies of China and the United Kingdom, and put forward optimization directions for the sustainable development price settlement mechanism proposed in China's Document 136. Main results indicate that the conventional CfD mechanism effectively mitigates electricity price-related revenue risks but fails to address volume risks. Our analysis suggests volume risks may grow significant in China over the next five years, potentially discouraging investments. We recommend addressing volume risk both by accelerating development of flexible demand sources to encourage offtake for VRE that would otherwise be curtailed; and piloting different CfD designs across provinces, with the results monitored and compared to inform future policy decisions.

## KEYWORDS

Renewable energy, contracts for differences (CfD), system mapping, decarbonization.

## 1 Introduction

The growth in deployment of renewable power technologies has far exceeded expectations all over the world. By the year 2020, total global deployment of solar photovoltaic (PV) was more than ten times the level implied by the targets that governments had set for that year, fifteen years previously[1]. Nowhere has the out performance of targets been as great as in China. In 2008, the Chinese government set a target of deploying 1.8 GW of solar power by 2020. When the year 2020 arrived, solar deployment in China stood at 252 GW; the capacity of renewables has grown rapidly since then (see Figure 1), and it has boosted confidence for China's low-carbon transition. On September 24, 2025, China announced a new round of Nationally Determined Contributions (NDCs) and made a commitment to the international community: by 2035, the total installed capacity of China's wind and solar power will exceed six times that of 2020, and strive to reach 3.6 billion kW.

This non-linear progress has been driven by the amplifying feedback of technology deployment and diffusion. Rapid growth in production and deployment of solar and wind technologies has led to reductions in their costs (understood as levelised cost of energy (LCOE)). These cost reductions are driven by several mechanisms[2]: the first is learning-by-doing: as cumulative production and deployment grows, improvements in manufacturing and project development lead to lower costs; the second is economies of scale: as production is scaled up, unit costs decrease, typically through both direct scale economies in factories and through enhanced supply chains; the last one is network effects and emergence of complementary technologies: as adoption increases, synergistic relationships form between the technology, users, institutions, and complementary technologies[3].

Improved performance and lower costs then lead to increased demand and profitability (assuming cost reductions are not competed away), which prompts further investment and deployment. This will incentivize technological innovation, thereby further reducing the deployment costs of renewable energy[5]. This reinforcing feedback is central to the transition to clean power. Keeping it operating is essential for meeting the policy goals of carbon peaking and carbon neutrality in the power sector, and for keeping electricity costs low for consumers. The conditions that have supported the rapid growth of renewables in China's power sector are changing. Previously, variable renewable energy (VRE) enjoyed guaranteed full purchase with fixed prices, backed by the 2009 amendment to China's Renewable Energy

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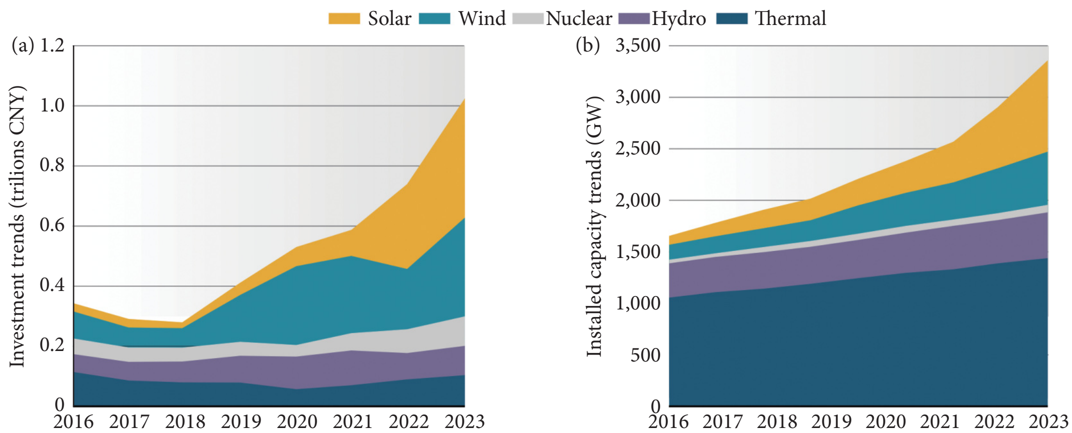


**Fig. 1 Trends in Chinese power generation investment and installed capacity by technology. (a)** Investment trends. and **(b)** installed capacity trends. Data are from 2016-2024. Reproduced with permission from Ref. [4], © China Energy Media Research Institute 2024.

Law[6]. However, rapid growth in deployment, supported by feed-in tariff policies, has ushered in new issues of VRE integration and large subsidy burdens. To address the latter issue, subsidised feed-in tariffs were gradually wound back through the 2010s in line with VRE technology cost reductions, before being phased out altogether in 2021 (Table 1). Now, reform efforts are firmly set on establishing a "unified national power market system" by 2030 to promote efficiency and enable ongoing market-based integration of VRE[7]. To this end, requirements that renewable power be sold via market channels are growing stricter by the year, with the proportion of output covered by purchase guarantees being wound back accordingly.

**Table 1 Fixed prices of onshore wind and solar power from 2009–2021.**

| | Resource area type | 2009 | 2013 | 2015 | 2018 | 2019 | 2020 | After 2021 |
|---|---|---|---|---|---|---|---|---|
| Onshore wind (CNY/(kWh)) | I | 0.51 | 0.51 | 0.49 | 0.4 | 0.34 | 0.29 | Coal-fired power benchmark price |
| | II | 0.54 | 0.54 | 0.52 | 0.45 | 0.39 | 0.34 | |
| | III | 0.58 | 0.58 | 0.56 | 0.49 | 0.43 | 0.38 | |
| | IV | 0.61 | 0.61 | 0.61 | 0.57 | 0.52 | 0.47 | |
| Solar (CNY/(kWh)) | I | n/a | 0.9 | 0.9 | 0.5 | 0.4 | 0.35 | |
| | II | n/a | 0.95 | 0.95 | 0.6 | 0.45 | 0.4 | |
| | III | n/a | 1 | 1 | 0.7 | 0.55 | 0.49 | |

Note: "Resource area type" refers to zoning categories assigned based on VRE resource abundance, with zone I experiencing the best VRE resources, and zone IV experiencing relatively poorer conditions[8–13].

In the post-subsidy era, and as part of the long-term process of market liberalisation, market reforms are increasingly exposing renewables to competition. A 2029 deadline has been set for full market participation, per a 2024 blue book prepared by the China Electricity Council (CEC) for the National Energy Administration (NEA)[14]. The proportion of VRE sold via market channels has risen rapidly in the post-subsidy era to 47.3% of total VRE output in 2023[4], driven by provincial policies phasing out VRE guaranteed purchase in favour of market entry. This follows the broader trend of market expansion across the system's supply side (see Figure 2).

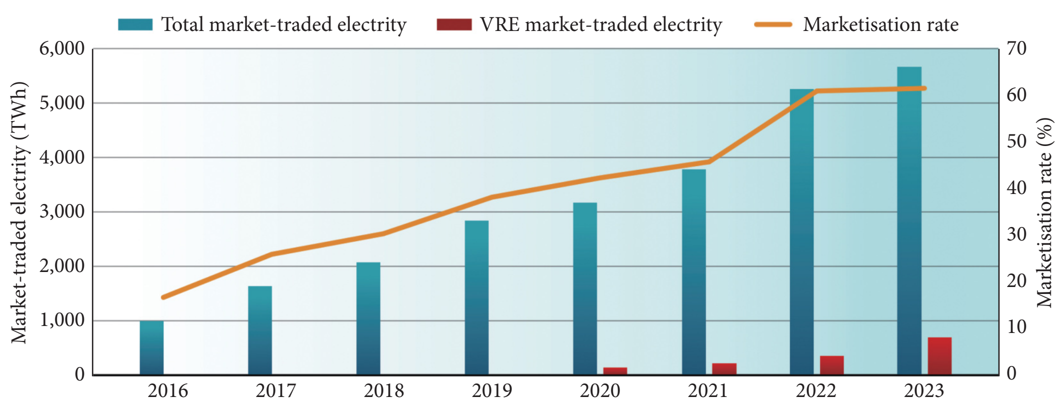


**Fig. 2 Trends in market trading of electricity.** Note: Quantities of market-traded VRE electricity are shown in red[15], and that of electricity from all sources in blue. The orange line (marketisation rate) depicts the proportion of all power that is sold via market-oriented channels[14].

These shifts imply changes to the size of different components of the power market system. For the generation side, all thermal power is integrated into market trading, while VRE is partially sold through guaranteed purchase policies, with the remaining portion participating in the market. On the consumer side, when purchasing electricity, not only do users bear the on-grid electricity prices of generators, but they also incur costs for transmission and distribution, line losses, system operation, as well as government funds and other expenses. Currently, residential and agricultural users continue to follow fixed electricity prices set by the government, while industrial and commercial users have the option to directly participate in market trading or engage in transactions through grid proxy services.

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## 2 Literature review

### 2.1 Research status of market entry risks for renewable energy

With the deepening of China's electricity market reform and renewable energy's market entry, renewable energy investors are confronting uncertainty in revenue expectations caused by multiple risks[16]. Firstly, the shift from fixed feed-in tariffs to market-oriented transactions has transformed the pricing mechanism from unified government subsidies to competitive market pricing, exposing renewable energy to electricity price-related risks[17]. Secondly, the dispatch logic has also changed from full guaranteed purchase to grid-connected power generation after winning bids, subjecting renewable energy to electricity production-related risks. In recent years, research on the market entry risks of renewable energy and relevant policies has become a research hotspot in academia.

Regarding the price risks arising from renewable energy's market entry, scholars argue that they primarily manifest as electricity price volatility and downward price risk. Among these, price volatility risk stems from the inherent intermittency and volatility of renewable energy technologies. Under market-oriented mechanisms, output fluctuations of intermittent resources such as wind and solar power directly affect spot prices. Rai et al.[18] indicates that the increase in VRE penetration will significantly amplify the extreme volatility of spot prices Therefore, factors influencing renewable energy output—such as meteorological conditions[19], resource endowments[20], and power system regulation ability[21] —will indirectly induce market price fluctuations. Meanwhile, downward price risk is also caused by multiple factors, among which the most prominent is that low-cost technologies replace high-cost ones as marginal generation units driven by market competition. Halttunen et al.[22] detailed these merit order effects, with initial estimates of how much rising renewable capacities may reduce the prices secured. Diana also indicates that with the increase in VRE penetration rate, the market clearing price will decrease significantly due to the merit-order effect[23].

In terms of the electricity volume risks associated with renewable energy's market entry, their causes and impacts are more complex. Firstly, they result from renewable energy absorption challenges rooted in technical factors. Due to the inherent volatility and intermittency of renewable energy, the electricity volume risk will be significantly amplified when there is a high penetration of new energy without adequate energy storage or peak-shaving measures[24]. Secondly, the risks are exacerbated by the current overcapacity, which arises from the faster growth rate of renewable energy development compared to that of electricity demand on the consumption side[25]. In addition, some researchers note that technical curtailment of distributed renewable energy directly causes output risks and thus impacts project revenue expectations[26].

### 2.2 International experience for mitigating renewable energy market entry risks

Both China and the UK are leading the low-carbon energy transition. China leads the world by a wide margin in renewable energy investment, while the UK, through its CfD mechanism, blazed the trail in the large-scale deployment of offshore wind power. China's ongoing electricity system reform is shifting from a highly state-regulated power system toward an increasingly liberalized market-oriented system; meanwhile, as one of the world's first countries to liberalize its electricity market, the UK's power system is currently undergoing continuous adjustments to adapt to the demands of the energy transition. Despite differences in scale, starting points, and institutional frameworks, both countries now face a series of similar challenges as they strive to align their power systems with new technologies. The commonality of these challenges presents opportunities for policymakers in China and the UK to learn from each other's ideas and experiences while advancing their respective power sector reform agendas. This section summarises essential features of the UK journey with reference to renewable energy investment, culminating with the rationale for and experience of CfDs. And then explain the joint challenges facing both countries in China and the UK and options to sustain the growth of renewables investment.

#### *2.2.1 The UK experience (the first 20 years, 1990–2010)*

When the UK first liberalised its electricity system in 1990—both selling state-owned assets, and injecting competition—a dominant question was around operation and financing of nuclear power. The government introduced the Non-Fossil Fuel Obligation (NFFO), which obliged electricity suppliers (i.e. companies selling to final consumers) to procure a certain percentage of electricity from non-fossil sources. While primarily designed to ensure the economic viability of nuclear generators, 5% of the funds in the NFFO were set aside to support renewable generation[27].

As attention turned to renewables, there were five bidding rounds for capacity, procured through a central Non-Fossil Purchasing Agency, which awarded contracts to the cheapest bidders for (mainly) 20-year fixed price contracts. The additional costs—both of renewables, and the nuclear fleet—were paid for by a levy on electricity consumers. Whilst the NFFO succeeded in getting renewables launched, it suffered from the "winner's curse" of largely unregulated auctions (i.e. the incentive for bidders to gamble on extremely low-priced bids, and auction outcomes to select those most optimistic bids). With no significant penalties for withdrawal, a substantial proportion of awarded NFFO projects never went ahead[28].

Two major changes occurred from 2000. In the original privatisation process, competition was conducted through a central pool. A national spot price emerged based on generation bids (to sell at a specific price), and offers to buy, with a top-up charge added to the spot price to fund recovery of investment costs. Due to concentrated market power, however, by the late 1990s, costs and prices increasingly diverged. In 2000, the government moved to bilateral contracts, using competition to reduce the cost–price gap. This change also inevitably removed the capacity top-up. Second, from 2000, the government replaced the NFFO supports with Renewable Obligation Certificates (ROCs), alongside feed-in tariffs for smaller renewables installations (mainly PV). The generators received ROC certificates, which they could sell to suppliers who were, again, required to meet a mandated percentage of renewables generation (a form of portfolio standard similar to the Chinese GEC system). In practice, the value of ROCs hovered around £50/(MWh), which for most of the period was more than the wholesale electricity price, thus more than doubling the revenues to renewable investors.

From about 2005, the VRE growth occurred alongside rapid increases in the wholesale electricity price driven by the large price increases in all fossil fuels. In the context of higher overall electricity prices, the cost of renewables thus attracted more political attention. The industry continued to insist that renewables required substantial subsidies, not least because of the large uncertainties around wholesale electricity prices. As summarised by Grubb and Newbery[29]. Banding reforms in 2009 established rules for some less mature technologies to get multiple ROCs. Notably, offshore wind was awarded two ROCs for every MWh of output, in effect a subsidy of about £100/(MWh) over and above the wholesale electricity price.

#### 2.2.2 UK CfDs from the 2013 UK electricity market reform

At the end of the 2000s, two official assessments argued that the system had to change: The UK's new Climate Change Committee warned in 2008 that the government's climate objectives would be almost impossible given the existing structures, whilst in 2009 the energy regulator concluded that energy security itself was at risk due to low levels of investment in the liberalised market. A new government in 2010 embarked on a major set of reforms which culminated with the 2013 Electricity Market Reform. Alongside a carbon price floor and a capacity market, this introduced (investment-related) CfDs as a wholly new instrument to support renewables investment through private finance. Such CfDs are 15-year contracts which in effect offer a fixed price for electricity generated, but are implemented through a contract which pays generators the difference between the wholesale market spot price, and a fixed strike price.

Technically, the payment settlement formula for the 15-year CfD is

$$R_{\mathrm{CfD}} = \sum Q \times (p_{\mathrm{strike}} - p_{\mathrm{ref}}) \tag{1}$$

$R_{\mathrm{CfD}}$ represents the revenues received by a generator with a CfD, $p_{\mathrm{strike}}$ represents the generator's strike price, $p_{\mathrm{ref}}$ represents the reference price (the day-ahead price), and $Q$ represents the quantity of electricity generated and sold.

Note that CfDs are not technically a subsidy: they are a mechanism to stabilise revenues, underwritten by government. The specific aim is to reduce investor risk, and thereby to reduce the financing costs of private investment capital (i.e. interest rates and cost of equity investments). Whether or not CfDs are a subsidy, or a net saving, depends on how the CfD strike price compares to the long-run wholesale price of electricity.

#### 2.2.3 Outcomes of UK CfDs

The CfD system and its institutional architecture took several years to design and legislate. To minimise further delays, the government promptly issued a first round of administered contracts based on negotiations (including for a nuclear power plant, as well as wind and other renewable energy projects). After that, CfDs were priced and allocated through pay-as-clear, reverse-price auctions. Companies bid project specific capacities for specified strike prices, and the government selects projects from the cheapest bid up (within a given category), until a predefined overall budget is exhausted. Along with this and rigorous pre-qualification criteria, additional mechanisms ensure commitments to projects and minimize the risk of "winners curse" outcomes of unviable projects.

This system of CfDs achieved remarkable results. Given the security and predictability of the price received for output, private capital poured into renewable energy. With the introduction of the first Auction Round (AR1) in 2014 for these 15-year contracts, costs fell sharply across all the major renewable technologies. In 2015, following a new government effectively banning onshore wind energy (largely due to internal party politics), attention turned to offshore wind. The subsequent progress of offshore wind in CfD auctions is summarised in Figure 3.

Overall, the results were dramatic: 1) In 2013, after a decade of support from the ROCs, the UK had less than 4 GW of offshore wind capacity. By 2024 this had grown to almost 15 GW installed, with more than an additional 12GW already in progress through the contracts awarded in the 2022 and 2024 auctions. 2) Within a decade, the cost of offshore wind fell by more than a factor of three, from over £150/(MWh) in 2013 to around £40/(MWh) in 2022 (measured in 2012 GBP). Auction prices did, however, climb again in the 2024 auction for reasons described below.

Analysis of the causes of this dramatic cost decline points to four contributing factors[32]:

(1) Innovation through research and development, both public and private, being stimulated by industrial collaboration convened through a government-backed Offshore Wind Accelerator, combined with the scale of the growing market;

(2) Learning-by-doing, as experience revealed lessons and areas of improvement;

(3) Scale economies, for example in turbine size and supply chains;

(4) Financing costs: the interest rate charged for private finance of renewables fell substantially as the perceived risks reduced, and as the CfDs provided stable and more predictable revenues. This also facilitated a move from reliance mainly on equity funding to a far greater role for cheaper bank finance. Empirical analysis focused on the UK indicates that financial development will significantly incentivize renewable energy investment[33].

In summary, numerous studies by scholars both domestically and internationally have clearly identified the risks associated with integrating renewable energy into electricity markets. However, existing studies have not conducted a targeted analysis of the mechanism of action of various renewable energy support policies from the perspective of mitigating various market entry risks.

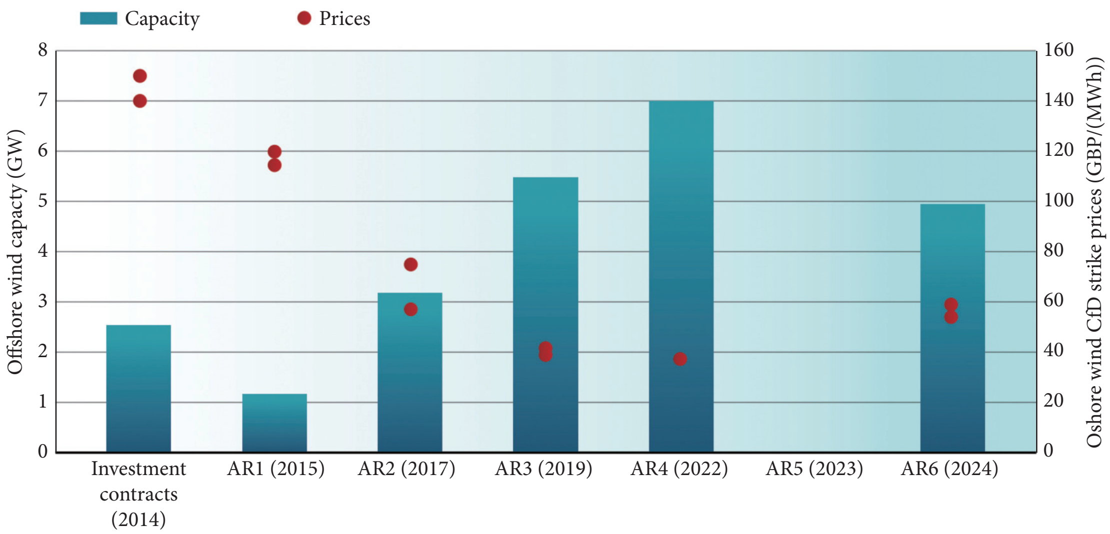


**Fig. 3 UK offshore wind CfD auction outcomes (2014–2024).** Note: The blue bars show the capacity of awarded CfDs, at prices shown by the red dots (in 2012 GBP), in each of six auction rounds (AR1–AR6). These followed initial government contracts arising from direct negotiations (2014). Some years have multiple prices due to varying start dates. Source: Grant Thornton and Poyry[30] and Low Carbon Contracts[31].

Based on this backdrop, this study aims to systematically address the following core research questions: (1) What are the key risk feedback mechanisms and pathways that hinder VRE investment within the specific context of China's electricity market transition? (2) What are the limitations of the current green certificate market and medium- to long-term contracts in managing these risks? (3) How can international experiences, particularly the UK's CfDs, inform the design of a CfD mechanism tailored to China's institutional framework to simultaneously mitigate both price and capacity risks? To address these questions, this research will employ a mixed-methods approach combining provincial empirical data analysis, a system dynamics framework based on CLDs, and in-depth comparisons.

## 3 Methodology

### 3.1 Causal loop diagram

To address the research question explored in this study, we employ CLDs within the system dynamics (SD) methodology to illustrate the positive and negative feedback loops influencing renewable energy investments under market-oriented reforms. Firstly, CLDs excel at unpacking the causal mechanisms underlying market risks. By mapping feedback loops, they enable the visualization of how interconnected factors co-evolve to generate risks including electricity price volatility, revenue declines for renewable energy generators, and oversupply-induced curtailment. Secondly, pinpointing the causal loops influencing renewable energy investments facilitates the design and implementation of targeted incentive policies, which fosters positive feedback loops while mitigating negative ones.

Regarding the construction methodology of the CLD, this study developed the framework through the finding of literature review and repeated expert workshops and consultations, with the participation of experts including Chinese and British policymakers, industry analysts, and scholars from research institutions. Specifically, we organized multiple rounds of online seminars to deliberate on the development of renewable energy policies and electricity markets in China and the UK, laying the groundwork for policy mutual learning between the two countries in this study. Furthermore, during the construction of the causal loop diagram, we convened a two-day large-scale offline workshop involving experts from renowned universities and research institutions — including the UK Government, World Resources Institute (WRI), Energy Research Institute of the National Development and Reform Commission (NDRC) of China, University of Oxford, and University College London (UCL). During the workshop, group discussions were conducted via brainstorming sessions focusing on distinct themes related to factors influencing renewable energy investments. Through these deliberations, we validated the relevance of the identified variables and causal relationships to real-world market operations, supplemented specific factors that may not have been fully addressed in the existing literature, further refined and revised the feedback loops, and clarified the operational pathways through which existing policies shape renewable energy profit expectations and investment incentives.

### 3.2 Quantitative analysis and data sources

This study combines empirical data to analyze power price fluctuations and the risk of power price decline, and uses the future low-carbon power transition pathways obtained through model prediction to simulate electricity quantity risk. The data related to verifying power price risk is derived from publicly disclosed power transaction data and market operation statistical reports of provincial power trading centers, covering the power price dynamics of different trading periods and varieties. For predicting electricity quantity risk, the simulation results of the RESPO (Renewable Energy Siting and Power-system Optimization) model developed by Zhang et al. from Tsinghua University[34] are adopted. As a high spatiotemporal resolution energy system optimization tool, this model focuses on China's 2060 carbon neutrality target. It synergistically optimizes the siting and layout of renewable energy sources such as onshore wind, offshore wind, utility-scale solar, and distributed solar, as well as the planning and construction of supporting infrastructure including inter-provincial transmission corridors, pumped hydroelectric storage, electrochemical storage, and long-duration energy storage. The model systematically integrates key influencing factors such as land use constraints, renewable energy resource endowments, grid integration and absorption capacity, technological cost evolution, and policy orientation, enabling accurate simulation of the power source structure adjustment, electricity supply-demand balance, and full-time operation status of the future power system during the low-carbon transition.

Based on the model's simulation outputs, we calculated the proportion of time in 2030 during which the output of variable renewable energy (VRE), nuclear power, and must-run thermal power exceeds electricity demand across all provinces. This metric serves as the basis for assessing the volume risk induced by the large-scale development of renewable energy in each province. Notably, we treat nuclear power plants and combined heat and power (CHP) units primarily engaged in heating as "must-run" units lacking downward dispatch flexibility during the heating season. This assumption is grounded in China's current technical constraints and operational practices: nuclear power plants typically operate as base-load units due to safety and technical considerations, while CHP units during the winter heating season face a rigid minimum output threshold to ensure residential heating supply. While theoretically, extreme price signals could incentivize limited adjustments in some technologically advanced CHP units, most thermal power plants in China derive their revenue not from the spot market but from long-term contracts that lock in earnings in advance. Consequently, even during periods of negative or low electricity prices, thermal power plants have no economic incentive to engage in peak shaving to avoid revenue risks if these periods are covered by long-term contracts. In fact, such peak shaving actions could even lead to the loss of heating-related income. Therefore, our assumption is justified under the current policy and market conditions.

## 4 Results and discussion

### 4.1 Challenges for sustaining VRE investment in China

#### *4.1.1 Dampening feedbacks of cannibalisation*

Based on the previous literature review and expert discussions, we have developed a CLD of renewable energy market entry risks in the market environment, as shown in Figure 4.

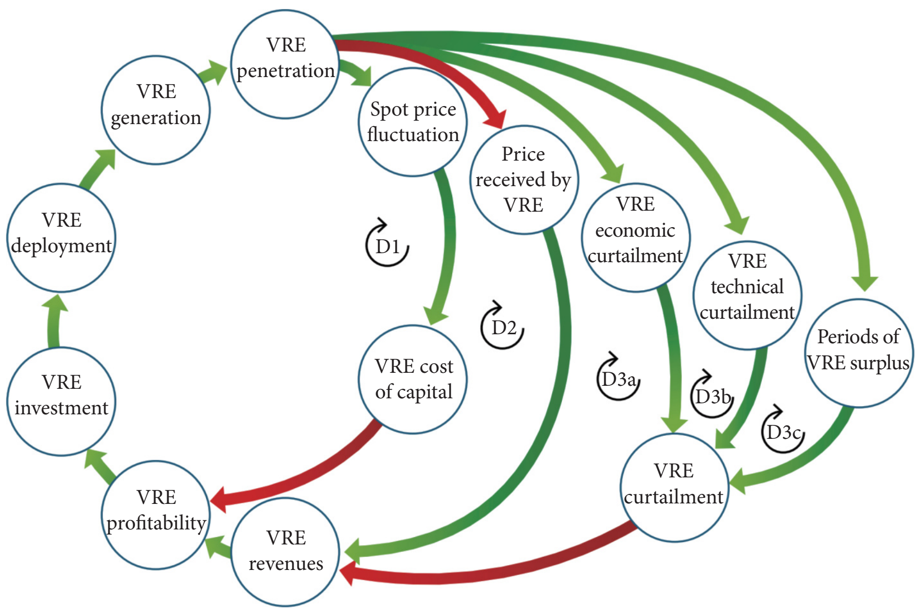


**Fig. 4 CLD showing multiple channels of VRE revenue cannibalisation.** Note: Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). The letter "D" denotes dampening feedback loops.

Specifically, three dampening feedbacks act through the following channels:

(1) Merit order price reduction (loop D2 in Figure 4). As VRE penetration rises, grids will experience periods of high supply during time of VRE generation (e.g. midday peak). Higher-cost generation sources may be pushed out of the merit order, and will be needed less often. This will reduce the market clearing price during periods of high VRE generation, reducing VRE profitability.

(2) Volatility (loop D1 in Figure 4). High levels of VRE penetration increase volatility of spot market prices, reduce the predictability of market returns, and increase the investment risks of renewable energy while the system is transitioning. This is particularly true insofar as uncertainty over future trends in supply, demand, and the generation mix create uncertainties regarding potential revenue capture opportunities. As liberalisation increasingly exposes VRE projects to price signals, these uncertainties may cause financiers to reassess risk premiums and interest rates, leading to an increase in project financing costs.

(3) Volume risk (loops D3a, D3b, D3c in Figure 4). Besides price risks, the expansion of VRE supply also increases volume risk, which refers to uncertainties regarding the ability of VRE projects to sell the power they generate. Inability to sell power generated can arise from technical curtailment (when grids are unable to absorb VRE due to network or system constraints), economic curtailment (when VRE is bid out of dispatch), or VRE surplus events (when instantaneous VRE generation surpasses total demand). This volume risk creates additional revenue uncertainty, weakening incentives for further investment.

In Chinese provinces where the renewable share of generation is highest, there are already signs that increasing VRE penetration is beginning to lower electricity prices. For example, spot prices in Shanxi and Shandong increasingly exhibit patterns characteristic of systems with growing VRE (especially solar) penetration—such as very low prices during daylight hours (see Figure 5) Some research indicates that with rising PV installed capacity and daytime output, PV power often becomes the power system's marginal unit, leading to a structural drop in spot market intraday clearing prices.[35,36]

Over the mid- to long-term timescales, however, decreases in average spot prices to date are probably more likely to have been driven by falling coal prices (see Figure 6). To address the cannibalisation issue, policy must break the dampening feedback present in Figure 5. The sale of GECs (with tightening Renewable Energy Portfolio Stardard (RPS) targets) could increase the profitability of renewables sold in the spot market, weakening dampening feedback D2, but it would not reduce either the price or revenue volatility in a system with growing VRE penetration (feedback loop D1), or volume risks associated with curtailment (loops D3a, D3b, D3c). Contracts-for-Differences (CfDs), on the other hand, can potentially break all three feedback loops, subject to various policy design choices.

The volatility of revenues, and the way this deterred (and raised the cost of) private investment, was the principal reason for the UK abandoning its ROC system. However, there was also an increasing recognition that ROCs would not provide any protection against volume risks associated with periods of surplus

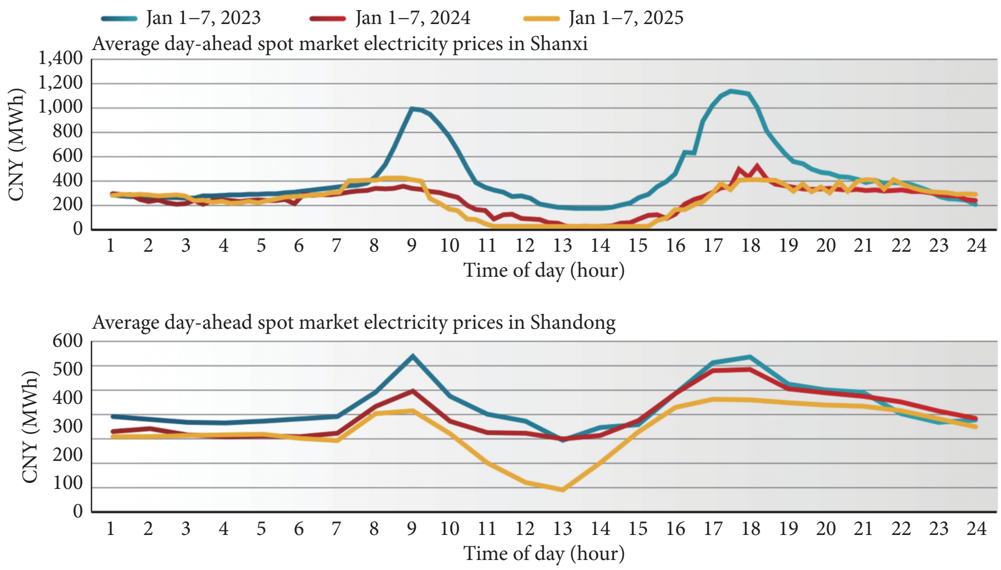


**Fig. 5 Average day-ahead spot market electricity prices in Shanxi and Shandong during 1–7 Jan 2023, 1–7 Jan 2024, 1–7 Jan 2025. Data source: Shanxi and Shandong electricity trading centers.**

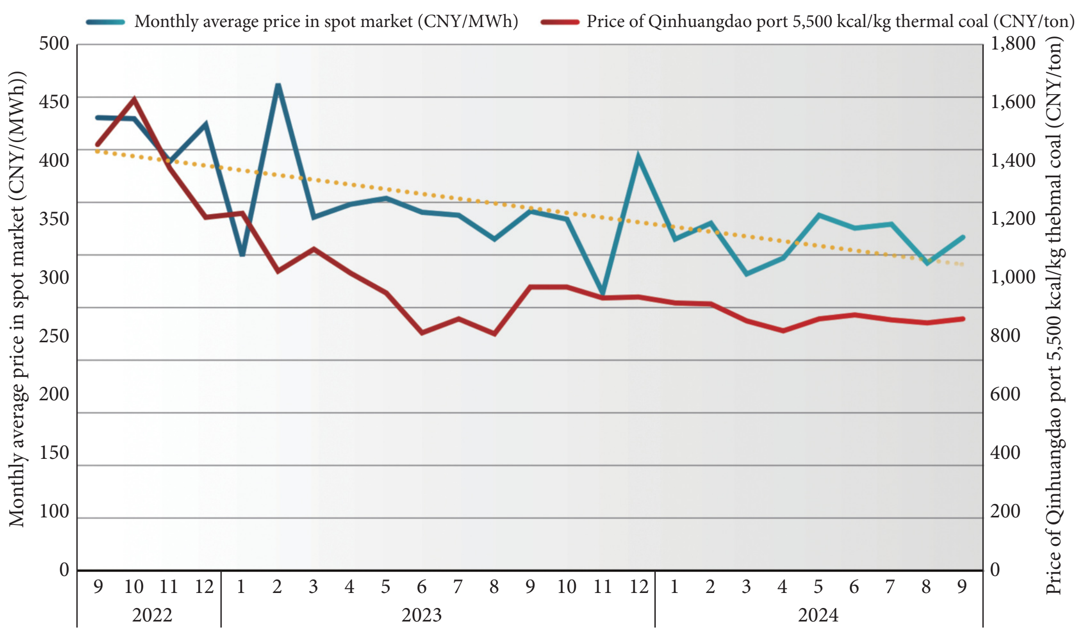


**Fig. 6 Comparison between Shanxi electricity spot prices and coal price.** Note: The blue line shows the monthly average spot market price in Shanxi, and the yellow dotted line is a trendline for this data. The red line shows the price of Qinhuangdao port 5,500 kcal/kg thermal coal. Data from Shanxi Electricity Trading Centre and Wind database.

generation. Furthermore, ROCs create spot market distortions by incentivising generators to submit negative bids in the wholesale market—to pay £30/(MWh), for example, if it enables them to find a buyer for their power, and thereby get a ROC credit worth £50/(MWh). In 2023, Great Britain had 214 hours of negative prices in the day-ahead electricity market — a tripling from the previous year — and the frequency is rising rapidly[37]. Negative wholesale price events are becoming increasingly frequent across Europe, and are already starting to deter renewables investment[38].

### 4.1.2 Potential generating surplus and negative prices

Brown et al. highlight the scale of the challenge in the UK: given the high ambition for renewables, they estimate that by 2030, nuclear, wind, and solar may together exceed demand (on an hour-by-hour basis) for roughly half of the day, on average[39]. Negative wholesale prices are driven by misaligned incentives for both generators on ROCs and those on early rounds of CfDs, which will bid negative in the wholesale market to secure their top-up payments.

To remove the incentive for new generators to drive prices further below zero, the UK government changed the CfD rules in 2022 to preclude new generators from receiving top-up payments to their strike price whenever the reference price (in the day-ahead market) is negative. Whilst this tackles the operational distortion, if and as growing periods of surplus do lead to more negative prices, this does, however, introduce more risk into the CfDs. Compensating for this risk presumably contributed to the higher CfD prices in the most recent CfD auction in 2024. This tension between investment efficiency and operational distortion, set off by negative prices, is one of the factors motivating the UK's current REMA process and consideration of new approaches.

In 2024, the wind and solar penetration, at 18.6%, was about half of that in the UK, where VRE generated 36% of electricity. However, provincial penetration levels vary considerably within China. The provinces most advanced in the transition are already experiencing penetration levels similar to, or higher than, that of the UK, such as Qinghai (44.8% in 2023)[40], Hebei, and Gansu. Most provinces had a solar and wind share of generation in the range of 10%–20% in 2023, substantially lower than that of the UK but growing on a similar trajectory[41]. The spread of results in Figures 7 and 8 below show how the frequency and magnitude of renewable surplus could vary widely between province-level regions in 2030.

For China, a modelling study carried out using the Renewable Energy Siting and Power system Optimisation (RESPO) model developed by Tsinghua University aims to estimate how often the supply of renewable power will exceed power demand in 2030 in each province. The increasing frequency of surplus events poses significant risk to VRE revenues, both in terms of volume risk (some VRE generation will need to be curtailed) and price risk (regardless of specific pricing arrangements, prices during these events are likely to be extremely low, reflecting the real-time value of VRE generation in that moment).

To represent the frequency with which the output of renewable energy exceeds demand, we first calculate demand in each provincial-level region. Two scenarios are considered: the first

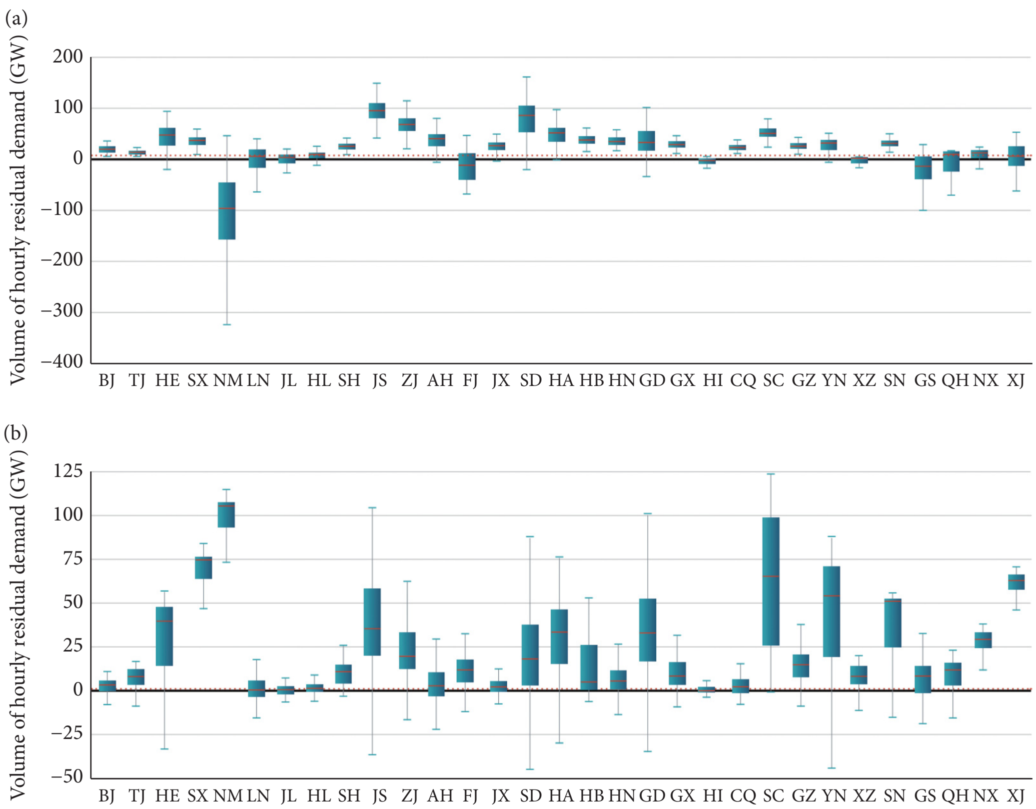


**Fig. 7 Residual load projections for each Chinese provincial-level region in 2030.** Note: Each box represents 8,760 data points for the residual loads during each hour of the year 2030. Residual load is calculated by subtracting VRE, nuclear, and must-run generation from total projected demand. Subfigure (a) assumes zero interprovincial flows. Subfigure (b) incorporates interprovincial transmission. Red lines are medians, boxes show interquartile range, and whiskers extend to the maximum and minimum values. A red dotted line at zero indicates a perfectly balanced supply and demand situation. The abbreviations for China's provincial-level administrative regions are derived from the national standard GB/T 2260-2007[42]. The Hong Kong, Macao, and Taiwan are not included due to data available.

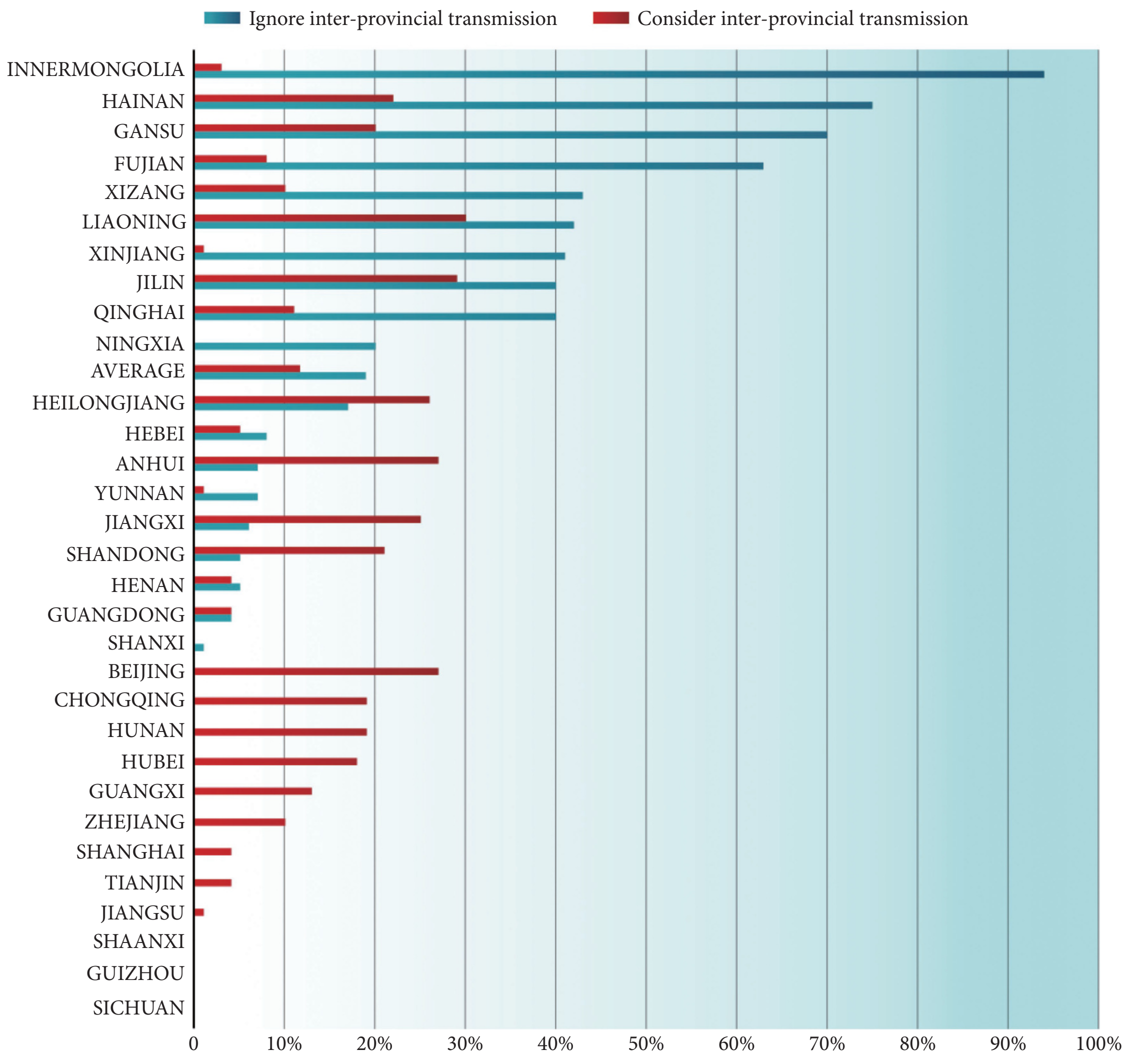


**Fig. 8 Prevalence of net negative residual load for each Chinese provincial-level region in 2030.** Note: Residual load is calculated by subtracting VRE, nuclear, and must-run generation from total projected demand. Percentages along the $x$ axis indicate the proportion of time that residual load is projected to be net negative. For example, a value of 20% indicates that for 20% of hours in 2030, VRE, nuclear and must-run thermal generation is expected to together surpass total demand. The Hong Kong, Macao, and Taiwan are not included due to data available.

assumes zero inter-provincial flows, whereas in the second scenario we allow for inter-provincial transmission. In the second scenario, the supply of renewables is compared to the sum of provincial demand plus net exports. Then, after deducting generation from must-run technologies (including nuclear power and combined heat and power plants) and VRE output, we obtained the hourly residual power demand in 2030. It is acknowledged that negative prices may induce greater flexibility for nuclear and combined heat and power plants, but for the sake of simplicity, these plants have been assumed to be must-run. A value below zero indicates that over the course of the year in 2030, total renewable power generation is projected to surpass total demand. Data are from Zhang et al[34].

Figure 7 shows that when interprovincial transmission is included, median residual demand is either close to zero or positive, for all provinces. However, many provinces are still projected to experience net negative residual demand for a significant proportion of the time. Figure 8 shows the proportion of time in which the supply of VRE, nuclear, and must-run thermal generation is projected to exceed electricity demand in 2030 for each province, including simulations that both include and ignore cross-provincial transmission. It can be seen that interprovincial transmission greatly reduces the frequency of renewables exceeding power demand in power-exporting provinces, notably Inner Mongolia and Xinjiang, while increasing the frequency in some power-importing provinces, such as Beijing and Tianjin. Most importantly, Figures 7 and 8 represent a substantial change compared to the situation at present. We project that nine provinces will experience frequent surplus generation events (in the range of 20%–30% of the time) in 2030. This represents a significant volume risk, in addition to the price risk faced by renewables. Given the long payback period of VRE investments, this trend threatens to erode market-based revenues of VRE installed today.

### 4.2 Policies for renewables investment in a competitive electricity market

#### *4.2.1 Dampening feedbacks with GECs and portfolio standards*

China's Green Electricity Certificate (GEC) scheme has to date had very low prices, far too low to meaningfully support investment in renewables. Scholarly research indicates that when the investment cost of renewable energy is equivalent to or higher than that of non-renewable energy, the incentive effect of GEC will be lower than that of the fixed feed-in tariff policy[43]. To buttress the system in the post-subsidy era, China launched the Renewable Energy Portfolio Standard (RPS) system in 2020[44]. The RPS sets targets for renewable energy as a share of power sold (for state-owned electricity distribution companies, retail electricity companies and independent retail electricity companies), and as a share of power consumed (for electricity users who purchase electricity through the electricity wholesale/merchant market and companies that operate their own power plants). These targets are updated annually by the National Development and Reform Commission (NDRC) for the coming year for each province-level region. Companies buy GECs to demonstrate their compliance with the RPS targets.

Maintaining a GEC price high enough to support investment is difficult because the policy has a builtin dampening feedback: if it succeeds in causing more renewables to be deployed, this will increase the supply of GECs, and that will tend to decrease the GEC price (Figure 9). High GEC prices can, however, be supported by strong RPS targets, as the extra demand created through higher targets acts to inflate GEC prices, potentially forming a kind of price floor mechanism.

The GEC system bears some similarities to the UK's Renewable Obligation Certificates (ROCs). The UK attempted to tackle the problem of price cannibalisation by implementing a "buy-out" price cap. If suppliers do not purchase sufficient ROCs to meet their obligations, they are required to pay this buy-out price per unit of their ROC shortfall. The regulator set the target volume for ROCs deliberately in excess of feasible deployment, in effect, ensuring that the price of all ROCs stayed at the buy-out price. However, this system worked only to a limited extent, partly because the funds suppliers paid to meet their ROC shortfall were distributed back to all suppliers, dampening incentives to deploy enough renewables to meet their obligations.

It is far from clear that strengthening the RPS targets in China to bring the GEC price up—even if the extreme UK solution were adopted—would overcome the challenges facing VRE investment. This is because it would only partially offset one of several more fundamental dampening feedbacks in the wholesale market that risk undermining VRE investment as capacity grows and markets liberalise (Figure 4). To address these risks, drawing on the lessons and outcomes of the UK's electricity market reform, we maintain that the CfD mechanism is widely regarded as a more effective policy instrument for mitigating renewable energy market entry risks. The following sector will first offer a brief overview of China's current CfD policy, subsequently undertakes a comparative analysis with its UK counterpart, and ultimately puts forward targeted recommendations for optimization.

#### *4.2.2 Existing arrangements for power contracts and CfDs in China*

##### *4.2.2.1 MLT market contracts*

Most electricity trading in China occurs through medium- and long-term contracts (MLTs). These are the backbone of power "markets" in China and the vast majority are one-year contracts, supplemented by monthly or other intra-year contracts. Their aim is to reduce contracting and related budgetary risk for parties, especially thermal plants, which need to sign contracts with coal suppliers. For VRE generators, there are two main options for trading: conventional MLT transactions (which only trade electrical energy) and green power trading (which involves trading both energy and GECs). VRE generators typically sign MLT contracts at least a month in advance and must deliver power according to the contract's predefined power curve. In provinces where spot markets have been operating, the deviation between the actual power generation and the contracted power quantity can be covered through spot trading. In provinces without spot markets, the rolling MLT markets can mitigate deviations. However, significant deviations may still incur penalties under some occasions.

Now, in certain provinces where spot markets are established and operational, MLT contracts can be settled financially via a CfD-like mechanism. In economic language, these are fixed-for-floating swaps, relevant when one contract party is exposed to variable prices and wishes to stabilise them. The MLT contract locks in a strike price, with the spot market providing a reference

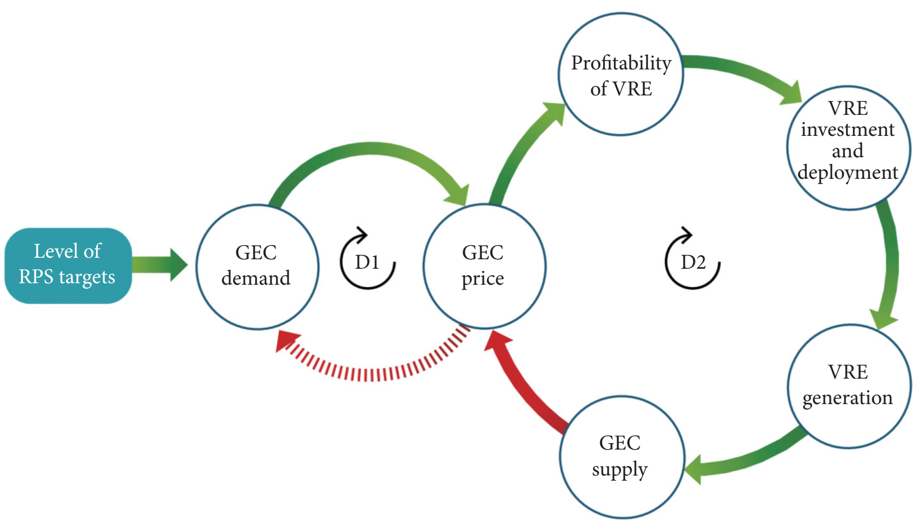


**Fig. 9 CLD showing dampening feedbacks of GEC market.** Note: Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). A dotted arrow indicates a weak or conditional relationship. White nodes represent variables in the system. Blue rectangular nodes represent policy factors. The letter "D" denotes dampening feedback loops.

price to calculate the CfD payments to the MLT counterparty (either the grid or industrial users). Surplus or deficit generation is then traded on the spot market. Compared with the clearing of all electricity volume in the spot market, the MLT market contracts lock in part of the revenue in advance, and to a certain extent, hedge against the risks of electricity volume and price.

This MLT-CfD arrangement is clarified by the Basic rules for electricity spot markets (trial), issued by NDRC and NEA in 2023.

$$\begin{cases} R_{\text{total}} = R_{\text{spot}} + R_{\text{MLT}} \\ R_{\text{spot}} = \sum (Q_{\text{total}} \times p_{\text{spot}}) \\ R_{\text{MLT}} = \sum [Q_{\text{MLT}} \times (p_{\text{MLT}} - p_{\text{ref}})] \end{cases} \tag{2}$$

$R_{\text{total}}$ represents total revenues, $R_{\text{spot}}$ represents revenues from spot market transactions, and $R_{\text{MLT}}$ represents revenues from MLT contracts. $Q_{\text{spot}}$ represents the quantity of electricity sold on the spot market in any settlement period and $p_{\text{spot}}$ represents the spot price during that period. $Q_{\text{MLT}}$ represents the quantity of output covered by MLT contract in any settlement period, $p_{\text{MLT}}$ is the price set in the MLT contract, and $p_{\text{ref}}$ is the reference price, which is equivalent to the spot price in provinces where spot markets are set up.

If we thus assume $p_{\text{ref}} = p_{\text{spot}}$, then rearranging terms then gives

$$R_{\text{total}} = \sum [(Q_{\text{total}} - Q_{\text{MLT}}) \times p_{\text{spot}} + Q_{\text{MLT}} \times p_{\text{MLT}}] \tag{3}$$

This arrangement shows that the portion of revenue represented by $Q_{\text{MLT}} \times p_{\text{MLT}}$ is locked in by the MLT contract, with the remainder dependent on spot trading. Note that, according to this formula, if generators deliver less than their contracted output, they still need to pay the difference between the contracted electricity and their actual generated electricity based on the spot market price, thus maintaining revenue uncertainty. To emphasise however, whilst the mechanism is similar, the MLT-CfDs are totally different in purpose from UK CfDs, in that they protect, annually, year-ahead revenue. Unlike the 15-year CfDs of the UK they are not, in their current form, so relevant to renewables investment. Generally, multi-year CfDs are more conducive to enhancing investor confidence and promoting the development of renewable energy.

##### *4.2.2.2 Government-authorised contracts for renewables*

Recognising the risks faced by renewables, some provinces had taken steps to stabilise revenues using a price difference settlement mechanism, which functions similarly to CfDs. Termed "government-authorised contracts" (GACs), specific implementation details have varied between provinces. The strike prices for different settlement mechanisms are set by provincial governments, not via competitive processes, and are based on the local coal-fired benchmark price. In addition, unlike the 15-year CfDs in the UK, there is no official guarantee period for this mechanism, which can vary depending on the type of project and local policies.

Mooted in 2022 in Document 118, GACs represent a progression from the guaranteed purchase regime. Unlike the MLTs signed between electricity generators and consumers, the government acts as the counterparty for these contracts. The electricity volume covered by the GACs is settled based on the price difference between the strike price and the market reference price, with any costs allocated to industrial and commercial users.

The extent to which these current arrangements limit price and quantity risks for investors in renewable power is summarised in Table 2. The shift to market-oriented trading of renewable power introduces both price and volume risk to developers' revenues, as shown in Table 2. The GAC arrangements in the MLT market limit these risks, but only up to one year in advance. Coupled with the fact that strike prices may be adjusted on a year-to-year basis by governments via non-competitive means, this arrangement may not engender sufficient investor confidence to sustain high levels of deployment, as investment decisions are made according to revenue projections with 20-year time horizons. In addition, the strike price of GACs obtained through non-competitive means is decoupled from the actual costs associated with producing VRE. These shortcomings were, however, addressed in the newly released Document 136, issued in February 2025.

**Table 2 Comparison of effects on price and volume risk of different electricity trading mechanisms in China.**

| | Guaranteed purchase quantity | Quantity covered by MLT contracts | Quantity in excess of that covered by MLT contract |
|---|---|---|---|
| Price risk | None-price is fixed | None for the duration of the contract (typically 1 year) because difference contracts (not an investment-supportive CfD) top up the price of any electricity sold in the spot market to the MLT contract price, within this quantity.<br>Increasing price risk in future years, if MLT prices are influenced by the spot market price. | High-price (for this quantity) is entirely set by spot market. |
| Volume risk | None-quantity is fixed | None in the short-term, if MLT contracts are fully-executed.<br>Increasing volume risk in future years, if RE supply (and must-run thermal) more frequently exceeds total market demand. | High-volume is entirely dependent on spot market. |

##### *4.2.2.3 Document 136 mechanism and comparison to UK CfD*

Most notably, the document establishes a price settlement mechanism for the sustainable development of new energy, which functions similarly to an investment-supportive CfD, building on the GAC concept by introducing competitive reverse auctions and ensuring that power generators can secure stable returns over a multi-year period. Certain details regarding implementation remain undecided, as these will be specified in province-level policy later in 2025, but some general comments can be made based on the NDRC and NEA's directives contained in the document.

Document 136 outlines new pricing mechanisms for VRE projects, with separate provisions for existing projects and new ones that connect to the grid after 1 June 2025. Here, we focus our analysis on the latter mechanism, as it is most relevant for future investment decisions. This mechanism bears some resemblance to the UK CfD, with notable similarities including

(1) Strike price auction mechanism—in both the UK and Chinese-style CfDs, strike prices are set by the highest winning bid in a reverse auction process, with predefined price ceilings set by government.

(2) Two-sided settlement—in both settings, if the reference price is below the strike price, generators receive the difference; if

the reference price is above the strike price, generators pay back the difference.

(3) Mid- to long-term revenue certainty—both instruments are designed to stabilise revenues over the mid- to long-term to de-risk investment. However, the exact time scales differ: UK CfDs are valid for 15 years, whereas the validity of the Chinese versions will align with the necessary duration to facilitate investment cost recovery—likely 8–10 years according to industry experts.

(4) Technology competition—UK CfD auctions are separated by pots; different pots correspond to different levels of technological maturity to ensure that nascent generation technologies do not compete with established ones. In auction round 6 (2024), solar PV, onshore wind, and hydro all competed against each other as established technologies. In China, detailed guidance on this point has not yet been released, but Document 136 encourages using separate auction pots when there are significant differences in technology costs.

However, despite their similarities, the two countries' CfD policies contain major differences. This is not surprising given the vast differences between the two in their governance and policy environments, historical contexts, and progress on the transition. Key differences include

(1) Project-level coverage—the UK CfD covers 100% of a CfD-backed generator's output, whereas the Chinese version provides only partial coverage, subject to provincial government decisions. Initially, coverage will match the proportion of output previously covered by guaranteed purchase policies.

(2) Scale of total capacity coverage—the scale of total UK CfD coverage is set by auction budgets determined by government ahead of each auction round. In China, provincial governments will determine the scale of each round of annual auctions based on progress against renewable energy consumption targets.

(3) Strike price auction floor—Chinese CfD auctions will likely employ price floors to prevent "unhealthy competition" (projects bidding infeasibly low prices to win market share); the UK scheme does not use price floors.

(4) Reference price market—the reference price for calculating UK CfD payments is the day-ahead market price. In China, provinces that have set up functional spot markets are directed to use real-time spot prices as the reference price; those that have not are to use prices from MLT markets.

(5) Reference price calculation—reference prices for CfD-backed assets in the UK are based on the prices received by each individual generator, so each generator receives its strike price for every MWh of power it produces. In the Chinese policy, reference prices are calculated as the average price received by generators of the same technology within a province. This could mean, for example, that the reference price for all onshore wind farms in a province is the same in a given month. Thus, differences in earnings arising from location (e.g. proximity to high-price nodes) or trading strategies will translate to differences in total revenues. As such, two onshore wind farms awarded CfDs in the same year and province may have the same strike price but end up with different total CfD-associated revenues.

(6) Difference payment funding mechanisms—the difference payments for the Chinese CfD are to be funded by charging them as system costs (which mostly fall to commercial and industrial users); in the UK, they are passed through to all customers via retailers.

(7) Implementation governance—UK CfD policy is designed and implemented by the national government. In China, the central government provides guidance and directives (e.g. via Document 136), but exact arrangements and prices are determined by provincial governments.

### 4.3 Possible amendments to CfD design

#### 4.3.1 *Differentiated CfD mechanisms to mitigate investment risks*

In 2022, the UK modified its CfDs to prevent renewables receiving top-up payments when the reference (day-ahead) price is negative. This reduces operational distortions but introduces some risk for investors. It may also be valuable for encouraging storage investment; holders of these CfDs have a strong incentive to prevent negative price events and find off-takers for their energy. This should, in theory, reward any investment in storage with the prospect of increasingly frequent opportunities to buy electricity when wholesale prices, if not negative, are extremely low.

In a fully liberalised system based solely on private finance, as in the UK, the question remains as to how much the CfD may alleviate perceived risks to investors, who may still choose not to build additional renewable capacity. The current CfD design largely removes price risk, but volume risk will remain, and depends on assumptions about how much storage or other flexibility may be developed, and when. The UK government's REMA program is considering two more radical options to enhance investor confidence:

(1) A "deemed CfD" in which the payment received by generators is linked to the "deemed" power generation of each asset—the maximum it could have potentially generated at any given time, instead of being linked to the actual volume of power generated. Revenue is calculated as Eq. (4).

$$R_{\text{total}} = R_{\text{CfD}} + R_{\text{market}} \tag{4}$$

$R_{\text{total}}$ is the total revenue earned by a VRE generator (excluding earnings from ancillary service markets), $R_{\text{CfD}}$ is revenue associated with CfD-related payments, and $R_{\text{market}}$ is revenue earned via selling power on merchant terms.

Total revenue is thus the sum of CfD-associated revenues and those earned from trading in the wholesale market. This differs from the UK's current policy, in which VRE revenues are entirely delinked from market prices, with the exception of negative price events. Revenues from CfDs and the market are given by

$$\begin{cases} R_{\text{CfD}} = \sum Q_{\text{deemed}} \times (p_{\text{strike}} - p_{\text{ref}}) \\ R_{\text{market}} = \sum Q_{\text{actual}} \times p \end{cases} \tag{5}$$

$Q_{\text{deemed}}$ is the quantity that a generator is deemed to have been able to generate, and $Q_{\text{actual}}$ is the actual volume of power generated and sold on the wholesale market. $p_{\text{strike}}$ and $p_{\text{ref}}$ are the strike and reference prices, respectively. $p$ is the market price, and is thus functionally equivalent to $p_{\text{ref}}$ in this example.

The "deemed" power generation quantity would be estimated through site-specific data on asset capacity, weather, and any other relevant factors. This removes price and volume risk related to potential renewable surplus events. The deemed CfD effectively breaks all three of the dampening feedbacks (Figure 4) that threaten to undermine renewables investment. In principle, actual generation could instead respond more flexibly to real-time system requirements, reducing balancing costs and potentially opening the door to increasing ancillary service market revenues.

In practice, these benefits may be more difficult to realise in the Chinese power system, at least as it currently operates. The benefits of enhanced operational efficiency will only be possible if clear price signals are sent through spot markets, yet these remain underdeveloped in almost all provinces. In addition, VRE generators are currently unable to directly participate in the ancillary services market. Conversely however, the most obvious drawback of the deemed CfD—paying renewables even for output that cannot be used—may be lower in China than that in the UK due to projected future demand growth. In addition, as the deem-CfD weakens the guiding role of market signals, it may lead to excessive incentivization of VRE investments.

(2) Alternately, a capacity-based CfD would provide a fixed payment based on a VRE asset's capacity. The revenue would be de-linked from generation, and so insulated from any price or quantity risks. Its operation would be entirely driven by market incentives, which should tend to support system flexibility and operational efficiency. Revenue is calculated as Eq. (6).

$$\begin{cases} R_{\text{total}} = R_{\text{CfD}} + R_{\text{market}} \\ R_{\text{CfD}} = C \times p_{\text{strike}} \\ R_{\text{market}} = \sum Q \times p \end{cases} \tag{6}$$

As with the deemed CfD example above, $R_{\text{total}}$ is the total revenue earned by a VRE generator (excluding earnings from ancillary service markets), $R_{\text{CfD}}$ is revenue associated with CfD-related payments, and $R_{\text{market}}$ is revenue earned via selling power on merchant terms. $C$ is the CfD-backed generator's capacity (in MW), and $p_{\text{strike}}$ is the strike price. $Q$ is the quantity of power generated and sold on the wholesale market, and $p$ is the price at which it is sold.

In this model, the CfD would provide generators with a regular, fixed payment based on their installed capacity (¥/MW or £/MW). Beside their CfD-associated revenues, however, generators could also operate in markets on merchant terms. This would promote efficient operational decisions as generators seek optimise their trading strategies, but would expose generators to a degree of volume and price risk on a day-to-day basis.

With a capacity-based CfD, the optimal share of VRE revenues paid from the fixed capacity payments (relative to the share from market activity) could in principle be revealed through auctions to award the capacity payments. The three dampening feedbacks shown in Figure 4 would be weakened, but not eliminated, as generators would still earn variable revenues by selling power on the wholesale market.

At the time of writing, the UK is yet to decide between the options of maintaining the current CfD design or choosing one of these two other options, noting some additional variations. Unlike the UK, where power sector policies are almost always implemented nationally, China often takes advantage of the diversity of its provinces to pilot different approaches. An example is the freedom for provinces to choose between whole system, zonal, or nodal pricing within the new spot markets. Given the significant uncertainties around how effectively CfDs will support continued renewable investment in future, there could be advantages to allowing provinces to test different approaches, including the standard CfD, deemed CfD and capacity-based CfD designs.

#### *4.3.2 Trade-offs and consideration in the implementation of China's provincial-level CfD schemes*

When implementing the CfD mechanism, China's provincial governments should adopt region-specific approaches and strike a balanced trade-off when determining key parameters such as the contracted electricity volume, upper and lower bounds of the contracted price, and implementation duration. Firstly, broad coverage of all VRE projects can maximize investment incentives, but it may impose substantial fiscal subsidy burdens or upward pressure on end-user electricity prices. Secondly, a relatively small coverage scale coupled with a low contracted price risk leading to vicious competition, where even VRE projects admitted to the CfD scheme struggle to secure stable returns—thus defeating the original purpose of the mechanism. Therefore, to effectively incentivize renewable energy investment, sufficient contracted electricity volume must be guaranteed. Meanwhile, to avoid excessive subsidy pressures, a reasonable contracted price should be set, with such price dynamically linked to the province's renewable energy development status and prevailing electricity market conditions.

Under Document 136, the total volume of contracted electricity under the CfD mechanism is tied to provincial renewable energy consumption responsibility weights. This means that renewable energy power capacity that exceed provincial renewable energy consumption targets will not qualify for the revenue protection offered by the contracted electricity volume. To incentivize renewable energy investment while safeguarding project revenues, local governments must issue clear, reasonable planned capacity guidelines—with such planned renewable energy capacity aligned with local renewable energy consumption responsibility weights. The rationale is as follows: the renewable energy consumption target for a given period dictates the total contracted electricity volume available under the mechanism. As more renewable energy projects participate in the mechanism, the contracted electricity volume allocated to each individual project decreases. Thus, only through the implementation of clear guidelines to control the total scale of renewable energy development can sufficient contracted electricity volume be ensured, and can vicious competition—which would push the contracted price down to levels inadequate for recovering investment costs—be prevented.

Similarly, if certain provinces pilot innovative mechanisms such as deemed-CfD and capacity-based CfD, equal emphasis should be placed on aligning these schemes with local development plans. Specifically, the deemed renewable energy generation volume under a deemed-CfD and the guaranteed renewable energy development capacity under a capacity-based CfD can be set with reference to the outcomes of renewable energy development plans. Firstly, development and utilization plans are formulated to minimize transition costs or maximize social benefits while adhering to various constraints—including energy supply-demand balance, renewable energy consumption responsibility weights, and territorial spatial planning—thereby minimizing potential increases in transition costs. Secondly, anchoring deemed generation volume to planning outcomes helps ensure the fairness, transparency, and scientific rigor of the MRV (measurement, reporting, and verification) system, safeguarding against manipulation by market power. Similar to conventional CfDs, the costs associated with these innovative mechanisms can be borne by local industrial and commercial consumers. Additionally, we propose that electricity users responsible for contracted electricity volume should be eligible for green certificates corresponding to the generated electricity, enabling them to claim the use of green power.

## 5 Conclusions and recommendations

In this paper, we analyse the primary risks facing VRE investment in China under market-oriented reforms, including merit order reduction risk, price volatility risk, and volume risk associated with surplus events. Using causal loop diagrams, we elucidate why these risks are likely to increase over time, and why the existing

GEC system may not adequately incentivise VRE investment in this context. Drawing on decades of experience from the UK's electricity market framework, we propose recommendations for designing differentiated CfD mechanisms to mitigate investment risks and advance renewable energy investments. This includes improving the existing policies in Document 136 and some potential optimization directions. Document 136 promotes the full market-based formation of on-grid electricity prices for VRE. The release of this policy is a crucial step in advancing China's power system reform. However, as a national document, it remains quite vague regarding specific implementation details. There are still many issues that need to be clarified and refined at the provincial level, including:

(1) Multi-tiered planning and coordination. Although Document 136 requires provinces to align renewable development targets with the national plans, it does not clearly state a mechanism to ensure this alignment. Furthermore, since the CfD arrangements deal with generation metrics, not capacity, it remains unclear as to what role the new mechanism will play in promoting VRE investment in the context of national installed capacity targets.

(2) Coordination with GECs. Document 136 states that generators will not receive income from GECs for the electricity volume included in the new CfD mechanism. Therefore, there remains uncertainty regarding the management of the GEC (and RPS) scheme and how they will be linked to the new pricing regime.

(3) Negative price management. The Document 136 mechanism does not specify processes for handling negative electricity prices. Following experiences in the UK, we recommend that if zero electricity prices or negative electricity prices continuously occur for a long time in the spot market, CfD difference payments should not be paid.

(4) Mechanisms to incentivise energy storage deployment. The policy abolishes a mandate that previously required VRE generators to install energy storage, but it does not specify future options to incentivise the development of energy storage through market mechanisms.

(5) Cost allocations remain opaque. Per Document 136, the CfD settlement payments to generators will be incorporated into system operation fees, the bulk of which are currently charged to commercial and industrial users. However, it remains unclear whether the fees should be wholly or partially borne by users, and it is also not clear which types of users should bear these fees, which may lead to questions regarding fairness.

The CfD policy created by Document136 addresses price risk but not the volume risk faced by renewable generators. Our analysis suggests that volume risk could become significant in China within the next five years, especially in provinces more advanced in the transition, and this could quickly become a negative influence on investment decisions. We recommend addressing volume risk both by accelerating development of flexible demand sources to encourage offtake for VRE that would otherwise be curtailed, and by experimenting with different CfD designs, including deemed and capacity-based CfDs, across China's provinces, with the results monitored and compared to inform future policy decisions. Since these two mechanisms decouple renewable energy revenues from actual electricity generation to a certain extent, thereby reducing volume risk, they may lead to excessive incentives for renewable energy investment. In practical implementation, the implementation scale of such mechanisms in pilot provinces should be aligned with the local scale of renewable energy development and utilization, so as to avoid the expansion of transition costs caused by the unregulated development of technologies. For instance, when local governments decide to pilot the deemed-CfD and capacity-based CfD mechanisms, they can determine the support scale in conjunction with local renewable energy development and utilization plans. This not only prevents over-development but also aligns with the national energy development plan, promoting the rational layout of renewable energy.

## Appendix

The division of wind and solar resource zones as described in Table 1 of the manuscript is detailed in Table A1.

**Table A1 Classification of wind and solar resource zones.**

| | Resource area type | Regions covered by each resource zone |
|---|---|---|
| Onshore wind | Ⅰ | All regions of Inner Mongolia autonomous region except Chifeng city, Tongliao city, Xing'an league, and Hulunbuir city; Urumqi city, Ili Kazakh autonomous prefecture, Changji Hui autonomous prefecture, Karamay city, and Shihezi city of Xinjiang Uygur autonomous region. |
| | Ⅱ | Zhangjiakou city and Chengde city of Hebei province; Chifeng city, Tongliao city, Xing'an league, and Hulunbuir city of Inner Mongolia autonomous region; Zhangye city, Jiayuguan city, and Jiuquan city of Gansu province. |
| | Ⅲ | Baicheng city and Songyuan city of Jilin province; Jixi city, Shuangyashan city, Qitaihe city, Suihua city, Yichun city, and Daxing'anling prefecture of Heilongjiang province; all regions of Gansu province except Zhangye city, Jiayuguan city, and Jiuquan city; all regions of Xinjiang Uygur autonomous region except Urumqi city, Ili Kazakh autonomous prefecture, Changji Hui autonomous prefecture, Karamay city, and Shihezi city; Ningxia Hui autonomous region. |
| | Ⅳ | Other regions except Class I, Class II, and Class III resource zones. |
| Solar | Ⅰ | Ningxia Hui autonomous region; Haixi Mongolian and Tibetan autonomous prefecture of Qinghai province; Jiayuguan city, Wuwei city, Zhangye city, Jiuquan city, Dunhuang city, and Jinchang city of Gansu province; Hami city, Tacheng prefecture, Altay prefecture, and Karamay city of Xinjiang Uygur autonomous region; all regions of Inner Mongolia autonomous region except Chifeng city, Tongliao city, Xing'an league, and Hulunbuir city. |
| | Ⅱ | Beijing, Tianjin, Heilongjiang province, Jilin province, Liaoning province, Sichuan province, Yunnan province; Chifeng city, Tongliao city, Xing'an league, Hulunbuir city (Inner Mongolia); Chengde city, Zhangjiakou city, Tangshan city, Qinhuangdao city (Hebei); Datong city, Shuozhou city, Xinzhou city (Shanxi); Yulin city, Yan'an city (Shaanxi); Qinghai province, Gansu province, and all areas of Xinjiang except Class I zones. |
| | Ⅲ | Other regions except Class I and Class II resource zones |

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## Author contribution statement

Jian Han: writing – review & editing, writing – original draft, visualization, software, methodology, investigation, data curation. Ying Zhou & Yang Qu: writing – review & editing, investigation. Max Collett: writing – review & editing, visualization, validation. Michael Grubb & Simon Sharpe: writing – review & editing, conceptualization, resources, funding acquisition, formal analysis. Jun-ling Huang: supervision, project administration. Da Zhang: resources, writing – review & editing, supervision, project administration.

## Data availability

Not applicable.

## Use of AI statement

None.

## Declaration of competing interest

The authors have no competing interests to declare that are relevant to the content of this article. The author Da Zhang is the Associate Editor of this journal. The author Michael Grubb is the member of Advisory Board of this journal.

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