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Trading and Settlement Methods for Full Participation of New Energy in the Spot Market Under China's Mechanism Price Policy

Haitao Huang ¹, Yunlong Ye ^{1,*} and Ning Hu ²

¹ Faculty of Electrical Engineering, Shanghai University of Electric Power, Yangpu 200090, China; hbd_l_huanghaitao@sina.com

² Economic and Technical Research Institute, State Grid Yueyang Power Supply Company, Yueyang 414000, China; whu_ninghu@outlook.com

* Correspondence: yylsuep@mail.shiep.edu.cn

Abstract

Facing China's complex operating environment, in which the spot electricity market is still at an early stage of development and the mechanism price policy for new energy is implemented in parallel, this paper addresses the mechanism adaptability challenges that arise when high-proportion new energy participates in the spot electricity market on a full-volume basis. A trading and settlement mechanism with trading flexibility, multi-timescale coordination, and policy alignment is then constructed. Full-volume electricity on both the generation and consumption sides is incorporated into spot market clearing and settlement, thereby strengthening the role of the spot market in resource allocation. Differentiated bidding, settlement, and responsibility-bearing mechanisms are further designed according to electricity type and participant category, thereby clarifying responsibility boundaries and supporting imbalance-fund allocation. A multi-timescale trading mechanism is constructed to link short-cycle flexible trading, day-ahead bidding, intraday rolling adjustment, and real-time balancing. In addition, a differentiated medium- and long-term contract mechanism and a secondary settlement system are designed to meet the needs of system peak-regulation and market risk management. These designs also support coordination with the mechanism price policy for new energy, priority generation of hydropower and nuclear power, guaranteed electricity consumption, and grid-company agency purchasing. Case studies show that the proposed mechanism can help mitigate market efficiency distortions, improve the adaptability of the spot market to high-proportion new energy, and support the reasonable allocation of policy-related compensation costs and system regulation costs.

Keywords: new energy; mechanism price policy; spot market; trading mechanism; settlement mechanism



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1. Introduction

China continues to advance its carbon peaking and carbon neutrality goals and accelerate the development of a new-type power system. This system is characterized by high shares of new energy and stronger flexibility requirements. Against this background, the installed capacities of wind power and solar photovoltaic (PV) generation have grown rapidly. Promoting the full participation of new energy in the electricity market has therefore become an important direction for both electricity market reform and the high-quality

development of new energy [1]. In this study, new energy mainly refers to wind power and solar PV. In this paper, “full participation” refers to the full-volume inclusion of new energy electricity in spot-market clearing and settlement. It does not mean uniform active price bidding or identical balancing responsibility for all electricity at all stages. Under the transitional arrangement considered in this study, mechanism-covered electricity is included in spot clearing through grid-submitted forecast curves. This category refers to the portion of new energy electricity eligible for off-market price-difference settlement under the mechanism price policy. By contrast, non-mechanism-covered electricity participates in day-ahead trading under a phased arrangement. This category refers to the remaining portion that is more directly exposed to market prices and balancing responsibility. In February 2025, the National Development and Reform Commission and the National Energy Administration jointly issued the Notice on Deepening the Market-Oriented Reform of On-Grid Electricity Pricing for New Energy and Promoting the High-Quality Development of New Energy [2]. The Notice requires all on-grid electricity generated by new energy to be incorporated into the electricity market and priced through market transactions. The policy also establishes an off-market price-difference settlement mechanism to support the sustainable development of new energy. For mechanism-covered electricity, the grid company settles the price difference in accordance with relevant regulations when the average market transaction price deviates from the mechanism price. The scale and proportion of mechanism-covered electricity are determined based on project type, existing policy arrangements, progress in fulfilling the non-hydro renewable energy power consumption responsibility weights assigned by the national authority, and users’ affordability. The mechanism price is formed through voluntary bidding by eligible projects. This policy marks a transition from guaranteed-price accommodation to market-based participation with off-market revenue support. It also creates new requirements for trading organizations, spot-market participation, and settlement coordination.

Existing studies have shown that, as wind power and solar PV penetration increases, coordinated day-ahead, intraday, and real-time markets are needed to mobilize flexibility and support efficient short-term system operation [3,4]. Meanwhile, the market value of variable renewable energy may decline as its penetration increases, because wind and solar output tend to be concentrated in periods of low residual demand and low electricity prices [5–7]. Therefore, new energy market participation requires not only effective spot market clearing but also support mechanisms that balance market-based price formation, revenue stabilization, and risk allocation.

Market premium and feed-in premium mechanisms have become important instruments for promoting market-based renewable energy participation. Under these mechanisms, renewable generators sell electricity in the wholesale market and receive an additional premium or out-of-market revenue adjustment. This design preserves exposure to market price signals while providing revenue support. Germany’s market premium scheme is a representative example: it promotes the direct marketing of renewable electricity, and empirical evidence shows that it has significantly reduced negative-price hours in the German day-ahead market [8]. Recent European studies also show that feed-in premiums have been increasingly adopted as renewable support schemes because they combine market participation with revenue stabilization [9]. However, these mechanisms are generally designed around reference prices, technology-specific market values, or support levels. As a result, they remain limited in addressing the project-specific capture-price, volume, and operational risks faced by wind power and solar PV [10,11].

Government-authorized contracts for difference (CfDs) provide another major support mechanism for renewable energy participation in electricity markets. Under this mechanism, a public entity or government-authorized counterparty signs a long-term

contract with low-carbon or renewable generators and settles the difference between an agreed strike price and a market reference price. The United Kingdom's CfD scheme is a representative case in which low-carbon generators sign private-law contracts with the Low Carbon Contracts Company, a government-owned company [12]. Such contracts reduce developers' exposure to volatile wholesale electricity prices and support investment by providing more predictable revenue streams. Recent studies further argue that CfDs should be understood not only as subsidies but also as risk-management instruments that create long-term markets for stable renewable electricity revenues [13]. Nevertheless, government-authorized CfDs depend on the design of strike prices, reference prices, eligible volumes, settlement periods, and cost-recovery arrangements. When renewable output is stochastic and highly weather-dependent, their implementation may involve relatively high institutional complexity [14,15].

Power purchase agreement (PPA)-based arrangements, medium- and long-term contracts, time-segmented products, and hourly settlement tools provide market-oriented instruments for managing the price and delivery risks of renewable energy. PPAs and long-term contracts can help renewable generators secure part of their long-term revenues while enabling buyers to hedge against spot price volatility. Recent studies on corporate renewable PPAs show that PPA portfolios can be optimized to improve financial performance and reduce offtakers' financial risks [16]. The value and risk of renewable PPAs also depend on capture prices, market volatility, credit risk, contract duration, and delivery profiles [17]. Time-segmented products, contract curves, and hourly settlement tools further refine electricity transactions by aligning contracted quantities with the temporal characteristics of generation and consumption. Recent studies on hourly electricity rights and digital settlement architectures further suggest that finer temporal granularity and digitalized settlement tools can improve the traceability of electricity delivery rights and cash-flow obligations [18]. However, these instruments are essentially commercial risk-management tools rather than policy-based revenue support mechanisms. For wind power and solar PV, forecasting errors and output uncertainty may still result in replacement power costs, imbalance charges, contract price discounts, or more complex risk-sharing clauses.

Overall, existing support mechanisms have promoted renewable energy participation in electricity markets by improving revenue stability, reducing price risks, and refining transaction granularity. However, their ability to support the sustainable development of new energy under full market participation remains limited. Market premium mechanisms provide out-of-market revenue adjustments, but project revenues may still be affected by capture-price risk, volume risk, forecasting deviations, and operational costs. Government-authorized CfDs can stabilize long-term revenues through public-backed contracts, but their effectiveness depends on strike prices, reference prices, eligible volumes, settlement rules, and cost-recovery arrangements. As a result, revenue support remains sensitive to contract design and implementation details. PPAs and medium- and long-term contractual tools can hedge price risks through market-based arrangements, but they may convert renewable output uncertainty into delivery-profile obligations, replacement power costs, contract price discounts, or complex risk-sharing clauses. Therefore, the key unresolved problem is how to provide sustainable revenue support for new energy while preserving market-based price formation and preventing market-participation risks from unduly weakening its investment viability. Addressing this problem further requires executable trading rules, settlement linkages, and responsibility allocation methods.

In this context, the mechanism price policy provides a more targeted institutional basis for new energy participation in the spot market by combining market-based price formation with off-market price-difference settlement for mechanism-covered electricity. This design helps balance market participation, revenue support, and transitional risk

management during China's electricity market reform. However, existing studies have not yet sufficiently clarified several implementation issues under this policy. These issues include how to differentiate mechanism-covered and non-mechanism-covered new energy electricity in market participation and settlement. They also include how to coordinate full-volume spot clearing with phased active bidding participation and how to link off-market price-difference settlement with spot-market revenues. Another issue is how to allocate imbalance funds through secondary settlement when priority generation, guaranteed electricity consumption, and grid-company agency purchasing coexist. Against this background, the main contributions of this paper are summarized as follows.

- (1) A coordinated trading and settlement framework is constructed to support the participation of new energy in the electricity spot market. The proposed framework integrates flexible medium- and long-term trading, multi-timescale spot trading across the day-ahead, intraday, and real-time markets, mechanism-price difference settlement, imbalance fund identification, and secondary settlement. It clarifies the linkages among market trading, responsibility allocation, and settlement procedures. It also coordinates market-based trading, mechanism-price revenue support, balancing responsibility allocation, and settlement cost pass-through for new energy.
- (2) A transitional arrangement is proposed under the mechanism price policy in which mechanism-covered electricity from new energy is excluded from medium- and long-term contract allocation and medium- and long-term contract-for-difference settlement. This arrangement prevents responsibility for medium- and long-term contract curve deviations from being directly assigned to mechanism-covered new energy, thereby supporting its sustainable development. In addition, a staged participation mechanism is designed for mechanism-covered electricity in the day-ahead spot market, considering the limited ability of new energy to bear deviation risks. This design reduces spot-market risk exposure while retaining the necessary quantity-declaration basis for subsequent settlement.
- (3) A system for imbalance responsibility identification, imbalance fund classification, and secondary settlement is established. The proposed method classifies imbalance funds into two categories. The first arises from market trading deviations, and the second arises from policy-based revenue compensation. The method further clarifies the responsibility boundaries and calculation methods for different types of imbalance funds. Following the principle that costs should be borne by the beneficiaries, the identified imbalance funds are allocated among generation- and load-side market participants. In addition, a secondary settlement statement of electricity prices and charges is generated for implementation.

2. Overall Framework Design

As shown in Figure 1, the proposed framework establishes a multi-timescale coordinated spot market and a flexible, continuous medium- and long-term trading mechanism based on full-volume spot trading. It also considers the differentiated characteristics of market participants and the phased arrangements for new energy participation in the day-ahead market. A clear responsibility–settlement closed loop is also established to support a smooth market transition. The spot market is organized through progressive refinement and rolling optimization across the day-ahead, intraday, and real-time stages. In the medium- and long-term market, weekly, multi-day, and daily trading arrangements are introduced, and standardized time-segmented trading products are explored. These measures shorten trading cycles, increase trading frequency, and meet the short-cycle and high-frequency deviation-adjustment needs of new energy producers. For policy alignment, differentiated participation arrangements are designed according to the policy positioning

and technical characteristics of different market participants. To ensure a smooth transition, new energy participation is organized through classification-based and phased arrangements. Meanwhile, government-authorized contracts for difference are introduced into medium- and long-term trading. This arrangement helps integrate generation- and demand-side entities into the spot market. It also reduces resource-allocation distortions caused by administrative planning and coordinates the matching between priority generation and priority consumption. Full-volume spot trading helps clarify the balancing responsibility of each market participant and provides a transparent basis for accurately tracing and fairly allocating imbalance funds. On this basis, imbalance funds are classified and calculated. They are then fairly allocated to generation- and demand-side market participants through secondary settlement in accordance with the principle that “beneficiaries bear the costs.” In addition, off-market difference settlement is used to align with the mechanism price policy for new energy, thereby facilitating the transition of the new energy revenue model from planned guarantees to market-based competition.

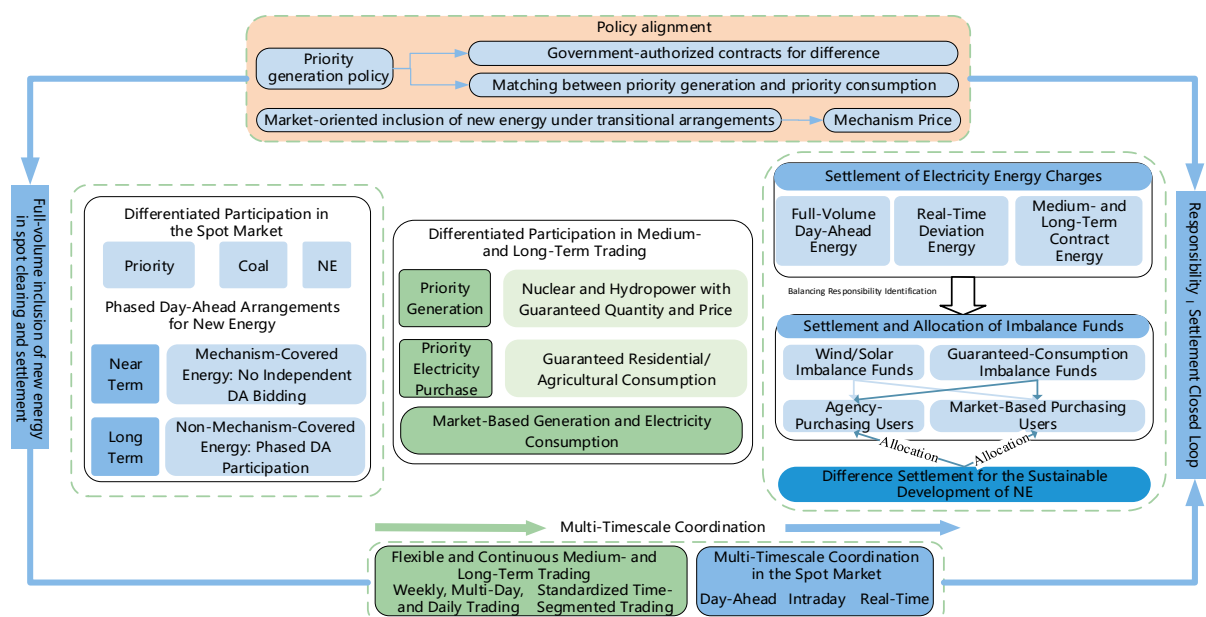


Figure 1. Overall framework of the proposed trading and settlement mechanism.

3. Flexible Medium- and Long-Term Trading Mechanism Adapted to High-Penetration New Energy

3.1. Organization of Medium- and Long-Term Trading for Spot-Market Coordination

At the early stage of spot electricity market development, priority generation and guaranteed electricity consumption policies still coexist with market-based trading. In this transitional context, medium- and long-term electricity trading should play a dual role in risk management and policy coordination. Specifically, differentiated contracts are required to match the characteristics and policy positions of different market participants. Continuous and flexible adjustment mechanisms are also needed to address wind power and solar PV output fluctuations. Curve-based standardized contracts should also be introduced to strengthen coordination with the spot market. The proposed trading mechanism is illustrated in Figure 2.

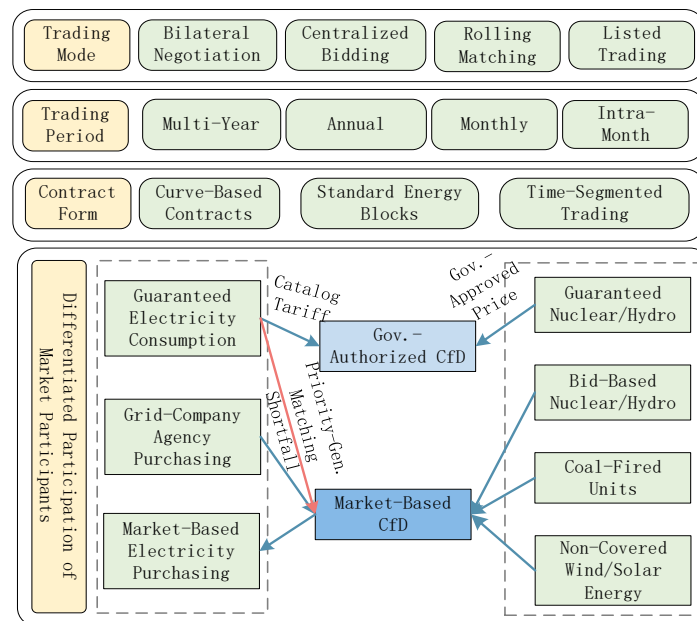


Figure 2. Schematic diagram of the organization of medium- and long-term trading. Blue arrows denote contractual relationships in medium- and long-term trading, whereas red arrows denote the market-based procurement of guaranteed electricity when priority generation is insufficient to satisfy guaranteed electricity demand.

Medium- and long-term electricity trading includes bilateral negotiation and centralized trading and covers different delivery periods, including multi-year, annual, monthly, intra-month, ten-day, weekly, and multi-day products. Centralized trading includes centralized bidding, rolling matching, and listed transactions. To promote effective coordination between medium- and long-term trading and the spot market, market participants are required to specify contract curves and conduct energy-block trading at intra-month and shorter timescales. Standard energy blocks correspond to peak, flat, valley, and other typical periods, thereby meeting market participants' combined trading needs associated with typical load patterns and new energy output characteristics. Time-segmented energy blocks further refine trading products to the hourly level and support shorter-cycle curve correction and deviation adjustment. By shortening trading cycles and increasing trading frequency, the mechanism can better respond to changes in new energy generation forecasts. Meanwhile, generation- and demand-side entities are allowed to determine the quantity, price, and curve of medium- and long-term contracts according to new energy output characteristics and to make flexible adjustments based on actual conditions. No mandatory contract coverage ratio is imposed. However, a lower contract coverage ratio may expose demand-side entities to greater spot price volatility.

3.2. Design of Differentiated Medium- and Long-Term Contracts

To align with policy objectives, differentiated participation rules for generation- and demand-side entities are designed based on government-authorized contracts for difference and market-based contracts for difference. Under government-authorized contracts for difference, the sellers are power generation enterprises, while the buyer is the grid company authorized by the government to represent non-market-based users. Under market-based contracts for difference, the buyers and sellers are corresponding electricity market participants, such as generators, electricity retailers, and end users.

For nuclear and hydropower units, the portion subject to guaranteed quantity and price signs government-authorized contracts for difference with the grid company responsible for agency purchasing, according to unit type. The portion subject to guaranteed

quantity but competitive pricing, together with the full output of coal-fired units, directly participates in the market and signs market-based contracts for difference. Mechanism-covered new energy electricity does not participate in medium- and long-term trading. Non-mechanism-covered new energy electricity may sign market-based contracts for difference and assume balancing responsibilities, or transfer market-balancing responsibility risks to electricity consumers through multi-year power purchase agreements with price concessions.

On the demand side, users are classified into three categories: guaranteed-consumption users, users under grid-company agency purchasing, and market-based users. On-grid electricity generated from new energy is no longer used by grid companies as a source of priority generation to match residential, agricultural, or agency-purchased industrial and commercial electricity consumption. When priority generation results in a surplus or shortfall after being matched with guaranteed consumption, the surplus or shortfall should preferably be handled through market-based arrangements. The remaining generation and consumption are balanced through market-based trading. Electricity under the “guaranteed quantity and price” arrangement for priority generation is settled at the government-approved electricity price, while all other generation is settled at market-based prices.

4. Full-Volume Spot Trading and Unified Clearing Mechanism

4.1. Multi-Timescale Organization of Spot Market Trading

The spot market is organized through multi-timescale coordination and phased arrangements, taking into account both fair competition and a smooth market transition. Day-ahead (DA), intraday (ID), and real-time (RT) markets are optimized in a progressively refined manner, with appropriate market price limits set to guide resource allocation through time-varying price signals. The market adopts quantity-price bidding on the generation side and quantity-only submission without price bidding on the demand side. Considering the limited day-ahead forecasting accuracy of wind power and solar PV and the relatively weak ability of new energy producers to bear deviation-assessment risks at the early stage of market participation, day-ahead participation by new energy is arranged in phases. Mechanism-covered electricity is incorporated into day-ahead clearing through forecast curves submitted by the grid company on behalf of new energy producers. However, no independent price bids are submitted for this electricity during the transitional stage. Non-mechanism-covered electricity participates voluntarily in day-ahead trading. At the early stage, new energy producers submit quantities without price bids for this electricity. At the mature stage, they may submit quantity-price offers. Meanwhile, the development of a two-sided spot market should be accelerated. Market-based users should also be gradually encouraged to participate in spot trading through quantity-price bidding when appropriate. The trading timeline is shown in Figure 3.

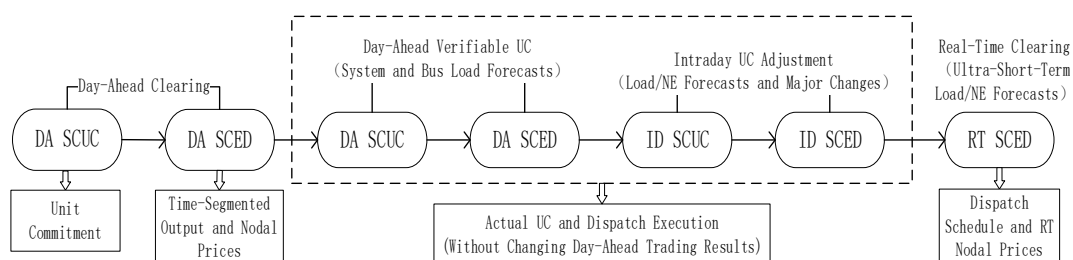


Figure 3. Timeline of day-ahead, intraday, and real-time spot trading.

In the day-ahead market, security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) are adopted for centralized optimization and clearing, generating unit commitment decisions, generation output schedules, and clearing prices, which are implemented after reliability verification. In the intraday stage, unit commitment is adjusted based on updated new energy generation forecasts, forming intraday clearing results. In the real-time market, generation outputs are optimized on a rolling basis to form the actual dispatch schedule and real-time clearing prices.

4.2. Spot Market Clearing Model

4.2.1. Security-Constrained Unit Commitment

The spot market clearing model is formulated as a unified generation-side clearing model based on standard SCUC and SCED formulations. It provides the clearing quantities, clearing prices, and deviation bases required for the proposed trading and settlement mechanism. For resources submitting quantity-price offers, the submitted price segments are directly incorporated into the objective function. For mechanism-covered electricity and electricity submitted on a quantity-only basis during the transitional stage, the submitted forecast or quantity curve is used as the available-output boundary. The corresponding price-bidding treatment follows the phased participation arrangement described in Section 4.1. Within this framework, the SCUC model minimizes the total system electricity procurement cost. Following the standard cost-minimization formulation used in centralized electricity market clearing, the objective function of the SCUC model is formulated as follows:

$$\min F = \sum_{t=1}^T \left[\sum_{i=1}^N \sum_{k=1}^K \lambda_{i,k,t} \times P_{i,k,t} \times \Delta t + \sum_{i \in \Omega^{coal}} C_{i,t}^{on} \right] \quad (1)$$

$$C_{i,t}^{on} = U_{i,t} \times (1 - U_{i,t-1}) \times C_i^S \quad (2)$$

where T denotes the total number of market clearing periods; N denotes the total number of generating units participating in the spot market; K denotes the number of submitted price segments; $\lambda_{i,k,t}$ denotes the submitted price of segment k of unit i in period t ; $P_{i,k,t}$ denotes the cleared output of segment k of unit i in period t ; Δt denotes the duration of each clearing period; Ω^{coal} denotes the set of coal-fired units; $C_{i,t}^{on}$ denotes the start-up and shutdown cost of coal-fired unit i in period t ; C_i^S denotes the start-up cost of coal-fired unit i ; and $U_{i,t}$ denotes the binary on/off status variable of coal-fired unit i in period t , where $U_{i,t} = 0$ indicates that the unit is offline and $U_{i,t} = 1$ indicates that the unit is online.

The constraints of the SCUC model are described as follows. The segmented cleared output constraints are given by:

$$P_{i,t} = \sum_{k=1}^K P_{i,k,t} \quad (3)$$

$$0 \leq P_{i,k,t} \leq \overline{P}_{i,k,t} \quad (4)$$

where $P_{i,t}$ denotes the total cleared output of unit i in period t ; and $\overline{P}_{i,k,t}$ denotes the submitted output upper limit of segment k of unit i in period t .

The system power balance constraint is expressed as:

$$\sum_i P_{i,t} = P_t^D \quad (5)$$

where P_t^D denotes the total load demand in period t .

The transmission line power flow constraint is given by:

$$-P_l^{max} \leq \sum_{i=1}^I G_{l-i} \times P_{i,t} + \sum_{j=1}^J G_{l-j} \times D_{j,t} \leq P_l^{max} \quad (6)$$

where P_l^{max} denotes the active power transmission limit of line l ; G_{l-i} denotes the power transfer distribution factor of the node where unit i is located with respect to line l ; G_{l-j} denotes the power transfer distribution factor of node j with respect to line l ; and $D_{j,t}$ denotes the bus load at node j in period t . Generation output is treated as positive injection, while load demand is treated as negative injection.

The ramping constraint of coal-fired units is expressed as:

$$P_{i,t} - P_{i,t-1} \leq \Delta P_i^{up} \times U_{i,t-1} + P_i^{min}(U_{i,t} - U_{i,t-1}) + P_i^{max}(1 - U_{i,t}), i \in \Omega^{coal} \quad (7)$$

$$P_{i,t-1} - P_{i,t} \leq \Delta P_i^{down} \times U_{i,t-1} + P_i^{min}(U_{i,t-1} - U_{i,t}) + P_i^{max}(1 - U_{i,t-1}), i \in \Omega^{coal} \quad (8)$$

where ΔP_i^{up} and ΔP_i^{down} denote the upward and downward ramping limits of coal-fired unit i , respectively. These constraints limit the output changes in coal-fired units between adjacent periods while coordinating ramping limits with changes in the unit commitment status. Under this simplified formulation, a unit starts up from, or shuts down at, its minimum technical output.

The system reserve constraints are given by:

$$\sum_{i=1}^I (P_i^{max} U_{i,t} - P_{i,t}) \geq R_t^{up}, i \in \Omega^{coal} \quad (9)$$

$$\sum_{i=1}^I (P_{i,t} U_{i,t} - P_i^{min}) \geq R_t^{down}, i \in \Omega^{coal} \quad (10)$$

where R_t^{up} and R_t^{down} denote the upward and downward spinning reserve requirements of the system in period t , respectively. In this study, coal-fired units are assumed to provide the main spinning reserve because they are the primary flexible resources for peak regulation in the test system.

The minimum on/off time constraints of coal-fired units are expressed as:

$$T_{i,t}^U - (u_{i,t-1} - u_{i,t})T_i^U \geq 0 \quad (11)$$

$$T_{i,t}^D - (u_{i,t} - u_{i,t-1})T_i^D \geq 0 \quad (12)$$

$$T_{i,t}^U = \sum_{\tau=t-T_i^U}^{t-1} u_{i,\tau} \quad (13)$$

$$T_{i,t}^D = \sum_{\tau=t-T_i^D}^{t-1} (1 - u_{i,\tau}) \quad (14)$$

where $T_{i,t}^U$ denotes the on-time of unit i in period t ; $T_{i,t}^D$ denotes the off-time of unit i in period t ; T_i^U denotes the minimum on-time requirement of unit i ; and T_i^D denotes the minimum off-time requirement of unit i .

The minimum and maximum output constraints of generating units are given by:

$$U_{i,t} \times P_i^{min} \leq P_{i,t} \leq U_{i,t} \times P_i^{max}, i \in \Omega^{coal} \quad (15)$$

$$0 \leq P_{i,t} \leq P_{i,t}^{pre}, i \in \Omega^{ren} \quad (16)$$

$$P_{i,t}^{\min} \leq P_{i,t} \leq P_{i,t}^{\max}, i \in \Omega^{nh} \quad (17)$$

where $P_i^{\min}$ denotes the minimum power output of coal-fired unit i ; $P_i^{\max}$ denotes the maximum power output of coal-fired unit i ; $P_{i,t}^{pre}$ denotes the forecast output of new energy unit i in period t ; Ω^{ren} denotes the set of new energy units; and Ω^{nh} denotes the set of nuclear and hydropower units. Nuclear and hydropower units are modeled as limited-dispatchable units with exogenously specified lower and upper output bounds, reflecting their priority-generation status and operational constraints.

4.2.2. Security-Constrained Economic Dispatch

After the unit on/off status is determined by the SCUC model, the SCED model fixes the commitment status and further optimizes the period-by-period dispatch output of each generating unit. The SCED model removes start-up and shutdown decision variables and focuses on continuous dispatch adjustment under system balance, network constraints, output limits, and ramping constraints, thereby minimizing the total system electricity procurement cost. The objective function of the SCED model is formulated as follows:

$$\min F = \sum_{t=1}^T \sum_{i=1}^N \sum_{k=1}^K \lambda_{i,k,t} \times P_{i,k,t} \times \Delta t \quad (18)$$

Except for the commitment-related constraints and start-up/shutdown cost terms, the main mathematical formulations of the SCED model are consistent with those of the SCUC model. For coal-fired units, let $U_{i,t}^*$ denote the fixed on/off status of unit i in period t obtained from the SCUC solution. The fixed commitment status is explicitly incorporated into the output-limit and ramping constraints of coal-fired units. The output limits of coal-fired units in the SCED model are given by:

$$U_{i,t}^* P_i^{\min} \leq P_{i,t} \leq U_{i,t}^* P_i^{\max} \quad (19)$$

The ramping constraints of generating units are expressed as:

$$P_{i,t} - P_{i,t-1} \leq \Delta P_i^{up} \times U_{i,t-1}^* + P_i^{\min} (U_{i,t}^* - U_{i,t-1}^*) + P_i^{\max} (1 - U_{i,t}^*), i \in \Omega^{coal} \quad (20)$$

$$P_{i,t-1} - P_{i,t} \leq \Delta P_i^{down} \times U_{i,t-1}^* + P_i^{\min} (U_{i,t-1}^* - U_{i,t}^*) + P_i^{\max} (1 - U_{i,t-1}^*), i \in \Omega^{coal} \quad (21)$$

In the SCED model, $U_{i,t}^*$ is treated as a fixed parameter rather than a decision variable. Equation (19) fixes the output of an offline coal-fired unit at zero, while Equations (20) and (21) retain the commitment-dependent ramping logic of the SCUC formulation.

5. Energy Charge Settlement Method Considering Alignment with the Mechanism Price and Allocation of Imbalance Funds

Based on the multi-timescale spot trading mechanism described above, the spot energy charges of both generation- and demand-side entities are calculated according to the principle of “full-volume settlement in the day-ahead market and deviation settlement in the intraday and real-time markets”. On this basis, the economic responsibility of market participants for spot deviations across different trading timescales is quantified. Curve-based medium- and long-term contracts for difference are incorporated to manage spot price risks, while off-market difference settlement for new energy is used to align with the mechanism price policy. Furthermore, a mechanism for calculating and allocating imbalance funds is established. Accordingly, each settlement component has a clearly defined boundary. Spot settlement applies to day-ahead cleared electricity and the DA-ID and ID-RT deviation electricity. Contract-for-difference settlement applies to medium- and long-term contracted

electricity. Mechanism-price difference settlement applies to mechanism-covered new energy electricity. Finally, secondary settlement is used to coordinate spot energy settlement, medium- and long-term contract-for-difference settlement, mechanism-price-based revenue adjustment, and the calculation and allocation of imbalance funds. This establishes a closed-loop settlement framework with clearly defined responsibilities, transparent charges, and reasonable cost allocation. In the following settlement equations, a positive settlement value represents revenue for a generation-side entity and an electricity charge for a demand-side entity, unless otherwise specified. Positive imbalance funds or allocated charges represent system-level costs to be allocated, whereas negative values represent settlement surpluses.

5.1. Spot Energy Market Settlement

In the day-ahead spot market, energy charges are settled on a full-volume basis. The deviation between intraday cleared electricity and day-ahead cleared electricity is settled at the intraday price, while the deviation between actual electricity and intraday cleared electricity is settled at the real-time price.

$$R_{B,DM}^{\Sigma} = \sum_{t=1}^T [Q_{B,t}^{DM} \times \lambda_{B,t}^{DM}] \quad (22)$$

$$R_{B,IM}^{\Sigma} = \sum_{t=1}^T [(Q_{B,t}^{IM} - Q_{B,t}^{DM}) \times \lambda_{B,t}^{IM}] \quad (23)$$

$$R_{B,RM}^{\Sigma} = \sum_{t=1}^T [(Q_{B,t}^{RM} - Q_{B,t}^{IM}) \times \lambda_{B,t}^{RM}] \quad (24)$$

where $R_{B,DM}^{\Sigma}$, $R_{B,IM}^{\Sigma}$, $R_{B,RM}^{\Sigma}$ denote the day-ahead, intraday, and real-time spot energy charges of entity, respectively. A positive value represents receivable energy revenue for a generation-side entity and payable energy charges for a demand-side entity; $Q_{B,t}^{DM}$, $Q_{B,t}^{IM}$, and $Q_{B,t}^{RM}$ denote the cleared electricity of market participant in period t in the day-ahead, intraday, and real-time markets, respectively; and $\lambda_{B,t}^{DM}$, $\lambda_{B,t}^{IM}$, and $\lambda_{B,t}^{RM}$ denote the corresponding clearing prices of market participant in period t in the day-ahead, intraday, and real-time markets, respectively.

5.2. Medium- and Long-Term Contracts and Off-Market Difference Settlement

For medium- and long-term contract settlement, the contracted electricity is settled using the unified settlement point of the day-ahead market as the settlement reference. The settlement amount is calculated based on the difference between the medium- and long-term contract price and the spot price at the reference point.

$$R_{B,CM}^{\Sigma} = \sum_{t=1}^T [Q_{B,t}^{CM} \times (\lambda_{B,t}^{CM} - \lambda_{B,t}^{DM})] \quad (25)$$

where $R_{B,CM}^{\Sigma}$ denotes the medium- and long-term contract-for-difference settlement amount of entity. A positive value represents compensation received through the medium- and long-term contract-for-difference settlement, whereas a negative value represents a return payment under the contract-for-difference settlement; $Q_{B,t}^{CM}$ denotes the contracted electricity signed by the market participant through medium- and long-term trading in period t ; and $\lambda_{B,t}^{CM}$ denotes the contract price signed by market participant through medium- and long-term trading in period t .

For off-market difference settlement, when the average market transaction price of mechanism-covered electricity is lower or higher than the mechanism price, the grid

company conducts difference settlement according to relevant rules. The corresponding difference settlement charges are included in local system operation charges, a regulated settlement category used to recover specified system-level costs under local electricity market rules, and are allocated to, or shared by, all users. Mechanism-covered electricity is determined according to the monthly actual on-grid electricity of each project and its mechanism-covered electricity ratio. The new energy sustainability difference settlement charge is expressed as follows:

$$R_{r,MP}^{\Sigma} = \sum_{m=1}^M \left[Q_{r,m}^{ME} \left(\lambda_r^{MP} - \bar{\lambda}_{r,m}^{ref} \right) \right] \quad (26)$$

where $R_{r,MP}^{\Sigma}$ denotes the mechanism-price difference settlement charge of new energy unit r during the statistical period. Under this convention, a positive $R_{r,MP}^{\Sigma}$ represents an off-market compensation payment to mechanism-covered new energy when the mechanism price is higher than the market reference price, whereas a negative value represents a recovery payment when the market reference price exceeds the mechanism price; $Q_{r,m}^{ME}$ denotes the electricity of unit r covered by the mechanism in month m ; λ_r^{MP} denotes the mechanism price of unit r ; and $\bar{\lambda}_{r,m}^{ref}$ denotes the average market transaction price in month m , which is determined according to the monthly generation-side real-time market weighted average price of the same type of project.

5.3. Responsibility Identification and Allocation Settlement Method for Imbalance Funds

For guaranteed-consumption users such as residential and agricultural users, load forecast curves are forecast and submitted by the grid company on their behalf, and the grid company assumes the balancing responsibility arising from forecasting deviations. The imbalance funds for guaranteed consumption are defined as the premium by which the time-segmented average purchase price exceeds the purchase price of market-based users in the same trading cycle. This premium is caused by multi-year, monthly, intra-month, and multi-day trading adjustments triggered by net-load forecasting deviations.

$$C_{GU}^{B,MD} = Q_{GU}^{B,MD,H} \times p_{GU}^{B,MD,H} + Q_{GU}^{B,MD,M} \times p_{GU}^{B,MD,M} + Q_{GU}^{B,MD,L} \times p_{GU}^{B,MD,L} \quad (27)$$

where $C_{GU}^{B,MD}$ denotes the imbalance funds for guaranteed electricity purchasing caused by load forecasting deviations in multi-day and longer-term trading; $Q_{GU}^{B,MD,H}$, $Q_{GU}^{B,MD,M}$, and $Q_{GU}^{B,MD,L}$ denote the quantities of medium- and long-term electricity purchased by the grid company during peak, flat, and valley periods, respectively; and $p_{GU}^{B,MD,H}$, $p_{GU}^{B,MD,M}$, and $p_{GU}^{B,MD,L}$ denote the premium levels by which the average purchase prices of the grid company in medium- and long-term trading during peak, flat, and valley periods exceed the average price of direct medium- and long-term trading, respectively.

The medium- and long-term balancing responsibility of mechanism-covered new energy electricity is included in system operation charges through the new energy sustainability pricing and settlement mechanism and is allocated to the demand side. Mechanism-covered new energy electricity does not directly participate as a bidding entity in the day-ahead market, while non-mechanism-covered electricity participates in the day-ahead market in phases. The new energy generation forecast curve is submitted by the grid company on behalf of new energy producers and incorporated into day-ahead market clearing; however, the corresponding electricity does not assume the balancing responsibility arising from day-ahead new energy generation forecast deviations. At the spot stage, load forecasting accuracy is relatively high, and the adjustment costs incurred by the grid company for guaranteed consumption and agency purchasing in the day-ahead

spot market are mainly reflected as day-ahead imbalance funds for wind and solar power, denoted by $C_{WS}^{B,DA}$. The calculation is as follows:

$$C_{WS}^{B,DA} = \sum_{t=1}^T \left((P_{GU+AP,t} - Q_{cover,t}^{B,MD}) \times \lambda_t \right) \quad (28)$$

$$Q_{cover,t}^{B,MD} = \sum (Q_{GM,t} + Q_{GN,t}) \quad (29)$$

where $P_{GU+AP,t}$ denotes the day-ahead submitted curve of guaranteed-consumption users and users under grid-company agency purchasing in each period; $Q_{cover,t}^{B,MD}$ denotes the medium- and long-term contract electricity covered by market-based and government-authorized contracts for difference in period t ; $Q_{GM,t}$ denotes the electricity corresponding to the load curve specified in market-based contracts for difference; $Q_{GN,t}$ denotes the electricity corresponding to the load curve specified in government-authorized contracts for difference signed by nuclear and hydropower units; and λ_t denotes the difference between the average day-ahead market price and the average price of direct medium- and long-term trading.

The imbalance funds for guaranteed consumption are associated with policy-based electricity-price support for guaranteed-consumption users, such as residential and agricultural users. Although the load curves of these users are forecast and submitted by the grid company and incorporated into market clearing, their electricity charges are still settled according to regulated catalog tariffs under China's current electricity-pricing policy. Therefore, these imbalance funds cannot be directly recovered from guaranteed-consumption users through spot-market settlement. Instead, they are allocated to market-based users in proportion to their electricity consumption. During the transitional stage of the spot market, mechanism-covered electricity from new energy is incorporated into day-ahead market clearing, but new energy producers are not required to independently submit day-ahead market bids for this electricity. Instead, the corresponding output forecast curves are submitted by the grid company on behalf of these producers. This arrangement is intended to avoid imposing excessive deviation risks on new energy producers and to stabilize their revenue expectations under the mechanism price policy. From the perspective of responsibility attribution, the day-ahead imbalance funds for wind and solar PV are costs incurred for new energy accommodation. These costs have system-level and public-interest attributes and should, in principle, be shared by all users. However, because guaranteed-consumption users are settled according to regulated catalog tariffs, a regulated retail tariff schedule approved by government pricing authorities for specified non-market users, these costs are allocated to market-based users through secondary settlement.

5.4. Mathematical Model for the Secondary Settlement of Energy Charges

The energy charge of a new energy entity consists of day-ahead market revenue, intraday market revenue, real-time market revenue, medium- and long-term contract-for-difference revenue, and off-market new energy sustainability difference settlement revenue. The settlement model is formulated as follows:

$$R_r^\Sigma = R_{r,DM}^\Sigma + R_{r,IM}^\Sigma + R_{r,RM}^\Sigma + R_{r,CM}^\Sigma + R_{r,MP}^\Sigma \quad (30)$$

where R_r^Σ denotes the total revenue of new energy entity r after secondary settlement; and $R_{r,DM}^\Sigma$, $R_{r,IM}^\Sigma$, $R_{r,RM}^\Sigma$, and $R_{r,CM}^\Sigma$ denote the day-ahead market revenue, intraday market revenue, real-time market revenue, and medium- and long-term contract-for-difference revenue of new energy entity r , respectively.

The energy charge of a market-based user consists of day-ahead market charges, intraday market charges, real-time market charges, medium- and long-term contract-for-difference charges, allocated imbalance funds, and allocated system operation charges.

$$R_j^\Sigma = R_{j,DM}^\Sigma + R_{j,IM}^\Sigma + R_{j,RM}^\Sigma + R_{j,CM}^\Sigma + A_{j,UB}^\Sigma + A_{j,SO}^\Sigma \quad (31)$$

where R_j^Σ denotes the total electricity charge of market-based user j after secondary settlement; $R_{j,DM}^\Sigma$, $R_{j,IM}^\Sigma$, $R_{j,RM}^\Sigma$, and $R_{j,CM}^\Sigma$ denote the day-ahead market charge, intraday market charge, real-time market charge, and medium- and long-term contract-for-difference charge of market-based user j , respectively; $A_{j,UB}^\Sigma$ denotes the imbalance funds allocated to market-based user j ; and $A_{j,SO}^\Sigma$ denotes the system operation charges allocated to market-based user j .

For non-market-based users, energy charges are settled according to the catalog sales tariff. The settlement model is expressed as follows:

$$R_h^\Sigma = \sum_{t=1}^T Q_{h,t}^{NM} \lambda_{h,t}^{reg} \quad (32)$$

where R_h^Σ denotes the total electricity charge of non-market-based user h ; $Q_{h,t}^{NM}$ denotes the electricity consumption of non-market-based user h in period t ; and $\lambda_{h,t}^{reg}$ denotes the catalog sales tariff of non-market-based user h in period t .

6. Case Study

6.1. Test System

The modified IEEE 39-bus system is used to simulate spot market trading, as shown in Figure 4. The total installed capacity of the test system is 10,000 MW, comprising 1500 MW of wind power, 3000 MW of solar PV, 4520 MW of coal-fired power, 180 MW of nuclear power, and 800 MW of hydropower. Wind power and solar PV together account for 45% of the installed capacity, representing a high-penetration new energy scenario.

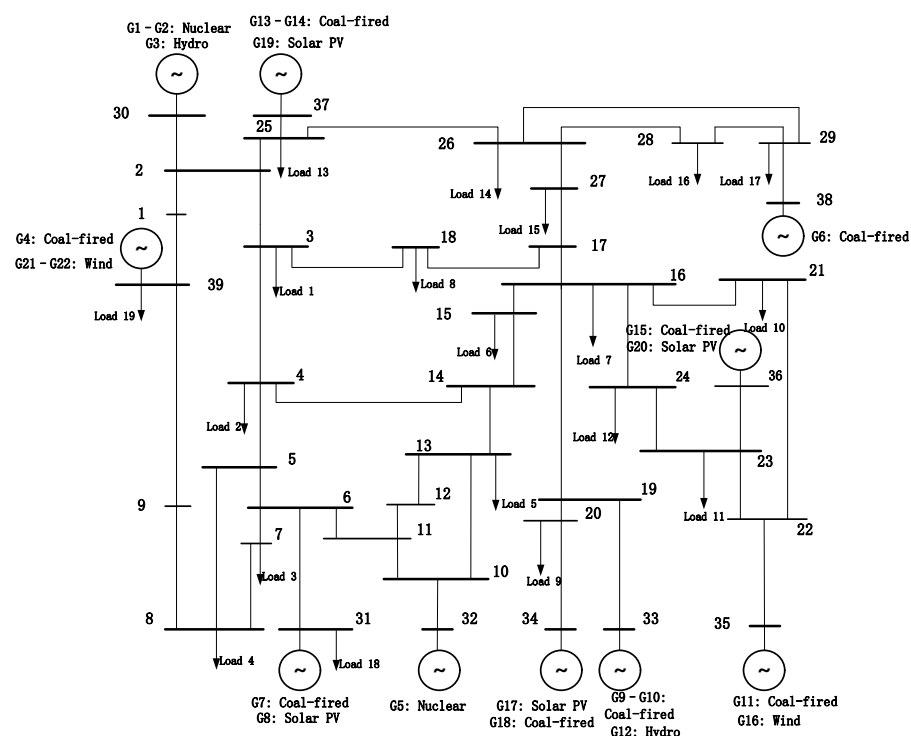


Figure 4. Topology of the modified IEEE 39-bus test system.

The mechanism-covered electricity ratios for wind power and solar PV are set at 70% and 85%, respectively, representing a transitional stage in which part of the electricity from existing new energy projects remains subject to mechanism-price arrangements. These ratios are determined with reference to the original guaranteed-accommodation proportions of existing new energy projects in a Chinese provincial spot market that has entered formal operation. The mechanism price is set at 0.416 CNY/kWh with reference to the local coal-fired benchmark on-grid tariff. These parameters are not intended to represent nationally uniform values. Instead, they are treated as policy-derived baseline assumptions for this case study.

To capture the daily peak–valley characteristics of load demand and the time-varying outputs of wind power and solar PV while maintaining computational tractability, a typical operating day is divided into 24 hourly clearing periods. The forecast curves of load demand and new energy generation are shown in Figure 5. Accordingly, the optimization framework in this case study is deterministic and uses point forecasts of load demand, wind power, and solar PV output as inputs. Forecast uncertainty is not explicitly modeled in the clearing model; it could be incorporated in future extensions through scenario-based stochastic SCUC/SCED, robust optimization with uncertainty sets, or chance-constrained formulations, while the proposed settlement framework could be evaluated over the resulting dispatch and deviation scenarios. The optimization model is implemented in MATLAB R2023b (The MathWorks, Inc., Natick, MA, USA) and solved using the CPLEX solver in IBM ILOG CPLEX Optimization Studio 12.9.0 (IBM, Armonk, NY, USA). The spot market clearing price is constrained within the range of 0–800 CNY/MWh. Detailed numerical input data, including the modified network parameters, unit characteristics, bidding parameters, and time-series profiles are provided in Appendix A. The SCUC model includes binary unit commitment variables and is formulated as a mixed-integer linear programming (MILP) problem. Once the unit commitment status is determined, the SCED model is solved as a continuous optimization problem. Non-convex operating characteristics related to unit start-up and shutdown, minimum on/off time constraints, and ramping constraints are represented using binary variables and linear constraints, without heuristic relaxation. The default CPLEX optimality and feasibility tolerances are used, and all scenarios are solved under identical computational settings to ensure the comparability of results.

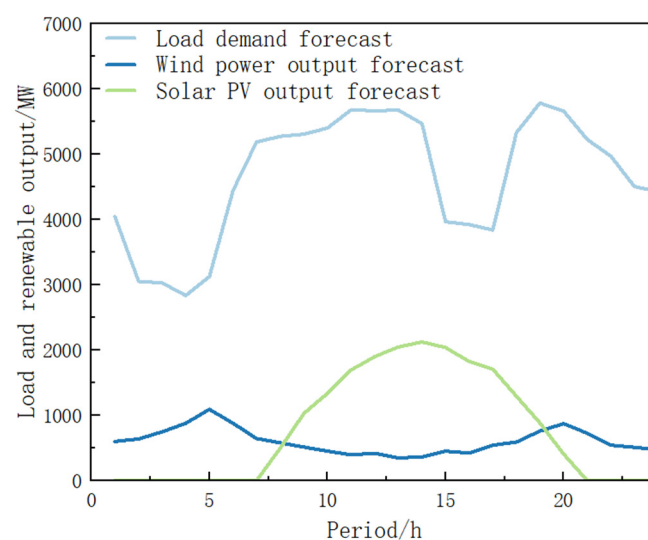


Figure 5. Forecast profiles of load demand and new energy generation.

6.2. Analysis of Market Resource Allocation Results

The clearing results of the day-ahead and real-time spot markets are shown in Figure 6. With the integration of a high proportion of new energy, large-scale solar PV generation at noon significantly offsets load demand, resulting in a midday valley in net load. The wind power output curve exhibits a double-saddle-shaped profile and is negatively correlated with the load curve, further deepening the early-morning net-load valley. The counter-peak-regulation characteristics of new energy increase the peak–valley difference in net load to 2808.2 MW, and the net load curve shows a double-peak and double-valley pattern. During low-net-load periods in the day-ahead market, coal-fired units are required to operate under deep peak-regulation conditions. Multiple units even undergo start-up and shutdown for peak regulation during 15:00–17:00. As a result, the market clearing price fluctuates sharply. During 04:00–05:00 in the early morning and 15:00–17:00 in the afternoon, new energy curtailment becomes marginal, causing the market clearing price to fall to 0 CNY/MWh. During the morning and evening peak periods, namely 07:00–09:00 and 19:00–22:00, coal-fired units become the marginal units. The electricity price therefore rises to 680 CNY/MWh, resulting in a peak–valley price spread of 680 CNY/MWh.

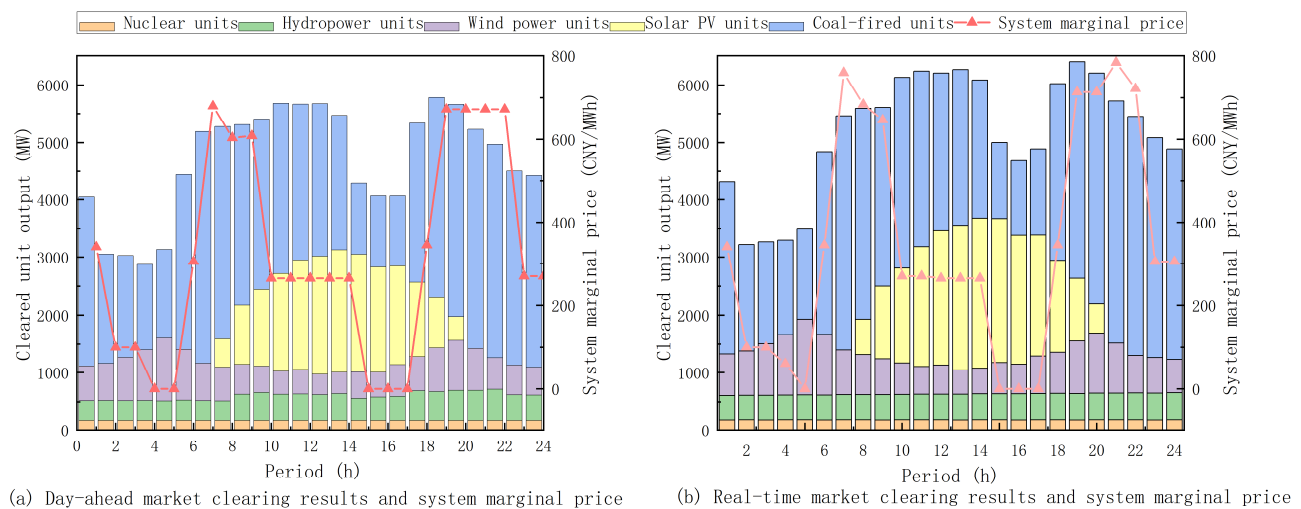


Figure 6. Day-ahead and real-time clearing results: output structure and clearing prices.

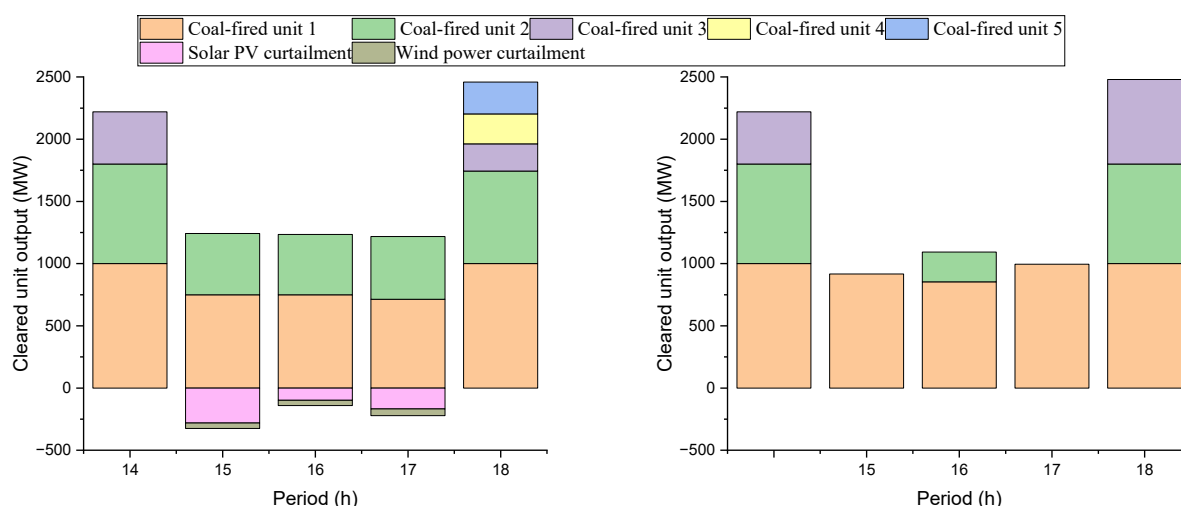
6.3. Market Efficiency Analysis

For the high-penetration new energy scenario, the total system electricity procurement cost and new energy curtailment are calculated under three modes. The first is the traditional dispatch mode based on the day-ahead generation schedule. The second is the priority-accommodation mode, in which new energy accommodation is prioritized in medium- and long-term arrangements and the accommodated new energy output is used as a boundary condition for spot market clearing. The third is the quantity-price bidding mode, in which new energy participates in the spot market through quantity-price bidding. As shown in Table 1, under the quantity-price bidding mode, the total system electricity procurement cost is CNY 47.039 million, which is CNY 5.357 million lower than that under the priority-accommodation mode and close to that under the traditional dispatch mode.

Table 1. Total system electricity procurement cost and curtailment under different scenarios.

Mode	Traditional Dispatch	Priority Accommodation	Quantity-Price Bidding
Total electricity procurement cost (10^4 CNY)	4397.8	5239.6	4703.9
Wind power curtailment (MW)	583.7	0	319
Solar PV curtailment (MW)	468.4	0	265.8

The underlying reason is that, although new energy has a zero marginal cost, its full accommodation may require deep peak regulation and even start-up/shutdown peak regulation of coal-fired units, thereby significantly increasing system regulation costs. In the spot market environment, market-based decision-making can reduce the total system operating cost through a certain amount of wind and solar PV curtailment. As shown in Figure 7, under the quantity-price bidding mode, the system actively curtails new energy and controls the load rates of coal-fired units 1 and 2 at 71% and 50%, respectively, thereby avoiding deep peak regulation. By contrast, under the priority-accommodation mode, the mandatory full on-grid consumption of new energy causes start-up and shutdown peak regulation of coal-fired units 2 and 3 during periods 14–15. In period 16, unit 2 is forced to operate at its minimum technical output of 30%, leading to a significant increase in system regulation costs.

**Figure 7.** Clearing results during low-net-load periods in the day-ahead market.

6.4. Revenue Support and Balancing Responsibility of New Energy

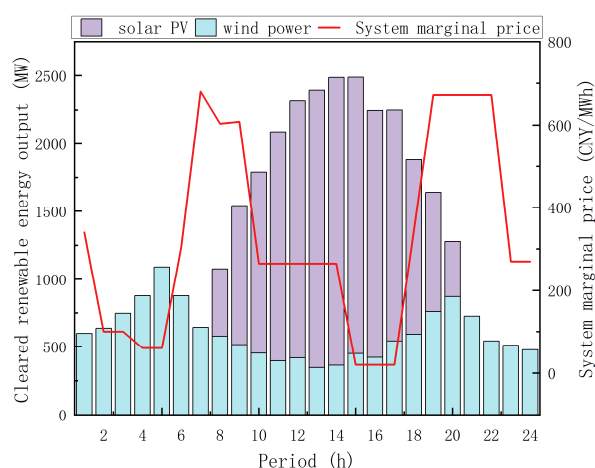
6.4.1. Revenue Support Under the Mechanism Price Policy

Energy charge settlement is conducted separately for the mechanism-covered and non-mechanism-covered electricity of wind power and solar PV. The results are shown in Table 2. For wind power, mechanism-covered electricity obtains CNY 4.336 million in spot market revenue, while non-mechanism-covered electricity obtains CNY 0.103 million in medium- and long-term contract-for-difference revenue and CNY 1.858 million in spot market revenue. For solar PV, mechanism-covered electricity obtains CNY 5.124 million in spot market revenue, while non-mechanism-covered electricity obtains CNY 0.254 million in medium- and long-term contract-for-difference revenue and CNY 0.904 million in spot market revenue.

Table 2. Energy-market revenues of mechanism-covered and non-mechanism-covered new energy.

Settlement Item	Mechanism-Covered Electricity		Non-Mechanism-Covered Electricity	
	Wind Power	Solar PV	Wind Power	Solar PV
Medium- and long-term contract-for-difference revenue (10^4 CNY)	/	/	10.3	25.4
Spot-market revenue (10^4 CNY)	433.6	512.4	185.8	90.4
Average spot price (CNY/MWh)	337.7	261.5	337.7	261.5
Off-market difference subsidy (10^4 CNY)	94.8	303.5	/	/
Average comprehensive settlement price (CNY/MWh)	416	416	/	/

Due to the stochastic, fluctuating, and intermittent characteristics of new energy output, direct participation in the spot market may lead to a substantial revenue decline, as new energy tends to generate more electricity during low-price periods and less during high-price periods. As shown in Figure 8, solar PV output is high during 10:00–18:00, when the spot price falls to as low as 0 CNY/MWh. The average spot price of solar PV is 261.5 CNY/MWh, which is 115.4 CNY/MWh lower than the market average price and 164.6 CNY/MWh lower than the average price of coal-fired units. The difference-settlement mechanism for the sustainable development of new energy compensates the average on-grid electricity price of mechanism-covered new energy electricity to 416 CNY/MWh, thereby significantly improving its revenue. Since medium- and long-term prices are anchored to spot prices, the two existing medium- and long-term trading arrangements for non-mechanism-covered electricity have limited ability to improve cost recovery. For non-mechanism-covered solar PV electricity, participation in medium- and long-term trading yields only CNY 0.254 million in contract-for-difference revenue and increases its average energy market price by only 20 CNY/MWh.

**Figure 8.** Cleared new energy output and market clearing price in the real-time market.

6.4.2. Balancing Responsibility Management and Pass-Through for New Energy

The balancing costs allocated per unit of electricity are calculated based on the forecast-deviation responsibilities that new energy should bear in medium- and long-term, day-ahead, and intraday trading. The results are shown in Figure 9. The per-kWh balancing costs of new energy in medium- and long-term, day-ahead, and intraday trading are 0.076 CNY/kWh, 0.024 CNY/kWh, and 0.016 CNY/kWh, respectively. If these costs were fully borne by new energy, its per-kWh revenue would decrease by 0.116 CNY/kWh. Due to differences in market participation among different categories of new energy electricity, the actual forecast-deviation balancing responsibilities borne by each category of electricity show significant differentiation. Mechanism-covered electricity does not participate in medium- and long-term or day-ahead trading. It therefore avoids a forecast-deviation responsibility of 0.1 CNY/kWh and reduces the revenue-volatility risk of mechanism-covered new energy electricity. Its forecast deviations are implicitly passed through to the demand side, pushing the electricity procurement structure of users toward the spot market and exposing a larger share of their electricity consumption to spot price volatility risks. Under the phased arrangement for non-mechanism-covered electricity participation in the spot market, non-mechanism-covered electricity can avoid day-ahead forecast-deviation responsibility and increase its own revenue by 0.024 CNY/kWh. However, the corresponding balancing responsibility is transferred to the demand side through imbalance fund settlement. These results show that the phased participation arrangement mitigates deviation risks on the new energy generation side. However, it also transfers part of the balancing responsibility to consumers. This makes it necessary to clarify responsibility boundaries and allocation paths through imbalance-fund identification and secondary settlement.

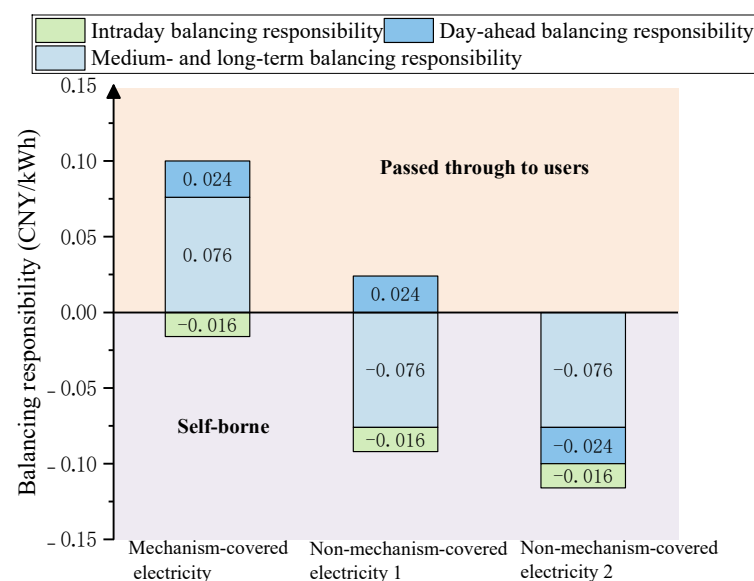


Figure 9. Balancing responsibility and cost pass-through for new energy.

6.5. Analysis of System Regulation Costs and Imbalance Fund Allocation

6.5.1. Peak-Regulation Costs

The cleared outputs of coal-fired units, wind power, and solar PV, together with the market clearing price, are selected for typical peak and valley periods. The results are shown in Figure 10. There is a clear temporal mismatch between new energy output and load demand, characterized by insufficient output during peak periods and surplus output during valley periods. This intensifies both the peak–valley difference and the fluctuation frequency of net load, thereby significantly increasing system peak-regulation pressure. Taking peak period 7 as an example, system net load demand rises sharply, and high-cost

coal-fired units become the marginal units. Their cleared output accounts for 86% of the total, driving the marginal price up to 680 CNY/MWh and compensating peak-regulation costs through high electricity prices. At this time, new energy output is insufficient due to meteorological constraints. Taking valley period 17 as an example, new energy becomes the marginal resource, and its cleared output accounts for 65% of the total. Coal-fired generation is compressed to a low level, with its cleared output share reduced to only 35%, representing a decrease of 51% compared with period 7. For system operators, the contrast between periods 7 and 17 shows that spot prices and cleared-output structures can reveal regulation-resource scarcity and provide a basis for allocating peak-regulation responsibility. In high-net-load periods, high clearing prices compensate conventional units that provide regulation capability; in low-net-load periods, peak-regulation responsibility is shared between reduced coal-fired output and new energy curtailment.

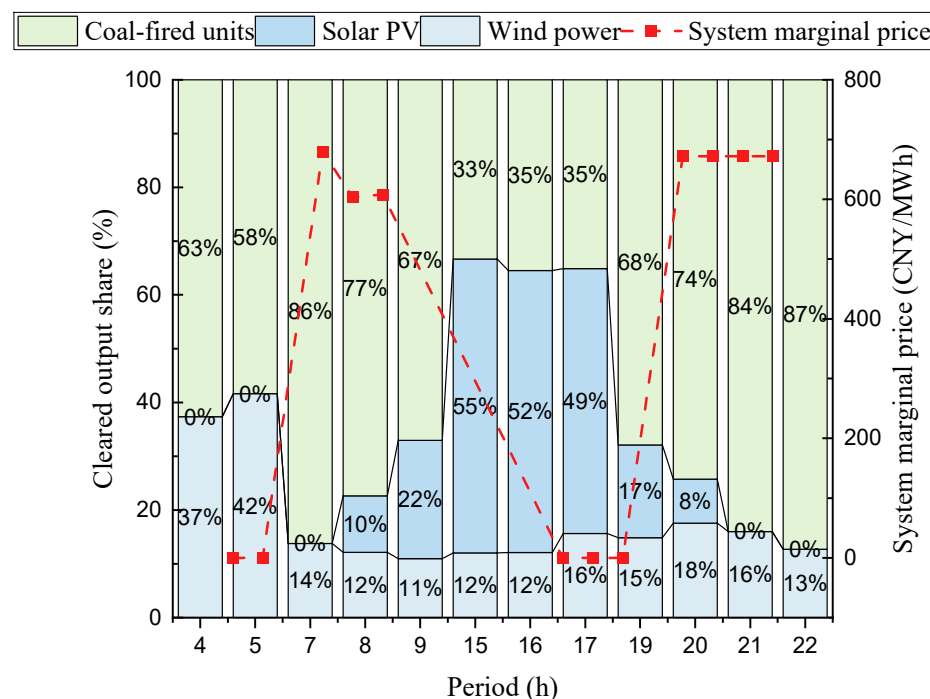


Figure 10. Cleared output shares and marginal prices in typical periods.

6.5.2. Imbalance Funds

The settlement results of energy charges for the generation and demand sides are shown in Table 3. The energy charges consist of day-ahead, intraday, and real-time market energy charges, as well as contract-for-difference charges. The settlement gap in energy charges is affected by the phased arrangement for new energy market participation. At the initial stage of new energy market integration, the electricity charges to be settled amount to CNY 47.039 million on the generation side and CNY 45.971 million on the demand side, resulting in a settlement gap of CNY 1.068 million. In the long term, this gap narrows to CNY 0.884 million.

Table 3. Energy charge settlement results on the generation and demand sides.

In-Market Settlement Item		Total Generation-Side Settlement						Total Demand-Side Settlement			
		Nuclear	Hydro	Wind Power	Solar PV	Coal-Fired Power	Total	Guaranteed Consumption	Agency Purchasing	Market-Based Purchasing	Total
Scenario 1	Medium- and long-term settlement	40.7	−3.1	10.3	25.4	181.6	255.1	3.9	99.4	96.6	199.9
	Day-ahead market settlement	130.6	356.4	0.0	0.0	2564.3	3051.2	604.1	1217.5	2184.8	4006.4
	Intraday market settlement	5.7	0.8	458.4	434.0	112.5	1011.4	33.8	82.0	157.4	273.2
	Real-time market settlement	3.0	0.4	161.1	168.8	52.9	386.2	16.6	33.5	67.4	117.5
Scenario 2	Medium- and long-term settlement	28	−21.9	4.8	25.3	−57.6	−21.4	−48	4.5	−15.2	−58.8
	Day-ahead market settlement	143.7	390	158.8	77.2	2801.4	3571.2	649.9	1294.2	2435.2	4379.3
	Intraday market settlement	6.5	1.4	370.3	442.1	122.7	943.0	52.3	103.2	138.0	293.5
	Real-time market settlement	3.0	0.7	137.0	147.4	55.1	343.2	22.4	40.1	71.1	133.4

Note: The unit of all settlement amounts in this table is 10⁴ CNY.

The composition and allocation of imbalance funds are further calculated and analyzed. The results are shown in Table 4. Guaranteed consumption is forecasted and submitted by the grid company on behalf of users. Deviations in medium- and long-term trading therefore need to be corrected on a rolling basis through multi-month, intra-month, weekly, and multi-day trading. Due to the relatively high forecasting accuracy and stable electricity consumption characteristics on the demand side, the imbalance funds for guaranteed consumption are 7.6×10^4 CNY in both scenarios. These funds are allocated to agency-purchasing users and market-based purchasing users in proportion to their electricity consumption. The allocated amounts are 2.7×10^4 CNY and 4.9×10^4 CNY, respectively. Wind and solar PV output are stochastic and fluctuating. Under the proposed arrangement, mechanism-covered electricity does not independently submit day-ahead market bids. Non-mechanism-covered electricity participates in day-ahead market submissions in phases. As a result, new energy uses balancing services without assuming the corresponding balancing responsibility. In Scenario 1, no new energy electricity independently submits day-ahead market bids. This results in imbalance funds of 99.2×10^4 CNY because the corresponding balancing responsibility is not borne by new energy. In Scenario 2, as new energy gradually participates in the day-ahead market, the imbalance funds narrow to 80.8×10^4 CNY. The accommodation of intermittent wind and solar new energy serves the public interest. Therefore, according to responsibility attribution, wind and solar imbalance funds should be allocated to all users. However, since guaranteed consumption is settled according to the catalog sales tariff, these costs are passed through to all market-based users. Taking Scenario 1 as an example, the wind and solar imbalance funds are allocated to agency-purchasing users and market-based purchasing users in proportion to their electricity consumption. The allocated amounts are 35.1×10^4 CNY and 64.2×10^4 CNY, respectively. The corresponding allocation prices are 9.21 CNY/MWh and 9.45 CNY/MWh, respectively. In Scenario 2, the corresponding allocation prices decrease to 6.83 CNY/MWh and 6.91 CNY/MWh, respectively. For consumers, these results indicate that the proposed mechanism does not eliminate cost pass-through, but makes the sources, amounts, and allocation paths of imbalance funds explicit. Meanwhile, the gradual day-ahead participation of new energy reduces the wind and solar imbalance-fund allocation pressure passed through to the demand side.

Table 4. Calculation and allocation results of imbalance funds.

Scenario	Imbalance Funds	Imbalance Fund Amount (10^4 CNY)	Allocation to Agency Purchasing (10^4 CNY)	Allocation Price for Agency Purchasing (CNY/MWh)	Allocation to Market-Based Purchasing (10^4 CNY)	Allocation Price for Market-Based Purchasing (CNY/MWh)
1	Imbalance funds for guaranteed consumption	7.6	2.7	0.71	4.9	0.72
	Wind and solar imbalance funds	99.2	35.1	9.21	64.2	9.45
2	Imbalance funds for guaranteed consumption	7.6	2.8	0.71	4.8	0.72
	Wind and solar imbalance funds	80.8	28.2	6.83	52.6	6.91

6.6. Mechanism Comparison and Sensitivity Analysis

6.6.1. Comparison Between the Mechanism Price Policy and Government-Authorized Contracts for Difference

To evaluate the stage-specific applicability of the mechanism price policy in the transitional stage of China's spot market development, this paper uses government-authorized contracts for difference (CfDs) as a comparative scenario. The two approaches use the same IEEE 39-bus system, load profile, new energy generation forecast profile, unit parameters, and spot market-clearing model. Under the mechanism price policy, mechanism-covered new energy electricity receives revenue support through off-market price-difference settlement, and the corresponding sustainability price-difference settlement charge is included in system operation charges and passed through to the demand side. Under the government-authorized CfD approach, priority-generation revenue is supported through medium- and long-term financial contracts. The annual government-authorized CfD quantities and contract prices for different generation types are shown in Table 5.

Table 5. Installed capacity, annual quantity covered by government-authorized CfDs, and contract price by generation type.

Generation Type	Installed Capacity/MW	Annual Quantity Covered by Government-Authorized CfDs/GWh	Contract Price/CNY·MWh ^{−1}
Coal-fired power	4520	—	—
Nuclear power	180	1463.65	430
Hydropower	800	2797.825	350
Wind power	1500	3684.05	416
Solar PV	3000	6853.24	416

As shown in Table 6, the differences in total system purchase cost and new energy curtailment between the two approaches are relatively small. This indicates that, under the same spot market-clearing model, changing the policy-support approach does not significantly affect the market-based resource allocation results. In terms of new energy revenue, the mechanism price policy directly stabilizes the comprehensive settlement price of mechanism-covered electricity at 416 CNY/MWh through off-market price-difference settlement. Under the government-authorized CfD approach, the average settlement prices of wind power and solar PV are 413.4 CNY/MWh and 410.6 CNY/MWh, respectively, which are slightly lower than the guaranteed level under the mechanism price policy. These results show that both approaches can support new energy revenue, whereas the mechanism price policy provides a more direct revenue-support path and stronger protection for mechanism-covered electricity.

Table 6. Market-clearing and settlement comparison of the two mechanisms.

Mechanism	Total System Purchase Cost/10 ⁴ CNY	New Energy Curtailment/MW	Average Settlement Price of Wind Power/CNY·MWh ^{−1}	Average Settlement Price of Solar PV/CNY·MWh ^{−1}	System Operation Charge/10 ⁴ CNY	Imbalance Funds/10 ⁴ CNY
Mechanism price policy	4703.9	584.8	416.0	416.0	398.3	—
Government-authorized CfDs	4747.6	576.4	413.4	410.6	—	401.0

From the perspective of settlement implementation, the system operation charge under the mechanism price policy is CNY 3.983 million, whereas the imbalance funds under the government-authorized CfD approach amount to CNY 4.010 million. The two values are therefore broadly comparable in magnitude. However, their cost attributes and formation mechanisms differ. Under the mechanism price policy, the new energy sustainability price-difference settlement charge is treated as a system operation charge, with a clearly defined pass-through direction. By contrast, under the government-authorized CfD approach, imbalance funds involve more complex responsibility-allocation relationships related to priority generation, guaranteed electricity consumption, grid-company agency purchasing, contract curves, and new energy forecast deviations. Therefore, the settlement logic is more complex. Accordingly, when market rules and settlement systems are still in transition, the mechanism price policy has lower implementation complexity and higher operational feasibility.

A limitation of the mechanism price policy is that mechanism-covered electricity does not participate in medium- and long-term trading, thereby reducing demand-side contract coverage. In the case study, demand-side medium- and long-term contract coverage under the mechanism price policy is only 71.2% of that under the government-authorized CfD approach, which increases users' exposure to spot-market price risks. However, this impact remains controllable at the current stage. First, the electricity-generation share of new energy remains significantly lower than its installed-capacity share, so the risk caused by the decline in demand-side contract coverage has not yet been fully amplified. Second, medium- and long-term prices have not yet converged with spot prices. During the transitional stage of the spot market, medium- and long-term prices may even be higher than spot prices, which limits the hedging function of such contracts. In addition, spot market price caps and floors remain in place, which constrains users' short-term exposure to spot price volatility.

6.6.2. Sensitivity Analysis of the New Energy Penetration Level

To examine the adaptability of the proposed trading and settlement mechanism under different new energy penetration levels, three scenarios with new energy installed-capacity shares of 35%, 45%, and 55% are considered. In all scenarios, the system load profile, nuclear and hydropower output profiles, conventional unit parameters, mechanism price, mechanism-covered electricity ratio, and settlement rules remain unchanged. Only the installed capacities of wind power and solar PV and their corresponding forecast output profiles are adjusted. Figure 11 shows the forecast output profiles of wind power and solar PV under different new energy penetration levels.

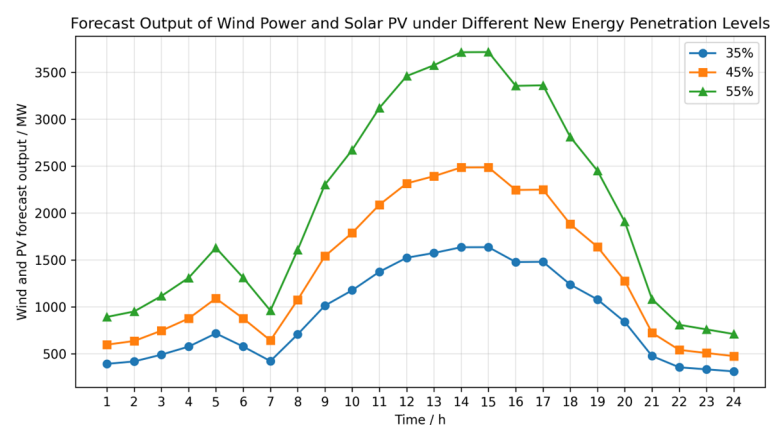


Figure 11. Wind and solar PV forecasts under different new energy penetration levels.

Table 7 presents the market-clearing and settlement results under different new energy penetration levels.

Table 7. Sensitivity results under different new energy penetration levels.

New Energy Installed-Capacity Share/%	Load-Weighted Average Real-Time Clearing Price /CNY·MWh ⁻¹	Weighted Average Real-Time Price of Wind Power /CNY·MWh ⁻¹	Weighted Average Real-Time Price of Solar PV /CNY·MWh ⁻¹	Mechanism Price-Difference Settlement Amount/10 ⁴ CNY	Wind and Solar Imbalance Funds/10 ⁴ CNY	Secondary Allocation Rate /CNY·kWh ⁻¹	Equivalent Purchase Price for Grid-Company Agency Purchasing /CNY·MWh ⁻¹	Equivalent Purchase Price for Market-Based Purchasing /CNY·MWh ⁻¹
35	419.71	394.26	321.19	139.62	66.78	0.0202	439.47	439.99
45	376.26	337.7	261.5	398.3	99.22	0.0401	416.88	416.99
55	331.46	319.05	223.77	714.03	127.44	0.0802	411.26	411.70

From the market-clearing perspective, as the new energy installed-capacity share increases from 35% to 55%, the load-weighted average real-time clearing price decreases from 419.71 CNY/MWh to 331.46 CNY/MWh. This indicates that the expanded output of low-marginal-cost wind power and solar PV replaces part of the output of conventional units, thereby reducing the market-clearing price.

From the new energy revenue perspective, the weighted average real-time prices of both wind power and solar PV decrease as the new energy penetration level increases. The weighted average real-time price decreases from 394.26 CNY/MWh to 319.05 CNY/MWh for wind power and from 321.19 CNY/MWh to 223.77 CNY/MWh for solar PV. The decrease is more pronounced for solar PV because its output is concentrated in midday low-net-load periods, making its market revenue more sensitive to low-price periods and curtailment.

At higher new energy penetration levels, the scale of mechanism-covered electricity increases, whereas the weighted average real-time prices of wind power and solar PV decline. As a result, the gap between the mechanism price and the market reference price widens, and the off-market price-difference settlement amount increases from CNY 1.3962 million to CNY 7.1403 million. This result shows that the mechanism price policy supports new energy revenue but also increases system operation charges and demand-side cost-allocation pressure. In addition, higher new energy penetration leads to larger imbalance funds caused by wind and solar PV forecast deviations. After secondary settlement, the demand-side allocation rate increases from 0.0202 CNY/kWh to 0.0802 CNY/kWh.

Although the secondary allocation rate increases with the new energy penetration level, the spot market price decreases simultaneously. As a result, the equivalent purchase price for grid-company agency purchasing decreases from 439.47 CNY/MWh to 411.26 CNY/MWh, and that for market-based purchasing decreases from 439.99 CNY/MWh to 411.70 CNY/MWh. This indicates that the proposed settlement mechanism can pass new energy revenue compensation and imbalance funds through to the demand side in an orderly manner while keeping users' exposure to spot price risk within a controllable range.

Overall, changes in the new energy penetration level affect market-clearing prices, new energy curtailment, new energy market revenue, mechanism price-difference settlement amounts, imbalance funds, and demand-side cost allocation. The proposed trading and settlement mechanism maintains new energy revenue support, clarifies imbalance-fund allocation, and keeps spot price risk controllable under different new energy penetration levels. These results indicate that the proposed mechanism is not only effective in the baseline scenario, but also remains adaptable under changing new energy penetration conditions.

7. Conclusions

This paper addresses the issues of trading linkage, revenue support, responsibility allocation, and cost pass-through associated with the policy-driven transition toward full-volume participation of new energy in the spot electricity market under the mechanism price policy. A coordinated trading and settlement mechanism with differentiated bidding, settlement, and responsibility-bearing arrangements is proposed by integrating medium- and long-term trading, day-ahead–intraday–real-time spot market clearing, price settlement for the sustainable development of new energy, imbalance-fund identification, and secondary settlement of energy charges. The case study based on the modified IEEE 39-bus system shows that, under the tested conditions, the proposed mechanism can characterize the transmission relationships among spot prices, new energy revenues, mechanism-price difference settlement, imbalance funds, and user-side cost allocation under high new energy penetration. The spot market clearing results reflect the effects of new energy output fluctuations on system regulation requirements and market prices. The price settlement for the sustainable development of new energy provides revenue support for mechanism-covered electricity. The imbalance-fund classification and secondary settlement method further clarify the sources of different charges and their pass-through paths to users. The comparison with the government-authorized contract-for-difference approach and the sensitivity analysis of new energy penetration further indicate that the proposed mechanism has operational adaptability and result robustness within the tested scenarios.

The case study is based on a modified IEEE 39-bus system and several simplified market assumptions. In particular, it assumes rule-compliant bidding behavior and uses given bidding, forecasting, and settlement data as model inputs. Strategic bidding, market power, and information asymmetry are not endogenously modeled in this study. Therefore, the results should be viewed as evidence of feasibility and potential effects under the tested assumptions, rather than as proof of universal effectiveness across Chinese provincial spot markets. In practice, the mechanism's performance and implementation may vary due to provincial differences in resource mix, network constraints, load profiles, market rules, bidding behavior, demand-side participation, ancillary-service arrangements, and settlement procedures. Strategic bidding or imperfect information may further affect clearing prices, dispatch schedules, imbalance-fund formation, and settlement outcomes. In addition, larger provincial systems with shorter clearing intervals, more participants, and stricter security constraints may increase the computational burden of SCUC/SCED clearing. Reliable implementation also depends on adequate data availability, such as bidding data, load and new energy forecast data, contract curves, mechanism-covered electricity information, and settlement records. Moreover, the allocation of imbalance funds and system operation charges must align with provincial market rules, tariff regulations, information-disclosure requirements, and settlement-system capabilities. Future research should evaluate the applicability of the proposed mechanism using real provincial market data, detailed operational rules, actual settlement procedures, and more realistic representations of strategic bidding, market power, and information asymmetry.

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Abbreviations

The following abbreviations are used in this manuscript:

CfD	Contract for Difference
CNY	Chinese Yuan
DA	Day-ahead
ID	Intraday
IEEE	Institute of Electrical and Electronics Engineers
PV	Photovoltaic
NE	New Energy
RT	Real-time
SCED	Security-Constrained Economic Dispatch
SCUC	Security-Constrained Unit Commitment
UC	Unit Commitment

Appendix A

Table A1. Generation portfolio and unit locations in the modified IEEE 39-bus system.

Unit ID	Bus	Unit Type	Installed Capacity/MW
G1	30	Nuclear	50
G2	30	Nuclear	60
G3	30	Hydropower	350
G4	39	Coal-fired	1000
G5	32	Nuclear	70
G6	38	Coal-fired	800
G7	31	Coal-fired	700
G8	31	Solar PV	600
G9	33	Coal-fired	600
G10	33	Coal-fired	640
G11	35	Coal-fired	300
G12	33	Hydropower	450
G13	37	Coal-fired	240
G14	37	Coal-fired	100
G15	36	Coal-fired	80
G16	35	Wind	400
G17	34	Solar PV	700
G18	34	Coal-fired	60
G19	37	Solar PV	800
G20	36	Solar PV	900
G21	39	Wind	500
G22	39	Wind	600

To represent different operating conditions under high new energy penetration, coal-fired units are assumed to submit time-segmented four-segment bid curves in peak, normal, and valley periods. The physical output range of each bid segment remains unchanged across periods, while the submitted bid prices vary by period type. The adjusted bid prices are bounded by the price floor and cap of 0 and 800 CNY/MWh, respectively. The detailed bid parameters used in the baseline case are listed in Table A2.

Table A2. (a) Peak-period segmented bid parameters of coal-fired units. (b) Normal-period segmented bid parameters of coal-fired units. (c) Valley-period segmented bid parameters of coal-fired units.

(a)												
Unit ID	Segment 1			Segment 2			Segment 3			Segment 4		
	Start/MW	End/MW	Price/CNY·MWh ^{−1}	Start/MW	End/MW	Price/CNY·MWh ^{−1}	Start/MW	End/MW	Price/CNY·MWh ^{−1}	Start/MW	End/MW	Price/CNY·MWh ^{−1}
G4	0	250	400	250	500	442	500	750	513	750	1000	588
G6	0	200	464	200	400	510	400	600	589	600	800	672
G7	0	175	472	175	350	518.5	350	525	598.5	525	700	682.5
G9	0	150	528	150	300	578	300	450	665	450	600	756
G10	0	160	536	160	320	586.5	320	480	674.5	480	640	766.5
G11	0	75	592	75	150	646	150	225	741	225	300	800
G13	0	60	656	60	120	714	120	180	800	180	240	800
G14	0	25	664	25	50	722.5	50	75	800	75	100	800
G15	0	20	720	20	40	782	40	60	800	60	80	800
G18	0	15	784	15	30	800	30	45	800	45	60	800

(b)												
G4	0	250	50	250	500	145	500	750	185	750	1000	230
G6	0	200	90	200	400	185	400	600	225	600	800	270
G7	0	175	95	175	350	190	350	525	230	525	700	275
G9	0	150	130	150	300	225	300	450	265	450	600	310
G10	0	160	135	160	320	230	320	480	270	480	640	315
G11	0	75	170	75	150	265	150	225	305	225	300	350
G13	0	60	210	60	120	305	120	180	345	180	240	390
G14	0	25	215	25	50	310	50	75	350	75	100	395
G15	0	20	250	20	40	345	40	60	385	60	80	430
G18	0	15	290	15	30	385	30	45	425	45	60	470

(c)												
G4	0	250	0	250	500	0	500	750	30	750	1000	80
G6	0	200	0	200	400	0	400	600	70	600	800	120
G7	0	175	0	175	350	5	350	525	75	525	700	125
G9	0	150	0	150	300	40	300	450	110	450	600	160
G10	0	160	0	160	320	45	320	480	115	480	640	165
G11	0	75	20	75	150	80	150	225	150	225	300	200
G13	0	60	60	60	120	120	120	180	190	180	240	240
G14	0	25	65	25	50	125	50	75	195	75	100	245
G15	0	20	100	20	40	160	40	60	230	60	80	280
G18	0	15	140	15	30	200	30	45	270	45	60	320

Table A3. Operating parameters of coal-fired units in the baseline case.

Unit ID	P _{max} /MW	P _{min} /MW	Hot Start-Up Cost/CNY	Cold Start-Up Cost/CNY	Minimum on Time/h	Minimum off Time/h	Cooling Time/h	Initial Status/h	Ramp-Up Limit/MW·h ^{−1}	Ramp-Down Limit/MW·h ^{−1}
G4	1000	250	5000	10,000	8	8	5	8	300	350
G6	800	200	5000	10,000	8	8	5	8	240	280
G7	700	182	4500	9000	8	8	5	8	210	245
G9	600	162	2400	4800	4	4	4	−4	240	270
G10	640	160	2000	4000	5	5	4	8	256	288
G11	300	96	1500	3000	5	5	4	8	120	135
G13	240	90	1100	2200	3	3	3	−3	192	204
G14	100	18	1000	2000	3	3	3	−3	80	85
G15	80	16	960	1820	6	6	4	8	40	44
G18	60	10	550	1100	3	3	2	8	30	33

Note: P_{max} and P_{min} denote the maximum and minimum output limits of each coal-fired unit, respectively. A positive initial status indicates that the unit has been continuously online for the corresponding number of hours before the optimization horizon, whereas a negative initial status indicates that the unit has been continuously offline. If the offline duration before start-up is longer than the cooling time, the cold start-up cost is applied; otherwise, the hot start-up cost is applied.

Table A4. Time-series input data for day-ahead market clearing in the baseline case.

Period/h	Load Demand/MW	Wind Power Forecast/MW	Solar PV Forecast/MW
1	4043.44	598	0
2	3051.97	637	0
3	3027.88	747	0
4	2834.71	877	0
5	3124.29	1091	0
6	4445.6	878	0
7	5188.05	643	0
8	5272.6	578	498
9	5305.93	513	1028
10	5401.3	451	1338
11	5678.55	395	1694
12	5665.09	417	1899
13	5673.94	346	2047
14	5466.57	363	2123
15	3964.64	449	2038
16	3921.54	421	1825
17	3839.55	542	1708
18	5330.72	591	1291
19	5783.96	759	881
20	5659.28	871	406
21	5224.65	725	0
22	4970.4	542	0
23	4504.97	509	0
24	4426.25	476	0

Table A5. Branch parameters and scaled thermal limits of the modified IEEE 39-bus system.

Branch ID	From Bus	To Bus	Reactance/p.u.	Thermal Limit/MW	Branch ID	From Bus	To Bus	Reactance/p.u.	Thermal Limit/MW
1	1	2	0.0411	1520	24	16	24	0.0060	1520
2	1	39	0.0250	1520	25	17	18	0.0080	1520
3	2	3	0.0151	1520	26	17	27	0.0170	1520
4	2	25	0.0086	1520	27	21	22	0.0140	1520
5	3	4	0.0213	1520	28	22	23	0.0100	1520
6	3	18	0.0133	1520	29	23	24	0.0350	1520
7	4	5	0.0128	1520	30	25	26	0.0320	1520
8	4	14	0.0129	1520	31	26	27	0.0150	1520
9	5	6	0.0026	1520	32	26	28	0.0470	1520
10	5	8	0.0112	1520	33	26	29	0.0630	1520
11	6	7	0.0092	1520	34	28	29	0.0150	1520
12	6	11	0.0082	1520	35	12	11	0.0440	1520
13	7	8	0.0046	1520	36	12	13	0.0440	1520
14	8	9	0.0363	1520	37	6	31	0.0250	1790
15	9	39	0.0250	1520	38	10	32	0.0200	1520
16	10	11	0.0043	1520	39	19	33	0.0140	1520
17	10	13	0.0043	1520	40	20	34	0.0180	1520
18	13	14	0.0101	1520	41	22	35	0.0140	1520
19	14	15	0.0217	1520	42	23	36	0.0270	1520
20	15	16	0.0094	1520	43	25	37	0.0230	1520
21	16	17	0.0089	1520	44	2	30	0.0180	1960
22	16	19	0.0195	1520	45	29	38	0.0160	1520
23	16	21	0.0135	1520	46	19	20	0.0140	1520

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