

Article

Research on Capacity Cost Compensation Mechanism for Coal-Fired Power in the Electricity Market Environment

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Abstract

With the rapid expansion of renewable energy and the acceleration of electricity market reforms, coal-fired units are facing increasing difficulty in recovering fixed costs due to marginal cost-based bidding competition and depressed clearing prices caused by low-cost renewable integration, circumstances in which reasonable returns and investment incentives for coal-fired power plants are not guaranteed. To address this issue, this paper proposes a capacity cost compensation mechanism for coal-fired power in the electricity market environment. First, a joint clearing model for the electricity spot market considering both energy and reserve services is established, and annual market operation simulations are conducted to obtain unit output schedules, clearing prices, and annual revenues. Second, based on the long-term simulation results, the marginal clearing probability and fixed cost recovery deficit of each coal-fired unit are calculated, and a capacity compensation pricing method based on marginal clearing probability weighting is proposed to determine the system unit capacity compensation price. Subsequently, the compensated capacity is determined using the availability factor method, comprehensively reflecting each unit's actual contribution to system capacity adequacy. Finally, case studies conducted on a modified IEEE 30-bus system validate the effectiveness of the proposed mechanism. The results demonstrate that following the implementation of the proposed mechanism, the investment payback periods of all coal-fired units are reduced to within the planned 20-year horizon, thereby ensuring the sustainable operation of coal-fired units and maintaining adequate reliability margins in the power system.

Keywords: coal-fired power; capacity cost compensation; electricity market; resource adequacy



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1. Introduction

In response to global carbon neutrality goals, the installed capacity share of renewable energy sources such as wind and photovoltaic power has been continuously increasing [1]. Propelled by this worldwide momentum, the global cumulative installed capacity of wind and solar power surpassed 3000 GW at the end of 2025 [2,3]. Meanwhile, electricity market reforms to optimize resource allocation and improve energy efficiency are accelerating [4]. However, these changes have posed severe challenges to the stable and reliable operation of coal-fired power plants. In competitive electricity markets, coal-fired units bid based on marginal costs, and high-cost units often struggle to recover their fixed costs solely through energy prices, leading to the well-known “missing money” problem [5]. Further,

large-scale renewable integration, with its extremely low marginal costs, depresses spot market clearing prices, further eroding coal-fired revenues and intensifying cost-recovery pressures [6]. Consequently, the potential premature retirement of coal-fired units due to economic distress would undermine the system's generation and regulation capabilities, jeopardizing the sustainable and healthy development of the power system [7,8]. Therefore, establishing appropriate mechanisms to ensure adequate compensation for coal-fired capacity has become a critical priority for maintaining long-term system security and reliability.

Currently, generation capacity adequacy mechanisms in power systems comprise two categories: capacity mechanisms and scarcity pricing mechanisms [9]. Capacity mechanisms encompass capacity markets, capacity compensation mechanisms, and strategic reserve mechanisms [10]. Capacity markets and scarcity pricing mechanisms can guide systems toward optimal capacity allocation and are suitable for regions with well-developed electricity markets, whereas strategic reserve mechanisms are more applicable to regions experiencing substantial unit retirements [11]. In comparison, the capacity compensation mechanism demonstrates unique advantages in the early stages of electricity market development, owing to its simple design and low implementation risk [12,13].

Regarding the design of capacity compensation mechanisms, existing research primarily focuses on two dimensions: compensation price determination and effective capacity assessment [14–18]. In terms of compensation price determination, Liu et al. [14] and Liu et al. [15] both determined compensation prices based on the investment cost shortfall of marginal units, with the former directly calculating cost shortfalls and the latter annualizing marginal unit investment costs during peak load periods. Furthermore, Yu et al. [16] propose two differentiated schemes based on full fixed cost recovery and long-term marginal costs, respectively. Regarding effective capacity assessment, Zhang et al. [17] comprehensively consider the effective capacity of various power source types and system generation capacity adequacy. Similarly, Liu et al. [14] and Liu et al. [15] both employ average available capacity methods, with the former based on unit output during system peak load periods and the latter directly calculating the average available capacity of thermal units. Yu et al. [16] introduce a reduction coefficient of less than 0.8 that is applied to assessed capacity values. Additionally, Liu et al. [18] establish a specialized compensation mechanism for recovering deep peak-shaving retrofit costs of thermal power units. However, existing research remains limited in precisely quantifying coal-fired investment cost recovery shortfalls, as it often relies on a single marginal unit as the pricing reference and offers insufficient treatment of multi-product revenues, failing to establish a systematic link with comprehensive annual market results.

Against this backdrop, this paper proposes a capacity cost compensation mechanism for coal-fired power plants in the electricity market environment. The main contributions of this work are as follows: (1) a comprehensive framework encompassing capacity pricing, quota determination, cost allocation, and settlement with performance assessment is established; (2) a capacity compensation price calculation method based on marginal clearing probability weighting is proposed, which avoids the bias resulting from using a single marginal unit as the pricing reference; and (3) a compensated capacity determination method considering available capacity and compensation requirements is designed, which comprehensively reflects the contribution of each unit's actual generation capability and availability to system capacity adequacy.

The remainder of this paper is organized as follows: Section 2 presents the overall framework of the coal-fired power capacity compensation mechanism. Section 3 develops the electricity market clearing model for coal-fired units participating in energy and reserve markets. Section 4 elaborates the detailed methodology for capacity compensation price calculation and compensated capacity determination. Section 5 validates the effectiveness

of the proposed mechanism through case studies. Section 6 concludes the paper and outlines directions for future research.

2. Coal-Fired Power Capacity Compensation Mechanism Framework

The main entities involved in the capacity compensation mechanism include power dispatching, trading, and regulatory institutions, with the key elements of the framework being capacity price and compensable capacity. The capacity price should reflect the unrecovered costs and value of generation capacity, while the compensable capacity should be determined based on the results of generation unit adequacy assessment in conjunction with system requirements. This paper comprehensively considers the revenues from both energy and reserve spot markets and designs the capacity compensation mechanism framework shown in Figure 1, which can be divided into the four steps outlined below.

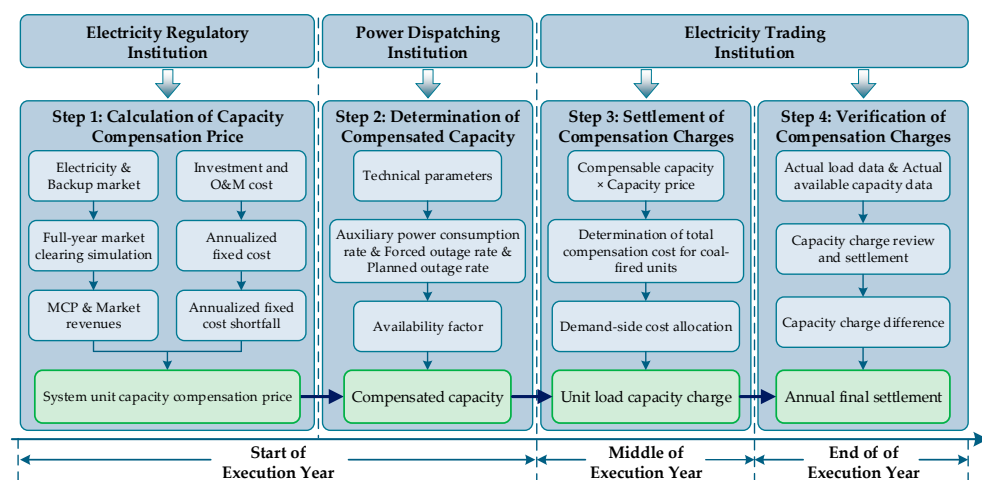


Figure 1. Coal-fired power capacity compensation mechanism framework.

Step 1: Calculation of capacity compensation price. Prior to the formal operation of the electricity spot market, the market operating institution conducts full-cycle joint simulation of spot energy and reserve markets based on the annual forecasts of wind power and load to determine the marginal clearing probability of each unit. This approach addresses the difficulty of uniquely identifying marginal units due to supply–demand fluctuations and adjustments in market participants’ bidding quantities and prices during long-term market operation. Through the annual joint simulation of energy and reserve markets, the energy revenues, reserve revenues, and annual fuel costs of each unit in the spot market can be obtained. On this basis, the annualized fixed costs are determined from the annual investment and operation and maintenance costs of coal-fired units. The annualized fixed cost recovery gap is calculated by deducting the net energy revenues and net reserve revenues from the spot market, and the system unit capacity compensation price is then determined through probability-weighted aggregation based on marginal clearing probabilities.

Step 2: Determination of compensated capacity. The average auxiliary power consumption rate is determined based on the technical parameters of units at each capacity level. Combined with the statistics of planned and unplanned outage periods, the average outage rate is obtained, thereby revealing the compensable capacity of each coal-fired unit.

Step 3: Settlement of compensation charges. During the execution year, the electricity trading institution conducts settlement based on the compensable capacity and capacity price of generating units. The total compensation cost for coal-fired units is determined according to the system unit capacity compensation price and the compensable capacity of coal-fired units. Users allocate the total compensation cost based on their projected

electricity consumption, thereby determining the capacity charges to be recovered through spot energy market settlement in that year.

Step 4: Verification of compensation charges. At the end of the execution year, the electricity trading institution conducts the final settlement of capacity compensation costs. This process is executed by sequentially repeating the procedures outlined in Steps 1 through 3 using realized operational data. Specifically, the initial annual forecasts of wind power and load and the statistical estimates of planned and unplanned outage periods are replaced with the actual wind power output, actual system load, and actual recorded outage hours logged during the operating year. Based on these realized parameters, the actual system unit capacity compensation price and the actual compensable capacity of each unit are recalculated. The final total compensation costs and user allocations are then exactly determined to complete the ex-post settlement.

3. Modeling of the Coal-Fired Power Units Participating in the Electricity Market Clearing

3.1. Overview of the Electricity Market Clearing Model

The electricity market considered in this study is the spot market, in which coal-fired generating units participate in both the energy market and the reserve ancillary service market, thereby obtaining revenues from multiple sources. Accordingly, this work focuses on the co-optimization of energy and reserve services.

Two types of objective functions are commonly adopted in market clearing models. The first minimizes the total purchasing cost, resulting in lower clearing prices and benefiting consumers; however, the resulting dispatch solution is not system-optimal. The second minimizes the total system operating cost, which may yield relatively higher clearing prices but ensures globally optimal system operation [19]. Given that this paper investigates market operation under high wind power penetration and emphasizes overall system efficiency, total operating cost minimization is selected as the objective to guarantee globally optimal dispatch.

The total operating cost consists of energy production costs and reserve costs. Energy production costs include fuel and start-up/shutdown costs. Reserve costs typically contain capacity and fuel-related components, but this paper considers only the opportunity cost of reserves and excludes fuel consumption during reserve deployment. Furthermore, considering the superior active regulation capability of wind power units [20], wind generation is incorporated as a decision variable for coordinated dispatch with conventional generators. A wind curtailment penalty is introduced to simultaneously reduce total costs and promote renewable energy utilization, thus achieving both economic and environmental objectives.

In summary, the optimization objective of the proposed market clearing model includes fuel costs, start-up and shutdown costs, reserve capacity costs, and penalties for wind curtailment.

3.2. Construction of the Joint Clearing Model for the Electricity Spot Market

3.2.1. Objective Function

Based on the fundamental principles of power system economics and standard joint market clearing frameworks [4], the electricity spot market clearing model proposed in this study adopts the minimization of the total system operating cost as its optimization objective. The decision variables include the cleared output of conventional and wind power units, the procurement of upward and downward reserves, and the unit commitment status of thermal generating units. The formulation is detailed as follows:

$$\min \sum_{t=1}^T \sum_{i=1}^{N_g} \left[C_i^{fuel}(P_{i,t}) + C_i^{UD}(x_{i,t}, y_{i,t}) + C_i^R(P_{i,t}^{UR}, P_{i,t}^{DR}) \right] + \sum_{t=1}^T \sum_{j=1}^{N_w} C_j^{WC}(P_{j,t}^{wp}, P_{j,t}^w) + K_{Ls} P_{Ls,t} \quad (1)$$

where

$$C_i^{fuel}(P_{i,t}) = a_i P_{i,t}^2 + b_i P_{i,t} + c_i \quad (2)$$

$$C_i^{UD}(x_{i,t}, y_{i,t}) = C_i^{SU} x_{i,t} + C_i^{SD} y_{i,t} \quad (3)$$

$$C_i^R(P_{i,t}^{UR}, P_{i,t}^{DR}) = C_i^{UR} P_{i,t}^{UR} + C_i^{DR} P_{i,t}^{DR} \quad (4)$$

$$C_j^{WC}(P_{j,t}^{wp}, P_{j,t}^w) = K_{wc}(P_{j,t}^{wp} - P_{j,t}^w) \quad (5)$$

where T is the number of simulation periods; N_g is the number of coal-fired power units; N_w is the number of wind power units; C_i is the fuel cost of coal-fired unit i ; $P_{i,t}$ is the active power output of coal-fired unit i in period t ; a_i , b_i , and c_i are the coefficients for the quadratic, linear, and constant terms of the fuel cost for coal-fired unit i ; $C_i^{UD}(x_{i,t}, y_{i,t})$ is the startup/shutdown cost of coal-fired unit i ; $x_{i,t}$ and $y_{i,t}$ are the startup and shutdown states of coal-fired unit i in period t , respectively; C_i^{SU} and C_i^{SD} are the startup and shutdown costs of coal-fired unit i per instance; $C_i^R(P_{i,t}^{UR}, P_{i,t}^{DR})$ is the reserve cost of coal-fired unit i ; $P_{i,t}^{UR}$ and $P_{i,t}^{DR}$ are the upward and downward spinning reserve capacities of coal-fired unit i in period t , respectively; C_i^{UR} and C_i^{DR} are the upward and downward spinning reserve costs for coal-fired unit i ; $C_j^{WC}(P_{j,t}^{wp}, P_{j,t}^w)$ is the wind curtailment penalty cost for wind power unit j in period t ; K_{wc} is the wind curtailment penalty coefficient; $P_{j,t}^{wp}$ and $P_{j,t}^w$ are the forecasted and actual outputs of wind power unit j in period t , respectively; $P_{Ls,t}$ is the load shedding power at time t , and K_{Ls} is the load shedding penalty coefficient.

3.2.2. Constraints

Based on the theoretical framework established in Reference [4], the operational and physical constraints adopted in this model are detailed below.

1. System Operating Constraints

The power balance constraint can be expressed as

$$P_{Ls,t} = P_{L,t} - \sum_{i=1}^{N_g} P_{i,t} + \sum_{j=1}^{N_w} P_{j,t}^w \quad (6)$$

where $P_{L,t}$ is the system load at time period t .

The load shedding constraint can be formulated as

$$0 \leq P_{n,t}^{Ls} \leq P_{n,t}^L \quad (7)$$

where $P_{n,t}^{Ls}$ represents the load shedding power at node n during time period t , and $P_{n,t}^L$ represents the load power at node n during time period t .

2. Unit Operating Constraints

The wind power output constraint can be expressed as

$$0 \leq P_{j,t}^w \leq P_{jt}^{wp} \quad (8)$$

The output constraint for coal-fired units is as follows:

$$u_{i,t} P_i^{\min} \leq P_{i,t}^{\min} \leq P_{i,t} \leq P_{i,t}^{\max} \leq u_{i,t} P_i^{\max} \quad (9)$$

where $u_{i,t}$ represents the operating status of coal-fired unit i at time t ($u_{i,t} = 1$ indicates that unit i is online, and $u_{i,t} = 0$ indicates that unit i is offline); $P_i^{\max}$ and $P_i^{\min}$ represent the maximum and minimum technical outputs of coal-fired unit i , respectively; $P_{i,t}^{\max}$ and $P_{i,t}^{\min}$ represent the upper and lower output limits of coal-fired unit i at time period t .

The ramp rate constraint for coal-fired units can be represented as

$$\begin{cases} P_{i,t} - P_{i,t-1} \leq \Delta P_i^{up} u_{i,t-1} + P_{i,t}^{\min} (u_{i,t} - u_{i,t-1}) + P_{i,t}^{\max} (1 - u_{i,t}) \\ P_{i,t-1} - P_{i,t} \leq \Delta P_i^{down} u_{i,t} - P_{i,t}^{\min} (u_{i,t} - u_{i,t-1}) + P_{i,t}^{\max} (1 - u_{i,t-1}) \end{cases} \quad (10)$$

where ΔP_i^{up} and ΔP_i^{down} represent the maximum upward and downward ramp rates of coal-fired unit i , respectively.

The minimum startup and shutdown time constraints for coal-fired units are

$$\begin{cases} \sum_{k=t}^{t+T_{i,\min}^{on}-1} (1 - u_{i,k}) \geq (u_{i,t-1} - u_{i,t}) T_{i,\min}^{on} \\ \sum_{k=t}^{t+T_{i,\min}^{off}-1} (1 - u_{i,k}) \geq (u_{i,t} - u_{i,t-1}) T_{i,\min}^{off} \end{cases} \quad (11)$$

where $T_{i,\min}^{on}$ and $T_{i,\min}^{off}$ represent the minimum startup and shutdown times for coal-fired unit i , respectively.

The startup and shutdown logic constraint for coal-fired units can be expressed as

$$\begin{cases} x_{i,t} + y_{i,t} = 1 \\ u_{i,t} - u_{i,t-1} = x_{i,t} - y_{i,t} \end{cases} \quad (12)$$

3. System Reserve Service Constraints

The reserve capacity constraints are as follows:

$$\begin{cases} 0 \leq P_{i,t}^{UR} \leq \min \{ P_{i,t}^{\max} - P_{i,t}, P_{i,\max}^{UR} \} \\ 0 \leq P_{i,t}^{DR} \leq \min \{ P_{i,t} - P_{i,t}^{\min}, P_{i,\max}^{DR} \} \end{cases} \quad (13)$$

where $P_{i,\max}^{UR}$ and $P_{i,\max}^{DR}$ represent the maximum upward and downward spinning reserve capacities of coal-fired unit i , respectively.

The reserve demand constraint is as follows:

$$\begin{cases} \sum_{i=1}^{N_g} P_{i,t}^{UR} \geq \alpha P_{L,t} + \sum_{j=1}^{N_w} k_{down} P_{j,t}^w \\ \sum_{i=1}^{N_g} P_{i,t}^{DR} \geq \beta P_{L,t} + \sum_{j=1}^{N_u} k_{down} P_{j,t}^w \end{cases} \quad (14)$$

where α and β represent the reserve demand coefficients for upward and downward reserves, respectively; k_{down} and k_{up} represent the upward and downward reserve demand coefficients declared by wind power units. The setting of reserve demand coefficients aims to characterize the relationship between the amount of renewable energy consumed and the system's reserve requirements. As the consumption of renewable energy increases, the system's uncertainty also rises, thereby increasing the demand for reserve capacity accordingly.

4. System Network Constraints

The node power balance constraint is as follows:

$$P_{line,t} = H [X_g P_{i,t} + X_w P_{i,t}^w - (P_{L,t} - P_{Ls,t})] \quad (15)$$

where $P_{line,t}$ is the branch power flow at time period t ; H is the conversion matrix that represents the relationship between branch power flow and the node's coal-fired power, wind power, and load; X_g and X_w are sparse matrices representing the correspondence between coal-fired units and wind power units with the nodes.

The transmission line flow constraint is as follows:

$$P_{L,min} \leq P_{line,t} \leq P_{L,max} \quad (16)$$

where $P_{L,min}$ is the minimum load on the branch, and $P_{L,max}$ is the maximum load on the branch.

3.2.3. Revenue Calculation

Although DC network constraints (including nodal balance and transmission limits) are included in the market-clearing model to ensure the physical feasibility of system operation, congestion rents and transmission loss components are not incorporated into the pricing mechanism in this study. Consequently, nodal prices are assumed to be identical across all buses and are determined by the Lagrange multiplier associated with the system-wide power balance constraint. The resulting electricity price therefore represents a uniform market-clearing price for coal-fired generating units [21]. In addition, the reserve prices for coal-fired units can be derived from the Lagrange multipliers of the reserve requirement constraints.

To represent annual operation while maintaining computational tractability, the simulation is performed using four representative days corresponding to the four seasons. Each representative day consists of 24 hourly periods and is assigned a seasonal weight according to the number of days it represents in a year (91, 94, 91, and 89 days, respectively). The results of each representative day are aggregated using these weights to obtain annual values.

Based on the resulting electricity and reserve prices, the annual net revenue of a coal-fired generating unit in the spot market is calculated as follows:

$$I_{e,i} = \sum_{s \in S} D_s \sum_{t \in T} [(\rho_{s,i,t}^E - \rho_{s,i,t}^{\text{fuel}})P_{s,i,t}\Delta t - (C_i^{\text{SU}}x_{s,i,t} + C_i^{\text{SD}}y_{s,i,t})\Delta t] + \sum_{s \in S} D_s \sum_{t \in T} [(\rho_{s,i,t}^{\text{UR}} - C_i^{\text{UR}})P_{s,i,t}^{\text{UR}}\Delta t + (\rho_{s,i,t}^{\text{DR}} - C_i^{\text{DR}})P_{s,i,t}^{\text{DR}}\Delta t] \quad (17)$$

where $I_{e,i}$ is the annual net revenue of coal-fired unit i ; D_s denotes the number of days represented by the typical day in each season; S is the set of the four seasons (spring, summer, autumn, and winter); $\rho_{s,i,t}^E$ is the clearing price of coal-fired unit i at time period t on representative day of season s ; $\rho_{s,i,t}^{\text{fuel}}$ is the fuel cost per unit electricity of coal-fired unit i at time period t on representative day of season s ; $P_{s,i,t}$ is the power output of coal-fired unit i at time period t on representative day of season s ; $x_{s,i,t}$ and $y_{s,i,t}$ are the start-up and shut-down status of coal-fired unit i at time period t on representative day of season s , respectively; $\rho_{s,i,t}^{\text{UR}}$ and $\rho_{s,i,t}^{\text{DR}}$ are the up and down spinning reserve prices of coal-fired unit i at time period t on representative day of season s , respectively; $P_{s,i,t}^{\text{UR}}$ and $P_{s,i,t}^{\text{DR}}$ are the reserve capacities of coal-fired unit i at time period t on representative day of season s , respectively; and Δt is the unit scheduling period, which is set to 1 h in this paper.

4. The Coal-Fired Power Capacity Cost Compensation Mechanism Under the Electricity Market Environment

4.1. Calculation of Capacity Compensation Price

To reflect the value of generation capacity, the system-wide unit capacity compensation price should be determined based on the annualized investment costs of marginal units over a long-term period. However, in actual market operations, marginal units vary

across different time periods due to supply–demand fluctuations and adjustments in market participants’ bidding quantities and prices, making it difficult to uniquely identify a reference unit. To address this issue, this paper proposes a capacity compensation price calculation method based on the marginal clearing probability. First, through long-term spot energy market operation simulations, the number of periods each unit serves as the marginal unit is counted to calculate the marginal clearing probability. Under the Locational Marginal Pricing (LMP) principle, a marginal unit is defined as the generator providing the last increment of energy required to satisfy system demand, with the clearing price derived from the Lagrangian multiplier of the power balance constraint. The marginal unit is identified through a joint evaluation of market clearing results and unit operating conditions. For any given interval, all committed generators that have not reached their maximum output limits are first selected to form a candidate set with regulation capability. Within this set, the generator with the highest offer price whose infinitesimal output variation directly alters the Lagrangian multiplier of the system power balance constraint is identified as the unique marginal unit for that interval. Units that are forced online due to minimum output or startup constraints but lack marginal adjustment capability are treated as price takers and excluded from marginal unit identification. Second, the fixed cost recovery deficit is determined based on the annualized investment and operation and maintenance costs of coal-fired units. Finally, the system-wide unit capacity compensation price is obtained by weighting and summing the per-unit-capacity fixed cost recovery deficit of each unit according to its marginal clearing probability. This method not only avoids over-compensation or under-compensation caused by selecting a single marginal unit but also reasonably reflects the contribution of different units to system capacity value.

First, based on the simulation clearing results of the long-term spot electricity market, the marginal units for each time period are determined, and the marginal clearing probabilities of each unit are subsequently calculated. The formula is

$$\varphi_i = \frac{T_i}{\sum_{i \in N_g} T_i} \quad (18)$$

where φ_i is the marginal clearing probability of coal-fired unit i in the spot market simulation; T_i is the annual number of marginal clearing periods for coal-fired unit i .

Subsequently, the annual fixed cost is calculated, including annualized investment and O&M costs, as follows:

$$C_{fix,i}^{ann} = C_{inv,i}^{ann} + C_{om,i}^{ann} \quad (19)$$

where

$$C_{inv,i}^{ann} = \frac{1}{P_i^{max}} \frac{\beta \times (1 + \beta)^Y}{(1 + \beta)^Y - 1} C_{inv,i} \quad (20)$$

where $C_{fix,i}^{ann}$ is the annual fixed cost of coal-fired unit i ; $C_{inv,i}^{ann}$ is the annualized investment cost of coal-fired unit i ; $C_{om,i}^{ann}$ is the annual operation and maintenance (O&M) cost of coal-fired unit i ; β is the real discount rate; Y is the planned investment recovery period; and $C_{inv,i}$ is the investment cost of coal-fired unit i .

Accordingly, the unit capacity fixed cost recovery deficit of coal-fired unit i can be calculated as

$$C_{lack,i} = C_{fix,i}^{ann} - \frac{I_{e,i}}{P_i^{max}} \quad (21)$$

Based on the per-unit-capacity fixed cost recovery deficit of coal-fired units, a weighted average is calculated using the marginal clearing probability as the weight to determine the annual unit capacity compensation price, as detailed below:

$$\rho_c = \sum_{i \in N_g} \varphi_i C_{lack,i} \quad (22)$$

4.2. Determination of Compensated Capacity

To accurately assess the actual contribution of coal-fired units to system capacity adequacy, it is necessary to comprehensively consider both the actual generation capability and availability level of each unit. This study employs the availability factor method to determine the available capacity of coal-fired units, where the factor comprehensively reflects the combined effects of planned outages, unplanned outages, and derating on the actual available capacity.

Building upon this foundation, and referring to the actual available capacity of coal-fired units in electricity markets, as well as the system capacity adequacy assessment method proposed in Reference [22], this study calculates the available capacity of coal-fired unit i in the target year using Equations (23)–(25):

$$P_{c,i} = k_i P_i^{\max} \quad (23)$$

$$k_i = (1 - \lambda_i) \frac{T_{AH,i}}{D \cdot T} \quad (24)$$

$$T_{AH,i} = D \cdot T - T_{PS,i} - T_{US,i} \quad (25)$$

where $P_{c,i}$ is the compensated capacity of coal-fired unit i ; k_i is the annual availability factor of coal-fired unit i ; λ_i is the auxiliary power rate of coal-fired unit i ; $T_{AH,i}$ is the annual available hours of coal-fired unit i ; $T_{PS,i}$ is the planned outage hours of coal-fired unit i ; and $T_{US,i}$ is the unplanned outage hours of coal-fired unit i .

4.3. Settlement of Capacity Compensation Charge

The settlement module calculates the capacity compensation for each power source based on the principle of “compensated capacity $\times$ capacity price.” Specifically, the monthly revenue of generating unit i under the capacity compensation mechanism is given by

$$R_i = \rho_c \cdot P_{c,i} \quad (26)$$

where R_i is capacity compensation revenue of unit i .

The annual system capacity compensation charge is allocated to the demand side. The capacity charge per unit load is calculated as

$$\rho_{c,L} = \frac{\sum_{i \in N_g} R_i}{\sum_{d \in D} \sum_{t \in T} P_{L,d,t}} \quad (27)$$

4.4. Solving of System Unit Capacity Compensation Price

Based on the proposed capacity compensation mechanism, the calculation process for the system unit’s capacity compensation price is systematically illustrated in Figure 2. The workflow commences with the data preparation phase, which involves acquiring wind and solar generation profiles, annual net load curves, and the comprehensive technical–economic parameters of all participating generating units. Following this, an annual electricity spot market simulation is performed. This simulation jointly considers both

energy and reserve revenues to accurately derive the annual net revenues alongside the marginal clearing probabilities for each coal-fired unit. Subsequently, a cost recovery deficit assessment is conducted to calculate the specific annual fixed cost recovery deficit for each unit based on the preceding simulation outcomes. Ultimately, in the compensation price determination phase, the final system unit capacity compensation price is formally established by calculating the weighted average of these individual cost recovery deficits, utilizing the previously derived marginal clearing probabilities.

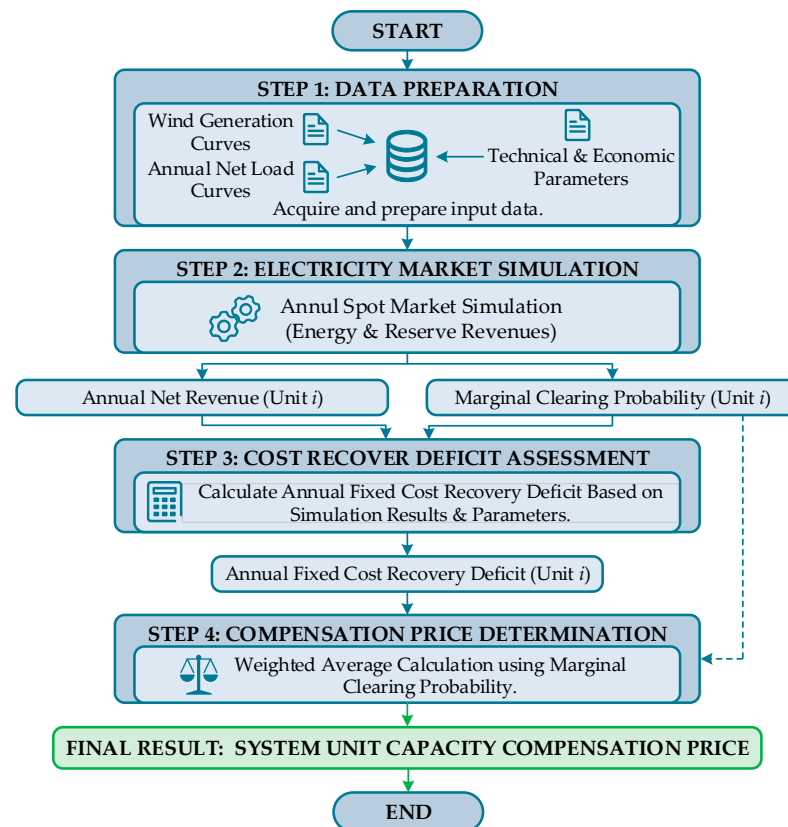


Figure 2. Calculation process of system unit capacity compensation price.

5. Case Study Analysis

5.1. Case Study Base Data

To verify the effectiveness of the proposed capacity compensation mechanism for coal-fired units, this section conducts case studies based on a modified IEEE 30-bus system. The topology of the case system, shown in Figure 3, includes 41 transmission lines, 20 load buses, six coal-fired units (G1–G6), and one wind power unit (W1), where wind unit W1 is connected to bus 20. The technical parameters and bidding information of the coal-fired units are referenced from [23], as detailed in Table 1. Furthermore, the payback period for coal-fired units is set to 20 years, and the investment costs and operation and maintenance costs are configured according to [24], as shown in Table 2. Additionally, the equivalent forced outage rates of each coal-fired unit are set based on the “National Power Reliability Status Report for the First Half of 2020” [25], while the auxiliary power consumption rates and scheduled maintenance rates are taken from the average values of units with corresponding capacity levels in actual power grids, as detailed in Table 3. The unit availability factors are calculated using Equations (24) and (25).

Regarding the operational parameters, the load power forecast curves and wind power output forecasts for typical days in four seasons of the case system are shown in Figures 4 and 5, respectively. And the penalty cost for load shedding is 5000 CNY/(MW·h). The

up and down reserve requirement coefficients for load are set at 5% and 6%, respectively, while both the up and down reserve requirement coefficients for wind power are set at 25%. Moreover, the wind curtailment penalty cost is set at 1000 CNY/(MW·h).

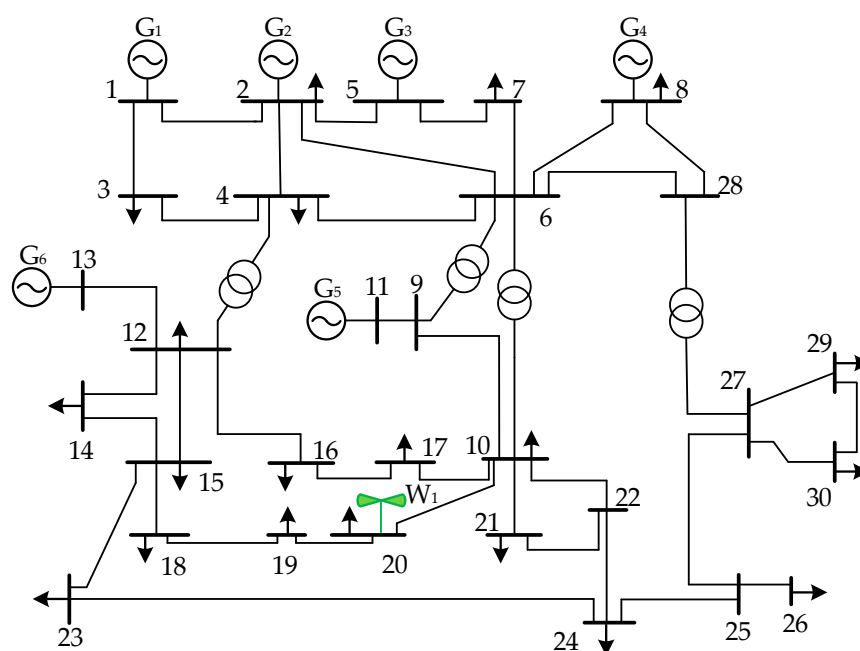


Figure 3. Modified IEEE 30-bus system.

Table 1. Technical parameters of coal-fired units.

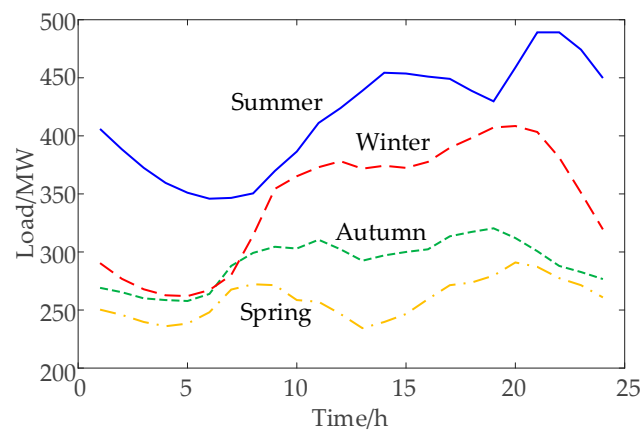
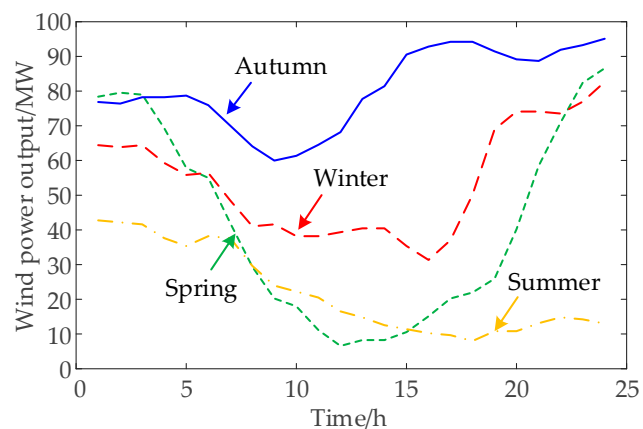
Unit Number	G ₁	G ₂	G ₃	G ₄	G ₅	G ₆
Maximum technical output of unit (p.u.)	2.00	0.80	0.50	0.40	0.35	0.30
Minimum technical output of unit (p.u.)	0.80	0.30	0.15	0.18	0.12	0.10
Fuel cost quadratic coefficient a (CNY/MW ²)	0.3197	0.2595	0.2642	0.2894	0.2771	0.3013
Fuel cost linear coefficient b (CNY/MW)	319.8	333.8	345.8	364.6	374.8	385.7
Fuel cost constant coefficient c (CNY)	0	0	0	0	0	0
Up/down ramp rate (p.u./h)	0.80	0.40	0.35	0.35	0.40	0.22
Minimum shutdown/startup duration (h)	6.00	4.00	3.00	2.00	1.00	1.00
Startup cost (CNY/instance)	80,000	50,000	20,000	8600	2000	500
Shutdown cost (CNY/instance)	80,000	50,000	20,000	8600	2000	500
Upward spinning reserve cost (CNY/MW)	111.80	129.80	137.30	141.30	114.30	117.80
Downward spinning reserve cost (CNY/MW)	96.60	124.40	143.60	130.90	116.00	134.30
Maximum upward spinning reserve capacity (p.u.)	0.068	0.066	0.061	0.074	0.049	0.062
Maximum downward spinning reserve capacity (p.u.)	0.050	0.064	0.069	0.076	0.051	0.062

Table 2. Economic parameters of coal-fired units.

Unit Number	Investment Cost (10,000 CNY/MW)	O&M Cost (10,000 CNY/MW/Year)	Annualized Investment Cost (10,000 CNY/MW/Year)
G ₁	350	40	30.51
G ₂	380	32	33.13
G ₃	420	30	36.62
G ₄	440	30	38.36
G ₅	450	26	39.23
G ₆	460	25	40.10

Table 3. Annual availability factor of coal-fired units.

Unit Number	Fuel Availability Rate	Auxiliary Power Rate	Planned Outage Rate	Forced Outage Rate	Annual Availability Factor
G ₁	99.92%	7.62%	11.23%	0.60%	0.8145
G ₂	99.98%	6.21%	12.56%	0.51%	0.8158
G ₃	99.25%	5.16%	10.41%	0.45%	0.8395
G ₄	99.98%	4.92%	12.02%	0.14%	0.8352
G ₅	99.46%	4.87%	11.02%	0.23%	0.8400
G ₆	99.11%	4.75%	13.02%	0.76%	0.8149

**Figure 4.** Typical daily load power curves for the four seasons.**Figure 5.** Typical daily wind power output curves for the four seasons.

For the implementation, the electricity market clearing model is programmed in MATLAB R2021b. The daily joint optimization clearing of energy and reserve capacity in the electricity spot market is performed by invoking the YALMIP toolbox (version R20230622) and the CPLEX 12.10 solver on a computer equipped with an Intel Core i7-12700 CPU and 32 GB of RAM. To ensure both solution quality and computational tractability, the CPLEX relative mixed-integer programming (MIP) gap tolerance is set to 0.01%. During the execution, the solver's return status is systematically checked for each daily instance to guarantee that a feasible and optimal solution is successfully achieved. Regarding computational performance, the typical runtime for a single daily joint clearing problem is approximately 12 s.

5.2. Case Study Analysis Results

By applying the power market clearing model to simulate the case study system, key results including unit output schedules, electricity clearing prices, and annual revenues for

each coal-fired generating unit are obtained, as illustrated in Figures 6–8. Subsequently, based on these simulation results and the proposed capacity compensation mechanism, the fixed cost recovery deficits and marginal clearing probabilities of each unit are calculated, which in turn enable the determination of capacity compensation prices and investment payback periods. The detailed results are presented in Figures 9 and 10 and Table 4.

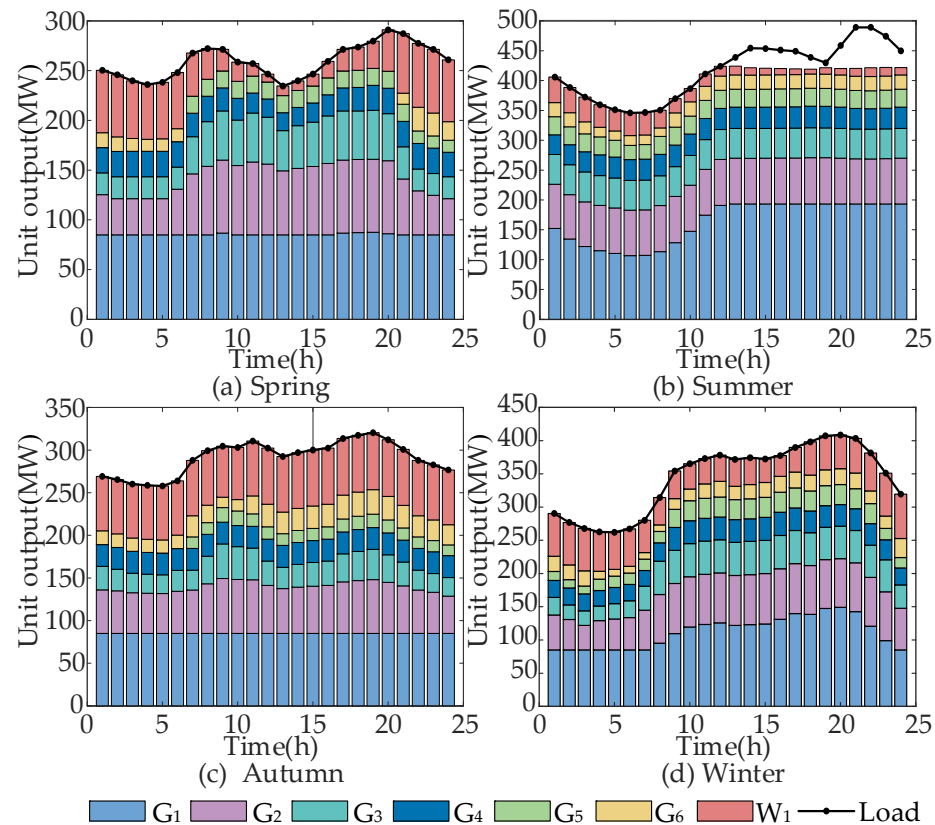


Figure 6. Typical daily unit output plan for the four seasons.

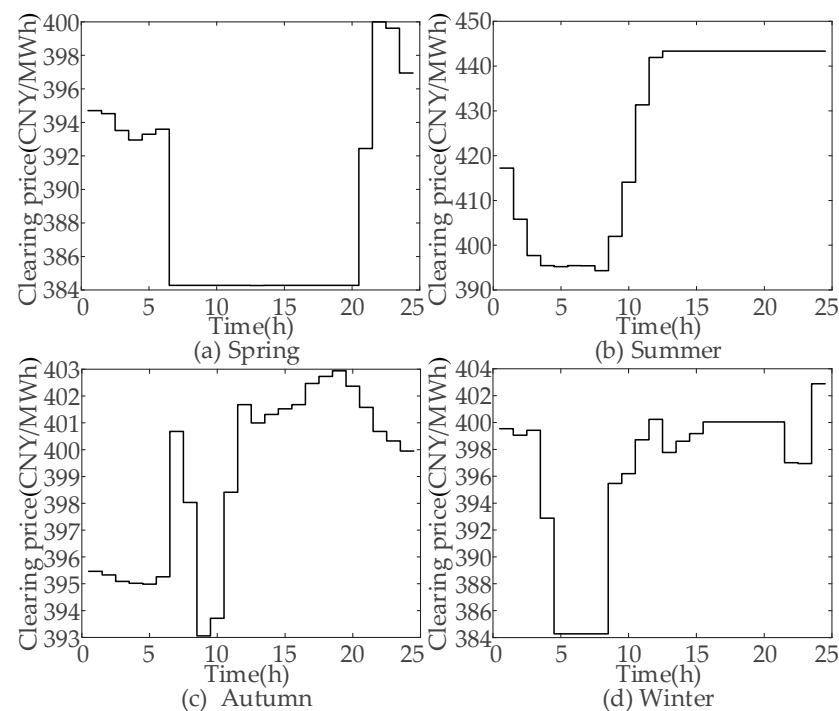


Figure 7. Typical daily electricity clearing price for the four seasons.

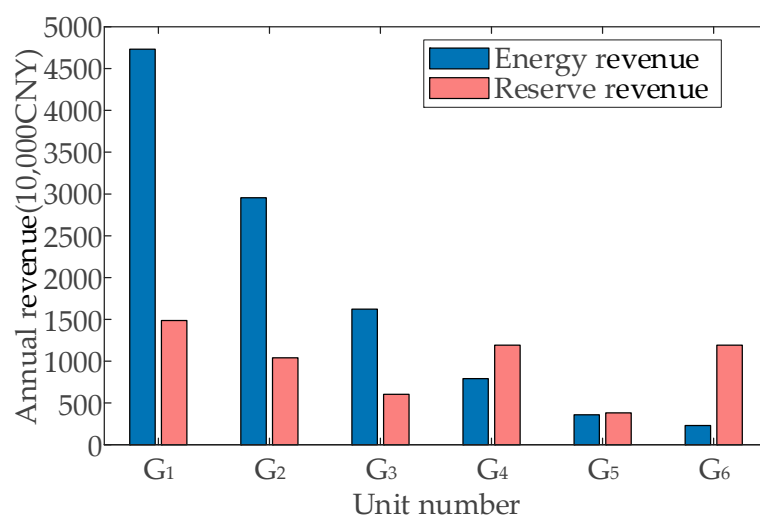


Figure 8. Annual revenue from coal-fired power units participating in the electricity market.

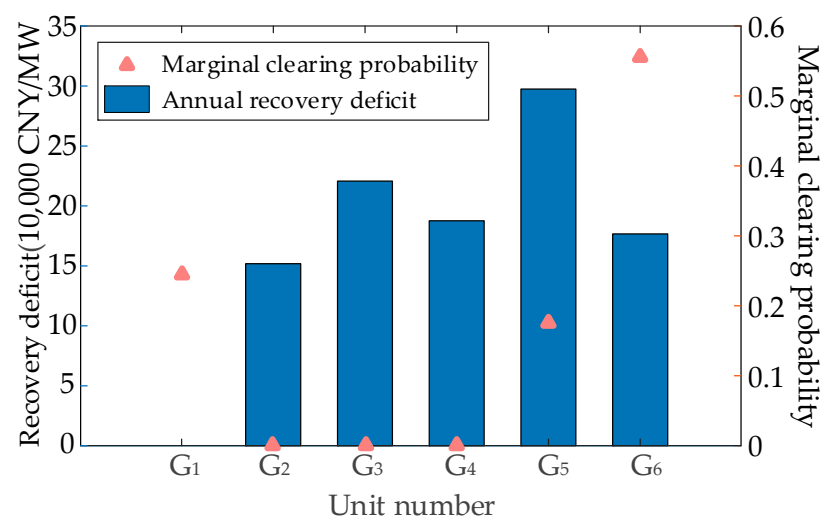


Figure 9. Annual fixed cost recovery deficit and marginal clearing probability.

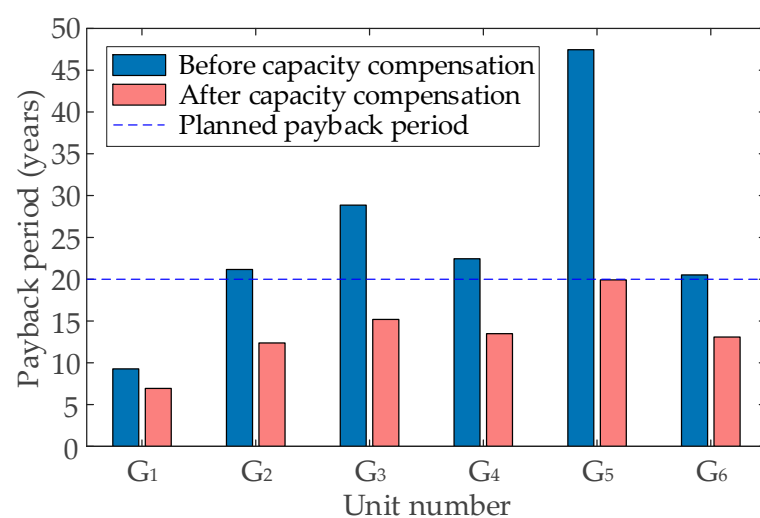


Figure 10. Comparison of investment payback periods for coal-fired power units before and after the establishment of the capacity compensation mechanism.

Table 4. Compensated capacity and compensation revenue of coal-fired units.

Unit Number	Compensation Capacity (MW)	Compensation Revenue (10,000 CNY)
G ₁	162.90	2543.68
G ₂	65.26	1019.06
G ₃	41.98	655.46
G ₄	33.41	521.66
G ₅	29.40	459.07
G ₆	24.45	381.73

Figure 6 presents the typical daily output schedules of coal-fired generating units across the four seasons. It can be observed that the units are dispatched sequentially according to their installed capacities, with G₁ serving as the baseload unit due to its largest capacity, while G₂ through G₆ progressively participate in peak-shaving operations. Furthermore, during spring and autumn when load demand is relatively low, certain smaller-capacity units experience either forced outages or operate under reduced load conditions. In contrast, during summer periods characterized by high load levels, load shedding events occur due to insufficient available generation capacity.

Figure 7 presents the energy clearing prices for typical days across the four seasons. It can be observed that when rising load demand triggers the commitment of generating units with higher marginal costs, the market clearing price exhibits corresponding step-wise increases, which exemplifies the fundamental principle of marginal pricing in competitive wholesale electricity markets.

Figure 8 illustrates the annual profit composition of coal-fired generating units participating in the electricity market, comprising energy profit and reserve profit. It can be observed that large-capacity units derive their revenue primarily from the energy market, with energy profit significantly exceeding reserve profit. In contrast, smaller-capacity units rely predominantly on the reserve ancillary service market for revenue generation, reflecting their designated role in providing flexibility services such as peak shaving and frequency regulation within the power system.

Figure 9 presents the annual fixed cost recovery deficit per unit capacity and marginal clearing probability for each coal-fired unit. It can be observed that unit G₁, benefiting from lower generation costs and higher cleared energy volumes in the spot market, is capable of recovering its annual fuel costs, operation and maintenance costs, and annualized investment costs solely through electricity market revenues. In contrast, units G₂ through G₆, characterized by higher generation costs and lower cleared energy volumes, are unable to fully recover their total costs through market revenues alone.

Based on the annualized fixed cost recovery deficit and marginal clearing probability of each coal-fired unit, the system unit capacity compensation price is determined to be 15.62×10^4 CNY/MW/year. On this basis, the compensated capacity and corresponding compensation revenue for each coal-fired unit under the proposed mechanism are calculated, as presented in Table 4. Furthermore, Figure 10 compares the investment payback periods of coal-fired units before and after the implementation of the capacity compensation mechanism, with the planned payback period of 20 years indicated by the dashed line. In the absence of the capacity compensation mechanism, only unit G₁ achieves cost recovery within the planned period, whereas units G₂ through G₆ all exhibit payback periods exceeding 20 years. Following the implementation of the capacity compensation mechanism, however, the investment payback periods of all units are significantly reduced, enabling all units to achieve cost recovery within the planned horizon. In conclusion, the compensation revenue effectively bridges the annualized fixed cost recovery gap for each

coal-fired unit, ensuring full cost recovery within the planned payback period and thereby maintaining sustainable operation under the electricity market environment.

6. Conclusions

This paper proposes a capacity cost compensation mechanism to address the investment cost recovery challenge faced by coal-fired units in electricity market environments. First, a joint clearing model for the electricity spot market considering both energy and reserve services is established, and annual market operation simulations are conducted to obtain unit output schedules, clearing prices, and annual revenues. Second, based on long-term simulation results, the marginal clearing probability and fixed cost recovery deficit of each coal-fired unit are calculated, and a capacity compensation pricing method based on marginal clearing probability weighting is proposed to determine the system-wide unit capacity compensation price. Subsequently, the compensated capacity is determined using the availability factor method, comprehensively reflecting each unit's actual contribution to system capacity adequacy. Finally, case studies conducted on a modified IEEE 30-bus system validate the effectiveness of the proposed mechanism. The main conclusions are as follows:

- (1) A power market clearing model for coal-fired power units considering wind curtailment and load shedding penalties has been established. This model takes into account the two most common sources of revenue for coal-fired units and simulates the market operation throughout the year. The results indicate that, under scenarios with high penetration of wind power, coal-fired units are unable to recover their fixed investment costs solely through power market revenues.
- (2) A capacity compensation pricing method based on marginal clearing probability weighting has been proposed. This method fully considers the marginal contribution of each unit and the fixed cost recovery gap, reflecting the actual value of each unit's contribution to system reliability through the marginal clearing probability.
- (3) A compensated capacity determination method based on the availability factor method has been designed. It comprehensively considers the rated capacity, availability, and actual operating conditions of coal-fired units, thereby reflecting the actual contribution of each unit to system capacity adequacy.
- (4) A complete capacity cost compensation mechanism tailored for coal-fired power units under the modern electricity market environment is proposed. Following the implementation of this mechanism, the investment payback periods of all coal-fired units are significantly shortened and strictly controlled within the planned 20-year horizon, thereby ensuring the full recovery of fixed costs.

The findings of this study provide valuable insights for electricity market development and capacity compensation mechanism design. Future research will further explore the impact of factors such as long-term contracted electricity volumes, energy storage participation in the market, and demand response on capacity compensation costs.

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