

Article

Stochastic Source–Load Optimal Scheduling of an Integrated Energy System Considering Carbon–Green Certificate Market Synergy and Diversified Hydrogen Utilization

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Abstract

To address the challenges of restricted renewable energy accommodation, high carbon emissions, and elevated operating costs in integrated energy systems (IES), this paper proposes a stochastic optimization scheduling method that incorporates the synergy between carbon–green certificate trading and the multi-use applications of hydrogen energy. First, an integrated “electricity–carbon–hydrogen–methanol” model is constructed, incorporating proton exchange membrane (PEM) electrolyzers (ELs), methanol synthesis reactors, hydrogen storage systems, and hydrogen fuel cells (HFCs). Second, a concentrating solar power (CSP) plant coupled with an electric heater (EH) is integrated based on an “electricity–heat–electricity” mechanism. Concurrently, a joint carbon emission trading (CET) and green certificate trading (GCT) mechanism is incorporated into a low-carbon economic dispatch model to minimize total operational costs. On this basis, Information Gap Decision Theory (IGDT) is applied to address source–load uncertainties via risk-averse (RAS) and opportunity-seeking (OSS) strategies. Simulation results demonstrate that the proposed strategy achieves full accommodation of renewable energy. The EH-coupled CSP plant increases thermal output by 4.96%, reducing system carbon emissions by 8.07% compared with the non-EH scenario and decreasing natural gas procurement costs by 14.1%. Furthermore, the joint CET-GCT mechanism overcomes single-market limitations, increasing carbon trading revenues by 298.01% and lowering total operating costs by 39.6% compared with uncoordinated mechanisms. Finally, under IGDT uncertainty analysis, the opportunity-seeking strategy further reduces operating costs by 9.5% compared with the risk-averse strategy, enhancing the system’s low-carbon economic performance and operational flexibility. From the perspective of sustainable development, this study provides a practical dispatch framework for regional integrated energy systems to balance energy security, low-carbon transition and economic cost, offering methodological support for advancing the sustainable transformation of multi-energy systems amid the dual-carbon drive.

Keywords: integrated energy system; multi-pathway utilization of hydrogen; CSP plant; CET-GCT; IGDT

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1. Introduction

Driven by “dual-carbon” targets, the grid-integrated capacity of renewable energy, predominantly represented by wind and photovoltaic power, has increased steadily [1]. Nevertheless, the inherent variability of renewable power generation poses operational challenges to power grids, frequently leading to renewable energy curtailment [2,3]. As a framework for achieving multi-energy complementarity and enhancing energy efficiency, integrated energy systems (IES) provide a viable pathway for low-carbon energy transitions. However, a key challenge remains: expanding accommodation channels for renewable energy while simultaneously reducing system carbon emissions and operational costs, while maintaining the reliability of electricity and heat supply.

Power-to-gas technology provides an effective mechanism for accommodating surplus renewable electricity within integrated energy systems [4,5]. Regarding hydrogen energy applications, existing literature primarily focuses on coupling hydrogen storage with fuel cells to achieve temporal energy shifting and combined heat and power (CHP) generation [6]. However, conventional power-to-methane routes face decarbonization limitations, as secondary carbon emissions are generated during end-use applications [7]. To address this, recent low-carbon dispatch studies integrate carbon capture systems (CCS) with power-to-methanol technology, synthesizing green methanol from green hydrogen and CO₂ captured from thermal units, thereby coupling clean power generation with chemical carbon sequestration [8]. Despite these advancements, most existing studies treat carbon capture and utilization solely as an auxiliary decarbonization measure for thermal units, or separate power-to-hydrogen and power-to-methanol into independent operational stages, lacking integrated optimization across the entire “electricity–carbon–hydrogen–methanol” chain. Consequently, the synergistic coupling between system-level hydrogen supply and methanol synthesis is rarely fully captured.

Concurrently, concentrating solar power (CSP) plants equipped with thermal energy storage (TES) are increasingly utilized to enhance system flexibility due to their low-carbon characteristics and thermoelectric decoupling capabilities [9]. To further expand operational flexibility, some studies propose integrating electric heaters (EHs) into CSP plants to establish a “power-to-heat-to-power” mechanism: during periods of high renewable output or low electricity prices, electric heaters convert surplus electricity into thermal energy for storage [10]; during peak demand hours, the stored heat is used to drive steam turbines for power generation or direct heat supply [11]. This mechanism relaxes the “following thermal load” constraint of conventional combined heat and power (CHP) units, thereby increasing renewable energy accommodation [12]. However, existing research on CSP dispatch primarily models these facilities as isolated regulation assets. Few studies have integrated them with an “electricity–carbon–hydrogen–methanol” pathway to evaluate their combined operational performance and decarbonization potential.

Furthermore, Carbon Emission Trading (CET) and Green Certificate Trading (GCT) serve as key market-based mechanisms to promote low-carbon and economic operation in integrated energy systems. Previous studies have examined the design and quota allocation frameworks of these trading mechanisms. Regarding CET, several studies incorporate tiered carbon trading costs into integrated energy system (IES) planning and economic dispatch [13,14], whereas others formulate microgrid optimization strategies accounting for dual demand response [15]. Regarding GCT, evaluation frameworks based on methods such as entropy weighting have been proposed to quantify green certificate issuance and evaluate clean energy integration [16]. Considering the stochastic nature of renewable generation, other research has developed quota-driven secondary trading models for green certificates across multiple stages [17]. However, most existing literature models these market schemes separately, without fully accounting for the potential synergies in cost reduction and emission abatement resulting from joint GCT-CET operation.

From a system optimization perspective, the low-carbon transition of integrated energy systems depends on effective scheduling. A comprehensive optimization framework should extend beyond short-term operational cost minimization to consider grid support and long-term economic metrics [18].

To address challenges related to renewable energy accommodation, hydrogen energy utilization, and carbon emissions in integrated energy systems, this paper proposes an Information Gap Decision Theory (IGDT)-based optimal dispatch model. The model incorporates an “electricity–carbon–hydrogen–methanol” system and EH-coupled CSP generation within a joint CET-GCT framework. The primary contributions of this work are as follows:

(1) To overcome the curtailment bottlenecks of renewable energy, a unified “electricity–carbon–hydrogen–methanol” infrastructure is constructed, which amalgamates PEM EL, methanol synthesis modules, hydrogen storage devices, and hydrogen fuel cells. The operational impacts of this architecture on augmenting renewable energy penetration, curbing total carbon emissions, and compressing overall operational costs are extensively analyzed.

(2) A model of a CSP plant coupled with an EH was developed, achieving a closed-loop “electricity–heat–electricity” conversion. The study analyzed the unique advantages of this mechanism in enhancing the system’s regulatory flexibility and meeting electricity and heating load demands.

(3) By introducing the CET-GCT joint trading mechanism, this study conducted an in-depth investigation into the impact of the joint trading mechanism on the optimal allocation of system resources and operating costs.

(4) Through multi-scenario construction and comparative evaluation, the efficacy and superiority of the proposed strategy are rigorously substantiated across key performance metrics, including renewable energy accommodation capability, aggregate carbon emissions, and comprehensive operational expenditures. Furthermore, an in-depth sensitivity analysis is conducted to elucidate how individual component capacity allocations and baseline prices of CET and GCT govern overall system performance.

(5) A dual strategy of robust risk avoidance and opportunity seeking was proposed, and a comparative analysis was conducted to examine how different strategic preferences influence the focus of system scheduling schemes.

Appendixes A and B provide the definitions of abbreviations and model symbols, respectively.

2. Integrated Energy System Framework

The integrated energy system (IES) is composed of wind farms, photovoltaic (PV) stations, TPUs equipped with carbon capture capabilities, CSP plants integrated with EHs, gas boilers (GBs), hydrogen fuel cells (HFCs), proton exchange membrane electrolyzers (PEM ELs), and methanol synthesis units (MSUs). Within this architecture, the electrical demand is jointly satisfied by the wind farms, PV stations, TPUs, HFCs, and CSP plants. Concurrently, the thermal load is fulfilled by the gas boilers, CSP plants, and HFCs. Specifically, the EH is deployed to assimilate redundant wind and PV generation, converting this excess electricity into thermal energy that is preserved within the thermal energy storage system, thereby actualizing an “electricity–heat–electricity” coupled regulation mechanism.

Furthermore, the PEM EL leverages renewable electricity to produce green hydrogen. A specific fraction of this generated hydrogen is allocated to the HFC for power production and to the synthesis modules for methanol production, while the remainder is deposited into hydrogen storage tanks for subsequent dispatch. The synthesized methanol is ultimately transported to chemical markets for commercial sale to yield economic

revenues. The comprehensive framework of this multi-energy complementary IES is illustrated in Figure 1.

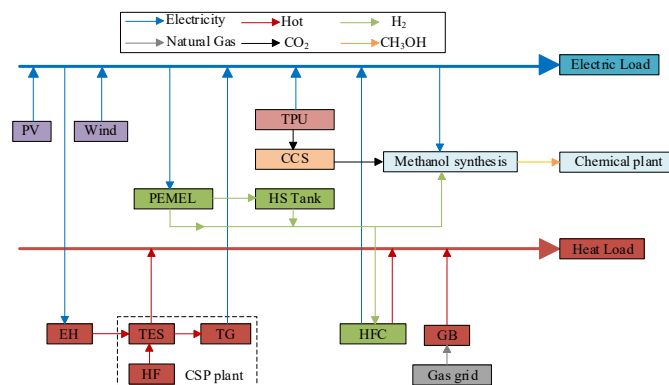


Figure 1. Framework of the proposed integrated energy system.

2.1. The “Electricity–Carbon–Hydrogen–Methanol” Integrated Model

The system utilizes surplus electricity generated from wind and PV generation to drive the PEM EL for hydrogen production, thereby broadening the efficient accommodation pathways for renewable energy. On one hand, a portion of the yielded hydrogen is injected into the hydrogen storage system to provide temporal regulation and energy buffering. On the other hand, the remaining hydrogen is channeled into the MSU, where it reacts with the carbon dioxide sequestered from the flue gas of TPUs to synthesize green methanol. This specific procedure not only facilitates the chemical conversion of hydrogen into liquid fuels but also effectively slashes the aggregate carbon emissions originating from the thermal generators. Simultaneously, hydrogen can be directly supplied to the HFC modules to achieve CHP cogeneration, demonstrating the multi-scenario utilization of hydrogen energy.

The integrated “electricity–carbon–hydrogen–methanol” operational architecture formulated by this paradigm is depicted in Figure 2.

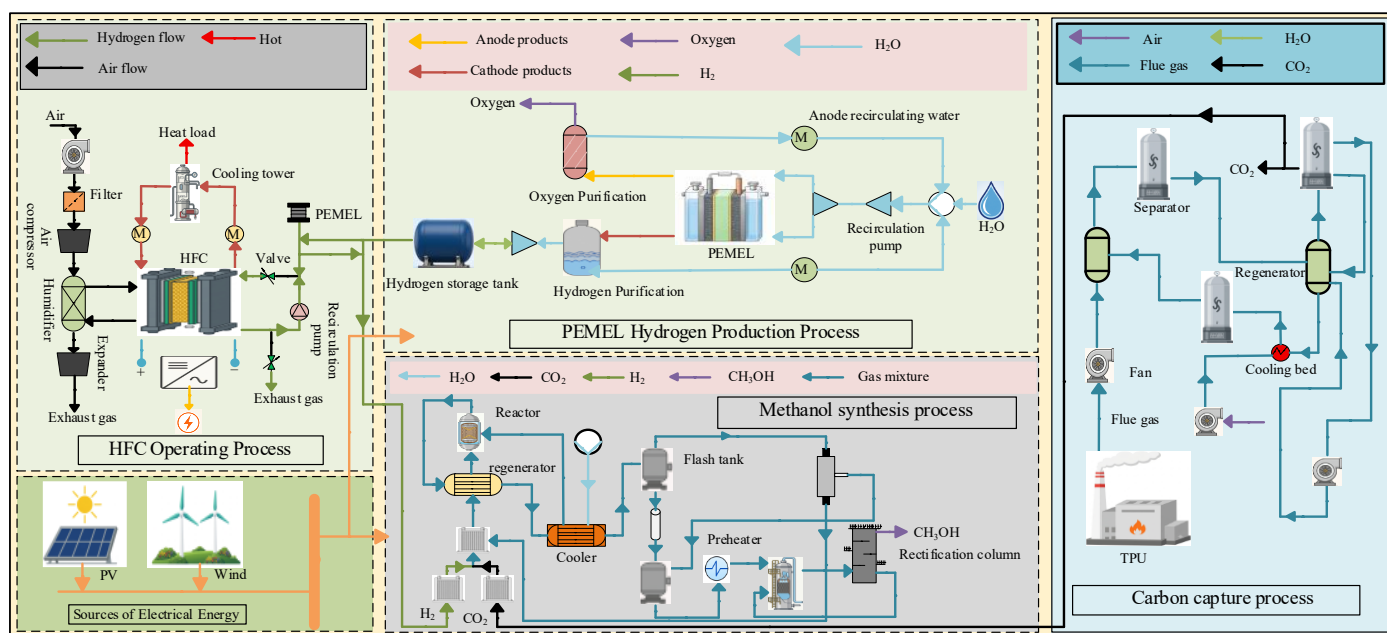


Figure 2. Operational framework of the “electricity–carbon–hydrogen–methanol” integrated system.

2.1.1. PEM EL Model

Currently, common water electrolysis technologies for hydrogen production mainly comprise alkaline, proton exchange membrane (PEM), and solid oxide electrolysis. Compared with solid oxide electrolysis, which features high efficiency and integration with solar thermal energy storage or waste heat [19], PEM electrolysis exhibits faster response speeds and superior dynamic regulation capabilities, thereby better accommodating the volatile output characteristics of wind and photovoltaic power [20]. On this basis, the model is formulated as follows:

$$\begin{cases} M_{EL,t}^{H_2} = \eta_{H_2} P_t^{EL} / r_{H_2} \\ P_{\min}^{EL} \leq P_t^{EL} \leq P_{\max}^{EL} \\ |P_t^{EL} - P_{t-1}^{EL}| \leq \Delta P_{\max}^{EL} \\ M_{EL,t}^{H_2} = M_{stor,t}^{H_2,in} + M_{EL,t}^{H_2,HFC} + M_t^{H_2,MSU} + M_{EL,t}^{H_2,loss} \end{cases} \quad (1)$$

where $M_{EL,t}^{H_2}$ is the mass of hydrogen produced by the EL at time period t ; η_{H_2} is the operational efficiency of the EL; r_{H_2} denotes the electricity-to-hydrogen conversion coefficient; $M_{stor,t}^{H_2,in}$, $M_{EL,t}^{H_2,HFC}$, and $M_t^{H_2,MSU}$ represent the masses of hydrogen dispatched from the EL to the hydrogen storage tank, HFC and MSU at time period t , respectively; $M_{EL,t}^{H_2,loss}$ indicates the mass of unutilized hydrogen generated at time period t ; $P_{\max}^{EL}$ and $P_{\min}^{EL}$ define the maximum and minimum output power limits of the EL, respectively; and is the maximum permissible ramping power of the EL.

To coordinate the hydrogen production and consumption demands, the system is equipped with a hydrogen storage tank for hydrogen preservation and regulation. The operational constraints of the hydrogen storage (HS) tank can be found in reference [20].

2.1.2. Hydrogen Fuel Cell Model

The HFC is capable of highly efficiently converting the chemical energy of hydrogen into both electricity and heat. Its electrical and thermal conversion efficiencies can be dynamically adjusted in accordance with operational demands [21,22], thereby facilitating flexible energy dispatch. The operational model of the HFC is formulated as follows:

$$\begin{cases} P_t^{HFC,E} = \eta_t^{HFC,E} L_{H_2} (M_{EL,t}^{H_2,HFC} + M_{stor,t}^{H_2,HFC}) / (3.6 \times 10^3) \\ E_t^{HFC,h} = \eta_t^{HFC,H} L_{H_2} (M_{EL,t}^{H_2,HFC} + M_{stor,t}^{H_2,HFC}) / (3.6 \times 10^3) \\ \eta_t^{HFC,E} + \eta_t^{HFC,H} \leq 85\% \\ 33\% \leq \eta_t^{HFC,E} \leq 55\%, 30\% \leq \eta_t^{HFC,H} \leq 52\% \\ 0 \leq M_t^{H_2,HFC} \leq M_{\max}^{H_2,HFC} \\ |M_t^{H_2,HFC} - M_{t-1}^{H_2,HFC}| \leq \Delta M_{\max}^{H_2,HFC} \end{cases} \quad (2)$$

where $P_t^{HFC,E}$ and $E_t^{HFC,h}$ are the electrical and thermal power outputs of the HFC at time period t , respectively; L_{H_2} is the lower heating value of hydrogen; $\eta_t^{HFC,E}$ and $\eta_t^{HFC,H}$ denote the electricity and heat generation efficiencies of the HFC at time period t , respectively.

$$\begin{cases} 0 \leq M_t^{H_2,HFC} \leq M_{\max}^{H_2,HFC} \\ |M_t^{H_2,HFC} - M_{t-1}^{H_2,HFC}| \leq \Delta M_{\max}^{H_2,HFC} \end{cases} \quad (3)$$

where $M_{\max}^{H_2,HFC}$ and $\Delta M_{\max}^{H_2,HFC}$ define the maximum hydrogen consumption capacity and the maximum permissible ramping power of the HFC, respectively.

2.1.3. Carbon-Capture-Enabled TPU Model

The carbon capture system is capable of highly efficiently separating and sequestering carbon dioxide emitted from TPUs, thereby significantly lowering the carbon emission

level of the unit. Its operational process encompasses multiple sequential stages, including absorption, regeneration, and compression. The captured carbon dioxide can either be further dispatched to the methanol synthesis unit for resource utilization or permanently sequestered to achieve long-term emission abatement [23]. Based on the aforementioned coupling relationships, the comprehensive operational model of the carbon-capture-enabled thermal power unit is formulated as follows:

$$\begin{cases} P_{\text{TPU},t} = P_{\text{TPU},t}^{\text{out}} + P_t^{\text{cc,ope}} + P^{\text{cc,base}} \\ P_t^{\text{cc,ope}} = \gamma^{\text{cc}} M^{\text{cc,CO}_2} \\ M^{\text{cc,CO}_2} = e\eta^{\text{cc}} P_{\text{TPU},t} = M_t^{\text{CO}_2,\text{MSU}} + M_t^{\text{CO}_2,\text{stor}} \end{cases} \quad (4)$$

where $P_{\text{TPU},t}$, $P_{\text{TPU},t}^{\text{out}}$, $P_t^{\text{cc,ope}}$, and $P^{\text{cc,base}}$ are the total output power, net output power, carbon capture power consumption, and fixed energy losses of the TPU at time period t , respectively; γ^{cc} and η^{cc} denote the energy consumption coefficient and operational efficiency of the carbon capture system, respectively; $M_t^{\text{CO}_2,\text{MSU}}$ is the quantity of carbon dioxide absorbed by the methanol synthesis device at time period t ; e represents the carbon emission intensity of the thermal unit; $M_t^{\text{CO}_2,\text{stor}}$ indicates the amount of carbon dioxide undergoing sequestration at time period t .

$$\begin{cases} P_{\min}^{\text{TPU}} \leq P_{\text{TPU},t} \leq P_{\max}^{\text{TPU}} \\ |P_{\text{TPU},t} - P_{\text{TPU},t-1}| \leq \Delta P_{\max}^{\text{TPU}} \end{cases} \quad (5)$$

where $P_{\max}^{\text{TPU}}$ and $P_{\min}^{\text{TPU}}$ define the maximum and minimum generation limits of the TPU, respectively; and $\Delta P_{\max}^{\text{TPU}}$ is the maximum permissible ramping power of the thermal unit.

2.1.4. Methanol Synthesis Model

The methanol synthesis process relies on surplus electricity generated from renewable energy sources to drive equipment operations. By leveraging the catalytic reaction between hydrogen and captured carbon dioxide [24], this process successfully realizes deep decarbonization while facilitating renewable energy accommodation. Consequently, the mathematical model for the methanol synthesis system is formulated as follows:

$$\begin{cases} P_t^{\text{MSU}} = \lambda_{\text{CH}_3\text{OH}} M_t^{\text{MSU}} \\ M_t^{\text{CH}_3\text{OH}} = \lambda_{\text{H}_2} (M_{\text{EL},t}^{\text{H}_2,\text{MSU}} + M_{\text{stor},t}^{\text{H}_2,\text{MSU}}) \\ M_t^{\text{CH}_3\text{OH}} = \lambda_{\text{CO}_2} M_t^{\text{CO}_2,\text{MSU}} \end{cases} \quad (6)$$

where P_t^{MSU} is the output power of the MSU at time period t ; $\lambda_{\text{CH}_3\text{OH}}$, λ_{H_2} , and λ_{CO_2} represent the energy consumption coefficient, hydrogen ratio coefficient, and carbon dioxide ratio coefficient, respectively; M_t^{MSU} denotes the mass of methanol produced at time period t ; $M_{\text{stor},t}^{\text{H}_2,\text{MSU}}$ defines the amount of hydrogen dispatched from the hydrogen storage tank to the MSU at time period t .

$$\begin{cases} 0 \leq P_t^{\text{MSU}} \leq P_{\max}^{\text{MSU}} \\ |P_t^{\text{MSU}} - P_{t-1}^{\text{MSU}}| \leq \Delta P_{\max}^{\text{MSU}} \end{cases} \quad (7)$$

where $P_{\max}^{\text{MSU}}$ represents the maximum operating power per unit time; and $\Delta P_{\max}^{\text{MSU}}$ is the maximum permissible ramping power of the MSU.

2.2. Model of the CSP Plant Integrated with an EH

A CSP plant integrated with an EH is primarily composed of an electric boiler, a heat exchange platform, a molten salt TES system, and a thermodynamic cycle unit. Powered by the surplus electricity from wind and PV generation, the EH achieves high-efficiency conversion of electrical energy into thermal energy, which is subsequently delivered to

the TES system for storage. The molten salt TES unit executes energy charging and discharging within the thermodynamic cycle, driving electricity generation on one hand and fulfilling the heating demand on the other. Consequently, it synergizes with the electric boiler to establish a “power–heat–power” coupled operational mechanism, thereby enhancing the flexibility, stability, and energy utilization efficiency of the CSP plant.

The joint operational configuration of the CSP plant and the EH is illustrated in Figure 3.

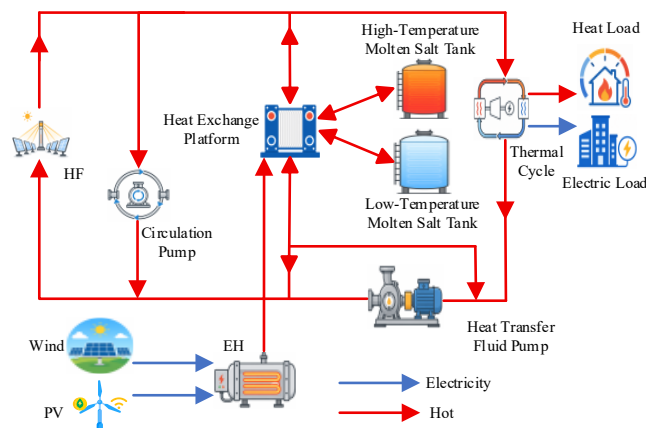


Figure 3. Joint operational structure of the CSP plant and EH.

2.2.1. CSP Plant Model

CSP plants utilize solar energy for electricity generation, boasting salient features such as environmental cleanness, low carbon emissions, and high dispatchability. When integrated with a TES system, a CSP plant can achieve temporal storage and flexible release of solar thermal energy, thereby enhancing the controllability and continuity of its power output. This configuration ultimately bolsters the operational flexibility of the entire system and promotes renewable energy accommodation [25]. Consequently, the operational model of the CSP plant is formulated as follows:

$$\begin{cases} P_t^{\text{CSP}} = \eta_{r-d} (E_t^{\text{HF,TG}} + E_t^{\text{TES,TG}}) \\ P_{\min}^{\text{CSP}} \leq P_t^{\text{CSP}} \leq P_{\max}^{\text{CSP}} \\ E_t^{\text{HF}} = E_t^{\text{HF,TES}} + E_t^{\text{HF,TG}} + E_t^{\text{HF,loss}} \end{cases} \quad (8)$$

where P_t^{CSP} is the output power of the CSP plant at time period t ; $E_t^{\text{HF,TG}}$ and $E_t^{\text{TES,TG}}$ denote the thermal power delivered from the solar field and the TES system to the generator at time period t , respectively; E_t^{HF} indicates the thermal power harvested by the solar field at time period t ; $E_t^{\text{HF,TES}}$ is the thermal power directed from the solar field to the TES system; $E_t^{\text{HF,loss}}$ stands for the unutilized thermal power of the CSP plant at time period t ; η_{r-d} represents the thermal-to-electric conversion efficiency; $P_{\max}^{\text{CSP}}$ and $P_{\min}^{\text{CSP}}$ are the maximum and minimum generation limits of the CSP plant, respectively.

Serving as a key link to realize temporal energy shifting, the operational constraints governing the TES system are established as follows:

$$\begin{cases} E_t^{\text{TES},\text{in}} = U_t^{\text{TES},\text{in}} \eta_{\text{in}} (E_t^{\text{HF},\text{TES}} + E_t^{\text{EH},\text{TES}}) \\ E_t^{\text{TES},\text{out}} = U_t^{\text{TES},\text{out}} (E_t^{\text{TES},\text{TG}} + E_t^{\text{TES},\text{h}}) / \eta_{\text{out}} \\ E_t^{\text{TES}} = (1 - \xi_{\text{TES}}) E_{t-1}^{\text{TES}} + (E_t^{\text{TES},\text{in}} - E_t^{\text{TES},\text{out}}) \Delta t \\ 0 \leq E_t^{\text{TES},\text{in}} \leq U_t^{\text{TES},\text{in}} E_{\text{max}}^{\text{TES},\text{in}} \\ 0 \leq E_t^{\text{TES},\text{out}} \leq U_t^{\text{TES},\text{out}} E_{\text{max}}^{\text{TES},\text{out}} \\ U_t^{\text{TES},\text{out}} + U_t^{\text{TES},\text{in}} \leq 1 \\ E_{t_0}^{\text{TES}} = E_T^{\text{TES}} \end{cases} \quad (9)$$

where E_t^{TES} is the thermal energy stored in the TES system at time period t ; $E_t^{\text{HF},\text{TES}}$ and $E_t^{\text{EH},\text{TES}}$ denote the thermal power directed to the TES system from the solar field and the electric boiler, respectively; $E_t^{\text{TES},\text{h}}$ is the thermal power provided by the TES system to satisfy the heating load; ξ_{TES} indicates the thermal dissipation rate during the storage process; η_{in} and η_{out} represent the charging and discharging efficiencies of the TES system, respectively; $E_t^{\text{TES},\text{in}}$ and $E_t^{\text{TES},\text{out}}$ are the charging and discharging power of the TES system at time period t , respectively; $E_{\text{max}}^{\text{TES},\text{out}}$ and $E_{\text{max}}^{\text{TES},\text{in}}$ define the maximum allowable charging and discharging power, respectively; $U_t^{\text{TES},\text{in}}$ and $U_t^{\text{TES},\text{out}}$ are the charging and discharging state variables of the TES system; $E_{t_0}^{\text{TES}}$ and E_T^{TES} stand for the initial and final thermal storage levels of the system, respectively; and Δt is the time interval.

2.2.2. EH Model

By accommodating surplus wind and PV power, the EH converts electrical energy into thermal energy and stores it within the TES system [26]. When required, this thermal energy can be flexibly released for power generation, thereby realizing an efficient “electricity–heat–electricity” energy cycle. This mechanism significantly improves the renewable energy accommodation capacity and enhances the operational flexibility of the system. Its operational model is formulated as follows:

$$\begin{cases} P_t^{\text{EH}} = E_t^{\text{EH},\text{TES}} / \eta_{\text{EH}} \\ P_{\text{min}}^{\text{EH}} \leq P_t^{\text{EH}} \leq P_{\text{max}}^{\text{EH}} \\ |P_t^{\text{EH}} - P_{t-1}^{\text{EH}}| \leq \Delta P_{\text{max}}^{\text{EH}} \end{cases} \quad (10)$$

where P_t^{EH} is the operating power of the EH; η_{EH} denotes the power-to-heat conversion efficiency; $P_{\text{max}}^{\text{EH}}$ and $P_{\text{min}}^{\text{EH}}$ define the maximum and minimum power bounds of the EH, respectively; and $\Delta P_{\text{max}}^{\text{EH}}$ is the maximum permissible ramping power of the electric boiler.

2.3. GB Model

A GB serves as a thermal energy conversion device that harnesses the heat released from the combustion of gaseous fuels, such as natural gas, to heat water or generate steam [27]. The operational model of the gas boiler is formulated as follows:

$$\begin{cases} E_t^{\text{GB},\text{h}} = \eta_{\text{GB}} P_t^{\text{GB},\text{g}} \\ 0 \leq P_t^{\text{GB},\text{g}} \leq P_{\text{max}}^{\text{GB},\text{g}} \\ |P_t^{\text{GB},\text{g}} - P_{t-1}^{\text{GB},\text{g}}| \leq \Delta P_{\text{max}}^{\text{GB},\text{g}} \end{cases} \quad (11)$$

where $E_t^{\text{GB},\text{h}}$ and $P_t^{\text{GB},\text{g}}$ are the output and input power of the GB at time period t , respectively; η_{GB} denotes the heat generation efficiency; $P_{\text{max}}^{\text{GB},\text{g}}$ defines the maximum operating capacity of the gas boiler; and $\Delta P_{\text{max}}^{\text{GB},\text{g}}$ stands for the maximum permissible ramping power of the GB.

3. Joint GCT-CET Trading Mechanism

3.1. CET Mechanism

At the current stage, China primarily adopts the baseline method to allocate carbon emission allowances for IES, taking into account only the carbon emissions generated during the energy consumption process [28,29]. The carbon emissions of an IES mainly originate from TPUs and gas-fired units, among which external power purchases are predominantly supplied by coal-fired generation. Based on this premise, the carbon allowance allocation model for the IES is established as follows:

$$\begin{cases} D_{\text{IES}} = D_{\text{TPU}}^{\text{CO}_2} + D_{\text{GB}}^{\text{CO}_2} \\ D_{\text{TPU}}^{\text{CO}_2} = \sum_{t=1}^T \lambda_{\text{TPU}} P_{\text{TPU},t}; D_{\text{GB}}^{\text{CO}_2} = \sum_{t=1}^T \lambda_{\text{GB}} E_t^{\text{GB},h} \end{cases} \quad (12)$$

where D_{IES} is the total carbon emission allowance granted to the system; $D_{\text{TPU}}^{\text{CO}_2}$ and $D_{\text{GB}}^{\text{CO}_2}$ denote the carbon allowances assigned to the thermal power unit and the gas boiler, respectively; λ_i represents the carbon allowance coefficient, $i = \{\text{TPU}, \text{GB}\}$.

The model for the actual carbon emissions of the IES is formulated as follows:

$$\begin{cases} E_{\text{All}}^{\text{CO}_2} = E_{\text{TPU}}^{\text{CO}_2} + E_{\text{GB}}^{\text{CO}_2} \\ E_{\text{TPU}}^{\text{CO}_2} = \sum_{t=1}^T e P_{\text{TPU},t} - M^{\text{cc},\text{CO}_2}; E_{\text{GB}}^{\text{CO}_2} = \sum_{t=1}^T \psi_{\text{GB}} P_t^{\text{GB},g} \end{cases} \quad (13)$$

where $E_{\text{All}}^{\text{CO}_2}$ is the total carbon emissions of the IES during a scheduling period; $E_{\text{TPU}}^{\text{CO}_2}$ and $E_{\text{GB}}^{\text{CO}_2}$ denote the carbon emissions produced by the TPU and the GB over a scheduling period, respectively; and ψ_{GB} represents the carbon emission coefficient of the GB.

The trading interval index R_{CET} for the carbon emission rights of the IES can be calculated by the following equation:

$$R_{\text{CET}} = E_{\text{All}}^{\text{CO}_2} - D_{\text{IES}} \quad (14)$$

To further leverage the incentive and restrictive roles of the carbon market, this paper introduces a stepped CET mechanism. Based on the difference between actual carbon emissions and the allocated carbon allowances, this mechanism divides the trading volume into distinct intervals. It imposes step-increasing carbon trading costs on excess emissions while granting corresponding revenues for the emission reduction portion, thereby promoting the low-carbon operation of the system. Consequently, the stepped CET model is established as follows:

$$F_{\text{CET}} = \begin{cases} -\lambda(2+3\gamma_1)d + \lambda(1+3\gamma_1)(R_{\text{IES}} + 2d), & R_{\text{IES}} < -2d \\ -\lambda(1+\gamma_1)d + \lambda(1+2\gamma_1)(R_{\text{IES}} + d), & -2d \leq R_{\text{IES}} < -d \\ \lambda(1+\gamma_1)R_{\text{IES}}, & -d \leq R_{\text{IES}} < 0 \\ \lambda R_{\text{IES}}, & 0 \leq R_{\text{IES}} < d \\ \lambda d + \lambda(1+\gamma_2)(R_{\text{IES}} - d), & d \leq R_{\text{IES}} < 2d \\ \lambda(2+\gamma_2)d + \lambda(1+2\gamma_2)(R_{\text{IES}} - 2d), & R_{\text{IES}} \geq 2d \end{cases} \quad (15)$$

where F_{CET} is the total carbon trading cost; R_{IES} denotes the final equivalent total carbon emissions after conversion; λ represents the base carbon trading price; γ_1 and γ_2 indicate the price incentive and penalty coefficients for carbon trading, respectively; and d defines the interval width of the carbon emission tiers.

3.2. GCT Mechanism

The GCT mechanism provides an additional revenue channel for renewable energy generation by converting renewable power output into tradable green certificates, coupled with a renewable energy quota system to mandate green electricity consumption

[30,31]. When the number of green certificates held by the system is insufficient, it must purchase additional certificates to make up the shortfall. Conversely, when the held certificates exceed the quota requirement, the surplus can be sold for profit, thereby incentivizing the generation and accommodation of renewable energy. Figure 4 illustrates the basic principle of the GCT mechanism.

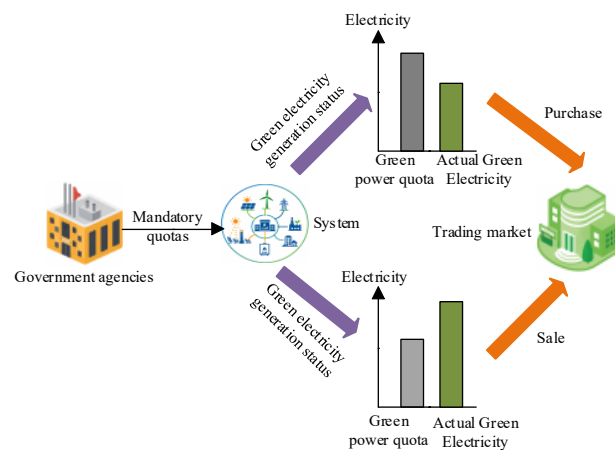


Figure 4. Schematic diagram of the trading principle of the green certificate market.

The GCT mechanism model is as follows:

$$\begin{cases} F_{\text{GCT}} = \lambda_{\text{green}} R_{\text{GCT}}; R_{\text{GCT}} = G_d - G_s \\ G_d = \alpha_{\text{green}} \sum_{t=1}^T P_t^{\text{e,load}}; G_s = \beta_{\text{green}} \sum_{t=1}^T (P_t^{\text{w}} + P_t^{\text{csp}} + P_t^{\text{G}}) \end{cases} \quad (16)$$

where R_{GCT} is the volume of tradable green certificates for the IES; G_d denotes the number of green certificates acquired from renewable power generation; G_s represents the prescribed green certificate holding ratio parameter; α_{green} is the quantitative conversion coefficient from renewable energy generation to green certificates; β_{green} indicates the green certificate trading cost; F_{GCT} defines the market price of green certificates; and λ_{green} stands for the allocated green certificate quota of the system.

3.3. Joint CET-GCT Mechanism

As the environmental value certificate for renewable energy generation, the green certificate inherently encompasses significant carbon emission reduction benefits. Once the ownership of the green certificate rights is clarified, the operator can calculate the corresponding carbon emission reductions based on the number of held green certificates. These reductions can be utilized to directly offset a portion of the carbon emissions generated during system operation, thereby influencing the allowance demand and trading strategies in the carbon trading market [32,33]. The operational framework of the CET-GCT mechanism is illustrated in Figure 5.

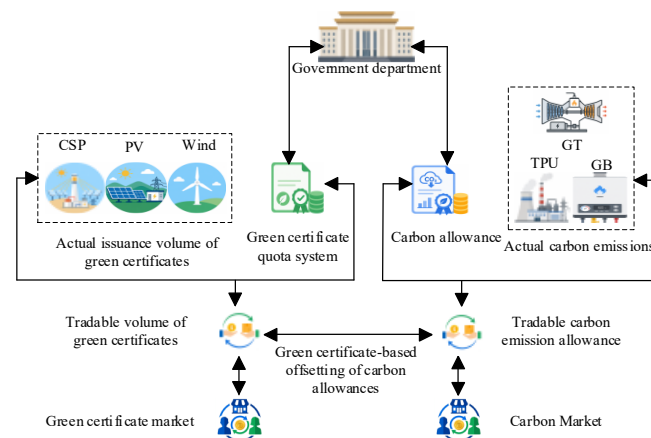


Figure 5. Operational framework of the CET-GCT mechanism.

The specific operational steps of the CET-GCT mechanism are as follows:

(1) Calculation of carbon emission reductions corresponding to green certificates

Given that China's energy structure is dominated by coal-fired generation, the carbon emission reductions corresponding to green certificates can be quantified by comparing the difference in carbon emission intensity between renewable energy generation and coal-fired generation. The specific calculation formula is shown in Equation (17).

$$\begin{cases} E_{\text{reduce}} = E_{\text{coal}} - E_{\text{res}} \\ E_{\text{Green}} = E_{\text{reduce}} G_d \end{cases} \quad (17)$$

where E_{coal} and E_{res} denote the carbon emission equivalents across the industrial chain life cycles of coal-based and renewable energy supply, respectively; E_{reduce} indicates the carbon mitigation coefficient associated with green certificates; and E_{Green} stands for the equivalent carbon reductions derived from green certificates.

(2) Updating of carbon emission rights

Based on the carbon emission reductions calculated in Equation (17), the carbon emission rights of the IES can be readjusted, as shown in Equation (18). The updated carbon emission rights will be incorporated into the carbon trading market for the trading and optimization of carbon allowances.

$$R_{\text{CET}} = R_{\text{CET}} - E_{\text{Green}} \quad (18)$$

4. Optimal Scheduling Model of the IES Considering CET-GCT

4.1. Objective Function

To balance the low-carbon performance and economic efficiency of the IES operation, the objective function comprehensively considers the gas purchasing cost, methanol revenue, equipment operation and maintenance costs, and the penalty cost for power curtailment. Furthermore, by incorporating the joint “electricity–carbon–green certificate” trading market, the objective function can be formulated as follows:

$$\min(F_{\text{total}}) = F_1 + F_2 + F_3 + F_{\text{buy}} + F_{\text{GCT}} + F_{\text{CET}} - F_{\text{CH}_3\text{OH}} \quad (19)$$

where F_{total} is the total operating cost of the IES; F_1 denotes the generation cost of the thermal power units; F_2 represents the system operation and maintenance cost (O&M); F_3 indicates the penalty cost for electricity curtailment; F_{buy} stands for the natural gas procurement cost; and $F_{\text{CH}_3\text{OH}}$ is the profit generated from methanol.

(1) Power generation cost of the TPU

$$F_1 = \sum_{t=1}^T (C_{\text{coal}} (aP_{\text{TPU},t}^2 + bP_{\text{TPU},t} + c) + SU_t (1 - U_{t-1})) \quad (20)$$

where C_{coal} is the coal price; a , b , and c denote the fuel consumption characteristic coefficients of the thermal power unit; S represents the start-up cost of the coal-fired unit; and U_t indicates the operating state variable of the unit during time interval t .

(2) Equipment O&M costs

$$\begin{cases} F_2 = \sum_n F^n \\ F_2^W = \sum_{t=1}^T k_W P_t^W; F_2^G = \sum_{t=1}^T k_G P_t^G; F_2^{\text{GB}} = \sum_{t=1}^T k_{\text{GB}} P_t^{\text{GB},g} \end{cases} \quad (21)$$

$$\begin{cases} F_2^{\text{CSP}} = \sum_{t=1}^T k_{\text{CSP}} P_t^{\text{CSP}}; F_2^{\text{EH}} = \sum_{t=1}^T k_{\text{EH}} P_t^{\text{EH}} \\ F_2^{\text{TES}} = \sum_{t=1}^T k_{\text{TES}} (E_t^{\text{TES},\text{in}} + E_t^{\text{TES},\text{out}}) \end{cases} \quad (22)$$

$$\begin{cases} F_2^{\text{EL}} = \sum_{t=1}^T k_{\text{EL}} P_t^{\text{EL}}; F_2^{\text{Stor}} = \sum_{t=1}^T k_{\text{Stor}} M_{\text{stor},t}^{\text{H}_2} \\ F_2^{\text{HFC}} = \sum_{t=1}^T k_{\text{HFC}} P_t^{\text{HFC},\text{E}}; F_2^{\text{MSU}} = \sum_{t=1}^T k_{\text{MSU}} P_t^{\text{MSU}} \end{cases} \quad (23)$$

where F_2^n represents the O&M cost of equipment n ; and k_n indicates the unit O&M cost coefficient for equipment n , $n = \{W, \text{EL}, \text{Stor}, \text{TES}, \text{CSP}, \text{G}, \text{EH}, \text{HFC}, \text{GB}, \text{MSU}\}$.

(3) Penalty cost for power curtailment

$$F_3 = \sum_{t=1}^T \xi_q (P_t^{\text{WQ}} + P_t^{\text{GQ}}) \quad (24)$$

where ξ_q is the unit penalty coefficient for power curtailment; P_t^{WQ} and P_t^{GQ} denote the curtailed power of wind and PV generation at time period t , respectively.

(4) Gas purchasing cost and methanol revenue

$$\begin{cases} F_{\text{buy}} = (3600 / L_{\text{CH}_4}) \sum_{t=1}^T c_{\text{gas}} P_t^{\text{GB},g} \\ F_{\text{CH}_3\text{OH}} = \chi_{\text{CH}_3\text{OH}} \sum_{t=1}^T M_t^{\text{CH}_3\text{OH}} \end{cases} \quad (25)$$

where L_{CH_4} represents the lower heating value of natural gas; c_{gas} indicates the unit gas purchasing price; and $\chi_{\text{CH}_3\text{OH}}$ stands for the unit selling price of methanol.

4.2. Constraints

(1) Power balance constraints

$$\begin{cases} P_t^{\text{e,load}} = P_{\text{TPU},t}^{\text{out}} + P_t^{\text{W}} + P_t^{\text{G}} + P_t^{\text{CSP}} + P_t^{\text{HFC},\text{E}} \\ E_t^{\text{TES},\text{h}} + E_t^{\text{EH},\text{h}} + E_t^{\text{HFC},\text{h}} + E_t^{\text{GB},\text{h}} = E_t^{\text{h,load}} \end{cases} \quad (26)$$

where $P_t^{\text{e,load}}$ and $E_t^{\text{h,load}}$ denote the electrical and thermal load power during time period t , respectively; P_t^{W} and P_t^{G} stand for the output power of the wind farm and PV power plant at time period t , respectively.

(2) Wind and PV power balance

$$\begin{cases} P_t^{\text{m}} = P_{m,t}^{\text{G}} + P_{m,t}^{\text{W}} \\ P_t^{\text{W}} + P_{\text{EL},t}^{\text{W}} + P_{\text{EH},t}^{\text{W}} + P_{\text{MSU},t}^{\text{W}} = P_{\text{w},t}^{\text{pre}} \\ P_t^{\text{G}} + P_{\text{EL},t}^{\text{G}} + P_{\text{MSU},t}^{\text{G}} = P_{\text{g},t}^{\text{pre}} \end{cases} \quad (27)$$

where P_t^m denotes the power of equipment m in period t , $m = (\text{EH}, \text{EL}, \text{MSU})$; $P_{m,t}^W$ and $P_{m,t}^G$ represent the wind power and photovoltaic power consumed by equipment m in period t , respectively.

(3) Operational constraints of the CSP plant

The detailed mathematical models for the ramping and start-up constraints of the CSP plant can be found in References [34,35].

4.3. Linearization of the Coal Consumption Cost Function

To address the low solution efficiency caused by the high-order nonlinearity of the coal consumption cost, a piecewise linearization method is employed to convert it into linear constraints. This approach successfully balances computational accuracy and solving speed. The detailed formulation process can be referred to in [36]. The output range of a TPU can be divided into m segments. Figure 6 shows the coal consumption curve for a TPU.

$$\begin{cases} M_t^{\text{coal}} = M_t^{\text{coal},\min} U_t + \sum_{n=1}^m K_n P_{t,n}^0 \\ M_t^{\text{coal},\min} = a(P_{\min}^{\text{TPU}})^2 + bP_{\min}^{\text{TPU}} + c \\ 0 \leq P_{t,n}^0 \leq \frac{(P_{\max}^{\text{TPU}} - P_{\min}^{\text{TPU}})}{m}, P_{\text{TPU},t} = \sum_{n=1}^m P_{t,n}^0 + P_{\min}^{\text{TPU}} \end{cases} \quad (28)$$

where K_n represents the segment slope of the linearized coal consumption characteristic for thermal units; M_t^{coal} is the total coal consumption of thermal units at time t ; $M_t^{\text{coal},\min}$ denotes the minimum-output coal consumption of committed thermal units in time frame t ; and $P_{t,n}^0$ corresponds to the piecewise power generation of thermal units during period t .

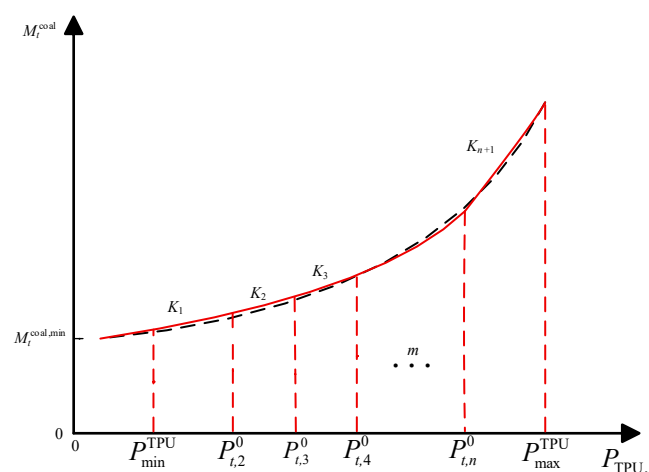


Figure 6. Coal consumption curve for a thermal power unit.

5. IES Optimal Scheduling Model Based on IGDT

Currently, primary methodologies for addressing uncertainty mainly comprise stochastic programming (SP), scenario-based dispatch (SBD), robust optimization (RO), and distributionally robust optimization (DRO). While these approaches are respectively suitable under different conditions, practical applications reveal key limitations: SP and SBD rely on precise probability distributions or massive data; DRO features high model complexity and heavy computational load; whereas RO requires presetting uncertainty boundaries, where inaccurate boundary specification easily leads to decisions that are overly conservative or invalid.

In contrast, IGDT requires neither known probability distributions nor exact fluctuation intervals. Under the premise of satisfying minimum system requirements, it inversely evaluates the maximum fluctuation range the system can tolerate. This mechanism not only reduces data reliance but also allows for a more intuitive trade-off between safety margin and risk-averse capability. In summary, this study selects IGDT as the approach for handling uncertainty.

5.1. Deterministic IES Optimal Scheduling Model

The formulated deterministic model is expressed as follows:

$$\begin{cases} \min F_{\text{total}}(X, u_{\text{est},z}^{(i)}) \\ H(X, u_{\text{est},z}^{(i)}) = 0, G(X, u_{\text{est},z}^{(i)}) \leq 0 \end{cases} \quad (29)$$

where X is the optimization variable; $u_{\text{est},z}^{(i)}$ is the forecasted value of the z type of uncertainty factor during period i , with z corresponding to wind power, PV power, electrical load, and thermal load, respectively; H denotes the system equality constraints; and G denotes the system inequality constraints.

5.2. IGDT-Based Optimal Scheduling Model for IES Under Uncertainty

IGDT can characterize uncertainty through non-probabilistic distribution models under deep uncertainty; therefore, an envelope model is adopted for its representation.

$$U(\alpha_z, u_{\text{est},z}^{(i)}) = \left\{ u_{\text{act},z}^{(i)} \mid \left| u_{\text{act},z}^{(i)} - u_{\text{est},z}^{(i)} \right| \leq \alpha_z u_{\text{est},z}^{(i)} \right\} \quad (30)$$

where U denotes the fluctuation range of the uncertainty factor; $u_{\text{act},z}^{(i)}$ represents the actual value of the z type of uncertainty factor during period i ; and α_z is the deviation coefficient of the z type of uncertainty factor.

Based on IGDT, a risk aversion strategy (RAS) can be established from a pessimistic perspective, which assumes that uncertainty will bring adverse impacts. Its objective is to maximize the level of uncertainty the system can withstand without the system cost exceeding a predefined threshold [37]. Conversely, an opportunity seeking strategy (OSS) can be established from an optimistic perspective, assuming that uncertainty will yield favorable impacts. Its objective is to minimize the risks induced by uncertainty to the greatest extent while pursuing the potential benefits of the system [38]. Both strategies must be founded on a deterministic model. The optimization models for RAS and OSS are formulated as follows:

$$\begin{cases} \max \alpha \\ \max F_{\text{total}}(X, u_{\text{act},z}^{(i)}) \leq (1 + \beta_R) F_0 \\ H(X, u_{\text{act},z}^{(i)}) = 0, G(X, u_{\text{act},z}^{(i)}) \leq 0 \\ u_{\text{act},z}^{(i)} \in U(\alpha_z, u_{\text{est},z}^{(i)}) \\ \alpha_z = k_z \alpha \end{cases} \quad (31)$$

$$\begin{cases} \min \alpha \\ \min F_{\text{total}}(X, u_{\text{act},z}^{(i)}) \leq (1 - \beta_0) F_0 \\ H(X, u_{\text{act},z}^{(i)}) = 0, G(X, u_{\text{act},z}^{(i)}) \leq 0 \\ u_{\text{act},z}^{(i)} \in U(\alpha_z, u_{\text{est},z}^{(i)}) \\ \alpha_z = k_z \alpha \end{cases} \quad (32)$$

where α denotes the comprehensive deviation coefficient; F_0 represents the total system profit of the deterministic model; β_R and β_0 are the robustness deviation factor and the opportunity deviation factor, respectively; and k_z is the weighting coefficient of the z type of uncertainty factor, the sum of which equals 1.

The aforementioned models are all bi-level models. As indicated by Equation (31), the system cost reaches its maximum when the load demand hits the upper bound of its corresponding envelope, while the wind and PV power outputs drop to the lower bounds of their respective envelopes. The same logic applies to Equation (32). Consequently, the above models can be transformed into a single-level model, which is specifically formulated as follows:

$$\left\{ \begin{array}{l} \max \alpha \\ F_{\text{total}} \leq (1 + \beta_R) F_0 \\ H(X, u_{\text{act},z}^{(i)}) = 0, G(X, u_{\text{act},z}^{(i)}) \leq 0 \\ u_{\text{act},1}^{(i)} = (1 - \alpha_1) u_{\text{est},1}^{(i)}, u_{\text{act},2}^{(i)} = (1 - \alpha_2) u_{\text{est},2}^{(i)} \\ u_{\text{act},3}^{(i)} = (1 + \alpha_3) u_{\text{est},3}^{(i)}, u_{\text{act},4}^{(i)} = (1 + \alpha_4) u_{\text{est},4}^{(i)} \\ \alpha_z = k_z \alpha \end{array} \right. \quad (33)$$

$$\left\{ \begin{array}{l} \min \alpha \\ F_{\text{total}} \leq (1 - \beta_O) F_0 \\ H(X, u_{\text{act},z}^{(i)}) = 0, G(X, u_{\text{act},z}^{(i)}) \leq 0 \\ u_{\text{act},1}^{(i)} = (1 + \alpha_1) u_{\text{est},1}^{(i)}, u_{\text{act},2}^{(i)} = (1 + \alpha_2) u_{\text{est},2}^{(i)} \\ u_{\text{act},3}^{(i)} = (1 - \alpha_3) u_{\text{est},3}^{(i)}, u_{\text{act},4}^{(i)} = (1 - \alpha_4) u_{\text{est},4}^{(i)} \\ \alpha_z = k_z \alpha \end{array} \right. \quad (34)$$

All numerical simulations were executed on a personal computer equipped with an Intel(R) Core(TM) i7-10750H CPU @ 2.60 GHz and 16 GB of RAM. The optimization models were formulated via the YALMIP optimization toolbox in MATLAB (2016a) and solved using the commercial CPLEX solver. The results indicate that the average computational time required to solve the 24 h scheduling model under the proposed strategy is approximately 1.2 s.

6. Case Study

6.1. Parameter Settings and Scenario Construction

The case study constructs a multi-energy complementary IES based on the energy structure of a certain region in Northwest China. The system comprises a 200 MW TPU, a 400 MW wind farm, a 300 MW PV power station, a 100 MW CSP plant, a 90 MW GB, and a HFC power generation system with an installed capacity of 35 MW.

The economic parameters are presented in Table 1, and the operational parameters of each piece of equipment are detailed in Table 2. Figure 7 illustrates the forecasted curves of the “source–load” sides on a typical day.

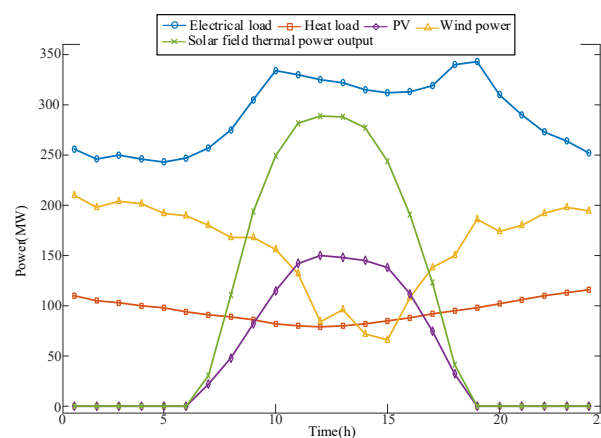


Figure 7. Forecasted generation-load profiles.

Table 1. Economic parameters.

Parameter	Value	Parameter	Value
k_w (CNY/MW)	20	k_G (CNY/MW)	30
k_{EH} (CNY/MW)	15	k_{TES} (CNY/MW)	30
k_{EL} (CNY/MW)	120	k_{Stor} (CNY/ton)	50
k_{HFC} (CNY/MW)	84	k_{CSP} (CNY/MW)	100
ξ_q (CNY/MW)	200	c_{gas} (CNY/m ³)	3.5

Table 2. Device settings.

Parameter	Value	Parameter	Value
P_{min}^{CSP} (MW)	10	P_{min}^{TPU} (MW)	100
P_{max}^{CSP} (MW)	100	P_{max}^{TPU} (MW)	200
E_{t0}^{TES} (MW)	600	ΔP_{max}^{TPU} (MW·h)	70
$E_{max}^{TES,out}$ (MW)	400	$E_{max}^{TES,in}$ (MW)	400
P_{max}^{MSU} (MW)	40	ΔP_{max}^{MSU} (MW·h)	10
P_{max}^{EL} (MW)	90	$\Delta M_{max}^{H_2,HFC}$ (ton·h)	1
P_{min}^{EL} (MW)	0	$M_{max}^{H_2,HFC}$ (ton)	2
ΔP_{max}^{EL} (MW·h)	90	γ^{cc} (MW·ton ⁻¹)	0.23
c (ton)	14.618	e (ton·MW ⁻¹ ·h ⁻¹)	0.98
a (ton·(MW ⁻²))	0.000072	b (ton·(MW ⁻²))	0.2292
η^{cc} (%)	85	η_{GB} (%)	90
$P_{max}^{GB,g}$ (MW)	100	$\Delta P_{max}^{GB,g}$ (MW·h)	35

6.2. Analysis of Optimal Operation Results Under the Base Case Scenario

The simulation results under the base operating condition, without considering uncertainties, are analyzed to verify that the proposed scheme satisfies the operational requirements of the system. Figures 8 and 9 present the electrical and thermal power balance results of the system, respectively. Figure 10 illustrates the accommodation of wind and PV power.

Based on the analysis of Figures 8–10, during the 1:00–7:00 period, the system exhibits typical characteristics of a high heat load and a low electrical load. During this time, the PV output is zero, while wind resources are extremely abundant. The net power output of the carbon capture TPU is reduced to its minimum stable operation baseline (77.84 MW), which not only expands the accommodation space for new energy but also ensures the safety and stability of the system's operation. In terms of thermal power dispatch, the heating demand is primarily met independently by the TES system of the CSP plant. As its available heat gradually depletes, the GB rapidly cuts in and ramps up to 70.24 MW, effectively filling the heat deficit. Furthermore, the system flexibly dispatches the EL and the MSU to convert surplus new energy power into hydrogen and green methanol. This strategy not only broadens the efficient accommodation pathways for renewable energy but also generates additional economic benefits by selling chemical products to downstream chemical plants, achieving a mutual enhancement of new energy accommodation levels and economic returns.

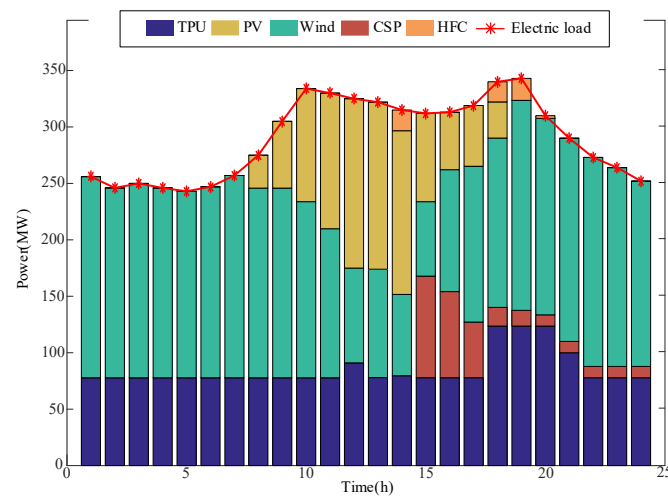


Figure 8. Electrical power balance.

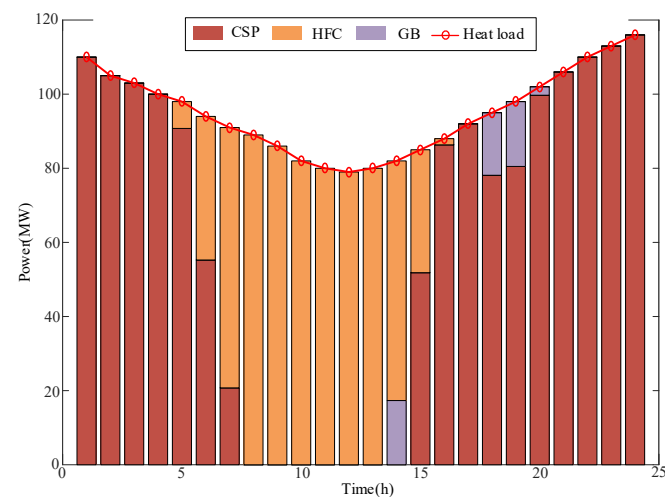


Figure 9. Thermal power balance.

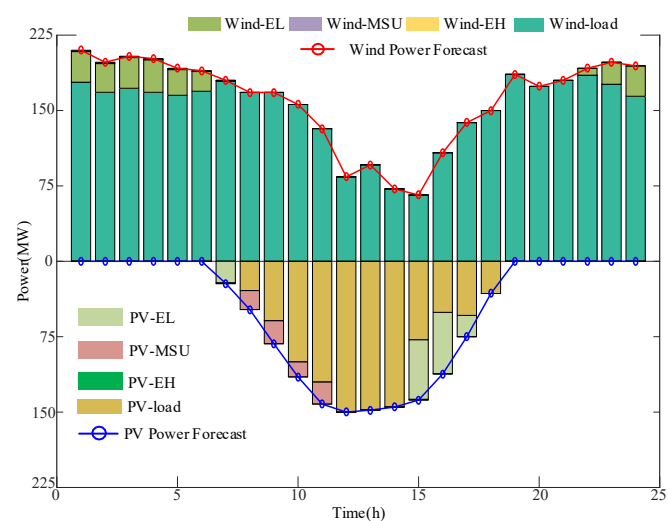


Figure 10. Analysis of wind and PV power accommodation.

During the 8:00–14:00 period, accompanied by enhanced solar radiation and rising temperatures, the PV plant enters a strong output phase, and the heat load bottoms out. During this period, the electrical load shows a steady ramping trend. PV power generation climbs rapidly, replacing wind power as the dominant force in power supply, while

the TPU continues to operate stably at its minimum output for the majority of the time. On the thermal energy supply side, the TES system of the CSP plant pauses heat release, and the base heat load is primarily shifted to the GB, with the HFC providing a portion of auxiliary thermal power. Addressing the localized output redundancy of PV during the noon hours, the system dispatches the EH to absorb surplus PV power up to 22.84 MW and convert it into thermal energy, effectively achieving the efficient coupling of the “electricity–heat–electricity” energy flow.

During the 15:00–21:00 period, the system faces the most severe energy supply challenge of the day. The electrical load peaks at 343 MW, and the heat load demand experiences a secondary surge. On the power supply side, the output of the carbon capture TPU leaps significantly to a peak state of 123.58 MW; simultaneously, the CSP plant provides up to 90 MW of electrical power, and the HFC continuously outputs electrical energy. On the thermal energy supply side, the GB is gradually phased out of operation, while the CSP-TES system and the hydrogen fuel cell leverage their CHP advantages to synergistically safeguard the thermal energy supply. In addition, the system restarts the EL during this period to absorb surplus PV power and produce hydrogen, reserving sufficient fuel for the subsequent operation of the HFC.

During the 22:00–24:00 period, the system operation and load characteristics gradually return to a state similar to the early morning hours. The electrical load drops rapidly from its high level, PV output returns to zero, and wind power generation ushers in a secondary surge. Under these operating conditions, the TPU quickly adjusts its output back to the minimum operating baseline, proactively making room for wind power grid integration. Regarding the thermal energy balance, both the GB and the hydrogen fuel cell are in a shutdown state. The high heat load demand of 116 MW is fully borne by the CSP-TES system, completely validating its excellent cross-period thermal storage regulation and comprehensive support capabilities.

In summary, the proposed strategy broadens the flexible accommodation pathways for new energy and substantially compresses the operational space of high-carbon-emission TPUs. Under the premise of ensuring the absolute security of the “power and heat” supply, it significantly enhances the low-carbon economics and dispatch flexibility of the overall operation.

6.3. Validation of the Effectiveness of the Proposed Strategy

6.3.1. Analysis of the Operational Effectiveness of the CSP Plant with an EH

To verify the effectiveness of the proposed model for the CSP plant integrated with an EH, the following three scenarios are established for comparative analysis:

Scenario 1: Only the CSP plant is considered, without the introduction of an EH.

Scenario 2: A gas-fired CHP unit with equivalent power and ramping constraints replaces the CSP plant with an EH to participate in the system operation.

Scenario 3: The joint participation of the EH and the CSP plant in the system operation is considered, which represents the strategy proposed in this paper.

The cost results of the IES under the different scenarios are illustrated in Figure 11, and the total output of each unit is presented in Table 3.

Table 3. Total output of each unit.

Scenario	Scenario 1	Scenario 2	Scenario 3
Total power output of the wind farm (MW·h)	3603.6	3527.2	3603.6
Total power output of the PV plant (MW·h)	1016.46	1108.68	966.48
Total power output of the CSP plant (MW·h)	302.47	0	296.15
Total power output of the HFC system (MW·h)	9.17	49.52	58.07

Total power output of the TPU (MW·h)	2035.3	2125.8	2042.7
Total power output of the CHP plant (MW·h)	0	155.80	0
Total thermal output of the CSP plant (MW·h)	1446.60	0	1518.3
Total thermal output of the HFC system (MW·h)	8.67	75.22	54.00
Total thermal output of the CHP plant (MW·h)	0	175.28	0
Total thermal output of the GB (MW·h)	828.73	2033.50	711.70
Total carbon emissions of the base (tons)	917.25	1811.20	843.20

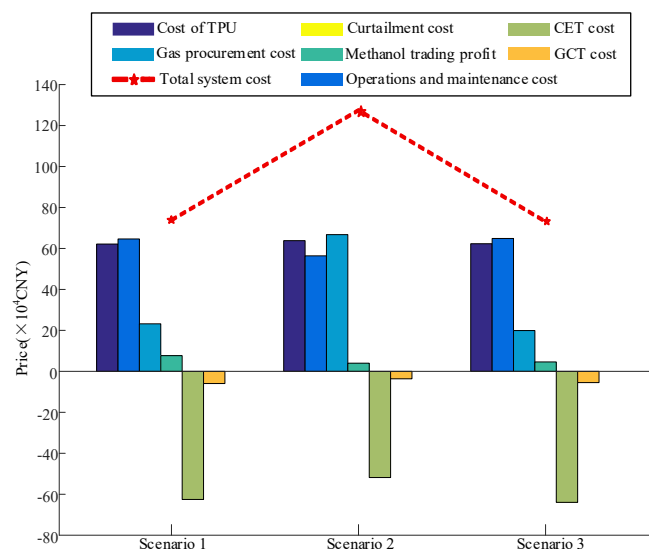


Figure 11. Costs under different scenarios.

The optimization results from Figure 11 and Table 3 indicate that the strategy proposed in this paper possesses significant advantages in enhancing the low-carbon benefits and dispatch flexibility of the system. In terms of low-carbon emission reduction, the total carbon emissions in Scenario 3 are only 843.20 tons, representing a decrease of approximately 8.07% compared with Scenario 1, and a substantial reduction of 53.45% compared with Scenario 2 with the gas-fired CHP unit. Taking into account the output distribution of the units, introducing an electric boiler into the CSP plant effectively broadens the system's "electricity–heat–electricity" multi-energy coupling space. Under this mechanism, the total thermal output of the CSP plant increases by approximately 4.96% compared with Scenario 1, thereby reducing the thermal output demand of the GB and successfully achieving a deep substitution for high-carbon-emission energy supply methods.

Benefiting from the highly efficient and low-carbon energy supply of the "EH-CSP plant" configuration, the gas purchase cost in Scenario 3 is significantly compressed to 199,300 CNY, reflecting a decrease of approximately 14.1% and 70.1% compared with Scenarios 1 and 2, respectively. Concurrently, due to the strict control of carbon emissions, Scenario 3 achieves the highest carbon trading revenue (639,600 CNY) and the lowest total operating cost (730,600 CNY). This is not only superior to Scenario 1 (738,500 CNY) but also far lower than Scenario 2 (1,274,700 CNY).

Consequently, the joint operation strategy of the EH and the CSP plant proposed in this paper fully leverages the synergistic advantages of multi-energy complementarity, successfully achieving a win-win situation for both low-carbon operation and economic benefits.

6.3.2. Analysis of the Effectiveness of the “Electricity–Carbon–Hydrogen–Methanol” Model

To verify the effectiveness of the “electricity–carbon–hydrogen–methanol” strategy proposed in this paper, the following four operating scenarios are established for comparative analysis:

Scenario 1: Only the HFC system is configured, without the introduction of MSU.

Scenario 2: Only the MSU is configured for external sales and profit, without considering the operation of the HFC.

Scenario 3: Neither the HFC system nor the MSU is considered.

Scenario 4: Both the HFC power generation system and the MSU are configured simultaneously, representing the strategy proposed in this paper.

The operating results of the different scenarios are presented in Table 4.

Table 4. System operation results under different scenarios.

Scenario	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total system cost ($\times 10^4$ CNY)	82.39	74.24	74.37	73.06
Cost of TPU ($\times 10^4$ CNY)	61.6	62.19	62.05	62.29
Operations and maintenance cost ($\times 10^4$ CNY)	59.8	64.5	62.96	64.88
Gas procurement cost ($\times 10^4$ CNY)	23.93	23.93	18.96	19.93
Methanol trading profit ($\times 10^4$ CNY)	0	8.13	0	4.59
CET cost ($\times 10^4$ CNY)	−61.81	−62.26	−64.16	−63.96
GCT cost ($\times 10^4$ CNY)	−6.27	−5.99	−5.44	−5.49
Curtailement cost ($\times 10^4$ CNY)	5.12	0	0	0
Curtailement rate (%)	5.07	0	0	0

The optimization results in Table 4 clearly demonstrate that the joint operation strategy proposed in this paper possesses significant advantages in terms of comprehensive economic benefits and new energy accommodation levels. Regarding the total system cost, Scenario 4 reduces the comprehensive operating cost to a minimum of 730,600 CNY through deep synergistic optimization among multiple devices. Compared with Scenarios 1–3, Scenario 4 achieves cost reductions of 11.32%, 1.59%, and 1.76%, respectively, fully validating the economic superiority of the proposed strategy.

Furthermore, due to limitations in the system’s regulation capability, Scenario 1 experiences a power curtailment rate of 5.07% and incurs a curtailment penalty cost of 51,200 CNY. In contrast, Scenario 4 effectively mitigates the fluctuations in new energy output, reducing the curtailment rate to 0% and achieving the complete accommodation of clean energy. Regarding carbon emission reduction, Scenario 4 achieves optimal carbon emission control. Its carbon trading cost reaches −639,600 CNY, yielding the highest carbon trading revenue among all scenarios. In terms of energy consumption, the gas purchase cost in Scenario 4 is significantly reduced by approximately 16.71% compared with Scenarios 1 and 2, effectively decreasing reliance on external fossil fuels. Although Scenario 2 generates higher revenue from external methanol sales (81,300 CNY), it fails to fully exploit the synergistic emission reduction and regulation potential of the entire system; consequently, both its overall operating cost and carbon trading performance are inferior to those of Scenario 4.

In summary, the strategy proposed in this paper achieves a global optimum in terms of low-carbon emission reduction, new energy accommodation, and economic benefits.

6.3.3. Analysis of the Effectiveness of the Joint CET-GCT Operation

To verify the effectiveness of the joint CET-GCT mechanism, this paper conducts a comparative analysis of Scenarios 1–4. The specific settings and operating results are presented in Tables 5 and 6.

Table 5. Basic information of scenario settings.

Scenario	CET	GCT	Coordination
Scenario 1	√	×	×
Scenario 2	×	√	×
Scenario 3	√	√	×
Scenario 4	√	√	√

Note: In Table 5, “√” indicates that the element is considered in the scenario, whereas “×” indicates that it is not.

Table 6. Operating results of different scenarios.

Scenario	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total system cost ($\times 10^4$ CNY)	126.53	136.22	120.95	73.06
Cost of TPU ($\times 10^4$ CNY)	62.33	61.94	62.29	62.29
Operations and maintenance cost ($\times 10^4$ CNY)	61.5	64.8	64.88	64.88
Gas procurement cost ($\times 10^4$ CNY)	23.59	22.48	19.93	19.93
Methanol trading profit ($\times 10^4$ CNY)	5.05	7.04	4.59	4.59
CET cost ($\times 10^4$ CNY)	−15.84	0	−16.07	−63.96
GCT cost ($\times 10^4$ CNY)	0	−5.96	−5.49	−5.49
Curtailment rate (%)	0	0	0	0
Total carbon emissions of the base (ton)	859.95	898.43	843.20	843.20

Judging from the operating results of the various scenarios in Table 6, the total carbon emissions of the system in Scenarios 3 and 4, which simultaneously introduce CET and GCT, both decrease to 843.20 tons. This is significantly lower than Scenario 1 (859.95 tons) and Scenario 2 (898.43 tons), which only consider a single mechanism, indicating that the dual-market combination demonstrates superior emission reduction performance. The total cost of Scenario 4, which features the joint CET-GCT mechanism, is only 730,600 CNY, representing a substantial reduction of approximately 39.6% compared with Scenario 3 (1,209,500 CNY), which does not consider the joint mechanism. Meanwhile, the new energy power curtailment rate for all scenarios remains at 0%, achieving the full accommodation of renewable energy.

Comparing the specific data of Scenario 3 and Scenario 4 reveals that their thermal power costs, new energy O&M costs, gas purchase costs, and carbon emission values are exactly the same. Driven by the joint CET-GCT mechanism, the carbon trading revenue in Scenario 4 increases significantly from 160,700 CNY in Scenario 3 to 639,600 CNY, representing a massive surge of 298.01%. This indicates that by integrating the carbon trading market with the green certificate market, the system can better achieve the dual optimization of carbon emissions and operating costs without altering its original dispatch

6.4. Sensitivity Analysis

6.4.1. Analysis of Results Under Different Maximum Operating Powers of the EH

By limiting the maximum output of the EH to six levels ranging from 0 to 50 MW (in increments of 10 MW), this paper comparatively analyzes the impact of differences in the equipment’s rated capacity on system operation. The specific operating data for the relevant working conditions are detailed in Table 7.

Table 7. Operating results under different rated powers of the EH.

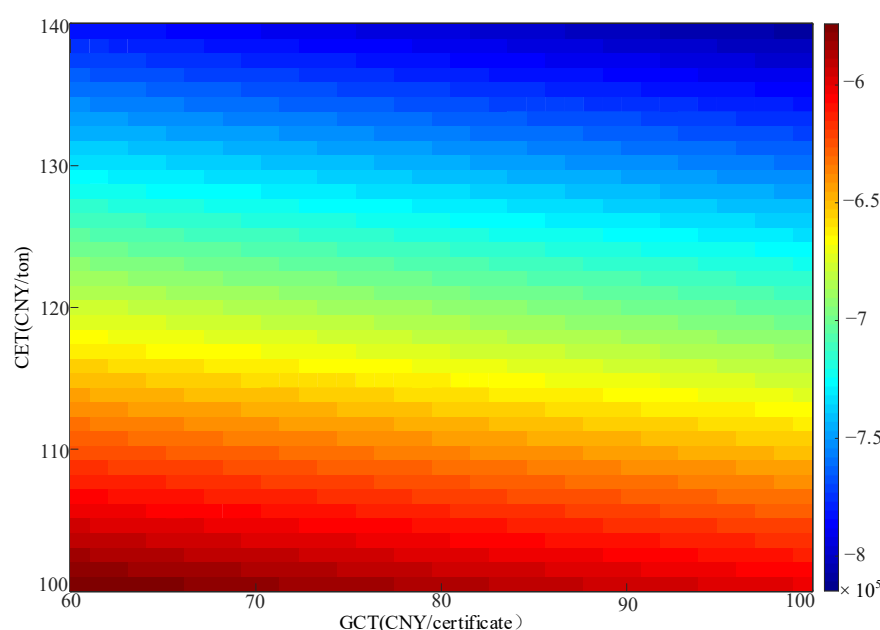
Power (MW)	0	10	20	30	40
Total system cost ($\times 10^4$ CNY)	73.45	73.45	73.10	73.06	73.06
Cost of TPU ($\times 10^4$ CNY)	62.12	62.12	62.29	62.29	62.29
Operations and maintenance cost ($\times 10^4$ CNY)	64.76	64.76	64.90	64.88	64.88
Gas procurement cost ($\times 10^4$ CNY)	22.48	22.48	19.93	19.93	19.93
Methanol trading profit ($\times 10^4$ CNY)	7.24	7.24	4.60	4.59	4.59
CET cost ($\times 10^4$ CNY)	−62.79	−62.79	−63.95	−63.96	−63.96
GCT cost ($\times 10^4$ CNY)	−5.88	−5.88	−5.47	−5.49	−5.49
Curtailment rate (%)	0	0	0	0	0
CSP contribution to total power supply (%)	4.24	4.24	4.23	4.25	4.25
CSP contribution to total heat supply (%)	64.1	64.1	66.45	66.47	66.47

The operating data in Table 7 demonstrate that increasing the rated power of the EH within a certain range can effectively enhance the economic and environmental performance of the system; however, this optimization effect tends to saturate once the power reaches 30 MW. Specifically, as the rated power increases from 10 MW to 30 MW, the total system cost decreases from 734,500 CNY to 730,600 CNY. This is primarily attributed to a significant reduction in gas purchase costs and an increase in carbon trading revenue. Simultaneously, the heating proportion of the CSP plant rises from 64.1% to 66.47%.

However, when the power is further increased to 40 MW, the various costs, revenues, and heating proportion of the system remain largely unchanged, and the power curtailment rate consistently stays at 0%. The aforementioned results indicate that configuring the electric boiler with a rated power of around 30 MW can achieve the optimal operating state for the system; blindly pursuing a larger electric boiler capacity will not yield further improvements in marginal benefits.

6.4.2. Sensitivity Analysis of the Joint CET-GCT Trading Mechanism

The impact of different base prices on the total cost of CET-GCT trading is illustrated in Figure 12.

**Figure 12.** Total cost of CET-GCT trading.

As illustrated in Figure 12, following the introduction of the CET-GCT collaborative trading architecture, the sensitivity of the system's joint total cost to benchmark prices exhibits a significant negative correlation. Specifically, when the GCT base price remains constant, the joint total cost decreases linearly with the increase in the CET base price; similarly, if the CET base price is fixed, the joint total cost further declines as the GCT base price rises. This is because, under the current system operating parameters, both the carbon allowances and green certificates generated by the IES yield net revenues in the market (i.e., the corresponding costs are negative). As the base price of either CET or GCT increases, the joint total cost of CET-GCT continuously decreases (visually represented in the figure by a transition from high-cost dark-red regions to low-cost blue regions). This further validates the practical efficacy of introducing the joint CET-GCT operational mechanism in enhancing the overall system economics.

However, it should be noted that the aforementioned sensitivity analysis treats the benchmark prices of CET and GCT as mutually independent external input variables. In practice, the carbon emission and green certificate markets often exhibit significant macroeconomic cross-elasticity and regulatory policy coupling. If the prices in both markets decline simultaneously due to external shocks, the revenue that the system relies upon to offset operating costs via joint CET-GCT trading will face a risk of dual contraction. Consequently, this would lead to an uncontrollable and sharp rebound in the joint CET-GCT total cost. Furthermore, under extreme market volatility, if physical dispatch lacks endogenous coordinated response and adaptive adjustment flexibility, static trading strategies will struggle to effectively mitigate the risks posed by concurrent multi-market shocks. Therefore, in future system planning and actual dispatch, it is necessary to further introduce a CET-GCT endogenous coordinated response mechanism alongside risk-hedging indicators, thereby enhancing the system's robustness against simultaneous high-volatility shocks across multiple markets.

6.4.3. Sensitivity Analysis on the Capacity Sizing of Energy Storage and Hydrogen Conversion Equipment

To investigate the specific impacts of equipment sizing on renewable energy accommodation levels and total costs, a capacity sensitivity analysis was conducted for the EL, TES, MSU, HFC, and HS tank. Table 8 records the sensitivity data of total system cost with respect to individual equipment capacities, while Figure 13 displays the renewable energy curtailment rates under different configuration scenarios.

Table 8. Sensitivity of total system cost to variations in equipment capacities (cost: in 10,000 CNY).

Device	−80%	−60%	−40%	−20%	0% (Baseline)	20%
EL	76.11	73.25	73.11	73.06	73.06	73.06
HFC	74.08	73.92	73.73	73.37	73.06	72.99
MSU	73.06	73.06	73.06	73.06	73.06	73.06
TES	102.15	89.96	79.46	75.06	73.06	71.64
HS tank	72.54	72.59	72.75	72.91	73.06	73.22

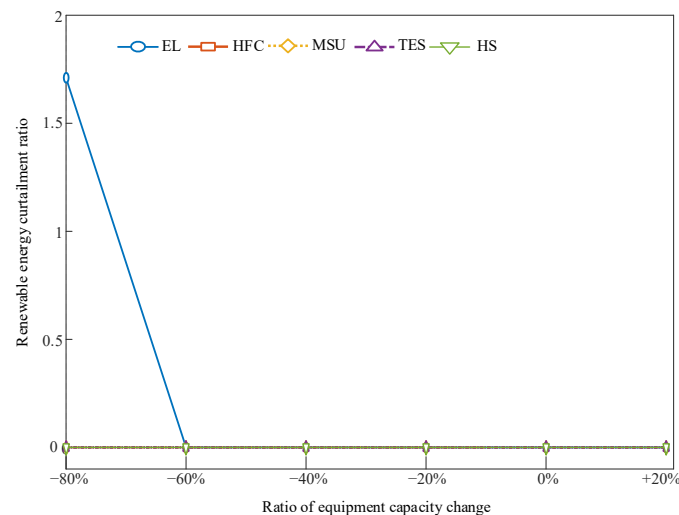


Figure 13. Renewable energy curtailment rate results.

Combined with the operational data in Table 8 and Figure 13, it is evident that the system achieves high-level renewable energy integration with remarkably low curtailment rates under most operating conditions. Further capacity analysis reveals that the TES exerts the most significant impact on the total cost. Specifically, an 80% reduction in capacity leads to an approximately 40% increase in total cost (exceeding 1.02 million CNY), whereas a 20% capacity expansion achieves the lowest cost across all operating conditions. This indicates that the thermal storage component serves as the critical constraint for balancing supply and demand as well as mitigating costs; an insufficient capacity would result in substantial cost inflation. Meanwhile, the EL plays a pivotal role in ensuring effective renewable energy accommodation. Reducing its capacity by up to 60% exerts a negligible impact on the system; however, an 80% reduction leads to a renewable curtailment rate of 1.71%. This demonstrates that the system's renewable accommodation capacity has a critical threshold, beyond which an excessive reduction in EL sizing renders the system incapable of absorbing the renewable generation output.

Additionally, certain equipment exhibits substantial capacity redundancy. When the capacity of the MSU varies within the range of −80% to +20%, both the total cost and various operational metrics remain unchanged. The economic trends of hydrogen equipment exhibit marked divergence: expanding the HFC capacity yields a marginal cost reduction, whereas downsizing the HS tank by 80% similarly lowers the total cost. This indicates that the capital expenditure of HS equipment outweighs its flexibility benefits. The system operates more favorably under a “just-in-time” paradigm, whereas excessive intermediate storage links compromise overall economic performance.

The above findings demonstrate that the baseline capacities configured for the TES and EL already enable effective renewable energy accommodation while safeguarding overall economic efficiency. Unilaterally expanding the capacities of MSU and hydrogen storage yields negligible marginal benefits, while incurring redundant investment costs.

6.5. Uncertainty Analysis Based on IGDT

To analyze the impact of “source–load” side uncertainties on the operational stability and economics of the IES, this paper establishes two different uncertainty scenarios: scheme 1 and scheme 2. Based on historical statistical prediction errors and the entropy weight method for objective normalized weighting, the uncertainty deviation coefficient weights for wind power, PV, electrical load, and heat load are calculated to be 0.455, 0.341, 0.114, and 0.091, respectively.

Scheme 1: The RAS is adopted, with $\beta_R = 0.05$ specified.

Scheme 2: The OSS is adopted, with $\beta_0 = 0.05$ specified.

Figures 14–17 show the electrical and thermal power operation results of the IES under conditions of uncertainty, as well as the integration of wind and PV power, respectively; the system operating costs under different IGDT scenarios are shown in Table 9.

Table 9. Analysis of system operating costs under the IGDT scenario.

Case	1	2
Total system cost ($\times 10^4$ CNY)	76.72	69.41
Cost of TPU ($\times 10^4$ CNY)	63.13	61.84
Operations and maintenance cost ($\times 10^4$ CNY)	64.85	65.25
Gas procurement cost ($\times 10^4$ CNY)	22.73	19.67
Methanol trading profit ($\times 10^4$ CNY)	4.57	8.26
CET cost ($\times 10^4$ CNY)	−63.82	−63.32
GCT cost ($\times 10^4$ CNY)	−5.60	−5.77

The comparative data from Figures 14–17 and Table 9 demonstrate that Scheme 2, adopting the OSS, exhibits significant comprehensive economic advantages over Scheme 1, which relies on the RAS. Specifically, the actual total cost of Scheme 2 is reduced to approximately 694.1 thousand CNY, representing a decrease of roughly 9.5% compared with the 767.2 thousand CNY in Scheme 1. Scheme 1 is predicated on extremely pessimistic expectations. To ensure sufficient robust regulation capability of the system under severe fluctuations, it is forced to maintain high thermal power output and increase gas procurement (reaching up to 227.3 thousand CNY) to backstop electrical and thermal loads, ultimately resulting in persistently high fossil fuel-related costs. In contrast, Scheme 2 is based on optimistic expectations, significantly reducing the operating costs of conventional energy sources such as thermal power and gas-fired boilers (with gas procurement costs dropping to 196.7 thousand CNY). Furthermore, it absorbs surplus renewable energy, increasing methanol revenue from 45.7 thousand CNY to 82.6 thousand CNY, which substantially reduces the overall operational cost of the system.

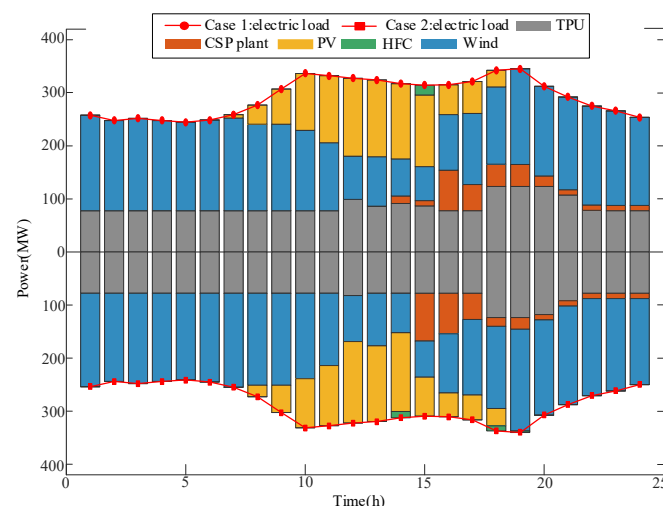


Figure 14. IES electrical power balance under uncertainty.

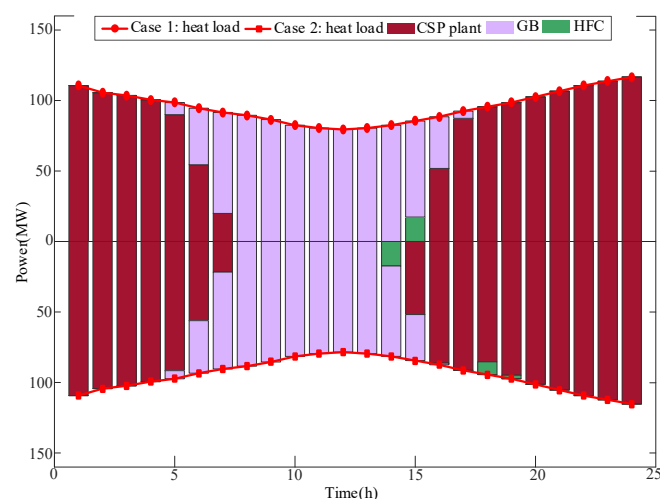


Figure 15. IES thermal power balance under uncertainty.

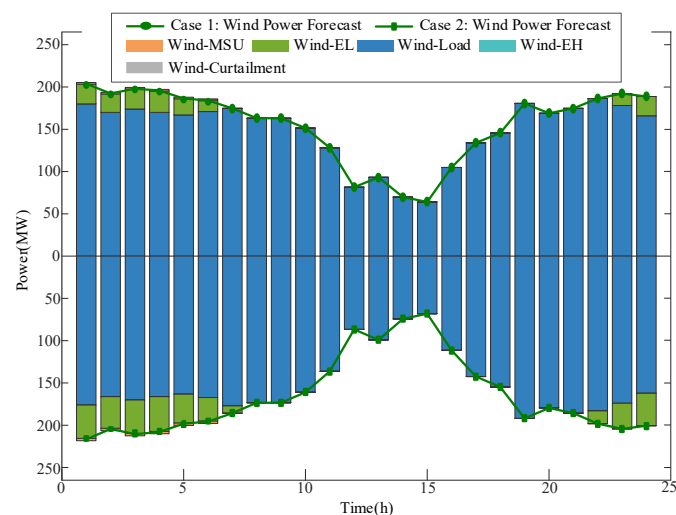


Figure 16. IES wind power accommodation under uncertainty.

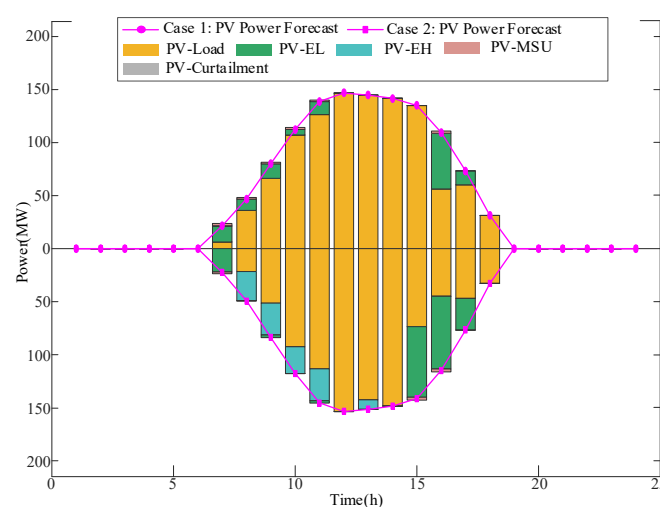


Figure 17. PV accommodation status of the IES under uncertainty.

Regarding renewable energy accommodation, Scheme 2 fully leverages the flexibility potential of the “power–carbon–hydrogen–methanol” system by directing substantial renewable power into EH, EL, and MSU. Furthermore, in terms of thermal dispatch, it diminishes reliance on gas-fired boilers, shifting toward combined heating supplied by

thermal energy storage systems and HFC. By comparison, Scheme 1 contracts the operational space for Power-to-X equipment and energy storage, prioritizing the rigid demands of base loads, which consequently restricts the upper limit of the system's flexible regulation capability.

Overall, when utilizing the IGDT method for scheduling decisions, decision-makers must balance their strategies by combining the actual operating conditions of the system with their own risk preferences: when the overall economic budget of the system is relatively ample and sufficient carbon emission allowances are available, choosing the RAS can maximize the stable and safe operation of the system; conversely, if the decision-maker leans toward the potential economic dividends of uncertainty and aims to deeply compress the actual carbon emissions of the system, the OSS is undoubtedly the better choice for achieving the synergistic optimization of low carbon emissions and economic efficiency.

6.6. Limitations and Boundary Conditions

To explicitly delineate the scope and applicability boundaries of the proposed framework, its primary limitations are summarized as follows:

(1) Aiming to minimize the total intra-day (24-h) operating cost, this study focuses on short-term low-carbon dispatch and multi-market coordination. System-grid interactions are modeled purely via macro-level power balance, omitting non-linear physical constraints such as bus voltage deviations, dynamic frequency, and AC power flow. Qualitatively, this simplification bypasses non-convex AC power flow equations, safeguarding the computational tractability of the large-scale mixed-integer model that incorporates IGDT under uncertainty alongside multi-market mechanisms. Nevertheless, neglecting line impedance and voltage limits may yield overly optimistic cost estimates. Future research will integrate convexified AC power flow formulations—such as second-order cone programming—along with voltage and frequency security constraints, achieving a co-optimization of macroscopic low-carbon scheduling and physical grid security.

(2) In this study, a static conversion efficiency is adopted for the “electricity–heat–electricity” cycle. Sub-minute thermodynamic transient processes are omitted primarily due to the order-of-magnitude temporal separation between hour-scale system dispatch—which focuses on macro-level energy equilibrium—and minute-to-second-scale micro-thermal dynamics (such as the temperature field evolution of heat transfer fluids and the degradation of molten-salt thermal stratification in storage tanks). However, under operational scenarios characterized by sudden surges or steep ramping of renewable generation, this simplification may induce slight estimation biases regarding instantaneous responsiveness and actual heat losses during extreme volatility. To address this, future research will establish a multi-temporal-scale joint modeling framework that reformulates sub-minute thermal dissipation into computationally tractable dynamic constraints, thereby enhancing the alignment precision between macroscopic scheduling and microscopic thermodynamic behaviors.

(3) Grounded in the existing industrial infrastructure of Northwest China, this study categorizes both the MSU and the CCS as legacy assets, focusing primarily on the optimal economic operational dispatch of the integrated system. Consequently, the objective function omits upfront capital expenditure depreciation as well as the long-term physical performance degradation of equipment. Nevertheless, neglecting asset amortization and hardware degradation risks overestimating the true profitability derived from methanol sales over extended operational horizons. To address this limitation, subsequent research will concentrate on establishing a multi-temporal-scale optimization framework that incorporates long-term asset depreciation, thereby enabling high-precision assessment of full life-cycle synthesized costs.

7. Conclusions

This paper proposes an optimal scheduling strategy for IES incorporating a collaborative “electricity–carbon–hydrogen–methanol” framework and solar thermal power, while integrating the IGDT to manage uncertainties on both the supply and demand sides. Through case simulations and comparative assessments, the primary conclusions are derived as follows:

(1) The “electricity–carbon–hydrogen–methanol” infrastructure facilitates multi-pathway high-efficiency hydrogen utilization and deep CO₂ mitigation, achieving a global optimum across carbon reduction and economic returns. This approach enables the full integration of renewable power. Concurrently, it broadens the profit margins by selling methanol externally and curbing reliance on fossil fuels. Consequently, the comprehensive operating cost is minimized to 730,600 CNY, while maximizing the revenues generated from carbon emissions trading.

(2) The CSP plant coupled with an EH establishes an “electricity–heat–electricity” coupling, thereby enhancing scheduling flexibility and environmental performance. This cooperative dynamic exploits the potential for multi-energy complementarity, elevating the total thermal output of the CSP plant by 4.96% and substantially substituting high-emission gas-fired boilers. Under this configuration, total carbon emissions drop to 843.20 tons, and gas procurement costs are trimmed to 199,300 CNY. This demonstrates the efficacy of such plants in balancing energy security with low-carbon, cost-effective operations.

(3) The joint CET-GCT mechanism delivers a win-win scenario for decarbonization and economics via cross-market linkage. While preserving the baseline scheduling status of the system, this mechanism overcomes the mitigation constraints of single markets by introducing a “green certificates offsetting carbon emissions” approach. Compared with independent market operations, the joint framework boosts carbon trading revenue by 298.01% and slashes overall operating costs by roughly 39.6%, highlighting the synergistic amplification and dual incentive effects of combined environmental policies.

(4) Expanding the maximum operating capacity of EH within a specific threshold significantly drops gas purchasing expenses, enhances the heating share of the solar thermal plant, and increases carbon trading revenue. However, continually scaling up the rated capacity fails to yield sustained marginal benefits. Furthermore, the combined CET-GCT framework exhibits high sensitivity to the baseline price of green certificates; a lower baseline price unlocks the offsetting advantage to drastically lower trading expenditures, whereas excessive baseline pricing escalates the aggregate system operating costs.

(5) Through the multi-device capacity sensitivity analysis, the system demonstrates strong renewable energy accommodation capabilities; however, individual equipment exhibits heterogeneous capacity sensitivities, with certain configurations containing noticeable redundancies. Specifically, moderately expanding the TES capacity can curb natural gas procurement demand, thereby enhancing overall economic efficiency. The EL currently offers a downsizing margin of approximately 60%; however, excessive capacity reduction will lead to both renewable power curtailment and cost escalation. In addition, the MSU exhibits noticeable capacity redundancy, and either modestly downsizing the HS tank or expanding the HFC capacity contributes to lowering total system costs.

(6) Regarding the volatility on the supply and demand sides, the RAS adopts a pessimistic stance, leaning toward sustaining high outputs from conventional units to ensure system security and meet rigid load demands. Conversely, the OSS takes an optimistic perspective, maximizing the flexibility of the “electricity–carbon–hydrogen–methanol” complex to encourage clean energy consumption. As a result, the OSS lowers the actual total cost by approximately 9.5% compared with the RAS, achieving a collaborative optimization of low-carbon performance and economic efficiency.

It should be noted that the primary objective of this study is to investigate the macro-level dispatch, optimal economic operational costs, and system generalizability within integrated energy systems. Consequently, physical security constraints associated with the electricity, heating, and natural gas networks are omitted from the quantitative modeling framework. Qualitatively speaking, electric power transmission occurs nearly instantaneously; thus, operational boundaries are primarily governed by line transfer capacities. Provided that these capacities safely exceed load demands, the impact of power grid constraints on overall economic performance remains negligible. In stark contrast, the transport of thermal energy and natural gas operates on significantly slower, typically hourly, time scales. Therefore, transmission losses and dynamic delay characteristics—specifically linepack effects—become highly relevant. Given that transport losses are relatively minor, the intrinsic storage capability of the pipelines plays a dominant role. Thermal linepack effectively expands the available pathways for heat storage, whereas natural gas linepack functions synergistically with electricity-to-gas facilities to facilitate higher levels of wind power integration. Therefore, the storage characteristics of the heating and gas networks can improve the system’s operational flexibility, while electricity constraints have little impact on the system.

From the perspective of sustainable development, the proposed multi-energy coupling path and the joint carbon green certificate mechanism jointly promote the synergy of renewable energy acceptance, carbon emission reduction and economic cost, and provide some theoretical support for the sustainable transformation of regional energy systems and the realization of global decarbonization goals.

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Appendix A

Acronym	Spelled-Out Form
CCS	Carbon capture system
CET	Carbon emission trading
CHP	Combined heat and power
CSP	Concentrated solar power
DRO	Distributionally robust optimization
EH	Electric heater

EL	Electrolyzer
GB	Gas boiler
GCT	Green certificate trading
HS	Hydrogen storage
HFC	Hydrogen fuel cell
IGDT	Information gap decision theory
O&M	Operation and maintenance cost
PEM	Proton exchange membrane
PV	Photovoltaic
RO	Robust optimization
SBD	Scenario-based dispatch
SP	Stochastic program-ming
TPU	Thermal power unit
TES	The thermal storage system

Appendix B

Table A1. Parameters definition and sets of the proposed model.

Parameter	Description	Parameter	Description
$M_{EL,t}^{H_2}$	The hydrogen quality of EL production at time t .	$M_{EL,t}^{H_2,HFC}$	The quality of hydrogen provided by the EL to the HFC at time t .
η_{H_2}	EL work efficiency.	r_{H_2}	Electrohydrogen conversion coefficient.
$M_t^{H_2,MSU}$	The quality of hydrogen provided by the EL to the MSU at time t .	$M_{EL,t}^{H_2,loss}$	Unused hydrogen mass of electrolytic cell at time t .
$M_{stor,t}^{H_2,in}$	The quality of hydrogen provided by the EL to the HS tank at time t .	P_{max}^{EL}	Maximum power output of the EL.
P_{min}^{EL}	The minimum power of EL output.	ΔP_{max}^{EL}	Maximum climbing power of EL.
$P_t^{HFC,E}$	Power generation of HFC at time t .	$E_t^{HFC,h}$	Heat generation power of HFC at time t .
L_{H_2}	Low calorific value of hydrogen.	$\Delta M_{max}^{H_2,HFC}$	The maximum climbing power of HFC
$\eta_t^{HFC,H}$	Thermal efficiency of HFC at time t .	$P_{TPU,t}^{out}$	Net output power of TPU at time t .
$\eta_t^{HFC,E}$	Power generation efficiency of HFC at time t .	$P_{TPU,t}$	Total output power of TPU at time t .
$M_{max}^{H_2,HFC}$	Maximum hydrogen consumption power of HFC	$P_t^{cc,ope}$	CCS energy consumption of TPU at time t .
$P^{cc,base}$	CCS fixed energy consumption	$M_t^{CO_2,MSU}$	The amount of carbon dioxide consumed by MSU at time t .
γ^{cc}	CCS energy consumption coefficient	η^{cc}	Energy efficiency of CCS
e	Carbon emission intensity of TPU	P_{max}^{TPU}	The maximum output power of TPU
P_{min}^{TPU}	The minimum output power of TPU	ΔP_{max}^{TPU}	Maximum climbing power of TPU
$M_t^{CO_2,stor}$	Carbon Sequestration of carbon dioxide at time t .	$M_{stor,t}^{H_2,MSU}$	The amount of hydrogen consumed by the MSU from the HS tank at time t .
P_t^{MSU}	Output of MSU at time t .	λ_{CH_3OH}	Energy consumption coefficient.
λ_{H_2}	Hydrogen proportional coefficient.	λ_{CO_2}	Ratio coefficient of carbon dioxide.
$M_t^{CH_3OH}$	The quality of methanol produced at time t .	ΔP_{max}^{MSU}	Maximum ramp power of MSU.
P_t^{CSP}	Output of CSP plant at time t .	η_{r-d}	thermoelectric conversion efficiency.
$E_t^{HF,TG}$	The thermal power provided by the mirror field to the generator at time t .	$E_t^{TES,TG}$	The thermal power provided by the TES to the generator at time t .
$E_t^{HF,TES}$	The thermal power provided by the mirror field to the TES at time t .	$E_t^{HF,loss}$	Unused thermal power of photothermal power station at time t .
P_{max}^{CSP}	The maximum output power of CSP plant.	P_{min}^{CSP}	The minimum output power of CSP plant.

E_t^{HF}	Thermal power collected by the mirror field at time t .	E_t^{TES}	Heat storage capacity of TES at time t .
$E_t^{\text{HF,TES}}$	The thermal power provided by the mirror field to the TES at time t .	$E_t^{\text{EH,TES}}$	The thermal power provided by the EH to the heat storage system at time t .
$E_t^{\text{TES,h}}$	The TES provides the thermal power of the heat load at time t .	ξ_{TES}	The degree of heat loss in the storage process of the TES.
η_{in}	Thermal storage efficiency of TES.	η_{out}	The heat release efficiency of TES.
$E_t^{\text{TES,in}}$	Heat storage power of TES at time t .	$E_t^{\text{TES,out}}$	The heat release power of the TES at time t .
$E_{\text{max}}^{\text{TES,out}}$	The maximum heat storage power of the TES.	$E_{\text{max}}^{\text{TES,in}}$	The maximum heat release power of the TES.
$U_t^{\text{TES,in}}$	Heat storage state variables of TES at time t .	$U_t^{\text{TES,out}}$	Exothermic state variables of TES at time t .
E_{t0}^{TES}	The initial heat storage power of the TES.	$E_{\text{T}}^{\text{TES}}$	The final heat storage power of the TES at time t .
Δt	Time interval.	P_t^{EH}	Output power of EH at time t .
η_{EH}	Electrothermal conversion efficiency.	$\Delta P_{\text{max}}^{\text{EH}}$	The maximum climbing power of EH.
$P_{\text{EH,max}}$	The maximum output power of EH.	$P_{\text{EH,min}}$	The minimum output power of EH.
$E_t^{\text{GB,h}}$	The output thermal power of GB at time t .	$P_t^{\text{GB,g}}$	The input power of GB at time t .
η_{GB}	Thermal efficiency of production.	$P_{\text{max}}^{\text{GB,g}}$	The maximum operating power of GB.
$\Delta P_{\text{max}}^{\text{GB,g}}$	The maximum climbing power of GB at time t .	D_{IES}	The total amount of carbon quota obtained by the system.
$D_{\text{TPU}}^{\text{CO}_2}$	Carbon quotas obtained by TPU.	$D_{\text{GB}}^{\text{CO}_2}$	Carbon quotas obtained by GB.
λ_i	Carbon quota coefficient.	$E_{\text{All}}^{\text{CO}_2}$	The carbon emissions of IES in the scheduling period.
$E_{\text{TPU}}^{\text{CO}_2}$	Carbon emissions in the scheduling cycle of TPU.	$E_{\text{GB}}^{\text{CO}_2}$	Carbon emissions in the scheduling cycle of GB.
ψ_{GB}	Carbon emission coefficient of GB.	F_{CET}	Carbon trading cost.
R_{IES}	The final total carbon emissions after conversion.	λ	Carbon trading base price.
γ_1	Carbon trading price incentive coefficient.	γ_2	Carbon trading price penalty coefficient.
d	Interval width of carbon emissions.	R_{GCT}	The amount of green certificates that IES participates in green certificate trading.
G_{d}	The number quota of green certificates allocated by the system.	G_{s}	The number of green certificates obtained by new energy power generation.
α_{green}	The green card holding ratio parameter set by the system.	β_{green}	The quantitative coefficient of the conversion of new energy power generation into the number of green certificates.
F_{GCT}	System green certificate transaction cost.	λ_{green}	Market transaction price of green certificate.
E_{coal}	Carbon emission equivalent of coal-fired energy supply life cycle.	E_{res}	Carbon emission equivalent of new energy supply life cycle.
E_{reduce}	The carbon emission reduction coefficient corresponding to green certificate.	E_{Green}	Carbon emission reduction corresponding to green certificate.
F_{total}	Total cost of IES operation.	F_1	Power generation cost of TPU.
F_2	Running-maintenance cost.	F_3	Power abandonment penalty cost.
F_{buy}	Cost of gas purchase.	$F_{\text{CH}_3\text{OH}}$	Methanol profit.
C_{coal}	Coal price.	$a, b \text{ and } c$	Coal consumption characteristic coefficient of thermal power unit.
S	Start-up cost of coal-fired TPU	U_t	Operation state variables of coal-fired TPU.
F_2^n	Operation and maintenance cost of equipment n .	k_n	Unit operation maintenance coefficient of equipment n .
ξ_q	Unit abandonment penalty coefficient.	P_t^{WQ}	Abandoned power of wind power at time t .

P_t^{GQ}	Abandoned power of photovoltaic at time t .	L_{CH_4}	Low calorific value of natural gas.
c_{gas}	Unit gas purchase price.	$\chi_{\text{CH}_3\text{OH}}$	Unit price of methanol.
$P_t^{\text{e,load}}$	Electrical load power at time t .	$E_t^{\text{h,load}}$	Thermal load power at time t .
P_t^{W}	The output power of wind farm at time t .	P_t^{G}	Output power of photovoltaic power station at time t .
P_t^m	The power of device m at time t .	$P_{m,t}^{\text{W}}$	Wind power consumed by equipment m at time t .
$P_{m,t}^{\text{G}}$	Photovoltaic power consumed by equipment m at time t .	K_n	Slope of each section of coal consumption function after linearization of TPU.
M_t^{coal}	Coal consumption generated by TPU at time t .	$M_t^{\text{coal,min}}$	Coal consumption of thermal power units operating at minimum output at time t .
$P_{t,n}^0$	Sectional output of TPU at time t .	X	Optimization variable.
$u_{\text{est},z}^{(i)}$	The predicted value of the z -type uncertainty factor in the i -period.	z	Corresponding to wind power, photovoltaic, electric load, heat load.
H	System equality constraints.	G	System inequality constraints.
U	Fluctuation range of uncertainty factors.	$u_{\text{act},z}^{(i)}$	The actual value of the z -type uncertainty factor in the i -period.
α_z	Deviation coefficient of type z uncertainty factors.	α	Comprehensive deviation coefficient.
F_0	The total system cost of the deterministic model.	β_{R}	Robust deviation factor.
β_0	Opportunity deviation factor.	k_z	The weighting coefficient of the z -th uncertainty factor.

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