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RESEARCH ARTICLE

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Will fuel switching ever happened in China's thermal power sector? The rule of carbon market design

Abstract To assess the effectiveness of China's emissions trading scheme (ETS) in facilitating energy structure optimization, we constructed a fuel-switching model utilizing data from 1067 generating units under the Chinese ETS framework. The model simulates the fuel-switching price in China's thermal power sector, taking into account various allowance allocation strategies. The results show the following: 1) Thermal power plants will transition from coal to gas if the current ETS auction rate surpasses 26%. 2) Furthermore, in scenarios where the ETS operates independently, a transition will occur if the carbon allowance market is entirely auction-based and the carbon price attains 119.50 USD/tCO_2. 3) In a collaborative scenario involving both the ETS and a gas feed-in tariff subsidy, a carbon price of 9.39 USD/tCO_2 will effect a transition from coal to gas, provided both the auction ratio and subsidy price are maximized.

Keywords ETS, thermal power plant, fuel switching, allowance allocation method, feed-in tariff subsidy

1 Introduction

China's energy endowment exerts a substantial influence on the long-term structure of coal-based energy consumption (Liang et al., 2020; Li et al., 2021). In 2022, the total coal consumption amounted to 4.59 billion tons of standard coal, constituting 56% of China's primary energy consumption. While this marks the lowest level in two decades, it still represents 57.2% of global coal consumption. Notably, China's power sector alone accounts for one-third of global coal consumption (IEA, 2022). In 2022, China's greenhouse gas emissions contributed 27% of the global total (National Energy Information Platform, 2022). It is anticipated that China will maintain its status as the world's largest greenhouse gas emitter (Li et al., 2012; Ji, 2022).

To mitigate greenhouse gas emissions, enhance air quality, and fulfill the "dual carbon" objective, which targets peaking CO_2 emissions prior to 2030 and achieving carbon neutrality before 2060, China must decrease its carbon intensity by 65% by 2030 compared to the 2005 level. Reducing total coal consumption and the coal consumption proportion takes precedence in China's energy reform, air pollution control, and air quality enhancement efforts (Gao, 2016; Wang et al., 2016; Li et al., 2021). Natural gas is poised to play an indispensable role in China's transition from high-emission to low-emission and zero-emission energy. Facilitating the concurrent development of natural gas and renewable energy presents the most promising pathway for China's energy transformation (Shan, 2021).

As a globally acknowledged clean energy source, natural gas boasts numerous advantages in terms of energy efficiency, environmental sustainability, energy security, flexibility, and storage (Xu et al., 2021). In the global power sector, the average proportion of gas-fired generation stands at approximately 23%, whereas in China, it currently lingers at only 3.5% (Li and Kong, 2023). Consequently, gas-fired generation exhibits substantial growth potential. Additionally, the Chinese government has set forth the policy objective of having "natural gas consumption account for more than 15% of primary energy consumption and more than 10% of the electricity

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consumption structure by 2030" (NDRC, 2017). Despite China's proven natural gas reserves ranking sixth globally at 12.4 trillion m^3, the proven utilization rate remains a modest 19% (Tang et al., 2020). Nevertheless, China's natural gas production reached 217.79 billion m^3 by 2022, marking an annual increase of approximately 65 billion m^3. In that year, China emerged as the world's largest natural gas importer and the fourth largest producer (Ma et al., 2022).

Although natural gas supply and demand experienced tension in the past two years due to pandemic-related disruptions, post-pandemic, global natural gas production is expected to maintain steady growth, with medium and long-term supply projected to remain generally ample. It is forecasted that output will reach 5.67 trillion m^3 by 2050 (BP, 2021). These favorable domestic and international conditions provide a robust and enduring foundation for China's strategy of replacing coal with gas. It is envisioned that gas will ascend to become the predominant energy source by 2040 (Zhou et al., 2021).

For an extended period, coal power has held sway in China's power industry, emerging as the leading contributor to the nation's greenhouse gas emissions (Yang et al., 2018). Reconfiguring the energy composition of the power sector and substituting coal with clean energy sources for power generation currently stand as the most efficacious measures for emission reduction. Among these measures, transitioning from coal to gas for power generation represents the simplest and most readily implementable approach to curbing CO_2 emissions in the short term (Han et al., 2017).

In terms of technical feasibility, several critical factors are worth considering. First, when examining the combustion status, it is evident that coal combustion necessitates a significant amount of space, typically resulting in a furnace volume heat intensity for coal-fired boilers of less than (1047–1256) × 10^3 kJ/(m^3·h). In contrast, due to the rapid combustion rate and high flammability of gas, gas boilers typically exhibit a furnace volume heat intensity of approximately 4186 × 10^3 kJ/(m^3·h). Consequently, the existing furnaces designed for coal-fired boilers are well suited for the transition to gas-fired boilers. Second, gas combustion generates a smaller quantity of smoke compared to coal combustion, facilitating the smooth discharge of post-combustion gases through the original coal-fired boiler's flue (Fang, 2015). Third, while heat transfer in coal-fired boiler furnaces relies on radiation from coke particles, ash particles, and trimixes, gas combustion predominantly involves the radiation of trimix and carbon particles. Therefore, transitioning from coal to gas can enhance radiation heat transfer within the furnace. Fourth, in terms of the condition of the boiler tube bundle, high-temperature flue gas primarily releases heat through convection. The heat transfer coefficient of the gas-fired boiler's tube bundle is essentially on par with that of the original coal-fired boiler, ensuring that the heat transfer performance remains unaffected (Sun and Liu, 2003; Xun, 2019). Experimental evidence supports the assertion that the thermal efficiency of a gas boiler modified from a coal-fired boiler can achieve 80%, thus aligning it with national standards.

In terms of cost, gas boilers offer distinct advantages. Unlike coal-fired boilers, gas boilers do not require extensive space for fuel storage, resulting in substantial savings on fuel transportation costs, labor, and space during transportation (Wu, 2022). Additionally, the adoption of gas boilers eliminates the need for various auxiliary equipment, such as coal loading machines and slag removal machines, which significantly reduces both initial capital investments and ongoing operational and maintenance costs. The engineering cost associated with transforming coal-fired boilers into gas-fired boilers typically ranges from 1/4 to 1/2 of the cost of installing a new gas-fired boiler, delivering noteworthy cost savings for power plants (Su, 2014).

The transition from coal to gas has emerged as the primary and viable choice for power plants in the short term. First, the technological transformation of existing coal-fired boilers into gas-fired boilers offers advantages such as cost savings, short construction periods, and swift efficiency gains. Second, gas-fired units outperform their coal-fired counterparts in various aspects, including rapid system startup, superior heat transfer capabilities, potent thermal radiation, lower exhaust smoke temperatures, and heightened thermal efficiency. With equivalent power generation capacities, gas-fired generation can reduce CO_2 emissions by 50%, NO_x emissions by 36%, and SO_2 emissions by 98% when compared to coal-fired generation (Alhajeri et al., 2019). The transition from coal to gas by coal power companies plays a pivotal role in emissions reduction. Furthermore, the operation of gas-fired units is more convenient than that of coal-fired units, with easier automation and control, thereby diminishing safety risks during production processes (Zhang and Dong, 2018).

Moreover, natural gas power generation can effectively ensure peak load management and frequency regulation, thus ensuring the stable operation of the power grid. According to projections from the State Grid Energy Research Institute, renewable energy sources such as wind and solar power will constitute 58% to 60% of the power sector by 2050 (State Grid Energy Research Institute, 2020). The significant presence of renewable energy sources results in an increased disparity between peak and off-peak grid loads, heightening the demand for flexible power supply solutions. Experience from developed nations suggests that to maintain power system stability, the installed capacity of a flexible peak-shaving power supply should represent at least 10% to 15% of the total installed capacity (NDRC, 2017). However, as of the end of 2020, China's proportion of flexible peak-shaving power supply stands at only 6%, falling short of meeting the peak shaving requirements associated with a high proportion of renewable energy generation. Gas-fired generation, distinguished by its flexibility, ease of startup and shutdown, exceptional regulation performance, and swift construction, emerges as an ideal solution for flexible peak shaving. It possesses optimal responsiveness and power supply continuity and can function as a "stabilizer" for power system security in the context of a substantial share of renewable energy generation. In the power sector, gas-fired generation stands as the premier choice for flexible peak shaving within the power system.

In summary, natural gas will assume an indispensable role in the establishment of a clean energy framework in China. It will serve as the "ideal partner" for the advancement of renewable energy, bolstering China's energy structure adjustments. When compared to other fuel sources, natural gas emerges as the top alternative to coal (Han et al., 2017; Chen et al., 2020). Therefore, the transition from coal to gas for power generation is primary in achieving China's carbon peak by 2030.

Nonetheless, the considerably high price of natural gas has posed a substantial cost hurdle for thermal power companies looking to transition from coal to gas for power generation (Bertrand, 2014). In an effort to overcome this cost barrier, China has introduced carbon pricing mechanisms for thermal power plants through the emissions trading scheme (ETS) (Mo et al., 2021a; 2021b). This initiative alters the cost dynamics between coal-fired and gas-fired power generation units. The national ETS was officially launched in July 2021 and includes 2162 power generation companies with annual emissions exceeding 26000 tCO_2 equivalent. These companies collectively produce approximately 4.5 billion tons of CO_2 annually, accounting for approximately 45% of China's total carbon emissions. It represents the world's largest ETS (Chen, 2019), and the second ETS exclusively focuses on the power industry after the Regional Greenhouse Gas Initiative (RGGI) (Wang and Wang, 2019). In November 2022, the Ministry of Ecology and Environment of China unveiled the *Implementation Plan for the Setting and Distribution of the National Carbon Emission Trading Allowances for 2021 and 2022* (*Discussion Draft*) (hereinafter referred to as "Discussion Draft"), which outlines two distinct allowance allocation methods for 2021 and 2022, respectively.

To investigate the influence of various allowance allocation methods within China's ETS on fuel switching behavior, this study defines the carbon price at which coal and gas exhibit identical marginal power generation costs as the "fuel switching prices". For simulation purposes, the shadow price, equivalent to the clean dark spread and clean spark spread, serves as the fuel switching price. Additionally, beyond examining the ETS's effect on the fuel-switching prices of thermal power plants, this paper explores the synergistic effects of the ETS and gas feed-in tariff subsidies on these prices within China.

The primary contributions of this research are as follows. 1) Evaluation of the effectiveness of published allowance allocation methods within China's ETS in promoting short-term fuel switching among thermal power plants, along with recommendations for enhancements. 2) Optimization of benchmark value settings and the ratio of ETS allowance auctions to incentivize thermal power plants to embrace short-term fuel switching. 3) Dynamic forecasting of coal and gas prices to enhance the precision of switching prices. 4) A comprehensive analysis of the combined effect of the ETS and gas feed-in tariff subsidies on the fuel switching behavior of thermal power plants.

This paper not only proposes a more scientifically grounded allowance allocation scheme for China's unified ETS but also contributes to China's expedited achievement of its carbon emission reduction targets. Furthermore, it offers valuable insights for other nations seeking to employ ETS to encourage short-term coal-to-gas transitions among thermal power plants, thereby supporting global carbon reduction efforts.

The subsequent sections of this paper are structured as follows. Section 2 provides a concise review of the pertinent literature. Section 3 outlines the fuel-switching model employed in this study. Section 4 conducts simulations to portray the dynamics of fossil fuel prices. Section 5 details the data used and establishes relevant scenarios. Section 6 simulates fuel switching prices for thermal power plants under various allowance allocation scenarios. The concluding section offers policy recommendations.

2 Literature review

In many advanced countries, the transition from coal to gas in the power sector is viewed as a promising strategy for reducing carbon emissions. Research has demonstrated that since 2005, the power sector in the United States has witnessed an 8.2×10^8 t reduction in CO_2 emissions attributed to the expansion of gas-fired generation. Notably, the shift from coal to gas has been responsible for a 65% contribution, reducing CO_2 emissions by 5.3×10^8 t (Brehm, 2019; Li and Kong, 2023). This transition has played a pivotal role in the energy sector's transition toward low-carbon practices. Some experts argue that Europe can effectively curtail CO_2 emissions in its power sector through coal-to-gas fuel switching. Specifically, Germany, Spain, and the United Kingdom are identified as having significant potential for such transitions (Delarue et al., 2010; de Vos, 2015).

In contrast, other scholars contend that the cost of fuel switching outweighs the cost of carbon emission reduction for thermal power companies (Bertrand, 2014; Yi et al., 2016). Despite the substantial expenses associated with

China's "coal-to-gas" policy, the long-term health benefits are deemed to outweigh the policy's costs (Fan et al., 2020). Therefore, it is crucial to vigorously promote China's coal-to-gas policy, with the establishment of a unified ETS in China serving as a catalyst for coal-to-gas transitions. To minimize generating unit costs, power generators assess the marginal costs of various fuel technologies, arranging them from low to high cost (Sijm et al., 2006; Bersani et al., 2022). This ranking determines the "priority order" of fuels for power generation, with factors such as fuel prices, fuel consumption per unit of power generated, and carbon emission factors influencing the decision. Carbon pricing signals compel coal-fired power plants to internalize emissions costs, sharing environmental costs with consumers. Furthermore, these signals promote auction revenue generation from natural gas power generation to finance regional low-carbon and energy efficiency initiatives (Murray and Maniloff, 2015). The fuel switching behavior of thermal power companies presents opportunities for reducing CO_2 emissions (Abadie et al., 2010). To capitalize on these opportunities, power generation companies must compare carbon prices and the marginal abatement costs associated with different fuels. Ultimately, this process fosters the convergence of marginal costs among various power generation companies, reducing overall abatement costs for power plants (Yang, 2010).

The key determinant for fuel switching becomes the marginal cost of power generation for each fuel, which includes the carbon cost. Delarue and D'haeseleer (2007) and Delarue et al. (2007) calculated the fuel switching price by comparing the marginal cost, including the carbon cost, between coal-fired and natural gas power plants. They used the switching price as an effective indicator for fuel switching in thermal power plants. Building upon this theory, Hintermann (2010) formulated the objective function as the minimum cost needed to achieve established emission reduction goals. He set the marginal abatement cost of enterprises covered by the ETS equal to the equilibrium carbon price as a constraint condition and employed coal and gas prices as parameters to derive the expression of the carbon price.

Carmona et al. (2009) employed a partial equilibrium model to investigate the fuel-switching costs of power generation plants, revealing that the marginal abatement cost consistently equates to the fuel switching price. Subsequently, various studies have considered different scenarios involving carbon prices and fuel prices, applying this approach to simulate the switching costs associated with transitioning from coal-fired to gas-fired power generation by thermal power plants (Sijm et al., 2006; Delarue et al., 2007; 2010; Elias et al., 2016).

Furthermore, other literature has explored fuel switching from coal to gas using various modeling methodologies, including the System Dynamics model (Xiao et al., 2016), Integer Programming model (Ishfaq et al., 2016), Linear Programming Power Planning model (Zhang et al., 2012), optimization models (Wu and Huang, 2014), and alternative approaches (Kahrl et al., 2013; Rad et al., 2019).

It is evident that most relevant literature primarily focuses on the ETS as a policy tool to introduce carbon pricing to thermal power plants. However, there is a notable scarcity of theoretical analyses exploring how the internal mechanisms of the ETS influence fuel switching prices, particularly with regard to the effect of different allowance allocation methods within the ETS on the fuel switching behavior of thermal power plants (Bertrand, 2014).

3 Fuel switching model

Thermal power plants typically assess their marginal power generation profitability by computing the difference between generation revenue and generation fuel cost. This metric holds significant importance, as it aids power plants in determining their financial bottom lines. In cases where the spark spread is minimal on a given day, electricity production might be deferred until a more lucrative spread becomes available (Elias et al., 2016). The introduction of carbon costs through the ETS incorporates climate change factors into the financial equation of power plants, altering the marginal cost associated with different power generation fuels. Consequently, it reshapes the "priority order" of power generation using various fuels and enhances the competitive edge of clean energy power generation. It is crucial to emphasize that this paper primarily focuses on the effect of ETS introduction on the short-term marginal cost of power plants, aiming to modify the "priority order" between coal-fired and gas-fired generations. It does not explore the influence on the life cycle costs of power plants. Therefore, this model solely takes into account the disparity between the market price of electricity and the costs associated with fuel and carbon emissions, without considering the comparison of capital, operational, and maintenance costs between coal-fired and gas-fired generations or the additional costs linked to facility modifications needed for fuel substitution.

3.1 Basic fuel switching model

Dark spread, spark spread, and the discrepancy between them are complexly tied to the profit and loss considerations of thermal power plants. The dark spread represents the theoretical profit accrued by coal-fired power plants when selling one unit of electricity, excluding the fuel cost needed to acquire that unit of electricity. Conversely, spark spread signifies the theoretical profit earned by gas-fired power plants. Upon the introduction of carbon costs through the in-power sector, both the dark spread and the spark spread are adjusted by the carbon price, transforming into a clean dark spread and a clean spark spread, respectively. The price at which clean dark spread equals clean spark spread is termed the "switching price" (Chevallier, 2012). When the carbon price surpasses the switching price, it becomes more profitable for thermal power plants to transition from coal to gas. Conversely, when the carbon price falls below the switching price, it is more advantageous to persist with coal-fired generation. Consequently, thermal power plants make fuel choices based on clean dark spread, clean spark spread, and switching prices. This relationship can be expressed as follows.

(1) Clean dark spread (USD/MWh):

$$Cleandark = elec - (P^{\text{coal}} \times U^{\text{coal}} + P^{\text{co}_2} \times EF^{\text{coal}}). \quad (1)$$

Clean dark spread represents the difference between the unit feed-in tariff and the unit energy input and unit carbon cost of coal-fired power plants. Here, *elec* is the feed-in tariff of power generation plants, P^{coal} is the price of coal, U^{coal} is the coal consumption per unit of coal-fired generating units, EF^{coal} is the CO_2 emission factor of coal-fired generating units, and P^{co_2} is the price of CO_2.

(2) Clean spark spread (USD/MWh):

$$Cleanspark = elec - (P^{\text{gas}} \times U^{\text{gas}} + P^{\text{co}_2} \times EF^{\text{gas}}). \quad (2)$$

Clean spark spread represents the difference between the unit feed-in tariff and the unit energy input and unit carbon cost of gas-fired power plants. Here, P^{gas} is the price of natural gas, U^{gas} represents the gas consumption per unit of gas-fired generating units, and EF^{gas} represents the CO_2 emission factor of gas-fired generating units.

(3) Switching price ($P^{\text{co}_2}_{\text{switch}}$, USD/MWh)

The switching price is the shadow price which equals the clean dark spread and the clean spark spread:

$$P^{\text{co}_2}_{\text{switch}} = \frac{P^{\text{gas}} \times U^{\text{gas}} - P^{\text{coal}} \times U^{\text{coal}}}{EF^{\text{coal}} - EF^{\text{gas}}} = \frac{cost^{\text{gas}} - cost^{\text{coal}}}{EF^{\text{coal}} - EF^{\text{gas}}}, \quad (3)$$

where $cost^{\text{gas}}/cost^{\text{coal}}$ represents the production cost (USD/MWh) needed by the gas/coal-fired power plant to produce a unit of electricity (1 MWh) with net CO_2 emissions.

3.2 Fuel switching model considering the allowance allocation method

Equations (1)–(3) exclusively account for the fuel switching price when all carbon emissions incur emission costs. However, in practice, governments allocate carbon emission allowances to various types of fuels and power generating units with varying capacities using diverse methods. A majority of these allocations are distributed at no cost, while some are acquired through auctions conducted by enterprises. Consequently, when contemplating the varied allowance allocation methods within the ETS, the fuel switching model can be redefined in the following manner.

(1) Clean dark spread

$$Cleandark = elec - (P^{\text{coal}} \times U^{\text{coal}} + P^{\text{co}_2} \times (EF^{\text{coal}} - B^{\text{coal}} + \alpha B^{\text{coal}})), \quad (4)$$

where B^{coal} is the benchmark corresponding to the coal-fired generating units covered by the ETS. Here, we assume that part of the allowances will be auctioned to the thermal power plant at market prices, and α is the auction ratio of the ETS allowances.

(2) Clean spark spread

$$Cleanspark = elec - (P^{\text{gas}} \times U^{\text{gas}} + P^{\text{co}_2} \times (EF^{\text{gas}} - B^{\text{gas}} + \alpha B^{\text{gas}})), \quad (5)$$

where B^{gas} is the benchmark corresponding to the gas-fired generating units covered by the ETS.

(3) Switching price

$$P^{\text{co}_2}_{\text{switch}} = \frac{cost^{\text{gas}} - cost^{\text{coal}}}{(EF^{\text{coal}} - (1-\alpha)B^{\text{coal}}) - (EF^{\text{gas}} - (1-\alpha)B^{\text{gas}})}. \quad (6)$$

3.3 Fuel switching model under the synergy of ETS and gas feed-in tariff subsidies

As China's power industry has evolved, it has transitioned from a differentiated electricity pricing system during the planned economy era to a competitive feed-in tariff structure in the market economy. This shift has led to the implementation of a unified "benchmark electricity price" policy (Energy News Network, 2018). In a bid to promote energy conservation and emissions reduction and to incentivize the use of clean fuels, local governments offer specific subsidies to power generation plants using particular fuel types. In 2019, the Chinese government outlined that "feed-in tariff subsidies for gas-fired power generation should be adjusted in line with gas prices; additionally, the maximum subsidies should not surpass the benchmark electricity price for local coal-fired power generation or the average purchase price of local power grid companies, which is set at 0.35 yuan" (NDRC, 2019).

Consequently, when thermal power plants contemplate fuel switching, they must consider not only the effect of carbon costs on the marginal costs of power generation plants but also the influence of relevant feed-in tariff subsidies on these marginal costs. Therefore, when factoring in gas feed-in tariff subsidies and the various allowance allocation methods within the ETS, the fuel switching model can be articulated as follows.

(1) Clean dark spread

For coal-fired power plants, there is no feed-in tariff subsidy, so the clean dark spread can still be expressed by Eq. (4).

(2) Clean spark spread

For gas-fired power plants, it is essential to note that feed-in tariff subsidies should be promptly adjusted in alignment with fluctuations in gas prices. Furthermore, these subsidies should not surpass the benchmark electricity price established for local coal-fired power generation or the average purchase price set by local power grid companies, which is capped at 0.35 yuan. Consequently, the clean spark spread is influenced by the combined effect of the ETS and the gas feed-in tariff subsidy policy, and this relationship can be articulated as follows:

$$\begin{aligned} Cleanspark = elec + Sub^{\text{gas}} - (P^{\text{gas}} \times U^{\text{gas}} + P^{\text{co}_2} \\ \times (EF^{\text{gas}} - B^{\text{gas}} + \alpha B^{\text{gas}})), \end{aligned} \tag{7}$$

where Sub^{gas} is the natural gas feed-in tariff subsidy.

(3) Switching price

$$P^{\text{co}_2}_{\text{switch}} = \frac{(cost^{\text{gas}} - Sub^{\text{gas}}) - cost^{\text{coal}}}{(EF^{\text{coal}} - (1-\alpha)B^{\text{coal}}) - (EF^{\text{gas}} - (1-\alpha)B^{\text{gas}})}. \tag{8}$$

4 Accurately modeling fossil fuel market prices

4.1 Fossil fuel price dynamic model

To simulate the dynamic evolution of fuel prices, the process unfolds in several steps. Initially, we construct a model for the continuous-time random fluctuations in fuel prices, following the approach outlined by Lucheroni and Mari (2014). Subsequently, we estimate the dynamic parameters of this model using historical data. Finally, we employ these estimated parameters to project fuel prices into a future discrete time series.

First, we assume that the random fluctuation process governing the coal price (P^{coal}) adheres to geometric Brownian motion, as described by Lucheroni and Mari (2017). This can be expressed as follows:

$$\frac{\mathrm{d}P_t^{\text{coal}}}{P_t^{\text{coal}}} = \pi^{\text{coal}}\mathrm{d}t + \sigma^{\text{coal}}\mathrm{d}W^{\text{coal}}, \tag{9}$$

where π^{coal} is the actual floating rate of the coal price, σ^{coal} is the volatility rate of the coal price, and W^{coal} is the standard Brownian motion.

It is important to acknowledge that while geometric Brownian motion is frequently employed to model the dynamics of fossil fuel prices (Hogue, 2012), it may not comprehensively capture the observed behavior of gas prices. There is evidence suggesting more complex dynamics, including mean reversion toward a long-run value, occasional jumps, and stochastic volatility (Lucheroni and Mari, 2017; 2018). Therefore, we propose that the random fluctuation process governing natural gas price (P^{gas}) adheres to the jump-diffusion model, as proposed by Matsuda (2004). In this model, the instantaneous change in gas prices comprises a simple diffusion process and a random jump term (García-Martos et al., 2013; Jin et al., 2018). The jump term is a combination of a random jump amplitude following a normal distribution and a jump interval governed by a Poisson process. This relationship can be expressed as follows:

$$\frac{\mathrm{d}P_t^{\text{gas}}}{P_t^{\text{gas}}} = (\pi^{\text{gas}} - \lambda_J\mu_J)\mathrm{d}t + \sigma^{\text{gas}}\mathrm{d}W^{\text{gas}} + (J_t - 1)\mathrm{d}P(t). \tag{10}$$

According to the Itô formula (Cont and Tankov, 2004), the jump-diffusion process can be expressed as:

$$\begin{aligned} \mathrm{d}\ln P_t^{\text{gas}} = {} & \frac{\partial \ln P_t^{\text{gas}}}{\partial t}\mathrm{d}t + (\pi^{\text{gas}} - \lambda_J\mu_J)P_t^{\text{gas}}\frac{\partial \ln P_t^{\text{gas}}}{\partial P_t^{\text{gas}}}\mathrm{d}t \\ & + \frac{\sigma^{\text{gas}2}P_t^{\text{gas}}}{2}\frac{\partial^2 \ln P_t^{\text{gas}}}{\partial (P_t^{\text{gas}})^2}\mathrm{d}t \\ & + \sigma^{\text{gas}}P_t^{\text{gas}}\frac{\partial \ln P_t^{\text{gas}}}{\partial P_t^{\text{gas}}}\mathrm{d}W^{\text{gas}} \\ & + (\ln J_t P_t^{\text{gas}} - \ln P_t^{\text{gas}}). \end{aligned} \tag{11}$$

The logarithm of the natural gas price (P^{gas}) can be obtained as follows:

$$\mathrm{d}\ln P_t^{\text{gas}} = \left(\pi^{\text{gas}} - \frac{(\sigma^{\text{gas}})^2}{2} - \lambda_J\mu_J\right)\mathrm{d}t + \sigma^{\text{gas}}\mathrm{d}W^{\text{gas}} + \ln J_t, \tag{12}$$

where π^{gas} is the mean reversion parameter, σ^{gas} is the gas price volatility, and W^{gas} is a standard Brownian motion. $P(t)$ is a Poisson process with constant intensity λ_J, and the jump amplitude J is satisfied with the normal distribution $N(\mu_J, \sigma_J^2)$.

4.2 Dynamical parameter fitting

The dynamic parameters of coal prices σ^{coal} and π^{coal} are computed using data from the Qinhuangdao Port coal price spanning from December 2013 to December 2022 (data source: Wind). The historical trend of coal prices is illustrated in Fig. 1.

The dynamic parameters of natural gas prices π^{gas}, σ^{gas}, λ_J, μ_J, and σ_J are estimated using the monthly market price of natural gas at the prices of essential means of production in the circulation sector from December 2013 to December 2022 (data source: Wind). The historical price trend of natural gas is depicted in Fig. 2.

The dynamic parameters of the fuel price model are determined by fitting them to the historical monthly prices of coal and natural gas. Initially, we assume that coal prices and gas prices are independent and do not exert mutual influence. Consequently, the dynamic processes of W^{coal}, W^{gas}, and $P(t)$ are considered to be independent of each other, indicating that the covariance

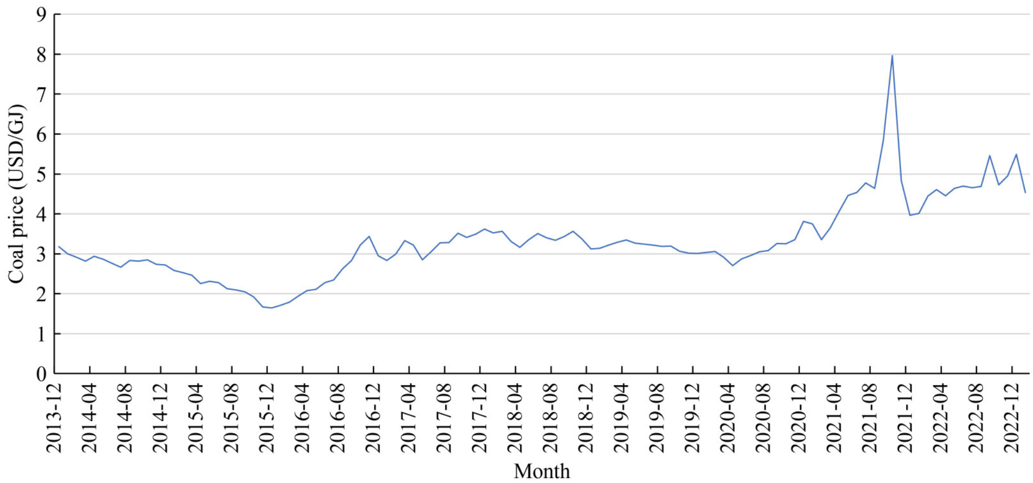

Fig. 1 Historical behavior of monthly changes in coal prices from December 2013 to December 2022 (prices are deflated and expressed in USD/GJ).

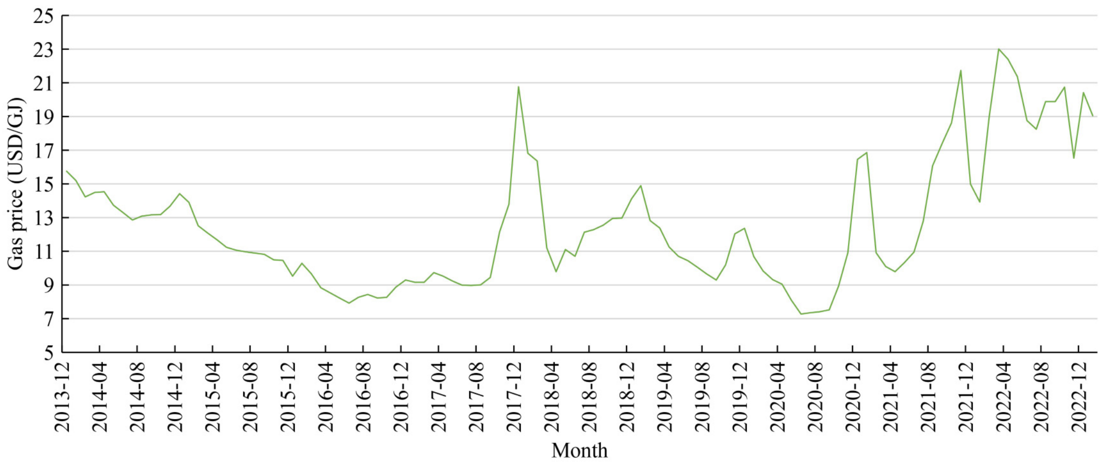

Fig. 2 Historical behavior of monthly changes in gas prices from December 2013 to December 2022 (prices are deflated and expressed in USD/GJ).

between coal price (P_t^{coal}) and the natural gas price (P_t^{gas}) is zero.

However, in reality, there exists a long-term negative correlation between coal prices and natural gas prices. Nevertheless, short-term positive fluctuations in coal prices tend to exert a notable positive effect on natural gas prices. Conversely, short-term positive fluctuations in natural gas prices do not significantly influence coal prices (Sun and Xie, 2020). Consequently, when considering the interplay between gas prices and coal prices, it becomes evident that in the short term, a rise in coal prices leads to a substantial increase in gas prices, elevating the cost of fuel for power generation and potentially hindering the transition from coal to gas in thermal power plants. Conversely, over the long term, an increase in coal prices is likely to cause gas prices to decline, thereby promoting the shift from coal to gas in thermal power plants. The resulting parameter fitting results are displayed in Table 1.

Table 1 Dynamic parameters of coal prices and gas prices

Parameter		Fitting result
Coal	π^{coal}	0.0543
	σ^{coal}	0.0063
Gas	π^{gas}	−0.0033
	σ^{gas}	0.0980
	λ_J	0.0769
	μ_J	−0.0026
	σ_J	0.0275

5 Scenario setting and data description

5.1 Scenario setting of allowance allocation in the ETS

To expedite the establishment of the national ETS, in December 2022, the Ministry of Ecology and Environment of China formulated and released the "Discussion Draft".

The ETS primarily includes plants or other economic entities within the power generation industry that emit 26000 tons of CO_2 equivalent or more. It predominantly involves thermal power plants utilizing fossil fuels such as coal and gas.

The plan entails the allocation of allowances for the years 2019 to 2020 to be provided free of charge. Additionally, it employs the benchmark approach to establish benchmark values for various categories of power generation units. These categories include conventional coal-fired generating units above 300 MW, conventional coal-fired generating units of 300 MW and below, unconventional coal-fired generating units such as coal-fired gangue and coal water slurry (including coal-fired circulating fluidized bed units), and gas-fired units, each having their respective benchmarks.

Furthermore, to assess the influence of different allowance allocation methods in the ETS on the short-term fuel switching behavior of China's thermal power plants, this paper formulates various scenarios representing different benchmark methodologies in the ETS, as detailed in Table 2.

5.2 Data description

5.2.1 Statistical description of thermal power generating unit data

This paper has gathered microdata from 1132 generating units within 431 thermal power plants that participated in the national benchmark and competition for energy efficiency of thermal power units organized by the China Electricity Council. After excluding 65 generating units that did not meet the qualification criteria, specifically those with operating hours below 4500 h, we proceeded with the data from 1067 generating units with varying generation capacities for subsequent analysis. These data represent the generating units of nearly 1/5 of the thermal power plants covered by the national ETS.

Following the division standard for generating unit types outlined in the "Discussion Draft", the 1067 generating units were categorized into three distinct types. Subsequently, the carbon emissions per unit power generation were computed for each group, corresponding to different positions within the benchmark, as illustrated in Table 3.

The data for benchmarking the energy efficiency of thermal power units include both basic unit data and annual production and operation indicator data. Table 3 summarizes various parameters, such as coal consumption for power generation, carbon intensity, operating hours, generating capacity, and load, for different types of generating units. First, based on coal consumption data for 1067 coal-fired generation units, it can be observed that the average coal consumption for China's supercritical power generation units is approximately 0.30 t/MWh, while for ultrasupercritical power generation units, the average coal consumption is approximately 0.28 t/MWh, representing a world-leading level (Zhang et al., 2017; Zhang, 2019; Zhuang et al., 2021). Second, significant differences exist in the average carbon intensity among different types of generation units. For instance, the average carbon intensity for conventional coal-fired generating units above 300 MW ranges from 0.78 to 0.88 tCO_2/MWh, whereas unconventional coal-fired generating units exhibit an average carbon intensity of approximately 0.92 tCO_2/MWh. Consequently, there are substantial variations in CO_2 emissions between less advanced and more advanced generating units. Finally, although there is a negligible difference in the average operating hours of power generation units, a notable discrepancy emerges in their average load. For example, 1000 MW ultrasupercritical units have an average operating duration of 7194.58 h and an average load of 721.74 MW_e, while below 300 MW, circulating fluidized bed integrated gasification combined cycle (IGCC) units operate for an average of 6551.10 h with an average load of only 109.19 MW_e. Consequently, the removal of small-capacity, high-energy consumption, and high-emission coal-fired generating units can significantly contribute to energy conservation and emission reduction (Qi et al., 2020).

Table 2 Scenario descriptions of different allowance allocation methods in the ETS

Allowance allocation method	Definition
Allowance Allocation Method 2021 (AAM2021)	The benchmark in 2021 of the "Discussion Draft"
Allowance Allocation Method 2022 (AAM2022)	The benchmark in 2022 of the "Discussion Draft"
Benchmark-Based Method 1 (BBM 1)	All types of coal-fired units and gas-fired units set their Benchmarks at the 20th quantile of the same type of unit's carbon emission intensity level, and the government allocates initial allowance to the generating units covered by ETS based on these Benchmarks
Benchmark-Based Method 2 (BBM 2)	All types of coal-fired units and gas-fired units set their Benchmarks at the 10th quantile of the same type of unit's carbon emission intensity level, and the government allocates initial allowance to the generating units covered by ETS based on these Benchmarks
Benchmark-Based Method 3 (BBM 3)	Different types of coal-fired units set their Benchmarks at the 10th quantile of the same type of coal-fired unit's carbon emission intensity level; Different types of gas-fired units set their Benchmarks at the 20th quantile of the same type of gas-fired unit's carbon emission intensity level; in addition, the government allocates initial allowance to the generating units covered by ETS based on these Benchmarks

Table 3 Basic statistics of different types of coal-fired generating units

Generating unit type		Minimum coal consumption for power generation (t/MWh)	Maximum coal consumption for power generation (t/MWh)	Average coal consumption for power generation (t/MWh)	Average carbon intensity (tCO_2/MWh)	Average operating hours (h)	Average generating capacity (MWh)	Average load (MW_e)
Conventional coal-fired generating units above 300 MW	1000 MW ultrasupercritical units	0.2642	0.2999	0.2834	0.7858	7194.58	5366106.70	721.74
	600 MW ultrasupercritical units	0.2713	0.3060	0.2884	0.7996	7195.95	3287637.01	456.79
	600 MW supercritical units	0.2827	0.3967	0.3055	0.8471	6921.95	3013017.95	434.78
	600 MW subcritical units	0.2955	0.3485	0.3188	0.8838	6975.05	3006527.40	430.46
Conventional coal-fired generating units of 300 MW and below	300 MW supercritical units	0.2269	0.3298	0.2906	0.8056	7296.87	1730283.91	237.41
	300 MW subcritical units	0.2214	0.3546	0.3085	0.8553	6958.34	1562039.15	224.40
	Below 300 MW ultrahigh pressure/high pressure units	0.2599	0.3770	0.3273	0.9075	6424.62	844589.03	132.11
Unconventional coal-fired generating units	Above 300 MW circulating fluidized bed IGCC units	0.2860	0.3635	0.3317	0.9195	6365.86	1403931.21	220.84
	Below 300 MW circulating fluidized bed IGCC units	0.1837	0.3774	0.3326	0.9221	6551.10	718839.96	109.19

5.2.2 Benchmark values corresponding to each type of generating unit under different scenarios

Using data from 1067 coal-fired generating units with varying generation capacities, in conjunction with the *China Electric Power Industry Annual Development Report 2022* from the China Electricity Council and the "Discussion Draft", we calculated and organized the average coal consumption for power generation, average carbon intensity, and benchmark values corresponding to different allowance allocation method scenarios for different types of coal-fired generating units. The results are presented in Table 4.

In addition, based on "Discussion Draft" and relevant literature research, we calculated and sorted the average coal consumption for power generation, average carbon intensity and benchmark values corresponding to different allowance allocation method scenarios of different types of gas-fired generating units. The results are shown in Table 5.

First, with regard to the "Discussion Draft," the specific allocation method for AAM2021 is presented in the 5th columns of Tables 4 and 5. The benchmark values for conventional coal-fired generating units above and below 300 MW, unconventional coal-fired generating units, and gas-fired units are 0.8218, 0.8773, 0.9350, and 0.3920 tCO_2/MWh, respectively. Building upon AAM2021, AAM2022 further refines the benchmark levels for coal-fired and gas-fired units, as indicated in the 6th columns of Tables 4 and 5. The benchmark values for conventional coal-fired generating units above and below 300 MW, unconventional coal-fired generating units, and gas-fired units under AAM2022 are 0.8159, 0.8729, 0.9303, and 0.3901 tCO_2/MWh, respectively.

Second, when categorizing the ETS benchmark according to BBM 1, as shown in Table 2, the benchmark values are detailed in the 8th column of Tables 4 and 5. Specifically, the benchmark values for conventional coal-fired generating units above and below 300 MW, unconventional coal-fired generating units, and gas-fired units are 0.7939, 0.8034, 0.8648, and 0.3755 tCO_2/MWh, respectively. In the case of dividing the ETS benchmark according to BBM 2, the benchmark values for these units are outlined in the 7th columns of Tables 4 and 5, with values of 0.7787, 0.7644, 0.8145 and 0.3604 tCO_2/MWh, respectively. Last, if the ETS benchmark is divided according to BBM 3, the benchmark values for conventional coal-fired generating units above and below 300 MW, unconventional coal-fired generating units, and gas-fired units are 0.7787, 0.7644, 0.8145, and 0.3755 tCO_2/MWh, respectively, which are depicted in the 7th column of Table 4 and the 8th column of Table 5.

6 Scenario analysis

To determine the fuel switching price of thermal power plants under various allowance allocation scenarios within the ETS, we employ the Monte Carlo method to simulate this price. Here is the process.

Initially, we conduct 10000 Monte Carlo simulations focusing on the coal and gas sectors. These simulations are based on the dynamic model of fossil fuel prices, the associated parameters, and historical monthly prices of fossil fuels as detailed in Section 3. These simulations yield 10000 sets of independent monthly price dynamics for coal and natural gas combinations. Subsequently, we utilize the dynamic simulation results for each set of fuel

Table 4 Coal consumption, carbon intensity, and benchmark values of different types of coal-fired generating units

Generating unit type		Coal consumption for power generation (t/MWh)	Carbon intensity (tCO_2/MWh)	Allowance allocation standard (tCO_2/MWh)			
				AAM2021	AAM2022	BBM 2	BBM 1
Conventional coal-fired generating units above 300 MW	1000 MW ultrasupercritical units	0.2834	0.7858	0.8218	0.8159	0.7787	0.7939
	600 MW ultrasupercritical units	0.2884	0.7996				
	600 MW supercritical units	0.3055	0.8471				
	600 MW subcritical units	0.3188	0.8838				
Conventional coal-fired generating units of 300 MW and below	300 MW supercritical units	0.2906	0.8056	0.8773	0.8729	0.7644	0.8034
	300 MW subcritical units	0.3085	0.8553				
	Below 300 MW ultrahigh pressure/high pressure units	0.3273	0.9075				
Unconventional coal-fired generating units	Above 300 MW circulating fluidized bed IGCC units	0.3317	0.9195	0.9350	0.9303	0.8145	0.8648
	Below 300 MW circulating fluidized bed IGCC units	0.3326	0.9221				
Average		0.3064	0.8494	0.8580	0.8540	0.7744	0.8081

Table 5 Coal consumption, carbon intensity, and benchmark values of different types of gas-fired generating units

Generating unit type	Coal consumption for power generation (t/MWh)	Carbon intensity (tCO_2/MWh)	Allowance allocation standard (tCO_2/MWh)			
			AAM2021	AAM2022	BBM 2	BBM 1
Gas units above class F	0.2072	0.4095	0.3920	0.3901	0.3604	0.3755
Gas units below class F	0.1932	0.3818				
Average	1.9980	0.3930				

price dynamics and incorporate them into the fuel switching model corresponding to the allowance allocation method within different scenarios discussed in Table 2. This integration allows us to derive a sampling point for the switching price. Finally, we calculate the average value of the obtained sampling points. This average value serves as the fuel switching price from coal to gas under the specified conditions and scenarios within the ETS.

6.1 Fuel switching price of thermal power plants under the independent role of the ETS

First of all, this subsection exclusively examines the standalone role of the ETS and operates under the assumption that all units continue to generate electricity in accordance with their historical carbon intensity. Subsequently, in line with the forecasts made by the Intergovernmental Panel on Climate Change, it is revealed that the carbon price, ranging from 135 to 6050 USD/tCO_2, carries a 50%–65% probability of attaining the 1.5 °C temperature control objective. However, it is noteworthy that, based on the latest data released by the World Bank, the actual global carbon price range in 2019 fluctuated between 1 to 127 USD/tCO_2. Furthermore, nations with higher carbon prices have adopted carbon taxation policies, while those with lower carbon prices have established carbon trading markets.

Consequently, our analysis posits that when the fuel switching price assumes a negative value, it loses its significance, thus warranting no further examination. Similarly, if the fuel switching price exceeds 1000 USD/tCO_2, it lacks economic feasibility and policy viability. Consequently, any policy framework associated with such high switching prices is rendered invalid for the short-term transition from coal to gas in thermal power plants and thus does not merit further analysis. In the event that the switching price falls within the range of 500 to 1000 USD/tCO_2, it remains economically meaningful but remains implausible in practical implementation. Only when the carbon price descends below 500 USD/tCO_2 is it deemed feasible in the context of this article. In such a scenario, thermal power plants may achieve the transition from coal to gas through the utilization of the ETS.

6.1.1 Fuel switching price under the “Discussion Draft”

(1) The switching price corresponding to AAM2021

We calculate the fuel switching price linked to the benchmark value in 2021 as per the “Discussion Draft”. This calculation is conducted using the fuel switching model that incorporates the carbon allowance allocation method outlined in Section 3.2. The results of this analysis are presented in Table 6 and Fig. 3.

First, in cases where the carbon allowances are entirely allocated free of charge within the ETS, the fuel switching price either assumes a negative value or significantly

Table 6 Fuel switching prices of different types of generating units under the AAM2021 (USD/tCO_2)

Coal units	Auction ratio											
	Free allocation	10%	16%	20%	30%	40%	50%	60%	70%	80%	90%	100%
1000 MW ultrasupercritical units	–	10924.11	1868.88	1203.70	636.94	433.04	328.03	264.01	220.90	189.89	166.52	148.27
600 MW ultrasupercritical units	–	2989.95	1275.30	922.59	545.44	387.17	300.09	244.99	206.99	179.19	157.98	141.25
600 MW supercritical units	2286.01	816.92	589.59	497.32	357.47	279.01	228.79	193.90	168.23	148.57	133.02	120.42
600 MW subcritical units	864.56	506.35	405.54	358.02	276.90	225.75	190.55	164.85	145.25	129.82	117.36	107.07
300 MW supercritical units	–	–	21435.24	2573.01	804.09	476.50	338.57	262.56	214.43	181.20	156.90	138.34
300 MW subcritical units	–	2321.70	1030.28	751.58	448.36	319.47	248.14	202.85	171.54	148.60	131.07	117.25
Below 300 MW ultrahigh pressure/high pressure units	1894.55	675.64	487.46	411.13	295.46	230.58	189.07	160.22	139.01	122.76	109.91	99.50
Above 300 MW circulating fluidized bed IGCC units	–	1416.01	738.37	559.78	348.84	253.37	198.93	163.74	139.13	120.95	106.98	95.90
Below 300 MW circulating fluidized bed IGCC units	–	1315.65	709.20	542.49	341.69	249.38	196.34	161.91	137.75	119.86	106.09	95.15

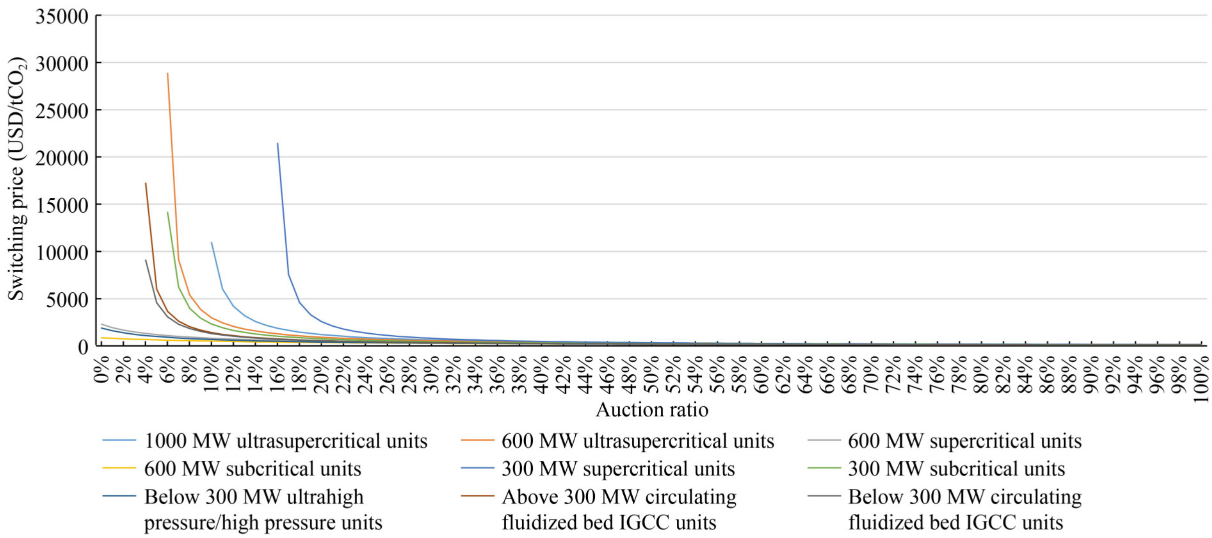

Fig. 3 Comparison of fuel switching price trends for different types of units with different auction ratios in AAM2021.

exceeds 1000 USD/tCO_2, except for 600 MW subcritical units, where the switching price stands at 864.56 USD/tCO_2. Despite the possibility of coal-to-gas switching for these subcritical units, the switching price remains prohibitively high, making it unattainable. Consequently, the ETS proves ineffective in promoting short-term coal-to-gas transitions for all other categories of thermal power units, except for the 600 MW subcritical units.

Second, under AAM2021, unit categorization based on capacity reveals that, when compared to older units such as the 600 MW subcritical units, more advanced coal-fired units such as 1000 MW ultrasupercritical units, 600 MW ultrasupercritical units, and 300 MW supercritical units require higher switching prices under identical auction ratios and unit types. Consequently, the allocation method specified in AAM2021 makes it more feasible for older, energy-intensive, and high-emission coal-fired units to transition to alternative fuels.

Third, as illustrated in Fig. 3, an increase in the proportion of ETS allowance auctions correlates with a gradual decrease in fuel switching prices for 600 MW supercritical units, 600 MW subcritical units, and units with capacities below 300 MW ultrahigh pressure/high pressure. In contrast, other types of generating units exhibit progressively increasing positive switching prices. Beyond an auction ratio of 16%, all categories of thermal power units registered positive switching prices. Subsequently, with increasing auction ratios, the fuel switching prices for all coal-fired unit types decline, with diminishing marginal reductions. Among them, units with more lenient benchmark levels experience more significant reductions in switching prices, whereas units with stricter benchmark levels witness smaller decreases. Ultimately, when the auction ratio reaches 39%, the switching price for all thermal power units falls below 500 USD/tCO_2. Within this range, 300 MW supercritical units with relatively lenient benchmark levels display the highest switching price when transitioning to gas units, standing at 496.74 USD/tCO_2, while units below 300 MW ultrahigh pressure/high pressure with more stringent benchmark levels record a lower switching price of only 235.76 USD/tCO_2.

Finally, as indicated in the last column of Table 6, when 100% of allowances are auctioned within the ETS, each unit's fuel switching price reaches its minimum value. Among these units, the most advanced 1000 MW ultrasupercritical units exhibit the highest fuel switching price at 148.27 USD/tCO_2. Conversely, as the most outdated units, the switching price for circulating fluidized bed IGCC units with capacities below 300 MW is a mere 95.15 USD/tCO_2. Consequently, it is evident that more advanced coal-fired unit types necessitate higher fuel switching prices and face greater challenges in transitioning to alternative fuels. In contrast, older units have relatively lower fuel switching costs, making it more likely for thermal power plants to prioritize coal-to-gas transitions for these units. Overall, the ETS can effectively aid companies in phasing out outdated production capacity when their allowances are fully auctioned.

(2) The switching price corresponding to AAM2022

We simulate the fuel switching price corresponding to the benchmark value in AAM2022 based on the fuel switching model that considers the carbon allowance allocation method in Section 3.2. The results are shown in Table 7 and Fig. 4.

First and foremost, as indicated in the second column of Table 7, when allowances are entirely free and allocated following AAM2022, the ETS proves ineffective in expediting short-term transitions from coal to gas for all remaining types of thermal power units, except for 600 MW subcritical units.

As depicted in Fig. 4, akin to AAM2021, an increase in the auction ratio results in a gradual decline in the fuel switching prices for 600 MW supercritical units, 600 MW subcritical units, and units with capacities below 300 MW in ultrahigh pressure/high pressure categories. Conversely, the fuel switching prices for other types of generating units progressively exhibit positive values. Only when the auction ratio surpasses 16% do all categories of thermal power units registered positive switching prices. Subsequently, with continued increases in the auction ratio, the fuel switching prices for all coal-fired unit types gradually decrease, displaying a

Table 7 Fuel switching prices of different types of units under AAM2022 (USD/tCO_2)

Coal units	Auction ratio										
	Free allocation	10%	16%	20%	30%	40%	50%	60%	70%	80%	90%	100%
1000 MW ultrasupercritical units	–	7952.99	1763.67	1161.21	626.33	428.81	326.00	262.96	220.34	189.62	166.41	148.27
600 MW ultrasupercritical units	–	2709.11	1224.76	897.08	537.54	383.74	298.37	244.07	206.49	178.94	157.88	141.25
600 MW supercritical units	2092.58	793.34	578.01	489.45	353.89	277.13	227.74	193.29	167.89	148.39	132.95	120.42
600 MW subcritical units	834.23	496.83	399.81	353.75	274.66	224.47	189.79	164.39	144.99	129.68	117.30	107.07
300 MW supercritical units	–	–	11954.61	2359.12	784.64	470.57	336.06	261.35	213.82	180.92	156.79	138.34
300 MW subcritical units	–	2116.68	990.54	731.20	441.93	316.66	246.72	202.09	171.13	148.40	130.99	117.25
Below 300 MW ultrahigh pressure/high pressure units	1733.45	656.07	477.87	404.60	292.49	229.03	188.20	159.72	138.73	122.61	109.85	99.50
Above 300 MW circulating fluidized bed IGCC units	–	1322.16	713.72	546.16	344.16	251.24	197.83	163.15	138.81	120.79	106.91	95.90
Below 300 MW circulating fluidized bed IGCC units	–	1234.03	686.36	529.65	337.19	247.32	195.27	161.32	137.43	119.70	106.02	95.15

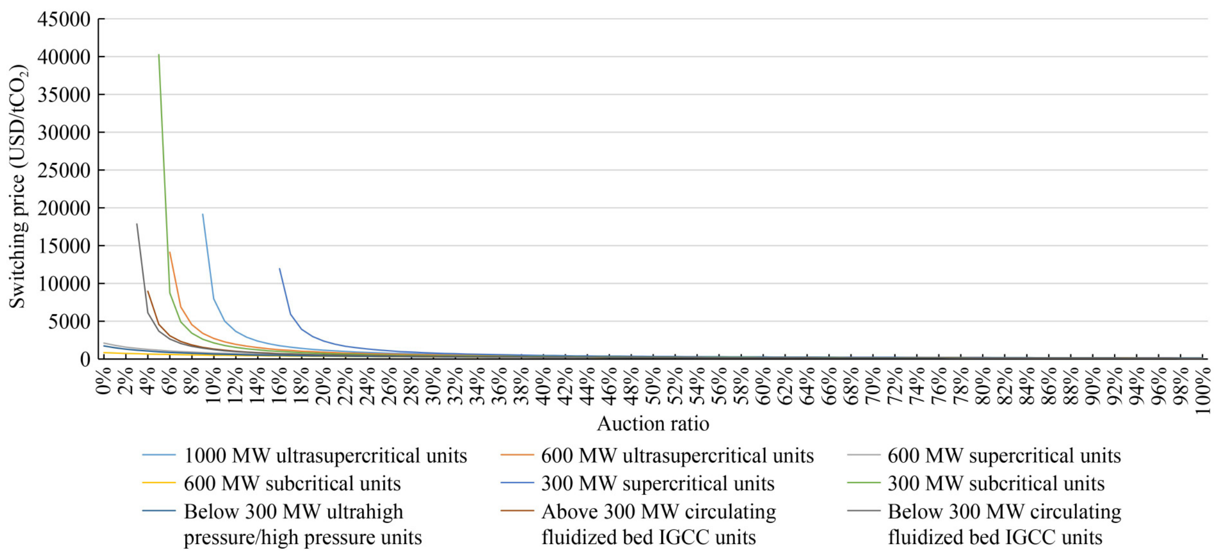

Fig. 4 Comparison of fuel switching price trends for different types of units with different auction ratios in AAM2022.

trend of diminishing marginal reductions. Once the carbon allowance auction ratio reaches 39%, the switching price for all units falls below 500 USD/tCO_2, signifying practical significance. Among conventional coal-fired generating units, 300 MW supercritical units exhibit the highest switching price at 490.19 USD/tCO_2, while below 300 MW ultrahigh pressure/high pressure units have the lowest at 234.11 USD/tCO_2. This variation can be attributed to the more lenient benchmark levels for advanced conventional coal-fired units with lower carbon intensity, resulting in higher switching prices and greater difficulty in achieving fuel switching. Conversely, stricter benchmark levels apply to older conventional coal-fired units with higher carbon intensity, leading to lower switching prices and easier transitions to alternative fuels.

Last, as demonstrated in the last column of Table 7, in a scenario where the ETS operates as a 100% auction market, the fuel switching price for each unit type reaches its minimum value. This aligns with the fuel switching price for each type of generating unit when allowances are allocated based on AAM2021 and fully auctioned. Consequently, when carbon allowances are 100% auctioned, the fuel switching price for thermal power units is solely dependent on the carbon intensity of each unit and remains unaffected by benchmark levels.

6.1.2 Fuel switching price under the benchmark-based method

(1) The switching price corresponding to BBM 1

In this section, we employ BBM 1 to categorize the benchmark values for various types of generating units. Specifically, we position the benchmarks for coal-fired and gas-fired units at the 20th quantile of carbon emissions per unit power generation within the same unit type. Utilizing the fuel switching model that incorporates the allowance allocation method detailed in Section 3.2, we simulate the switching prices for various generating units under BBM 1. The results of this simulation are presented in Table 8 and Fig. 5.

Table 8 Fuel switching prices of different types of units under BBM 1 (USD/tCO_2)

Coal units	Auction ratio										
	Free allocation	7%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
1000 MW ultrasupercritical units	–	41713.11	4153.36	1037.97	593.09	415.16	319.35	259.47	218.50	188.70	166.06	148.27
600 MW ultrasupercritical units	–	3760.07	2058.69	820.75	512.55	372.62	292.71	241.02	204.85	178.12	157.56	141.25
600 MW supercritical units	1628.95	867.90	723.11	464.70	342.35	271.00	224.27	191.28	166.75	147.80	132.71	120.42
600 MW subcritical units	746.16	526.28	467.27	340.14	267.39	220.27	187.28	162.88	144.10	129.21	117.11	107.07
300 MW supercritical units	–	4594.88	2253.30	834.96	512.42	369.63	289.08	237.35	201.33	174.80	154.45	138.34
300 MW subcritical units	1680.16	869.15	720.16	458.30	336.09	265.34	219.20	186.72	162.63	144.04	129.27	117.25
Below 300 MW ultrahigh pressure/high pressure units	604.55	446.06	401.00	300.00	239.64	199.50	170.88	149.44	132.78	119.46	108.57	99.50
Above 300 MW circulating fluidized bed IGCC units	1440.36	726.94	599.65	378.64	276.67	217.97	179.82	153.03	133.19	117.91	105.77	95.90
Below 300 MW circulating fluidized bed IGCC units	1336.70	698.61	579.96	370.32	272.00	214.93	177.66	151.40	131.91	116.86	104.90	95.15

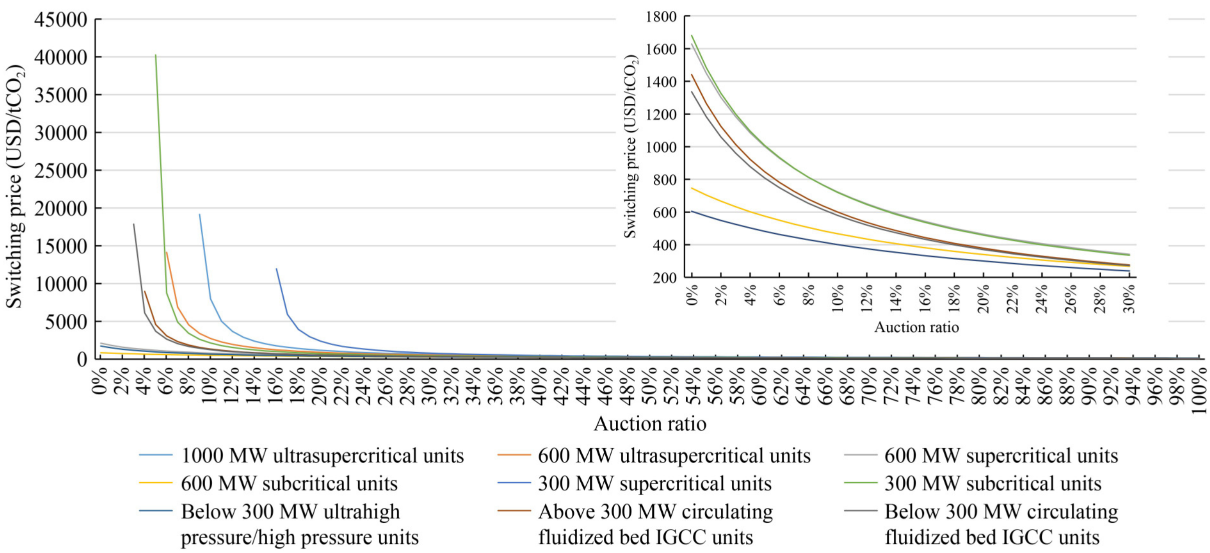

Fig. 5 Comparison of fuel switching price trends for different types of units with different auction ratios in BBM 1.

First, as depicted in the second column of Table 8, in the scenario where allowances are entirely free and allocated based on BBM 1, the switching prices for more advanced units, such as 1000 MW ultrasupercritical units, 600 MW ultrasupercritical units, and 300 MW supercritical units, are rendered invalid. Additionally, the switching prices for 600 MW supercritical units, 300 MW subcritical units, above 300 MW circulating fluidized bed IGCC units, and below 300 MW circulating fluidized bed IGCC units exceed 1000 USD/tCO_2. Consequently, the ETS proves entirely ineffective in expediting short-term transitions from coal to gas for all remaining types of thermal power units, except for 600 MW subcritical units and below 300 MW ultrahigh pressure/high pressure units.

As illustrated in Fig. 5, with an increase in the auction ratio, the fuel switching prices for 1000 MW ultrasupercritical units, 600 MW ultrasupercritical units, and 300 MW supercritical units progressively exhibit positive values. Conversely, the fuel switching prices for other types of generating units gradually decrease. It is only when the auction ratio surpasses 7% that all categories of thermal power units registered positive switching prices. Subsequently, with continued increases in the auction ratio, the fuel switching prices for all coal-fired unit types gradually decline, demonstrating a trend of diminishing marginal reductions. Once the carbon allowance auction ratio reaches 35%, the switching price for all units falls below 500 USD/tCO_2, signifying practical significance. Among conventional coal-fired generating units, 1000 MW ultrasupercritical units exhibit the highest switching price at 488.42 USD/tCO_2, while below 300 MW ultrahigh pressure/high pressure units have the lowest at 217.13 USD/tCO_2.

Finally, as indicated in the last column of Table 8, in a scenario where the ETS operates as a 100% auction market, the fuel switching price for each unit type reaches its minimum value. This aligns with the fuel switching price for each type of generating unit when allowances are allocated based on the “Discussion Draft” and fully auctioned. Consequently, when carbon allowances are 100% auctioned, the fuel switching price for thermal power units is solely dependent on the carbon intensity of each unit and remains unaffected by benchmarks.

(2) The switching price corresponding to BBM 2

In this section, BBM 2 is employed to determine the benchmark values for various types of generating units. Initially, we establish the benchmark position for both coal-fired and gas-fired units at the 10th quantile of carbon emissions per unit power generation within the same unit type. Subsequently, utilizing the fuel switching model that incorporates the allowance allocation method detailed in Section 3.2 and relevant data from various generating units, we simulate the switching prices for different types of generating units under BBM 2. The results of this simulation are presented in Table 9 and Fig. 6.

First, as evident in the second column of Table 9, when allowances are entirely free and allocated in accordance with BBM 2, similar to BBM 1, the switching prices for 1000 MW ultrasupercritical units and 600 MW ultrasupercritical units are rendered invalid. However, the switching price for 300 MW supercritical units and 600 MW supercritical units exceeds 1000 USD/tCO_2. Despite having positive values, the ETS remains insufficient to facilitate the transition from coal to gas for these generating units under this scenario. Conversely, the switching price for other types of generating units, such as 600 MW subcritical units and units below 300 MW in the ultrahigh pressure/high pressure category, falls below 1000 USD/tCO_2. Notably, for units below 300 MW in the ultrahigh pressure/high pressure category, the switching price is merely 471.01 USD/tCO_2, which is lower than 500 USD/tCO_2. Consequently, the ETS proves entirely ineffective in promoting short-term coal-to-gas transitions for all remaining types of thermal power units, except for units below 300 MW in the ultrahigh pressure/high pressure category.

As depicted in Fig. 6, an increase in the auction ratio correlates with progressively positive fuel switching prices for 1000 MW ultrasupercritical units and 600 MW

Table 9 Fuel switching prices of different types of units under BBM 2 (USD/tCO_2)

Coal units	Auction ratio										
	Free allocation	7%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
1000 MW ultrasupercritical units	–	39093.72	4126.71	1036.48	592.67	414.98	319.26	259.42	218.47	188.69	166.05	148.27
600 MW ultrasupercritical units	–	3737.19	2052.03	819.81	512.23	372.48	292.64	240.98	204.83	178.11	157.55	141.25
600 MW supercritical units	1624.09	866.61	722.25	464.38	342.20	270.92	224.22	191.25	166.73	147.79	132.71	120.42
600 MW subcritical units	745.10	525.79	466.89	339.96	267.29	220.22	187.24	162.86	144.09	129.20	117.10	107.07
300 MW supercritical units	9009.60	1641.43	1215.43	651.67	445.18	338.06	272.49	228.23	196.34	172.26	153.45	138.34
300 MW subcritical units	963.09	639.93	559.47	394.25	304.36	247.85	209.04	180.74	159.19	142.23	128.53	117.25
Below 300 MW ultrahigh pressure/high pressure units	471.01	373.41	342.96	269.65	222.16	188.89	164.29	145.36	130.34	118.14	108.02	99.50
Above 300 MW circulating fluidized bed IGCC units	717.10	493.37	435.19	312.38	243.63	199.68	169.17	146.74	129.57	115.99	104.99	95.90
Below 300 MW circulating fluidized bed IGCC units	689.50	479.74	424.40	306.55	239.92	197.08	167.23	145.23	128.34	114.97	104.13	95.15

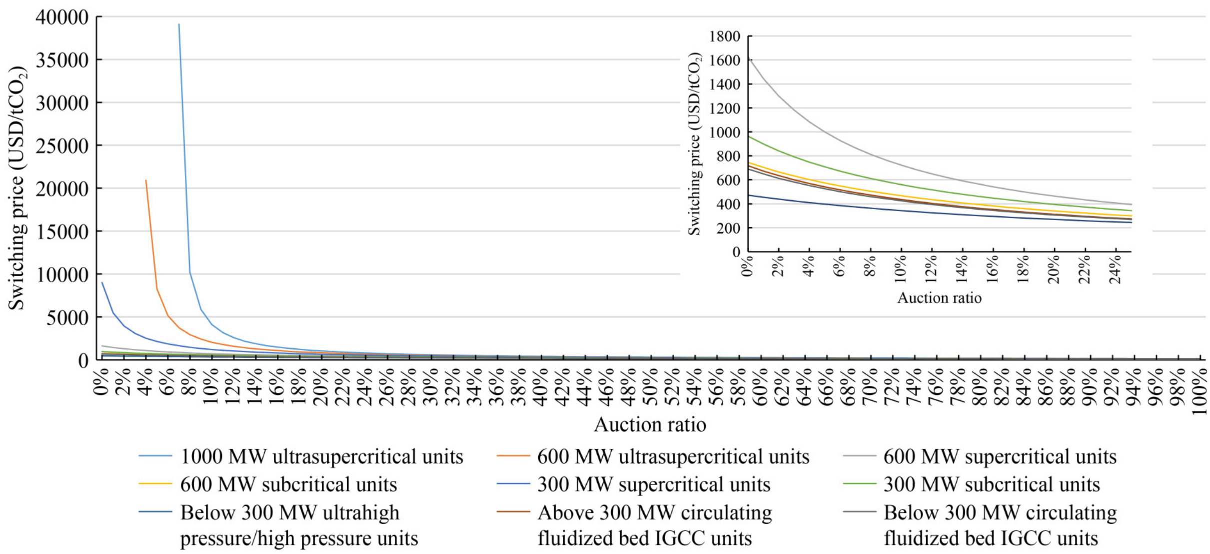

Fig. 6 Comparison of fuel switching price trends for different types of units with different auction ratios in BBM 2.

ultrasupercritical units. Conversely, the fuel switching prices for other types of generating units gradually decrease. It is only when the auction ratio surpasses 7% that all categories of thermal power units registered positive switching prices. Subsequently, with continued increases in the auction ratio, the fuel switching prices for all coal-fired unit types gradually decline, displaying a trend of diminishing marginal reductions. Once the carbon allowance auction ratio reaches 35%, the switching price for all units falls below 500 USD/tCO_2, indicating practical significance. Among conventional coal-fired generating units, 1000 MW ultrasupercritical units exhibit the highest switching price at 488.15 USD/tCO_2, while units below 300 MW in the ultrahigh pressure/high pressure category have the lowest at 204.18 USD/tCO_2.

Last, under scenarios with identical auction ratios, the switching prices for all types of coal-fired units in BBM 2 are notably lower than those in BBM 1, except in the 100% auction market scenario. Moreover, the smaller the auction ratio, the more pronounced the difference between the switching prices corresponding to the two allocation methods. Consequently, when the benchmark positions of coal-fired and gas-fired units align, a more stringent benchmark position facilitates the transition from coal to gas.

(3) The switching price corresponding to BBM 3

In this section, we employ BBM 3 to determine the benchmark values for various types of generating units. Specifically, we establish the benchmark position for coal-fired units at the 10th quantile of carbon emissions per unit power generation within the same unit type. Simultaneously, we position the benchmark for gas-fired units at the 20th quantile of carbon emissions per unit power generation within the same unit type. Subsequently, utilizing the fuel switching model that incorporates the allowance allocation method detailed in Section 3.2 and relevant data from various generating units, we simulate the switching prices for different types of generating units under BBM 3. The results of this simulation are presented in Table 10 and Fig. 7.

First and foremost, as illustrated in column 2 of Table 10, in contrast to the previous four scenarios, in BBM 3, the fuel switching price for most types of units is positive when allowances are entirely free, except for the most advanced 1000 MW ultrasupercritical units. Notably, when allowances are entirely free within the ETS, there is a noticeable disparity in fuel switching prices among different types of thermal power generating units. Consequently, the switching price for units below 300 MW in the ultrahigh pressure/high pressure category falls below 500 USD/tCO_2, while the switching prices for 600 MW ultrasupercritical units, 600 MW supercritical units, and 300 MW supercritical units exceed 1000 USD/tCO_2. This implies that it is more challenging for advanced generating units to transition to alternative fuels.

Second, under scenarios with identical auction ratios, the switching prices for all types of coal-fired units in BBM 3 are notably lower than those in BBM 2, except in the 100% auction market scenario. Moreover, the smaller the auction ratio, the more pronounced the difference between the switching prices corresponding to the two allocation methods. Consequently, when defining benchmarks for different types of generating units, moderately relaxing the benchmark values for gas-fired units not only facilitates the government's efforts to encourage spontaneous fuel switching among thermal power plants through the ETS, thereby accelerating the adjustment of the energy structure in the power sector, but also aids thermal power plants in expediting the elimination process of outdated generating units, preventing situations akin to "whipping fast cattle" in the ETS.

Table 10 Fuel switching prices of different types of units under BBM 3 (USD/tCO_2)

Coal units	Auction ratio											
	Free allocation	4%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
1000 MW ultrasupercritical units	–	16889.67	2096.23	852.19	534.80	389.67	306.50	252.59	214.80	186.85	165.34	148.27
600 MW ultrasupercritical units	51916.38	3314.84	1378.75	698.65	467.87	351.69	281.74	234.99	201.55	176.44	156.90	141.25
600 MW supercritical units	1119.48	840.55	611.86	420.98	320.87	259.23	217.45	187.27	164.45	146.59	132.22	120.42
600 MW subcritical units	613.20	515.70	416.38	315.21	253.59	212.13	182.31	159.85	142.31	128.25	116.71	107.07
300 MW supercritical units	2652.36	1535.89	941.46	572.30	411.10	320.75	262.96	222.82	193.31	170.70	152.82	138.34
300 MW subcritical units	758.55	622.38	490.35	362.26	287.23	237.95	203.10	177.16	157.09	141.10	128.07	117.25
Below 300 MW ultrahigh pressure/high pressure units	413.33	367.02	314.22	253.45	212.37	182.76	160.39	142.90	128.85	117.31	107.67	99.50
Above 300 MW circulating fluidized bed IGCC units	590.01	489.18	389.38	290.57	231.76	192.75	164.98	144.20	128.07	115.19	104.66	95.90
Below 300 MW circulating fluidized bed IGCC units	570.91	475.76	380.61	285.46	228.37	190.30	163.12	142.73	126.87	114.18	103.80	95.15

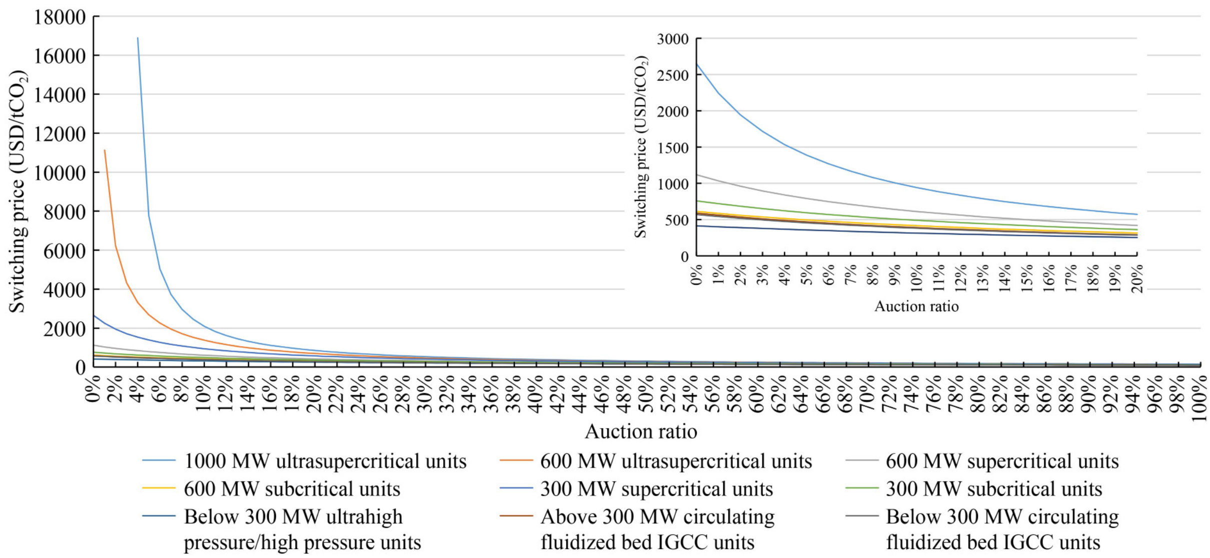

Fig. 7 Comparison of fuel switching price trends for different types of units with different auction ratios in BBM 3.

Third, upon comparing the trends in fuel switching prices for different types of units corresponding to various auction ratios in Fig. 7, it becomes evident that as the allowance auction ratio increases within the ETS, the fuel switching prices for different types of coal-fired and gas-fired units exhibit a consistent decrease, showcasing a trend of diminishing marginal reductions. Particularly noteworthy is the strong correlation between the allowance auction ratio and the fuel switching price when the auction ratio ranges from 0% to 12%, especially for more advanced unit types. Subsequently, as the allowance auction ratio climbs to 32%, the switching price for all units falls below 500 USD/tCO_2, providing an opportunity for all types of generating units to transition from coal to gas through the ETS. Finally, when allowances are fully auctioned within the ETS, the fuel switching price for each unit reaches its lowest value, mirroring the fuel switching price under the announced benchmark scenario when the allowance auction ratio reaches 100%.

It should be emphasized that in BBM 3, the benchmark position for gas-fired units, set at the 20th quantile of carbon emissions per unit power generation, is more lenient compared to the 10th quantile benchmark position for coal-fired units. This indicates that when establishing benchmarks for thermal power plants covered by the ETS, moderately relaxing the benchmark level for gas-fired units can enhance the fuel switching behavior of thermal power plants. However, it is important to note that even the 20th quantile benchmark for gas-fired units remains stringent, ensuring that the emission reduction objectives include all types of units within the ETS. This combination of BBM 3 and a specific auction ratio in the ETS ensures that thermal power plants can achieve fuel switching at a lower switching price while maintaining comprehensive coverage of emission reduction efforts for all unit types under the ETS.

6.1.3 Comparison of the effect of different allowance allocation methods in the ETS on fuel switching of thermal power plants

To assess and compare the effects of the aforementioned allowance allocation methods, as well as different auction ratios, on the transition from coal to gas in thermal power plants under the independent purview of the ETS and to identify a more effective allowance allocation approach within the ETS, this article takes into account the collective circumstances of various types of coal-fired and gas-fired units. Consequently, the data for different types of generating units are weighted and averaged in this section, with the summarized results presented in the last row of Tables 4 and 5. Employing the fuel switching model that incorporates the allowance allocation method detailed in Section 3.2, a comprehensive simulation of the fuel switching prices for the various types of units included by the ETS is conducted. The results of this simulation are presented in Table 11 and Fig. 8.

To provide a comprehensive analysis of the various allowance allocation methods and their effect on the transition from coal to gas in thermal power plants within the independent scope of the ETS, we consider the operational conditions of all thermal power plants covered by the ETS. As indicated in the second column of Table 11, when allowances are issued for free and allocated according to AAM2021 or AAM2022, the comprehensive switching price for thermal power units is negative. Consequently, if allowances are entirely free and allocated based on the "Discussion Draft", the ETS will prove ineffective in promoting short-term coal-to-gas transitions for the remaining types of thermal power units. Utilizing BBM 1 or BBM 2 to allocate allowances results in comprehensive switching prices for thermal power units significantly exceeding 1000 USD/tCO_2. Due to these high prices, thermal power plants are unlikely to transition from coal to gas. BBM 3, although yielding the lowest comprehensive fuel switching price, still requires a carbon price of 972.49 USD/tCO_2 to facilitate the transition. While this price is below 1000 USD/tCO_2, it remains prohibitively high. In summary, under the current allowance allocation method, if the ETS continues to distribute all allowances for free, thermal power plants will not transition fuels independently under its influence.

Second, as depicted in Fig. 8, when the auction ratio surpasses 3%, the comprehensive switching prices corresponding to various allowance allocation methods decline as the allowance auction ratio increases within the ETS. Furthermore, when the allowance auction ratio falls below 12%, the fuel switching prices associated with the two announced allowance allocation methods are highly

Table 11 Comparison of fuel switching prices under different allowance allocation methods

Allowance method	Auction ratio											
	0%	3%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
AAM2021	–	26088.84	1563.83	667.46	424.28	310.97	245.43	202.71	172.65	150.36	133.17	119.50
AAM2022	–	13180.66	1483.05	653.95	419.45	308.74	244.27	202.07	172.31	150.18	133.10	119.50
BBM 1	2523.94	1573.90	837.94	502.36	358.70	278.94	228.20	193.07	167.32	147.63	132.08	119.50
BBM 2	1353.24	1033.22	665.83	441.54	330.28	263.81	219.61	188.09	164.49	146.15	131.49	119.50
BBM 3	972.49	807.91	567.45	400.60	309.57	252.25	212.84	184.09	162.17	144.92	130.99	119.50

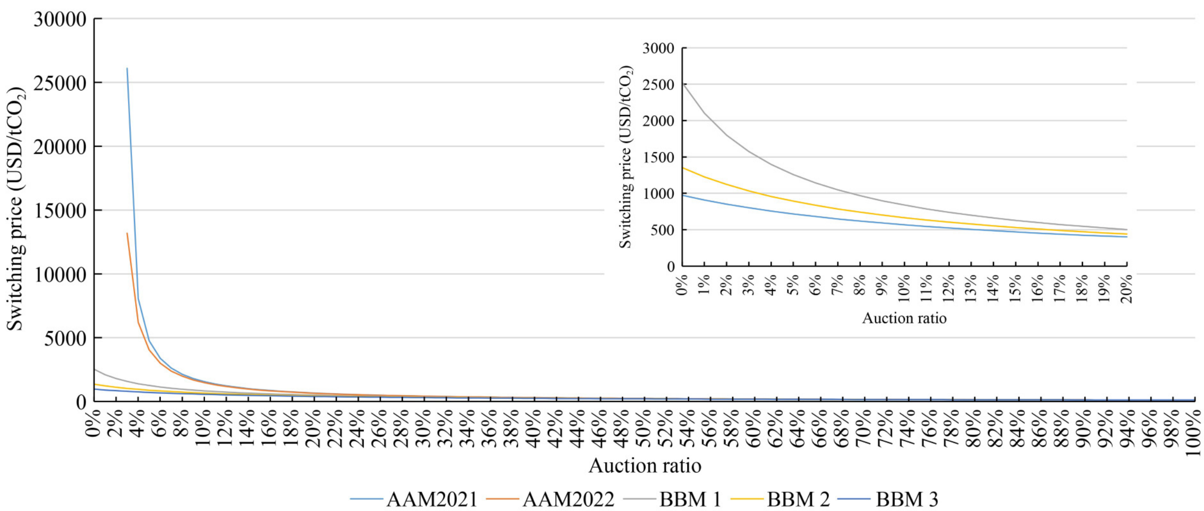

Fig. 8 Comparison of fuel switching price trends under different allowance allocation methods.

sensitive to the auction ratio, with substantial decreases in the switching price as the auction ratio increases.

Third, for the allowance allocation methods proposed in the "Discussion Draft", when the allowance auction ratio exceeds 26%, the average switching price falls below 500 USD/tCO_2, rendering the ETS effective in facilitating the transition from coal to gas. Additionally, when the allowance auction rate is relatively small, AAM2022 exhibits greater sensitivity to the auction ratio, resulting in lower switching prices compared to AAM2021. Consequently, in situations with a minimal allowance auction ratio, AAM2022 appears to be a more reasonable choice for promoting coal-to-gas transitions.

Moreover, when comparing the switching price curves of the five allowance allocation methods, it becomes evident that the comprehensive fuel switching price in BBM 3 is significantly lower than that in the other four methods. Thus, BBM 3 emerges as the most effective approach for coal-to-gas transitions in thermal power plants. Under BBM 3, with an allowance auction ratio exceeding 14%, the average switching price falls below 500 USD/tCO_2, making the ETS effective in driving the transition from coal to gas. However, as the auction ratio increases, the advantage of the fuel switching price under BBM 3 gradually diminishes until the ETS becomes a 100% auction market. Regardless of how the benchmark is divided within the ETS, the comprehensive fuel switching price for all generating units remains constant at 119.50 USD/tCO_2.

Last, by assuming that the gas price is twice the coal price in Europe, the carbon price reaches 62.5 Euro/tCO_2 in the EU ETS, prompting most coal-fired power plants to switch to gas-fired power generation (Delarue et al., 2010). Given the United States' status as the world's largest natural gas producer and its lower natural gas prices, generation costs declined by 59 million USD/year, through coal-to-gas fuel switching, totaling 5.1 billion USD (Lueken et al., 2016; Brehm and Zhang, 2021). Comparatively, the switching price of 119.50 USD/tCO_2 in China's national ETS is considerably higher. This discrepancy primarily arises from the strong dependence of carbon prices on coal and gas prices (Hu, 2023). An examination of monthly coal and gas prices in China, as shown in Figs. 1 and 2, reveals that gas prices in China are nearly four times higher than coal prices. Consequently, China's national ETS needs to achieve a higher carbon price to facilitate the transition of thermal power plants from coal to gas.

6.2 Fuel switching under the synergy of ETS and gas feed-in tariff subsidies

6.2.1 The effect of gas feed-in tariff subsidies on fuel switching prices

In addition to market-oriented policies such as the ETS, feed-in tariff subsidies represent another fiscal policy that influences the choice of fuel for power generation by altering the marginal cost of various types of generating units. According to the *Notice of the National Development and Reform Commission on Regulating the Management of Natural Gas Power Generation Tariffs*, local governments should establish a gas and electricity price linkage mechanism. Feed-in tariff subsidies for gas should be adjusted in response to changes in gas prices, with the maximum subsidy not exceeding 0.35 yuan/kWh, the average purchase price of local power grid companies, or the local benchmark for coal-fired power generation prices.

As such, we consider a range of feed-in tariff subsidies for gas, ranging from 0 to 0.5 USD/kWh. Initially, we assume that the ETS operates as a complete auction market to assess the effect of feed-in tariff subsidies on the fuel switching prices of various types of generating units in thermal power plants. Subsequently, we employ the fuel switching model that accounts for the synergy of the ETS and gas feed-in tariff subsidies, as outlined in Section 3.3. This model utilizes relevant data pertaining to different types of coal-fired and gas-fired units to simulate the fuel switching prices of these units under various levels of natural gas feed-in tariff subsidies. The results of these simulations are presented in Table 12 and Fig. 9.

First, when the gas feed-in tariff subsidy is set to zero, the fuel switching prices of all types of thermal power units within the purview of the ETS align with the prices observed when the ETS allowances are fully auctioned under the independent influence of the ETS. In this scenario, the comprehensive switching price remains constant at 119.50 USD/tCO_2.

Second, as the gas feed-in tariff subsidy increases, there is a linear decline in the fuel switching prices for all types of thermal power units included by the ETS. For instance, a 0.1 USD/kWh increase in the gas feed-in tariff subsidy results in an approximately 18.5 USD drop in the fuel switching price for less advanced generating units such as those below 300 MW ultrahigh pressure/high pressure units, above 300 MW circulating fluidized bed IGCC units, and below 300 MW circulating fluidized bed IGCC units. Conversely, more advanced generating units such as 1000 MW ultrasupercritical units, 600 MW ultrasupercritical units, and 300 MW supercritical units experience an even greater drop of approximately 25 USD. When considering all thermal power plants within the ETS, a 0.1 USD/kWh increase in the gas feed-in tariff subsidy leads to a comprehensive switching price reduction of 22.02 USD for both coal-fired and gas-fired units.

Additionally, when the gas feed-in tariff subsidy reaches 0.5 USD/kWh, the fuel switching price for relatively less advanced generating units, such as those below 300 MW ultrahigh pressure/high pressure units, above 300 MW circulating fluidized bed IGCC units, and below

Table 12 Fuel switching prices of different types of units corresponding to different gas feed-in tariff subsidies under the complete auction (USD/tCO_2)

Coal units	Feed-in tariff (USD/kWh)					
	0	0.1	0.2	0.3	0.4	0.5
1000 MW ultrasupercritical units	148.27	122.66	97.05	71.44	45.83	20.22
600 MW ultrasupercritical units	141.25	116.52	91.78	67.05	42.32	17.58
600 MW supercritical units	120.42	98.29	76.16	54.02	31.89	9.75
600 MW subcritical units	107.07	86.60	66.13	45.66	25.19	4.72
300 MW supercritical units	138.34	113.97	89.59	65.22	40.85	16.48
300 MW subcritical units	117.25	95.51	73.77	52.03	30.29	8.55
Below 300 MW ultrahigh pressure/high pressure units	99.50	79.98	60.45	40.93	21.40	1.88
Above 300 MW circulating fluidized bed IGCC units	95.90	76.82	57.74	38.67	19.59	0.51
Below 300 MW circulating fluidized bed IGCC units	95.15	76.17	57.19	38.20	19.22	0.24
Average	119.50	97.48	75.46	53.43	31.41	9.39

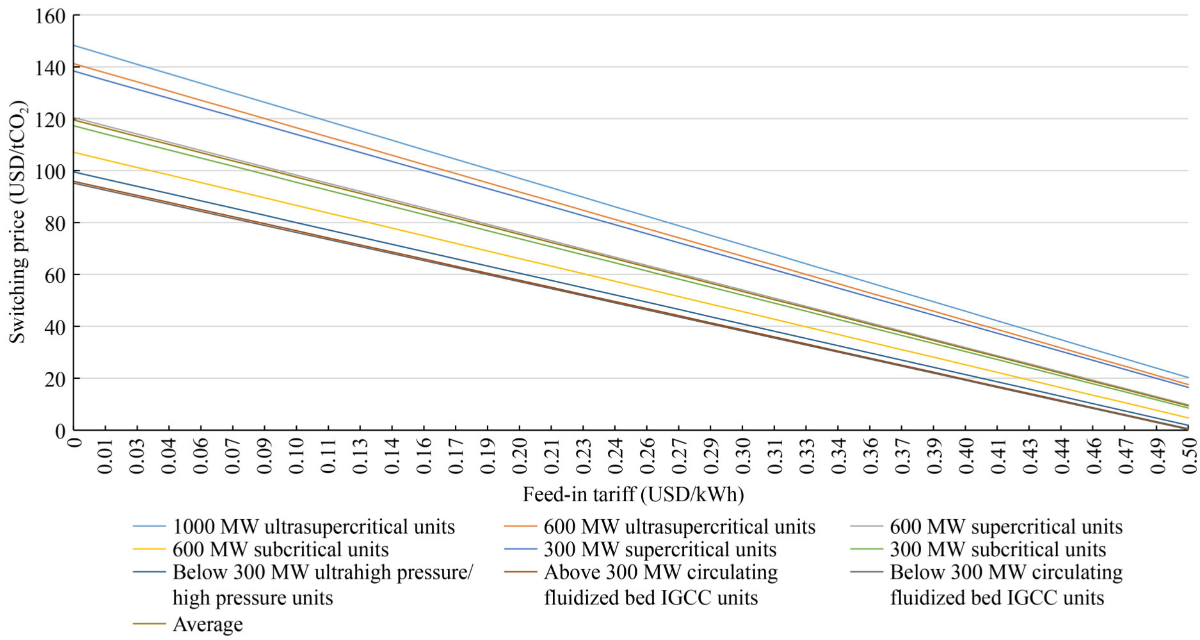

Fig. 9 Fuel switching price trends of different types of units corresponding to different gas feed-in tariff subsidies under the complete auction (USD/tCO_2).

300 MW circulating fluidized bed IGCC units, falls below 2 USD/tCO_2. This implies that with the support of gas feed-in tariff subsidies, it becomes unnecessary to fully auction ETS allowances to incentivize relatively less advanced coal-fired units to transition from coal to gas. Ultimately, when the gas feed-in tariff subsidy reaches 0.5 USD/kWh, the fuel switching price for thermal power plants subject to the ETS drops significantly to as low as 9.39 USD/tCO_2.

6.2.2 Fuel switching under the synergy of ETS and gas feed-in tariff subsidy

To holistically evaluate the combined effect of the ETS and gas feed-in tariff subsidy on thermal power plants' fuel switching prices, we integrate the BBM 3 approach with the gas feed-in tariff subsidy. Utilizing the fuel switching model developed for the synergy of the ETS and gas feed-in tariff subsidy as outlined in Section 3.3 and incorporating pertinent data for various types of coal-fired and gas-fired units, we simulate the fuel switching prices of different types of generating units across varying ETS allowance auction ratios and distinct levels of gas feed-in tariff subsidies. The findings are summarized in Table 13 and Fig. 10.

First, we rectify the allowance auction ratio within the ETS. For instance, when allowances are fully allocated within the ETS and as the gas feed-in tariff subsidy continually increases, the fuel switching cost for thermal

Table 13 Fuel switching prices under the synergy of ETS and gas feed-in tariff subsidy

Auction ratio	Feed-in tariff (USD/kWh)					
	0	0.1	0.2	0.3	0.4	0.5
0	972.49	793.28	614.06	434.85	255.64	76.43
10%	567.45	462.88	358.31	253.74	149.17	44.60
20%	400.60	326.77	252.95	179.13	105.31	31.48
30%	309.57	252.52	195.47	138.43	81.38	24.33
40%	252.25	205.77	159.28	112.80	66.31	19.83
50%	212.84	173.62	134.40	95.17	55.95	16.73
60%	184.09	150.16	116.24	82.31	48.39	14.47
70%	162.17	132.29	102.40	72.52	42.63	12.75
80%	144.92	118.22	91.51	64.80	38.10	11.39
90%	130.99	106.85	82.71	58.57	34.43	10.29
100%	119.50	97.48	75.46	53.43	31.41	9.39

power plants covered by the ETS experiences a linear decrease from 972.49 to 76.43 USD/ tCO_2. Moreover, as the allowance auction ratio steadily rises, the effect of gas feed-in tariff subsidies on the fuel switching cost of thermal power plants progressively diminishes. For instance, with 100% of allowances auctioned within the ETS, the cost of switching for thermal power units reduces from 119.50 to 9.39 USD/tCO_2. This decline is notably less pronounced than in the scenario where allowances are entirely free in the ETS.

Second, address the pricing of gas feed-in tariff subsidies. For example, with a gas feed-in tariff subsidy of 0.1 USD/kWh, as the allowance auction ratio increases, the fuel switching cost for thermal power units under the ETS continuously decreases from 793.28 to 97.48 USD/ tCO_2, with the rate of decline gradually slowing. Conversely, when the gas feed-in tariff subsidy is set at 0.4 USD/kWh, an increase in the allowance auction ratio results in a continuous decrease in the fuel switching cost for thermal power units within the ETS, from 255.64 to 31.41 USD/tCO_2. Hence, with higher gas feed-in tariff subsidies, the influence of the allowance auction ratio within the ETS on the fuel switching cost of thermal power units diminishes.

Consequently, in scenarios with low allowance auction ratios, it is crucial to guarantee higher feed-in tariff subsidies for gas-fired units. This ensures that thermal power plants covered by the ETS can autonomously transition to alternative fuels at a reasonable carbon price. For instance, when allowances are entirely free, a gas feed-in tariff subsidy of 0.27 USD/kWh can ensure that the comprehensive switching cost of thermal power plants remains below 500 USD/tCO_2. In cases where the allowance auction ratio exceeds 33%, a gas feed-in tariff subsidy of 0.4 USD/kWh or more is needed. This facilitates the ETS in promoting the switch from coal to gas when the carbon price is below 100 USD/tCO_2.

Last, when the allowance auction ratio reaches 100% and the gas feed-in tariff subsidy is set at 0.5 USD/kWh, the fuel switching cost for thermal power units under the ETS is merely 9.39 USD/tCO_2.

In conclusion, both the “auction ratio” within the ETS and the gas feed-in tariff subsidy positively influence the fuel switching cost of thermal power units. Furthermore, in comparison to market-oriented policy measures such as the ETS, direct fiscal policies such as gas feed-in tariff subsidies have more pronounced effects. Additionally,

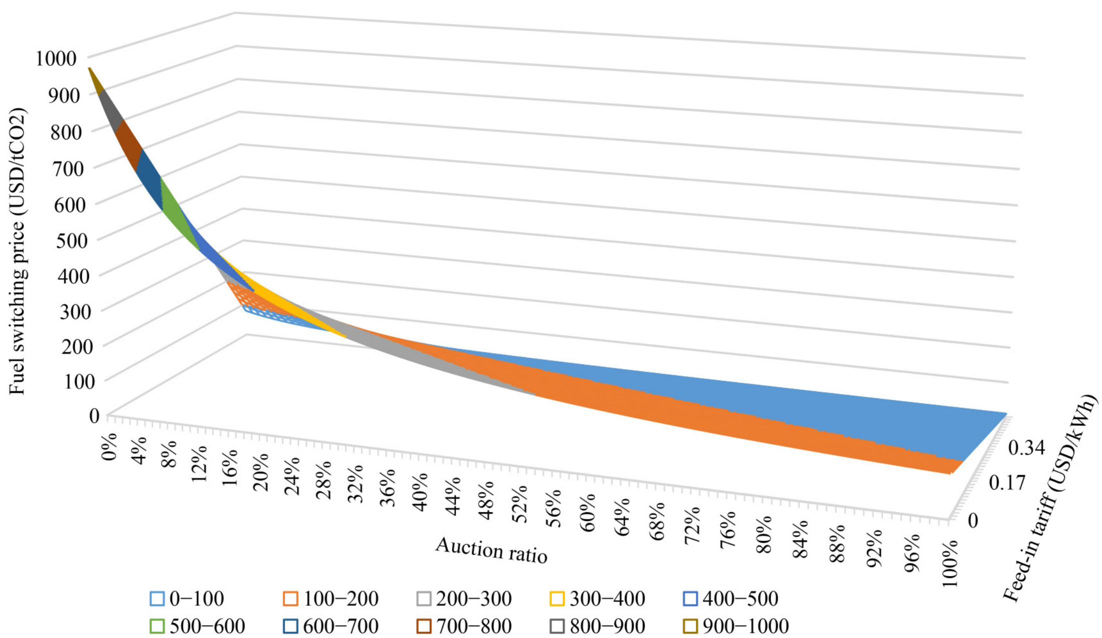

Fig. 10 Fuel switching price trends under the synergy of ETS and gas feed-in tariff subsidies.

when one of these policies has a weaker effect on the fuel switching cost of thermal power units, the other policy exhibits a significantly stronger influence. Thus, the ETS and gas feed-in tariff subsidies can function as complementary policies, working together to promote the transition to alternative fuels in thermal power plants.

7 Conclusions and policy recommendations

7.1 Conclusions

This paper formulates a model for fuel switching, including various allowance allocation methods, and utilizes microdata from 1067 thermal power units within the purview of the ETS. Our inquiry extends beyond assessing the influence of different allowance allocation methods on the fuel switching cost of thermal power plants solely within the ETS framework. We also conduct simulations to examine the fuel switching cost of these power plants under the combined effect of the ETS and subsidies for natural gas feed-in.

When we consider the fuel switching conduct of thermal power plants solely under the influence of the ETS, the results are as follows.

First, let us consider a scenario where the ETS continues to allocate allowances to thermal power plants entirely free of charge and allocates allowances in accordance with the two methods outlined in the "Discussion Draft". Under these circumstances, the cost of transitioning from coal to gas in China surpasses 1000 USD/tCO_2 or even assumes negative values. Consequently, the prospect of coal-to-gas conversion within thermal power plants through the ETS becomes unattainable. Furthermore, based on the two currently disclosed allowance allocation methods, the allowance auction ratio within the ETS must be set at a minimum of 39% to ensure that the switching cost for all categories of thermal power units remains below 500 USD/tCO_2, thereby enabling thermal power plants to contemplate the shift from coal to gas through the ETS.

Second, the comprehensive fuel switching cost under BBM 3 stands significantly lower than that associated with the other four allowance allocation methods. Consequently, BBM 3 emerges as the most efficacious approach for effecting the transition from coal to gas within thermal power plants. Nevertheless, as the auction ratio escalates, the advantage in terms of the fuel switching cost under BBM 3 gradually diminishes. It becomes feasible to guarantee that the switching cost for thermal power units remains below 500 USD/tCO_2, and that thermal power plants entertain the possibility of transitioning from coal to gas through the ETS when the allowance auction ratio exceeds 14%.

Finally, when the ETS adopts a 100% auction market approach, irrespective of the division of benchmarks within the ETS, the comprehensive fuel switching cost for all generation units remains constant at 119.50 USD/tCO_2. However, this cost is significantly higher than the switching cost within the EU ETS and RGGI. This discrepancy arises from the relatively elevated gas prices in China compared to other nations, and the substantial disparity between gas and coal prices in China necessitates a higher transition cost within the country.

Hence, to reduce the cost associated with transitioning from coal to gas for thermal power plants in China, we examine the synergistic effect of the ETS and gas feed-in tariff subsidies. The findings are as follows.

First, both the "auction ratio" within the ETS and the gas feed-in tariff subsidy exert a positive influence on the fuel switching cost for thermal power units. Furthermore, in comparison to market-oriented policy measures such as the ETS, direct fiscal policies such as gas feed-in tariff subsidies produce more pronounced effects.

Second, when one of these two policies exerts a weaker influence on the fuel switching cost for thermal power units, the other policy demonstrates a considerably stronger effect. Consequently, the ETS and gas feed-in tariff subsidies can function as complementary policies, working in concert to promote the transition to alternative fuels in thermal power plants.

Last, when the allowance auction ratio reaches 100% and the gas feed-in tariff subsidy is set at 0.5 USD/kWh, the fuel switching cost for thermal power units under the purview of the ETS amounts to a mere 9.39 USD/tCO_2.

7.2 Policy recommendations

Based on the simulation results pertaining to the fuel switching cost for thermal power plants under the jurisdiction of the ETS, influenced by various allowance allocation methods, it becomes evident that the allocation of initial allowances in accordance with the presently published national ETS allowance allocation method would not facilitate immediate fuel switching for thermal power plants through the ETS. Consequently, this article presents the following recommendations.

First, when considering solely the independent influence of the ETS, if it continues to allocate allowances based on the benchmark values outlined in the "Discussion Draft", the auction ratio for ETS allowances must exceed 26% to ensure that the fuel switching cost for thermal power units remains below 500 USD/tCO_2. This condition would provide thermal power plants with the opportunity to transition from coal to gas through the ETS.

Second, when considering solely the independent effect of the ETS and if the ETS allocates allowances according to BBM 3, the ETS allowance auction ratio should be set at a minimum of 14%. This would ensure that the fuel switching cost for thermal power units remains below

500 USD/tCO_2, enabling thermal power plants to contemplate transitioning from coal to gas through the ETS.

Third, the ETS and gas feed-in tariff subsidies can serve as complementary policies to jointly encourage the fuel switching behavior of thermal power plants. Therefore, in scenarios where the ETS allowance auction ratio is low, it is essential to ensure that gas-fired units receive higher feed-in tariff subsidies. This guarantees that thermal power plants covered by the ETS can autonomously engage in fuel switching at a carbon price deemed reasonable.

Fourth, the government can select combinations of different allowance auction ratios and feed-in tariff subsidy standards within the 0–100 USD/tCO_2 range, as depicted in Fig. 10, based on real-world circumstances. This approach ensures that the ETS can assist thermal power plants in achieving short-term transitions from coal to gas at low carbon prices.

Additionally, the introduction of a carbon price stabilization mechanism can mitigate policy uncertainties and provide clear and stable pricing signals for enterprises subject to the ETS (Wood and Jotzo, 2011; Mo et al., 2023). In the initial stages of China's ETS, the government can establish a price corridor, particularly a carbon price floor, which guarantees the fuel switching behavior of thermal power plants based on various combinations of allowance auction ratios and feed-in tariff subsidy standards. This approach ensures that the ETS can employ the carbon price stabilization mechanism to facilitate the short-term transition of thermal power plants from coal to gas.

In summary, this article builds upon previous literature by refining the ETS allowance allocation method in the context of coal-to-gas behavior in coal-fired power plants. We also introduce a discussion on the ETS allowance auction ratio. Furthermore, to ensure the accuracy of switching prices, we incorporate dynamic forecasts of coal and gas prices into our analysis. Within this framework, we explore the collaborative effect of the ETS and gas feed-in tariff subsidies on the fuel switching behavior of thermal power plants.

However, it is important to emphasize that the transition from coal to gas is primarily a short-term and practical choice for power plants. As a result, our research primarily focuses on examining whether the carbon price, within the scope of the ETS, incentivizes power plants to choose gas-fired units over coal-fired units in the short term, rather than evaluating the long-term transformation from coal-fired to gas-fired plants. There is still room for improvement in this research. First, we can consider the influence of the ETS on the life cycle cost of power plants in addition to the short-term fuel switching model. This could involve incorporating capital, operational, and maintenance costs for both coal-fired and gas-fired generations, as well as the additional costs associated with facility modifications for fuel substitution. Second, we should acknowledge that the promotion of natural gas over coal by the ETS in China's thermal power plants could have far-reaching consequences. This could significantly affect the demand for coal and gas in China, leading to a widening price disparity between the two energy sources. Ultimately, this may further affect the feasibility of transitioning from coal to gas in thermal power plants in China. Moreover, building on the foundation of our paper, we could explore the rebound effect of the ETS on the coal-to-gas switching behavior of thermal power plants. Additionally, it would be valuable to conduct further research on the switching costs associated with transitioning from coal to renewable energy in thermal power plants covered by the ETS. Last, in addition to investigating the synergy between the ETS and gas feed-in tariff subsidies, we can also explore the collaborative effect of the ETS and the generation-right trading market on the fuel switching behavior of thermal power plants.

Competing Interests The authors declare that they have no competing interests.

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