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Efficiency vs. equity as China's national carbon market meets provincial electricity markets

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ABSTRACT

Emissions reduction in the electricity sector is critical in achieving China's carbon neutrality target. While a national carbon trading market that covers the electricity sector has been established, its effectiveness depends on how this sector evolves into being a more integrated market. This study evaluated the impact of China's electricity market integration on the cost-effectiveness of carbon pricing. An integrated (regional electricity market) and a segmented (provincial electricity market) market scenario were used to identify possible reform paths going forward. Using high-frequency datasets of the five southern provinces in 2018, we assessed the impact of electricity market integration on the abatement potential and cost-effectiveness of carbon pricing. We found that carbon prices need to be as high as 200 yuan/ton to begin achieving overall carbon reduction. In this context, the regional market is more cost-effective in reducing emissions than the provincial one, as the abatement costs are saved by around 60% compared to the latter under the same emission reduction targets. However, the regional market may also raise potential equity issues. The provincial-level distribution of carbon emission reductions, as well as the withdrawal of coal power, are more concentrated in the regional market than in the provincial one, which indicates an inequitable social-economic-environmental impacts of market integration. Our research findings would help to improve policymakers' understanding of the interaction between carbon pricing and electricity market reforms. This would then assist them in coordinating an effective design of both the carbon and electricity markets, in addition to supporting China's carbon neutrality target.

1. Introduction

As the world's current largest carbon emitter, China has announced its goal of achieving a carbon emission peak before 2030 and then carbon neutrality by 2060. To help in these endeavors, a national carbon trading market was launched in 2021. This market covers >2000 thermal generators that are responsible for about half of China's carbon emissions, as well as about 10–14% of the world's total.

Carbon pricing is expected to encourage fuel switching within the electricity sector and, thus, reduce overall carbon emission; however, its effectiveness depends crucially on the existence of a well-functioning electricity market in order to pass through the carbon costs and to achieve equalized marginal abatement costs across both generators and regions. However, China's electricity sector

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had long been structured as a planning system, in which both the price and production were organized by the government and not determined by the merit order of generation costs. Even though China's electricity sector has experienced several rounds of restructurings and reforms since 1985 (Pollitt, Yang, & Chen, 2017; Wang & Chen, 2012), a market-based resource allocation system is still in progress. Up to the end of 2020, the share of market-based electricity generation only accounted for 42% of the total generation.

The progress and characteristics of these electricity sector reforms will interact with and impact the effectiveness of the carbon market. One notable feature of China's electricity market reform is its provincial segmentation. Until now >80% of electricity trade was transacted within the provincial markets, and cross-provincial electricity trading were limited and administratively implemented.

This market segmentation not only affects the efficiency of the electricity sector, but also weakens that of carbon pricing by restricting generation substitution across various provinces. While integrating electricity markets would help to improve the effectiveness of carbon pricing, it could also have certain distributional impacts across provinces, thereby raising equity concerns. As such, these impacts need to be quantitatively evaluated to improve both academic and policy understanding of the interaction between the electricity and carbon markets.

In this study, we adopted scenario simulations and the partial equilibrium model to evaluate and compare the effectiveness of carbon pricing on emission reduction efforts, as well as the distributional impacts between a regional versus a provincial electricity market scenario. Through using the unique high-frequency datasets of the five provinces in China Southern Electricity Grid in 2018, we simulated the emission reductions and abatement costs caused by the carbon pricing of the electricity sector under different scenarios, and then discuss the potential equity issues that may then arise.

This study's results can be summarized as follows. First, the carbon market cannot achieve any carbon emission until the carbon price increases to 200 yuan/ton in the regional electricity market scenario and 400 yuan/ton in the provincial market scenario, respectively, which is far higher than the current price. Second, the regional market is much more cost-effective in reducing carbon emissions compared with the provincial market. Given the same emission reduction targets, the abatement costs are reduced by around 60% more in the regional market than in the provincial market. This is because market integration amplifies the substitution effect of carbon pricing by allowing for the cross-provincial replacement of high-emission-efficiency units for low-emission-efficiency ones. Finally, the regional market also raises potential equity issues as electricity production and carbon emissions are then redistributed across various provinces. Compared with the provincial market scenario, emission reductions are more concentrated in Yunnan and Guizhou provinces within a regional market model. It is accompanied with the massive withdrawal of coal power in these provinces, which then indicates the occurrence of an inequitable impact of market integration on the electricity industry and economic development in each province.

Our study aimed to make two contributions to the existing literature and policy debates. First, we perform a detailed *ex ante* assessment of the potential impacts of China's newly launched carbon market on both its carbon reduction and electricity sectors, including its electricity generation structure, inter-provincial trading, and the resulting distributional impacts across provinces. Because the carbon market only covers the electricity sector, we analyzed how electricity market reforms and carbon market pricing interact with one another. Our results then illustrate how the electricity market's design affects the abatement potential and cost-effectiveness of carbon pricing.

Although there are many studies that have investigated the design and impact of carbon pricing in Europe and the US, there have been relatively few that have focused on China's carbon market specifically. In the Chinese context specifically, the studies by Cui, Zhang, and Zheng (2018) and Cao, Ho, Ma, and Teng (2021) both conducted an *ex post* evaluation of the effectiveness of China's pilot carbon trading programs across seven provinces. Among the few studies that have conducted an *ex ante* impact analysis of the national carbon market's potential effects, most have adopted the Computable General Equilibrium model, which assumes all industries are involved in the carbon market, with them then examining the relative impacts from the perspectives of different sectors, regions, and households (Cao et al., 2021; Fan, Wu, Xia, & Liu, 2016; Huang, Shen, & Liu, 2019).

In contrast with these prior studies, we adopted the partial equilibrium model as it provides a detailed depiction of the electricity sector characteristics as well as the unique features of China's carbon market using the high-frequency electricity load, production, and trade data. The use of this model would then help to improve the accuracy of assessments on the potential effects of carbon reduction and their overall cost-effectiveness. In addition, the scenario simulation considers electricity sector reform progress, as well as possible future directions. The results would then help improve policy makers' understanding of the interactions between the electricity and carbon markets, which would then allow them to coordinate the design of these two markets to help achieve China's carbon neutrality target.

Second, by simulating the heterogeneous impacts of carbon pricing on emissions across different provinces, we also addressed the CO_2 emission efficiency-equity trade-off between different electricity market reform designs. China is characterized by its diversity of resource endowments, electricity generation sources (and their associated carbon emission), and economic development by virtue of its large territory. Hence, a national carbon market can only achieve cost-effectiveness if it is able to equalize the resulting marginal abatement costs across regions, which would then require an integrated electricity market that encourages fuel-switching within a larger market through cross-province electricity trading and decreased carbon leakage across provinces. However, an equity-efficiency trade-off arises when provincial markets are integrated. Some provinces may be concerned with the negative economic and environmental impacts of these reforms. In this context, a quantitative assessment of these distributional impacts is a prerequisite in the formation of policy measures that are aimed at easing these concerns.

The rest of this paper is structured as follows. Section 2 analyzes the links between the carbon and electricity markets. Section 3 then introduces the scenarios and simulation methods used in this study and summarizes its datasets. Section 4 presents the simulation results of the carbon emission conditions at different carbon prices in different scenarios, as well as discussing the efficiency and equity of emission reduction. Section 5 then concludes this paper.

2. The interactions between the electricity and carbon markets

In theory, the effect of carbon pricing in the electricity sector occurs through the merit order effect as this then encourages stakeholders to engage in fuel switching from high to low emission intensity, which then reduces the overall carbon emission rate. By equalizing the marginal abatement costs among generators across various regions, the cost-effectiveness could be achieved. However, the actual effectiveness depends on the interactions between the carbon market and the electricity market. Specifically, the carbon market's features, the electricity marketization reform, and the electricity supply profile would affect the potential effectiveness of carbon pricing strategies. Below, we analytically outline when and how carbon pricing works in the electricity sector, and then analyze the impact of electricity market integration on the effectiveness of carbon pricing.

2.1. Background on China's carbon market and electricity sector

China's carbon market has several important features that can affect its effectiveness. First, it is a national market as it allows trading of emissions allowances across regions. Second, it has adopted a tradable performance standard for its allowance allocation, which is different from the EU and US carbon markets. It is a rate-based instrument and does not have a predetermined absolute cap on the total number of emissions allowances. The number of emissions allowances granted to a given electricity plant is the product of the benchmark emission intensity assigned to the plant and the plant's level of output in that period. Third, four benchmarks are then applied to different technology categories, namely coal-fired units with a capacity of 300 MW and below, coal-fired units with a capacity of >300 MW, gas-fired units, and other unconventional coal-fired units. Within each category, units with a carbon intensity below their benchmark will benefit from the sale of excess allowances, and tend to be allocated more output as carbon prices increase. As Fischer (2001), Fischer and Newell (2008) and Goulder, Long, Lu, and Morgenstern (2019) pointed out, a rate-based carbon market is less effective than a cap-based market given the same reduction target since it implicitly subsidizes the output. But it can have less impact on electricity output and price increase, thus has an attraction of fairness and political feasibility.

The progress of electricity sector reform and the interaction between electricity market and carbon market also affects the effectiveness of carbon pricing. A necessary condition for carbon pricing to be able to reduce generators' overall carbon emissions is that electricity plants need to sufficiently respond to changes in it. Before adopting the electricity marketization reform, China implemented a benchmark on-grid tariff in the electricity sector; that is, the same electricity generation technology would receive the same on-grid tariff as set by the government, resulting in no responses from these plants to changes in carbon prices. Therefore, in the absence of a market system that then reflects carbon costs, it is then difficult for carbon pricing to affect the generation structure, as well as to reduce the carbon emissions, of the electricity sector.

In 2015, China inaugurated a new reform with the goal of increasing the market-based allocation mechanism's role in both the electricity generation and retail segments, as well as to improve the regulation of distribution and transmission. This reform has, so far, helped the nation progress towards its marketization goal. The share of market-based electricity transactions within the total electricity consumption rate has increased from 13% in 2015 to 42% in 2020 (Fig. 1). However, this process is still far from being able to establish an efficient market due to both the common reform obstacles faced within international settings and the unique obstacles faced within China's institutional context. Based on this, several papers have provided a comprehensive review on this process and its potential pitfalls (Davidson & Pérez-Arriaga, 2020; Lin, Kahrl, Yuan, Chen, & Liu, 2019; Lin, Kahrl, Yuan, Liu, & Zhang, 2019).

2.2. Merit order effect of carbon pricing in the electricity market and the related abatement costs

2.2.1. Carbon pricing and carbon reduction

In a perfectly competitive electricity market— which is the goal of China's electricity sector reform— wholesale markets determine

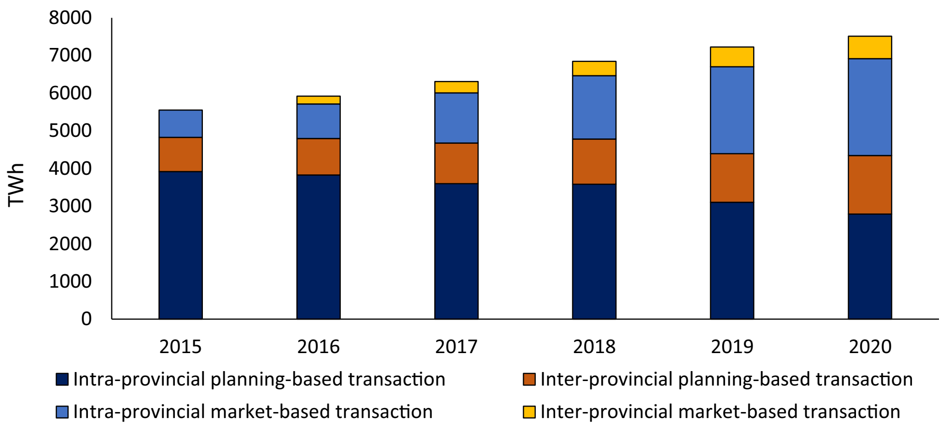

Fig. 1. China's electricity transaction from 2015 to 2020.
Note: Data are collected from the "Power Exchange Annual Report" published by the State Grid Corporation of China.

the electricity price according to demand and supply bids (i.e., the “merit order curve”), wherein the latter is determined by the marginal costs of available electricity plants. Carbon pricing then affects the merit order of this supply curve by increasing the marginal costs of fossil-fuel electricity plants, inducing substitution among different emission-intensity generation, as well as promoting carbon reduction.

Consequently, the magnitude of this substitution effect depends on the current supply profile in the market. Intuitively speaking, if carbon pricing only induces the switch among the coal-electricity plants, it would then only induce a small degree of emissions reductions overall. As shown in Fig. 2, for Yunnan, because its installed capacity is only composed of coal power and hydropower, introducing carbon pricing might have minor effects on its adoption of the merit order if the substitution is constrained within in the province. For Guangdong, wherein the supply curve is composed of gas and coal power, a moderate carbon price would then encourage certain gas plants to shift their positions within their coal plants to be based more on the merit order, thereby reducing their overall carbon emissions. At higher carbon prices, carbon emissions will decrease significantly as a larger amount of coal is then substituted by gas.

2.2.2. Carbon abatement costs

Carbon pricing can influence the merit order so that it then switches plants' output from coal power to the more expensive gas power, production costs (e.g., generation and transmission costs) then increase as carbon prices increase. In addition, carbon pricing imposes additional allowance costs on electricity plants that are then passed onto consumers through biddings within the electricity market. Therefore, these abatement costs are measurable as increases in the production and allowance costs following the transition from a no-carbon pricing system to one that requires a carbon price for a given reduction target.

2.3. Electricity market integration and its impact on carbon pricing effectiveness

Regulatory fragmentation across provinces has been another longstanding feature of China's electricity system (Qi, Dong, Dong, & Huang, 2019). Due to the nation's extensive history of electricity shortages, China's electricity supply and demand system was first balanced within each province. Provinces have traditionally been reluctant to increase their imports from other regions unless they are facing a specific shortage in order to protect their local generators. This is also related to the longstanding occurrence of inter-provincial barriers arising from local protectionism in China's provincial market (Naughton, 2003; Poncet, 2003; Wei & Zheng, 2017; Young, 2000; Zhou, 2004).

A key step for China's electricity market reform is to achieve market integration among different provinces. Drawing lessons from the failure of the 2002 reform, a strategy of this round of reform is to start its implementation from provincial markets to incentivize local governments so that the reform can gain momentum. Provincial governments are responsible for market reform, while the central

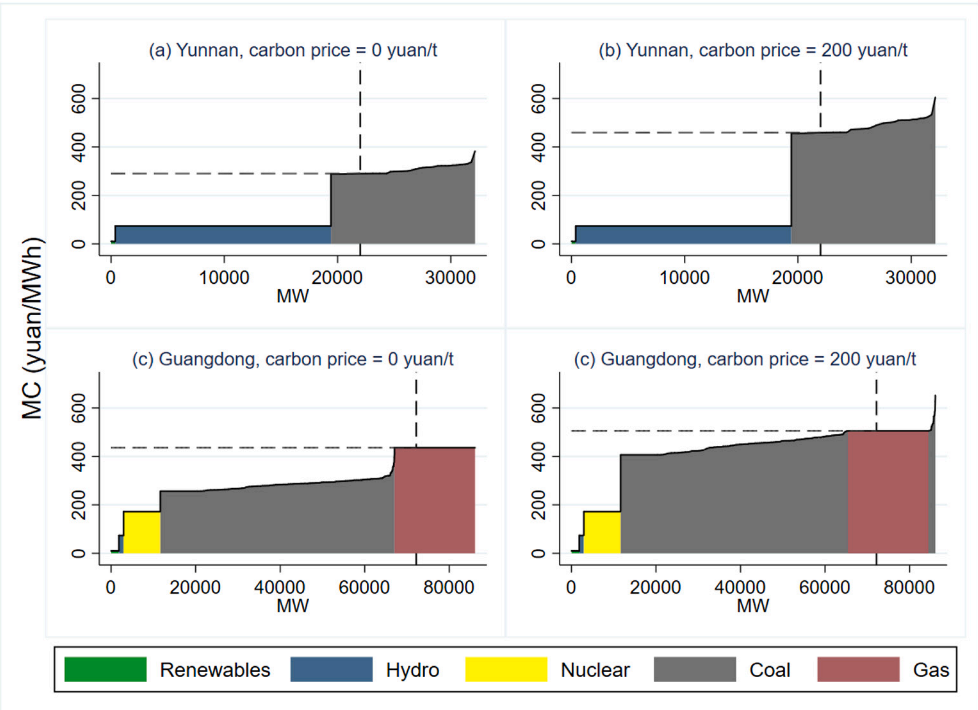

Fig. 2. An illustrative example of the merit order effects of different carbon prices: Yunnan and Guangdong.
Note: The vertical and horizontal dashed lines represent the demand curve and market clearing prices, respectively.

government only serves to provide general guidelines (Pollitt et al., 2017; Zhang, Andrews-Speed, & Li, 2018). This can then lead to a significant amount of diversity in the nation's market designs, as well as increased difficulties in market integration (Chen, Cui, Song, & Jiang, 2022; Davidson & Pérez-Arriaga, 2020).

Electricity market integration would serve to rearrange the merit order of plants by eliminating inter-provincial trade barriers, thereby improving the effectiveness of carbon pricing (Fig. 3).

2.3.1. Impact on carbon emission and the associated cost

Market integration facilitates the substitution of high-emission-efficiency plants for low-emission-efficiency ones through the introduction of inter-provincial electricity trade; in sum, it amplifies the substitution effect of carbon pricing and reduces the overall abatement costs. Given the assumption of a perfectly competitive market, the allowance cost is internalized into the electricity market by the carbon price, then the market is cleared by minimizing the social costs. And market integration will always reduce social costs by allowing inter-provincial substitution of power plants, thereby reducing the overall abatement costs.

Fig. 3 visually depicts the impact of market integration on abatement costs. Fig. 3(a) and 3(c) show production costs for provincial and regional market without carbon pricing, respectively. With the introduction of carbon pricing, the cost of allowances will be passed on to the electricity market and increase the competitiveness of gas-fired units to replace coal-fired units. Fig. 3(b) and 3(d) show the total costs (production costs plus allowance costs) for provincial and regional market with carbon pricing, respectively. Comparing Fig. 3(a) and 3(b), 3(c) and 3(d), the vertical shaded areas in Fig. 3(b) and 3(d) are the abatement costs under the two market scenarios. And the difference between the vertical shaded areas of Fig. 3(b) and 3(d) represents the savings in abatement costs due to market integration. What's more, the abatement cost savings depend on how much the market integration can amplify the inter-provincial substitution effect of carbon pricing, which, itself, depends on the electricity supply profile of the study area.

2.3.2. Equity concern

When market integration reallocates electricity production across provinces, carbon emissions are also redistributed across them. When electricity flows from provinces with high to those with low emission efficiency, carbon emissions then begin to flow in the opposite direction. As a result, greater amounts of carbon emissions are reallocated to provinces that possess a higher carbon emission efficiency. However, this increasingly concentrated distribution of carbon emission reductions in the regional market could then also increase regional equity concerns. Therefore, to assess the impact of electricity market integration on the abatement potential and cost-effectiveness of carbon pricing, we simulated and compared the emission reductions and abatement costs between the two market scenarios, following which we discussed the potential equity issues.

3. Data description and impact simulation model

In this section, we first introduced the study area and data. Then we described a partial market equilibrium model used to simulate the responses of electricity sector (including the generation, inter-provincial trade and associated carbon emission and costs) to the changing carbon price determined by the national market. Further, we discuss the differences in model settings between the segmented electricity market and the integrated electricity market.

3.1. Study area and data description

Our study area included the five provinces in the China Southern Electricity Grid territory in 2018; namely, Guangdong, Guangxi, Yunnan, Guizhou, and Hainan. Our detailed high-frequency datasets on the electricity sector in these five provinces are comprised of: (1) hourly electricity consumption, renewable energy generation, capacity utilization rates, and inter-provincial contracts in 2018 collected from the South China Energy Regulatory Office of the National Energy Administration; (2) installed capacity, energy consumption, and carbon emission intensity of coal-fired generators at the unit level, as well as of gas-fired generators at the provincial level, in addition to inter-provincial transmission capacities and technical loss rates as collected from Southern Electricity Grid's 2018 Dispatch Annual Report; (3) benchmark on-grid electricity tariffs and coal and gas prices in the electricity sector collected from the National Development and Reform Commission; and (4) the marginal costs of generation calculated using the price of fuel. Prices, costs, and other technical parameters are reported in this paper's appendix.

Fig. 4 shows the actual supply profile for each province, as well as the inter-provincial trade in 2018. There exist sizable cross-province differences, because the technology mix of production capacities and ensuing fuel and generation mixes vary across provinces. Specifically, as the largest electricity consumer and carbon emitter in the Southern Power Grid, Guangdong's local power generation structure is mainly composed of thermal power. Among them, gas-fired power generation with the highest carbon emission efficiency accounts for 10.5%. Within coal-fired power generation, units with an installed capacity of 1000 MW and 600 MW account for 17.0% and 24.9% respectively, and units with an installed capacity 300 MW and below account for 22.9%. On the contrary, in Yunnan, which has the second largest power generation, the main power source is the non-emitting hydropower, accounting for as high as 74.7%. The power generation structures in Guangxi and Guizhou are relatively similar. The dominant power source in these two provinces is hydropower, followed by coal-fired power with an installed capacity of 600 MW. Hainan has the least power generation, mainly contributed by coal-fired units with an installed capacity of 300 MW. The large differences in supply profiles across provinces mean that the effects of carbon pricing on them will also vary widely. Supported by unit-level data, we can characterize the inter-provincial differences and evaluate the province-level distribution of carbon pricing impacts.

Fig. 5 depicts the hourly electricity consumption, the hydroelectricity, and other renewable electricity generation at the regional/

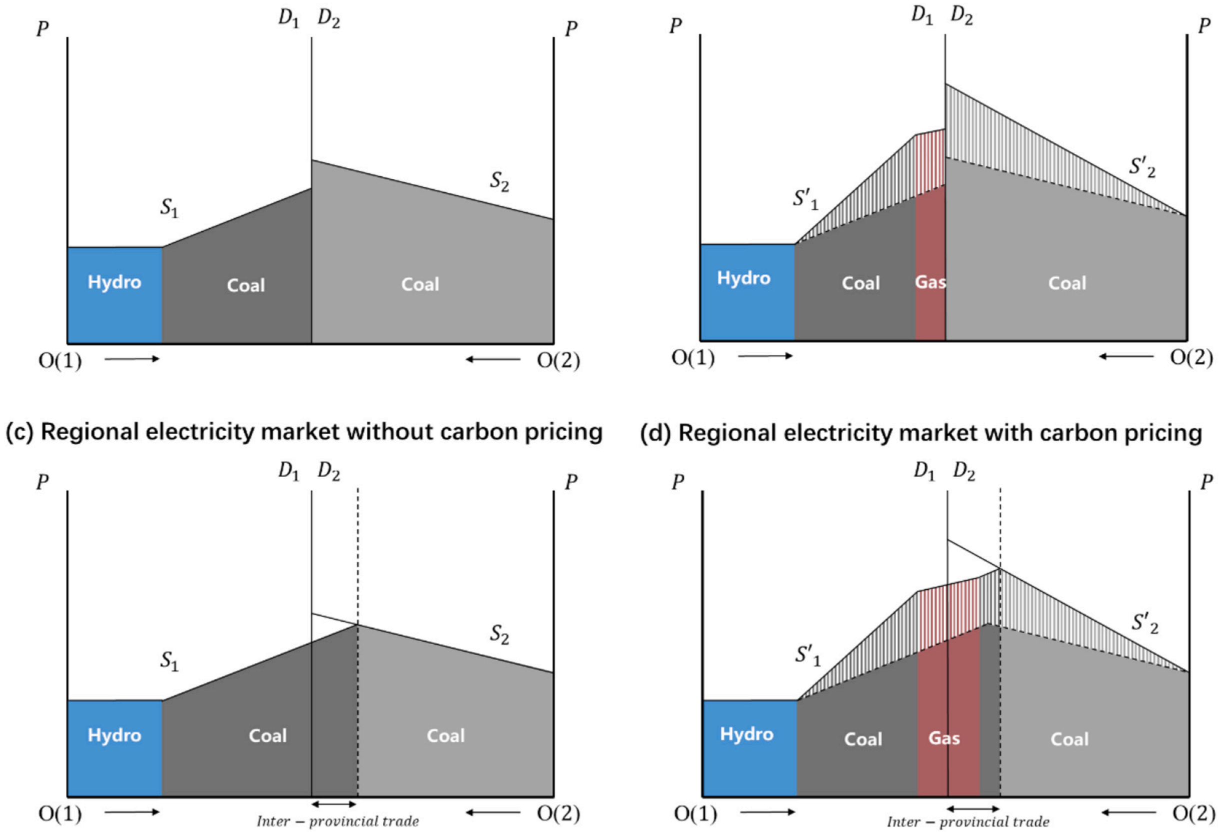

Fig. 3. The impact of market integration on abatement costs.
Note: The supply curve S_1 for Province 1 is composed of high-emission-efficiency coal and gas power and the supply curve S_2 for Province 2 is composed of low-emission-efficiency coal power. Without carbon pricing, the high marginal cost of gas-fired units results in no generation from market competition. Carbon pricing will shorten the cost gap between gas-fired units and coal-fired units, and promote the substitution of gas-fired units for coal-fired units. The vertical shaded areas in Fig. 3(b) and 3(d) represent the abatement costs compared to Fig. 3(a) and 3(c).

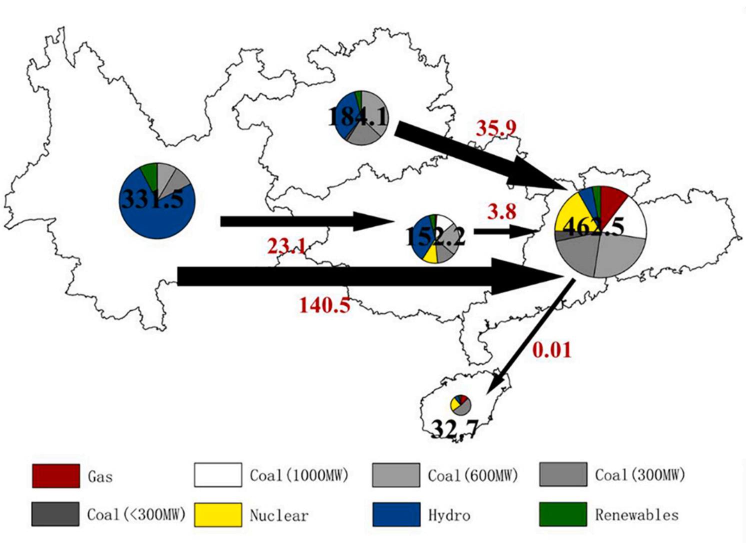

Fig. 4. Actual power generation and trade in 2018.
Notes: All numbers are in TWh.

aggregate level. The electricity demand exhibits obvious seasonality and strong short-term fluctuations, while hydroelectricity and other renewable energy sources are significantly periodic and intermittent. It reflects the advantages of the high-frequency data used in this paper; that is, it allowed us to control for the short-term fluctuations in the simulation analysis to improve the accuracy of our results.

3.2. Simulation method

This subsection lays out the partial market equilibrium model used to simulate the electricity market equilibrium and assess the impact of carbon pricing. The research framework is shown in Fig. 6. Assuming perfectly competitive condition prevails in both electricity market and national carbon market, the generators are price-takers.[1] In the competitive electricity market, the market equilibrium can be obtained through solving a cost minimization problem, of which the total costs consist of generation costs, transmission costs and allowance costs.[2] Given the demand, supply profile, and physical constraints, we can simulate the generation mix structure, the inter-provincial trade, carbon emissions and the associated costs for any given carbon price or emission reduction target. Based on these results, we can perform efficiency and equity analyses.

Based on the reform status and future direction of China's electricity sector, we define two scenarios, a segmented provincial market and an integrated regional market. Both market scenarios are based on the same cost-minimizing function, including generation cost, transmission cost, and allowance cost, but the difference is whether inter-provincial electricity trade is exogenous or market-determined. In the provincial market scenario, inter-provincial trade is predetermined by governmental contracts and is exogenous to the provincial market. This scenario is closer to the current stage of China's electricity market reform. Technology-specific marginal costs and installed generation capacities define the supply curve for domestically produced electricity in each province. Since inter-provincial trade is exogenous to the market, the inter-provincial transmission cost is also fixed and not affected by electricity market and carbon pricing. In contrast, in the regional market scenario, inter-provincial trade is determined by the market, and the generation capacity and demand are pooled together to form the aggregate supply curve and demand curve at the regional level. Since inter-provincial trade is market determined, the transmission cost is also affected by electricity market and varies with carbon prices.

The specific cost minimization model and related physical constraints are as follows, and the definitions of the parameters and variables in the model are shown in Table 1:

$$\begin{aligned} min\ Cost = & \underbrace{\sum_{t=1}^{8760}\sum_{i}\sum_{g}GEN_{t,i,g}MC_{i,g}}_{Generation\ cost} + \underbrace{\sum_{t=1}^{8760}\sum_{i}\sum_{j}TRA_{t,i,j}TC_{i,j}}_{Transmission\ cost} \\ & \underbrace{+CP\sum_{t=1}^{8760}\sum_{i}\sum_{g}GEN_{t,i,g}\left(EI_{i,g}-\overline{EI}_{g}\right)}_{Allowance\ cost} \end{aligned} \tag{2a}$$

$$\mathbf{s.t.}\sum_{g}GEN_{t,i,g}+\sum_{j}\left[TRA_{t,j,i}\left(1-line_{j,i}\right)-TRA_{t,i,j}\right]=D_{t,i} \tag{2b}$$

$$0 \le GEN_{t,i,g} \le \left(1-loss_{i,g}\right)CAP_{i,g}\ g\epsilon\{coal,gas,nuclear\} \tag{2c}$$

$$0 \le GEN_{t,i,g} \le CAP_{i,g}CF_{t,i,g}\ g\epsilon\{hydro,wind,solar\} \tag{2d}$$

$$0 \le TRA_{t,i,j} \le TL_{i,j} \tag{2e}$$

The objective function is the cost eq. (2a) which consists of electricity generation costs, transmission costs, and carbon allowance costs. The carbon market affects the equilibrium in the electricity market through the carbon price (CP) and the intensity benchmarks for allocating allowances ($\overline{EI}_g$).

Eqs. (2b) to (2e) represent the specific constraints in the electricity sector:

3.2.1. Real-time supply and demand balance (2b)

In each province, the hourly total electricity generation plus the hourly net imports, after deducting line losses, should meet the hourly demand.

3.2.2. Electricity generation capacity constraints (2c) and (2d)

Equation (2c) represents the electricity generation capacity constraint of the stable electricity supply, wherein the generation

[1] Since our study area is confined to the Southern grid provinces, referring to data from the IEA (https://www.iea.org/data-and-statistics/), in 2018, the power sector in this region emitted about 10.4% of the national electricity sector's CO_2. This relatively small share supports our assumption that the carbon price in the national carbon market is exogenous to the regional electricity market.

[2] Since we focus on short-term partial equilibrium within the electricity sector, hourly demand curve can be assumed to be completely inelastic and met by the supply curve. Then according to the fundamental theorems of welfare economics (Lange, 1942), the welfare maximization problem of social planners can be reducible to the cost minimization problem of the electricity sector.

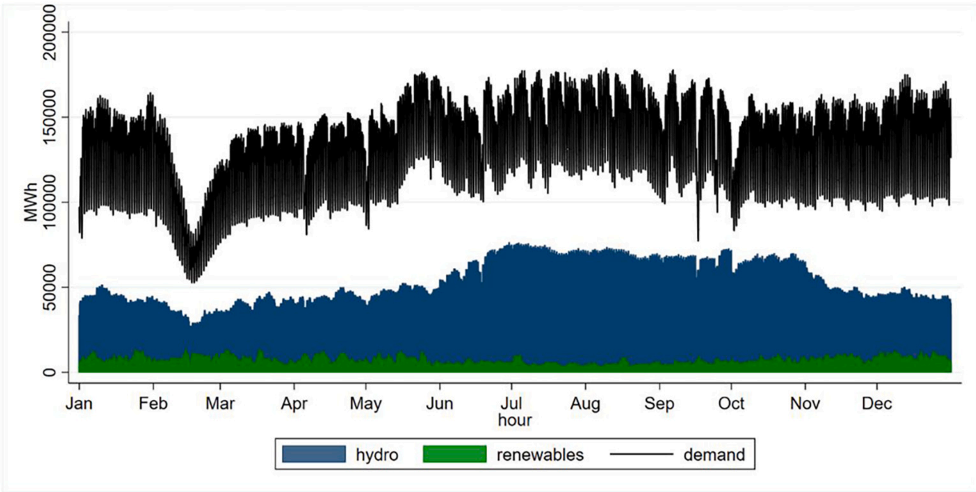

Fig. 5. Hourly electricity demand and the generation of hydroelectricity and other renewable energy sources at the regional level.

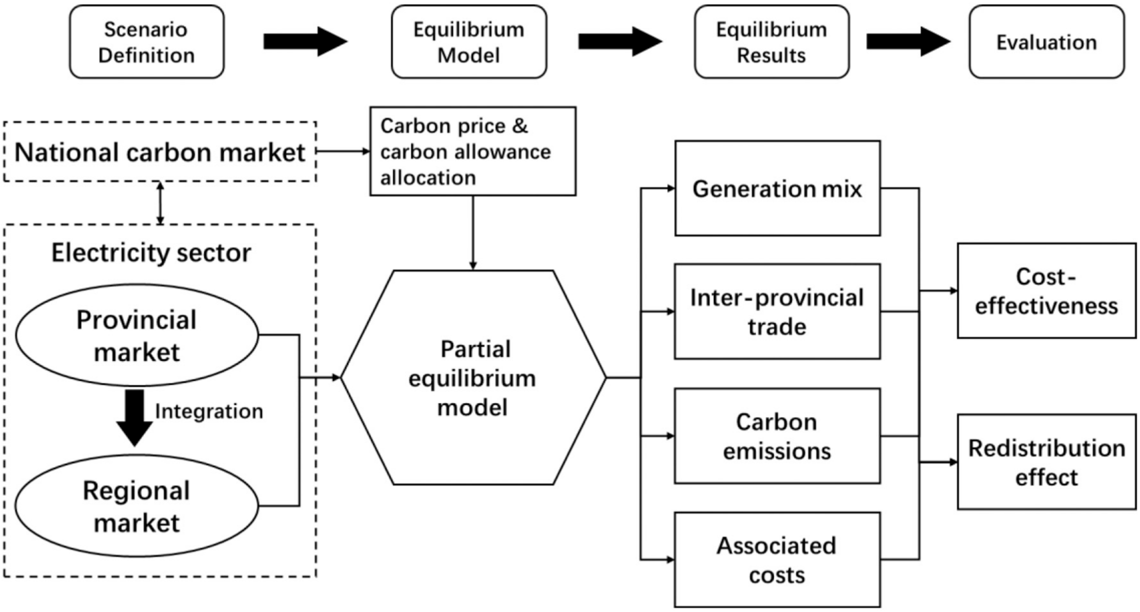

Fig. 6. Research framework.

capacity should not exceed the installed capacity after deducting for technical losses. Equation (2*d*) represents the electricity generation capacity constraints of variable electricity generation, including that within hydroelectricity, wind, and solar systems. Further, $CF_{t,\ i,\ g}$ is the capacity factor that represents the time-varying capacity utilization rate and is used to measure the intermittent and periodicity of variable electricity generation.

3.2.3. Inter-provincial flow constraints (2e)

The hourly trade flow between two provinces should not exceed their transmission capacity.

4. Results and discussion

We first examined the effects of carbon pricing on carbon emissions reduction, as well as the induced costs increase between the two scenarios, at the regional level during which the cost-effectiveness of the two scenarios is compared. Then, we analyzed the distributional impact at the provincial level to examine why the equity issue is a matter of concern.

Table 1
The definitions of parameters and variables.

Indices and parameters	Definitions
Subscripts:	
t	Hour in 2018, t ∈ [1,8760]
i	Province, i ∈ {Guangdong, Guangxi, Yunnan, Guizhou, Hainan}
g	Unit index, including coal-fired, gas-fired, nuclear, hydro, wind, and solar power, where coal-fired power will be subdivided into each unit
Decision variables:	
$GEN_{t,\ i,\ g}$	Power generation of unit g at time t
$TRA_{t,\ i,\ j}$	Power transmission from province i to j at time t
Parameters:	
$MC_{i,\ g}$	Marginal generation cost of unit g in province i
$TC_{i,\ j}$	Unit transmission cost from province i to j
CP	Carbon price in the national carbon market
$EI_{i,\ g}$	Carbon emission intensity of unit g in province i
$\overline{EI}_g$	Benchmark emission intensity used for the allocation of carbon allowances to thermal unit g in the national carbon market
$D_{t,\ i}$	Power demand of province i at time t
$line_{j,\ i}$	Transmission line loss rate from province i to j
$CAP_{i,\ g}$	Generation capacity of unit g in province i
$loss_{i,\ g}$	Generation loss rate for coal-fired, gas-fired and nuclear power, including maintenance rate and self-consumption rate
$CF_{t,\ i,\ g}$	The capacity factor for hydro, wind, and solar power
$TL_{i,\ j}$	Transmission capacity limit from province i to j

Note: In China's national carbon market, regulators set four benchmarks in the electricity sector for allocating allowances. These benchmarks are then applied to four technology categories, namely coal-fired units with a capacity of 300 MW and below, coal-fired units with a capacity of >300 MW, gas-fired units, and other unconventional coal-fired units. In the provincial market scenario, inter-provincial trade is predetermined by governmental contracts, and $TRA_{t,\ i,\ j}$ is exogenous to the cost minimization model. In the regional market scenario, inter-provincial trade is determined by the market, and $TRA_{t,\ i,\ j}$ is the decision variable in the model.

4.1. Comparing the differential effects on CO_2 emissions reduction of the two market scenarios

Fig. 7 depicts the regional-level emission reductions in the electricity sector as achieved by the two market reform scenarios at differing carbon prices. The first notable result is that changes in the carbon emission abatement are nonlinear when compared to the carbon price in both market scenarios (e.g., it is almost completely non-responsive at the low-price range and is only responsive at a higher price range).

Specifically, within the provincial market, the level of emissions does not change when the carbon price is below 100 yuan/ton, with it only slightly increasing when the price falls between 100 and 400 yuan/ton. Furthermore, carbon emission abatement is only effective when the price of carbon is above 400 yuan/ton. These novel findings are a result of the unique feature of China's carbon

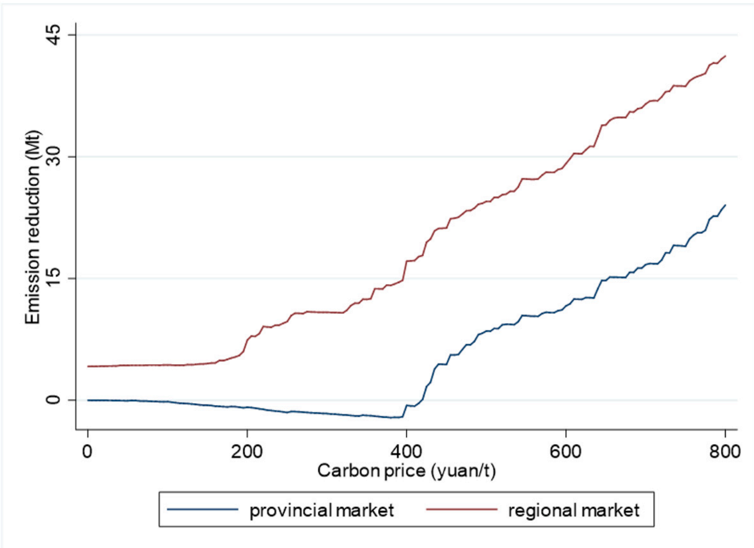

Fig. 7. Carbon emission reduction levels across the two market scenarios.
Note: The carbon emission reductions in this Figure were calculated by comparing emission levels within the provincial market without carbon pricing.

market in terms of its rate-based allocation of allowances, under which lower carbon prices within the provincial market only result in an output switch among similar coal power technologies within the same province. Although the low-emission-efficiency units are more polluting, they can benefit from rate-based carbon allowances and get more production due to the weak carbon intensity benchmark used for them, which is greater than their carbon emission intensity, thereby reducing the total costs but increasing their emissions. And across technology categories, high-capacity, high-emission-efficiency units face a stricter benchmark than low-capacity, low-mission-efficiency units, Carbon emissions may increase at low carbon price levels due to increased production of low-mission-efficiency units.

Fig. 8 reports the power generation structure at different carbon price levels, revealing the reason for the changes in carbon emissions. In the provincial market, when the carbon price rises from 0 yuan/ton to 100 yuan/ton, the power generation structure does not change much, resulting in almost no emission reduction. However, when the carbon price increases from 100 yuan/ton to 400 yuan/ton, the share of gas power generation then increased from 1.14% to 1.63%, while that of coal power generation with an installed capacity of less than or equal to 300 MW (which is relatively more carbon intensive) increased from 12.52% to 18.33%, with the share of coal power generation with an installed capacity of >300 MW then dropping from 38.26% to 31.97%, resulting the increase in carbon emissions.

This observable output mismatch among coal plants is due to the different intensity standards in the allocation of emission allowances to coal plants of different capacities. In our sample, for 94% of the total capacity of coal-fired power generators, the carbon emission intensity is lower than the carbon intensity benchmark for carbon allocation (i.e. $EI_{i,g} < \overline{EI}_g$), among them, the low-emission-efficiency units with installed capacity less than or equal to 300 MW account for a 39.0% share. This suggests that as the carbon price increases from 100 yuan/ton to 400 yuan/ton, these low-emission-efficiency units will benefit from carbon allowances and produce more, reducing the total cost of the power sector but increasing emissions.

However, when the carbon price increases from 400 yuan/ton to 800 yuan/ton, the shares of gas power generation then rapidly increase from 1.63% to 9.59%, indicating that only the occurrence of a high carbon price level within the provincial market has a substitution effect and then promotes the output switching between gas and coal plants within the province.

In the regional market, we found that there is a more sensitive nonlinear response of emission reductions to carbon prices. At low carbon prices (i.e., those <200 yuan/ton), carbon emissions respond relatively weakly to changes in carbon prices at around 0.84%–

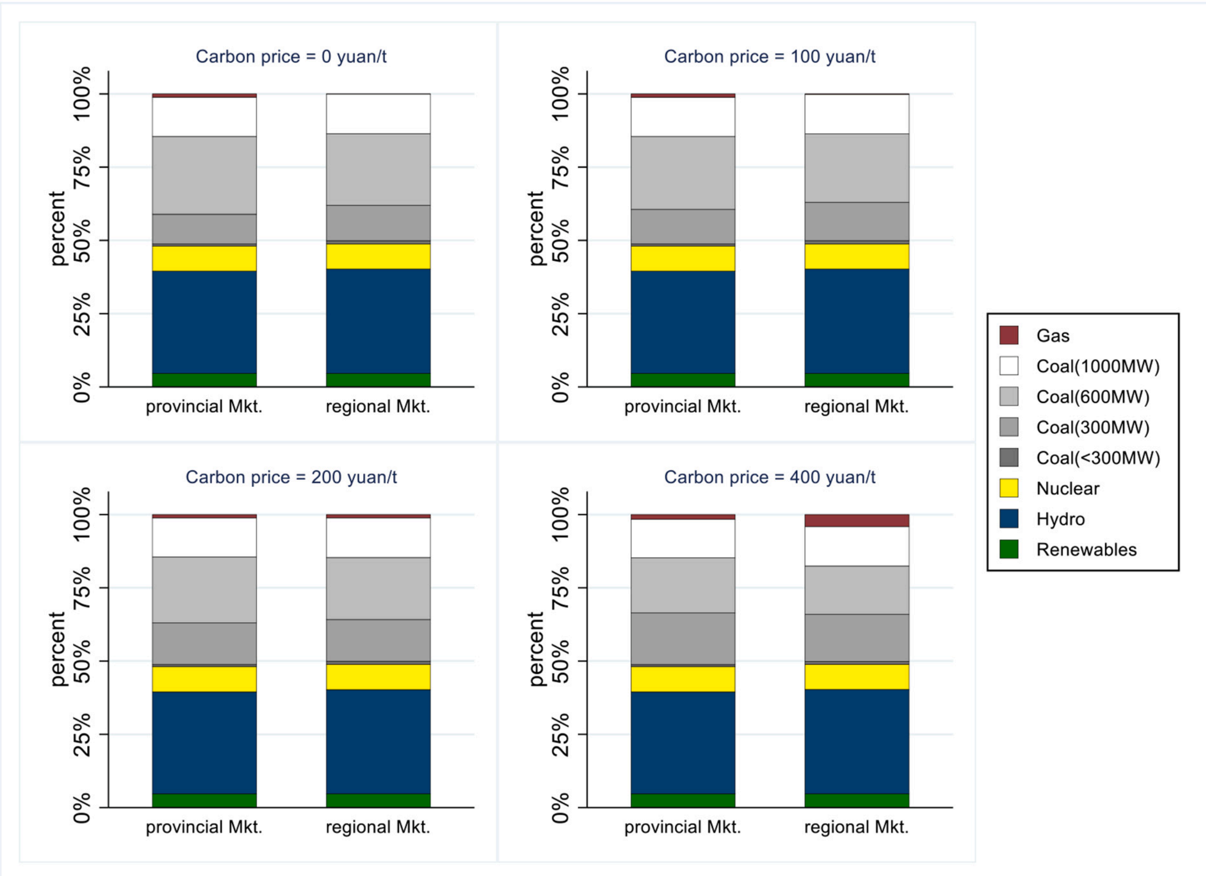

Fig. 8. Regional supply structure across the different market scenarios.
Note: Coal power units are divided into four groups based on their installed capacity.

1.49% less than emissions within the provincial market. This emission reduction is primarily due to increases in the shares of hydroelectricity generation. As shown in Fig. 8, when moving from the provincial to the regional market, there are relatively few changes in the thermal electricity generation structure; however, the shares of hydroelectricity generation would then increase from 34.82% to 35.53% due to them being dispatched across a larger region, with them then replacing 1.52% of thermal electricity generation.

Additionally, when the carbon price increases to above 200 yuan/ton, the total carbon emission reductions within the regional market respond significantly to the overall carbon price. Because the integration of the electricity market allows for the replacement of coal power with gas power across provinces, the shares in gas power generation within the regional market then respond more quickly to increases in carbon prices than they do in the provincial market, resulting in a more sensitive response curve. Furthermore, at a carbon price of 400 yuan/ton, the share of gas power generation then increases to 4.12% in the regional market, which is higher than the 1.63% observed within the provincial market, with the carbon emissions then being reduced by a further 12.97 million tons (2.61%), which confirms that electricity market integration amplifies the substitution effect of carbon pricing strategies.

4.2. The cost-effectiveness of carbon pricing between the two market scenarios

We have thus far analyzed the abatement effects of carbon pricing across two different electricity markets. Next, we assessed how much it would cost in total to reduce carbon emissions and to identify which market design is more efficient in reducing the overall emissions. As carbon pricing changes the overall merit order and imposes additional allowance costs that would be passed on to consumers through the electricity plant's bidding, we measured the abatement costs using increases in production and allowance costs. Given the same carbon reduction target, the required carbon price and the abatement costs for each market design are provided in Fig. 9.

As shown in Fig. 9, under the same emission reduction target, both the required carbon price and abatement costs are lower in the regional market than in the provincial, which indicates that the former is more cost-effective in reducing emissions. For example, when taking into consideration the total carbon reduction target of 1.0%, (which is close to the annual total carbon emission reduction target required by China's 14th Five-Year Plan[3]), the carbon price needs to be as high as 455 yuan/ton and 190 yuan/ton in the provincial and regional markets, respectively. Additionally, the abatement costs in these two scenarios would need to be 11.76 billion yuan and 1.32 billion yuan, respectively. Among these two scenarios, the allowance costs would account for 62.6% and 70.2% of the total, with the remainder of expenses being generation and transmission costs. On average, across all the emission reduction targets, electricity market integration would save around 60% of abatement costs, meaning that market integration would significantly improve the cost-effectiveness of carbon pricing.

4.3. Distributional impacts and equity concerns

The above results highlight the aggregate effects of the carbon market on the carbon emission abatement and its associated costs at the regional level. Another important evaluation criterion herein is the distributional impacts of the two market scenarios. To this end, Table 2 reports the carbon emissions of each province in the two market scenarios within the same 1.0% emission reduction target. It reveals that the abatement distribution across the studied provinces differ dramatically across the two market scenarios.

As reported in Table 2, abatement distribution at the provincial level is more concentrated within the regional market context compared to that within the provincial market. Comparing Fig. 4 and Fig. 10(a), in the provincial market, Guangdong, Guangxi, and Hainan all experience a decline in their carbon emissions due to the resulting substitution of gas power for coal power. Furthermore, both Yunnan and Guizhou then experience a slight increase in their emissions because the rate-based allocation of allowances would then distort the carbon price incentives for coal power generation within these regions. In contrast, in the regional market scenario, carbon emission reduction would be largely concentrated in Yunnan and Guizhou (Table 2). Comparing Fig. 4 and Fig. 10(b), electricity market integration redistributes electricity generation across these provinces, which would then reduce their electricity generation. Because the emission efficiency of coal-fired units in Yunnan and Guizhou is lower than that in Guangdong, Guangxi and Hainan, and high-emission-efficiency gas-fired units are installed in these three provinces. Market integration will reduce the share of coal power generation in Yunnan and Guizhou from 17.5% and 60.9% to 0.1% and 49.4%, increase the share of coal and gas power generation in Guangdong, Guangxi, and Hainan from 75.3%, 48.4%, and 65.3% to 78.1%, 53.1%, and 68.7%, respectively. Although Yunnan's hydroelectricity generation will increase, the reallocation of coal power generation is the main driver for the reallocation of electricity generation across provinces.

Additionally, when combined with the substitution of hydroelectricity for coal-fired electricity, as well as when considering the decrease in low-emission-efficiency thermal electricity generation, carbon emissions are then drastically reduced by 75.18% in Yunnan and 33.58% in Guizhou (Table 2). Conversely, Guangdong, Guangxi, and Hainan would then experience higher carbon emissions as market integration allocates more electricity generation to these regions specifically. The more concentrated distribution of emissions reductions in the regional market suggests that it is less effective in addressing carbon equity issues.

In addition to the emission allocation equity concern, market integration also raises an equity issue in terms of the development of

[3] Based on the energy consumption and carbon emission intensity targets of GDP as established by China's 14th Five-Year Plan, assuming constant energy consumption, we estimated that total carbon emissions would need to be reduced by at least 1% per year. Given the constant short-term electricity demand assumed in this paper, the emission reduction target was initially set at 1% and then increased to 4.5% in 0.5% increments to account for tighter emission reduction targets.

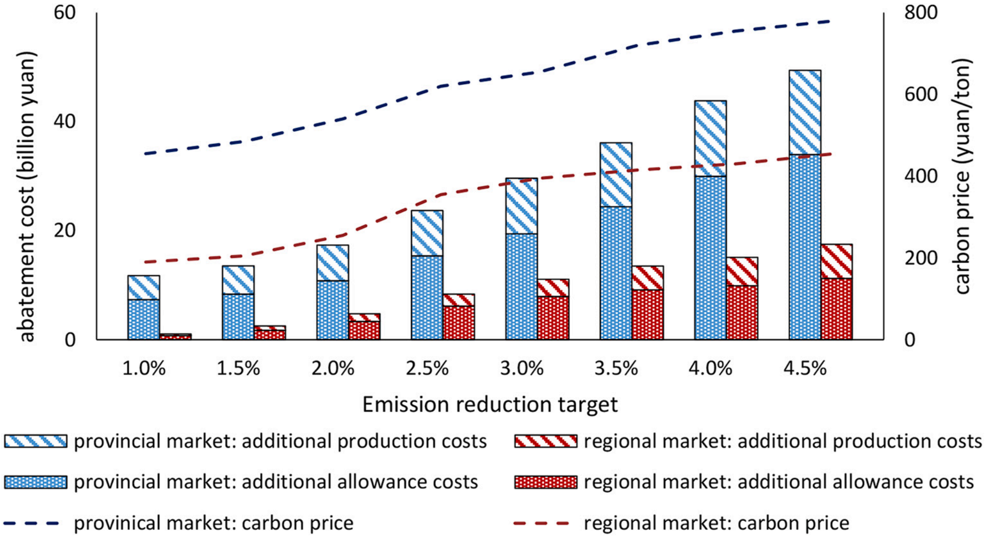

Fig. 9. The abatement costs of the different market scenarios.
Note: The abatement costs are calculated via increases in the production and allowance costs.

Table 2
The carbon emissions of each province in the two market scenarios under the same 1.0% emission reduction target.

	Guangdong	Guangxi	Yunnan	Guizhou	Hainan
Provincial market					
Carbon price (yuan/ton)	455				
CO_2 emissions (million ton)	283.75	54.29	41.81	96.12	15.65
Shares	57.72%	11.04%	8.50%	19.55%	3.18%
Changes	−0.04%	−8.96%	0.57%	1.79%	−11.63%
Regional market					
Carbon price (yuan/ton)	190				
CO_2 emissions (million ton)	314.46	84.93	10.32	62.72	19.26
Shares	63.95%	17.27%	2.10%	12.76%	3.92%
Changes	10.78%	42.42%	−75.18%	−33.58%	8.74%

Note: The above change rates were calculated in comparison with the provincial market without carbon pricing. The reported carbon price is that when the two scenarios each reached the target of 1.0% total carbon emission reduction.

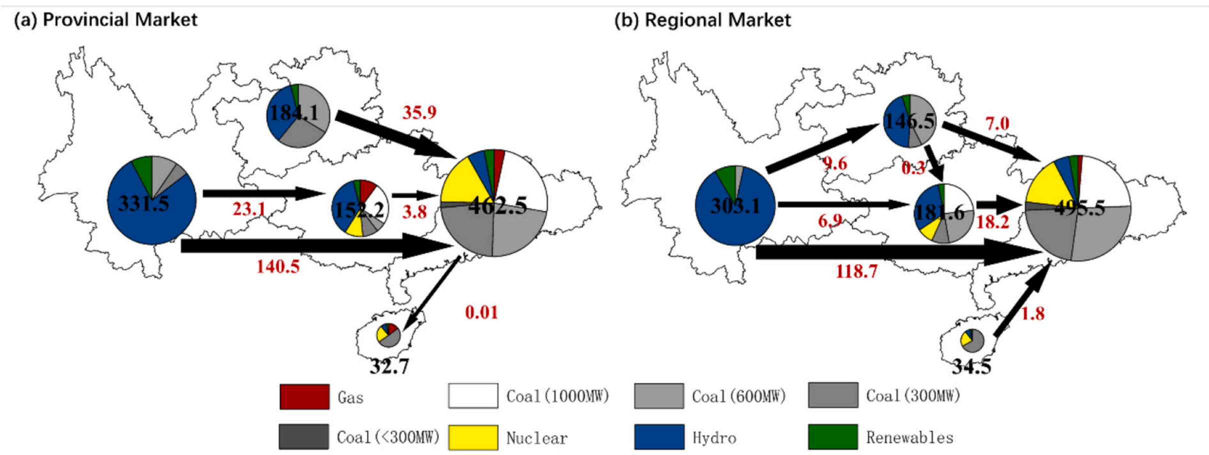

Fig. 10. Electricity generation and trade across the two market scenarios under the 1.0% emission reduction target.
Notes: All values are in TWh.

the electricity industry. Comparing Figure10(a) and 10(b), in the regional market context, the optimization of inter-provincial trade leads to a decrease in exports from Yunnan and Guizhou, as well as a large withdrawal of coal power in these provinces. When compared with the provincial market, the coal-fired electricity generation in Yunnan and Guizhou would drop by 74.82% and 33.56% in the regional market scenario. This largescale withdrawal of coal power production would then make it difficult for coal power plants to recover their stranded costs from the regional wholesale market. Without other tools (e.g., ancillary service markets, capacity payment scheme etc.) to cover the investment costs of coal power plants, the development of the electricity sector in Yunnan and Guizhou would suffer within a market integration context. Moreover, these two provinces are rich in renewable resources (Fig. 4). Further, a lack of market incentives for the development of local coal power plants may then result in an insufficient adjustable capacity level in the long term that would be needed to meet the flexibility requirement for large-scale renewable energy integration (Chu, Gao, & Li, 2021). Therefore, although the regional market scenario does improve the efficiency of short-term emission reduction, it may also cause a potential inequity in the long-term development of the electricity industry between provinces.

5. Conclusions

In this study, we examined the impact of electricity market integration on the abatement potential and cost-effectiveness of carbon pricing. Through the designing of two potential electricity market scenarios (a provincial versus a regional market type), as well as through considering the rate-based allocation of allowances in China's national carbon market, we were able to quantify the responses of regional-level carbon emissions to changes in carbon prices in the context of the five southern provinces. Herein, we measured the abatement costs using increases in the production and allowance costs, with us then comparing the cost-effectiveness of abatement between the two market scenarios. We further assessed the equity issues arising from the redistribution of carbon emissions and electricity production at the provincial level in the regional market scenario.

Our study found that carbon pricing has a limited emission reduction effect in the context of a segmented electricity market. The carbon prices need to be as high as 400 yuan/ton to begin achieving overall carbon reduction. While within an integrated electricity market, carbon emission reductions are larger and more responsive to changes within carbon prices. To achieve the carbon emission intensity goal outlined in China's 14th Five-Year Plan, the carbon price needs to be as high as 455 yuan/ton and 190 yuan/ton in the provincial and regional markets, respectively, which are both much higher than the average carbon price of 42.85 yuan/ton in China's national carbon market as of 2021. Furthermore, given the same emission reduction targets, abatement costs are saved by around 60% in the regional market than in the provincial market, which indicates that the former is more cost-effective in reducing carbon emissions. This is because market integration amplifies the abatement effect of carbon pricing changes through allowing for the cross-provincial substitution of high-emission-efficiency units for low-emission-efficiency one.

However, the distribution effects of carbon emissions and electricity production at the provincial level suggests that the regional market scenario would then result in potential equity issues. This is because emission reductions at the provincial level are more concentrated in regional market, with the primary contributors being Yunnan and Guizhou herein. Because market integration would then reduce the number of exports from Yunnan and Guizhou by optimizing inter-provincial trade, it would then drastically reduce the output of their local coal plants. It would also result in an inequitable impact on the development of the electricity industry in each province. The coal power plants in Guangdong, Guangxi, and Hainan would then benefit from the increases in output caused by market integration. The withdrawal of coal power would mostly be concentrated in Yunnan and Guizhou, which would then lead to tax loss, employment loss and GDP loss in these provinces.

Our research reveals the role of electricity market design in the effectiveness of carbon pricing, with our results then helping to improve policymakers' understanding of the interaction between changes to carbon pricing and electricity market reform. To support China's carbon neutrality target, the integration of the provincial electricity market would be a cost-effective tool within the context of the current national carbon market within the electricity sector. Our results also show that electricity market integration would help to reduce the required carbon price and would then save on abatement costs. Furthermore, China is currently promoting the construction of integrated electricity markets, with it having set the target of establishing a national integrated electricity market system by 2030 (NDRC (National Development and Reform Commission), 2022). We would thus expect that, when the national carbon market is integrated with the national electricity market, it will effectively support the realization of China's carbon neutrality target.

However, there are certain equity issues to be resolved in promoting this integration of the electricity market. The first is the unfair distribution of carbon emissions and energy consumption. In addition to the national carbon market, an important policy in China aimed at reducing carbon emissions is the dual control on energy consumption. Under this policy, each province sets its own total energy consumption and intensity control targets. Because the regional electricity market will then redistribute the energy consumption and carbon emission between provinces, it may then cause conflicts with the dual control target in certain regions. To coordinate these policies, one feasible approach might be to set energy consumption and emission reduction targets at the regional level.

In addition, the inequitable impact on the electricity industry in each province is another issue that needs to be addressed during the process of market integration. Given that some provinces may suffer losses from the withdrawal of low-capacity, low-emission-efficiency coal plants caused by market integration, policy makers and other potential investors need to then recognize the potential risk of plant's becoming stranded and take this into account when making decisions. The massive withdrawal of coal power plants in the short term will the place enormous pressure on the local power sector. With the large-scale development of renewable energy in the future, how to maintain the stability and reliability of their own power supply will be a major challenge for these provinces. Therefore, regional ancillary service markets and capacity compensation mechanisms should be established to compensate for the stranded costs, meet the flexibility requirement, and to alleviate the equity issues.

Code availability

The code used during the current study are available from the corresponding author on reasonable request.

Declaration of Competing Interest

There are no conflicts of interest to declare.

Data availability

The datasets used during the current study are available from the corresponding author on reasonable request.

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Appendix A. Appendix

A.1. Marginal cost

The marginal costs of the different technologies available are reported in Table A1. Because there are no official sources for the marginal cost of each unit type, these data were then estimated. For the coal- and gas-fired electricity units, we used fuel cost as a proxy variable for marginal cost. The coal and gas consumption at the unit level was collected from the Southern Electricity Grid 2018 Dispatch Annual Report. The coal and gas prices were 600 yuan/t and 2.7 yuan/m^3, respectively, which were the average fuel prices of coal and natural gas within the electricity sector in 2018 as published by the National Development and Reform Commission (NDRC). For the hydro and nuclear electricity units, we deducted the fixed costs from the levelized costs to estimate the overall marginal cost. The cost parameters are then derived from the Renewable Electricity Generation Costs in 2018, as published by the International Renewable Energy Agency (IRENA), as well as the Projected Costs of Generating Electricity that was published by the International Energy Agency (IEA) and the Nuclear Energy Agency (NEA).

Table A1
Marginal costs of the different electricity technologies.

(yuan/kWh)	Solar	Wind	Hydro	Nuclear	Coal 1000 MW	Coal 600 MW	Coal 300 MW	Coal <300 MW	Gas
Guangdong	0.000	0.000	0.074	0.172	0.265	0.288	0.297	0.338	0.436
Guangxi	0.000	0.000	0.074	0.172	0.273	0.287	0.305	–	0.615
Yunnan	0.000	0.000	0.074	–	–	0.292	0.322	–	–
Guizhou	0.000	0.000	0.074	–	–	0.291	0.310	0.349	–
Hainan	0.000	0.000	0.074	0.172	–	–	0.288	–	0.647

A.2. Inter-provincial transmission capacity

The inter-provincial transmission capacities between the five provinces in 2018 are shown in Table A2. The line loss rate herein is 5.51%, which is the average rate as calculated from the Southern Electricity Grid 2018 Dispatch Annual Report.

Table A2
Inter-provincial electricity transmission capacity in 2018.

(GW)		To				
		Guangdong	Guangxi	Yunnan	Guizhou	Hainan
From	Guangdong	0	0	0	0	2 (0.057)
	Guangxi	6.8 (0.057)	0	0	0	0
	Yunnan	31.6 (0.080)	3.2 (0.057)	0	3 (0.057)	0
	Guizhou	12 (0.080)	3.4 (0.057)	0	0	0

(*continued on next page*)

Table A2 (*continued*)

(GW)	To				
	Guangdong	Guangxi	Yunnan	Guizhou	Hainan
Hainan	2 (0.057)	0	0	0	0

Note: The transmission costs are reported in parentheses and their unit is yuan/kWh.

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