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Economic and environmental benefits of market-based power-system reform in China: A case study of the Southern grid system

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ABSTRACT

China, whose power system accounts for about 13% of global energy-related CO_2 emissions, has begun implementing market-based power-sector reforms. This paper simulates power system dispatch in China's Southern Grid region and examines the economic and environmental impacts of market-based operations. We find that market-based operation can increase efficiency and reduce costs in all Southern Grid provinces—reducing wholesale electricity costs by up to 35% for the entire region relative to the 2016 baseline. About 60% of the potential cost reduction can be realized by creating independent provincial markets within the region, and the rest by creating a regional market without transmission expansion. The wholesale market revenue is adequate to recover generator fixed costs; however, financial restructuring of current payment mechanisms may be necessary. Electricity markets could also reduce the Southern Grid's CO_2 emissions by up to 10% owing to more efficient thermal dispatch and avoided hydro/renewable curtailment. The benefits of regional electricity markets with expanded transmission likely will increase as China's renewable generation increases.

1. Introduction

China's electricity system is the largest in the world, with an installed capacity of roughly 1800 GW at the end of 2018 (China Electric Council, 2019a). It accounts for about 45% of China's energy-related carbon dioxide (CO_2) emissions, or about 13% of total global energy-related CO_2 emissions (International Energy Agency, 2018). Decarbonizing China's electricity system is thus essential to reducing CO_2 emissions from China's and the world's energy systems, as well as other economic sectors—such as transportation, industry, and buildings—in China.

Since 2015, China has embarked on a new round of power-sector reforms to expand the role of markets in allocating resources. Key areas of reform include developing market-based wholesale prices, establishing separate transmission and distribution tariffs, introducing retail electricity competition, and expanding interprovincial and interregional transmission. If successful, such reform could provide large economic and emissions-reduction benefits, significantly increase the renewable energy generation that can be reliably integrated into the grid, and accelerate the transition to a low-carbon power system in China (Lin, 2018; Lin et al., 2019).

In August 2017, the China National Development and Reform Commission and China National Energy Administration identified eight provinces/regions as the first batch of wholesale market pilots, including the Southern Grid region (starting with Guangdong), West Inner Mongolia, Zhejiang, Shanxi, Shandong, Fujian, Sichuan, and Gansu (National Energy Administration, 2017). By the end of June 2019, all of the eight pilots have started trial operation and by early September, Guangdong and Shanxi have actual electricity wholesale market transactions settled (National Development and Reform Commission (NDRC), 2019a; China Electric Council, 2019b; Xinhua net, 2019). Despite these progresses, under the current reforms, pilots for wholesale markets are mostly limited to provincial markets, with only limited trials for direct cross-provincial trades. However, many of the issues to be resolved in the power-sector reform, such as integration of renewable energy and resource adequacy, are regional in nature. Thus, it is important to explore additional economic and environmental benefits beyond the current provincial-market model. Experience elsewhere has demonstrated large economic, reliability, and environmental benefits from adopting a wider balancing area (Greening the Grid et al., 2015; Goggin et al., 2018; Holttinen et al., 2007; Corcoran et al., 2012; Kirby and Milligan, 2008).

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This paper assesses the impact of market-based power-system dispatch in China, expansion from provincial to regional markets, and expansion of transmission capacity across provinces. We use the Southern Grid region as a case study, mainly because the provinces within this region have already established significant electricity trade with each other.[2] As a result, moving to market-based powerplant dispatch may be feasible in the near term. We simulate hourly powerplant dispatch of the Southern Grid system using PLEXOS (a state-of-the-art production-cost model) for a variety of dispatch-rules scenarios, from current practices to a full regional market. For each scenario, we assess the impact on total market costs, production costs, and CO_2 emissions.

The remainder of the paper is organized as follows. Section 2 reviews the literature on assessing the economic impacts of market-based system dispatch and regionalization of electricity markets. Section 3 describes our methods and data. Section 4 describes our key results, and Section 5 presents a sensitivity analysis. Finally, Section 6 discusses conclusions and policy implications.

2. Literature review

There has been significant research on how market-based economic dispatch of the power system can reduce electricity production costs relative to regulated or self-schedule regimes. Green and Newbery found that, in the British electricity spot market, more competition led to lower electricity costs (Green and Newbery, 1992). Cicala studied the effect of introducing market-based dispatch into U.S. power-control areas, finding that deregulation reduced operational costs by about 20% ($3 billion per year) and increased regional electricity trades by about 20% (Cicala, 2017). Other researchers found that restructuring led to reduced production costs at the powerplant level and substantive efficiency gains (Fabrizio et al., 2007). Cicala also found that the price of coal in coal powerplants in deregulated markets dropped by 12% compared with similar non-deregulated plants (Cicala, 2015). Lin et al. studied the economic and carbon-emissions impacts of transitioning to an electricity market in China's Guangdong province, finding that electricity reforms led to significant consumer savings (Lin et al., 2019). Wei et al. used an optimization model to quantify the impacts of economic dispatch on coal-fired powerplants. They found major differences in heat rates among coal powerplants and that, with economic dispatch, average electricity prices could be reduced owing to reduced coal use for power generation (Wei et al., 2018).

One criticism of energy-only wholesale markets is the "missing money" problem. In a competitive energy-only market, powerplants typically recover only their marginal costs. Therefore, financial restructuring and reallocation of market benefits are necessary for the powerplants to recover their fixed capacity costs (Joskow, 2008). Lin et al. explored this issue in Guangdong province and concluded that mechanisms to allow generators to recover their fixed costs are likely necessary (Lin et al., 2019). In this paper, we also assess whether the wholesale market revenue is enough to cover the production and fixed costs of all powerplants.

Substantive research has also been done regarding the impacts on grid reliability and costs of increasing balancing-area size. One example of current coordination across balancing areas is the Western Energy Imbalance Market, which covers eight balancing areas across the western United States. This market system finds the lowest-cost energy to serve real-time demand across a wide geographical area and has saved over $564 million since its inception in 2014 (Western Energy Imbalance Market, 2019). More generally, a larger balancing area—-with everything else held equal—decreases system costs and improves grid reliability by decreasing peak load relative to installed capacity and thus reducing both the hours when the most expensive units run and the required operating reserves (Smith et al., 2007; DeCesaro et al., 2009; King et al., 2011). It also increases the load factor and minimum system load while reducing the relative load variability through geographical and temporal diversity (King et al., 2011; DeCesaro et al., 2009; EnerNex Corporation et al., 2006; European Climate Foundation, 2010; GE Energy and NREL, 2010; Gramlich and Goggin, 2008; Holttinen et al., 2007; Kirby and Milligan, 2008; Miller and Jordan, 2006). In addition, larger balancing areas reduce capacity requirements to meet ramping rates, increase access to flexible generation, and thus reduce the overall costs to serve load (Milligan and Kirby, 2008a; King et al., 2011; EnerNex Corporation et al., 2006; European Climate Foundation, 2010; GE Energy and NREL, 2010; Gramlich and Goggin, 2008; Holttinen et al., 2007; Kirby and Milligan, 2008; Ackermann et al., 2009; DeCesaro et al., 2009; Smith et al., 2007; Milligan and Kirby, 2008b; Greening the Grid et al., 2015). Most of the existing literature has focused on the U.S. and European power systems. Little or no literature addresses such issues in China.

Research suggests that two factors affect the grid benefits due to increasing the size of balancing areas. The first factor is the additional costs associated with transmission-expansion projects that might parallel the consolidation of management across multiple smaller balancing areas. If no new extensive transmission investments are required when increasing the size of a given balancing area, decreased system costs and improved reliability are significant (Corcoran et al., 2012). Corcoran, Jenkins, and Jacobson studied the costs and benefits of interconnecting across different Federal Energy Regulatory Commission regions with transmission expansions. They found that, in most scenarios, benefits are outweighed by additional transmission costs. The most cost-effective interconnection scenarios were those consolidating multiple, small areas via relatively short transmission projects. Because their assumptions do not include fuel diversity, price uncertainty, and energy price differences due to congestion, more research on the impact of transmission is needed, especially across other regions and system assumptions. The second factor affecting the grid benefits of larger balancing areas is the time scale of interest. Miller and Jordan found that aggregating load provided modest benefits in the hourly time frame, but significant benefits in the five-minute and minute-to-minute time frames (Miller and Jordan, 2006).

Other strategies to improve reliability include improving regional market access and sharing scheduling and area control error responsibilities across larger areas (Smith et al., 2007). In addition, in a future with increased renewable energy penetration, the benefits of increasing balancing-area size are magnified. Recent studies of market reforms in preparation for higher renewable energy penetration suggest moving towards increased flexibility and larger geographical areas (Goggin et al., 2018).

3. Methods

We simulate hourly powerplant dispatch in the Southern Grid region for the year 2016 using PLEXOS, an industry-standard unit-commitment and production-cost model. PLEXOS is one of the state-of-the-art models that allows us to model the generator unit commitment and dispatch (using direct current (DC) optimal power flow algorithm) considering a range of real-life power system constraints. We model the Southern Grid network using five nodes, one node for each province: Guangdong (GD), Guangxi (GX), Guizhou (GZ), Yunnan (YN), and Hainan (HN); see Fig. 1. We also simulate the region's exchange with other grids, such as the Southwestern Grid or Central Grid. Using the

[2] The Southern Grid region is in the southeastern area of China encompassing five provinces: Guangdong, Guangxi, Guizhou, Yunnan, and Hainan. The region hosts significant economic activity (~17% of national GDP in 2016), and the region's electricity load (~1,000 TWh/yr) constitutes over 20% of the national total. The Southern Power Grid Company owns and operates the region's transmission network, while the generation assets are mostly owned by the provincial generation companies. Coal and hydro powerplants dominate the current electricity generation mix, which is described in detail in the subsequent sections of this paper.

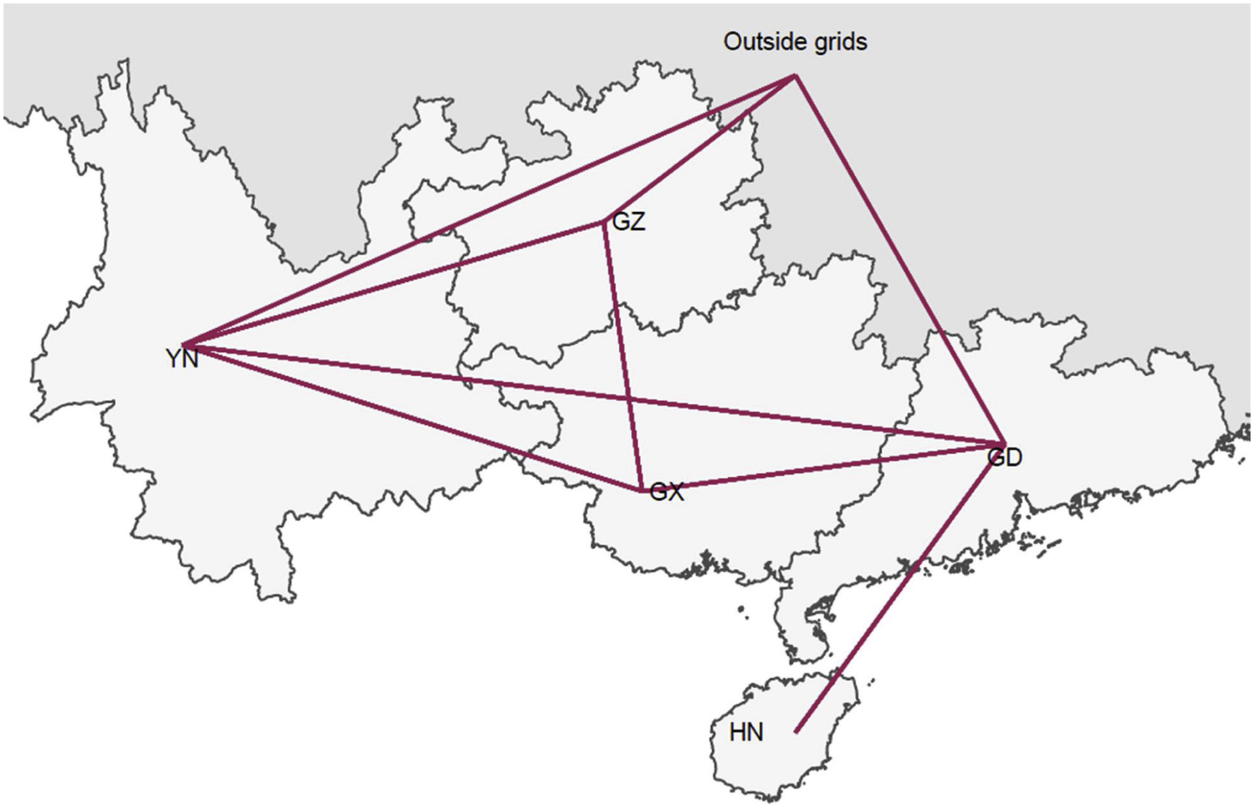

Fig. 1. Five Southern Grid nodes and outside grid node modeled in the analysis.

2016 actual fleet-level electricity generation and curtailment data in each province and interprovincial import/export data, we calibrate the key parameters in our model (availability, dispatch restrictions, etc.).

Modeling the transmission network in a reduced form (single node per province) allows us to focus on the interprovincial trade issues, which are critical to setting up economic dispatch/markets. While we understand that this approach risks missing the potential congestion issues in the intra-province transmission network, in our future work, we intend to model the transmission network in a more spatially resolved manner so we can assess those. Also, data on intra-province transmission was not easily available in the public domain.

3.1. Model

We use PLEXOS to simulate Southern Grid operation at hourly resolution. PLEXOS is industry-standard software by Energy Exemplar that is used by system operators and utilities worldwide (Palchak et al., 2017; Jorgenson et al., 2014; Eichman et al., 2015; Abrams et al., 2013). PLEXOS uses deterministic or stochastic mixed-integer optimization to minimize the cost of meeting load given physical (e.g., generator capacities, ramp rates, transmission limits) and economic (e.g., fuel prices, startup costs, import/export limits) grid parameters. More specifically, PLEXOS simulates unit commitment and actual energy dispatch for each hour (or at 1-min interval) of a given time period. PLEXOS is also a transparent model meaning that the entire mathematical problem formulation is available to the user.

In this analysis, we use a deterministic model in PLEXOS meaning that the model assumes perfect foresight in relation to renewable energy production and load. We do not believe that this assumption changes the results significantly mainly because the current renewable energy penetration in the southern grid region is very small (less than 4% by energy). Also, majority of the electricity load is industrial that has very small forecast errors. In order to model unit commitment and outages accurately, we use mixed integer programming (MIP) in PLEXOS. Also, in order to simulate the actual scheduling practices, we simulate day-ahead operation at an hourly resolution. PLEXOS simulates daily operation as a MIP at an hourly resolution in chronological sequence. For avoiding issues with any inter-temporal constraints at the day boundaries (e.g. minimum up or down time of thermal units, or minimum load constraints), PLEXOS can 'look ahead' into the next day meaning that PLEXOS solves for the current day and the next day together, however, only results for the current day are kept. PLEXOS can fix the maintenance schedules for generation units exogenously based on actual maintenance data. Forced outages for units are calculated based on Monte Carlo simulations. Forced outages occur at random times throughout the year with frequency and severity defined by forced outage rate, mean time to repair and repair time distribution. The transmission between provinces are modeled using DC optimal power flow algorithm. At simulation run time PLEXOS dynamically constructs the linear equations for the problem and uses a solver to solve the equation. In this analysis, we used Xpress-MP solver with a duality gap set to 0.1%.

For each scenario mentioned below, we simulate Southern Grid operation at hourly resolution for the entire year of 2016 and report key model outputs such as powerplant dispatch, transmission flows between provinces, production and wholesale electricity costs, curtailment of hydro and renewable resources, CO_2 emissions, and so forth.

3.2. Scenarios

We develop three scenarios to evaluate the impacts of provincial and regional electricity markets in the Southern Grid territory. The order of the scenarios as listed below shows a gradual release on market constraints.

1. Baseline: The baseline scenario simulates the actual thermal dispatch, interprovincial imports and exports, and constraints on hydro dispatch in the Southern Grid system in 2016.

2. Provincial Market: In this scenario, we model the creation of a provincial market in the Southern Grid. We assume that, within each province, powerplant dispatch is market based—that is, based on least cost. However, existing contracts governing the interprovincial import and export of electricity are same as in the Baseline scenario i.e. we hold interprovincial imports and exports the same as in the Baseline scenario. Also, constraints on hydro dispatch are assumed to remain the same as in the Baseline scenario.

3. Regional Market: In this scenario, we model the creation of a Southern Grid-wide regional electricity market. We assume that the current interprovincial contracts are renegotiated, and the entire Southern Grid system dispatch is optimized for least cost. However, constraints on hydro dispatch are assumed to remain the same as in the Baseline scenario. Also, the current transmission line limits would still apply to the interprovincial flows.

3.3. Data and key parameters

3.3.1. Electricity demand

We use the actual annual 2016 electricity consumption in each province from the China Electric Power Statistical Yearbook 2017 (China Electric Council, 2017a). We construct the hourly load curve in each province based on load shapes for winter and summer typical days and monthly electricity consumption in 2016 in each province (Cai et al., 2014; Guangdong Statistics, 2016; Yunnan Statistical Bureau, 2017; Guizhou Statistical Bureau, 2017; People's Government of Hainan Province, 2017; People China Newspaper, 2016; Zhang and Hongli, 2014; Yang and Bo, 2014; Li, 2014; Lv, 2013), as well as assumptions about winter and summer duration and a ratio between weekend and weekday electricity consumption. For a more detailed methodology, see Lin et al. (2019).

3.3.2. Hydro generation

We model hydro generation using the fixed hydro method, constraining monthly imports and hydro generation by historical monthly shares and fixing the hourly hydro dispatch in each province assuming a ratio between on-peak and off-peak hours in a day. For a more detailed description of this method, see Lin et al. (2019). We only had access to the hydro generation profile in Guangdong, so we assume the hydro generation profiles to be the same in all the other provinces. Because Guangdong accounts for over 50% of the electricity demand in the southern region, we do not believe this assumption would change the results significantly. We also conduct a sensitivity analysis by making the hydro dispatch flexible, albeit with the same monthly energy budgets.

3.3.3. Solar and wind generation

For each province, we take the hourly solar photovoltaic (PV) and wind energy generation profiles from the SWITCH-China model, simulating the profiles using hourly irradiance and wind-speed data at 10 sites with the best resource potential (i.e., the 10 best solar sites and the 10 best wind sites) in each province (He and Kammen, 2014, 2016).

3.3.4. Powerplant operational parameters

Powerplant operational parameters—such as heat rates, ramp rates, and minimum stable generation levels—are estimated using historical fleet-level performance data, regulatory orders on heat rates and costs, international benchmarks and other relevant literature, and conversations with system operators about actual practices (China Electricity Council, 2017b; Abhyankar et al., 2017; Liu, 2014, 2015; California ISO, 2016). Please refer to SI for the values used in this paper.

3.3.5. Fuel prices

We use 2016 actual coal prices in each province (National Development and Reform Commission, 2019b). Coal prices show significant month-to-month variability (Fig. 2). However, the trend is largely similar in all provinces. In all provinces, coal prices are largely flat between January and August; between September and December, they increase by about 20%–40%. Coal prices in Guizhou are the lowest, while those in Guangxi are the highest.

We did not have access to the 2016 natural gas prices by month in each province. Therefore, we use the 2016 annual average natural gas price in Guangdong (54.4 Yuan/GJ) for all provinces. We do not believe this assumption would change our results significantly, because natural gas-based power generation is very small relative to coal-based generation or overall load.

3.3.6. Exchange with other regional grids

Across all scenarios, we assume exports and imports to and from other regions are the same as the actual 2016 flows. The 2016 actual numbers are from the Electric Power Industry Statistical Compilation in 2016 (China Electric Council, 2017b).

3.3.7. Fuel CO_2 emission factors

We use the CO_2 emission factors for thermal power plants from the southern grid territory in 2016 reported by the National Development and Reform Commission (2017), which is equal to 0.8676 tCO_2/MWh.

3.3.8. Interprovincial transmission limits

The inter-provincial transmission limits have been taken as a sum of installed capacities all transmission lines connecting the two provinces. While we understand that in an AC network, the available transfer capacity (ATC) between two provinces would be smaller than the sum of the installed line capacities. However, estimating the ATC requires AC power flow modeling and is outside the scope of this study. In our future work, we will create scenarios on actual ATCs on transmission lines. The data sources for individual line limits are given in the SI.

3.4. Model calibration and data

We calibrate the model so that the Baseline scenario results match with the actual fleet-level dispatch in each province as well as interprovincial trade in 2016. The actual data for 2016 are from China Electric Council (2017b). More specifically, for the baseline scenario, the following constraints are applied with a permissible slack of 10%: (a) within each province, the fleet level electricity generation for each technology equals the actual fleet level generation in that province, (b) inter-provincial transmission flows should equal the actual inter-provincial imports /exports. The calibration results are shown in Table 1.

4. Results

In this section, we describe the key results of our analysis. Additional results can be found in the supplementary information.

4.1. Simulated generation mixes and marginal costs

Market operations lead to more efficient dispatch of the thermal fleet and lower overall production costs. In the Baseline scenario (current dispatch practices), all coal generators are operated at similar capacity factors irrespective of their marginal costs, resulting in a highly non-optimal dispatch as well as significant curtailment (5%–10%) of the renewable energy and hydro generation.

Table 2 shows total annual generation in the Southern Grid region by fuel type in all the simulated scenarios. In the Baseline scenario, coal generation accounts for about 50% of total regional electricity generation, while about 8% of the hydro and renewable energy generation must be curtailed. However, market-based dispatch reduces coal generation: by 7% under Provincial Market (market based within provinces) and 10% under Regional Market (regional market with current transmission constraints). At the same time, nuclear generation (which has very low marginal costs) increases by about 25% in all market scenarios, hydro generation increases by up to 9%, and hydro/

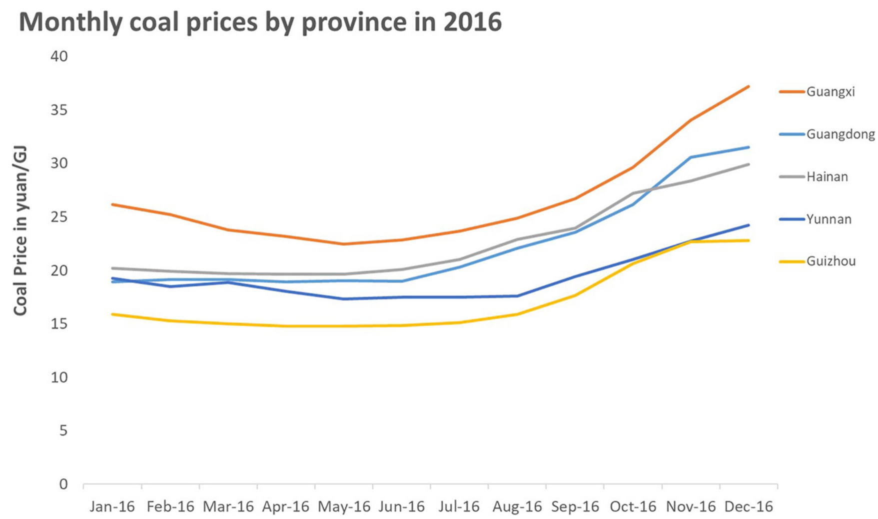

Fig. 2. Monthly coal prices in each province.

Table 1
Model Calibration: Comparison of 2016 Actual and Simulated (Baseline) Southern Grid Fleet-Level Generation and Key Interprovincial Transmission Flows (TWh/yr).

Total Generation or Imports/Exports (TWh/yr)	2016 Actual	Model Baseline (Simulated 2016)
Nuclear	87	86
Coal	503	500
Natural gas	0	1
Hydro	404	394
Wind + PV	31	29
Hydro and renewable energy curtailment	32	36
Total energy generation	1,024	1,010
Interprovincial flows on key corridors		
Guangxi to Guangdong	8	6
Guizhou to Guangdong	55	60
Yunnan to Guangdong	110	100

Table 2
Annual Generation by Source and Scenario for Southern Grid, 2016 (TWh/yr).

Source	Baseline	Provincial Market	Regional Market
Nuclear	86	107	107
Coal	500	465	450
Natural gas	1	0	0
Hydro	394	413	425
Wind	22	19	22
PV	7	6	6
Total generation	1,010	1,010	1,010
Hydro and renewable energy curtailment	36	21	6

renewable energy curtailment decreases by up to 83%.

Fig. 3 groups annual powerplant dispatch by marginal cost of production. With market-based dispatch, plants with marginal costs less than 160 Yuan/MWh generate more electricity (subject to physical constraints), while plants with marginal costs above 160 Yuan/MWh generate less. As a result, overall production cost and the wholesale price of electricity decrease significantly.

4.2. Economic benefits of market-based dispatch

With market-based (least-cost) powerplant dispatch, the total wholesale cost of electricity in the Southern Grid territory decreases by 20%–35% relative to the current practice of planned powerplant dispatch (Fig. 4).[3] The establishment of provincial markets contributes the most to the cost reduction (20%), followed by creating a regional market (15% additional reduction). Establishing provincial markets reduces wholesale costs in all provinces relative to the baseline, and costs are reduced 10%–41% more when the market is regionalized (i.e., when transitioning from the provincial market to a regional market) in all provinces. The percentage reduction is lowest in Guangdong (~10%), indicating that the province already imports significant amount of electricity from other provinces in the region.

4.3. Provincial generation and interprovincial transmission

Here we illustrate the generation within and transmission between provinces under each of our scenarios. Under the 2016 Baseline scenario, Guangdong has the highest generation in the region at 383 TW h, followed by Yunnan at 271 TW h (Fig. 5). Guangdong is also a net importer, with imports from Guangxi, Hainan, Yunnan, and outside grids. Coal dominates the generation in Guangdong, Guizhou, and Hainan, while hydro dominates the generation in Guangxi and Yunnan. The largest net transfer of electricity between provinces occurs between Guangxi and Guangdong, with net transmission of 119 TW h from west to east.

In the Provincial Market scenario, the total amount of generated electricity in each province and electricity imports/exports between provinces do not change (Fig. 6). Instead, electricity generation within each province is optimized for the least cost, which leads to changes in the generation mix. For example, while coal still dominates Guangdong's generation, it contributes 7 TW h less (compared with the Baseline scenario) in that province, which experiences an equivalent increase in nuclear generation. For Yunnan, coal generation decreases from 40 to 25 TW h, while hydro generation increases from 216 to 235 TW h. Overall, the region experiences reduced coal generation and increased hydro generation under this provincial-level market scenario.

The Regional Market scenario produces more significant generation and transmission changes (Fig. 7). Compared with the Baseline scenario, total provincial-level generation in Guangdong decreases from 383 to 352 TW h, with coal generation decreasing from 264 to 226 TW h. Yunnan provincial generation increases from 271 to

[3] Planned powerplant dispatch is the status quo, in which operating hours for all types of generation are planned on a year-ahead basis, and generators are paid at a fixed feed-in tariff for their next generation.

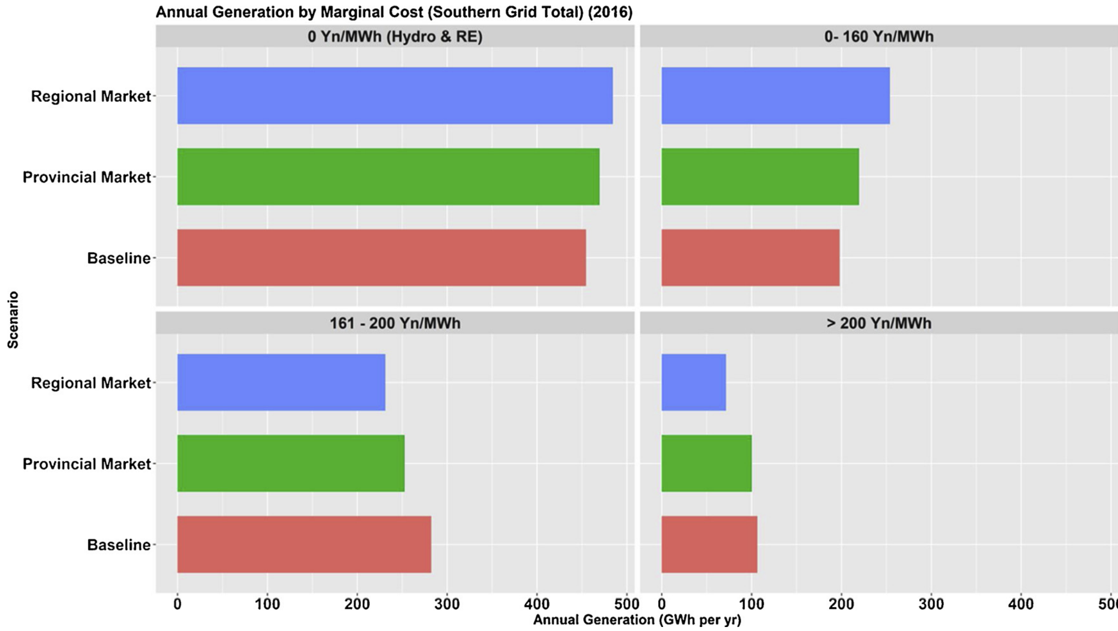

Fig. 3. Annual electricity generation in Southern Grid by marginal cost of production, 2016.

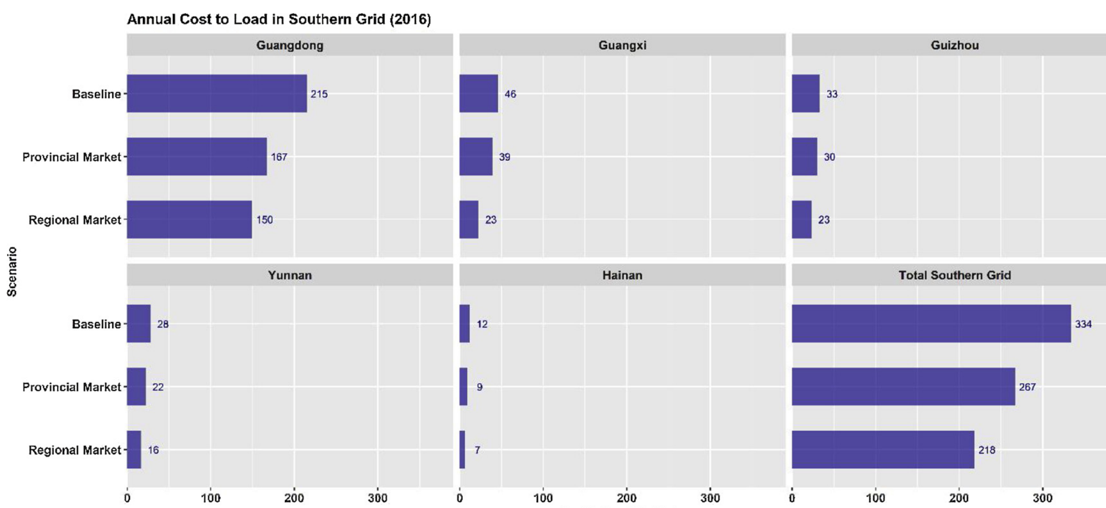

Fig. 4. Annual wholesale cost of electricity in Southern Grid, 2016.

279 TW h, with hydro generation increasing from 216 to 247 TW h. Guangxi's provincial generation decreases from 120 to 90 TW h, with most of the reduction from lower coal generation. On the other hand, Guizhou's provincial generation increases from 206 to 262 TW h, with most of the increase from higher coal generation. Transmission among provinces also changes significantly. For example, Guangxi to Guangdong transmission increases from 119 to 153 TW h, while Guizhou to Guangxi transmission increases from 77 to 136 TW h. Under a regional market, Guangxi becomes a hub for electricity transmission to Guangdong while decreasing its local generation at the same time.

4.4. CO_2 emissions reductions

Owing to the significant reduction in hydro curtailment and more efficient operation of the thermal fleet, market-based dispatch significantly reduces CO_2 emissions from the Southern Grid (Fig. 8). Creating a provincial market, albeit with constraints on hydro dispatch and transmission capacity, reduces CO_2 emissions by 7% relative to the current emissions (Baseline scenario). Creating a regional market reduces the CO_2 emissions further by 3 percentage points.

4.5. Recovery of fixed costs

The current generation tariffs/contract prices in the Southern Grid region are significantly higher than the total fixed (mainly capital servicing and fixed O&M) and variable (fuel and variable O&M) costs of powerplants. With market-based economic dispatch, the total wholesale electricity cost (i.e., the gross revenue of generators) decreases significantly (Fig. 4). However, the market revenue is still enough to meet the total generator costs (fixed and variable) under the Provincial Market and Regional Market scenarios (Fig. 9).

In the Provincial Market scenario, the total market revenue is 267 billion yuan/yr, which is higher than the total generator costs of 222 billion yuan/yr. In the Regional Market scenario, the generator revenue drops to 218 billion yuan/yr—still marginally higher than the total generator costs of 215 billion yuan/yr, implying that the regional and provincial market pool revenue is enough to recover the generator fixed costs at the system level. For ensuring fixed-cost recovery at the

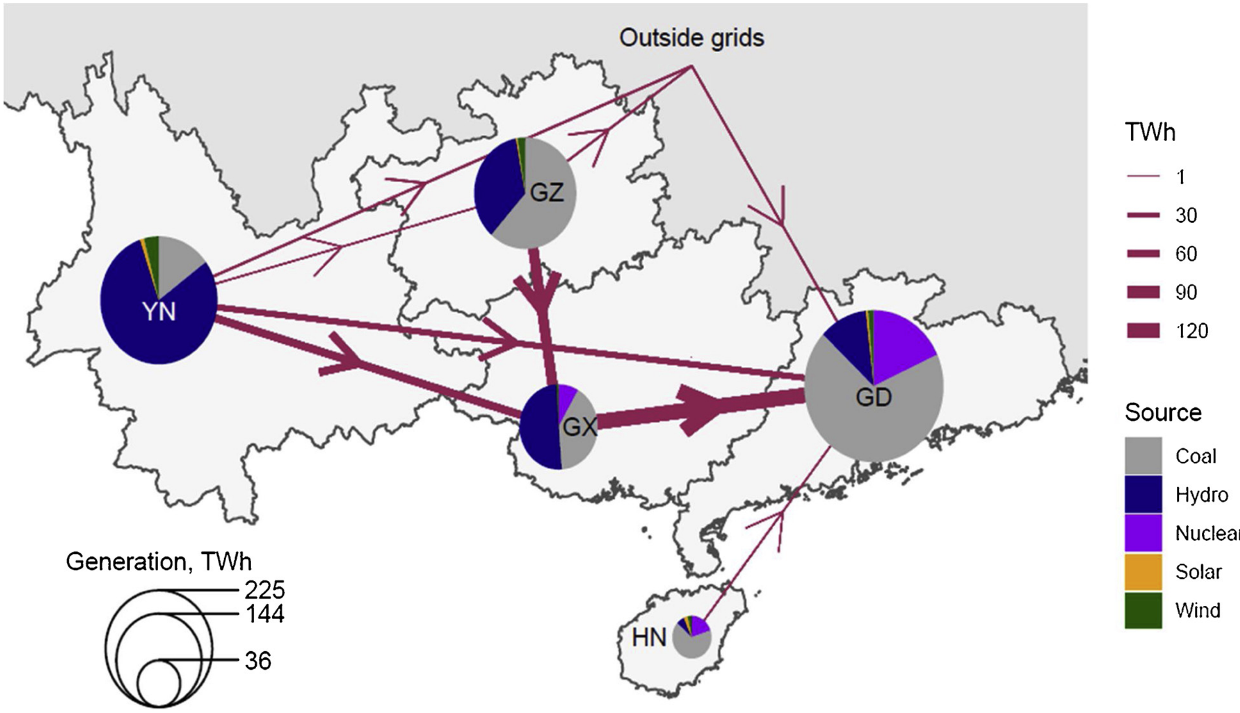

Fig. 5. Electricity generation and interprovince transmission in the Southern Grid under the Baseline scenario.

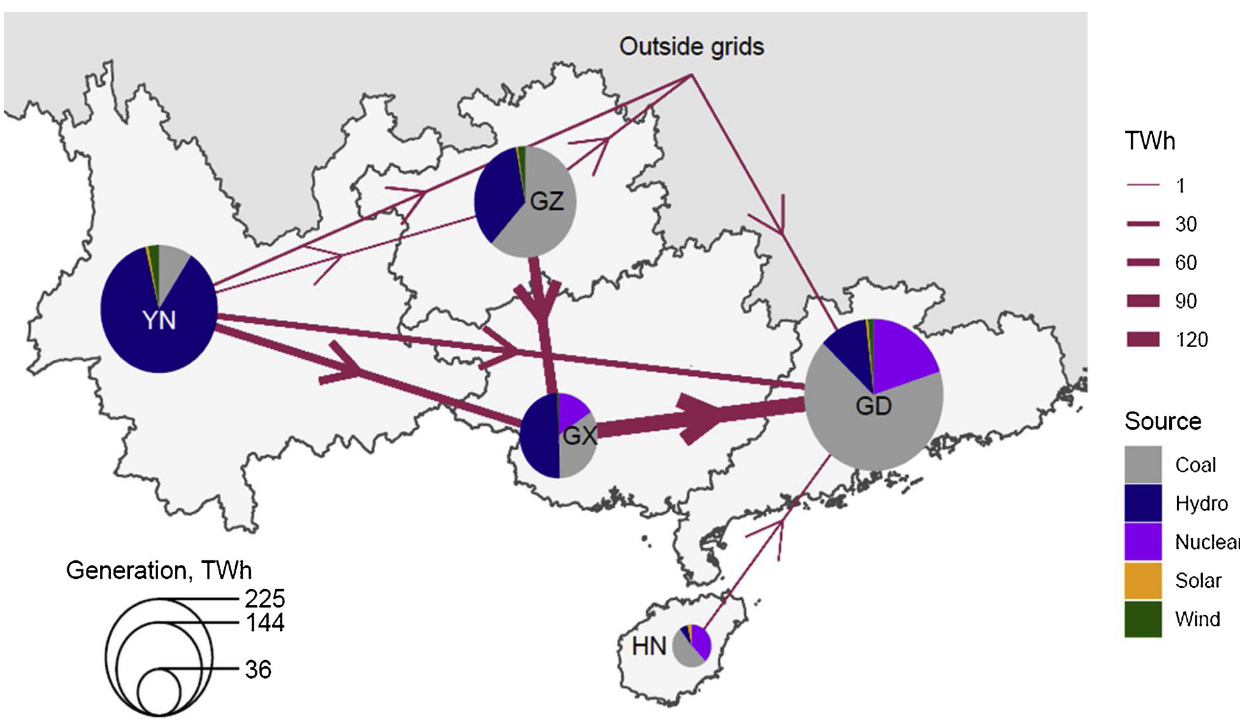

Fig. 6. Electricity generation and interprovince transmission in the Southern Grid under the Provincial Market scenario.

individual plant level, financial restructuring of the current contractual/payment arrangements may be necessary; assessing the details of such restructuring is outside the scope of this paper.

5. Sensitivity analysis

To test the robustness of our findings, we conducted a sensitivity analysis by varying the coal price, the transmission capacity between provinces, and the restrictions on hydro dispatch.

5.1. Higher coal price (High_Coal)

A higher coal price affects market prices and thus savings due to market-based dispatch, because coal powerplants contribute nearly 50% of total electricity generation in the Southern Grid region. If the coal price increases by 25%, the average market price increases by nearly 12% in the Provincial Market scenario and 10% in the Regional Market scenario, so the cost to load increases to 296 billion yuan/yr in the Provincial Market scenario and 240 billion yuan/yr in the Regional

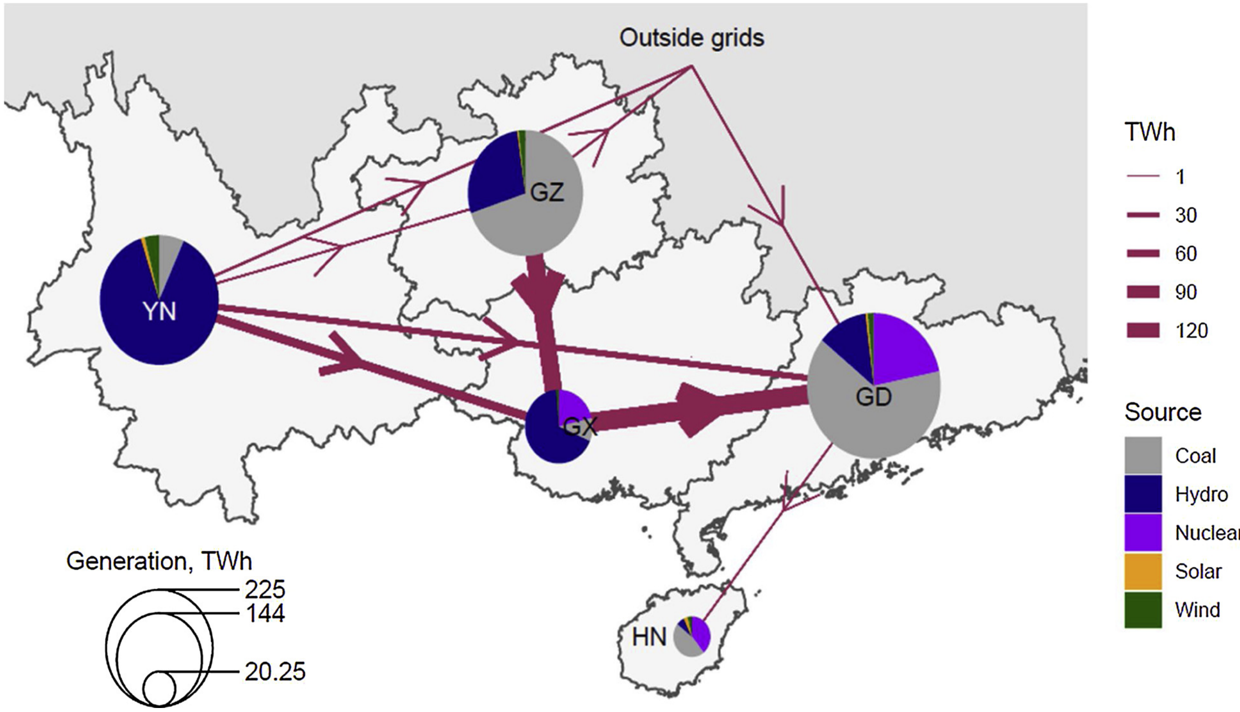

Fig. 7. Electricity generation and interprovince transmission in the Southern Grid under the Regional Market scenario.

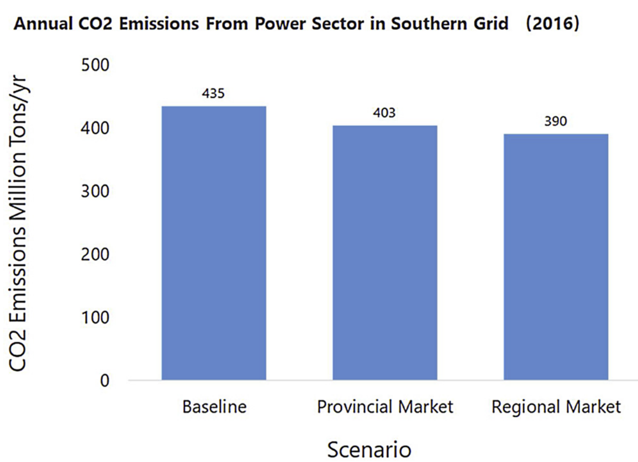

Fig. 8. Annual CO_2 emissions from the Southern Grid power sector, 2016.

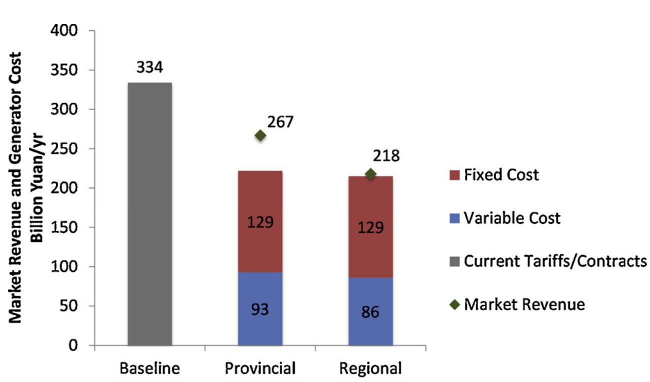

Fig. 9. Annual market revenue and total generator cost in the Southern Grid, 2016.

Market scenario. Assuming the generation tariffs (only the variable cost part) also increase to reflect the higher coal price, the total cost to load in the Baseline scenario would increase by about 7%, to 356 billion yuan/yr. Thus, compared with the Baseline scenario, the total wholesale electricity cost would be 17% lower in the Provincial Market scenario and 33% lower in the Regional Market Scenario. These percentage reductions are smaller than in our core (lower-priced coal) analysis, where reductions are 20% in the Provincial Market scenario and 35% in the Regional Market Scenario; see Fig. 4.

5.2. New transmission investments (Add_Tx)

Here we assume new investments are made in the interprovincial transmission capacity, and the available transfer capacity increases by 50% of the existing capacity under the Regional Market scenario. The expansion gives other provinces access to cheaper hydro resources from Yunnan and cheap coal resources from Guizhou, which reduces costs in net-importing provinces (Guangdong, Guangxi, and Hainan) but increases overall exports and electricity costs in Yunnan and Guizhou. However, costs in all provinces are still lower under the Regional Market Add_Tx sensitivity case than under the Baseline scenario. When summed across the entire region, the additional cost reduction in the Add_Tx sensitivity case is only 3.2% beyond the reduction in the core Regional Market scenario, which suggests that this approach has limited value given the region's current resource mix and loads. However, as renewable energy penetration and load grow, the value of additional transmission could be significant. Finally, the Add_Tx case drives significant operational changes. At the provincial level, the increased transmission capacities make it more economical to reduce generation in Guangxi and Guangdong and increase transmission from cheaper-electricity provinces like Yunnan and Guizhou. For example, Guangdong's total generation decreases from 383 to 293 TW h, with most of the reduction due to coal generation declining from 264 to 167 TW h (compared with the Baseline scenario); as a result, Yunnan and Guizhou become the new largest and second-largest electricity generators. Generation increases from 271 to 312 TW h in Yunnan (mostly from increased hydro generation) and from 206 to 296 TW h in

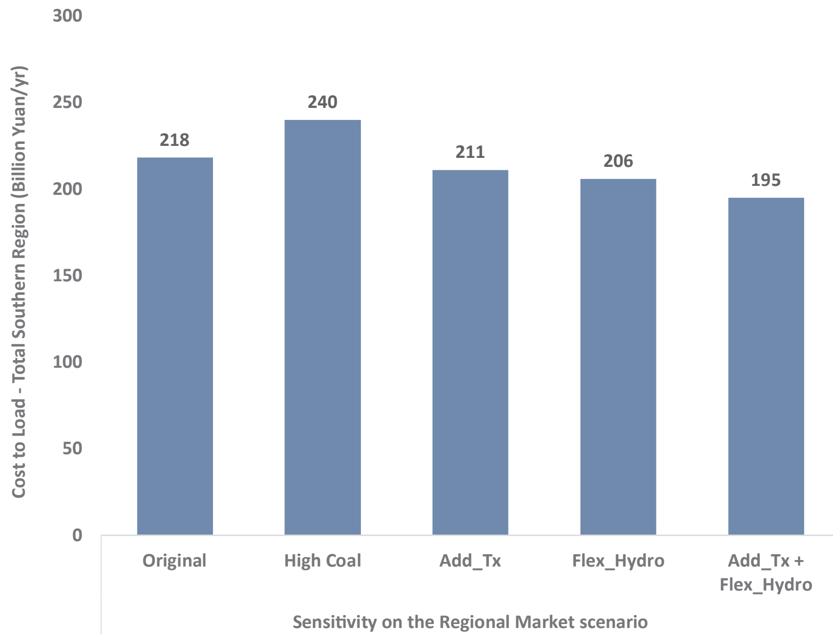

Fig. 10. Sensitivity to key parameters of cost to load (total Southern Grid), Regional Market scenario, 2016.

Guizhou (mostly from increased coal generation); most of this increased generation is exported to Guangdong. With more transmission across all provinces, transmission from west to east increases, with Guangxi as a transmission hub to Guangdong. Details of the operational changes are provided in the Supplemental Information.

5.3. Flexible hydro dispatch (Flex_Hydro)

Because hydro powerplants supply nearly 40% of the Southern Grid's total electricity generation, their dispatch constraints affect the wholesale electricity costs and system operations significantly. To explore the benefits of a more flexible hydro dispatch, here we allow the hydro powerplants to deviate by 25% from their fixed dispatch simulated in the Baseline scenario; they still must follow the same monthly energy budget constraints. The additional flexibility changes hydro generation little in the Regional Market scenario, but grid operation changes significantly. First, the coal dispatch becomes significantly flatter. Hydro powerplants increase output during peak periods and reduce output during off-peak periods, and thus the ramping and cycling of coal powerplants decrease significantly. Although the total coal generation remains almost the same, cheaper coal plants are dispatched more. Second, because Guizhou has some of the cheapest coal resources in the Southern Grid region, exports from Guizhou to Guangxi and Guangdong increase. Finally, most of the expensive natural gas powerplant dispatch is eliminated.[4] As a result, the wholesale electricity cost drops to 206 billion Yuan/yr in the Regional Market Flex_Hydro case, 6% lower than in the core Regional Market scenario and 38% lower than in the core Baseline scenario.

5.4. Sensitivity analysis summary for regional market scenario

Fig. 10 summarizes the wholesale electricity cost impacts of the sensitivity cases on the Regional Market scenario. In addition to the three cases described above, it shows a case with both flexible hydro and additional transmission investments. In that case, the wholesale electricity cost is about 10% lower than in the core Regional Market scenario. Additional results can be found in the Supplemental Information.

[4] The Supplemental Information provides detailed dispatch results.

6. Conclusion and policy implications

Organized wholesale markets over large balancing areas provide multiple benefits in many developed economies: reducing the costs of serving consumers, improving renewable integration, and reducing environmental footprints. Our findings suggest that market-based operation of China's Southern Grid can increase efficiency and reduce costs in all provinces—reducing wholesale electricity costs by up to 35% for the entire region. Most of the cost reduction is captured by creating independent provincial markets while maintaining the current interprovincial import/export commitments, indicating that such a policy could provide near-term benefits in conjunction with appropriate fixed-cost recovery arrangements (Lin et al., 2019).

The market-driven reductions in systemwide electricity costs might help provide the resources necessary for fixed-cost compensation. In addition, in a wholesale electricity market, transactions with generators that have the lowest marginal costs would be settled at the market price, which is likely to cover their fixed costs as well—thus, fixed-cost compensation need not be entirely additional to wholesale electricity costs. Most of the compensation would be needed for generators with high marginal costs or those that do not get dispatched at all. Our preliminary analysis of fixed costs suggests that low-cost generators would have enough excess revenue to cover their own fixed costs and compensate high-cost generators, which may require financial restructuring of current contracts/payment mechanisms. However, this topic requires further investigation, which we intend to explore in our future work.

At the provincial level, Guangdong benefits most from markets, mainly because it uses high-cost coal and imports more than 30% of its energy, even in the Baseline scenario. With the region's highest-cost coal, Guangxi's largest cost reduction stems from expanding provincial markets into a regional market, mainly because Guangxi can then import more cheap Guizhou coal power and Yunnan hydropower. Guangxi's coal generation drops significantly as a regional market develops. Because Guizhou has the region's cheapest coal, establishing a provincial market reduces costs only slightly. In a regional market, Guizhou exports significant additional coal power and imports hydropower from Yunnan, but those exchanges are limited by transmission constraints. Once those constraints are removed, other provinces import substantial Guizhou coal power, which reduces net regional costs but increases Guizhou's costs. Yunnan generally benefits with transmission-constrained market development, because hydro generation increases significantly. Expanded transmission enables other provinces to import more from Yunnan, which reduces regional costs while increasing costs in Yunnan. Electricity markets could also reduce the Southern Grid's CO_2 emissions by up to 10% owing to more efficient thermal dispatch and avoided hydro/renewable curtailment—placing electricity markets among China's most cost-effective power-sector decarbonization strategies. We understand that our overall modeling approach of only including interprovincial transmission network risks missing the potential congestion issues in the intra-province transmission network. However, in our future work, we intend to model the transmission network in a more spatially resolved manner so we can assess the intra-province transmission issues as well as actual AC transfer limits (instead of DC limits) in the network.

The environmental and economic value of the market approach likely will increase over time. For example, our analysis based on 2016 electricity systems shows only a small reduction in regional wholesale electricity cost and CO_2 emissions due to expanding transmission in a regional market. However, as China increases its renewable generation to achieve environmental goals, a regional market with expanded transmission may facilitate lower costs and larger benefits. This topic requires further research. Finally, if China institutes a power-sector carbon market, market-based electricity pricing will be needed to enable pass-through of carbon prices. As carbon prices are factored into generation costs—and the costs of solar, wind, and storage technologies continue to decline—electricity markets would facilitate large-scale renewable integration and accelerate the transition to a clean power system in China (Lin, 2018).

Declarations of Competing Interest

None.

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Appendix A. Supplementary data

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