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Economic and CO_2 Emission Impacts of Electricity Market Transition in China: A Case Study of Guangdong Province

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Abstract

China's electricity system is the world's largest, in terms of installed generating capacity, and is also the world's largest single source of greenhouse gas emissions. In 2015, China embarked on reforms in its electricity sector that aim to introduce market mechanisms in wholesale pricing. This study provides a quantitative assessment of the economic and CO_2 emission impacts of transitioning to electricity markets in China, focusing on Guangdong Province. We find that market reforms deliver significant annual cost savings (21 to 63 billion yuan, 9%-27% reduction in total costs in a base case) to consumers in Guangdong, with smaller production cost savings (12 billion yuan, 13% reduction in production costs in a base case). Savings for consumers are accompanied by a large reduction in net revenues for coal and natural gas generators, raising concerns about generator solvency, longer-term resource adequacy, and the need for transition mechanisms. Market reforms increase CO_2 emissions in Guangdong, as a result of gas-to-coal switching, though higher hydropower imports from neighboring provinces could offset these emissions. CO_2 pricing has a limited impact on CO_2 emissions in the short run and has the potential to lead to significant wealth transfers. The most important benefit of market reforms will be in providing an economic framework for longer-term operations and investment.

Highlights

• Significant potential cost savings to electricity consumers from market reforms;

• Average market revenues fall to the level of a medium-efficient coal unit;

• Mechanisms to allow generators to recover their fixed costs are likely necessary;

• Emissions may increase in the short run, but can be offset by higher hydro imports;

• CO_2 pricing does not reduce emissions in the short run and may lead to significant wealth transfers.

Keywords

[1] a Lawrence Berkeley National Lab, b University of California, Berkeley, c Energy and Environmental Economics, d North China Electric Power University, e Tsinghua University

Electricity market, power sector reform, China, environment, carbon pricing

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1 Introduction

In 2002, China began an ambitious round of electricity reforms aimed at transitioning the sector toward wholesale competition. These reforms created separate, nationally-owned generating companies from the State Power Corporation, but efforts to create wholesale market mechanisms were put on hold following explosive growth in electricity demand in the wake of China's accession to the World Trade Organization. For more than a decade, a series of government-set generation tariffs filled the gap. These tariffs were set on an embedded (long-run average) cost basis and generators were operated (dispatched) to ensure fair cost recovery under these tariffs [1]. This approach created operating inefficiencies and led to higher emissions, as units with higher operating costs were dispatched when lower-cost and lower-emitting units were available [2].

In March 2015, the Communist Party of China and the State Council issued an overarching policy document ("Document 9") that officially resumed the reform process. Document 9 outlined series of broadly framed tasks for reforms: improving price formation; creating and expanding the institutions to support wholesale transactions; opening the retail market to new entrants; improving reliability and safety; and strengthening oversight of investment planning [3].

Document 9 was followed by several supporting policy documents, focusing on different aspects of reform, and the designation of reform pilots. Wholesale and retail competition, and more recently the creation of spot markets, is a centerpiece of reform efforts. Pilots for wholesale market reforms remain in the early stages, though are expected to accelerate in the next two to three years.

As China's largest provincial economy and its largest electricity consumer, Guangdong has been a key actor in the national reform process. Guangdong began a wholesale competition reform pilot in 2015, enabling large industrial customers to directly sign contracts with generators or to purchase their power through competitive retail providers. To facilitate this market, a consortium of government agencies and industry facilitated the creation of a power exchange that supports forward bilateral contracts and centralized monthly auctions for energy. Guangdong is in the process of establishing a spot market pilot [4].

Guangdong's market reforms will have regional implications. Like many of China's coastal provinces, Guangdong relies on imports for a large share of its peak demand and annual energy needs. Imports include point-to-point and network-network imports from neighboring provinces in the China Southern Grid, as well as longer-distance imports from dedicated facilities like the Three Gorges Dam. More recently, neighboring provinces, and in particular Yunnan Province, have experienced significant hydropower curtailment, leading to questions over whether more of this energy could be imported to Guangdong and at what price. Because of Guangdong's import dependence, questions around market design in Guangdong are fundamentally regional in nature.

This paper assesses the cost, environmental, and political economic impacts of electricity market reforms in Guangdong Province. The paper makes four main contributions. First, as far as we know this is the first quantitative assessment of the cost and environmental impacts of electricity market reform in China. There is a rich literature covering the institutional and political economy challenges to electricity reform in China [1,5–13], but much of it predates the current round of reforms and its emphasis on markets. Pollitt et al. [14] examines the power reform in Guangdong and provides an overview of its policies, operations, and potential effects on power sector operation and investment, but this work is qualitative.Kahrl et al. [2] find that the production cost savings from transitioning to least-cost dispatch in China's Guangxi Province would likely be small because larger coal generators with similar heat rates account for most non-hydro generation in the province. However, this analysis does not explicitly examine the rent transfers that occur as a result of the transition to a market clearing price or their implications for electricity market design.

Second, the analysis provides further evidence on the importance of well-designed transition mechanisms and of accounting for in electricity market design [15,16]. For instance, poor design of transition mechanisms — disincentives for long-term contracting, frozen retail rates, lack of clarity over tradeoffs between reliability and spot prices — were an important driver of the collapse of California's electricity market [17–19]. Evidence from this analysis suggests that a similar set of transition issues will be critical to address in China as well.

Third, the analysis provides a bridge between planning studies for reducing carbon dioxide (CO_2) emissions in China's electricity sector and the market and ultimately cost impacts of CO_2 pricing in electricity generation. Most studies of CO_2 abatement costs in China's electricity sector are engineering-economic estimates [20–22], which provide useful benchmarks of CO_2 price levels but not their impact on electricity market prices and the shifting of economic rents that occurs as a result of CO_2 pricing. The results in this analysis underscore the importance of considering the market and revenue impacts of CO_2 pricing in designing a portfolio of emission reduction policies.

Fourth, the paper provides a reasonably low-data-input approach to examining electricity market outcomes, balancing the detail needed to produce robust results with the transparency needed to understand how changing assumptions would affect the results. This approach could be applied in other national and sub-national contexts where data availability and quality is a concern.

The paper's results have implications and relevance beyond Guangdong and China. Guangdong has been at the forefront of electricity reforms in China and other provinces are likely to follow its lead. China's electricity system is of global importance, because of its size, links to the rest of the Chinese economy, and its contribution to regional air pollution and global climate change. China's electricity reforms over the next decade will shape the sector's environmental footprint, which has generated a significant amount of international interest in its reform process. Lastly, other large developing countries, including India, are considering market-oriented reforms in their electricity sectors. Many will face transition issues similar to those in China.

The rest of this paper is organized as follows. Section 2 briefly describes the methods used in the paper, with a more detailed description included as an appendix. Section 3 presents aggregate and generator-specific results. Section 4 distills key conclusions and discusses their implications.

2 Methods

Wholesale electricity markets facilitate transactions between electricity buyers and sellers. By doing so, well-designed markets will also facilitate the least-cost operation of the electricity system, whereby generators with the lowest operating costs are dispatched to meet electricity demand subject to generator and transmission constraints. Short-term electricity markets are typically cleared and settled using market clearing prices, which are based on the marginal cost of the generator dispatched to meet the next increment of demand. In these short-term markets, buyers and seller payments are based on market clearing prices.

Our analysis compares a market scenario, in which generators are dispatched in order of their operating costs with a market clearing price, to a reference scenario, which uses historical tariffs and an idealized, historical approach to operating generators. The reference scenario represents an idealized benchmark, as historical operating practices may have deviated from our assumptions and, relatedly, some of the cost savings from market reforms may have already been realized through bilateral markets. Nevertheless, given the lack of publicly-available data on actual operations or bilateral market transactions we argue that the reference case still provides a useful benchmark against which to compare market savings.

The market scenario assumes that a wholesale market for generation — however designed and implemented — facilitates economic ("merit order") dispatch. This assumption is consistent with theory and practice, where forward contract prices and regulated prices converge toward spot market pricing over time.

With market clearing prices, generators earn the difference between the market clearing price and their operating costs in each hour. In a market, these net revenues contribute to generators' recovery of their investment, tax, and other fixed costs. Generator net revenues are often expressed on a per kilowatt per unit time basis (e.g., yuan/kW-yr), which facilitates comparison with their anticipated recovery of fixed costs over that timeframe (e.g., one year).

Market pricing may cause revenue shortfalls for generators, leading to concerns over reliability or the achievement of environmental goals. To address this concern, we consider two additional market scenarios in which generators receive additional scarcity revenues, which compensate generators for reliability services, or premium payments, which compensate wind, solar, nuclear, and hydro generators for their above-market costs.

We use a broad definition of the term 'scarcity payment' throughout to refer to any payments made to generators by electricity consumers that compensate them for their availability during supply-constrained periods, such as payments made via scarcity prices or capacity markets.[2] We use 'premium payment' to refer to the above-market cost (if any) of hydropower, solar, wind, and nuclear generation.

Table 2 summarizes key assumptions of the three market scenarios: market only, low scarcity and premium payments (SPP), and high SPP.

Table 2. Three Market Scenarios

Scenario	Scarcity payment	Premium payment
Market only ("Market Only")	None	None
Low SPP payments ("Low SPP")	100 yuan/kW-yr, paid to all qualifying generators	Difference between energy market and scarcity revenues and current feed-in tariffs
High SPP payments ("High SPP")	400 yuan/kW-yr, paid to all within-province thermal generators	Difference between energy market revenues and current feed-in tariffs

For hydropower, solar, wind, and nuclear generation, premium payments for different resources (PPY_i for resource i) in the High SPP and Low SPP scenarios are shown in equations 1 and 2

$$PPY_i^{High\,SPP} = FIT \times \sum_h GEN_{h,i} - \sum_h MCP_h \times GEN_{h,i} \quad (1)$$

$$PPY_i^{Low\,SPP} = FIT_i \times \sum_h GEN_{h,i} - \sum_h MCP_h \times GEN_{h,i} - SCP \times CPC_i \quad (2)$$

where FIT_i is the feed-in tariff for resource i, $GEN_{h,i}$ is generation in hour h for resource i, MCP_h is the market clearing price in hour h, SCP is the scarcity payment

[2] More specifically, in this paper we make a distinction between "scarcity payments" and "scarcity pricing." We use "scarcity payments" and "scarcity revenues" more broadly to refer to payments that incentivize generators to be available when supply is scarce. Scarcity payments could include payments to generators from a scarcity reserve pricing mechanism (e.g., ERCOT's operating reserve demand curve or Germany's high energy market price caps) or a centralized or bilateral capacity market, and are the portion of an equivalent market price duration curve (PDC) where prices exceed a variable cost-based benchmark. In a competitive environment, total scarcity payments — the area between the PDC and the benchmark cost curve — should, in principle, be the same regardless of approach (e.g., scarcity reserve pricing, capacity payments). We use "scarcity pricing" to refer to market prices that reflect scarcity conditions, as would be the case in energy-only market.

(100 yuan/kW-yr or 400 yuan/kW-yr) and CPC_i is the reliable capacity contribution for resource i (see appendix A for details).

In the “Market Only” scenario, total generation costs to electricity consumers in Guangdong only include energy market costs, absent any form of scarcity payments to generators. In the “Low SPP” scenario, all generators and imports receive some form of a scarcity payment, as would be the case in a capacity market or with scarcity reserve pricing, with a relatively low payment (100 yuan/kW-yr) that reflects current oversupply if imports are able to participate in price formation for scarcity payments.[3] Hydro, wind, solar, and nuclear generators are paid the difference between their feed-in tariff and their energy market and scarcity revenues.

In the “High SPP” scenario, all thermal generators within Guangdong receive a much higher scarcity payment (400 yuan/kW-yr), reflecting a political decision to compensate thermal generators for above-market costs at a price close to the gross cost of new capacity.[4] Hydro, wind, solar, and nuclear generators are paid the difference between their feed-in tariff and their energy market revenues. The “Low SPP” and “High SPP” scenarios are intended to represent two ends of a spectrum for the level of scarcity revenues in the market case scenarios.

We approximate economic dispatch in these market cases using a “stack” model. The stack model orders generators in each hour in order of operating (variable) cost to meet demand, ignoring generator and transmission constraints. This approach provides a reasonable, high-level estimate of changes in cost and intuition for structural drivers of change, without the need for more detailed operational data and assumptions.

Because it ignores generator and transmission constraints, the stack model will tend to overstate changes in the market case, and thus any market case savings. However, the main factors that drive changes in dispatch and costs between the reference and market cases are less affected by detailed constraints. Given the need for transparency due to data limitations, the stack model thus provides a reasonable balance between simplicity and completeness.

Both the market and reference scenarios use a common set of key “base case” assumptions, shown in Table 1. We examine the impact of these assumptions on the results through sensitivity analysis.

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[3] Capacity market prices in a market that has excess generation will tend to fall to the net going forward costs for the marginal capacity resource. The estimate here uses a ratio (~20%) between capacity market clearing prices in an oversupplied market and gross cost of new energy (CONE) based loosely on estimates from the U.S. For instance, the gross CONE used in the PJM 2019/2020 and 2020/2021 Base Residual Auctions is ~$130/kW-yr, whereas PJM capacity market prices in years with excess supply have generally been around or less than $100/MW-day ($36.5/kW-yr) [39]. In California, Resource Adequacy contract prices were ~$36/kW-yr in 2016, relative to a gross CONE of ~$200/kW-yr for a new CCGT or CT [40,41].

[4] The gross capacity (fixed) cost of a new coal-fired and gas-fired generator in China has generally ranged from 400 to 500 yuan/kW-yr during the past decade, based on overnight capital costs of 4,000 to 5,000 yuan/kW.

Table 1. Base Case Values for Sensitivity Variables

Variable	Base Case Value
Net imports	28% of total consumption
Net import shape	On-peak and off-peak blocks
Hydropower shape	On-peak and off-peak blocks
Fuel prices	Coal: 800 yuan/tce (571 yuan/ton) Natural gas: 1,870 yuan/tce (2.3 yuan/m^3)
Solar and wind capacity	Wind: 2,680 MW Solar: 1,560 MW
CO_2 price	0 yuan/tCO_2

A detailed description of methods, assumptions, and data sources is included in appendix A.

3 Results and Discussions

The results are oriented around a base case scenario, where the values of six key variables (Table 1) are constrained close to historical values. We then explore incremental sensitivities around these key variables. For the overall results, we report three key metrics: (1) total generation costs, which include all payments made to generators, using tariffs in the reference case and energy market, scarcity, and premium payments in the market case; (2) production costs, which are limited to generator operating costs but include any CO_2 emission costs; and (3) within-province CO_2 emissions.

The results — and in particular cost savings to consumers and net revenue impacts on generators — depend on whether and how electricity consumers in Guangdong pay for any above-market costs embedded in current generation tariffs in the form of SPP.

3.1. Overall Results

Economic dispatch in the market case scenarios leads to a significant reduction in total generation costs, a moderate reduction in production costs, and a small increase in CO_2 emissions (Table 3). Total generation costs fall from 233 billion yuan in the reference case to 170 to 212 billion in the market case scenarios, a savings of 21 to 63 billion yuan (9% to 27%). Production costs fall from 94 billion yuan in the reference cost to 82 billion in the market case, a savings of 12 billion yuan (13%). CO_2 emissions increase by 7 million tons (MtCO_2), or by around 3%. Table 3 illustrates that the extent of scarcity and premium payments across the market case scenarios is primarily a question of fixed cost allocation and does not affect operations (production costs or emissions).

Table 3. Overall Results

			Market Case Scenario		
Metric	**Units**	**Reference Case**	**Market Only**	**Low SPP**	**High SPP**
Total generation costs	Billion yuan (% reduction)	233	170 (-27%)	193 (-17%)	212 (-9%)
Production costs	Billion yuan (% reduction)	94	82 (-13%)	82 (-13%)	82 (-13%)
CO_2 Emissions	Million tons CO_2 (% reduction)	224	231 (+3%)	231 (+3%)	231 (+3%)

Table 4 shows a more detailed breakdown of total generation costs between the reference and market cases. Without scarcity and premium payments, total generation costs fall by 63 billion yuan. Import costs increase by 3 billion yuan, as Guangdong's average market price is higher than its reference import tariff. Adding scarcity and premium payments in the Low SPP and High SPP scenarios increases total generation costs by 24 to 42 billion yuan relative to the Market Only scenario, but total generation costs in the High SPP and Low SPP scenarios still fall by 21 to 40 billion yuan, respectively, relative to the reference case (Figure 1). Total generation cost savings are savings to electricity consumers.

Table 4. Breakdown of Total Generation Costs (Billion Yuan) in the Reference and Market Scenarios

		Market Scenario		
Cost Category	**Reference**	**Market Only**	**Low SPP**	**High SPP**
Within-province energy costs	189	123	123	123
Import energy costs	44	47	47	47
Scarcity payments	—	—	12	29
Premium payments	—	—	12	13
Total generation costs (sum of above)	233	170	193	212

Sums may not equal totals due to independent rounding.

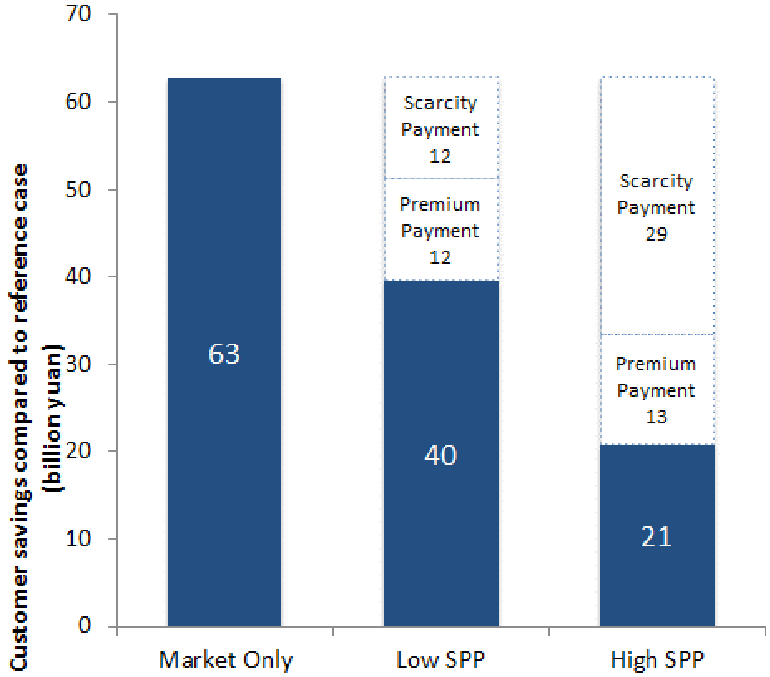


Figure 1. Premium Payments, Scarcity Payments, and Customer Savings in the Market Only, Low SPP, and High SPP Scenarios

Three main factors drive total generation cost savings: (1) a reduction in energy margins for thermal generators; (2) natural gas to coal switching; and (3) average heat rate improvements for coal and gas units.

***Reduction in energy margins for thermal generators*.** Current average tariffs for coal generators are high relative to costs. At 303 yuan/MWh, average energy market prices are close to the marginal cost of a mid-merit (medium-low efficiency) coal unit. At 306 yuan/MWh, average revenues for coal generators are close to this average market price. For coal generators, most of the difference between average revenues and their average reference tariff (450 yuan/MWh) would be a contribution to generator fixed costs. However, this difference of around 150 yuan/MWh — around 600 yuan per kW per year (yuan/kW-yr) — is higher than the fixed costs of a new coal generator.[5] As a result, even after making 400 yuan/kW-yr scarcity payments to all within-province thermal generators in the High SPP scenario, total generation costs fall (Figure 2).

[5] The conversion between yuan/kWh and yuan/kW-yr is annual operating hours, or in this case 3,932 hours per year (150 yuan/MWh * 3,932 hrs/yr = 590 yuan/kW-yr).

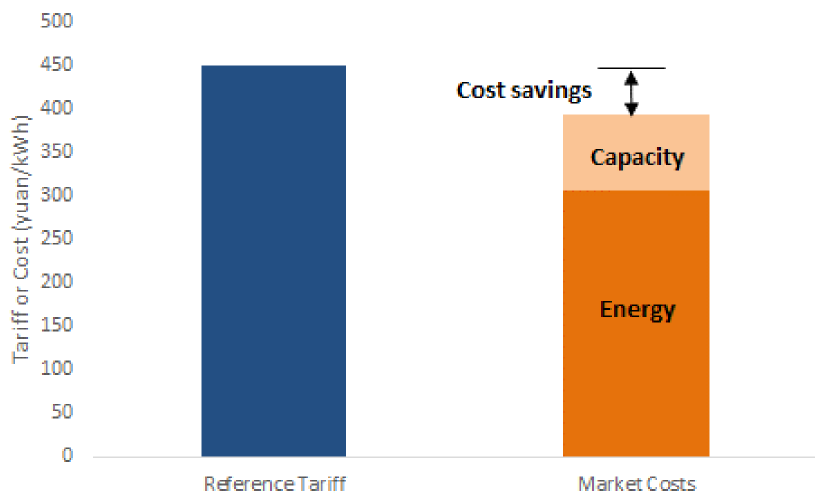


Figure 2. Illustration of Cost Savings for Coal Generation in the Market Case, Relative to an Average Reference Tariff

Natural gas to coal switching. Natural gas generation is significantly more expensive to operate than coal generation, due to Guangdong's high delivered natural gas prices. In a merit order dispatch, coal generation displaces natural gas generation in the dispatch order and natural gas units effectively become a peaking resource during the summer. Average annual operating hours for coal units increase from 3,932 in the reference case to 4,543 in the market case, while average annual operating hours for natural gas units fall from 3,200 in the reference case to 154 in the market case (Figure 3). Because coal generation has lower operating costs, this shift from natural gas to coal reduces production costs. On its own, this shift would lead to a large increase in CO_2 emissions. However, a decline in the average heat rate of coal and gas generators, as a result of increasing operating hours for more efficient generators, partially offsets this effect and leads to a relatively small overall increase in CO_2 emissions in the market case.

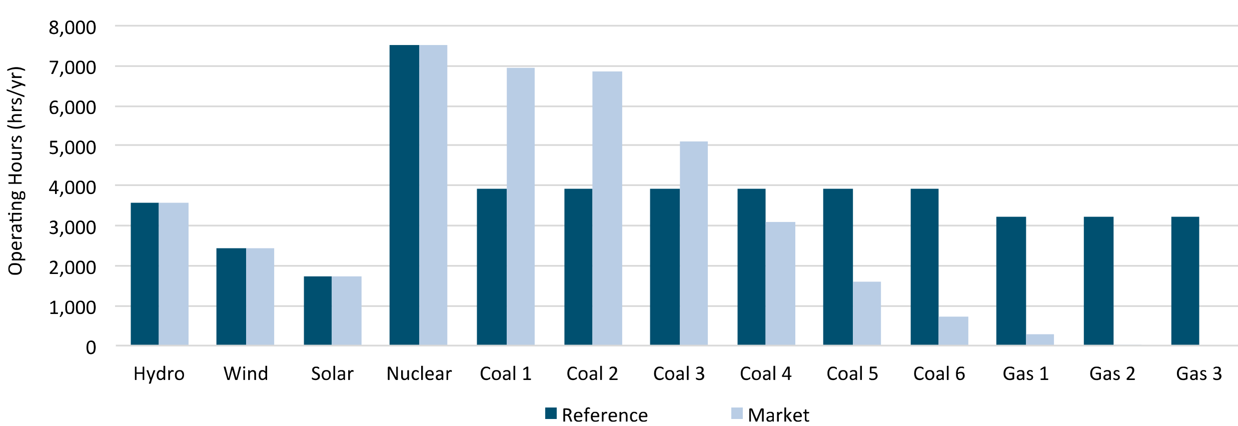


Figure 3. Annual Operating Hours in the Reference and Market Cases, by Generator Type[6]

Average heat rate improvements for coal and gas units. Enabling more efficient coal and gas generators to displace less efficient generators in the dispatch order reduces average heat rates for coal generators by 3% and gas generators by 11%. Reductions in average heat rates for both coal and gas generators reduce production costs. Coal generation heat rate improvements dominate this effect because coal generation accounts for a much larger share of total generation.

Table 5 summarizes the changes in average operation and performance for coal and gas units in the reference and market cases. Disentangling the effects of natural gas to coal switching and average heat rate improvements is complicated by the fact that average heat rates and operating hours are changing simultaneously.

Table 5. Average Coal and Gas Generator Operations and Performance in the Reference and Market Cases

		Coal		Gas	
	Units	**Reference**	**Market**	**Reference**	**Market**
Operating hours	Hours/yr	3,932	4,543	3,200	154
Average net heat rate	gce/kWh	313	302	250	222
Production costs	Billion yuan/yr	66	74	18	1
CO_2 emissions	Million tons CO_2	206	230	18	1

3.2 Generator-Specific Results

Each generator earns revenues in the energy market equal to the product of an hourly market clearing price and the generator’s net output in that hour. Inframarginal generators — those whose costs are lower than the market clearing price — earn net revenues that contribute to fixed cost recovery. Fixed costs include fixed O&M costs, depreciation, debt interest, return on equity, and non-marginal taxes.

Economic dispatch with a market clearing price produced an average market price of around 300 yuan/MWh. This average price is significantly less than the current benchmark tariff for coal units (450 yuan/MWh), underscoring a large reduction in net revenues for coal generators and raising concerns about their financial solvency and, by extension, system reliability given that within-province coal units account for around 60% of Guangdong’s peak generation needs. Market reforms similarly depressed net revenues for natural gas, nuclear, wind, and solar generators, but slightly increased them for hydro generators.

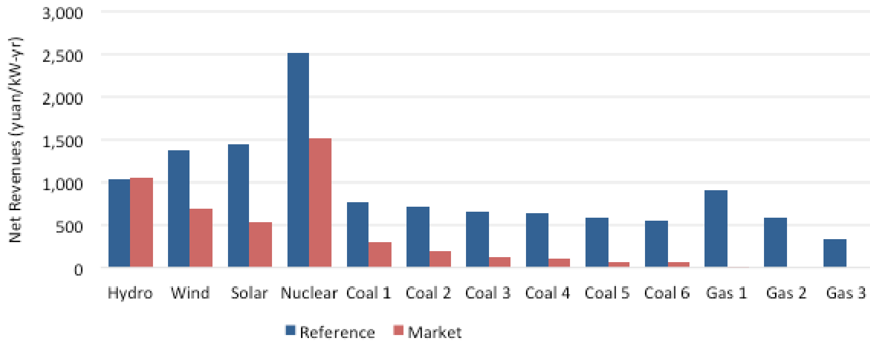
[6] Note: Coal 1 represents the most efficient type of coal generation, Coal 2 is the second most efficient type of coal generation, and so on. Gas generators are also aggregated on the basis of efficiency, with Gas 1 being the most efficient type of gas generation and Gas 3 being the least efficient.

Figure 4a show net revenues for each generator type on a yuan/kW-yr basis — annual market revenues minus fuel and variable O&M costs per kW of installed capacity. For coal generators, more efficient units earn significantly higher net revenues (e.g., Coal 1 earns 293 yuan/kW-yr) than less efficient ones (e.g., Coal 6 earns around 62 yuan/kW-yr). Net revenues for natural gas units are very low, reflecting the fact that, when they are operating, they are typically the marginal generator.

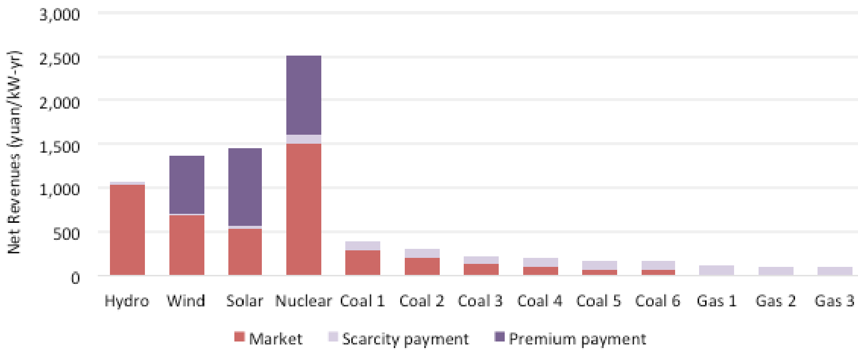
Given reduced net revenues for generators, some form of side payments to generators may be needed to meet reliability, renewable energy, and emissions goals. Our results show that adding premiums for wind, solar, and nuclear generation and scarcity payments increases revenues for generators in the Low SPP and High SPP scenarios (Figure 4b and Figure 4c).

Figure 4b illustrates that, in the Low SPP scenario, where all within-province generators and imports were eligible to receive 100 yuan/kW-yr payments for their availability during peak demand periods and non-thermal generators were paid a premium payment that was the difference between their feed-in tariff and their market and scarcity revenues, scarcity payments to hydro, wind, solar, and nuclear generators are a small share of total net revenues, but can be a significant portion of net revenues for less efficient coal and natural gas generators. However, net revenues (including scarcity payments) of thermal power plants are still much lower than what those under the reference scenario.

Figure 4c shows that in the High SPP scenario, where thermal generators were paid 400 yuan/kW-yr for their availability during peak demand periods and non-thermal generators were paid a premium payment that was the difference between their feed-in tariff and market revenues, net revenues to Coal 1 (693 yuan/kW-yr) are closer to net revenues under the average feed-in tariff (830 yuan/kW-yr) and could potentially support new investment, but there is no indication that Guangdong needs new generation investment in the near term.



(a)



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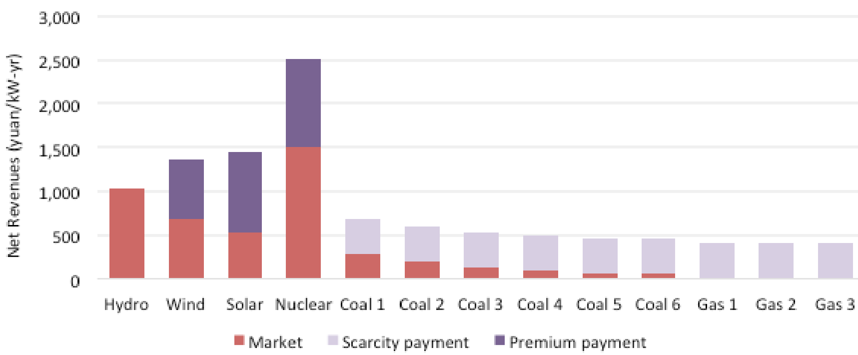

(c)

Figure 4. Net Revenues for Each Generation Type[7]

(a) Net Market Revenues under Reference Scenario and Market Only Scenario

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[7] Note: For reference, the total annual fixed costs for coal and gas units in China (including financing costs) are between 400 and 500 yuan/kW-yr. Based on estimates from E3's Generation Cost Model for China. Model is available upon request.

(b) Net Market Revenues, Premium Payments, and Scarcity Payments for Each Generation Type under Low SPP Scenarios

(c) Net Market Revenues, Premium Payments, and Scarcity Payments for Each Generation Type under High SPP Scenarios

3.1 Sensitivities

The results may be sensitive to several variables, four of which we focus on in this analysis: (1) the timing and level of net imports; (2) coal and natural gas fuel price levels; (3) the timing and level of hydro resources, and levels of solar and wind generating capacity;[8] and (4) CO_2 prices. This section examines each of sensitivities around these variables in greater detail, by assessing their impact on total generation costs, production costs, and CO_2 emissions in the Low SPP scenario. We use the Low SPP scenario because it represents a middle-of-the-road estimate of total generation costs, though we explore areas where total generation costs would be structurally different in the Market Only or High SPP scenarios. Production costs and CO_2 emissions do not vary among scenarios.

3.1.1 Net Imports

Currently (in the reference scenario), Guangdong's annual electricity imports are determined bilaterally through negotiations. In the market scenario, they are determined through differences in marginal cost: if the market clearing price in Guangdong is higher than the marginal cost of generation in surrounding provinces, those provinces will find it economically attractive to export power to Guangdong.

Changes in import levels may occur on both the alternating current (AC) interties connecting Guangdong with its neighbors, and the point-to-point direct current (DC) and AC lines that directly connect Guangdong's electricity system with dedicated hydro and thermal power plants in neighboring provinces. In both cases, current indications are that import levels are suppressed; that is, it would be economically efficient for Guangdong to import more electricity and rely more on neighboring provinces to provide peak capacity.

We examine two sensitivities for import levels: (1) an incremental case, where imports rise from current levels of 28% to 35% of total annual electricity consumption, and (2) a high case, where imports rise to 40% of total consumption.

With the price-taker assumption for imports, increasing net imports reduces total generation costs, within-province production costs, and within-province CO_2 emissions (Figure 5, Table 6). Incremental expansion of imports displaces higher cost generation in Guangdong, but this effect saturates somewhat at higher import levels once higher cost generation has already been displaced. Each percentage point increase in imports decreases within-province CO_2 emissions by about 5 million tons. Increasing the level of imports from the current 28% to 35 and 40% in the future would lead to about 15% and 25% reduciton in CO_2 emissions, respectively, while reducing total generation costs by 3% and 5%.

[8] This sensitivity is more forward looking than the others, but reflects the fact that lead times for wind and solar generation are often much shorter than for conventional hydro, nuclear, and thermal generation.

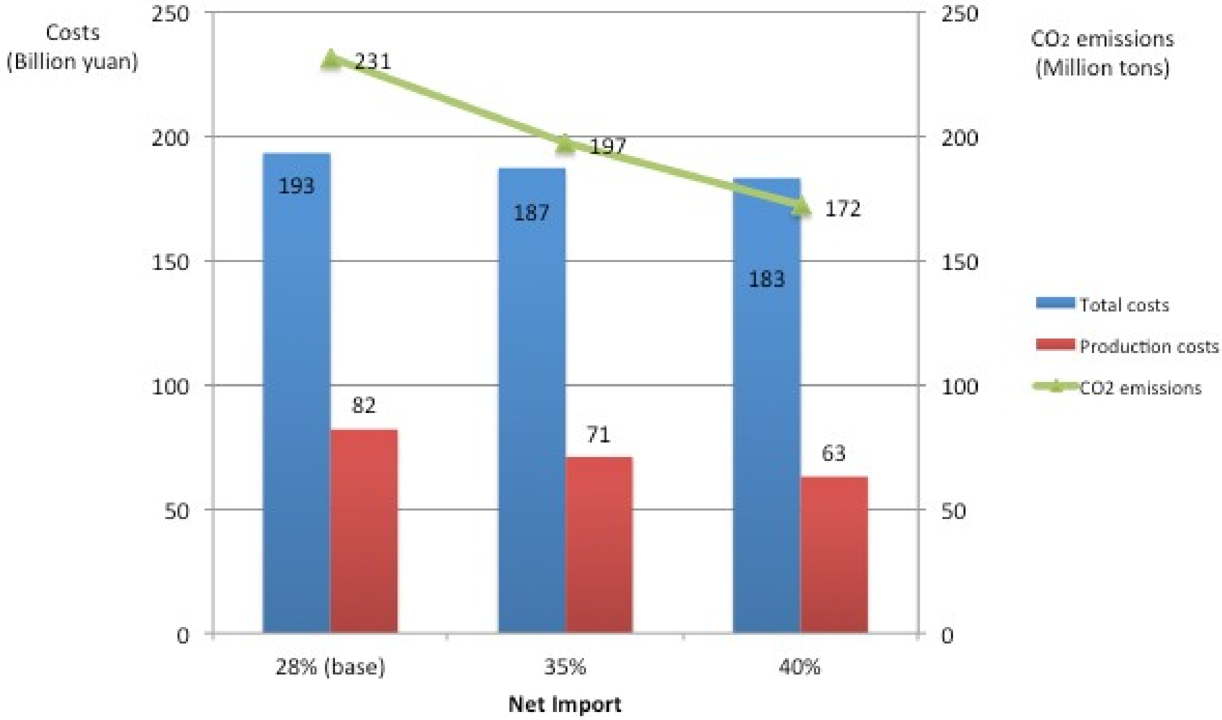

Figure 5. Guangdong Market Costs and CO_2 Emissions Under Different Levels of Net Imports

Table 6. Guangdong Market Results for Different Levels of Net Imports

		Net Imports		
	Unit	28% (base)	35%	40%
Total generation costs	Billion yuan	193	187	183
Production costs	Billion yuan	82	71	63
CO_2 emissions	Million tons CO_2	231	197	172

Imports affect total generation costs and within-province production costs differently, as Table 6 illustrates. Higher imports result in larger reductions in production costs than in total generation costs, because in some hours imports are replacing generation in Guangdong without changing the market clearing price.

If import levels into Guangdong are allowed to increase, import levels will likely also become more variable because a significant portion of Guangdong's imports are from hydropower. Like the California Independent System Operator (CAISO) market in California, average market prices in Guangdong would be heavily influenced by inter-annual variability in precipitation and hydropower output.

In the reference case, imports are assumed to be block loaded in on-peak and off-peak periods ("TOU block"). Allowing greater flexibility in import flows would allow the timing of imports to better match hourly marginal generation costs in Guangdong. We approximate this effect by examining a sensitivity case in which imports follow load, with the "shape" of imports matching the load shape ("load following").

As Table 7 shows, the primary effect of allowing more flexibility in imports is in dampening market prices (reducing total generation costs), whereas the effect on production costs and CO_2 emissions is relatively limited. This market price effect diminishes at higher levels of imports.

Table 7. Results for Different Import Shapes and Levels

		28% Imports		35% Imports	
	Unit	TOU block (base)	Load following	TOU block	Load following
Total generation costs	Billion yuan	193	190	187	185
Production costs	Billion yuan	82	82	71	70
CO_2 emissions	Million tons CO_2	231	231	197	196

Whether the interprovincial and interregional transmission system would be able to support higher levels of imports into Guangdong is unclear. In our base case, imports reach a maximum of 25 GW. In the 35% sensitivity, maximum imports rise to 31 GW (35 GW load following); in the 40% sensitivity they increase to 35 GW (40 GW load following).

3.1.2 Fuel Prices

The impact of coal and natural gas fuel price levels on the outcomes of market reforms is complex, because in theory it should depend on what the impact of fuel price changes would have been in a fictitious counterfactual world. From a more practical and political perspective, the most important reference for considering the fuel price impacts of reforms is current total generation costs, which captures the significant historical lag between fuel price changes and generation tariff changes in China.

For reference, our base case coal prices are 800 yuan per ton coal equivalent, or 571 yuan per raw ton of 5,000 kCal/kg coal. Our base natural gas prices are 1,870 yuan per ton coal equivalent, or 2.3 yuan per m^3.

Higher/lower coal prices tend to reduce/increase total generation cost savings in the market case (Table 8). At an extreme, total generation costs in the market case would be higher than in the reference case if delivered coal prices rose to 1,100 yuan per ton coal equivalent (tce), or around 790 yuan per raw ton of 5,000 kCal/kg coal. This threshold is lower (just over 900 yuan/tce) in the High SPP case.

Table 8. Results for Different Coal Prices

			Coal Price (yuan/tce)				
	Unit	**Case**	**700**	**800 (base)**	**900**	**1,000**	**1,100**
Total generation costs	Billion yuan	Reference	233	233	233	233	233
		Market	179	193	208	222	236
Production costs	Billion yuan	Reference	87	94	102	109	116
		Market	74	82	90	99	107
Production cost savings	Billion yuan	n/a	13	12	11	10	9
CO_2 emissions	Million tons CO_2	Market	231	231	231	231	231

Differences between total generation costs in the reference and market cases reflect transfers and different risk allocations between generators and consumers. Generators increase/decrease profits in the reference case if coal prices fall/rise because the generation tariff remains fixed in the short run. In the market case, market prices adjust to allow generators to recover changing fuel costs. Consumers are protected from rising coal costs in the reference case, but lose any upside from lower coal costs.

Although total generation costs are insulated from fuel price changes in the reference case, production costs are not. That is, changes in fuel costs will affect total operating costs regardless of whether generation tariffs adjust to account for fuel cost changes. As Table 8 shows, higher coal prices will tend to reduce production cost savings between the reference and market cases, because they reduce the benefits of coal to natural gas switching. At the coal price range in Table 8, higher coal prices have no impact on dispatch order and CO_2 emissions in the market case.

Higher/lower natural gas prices similarly reduce/increase market case benefits because natural gas generation tariffs are fixed in the short run. However, the effect of natural gas prices on the results is limited because natural gas accounts for such a small share of generation (less than 1%) in the market case (Table 9). Higher natural gas prices have the opposite effect as coal prices on production cost savings, because they increase the benefits of coal to natural gas switching.

Table 9. Results for Different Natural Gas Prices

		Natural Gas Price		
	Unit	**1670 yuan/tce (2.1 yuan/ m^3)**	**1870 yuan/tce (2.3 yuan/ m^3) (base)**	**2070 yuan/tce (2.5 yuan/ m^3)**
Total generation costs	Billion yuan	191	193	195

Production costs	Billion yuan	82	82	82
Product cost savings	Billion yuan	10	12	14
CO_2 emissions	Million tons CO_2	231	231	231

3.1.3 Hydropower, Wind, and Solar

3.1.3.1 Hydropower Output

The amount and hourly shape of within-province hydropower may affect market outcomes through its impact on market prices and total fixed costs. In the base case, hydropower is assumed to be dispatched in on-peak and off-peak blocks ("TOU block" in Table 10). Allowing hydropower to be dispatched more flexibly, in this case by allowing it to follow load ("load following"), reduces costs and emissions, but as Table 10 shows this effect is small.

Table 10. Results for Different Hydro Shapes and Hydro Operating Hours

		Hydro Shape		Hydro Operating Hours	
	Unit	**TOU block (base)**	**Load following**	**3,550 (base)**	**2,096 (2015)**
Total generation costs	Billion yuan	193	192	193	200
Production costs	Billion yuan	82	82	82	88
CO_2 emissions	Million tons CO_2	231	231	231	248
Average market price	yuan/MWh	303	301	303	316

2016 was a "wet" hydro year, meaning that operating hours for hydropower were high relative to recent history. Reducing hydro operating hours to 2015 levels (2,096 hours) increases total costs, production costs, market prices, and CO_2 emissions, as within-province thermal generation — mostly coal but some natural gas — makes up the shortfall.

3.1.3.2 Wind and Solar Generation Capacity

Wind and solar generation affect market prices through annual variation in generation and through increases in installed capacity. In this analysis, we focus on the latter effect, examining the impact of a doubling and tripling of base case wind and solar installed capacity. Table 11 shows that a doubling and tripling of wind and solar generation capacity lead to increases in total costs through higher premiums (about 2%), and decreases in production costs, average market prices, and CO_2 emissions (-7%) by displacing more expensive and inefficient thermal generation. However, given the fall in solar and wind generation tariffs, increasing renewable generation could be still an effective strategy to reduce carbon emissions.

Table 11. Results for Different Levels of Wind and Solar Installed Generation Capacity

		Wind and Solar Installed Capacity		
	Unit	**4,240 MW (base)**	**8,480 MW**	**12,720 MW**
Total generation costs	Billion yuan	193	195	197
Production costs	Billion yuan	82	80	77
CO_2 emissions	Million tons CO_2	231	223	215
Average market price	yuan/MWh	303	300	297

3.1.4 CO_2 Prices

Imposing CO_2 prices on thermal generators leads to increases in production and total generation costs. The effect on total generation costs will be larger than the impact on production costs due to the embedding of CO_2 costs into market clearing prices. For instance, if a less efficient coal generator is on the margin, its price, and thus the market clearing price, will increase by its marginal emissions rate multiplied by a CO_2 allowance price. This higher market clearing price affects all load, rather than just the portion that is served by the less efficient coal generator. Generators that have lower emissions rates than this less efficient coal generator will increase their economic rents.

As Table 12 and Figure 6 show, these price impacts are substantial. A CO_2 price of 50 to 200 yuan/tCO_2 increases total generation costs by 21 to 87 billion yuan but has little to no impact on dispatch order and CO_2 emissions in the short run. A 500 yuan/tCO_2 price leads to larger reductions in emissions but increases total and production costs by more than a factor of two. Maintaining CO_2 emissions at the reference level (231 million tons CO_2, “ref” in Table 12) requires a CO_2 price of around 260 yuan/tCO_2. Because coal generation drives CO_2 emission costs, most of the increase in market clearing prices with CO_2 pricing occurs during non-peak periods, when gas generators are not operating.

Table 12. Guangdong Market Results for Different CO_2 Price Levels

		CO_2 Price (yuan/tCO_2)						
	Unit	**0 (ref)**	**0**	**50**	**100**	**200**	**300**	**500**
Total generation costs	Billion yuan	233	193	214	235	280	325	420
Production costs	Billion yuan	94	82	94	105	128	151	191
CO_2 emissions	Million tons CO_2	224	231	231	231	229	208	201

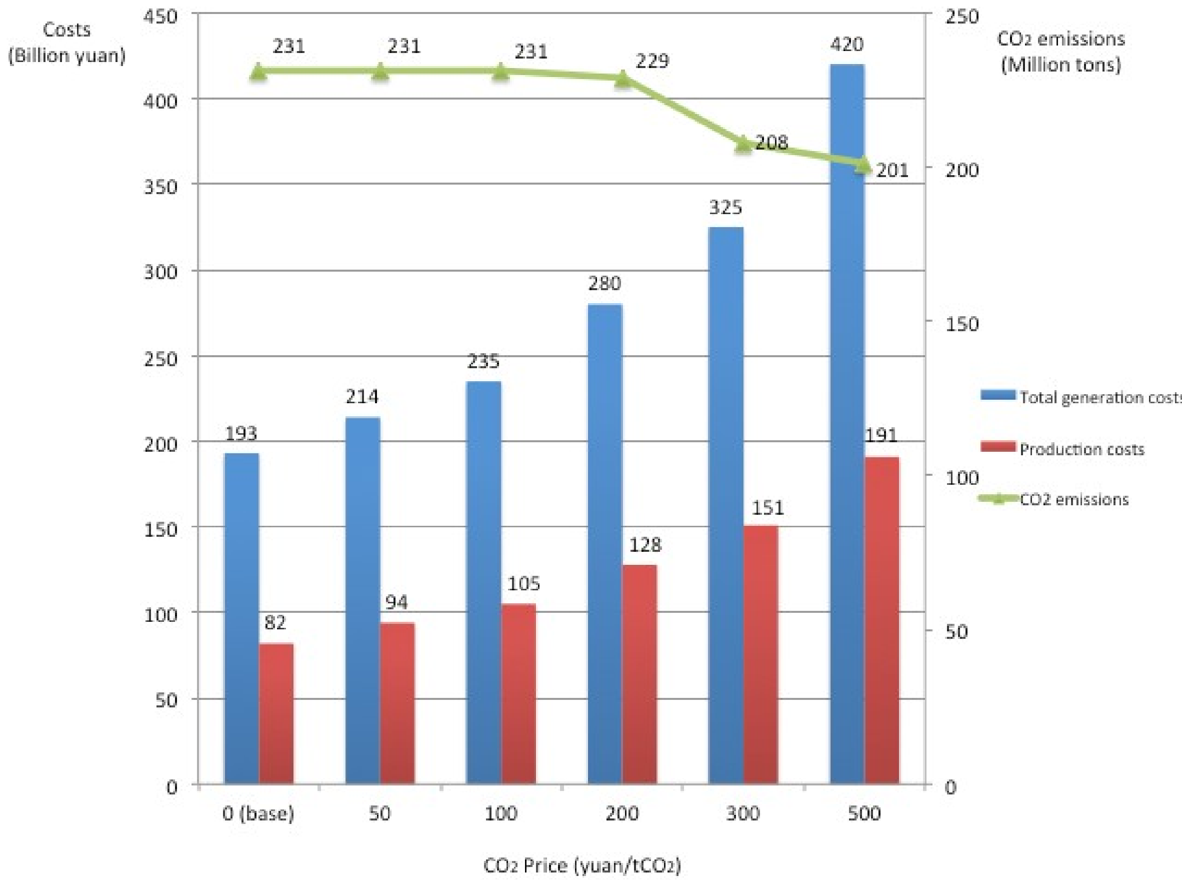

Figure 6. Cost and CO_2 Emissions Under Different CO_2 Price Levels

CO_2 costs impact generator gross and net revenues, and in doing so influence scarcity and premium payments to generators. For hydro, wind, solar, and nuclear generators, higher market prices resulting from the passthrough of CO_2 costs increase gross revenues without increasing their costs, leading to higher gross revenues and lower premium payments. Above 500 yuan/tCO_2, for instance, premium payments become negligible.

By impacting net revenues for thermal generators, CO_2 pricing will also influence the level of any scarcity payments made to these generators, though we are not able to capture these effects in our analysis. In general, market price effects from CO_2 costs will tend to increase net revenues for more efficient thermal generators (Coal 1, Gas 1, Coal 2) and reduce them for less efficient coal generators (Coal 3-6). This reduction in net revenues for less efficient coal units is due to higher costs, and thus lower economic rents, when gas generators are on the margin. The impact of changes in net revenues on scarcity payments will depend on which generator is on the margin for price formation. For instance, in a capacity market, if less efficient coal or gas generators are setting the market clearing price, capacity prices may rise. If more efficient generators are setting price, capacity prices may fall.

Some of the impact of high CO_2 costs on retail rates could be mitigated by returning revenues from CO_2 allowance auctions or taxes to consumers. The maximum amount that can be returned is the total revenue generated by the auctions or taxes, equal to the CO_2 price multiplied by total emissions. For instance, with a 200 yuan/tCO_2 price the total returnable revenue would be 46 billion yuan. The difference between this amount and the change in total generation costs between the 200 yuan/tCO_2 and the base case in Table 12 (87 billion yuan) reflects the net of: (1) increased economic rents to generators, particularly to non-fossil fuel generators; (2) lower premium payments to generators as a result of higher gross revenues to hydro, wind, solar, and nuclear generators. With a 200 yuan/tCO_2 CO_2 price, net costs increase by 41 billion yuan, or a 21% increase over the base case. Most of the increase in economic rents, net of reduced premium payments, is for hydro generators.

The results in Table 12 illustrate that, for provinces with minimal curtailment of hydro, wind, and solar generation and where imports are constrained, CO_2 pricing is an expensive means of achieving CO_2 emission reductions in the short run. In Guangdong, CO_2 prices must cover the spread between the marginal cost of coal and natural gas generation to change dispatch. Table 13 shows breakeven CO_2 prices for each natural gas and coal category. This implies that for Gas 1, a 165 yuan/tCO_2 price is needed for it to displace Coal 6 in the merit order, a 192 yuan/tCO_2 price is needed to displace Coal 5, and so on. Beyond replacing some inefficient coal generation with efficient gas generation, coal-gas switching is an expensive mitigation strategy in China because of the large spread between coal and gas prices.

Table 13. Breakeven CO_2 Prices (yuan/tCO_2) for Different Natural Gas and Coal Generators

	Coal 1	Coal 2	Coal 3	Coal 4	Coal 5	Coal 6
Gas 1	372	294	251	222	192	165
Gas 2	782	627	545	491	437	389
Gas 3	1,256	985	851	765	681	608

This analysis focuses on short-term market impacts, whereas a goal of CO_2 pricing is to influence longer-term investment decisions. Table 14 shows a similar simplified CO_2 price breakeven analysis for hydro, wind, solar, and nuclear generation replacing coal, based on current feed-in tariffs for hydro, wind, solar, and nuclear and, as a simplification, assuming no capacity value for new resources. With modest CO_2 prices, hydro and nuclear could be cost-competitive with less efficient coal, whereas average prices for wind and solar would need to fall significantly — at least if current costs are close to feed-in tariff levels — for these resources to be cost-competitive with lower CO_2 prices.

Table 14. Breakeven CO_2 Prices (yuan/tCO_2) for Hydro, Wind, Solar, Nuclear and Coal Generator Categories

	Coal 1	Coal 2	Coal 3	Coal 4	Coal 5	Coal 6
Hydro	58	35	21	11	0	-10

Wind	403	356	328	308	287	266
Solar	760	689	647	616	584	553
Nuclear	224	190	169	154	138	123

4 Conclusions

This study examined the economic and CO_2 emissions impacts of market reforms in Guangdong. We found that the economic dispatch of existing power plants, facilitated by reforms, reduced total (fixed and operating) generating costs by 21 to 63 billion yuan per year (9-27%), reduced production costs by 12 billion yuan per year (13%), and increased CO_2 emissions by 7 million tons (3%) for the year of this analysis (2016).

Economic dispatch with a market clearing price produced an average market price of around 300 yuan/MWh. This average price is significantly less than the current benchmark tariff for coal units (450 yuan/MWh), implying a large reduction in net revenues for coal generators and raising concerns about their financial solvency and, by extension, system reliability given that within-province coal units account for around 60% of Guangdong's peak generation needs. Market reforms similarly depressed net revenues for natural gas, nuclear, wind, and solar generators, but slightly increased them for hydro generators. To address issues around generator solvency, reliability, and emissions, some form of payment for reliability and environmental attributes may be needed.

We explored two scenarios for providing scarcity revenues for thermal (coal, natural gas) and non-thermal (hydro, nuclear, wind, solar) generators and premiums for non-thermal generators. The Low SPP scenario was agnostic as to how generators earn scarcity revenues. For instance, a capacity market or scarcity reserve pricing could produce scarcity revenues. The High SPP scenario implicitly assumed some form of administrative payments to thermal generators, given that prices in this scenario were likely above a market price for available capacity. It represents a high-end estimate for possible scarcity and premium payments to generators. The High SPP scenario corresponds to the lower end (21 billion yuan) of the total generation cost savings range, illustrating that even with high side payments to generators market reforms can lead to substantial savings for consumers.

The results were sensitive to assumptions around several variables, four of which we explored in this study: (1) net imports, (2) coal and natural gas fuel prices, (3) hydro, solar, and wind generation, and (4) CO_2 prices. As described in Section 3.3, each of these sensitivities may have a significant impact on market outcomes.

The study highlights several important electricity market design issues for Guangdong.

Issues around interprovincial trade are a critical and politically sensitive part of market design for Guangdong. Allowing generators in neighboring provinces to participate in Guangdong's wholesale market would create winners and losers. Higher hydropower imports would reduce consumer costs and generator emissions in Guangdong, as well as reducing the level of scarcity prices or capacity payments needed to maintain a target level of reliability in Guangdong. However, higher imports would also reduce net revenues for generators within Guangdong, lead to a net transfer of economic rents to neighboring provinces, and likely increase wholesale price volatility within Guangdong due to greater exposure to interannual variability in hydro generation. Higher market-driven imports into Guangdong would also put upward pressure on prices in neighboring provinces, by creating a more explicit opportunity cost, and may increase their emissions. Facilitating higher levels of imports would require addressing transmission cost allocation issues, as interprovincial and interregional transmission costs are currently incorporated into import tariffs. Resolving these issues requires a governance framework for negotiating market rules among provinces.

Market transition will likely require addressing revenue impacts on generators. Competitive market prices could drive generator net revenues — market revenues minus operating costs — below the going-forward fixed costs that existing generating companies need to recover to remain solvent, which may lead them to mothball or retire units that are needed for reliability or to meet environmental requirements. If payments in excess of what can be earned from the competitive energy (and ancillary services) markets are needed to address generator revenue shortfalls, it raises the question of what mechanism is most appropriate to China's political and institutional context.

The design of environmental regulation is a critical consideration for electricity market reforms. Guangdong's Pearl River Delta is one of three regions in China that were required to achieve significant absolute reductions in $PM_{2.5}$ concentrations by 2017. In the short run, however, electricity market reforms may increase coal-fired generation within the province and complicate efforts to meet air quality goals and reduce CO_2 emissions. Relatively high CO_2 prices, here estimated at around 260 yuan/tCO_2, would be necessary to avoid increases in CO_2 emissions during market transition, but emissions pricing is one among several strategies for regulating emissions. By integrating the design of environmental regulation for the electricity sector into electricity market reforms, policymakers can strike the right balance between market-based and administrative approaches to achieving emission reductions.

The largest benefits of market reforms in Guangdong are likely to be long term. Most of the potential short-term cost savings associated with electricity reform in China are cost transfers from generators to consumers — the accumulated legacy of central planning and incomplete reforms. Going forward, and in the long run, the largest benefits of market reforms will be in improvements in operational and investment efficiency that result from having an economic framework for short-run operations and longer-term investment decisions. Market prices can help to guide both the level and composition of investments in utility-scale generation, energy storage, and demand-side resources.

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Appendix A: Methods, Assumptions, and Data Sources

This appendix describes methods, assumptions, and inputs used in this study. It first describes methods for the reference case, followed by those for the market case.

A.1 Reference Case

The reference case resembles the status quo, where fully-loaded operating hours (□□□□) for all types of generation are planned on a year-ahead basis and generators are paid a fixed tariff (□□□□) for their net generation.

Total reference generation costs (TRC) are the product of installed capacity (IC), annual operating hours (AOH), and a generation tariff (GT) for each generating resource i, plus imports (IM) multiplied by an average import tariff (IT).

$$TRC=\sum_i IC_i \times AOH_i \times ¿_i + \Im \times IT$$

For generation tariffs, we use best available data on most recent average tariff levels for each generation technology (Table A1). All coal generators in Guangdong are paid a single benchmark tariff (□□□□), which is different — and higher — than neighboring provinces [23]. Natural gas generators in Guangdong are paid generator-specific tariffs; the natural gas tariff value in Table 1 is Guangdong's current benchmark tariff for natural gas [24]. Hydropower generators are also paid facility-specific tariffs, but we were not able to find data on average tariff levels. The hydropower tariff in Table 1 is conservatively based on levels in neighboring provinces [25]. Feed-in tariffs for nuclear, wind, and solar generation are set at a national level [26–28].

Table A1. Generation Tariffs by Generation Technology Used in the Reference Case

Generation Technology	Average Tariff (yuan/MWh)
Coal	450.5
Natural gas	715.0
Hydropower	300.0
Nuclear	430.0
Wind	570.0
Solar	850.0
Imports	280.5

The import tariff value in Table A1 is based on the current contract price in the framework agreement between Guangdong and its neighbors, which is the benchmark cost for coal-fired generation (450.5 yuan/MWh).[9] From this we subtract an estimated average transmission charge of 150 yuan/MWh and an estimated average line loss charge of 20 yuan/MWh, based on reported charges in Yunnan's

[9] This price is for delivered energy imports into Guangdong (□□□□□□), based on the East-West Transmission Project's framework agreement (□□□□□□□□).

agreement with Guangdong [29].[10] This assumption that only generation costs would be avoided in a transition to market pricing would imply that there is a separate, and new, mechanism to allocate and recover transmission costs and interprovincial line losses.

To calculate reference case operating hours for each type of generation, we assume: (1) that hydropower, wind, solar, and nuclear generation are used whenever available, and (2) that natural gas fully-loaded annual operating hours (capacity factor) are fixed by through an annual planning process. Total operating hours for coal generation are thus the residual of electricity consumption minus imports and hydropower, wind, solar, nuclear, and natural gas generation, divided by the product of total coal installed capacity and total annual hours (8,760).

$$COH = \frac{TEC - \Im - HWSN - GIC \times GOH}{CIC}$$

COH is annual operating hours for coal generation, TEC is total provincial electricity consumption (generator-side), IM is net provincial imports, HWSN is hydropower, wind, solar, and nuclear generation, GIC is natural gas installed capacity, GOH is natural gas annual operating hours, and CIC is coal installed capacity. Hydropower, wind, solar, and nuclear generation (HWSN) are the product of installed capacity and a pre-determined number of annual operating hours. This calculation leads to a reference case estimate of 3,932 fully-loaded operating hours for coal generators.

Table A2 and Table A3 show total electricity consumption and net imports and installed capacities and annual operating hours for different generating technologies used to calculate reference costs. All data and estimates are for 2016.

Table A2. Total Electricity Consumption and Net Imports for Guangdong in 2016 [30]

Total electricity consumption	561 TWh
Net imports’ share of total consumption	157 TWh (28%)

[10] For Yunnan, the delivered price of 450.5 yuan/MWh reportedly includes a charge of 82 yuan/MWh for interprovincial transmission, a 91.5/MWh charge for the 500-kV transmission system in Yunnan, and a 24 yuan/MWh charge for line losses. Our approximate estimates of 150 yuan/MWh and 20 yuan/MWh for transmission and line loss charges, respectively, reflect the fact that transmission and line loss charges from Guangdong’s other import sources (Guizhou, Guangxi) should be lower than Yunnan.

Table A3. Installed Capacity and Reference Case Annual Operating Hours by Generation Technology for Within-Province Generation [31,32]

Generation Technology	Installed Capacity (MW)	Annual Operating Hours (hours/yr)
Coal	59,920	3,932
Natural gas	13,438	3,200
Hydropower	14,110	3,550
Wind	2,680	2,438
Solar	1,560	1,717
Nuclear	9,360	7,516

Production costs are the cost of operating the electricity system, excluding capital and other fixed costs. We calculate total production costs (PC) in the reference case as the product of a generation technology average (nameplate) heat rate (HR) and fuel price (FP) plus variable operation and maintenance (O&M) (VOM) costs and CO_2 emissions costs. CO_2 emissions costs are the product of an emissions rate, average heat rate multiplied by a generation technology-specific fuel emissions factor (EF), and CO_2 price (CP).

$$PC = \sum_i \left(HR_i \times FP_i + VOM_i + HR_i \times EF_i \times CP \right)$$

Table A4 shows the generation technology average net heat rates, average annual fuel costs, variable O&M costs, and fuel emission factors used in this analysis.

Table A4. Average Net Heat Rate, Average Annual Fuel Cost, Variable O&M Cost, and Fuel Emission Factor Inputs [33–36]

Generation Technology	Net Heat Rate (gce/kWh)	Fuel Cost (yuan/tce)	Variable O&M Cost (yuan/MWh)	Fuel Emission Factor ($kgCO_2$/ kgce)
Coal	313	800*	30	2.79
Natural gas	256	1870**	20	1.64
Nuclear	396	140	40	n/a
Hydropower	n/a	n/a	8	n/a
Wind	n/a	n/a	9	n/a
Solar	n/a	n/a	9	n/a

* Equivalent to 571 yuan/ton at a 5,000 kCal/kg coal heat content

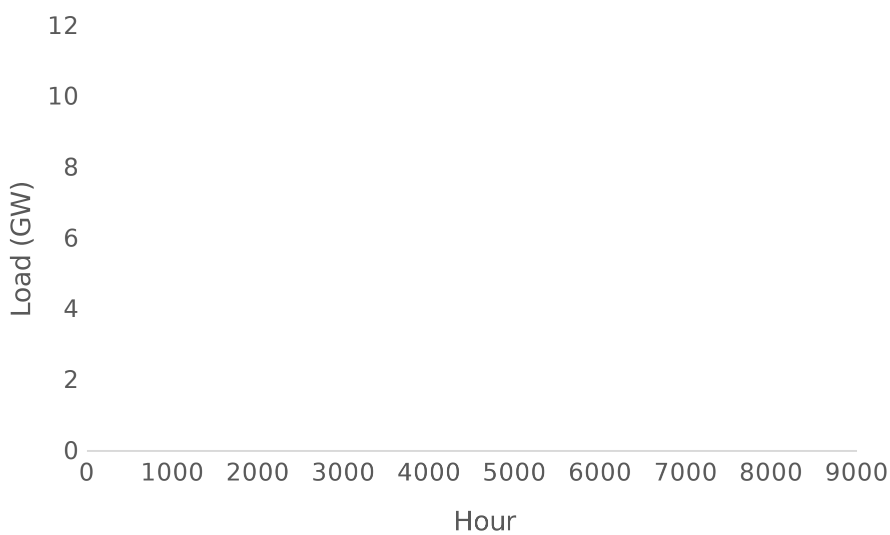
** Equivalent to 2.3 yuan/m^3 at 8,600 kCal/m^3 natural gas heat content

Guangdong has a significant amount of behind-the-meter generation. Behind-the-meter generation is not paid a feed-in tariff and its cost structure may differ from central-scale generation if it is also producing heat. However, we did not have sufficient data to distinguish behind-the-meter generation from total generation. For simplicity, we treat behind-the-meter generation like central-scale generation. This assumption may overstate differences between the reference and market cases, depending on how responsive interconnected loads with behind-the-meter generation are.

A.2 Market Case

Because generators are dispatched to meet hourly loads, the market case requires hourly loads and more detailed representation of generators. Load data is generally not publicly available in China. To estimate an annual load shape for Guangdong, we use three data inputs: (1) daily average load shapes for summer and winter Guangdong, combined with an assumption of summer start (May) and end (September) months [37]; (2) monthly electricity consumption data for Guangdong [38]; and (3) an assumption about the ratio between weekend and weekday electricity consumption (0.8), which we assume is constant over the course of the year. These assumptions produce the (generator-side) load duration curve shown in Figure A1.

Figure A1. Estimated Load Duration Curve for Guangdong



The market case requires greater disaggregation of coal and gas generators than in the reference case, as these generators set the market clearing price in all hours and differences in heat rates thus determine market prices. Our disaggregation scheme attempts to preserve simplicity while capturing significant differences in heat rates among different sizes and vintages of coal and gas generators.

We create six bins for coal generation, based on unit size (capacity) and vintage. Table A5 shows bin-average net heat rates and total installed capacity for each bin.

Table A5. Net Heat Rates and Installed Capacity for Each Coal Generator Bin[11]

Category	Size (Capacity)	Vintage	Installed Capacity (MW)	Average Net Heat Rate (gce/kWh)
Coal 1	> 1,000 MW	All	14,362	281
Coal 2	600-1000 MW	2010-2017	6,887	301
Coal 3		1980-2009	15,530	315
Coal 4	300-600 MW	2000-2017	9,877	325
Coal 5		1980-1999	6,283	337
Coal 6	< 300 MW	All	6,981	350
Totals			**59,920**	**313**

For gas generators, we create three bins, based on differences in reported heat rates for a subset of generating units. Table A6 shows bin-average net heat rates and total installed capacity for each bin.

Table A6. Net Heat Rates and Installed Capacity for Each Gas Generator Bin [33]

Category	Installed Capacity (MW)	Average Net Heat Rate (gce/kWh)
Gas 1	7,391	220
Gas 2	4,703	275
Gas 3	1,344	315
Totals	**13,438**	**256**

To prevent them from being dispatched in all hours, coal, natural gas, and nuclear generators are subject to a maximum capacity factor, which reflects both forced and unforced outages. These maximum capacity factors are based on historical availability factors and assumptions (Table A7). The maximum capacity factor for nuclear is equivalent to its annual operating hours from Table A3.

Table A7. Maximum Capacity Factors for Coal and Gas Generators[12]

Generator	Maximum Capacity Factor
Coal 1	80%
Coal 2	85%
Coal 3	84%
Coal 4	90%
Coal 5	80%

[11] Data used to create these bins, and the averages in each bin, are from the China Southern Grid Dispatch Center. The original data was for 59,511 MW of total capacity; we made this consistent with 2016 data on total capacity (59,920 MW) by maintaining the shares for each bin.

[12] Historical availability factors for coal are from the China Southern Grid Dispatch Center. Availability factors for gas and nuclear are based on middle-of-the-road assumptions.

Coal 6	87%
Gas 1	85%
Gas 2	85%
Gas 3	85%
Nuclear	90%

For the purposes of assigning capacity credits in the Low SPP scenario, we assume that all coal, gas, and nuclear units can contribute their full rated capacity. For hydro, wind, and solar, we assume that they contribute 30%, 20%, and 40% of their rated capacity, respectively, based on rule-of-thumb estimates from the U.S. In the Low SPP scenario, we assume that imports are paid 100 yuan/kW-yr multiplied by the difference between peak demand plus a 15% reserve margin (total 116 GW) and local qualifying capacity resources (88 GW).

Hourly output for imports and hydro, wind, and solar generation is constrained by fixed resource profiles. For imports and hydro, we develop base case assumptions and test sensitivities to determine how changing resource profiles influences the results. In the base case, we assume that imports and hydro resources are not able to fully respond to market prices. We constrain monthly imports and hydropower by historical monthly shares (Table A8). Daily imports and hydropower are shaped in on-peak (beginning at 8:00) and off-peak blocks (beginning at 22:00). We assume that the ratio between on-peak and off-peak mirrors the monthly average ratio between on-peak and off-peak load (1.3 for all months), but for imports we adjust the ratio slightly higher (from 1.3 to 1.4) in July to ensure total supply is sufficient to meet demand.

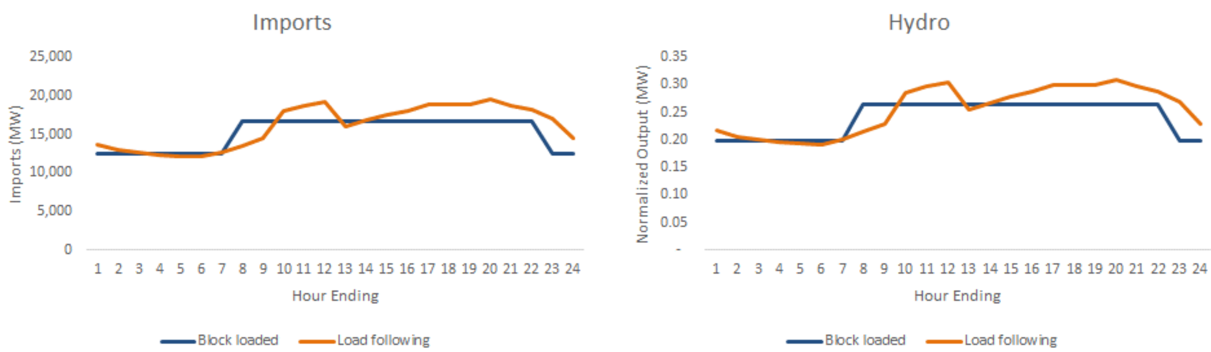
Table A8. Monthly Shares of Hydro Generation and Imports[13]

	Month											
	1	2	3	4	5	6	7	8	9	10	11	12
Monthly share of annual hydro generation	5%	4%	5%	7%	9%	10%	12%	12%	10%	9%	9%	9%
Monthly import share of annual imports	7%	5%	8%	8%	9%	10%	10%	10%	9%	9%	8%	8%

As a sensitivity to block loaded on-peak and off-peak imports and hydro generation, we test sensitivities in which both resources are able to perfectly follow, or have the same shape, as load in each month. Figure A2 illustrates the differences in these “block loaded” and “load following” approaches to shaping imports and hydro generation.

[13] Monthly hydropower output data for Guangdong was not available. We use 2009 Guangxi data as a proxy [2].

Figure A2. Illustration of Block Loaded and Load Following Approaches to Shaping Imports and Hydro, for January 1



Given the lack of publicly-available data on wind and solar profiles for Guangdong, we use generic wind and solar generation shapes from the U.S. for this analysis. Wind and solar generation are currently a small portion of total generation in Guangdong. Thus, changes in wind and solar profiles have a negligible impact on the results.

Using information on generator net heat rates, fuel costs, variable costs, and emissions costs (Table A4, Table A5, Table A6), the stack model creates a dispatch order (Table A9).[14] The stack model then dispatches available generation according to this dispatch order to meet demand in each hour, accounting for maximum capacity factors (Table A7) and hourly shapes for imports and hydro, wind, and solar generation. The supply curve and inelastic demand curve in Figure A3 illustrates this process for 16:00 on July 1. Imports are included in the “price-taker” (0 yuan/MWh) portion of the supply curve.

[14] We had originally intended to use monthly fuel costs in this analysis, but were limited by data availability.

Table A9. Dispatch Order and Short-Run Marginal Costs (SRMC) for Base Case (No CO_2 Price)

Order	1	2	3	4	5	6	7	8	9	10	11	12	13
Generator	H	W	S	N	C1	C2	C3	C4	C5	C6	G1	G2	G3
SRMC ($/MWh)	8	9	9	95	255	271	282	290	300	310	431	534	609

H = hydro, W = wind, S = solar, N = nuclear, C1-C6 = coal 1 through coal 6, G1-G3 = gas 1 through gas 3

Figure A3. Supply-Demand Curve Illustration of Hourly Dispatch in the Stack Model, for Hour Ending 16:00 on July 1

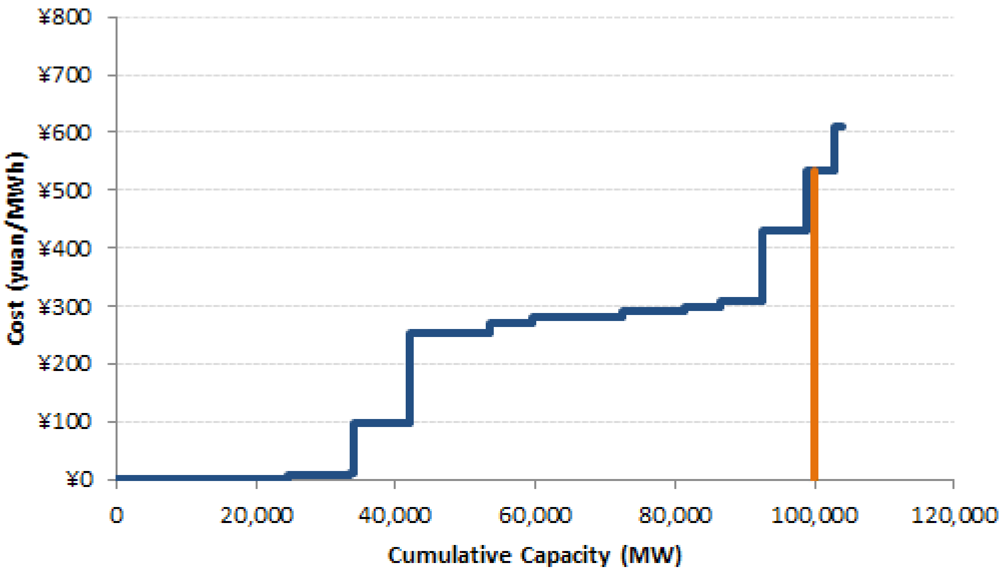
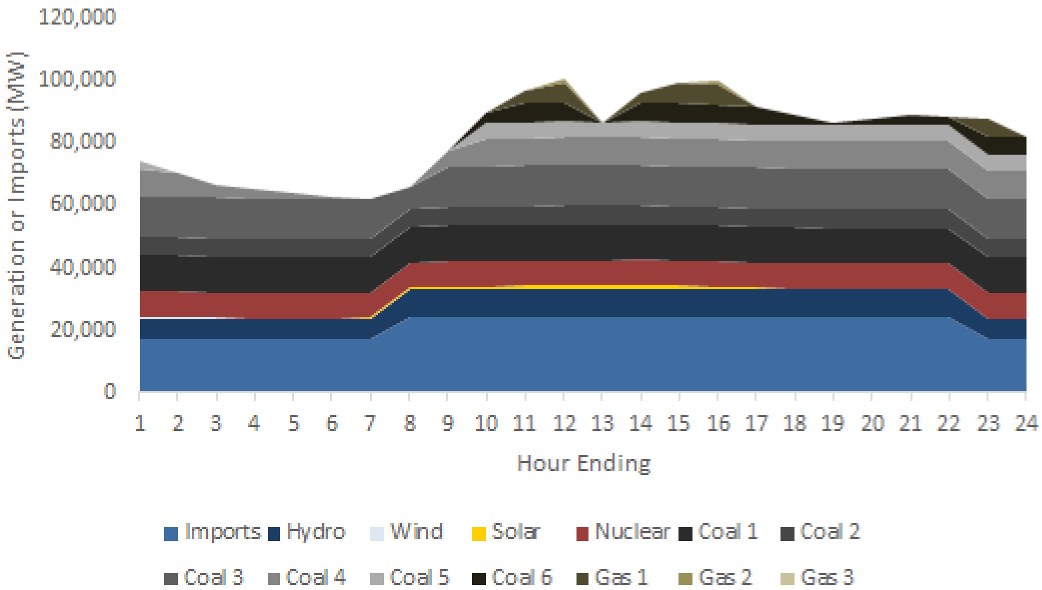


Figure A4 illustrates how the stack model then “stacks” generation for each hour to meet demand over the course of a day, in this case also for July 1. Although coal units are not ramp limited in the model, aggregate ramp rates (MW/min) are within -1.5% (down) and 1.5% (up) of nameplate capacity, with ramp rates between -1% and 1% in 95% of hours.

Figure A4. Illustration of Generator "Stacking" Over the Course of a Day, for July 1



We calculate production costs in the market case in the same way that we do in the reference case. Total energy market costs (EMC) in the market case, however, are the sum of the product of the market clearing price (MCP) and load (L) across all hours.

$$EMC = \sum_h MCP_h \times L_h$$

Total generation costs (TGC) in the market case are the sum of energy market costs (EMC), premium payments (PMP), and scarcity revenues (SCR).

$TGC = EMC + PMP + SCR$