How do Price Caps in China's Electricity Sector Impact the Economics of Coal, Power and Wind? Potential Gains from Reforms

*Bertrand Rioux,** Philipp Galkin,** Frederic Murphy,*** and Axel Pierru**

ABSTRACT

China imposes maximum prices by plant type and region on the electricity that generators sell to utilities. We show that these price caps create a need for subsidies and cross-subsidies, and affect the economics of wind power. We model the price caps using a mixed complementarity formulation, calibrated to 2012 data. We find that the caps impose an annual cost of 45 billion RMB, alter the generation and fuel mixes, require subsidies for the market to clear, and do not incentivize adding capacity for a reserve margin. They incentivize market concentration so that generators can cross-subsidize power plants. Depending on the regulatory response, increasing wind capacity can alleviate the distortions due to the price caps. The added wind capacity, however, does not have a significant impact on the amount of coal consumed. We also find that the feed-in tariff was priced slightly higher than necessary.

Keywords: China, electricity, subsidies, wind, coal, price caps, mixed complementarity

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1. INTRODUCTION

In the past decade, China has introduced many reforms into its power sector and fuel markets, moving to a more market-oriented energy system, yet retaining major government controls. Unlike the restructured spot and capacity markets in the U.S. and Europe, the current system is organized around government-owned utilities that operate the grid and purchase power under long-term contracts from generators. A major government restriction is that the National Development and Reform Commission (NDRC) caps the prices (the on-grid tariffs) a utility can pay a generator for electricity, with the caps differentiated by technology and region. Because of these caps, some regional generators receive government subsidies, other generators subsidize this business using profits from other businesses, and generators are encouraged to cross-subsidize power plants.

Credit Suisse (2012) and Akkemik and Li (2015) identify the disconnect between market-based coal prices and the rigidity of on-grid tariffs as the fundamental issue confronting the Chinese electricity sector. The price caps have the potential to complicate policies aimed at meeting ambitious capacity development and renewables targets for 2020 in China's Energy Development Strategic Action Plan (State Council, 2014).

* Corresponding author. King Abdullah Petroleum Studies and Research Center (KAPSARC), Saudi Arabia. E-mail: Axel.Pierru@kapsarc.org.

** King Abdullah Petroleum Studies and Research Center (KAPSARC), Saudi Arabia.

*** Temple University, USA and King Abdullah Petroleum Studies and Research Center (KAPSARC), Saudi Arabia.

The Chinese authorities are in the process of reforming the price-cap policy (State Council, 2015, and NDRC and NEA, 2015) and some proposals have been studied (Zeng et al., 2015 and Zhang, 2012). To estimate the benefits of reforming price caps, we model the Chinese electricity sector as an economic equilibrium, where every regional grid ("utility") is a monopsonist that minimizes generation costs in the face of externally imposed price caps. Through its pricing of generation in contracts, the utility fosters cross subsidies among power plants that lower its costs. The way in which the utility uses contracts with cross-subsidies to lower costs is described in Section 2.2. When price caps are removed, the utility is a classic monopsonist and cross-subsidies no longer lower costs.

To our knowledge, our study is the first to model the Chinese tariff caps and our representation of the price caps as a Mixed-Complementarity Problem (MCP) is novel. We connect three different strands of research. First, we develop a model with detailed representations of technologies and regional breakdowns for analyzing the Chinese power sector. This approach allows us to address a wide range of policy scenarios, including the sector's strategic development plan (Cheng et al., 2015 and Chandler et al., 2013), the costs of policies for meeting emission control targets (Li et al. 2014, Dai et al. 2016 and Zhang et al. 2013), and the opportunities for developing interregional integration of electricity markets (Gnansounou and Dong, 2004). A number of studies also explore the integration of renewables (Despres et al., 2015 and Lu et al., 2013) and the effect of renewable energy quotas (Xiong et al., 2014) on the power sector. Second, we link the coal sector with the electricity sector, relating to the literature examining cross-sectoral interactions of coal and electricity policies. Kuby et al. (1993, 1995) and Xie and Kuby (1997) explore development options for coal and electricity delivery and Chen (2014) studies the effects of coal price fluctuations on the other sectors in China's economy.

Third, we add to the literature on modeling, showing how price caps and subsidies can be represented in MCPs through directly manipulating both primal (physical) and dual (prices) variables, expanding on Matar et al. (2015) and Murphy et al. (2016). This MCP representation supersedes the iterative approach taken by Greenberg and Murphy (1985) to model price controls in the United States.

This paper examines the impact of the price caps on China's electricity market and renewables. Specifically,

- The economic efficiency of the market,
- The need for subsidies and cross-subsidies,
- The economics of coal and wind.

The next section covers the price caps and their effects, providing the background on features essential for modeling China's electricity sector. Section 3 describes the design of our model and scenarios. Section 4 covers our results. The last section contains our conclusions. The mathematical formulation of the model and details on the data used for calibration are given in the electronic Appendices.

2. PRICE REGULATION IN CHINA'S ELECTRICITY SECTOR: EFFECTS AND CONSEQUENCES

2.1 Market structure and effects of on-grid tariffs

China's electricity sector consists of a mix of publicly and privately-owned entities. The last major structural change occurred in 2002 with the dismantling of the State Power Corporation

Table 1: Average on-grid tariffs caps for selected regions in 2012 (RMB/MWh)

	Technologies				
Regions	Coal	Gas	Nuclear	Hydro	Wind*
Coal Country**	310	573	387	300	610
East	460	573	387	305	610
South	550	573	377	237	610
Central	480	579	387	350	610
Northeast	415	573	380	300	564

Source: NDRC
Note: average exchange rate in 2012: 1 RMB = 0.1584 USD (China Statistical Yearbook, 2015)
*The tariffs for wind are the feed-in tariffs
**Includes Shanxi, Shaanxi, Ningxia and Inner Mongolia

(Liu, 2013), resulting in limited competition in power generation. However, market concentration remains high with the top five companies accounting for about 50% of the market (Epikhina, 2015). Hubbard (2015) measures ultimate ownership, finding that the Herfindahl-Hirschman Index of company generation revenues at the national level reaches 0.222 for thermal, 0.220 for hydroelectric, and 1 for nuclear power. He also estimates that central and local State Owned Enterprises (SOE's) control 83% of thermal, 84% of hydroelectric, and 100% of nuclear power generation. The concentration is probably higher in each of the utility regions, where market efficiency is further impaired by low levels of interregional trade.

The reform had even less impact on the transmission and distribution sector which is still operated by two monopolies owned by the national government: the State Grid and the South Grid. These utilities are the sole purchasers of power from generators, buying under long-term contracts and selling to consumers at government-controlled prices in their regional markets. The NDRC determines the maximum reference prices that generators can charge (on-grid tariff caps) to cover their total costs, including fuel costs.

Table 1 presents the price caps for each technology and region. Note that the coal price caps vary significantly by region, reflecting the regional differences in coal prices. Since coal is far cheaper than other fuels, coal generated 76% of the total electricity produced in 2012 (World Bank, 2016) and coal plants provide spinning reserves despite the higher capital costs.

The caps are adjusted to reflect conditions in fuel markets or to promote or restrict a particular technology. Typically, this is done annually but can be done more frequently. However, these adjustments are not always timely. Table 2 contains the total costs of coal and combined-cycle plants operating at two different utilizations, as well as the caps. At a low utilization the plant costs are above the caps. In 2012, the government abolished mandatory long-term contracts and the allocation of railway capacity to coal sold under contract, liberalizing coal markets and exposing generators to greater price risk between the periodic adjustments to the caps.

Price caps are used around the world to limit price volatility and market power in electricity markets. However, the price caps in China differ substantially from the caps in standard electricity markets with spot-market auctions. Typically, one very high cap is imposed on all generators, limiting prices in extreme situations, such as plant outages or abnormally high demand, where only one or a few generators are available to provide incremental power. These caps limit transient price spikes but still provide returns that incentivize long-run investment. Furthermore, to provide re-

Table 2: Economics of selected power generation technologies in the East and South regions, 2012

Annual Utilization	Fuel Costs*	Fuel and Variable Costs, RMB/MWh (USD/MWh)	Fixed Operating and Capital Costs, RMB/MWh (USD/MWh)		Total costs, RMB/MWh (USD/MWh)		On-grid Tariff Caps, RMB/MWh (USD/MWh)
			8760 Hours	*2000 Hours*	*8760 Hours*	*2000 Hours*	
Coal-fired Power Plant (Assuming 37% Efficiency)							
East	986(156)	351(56)	53(8)	231(37)	404(64)	582(92)	460(73)
South	965(153)	344(55)	53(8)	231(37)	397(63)	575(91)	550(86)
Combined Cycle Gas Power Plant							
East	69(11)	408(65)	46(7)	201(32)	454(72)	609(97)	573(91)
South	73(12)	435(69)	46(7)	201(32)	481(76)	636(101)	573(91)

*RMB/tce (USD/tce) for coal-fired power plants; RMB/mbtu (USD/mbtu) for combined cycle plants
Note: average exchange rate in 2012: 1 RMB = 0.1584 USD (China Statistical Yearbook, 2015)
Source: IEA, KAPSARC estimations

serves, after the generation auction, a second auction provides a market for capacity where generators are paid to be available even if they do not send electricity into the grid. The Chinese market has no standard payment mechanism for making capacity available.

Since the Chinese power generators are paid only for kilowatt hours generated, have binding price caps on long-term contracts, and have a single purchaser per region, a model of the sector differs from one that represents standard electricity markets. The grid operators, due to incomplete unbundling within the 2002 reform, operate in defined territories, own distribution, and can exercise monopsony power[1] over the generators. This allows them to drive contract prices to cost, setting the prices and hours in contracts with power generators so that the generators make a fair rate of return. Figure 1 shows the cost per kilowatt-hour as a function of plant utilization, assuming an annualized per-kilowatt capital cost and an operating cost that is constant per kilowatt-hour. The per-kilowatt-hour total cost is the sum of the per-kilowatt-hour variable cost plus the annualized investment cost divided by kilowatt-hours of operation.

A plant that is utilized less than $\hat{h}$ hours in a year is unprofitable with a price cap of $\hat{p}$. Thus, using this plant to meet peak load and provide reserves for grid reliability would not be profitable and it would not be built without a subsidy or a cross-subsidy.

2.2 Market adaptation to price regulation

The utilities and generators can respond in three possible ways to have sufficient generation capacity despite binding price caps. The first matches the least-cost capacity mix in the absence of price caps. The second distorts this mix and the third increases the value of market concentration in generation.

First, let the least-cost generation plan without caps set the highest and lowest operating hours for plants of type A at h_A^{max} and h_A^{min}, respectively. For example, some plants of type A can

1. This is consistent with Hubbard's (2015) observation that the Chinese electricity sector yields low profits despite its market concentration.

Figure 1: Monopsony price (average cost) as a function of utilization for a plant

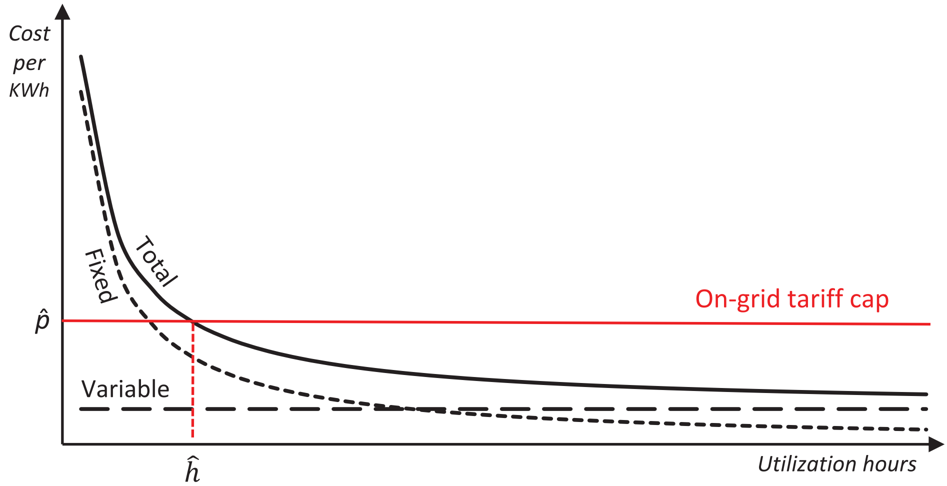
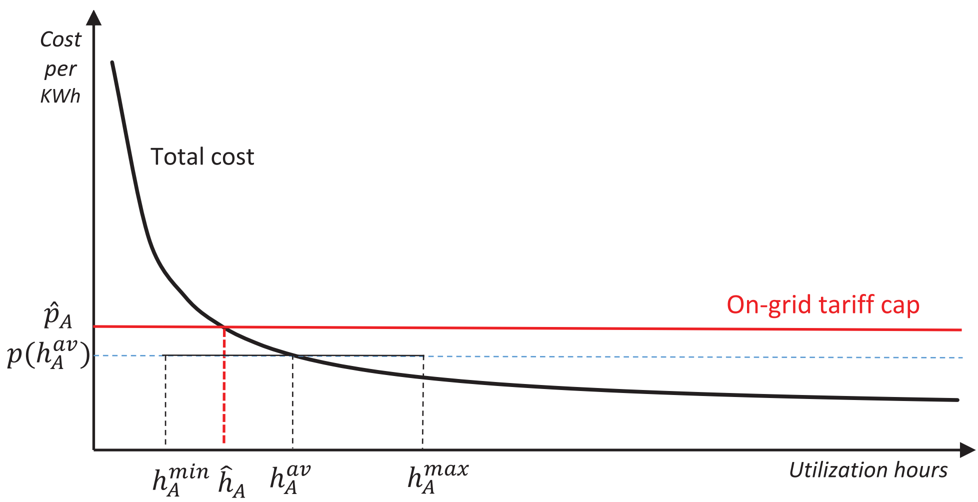


Figure 2: Paying the price of $p(h_A^{av})$ to all plants of type A and having cross subsidies within the same generator allows plants to operate at h_A^{min}



be used in intermediate load (between base and peak), whereas others are used in peak hours. Let us assume $h_A^{min} \leq \hat{h}_A$, the lowest number of hours of operation for a plant to remain profitable at the price cap $\hat{p}_A$, as illustrated by Figure 2. Let h_A^{av} be the average hours of generation by plants of type A in the least-cost generation plan. If $h_A^{av} \geq \hat{h}_A$, then, the utility can achieve the least cost dispatch by paying the price $p(h_A^{av})$ to all generators and dispatching the plants so that each has an average utilization of h_A^{av} (for instance by sharing the non-peak hours among all plants). Alternatively, if the utility contracts with a generator that owns several plants of type A, the price paid provides an economic return for the portfolio of plants, while the utilization of individual plants can differ.

We now consider the case where $h_A^{av} < \hat{h}_A$. Then averaging the utilization over the plants leads to a price $p(h_A^{av}) > \hat{p}_A$ and capacity cannot be built to operate at the lowest utilization h_A^{min}

without changing the capacity mix. In this case, it may become economic to add new capacity and increase the average hours of utilization of type A plants by generating, for instance, in baseload. This would correspond to increasing h_A^{max} and decreasing $p(h_A^{av})$ below $\hat{p}_A$ in Figure 2. By moving from the least-cost capacity mix, this strategy increases generation costs.

As a third strategy, if the average cost for plants of type A is below $\hat{p}_A$ because $h_A^{av} > \hat{h}_A$ and the average utilization of capacity of type B falls below $\hat{h}_B$, then, when the same generator supplies a bundle of both capacity types, the utility can pay up to $\hat{p}_A$ for capacity of type A and $\hat{p}_B$ for capacity of type B. Furthermore, capacity of type B can be increased as in the second strategy. This cross-technology subsidization adds value to market concentration in a utility's service territory because the cross subsidization has to be within a firm, impeding competition.

The model represents the three strategies in one revenue-sufficiency constraint per utility region. When this constraint is binding, the plant mix is distorted. When it cannot be satisfied, we find the smallest subsidy that is necessary to be feasible. National and provincial governments subsidize[2] input costs using reduced fuel costs, soft loans and land-use rights among other strategies so that plant costs can fall below the cap. Alternatively, a state-owned generator can have other businesses that cover its losses, while a private generator has no incentive to cross subsidize electricity generation and lower its total profits. These measures reduce the losses of power generation companies but don't address the structural problems that cause them.

3. MODELING APPROACH

3.1 Model overview

The model combines a power model with the coal-supply model described in Rioux et al. (2016) into a single Mixed-Complementarity Problem (MCP). Provincial level supply curves and imports feed coal into a multimodal transshipment network that links to generators. The coal sector is liberalized and sells at prices set to marginal costs, the dual variables associated with the coal supply constraints. The prices of other fuels, including natural gas, are fixed to the 2012 city-gate prices as seen by power producers, and end-use demands are set to 2012 levels.

Each regional grid, termed a "utility" in China, has to serve the electricity demand in its region. The demand is exogenously fixed in the model since the Chinese government sets the retail prices of electricity. Each regional grid is a government-owned monopsonist since it is the single buyer of all the electricity produced by the region's generators and has the mandate to minimize its procurement cost. This monopsonist is not a classical one, since the government fixes the retail price and the utility faces a fixed demand for electricity. To fulfill its mandate, if there were no price caps, the grid operator would sign a separate purchase power agreement for each power plant, which provides a payoff to the plant owner. This contract guarantees the purchase of a given quantity of electricity at a price that covers capital, O&M and fuel costs, and a fair rate of return. The grid operator is assumed to have full information on all capacity and generation costs. The quantities produced and the technologies used match the solution of the long-term competitive equilibrium, since total cost is minimized. The only difference is that in this market the grid extracts all rents from generators if there are any. We do not address how these rents would be redistributed to customers or the utility. Since retail prices of electricity are fixed by the government, the utility

2. See for instance China Coal Resource (2009, 2011), Reuters (2011, 2015) and Liu (2012).

may or may not cover its costs. If it cannot cover its costs, we presume it receives a subsidy from some level of government.

With the price caps set by the government, a plant meeting peak demand could have costs that exceed the price cap. In this case, the grid operator can offer a contract for a bundle of plants owned by the same generator where the payment covers all costs plus a fair rate return for the plants in the bundle. In this contract, each plant is nominally paid a price that falls below the corresponding price cap for that plant, with some plants paid below cost and others paid above cost. We therefore presume the system minimizes cost subject to the NDRC's pricing restrictions, through cross-subsidization. Grids can trade electricity between each other to further reduce the total system cost. Non-coincident peaks, combined with trading, increase the utilization of peak load plants and lower the per kWh costs of these plants.

The power model minimizes the costs of power-plant construction and generation for a mix of technologies plus the costs of construction and operation of the transmission and distribution grid, while meeting power demand. Capital costs of existing capacity are treated as sunk when comparing the economics of technologies. We add a revenue constraint in each region, ensuring generators' total costs do not exceed total revenues, given the price caps. Having one binding revenue constraint for all generators implies that generators must have a mix of plants to be profitable. Market concentration and owning a portfolio of plants give generators the ability to cross-subsidize their losses in some plants with their profits from others and increase their profits.

Each revenue constraint ensures all generator costs are covered, including fuel costs and existing capacity costs, as this capacity is under long-term contract to utilities. Note that generators do not overbuild to increase their profits because the utilities contract for only enough capacity to meet demand plus a reserve margin. Since the prices of coal are endogenous in the model and come from dual variables in the coal supply component, both primal and dual variables appear in the revenue constraints. Consequently, the price caps cannot be represented in an optimization model and we use an MCP.

When comparing the implications of the caps versus removing the caps, we set wind capacity at its 2012 level and find the subsidies necessary for that production level. We do not model the feed-in tariffs directly because that would require inventorying the wind resources of China and building regional wind supply curves, information we do not have.

Existing environmental policies are modeled by capping sulfur dioxide (SO_2) and nitrous oxides (NOx) emissions at 2012 levels. Power demand is represented by regional load duration curves with vertical load steps. The formulation of the power model is given in Online Appendix 1.

All scenarios include capacity that existed in 2012. The policy comparisons are made using long-term, single-period scenarios that allow new capacity to displace existing plants when profitable. Capacity costs are single-year annuitized costs, and operating costs are the same throughout the life of the equipment. This formulation can be thought of as a myopic view that trades off annuitized investment costs and fuel and operating costs of new plants and the operating costs of existing plants in the year of interest to determine the capacity acquired. The sources of the data used for calibration year are detailed in Online Appendix 2.

3.2 Scenarios

Three scenarios illustrate the impact of China's price-cap policies and another set of scenarios examines the effect of ranging on wind capacity.

- *Calibration scenario*: this scenario replicates what actually happened in 2012 in the coal and power markets with the capacities available then and allows us to benchmark our model. The on-grid prices are capped by the maximums allowed.
- *Long-run with caps scenario:* the on-grid prices are capped and capital investment is allowed in both the coal and power sectors.
- *Long-run without caps scenario*: the caps are removed and capital investment is allowed in both the coal and power sectors.
- *Wind scenarios*: for the long-run with and without caps cases we range on the wind capacities and estimate the associated subsidies resulting from the 2012 feed-in tariff.

4. RESULTS AND DISCUSSION

4.1 Establishing the baseline

In a rapidly evolving market like China, the existing capacity mix is not necessarily the most efficient. Furthermore, coal markets experienced bottlenecks in 2012 that have subsequently been removed. To isolate the effects of the price caps and cross subsidies from other aspects of the electricity sector, we make the Long-run scenario with caps the baseline for estimating the impacts of alternative policies.

Under the Long-run scenario with price caps the energy mix changes versus the Calibration scenario: the share of thermal power decreases—primarily coal-fired generation—from 75.7% to 70.1%, compensated by increased nuclear (from 2 to 7.6%). Investment in nuclear power is driven by its competitive long-run marginal costs (LRMC). For instance, at the discount rate of 6% used in the model, in Shandong the LRMC for baseload nuclear is 304 RMB/MWh (48.1 USD/MWh) compared to 322 RMB/MWh (51.1USD/MWh) for ultra-supercritical coal. In comparison, the short-run marginal cost of existing subcritical coal plants is 351 RMB/MWh (55.6 USD/MWh). The mix of coal plants shifts: 87 gigawatt of ultra-supercritical capacity is added and 98 gigawatt of inefficient legacy plants are retired. Reflecting actual developments in China's coal market since 2012, expanded western coal production and increased capacity to transport coal lowers steam coal imports from 227 mt to zero and reduces the weighted average price of delivered coal from 925 to 785 RMB/t. SCE.

Table 3 presents the average costs of generation, transmission and distribution with price caps. The average costs in the Calibration scenario fall between the residential and industrial/commercial tariffs, while the long-run average costs are around the residential prices, indicating the extent of the savings from improving the equipment mix and debottlenecking coal transportation[3]. The data suggest that commercial and industrial consumers cross-subsidize residential consumers. Thus, customers are cross-subsidized along with generators.

We estimate total subsidies from the government plus cross-subsidies from other businesses owned by generators to be 217 billion RMB in the Calibration Scenario and 29 billion RMB in the Long-run scenario with price caps. The decrease is due to the drop in coal prices.

Given the price-cap changes observed in 2015, the lower coal prices in the long-run scenario would likely have led to lower caps on coal generation, increasing the needed subsidies and inefficiencies. However, in this scenario we do not decrease the caps on coal plants despite the fall

3. The impact of congestion of both transmission lines and coal supply chain is illustrated by the large differences in the regional marginal costs in the Calibration scenario.

Table 3: Comparison of supply cost with actual, 2012, end-user electricity tariffs (RMB/MWh)

	Scenarios with price caps Average Generation cost + T&D Cost*		Actual End-user Tariffs	
Region (Province)	Calibration	Long-run	Industrial and Commercial	Residential
Northeast (Jilin)	641	536	917	515
North (Hebei)	658	500	733	470
Shandong	690	504	745	493
Coal Country (Shanxi)	536	495	754	467
South (Guangdong)	644	549	873	606

* Total generation cost divided by the total quantity of electricity in the scenario considered, plus the transmission and distribution tariff set by the regional grid operator
Sources: Polaris Power Grid, KAPSARC research

Table 4: Total costs and the cost of price caps (billion RMB)

Indicators	Calibration	Long-run with caps	Long-run without caps
Total Systems Cost	1,971	1,789	1,745
Savings	—	182	227
Cost of Caps	—	—	45

Note: average exchange rate in 2012: 1 RMB = 0.1584 USD (China Statistical Yearbook, 2015)

in coal prices. Therefore, the 29 billion RMB of subsidies and cross-subsidies that we find in this scenario is likely considerably lower than the actual amount of distortion due to the caps.

In the Calibration scenario the government subsidy paid to wind generators is the difference between the 2012 feed-in tariff and the on-grid tariff paid by the utilities[4] times the kilowatt-hours generated. Rather than modeling the feed-in tariffs, we require the existing capacity of 61 gigawatts to operate and calculate the subsidy needed to make that capacity economic. The subsidy necessary for this level of capacity is only 16.5 billion RMB in the Long-run scenario with caps, compared to 20 billion RMB of subsidies paid in the Calibration scenario.

4.2 Capping prices increases costs

We now compare the market outcomes in the long-run scenarios with and without caps. Removing price caps facilitates structural changes in the power market, eliminates generator losses and produces cost savings of RMB 45 billion, or 4% of the power-system cost and 2.6% of the total system cost (Table 4). Utilities can contract with generators and meet demand in all load segments more efficiently.

As shown by Table 5, when price caps are removed, electricity generation is 2% lower, due to increased transmission efficiency and lower use of pumped storage. This decrease comes essentially from coal and, only marginally, from nuclear. The optimal mix builds less capacity (41 instead of 87 gigawatts) of ultra-supercritical coal-fired generation in part because removing the caps eliminates the need to add capacity to increase the average utilization of coal plants as explained

4. The price paid by the utility to wind generators is capped at the maximum on-grid tariff for coal.

Table 5: Key indicators of China's power sector under various scenarios

Indicators	Calibration	Long-run with caps	Long-run without caps
Electricity produced, Nuclear (TWh)	99	380	365
Electricity Produced, Wind (TWh)	102	102	102
Electricity Produced, Hydro (TWh)	875	875	875
Electricity Produced, Thermal (TWh)	3,930	3,661	3,576
Additional capacity, Nuclear (GW)	—	36	34
Additional Capacity, Coal (GW)	—	87	41
Additional capacity, HV Transmission (GW)	—	248	183
Coal Consumption, mt SCE	1,236	1,089	1,079
Weighted Average Marginal Value of Coal, RMB/t SCE	925	785	730
Outgoing Interregional Transmission, TWh	516	775	1,009

in Section 2.2. When price caps are removed, despite the utilization of more capacity from less efficient plants, coal consumption remains essentially the same because the average utilization of coal plants drops.

Removing caps results in an additional 234 terawatt-hours of interregional electricity trade, a 30% increase. The scenario with caps actually builds more less-efficient, low-utilization AC transmission for peak shaving. Without caps, inland coal-producing regions, such as Xinjiang and other western provinces, produce more baseload power and export it via new UHV lines. Shifting coal production and expanded UHV lines decrease coal consumption in major Eastern importing provinces, such as Shandong. These provinces no longer need high-utilization capacity to cross-subsidize local lower-utilization capacity. This also lessens the need for supercritical capacity, as lower-cost, less efficient plants are economic when the costs of coal transportation are avoided. Increased power transmission also reduces the ton-km movements of coal by rail and water by 6%, reducing new rail capacity by 1,250 km, saving RMB 24 billion in total rail investment.

In sum, removing the price caps eliminates the need for generator subsidies, lowers costs, results in more efficient interregional transmission and reduces the value of market concentration in power generation. Removing the caps slightly decreases coal consumption and does not increase significantly the subsidies for wind. Our results are a lower bound on the benefits of removing the caps because the price caps on coal generators in the long-run scenario would probably have been lowered with lower coal prices, as China did in 2015, exacerbating the effects of the caps, especially increasing the need for subsidies.

4.3 Increasing wind capacity mitigates the effects of the price caps

We now examine the effect of increasing wind capacity up to 261 gigawatts with and without price caps. The wind subsidy column in Table 6 shows the average of the regional minimum subsidies required for the target capacity to be built with and without caps.

With caps the average wind subsidy per megawatt-hour increases with increasing wind because the marginal value of wind decreases, while coal consumption and prices decrease, as expected. Without caps the wind subsidy per kilowatt-hour initially decreases because the average efficiency of the existing plants is below that of new plants added to the wind-rich Northern provinces. Total costs increase monotonically and the average subsidy increases monotonically after the initial decrease.

Table 6: The effects of increasing the share of wind power with and without price caps

Wind Capacity, GW	Equilibrium Total Cost, billion RMB (excluding subsidies)	Average Wind Subsidy, RMB/MWh	Coal Use, mt SCE	Coal Price, RMB/ t SCE	Generator Losses, billion RBM	Cost of Tariff Cap, billion RMB
Long-run Wind Scenarios With Price Caps						
61*	1,789	162	1089	785	29	45
111	1,803	178	1088	745	26	43
136	1,804	181	1087	735	19	37
161	1,813	183	1087	731	16	37
186	1,815	186	1087	721	14	30
211	1,800	212	1077	636	1	5
261	1,819	223	1047	591	—	4
Long-run Wind Scenarios Without Price Caps						
61*	1745	170	1079	730		
111	1760	157	1079	730		
136	1767	169	1078	690		
161	1776	180	1078	686		
186	1785	187	1076	668		
211	1795	197	1073	640		
261	1815	221	1041	588		

*Capacity existing in 2012

With caps the decreases in coal prices with increasing wind relax the revenue constraints, despite the added wind decreasing the average utilization of thermal plants. This lessens the need for subsidies for generators and reduces the cost differences with and without caps. Increasing wind capacity requires increased wind subsidies. Still, despite the substantial drop in coal prices under both long-run scenarios due to steep coal supply curves, the subsidy needed for existing capacity to be economic and to add 150 megawatts additional wind generation capacity is below the actual range of 241–216 RMB per megawatt-hour reported by Zhao et al. (2014). These results suggest that the current level of wind-power subsidies, determined by the feed-in tariffs, is higher than required and the intention of Chinese policymakers to reduce it is justified.

5. CONCLUSION

China's past reforms have moved its electricity sector to the middle ground between fully functioning markets and a command system. That middle ground leaves fewer ways for government or markets to ameliorate problems and makes markets more brittle with less ability to adjust to unforeseen events. In the current system using price caps to control costs actually leads to higher costs and generator subsidies.

By eliminating the caps, the generation mix improves and costs go down. Annual subsidies of 29 billion RMB are no longer necessary. Removing caps also facilitates the development of cost-effective renewables policies, since the baseline costs and carbon levels are altered by the caps and the utilities are better able to provide the backup to intermittent technologies.

Eliminating the caps reduces the advantages of market concentration by the generators, lowering the barriers to entry for new participants and expanding competition. The need for vertical integration to control fuel costs is also reduced. Furthermore, eliminating the tariff caps expands interregional power trade, unifying the country's power market.

Usually, adding a non-dispatchable technology like wind with feed-in tariffs increases expenditures on subsidies. However, wind ameliorates the problems created by the price caps. By lowering the demand for coal, added wind capacity lowers the coal price, relaxing the revenue constraint and lessening the distortions due to the caps. Thus, the cost of subsidies for the feed-in tariffs is partially offset by the efficiency improvements from relaxing the caps.

The expansion of China's capacity to move coal lowers the costs of delivered coal, making coal-fired generation extremely competitive. As a result, neither restrictive tariff caps on coal-fired generation, nor the increase in the share of renewables have a significant effect on total generation with coal. A substantial reduction in coal use in China's energy system would require additional policy interventions.

We have focused on removing the price caps as a modification to the current regulations. The main problem with the caps on the price per kWh is that two distinct cost components should be covered in a market, the fixed cost of capacity and the variable costs of generation. An alternative that could achieve or come close to the results of the competitive equilibrium, given the monopsony power of the utilities, could be the introduction of an alternative set of price limits: caps on payments for capacity per kW and separate caps on operating costs per kWh combined with fuel-cost adjustments based on market prices for fuels. If these caps leave the utilities room to adjust to special circumstances, then the caps would be unlikely to bind and the national government can retain a regulatory check without distorting the market significantly.

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