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CASE STUDY

Strategies for expanding natural gas-fired electricity generation in China: Economics and policy

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ABSTRACT

We analyzed the changes necessary to increase the share of natural gas in China's electricity mix, currently at 2%. The competitiveness of natural gas generation relative to coal generation depends on three factors: the price of natural gas relative to coal; the capital cost of natural gas power plants relative to coal power plants; and a carbon price. We modeled how changes in these factors would make natural gas cost-competitive in baseload, load following, and peaking applications in China. We found that natural gas is already cost-competitive for peaking, but that government agencies must adjust current methods of compensating generators in order to bring more gas peakers online. Natural gas load following and baseload generation are not currently cost-competitive, but could become so with relatively modest decreases in both capital costs and fuel prices, especially if a small price was imposed on carbon emissions. A government policy of indigenizing natural gas turbine technology could reduce capital costs, which is the primary factor in making gas cost-competitive for load following with relatively low capacity factors. Reforms in the natural gas supply industry, a carbon price, and fundamental changes in electricity wholesale pricing could make gas competitive as a baseload resource.

1. Introduction

Since the early 2000s, central and local governments in China have sought to expand the use of natural gas-fired power generation, with limited success. Natural gas generation accounted for less than 2% of China's electricity generation mix in 2010 [1], compared to a global average of around 25% [2]. However, new opportunities for gas-fired generation in China are emerging, including greater industrial policy attention to gas generation technologies, reforms to natural gas pricing and regulation, and proposed pilots for carbon trading.

Expansion of natural gas-fired generation in China would have significant implications for global energy markets and the global environment, in addition to its domestic importance. Future natural gas demand in China is a major source of uncertainty in global natural gas markets, as investors ponder the prospects of greatly expanded LNG, pipeline, and unconventional gas extraction infrastructure to increase China's supply [3]. China is the world's largest emitter of CO_2 [4] and a major source of trans-Pacific pollution [5], both of which could be mitigated by substituting natural gas for coal-fired generation.

This paper examines three key drivers of natural gas use in China's power sector over the coming decade: (1) capital costs for natural gas power plants, (2) natural gas prices, and (3) CO_2 prices. We assess the influence of each of these factors on the cost-competitiveness of a natural gas power plant against an advanced coal power plant, using a total system cost approach. Our goal is not to forecast future natural gas use, but to provide insight into how changes in the key drivers shape the economics of gas-fired generation relative to coal generation in China. Building on that understanding, we outline policy strategies for expanding the role of natural-gas fired generation in China's power sector.

2. Background

The economics, regulation, and planning of China's electricity, natural gas, and coal

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sectors are very different from those found in OECD countries. This section describes some unique characteristics of China's energy sectors relevant to our analysis of natural gas generation: (1) why the ratio of coal plant capital costs to natural gas plant capital costs is much smaller in China than in most other countries; (2) why there is a significant amount of variation in natural gas prices faced by different power plants in China; (3) why potential CO_2 prices are significant for the analysis in this paper, but criteria pollutant prices are not; and (4) why it is important to focus on the optimal "role" of natural gas in China's power system rather than making simple levelized cost comparisons with coal.

Unlike most other countries, the difference in capital costs between coal and natural gas power plants in China is relatively small. The ratio between the two, which is a minimum of 2 to 1 in the U.S. [6–8], is only around 1.1 to 1 in China [9]. The reasons for this discrepancy are historical. Chinese firms began to produce steam turbines domestically in the 1980s, and through a mixture of industrial policy, regulation, and price incentives, the Chinese government provided significant support to the development and deployment of advanced coal technologies during the 2000s [10]. A supercritical coal unit in China, with an overnight cost of roughly \$600 kW^{-1} [9], is around one-fifth to one-sixth of the cost of a new advanced pulverized coal unit in the U.S. [6–8]. By contrast, the government has given very little support to natural gas generation technologies; all of China's gas turbines, for example, are imported.

While coal prices in China were liberalized beginning in the mid-2000s [11], wholesale and retail natural gas prices are still tightly controlled by government agencies. Wellhead prices are set by the central government, with different prices for fertilizer producers, industrial customers, residential customers, and power plants. Transport prices are set by the central government, reflecting the often significant distance between centers of supply and demand. Retail prices are set by local governments to achieve cost recovery but also reflect local priorities. As a result, there is a significant amount of variation in gas prices among regions and sectors [12]. In our analysis, we use 2 yuan m^{-3} (around US\$8.82 GJ^{-1}) as a rough, middle of the road value for the price faced by a new, generic gas power plant, based on average LNG import prices over 2011 and the first part of 2012 [13].

The Chinese central government's approach to controlling air pollution from power plants has shown a greater preference for post-combustion controls than has historically been the case in many OECD countries. SO_2 control in China's power sector, for instance, has largely been through a combination of mandates and incentives for installing flue gas desulfurization (FGD) units, which by the end of 2010 had been installed on nearly 90% of coal-fired power plants [14]. During the 12th Five-Year Plan (2011–2015), all coal units 300 MW and larger will be required to install equipment to control NO_x emissions [15]. As a result, the costs of pollution control for coal-fired power plants will largely be integrated into the plants' fixed costs rather than the market value of emission reductions. This implies that, while CO_2 prices could have significant implications for the economics of gas-coal substitution in the power sector, prices or fees for criteria pollutants will not.

Natural gas has historically not played the role in China's power sector that it has in most other countries, namely providing load following and peaking generation. Because it tends to have lower fixed costs than coal generation, using natural gas generation in these roles can reduce the total cost of meeting demand. In China, however, a large share of load following and peaking generation is provided with coal. This is due in part to the relatively small difference in capital costs between coal and gas power plants, as described above. However, it is also due to the current approaches to capacity planning, generation pricing, and generator dispatch in China, which don't account for the fact that the cost of generating electricity varies over the course of a day, week, and year [16], in contrast to standard practice in the OECD.

3. Methods and data

Our analysis determines the breakeven cost for a combined cycle gas turbine (CCGT) using natural gas that would make it cost-competitive with a supercritical coal (SPC) unit, for a given CCGT capital cost (CC_{CCGT}), SPC capital cost (CC_{SPC}), gas price (P_{GAS}), coal price (P_{COAL}), CO_2 price (P_{CO2}), and number of annual operating hours (h).

The breakeven point occurs when the total unit operating cost of an incremental unit of CCGT capacity (e.g., 1 kW) is equal to the total operating cost of an incremental unit of SPC capacity. Total unit operating costs are defined as the sum of unit fixed costs (FC) and annual unit variable costs (VC), where fixed costs (\$ $kW^{-1}\ yr^{-1}$) are primarily a function of capital costs, and annual unit variable costs (\$ $kW^{-1}\ yr^{-1}$) are the product of annual operating hours (h yr^{-1}) and unit variable costs (\$ $kW\ h^{-1}$), which in turn are primarily a function of fuel prices and CO_2 prices (equation (1)).

$$\begin{aligned} &FC_{CCGT}(CC_{CCGT},\ldots)+VC_{CCGT}(P_{GAS},P_{CO_2},\ldots)\cdot h \\ &=FC_{SPC}(CC_{SPC},\ldots)+VC_{SPC}(P_{COAL},P_{CO_2},\ldots)\cdot h \end{aligned} \quad (1)$$

Allocation of taxes over fixed and variable costs means that this problem does not have an analytical solution, as some taxes (e.g., the value added tax) have both fixed and variable components. To address this issue, we use a numerical approach to find solutions to equation (1). For the same reason, fixed and variable costs for CCGT and SPC units do not scale linearly with capital and fuel cost ratios. We thus present results in terms of absolute CCGT capital costs and natural gas prices rather than ratios.

The operating hours in equation (1) are an upper bound for the annual operating hour range in which CCGTs are cost-competitive with SPC units. For load following, we use a value of 4000 annual operating hours in this analysis. In other words, CCGTs will be cost-competitive with SPC units for load following as long as they are used to meet demand that occurs for less than 4000 h per year. The capacity factor of a CCGT in this operating hour range will depend on load shape, but will generally be between 10 and 15%, or around 1000 h operated at nameplate capacity equivalent.[1] For baseload, we use an operating hour value of 8760 h, indicating that the CCGT's total operating cost must always be lower than the SPC unit.

The analysis is based on a detailed generator cost model that includes rigorous characterizations of fuel quality (heating value), technology parameters (gross and net heat rates), and non-capital and non-fuel costs (financing, taxes, insurance, labor, maintenance, pollution control). An overview of key modeling issues is provided in Appendix. The generation cost model, along with a complete list of data sources, is available online at http://ethree.com/public_projects/generation_cost_model_for_china.php.

We show the results in units commonly used in China, with results in SI units and U.S. customary units included alongside. We believe this approach provides more intuition about the results to a larger number of readers than relying on SI units alone.

In the section below, we present results as a progression of six scenarios, in which one factor is changed at a time, as illustrated in

[1] Capacity factor is the ratio between actual generation and the maximum potential generation if operating continuously at nameplate capacity. There is no formal definition for what constitutes load following generation. For a load following generator, the number of annual operating hours in equation (1) could range from around 2000 h to more than 8000 h. The 4000 h definition here is intended to reflect a middle of the road value between peaking and baseload generation.

Fig. 1. The scenarios include gas in both baseload and load following modes, with CCGT capital cost, coal prices, and CO_2 prices varied from case to case, and with reduced natural gas prices assumed in all cases. This step-by-step scenario approach is meant to provide greater intuition about the influence of different drivers and assumptions, both in isolation and in tandem. Table 1 shows initial values for the key variables in Fig. 1.

Table 1
Initial values for key scenario variables.

CCGT capital costs	3249 yuan kW^{-1} (\$516 kW^{-1})
Natural gas price	2 yuan m^{-3} (\$8.36 GJ^{-1}, \$8.82 $MMBtu^{-1}$)
High coal spot price (November 2011)	1051 yuan tce^{-1} (\$5.69 GJ^{-1}, \$6.00 $MMBtu^{-1}$)
Low coal spot price (November 2012)	785 yuan tce^{-1} (\$4.25 GJ^{-1}, \$4.48 $MMBtu^{-1}$)

Note: All USD/CNY conversions use an exchange rate of 6.3, based on official exchange rates quoted on www.oanda.com (accessed September 2012). Coal prices are from http://www.cqcoal.com/.

4. Results

Although it is commonly argued that natural gas is not cost-competitive with coal as a source of power generation in China [17–19], these arguments ignore the economics of the different roles that natural gas power plants play in electricity systems. These roles involve the interplay between the lower fixed costs and higher variable costs of gas power plants relative to those for coal power plants. As long as the fixed costs of gas plants are lower, it will be cost-effective to build and operate them for some number of hours.

Screening curves provide a useful way to visualize these dynamics. The screening curve in Fig. 2 shows the total unit operating costs of owning and operating an incremental unit (e.g., 1 kW) of a CCGT and SPC unit in China for the first 1000 h in a year, based on the generator cost model described above. In the screening curve, the *y*-intercepts are unit fixed costs (\$ kW^{-1} yr^{-1}), the slopes of the curves are unit variable costs (\$ kW h^{-1}), and each point on the curves is the total unit operating cost (\$ kW^{-1} yr^{-1}) for the indicated number of annual operating hours on the *x*-axis. The breakeven point for the CCGT is the point of intersection between the two lines. Fig. 2 indicates that, in China, the CCGT is already cost-competitive to meet the share of demand that occurs for less than a few hundred hours in the year (i.e., peak demand). Analysis of a simple-cycle gas turbine, not shown here, shows that it is also already cost-effective for peaking generation under current conditions in China.

Reductions in capital costs for natural gas power plants, natural gas market reforms that reduce the price of natural gas relative to coal, and a price on CO_2 would all increase the operating hour range for which CCGTs are cost-competitive with SPC units, either by lowering the *y*-intercept (capital costs) or reducing the slope (natural gas and CO_2 prices) of the CCGT cost curve in Fig. 2. The six scenarios described in Fig. 1 and shown below examine the required changes in our three key drivers to expand the operating hour range for which CCGTs are cost-competitive with SPC units for load following (4000 h) and baseload (8760 h).

In the results below, each scenario is illustrated using a figure that shows break-even curves for the CCGT for capital cost and natural gas price pairs. Each curve represents a different CO_2 price, which is equivalent to flattening a three dimensional figure with CO_2 prices on the *z*-axis onto two-dimensional space. The point on each figure is our initial CCGT capital cost and gas price pair. The arrows and percentages show reductions in capital costs and gas prices required to reach a desired point on a breakeven curve.

Scenario 1 (baseload, high coal prices, natural gas price reductions, no CO_2 price). Without reductions in CCGT capital costs, without a CO_2 price, and at higher coal prices, modest reductions in natural gas prices would be required for CCGTs to become cost-competitive with SPC units for baseload generation. Fig. 3 shows that, holding these higher coal spot prices constant, a 12% reduction in natural gas price — to 1.8 yuan m^{-3} (\$7.8 GJ^{-1}, \$8.2 $MMBtu^{-1}$) — would be needed.

Scenario 2 (baseload, high coal prices, natural gas price reductions, CCGT capital cost reductions, no CO_2 price). Capital cost reductions have a relatively small impact on the natural gas price reduction required to make CCGTs cost-competitive for baseload generation. A 20% reduction in capital costs decreases the required reduction in natural gas price by around 2 percentage points (Fig. 4). The steep slope of the breakeven curve in Fig. 4 shows that, when evaluating technologies competing for baseload operation, variable costs become the most important driver, since differences in fixed costs are diluted by the large number of operating hours. At a natural gas price of 2 yuan m^{-3} and a CO_2 price of zero, no amount of reduction in capital costs would make the CCGT cost-competitive for baseload generation.

Scenario 3 (baseload, high coal prices, natural gas price reductions, CCGT capital cost reductions, CO_2 prices). Relatively small CO_2 prices can significantly reduce the required reductions in natural gas prices to make the CCGT cost-competitive for baseload generation. For instance, as Fig. 5 shows, a 40 yuan tCO_2^{-1} (\$6 tCO_2^{-1}) price decreases required natural gas price reductions to 6%, to 1.9 yuan m^{-3} (\$8.3 GJ^{-1}, \$8.7 $MMBtu^{-1}$). For reference, in the high coal price scenario, without reductions in capital costs or gas prices, the CCGT would require a CO_2 price of around \$18 tCO_2^{-1} to break even.

Scenario 4 (baseload, lower coal prices, natural gas price reductions, CCGT capital

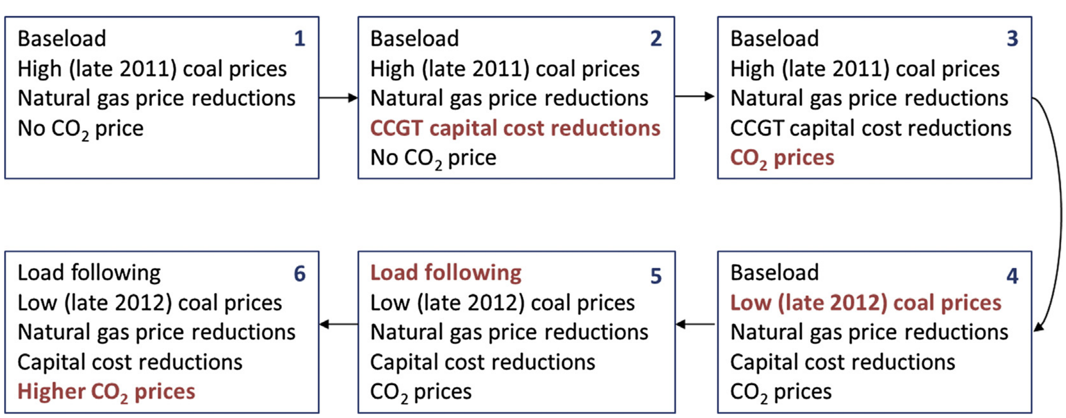

Fig. 1. Progression of six scenarios.

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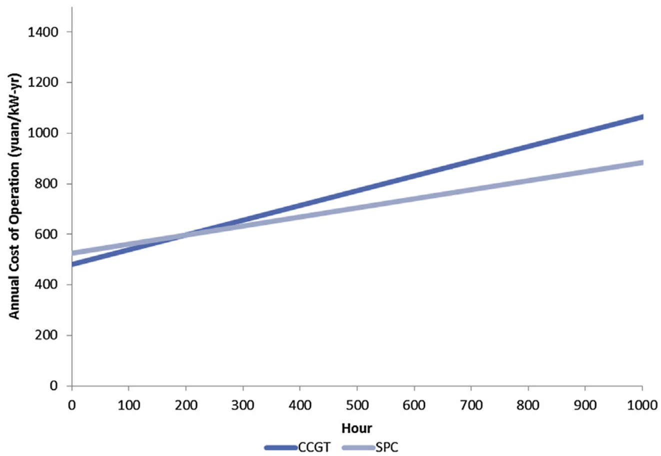

Fig. 2. Screening curve for a combined cycle gas turbine (CCGT) and a supercritical coal (SPC) unit in China, first 1000 h.

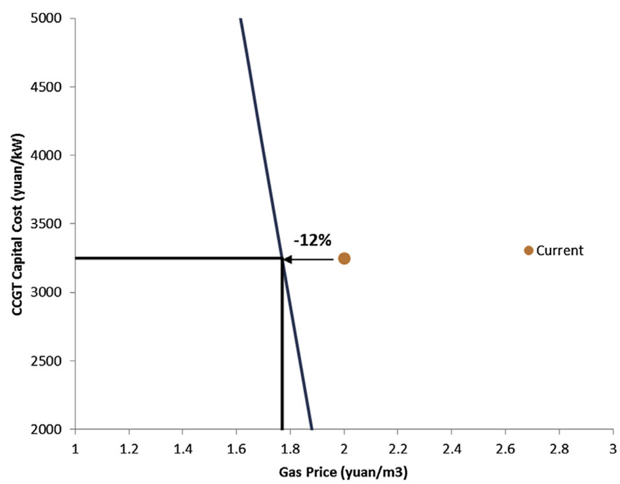

Fig. 3. CCGT breakeven curve for scenario 1.

cost reductions, CO_2 prices). Lower coal prices shift the breakeven curves to the left. At these lower coal prices, much larger reductions in natural gas prices or much higher CO_2 prices are required to make CCGTs cost-competitive for baseload. With 20% reductions in CCGT capital costs and a CO_2 price of \$6 tCO_2^{-1}, natural gas prices would need to fall by 28%, to around 1.5 yuan m^{-3} (\$6.4 GJ^{-1}, \$6.7 $MMBtu^{-1}$). For reference, without reductions in capital costs or gas prices, in the lower coal price scenario, the CCGT would require a CO_2 price of around \$50 tCO_2^{-1} to break even.

Scenario 5 (load following, lower coal prices, natural gas price reductions, CCGT capital cost reductions, CO_2 prices). Reducing the operating hour target rotates the breakeven curves to the left, increasing the importance of capital costs in CCGT cost-competitiveness. With lower coal prices, a 20% reduction in capital costs and a \$6 tCO_2^{-1} price decreases the reduction in required gas prices to 24%, to 1.5 yuan m^{-3} (\$6.7 GJ^{-1}, \$7.1 $MMBtu^{-1}$). At this price, the gas-coal price ratio—the ratio between prices for the two fuels on an energy basis—would have fallen from around 2.0 to 1.6 (Fig. 7).

Scenario 6 (load following, lower coal prices, natural gas price reductions, CCGT capital cost reductions, higher CO_2 prices). At higher CO_2 prices, reductions in capital costs could be largely sufficient to make the CCGT cost-competitive for load following generation. As Fig. 8 shows, the CCGT could breakeven with the SPC unit with a 20% reduction in CCGT capital costs, a 2% reduction in natural gas prices, and a \$40 tCO_2^{-1} price.

The results described above are very sensitive to CCGT thermal efficiency and future trends in relative coal and natural gas prices. If CCGT net thermal efficiency can be increased from 48% to 53% (to 0.18 m^3 $kW\,h^{-1}$ at a gas lower heating value of 8600 kcal m^{-3}), to levels seen for advanced CCGT units [21,22], required reductions in natural gas prices in scenario 4 (Fig. 6) fall from 28% to 19%. A rate of coal price increase that is double the rate of natural gas price increase has roughly the same effect, underscoring the fuel diversity benefits of natural gas generation.

5. Discussion

China's central government has sought to expand the use of natural gas in the power sector since the early 2000s [12], but natural gas continues to account for only a small share of China's generation mix. Concrete strategies, developed on the basis of total system generation cost and the relative costs of building and operating gas- and coal-fired power plants, are needed to achieve this goal.

This analysis has shown that the reductions in capital costs and fuel prices required to make gas-fired power plants more cost-competitive with coal-fired power plants in China are within the realm of feasibility, especially with the introduction of a small price on CO_2. Required reductions in capital costs for natural gas power plants, on the order of 20% of the current cost of a CCGT, are on par with 22% average capital cost reductions for coal units from 2001 to 2010 [23,24]. In addition, for peaking and low-operating-hour load following it may be more cost-effective to use simple cycle gas turbines (CTs) than CCGTs, which would further reduce capital costs at the cost of some loss in fuel conversion efficiency.[2] China has yet to start producing gas turbines domestically, a development that could dramatically reduce the cost of CCGTs and CTs relative to coal units.

Required reductions in natural gas prices relative to coal prices, in the range of 10–30% depending on coal price trends, may also be feasible. China's natural gas sector is still evolving. Its gas industry was historically dominated by local gas companies [25], and only became national with the construction of the West–East pipeline in 2004 and international with the construction of China's first LNG terminal in 2006 [12]. Although China's conventional natural gas reserves are relatively limited [26], it is thought to hold huge reserves of unconventional gas [3], and also has access to diverse gas imports overland from Central Asia, Russia, and Myanmar, and by sea through an expanding LNG terminal network [26]. A more vibrant natural gas market in China is currently hampered by

[2] In PJM (eastern U.S.), for instance, a new CT is roughly 20% cheaper than a new CCGT [21]. Although a CT is less efficient than a CCGT, the thermal efficiency of CTs has improved significantly in recent years; new CTs with NO_x and CO controls can achieve thermal efficiencies as high as 38% [21].

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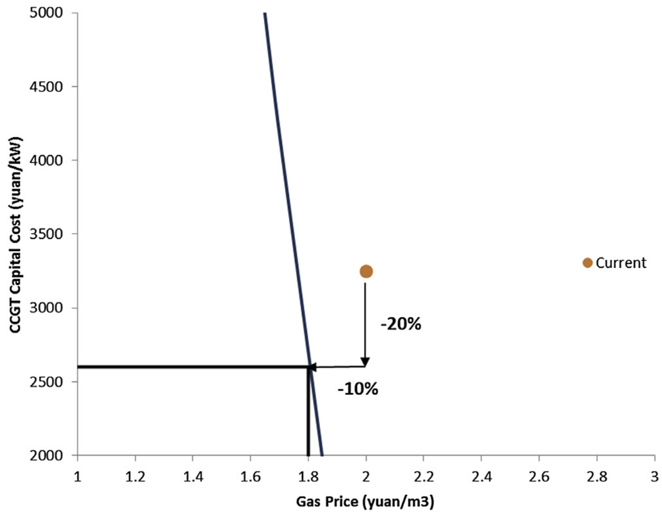

Fig. 4. CCGT breakeven curve for scenario 2.

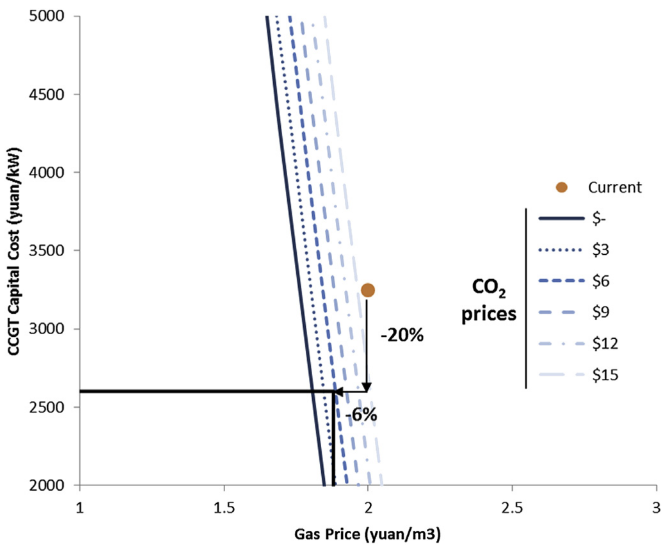

Fig. 5. CCGT breakeven curve for scenario 3.

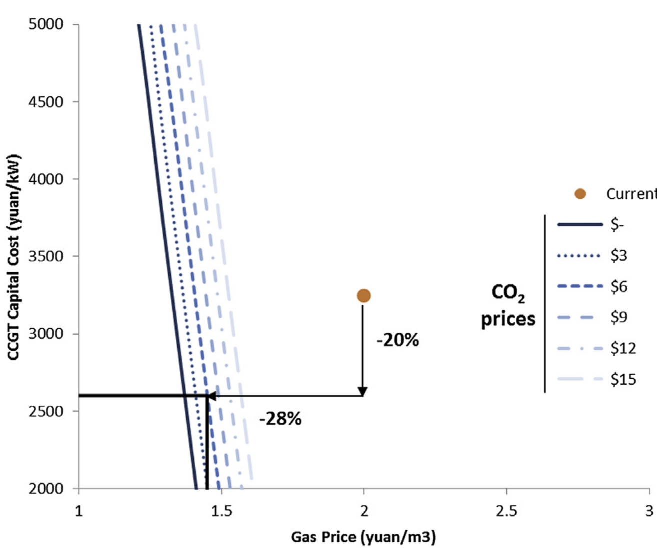

Fig. 6. CCGT breakeven curve for scenario 4.

limited long-haul pipeline and storage capacity, inefficient pricing, and the absence of an independent regulator [26].

A price on CO_2 emissions, which was not politically feasible a decade ago in China, now appears inevitable. China's central government plans to create a national CO_2 emissions trading system by 2015. Even if this system proves difficult to implement, some price on CO_2 is likely to materialize over the coming decade [27]. Relative to CO_2 reductions in other industries and other CO_2 measures in the electricity sector, gas-coal substitution could be a cost-effective mitigation strategy.

The results indicate that there is a logical sequence to strategies for expanding natural gas generation in China's power sector (Fig. 9). Natural gas units are already cost-competitive for peaking generation in China, but the current approach to capacity planning and wholesale generation pricing does not support them. Currently, the commonly used method for screening the economics of gas and coal generation is to simply compare the levelized cost of a gas unit that has a capacity factor of around 10–20% with a coal unit that has a capacity factor of around 60% [19]. This approach is erroneous—the appropriate comparison is to compare the two for equivalent operating hour ranges and capacity factors—and leads to coal generation being built and operated when it is not economic. Thus, a first strategic step would be for government agencies in charge of electricity policy to critically reexamine current planning and pricing methods and adjust them to support generation technologies that operate at low capacity factors.

Improved rules for generator access to gas supplies are also needed to enable a gas-peaking role. Gas-fired power plants in China currently buy fuel using take-or-pay contracts, typically with an annual contract quantity divided equally across all days [18,19]. Because a load following generator's demand for natural gas will vary throughout the year, and gas, unlike coal, is not typically stored in large quantities onsite, this daily take-or-pay contractual framework limits the effectiveness and cost-competitiveness of gas power plants. Not only must the power plant pay for gas when it is not needed, but there is also no guarantee that the plant would have access to gas above its daily contractual amount during periods of high demand. A near-term solution to this problem would be to allow low operating hour power plants to negotiate flexible supply contracts more aligned with the timing of their gas demand, for example seasonal and short-term contracts for firm or interruptible gas supply service.

Further steps would expand the operating hour range over which gas is cost-competitive

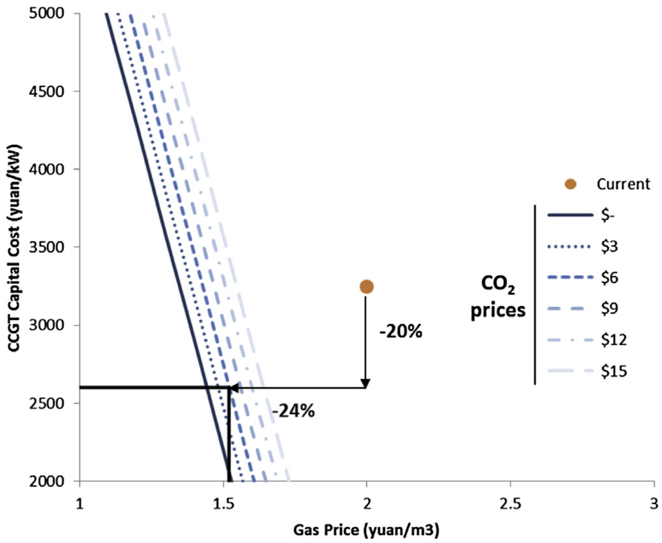

Fig. 7. CCGT breakeven curve for scenario 5.

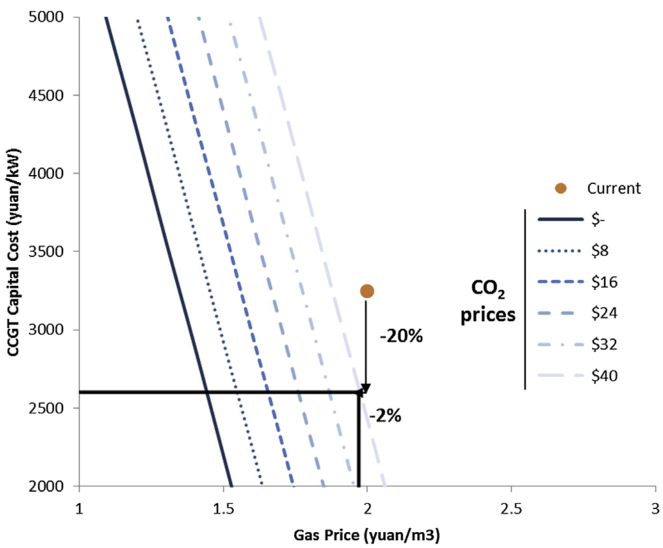

Fig. 8. CCGT breakeven curve for scenario 6.

with coal. The results show that, for lower operating hour units, reductions in capital costs are relatively more important in increasing the cost-competitiveness of gas units than reduction in gas price or imposition of a CO_2 price. Thus a second strategic step would be the design of industrial policies that reduce capital costs for natural gas power plants. The largest component of reductions in natural gas capital costs is likely to come from indigenizing gas turbine manufacturing, which will require both significant political commitment and time.

A third strategic step, in the area of energy policy, would be natural gas market planning, price, and regulatory reforms that expand natural gas production, transport, and storage. These reforms would likely bring domestic natural gas prices in China more in line with international prices, which could either increase or decrease prices in the short term but would likely drive them down over the longer term by expanding and increasing the flexibility in gas supply. A fourth strategic step, in the realm of climate policy, would be to impose a price on CO_2, which could start small and be increased over time. As this analysis has demonstrated, even a small CO_2 price could be an important complement to other strategies to expand natural gas generation in China.

The effectiveness of the previous two steps is predicated on significant changes in wholesale generation pricing and dispatch in China, a fifth strategic step that comes back to the domain of electricity policy. Currently, grid companies pay generators a single per kWh price that covers both fixed and variable costs and that is neither regularly nor systematically adjusted. Thermal generators are dispatched to facilitate fixed cost recovery rather than according to short-run marginal cost. This approach to pricing and dispatch would not lead to optimal use of gas units, which, once built, should compete with coal units for operating hours on the basis on variable fuel and environmental costs. Addressing this obstacle would require shifting to separate capacity and energy pricing and a marginal cost approach to dispatch [16], practices that are common in OECD countries.

There are a number of other power system and environmental benefits to natural gas generation that, while not explicitly considered in this study, could provide important motivation for expanding gas generation in China. These include: the benefits of fuel

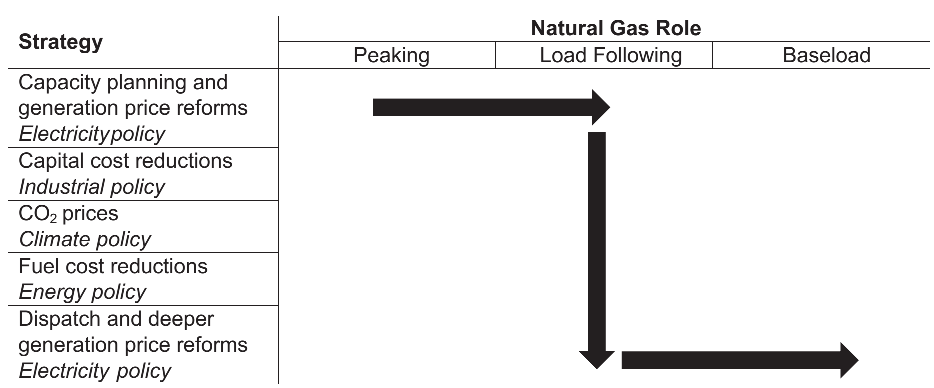

Fig. 9. A roadmap for expanding natural gas generation in China.

diversification, which we illustrated through higher historical coal prices and future coal prices that rise more rapidly than those for gas; the increased flexibility provided by gas units, which could play an important role in supporting intermittent renewable generation; additional criteria pollutant emission reductions in air quality management zones that have difficulty meeting air quality targets; greater ease of siting and reduced transmission costs, as gas units can be sited closer to load centers.

6. Conclusions

Increasing natural gas-fired generation in China has been an elusive goal, but may be achievable in a shorter time frame than commonly thought, given plausible fuel and capital cost reductions plus a set of policy interventions that are consistent with China's broader energy policy and economic reform goals. Contrary to conventional wisdom, natural gas generation is already cost-competitive for peaking applications in China's power system, and its use would lower total system cost. For gas peakers to actually be employed, however, government agencies would need to adjust current methods of compensating generators.

For natural gas to play a greatly expanded role in load following or baseload generation, various combinations of lower fuel prices and reduced capital costs could make gas competitive with coal. This could occur solely due to market forces, without policy intervention. For example, if natural gas prices were to fall to current North American levels while coal prices remain the same, natural gas baseload generation would be cost-competitive even with current capital costs and no carbon price. However, key interventions in energy policy, industrial policy, climate policy, and electricity policy could greatly facilitate the expansion of gas generation.

There is a logical sequence of these interventions that reflects the dominance of fixed costs at low operating hours and variable costs at higher operating hours. The greatest initial impact would come from government action to reduce the capital cost of natural gas generation technologies—in particular, gas turbines—to enable the use of gas in load following. Subsequently, reforms in the natural gas supply sector, imposition of even a small carbon price, and fundamental changes in electricity wholesale pricing and planning would enable gas to be competitive for baseload, given plausible decreases in the ratio of gas price to coal price.

Acknowledgments

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Appendix

Two assumptions in our analysis bear mentioning. First, we assume, conservatively, that the heat rate penalty for operating in load following mode is equivalent for CCGT and SPC units. Second, we assume, also conservatively, that maintenance rates are the same for CCGT and SPC units when they operate an equivalent number of hours. Relaxing both of these assumptions would improve the economics of the CCGT relative to the SPC unit.

The remainder of this Appendix describes the generation cost model. Our generation cost model calculates the unit fixed ($\$ \text{ kW}^{-1} \text{ yr}^{-1}$) and variable ($\$ \text{ kW h}^{-1}$) costs of owning and operating different thermal generation technologies in China. The model is based on a detailed representation of generator cash flows that includes technology and fuel characteristics; financing, labor, insurance, maintenance, and pollution control equipment costs; an array of taxes; and SO_2, NO_x and CO_2 fees. A significant portion of the data is from Wang [9].

The cost structure of thermal generation in China is different from that in, for instance, the U.S. Power plants in China generally have a lower cost of debt and equity, higher leverage, and a lower book life than power plants in the U.S. For instance, Dong et al. [19] report a 5.94% debt interest rate, an internal rate of return of 8%, and a 15-year book life. State-owned enterprises in China are required to provide at least 30% of capital expenditures through retained earnings [28], which is the equivalent of an equity share. By contrast, the 2010 updates to the California Energy Commission's Cost of Generation Model use a 40–60 debt-equity capital structure, a debt interest rate of 7.49%, an equity rate of 14.47%, and a book life of 20 years [22].

Power plants in China also tend to have significantly more workers and higher labor costs than those in the U.S. Dong et al. [19], for instance, report that a 2 × 180 MW CCGT in China requires 200 full-time equivalent (FTE) staff, or 0.56 FTEs per MW, whereas a CCGT in California a 500 MW CCGT requires an estimated 23 workers, or 0.05 FTEs per MW [20]. Dong et al. [19] estimate the cost of salaries for a CCGT at more than $\$5600 \text{ MW}^{-1}$, whereas in California it would be less than $\$330 \text{ MW}^{-1}$ [22]. Power plant maintenance costs are also higher in China. Dong et al. [19] estimate annual maintenance costs of roughly $\$17.6 \text{ kW}^{-1}$ for a 2 × 180 MW CCGT, whereas maintenance costs for the 500 MW unit in California would run $\$14.7 \text{ kW}^{-1}$ [22].

In the model we assume that all new coal generators are required to install SO_2 and NO_x controls, and that new CCGTs are required to install NO_x controls. Our NO_x emission factors for coal units assume that all new generators are required to have low-NO_x burners, as reflected in the emission factors from Zhao et al. [29]. We also assume that new coal units have particulate matter (PM_{10}) control equipment, and that the cost of this equipment is already embedded in the capital cost of the plant. We did not include mercury emissions in our model, because pollution fees for mercury are not high enough for these fees to be a significant contributor to costs and because of the difficulty in estimating an emission factor given the complex interaction among coal quality and other pollution control equipment [30].

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