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Impacts of China's emissions trading schemes on deployment of power generation with carbon capture and storage

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ABSTRACT

The establishment of an emissions trading scheme (ETS) in China creates the potential for a "least cost" solution for achieving the greenhouse gas (GHG) emissions reductions required for China to meet its Paris Agreement pledges. China has pledged to reduce CO_2 intensity by 60–65% in 2030 relative to 2005 and to stop the increase in absolute CO_2 emissions around 2030. In this series of studies, we enhance the MIT Economic Projection and Policy Analysis (EPPA) model to include the latest assessments of the costs of power generation technologies in China to evaluate the impacts of different potential ETS pathways on deployment of carbon capture and storage (CCS) technology. This paper reports the results from baseline scenarios where power generation prices are assumed to be homogeneous across the country for a given mode of generation. We find that there are different pathways where CCS might play an important role in reducing the emission intensity in China's electricity sector, especially for low carbon intensity targets consistent with the ultimate goals of the Paris Agreement. Uncertainty about the exact technology mix suggests that decision makers should be wary of picking winning technologies, and should instead seek to provide incentives for emission reductions. While it will be challenging to meet the CO_2 intensity target of 550 g/kWh for the electric power sector by 2020, multiple pathways exist for achieving lower targets over a longer timeframe. Our initial analysis shows that carbon prices of 35–40\$/tCO_2 make CCS technologies on coal-based generation cost-competitive against other modes of generation and that carbon prices higher than 100\$/tCO_2 favor a major expansion of CCS. The next step is to confirm these initial results with more detailed modeling that takes into account granularity across China's energy sector at the provincial level.

1. Introduction

The establishment of a national emissions trading scheme (ETS) in China creates the potential for a "least cost" solution to greenhouse gas (GHG) emissions reductions that can allow China to meet its Paris Agreement pledges to reduce CO_2 intensity by 60–65% in 2030 relative to 2005 and to reach a peak in its absolute CO_2 emissions around 2030. The details of the ETS remain to be worked out and economic modeling can provide insight into how China's energy system might respond to different ways the system can be set up. In this series of studies, we enhance the MIT Economic Projection and Policy Analysis (EPPA) model (Paltsev et al., 2005; Chen et al., 2016) to include the latest assessments of the costs of power generation technologies in China to evaluate the impacts of different potential ETS pathways on deployment of CCS technology. This paper reports results from our baseline study wherein we assume power prices are homogeneous across the country for a given mode of generation.

China is leading the world in terms of economic development. China's gross domestic product (GDP) in purchasing power parity (PPP) terms was \$23.1 trillion in 2017, which is larger than the USA's GDP PPP of \$19.4 trillion in 2017 (IMF, 2017). Energy is a key to fueling economic growth and China is leading the world in primary energy consumption. In 2016, China consumed 3006 million tonnes of oil equivalent (mtoe), which is larger than the USA's energy consumption of 2154 mtoe in 2016 (IEA, 2017). Carbon-emitting fossil fuels remain the world's dominant source of power (IEA, 2017) and China is the largest CO_2 emitter with 10.4 Gigatonnes (Gt) of CO_2 in 2016 from fossil fuel use and industrial processes, while the corresponding US emissions in 2016 were 5 GtCO_2 (Janssens-Maenhout et al., 2017).

The UN Paris Agreement (UN, 2015) calls for global greenhouse gas (GHG) emissions reductions to achieve a target of keeping the increase in the global average surface temperature to "well below" 2 °C relative to preindustrial levels, and to pursue efforts to limit the temperature

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rise to 1.5 °C. To contribute to the global goal, China submitted a pledge of reducing its CO_2 intensity of GDP by 60–65% in 2030 relative to 2005 and to stop the increase in absolute CO_2 emissions around 2030. The pledge also calls for an increase in the share of non-fossil fuels in primary energy consumption to about 20% by 2030 (UNFCCC, 2015). China's emissions mitigation actions are crucial for the ultimate success of climate stabilization as its participation or non-participation can lead to a 1.1–1.3 °C difference in global average surface temperature by 2100 (Paltsev et al., 2012).

Emission trading provides an opportunity for the most efficient way to reduce emissions (IPCC, 2014). With China's announcement (NDRC, 2017) of its national emissions trading scheme, the country has a potential to become a leader in efficient reduction of CO_2 emissions. Initially set to cover more than 3 billion tonnes of CO_2 from the power sector, China's carbon market will be the largest in the world and close to double the size of the next largest, the EU ETS (Timperley, 2018).

The experience of the EU ETS and other emission trading systems shows the difficulty of incentivizing carbon abatement. More than a decade of experience with the EU ETS has yielded valuable lessons on the importance of emissions data availability and quality, and the need for robust governance structures for market oversight. Most importantly, the EU ETS underscored how price discovery in emissions trading systems is susceptible to uncertainty and unanticipated shocks. Consistently depressed carbon prices in the EU ETS have prompted successive interventions to prevent undesirable dynamic effects (Paltsev et al., 2018).

Based on the lessons from emissions trading systems in other parts of the world, China has adopted a sequential approach, beginning with seven pilot trading schemes in cities to demonstrate that monitoring and reporting is possible for emissions trading. Movement to national emissions trading is also gradual with electricity being the first sector to be covered by the ETS. Work to establish the reporting and trading framework is underway and full trading in the electricity sector is expected after 2020 (NDRC, 2017). Other sectors will be included in the ETS at a later stage.

Successful design of an economy-wide and nation-wide ETS in China requires resolving many challenges, including allocation decisions for cap settings at the provincial level to ensure economic efficiency and equity considerations. The decision to structure the national market on emissions intensity standards (e.g. grams of CO_2 per kilowatt hour) rather than mass-based trading units (e.g. grams of CO_2) offers some flexibility in balancing CO_2 emission reductions with economic performance, but will require careful decision-making on targets for the standards. Reliable emissions and activity data and modeling tools will be needed to ensure the integrity of the carbon market and its effectiveness. While there are many potential difficulties, ETS offers the greatest economic efficiency benefits among the emission mitigation mechanisms. This paper seeks to provide insight on how the power generation mix might evolve towards progressively lower carbon intensity targets. We specifically consider the trade-offs between the deployment of CCS relative to other low-carbon power generation sources, subject to the constraints of decreasing average CO_2 emissions intensity targets.

2. Emission trading in China and CCS

Emission trading leaves the allocation of resources to the market and can thereby equalize abatement costs across all covered entities, avoiding technology-picking and offering superior cost-effectiveness over alternative instruments (Fischer and Newell, 2008). Zhang et al. (2014) explored the effects of two scenarios of national emission trading in China: Continued Effort (CE) and Accelerated Effort (AE). Zhang et al. (2014) assumed that the CE scenario maintains the pace set by China's CO_2 intensity reduction targets in 2016–2020 through 2050. To maintain a CO_2 intensity reduction rate of approximately 3% per year (corresponding to an extension of the targeted reduction pace for the Thirteenth Five-Year Plan, 2016–2020), an economy-wide carbon price was introduced. Carbon prices in this scenario grew from \$14/tCO_2 in 2020 to \$26/tCO_2 in 2030 and to \$58/tCO_2 in 2050. The AE scenario included a carbon price consistent with a more aggressive CO_2 reduction scenario (4% per year reduction in CO_2 intensity). The forecasted carbon price rose from \$20/tCO_2 in 2020 to \$38/tCO_2 in 2030 and to \$115/tCO_2 in 2050. For CCS technologies, Zhang et al. (2014) assumed availability of two options: integrated gasification combined cycle with CCS (IGCC-CCS) and natural gas combined cycle with CCS (NGCC-CCS). Their costs were based on estimates from Rubin and de Coninck (2005) and electricity production from IGCC-CCS estimated to be 55% more expensive than electricity produced by pulverized coal generation. The corresponding increase in cost for NGCC-CCS was 135% more expensive than pulverized coal-based electricity.

Our study seeks to extend these results to a wider range of low-carbon generation options including natural gas, nuclear, wind, solar, coal with CCS, and natural gas with CCS. We use a consistent representation of the cost components of power-generation technologies (Paltsev et al., 2010) to assess the power generation costs in China and determine which technologies might be favorable under different conditions (see Appendix for the detailed calculations). As a starting point, we assume homogeneous costs of power generation across the country. In reality, the generation mix (Lindner et al., 2013) and cost of electricity (Huaneng, 2016; Ouyang and Lin, 2014) can vary significantly from province to province, due to differences in the type of generation, fuel costs, local production capacity, dispatch requirements, and other technical factors. Although detailed modeling at the province level is ultimately needed to produce the most rigorous results, significant insights are available through a simplified, baseline analysis assuming homogeneous costs.

For CCS we have focused on post-combustion options. In the base case, we have assumed coal prices of 1.59 \$/MMBTU and natural gas price of 7.34 \$/MMBTU, which are representative of pricing in 2015 (Zhang and Paltsev, 2016). In contrast with Zhang et al. (2014), we relate our estimates to the base electricity price in China of \$0.05/kWh (Narayanan et al., 2012). For consistency with the majority of previous studies, we assume a CO_2 capture rate of 90% for both coal and natural gas cases. We estimate that CCS increases the cost of generation from coal by 45% and the cost of generation from natural gas by 78%. For coal plants, this incremental cost impact is lower than the general range of 58 to 108% reported by Hu and Zhai (2017) based on a bottom-up analysis of CO_2 capture at a reference power plant. This difference can be explained largely by the higher assumed fuel costs in Hu's analysis.

Without specific policies (e.g., a carbon price from emission trading) that promote CCS or penalize the use of unabated coal technology, CCS is a more expensive option and will not be deployed. To identify situations where CCS becomes attractive, we varied the calculations of relative costs of generation with different carbon prices. Fig. 1 represents the relative costs of dispatchable generation under CO_2 prices ranging from 0 to 50\$/tCO_2. With zero carbon price, coal-based generation is the cheapest electricity producing technology in China (at about 0.06\$/kWh). Nuclear generation cost approaches 0.08\$/kWh, natural gas and coal with CCS are about 0.09\$/kWh, and natural gas with CCS is at about 0.11\$/kWh. A range of costs for wind generation at different representative penetration levels are depicted separately on Fig. 1 (denoted by blue circles on the vertical axes). We do not show the range of costs for solar generation because it is close to the range of wind (see Appendix). While the cost of wind- and solar-based generation is not affected by the CO_2 price, they are impacted by the level of penetration, with higher penetration incurring higher costs of integration into the power system. We show the costs of wind generation at low penetration levels (less than 25% of generation mix), medium penetration levels (25–50%), and high penetration levels (more than 50%). The costs of wind power rise with penetration due to the need for backup generation or energy storage to ensure dispatchability and grid stability.

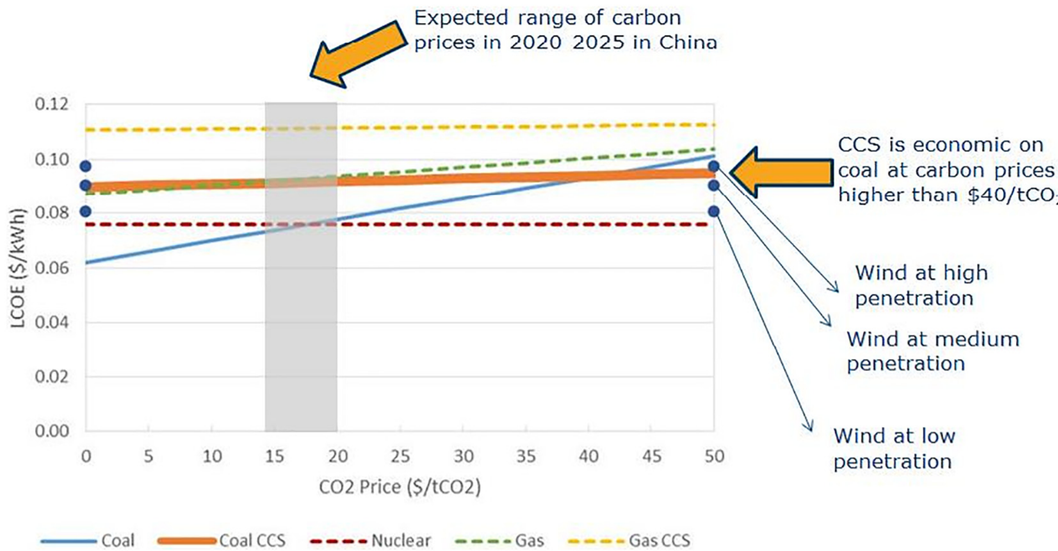

Fig. 1. Cost of producing electricity with coal price of 1.59 $/MMBTU and natural gas price of 7.34 $/MMBTU and different carbon prices.

A carbon price changes the order of technologies, in terms of which is the least expensive. Nuclear power is the lowest cost option at a carbon price of 50$/t$CO_2$ because it is not affected by carbon penalties. At this carbon price, coal with CCS becomes the second-best dispatchable option; coal, natural gas, and natural gas with CCS are all more expensive. Renewables can be cheaper than coal CCS depending on the penetration level. Fig. 1 also shows the range of expected carbon prices for 2020 in China, which is based on our anticipation of more aggressive emission reduction in 2020 in comparison to reductions in the regional pilot ETS systems within China (the historical range for carbon auction prices in the regional pilot ETS systems in, 2014–2017 was $1.50–10$/tCO_2 (Yang et al., 2018)). Our expected range for carbon prices corresponds to the estimates from Zhang et al. (2014).

At the price range of 14–20$/t$CO_2$, coal with CCS is more expensive than coal and nuclear options, but comparable cost of natural gas generation. Using national averages of power prices, coal with CCS becomes the cheapest dispatchable option for carbon prices higher than about 40$/t$CO_2$ in regions where nuclear power may be limited.

The general observation that nuclear power, where available, is economically preferred over coal should be tempered by several realities associated with deploying nuclear power. First, nuclear power deployment in China is generally limited to the coast, to take advantage of seawater cooling and to limit the risk of contamination. Second, some uncertainty exists in the deployment path of nuclear power due to the Fukushima nuclear accident. While nuclear deployment is mandated to reach 58 GW by 2020 under the 13th Five Year Plan period (2016–2020), there are questions as to the upward trajectory after this period (Guo and Guo, 2016). Third, Wang et al. (2011) performed case studies for emissions reductions in Fujian and Anhui provinces and found that provincial differences in the cost of coal, and the availability of hydropower and renewables can also impact the attractiveness of nuclear power as an option for reducing carbon emission intensities. It is most economical to operate nuclear power at high capacity factors. It is unclear how long the current overcapacity situation in China for electricity generation will persist and what policies might be introduced to prioritize dispatch from nuclear generation. Together, these realities suggest that further insight into the deployment of nuclear power requires modeling of power pricing at the provincial level with sensitivity scenarios related to different policy directions.

Figs. 2 and 3 show the results from a sensitivity analysis around coal costs. The analysis was performed for costs corresponding to high and

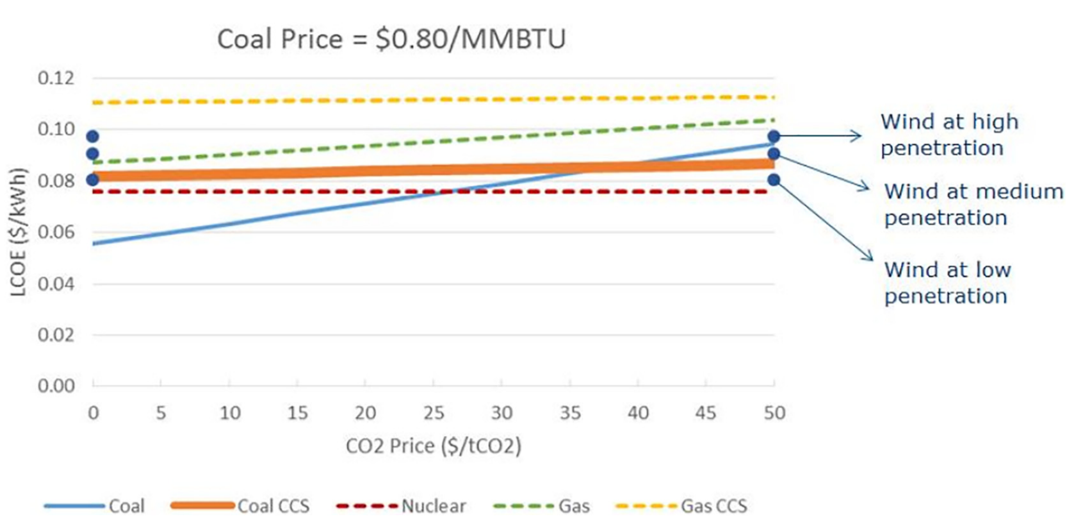

Fig. 2. Cost of producing electricity with coal price of 0.80 $/MMBTU and natural gas price of 7.34 $/MMBTU and different carbon prices.

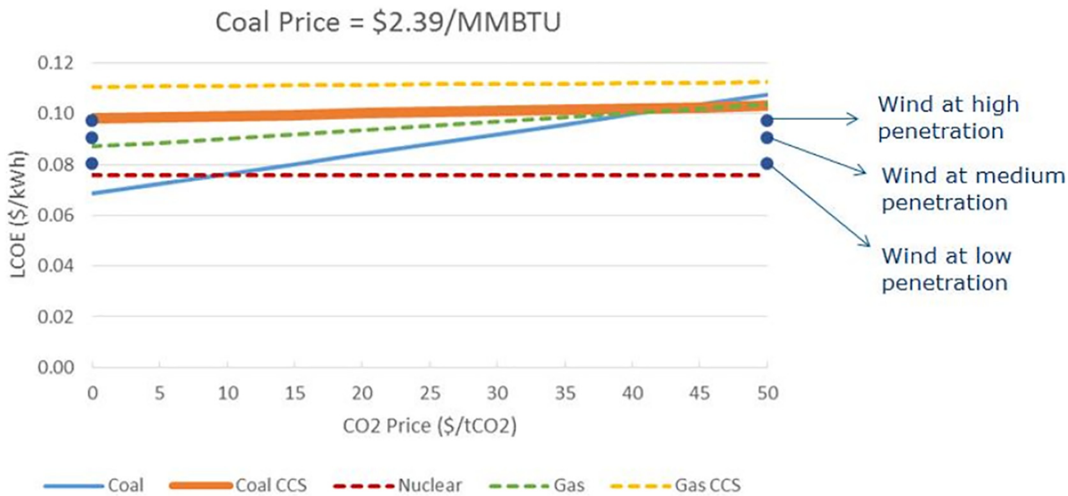

Fig. 3. Cost of producing electricity with coal price of 2.39 $/MMBTU and natural gas price of 7.34 $/MMBTU and different carbon prices.

low values representative of coal pricing in different provinces of China from 2013 to 2016. The lowest coal prices increased the relative attractiveness of coal with CCS, relative to nuclear power priced at a national average level, but did not change the overall conclusion. Fig. 2 shows the results of calculations using a coal price - 0.80$/MMBTU. At this coal price, coal with CCS becomes the second-cheapest dispatchable option when carbon prices are higher than about 35$/t$CO_2$. We also analyzed the scenario when coal prices are higher - 2.39$/MMBTU. With these coal prices, both nuclear and natural gas generation are cheaper than coal with CCS for the carbon prices from 0 to 50$/t$CO_2$, as are renewables even at high penetration (see Fig. 3).

In Fig. 4 we provide an illustration of relative generation costs even with higher coal prices of $3.20/MMBTU and a natural gas price of $10/MMBTU, which reflect market conditions in China in some periods of 2018. With these prices, coal with CCS outcompetes unabated coal at carbon prices above 40$/t$CO_2$ and outcompetes unabated natural gas at carbon prices above 15$/t$CO_2$. However, at all carbon prices it is now more expensive than renewables, even when they are at high penetration levels. These results illustrate the effect of fuel costs on the relative economic competitiveness of different modes of power generation, and reinforce the importance of incorporating provincial level granularity in future studies.

3. Assessing the scenarios of reducing carbon intensity of electricity in China

To assess the competition between CCS and other low-carbon power generation technologies, we employ the MIT Economic Projection and Policy Analysis (EPPA) model (Paltsev et al., 2005; Chen et al., 2016). The EPPA model offers an analytic tool that includes a technology-rich representation of power generation sector, and also captures interactions between all sectors of the economy, accounting for changes in international trade. Data on production, consumption, intermediate inputs, international trade, energy and taxes for the base year of 2007 are from the Global Trade Analysis Project (GTAP) dataset (Narayanan et al., 2012). The GTAP dataset is aggregated into 18 regions (Fig. 5) and 33 sectors (Table 1), including several advanced technology sectors parameterized with supplementary engineering cost data.

The model includes representation of CO_2 and non-CO_2 (methane, CH_4; nitrous oxide, N_2O; hydrofluorocarbons, HFCs; perfluorocarbons, PFCs; and sulphur hexafluoride, SF6) greenhouse gas (GHG) emissions abatement, and calculates reductions from gas-specific control measures as well as those occurring as a byproduct of actions directed at CO_2. The model also tracks major air pollutants (sulfates, SO_x; nitrogen oxides, NO_x; black carbon, BC; organic carbon, OC; carbon monoxide,

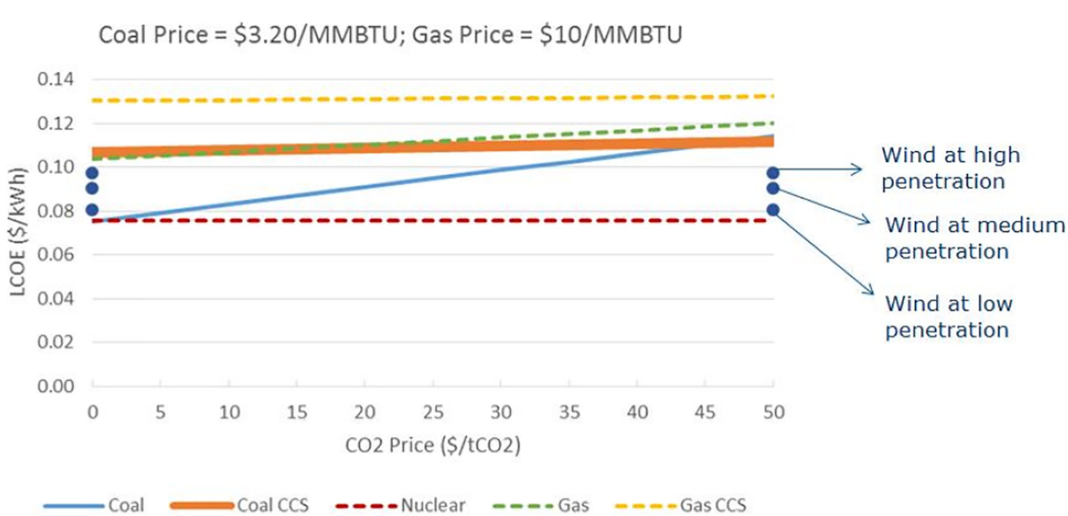

Fig. 4. Cost of producing electricity with coal price of 3.20 $/MMBTU and natural gas price of 10.00 $/MMBTU and different carbon prices.

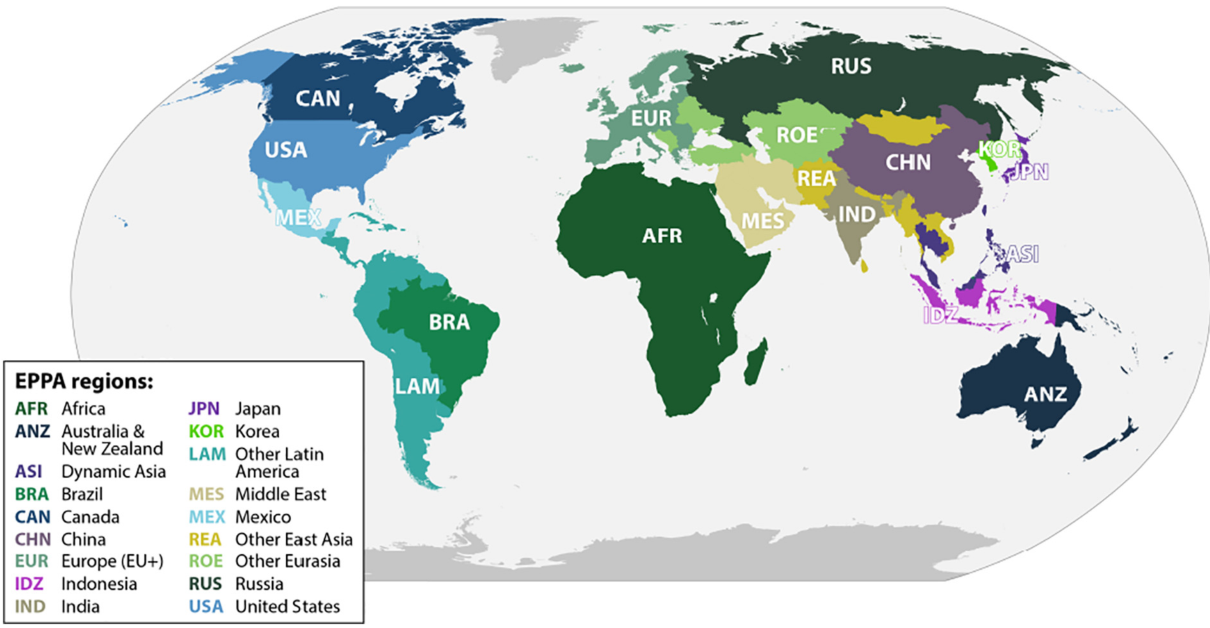

Fig. 5. EPPA model regional coverage.

CO; ammonia, NH_3; and non-methane volatile organic compounds, VOCs). The data on GHG and air pollutants are documented in Waugh et al. (2011).

From 2015 the model solves at 5-year intervals, with economic growth and energy use for 2010–2015 calibrated to data and short-term projections from the International Monetary Fund (IMF, 2015) and the International Energy Agency (IEA, 2017). To represent a competition between different power generation technologies, the EPPA model uses a metric called "markup". The markup is the measure of the cost of a technology relative to the price received for electricity generation (PRG) in that region (in \$/kWh). This markup provides a relative framework of comparing how competitive specific technologies are in specific countries. The PRG used is the cost per kilowatt-hour for a power plant to generate electricity.

To represent costs related to intermittency of large-scale renewable generation, we assume that the variability of the resource can be managed through the extra cost of backup capacity. For small-scale wind and solar with little impact on the overall power grid, the backup is not required. In the EPPA model, we assume that renewable generation does not incur additional integration costs until their combined share reaches about 30% of total generation. At higher levels of penetration, a corresponding capacity of natural gas or biomass generation is required to ensure full dispatchability. That is, 1GW of wind or solar requires an installation of 1GW of back-up power that will be employed in the situations when the wind is not blowing or the sun is not shining. This back-up requirement at higher renewable penetration levels increases the cost of renewables, opening the door to greater competition from other low-carbon technologies. The Appendix at the end of the report presents the derivation of the levelized cost of electricity (LCOE) and the corresponding markup calculations for power generation technologies in China. In this study, the model uses national average pricing for different modes of power generation.

China's Emissions Trading System will be initiated with output-based allocation (NDRC, 2017). It means that emissions permits will be allocated to companies in proportion to their output (kilowatt hour of electricity produced). The exact allocation scheme is under development. It is reasonable to assume that emissions intensity per unit of output (gCO_2/kWh) will be targeted, with a goal of reducing the current (2015) average CO_2 intensity of electricity generation in China of about 750 g/kWh (IEA, 2017).

While the exact numbers have not been announced yet, a potential near-term goal might be 550 g/kWh (Liu et al., 2017), which is based on the plan by the State Council of China. This could be achieved through a combination of fossil fuel generation with CCS and the addition of zero-carbon generation (like wind, solar, nuclear, or hydro) to arrive at an electricity generation mix with the desired average emissions intensity. Here, we use the EPPA model to impose different values of a

Table 1
Sectors in the EPPA Model.

Sectors	Abbreviation
Energy-Intensive Industries	EINT
Other Industries	OTHR
Services	SERV
Crops	CROP
Livestock	LIVE
Forestry	FORS
Food Processing	FOOD
Coal Production	COAL
Oil Production	OIL
Refining	ROIL
Natural Gas Production	GAS
Coal Electricity	ELEC: coal
Natural Gas Electricity	ELEC: gas
Petroleum Electricity	ELEC: oil
Nuclear electricity	ELEC: nucl
Hydro Electricity	ELEC: hydro
Wind Electricity	ELEC: wind
Solar Electricity	ELEC: solar
Biomass Electricity	ELEC: bele
Wind combined with gas backup	ELEC: windgas
Wind combined with biofuel backup	ELEC: windbio
Coal with CCS	ELEC: colcap
Natural Gas with CCS	ELEC: ngcap
Advanced Nuclear Electricity	ELEC: anuc
Advanced Natural Gas	ELEC: ngcc
Private Transportation: Gasoline & Diesel Vehicles	HTRN: ice
Private Transportation: Plug-in Hybrid Vehicles	HTRN: phev
Private Transportation: Battery Electric Vehicles	HTRN: bev
Commercial Transportation	TRAN
First-Generation Biofuels	BIOF
Advanced Biofuels	ABIO
Oil Shale	SOIL
Synthetic Gas from Coal	SGAS

Table 2
Time periods when different carbon intensity targets for power generation are achieved with different levels of carbon prices.

	550 g/kWh	350 g/kWh	100 g/kWh
20$/tCO2	2045		
50$/tCO2	2030		
80$/tCO2	2020	2025	2045–2050
100$/tCO2	2020	2020–2025	2035–2040

carbon tax in China to evaluate the timing of reaching different goals of carbon intensity (550 g/kWh, 350 g/kWh, 100 g/kWh). These targets correspond roughly to the State Council value, natural gas equivalence, and deep decarbonization equivalent to about 90% reductions from unmitigated coal power. In this setting, the carbon tax remained flat at a certain level over the whole period of projection. Table 2 shows the results for the year when specific targets are achieved. Because the EPPA model solves every 5-years, we report a 5-year range if the resulting carbon intensity is not close to a particular solution year, but between the time range.

The results of simulations show that achieving the 550 g/kWh target in a short period of time requires a substantial carbon price. In the EPPA model, the vintage structure of power generation represents an ability to substitute away from a particular technology. Once the investment is made, future decisions on whether to use it are based only on variable costs. This makes it more difficult for advanced technology to capture market share, as the price of output from the old technology can drop below the full replacement cost. In the EPPA model, only a portion of capital in any sector is vintaged, reflecting that some aspects of a plant's physical structure or siting can be reused, and that plants may be retrofitted to take some advantage of substitution possibilities (for a detailed discussion of the vintaging structure in the EPPA model, see Chen et al. (2016)).

A decision to shut down the portions of the old fleet is driven by financial penalties imposed by carbon prices imposed on fossil fuels. In terms of achieving the 550 g/kWh target, a quick response is obtained when carbon prices are more than 80$/t$CO_2$. At this level of carbon prices and the assumed baseline fuel costs, natural gas-based generation and solar and wind see substantial expansion. CCS also becomes economic, but the scaling-up of CCS technology is limited by the speed of penetration of new technology (Morris et al., 2014). With a carbon price of 50$/t$CO_2$, the 550 g/kWh target is achieved by 2030. With a carbon price of 20$/t$CO_2$, the 550 g/kWh target is achieved only by 2045. The period of simulation in our analysis is 2050 and the targets of 350 g/kWh and 100 g/kWh are not achieved by 2050 with carbon prices of $50/t$CO_2$ or lower.

Many carbon pricing schemes envision an increase in carbon prices over time, usually at some discount rate (IPCC, 2014). Table 3 represents the results of the EPPA model simulations with a carbon tax imposed in 2020 at the levels of 10, 20, 30, 40, 50, and 60$/tCO2 and then rising at 4% per year. The results give an indication about the level of carbon prices necessary to achieve particular carbon intensity targets. Reaching the 550 g/kWh target requires a carbon price of about 30–60$/t$CO_2$. More stringent carbon intensity targets require higher carbon prices. They are about 90–115$/t$CO_2$ for the 350 g/kWh target and 110–150 $/t$CO_2$ for the 100 g/kWh target.

Table 3 also reports the year when particular targets are met and major technologies employed to reach the corresponding emission intensity targets. An increase in carbon price from a lower level allows reaching the 550 g/kWh target at a lower price, but in a more distant future. This reinforces an important point about the trade-offs between emissions reduction rate, time, and expense. In this case, the target is reached by 2045 with 27$/t$CO_2$ when the carbon price in 2020 starts from 10$/t$CO_2$. To reach the same target, the resulting carbon prices are higher when the carbon price in 2020 starts from the higher levels than 10$/t$CO_2$, however the target is met sooner. This result is driven by the model feature that depicts the cost reduction with more experience with technology. However, achieving more stringent targets of 350 g/kWh and 100 g/kWh is less affected by this phenomenon.

While CCS plays some role in reaching 550 g/kWh and 350 g/kWh targets, most of emission reductions are achieved by deploying wind and solar generation. The targets consistent with the ultimate goals of the Paris Agreement (keeping the temperature increase well below 2 °C) employ an electricity mix that relies heavily on employing CCS (see Table 3) because at high levels of deployment, intermittent renewables incur substantial costs of integration.

Fig. 6 provides an illustration of the inflection points, where the nature of relationship between carbon prices and carbon intensity changes (e.g., some technology becomes competitive and it results in substantial change in carbon intensity). We show a baseline scenario where carbon price starts in 2020 at 20$/t$CO_2$ and rise at 4% per year (in our setting, emission trading scenario that leads to a carbon price is equivalent to a carbon tax scenario of the same magnitude). Fig. 7 shows sensitivity cases with starting prices of 10$/t$CO_2$ and 30$/t$CO_2$ rising at 4% and 20$/t$CO_2$ cases with escalations rates of 3 and 5%. In these scenarios we have not expanded nuclear generation on its cost basis but rather kept nuclear at low levels due to the uncertainty around its future growth prospects (Guo and Guo, 2016). If nuclear power is allowed to grow based on its relative levelized cost of electricity generation, then it dominates the generation mix in the second half of the century.

In all five cases, renewables (i.e., wind and solar) initially expand and reduce the emission intensity of electricity. In the base case (Fig. 6), the emissions intensity reaches 550 g/kWh at about 2040. The gradual expansion of renewables and gradual decrease in emission intensity continue until 2050. After 2050, the increasing carbon prices (recall that carbon prices are assumed to be rising at 4% per year) incentivize even

Table 3
Carbon prices, years to achieve and major technologies to reach carbon intensity targets of 550, 350, and 100 g/kWh.

	Year hits 550 g/kWh	Carbon Price at 550 g/kWh	Major technologies employed to reach 550 g/kWh	Year hits 350 g/kWh	Carbon Price at 350 g/kWh	Major technologies employed to reach 350 g/kWh	Year hits 100 g/kWh	Carbon Price at 100 g/kWh	Major technologies employed to reach 100 g/kWh
10$/tCO2 rising at 4%	2045	$27	wind&solar	2080	$105	wind&solar	2085–2090	$128–156	wind&solar+coalCCS
20$/tCO2 rising at 4%	2040	$44	wind&solar	2060–2065	$96–117	wind&solar	2065–2070	$117–142	wind&solar+coalCCS
30$/tCO2 rising at 4%	2035	$54	wind&solar	2050	$97	wind&solar	2055	$118	wind&solar+coalCCS
40$/tCO2 rising at 4%	2030	$59	wind&solar	2040–2045	$88–107	wind&solar	2045–2050	$107–130	wind&solar+coalCCS
50$/tCO2 rising at 4%	2025	$61	wind&solar	2035–2040	$90–110	wind&solar	2040–2045	$110–133	coalCCS+wind&solar
60$/tCO2 rising at 4%	2020	$60	wind&solar	2030	$89	wind&solar	2035–2040	$108–131	coalCCS+wind&solar

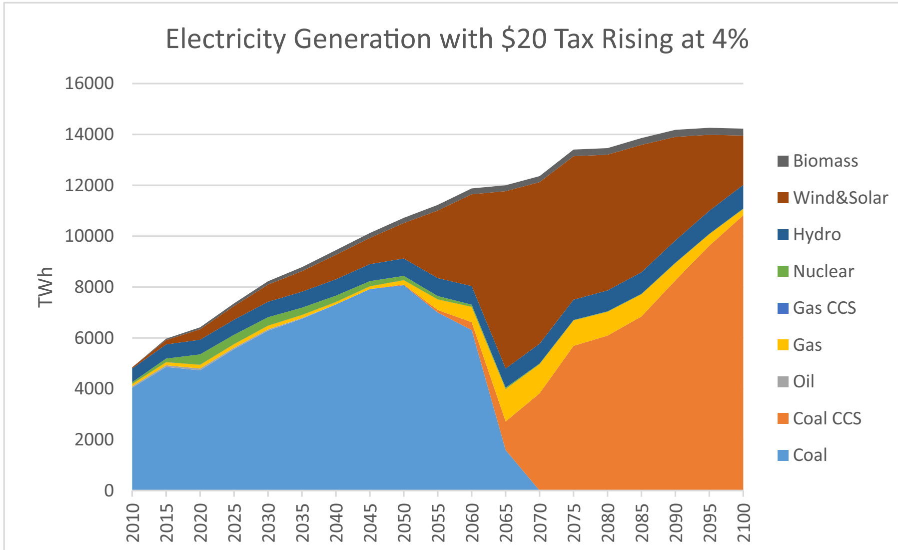

Fig. 6. Electricity Generation by Technology in China in the scenario with 20\$/tCO_2 rising at 4% per year.

faster growth in renewables. In 2050–2060, renewables expand to about 30% of generation. At this level of penetration, renewable generation starts to require back-up capacity.

Coal with CCS starts expanding after 2050, but the speed of CCS penetration is limited in the model. Initially the expansion of renewables is faster than the expansion of CCS because renewable generation is already an established option and therefore is not constrained by expansion limits. Gradually, as experience with building and operating CCS technology is gained, CCS costs decrease and adoption is accelerated. The speed of expansion depends on the output from this technology in previous periods and is parameterized in the EPPA model based on experience with nuclear power, where expansion was limited by construction and production constraints and access to qualified labor (Morris et al., 2014). In the case of CCS in China, the penetration limits are overcome in about 15 years (2050–2065). After 2065, coal CCS expands rapidly, replacing renewables as the major source of generation. Without constraints on the speed of expansion of a new technology, coal CCS would expand much quicker and would eliminate the large expansion of renewables past 2050.

This dynamic suggests the important role early-stage support for CCS development could play. In the case where we do not impose technology-specific limits for penetration, renewables do not expand much past 2050 and coal CCS completely overtakes unabated coal in the 20-year period from 2050 to 2070. In a scenario of government support to lower the CCS costs, this switch from coal to coal with CCS happens earlier in time and depends on the level of support.

In terms of carbon intensity targets, the target of 350 g/kWh is reached in 2060 (for the base setting with limits on scaling up penetration of a new technology and no government support of CCS). After 2060, with carbon prices more than 100\$/tCO_2, both renewables and coal with CCS are dramatically expanding and the target of 100 g/kWh is reached by 2065–2070. Once a large-scale experience with CCS is obtained, CCS squeezes out renewables and becomes the dominant technology in power generation. Similar trajectories are observed for other carbon price scenarios. Previous studies have explored the available CO_2 storage capacity and concluded that it is not a limiting factor in China (Kearns et al., 2017).

As shown in Fig. 7, reducing the starting price of carbon delays the renewables binge and increases the magnitude of expansion of renewables because CCS technology is not introduced at low carbon prices and its learning-by-doing is limited. While increasing the starting price of carbon hastens the expansion of renewables, it also reduces the magnitude of their expansion as it triggers earlier and more aggressive introduction of CCS. Different growth rate of carbon price shifts the timing of CCS introduction and expansion. While in the scenarios considered here, the magnitude, rate and timing of the two-stage transition (i.e., first – to renewables, then – to CCS) may change, but it appears to be a robust outcome of the modeling. Support to R&D and pilot CCS projects would increase the rate of CCS penetration and reduce the need for rapid expansion and the following contraction of deployment of intermittent renewables.

The results for the power generation mix are also sensitive to the evolution of the costs for a particular power generation technology. To illustrate the impact, we performed a sensitivity analysis, where the cost of nuclear generation was lowered by 25%. The resulting carbon prices to reach the stringent carbon intensity targets were lowered by about 30%. Lowering the cost of renewables has a different profile. In that case, the carbon price needed to reach the 350 g/kWh target is lowered by about 50%, while the carbon price to reach the 100 g/kWh is lowered only by about 20%, which reflects the fact that higher penetration of intermittent renewables leads to increased integration costs. Technology development related to renewables integration, such as advances in energy storage, may alter this situation and make the trajectories involving high renewables penetration more favorable.

We also explored the cases where CCS costs are increased or lowered by 25% in comparison to the base CCS cost setting. These scenarios can serve as an indication of situations in different provinces that experience different coal prices and levels of support. Higher CCS costs do not substantially affect the resulting carbon prices or the timing of reaching particular intensity targets, but they lead to a substantial expansion of nuclear and renewables, while CCS appears in the generation mix only by the end of the century.

Lowering CCS costs leads to a faster elimination of unabated coal generation. In the low CCS cost case, coal without CCS disappears from the generation mix by 2050, while in the base setting unabated coal is eliminated only by 2070. Lower CCS costs also reduce the carbon prices needed to reach particular intensity targets: the 550 g/kWh target can be reached 5–10 years earlier (in 2030–2035 instead of 2040) at 30% lower carbon prices, and the 350 g/kWh and 100 g/kWh targets can be reached 20–25 years earlier at about 50–60% lower carbon prices than in the base setting. These more optimistic CCS cost assumptions also dramatically reduce the need for nuclear power generation. This

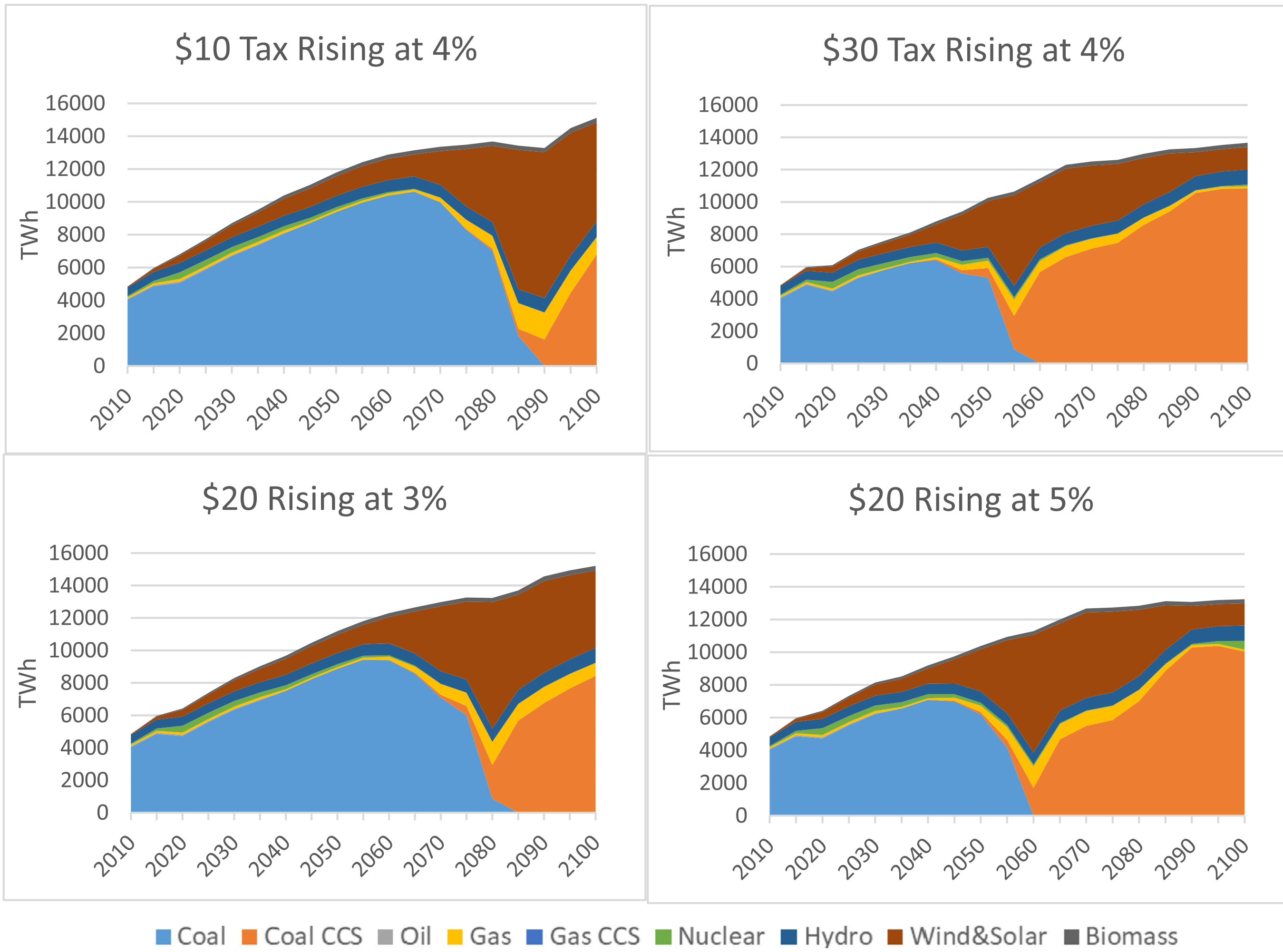

Fig. 7. Electricity Generation by Technology in China, under different starting carbon prices and different rates of carbon price escalation.

suggests that CCS can provide a pathway for decarbonization in the provinces where nuclear power might be challenging to expand for different political and technological reasons.

The results from this initial analysis provide guidance into the issues that must be explored at a more granular level using a provincial model of the energy system in China. National average prices for the cost of electricity are useful in highlighting the key trade-offs between different generating modes and the effects of carbon pricing. However, the exact nature of these trade-offs is highly sensitive to the costs, which in turn, depend on province-level details such as local fuel costs, the feasibility of nuclear, hydroelectric, and renewable generation, and limitations in transmission and distribution systems. Any of these features may introduce constraints that alter the local costs, and hence the specific energy mixes that will be optimal.

4. Conclusion

There are different pathways to reduce emission intensity in China's electricity sector. CCS might play an important role, especially for low carbon intensity targets consistent with the ultimate goals of the Paris Agreement. There are inflection points, where the nature of the relationship between carbon prices and carbon intensity changes (e.g., some technology becomes competitive and it results in substantial change in carbon intensity). One example of such an inflection point in our analysis was the sequential displacement of coal-fired power by a period of time where renewables dominate the energy mix, which is followed by a period where CCS becomes significant. The magnitude and timing of these inflection points are sensitive to the initial carbon prices and costs of technologies.

Our scenario analysis shows that the target of 550 g/kWh is not likely to be met by 2020, but there are many ways to achieve lower targets over longer time frames. A carbon market provides an essential incentive for CCS deployment. In our baseline scenario, carbon prices of 35–40$/t$CO_2$ make CCS technologies on coal-based generation competitive and carbon prices higher than 100$/t$CO_2$ lead to a major expansion of CCS.

The scale of CCS development is affected by assumptions about nuclear power development. Aggressive development of nuclear pushes CCS out of the generation mix. However, large-scale nuclear development would require resolving numerous issues, including inland water security and availability, seismicity resilience, and the disposal of nuclear waste. Wind and solar technologies are widely employed to achieve the initial emission intensity targets (of 550 g/kWh and 350 g/kWh). However, unless issues with nuclear are resolved, lower emission intensity targets require a wide deployment of CCS. Advanced research and pilot projects are necessary to get the CCS technology ready when deeper emission reductions are required.

Our results were based on national averages for the cost of electricity from different modes of generation and a simplified approach that does not explicitly consider China's provinces and how they interact. They should therefore be treated as illustrative. However, our sensitivity analysis for the cost of producing electricity with different coal prices and CCS costs provides an indication of how provincial circumstances may affect the resulting pathways for decarbonization. More detailed modeling that takes into account granularity across China's energy sector at the provincial level would provide deeper understanding of regional differences. Still, the national results provide useful insight into how China's power generation mix might evolve towards progressively lower carbon intensity targets.

Large-scale deployment of CCS in China crucially depends on political will for significant emission mitigation. Without substantial policies to reduce carbon emissions, CCS will not be developed at scale. Our approach consists of economic evaluation of different options. While we do not attempt to model political attitudes and preferences, in our paper we show that with a political will to increase emission reductions, CCS offers a viable option for decarbonization. Pilot projects at a commercial-scale might offer a way for broader public and political support for CCS, which in turn would enable more substantial emission mitigation targets.

Uncertainty surrounding large-scale deployment of new technologies (like CCS) is large. There are numerous factors that ultimately will affect the overall future of CCS, such as issues related to permanence of carbon storage, progress with new capture technologies, feasibility of transporting and storing the sequestered carbon in different provinces, applicability to hard-to-decarbonize industrial processes like cement production, and many others. Similar uncertainties about the overall system performance are relevant for all other large-scale low-carbon technologies. Uncertainty about the cost of different technologies and the resulting exact technology mix suggests that decision makers should refrain from picking the winner in terms of technology, but should pursue emission reductions from all sources.

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Appendix A. Cost of power generation in china

In the Appendix we describe the details of markup (i.e., the relative cost of generation to electricity price) calculations for several power generation technologies in China: advanced coal, advanced gas (natural gas combined cycle, NGCC), advanced nuclear, wind, solar PV, coal with carbon capture and storage (CCS), and natural gas with CCS. Table A1 presents the derivation of the levelized cost of electricity (LCOE) and the corresponding markup calculations. To represent costs related to intermittency of large-scale renewable generation, we assume that the variability of the resource can be managed through the extra cost of backup capacity. For small-scale wind and solar with little impact on the overall power grid, the backup is not required.

To illustrate how the values in Table A1 are obtained, we focus on an example of coal-based generation. We start with the IEA (2015) data for a global average overnight cost of different technologies. The overnight capital cost (represented in row [1] of Table A1) of coal is 2017$/kW. To represent the cost of capital in China, we use a capital-scaling factor that we have obtained based on the GTAP data (Narayanan et al., 2012). Row [2] represents the scaled overnight capital cost for different technologies. For coal power generation in China, this value is 660$/kW.

To find the total capital requirement (shown in row [3]), we adjust the overnight capital cost to represent the total cost accrued over the construction period (4-years). The capital recovery charge rate [4] uses the 8.5% discount rate and the 20-year financial project life [7] to determine the capital recovery necessary per year. Since financial lifetimes for all plants were assumed to be 20 years, the capital recovery rate of 10.6% is constant. Both the fixed [5] and variable [6] operations and management (O&M) costs were retrieved from the IEA, with costs of $36.4/kW and $0.0033/kWh, respectively. The capacity factor [8] for a new coal plant is 85%, and from this, the total number of hours in operation [11] was determined by multiplying the total number of hours in a year by 85%.

Table A1
Cost of power generation in China.

		Units	Advanced Coal	Coal with CCS	NGCC	Gas with CCS	Advanced Nuclear	Wind	Solar PV
[1]	"Overnight" Capital Cost	$/kW	2017	3850	968		4024	1733	1558
[2]	**SCALED** Overnight Capital Cost		660	1260	317	0	1317	567	510
[3]	Total Capital Requirement	$/kW	766	1512	342	652	1712	612	551
[4]	Capital Recovery Charge Rate	%	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%
[5]	Fixed O&M	$/kW	36.4	*58.4*	28.5	*55.2*	66.5	47.4	21.3
[6]	Variable O&M	$/kWh	0.0033	*0.0053*	0.0026	*0.0061*	0.0033	0.0138	0.0105
[7]	Project Life	years	20	20	20	20	20	20	20
[8]	Capacity Factor	%	85%	85%	85%	85%	85%	35%	27%
[9]	(Capacity Factor Wind)								
[10]	(Capacity Factor Biomass/NGCC)								
[11]	Operating Hours	hours	7446	7446	7446	7446	7446	3066	2365.2
[12]	Capital Recovery Required	$/kWh	0.0109	0.0215	0.0049	0.0093	0.0243	0.0211	0.0246
[13]	Fixed O&M Recovery Required	$/kWh	0.0049	0.0078	0.0038	0.0074	0.0089	0.0155	0.0090
[14]	Heat Rate	BTU/kWh	*8173*	*10349*	*6234*	*7393*	10479	0	0
[15]	Fuel Cost	$/MMBTU	1.59	1.59	7.34	7.34	0.89	0.00	0.00
[16]	(Fraction Biomass/NGCC)	%							
[17]	Fuel Cost per kWh	$/kWh	0.0130	0.0165	0.0458	0.0543	0.0093	0.0000	0.0000
[18]	**Levelized Cost of Electricity**	**$/kWh**	**0.0321**	**0.0600**	**0.0570**	**0.0806**	**0.0459**	**0.0504**	**0.0441**
For EPPA Model									
[19]	Transmission and Distribution	$/kWh	0.03	0.03	0.03	0.03	0.03	0.03	0.03
[20]	**Cost of Electricity inc. T&D**	**$/kWh**	**0.0621**	**0.0900**	**0.0870**	**0.1106**	**0.0759**	**0.0804**	**0.0741**
[21]	**EPPA Base Year Elec Price**	**$/kWh**	**0.0505**	**0.0505**	**0.0505**	**0.0505**	**0.0505**	**0.0505**	**0.0505**
[22]	**Markup Over Base Elec Price**		**1.23**	**1.78**	**1.72**	**2.19**	**1.50**	**1.59**	**1.47**

Table A2
Additional costs for carbon emissions and CO2 transportation and storage.

		Units	Advanced Coal	Coal with CCS	NGCC	Gas with CCS
[23]	Amount Fossil Fuel	EJ/KWh	8.6E-12	1.1E-11	6.6E-12	7.8E-12
[24]	Carbon Content	mmtC/EJ	24.686	24.686	13.700	13.700
[25]	Carbon Emissions	mmtC/KWh	0.0000	0.0000	0.0000	0.0000
[26]	Carbon Dioxide Emissions	tCO2/KWh	0.0008	0.0010	0.0003	0.0004
[27]	CO2 Emissions after 90% Capture	tCO2/KWh		9.9E-05		3.9E-05
[28]	Cost of CO2 T&S	$/tCO2		10		10
[29]	CO2 Transportation and Storage Cost	$/KWh		0.00889		0.00353
[30]	Carbon Price	$/tonCO2	**10**	10	10	10
[31]	Levelized Carbon Price	$/kWh	0.0078	0.00099	0.0033	0.00039
[32]	**LCOE+Carbon Price**	**$/kWh**	**0.0699**	**0.0910**	**0.0904**	**0.1110**
[33]	**Markup with Carbon Price**		**1.38**	**1.80**	**1.79**	**2.20**

In order to determine the capital recovery required [12], the capital recovery charge rate of 10.6% is multiplied by the total capital requirement. The result is the total capital requirement per kilowatt. By dividing by the total operating hours, the capital recovery required per year in $/kWh is obtained. The fixed O&M recovery required [13] is found by dividing the fixed O&M costs per year [5] by the total number of operational hours [11]. Heat rate [14] is converted to high heating value from IEA's reported low heating value. The fuel cost [15] is taken from the GTAP dataset and it is equal to $1.59/MMBTU for coal. Then, by multiplying the heat rate and the fuel cost and converting to kWh, the fuel cost per kilowatt-hour [17] is found. A fuel cost of $0.013 produces one kilowatt-hour of electricity from coal, as determined by the plant's efficiency.

The sum of the variable O&M [5], the scaled capital recovery required [12], the fixed O&M required [13], and the fuel cost per kWh [17] yields the LCOE [18] for coal. Adding the $0.03/kWh for transmission and distribution [19] yields line [20], which is the total cost of electricity for that technology. The markup [22] of this technology is then calculated by dividing the total cost of electricity [20] by the value of the base year electricity price [21] in the GTAP dataset.

Plants with CCS (Coal with CCS and Gas with CCS) have additional costs, which reflect higher capital requirements (and fixed and variable O&M). The cost for CCS power generation also includes the cost of transportation and storage of CO_2. Table A2 provides a calculation of additional costs with an assumed carbon price of 10$/t$CO_2$ and the cost of CO_2 transportation and storage of 10$/t$CO_2$.

The calculation of additional costs related to carbon is shown in lines [23] through [33] of Table A2. The amount of fossil fuel consumption [23] was determined by converting the heat rate [14, Table A1] from BTU/kWh to EJ/kWh. This figure is then multiplied by the carbon content [24] of the various fuel types, in tonnes of carbon per exajoule (MtC/EJ) to give the carbon emissions in million tons of carbon per kWh [25]. The carbon content of each fossil fuel was retrieved from the EPA (EPA, 1998). Then, the carbon emissions are converted to tonnes of CO_2 per kWh [26]. The CCS system is assumed to remove 90% of CO_2 from the combustion process, yielding [27]. The CO_2 emissions captured need to be transported and stored. Based on Rubin et al. (2015), $10/t$CO_2$ for CO_2 transportation and storage costs is assumed, which is multiplied by the CO_2 emissions captured (1-[27]) to determine the cost of transportation and storage per kWh produced [29]. The levelized carbon price (assumed here at 10$/t$CO_2$) is added to calculate the total markup. Note that our calculations use average values from the existing literature. Additional studies are need to provide granularity at a provincial level.

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