REDUCING CHINA'S COAL POWER EMISSIONS WITH CCUS RETROFITS

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IEA CLEAN COAL CENTRE

CIAB

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PREFACE

This report has been produced by the IEA Clean Coal Centre for the Coal Industry Advisory Board. It is based on a survey and analysis of published literature, and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own, and are not necessarily shared by those who supplied the information, nor by our member organisations.

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The overall objective of the IEA Clean Coal Centre is to continue to provide our members, the IEA Working Party on Fossil Fuels and other interested parties with independent information and analysis on all coal-related trends compatible with the UN Sustainable Development Goals. We consider all aspects of coal production, transport, processing and utilisation, within the rationale for balancing security of supply, affordability and environmental issues. These include efficiency improvements, lowering greenhouse and non-greenhouse gas emissions, reducing water stress, financial resourcing, market issues, technology development and deployment, ensuring poverty alleviation through universal access to electricity, sustainability, and social licence to operate. Our operating framework is designed to identify and publicise the best practice in every aspect of the coal production and utilisation chain, so helping to significantly reduce any unwanted impacts on health, the environment and climate, to ensure the wellbeing of societies worldwide.

ACRONYMS AND ABBREVIATIONS

ACTC	Advanced Coal Technology Consortium
capex	capital expenditure
CCS	carbon capture and storage
CCUS	carbon capture, utilisation, and storage
EOR	enhanced oil recovery
EPC	engineering, procurement, and construction
ETS	emissions trading system
FGD	flue gas desulphurisation
FYP	five-year plan
GCCSI	Global Carbon Capture and Storage Institute
GDP	gross domestic product
IEA	International Energy Agency
IP	intermediate pressure
IPCC	Intergovernmental Panel on Climate Change
LCOE	levelised cost of electricity
LF	load factor
LHV	lower heating value
LP	low pressure
MEE	Ministry of Ecology and Environment
MHI	Mitsubishi Heavy Industries
MOF	Ministry of Finance
MOST	Ministry of Science and Technology
NDC	Nationally Determined Contribution
NDRC	National Development and Reform Commission
NEA	National Energy Association
NETL	National Energy Technology Laboratory (USA)
NG	natural gas
NICE	National Institute of Clean-and-Low-Carbon Energy
NOx	oxides of nitrogen
NPV	net present value
NZEC	Near Zero Emission Coal
O&M	operation and maintenance (costs)
opex	operating expense
PM	particulate matter
SCR	selective catalytic reduction
SEAP	Strategic Energy Action Plan
SPIC	State Power Investment Corporation
T&S	transport and storage (of CO_2)
TCR	total capital requirement
TPC	total plant cost
ULE	ultra-low emissions
USC	ultrasupercritical
WACC	weighted average cost of capital
2DS	two degree (2°C) scenario

UNITS

CNY/t	Chinese yuan per tonne (coal or CO_2 price)
CNY/y	Chinese yuan per year
CNY/t.y	Chinese yuan per tonne CO_2 per year (CO_2 price growth rate)
gCO_2/kWh	grams of CO_2 generated per kilowatt-hour electricity generated
Gtce	billion tonnes of coal equivalent (equivalent energy)
GW	gigawatts (electric power generation capacity)
kcal/kg	kilocalories per kilogram of coal
kgce	kilograms of coal equivalent (equivalent energy)
kJ/kg	kilojoules per kilogram of coal
$ktCO_2$/y	thousand tonnes CO_2 captured per year
kWh	kilowatt-hours (electric energy generation)
$MtCO_2$/y	million tonnes CO_2 captured per year
MW	megawatts (electric power generation capacity)
MWh	megawatt-hours (electric energy generation)
MWth	megawatts thermal energy generation
tce	tonnes of coal equivalent (equivalent energy)
tCO_2/y	tonnes of CO_2 captured per year

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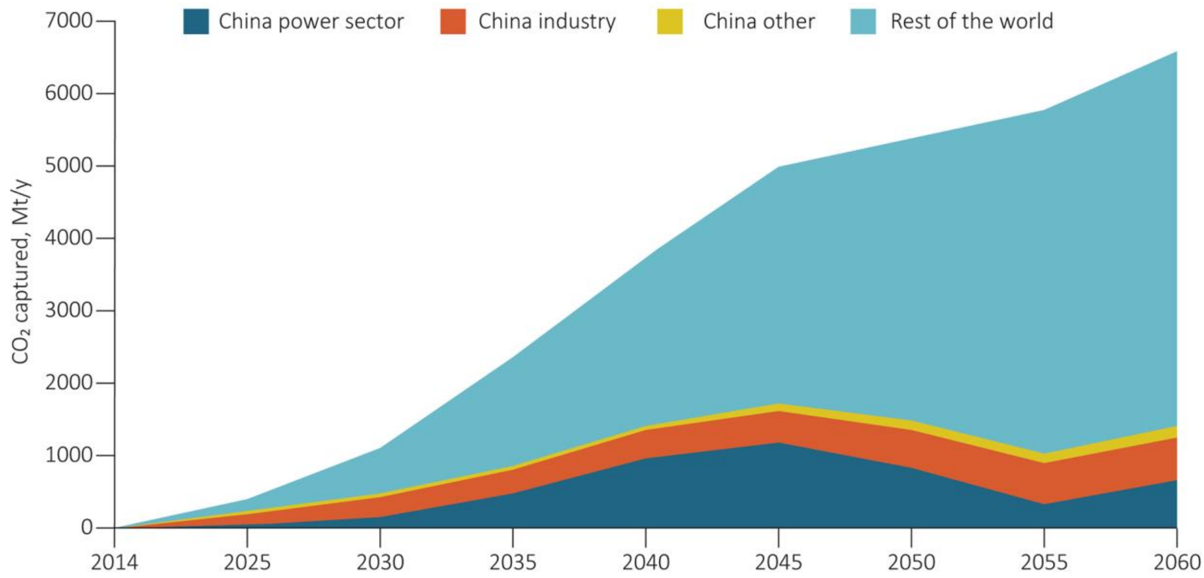
EXECUTIVE SUMMARY

CHINA'S COAL FLEET: A CHALLENGE AND OPPORTUNITY FOR CCUS

Following rapid expansion over the last two decades, China's coal power fleet has reached a capacity of around 940 GW, representing over 12% of global CO_2 emissions, and is expected to grow to 1100 GW in 2020. With little prospect of early plant closures in China's fast-growing economy, it will be essential to retrofit carbon capture, utilisation and storage (CCUS) to a significant proportion of this young fleet if ambitious global climate goals are to be reached. CCUS has been internationally recognised as an essential technology for decarbonisation at least cost to society, contributing 14% of CO_2 emissions reductions in the International Energy Agency's 'two degree scenario' (2DS); 16% of this is associated with CCUS fitted on up to 180 GW of Chinese coal capacity (*see* Figure below).



The contribution of CCUS in China's power and industrial sectors to total CO_2 captured in the IEA's 2DS to 2060 (IEA, 2017a)

Although 23 large CCUS projects (equivalent to around 38 $MtCO_2/y$ stored) are now operating or under construction worldwide, the technology has not progressed at the necessary rate, with most regions lacking adequate incentives to build a business case around capturing CO_2. Deployment in the power sector is particularly challenging, as the technology incurs a significant capital cost and energy penalty, while energy revenues are increasingly limited by non-baseload operation. However, China's high proportion of large, efficient coal power units with intensive pollutant controls presents an ideal case for minimising retrofit costs, particularly when combined with relatively low manufacturing costs and clear opportunities for mass production and economies of scale.

CLIMATE POLICY AND CCUS DEVELOPMENTS IN CHINA

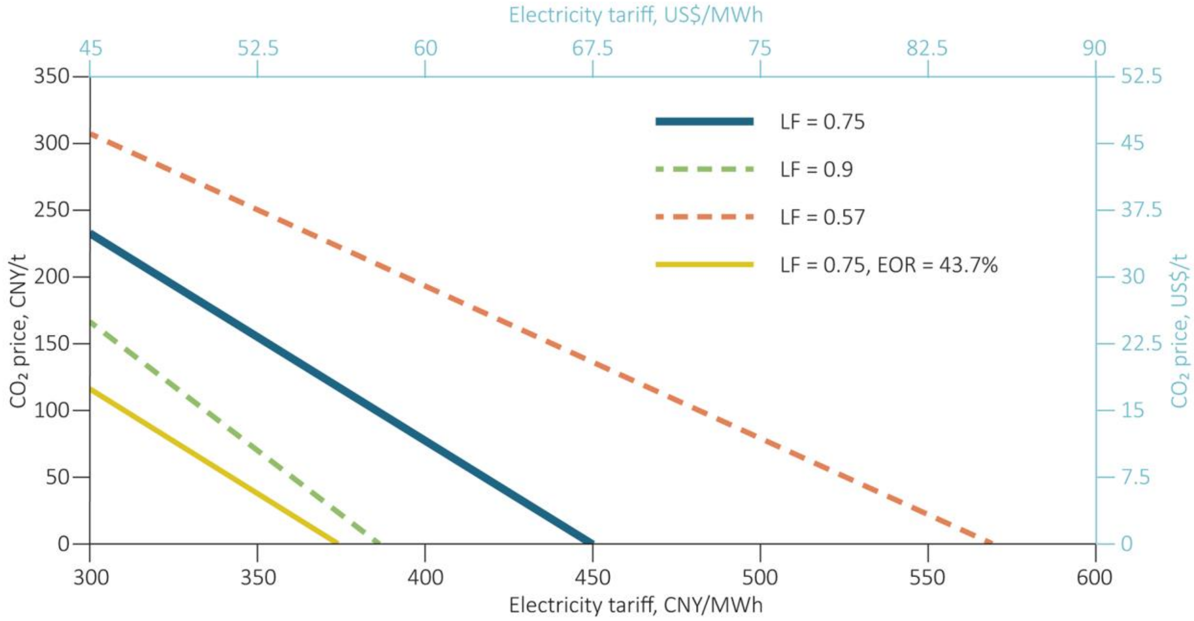
Starting from 2007, China has established a strong domestic capacity in CCUS technology, operating a few industrial-scale pilots for capture technologies and, more recently, taking three large (>300 ktCO_2/y) integrated capture and storage projects in chemical production and natural gas processing into a construction or operational phase. As for the majority of international CCUS deployment, these larger projects have been almost exclusively driven by the application of CO_2 in enhanced oil recovery (EOR). Although an important driver for early CCUS deployment and infrastructure development, EOR may not provide a long-term incentive for coal power-based projects, due to limited demand and competition from other emitters with lower capture costs.

In 2013, China's National Development and Reform Commission issued a notice to promote CCUS deployment, resulting in some provincial-level support for projects in Shaanxi and Guangdong. The planned implementation of a national emissions trading system (ETS) for power sector CO_2 emissions in 2020, and a challenging 550 gCO_2/kWh average emissions intensity target introduced for large state-owned power companies are potential positive drivers for the technology. The 2018 transition of the responsibility for CCUS to the new Ministry of Ecology and Environment could also act as a catalyst for developing more targeted incentives for deployment. However, widespread CCUS deployment is not currently a high-level political priority, and the technology is not required in China's key commitment to the Paris Agreement to peak CO_2 emissions by 2030.

POTENTIAL INCENTIVES FOR CCUS

This report takes as a case study a generic 1000 MW ultrasupercritical (USC) coal unit, of which there are 104 currently operating in China – nearly all commissioned in the last ten years. Over half of these power plants have good access to onshore geological basins suitable for CO_2 storage (within 250 km). Retrofit of a state-of-the-art amine-based post-combustion capture plant with a 90% CO_2 capture rate is then considered to take place in the period 2025 to 2030. In order to compensate power companies for the significant capital outlay for retrofit (of similar magnitude to the initial plant investment), as well as lost electricity sales and additional operating costs, a number of possible incentives are investigated – many of which find parallels in other regions worldwide.

China's coal plants have experienced falling load factors due to overcapacity and slowing demand growth, so there is considerable scope for CCUS-retrofit plants to counter the loss of power output with greater running hours accorded to low-carbon generation. The price of CO_2 in the national ETS is projected to rise steadily to around 100 CNY/MWh (15 US$/MWh) by 2025, providing a value for avoided emissions. Perhaps most significantly, premium electricity tariffs for CCUS plants could be applied in the same way as wind and solar power have benefited from substantial (>600 CNY/MWh (>90 US$/MWh)) feed-in tariffs since 2009. The figure below shows how these incentives could be variously combined to result in 'break-even' net present value for the retrofit investment.



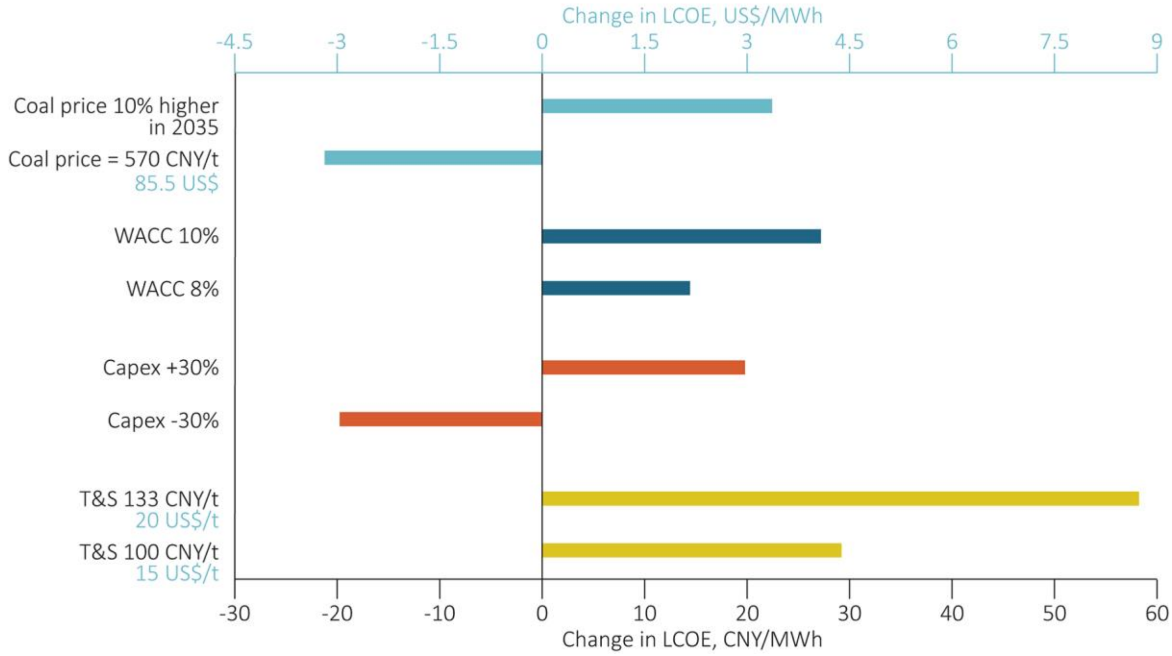
Combinations of CO_2 price and electricity price at which retrofit projects can break even, shown for different load factors (LF) and an EOR scenario which breaks even under baseline conditions

This analysis finds the electricity tariff required to enter profitability is 450 CNY/MWh (68 US$/MWh) at a CO_2 price of zero, which is well below the tariffs currently available for existing renewable developments. Even lower tariffs of below 400 CNY/MWh (60 US$/MWh) may be viable should the national CO_2 price reach 100 CNY/t (15 US$/t) as projected, representing a 25% increase on current average tariffs for coal power. For projects in suitable locations, sale of a portion of CO_2 for EOR can act as a key supplement to these incentives, placing a higher value on CO_2 (around 200 CNY/t (30 US$/t)) and providing a bankable revenue stream.

COMPETITIVE COST OF ELECTRICITY

CCUS retrofits can also be assessed on a levelised cost of electricity (LCOE) basis, while bearing in mind that this measure does not account for the additional value to the grid provided by dispatchable, low-carbon generation. This analysis finds an LCOE of 426 CNY/MWh (64 US$/MWh) for the baseline retrofit case – a 61% increase over unabated coal at the same load factor, or a 52% increase over coal plant with currently prevailing load factors. This cost represents a highly competitive cost of CO_2 avoided of 215 CNY/t (32 US$/t).

It is clear that considerable uncertainty remains around many of the factors governing future CCUS costs, including plant capital cost, financing cost, and the cost of CO_2 transport and storage in particular. The figure below shows how these variables could contribute to increases or reductions in the cost of electricity from retrofit plants. Whilst capture plant capital cost (capex) has the greatest impact per unit increase, costs are expected to reduce as the technology reaches commercial maturity. Variation in transport and storage costs are likely to present a greater investment risk in China, where there is very little established CO_2 pipeline infrastructure or established geological stores for CO_2, and thus potential for costs to be more than double current estimates (67 CNY/t (10 US$/t)). Nevertheless, the potential resulting increase in LCOE (~15%) should not pose an insurmountable risk to project viability.



The effect of changes in fuel cost, weighted average cost of capital (WACC), capture plant capex, and transport and storage (T&S) cost on LCOE

OUTLOOK FOR CCUS IN CHINA

The cost analysis presented in this report demonstrates that, given appropriate policy actions commensurate with the support provided for other low-carbon technologies, application of CCUS to China's largest coal units can become a commercially viable prospect for power companies in 2025. Whilst this case study can be considered a 'best case' for CCUS deployment in the power sector, it is by no means unrepresentative of China's coal fleet, and similar costs should be achievable for the 78 GW of smaller (660 MW) USC units, provided storage is available.

As for other countries, wider CCUS deployment is ultimately dependent on the implementation of ambitious targets for CO_2 emissions reduction, requiring decarbonisation of the power sector beyond that achievable by high grid-penetration of renewables alone. Furthermore, there remain a number of barriers to initial investment in CCUS which are unique to the technology and are not addressed by the revenue-based incentives examined in this report. These concern the need to develop a shared infrastructure for CO_2 transport and storage, and is likely to require a degree of government involvement in encouraging state-owned oil companies to invest – without bearing excessive risk – in storage characterisation and pipeline infrastructure available for use by other emitters. The necessary regulatory framework for infrastructure development beyond EOR-based storage is yet to be developed in China.

Coal power deployment continues in China, and the total coal capacity is projected to remain close to the 2020 target of 1100 GW for the next two decades, with a growing proportion of large, high-efficiency units. Following the model of rapid deployment, 'learning by doing', and associated cost reductions achieved for domestically developed energy technologies such as USC coal plants, solar photovoltaics, and wind power, China could realistically proceed to retrofit a significant portion of the country's coal fleet by 2035, should adequate policy incentives be introduced. This manufacturing capability and technological expertise could then feasibly be exported to other major coal-using countries. Equally, international governments and industry can help accelerate CCUS uptake in China through clearer commitment to deploying the technology, and through greater sharing of technical and regulatory expertise and experience.

INTRODUCTION

Following rapid expansion over the last two decades, China's coal power fleet has reached a capacity of around 940 GW, representing nearly half the total global coal capacity and over 12% of global CO_2 emissions (Platts, 2018; IEA, 2017a). This is expected to continue to grow to at least 1100 GW by 2020 (NEA, 2016; Platts, 2018). With a median plant age of around 12 years, and little prospect of early plant closures in China's fast-growing economy, it will be essential to retrofit carbon capture and storage (CCS) to a significant proportion of this fleet if ambitious global climate goals such as those stated in the Paris Agreement are to be reached (Platts, 2018; UNFCCC, 2018). CCS technologies involve the separation of CO_2 emissions from industrial processes for permanent storage in geological formations such as saline aquifers or oil and gas reservoirs, and have been widely recognised as a vital tool in global decarbonisation (IPCC, 2014; IEA, 2017b; IPCC, 2018). In the IEA's 'two degree scenario' (2DS) – a least-cost pathway to limiting global warming to 2°C above pre-industrial levels – CCS contributes 14% of global CO_2 emissions reductions to 2060, of which around 16% (22 Gt) of the total CO_2 stored globally is associated with coal power plants in China (Figure 1) (IEA, 2017a). This projection corresponds with a maximum of 180 GW of China's coal fleet being fitted with CCS by 2045. The addition of carbon capture technology to new or existing power plants incurs significant costs, associated with both the capital cost of the additional equipment and the energy consumed in separating and compressing CO_2. However, the large size and high efficiency of the majority of China's coal-fired units, together with relatively low manufacturing costs, suggest that CCS retrofits will be achievable at much lower cost than equivalent power plant-based projects in North America and Europe (IEAGHG, 2018; Singh and others, 2018). The 2016 IEA analysis 'The potential for equipping China's coal fleet with CCS' has broadly identified 100 GW of coal capacity which could be retrofitted with CCS for an additional cost of less than 50 US$/MWh, based on factors including age, size, and proximity to storage (IEA, 2016a).

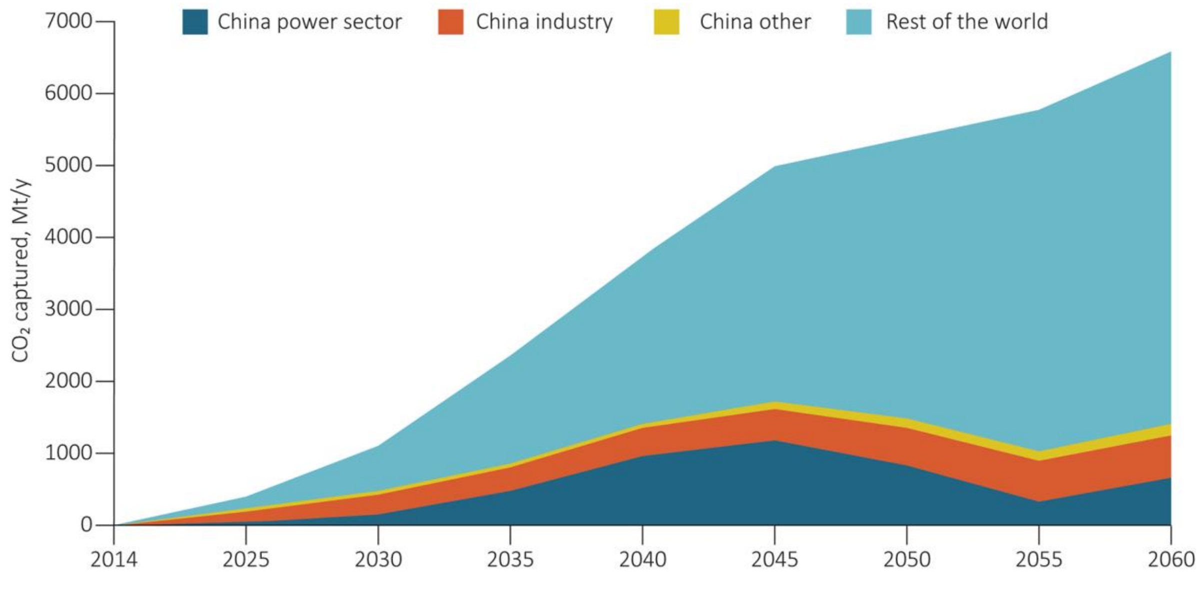


Figure 1 The contribution of CCS in China's power and industrial sectors to total CO_2 captured in the IEA's 2DS to 2060 (IEA, 2017a)

Despite several governments showing a degree of support for CCS from the early 2000s, progress has been slow relative to some other low-carbon energy sources, and only 23 large-scale CCS projects are currently operational or under construction (equivalent to 38 $MtCO_2/y$) (GCCSI, 2017, 2018a). Two of these projects are associated with coal-fired power plant retrofits, at Boundary Dam in Saskatchewan, Canada, and the WA Parish power plant in Texas, USA (the Petra Nova project). Like most other carbon reduction solutions, widespread implementation of CCS is reliant on policy incentives which are able to provide investors with a viable business case for deploying the technology. This could take the form of a carbon price (as a penalty on emissions), a credit for storing CO_2, or a premium on low-carbon power. While forms of carbon pricing found worldwide have functioned as a viable operating incentive for a few CCS projects based on lower-cost CO_2 capture processes (sometimes in addition to capital grants), the majority of large-scale CCS projects operating today instead rely on revenue from CO_2-based enhanced oil recovery (EOR), in which CO_2 is injected and permanently stored in mature oil fields to boost production (GCCSI, 2018). Strategic decisions by fossil fuel companies to gain a technological head-start, improve their climate image, or ease regulatory processes have been another factor in previous investment in CCS (Herzog, 2016; IEA, 2016b; Lockwood, 2017). In China, this combination of 'soft' climate policy pressure and revenue from EOR is also providing the impetus for a growing number of small- to medium-scale CCS projects, typically based on natural gas processing or chemical production. However, the value of CO_2 for EOR and the scale of the demand is unlikely to meet the requirements for widespread retrofit of China's enormous coal fleet alone. Some other form of policy-based incentive is therefore necessary to bring about investment on the scale necessary to store very large quantities of CO_2 (Gt/y) in 'dedicated' geological stores such as saline aquifers. In addition to creating bankable revenue streams for capture projects, any country seeking to develop CCS on a large scale requires a regulatory framework which can reduce the investment risks associated with developing a new transport and storage infrastructure (McCoy, 2014; ZEP, 2014; IEA, 2016b).

This study seeks to build on the 2016 IEA assessment of the CCS retrofit potential in China by exploring how various incentives could create a business case for power companies to invest in CCS retrofit (IEA, 2016a). The first half of the report reviews the current status of climate and energy policy in China, relevant developments in the coal power sector, and the extent of policy support and deployment of CCS in the country, with a view to identifying the most likely drivers and challenges for CCS, and areas where greater policy action is required. The second half is a case study of the retrofit of a generic high-efficiency, low-emissions coal-fired power unit – increasingly typical of China's coal fleet – in the period 2025-2030. The effect of potential incentives for CCS retrofit including carbon pricing, increased electricity tariffs, increased load factor, and demand for CO_2 in EOR is assessed, using net present value and levelised cost of electricity as measures of commercial viability. This analysis has drawn on data and input from China Energy – the largest power company in the world by installed capacity, and its associated research organisation, the National Institute of

Clean-and-Low-Carbon Energy (NICE), as well as perspectives from other industrial and political stakeholders in China's energy sector.

In China, and increasingly internationally, the broader term 'carbon capture, utilisation, and storage' (CCUS) is widely used in order to explicitly include technologies such as EOR which derive a commercial use from geological CO_2 storage, as well as a suite of emerging technologies which convert CO_2 into useful products such as plastics, building materials (carbonates), and hydrocarbon fuels (Zhu, 2018). CCUS will be used throughout the majority of this report, but should be understood to refer solely to geological storage of CO_2, either in connection with EOR or purely for storage purposes.

1 CLIMATE AND ENERGY POLICY

1.1 OVERVIEW

In 2014, China's government stated its ambition to transition the country's economy to a new model of economic growth referred to as the 'new normal'. This term describes a move away from investment-led growth and reliance on heavy industry and manufacturing, towards more economically and environmentally sustainable growth with an economy centred on hi-tech industry and highly-skilled services (Green and Stern, 2015). This overarching policy goal is closely linked with commitments to tackle China's major air pollution problem and reduce greenhouse gas emissions, and has had major implications for the energy sector and coal power especially (Zhu, 2016).

As a signatory to the Paris Agreement established at the 2015 United Nations Climate Change Conference (COP21), China submitted a Nationally Determined Contribution (NDC) to greenhouse gas reduction, centred on a series of goals to achieve by 2030: to peak CO_2 emissions, lower the carbon intensity of GDP by 60–65% relative to the 2005 level, and increase the share of non-fossil energy consumption to 20% (Figure 2) (NDRC, 2015). The document includes ambitions to accelerate deployment of lower carbon energy sources including solar, wind, nuclear, hydro, and gas, as well as 'to control' coal consumption while increasing the share of high-efficiency coal power. Carbon capture is highlighted as a key area for research. China appears to be well on course to meet its NDC targets, and yet, they are considered incompatible with meeting the Paris Agreement's principal goal of limiting global warming to below 2°C above pre-industrial levels (Climate Action Tracker, 2018; NCSC, 2018). As the agreement is reappraised at future COP meetings, international pressure may therefore result in more stringent objectives for greenhouse gas emissions being introduced over the next few years. China is currently formulating a longer-term plan for carbon reductions until 2050, which can be expected to inform future international commitments.

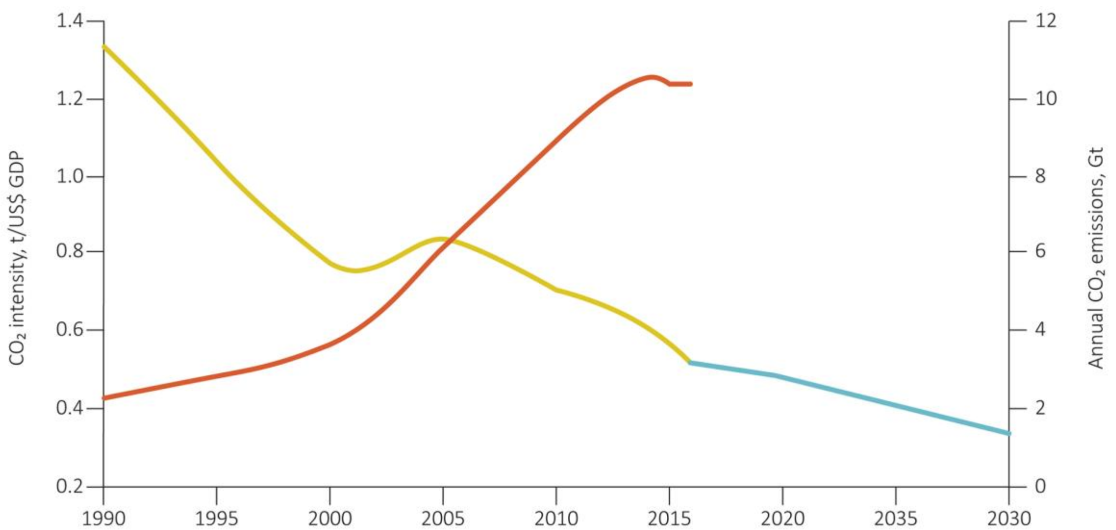


Figure 2 Historical CO_2 emissions (orange) and CO_2 intensity of GDP in China to 2016 (yellow), and the trajectory required to meet the 2020 and 2030 targets for CO_2 intensity (blue) (Edgar, 2017)

The cornerstones of Chinese policy are the five-year plans (FYP), composed of a Master Plan for Economic and Social Development which sets out major policy priorities and objectives, and a series of sub-plans aimed at specific sectors and different levels of government (Zhu, 2016). The current 13th FYP period (2016-2020) has seen the publication of a number of plans which reflect the country's commitment to the Paris targets and diversification of its energy sector. In the National 13th FYP Master Plan, a cap on total primary energy consumption of 5 Gtce/y was set, as well as targets to reduce CO_2 emissions per GDP by 18%, energy consumption per GDP by 15%, and increase the proportion of non-fossil fuel in primary energy consumption to 15% (NDRC, 2016a). These objectives were in keeping with China's progress in the previous five-year period and build on targets already established by an earlier policy document – the 2014 Strategic Energy Action Plan (SEAP) (Table 1) (State Council, 2014). The Energy 13th FYP sub-plan refined the policy goals for the energy sector, including an objective to reduce the proportion of coal in primary energy consumption to 58%, from its level of 64% in 2015, and below an absolute cap of 4.1 Gtce/y by 2020 (NEA, 2016). To help meet these targets, the NDRC announced that around 150 GW of planned coal capacity would be cancelled or delayed within the five-year period (Xinhua, 2017; NDRC, 2017a). Despite this, in recognition of growing energy demand and the value placed on energy security and affordability, coal capacity is still permitted to increase to 1100 GW under the FYP. More recently, it has been noted that even this target will be relaxed as China's economic recovery continues, and continuation of construction (or even operation) of halted coal capacity has been observed (Li, 2018a; McGrath, 2018).

TABLE 1 ENERGY AND CO_2 TARGETS IN RECENT CHINESE POLICY DOCUMENTS COMPARED AGAINST PROGRESS (TIANJIE, 2017; BP, 2018; IEA, 2017B)

2020 targets	SEAP (2014-2020)	National 13 FYP	Energy 13th FYP	2015 levels	2017 levels
Energy consumption cap	~4.8 Gtce	5 Gtce	≤5 Gtce	4.3 Gtce	4.49 Gtce
Coal consumption cap	4.2 Gtce	N/A	<4.1 Gtce	3.96 Gtce	4.12 Gtce
Energy consumption/GDP	N/A	-15% from 2015 level	N/A	0.39 kgce/$ (-18.2% from 2010 level)	0.37 kgce/$ (-5% from 2015 level)
CO_2 emissions/GDP	N/A	-18% from 2015 level	N/A	0.83 kg/$ (-20% from 2010 level)	0.75 kg/$ (-8% from 2015 level)
Coal in primary energy consumption	62%	N/A	58%	64%	60.4%
Non-fossil fuel in primary energy consumption	15%	15%	>15%	10%	11.4%

Targets for the country's energy mix in 2020 are set out in more detail by the 13th FYP for Electric Power Development, which calls for non-fossil capacity to increase by 250 GW to 39% of total installed capacity, including 250 GW (in total) solar power, 150 GW of wind power, and 58 GW of nuclear power (NDRC, 2016b). In 2017, the overall percentage target was already reached, although capacity of all sources will still need to significantly increase to 2020 to keep pace with fossil growth (Figure 3). Gas generation capacity must also expand to reach its target capacity of 110 GW (5% of total capacity), but domestic gas supplies in China are limited, and prioritised for replacing coal as a source of residential and industrial heating. Following slower growth in 2015 and 2016, electricity demand in China recovered to 6.6% annual growth in 2017, and growth of 9.4% has been posted for the first half of 2018 (Gao, 2018; Le R, 2018).

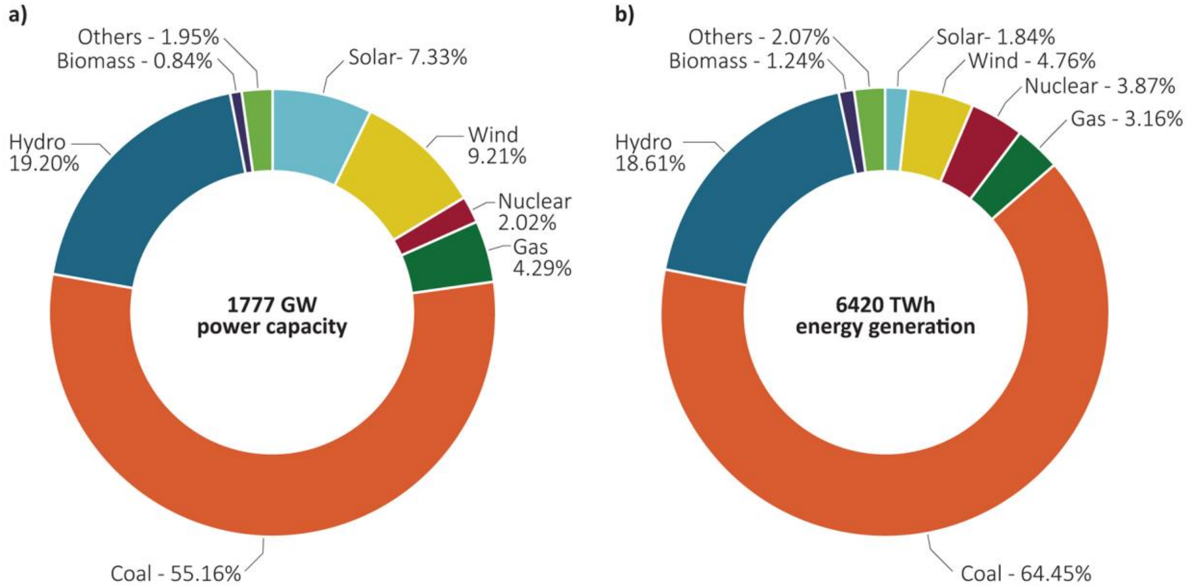


Figure 3 Electricity generation in China for 2017 by source, in terms of a) installed capacity, and b) energy generated (Li, 2018a). Total non-fossil generation was around 40% of capacity and 30% of energy generated

In October 2016, China's State Council released a Work Plan for the Control of Greenhouse Gas Emissions in the 13th FYP, which reiterated the Paris commitment to peak CO_2 emissions by 2030, and the targets for carbon intensity reduction and renewable energy laid out in the master plan (State Council, 2016). This Work Plan sets specific carbon intensity reduction targets for each province and calls on more developed regions and cities to peak CO_2 emissions before 2030. A key additional objective included in the document is for the country's largest power companies (China Energy, Huaneng Group, China Datang Corporation, China Huadian Corporation, and the State Power Investment Corporation (SPIC)) to reduce the average CO_2 intensity of the electricity they generate to 550 gCO_2/kWh by 2020. With three of these companies estimated to have an average intensity of over 700 gCO_2/kWh in 2014 (and the others over 600 gCO_2/kWh), the target is seen as highly ambitious and difficult for most of the generators to achieve (Liu and others, 2017). The Work Plan also develops the long-term policy ambition for a national system of CO_2 trading, described in the following section. Reflecting these current and announced policies, the IEA's New Policies Scenario for China projects strong growth in solar photovoltaic, wind and nuclear generation to meet growing electricity demand to 2040, while the absolute level of coal generation in the electricity mix remains constant at today's level (Figure 4).

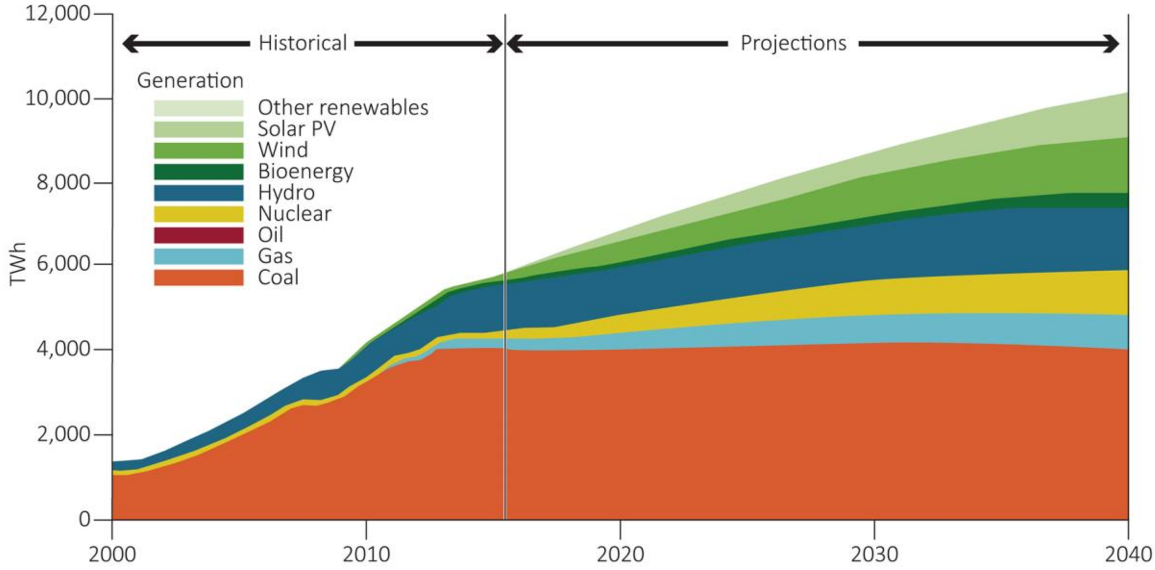


Figure 4 Historical and projected changes in China's power generation mix under the IEA's 'New Policies Scenario' (IEA, 2017a)

In China's political structure, the State Council is the highest administrative body, responsible for the five-year plan 'master plan' and supervising sub-plans and regulations produced by individual ministries. Matters concerning climate change and carbon emissions reductions have previously been largely the responsibility of the National Development and Reform Commission (NDRC) – a body charged with managing overall macroeconomic planning, including policy formulation for energy and climate change (Zhu, 2016). However, in 2018, the Ministry of Ecology and Environment (MEE) was created to replace the former Ministry of Environmental Protection (Environment Analyst, 2018). In addition to previous responsibilities concerning air and water pollution, the MEE will also take over responsibility for climate change and CCUS from the NDRC. During the current period of transition, some uncertainty remains over the exact role and budget of the new Department of Climate Change within the MEE. Coordination of other areas of energy policy and regulation between the various relevant ministries is performed by the National Energy Association (NEA).

1.1.1 The national emissions trading system

China has planned to create a national market for carbon emissions since its 12th FYP (made in 2011), and from 2013 has set up regional pilot trading projects in five cities (Beijing, Shanghai, Chongqing, Tianjin, and Shenzhen) and two provinces (Hubei and Guangdong), followed by related schemes in Fujian and Sichuan provinces (Zhang and others, 2017; Métivier and others, 2017). The ambition to roll out the national scheme was announced in a joint US-China statement in 2015, with early plans intending to cover eight major emitting industries (Obama White House Archives, 2015). In late 2017, an initial framework for a first phase of the scheme was released, containing the more modest goal of covering the power sector only – representing 3 Gt of CO_2, this market is still more than double the size of the EU ETS (NDRC, 2017b). The scheme will not be based on an absolute cap on CO_2 emissions (as in the EU or California ETS), and is likely to allocate emissions allowances based on power generation output and even the type of power plant (Schwartz, 2016; Timperley, 2018). For example, in recognition of its greater carbon intensity, a coal plant will be allocated more allowances than a gas plant, and more allowances if it generates more electricity during the year. Consequently, the scheme is likely to drive efficiency improvements at power plants rather than coal-to-gas switching or power plant closure. The carbon trading will be based on spot trading and will not include financial derivatives such as carbon futures. A proportion of allowances will be distributed between emitters for free (based on baseline emission levels) and the remainder sold at auction. There remains considerable uncertainty over the level of carbon price likely to emerge from the initial scheme, but prices in the regional pilot projects have average around 40 CNY/t (6 US$/t) (Zhang and others, 2017; Slater, 2018). An annual survey of stakeholder expectations is currently projecting the price to reach an average of 98 CNY/t (14 US$/t) in 2025 as the number of allowances is gradually restricted (Slater, 2018) (Figure 5).

The mechanisms and infrastructure for CO_2 reporting and trading are being put in place over the course of 2018. A simulated trial will begin in 2019, in which free allowances will be allocated to power companies to engage in mock trading without money changing hands (NDRC, 2017c; Timperley, 2018). Operation of the scheme in earnest will not commence until 2020 at the earliest. Currently there is no indication of a provision for CCUS in the ETS, but a proposal for its inclusion in the scheme is being outlined by the UK-China (Guangdong) CCUS Centre (Guangdong CCUS Centre, ND; Liang, 2018).

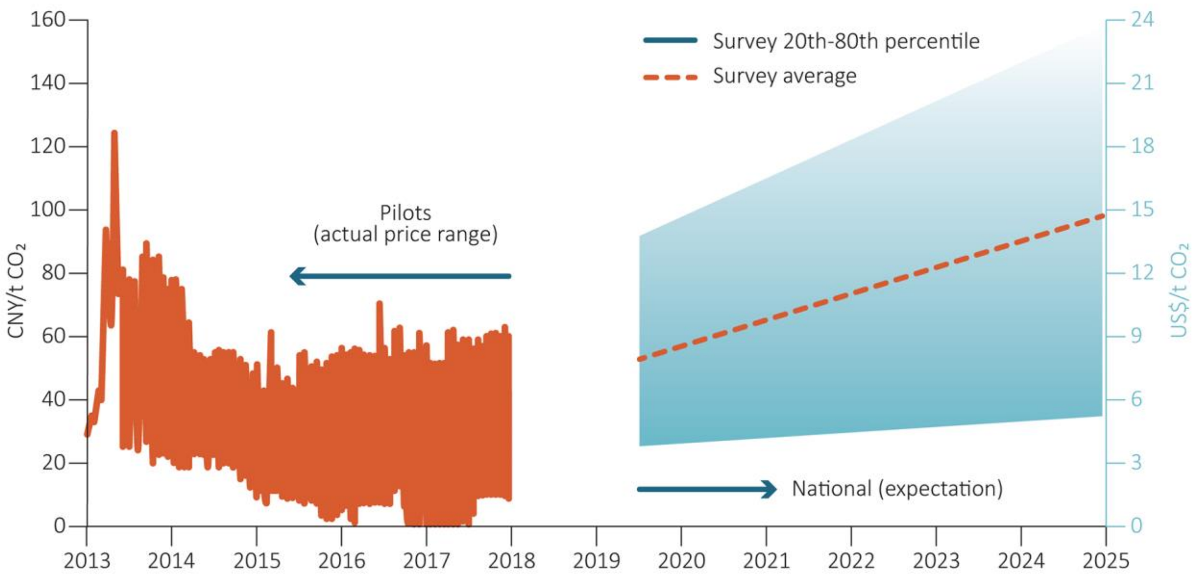


Figure 5 The range of prices in the regional pilot emissions trading systems to 2018, and expected prices for the national system from 2020 (Slater, 2018)

1.2 DEVELOPMENTS IN THE COAL POWER SECTOR

China possesses abundant coal reserves and relatively little oil and gas. As a result, the industrialisation of the country over the past few decades has relied largely on use of coal as an energy source, for both heat and power generation. Following the economic reforms begun in 1978, installed coal power capacity in China began to increase steadily during the 1980s and into the early 2000s, but still lagged behind the rate required to support industrialisation and economic growth. In 2002, the government reorganised the state-owned power companies and transformed the business model of the sector towards a more market-oriented model which attracted private and foreign investment (Zhu, 2016). Driven by a rapidly growing economy and energy demand, this shift enabled a remarkable acceleration in deployment of coal power from around 2005, with installed capacity growing from around 300 GW in 2004 to over 900 GW in 2018.

1.2.1 Larger, more efficient plants

The recent expansion of China's coal power sector has been accompanied by a parallel shift in favour of more efficient, less polluting generating units, driven by a series of policy measures. The period of early growth in the 1980s and 1990s had resulted in a large number of small, inefficient units with few air pollution controls, contributing to poor air quality and acid rain (Zhu, 2016). Although policies to restrict or close such units began in the 1990s, they were put on hold to meet the fast growth in energy demand in the early 2000s. Then, during the 11th FYP period (2006-2011) a programme of 'large-substituting-small' was implemented, imposing strict requirements such as the compulsory closure of units smaller than 50 GW, or older units of up to 100 MW (NDRC, 2007a). New units were required to be 600 MW or larger and use supercritical or USC boilers where possible, and power companies were obliged to decommission a proportional amount (60–80%) of small unit capacity before installing new capacity. These policies have resulted in the current composition of China's coal fleet shown in Figure 6, with newer, SC or USC units now comprising 44% of installed capacity, and units of >600 MW representing 50% of installed capacity (Platts, 2018). In 2014, the efficiency of the fleet was further targeted by the NDRC's Action Plan on the Upgrading and Reconstruction of Coal-Fired Power Plants for Energy Conservation and Emission Reduction, which required new coal plants to consume <300 gce/kWh and aimed for the average of the whole coal fleet to reach <310 gce/kWh by 2020 (NDRC, 2014; Zhu, 2016). New units should be designed at <282 gce/kWh for wet-cooled 1000 MW class units or <285 gce/kWh for wet-cooled 600 MW class units (slightly higher targets are permitted for air-cooled units). As a result of these polices (which have since been reiterated in the 13th FYP), there has been a steady increase in the average efficiency of the fleet (Figure 7), which reached 314 gce/kWh in 2017, equivalent to an efficiency of around 39% (LHV, net) (Li, 2017a, 2018a). China's NDC for the Paris Agreement explicitly includes the efficiency target of at least 300 gce/kWh for new coal units (>39.6%).

Efforts to further improve the carbon intensity of the coal fleet within the 13th FYP have targeted 340 GW of capacity for efficiency upgrades (largely comprising units in the range 300–660 MW) and 10 GW of inefficient plants to be closed (NEA, 2016; Ye, 2018). An increasing proportion of 300–350 MW units will also be converted to combined heat and power units (or even used to supply district heating alone) (Xu, 2018). Innovation in plant design, such as use of double reheat and high-temperature materials (for reheat steam temperatures of 630°C), should allow new units to attain high efficiencies of at least 48% (LHV, net) (Ye and Long, 2018).

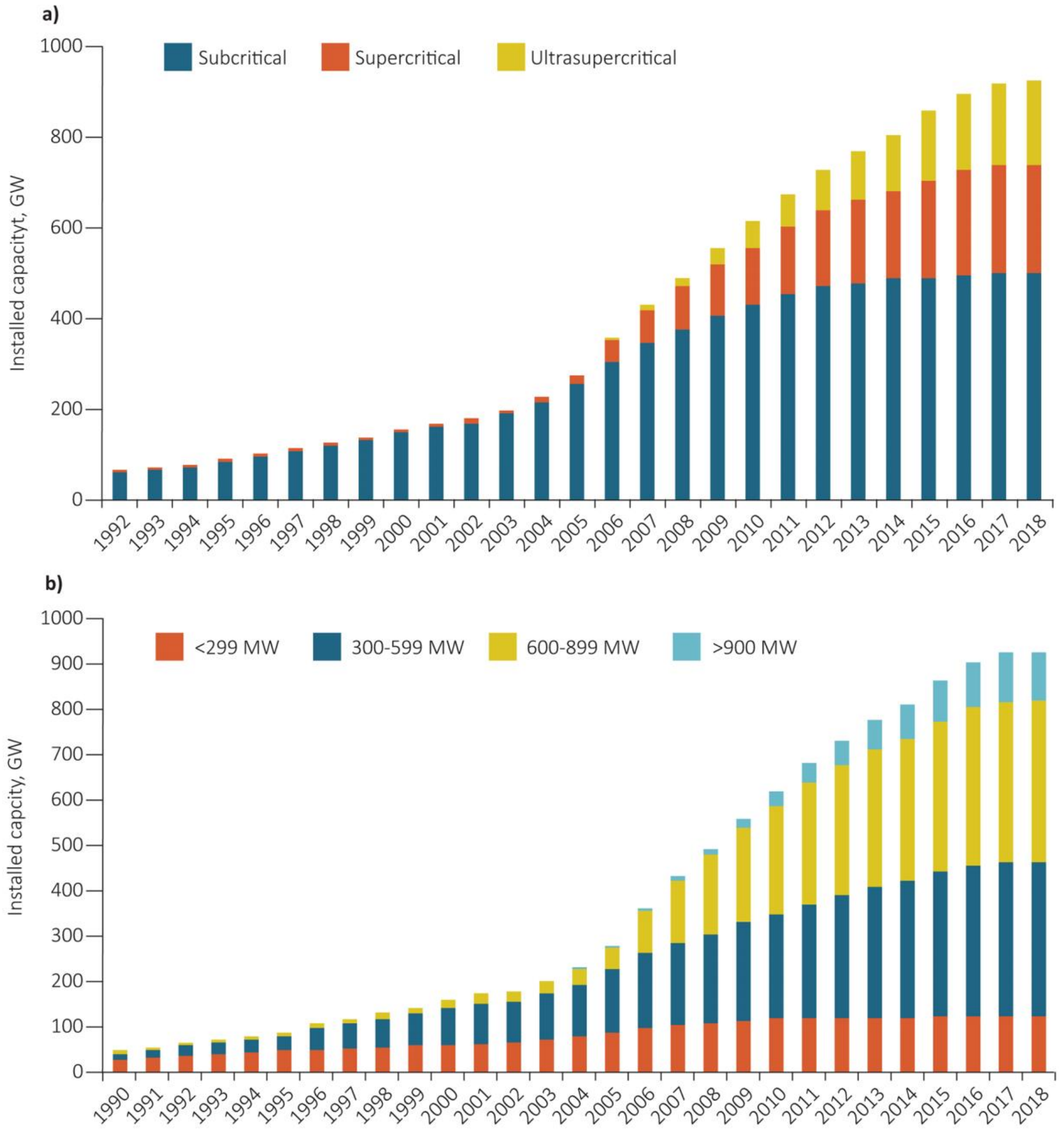


Figure 6 The composition of China's current coal power fleet by unit commissioning year, showing a) steam type and b) unit size (Platts, 2018)

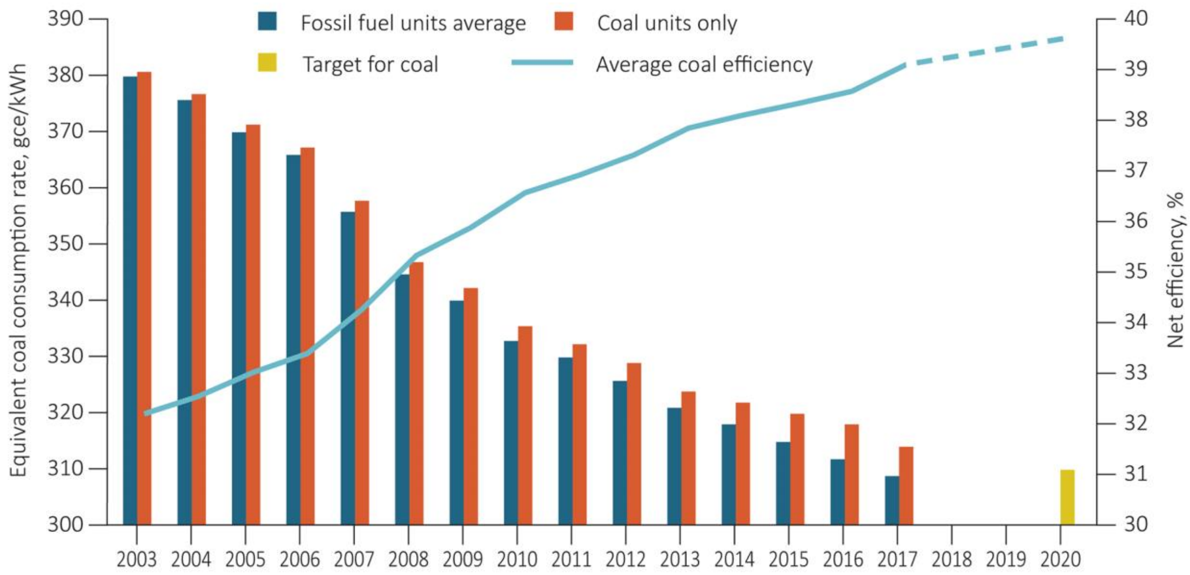


Figure 7 The reduction in average equivalent coal consumption for all fossil-fired units (including gas-fired plant) since 2003. Estimated from these figures are the approximate average coal consumption for coal units alone and the corresponding average efficiencies. The 2020 target for coal units is also shown (Li, 2017, 2018a)

1.2.2 Pollutant controls

Chinese standards for SOx, NOx and particulate emissions from large thermal plants have been progressively tightened, with the current standards constituting some of the strictest in the world (IEA CCC, 2015). In order to meet these limits, existing particulate matter controls were upgraded to (or supplemented with) wet electrostatic precipitators or fabric filters, all units were fitted with flue gas desulphurisation systems (FGD) by 2016, and over 88% of units have been fitted with selective catalytic reduction (SCR) systems for NOx removal (Li, 2017a) (Figure 8). In 2014, a government action plan required coal units to attain 'ultra-low emissions' status by meeting the even lower NOx, SO_2, and particulate emissions standards in force for gas-fired power plants, with particular urgency for units located in Eastern and Central provinces suffering from air quality issues. As part of this ongoing initiative, the 13th FYP for Energy Development has identified 420 GW of capacity which will be retrofitted to ultra-low emissions by 2020 (NEA, 2016; Ye and Long, 2018). To provide an incentive for units to upgrade, higher wholesale electricity tariffs are available to ultra-low emissions units, with increases of 10 CNY/MWh (150 ¢/MWh) for units commissioned before 2016 and 5 CNY/MWh (75 ¢/MWh) for new units (Zhu, 2016).

This investment demonstrates China's commitment to continuing the country's use of coal in its power sector and also to minimising the environmental footprint of its coal fleet. The stringent level of pollutant control associated with ultra-low emission units greatly reduces the need for additional downstream flue gas scrubbing should these units be retrofitted with CO_2 capture.

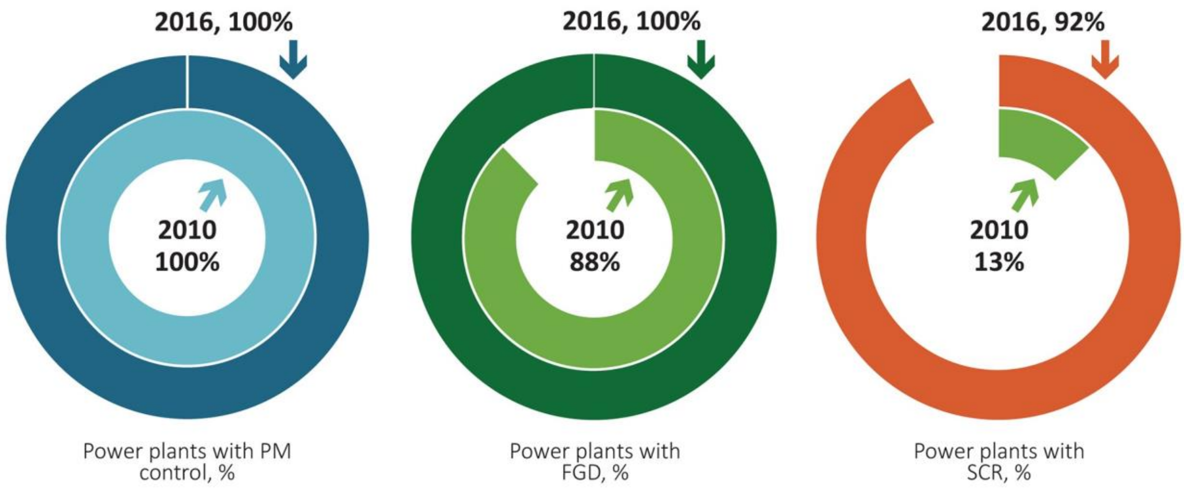


Figure 8 Installation rates of pollutant control devices in China's utility coal fleet in 2010 and 2016 (Li, 2017a)

1.2.3 Current status and overcapacity

Since 2016, coal power deployment in China has begun to level off, although the Platts database still identifies 76 GW of new capacity under construction and around 70 GW in various stages of planning – more than double the respective totals for India, the next largest market for coal power (Platts, 2018). However, the rapid growth in coal power, combined with (in recent years) even larger annual deployment of wind, solar, and hydro capacity and slowing overall energy demand has led to a recognised problem of overcapacity in the country, and an associated steady decline in average coal plant capacity factors below 50% (Figure 9) (Li, 2017a). In spite of falling operating hours, new coal plants have continued to be lucrative investments, partly due to provincially-set electricity tariffs which have not kept in line with generally falling coal prices. Whilst many current projects were approved during a period of greater demand growth, the rapid deployment of coal plants in 2014 and 2015 has also been attributed to this period seeing the adoption of responsibility for construction approval by provincial governments, which regard coal plants as good sources of employment and provincial tax revenue, and preferable to importing electricity from other provinces.

As noted above, to combat overcapacity the national government recently required up to 150 GW of proposed coal projects to halt, while still allowing for the total capacity to reach at least 1100 GW in 2020. Further to this, the NDRC's 'Notice of orderly development of electricity plans' decreed that plants commissioned after 15 March 2017 would not receive the state-controlled benchmark tariff for electricity sales (NDRC, 2017d). Whilst there is a clear goal of peaking coal capacity in the medium term, engagement with energy and political stakeholders in China suggests that there are no plans to close existing plants. The plateau in coal generation in the IEA New Policies Scenario to 2040 reflects these circumstances, with the only new plants being brought online to replace decommissioned capacity (IEA, 2017b) (Figure 4). However, the future for coal power will depend to a great extent on growth rates for the country's economy and energy demand. Following an economic slump in China's more industrial northern regions from around 2012, coal consumption declined from 2014 to 2016, but recovered by 3.3% in 2017 as the economy has improved (Hornby and others, 2018; Houser and

Marsters, 2018). Data for 2018 indicate continuing growth, with annual coal consumption projected to increase by 140 Mt, power demand increasing by 9.4% (year on year) in the first half of 2018, and utilisation rates of thermal power plants showing a 5.3% increase for the first seven months of the year (Le R, 2018).

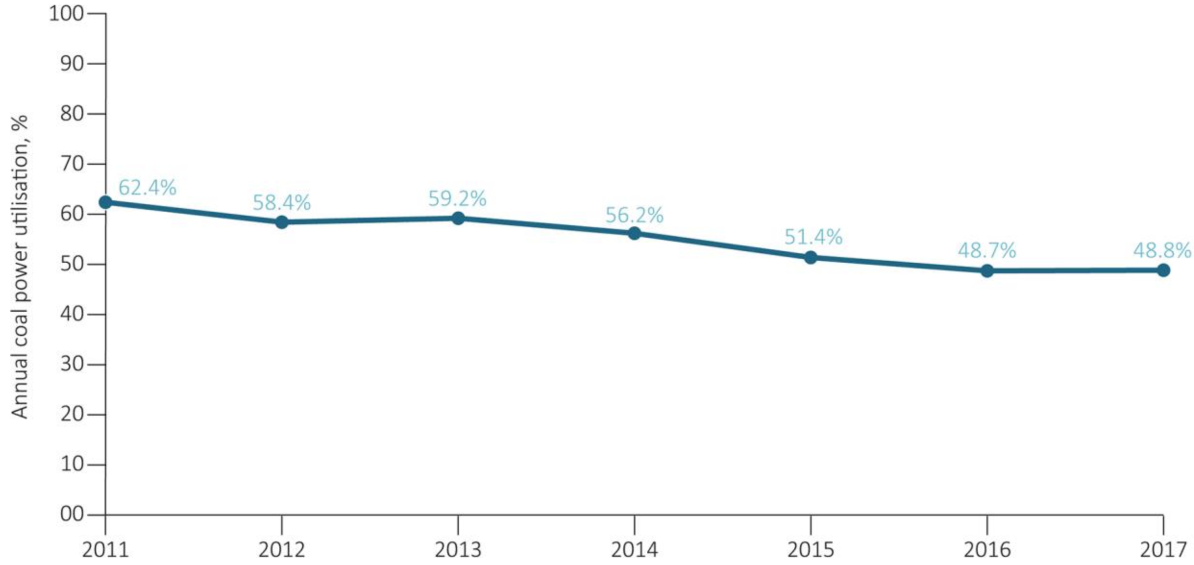


Figure 9 The decline in annual utilisation hours of coal power plants in China (Li, 2017, 2018)

1.3 ELECTRICITY MARKET REFORMS

China has been undergoing a gradual process of electricity market reform since 1985, moving from an entirely state-managed system towards liberalised wholesale and retail electricity markets. A major step was taken in 2002, which saw the separation of the generation and retail markets, the creation of two grid companies (the State Grid Company of China and China Southern Grid), and establishment of a regulatory authority for the sector (Pollitt and others, 2017; Lei and others, 2018; Dupuy, 2018). However, wholesale electricity prices for different generation sources continued to be set by provincial authorities under guidelines from central government, with operating hours also centrally allocated so as to give each generator a roughly equal share. Although this model has overseen the remarkable rapid investment and growth in the Chinese power sector, its failings have been highlighted under the recent period of slower demand growth. In particular, the poor response of wholesale prices to changing economic conditions, policy targets such as renewables growth, and market factors such as falling coal prices have encouraged over-investment in generation capacity. The lack of a dispatch system based on lowest short-run marginal cost of generation has contributed to huge curtailment of energy sources such as hydro and wind power. At the same time, there is no adequate business model for coal plants to act as flexible backup to variable renewables.

Efforts to develop more liberalised wholesale and retail electricity markets were launched in 2015 by the State Council's 'Decree No. 9: Several Guiding Principles of Furthering the Reform of the Electricity Market' (State Council, 2015). This led to several provinces and regions allowing power generators to supply contracts to large industrial users or retail companies through bilateral negotiations and auctions, and the scaling back of the planned allocation of operating hours (Göß, 2016). New wholesale companies have been set up in these regions, which negotiate with generators on behalf of major industrial consumers. In August 2017, the NEA set out a schedule for the introduction of shorter-term electricity trading in eight pilot provinces (Guangdong, Inner Mongolia, Zhejiang, Shanxi, Shandong, Fujian, Sichuan, and Gansu) (Göß, 2017; NEA, 2017). Following the introduction of monthly and quarterly trading in 2017, these regions will launch real-time spot markets by the end of 2018 (Reuters, 2018). The pilot schemes are intended to pave the way for national implementation of spot markets in 2020.

These reforms are likely to further constrain operating hours for unabated coal power plants, as renewables with low operating costs gain a greater share of generation. On the other hand, coal plants can gain greater income from generating at times of peak demand, when market-led prices increase. However, the creation of a successful electricity market which can efficiently price generation and reward cleaner energy sources, while properly rewarding investment in sufficient generation capacity to meet demand and security margins is a huge challenge, which has not yet been solved by countries with more developed markets.

On the retail side, prices have historically been set by regional distribution monopolies, but the relatively high price of industrial electricity resulting from this system has been of particular cause for concern. The market reforms launched in 2015 led to liberalised retail market pilots in Guangdong and Chongqing Municipality. Retail companies participate in the market by trading directly with generation companies on behalf of electricity users. The government has encouraged power generation companies to engage in the retail market, bringing in additional profits which help compensate for losses in the increasingly competitive wholesale markets (Xu, 2018).

2 DEVELOPMENTS IN CCUS

2.1 POLICY OVERVIEW

As China's commitment to global action on greenhouse gas emissions strengthened in the 2000s, the government also began to show early interest in CCUS technology, starting with the inclusion of CCUS as a key area for development in the 2007 National Plan to Address Climate Change (State Council, 2007). Since then, the NDRC and the Ministry of Science and Technology (MOST) have led a number of research and development programmes for CCUS technologies, leading to the development of some significant pilot-scale capture and storage projects (Ma, 2017). Most notably, the power company Huaneng Group led the way in developing a domestic solvent-based post-combustion capture technology, which was deployed at Gaobeidian power plant in Beijing in 2008 (3 $ktCO_2/y$) and Shidongkou power plant in Shanghai in 2009 (100–120 $ktCO_2/y$) – the largest power plant-based capture project operating at the time (GCCSI, 2014a). The CO_2 produced by these projects was sold for commercial applications in food and drink and welding. Huaneng Group have also pursued pre-combustion capture technology through its GreenGen IGCC project, which commissioned a 250 MW IGCC plant with a 100 $ktCO_2/y$ capture unit in Tianjin in 2014, but has failed to progress to a planned larger unit (400 MW) incorporating CCUS (Zhou, 2016). Research into carbon capture through oxyfuel combustion has been led by the Huazhong University of Science and Technology, where a 35 MWth pilot of the process was commissioned in 2015 (GCCSI, 2016). However, plans to scale-up this process at Shenhua's Jinjie power plant also stalled due to lack of sufficient financial incentive (Liang and others, 2014). Research and development of China's geological storage resources has mostly focussed on opportunities for EOR (including three National Basic Research Programmes funded by MOST), but high-level characterisation and mapping of saline aquifer storage potential has also been conducted by the Chinese Academy of Sciences (Wei and others, 2013; Liu and others, 2017) (*see* Section 3.1). In 2011, MOST produced a Technology Roadmap on CCUS in China, which evaluated the status of the technology and proposed pathways for future research, deployment, and supportive policies, including an aim to develop a commercial CCUS project by 2030 (MOST, 2011). CCUS remains an area of research interest under the current 13th FYP and has been covered in relevant sub-plans for national scientific and technological innovation and climate change science. As part of this, the Innovation 2030 project for clean and highly efficient utilisation of coal allocated 10% of its budget to CCUS (Ma, 2017).

Whilst national CCUS research programmes fall under the jurisdiction of MOST, the NDRC has taken responsibility for policies and incentives relating to the wider deployment of CCUS, until the transfer of the Department of Climate Change to the newly-formed Ministry of Ecology and Environment in 2018. As part of the 12th FYP for Greenhouse Gas Control (2011-2015), the NDRC issued a notice on promoting CCUS pilot and demonstration projects in 2013 (NDRC, 2013). This document called on regional governments and development and reform commissions (DRCs) to encourage and support the development of capture and storage projects, curb the use of natural CO_2 sources for EOR, and promote the characterisation of storage capacity and clustering of emitters. As a means of promoting such activity, they were requested to explore financial incentives mechanisms, make use of existing tax and land use support mechanisms, and encourage relevant enterprises to make use of multiple funding sources. Other directions included the need to establish industry regulations and environmental standards, strengthen capacity building for the sector, and increase international collaboration.

Provincial governments have responded to varying degrees to the NDRC's request to promote CCUS within their jurisdictions. Most notably, Shaanxi issued a 'Notice on carrying out pilot and demonstration projects for the near-zero carbon emission area', and has included CCUS in its Key Construction Project Plan approved by the provincial congress in 2018 (NDRC, 2017e; Ma, 2018). This covers 360 ktCO_2/y of capture and storage projects around the Ordos Basin, comprising the Yanchang project, Shenhua's Jinjie power plant project, and capture from PetroChina's Changqing oil field (*see* Section 2.2 for details). However, this status does not provide provincial funding to the projects in question, but eases processes such as land requisition and environmental assessments. Guangdong has issued the 'Implementation plan for demonstration projects of near-zero carbon emission area' and has provided support for a capture test centre and potential large demonstration project at Haifeng power plant (NDRC, 2017).

In 2015, the NDRC and the Asian Development Bank published a roadmap for CCUS demonstration and deployment in China (ADB, 2015). This called for the initial deployment (in the 13th FYP period) of EOR-based CCUS on lower cost capture sources such as coal-to-chemical plants in key storage areas with well-characterised oil fields such as the Ordos Basin (Figure 10). Application of CCUS to the power sector was envisaged to begin in a second phase of deployment in the 2020s, but should be anticipated by requiring larger new-build plants to adopt a 'capture-ready' design, as well as improving the regulatory framework and assessing storage sites (*see* Section 2.3.5 and Appendix 2). Commercial operation of CCUS plants, based on a form of economy-wide climate policy such as the national emissions trading scheme, was targeted for 2030. Whilst the initiation of a handful of EOR-driven capture projects on chemical plants or natural gas in recent years follows the roadmap's suggested course (detailed in Section 2.2), other recommendations such as the development of financial incentives and regulation in preparation for the second phase have not seen the required progress.

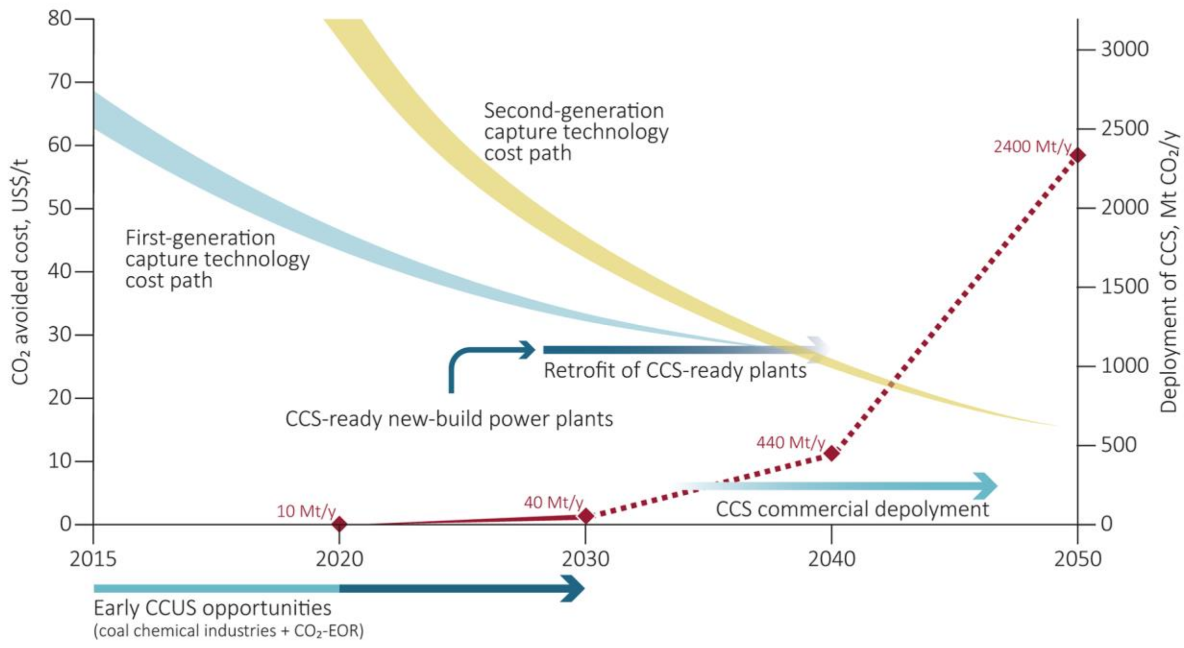


Figure 10 The NDRC and Asian Development Bank roadmap for CCS deployment in China (ADB, 2015)

For CCUS demonstration and deployment to progress further, the MEE must gain greater support for the technology at higher levels of China's state hierarchy, where there is currently much greater priority placed on the more pressing problem of reducing non-greenhouse gas pollutants to improve air quality (Ma, 2018). Such support is a vital prerequisite for the MEE to engage with the Ministry of Finance (MOF) on the formulation of appropriate funding mechanisms. Even when political will to develop CCUS is present at a provincial level, the necessary coordination of these entities (previously, also including the NDRC) has been a challenge for the development of appropriate policies, and is currently further complicated by the handover of CCUS and climate change issues from the NDRC to the MEE. Once established, the MEE may provide new impetus to developing policies favourable to CCUS deployment. However, major developments of this kind will also require the inclusion of CCUS as a development target in the 14th FYP in 2020.

The international community has long taken a strong interest in supporting the development of CCUS in China, in recognition of the country's great need for the technology to decarbonise, as well as its potential as a market place for international manufacturers (Lockwood, 2017). A number of bilateral initiatives have been set up between OECD countries and China with a view to developing China's CCUS capacity, and usually including the aim of deploying a large CCUS demonstration project. Among the earliest of these was the Near Zero Emission Coal (NZEC) initiative between the UK and China in 2005, which was soon linked to the related EU-China 'COACH' (Cooperation Action within CCUS China-EU) project (NZEC, 2009; COACH, 2011). The EU project conducted pre-feasibility studies for three potential demonstration projects, but subsequently received insufficient funds to progress to a construction phase. The Australia-China Joint Coordination Group on Clean Coal was established in 2007 and, among other collaborative work, ran pilot-scale capture tests in China and carried out a pre-feasibility study for a demonstration plant in Jilin province (Withers, 2017). The focus of this work has now shifted to using Chinese technology at a possible capture plant in Australia. The USA and China established the Clean Energy Research Centre in 2009, including an Advanced Coal Technology Consortium (ACTC) of Chinese and US companies and research institutes seeking to collaborate on CCUS (CERC, 2018). Although this collaboration was also conducted largely at a research level, the assistance of US research institutes in characterising the Ordos Basin contributed to the large-scale Yanchang CCUS facility (currently under construction) (CERC ACTC, 2015, 2016). In the period from 2008 to around 2012, several international manufacturers such as Babcock and Wilcox, Alstom, and Air Products, also sought to partner with Chinese companies to develop CCUS demonstration projects, but all have been cancelled in the absence of sufficient funding and policy support.

China's experience with CCUS is therefore not dissimilar to the challenges faced by the technology internationally, as early progress with research and growing investment in the 2000s largely failed to develop into full-scale demonstration projects. The economic crisis of 2009 led to reduced funding for bilateral initiatives with China (such as NZEC) and contributed to faltering international commitment to climate change policy. As in other countries, lack of government investment in CCUS was compounded by the absence of adequate policies to provide an incentive for demonstration projects, such as carbon pricing or guaranteed power prices. Many countries (such as the EU, USA, Canada, and Australia) have developed a regulatory framework to govern future CO_2 storage projects, which addresses issues such as liability for stored CO_2, storage monitoring and verification requirements, and definition of suitable site characteristics (McCoy, 2014). China is yet to develop a dedicated protocol for CO_2 storage, but such a process can draw substantially on adaptation of existing oil and gas industry regulation.

Despite this hesitant progress on CCUS policy, China still appears to hold the most potential for large-scale CCUS projects in the near-term, with six of the eleven projects classified as in 'early development' by the GCCSI, and two of the five currently under construction (GCCSI, 2018a). This dominance may change, as political interest in CCUS has reignited in countries such as the US, UK, Norway, and the Netherlands, but there is little or no focus on application of CCUS for the power sector (particularly coal) in Europe, and there are still very few projects in the pipeline. In the US, the 'Future Act' passed in early 2018 introduced a significant tax credit for every ton of CO_2 stored by CCUS projects (a maximum of 35 US$/t for EOR or 50 US$/t for saline storage), and is expected to lead to greater deployment, particularly in industries with low capture costs, such as bioethanol, natural gas, and chemical plants (CURC, 2018). There is also growing interest in CCUS in Saudi Arabia, United Arab Emirates, and Mexico (World Bank, 2016; CSLF, 2018). These international developments and the further deployment of large (or industrially scalable) projects worldwide will be vital in securing China's ongoing commitment to CCUS, as policy-makers in the country are unwilling to forge ahead of more developed countries in CCUS investment.

2.2 CCUS PROJECT STATUS

The deployment of full-chain CCUS projects (including capture, transport, and storage) in China to date has been largely driven by EOR in oil fields with declining production, mostly located in the north of the country. The major state-owned oil companies have conducted eight small-scale projects, each injecting around 50–200 ktCO_2/y (Table 2) (GCCSI, 2018b). Several of these projects are currently in the process of scaling up or planning to scale-up operations to larger capture rates, either from the same capture source or by collecting CO_2 from various regional sources. As for the majority of EOR-based CCUS projects operating worldwide, they have mostly used relatively low-cost capture sources such as CO_2 from coal-to-chemical facilities or from natural gas processing. Exploited since the 1960s, the Daqing oil field in Heiliongjang was the first to see large-scale CO_2-based EOR, following a decline in production in 2003 (Liu and others, 2017). In the same year, injection of around 200 ktCO_2/y captured from natural gas processing commenced. Also, in North-Eastern China, the Jilin oil field is another area suitable for EOR, where PetroChina has injected over 100 kt of CO_2 since 2008, using CO_2 separated from natural gas producing wells in the same field. In 2018, a new facility injecting 600 ktCO_2/y from the Changling gas well commenced operations, making it the largest CCUS facility operating in China (GCCSI, 2018c). PetroChina are also conducting small-scale EOR tests in the Changqing oil field in Shaanxi province, using CO_2 from a coal-to-liquids plant.

Since 2010, a subsidiary of Sinopec has captured 40 ktCO_2/y from its own coal power plant for use in EOR in the Shengli oil field in Shandong province (GCCSI, 2014b). In the same region, Sinopec are currently constructing a facility to capture 400 ktCO_2/y from the Qilu coal-to-chemicals plant. Two more Sinopec EOR projects were launched in 2015: the 120 ktCO_2/y Zhongyuan petrochemical-based capture plant in Henan, and the 50 ktCO_2/y 'Eastern China' project at a chemical plant in Jiangsu. There are early plans to scale-up the Eastern China project to 0.5 MtCO_2/y by the 2020s (GCCSI, 2016b).

Yanchang Petroleum is currently constructing a 0.41 MtCO_2/y capture facility at the Yulin coal-to-chemicals plant in northern Shaanxi province, building on smaller-scale capture tests ongoing since 2012 (Hydrocarbon Processing, 2017; Ma, 2017). The CO_2 is transported by tanker truck for EOR in the nearby Jingbian and Wuqi oil fields, but a pipeline is also planned. Yanchang Petroleum is a local enterprise in which the government of Shaanxi has a controlling share.

Xinjiang province in North Western China is a relatively new region for oil and gas exploitation (beginning in the 1990s), and one with great potential for growth. Dunhua Oil (an oil industry services provider) is planning to expand EOR projects across the region's Tarim and Junggar basins, with carbon capture operations having begun on a natural gas-to-methanol plant in 2015. In cooperation with Sinopec and Petrochina, the company's plans include capture of 30 ktCO_2/y from a coal plant in southern Xinjiang, and from coal-to-chemical facilities in the Ordos basin (with CO_2 sourced across Ningxia, Gansu, and Shaanxi provinces). Its ten-year strategy is to increase EOR operations across these regions to 30 MtCO_2/y (Li, 2018b).

TABLE 2 OPERATING AND PLANNED FULL CHAIN CCUS PROJECTS IN CHINA (GCCSI, 2018B)

Name	Province	Source	Capacity	Storage type	Year	Status
Daqing Oil Field EOR	Heilongjiang	NG processing	200 kt/y	EOR	2003	Operating
Jilin Oil Field EOR (PetroChina)	Jilin	NG processing	350 kt/y Increased to 600 kt/y in 2018	EOR by pipeline	2006	Operating
Shenhua Group Ordos CCS demonstration	Inner Mongolia	Coal-to-liquids	100 kt/y	Dedicated	2011-2014	Completed
Karamay Dunhua Oil tech CCUS EOR	Xinjiang	Methanol production (from NG)	100 kt/y	EOR	2015	Operating
Sinopec Zhongyuan CCUS pilot	Henan	Petrochemical production	120 kt/y	EOR	2015	Operating
PetroChina Changqing oil field EOR CCUS	Shaanxi	Coal-to-liquids	50 kt/y	EOR	2017	Operating
Yanchang Integrated CCS demonstration (and Jingbian EOR test)	Shaanxi	Coal-to-chemicals	Large-scale demonstration of 410 kt/y (existing pilot at 50 kt/y)	EOR	Demonstration from 2020, test from 2012	Construction
Sinopec Qilu	Shandong	Coal-to-chemicals	400 kt/y	EOR	2019	Construction
Sinopec Shengli Power Plant CCS	Shandong	Power generation	Demonstration would be 1 Mt/y (existing pilot at 40 kt/y)	EOR	Demonstration from 2020s, (pilot running from 2010)	Demonstration at advanced development
Sinopec Eastern China CCS	Jiangsu	Chemical production	0.5 Mt/y demonstration, (50 kt/y pilot operating)	EOR	Demonstration in 2020 (pilot running since 2015)	Demonstration at early development
Guohua Jinjie CCS full chain demonstration	Shaanxi	Power generation	150 kt/y	Dedicated	2019	Advanced development
CRP Haifeng Integrated CCS demonstration	Guangdong	Power generation	1 Mt/y demonstration planned (25 kt/y capture pilot under construction)	Dedicated geological storage	Demo in 2020s, test platform 2019	Early development
Shanxi International Energy Group CCUS	Shanxi	Power generation	2 Mt/y	Under evaluation	2020s	Early development
Shenhua Ningxia CTL	Ningxia	Coal-to-liquids	2 Mt/y	Under evaluation	2020s	Early development
Huaneng GreenGen IGCC	Tianjin	Power generation	Demonstration of 2 Mt/y planned (capture pilot 100 kt/y operated)	EOR	Pre-combusion capture test running since 2016	Demonstration appears to have been halted

Although there has been academic research into the storage potential of saline aquifers in China, few full-chain CCUS projects have made use of this kind of dedicated CO_2 storage to date. Shenhua Group, now China Energy, has pioneered this work, and from 2010-2014 captured 100 ktCO_2/y from the Ordos direct coal-to-liquids plant for storage in a saline aquifer in the Ordos Basin (Xiuzhang, 2014). The company is currently constructing a facility with the capacity to capture 150 ktCO_2/y from the nearby Jinjie power plant (operated by subsidiary Shenhua Guohua) in Shaanxi province, for storage in the same Ordos Basin formation. This project has received some capital funding from MOST, but all operational expenses will be covered by China Energy, so it will run only for finite test campaigns. It is scheduled to be commissioned in 2019 (Zhao, 2018).

Little onshore storage or EOR potential is available in the south of the country, but there are offshore oil fields and potential saline aquifer storage available in the South China Sea. China Resources Power has therefore looked at offshore storage for its planned capture project at Haifeng coal power plant in Guangdong, in cooperation with China National Offshore Petroleum. The power company is currently constructing a pilot-scale test platform for membrane and solvent-based capture from the power plant (to be commissioned in March 2019), but there are plans to capture 1 MtCO_2/y from a new 600 MW unit to be built at the same site (Li and Liang, 2017; Li and others, 2018).

2.3 POTENTIAL INCENTIVES AND BARRIERS FOR CCUS

2.3.1 Enhanced oil recovery

The demand for CO_2 in China's oil fields has been the primary driver behind deployment of full-chain CCUS projects to date. This is in keeping with the global trend, as only five of the large projects currently listed by the GCCSI as operating or under construction make use of dedicated CO_2 storage as opposed to EOR (GCCSI, 2018). Miscible CO_2-based EOR can increase oil production in Chinese fields by 12–19% compared to the alternative approach using water flooding (Ma, 2017). The profitability of EOR operations necessarily depends on oil prices, and global demand for CO_2 for EOR has therefore declined since the fall in oil prices in 2014. The returns available from EOR are also greatly dependent on local oil field geology, which varies between China's various oil fields, and is often challenging compared with fields exploited by the well-established CO_2-EOR industry in the USA. For instance, good conditions for EOR are found in the Shengli oil field, where the increased oil production can almost cover Sinopec's cost of capture from its power plant at Dongying (Li, 2017b). The Xinjiang and Changqing oil fields on the other hand, require a larger amount of CO_2 for each barrel of oil produced, and are therefore less economically favourable. Whilst few examples exist of transparent CO_2 supply contracts between companies, it has been estimated that oil companies would be able to pay in the range of 10–30 US$/t of CO_2 (66–200 CNY/t) for EOR to be profitable (Wei and others, 2015; Li, 2018a)

Expansion in EOR has not been driven purely by commercial concerns, but also by strategic and political factors. The large state-owned companies Sinopec and PetroChina are keen to be seen as taking an active role in mitigating their CO_2 emissions, as this should translate to more favourable treatment by national and local government, with respect to issues such as permitting or allocation of oil assets. State-owned power companies such as Huaneng and Shenhua Guohua are similarly motivated to take a lead on CCUS development. Equally, the involvement of China Resources Power and CNOOC in the Guangdong CCUS project has been partly attributed to both companies seeking to keep pace with the activities of their competitors in CCUS activities. Many of the EOR projects listed above, including the Yanchang and Zhongyuan projects, have also received non-financial support from government, through the NDRC, the relevant provincial DRCs, and the state-ownership of the oil companies involved (Ma, 2017).

As for international projects, the capture of CO_2 for EOR in China has mostly relied on relatively low-added cost capture processes, such as natural gas processing (where CO_2 must be removed regardless of whether it is stored) and chemical production facilities which produce highly concentrated streams of CO_2. China also possesses natural deposits of high-concentration CO_2, but use of these sources was discouraged by the NDRC in 2013 in order to increase the demand for captured CO_2 (NDRC, 2013). Current developments in CCUS therefore reflect the NDRC/ADB roadmap (ADB, 2015), which envisaged a first phase of CCUS centred on coal-to-chemical facilities and EOR. The higher cost of CO_2 capture from early coal power plant demonstration projects may put the sector at a disadvantage in competing with these sources for EOR supply contracts, with typical low-cost capture sources currently requiring around 200 CNY/t (30 US$/t) to cover costs (Dahowski and others, 2012). Economically viable EOR storage capacity has been estimated at 2.2 Gt (Wei and others, 2015), whereas sub-basin evaluation of onshore saline storage estimates around 746 Gt of CO_2 capacity associated with 'very highly suitable' sites (up to 1400 Gt in total) (Wei and others, 2013). This relatively limited capacity, combined with the fact that demand for CO_2 usually declines over an EOR project lifetime, suggests that large coal power plants may not find a market for their entire output (IEA, 2016a). Nevertheless, it is probable that some large power plants will be able to partially subsidise operations with the sale of a proportion of CO_2 to EOR, but the distance to suitable oil fields and the relative location of alternative sources of CO_2 will be key factors.

2.3.2 Carbon pricing

Widespread deployment of CCUS on coal power plants is therefore likely to require additional incentives beyond CO_2 sales for EOR. Fortunately, the power sector offers a number of mechanisms and incentives to support the additional cost of CCUS which are not available to other industries. Most obviously, the national ETS will apply to the power sector from 2020 and provide a value on carbon. The details of the ETS are still being established, but as currently envisaged, it is not likely to immediately drive strong emissions reduction measures at individual plants as emissions allowances will be allocated to generating companies based on their energy production and achievable 'benchmark' emissions for their current fleet. On the other hand, the carbon price is expected to increase assuming China's commitment to international climate agreements strengthens, and stakeholder surveys have predicted fairly significant average prices of around 100 CNY/t (15 US$/t) by 2025 (IEA, 2017b; Slater, 2018) (Figure 5).

In general, emitting industries are only able to derive revenue from reductions in their emissions if the CO_2 price is expressed in an increase in value of the industry's product. Hence, a CCUS-equipped coal plant could earn more than unabated plant, provided the power price reflects the increased running costs of equivalent, unabated plant. In practice, marginal power prices also reflect the operating costs of lower carbon sources on the grid such as renewables and gas plant, which are less affected by the CO_2 price, and the CCUS plant will not receive the full value of all its emissions savings. This 'decoupling' of CO_2 price and the power price becomes more significant as the proportion of CO_2 emitting generators on the grid diminishes. Partly due to this issue, combined with the collapse of the CO_2 price following the global financial crisis in 2008, the EU ETS has failed to lead to any large-scale CCUS projects. The ROAD demonstration project (retrofit to a coal power plant) in the Netherlands had built a commercial case based partly on the ETS carbon price prior to its fall in value, in combination with a capital grant (Read, 2017). A significant tax on CO_2 emissions from the offshore oil and gas industry in Norway has led to the two large-scale, gas-processing based projects at Sleipner and Snøhvit, highlighting that industries with strong revenue and low capture costs are better able to absorb the added cost of CCS (Herzog, 2016; Lockwood, 2017). A more viable incentive may be provided by a form of credit for stored CO_2. The Quest CCS project (associated with oil production from tar sands) in Alberta Canada has benefited from the province's carbon offset system, which awards credits of 30 CAN$/t$CO_2$ (39 US$/t) while increased investment is anticipated in CCUS in the USA following the introduction of the 45Q tax credit for CO_2 utilisation and storage (*see* Section 2.1) (Osler, 2016; ZeroCO_2, 2018; CURC, 2018). Whilst all CO_2 pricing systems are subject to a degree of uncertainty regarding future policy, price uncertainty is particularly present for 'cap-and-trade' markets such as the EU ETS. There is also a need for a thorough monitoring, reporting, and verification system to be put in place to account for emitted or stored CO_2.

There are two possible mechanisms by which a CCUS power plant could derive value from the ETS in China: either by reducing the emission allowances required by the generator, or qualifying for offset credits. In a market where all emissions allowances are auctioned to emitters, as is currently the case for the power sector in the EU ETS, plants which can verify they have stored CO_2 are able to avoid having to pay for allowances (Liang, 2018). However, for CO_2 prices to be reflected in wholesale power prices, China's electricity market will need to continue further towards liberalisation; the shortage of gas as a lower-carbon dispatchable power source could give CCUS coal plants more value in such a market than has been seen in Europe. Alternatively, some CCUS projects could qualify for tradable CO_2 offset credits known as Chinese Certified Emission Reductions (CCERs), based on the Certified Emission Reductions used in the international Climate Development Mechanism (CDM) and already accepted in China's regional pilot ETS (the CDM itself has recognised CCUS projects since 2011) (Schwartz, 2016; Liang, 2018). There is also the possibility that a scheme similar to the EU's 'NER300'

(New Entrants' Reserve 300) could be established, in which a number of CO_2 allowances are sold off with the aim of raising money to fund early CCUS projects (Lupion and Herzog, 2013; Liang, 2018).

A proxy value on carbon emissions is implied by the recent regulation for major power companies to reduce their emissions intensity to 550 gCO_2/kWh. Recent analysis of this target has concluded that all of these companies currently have carbon emissions intensities well above the prescribed level and will struggle to reach the 550 gCO_2/kWh target through their planned investments in clean energy (Liu and others, 2017). The regulation could, in principle, be an important driver for retrofitting CCUS (or partial CCUS) to a proportion of the companies' coal fleets. However, some power companies have indicated that they will not look to employ CCUS to meet the target, but pursue other options, such as grouping with hydro power companies to improve the average intensity (Huaneng CERI, 2018; Xu, 2018).

2.3.3 Electricity tariffs

As described in Section 1.3, wholesale power tariffs in China have historically been based on benchmark rates which are dictated by central and provincial government. These aim to reflect the generation costs and reasonable profit margins for specific generation sources and therefore provided a simple framework for introducing feed-in tariffs to promote the deployment of clean energy sources. Wind power tariffs have been available from as early as 1998, and in 2009 the NDRC set benchmark wind power tariffs for four different regions, ranging from 510 to 610 CNY/MWh (77–92 US$/MWh) (regions with more wind receive less support). The excess cost of generation over that of coal-fired generation are split between the provincial grid operators and central government (Ming and others, 2013). Support mechanisms for solar photovoltaic projects have evolved along similar lines since 2009, with a national feed-in tariff of 1150 CNY/MWh (173 US$/MWh) introduced in 2011 (or 1000 CNY/MWh (150 US$/MWh)) for projects completed after 2011. These prices can be adjusted over time according to changes in investment cost and technical advances. Alongside the tariffs, the government has set quotas for new capacity installation. Wind and solar power capacity in China has grown rapidly since the introduction of such incentives for investors, reaching over 130 GW of solar PV and over 188 GW of wind power in 2018, and with 53.1 GW of solar PV capacity added in 2017 alone. However, in June 2018, the government announced it would halt the allocation of feed-in tariffs for new solar projects and reduce the tariff for existing projects by 50 CNY/MWh (7.5 US$/MWh) (Hook and Hornby, 2018). This move was likely intended to curb the enormous pace of growth of the industry, which has surpassed government targets, led to high curtailment rates for renewable generation, and created a deficit of more than US$15 billion in the fund set up to pay for the tariffs. New utility-scale projects will bid in an auction process to set their power prices, and the government intends to encourage high quality projects which use advanced technology and can operate independent of subsidies.

To a lesser extent, incentives based on guaranteed wholesale tariffs have also been employed in the coal power sector as part of policies to promote higher-efficiency and lower-emissions plants. As noted above, a tariff increase of 5–10 CNY/MWh (75–150 ¢/MWh) was introduced in 2016 for plants achieving the ultra-low emissions status by meeting the emission levels required for gas-fired plants. Conversely, in 2007 the NDRC imposed reduced tariffs on smaller power plants as part of the programme to replace smaller, inefficient coal units – this policy effectively reduced the tariff received by smaller units to the provincial benchmark level for coal, or maintained them at their current levels if already below the benchmark (NDRC, 2007b; Zhu, 2016).

Despite the decline in political support for guaranteed power prices for renewable generation, such a system could still play a role in supporting emerging low-carbon technologies such as CCUS. As for renewable sources, this could be combined with national deployment targets for CCUS capacity, or 'portfolio' targets for a proportion of CCUS in retail power supply. The use of guaranteed power prices and portfolio standards has been proposed for CCUS power projects in the UK and USA respectively, although they have often met with political or public opposition due to concerns over the cost burden to government or consumers (Herzog, 2016; Polson, 2016; BEIS, 2017). However, most current estimates of the cost of CCUS power plants in China indicate that the level of tariff required to cover the cost of generation would fall below or within the range of existing feed-in tariffs for wind power, and well below those for solar power. As the challenges of handling large proportions of variable renewable energy on the grid grow in China, there could be increasing interest in supporting dispatchable low-carbon sources such as CCUS.

2.3.4 Increased operating hours

As indicated in Figure 9, the capacity factors of coal power plants in China have steadily fallen to below 50% in 2017. This is a result of fast growth in both renewables and coal power deployment during a period of slowing demand growth. Operating hours for coal power plants have recovered in early 2018 and are expected to increase as the Chinese economy recovers and measures to curb deployment of renewable and coal capacity start to take effect. However, many coal plants with low marginal operating costs will increasingly be obliged to adopt a role of ramping up and down in response to variable output from renewable generation, as is the case for coal fleets in Europe and North America. Nuclear power offers an alternative for low-carbon baseload generation but is not projected to grow much beyond 10% of installed capacity to 2040 (IEA, 2017b). Although CCUS plants have significant potential for flexible operation, coal power plants with CCUS are likely to be reserved for baseload operation (at least for the first few 10s of GW of capacity deployed) in order to make best use of the capital invested in the plant and the low-carbon power available. In a merit-order dispatch system with no incentives for low-emission sources, the high operating costs of a CCUS plant would prevent it from running under all but the most energy scarce periods, so some form of market intervention is necessary. The use of a guaranteed power price which covers generation costs would normally lead to high utilisation of the plant, provided overcapacity is reduced. Alternatively, under China's current system of centrally allocating generating hours, CCUS power plants could be given priority dispatch, as is currently the case (in principle) for renewable sources. The provision of guaranteed additional operating hours in this way has already been proposed or used as an incentive for CCUS demonstration projects in the power sector. The Shidongkou capture plant in Shanghai (which sold CO_2 to the food and beverage industry) benefited from such an incentive, while the Haifeng power plant in Guangdong has been offered roughly a 10% increase in operating hours as a reward for investing in its pilot capture facility (Li, 2017; Liang, 2018).

2.3.5 Transport and storage infrastructure

The need to develop transport and storage infrastructure is a major challenge for the early stages of CCUS deployment in most countries. The most economic means of transporting large quantities of CO_2 from emitters to storage sites is to pump it in a dense phase (liquid or supercritical state) through a pipeline, although transport by ship is seen as a viable alternative for distances over 800 km (Gao and others, 2011). Pipeline transportation of CO_2 is a well-established technology, with over 6000 km of pipeline used to service the EOR industry in the USA (IEA, 2016a), and individual CCUS projects currently employing pipelines of up to 330 km to reach storage sites. In China, the majority of operating EOR and dedicated CO_2 storage projects rely on transportation of liquid CO_2 by tanker trucks, but short pipelines for gas phase CO_2 are used for the Shengli and Jilin oil field projects, and larger supercritical CO_2 pipelines are planned for the Yanchang and (scaled-up) Shengli projects (Hill, 2017; Ma, 2017; Liu, 2018). Through research institutes and oil companies, China continues to build expertise and capacity in large-scale CO_2 pipeline engineering and EOR, but there is also a need to establish industry standards and regulations. Other regulatory and permitting challenges will be faced by pipeline projects which need to cross provincial borders. Ideally, investors in transport infrastructure could benefit from economies of scale and shared costs by developing large 'trunk' pipelines to service clusters of several emitters; this also presents a challenge of coordination and risk to the developer of the oversized infrastructure.

The initial development of dedicated CO_2 storage sites is a time-consuming and costly process, requiring detailed characterisation of possible reservoirs and drilling of exploratory wells. In North America, where there is an established onshore oil and gas sector, characterisation for recent CCUS projects has taken up to 5 years, while in Europe it has been estimated that site characterisation can take from 5 to 10 years and represent up to a quarter of total storage capital cost (Gilmore and others, 2016; ZEP, 2014). These factors can deter private investment in storage infrastructure, particularly when combined with uncertain or limited future revenue associated with CCUS. Research institutes and international research collaborations have already played an important role in characterising some of China's storage capacity in detail, however, very few saline aquifer-based storage projects are proposed. It is generally recognised that government will need to play a major role in funding site characterisation, or alternatively, guaranteeing sufficient returns on investment. A widely proposed future business model for CCUS is to separate the business of transport and storage from capture, with providers of transport and storage infrastructure guaranteed a regulated income as service providers, regardless of CO_2 delivery from emitters in a given year (ZEP, 2014; IEA, 2016b; Goldthorpe and Ahmad, 2017). This also allows organisations with sub-surface and CO_2 expertise (oil companies) to concentrate on transport and storage, while power companies and other emitters focus on capture. However, the first generation of large CCUS projects in China is likely to continue to be based on a single full-chain project structure, under the control of individual state-owned enterprises. This could be aided by the growing tendency for formation of large state-owned energy companies with broad portfolios, typified by Sinopec's coal power assets or the merger between Shenhua (primarily coal mining) and Guodian (primarily power) to form China Energy. Developing the business model for interaction between different groups represents a future challenge for CCUS deployment.

Responsibility for CO_2 storage sites after injection has been completed is another regulatory issue which has yet to be resolved in China. Most jurisdictions which have developed CCUS regulations (eg Australia, Canada, USA, and the EU) have established a protocol for handing over liability and stewardship for the site to the state, following an obligatory period of monitoring by the site operator (McCoy, 2014).

2.3.6 Potential for reduced costs in China

There is real potential for carbon capture retrofits to be deployed at lower cost in China than has been experienced in North America, where most large-scale carbon capture plants have been constructed to date. This expectation is based on typically lower labour and manufacturing costs in China, as well as the significant potential for economies of scale when applying capture plants to the large fleet of coal units of similar size (both 660 and 1000 MW units). China has demonstrated remarkable cost reductions through mass production of other energy technologies – most famously for solar photovoltaics, but also in large-scale deployment of supercritical and ultrasupercritical coal power units. An initial phase of deploying imported technology is usually followed by much wider-spread deployment of lower-cost, domestic technology. Owing to this opportunity for mass production and lower labour costs, typical capital costs for USC coal units in China are in the range of 580–670 US$/kW, compared to around 1500–2000 US$/kW for recent units in the Netherlands and Germany (IEA CCC, 2018).

Post-combustion capture plant makes use of large equipment such as absorber columns, for which off-site construction in a modular fashion (prior to straight-forward assembly on-site) is increasingly recognised as a key route towards cost reductions. This has been highlighted by the cost analysis of the International CCS Knowledge Centre for a retrofit at Canada's Shand Power Plant, based on experiences from the operating capture project at Boundary Dam (Bruce and others, 2018). Greater use of this modular approach to construction contributed towards a remarkable 67% reduction in capital costs (on a cost per tonne of CO_2 basis). China's enormous fleet of similar coal units presents an unparalleled opportunity to draw on the economies of scale available in this approach.

The possible cost reduction for CCUS power projects in China has recently been quantified by two notable studies. The IEAGHG report 'Effect of plant location on the costs of CO_2 capture' transposes costs of new coal and gas-fired power plants with post-combustion capture to ten other countries, including coastal and inland locations in China, and finds the lowest capital costs and cost of electricity in the China cases (IEAGHG, 2018). This study ascribes a labour cost to China which is 16% of the Netherlands baseline case and a 23% lower material cost, but also a reduced labour productivity (requiring 2.29 times the man-hours of the baseline case) and a 50% increase in project contingency.

A recent study by NICE similarly transposes the baseline cost estimates developed by the USA Department of Energy's National Energy Technology Laboratory (NETL) for a supercritical coal plant with CCUS to a Chinese retrofit context, finding a 30% reduction in first-year cost of electricity compared to the NETL case (NETL, 2015; Singh and others, 2018). This reduction was derived mainly from reduced capital and operating costs, but was offset by increased coal costs in China and the assumption that the retrofitted unit would continue to operate at the low load factors currently prevailing in China – this may be a conservative assumption for the utilisation hours of a costly, low-carbon generation source (Figure 11).

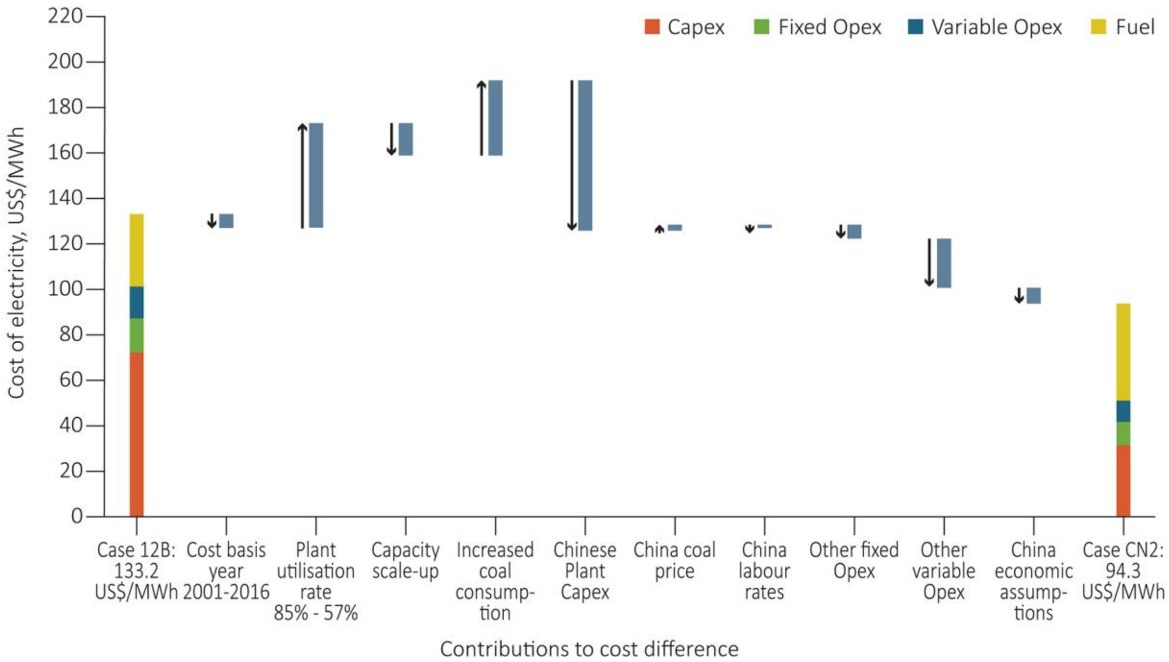


Figure 11 The difference in first year cost of electricity between the NETL baseline (new-build, Case 12B) case for a supercritical coal power plant with post-combustion capture and an equivalent retrofit case in China (Case CN2), showing the contributing factors (Singh and others, 2018)

However, it should be noted that skilled labour costs in China have increased rapidly in recent years, and may reach similar levels to the USA within the next decade (Trading Economics, 2018a). This could alter the perspective for cost reductions in CCUS after 2025, which is the earliest that widespread deployment could occur in China. It would therefore be beneficial to begin an initial phase of demonstration plants as early as possible, while lower labour costs are available, before capitalising on economies of scale in a commercial deployment phase.

3 ECONOMIC COST ANALYSIS

3.1 CCUS RETROFIT CASE STUDY

The cost analysis presented in this report uses a generic 1000 MW USC unit as its case study. There are 104 units with a net capacity of 1000–1060 MW currently operating in China, built over a period from 2006 to 2017 and distributed over 49 plant locations (most commonly as pairs, but three plants have four 1000 MW units) (Platts, 2018). As highlighted in IEA (2016a), larger, more efficient power units offer opportunities for cost reductions in capture retrofit, by enabling economies of scale in equipment for capture, transport, and storage, and by reducing the 'lost' fuel cost associated with the energy penalty from CO_2 capture. As China continues with its long-standing policy to replace smaller, inefficient units, SC and USC units of 600–1000 MW will also increasingly dominate the coal power sector. According to current policy, smaller units such as 300 and 350 MW class units are to be increasingly converted to combined heat and power (CHP) units – or even used solely to supply district heating. There is little likelihood that USC units (either 660 or 1000 MW class) will be obliged to close before the end of their useful life, as this would represent both a major asset loss to the power company and a significant loss of dispatchable capacity for China's grid. On the other hand, various incentives (as discussed in Section 2.3) may create a favourable environment for power companies to invest in retrofitting these units with CCUS.

More recently built units also represent a more likely case for CCUS retrofit, as a higher proportion of the remaining operational life of the plant is likely to overlap with future legislation to reduce CO_2 emissions. The majority of USC units were constructed in the last decade. As 2015 was the year in which the greatest number of 1000 MW USC units were commissioned in China, it has been chosen as the reference case for this study (Figure 12). However, the results should be broadly applicable to units commissioned across this period of strong growth in China's USC fleet.

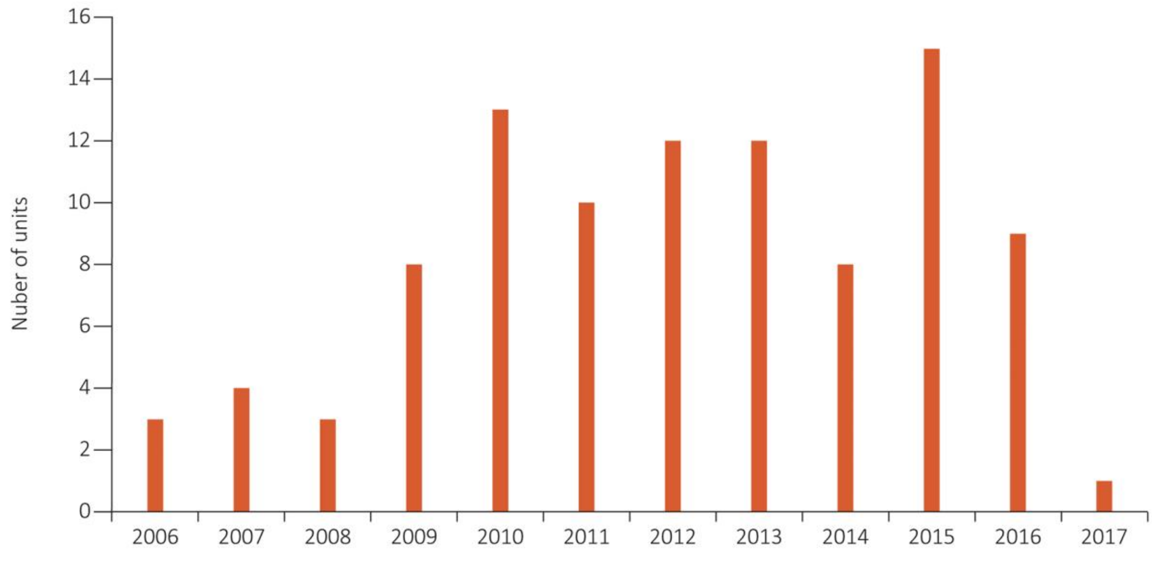


Figure 12 China's 1000 MW units by the year in which they were commissioned (Platts, 2018)

Whilst this case study does not select a specific 1000 MW unit location, it is important to consider whether a significant proportion of the existing units have access to suitable CO_2 storage. The major onshore sedimentary basins in China, possessing both saline aquifer storage and oil fields, are found across the north of the country, notably the Tarim and Junggar Basins in Xinjiang, the Ordos Basin in Shaanxi, the Bohai Basin in Shandong and Hebei, and the Shaoling Basin in Jilin and Heilongjang. Other storage areas are also found in the Sichuan Basin, the Dongting and Jianghan Basins near the city of Wuhan in Henan, and the Northern-Jiangsu Basin to the north of Shanghai. Unfortunately, the densely populated southern coast of China (Guangxi, Guangdong, and Fujian provinces), where many large power plants are found, has no onshore storage within a reasonable pipeline distance (<800 km). Whilst there is promising offshore storage available to these plants (as investigated by CNOOC for the Haifeng CCUS project in Guangdong), this option is not considered within this case study, as storage costs are likely to be higher, and there are much greater initial barriers to the development of offshore storage infrastructure. This region is therefore less likely to significantly participate in early development of large-scale CCUS.

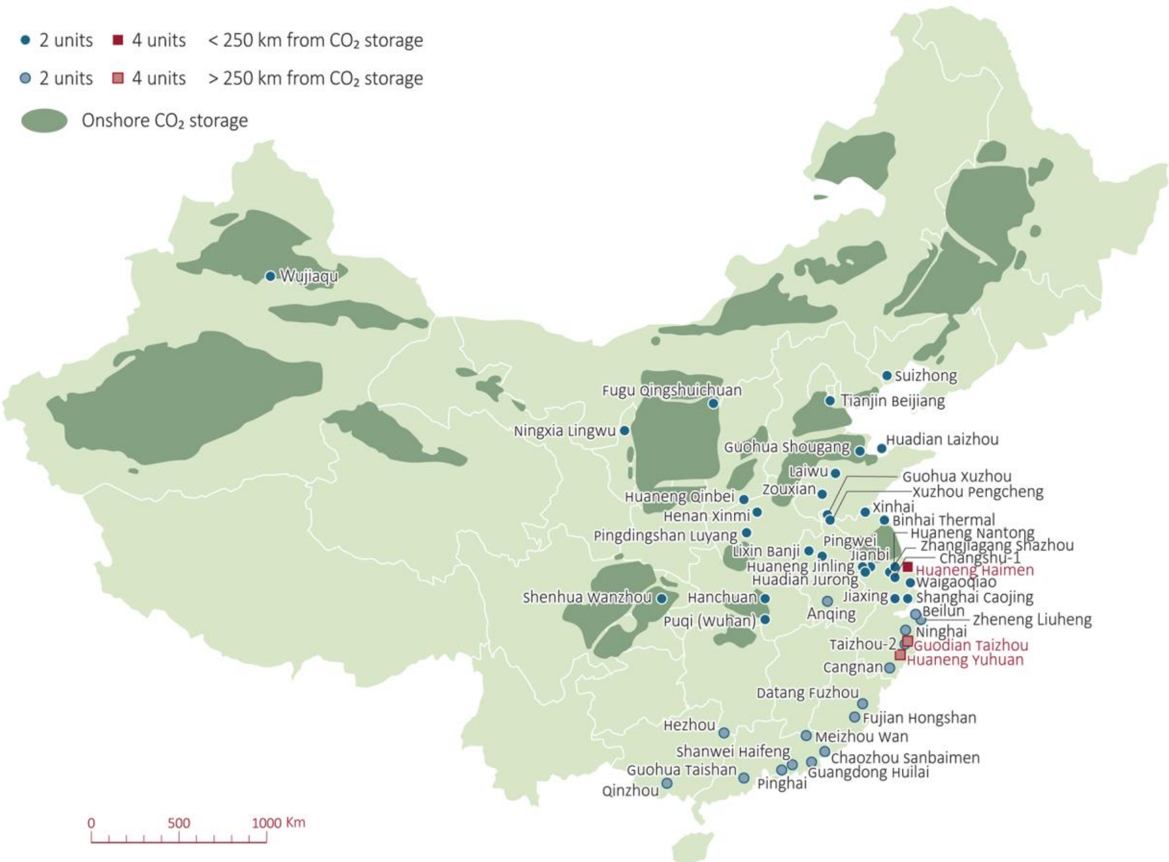


Figure 13 The location of power plants with 1000 MW units in relation to regions suitable for onshore CO_2 storage (dark green) (IEA, 2016a; Platts, 2018)

Of the 49 plants with 1000 MW units, nine plants are located on the southern coast without access to onshore storage (Figure 13). A further 10 plants in Guangxi, Zhejiang, and southern Anhui are over 250 km from storage, so would require very long pipelines, but many plants in these regions still obtained reasonable retrofit costs in IEA (2016a) in cases where long pipeline costs were offset by lower capture costs. Two plants within the metropolitan region of Shanghai may also face challenges in accessing storage (located roughly 250 km to the north in Jiangsu province and requiring a pipeline to cross the Yangtze River), but again, some plants in Shanghai still obtain reasonable overall retrofit costs in IEA (2016a). This leaves 28 plants with access to nearby (<250 km) storage, and 12 with more challenging circumstances. Particularly promising areas for retrofit of large power plants are Shandong and Jiangsu provinces, which are highly industrialised and also have access to the Bohai and Northern Jiangsu Basins respectively. The Ordos Basin is already an active area of current CCUS deployment, dominated by coal-to-chemical plants which could help establish an infrastructure for later power plant retrofits. Whilst some units in the west of China use air cooling due to water scarcity, the study will consider the more standard case of a once-through wet cooling using natural draft cooling towers.

TABLE 3 POWER PLANT AND CAPTURE PLANT TECHNICAL PARAMETERS

Gross power output, MW	1077
Net power output (without capture), MW	1015
Net efficiency (LHV)	43.5%
Coal calorific value, kJ/kg	24018
Coal carbon content	62%
CO_2 emissions (without capture), t/MWh	0.775
CO_2 capture rate	90%
Net power output with capture, MW	811
Net efficiency with capture (LHV)	34.8% (8.7% points penalty)
Total CO_2 captured at 0.75 load factor, Mt/y	4.7

In the reference case, the CCUS retrofit of the unit is considered to begin operations in 2025, but the effect of delaying retrofit until 2030 is also addressed. The CCUS technology applied is the amine-based post-combustion capture technology which is currently commercially available at large scales from a number of technology providers (further details of the status of this technology are provided in Appendix 2). Although higher capture rates are technically possible and commercially available, capture of 90% of the emitted CO_2 is considered, as this is the capture rate applied for the two existing CCUS projects on coal power plant (Boundary Dam 3 and Petra Nova), and is by far the most commonly studied case in the literature. The use of partial capture (usually in the form of 90% capture applied to a flue gas slipstream) has been proposed as a means of reaching the 550 g/kWh CO_2 intensity limit for power companies. However, recent analysis by the International CCS Knowledge Centre of a retrofit in Canada (where there is a CO_2 intensity limit of 420 g/kWh for thermal power plant) has suggested that using amine-based post-combustion technology for partial capture is much less cost-effective than achieving capture rates of 90% or higher (Bruce and others, 2018). Technical parameters for the case study are summarised in Table 3.

Costs for the capture plant used in this study are taken from the coastal China case in IEAGHG (2018), which uses equipment costs provided by Shell Cansolv (the technology provider for the Boundary Dam CCS project) (IEAGHG, 2018). Further details of the cost data and methodology used are presented in Appendix 1.

3.2 NET PRESENT VALUE OF CCUS RETROFIT

This study uses a net present value (NPV) approach to assess whether a CCUS retrofit to the 1000 MW USC unit would represent a favourable commercial investment for a power company in the period 2025-2030. This commercial decision involves a comparison of the NPV of cash flows associated with continued operation of an unabated coal plant against that of the CCUS retrofit case. As the underlying costs of the power plant operation remain the same in both cases, the additional costs or income arising in the retrofit case can be considered alone to obtain the relevant change in NPV. This approach therefore considers the retrofit investment as incurring additional costs comprising the capital investment in the capture plant, lost electricity sales associated with the capture energy penalty, additional operating and maintenance costs associated with the capture plant, and the cost of CO_2 transport and storage (Rohlfs and Madlener, 2010). On the other hand, various potential incentives for CCUS which can lead to increases in overall cash flows for the retrofitted plant are examined, including the reduced cost of CO_2 allowances in the national ETS, and increased electricity income due to either increased operating hours or a premium electricity tariff available for CCS plant. When the value of these incentives allows the NPV to become positive, the retrofit represents a favourable investment for the operating company.

The baseline load factor for an unabated plant is taken as 57%, based on the average capacity factor for China Energy 1000 MW units in the first half of 2018 (Shenhua, 2018). Whilst coal utilisation may be expected to increase in the next decade as overcapacity is reduced and fewer new units come online, the parallel growth in renewables will also have a depressing effect on utilisation of unabated coal, so the current low rate may seem indicative of future load factors. On the other hand, the baseline capacity factor for the retrofitted power plant is set at 75%, assuming a degree of priority dispatch for a low-carbon, dispatchable generator. Cases where the retrofitted plant is operated at the lower rate of 57% and a higher rate of 90% are also considered for completeness. Utilisation of the retrofitted plant at rates as low as 57% is considered unlikely, based on the need for low-carbon, dispatchable power and the significant capital investment, but could arise in a scenario where the entire grid is decarbonised, and a portion of CCUS-retrofitted coal units are used for load following.

The baseline CO_2 price in the national ETS is set at 100 CNY/t (15 US$/t), based on the projection shown in Figure 5, which is also in agreement with carbon price assumptions in the IEA World Energy Outlook 2017 (Slater, 2018; IEA, 2017b). The baseline electricity tariff is taken from the average electricity tariff for China Energy coal plants in the first half of 2018 (311 CNY/MWh (47 US$/MWh)) and increased in the analysis to model the effect of a premium tariff for low-carbon power. Additional value from CO_2 may also be gained from sales to EOR operators; however, to account for the fact that the power plant will be competing with other capture sources such as chemical plants, this value is set at 30 US$/t (200 CNY/t), which is typical of the capture costs achievable for such sources, and not much greater than the CO_2 prices which currently allow for profitable EOR operation in China (Dahowski and others, 2012; Wei and others, 2015). The proportion of CO_2 sold to EOR is then used as a variable in the analysis.

3.2.1 A profitable CCUS retrofit project

Figure 14 shows cash flows (before tax) and their present value (after tax) for an example CCUS retrofit project with a 30-year lifetime and positive NPV of 1.2 billion CNY. In this case, the CO_2 price and load factor of the retrofitted plant are set to their baseline values of 100 CNY/t (15 US$/t) and 75% respectively, and additional revenue is derived from 10% of the CO_2 being sold for EOR (at 200 CNY/t) and an increase in electricity tariff of 25% over the base rate for coal plant (to 389 CNY/MWh (58 US$/MWh)). It is clear that the additional revenue from the increase in load factor from the unabated coal average of 57% to the retrofitted baseline (75%) is a significant contribution to the profitability of the project, though it should be noted that this contribution also includes the effect of the higher tariff for the additional operating hours. The positive cash flow associated with the tariff increase on the original generating hours is accounted for separately (cyan), and generates a similar income to the saving in CO_2 allowances under the national ETS, while the contribution from EOR is much smaller. Following the initial capital outlay, the largest negative cash flows incurred by the capture plant is associated with the energy penalty for the capture process, followed by the cost of CO_2 transport and storage, and with a smaller contribution for operation and maintenance of the plant.

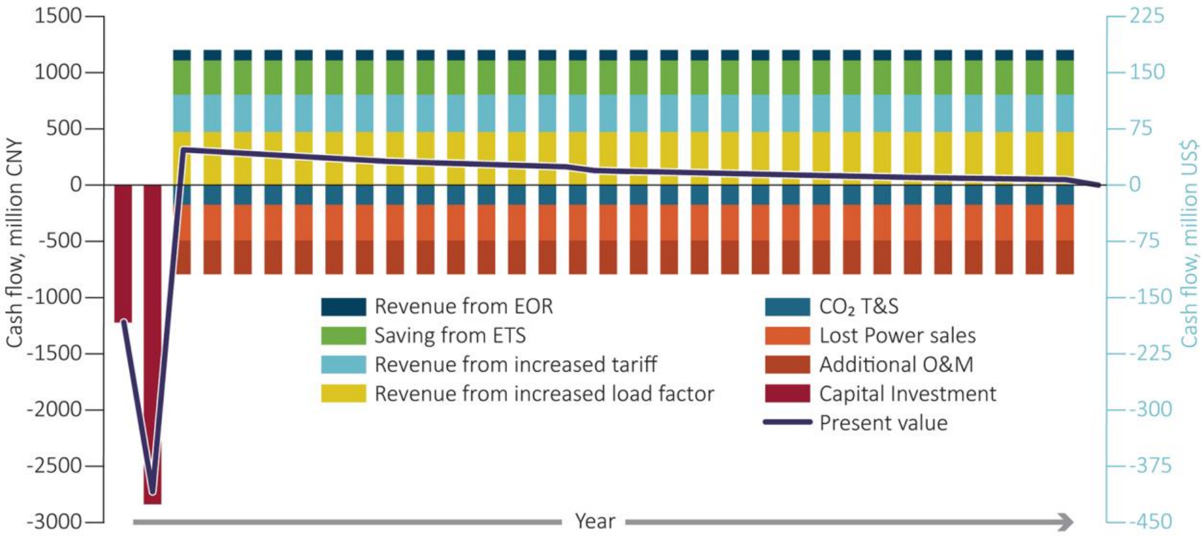


Figure 14 Typical cash flows for a 30-year retrofit project with positive NPV, based on a CO_2 price of 100 CNY/t (15 US$/t), 10% of CO_2 sold for EOR, and a 25% increase in electricity tariff

3.2.2 Effect of individual incentives

Figure 15a-c shows the rate at which the NPV of the retrofit becomes positive as the three incentives of CO_2 price (in the ETS), electricity tariff, and proportion of EOR sales are increased. The value of each incentive for NPV = 0 represents the 'break-even' value for a retrofit project. Unsurprisingly, retrofitted plants running at higher load factors require less of an incentive, with a breakeven CO_2 price of 149 CNY/t (22 US$/t) for 90% load factor, 219 CNY/t (33 US$/t) for 75% load factor, and 298 CNY/t (45 US$/t) for 57%. It is interesting to note that the saving associated with CO_2 emissions is actually greater in the lower load factor cases, as there are more uncaptured emissions in the higher load factor cases, whilst the emissions in the business-as-usual reference case remain the same. At a very high carbon price (around 2300 CNY/t), the benefit of increased operating hours in the 90% load factor case would be negated by the greater CO_2 saving in the baseline case.

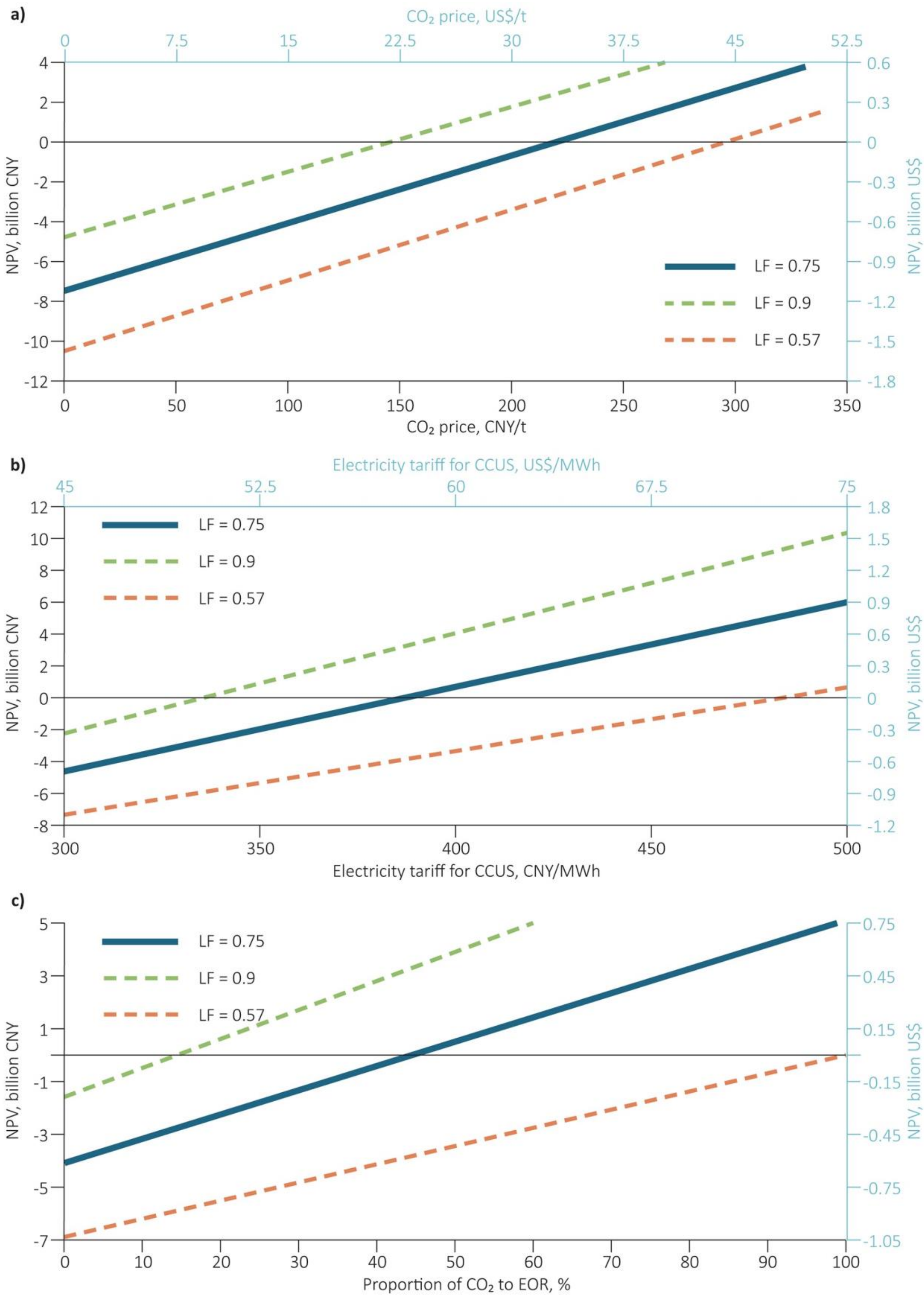


Figure 15 The change in NPV of the capture plant retrofit with increasing a) CO_2 price under the national ETS, b) electricity tariff for CCUS, and c) proportion of CO_2 sold for EOR, shown for three different load factors (LF)

Conversely, the NPVs for different load factors diverge as the premium electricity tariff for CCUS is increased, as the additional operating hours become increasingly lucrative for the plant. For the baseline case a tariff increase of 24% is required to break even, whilst only an 8% increase is required at 90% load factor, or 55% in the low load factor case. It can be seen that even small increases in an electricity tariff have a significant effect on project profitability, and could be a powerful and feasible incentive for retrofit projects. The tariff of 386 CNY/MWh (58 US$/MWh) required for the baseline case is not much greater than tariffs currently available for unabated coal plants in some regions, such as the 371 CNY/MWh (56 US$/MWh) (recorded in Sichuan for 2018 (Shenhua, 2018)).

In the absence of other incentives, the baseline case requires a large proportion (41%) of CO_2 to be sold for EOR (at a fixed price of 66.7 CNY/t) in order to break even – in reality, it may be challenging to find a continuous market for such a large quantity of CO_2 (3 $MtCO_2$/y). At higher load factors, both the absolute quantity of CO_2 for a given proportion of emissions is greater and compensation from electricity income are greater, so CO_2 sales of only 14% is required. At a load factor of 57%, the entirety of CO_2 production would need to be sold for EOR.

3.2.3 Combined incentives

In reality, a retrofit project is likely to be able to draw on several incentives to achieve a positive NPV, as for the example depicted in Figure 14. Figure 16a shows which combinations of CO_2 price and electricity tariff yield a NPV of zero for the three load factor cases. Also considered is the EOR case (43.7%) at which the project will break even under baseline conditions for CO_2 price (100 CNY/t (15 US$/t)) and electricity price (311 CNY/MWh (47 US$/MWh)); this is intended to represent the greatest extent of EOR sales a project would reasonably require to compensate for shortfalls in other incentives. A zone of project profitability is therefore bounded by the worst-case scenario line of low load factor and the best-case scenario of the EOR case. Even under the low load factor scenario, profitable combinations of incentive can be found which are entirely plausible under current policy directions in China, such as a CO_2 price of 150 CNY/t (23 US$/t) and a tariff of 440 CNY/MWh (66 US$/MWh) (well below the current tariffs for wind power). Figure 16b shows similar combinations of CO_2 price in the ETS and the proportion of CO_2 sold to EOR. It should be noted that such scenarios assume that CO_2 sold to EOR is also fully counted as offset CO_2 emissions for the purposes of the ETS, although in reality there may be a mechanism to place less value on CO_2 used in EOR (which increases hydrocarbon production) than that placed on dedicated storage. In the tax credit system in the USA, dedicated storage receives over 40% more per tonne of CO_2 than EOR. Whilst it is challenging for EOR sales to compensate retrofit investment credit alone for all but the highest of plant load factors, a more reasonable 44% of captured CO_2 is required for the baseline case (CO_2 price of 100 CNY and 75% load factor) to break even.

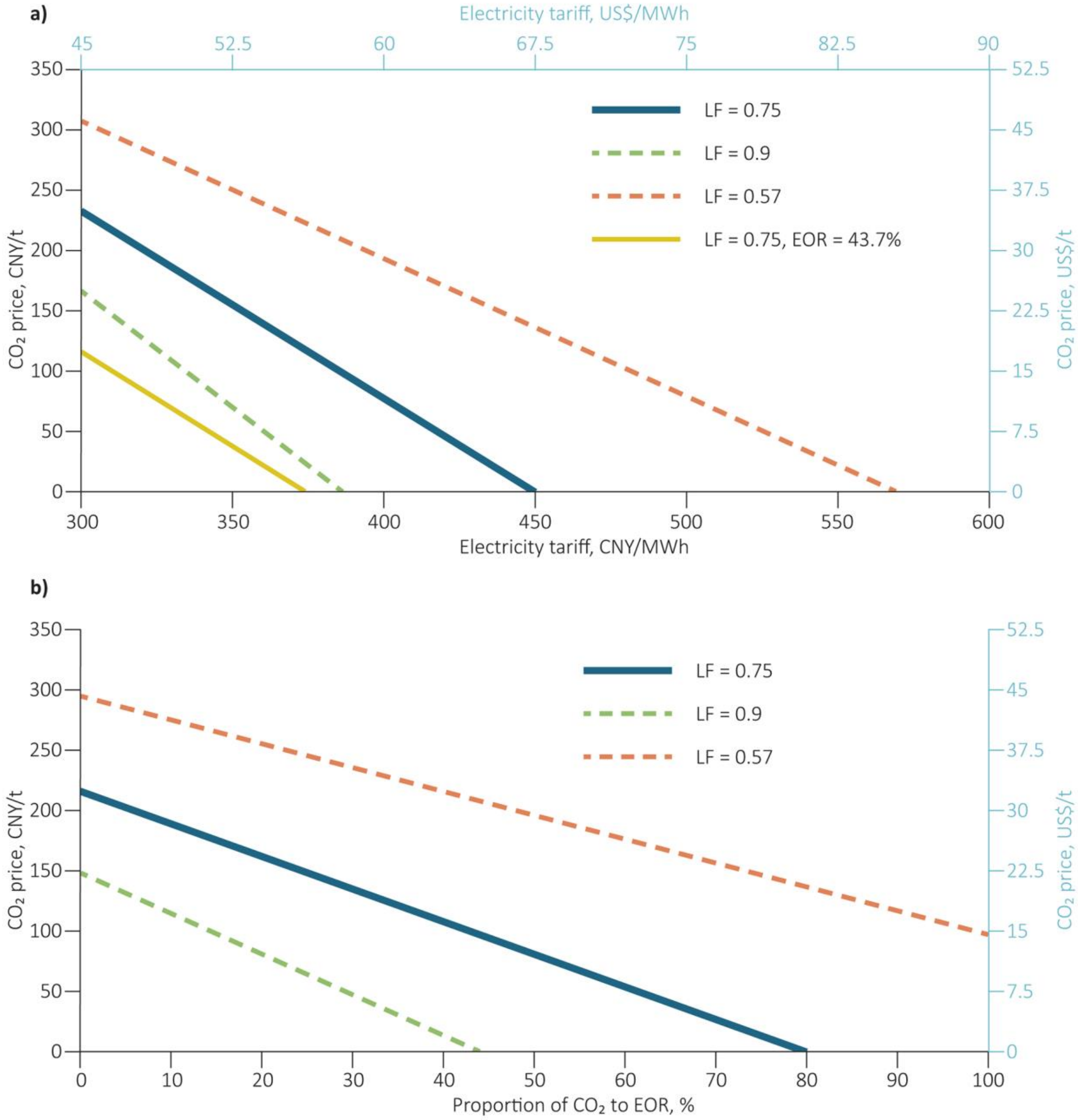


Figure 16 a) Combinations of CO_2 price and electricity price at which retrofit projects can break even, shown for different load factors and an EOR scenario which breaks even under baseline conditions. b) Combinations of CO_2 price and EOR sales at which retrofit projects break even, shown for different load factors

3.2.4 Sensitivity analysis

As there remains considerable uncertainty around many of the key inputs to this analysis, particularly regarding their future values in 2025 and beyond, it is informative to examine the effect of variations in these parameters on project profitability. The influence of increases (or reduction) in capture plant capital cost (capex), CO_2 transport and storage cost, and the weighted average cost of capital (WACC) on the CO_2 price necessary for the retrofit to break even are depicted in Figure 17.

The lower bound to capture plant capital cost (capex) of a 30% reduction is intended to represent the potential for significant cost reductions in capture plant following the deployment of demonstration plants in the early 2020s, in line with estimates from the developers of both the Boundary Dam and Petra Nova retrofit projects for second-generation retrofits. Such cost reductions are not dependent on advances in capture technology, but associated with process optimisation and reduced contingencies, improvements in supply chains, and off-site manufacture of plant components. On the other hand, some of these factors will have already been accounted for in the Shell Cansolv cost estimate underlying the capital cost used in this study, and manufacturing costs in China are projected to rise, so the actual cost reductions available may be more limited. Variation in capture plant cost has the strongest effect on the break-even CO_2 price of the parameters considered with an elasticity of 0.6. It will therefore be crucial to minimise potential project escalation, and counter rising labour costs in China with process cost optimisation and stream-lining manufacturing through modular production and economies of scale.

The consideration of increased transport and storage (T&S) costs (up to 200 CNY/t (20 US$/t)) reflects power plant retrofits which could be located further from storage sites (requiring longer pipelines), or which are making use of lower quality storage (eg poorer injectivity). Whilst an average T&S cost of 10 US$/t (66.7 CNY/t) is widely used in the literature for international CCUS cost estimates, there is a significant degree of uncertainty about true transport and storage costs in China, and estimates of up to 30 US$/t can be found in the literature (Li and others, 2011; Dahowski and others, 2013; Singh and others, 2018). Owing to the large volumes of CO_2 processed from a large power plant of this size, fairly small changes in the transport and storage cost can have a significant effect on project NPV. The effect of T&S cost on the break-even CO_2 price shown in Figure 17 yields an elasticity of 0.4. However, the T&S cost is much more likely to vary within the depicted range (10–20 US$/t) than capex (which is very unlikely to double), so it is also likely to have a more significant effect on retrofit viability.

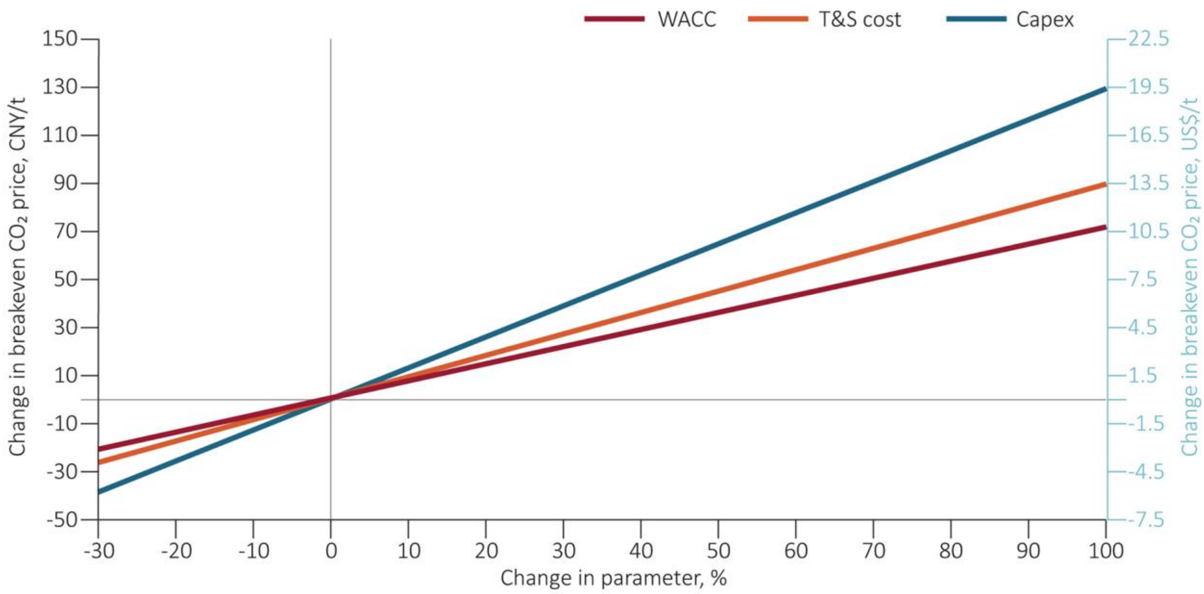


Figure 17 The effect of varying weighted average cost of capital (WACC), capture plant capex, and transport and storage cost on the CO_2 price required for the retrofit project to break even

In the baseline case, the financing of the capture plant is modelled according to a debt ratio (0.8) and interest rate (4.9%) typical of a current power plant investment in China (Singh and others, 2018). This is intended to reflect the relatively low risk of investment in a CCUS retrofit under conditions where appropriate incentives make the project commercially viable for the power company, and represents a 'best-case' scenario. However, as the Chinese economy recovers over the next five years, interest rates are projected to increase by over one percentage point in 2020 (Trading Economics, 2018b). Furthermore, the dependence of CCUS projects on changeable climate policy and carbon pricing may reduce the appetite of commercial lenders for such an investment, even when sufficient incentives are present; this may necessitate higher proportions of equity financing and an associated increase in the cost of capital. Such an increase reduces the present value of future cash flows, and requires greater incentives to pay back the initial retrofit investment. WACC has less of an effect on project NPV (and therefore break-even CO_2 price), with an elasticity of 0.33, but there is some potential for it to approach the upper end of this analysis (11%) in a low debt ratio and high interest rate scenario.

3.2.5 Increasing CO_2 price

The CO_2 prices used in the analysis above can be regarded as representing average CO_2 prices over the lifetime of the retrofit project. In reality, as depicted in the projection in Figure 5, the CO_2 price is more likely to increase in a roughly linear fashion, at least for the years following the introduction of the national ETS. Figure 18 shows cash flows for a scenario in which the CO_2 price starts at 100 CNY/t (15 US$/t) in 2025 and increases by 8 CNY/t (1.2 US$/t) annually – this is slightly lower than the annual increase projected in the annual stakeholder survey (Slater, 2018). At this rate, small additional incentives of 10% of the CO_2 sold to EOR and a 4.2% increase in electricity tariff are required to break even. An annual increase of almost 12 CNY/t (1.8 US$/t) would be required to break even in the absence of other incentives (*see* Figure 19 in Section 3.2.6).

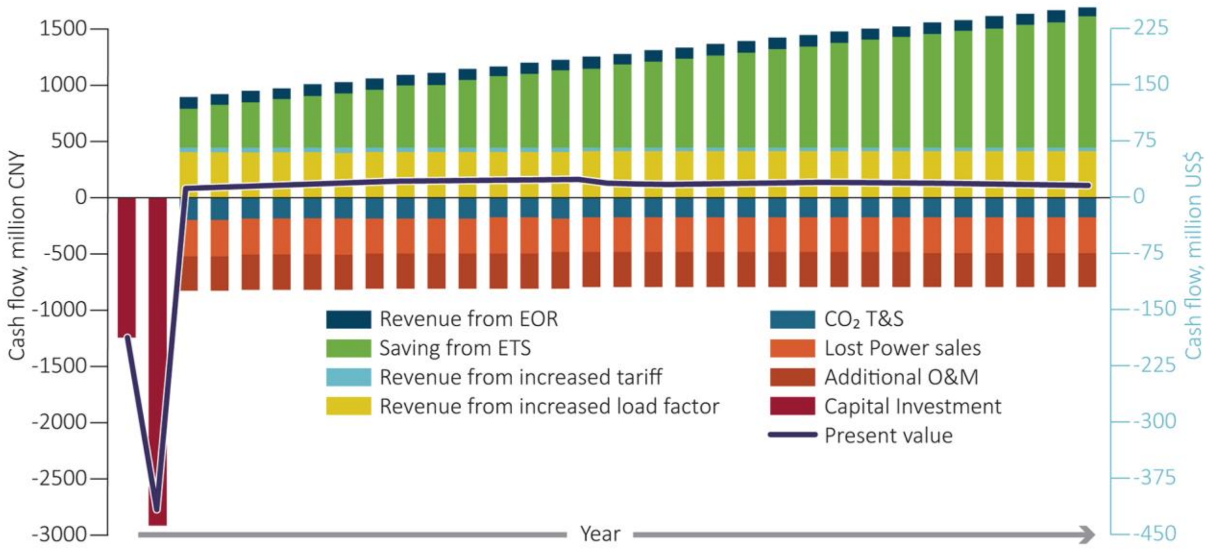


Figure 18 Cash flows and present value for a break-even retrofit project with a linearly increasing CO_2 price

3.2.6 Delaying retrofit in an increasing CO_2 price scenario

For any of the profitable steady-state retrofit scenarios described above, delaying retrofit of the power plant can only lead to a reduction in net present value, as the operation of the capture plant is curtailed by the closure of the power plant in 2055 (a conservative 40-year lifetime). However, in the more realistic scenario of gradually increasing CO_2 price, it may be more profitable to delay the retrofit. A thorough analysis of the value of delaying such an investment decision could make use of a real options method, which would place a value on the flexibility retained in waiting to invest in CCUS when uncertainty in future incentives and costs is present (Rohlfs and Madlener, 2010b; Liang and others, 2010). The straight-forward NPV analysis applied here can nevertheless provide some insight into the optimum time to invest. For the purposes of comparison, analysis of the NPV of an investment decision delayed to 2030 is treated as incurring no net change in power plant cash flows until construction of the retrofit project, so the main effect is to reduce the project lifetime and more heavily discount project cash flows (both costs and income). Figure 19 shows the increase in project NPV with increasing carbon price growth rates for retrofits in 2025 and 2030, indicating that the delayed investment actually yields higher NPVs for all positive growth rates, and a lower growth rate is therefore required to break even. This is a result of the much greater contribution of the early year cash flows to the NPV, meaning that higher carbon prices in the initial years of operation easily counteracts the extended lifetime of the earlier retrofit. This effect becomes less significant as the electricity tariff for the CCUS plant is increased, but the delayed investment retains its value under larger growth rates. The figure shows that under a 40% increase in tariff for CCUS plants, a retrofit in 2025 is more profitable for CO_2 price growth rates of around 10 CNY/t.y (1.5 US$/t.y). Whilst this comparison suggests a degree of value in waiting for CO_2 prices to increase further before investing in CCUS (in the absence of other incentives), it does not take into account the impact of additional regulation which could encourage or require earlier retrofit, such as the emissions intensity limits imposed on the larger power companies.

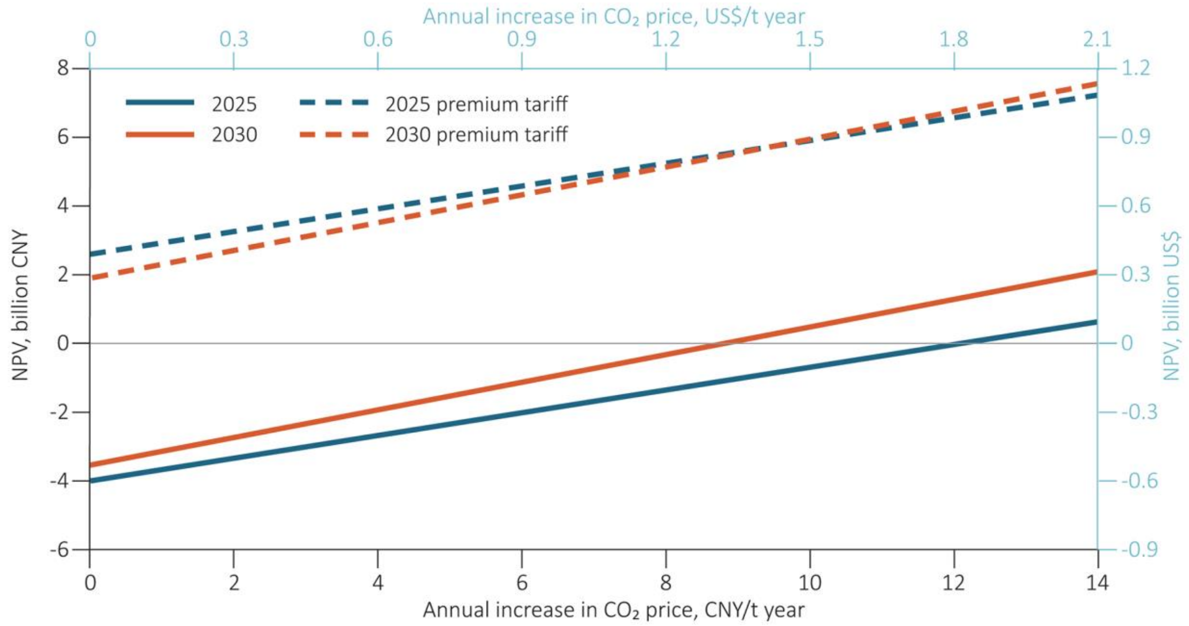


Figure 19 The variation in NPV of retrofit projects for different linear growth rates in CO_2 price, shown for investment in 2025 and 2030 (baseline parameters) and with a premium CCUS tariff of 40% above the unabated coal tariff

3.3 COST OF ELECTRICITY

Levelised cost of electricity is a widely used metric for comparing the generating costs of different power sources, often as a means of determining the optimum energy mix for a country's power supply, or the best-value source of low-carbon power. However, with the rapid growth of intermittent renewable energy (wind and solar power) in some regions, the limitations of LCOE have increasingly been recognised, as it fails to differentiate between the value to the grid of dispatchable generating capacity compared to intermittent sources. As the proportion of variable renewable energy sources on grids increases, the value of dispatchable power plants in providing back-up generation increases, but is not captured by LCOE and may not be fully compensated by existing energy markets. For this reason, many countries have introduced or are developing capacity markets, which provide payments for secure grid capacity, and there is growing value in existing markets for grid balancing services. Despite these limitations, LCOE can still be a useful indicator of the generating cost of CCUS retrofits, and one means of comparison with other low-carbon sources. A number of prior studies have estimated the LCOE of new-build CCUS plants in various regions (NETL, 2015; IEAGHG, 2014, 2018). However, placing a total cost of generation on a retrofit project is less common, and can be subject to varying assumptions, primarily regarding the treatment of the power plant capital (IEAGHG, 2011; Singh and others, 2018). For this analysis the investment in the power plant is treated as a sunk cost which should have no influence on future business decisions, following the approach of IEAGHG (2011). This yields lower LCOE than new-build CCUS plant, but is a real reflection of the cost savings to be obtained in making use of existing generating assets. LCOE for unabated and retrofitted coal plants at different load factors are shown in Figure 20; the non-baseline case of 75% load factor for an unabated plant is included, in order for the change in utilisation not to obscure the cost increase, and no CO_2 price is included. The LCOE of 426 CNY/MWh (64 US$/MWh) for the baseline (75% load factor) retrofit case represents a 52% increase over the low load factor unabated plant, or a 61% increase over an unabated plant operating at the same load factor. Although this is a significant increase over the unabated plant cost, it is still a highly competitive value for low-carbon generation in China. The average electricity tariff received by Huaneng Group's wind farms in 2017 is also shown for comparison. The breakdown of cost contributions to the baseline retrofit LCOE is shown in Figure 21, highlighting the dominance of fuel cost which is typical of coal plants in China. Whilst other operating costs are a minor factor, CO_2 transport and storage costs are clearly a major cost component – of similar magnitude to the capital cost over the plant lifetime.

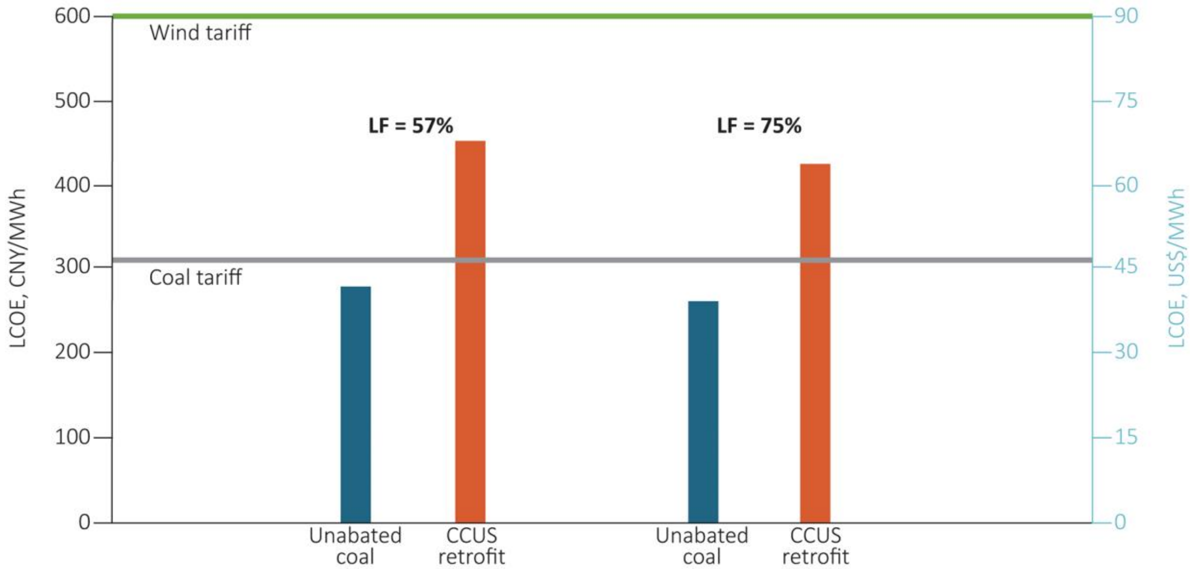


Figure 20 LCOE for unabated coal plant and CCS retrofits at different load factors, showing average coal tariffs (China Energy unit average for 2018) and wind power tariffs (Huaneng wind fleet average for 2017) for comparison

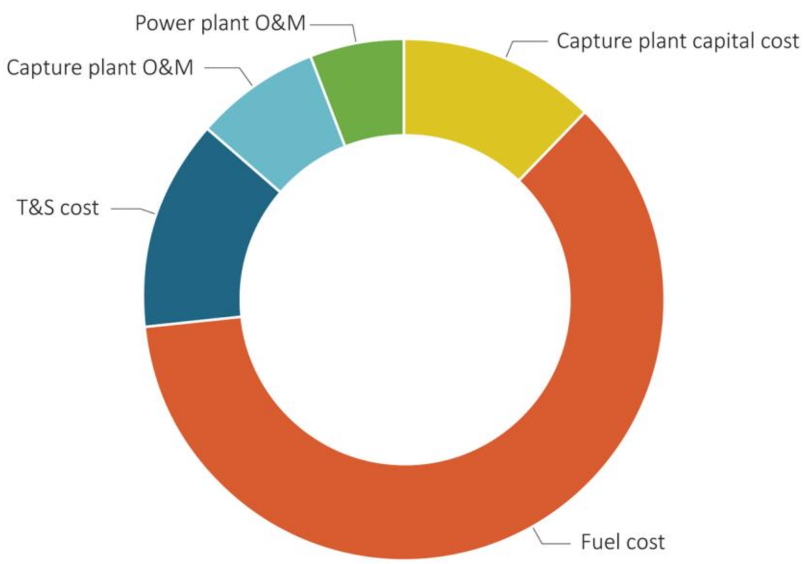


Figure 21 The breakdown of cost contributions to the LCOE for the baseline retrofit case

For further comparison, recent IEA projections to 2040 for the LCOE of wind, solar, coal, and gas in China are depicted in Figure 22 (in US$). These data should be compared with the current analysis with caution, as they are based on different assumptions, but it can be qualitatively observed that (having achieved the majority of available cost reductions by 2025) solar and wind power in 2025 (at 417 CNY/MWh (63 US$/MWh) and 459 CNY/MWh (69 US$/MWh)) are in the same range as CCUS retrofits, while gas generation in China remains highly costly at 750 CNY/MWh (113 US$/MWh) (noting again the limitations in direct comparison of dispatchable and intermittent sources).

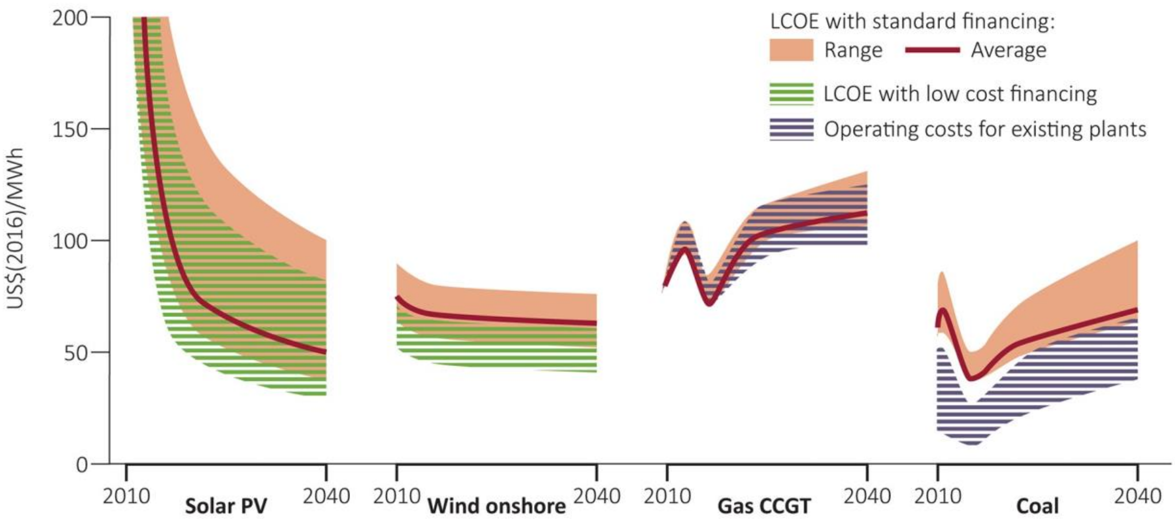


Figure 22 Projections of the LCOE of various generation sources in China from the IEA World Energy Outlook 2017, also showing the effect of low-cost financing on the cost of renewables

Figure 23 shows how the LCOE of the unabated coal plant increases with increasing CO_2 price, becoming more costly than the retrofitted plant at a price of 215 CNY/t (32 US$/t). The LCOE of the retrofitted plant also increases slightly with increasing CO_2 price, due to the 10% of uncaptured emissions. Higher CO_2 capture rates could further reduce this modest increase, but were not modelled in this analysis.

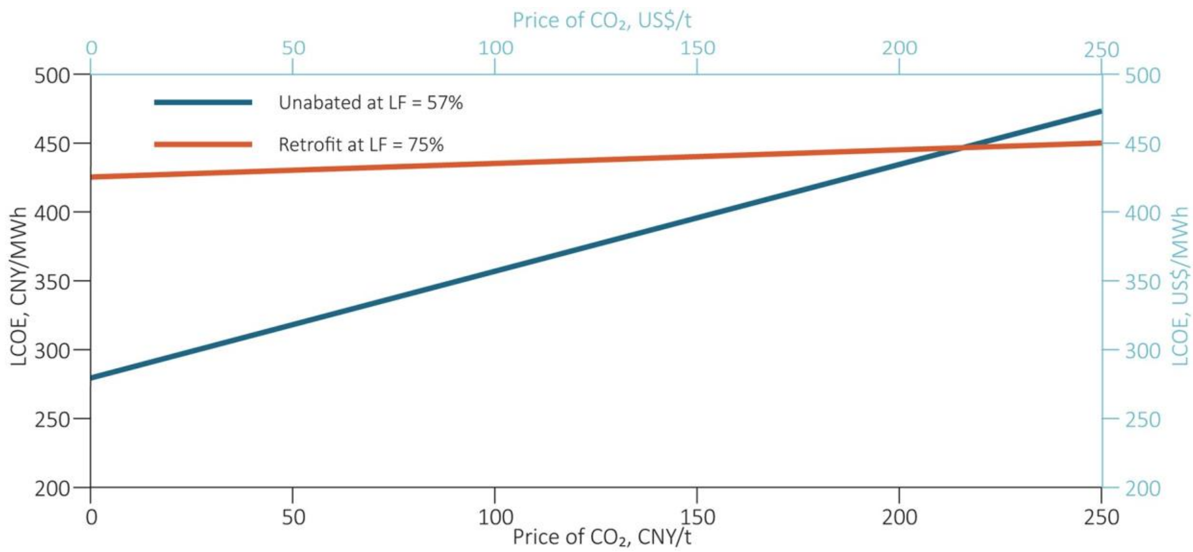


Figure 23 The effect of increasing CO_2 price on the LCOE of unabated and retrofitted coal plants

3.3.1 Sensitivity analysis

As for the NPV analysis, it is informative to investigate the effect of varying key parameters on the LCOE. Figure 24 again highlights the importance of T&S cost in the overall cost of CCUS retrofits, with the maximum anticipated case of 200 CNY/t (20 US$/t) adding 15% to the baseline LCOE. The high WACC case (10%) has the next most significant effect on LCOE, followed by the increased capex case (30% increase). Capital cost reductions of 30% would bring about only a 5% reduction in LCOE. Also examined is the effect of the coal price, showing a low-cost case which remains level at today's costs, and a higher-cost case where the cost increases linearly to a 10% higher level in 2035 than the baseline scenario (*see* Appendix 1 for details). As fuel cost is the major contributor to plant costs, these small changes have a relatively large impact on LCOE.

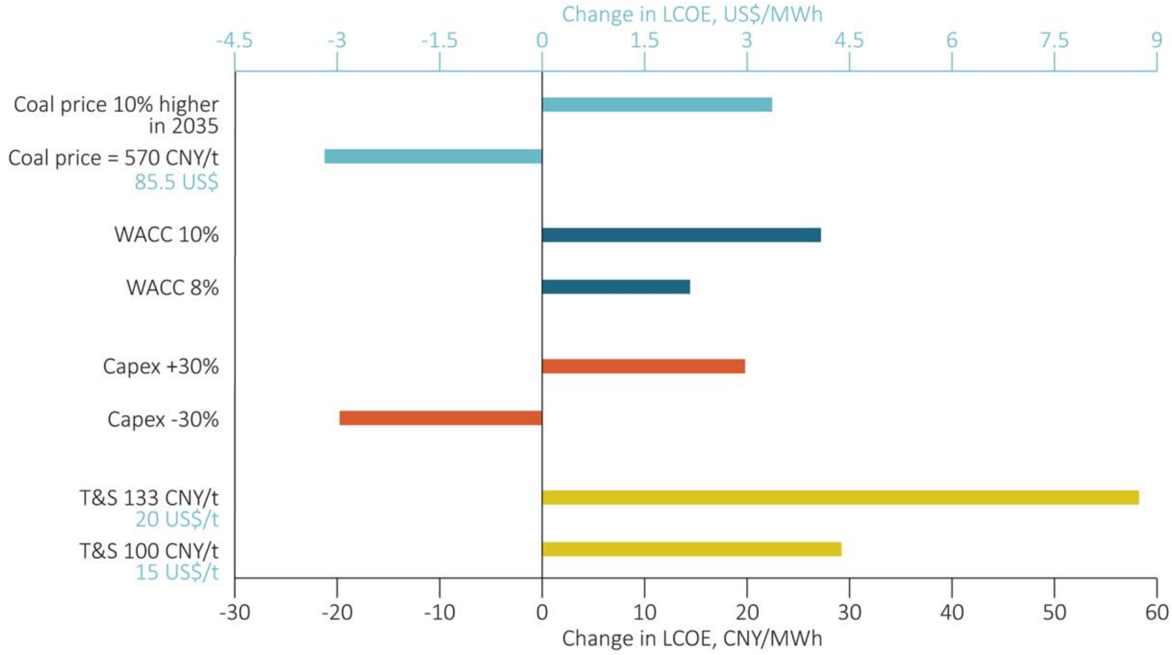


Figure 24 The effect of changes in coal price, weighted average cost of capital (WACC), capture plant capex, and transport and storage (T&S) cost on LCOE

3.3.2 Cost of CO_2

LCOE of low-carbon energy sources is routinely used to derive a cost of CO_2 avoided, which is a measure of the CO_2 savings which can be achieved from the additional expenditure (*see* Appendix 1). In this instance, the emissions of the retrofitted plant are compared to those of the unabated baseline coal plant, operating at 57% load factor (Figure 25). For carbon capture technologies, a related metric is the 'cost of CO_2 capture', which uses the increase in LCOE relative to the unabated plant to derive a cost for each tonne of CO_2 captured by the CCUS plant. For assessing the cost-effectiveness of climate impact, this is a less informative value, as it fails to take into account the remaining emissions of the CCUS plant, and thus the effect of capture rate and the plant energy penalty in the CO_2 mitigation impact of the investment – it is nevertheless included in Figure 24 for comparison. The baseline cost of CO_2 avoided obtained in this analysis is 215 CNY/t (32 US$/t), which is remarkably low for power-plant CCUS, and partly reflects the favourable nature of the case considered: a large power plant with a long remaining lifetime and relatively low investment costs for the capture plant (by international standards). The increase in load factor in the baseline retrofit case partly compensates for the energy penalty incurred by the capture plant, further reducing costs – the reduced load factor case (57%) leads to a 18% increase in cost of CO_2 avoided.

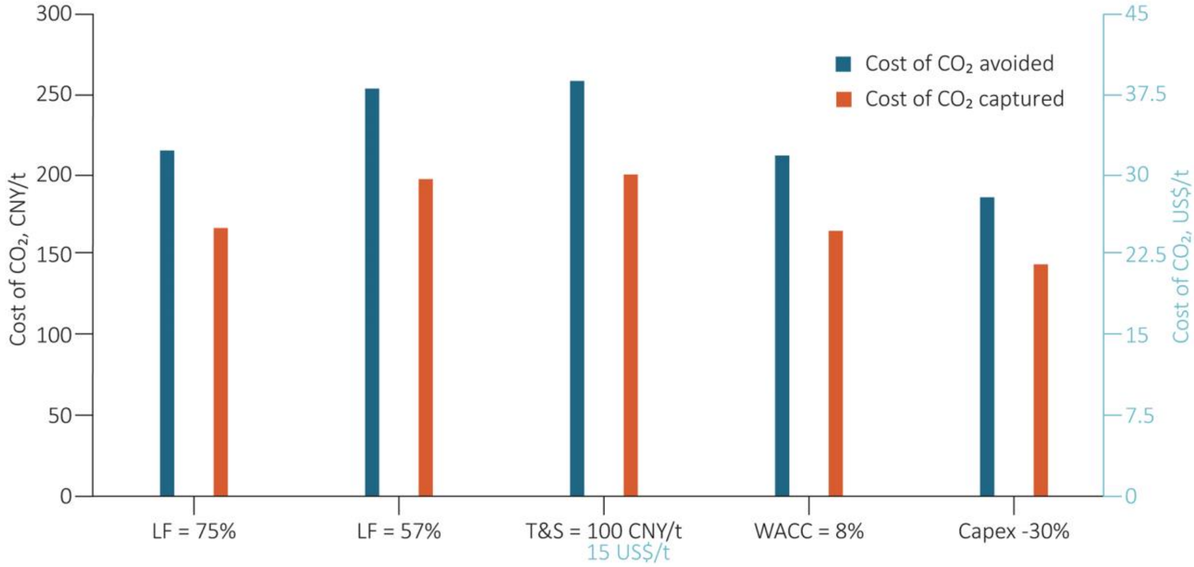


Figure 25 The cost of CO_2 avoided and captured for various CCUS retrofit cases in 2025

4 OUTLOOK FOR CCUS IN CHINA

In the last five years, China has emerged as a major player in the global development of CCUS, having built up a high level of research expertise and technological capacity. This has included the operation of several significant power plant-based capture pilots, small-scale CO_2 storage tests associated mostly with EOR, and more recently, commencing construction or operation of three larger-scale EOR-based projects based on relatively low-cost capture sources. Many of these projects have been promoted or led by provincial governments and state-owned enterprises, following direction from the NDRC to work towards CCUS demonstration. Whilst the large power companies have driven investment in new capture technologies and pilot plants, the state-owned oil companies have played the major role in integrated CCUS project deployment to date, driven by the value of CO_2 for EOR and their greater sub-surface expertise. The development of EOR and an associated CO_2 capture and transport infrastructure looks set to continue in the coming years, but greater development of dedicated storage in saline aquifers and wider deployment in the power sector will ultimately be required to deal with the scale of CO_2 emissions which need to be captured in the 2°C scenario – ideally reaching commercial operation before 2030. However, as CCUS is not required to meet the country's current decarbonisation targets for 2030, high-level political support for pushing power sector deployment beyond a small number of demonstration projects in this period appears to be uncertain. The state-owned power companies have accordingly shown limited appetite for further investment in CCUS, preferring to maintain a level of technological capacity in the technology in preparation for future, more stringent climate policies.

The cost analysis presented in this study demonstrates that, given appropriate policy actions commensurate with the support provided for other low-carbon technologies, application of CCUS to China's recently built, large and efficient coal units can realistically become a commercially viable prospect for power companies in 2025. The national emissions trading system (ETS) to be introduced in the power sector from 2020 should provide an important foundation for creating economic value in retrofit projects, particularly if the CO_2 price rises steadily through the 2020s as projections indicate. However, with an estimated break-even CO_2 price of greater than 200 CNY/t (30 US$/t) for this retrofit case study, this mechanism is unlikely to lead to deployment alone. Particularly for early commercial projects, the uncertainty in future CO_2 prices also poses an investment risk, and the exact mechanism by which CCUS projects could derive revenue from the ETS is yet to be developed. A premium electricity tariff for CCUS-equipped power plants is the most effective tool for providing a financeable revenue stream for retrofit investment, ideally in combination with some degree of priority dispatch to ensure CCUS power plants secure greater utilisation than the current low load factors for unabated coal. In combination with a realistic future CO_2 price of 100 CNY/t (15 US$/t), a 25% increase in the average benchmark coal power tariff is required for the case study CCUS project to enter profitability. This is still well below the tariffs currently received by solar and wind power generators (>550 CNY/MWh (>83 US$/MWh)). The highly competitive nature of this dispatchable low-carbon energy source is further reflected by LCOEs in the range of 405–480 CNY/MWh (61–72 US$/MWh) across all sensitivity cases – comparable to projections for wind and solar power generation in China in 2025, and costs of CO_2 avoided of 210–250 CNY/t (31–38 US$/t). Whilst it is vital to limit energy cost increases in China, where retail electricity prices are high by international standards, supporting CCUS retrofits as a dispatchable, low-carbon source of power should be a relatively cost-effective complement to the ambitious plans for renewable energy deployment. Also of note in this analysis is the minimal impact of delaying investment in CCUS retrofits, with a delay to 2030 potentially favourable in a scenario where CO_2 prices are expected to increase. This gives further support to the need for an alternative driver such as premium electricity tariffs, and the recently introduced cap on power companies' overall emissions intensity could also create greater urgency in CCUS deployment.

Revenue from CO_2-based EOR may also provide additional income to retrofit projects in suitable locations, but large power plants may not be able to secure offtake for the majority of their CO_2 output when competing with other capture sources for limited demand in an increasingly crowded market. Nevertheless, the EOR industry can play a greater role in developing CO_2 infrastructure and storage expertise within China (principally among the state-owned oil companies and associated service providers), with some proposed EOR projects already planning the first dense-phase CO_2 pipelines. Bringing this growing expertise to bear on the development of dedicated storage infrastructure is a major barrier to greater CCUS deployment, and the major source of investment uncertainty for prospective projects. The implementation of a sound regulatory regime for CO_2 storage, stronger financial backing for characterisation of promising storage sites, and development of business models by which power companies and storage site developers can interact are therefore important areas for government direction.

In the current Chinese context of exceptionally low coal power plant capital costs, the capture plant retrofit can be regarded as requiring a level of investment of the order of that of the initial power plant investment, resulting in a new low-carbon plant with higher operating costs and lower efficiency. For the case study considered in this report, the high initial efficiency of the USC plant means that the retrofitted efficiency (34.8%) is still close to the global average coal plant efficiency, and the 'lost' coal cost associated with the capture energy penalty is minimised. Given China's relatively high fuel costs, this is a key factor, both in economic viability and improving the image of coal power-based CCUS with policy-makers. The energy penalty cost can also be partly offset by the prospect of higher load factors. CO_2 transport and storage costs and capture plant capital represent the next most significant cost factors, and both face some future uncertainty, but can both reasonably expect to see reductions as CCUS becomes more established. The long remaining lifetime of the power plant in this case study also minimises the impact of the initial retrofit investment on levelised costs. This plant may therefore be considered a 'best case' for CCUS deployment in the power sector, but it is by no means unrepresentative of China's coal fleet, which includes at least 58 GW of similar USC plant with access to storage within 250 km, nearly all of which were commissioned in the last ten years. Similar costs should be achievable for the 78 GW (total) of 660 MW class USC units, and the available capacity of such units will grow as China continues to replace ageing, inefficient plant. Future regulation could ensure that new coal plants are made 'capture ready', primarily by locating them close to the best CO_2 storage capacity in the north and west of the country, which would also give ready access to domestic coal sources. The fast-growing ultra-high voltage grid should help enable these developments, which would be far from population centres on the coasts.

China's huge, recently built coal fleet of similarly sized units represents an ideal development ground for optimising CCUS technology and reducing costs through mass production. Following the model of rapid deployment, 'learning by doing', and associated cost reductions achieved for domestically developed energy technologies such as USC coal plants, solar photovoltaics, and wind power, China could realistically proceed to retrofit a significant portion of the country's coal fleet by 2035, should adequate policy incentives for CCUS be introduced. As has already occurred for other energy technologies, this manufacturing capability and technological expertise could then feasibly be exported to other major coal-using countries, particularly amongst the developing economies of Asia, and represent a major growth industry for the country.

The need for CCUS will become more evident as China plans its climate strategy to 2050, as the decarbonising value of additional renewables on the grid diminishes, and a source of low-carbon dispatchable power becomes vital to maintaining a reliable power supply. Options for decarbonisation beyond 2030 will be further constrained by the fact that (contrary to the approach seen in some countries), there is currently no political indication that the fleet of large, efficient coal units built up over the last decade could see premature closure. Even if widespread deployment of CCUS is indeed delayed until 2030, there remains a pressing need to progress large-scale, power plant-based demonstration projects in China and begin developing transport and storage infrastructure from 2020. Suitable policies and incentives to create a favourable regulatory and commercial environment for CCUS deployment in the power sector must therefore be included in the 14th five-year plan if China's initial progress in CCUS is to be maintained. For power sector CCUS to reach a commercial phase in an earlier timeframe, as examined in this report, the requisite political backing may ultimately need to stem from an increase China's emissions reductions ambitions within the framework of the Paris agreement. Such a commitment could be accompanied by the explicit inclusion of large-scale CCUS deployment in the country's updated NDC.

However, such an acceleration in climate and CCUS policy is unlikely to occur without strong signals from the rest of the international community, and a marked recovery in plans for large-scale CCUS deployment in other regions. Despite previous bilateral initiatives with China having largely failed to yield large-scale demonstration projects, such international collaboration remains an important means of sharing technical expertise and experience with the non-technical challenges facing CCUS deployment. In this respect, foreign governments and international stakeholders can play an important role in furthering the rapid decarbonisation of China's coal power fleet.

5 APPENDIX 1: METHODOLOGY AND DATA SOURCES

The first part of this cost analysis assesses the decision to invest in CCUS retrofit based on net present value (NPV). This method determines the sum of the present value of net cash flows (C_n) in each year (n) of project operation, with discounting of future cash flows according to the formula:

$$NPV = \sum_n \frac{C_n}{(1+WACC)^n}$$

where WACC is the investing company's weighted average cost of capital. A positive NPV indicates the project is a profitable investment decision.

A number of studies have estimated the costs for new build or retrofitted coal plants with CCUS in China, yielding a broad range of possible costs according to the various assumptions used (Zhao and others, 2008; Liang and others, 2010; Dave and others, 2011; Li and others, 2011; IEAGHG, 2011, 2018; Wu and others, 2013; Gibbins and others, 2013; ADB, 2015; IEA, 2016a; Hu and Zhai, 2017; Singh and others, 2018). These studies have either costed plant equipment based on detailed engineering studies, or drawn on real investment data for power plants, often estimating the cost of the capture plant based on a proportion of power plant cost. Hu and Zhai provided a useful summary of CCS cost estimates for China, adjusted to 2013-year dollars (Hu and Zhai, 2017). Power plant capital costs are usually in the range of 600–700 US$/kW (4100–4800 CNY/kW) and additional costs for capture plant are often assumed or calculated to be around 60% of the power plant cost (Li and others, 2010; Wu and others, 2013). Notably lower values for capture plant capex are found in ADB (2015) (new build) and Gibbins and others (2013) (retrofit) at around 22% of the original plant cost, while an added cost of 80% is found in the recent NICE analysis of retrofits (Singh and others, 2018).

For this analysis, operating and capital cost data for the capture plant are taken largely from Case 8b in IEAGHG (2018), which conducts a detailed engineering and cost analysis of a new 1000 MW USC unit with and without post-combustion capture (capturing 90% of the total CO_2 emissions). The cost data for the capture unit in this study is provided by Shell Cansolv, and is based on two trains of CO_2 capture and compression equipment equivalent to 500 MW each. Details of the breakdown of capital and operating costs for this equipment are kept confidential by the manufacturer. The IEAGHG study identifies its costs estimate accuracy as in the range +35%/-15%, in accordance with Class IV of the AACE International Cost Estimate Classification System.

In IEAGHG (2018), the capital cost of the capture plant and CO_2 compressors is only provided as a 'total plant cost' (TPC) item, which includes the cost of EPC and contingencies. In the current study, this amount is converted to 'total capital requirement' (TCR) through the addition of start-up costs, working capital, interest during construction and owner's costs largely in accordance with the method in IEAGHG (2018), but with reduced owner's costs of 5% of TPC, based on input from Chinese stakeholders. An additional 2% of the power plant capital cost (TPC) is added to account for modifications to the power plant itself in a retrofit case. It should be noted that, whilst the added cost of capture plant as a proportion of power plant cost in the IEAGHG study is fairly typical at 58%, it is nearly equivalent to the power plant cost used in the present work, which is obtained directly from China Energy (Xu, 2018). This estimate may therefore represent a conservative, high-cost case for 2025, particularly as the capital cost of capture plant is projected to decrease significantly as manufacturers progress beyond the demonstration stage. To represent potential cost reductions, a lower-cost case at 30% lower TCR is also considered. Construction of the capture plant takes place over two years (with 30% of capital expenditure in the first year and 70% in the second year), depreciation of the plant is scheduled over 15 years, and the capture plant is assumed to operate until the end of the 40-year lifetime of the power plant.

China Energy also provided the capital cost of 130.83 million CNY for the planned 150 ktCO_2/y demonstration project at Jinjie power plant which can be usefully compared with the capture plant estimate used in this study using a power-law scaling rule. Based on an increase in processed CO_2 of around 30 times, the scaling exponent is 0.95, again indicating that the cost estimate from the IEAGHG study used may be conservatively high (exponents of 0.7–0.8 are commonly used in scaling equipment costs).

Operating and maintenance costs can be separated into fixed costs, comprising labour, maintenance, insurance, and taxes, and variable costs comprising fuel and reagents. In Case 8b in IEAGHG (2018), the capture plant is allocated 10 workers at an annual salary of 80000 CNY/y (12000 US$/y) – in this analysis, 20 capture plant workers are assumed as a more conservative estimate, based on stakeholder consultation. According to standard assumptions for the power industry, additional maintenance costs are estimated at 2% of the total capture plant cost, of which half is maintenance labour and half is materials. Additional labour costs for administration and overheads are then calculated at 50% of the total direct labour cost (including the maintenance labour cost). Annual insurance costs are calculated at 0.25% of the total plant cost, and property taxes are 0.8% of the net asset value of the plant (this eventually falls to zero as the plant depreciates).

The additional cost of capture solvent and other chemicals such as NaOH (for SO_2 polishing) are only provided by Shell Cansolv as an annual figure in IEAGHG (2018), together with an annual cost of solvent disposal. These costs (associated with a 90% load factor) are converted to load factors used in the current study on a pro rata basis. The cost of CO_2 transport and storage will depend on the location of the plant, with studies such as IEA (2016a) and Dahowski (2013) finding typical values in the range of 5–15 US$/t, depending on the distance to storage and the quality of the storage site. This analysis therefore uses 10 US$/t (66.7 CNY/t) for the baseline case, and 15 US$/t as a higher cost case.

The energy penalty of the capture plant is calculated according to IEA (2016a), which assumes the capture solvent has a thermal regeneration energy of 2.4 GJ/tCO_2, and converts this to an equivalent loss of electrical output from the plant using a 'coefficient of performance' factor of 4 (IEA, 2016a). The capture process also consumes 100 kWh/tCO_2 for CO_2 compression and 20 kWh/tCO_2 for other auxiliary power requirements such as solvent pumping and induced draught fans. The resulting energy penalty closely matches the one derived by IEAGHG (2018). For the NPV analysis, this loss in electrical output is converted to a loss in income based on the average electricity tariff for China Energy coal plants in the first half of 2018 (311 CNY/MWh (47 US$/MWh).

To attempt to balance these costs associated with the capture plant and achieve a positive NPV for the retrofit, a range of potential policy-based CCS incentives are introduced and varied through the required range. The baseline CO_2 price in the national ETS is set at 100 CNY/t (15 US$/t), based on the projection shown in Figure 5, which is also in agreement with carbon price assumptions in the IEA World Energy Outlook 2017. Additional value from CO_2 may also be gained from sales to EOR operators; however, to account for the fact that the power plant will be competing with other capture sources such as chemical plants, this value is set at 30 US$/t (200 CNY/t), which is typical of the capture costs achievable for such sources, and not much greater than the CO_2 prices which currently allow for profitable EOR operation in China (Wei and others, 2015). The proportion of CO_2 sold to EOR is then varied in the analysis. The potential benefits of a 'low carbon premium' electricity tariff for a CCUS plant and the increased operating hours which could be derived from priority dispatch are also considered. The baseline capacity factor for the retrofitted power plant is set at 0.75, assuming a degree of priority dispatch for low-carbon plant, and a lower limit of 0.57 is based on the average capacity factor for China Energy 1000 MW units in the first half of 2018.

The baseline case considers typical project financing parameters for a power project in China, giving a weighted average cost of capital of 5.52%. To represent the possibility of a greater proportion of equity being necessary in accordance with the higher risks of a CCS retrofit, a higher WACC case of 8% is also considered.

In addition to the NPV analysis, the levelised cost of electricity (LCOE) for the non-retrofit and retrofit cases is calculated, based on the net present value method applied by the UK government and others (Mott MacDonald, 2010). This method uses the net present value of all cash flows for the power project (including capital costs) divided by the net present value of electricity generated, according to the formulae (where *n* is each year of operation):

$$LCOE = \sum_n \frac{NPV\ of\ total\ costs}{NPV\ of\ electricity\ generation}$$

$$NPV\ of\ total\ costs = \sum_n \frac{total\ capex\ and\ opex\ costs}{(1+WACC)^n}$$

$$NPV\ of\ electricity\ generation = \sum_n \frac{net\ electricity\ generation}{(1+WACC)^n}$$

Cost data for typical 1000 MW USC units are obtained from China Energy, including capital cost (based on half the standard investment in 2 x 1000 MW units), labour costs (based on 115 full-time employees), and reagent costs (limestone, ammonia, and makeup water) (Xu, 2018). The initial coal cost is taken at 570 CNY/t (86 US$/t), based on the 2018 average price of the CCI 5500 composite index, which reflects the composite price level of 5500 kcal/kg coal traded at three ports on the Bohai Sea (Sxcoal, 2018). It is then linearly increased to 627 CNY/t (94 US$/t) in 2035, according to the cost projection for coastal China coal in the IEA World Energy Outlook (IEA, 2017b), and remains constant at this value for the remainder of the plant lifetime. In the sensitivity analysis, a lower-cost case keeps the coal cost constant at 570 CNY/t (86 US$/t), whilst a higher-cost case increases the cost linearly to 690 CNY/t (104 US$/t) in 2035. Following the assumption of an IEAGHG study on retrofit costs, the capital cost of the power plant itself is not considered in the case of the retrofitted plant, as it can be regarded as a 'sunk' cost which should have no bearing on future business decisions (IEAGHG, 2011). All costs are in 2016 CNY, converted using average 3rd quarter 2018 exchange rates where necessary. Economic and technical parameters for the case study are summarised in Table 3 (in Section 3.1) and Table 4.

The difference in LCOE between capture and non-capture cases is used to determine a cost of CO_2 capture and cost of CO_2 avoided, according to the formulae:

$$Cost\ of\ CO_2\ captured = \frac{LCOE\ with\ CCS - LCOE\ without\ CCS}{CO_2\ captured}$$

$$Cost\ of\ CO_2\ avoided = \frac{LCOE\ with\ CCS - LCOE\ without\ CCS}{CO_2\ emissions\ without\ CCS - CO_2\ emissions\ with\ CCS}$$

TABLE 4 BASELINE COST AND FINANCIAL PARAMETERS	
Capital cost parameters	
Power plant capital requirement (million CNY)	4206.9
Capture plant capital requirement (million CNY)	4121.1
Depreciation schedule (years)	15
Debt ratio	0.8
Interest rate	4.9%
Return on equity	8%
WACC	5.52%
Power plant lifetime (years)	40
Tax rate	25%
Fixed operating costs	
Worker salary (CNY/year)	80000
Power plant workers	115
Capture plant workers	20
Maintenance	2% (1% for materials, 1% for maintenance labour)
Overhead and administration labour multiplier	50% of total direct and maintenance labour cost
Insurance	0.25%
Property tax	0.8%
Variable operating costs	
Coal (CNY/t)	570 increasing to 627 in 2035
Limestone (CNY/t)	155.46
Ammonia (CNY/t)	2090.1
Makeup water (CNY/t)	4.5 and 2.99 (in different proportions)
Capture solvents (CNY/tCO_2)	12.8
Capture solvent disposal (CNY/tCO_2)	1.43
CO_2 transport and storage (CNY/t)	66.7
Other baseline parameters	
Wholesale electricity tariff (CNY/MWh)	311
Capacity factor without CCS	0.57
Capacity factor with CCS	0.75
CO_2 price in ETS (CNY/t)	100
CO_2 price for EOR (CNY/t)	200

6 APPENDIX 2: CCUS RETROFIT TECHNOLOGY AND 'CAPTURE READY'

There are currently only two large-scale CCUS projects operating on coal power plant – both of these are retrofits, and both employ post-combustion capture technology based on a form of amine-based solvent to remove CO_2 from flue gases. Commissioned in 2014, the CO_2 capture plant at Saskpower's 120 MW (160 MW without capture) Boundary Dam 3 unit in Canada was designed by Shell Cansolv (IEAGHG, 2015). This was followed in early 2017 by NRG's Petra Nova project at the WA Parish power plant in Texas, which employs Mitsubishi Heavy Industries (MHI) KS-1 solvent technology to treat a coal flue gas slipstream equivalent to 240 MW (McMahon, 2016). Similar coal retrofit projects which progressed to a feasibility study or FEED stage before cancellation include the ROAD project in the Netherlands (using Fluor technology), the Mountaineer project in the US (Alstom technology), and the Longannet project in the UK (Aker Clean Carbon technology). Although carbon capture through oxyfuel combustion also reached an advanced stage of development as a solution for CCUS retrofit (notably, for the 100 MWth Callide project in Australia and the cancelled FutureGen 2.0 project in the USA), post-combustion capture with amine solvents has become the leading choice for any current coal retrofit project, with commercial guarantees available from several technology providers for large-scale capture plants. This process involves passing cooled flue gas through an absorber tower filled with an amine-based solvent with an affinity for CO_2. The CO_2-rich solvent is then transferred to a stripper column where it is heated with steam to release pure CO_2 for cooling and compression. Conventionally, it is envisaged that this steam will be taken from the power plant itself, via a connection to the crossover pipe between the intermediate pressure (IP) and low pressure (LP) turbines. This approach is adopted at Boundary Dam 3, which uses uncontrolled extraction of steam from the crossover pipe, but has benefitted from the fact the turbines were replaced in the retrofit with the steam cycle optimised for capture plant integration. Conversely, the Petra Nova project is notable for employing a separate gas-fired turbine to provide steam to the capture plant, as well as power for the pumps, fans, and other auxiliary requirements of the capture plant and CO_2 compressors. The loss of steam flow to the LP turbine and the power required for CO_2 compression represent the major energy penalties imposed by the capture process and are estimated to amount to a loss of 8–10% points in power plant efficiency. Some reduction in current efficiency penalties is anticipated through improved solvent design and greater thermal integration with the power plant.

The adaptation of most existing coal plants for CCUS retrofit is technically feasible, but there are a number of considerations unique to retrofits which are not faced by new-build projects. These include availability of space at the plant, provision of additional cooling duty, and how best to thermally integrate the power plant and capture plant with minimal interference to the existing steam cycle or loss of efficiency. Some retrofits may also aim to retain a degree of flexibility in being able to operate with or without capture (or at intermediate capture levels), or with different capture solvents with different thermal properties. Various options for extracting steam from the existing steam cycle at the correct temperature and pressure for solvent regeneration have been identified, with efficiency penalties potentially no greater than those of a purpose-built power plant with CCUS (Lucquiaud and Gibbins, 2011; Gibbins and others, 2013). As the steam pressure at the IP-LP crossover is usually greater than that required for solvent regeneration, several designs have employed a back-pressure turbine to let down steam pressure while recovering some energy (Lucquiaud and Gibbins, 2011; NETL, 2015; Singh and others, 2018). Alternatively, a valve can be introduced to throttle the steam, but this leads to greater energy losses. Additional stages may be added to the IP turbine to reduce the outlet pressure with minimal loss of efficiency, while avoiding excessive strains on the existing turbine blading from the reduction in pressure. This approach is employed in a detailed design study for retrofit of the 300 MW Shand power plant in Canada, produced by the International CCS Knowledge Centre based on experiences from Boundary Dam 3 and using MHI capture technology (Bruce and others, 2018). The design was also optimised to achieve higher capture rates at lower power plant load factors.

There are several ways in which the retrofitted capture plant can be further thermally integrated with the power plant steam cycle. In particular, heat recovered from the CO_2 leaving the stripper column can be used for condensate heating in the power plant, thus replacing steam that would otherwise be extracted from along the LP turbine and reducing the energy penalty. The steam extracted from the crossover pipe for solvent regeneration can also be first passed through a heat exchanger to recover superheat available for feedwater heating (Figure 10) (Gibbins and others, 2013; IEAGHG, 2018).

With the largest coal power-based CCUS plant at 240 MW equivalent (Petra Nova), some scale up of the technology is required for application to larger power plants such as the one considered in this study. MHI have proposed a straight-forward modular scale-up of the rectangular absorber employed at Petra Nova (increasing in cross-section rather than height) (Yonekawa, 2017). Shell Cansolv proposed a design based on two trains of 500 MW equivalent absorbers for the 1000 MW coal plant addressed in IEAGHG (2018), but in a more recent cost analysis for the UK government, proposed a single train absorber for a 1000 MW coal plant (Wood, 2018).

The potential barriers to retrofitting existing power plants have given rise to the concept of 'capture readiness', which assesses the ease with which a plant could be retrofitted, and aims to encourage new coal plants to adopt capture-ready characteristics. Capture ready criteria can include ensuring space is available for capture plant, assessing the proximity of storage sites and water availability, and ensuring there is easy access for steam extraction (IEAGHG, 2007). Some countries, including the UK and Canada, have made capture-readiness a regulatory requirement for new fossil-fuel power plant, but in practice these countries have ceased building new coal plant of any kind. Capture-ready criteria for China have been developed by the UK-China (Guangdong) CCUS Centre and applied in the design of units at China Resources Power's Haifeng power plant. A regulatory requirement for new coal plants to be made capture-ready was proposed by the ADB Roadmap for CCUS, but power companies are currently merely encouraged to implement these criteria in plant design. It is estimated that steam cycle modifications to allow for future retrofit should represent from 0.5–3% of total plant cost (depending on the complexity of the retrofit envisaged) (Gibbins and others, 2013).

A preliminary assessment of the suitability for retrofit for over 100 large power plants in China, based on location, space, efficiency and pollutant controls, found that only 19% had a high potential for retrofit (Li and others, 2011). On the other hand, an IEA analysis of 560 GW of coal capacity found that 310 GW (55%) were suitable for retrofit, based on factors such as proximity to storage, plant age, and pollutant controls (available space was not considered) (IEA, 2016a).

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