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The Techno-economic Prospect of Retrofitting Natural Gas Combined Cycle Power Plants in China: a case study of CCGT power plants in Huizhou and Shenzhen, Guangdong

Jia Li[a], Xi Liang[a], Jon Gibbins[a], Mathieu Lucquiaud[a], David Reiner[b], Di Zhoud[c]

Abstract—**Half of the gas power plants in Guangdong in the Pearl River Delta of China have high retrofit potential. We implement a detailed case study of retrofitting an existing CCGT power plant located on Daya Bay in Huizhou city in Guangdong. Using a GIS (geographical information system) base analysis, all three power plants demonstrate credible routes to transport CO2 to the Pearl River Basin for storage in a sub-seabed saline formation. The plant consists of two 400 MW units (9F turbine), running as a mid-merit plant. We also investigate the economics of retrofitting using a static analysis of the levelised cost of electricity and the cost of CO2 avoidance. In addition, we apply a stochastic cash flow model to identify the retrofitting option value in CCGT power plants. The value of the retrofit option for CCGT is found to be relatively low compared with that in large coal-fired power plants. However, a moderate investment in CCS ready in CCGT power plants can be justified in order to keep the retrofit option open. Appropriate designs of the power cycle can act as a hedge against very high carbon price scenarios.**

Keywords— **CCS; CCGT; Carbon dioxide capture, transport and storage; Retrofit; China.**

I. Introduction

Growing at an average rate of 16% per annum in the last decade, the total consumption of natural gas in China has quadrupled between 2000 and 2010 [1]. Switching from coal fired power plants to natural gas power plants began to emerge in these area [2].

The Chinese MLR [3] estimated the country has 25.08 trillion cubic metres of shale gas reserves, approximately equal to 250 times of total Chinese gas consumption in 2010. According to the Chinese Electricity Council (CEC), the total installed capacity of CCGT (Combined Cycle Gas Turbine) plants is estimated to reach 40 GW by 2015 and 50 GW by 2020 [4].

The growing trend of gas consumption is likely to accelerate, as there is increasing supply from conventional natural gas sources and the country is planning to extract exploitable gas from its significant shale-gas reserve by 2015 [2] and tougher regulations on emissions from new fossil fuel power plants has posed challenges in permit approval from National Development and Reform Commission (NDRC) for coal-fired power plants in developed area, such as Beijing, Shanghai and Guangdong.

Insofar as unabated gas generation displaces unabated coal generation, this will reduce future emissions. China has become the world’s largest greenhouse gas emitter since 2011 [5], and the government of China has attached great importance to the issue of climate change. The level of greenhouse gas emissions relates to both technology and the state of development [6] and CCS is the only promising technology to decarbonise natural gas power generation at large scale. However, there is still a lack of long-term incentives to deploy CCS for CCGT power plants at large scale. If CO2 capture cannot be fitted to new CCGT plants, that would result in perhaps 30 years (or more) of future ‘carbon lock-in’. Existing studies have found the financial benefit of capture-ready in coal-fired power plants in China is significant [7]; and a number of studies have examined the design considerations for CO2 capture from CCGT plants [8, 9, 10, 11]. However few CCS studies have yet examined the technical performance and the value of developing gas power plants in China. This analysis complements existing CCS studies on coal-fired generation in the China by investigating the techno-economic performance of retrofitting CCGT power plants with post-combustion capture technologies and identifies the gross benefit of capture ready investment.

The Pearl River Delta area in Guangdong was selected as a case study because there is strong demand for new CCGT (Combined Cycle Gas Turbine) plants in the Pearl River Delta region where electricity demand has always exceed electricity supply locally. In addition, no new large coal-fired plants have

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Jia Li, Xi Liang, Jon Gibbins, Mathieu Lucquiaud
University of Edinburgh, UK
j.li@ed.ac.uk

David Reiner
University of Cambridge, UK

Di Zhou
South China Sea Institute of Oceanology, Chinese Academy of Sciences
China

Table 1 Technical and Economic Assumption

Parameters	Unit	
Starting Operation Year		2015
Construction Period	year	3
Technical Performance		
Net Installed Capacity	MW	780
Operational Life	year	30
Net Efficiency (base plant, LHV basis)	%	52
Lifetime degradation factor	%	2
Average Load Factor (year 2-25)	%	85
Average Load Factor (year 1)	%	60
EOP (Electricity Output Penalty) for 90% CO2 Capture in 2015	kWh/tCO2	316
EOP for 50% CO2 Capture in 2015	kWh/tCO2	488
Learning Rate (EOP)	%	4
Base Plant Emission at full load	gram CO2/kWh	0.391
Emission with 90% Capture at full load	gram CO2/kWh	0.047
CO2 Avoided with 90% Capture at full load	gram CO2/kWh	0.344
Emission with 50% Capture at full load	gram CO2/kWh	0.236
CO2 Avoided with 50% Capture at full load	gram CO2/kWh	0.155
Capital Cost		
Base CCGT Total Plant Cost (TPC)	million US$	320
Owner's Cost (base plant)	% of TPC	5
CO2 Capture Plant cost - 90% capture (2015)	million US$	295
CO2 Capture Plant cost - 50% capture (2015)	million US$	221
Owner's Cost (capture plant)	% of TPC	5
Learning Rate (capital cost for CO2 capture)	%	4
Post-combustion Global Deployment Rate	%	20
Decommissioning Cost and Recycle Revenue	million US$	0
Non-fuel O&M Cost		
Base Plant Fixed O&M Cost	million US$	9
Base Plant Non-fuel Variable O&M Cost	US$/MWh	0.04
Capture Plant Fixed O&M Cost	million US$	7
Capture Plant Non-fuel Variable O&M Cost	US$/MWh	0.1
CO2 Transportation and Storage Cost (50%)	US$/tCO2	20
CO2 Transportation and Storage Cost (90%)	US$/tCO3	13
Market Assumption		
Electricity Price	US$/MWh	75
Carbon Emission Price	US$/tCO2	15
Gas Price	US$/MWh	45
Baseline regional emission factor in 2015	gram CO2/kWh	740
Risk Free Rate	%	2
Baseline Discount Rate (real)	%	10

been approvaed for a permit in the past 5 years in the region. The LNG terminal in Huizhou and the major pipeline from West to East could potentially secure gas supply for new CCGT power plants. The total installed capacity of Combined Cycle Gas Turbine (CCGT) power plants (incl. Liquefied Natural Gas (LNG) power plants) in Guangdong has reached 6 GW by the end of 2011. Because of tighter environmental regulation and the increasing difficulty in siting coal-fired power plants, the provincial government plans to reduce the proportion of coal-fired power plants from 70% to 50% by 2020, while increasing the contribution of natural gas generation. The study illustrates three key criteria related to retrofitting CCGT power plants in Guangdong: (1) their technical ability to add CO2 capture, (2) their access to secure storage sites and (3) the economic viability of low-carbon electricity with CCS.

Table 2 Retrofit Prospect of Natural Gas Power Plants in Pearl River Delta, Guangdong, China

Plant Name	Type	Installed Capacity (MW)	Estimated Effective Remaining Life (Year)	Estimated Retrofitting Investment (% of original capex)	Estimated EOP for capture (kWh/tCO2) (without compression)	Estimated Retrofitting Extra Non-fuel O&M (% of original capex)	Technical Prospect of Retrofit
Nantian A & B (ex. Meishi)	Gas	250	18	113%	219	65%	Low
Nanshan Redian	Gas	360	19	109%	214	65%	Low
Baochang (Datang)	Gas	360	23	96%	207	65%	Low
Juehu	Gas	360	23	96%	207	65%	Medium
Fuhuade (CNOOC)	Gas	690	20	97%	211	65%	High
Shenzhen Energy East	LNG	1050	25	83%	189	71%	High
Guangqian	LNG	1170	24	83%	192	71%	High
Futian	Gas	63	7	n/a	n/a	n/a	Low
Huizhou	LNG	1170	20	83%	192	71%	High

II. Methodology

In order to identify the technical viability and the economic performance for CCGT power plants in China, three major steps are implemented. In the first step, we first conduct a high level screening to identify the overall potential to retrofit all existing CCGT power plants in Guangdong by building on previous studies on the potential to retrofit of coal-fired power plants in China [12] and CO2 storage potential in Guangdong [13].

In the second step, we conduct a case study on a hypothetical generic CCGT power plant on the Daya Bay in Huizhou city in Guangdong, assuming it started operations in 2015.To identify the technical performance of CO2 capture, we developed an ASPEN plus process model building on knowledge of post-combustion capture process model developed for CO2 capture retrofit in ultra-supercritical coal-fired power plants (USCPC) in China [14]. The technical assumptions of the study are listed in Table 1.

The final step investigates the economics of retrofitting power plant to CO2 capture. We studied the levelised cost of electricity of retrofitting to CO2 capture in 2020, 2025 and 2030 respectively, building on an existing widely applied cash flow analysis methodology [15]. The technical and economic assumptions of this study are building on CCS value in Guangdong [16], gas plant CCSR assessment [17] and offshore storage cost assumptions of existing studies [13, 18]. We analyse the marginal impact of capture on levelised cost of electricity (from the retrofitting year) instead of the total lifecycle cost.

III. CO2 Capture Retrofit Technical Potential

Half of the existing CCGT power plants in Guangdong technically have high CO2 capture retrofit potential (Table 2), but the economic performance could be site specific. Space and uncertainties in gas supply are two key obstacles for retrofitting gas plants with CCS in Guangdong. Given that most of gas supply in Guangdong power plants is secured by long-term contract, and it may be difficult to build up a new plant to recovery the electricity penalty.

Only CCGT plants with an installed capacity of over 300 MW per unit are assessed in this study. Results from ASPEN Plus shown that the power output penalty is around 200 kWh/tCO2 with 90% post combustion capture with MEA (30%wt) without compression. The result is higher than the 15% output penalty for the 550MW CCGT units simulated by [19].

Onshore CO2 storage capacity in South China is very limited and uncertain [20], in particular in Guangdong. Offshore depleted oil/gas field and saline aquifer formation in South China Sea is considered to be technically viable for long-term CO2 storage [13]. The prospect for CO2 EOR in South China Sea is unknown. The study finds that a majority of gas power plants in Guangdong are within 50 km of the coast and 150 km from potential offshore CO2 storage site (Figure 1).

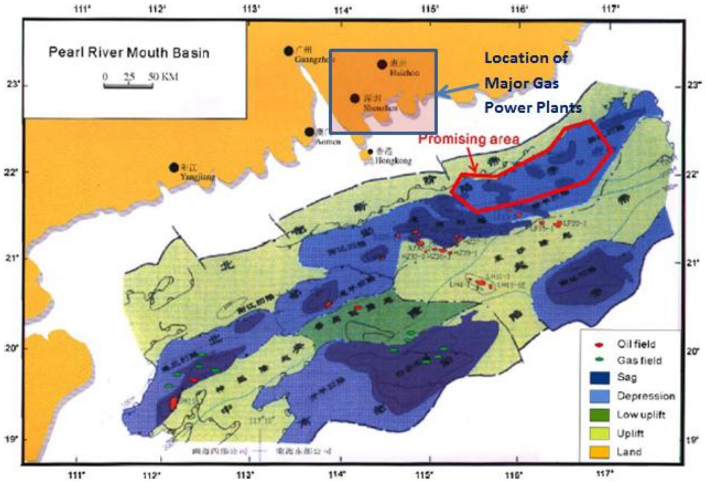

Figure 1 Location of Major Gas Power Plants and Potential CO2 Storage Site near Pearl River Delta, Guangdong, China ([13]

IV. Economic Performance

The study found a retrofit in 2020 would increase the levelised cost of electricity by approximately \$32/MWh, from US\$56/MWh (lifecycle COE without capture) to US\$88/MWh (COE after retrofit) at a 10% discount rate (Figure 2). The estimated abatement cost (i.e. cost of CO2 avoided) is US\$92/tCO2 for a retrofit in 2020 (Figure 3). The cost implication of retrofitting later is less significant even though the remaining lifetime will be much shorter, because the lifetime impact will be offset by technology learning, whilst a moderate learning rate (i.e. 4%) is assumed for both capital cost and electricity output penalty. With a 50% capture ratio, the marginal impact on the cost of electricity is reduced to \$23.7/MWh, but the cost of avoidance will increase dramatically to \$153/tCO2 (Figures 4 and 5).

Past stakeholder surveys have identified a significant gap between the rate of return required by state-owned and private-owned energy firms [21]. Unlike large coal-fired power plants in which state-owned firms are the primary investors,, a substantial fraction of CCGT operations in Guangdong are controlled by private energy companies (or joint-ventures), therefore, we identified the impact of different discount rates on gas power plants with and without CCS (Figure 2 and Figure 3). The impact of discount rate on the cost implications of CO2 capture is found to be very low, because fuel costs contributes to more than 60% of abatement cost in a CCGT with CCS case.

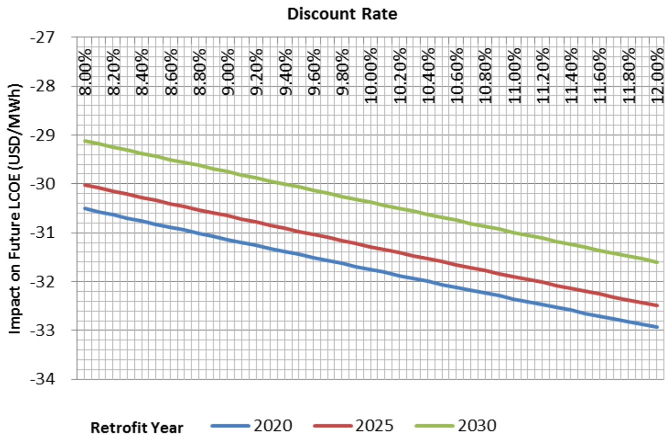

Figure 2 Impact of Retrofit to 90% CO2 Capture on Levelised Cost of Electricity (from the retrofitting year)

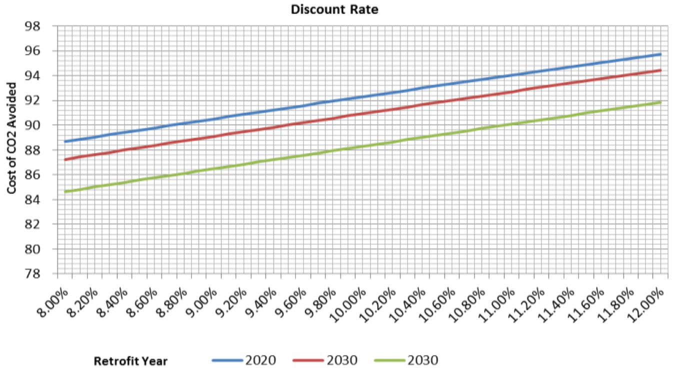

Figure 3 The estimated cost of CO2 avoided for retrofitting the underlying CCGT plant to 90% CO2 capture (in USD)

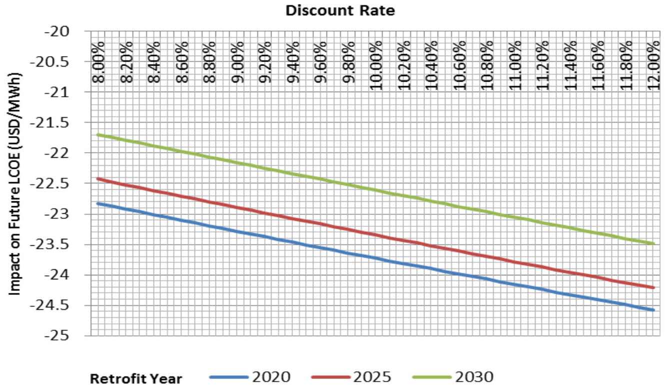

Figure 4 Impact of Retrofit to 50% CO2 Capture on Levelised Cost of Electricity (from the retrofitting year)

Figure 5 The estimated cost of CO2 avoided for retrofitting the underlying CCGT plant to 50% CO2 capture (in USD)

V. Conclusions and Discussion

Approximately half of the natural gas power plants in Guangdong have good retrofit potential technically. Offshore CO2 storage is due to the low partial pressure of CO2 in the flue gas, the simulated energy penalty of capturing and compressing CO2 is relatively high, at approximately 200 kWh/tCO2 before taking into account compression requirement. The impact on EOP by retrofitting to capture in 2020 is approximately US$32/MWh, as a result the levelised cost of electricity will be increased from $56 to $88/MWh or 57%. The cost of CO2 avoided for retrofitting at year 2020 is $92/tCO2. Partial capture (e.g. capturing only 50% of CO2) is not an economically viable option.

The level of carbon price through CDM or the prospective cap and trade scheme in Guangdong is unlikely to be sufficient for financing CCS in gas power plants unless China suddenly adopts a very aggressive domestic climate policy. Compared to other stationary emission sources (such as advanced pulverised coal-fired power plant, cement plants), CO2 captured from CCGT power plants is more expensive per tonne CO2 abated. However, deploying CCS in gas power plants in China may play an important role to reduce the cost of CO2 capture from gas plants [22] and therefore multi-lateral financial mechanism may be justified.

Remaining lifetime is found to have little influence on the abatement cost when a conservative assumption of the technology learning effect is made. As a result of the technology learning effect, CO2 capture retrofit at later years with shorter remaining lifetime (e.g. 2025 or 2030) will even have marginally lower capture operational cost. Therefore, even there is very low probability of retrofitting gas plants with CCS technologies by 2020, some essential level of CCS Ready investment to keep retrofit option throughout the plant’s lifetime is probably necessary.

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