A Potential Business Model for CCS System in Coal-fired Power Plants: A Case Study of Indonesia

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This paper presents a study of the implication of CCS adoption on the financial viability of coal power plants owned by Independent Power Producers (IPPs). Financial analysis of coal power with CCS is conducted for three scenarios: business as usual, carbon price policy, and CO_2 utilization for the EOR market. This study highlights the importance of CO_2 market availability for CCS capture in coal power plant financial feasibility. CCS capture technology needs to be further developed to reduce the cost of CO_2 capture installation at the coal power plant. Government support is needed if CCS technology will be a part of the solution for maintaining investment viability of IPP developers in coal power generation when carbon price policy is introduced.

Keywords: Carbon Capture and Storage, coal-fired power plants, carbon price, CO_2-EOR market

1. Introduction

The International Energy Agency (IEA) recently published a special report on the Southeast Asia Energy Outlook 2017[6]. The report forecasts that future growth of electricity generating capacity in Southeast Asia Energy will reach 565 gigawatts (GW) in 2040. Of out of this figure, coal power will constitute 40% of the total installed capacity and supercritical or ultra-supercritical technologies will be dominant for new coal power plants.

Although current supercritical or ultra-supercritical coal power technologies offer higher thermal efficiency, they barely reduce 3% of total carbon emissions in the APEC economies by 2040[2]. The Asian Development Bank has suggested carbon capture and storage (CCS) as the most important technologies for carbon emission reductions for fossil fuel power plants and industry[1].

Indonesia, one of APEC economies in Southeast Asia, is forecasted to add 66 GW of new coal-fired power plants by 2040[3]. Accordingly, the Indonesian government may need to introduce a policy for future coal power plants to be equipped with carbon capture equipment in order to substantially reduce potential carbon emissions.

Indonesias' electricity market is a single buyer market model in which private power generators known as the Independent Power Producers (IPPs) sell electricity to the state utility company through Power Purchase Agreements (PPAs) over 25 to 30 years. IPPs typically invest in baseload power generation such as coal and gas power plants that offer stable revenues to match their long-term debt service obligation. It is therefore important to evaluate the implication of future policy for CCS at coal power plants on the financial viability of coal-fired power plants owned by IPPs.

Deployment of CCS for coal-fired power plants may encounter substantial challenges as the technologies are currently at the demonstration stage. Accordingly, there are perceived and actual risks associated with technology maturity, investment cost, and operating performance of the CCS[1].

The World Bank conducted a study on potential CCS use for coal-fired power plants in Indonesia[9], it found that there are depleted gas fields in South Sumatera that have sufficient storage capacity to be used for storing captured CO_2 and also potential CO_2 demand for EOR in the amount of 243 million tonnes of CO_2 up to 2045.

This paper aims to evaluate the financial viability of private sector investment in IPPs in coal power plants under three different scenarios: business as

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usual (BAU), CCS under carbon price policy, and a CO_2 market for Enhanced-Oil-Recovery (EOR).

2. Methodology

The financial evaluation in this paper is based on the cash flow analysis of private sector IPPs over the duration of a PPA contract. A hypothetical coal power generator with a capacity of 660 MW to be constructed in South Sumatera is used as the basis of financial analysis in this study. Net present value (NPV) (1) is used to calculate the present monetary value for each scenario of BAU, CCS, and CCS-EOR market to understand the different levels of return on investment.

Net cash flow is established for every year of investment that begins from a year minus three (-3) when project construction commences until the end of year 25 at the end of the PPA contract agreement.

A long-term Indonesian bond rate of 7.75% is chosen as a discount factor to carry forward future costs and revenues from IPP investment. The selection of an appropriate discount factor is important to evaluate whether the financial profile of the IPP scenario meets the minimum required return on investment measured as an internal rate of return (IRR). Financial performance of an IPP will only be considered viable when the estimated IRR from the project cash flows higher than the relatively risk-free government long-term bond rate.

$$\text{NPV} = -\text{Initial investment} + \sum_{t=1}^{n} \frac{\text{net cash flow}_t}{(1+i)^t} \qquad (1)$$

The project finance structure of the coal power IPP is assumed to contain 30% of the project sponsors' equity and 70% long-term debt. Therefore, the IPP developer needs to ensure that the IPP tariff/price is adequate to cover its debt service obligation during the loan period.

There is no carbon price established in Southeast Asia but Singapore is taking the initiative to introduce a carbon price from 2019 at a cost of between \$10 - \$20 (equivalent to US\$ 7.35 - US\$ 14.69/ton of CO_2)[7]. This price reference will be applied to evaluate the cost of the carbon for electricity generation from coal power plants.

In this study, it is assumed that the IPP developer and the government share the investment risk of CCS whereby the former is responsible for adding carbon capture equipment in its coal power plant while the later for building the transport and storage infrastructure for CO_2 capture. This assumption is consistent with the current IPP business model in that it focuses on generating electricity while the government or state utility off-taker is responsible for transmission and distribution of the electricity. Accordingly, the IPP developer will only be exposed to the installation cost of CO_2 capture in the power plant.

The World Bank study identified 63.3 million ton of CO_2 for enhanced oil recovery (EOR) at the reference price of US\$ 20-40 per ton[9]. For this study, it is assumed the CO_2 price is US\$ 20 per ton. The government is assumed to charge the IPP for CO_2 delivery from the power plant to the EOR. Revenues from CO_2 sales are assumed to be equally shared between the IPP producer and the government.

The cost reference and technical performance of post-combustion capture for CO_2 follow the previous study on CCS[4]. The PPA contract structure typically allocates the fuel supply price to the public sector[5]. Accordingly, the increasing amount of coal consumption for coal power with CO_2 capture does not affect the cash flow of the IPP developer as the government or state utility off-taker will reimburse the cost of coal consumption.

Detailed key assumptions on power plant technical specification, project cost, and financial structure are summarized in Table 1.

Table 1 Key assumptions for the financial analysis

Key Parameters	Value
Power plant technical spec.	
Capacity	660 MW
Boiler technology	Supercritical(881 gr CO_2/kWh)[8]
Capacity Factor	80%
Own use power consumption	8%,+12% for CCS
Investment and Financial	
Total project cost	US\$ 850 million
Additional cost ofCO_2 capture	58% of a project cost□
Debt to Equity ratio	70/30
Loan interest and maturity	6% interest, 13 years

	(including 3 years of the grace period)□
Income tax and depreciation	30% and 20 years of asset depreciation
Discount factor	7.75%
Purchase generation price	US$ 4.43 cent/kWh (1-10 years) US$ 3.10 cent/kWh (11-25 years)
Concession contract	25 years
Construction period	3 years
Carbon price	Low: US$ 7.35/ton CO_2 High: US$ 14.69/ton CO_2
Price of CO_2 for EOR	US$ 20/ton CO_2
Revenue sharing from EOR	IPP/Public = 50:50
Amount of CO_2 for sale	1/3 of total captured CO_2

3. Results and Discussion

3.1 Favorable investment outcomes for coal-fired IPP generation under BAU scenario

Financial performance of coal power IPP under BAU scenario in Figure 1 shows that IPP sponsors gain favorable financial returns that are indicated by the net present value of US$ 491 million and estimated internal rate of return (IRR) of over 20%.

This strong financial performance is mainly driven by a combination of reliable electricity generation at an average price of US$ 3.63 cent/kWh and the availability of long term debt financing at competitive interest rates.

3.2 Carbon prices will substantially affect financial performance from coal-power IPPs

It can be seen from Figure 1 that under the scenario where future carbon prices will be applied, the projected financial returns will be substantially lower than that of the BAU scenario for both the low and high carbon price scenario.

It appears that the application of a carbon price to a coal power plant effectively reduces the financial viability of conventional coal power without CCS equipment. When a higher carbon price scenario of US$ 14.69/ton CO_2 is implemented, the estimated IRR of the coal power IPP is just over the discount rate threshold at 7.75%. Low returns on investment may justify future IPP developers of coal power plants in seeking alternative investment strategies in coal power business.

3.3 The need to substantially reduce the cost of CO_2 capture technology while improving efficiency

IPP developers of coal power may consider adding CO_2 capture to substantially reduce carbon emissions from generated electricity and to avoid a large payment on carbon prices. However, the financial results indicate very low profitability of coal power IPPs with CCS capture.

The installation of CO_2 capture will add 58% to total construction cost and reduce on average coal power plant efficiency by 12%[4]. The IPP developer of coal power in this scenario will need to arrange a total project cost of US$ 1.34 billion that contains 70% debt and 30% equity. Project cash flow will be severely affected especially during the project debt maturity period. The IPP developer needs to repay a substantially higher project debt principal and interest while electricity generation is reduced because of increased use of electricity to operate the CO_2 capture. The operating efficiency of CO_2 capture at 90% also means that the carbon price is still incurred for the remaining 10% of power plant carbon emissions. Accordingly, a combination of these factors causes the estimated IRR just above the discount rate in the low and high carbon price scenario.

The project cash flow is improved when a CO_2 market is available. In this study, CO_2 utilization for Enhanced Oil Recovery (EOR) creates opportunities for the IPP developer to have higher net present value and expected IRR than those without the availability of a CO_2 market. The revenues from the sales of captured CO_2 partly compensate the capital investment needed to add CO_2 capture equipment and enable the IPP developer to serve its debt service obligation.

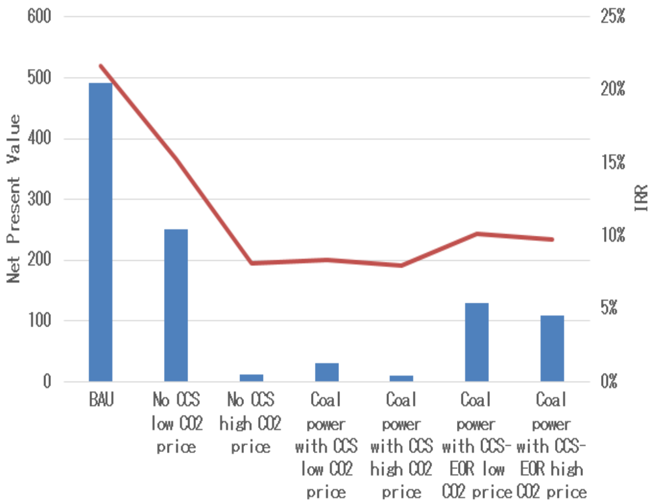

Figure 1: Results of financial analysis for coal-fired power project under different investment scenario

4. Conclusions

This paper presents a study of the implications of CCS adoption on the financial viability of coal power plants owned by Independent Power Producers. Financial analysis of coal power with CCS is conducted for three scenarios: business as usual, carbon price policy, and CO_2 utilization for EOR market.

It appears that financial returns on IPP investment for coal power projects will be severely affected if carbon price policy is implemented in the future. The installation of CCS capture in coal power plants will not be financially feasible if a CO_2 market is not available.

CCS capture technology needs to be further developed to reduce the cost of CO_2 capture installation at the coal power plant. The efficiency of CO_2 capture also needs to be improved so that the generated electricity can be maintained to provide the IPP developer with adequate revenues to serve its debt obligation.

It is evident from this study that government support is needed if CCS technology needs be a part of the solution for maintaining investment viability of IPP developers in coal power generators when carbon price policy is introduced in the future. IPP developers traditionally focus its business operation within the boundary of power generators while the state utility transmits and distributes the electricity to the customers. The public sector may need to build integrated CO_2 transport, storage, and utilization to maintain the interest of the private sector in the investment in future coal power generation.

Further work on this financial analysis is currently being conducted using the Monte Carlo financial risk analysis to evaluate the implication of uncertainty in coal and oil prices on coal power with CCS-EOR.

Acknowledgement

The research reported in this paper is generously supported by Asia Pacific Energy Research Centre (APERC). The views expressed, however, are those of the authors and not necessarily those of APERC.

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