Financial Analysis for Assessing the Economics of Carbon Capture in Coal-fired Power Plants: a Case Study of Sumatera, Indonesia

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Abstract

This paper compares the financial viability of private sector investment in a coal power plant with carbon capture and geothermal power plant based on long-term contract of Power Purchase Agreement (PPA). Based on the project cash flow analysis, it is found that investing in a coal power plant that must install carbon capture is only financially viable if there is demand for CO_2 from EOR market. Financial performance of a coal-fired power plant with carbon capture installation is significantly improved when there is demand for captured CO_2 to be utilised for EOR in oil production. Private investment in geothermal power plant offers more favorable investment returns than investing in coal-fired power plant with carbon capture. The private sector investment in power generation may choose to invest more in renewable energy power plants such as geothermal power that offer a more attractive return on investment than investing in clean coal technology such as coal-fired power plant with carbon capture.

Keywords *: coal power, carbon capture, financial analysis, geothermal power*

1. Introduction

Indonesia, the largest economy and energy consumer in South East Asia, is forecasted to add 66 GW of new coal-fired power plants by 2040[1)]. In 2016, Indonesia has submitted the first Nationally Determined Contribution to the United Nations Framework Convention on Climate Change to unconditionally reduce carbon emissions from the energy sector to 1,355 million ton CO_2 in 2030. The Indonesian government has introduced several key measures to achieve the CO_2 emissions reduction target such as increasing the share of renewable energy for electricity generation to 25% by 2025 and adopting clean coal technology to reduce CO_2 emissions from coal power generations. In the state electricity company's Business Plan 2018-2027, it is mentioned that PLN, the state electricity company, consider adopting carbon capture for coal power plants when the technology has become commercially available. This raises a consideration whether investment in coal power generation that must install a carbon capture technology is more attractive to the private power generation than investment in renewable energy such as geothermal power generation. Indonesia has the second largest installed capacity of geothermal power plant at 1,924 MW and has proven geothermal reserve equal to 17,000 MW.

This paper compares the financial viability of private sector investment in a coal power plant with carbon capture and geothermal power plant based on long-term contract of Power Purchase Agreement (PPA).

The Independent Power Producers (IPPs) in Indonesia sell electricity to the state utility company through Power Purchase Agreements (PPAs) over 25 to 30 years.

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2. Methodology

This study analyses net present value and the expected internal rate of returns of privately financed IPPs over the duration of a Power Purchase Agreement. Hypothetical power plant projects of coal and geothermal power that are constructed in Sumatera, one of the main island in Indonesia, were used as the basis of financial analysis. Key assumptions of project construction cost, financing structure and other financial parameters were derived from actual and recent power projects in Indonesia.

Net present value (NPV) (1) and Internal rate of return (IRR) (2) are used to calculate the present monetary value for coal and geothermal power plants to understand the different levels of return on investment.

Project cash flow is developed from the year when power plant construction commences until the year 25 and 30 when the PPA contract expires for coal and geothermal power, respectively.

The discount factor for geothermal power investment is estimated from a long-term Indonesian bond date of 7.75% to carry forward future costs and revenues from electricity generation and sales. Coal power investment has perceived higher investment risk than in geothermal, it therefore uses higher discount factor (10%). An investment proposal in an IPP project will only be considered feasible when the estimated IRR from the project cash flows is higher than the return from

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investing in long-term government bonds that are considered as a risk-free investment.

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

$$IRR = r_a + \frac{NPV_a}{NPV_a - NPV_b}(r_b - r_a)$$

r_a = lower discount rate chosen
r_b = higher discount rate chosen
N_a = NPV at r_a
N_b = NPV at r_b

(2)

The project finance structure of a privately financed power plant typically contains 30% of the project sponsors' equity and 70% long-term debt. As project financing structure in an IPP project is a non-recourse based investment, project lenders must ensure that the IPP tariff/price is adequate to cover its debt service obligation during the loan period.

It is assumed in this study that the IPP developer in coal-fired power plant is mandated to install carbon capture while the state utility company is liable to transport the captured CO_2 from a power plant to the permanent CO_2 storage or sell it to an oil company for enhanced-oil recovery utilization.

According to the World Bank study on CCS potentials in Indonesia, it identifies the need for 63.3 million ton of CO_2 for enhanced oil recovery (EOR) at the reference price of US$ 20-40 per ton in Sumatera[2)]. For this study, it is assumed the CO_2 price is US$ 20 per ton.

The state utility company will charge the IPP sponsors of US$ 20 per ton CO_2 to transport the CO_2 from the power plant location to the CO_2 storage of EOR consumers. When the EOR market is available, the IPP sponsors and the state utility company is assumed to equally share the revenues from CO_2 sales.

The PPA contract structure in Indonesia typically allocates fuel supply availability risk to the IPP sponsors while the risk of fuel price fluctuation is transferred to the public sector[3)]. Accordingly, the increasing price of coal or natural gas consumption for power generation does not affect the cash flow of the IPP developer. It is because the electric state utility will reimburse the cost of fuel consumption.

The coal power plant is assumed to install the post-combustion capture for CO_2. The technology is considered technically more suitable for coal power operation in Indonesia than the pre-combustion capture or oxy-fuel capture technologies that require more complex installation and operation processes. The cost and technical performance of post-combustion capture for CO_2 follow the previous study on CCS[4)]. Detailed key assumptions on power plant technical specification, project cost, and financial structure are summarized in **Table 1**.

Table 1 Key assumptions for coal power plant

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	10%
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
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

The technical parameters for comparative analysis on geothermal power plants are summarised in **Table 2**.

Table 2 Key assumptions for geothermal power plant

Key Parameters	**Value**
Power plant technical spec.	
Capacity	660 MW
Boiler technology	Steam and brine combined cycle units
Capacity Factor	90%

Own use power consumption	6%
Investment and Financial	
Total project cost	US$ 850 million
Debt to Equity ratio	70/30
Loan interest and maturity	5% interest, 30 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$ 6.79 cent/kWh
Concession contract	30 years
Construction period	3 years

3. Results and Discussion

3.1 Coal-fired power plant with CO_2 capture

It is found that investing in a coal power plant that must install carbon capture is only financially viable if there is demand for CO_2 from EOR market. **Table 3** shows a comparison of financial performance measured in NPV and IRR between coal-fired power plants with carbon capture and geothermal power plants. It shows that coal-fired power plant with carbon capture has negative NPV which indicates the investment option is not financially viable.

Installation of carbon capture in a coal power plant requires 58% of additional capital expenditure and it consumes 12% of electrical power generated by the coal power plant. This will create difficulties for the IPP sponsors to repay its debt obligation as the number of capital investment increases while the electricity output for sales decreases.

Table 3 Financial analysis of power plant investment

Scenario	Net Present Value (US$ million)	Estimated Internal Rate of Return
Coal power generation with CO_2 capture	-56	NA
Coal power generation with CO_2 capture – EOR market	21	10.50%
Geothermal power plant	630	13.50%

Financial performance of a coal-fired power plant with carbon capture installation is significantly improved when there is demand for captured CO_2 to be utilized for EOR in oil production. According to the World Bank study, the total amount of 63.3 million ton CO_2 is needed to increase oil productions from mature oil fields in Sumatera through EOR. With the CO_2 price of US$20/ton of CO_2, the NPV of a coal power plant with carbon capture increases to US$ 21 million and IRR of 10.5%. Despite coal power plant has a positive NPV value, the expected return on investment is only marginally higher than the cost of capital or discount factor for investing in coal power plant projects.

It appears that financial viability of future coal power plants depends on the development of carbon capture technology and the availability of CO_2 market. Capital cost for carbon capture installation must be substantially reduced from the current cost estimate. The public sector may need to develop an integrated carbon capture and storage system that interconnects between CO_2 captured from coal power plant, transportation, storage and potential utilization of CO_2 to enhance oil production through EOR.□

3.2 Geothermal Power Plant

Financial evaluation of geothermal power investment in **Table 3** indicates that geothermal power as renewable energy sources benefits from favorable support for renewable energy development. The cost of financing is substantially lower than in the coal power plant that is reflected into the lower discount rate, lower loan interest and longer debt maturity period. The electricity price to the state utility company is also 53% higher than electricity price from coal power generation.

The calculated NPV of geothermal power investment in **Table 3** is US$ 630 million and IRR is 13.5%, substantially higher than NPV and returns on investment in coal-fired power plant with carbon capture. However, investment in a geothermal power plant needs 140% higher upfront capital investment than in coal-fired power plant with carbon capture installation. Geothermal project developers need to develop geothermal steam resources, steam pipelines, and power generation plant. The capital cost for 660 MW geothermal power is estimated at US$ 3.2 billion.

The government or the state electricity company may compare total project cost between clean coal technology such as coal-fired power with carbon capture installation and renewable energy power generation like geothermal power plants. From the private sector IPP, investing in geothermal power plant offers more favorable investment returns than investing in coal-fired power plant with carbon capture installation whether there is available EOR market or not.

4. Conclusions

This paper presents financial analysis on private sector investment in coal-fired power plant and geothermal power plant. According to the Indonesian medium-term electricity business plan, the state electricity company will develop coal power plants with carbon capture if such technology has been commercially available. The private power company needs to conduct a financial assessment to evaluate the financial viability of various investment options including coal power plant with carbon capture technology.

It appears that financial viability of future coal power plants depends on the development of carbon capture technology and the availability of CO_2 market. Capital cost for carbon capture installation must be substantially reduced from the current cost estimate. The public sector may need to develop an integrated carbon capture and storage system that interconnects between CO_2 captured, transportation, storage and potential utilization of CO_2 to enhance oil production through enhanced oil recovery.

Financial viability of coal-fired power plant that must install carbon capture is adversely affected particularly when EOR market that may purchase the captured CO_2 from the power plant is not established. The estimated return on investment from an integrated coal-fired power plant and EOR market is only marginally higher than the select discount factor for a coal-fired power plant project.

The private sector investment in power generation may choose to invest more in renewable energy power plants such as geothermal power that offer a more attractive return on investment than investing in clean coal technology such as coal-fired power plant with carbon capture.

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