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Modelling of Carbon Capture Process for Coal-Fired Power Plants in Indonesia

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The high consumption of coal in the power generation sector results in high greenhouse gas (GHG) emissions in Indonesia. Indonesian Government still needs to reduce its GHG emissions to below 662 $MtCO_2e$ in order to meet the Intergovernmental Panel on Climate Change (IPCC) scenario. This condition encourages the government to develop a strategy for decarbonization as stated in the Long-term Strategy on Low Carbon and Climate Resilience 2050 document. The retrofitting potential of Indonesian coal power plant was evaluated. Several factors such as Levelized Cost of Electricity (LCoE), CO_2 emission intensity prior to capture, energy penalty, and the presence of installed flue gas desulfurizer (FGD) were used as determining parameters in selecting priority power plants to be retrofitted. The mass and energy balance of the CCS process was modelled using Aspen HYSYS V12. Based on simulation and techno-economic calculations results, it can be concluded that the LCoE value of CCS-retrofitted coal-fired power plants are influenced by the plant's capacity and the existence of FGD units. The implementation of CCS technology through retrofitting in Indonesia shall be prioritized for 1,000 MW ultra-supercritical power plants that already have existing seawater FGD technology. The increase in costs, together with a decrease in power production, results in an increase in LCoE values of up to USD 0.11/kWh for 1,000 MW power plants. This result is expected to be used as a consideration for the Indonesian government in mapping out a decarbonization strategy in the energy generation sector.

1. Introduction

Indonesia is one of the largest coal consuming countries in the world. Coal consumption is projected to continue to increase every year until it reaches 153 million t in 2028 with an annual growth rate of 5.2 % (Indonesia State Electricity Company, 2019). Nowadays, 98 % of national coal consumption comes from the power generation and cement industries, with electricity generation industry being the highest consumer (Arinaldo and Adiatma, 2019). The high consumption of coal in the power generation sector will result in high greenhouse gas (GHG) emissions, especially carbon dioxide (CO_2) gas that is produced from coal burning activities. Based on Climate Transparency (2020), Indonesia still needs to reduce its GHG emissions to below 662 MtCO2e in order to meet the Intergovernmental Panel on Climate Change (IPCC) scenario. This condition encourages the Indonesian government to develop a strategy for decarbonization as stated in the Long-term Strategy on Low Carbon and Climate Resilience 2050 document (LTS-LCCR 2050). One of the technologies that has been developed to control GHG emissions is post-combustion CO_2 capture or it's often referred to as PCC (Post-Combustion Capture). PCC is a method of capturing CO_2 gas from flue gas (Wang et al., 2017). With various PCC methods available, chemical absorption is considered the most cost-competitive method and can be implemented in the near future (Rao and Rubin, 2002) despite several drawbacks such as high regeneration energy (Feron, 2016) and solvent degradation (Handojo et al., 2018). Solvents that have been commercially applied for chemical absorption process are Cansolv and KS-1 (Raksajati et al., 2018).

Building a new power plant equipped with PCC technology is not the best option. Apart from requiring a lot of money, Indonesia has committed not to build a new power plant starting from 2023. One of the solutions that

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can be offered in these conditions is to retrofit the existing coal-fired power plants. Power plant retrofit is a modification or addition of process technology to an existing power plant by maximizing the use of existing equipment so that it remains economical (Qvist et al., 2021). Research on power plant retrofitting with PCC has been carried out in the past few years. Research by Ramezan and Skone (2007) on a comparison on four levels of CO_2 capture shows that the investment cost increases linearly with the increase in captured CO_2. Moioli and Pellegrini (2013) conducted a simulation on the regeneration section of CO_2 capture plant to come up with an accurate thermodynamics, kinetics, and mass transfer model. Gingerich and Mauter (2018) conducted a study on optimizing the allocation of energy sourced from steam, generators/turbines, and exhaust heat to run power plant operations, carbon capture, and waste treatment. Meanwhile, a study conducted by Qvist et al. (2021) offers a new retrofit scheme for power plant such as the use of CCS, biomass power plant, Integrated Gasification Combined Cycle Plants, and others. In this research, the retrofitting potential of Indonesian coal power plant will be evaluated. Several factors such as Levelized Cost of Electricity (LCoE), CO_2 emission intensity prior to capture, energy penalty, and the presence of installed flue gas desulfurizer (FGD) will be used as determining parameters in selecting priority power plants to be retrofitted.

2. Methodologies

2.1 Process Simulation

This study consists of three main stages. Firstly, the simulation of the CO_2 capture and compression process was carried out using Aspen HYSYS V12. Once the simulation model was validated, it was used to calculate energy penalties, emission intensity, as well as capital and operational costs (CAPEX and OPEX) of CCS. The results of the capital and operational cost calculations of CCS were used to calculate Levelized Cost of Electricity (LCoE) and the cost of CO_2 capture. Finally, each experimental variation was evaluated through a decision matrix to determine the priority power plants for retrofitting with CCS.

CO_2 capture simulation was performed using the Shell-Cansolv solvent (MDEA+PZ). The Fluid Package used in the simulation is Acid Gas-Chemical Solvents. The reactions related to CO_2 capture by the solvent and solvent regeneration are automatically defined by software, which consists of three reaction models: equilibrium, kinetic, and dissociation.

The criteria to be achieved in the CO_2 capture simulation are a minimum of 90 % CO_2 captured in the feed and limiting the reboiler temperature below 122 °C to prevent solvent degradation and erosion in the regenerator. The reboiler temperature limitation is done by setting the regenerator pressure in the range of 1.9 – 2.0 bar.

Figure 1a shows the CO_2 capture process flowsheet. The CO_2 capture column is modeled with an absorber while the solvent regenerator is modeled with a full reflux distillation column. Makeup solvent addition is mixed through a mixer model or makeup model (for versions V9 and above). Solvent return to the absorber column is assisted by a recycle manipulator that functions to solve the mass and energy balance of the recycle system using an iterative method.

After CO_2 is captured in the absorber, CO_2 gas compression process to a supercritical phase is required for transport and injection of CO_2 at the desired location. The Fluid Package used in this simulation is Peng-Robinson with the Costald method to calculate liquid density.

Figure 1b shows the CO_2 compression process flowsheet. CO_2 compression can be modeled with more than one compressor stage equipped with an intercooler as a cooler for compressor products and a 2-phase separator to ensure no liquid enters the compressor. The simulation in this research used four compression stages with a compression ratio of 2.793 (Yang et al., 2012).

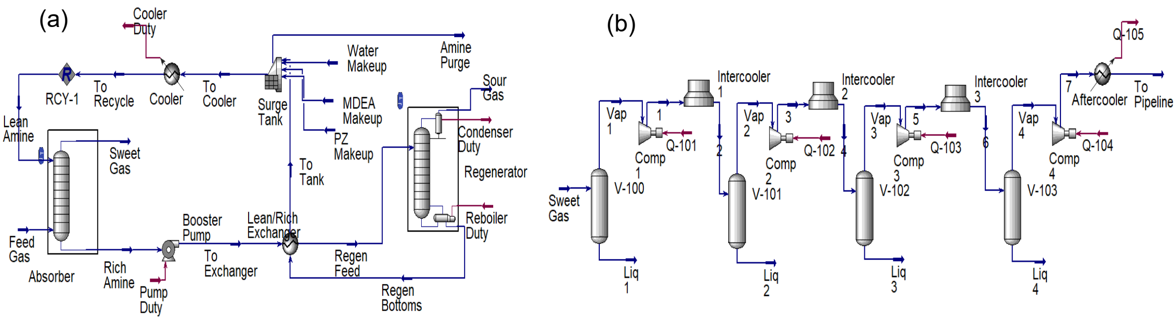

Figure 1: (a) CO_2 capture and (b) CO_2 compression simulation flowsheet on Aspen HYSYS

2.2 Techno-Economy Calculation

CCS fixed capital investment is defined by total module cost. Total module cost consists of 3 main components: direct expenses, indirect expenses, along with contingency and fees.
The total cost of all equipment (except for the FGD unit and flue gas blower) was obtained through calculations using Aspen Process Economic Analyzer (APEA), while the cost of the FGD unit and flue gas blower was calculated using actual data from literature. The cost of equipment from the APEA simulation takes into account the operating pressure factor and equipment materials. The equipment cost produced by APEA V12 is based on Q1 2019 cost, so a cost conversion to 2022 was carried out using the CEPCI ratio. The total cost of all equipment (Equipment FOB cost) is used as a basis for calculating other cost components using a multiplier factor based on Guthrie's method.
CCS operational cost can be divided into 3 components: direct cost, fixed cost, and general expenses. Direct cost includes raw material, waste treatment, labor cost, and other expenses incurred from daily operations. Fixed cost includes tax, insurance, and overhead cost. General expenses include research and development (RnD) cost and administration cost. The operational cost is used to calculate the annual cash flow and does not consider equipment depreciation. The equations to calculate each component refers to Turton et al. (2018).
The calculation of power plant CAPEX and OPEX is carried out using empirical constants obtained from various coal-fired power plant in Australia. The calculation of power plant CAPEX and OPEX is necessary to calculate the LCoE of power plant before CCS implementation.
Levelized Cost of Electricity (LCoE) is the average cost of generating electricity at present value (net present value) during the lifetime of the power plant. The calculation of LCoE involves several variables, such as capital cost for CCS unit ($CAPEX_{cap}$), operational cost for CCS unit ($OPEX_{cap}$), and carbon penalty. The calculation of LCoE is shown in Eq(1). Since the calculation of LCoE uses the NPV method, a discount factor is needed to convert future cash flows into present value. The discount factor used in this study is 8 %.
The cost of capturing CO_2 (capture cost) is the net present value of the average cost incurred to capture 1 t of CO_2 during the lifetime of the CO_2 capture unit (USD/tCO_2). The calculation of capture cost for retrofitted power plants is shown in Eq(2).

$$\text{LCoE} = \frac{\text{PV } \sum \text{CAPEX}_{\text{cap}} + \text{OPEX}_{\text{cap}} + \text{CP}}{\text{PV } \sum \text{EL (MWh)}} \tag{1}$$

$$\text{Capture Cost} = \frac{\text{LCOE}_{\text{after CCS}} - \text{LCOE}_{\text{before CCS}}}{\text{CEI}_{\text{before CCS}} - \text{CEI}_{\text{after CCS}}} \tag{2}$$

2.3 Experimental Variations

This research uses data from six coal-fired power plants in Indonesia. Each power plant variant will be treated as one experimental run. Each power plant data varies in terms of capacity, steam type, presence/absence of flue gas desulfurization (FGD), as well as flue gas flow rate. The tabulation of simulation variations is shown in Table 1.

Table 1: CCS simulation variations on coal-fired power plants

Parameter	300 MW Subcritical	300 MW Supercritical	660 MW Subcritical	600 MW Subcritical	660 MW Subcritical	1,000 MW Ultra-Supercritical
Flowrate (Nm^3/h)	1,441,213	972,745	2,130,506	1,993,679	2,237,382	3,279,214
Temperature (°C)	137.5	140.0	59.8	140.0	140.0	64.0
FGD Type	-	-	Limestone FGD	-	-	Seawater FGD
Gas Composition						
CO_2	13.9 %	14.6 %	14.8 %	14.4 %	14.2 %	13.0 %
H_2O	11.4 %	14.8 %	10.1 %	10.4 %	13.7 %	11.9 %
SO_2	0.04 %	0.03 %	0.03 %	0.04 %	0.01 %	0.10 %
N_2	71.3 %	68.4 %	72.7 %	72.6 %	69.4 %	70.4 %
O_2	3.32 %	2.18 %	2.42 %	2.69 %	2.67 %	4.59 %
Emission						
SO_2 (mg/Nm^3)	1,180	724	724	707	704	620
NO_x (mg/Nm^3)	126	724	724	707	704	620

3. Results and Discussion

3.1 Main Simulation Results

The main simulation and calculation results of six coal-fired power plants variations are compared in Table 2. Retrofitting coal-fired power plants with CCS system resulted in a decrease of energy delivered to the grid due to energy penalties, ranging from 30.46 % to 48.07 %, while the capital investment (CAPEX) and operational investment (OPEX) of the power plants increased. Changes in these variables resulted in the increase of Levelized Cost of Electricity (LCoE). Based on the simulation result, CCS unit produce CO_2 stream with 97.47 %-wt purity. After the compression process, CO_2 will be distributed with nearly 100 %-wt purity.

Table 2: Process Simulation Results

Parameter	300 MW Subcritical	300 MW Supercritical	660 MW Subcritical	600 MW Subcritical	660 MW Subcritical	1,000 MW Ultra-Supercritical
Energy Penalty (MW)	144	100	214	214	225	304
Energy Penalty Percentage (%)	48.1 %	33.5 %	32.4 %	35.7 %	34.1 %	30.5 %
Power Plant Capacity after CCS (MW)	156	200	446	386	435	695
Emission Intensity (tCO_2/MWh)	1.29	0.933	0.935	0.937	0.945	0.838
Emission Intensity after CCS (tCO_2/MWh)	0.237	0.131	0.136	0.137	0.140	0.118
Reboiler Duty (MJ/tCO_2)	2.91	2.96	2.92	2.93	2.93	3.01
Solvent Circulation (t/h)	4,378	3,205	7,004	6,410	7,098	9,693
Solvent Make-Up (t/h)	0.17	0.12	0.27	0.24	0.26	0.36
Water Make-Up (t/h)	194	135	306	280	285	409

The application of CCS in a power plant requires additional land and equipment, including a flue gas booster fan, CO_2 absorber, rich amine pump, rich/lean exchanger, regenerator, lean amine cooler, CO_2 compressor, dehydration unit, and water treatment plant. Existing units that need to be modified include the cooling water distribution system, condensate booster pump, Boiler Feed Pump, vacuum condenser (optional), and seawater FGD for power plants that doesn't have seawater FGD yet.

3.2 Capital and Operational Expenditures Summary

The summary of capital and operational expenditure for each power plant is shown in Table 3. The factors that affect capital and operational expenditure of CCS system include power plant capacity, availability of existing FGD, and emissions intensity before CCS.

Table 3: Financial profiles of power plants

Parameter	300 MW Subcritical	300 MW Supercritical	660 MW Subcritical	600 MW Subcritical	660 MW Subcritical	1,000 MW Ultra-Supercritical
CCS CAPEX (M USD)	308	231	477	479	478	558
CCS OPEX (M USD)	44.6	33.7	69.4	68.9	69.6	83.9
LCoE after CCS (USD/kWh)	0.223	0.144	0.133	0.127	0.122	0.111
LCoE Increment (USD/kWh)	0.142	0.074	0.073	0.0667	0.063	0.052
CO_2 capture cost (USD/tCO_2)	135	92.2	91.5	82.8	79.1	72.6

3.3 Effect of Power Plant Capacity on Energy Penalty and LCoE

Figure 2 shows the influence of power plant capacity on LCoE and energy penalty. Retrofitting CCS facilities increases the CAPEX and OPEX of power plants while reducing its power output due to energy penalty. Based on the LCoE calculation equation, the numerator variable (cost) increases while the denominator variable (electricity production) decreases, thus retrofitting CCS will result in an increase in LCoE.

On the power plant LCoE curve against capacity, it can be observed that the LCoE value of the power plant is relatively constant. LCoE after CCS graph is decreasing for power plants with higher capacity. One of the factors that causes this is the lower energy penalty for high-capacity power plants compared to low-capacity power plants. Installing CCS facilities will be more beneficial for high-capacity power plants.

The trend of the LCoE after CCS data is also similar with the curve of the percentage of energy penalty. The percentage of energy penalty tends to be lower in high-capacity power plants. As a result, the percentage of electricity delivered to the grid is higher, so the LCoE increment becomes lower.

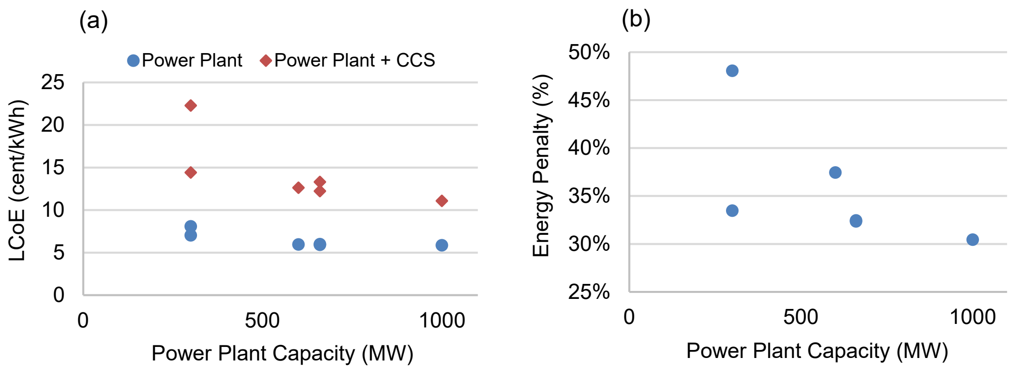

Figure 2: The effect of coal-fired power plant capacity on (a) LCoE, and (b) energy penalty

3.4 Carbon Tax Sensitivity Analysis

The power plant selected as the basis for carbon tax sensitivity analysis is a 1,000 MW ultra-supercritical power plant. The sensitivity analysis results are shown in Figure 3.

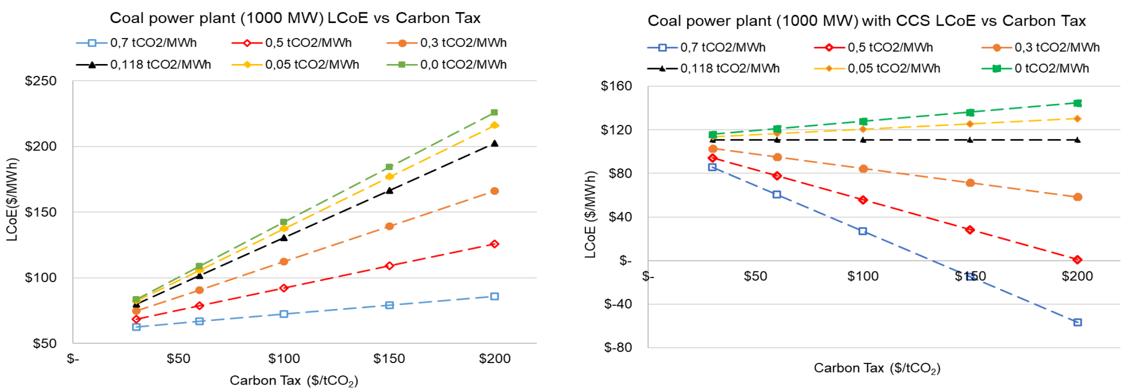

Figure 3: Effect of carbon tax on coal power plant LCoE (a) without CCS, and (b) with CCS

Based on Figure 3, LCoE increases as the carbon tax increases when emission cap is lower than emission intensity. LCoE decreases as carbon tax increases due to carbon credit sales when emission cap is higher than emission intensity. The breakeven LCoE and capture cost for power plant with CCS and without CCS can be found by intersecting graph 6a and 6b, which indicates the carbon tax required to equalize the LCoE value of power plant with CCS and without CCS, hence CCS retrofit becomes equally cost competitive to paying carbon taxes without CCS implementation. The intersection of the two graphs occurs at carbon taxes of USD 53.6/tCO_2 and LCoE USD 65.9/MWh (for emission cap 0.7 tCO_2/MWh), USD 58.9/tCO_2 and LCoE USD 78.4/MWh (for emission cap 0.5 tCO_2/MWh), carbon tax USD 65.4/tCO_2 and LCoE USD 93.7/MWh (for emission cap 0.3 tCO_2/MWh), carbon tax USD 72.6/tCO_2 and LCoE USD 111/MWh (for emission cap 0.118 tCO_2/MWh), carbon tax USD 75.73/tCO_2 and LCoE USD 118/MWh (for emission cap 0.05 tCO_2/MWh), and carbon tax USD 78.2/tCO_2 and LCoE USD 124/MWh (for no emission cap). Breakeven LCoE increases as the emission cap decreases and the carbon tax required to equalize the economics of CCS implementation also increases. Based on the analysis, it can be concluded that initial implementation of carbon tax should be carried out at high emission caps (above 0.7 tCO_2/MWh) with a tax rate of around USD 50/tCO_2. This scheme allows a transitional period where power producers using coal are prepared to start investing in CCS technology without being burdened by high tax costs. The transition period is also necessary to ensure that the increase in electricity price is not too high, which can burden the public. Over time, the emission cap must continue to be lowered to below 0.2 tCO_2/MWh, while the carbon tax should be increased to the range of USD 70-80/tCO_2. The reduction in emission caps and the increase in carbon tax are expected to force all power producers to implement CCS due to the drastic increase in carbon tax penalties.

4. Conclusions

Retrofit CCS on coal-fired power plant requires capital expenditures (CAPEX) averaging on M USD 269, M USD 47, and M USD 558 along with operational expenditures (OPEX) averaging on M USD 39.1, M USD 69.3, and M USD 83.9 per year for 300 MW, 600 MW, and 1000 MW power plants. The increase in costs, together with a decrease in power production, results in an increase in LCoE values of up to USD 0.18/kWh, USD 0.13/kWh, and USD 0.11/kWh for 300 MW, 600 MW, and 1,000 MW power plants. Based on simulation and techno-economic calculations results, it can be concluded that the LCoE value of CCS-retrofitted coal-fired power plants are influenced by the plant's capacity and the existence of flue gas desulfurization (FGD). The implementation of CCS technology through retrofitting in Indonesia shall be prioritized for 1,000 MW ultra-supercritical power plants that already have existing seawater FGD technology. With the high investment costs required, carbon tax is one instrument that can increase the economic attractiveness of CCS retrofit projects. Initial implementation of carbon tax is recommended to be applied at high emission cap as a transitional phase. Over time, gradual reduction in emission cap and increase in carbon tax shall be implemented until the emission cap is below 0.2 tCO_2/MWh and carbon tax at USD 70-80/tCO_2.

Nomenclature

CEI - CO_2 emission intensity, tCO_2/MWh
PV - Present Value
CP - Carbon Penalty
EL - Electricity generated by power plant, MWh

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