Simulation of CO₂ Capture Process for Coal based Power Plant in South Sumatra Indonesia

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Abstract. Indonesia committed to reduce greenhouse gas emission by 29% in 2030. Carbon dioxide (CO₂) emissions from flue gas in coal power plant must be captured to reduce greenhouse gas emissions. Technology to decrease greenhouse gases on a large scale and in a relatively short period is Carbon Capture and Storage (CCS). Chemical absorption method is a more advantageous CCS technology than other methods owing to high efficiency, low cost, and mature technology. Solvents in chemical absorption include amine-based solvent such as monoethanolamine (MEA) was frequently utilized to absorb CO₂ from low-pressure flue gas streams, especially fossil fuel-based power plant, owing to rapid reaction rate with CO₂ and low cost of raw amines compared to other amines. In this study, Aspen Hysys was used to simulate the CO₂ capture process and 30 wt% of MEA was selected as a solvent which is mainly handy for CO₂ capture from flue gas. The results show that lean amine temperature, flue gas temperature, and regenerator feed temperature has effects on the CO₂ capture and energy consumption. The rich-split stream configuration was developed to examine energy reduction in various split fractions. The minimum in energy consumption and reboiler duty occurs when 30% of the solvent is split to the top of the column.

Keywords: CO₂, coal-based power plant, absorption, MEA, Aspen Hysys.

1. Introduction

For the past two decades the greenhouse gas (GHG) emissions have increased, and threatened to the earth’s ecological system and human race [1-2]. Combustion of fossil fuels such as natural gas, coal for power generation, industrial processes and transportation has led to the huge increase of CO₂ concentration in the atmosphere [3]. Indonesia has joined a global wave of countries that submitted their post-2020 climate pledges to the United Nations Framework Convention on Climate Change (UNFCCC) called intended nationally determined contributions (INDCs) in 2015. Since then, Indonesia has signed the Paris Agreement, and formally submitted the first nationally determined contribution (NDC) in 2016. Indonesia committed to decrease unconditionally GHG emissions by 29% against a 2030 business-as-usual (BAU) scenario and GHG emissions by up to 41% below the 2030 BAU level which subjects to international assistance for finance, technology transfer, and capacity building [1].

Carbon dioxide (CO₂) capture and storage is a process consisting of the separation of CO₂ from industrial and energy-related sources, transport to a storage location and long-term isolation from the atmosphere. There are three major types for CCS: post-combustion capture, pre-combustion capture and oxyfuel process [4]. Post-combustion capture provides many advantages as existing combustion...
methods such as easier to implement as a retrofit option to existing plants compared to the other two types [5]. There are several separation methods that could be employed with post-combustion capture such as adsorption, chemical absorption, physical absorption, cryogenics separation and membranes [4]. Among various carbon capture technologies, chemical absorption method is more advantageous CCS technology than other methods due to high efficiency, low cost, and mature technology [6]. Solvents in chemical absorption include amine-based solvent such as monoethanolamine (MEA), diethanolamine (DEA), hindered amine (KS-1) and alkaline solvents such as NaOH, K2CO3, and Ca(OH)2 and Ionic liquids [7]. The utilization of amine solution is the most commonly methods for gas sweetening. Among the amines, MEA was frequently utilized to absorb CO2 from low-pressure flue gas streams, especially fossil fuel-based power plant, owing to rapid reaction rate with CO2 and low cost of raw amines compared to other amines [8-10].

Knudsen, et.al [11] informed that CO2 removal efficiency of CO2 capture pilot plan from coal-fired power plant at Esbjergværket, Denmark as part of EU CASTOR project achieved 90% with MEA 30 wt% during 4,000 h. In coal-fired power station at Queensland, Australia, amine-based CO2 absorption pilot plant has been operated to result in 84% of CO2 capture and regeneration energy of 3.6 GJ/ton CO2 with MEA 30wt% [12,13]. Meanwhile, Gjernes, et.al [15] reported that CO2 Technology Centre Mongstad (TCM), located at Statoil Refinery and one of largest post-combustion CO2 capture, treated flue gas from natural gas-based combined heat and power (CHP) and a residual fluid catalytic cracker (RFCC) which contain 3.5 and 13-14 vol% CO2, respectively. 83.4% of CO2 capture was attained using MEA 30 wt% at TCM [14-16]. On the other hand, Øi, et.al [17-19] has modelled three configurations namely standard, split-stream and vapor compression model of CO2 capture from natural gas-based power plant using Aspen Hysys. In standard configuration, heat consumption in regenerator was 3.26 GJ/ton CO2 while it could be decreased about 8% and 11% with split-stream and vapor compression scheme, respectively. Additionally, Aspen Hysys was also applied to simulate CO2 absorption of flue gas from cement industries which has CO2 content of 23.75 mole%. With CO2 capture of 85%, the energy consumption for MEA regeneration was 3.71 GJ/ton CO2 [20,21].

In this work, we demonstrated a model of CO2 absorption of flue gas from coal-fired power plant which has installed capacity of 4 x 65 MW (260 MW) in South Sumatra, Indonesia. Aspen Hysys was used to simulate the CO2 capture process and 30 wt% of MEA was selected as a solvent which is mainly handy for CO2 capture from flue gas. The parameters observed were the effect of lean amine, flue gas and regenerator feed mix temperature to CO2 capture, energy consumption and MEA losses. Moreover, the rich-split stream configuration was developed to examine energy reduction in various split fractions.

2. Methodology

2.1. Location
A coal-based power plant in South Sumatra, Indonesia was chosen for the location of CO2 capture simulation.

2.2. Data Collection
The data was obtained from a confidential third-party report that surveyed properties of flue gas in coal-based power plant, South Sumatra.

| Unit | Flue Gas Emission Flow Rate (Nm³/h) | Flue Gas Compositions (%vol) | Flue Gas Temperature (°C) | Flue Gas Pressure (Bar) |
|------|-----------------------------------|------------------------------|--------------------------|------------------------|
| 1    | 172,500                           | CO2: 13-14                   | 361.20                   | 1.5                    |
|      |                                   | O2: 4.5                      |                          |                        |
| 2    | 142,500                           | CO2: 13-14                   | 332.00                   | 1.5                    |
|      |                                   | O2: 4.5-5                    |                          |                        |

Table 1. Coal Power Plant Exhaust Emissions Characteristics.
| Unit | Flue Gas Emission Flow Rate (Nm³/h) | Flue Gas Compositions (%vol) | Flue Gas Temperature (°C) | Flue Gas Pressure (Bar) |
|------|-----------------------------------|-----------------------------|--------------------------|------------------------|
| 3    | 158,600                           | CO₂: 14-15                  | 369.04                   | 1.6                    |
|      |                                   | O₂: 4.5-5                   |                          |                        |
| 4    | 158,150                           | CO₂: 13-14                  | 378.54                   | 1.6                    |
|      |                                   | O₂: 4.5-5                   |                          |                        |

2.3. CO₂ Capture Simulation using Aspen Hysys V.10.0

CO₂ capture process was simulated using Aspen Hysys V10.0 software using the Acid Gas fluid package that is suitable to remove acid gases (H₂S and CO₂). Several parameters for simulation were taken from other studies [17,20,22]. The baseline flowsheet and process parameter of CO₂ capture is shown in Figure 1.

![Figure 1. Process flow diagram and modelling parameter of standard CO₂ capture from flue gas of coal-based power plant.](image)

The paper focused on CO₂ absorption-desorption process, excluding the pre-treatment process such as electrostatic precipitation, flue gas desulfurization (FGD), and selective catalytic reduction (SCR). Initially, the flue gas from four units was mixed and cooled to 40 °C before entering absorber column. MEA was chosen as amine solvent and contacted counter-current with flue gas in absorber. Thus, the rich MEA solution, containing CO₂ and trace of N₂ and O₂, was pumped to rich/lean amine heat exchanger for preheating to 103 °C. The gases in rich MEA were stripped at regenerator column and CO₂ was recovered in the top of column.

Hot lean MEA which still contains CO₂ from regenerator was cooled down to 40 °C in rich/lean amine heat exchanger and lean amine cooler. A makeup unit was added to ensure the desired flowrate and concentration of lean MEA as there was possibility of MEA and water losses at outlet of the absorber and regenerator column. Then, fresh lean MEA solution was pumped to absorber to start new absorption-desorption cycles. Due to high vapor pressure, the water wash unit was installed at the top of absorber in order to minimize MEA losses through vaporization [23]. Influence of lean amine, flue gas and regenerator feed mix temperature to CO₂ capture, energy consumption and MEA losses were studied. CO₂ capture was calculated using equation (1) from Qing, et. al work [25] which can be expressed as

\[
\text{CO}_2 \text{ capture} = \frac{P}{S} \times 100\% \tag{1}
\]

Where P and S show the mass flow of the CO₂ product and supply, respectively.
Moreover, rich-split model proposed by Cousins, et.al [13] and Eisenberg and Johnson [24] was built to analyze the reduction potential of regeneration energy of MEA. The system split unheated rich amine entering to the top of regenerator column and the heated rich amine was still flowed to stage 8. The split percentage of cold rich amine was varied. Figure 2 shows the rich-split flowsheet of CO₂ absorption.

![Rich-split configuration in CO₂ capture.](image)

Figure 2. Rich-split configuration in CO₂ capture.

3. Results and Discussion

Based on standard configuration, the CO₂ capture using MEA 30 wt% reached 85% with energy consumption of 5.42 GJ/ton CO₂. The percentage of CO₂ capture was similar with the work of Gervasi, et.al [20]. For validation, the regeneration energy of MEA 30 wt% in this study was in good agreement with industrial CO₂ absorption data reported by Wilson, et.al [26] and very closely with the experiment of Sakwattanapong, et.al [27]. Compared to another study, Badea and Dinca [28] stated that when MEA 30 wt% was applied, the heat consumption of 85% CO₂ capture was about 6.40 GJ/ton CO₂ which is greatly higher than that of this work. Moreover, installation of wash water was proven to decrease the MEA losses. Table 2 shows the comparison of CO₂ absorption process between this work and others.

| Parameter                          | This study | Gervasi, et.al [20] | Sakwattanapong, et.al [27] | Badea and Dinca [28] |
|-----------------------------------|------------|---------------------|-----------------------------|----------------------|
| CO₂ Capture (%)                  | 85         | 85                  | -                           | -                    |
| Lean CO₂ loading (mol CO₂/mol MEA) | 0.23       | 0.31               | 0.23                        | 0.26                 |
| MEA losses (ppm mole)            | 1          | 197                 | -                           | -                    |
| Regeneration Energy (GJ/ton CO₂)  | 5.42       | 3.71               | 5.20                        | 6.40                 |
| Purity of CO₂ (%)                | 97         | 98                  | -                           | -                    |

3.1. Effect of Lean Amine Temperature

The result of changing lean amine temperature is shown in Figure 3. The plot shows that the increase in temperature decreases the energy consumption and the CO₂ capture was stable over the simulation range. Usually, the absorption of acid gases with primary and secondary amines performance can be enhanced
by lowering the operating temperature of the absorber [29,30]. The lean amine temperature effect on the MEA losses is shown in Figure 3b. Based on the results it is clear that the increase in temperature increases the MEA losses. At a higher lean amine temperature, the absorber as a whole will be operated at a higher temperature. This higher operating temperature will increase the evaporation rate of MEA from the top of the absorber [31]. Compared to Gervasi’s study, the MEA losses in this study is relatively low as shown in Table 2.

3.2. Effect of Flue Gas Temperature

The effect of flue gas temperature is studied along the temperature range of 40–60 °C in plant’s performance condition and the response is plotted in Figure 4. The result shows that flue gas temperature variation affects the energy consumption and CO₂ capture. The energy consumption slightly increases as the temperature increases. Meanwhile, the CO₂ capture slightly decreases as the temperature increases. This is due to the fact that the CO₂ solubility decreases as the temperature increases [32].
3.3. Effect of Regenerator Feed Temperature
In order to investigate the response regenerator feed temperature on the process, the simulation was performed at temperatures range 96-110 °C. The simulation results are shown in Figure 5.

![Figure 5. The effect of regenerator feed temperature on CO\textsubscript{2} capture and energy consumption.](image)

The plot shows that the increase in regenerator feed temperature decreases the energy consumption. At the higher temperatures, the amount of carbon dioxide vapor in the feed stream increases, so regeneration energy needed was decrease [32]. The result shows that regenerator feed temperature variation does not affect the CO\textsubscript{2} capture and energy consumption.

3.4. Rich-Split Model
Rich-split model proposed by Cousins, et.al [13] and Eisenberg and Johnson [24] was built to analyze the reduction potential of regeneration energy of MEA. CO\textsubscript{2} capture efficiency of 85% and lean CO\textsubscript{2} loading of 0.23 were achieved for these runs. The effect of the fraction of solvent split to the top of the column on energy consumptions and reboiler duty is outlined in Figure 6. The minimum in energy consumption and reboiler duty occurs when 30% of the solvent is split to the top of the column. The minimum in reboiler duty should occur when the energy of vapor entering in the hot rich solvent stream matches the additional sensible heat requirement of the cold rich solvent entering at the top of the stripping column [13]. This minimum energy consumption was 5.08 GJ/ton CO\textsubscript{2} together with 759.43 GJ/h reboiler duty. This is a 35% reduction in energy consumption compared to the reference case without rich-split process. To investigate why this saving occurs, the CO\textsubscript{2} vapor mass flow rate and temperature along the stages in regenerator column for the baseline case was compared to the case when 30% of the cold rich solvent is split to the top of the stripping column.
As shown in Figure 7a, the CO₂ vapor mass flow rate in regenerator column was lower than baseline. This indicated that the driving force of the CO₂ desorption process was increased, which accelerates the CO₂ desorption rate and reduce the energy consumption of solvent regeneration. The split cold rich solvent decreased the temperature at the top stage of the stripper (stage 1) in the rich-split process, which was favorable because it could recover the steam and reduce the reboiler duty. Meanwhile, the temperatures along column after stage 2 were elevated. The temperature rise came from the heat exchanger where the unsplit rich solvent was heated to a higher temperature as a result of the decreasing solvent flow rate. The effectiveness of this rich split will be significantly influenced by the efficiency of the lean/rich heat exchanger [33].

Figure 6. The effect of split fraction on total energy consumption with 85% of CO₂ capture and 0.23 of lean CO₂ loading

Figure 7. Profile of (a) CO₂ vapor mass flowrate and (b) temperature at baseline and 30% split in regenerator column
4. Conclusion

The CO₂ removal of flue gas from coal-fired power plant model was developed in Aspen Hysys. The lean amine temperature, flue gas temperature, and regenerator feed temperature are varied to test its effect on the CO₂ capture and energy consumption. The increase in lean amine temperature decreases the energy consumption and the CO₂ capture was stable over the simulation range, besides that the increase in temperature increases the MEA losses. Flue gas temperature affects the energy consumption and CO₂ capture. The energy consumption slightly increases as the temperature increases, meanwhile the CO₂ capture slightly decreases as the temperature increases. The regenerator feed temperature on CO₂ capture and energy consumption has been studied. The result shows that regenerator feed temperature variation does not affect the CO₂ capture and energy consumption. The Rich-Split model was simulated to analyze the reduction potential of regeneration energy of MEA. The simulation result shows that the minimum in energy consumption and reboiler duty occurs when 30% of the solvent is split to the top of the column. The effectiveness of rich split will be significantly influenced by the efficiency of the lean/rich heat exchanger.

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