A Techno-Economic Feasibility and Performance Analysis of the CO_2 Capture Process Using Supersonic Separator and Methyldiethanolamine Sweetening

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Received: 28 April 2025 | Revised: 13 June 2025 | Accepted: 28 June 2025

DOI: https://doi.org/10.48084/etasr.11771

ABSTRACT

This study compared the performance and economic feasibility of two carbon capture technologies: Supersonic Separator (SS) and Chemical Absorption (CA) using Methyldiethanolamine (MDEA). Process simulations of natural gas processing plants were utilized through Aspen HYSYS. The resulted demonstrated that in CO_2-rich fields, SS achieved a maximum exergy efficiency of 74.01%, due to the absence of solvent regeneration. In contrast, CA demonstrated superior CO_2 removal in methane-rich streams, particularly at high pressures (51.34 bar) and flow rates (50 MMSCFD). The economic analysis indicated that CA offered a shorter Payback Period (PBP) and higher internal rate of return, making it suitable for short-term applications, while SS provided greater long-term profitability. The novelty of this work lied in its integrated evaluation of thermodynamic performance and economic viability across diverse gas compositions, providing a decision-making framework for optimizing Carbon Capture, Utilization, and Storage (CCUS) strategies in the natural gas sector.

Keywords-CCUS; techno-economic feasibility analysis; supersonic separator; MDEA sweetening; natural gas

I. INTRODUCTION

Indonesia is experiencing a significant surge in energy demand, leading to increased consumption of fossil fuels, such as gasoline, diesel, and aviation fuel, which reached 1.6 million barrels per day in 2022 [1]. Fossil fuels accounted for 72.3% of the country's energy mix, resulting in Greenhouse Gas (GHG) emissions totaling 692.2 $MtCO_2e$ in the same year [2]. Although Indonesia reduced the carbon emissions by 118 million tons in 2023, fossil fuels still dominate the energy landscape, underscoring the necessity for advanced mitigation strategies. CCUS is among the key solutions in reducing CO_2 emissions, particularly from power plants and heavy industries [3]. This technique involves capturing the CO_2 for reuse purposes or for permanent storage in depleted oil and gas reservoirs [4, 5]. Despite its potential, CCUS faces challenges due to high capital and operational costs, with CO_2 capture alone accounting for 70-80% of the total expenses [6-9].

Authors in [10] compared the energy consumption and CO_2 emissions using Supersonic Separation (SS) and conventional technologies, such as Membrane Permeation (MP). Their results demonstrated that SS exhibited a lower Hydrocarbon Dew-Point Adjustment (HCDPA), compared to the Triethylene Glycol (TEG) absorption process combined with the Joule-Thomson (JT) effect. Moreover, SS reduced the total energy required for CO_2 separation and Enhanced Oil Recovery (EOR) injection by up to 16.8% compared to MP, due to the higher temperature retained by the CO_2 stream exiting the SS system [11]. In [12, 13], steady-state simulations of a natural gas production facility were conducted utilizing the supersonic gas separation technology, known as the Gas Twister, through Aspen HYSYS software. Authors in [14] evaluated the facility's total energy consumption while considering hydrocarbon losses. By varying the CO_2 content in the natural gas and adjusting the arrival conditions, four case studies were carried out to assess their impact. The results revealed that higher CO_2 content led to lower energy consumption due to the reduced export gas recovery. This trend was consistent across the first and second case studies, even when the entire gas composition was altered in the latter. Meanwhile the third and fourth case studies examined the effects of varying inlet temperature and pressure. Although these factors had little effect on the overall energy consumption, they significantly affected the turboexpander performance, causing operational issues. While pressure variations were mitigated using a CO_2 reinjection system, extreme temperature changes required additional heating or cooling before the inlet separator to maintain stable operations. In [15], the performance of an amine absorber for CO_2 removal was examined using CA within a natural gas sweetening process. Their Aspen HYSYS simulations indicated that a blend of Methyldiethanolamine (MDEA) and Diethanolamine (DEA) effectively reduced the CO_2 content in the sweet gas to as low as 1.85 mol% at a rich amine temperature of 124.80 °C. Despite their effectiveness, the high-rich amine temperatures raised operational concerns, which could be mitigated with heat-stabilized salts. The MDEA/DEA blends offered a promising approach for an enhanced CO_2 removal in gas sweetening [16].

Research has been conducted on the effectiveness of two commonly used chemical solvents, MDEA and DEA, as well as their blends, in removing H_2S and CO_2 from natural gas [17, 18]. The findings indicated that the increase of the solvent concentration and circulation rate enhanced the sour gas absorption and increased the energy demand for regenerating the rich amine solution, leading to higher operational costs. Authors in [19] conducted a techno-economic analysis of CCS in an offshore natural gas field, evaluating four CO_2 capture technologies: membrane, CA, physical absorption, and cryogenics. The findings identified physical absorption as the most feasible option, with an Internal Rate of Return (IRR) of 15% and a PBP of 7.94 years. A sensitivity analysis revealed that the project Net Present Value (NPV) was highly dependent on gas price fluctuations, emphasizing the economic risks tied to market uncertainties [20].

While previous studies have focused on individual CCUS technologies or limited comparisons, there is still a gap in integrated, field-specific evaluations that combine both thermodynamic and economic assessments of SS and CA under varying gas compositions. This study provides a novel comparative analysis of the SS and CA technologies applied to Indonesian natural gas fields, using Aspen HYSYS simulations and economic modeling to deliver practical, scalable insights for optimizing the CO_2 capture strategies.

II. METHODOLOGY AND SYSTEM MODEL

This analysis was conducted using raw natural gas composition and condition data obtained from a plant facility across three gas fields in Indonesia. Each field exhibits distinct characteristics, as reflected in its composition and conditions, due to variations in the location and surrounding environment (Table I and Table II). Field Y, which is located in an offshore facility, had the lowest CO_2 content, while the others located in onshore fields had higher concentrations, with Field X exhibiting an ultra-rich CO_2 content.

TABLE I. RAW NATURAL GAS CONDITION DATA

Condition	**Field name**		
	Field X	**Field Y**	**Field Z**
Molar flow (MMSCFD)	29.00	50.00	27.86
Temperature (°C)	35.00	23.33	43.33
Pressure (bar)	27.90	51.34	15.49

TABLE II. RAW NATURAL GAS COMPOSITION DATA

Composition	**Field name**		
	Field X	**Field Y**	**Field Z**
Methane	0.3436	0.8435	0.6345
Ethane	0.0210	0.0714	0.0052
Propane	0.0100	0.0345	0.0005
i-Butane	0.0020	0.0096	0.0002
n-Butane	0.0030	0.0074	0.0001
i-Pentane	0.0014	0.0016	0.0001
n-Pentane	0.0011	0.0016	0.0001
n-Hexane	0.0037	0.0004	0.0002
Benzene	0.0001	0.0001	0.0001
Toluene	0.0001	0.0001	0.0001
H_2O	0.0027	0.0001	0.0001
H_2S	0.0001	0.0001	0.0001
CO_2	0.5973	0.0234	0.3545
Nitrogen	0.0140	0.0064	0.0046

A. Simulations

The simulation inputs included the operating conditions and natural gas composition for each field. This study compared the SS and CA capture models using MDEA, both built and validated in Aspen HYSYS.

1) Supersonic Seperation Model

The SS model was adapted from [14], as shown in Figure 1. This model was developed using the flow approach method applied to the SS process. After separation, the system utilized compressors and pumps to restore pressure, as the SS output had a high-pressure requirement. The gas composition data used in the simulation were in a dry condition, so they should be saturated with water before processing. The Equation of State (EOS) employed was the Peng-Robinson EOS, which served as the thermodynamic package for the simulation.

2) Chemical Absorption Model

Conversely, the CA model was adapted from [15], as displayed in Figure 2. The CA process utilized aqueous MDEA as the solvent to remove the acid gases, specifically CO_2. Two main units were included for CO_2 removal: an absorber column, which facilitated the absorption of CO_2 from the gas stream to produce sweet gas, and a distillation column, which separated the acid gas while regenerating the MDEA for reuse in the process. The acid gas-chemical solvent package was used as the thermodynamic package in this study, containing all the necessary amines and components, efficiently handling the chemical reactions and thermodynamic calculations involved in plant operations.

After completing the simulations in Aspen HYSYS, the process stream properties were reviewed in the worksheet section, particularly for exergy analysis. Physical exergy was determined using reference conditions: 25 °C and 101.3 kPa. These values were configured within Aspen HYSYS.

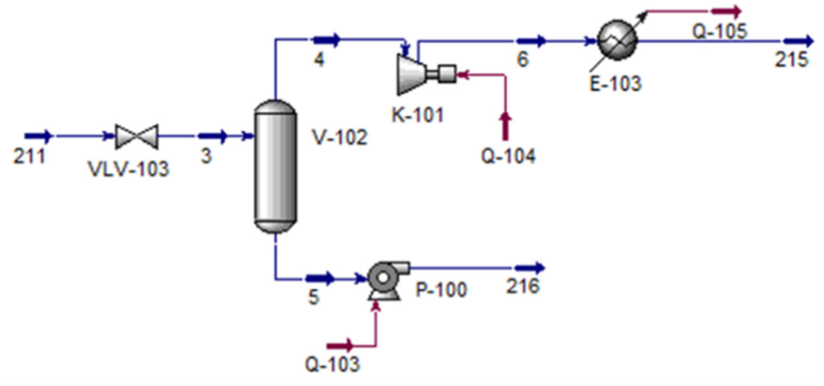

Fig. 1. SS model in Aspen HYSYS.

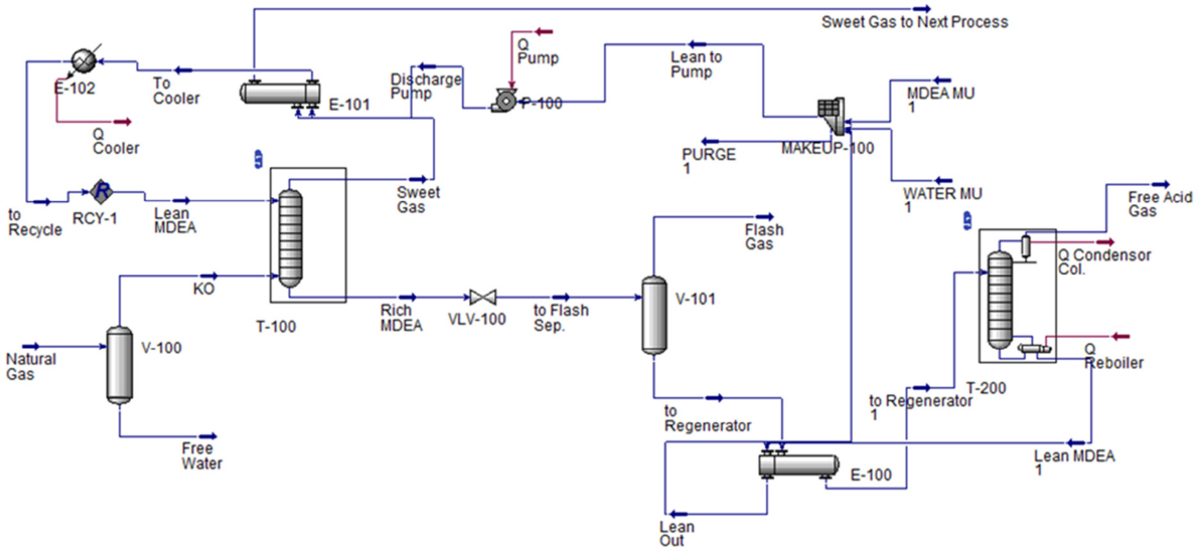

Fig. 2. CA model in Aspen HYSYS.

The variations in operating conditions and gas composition across the fields affected the equipment energy requirements. The factors influencing the equipment duty included the natural gas composition, product specifications (export gas or rich CO_2), and flow rates. The total equipment duty was an indicator of the energy demand and process efficiency.

B. *Performance Indicators*

Three performance indicators were calculated using Microsoft Excel to evaluate the process performance, obtained from the Aspen HYSYS simulation results and included: Pressure Recovery Rate, Carbon Dioxide Removal, and Methane Recovery Rate.

C. *Sensitivity Analysis*

The sensitivity analysis was conducted on both models to further evaluate the effectiveness of each process, particularly in assessing their thermodynamic properties and gas operating condition inputs. Two sensitivity analyses were performed: the first examined the effect of the gas molar flow on the CO_2 removal rate, while the second studied the impact of temperature input on the CO_2 molar flow.

D. *Techno-Economic Analysis*

The techno-economic analysis incorporated both revenue and cost models. The calculation methods were adapted from existing studies, with their parameters summarized in Table III [21].

1) *Revenue Model*

The revenue model was based on three primary sources: carbon tax, carbon credits, and capture cost fees. As CO_2 removal reduced the carbon tax liabilities, the project accounted for carbon tax as revenue, with a set rate of $10 per ton of CO_2. Additionally, revenue was generated through carbon credits, priced at $18 per ton, according to the global market rates. Further income was obtained by charging capture cost fees for providing CO_2 capture as a contractor.

2) *Cost Model*

Conversely, the cost model included expenses for the CO_2 capture, transportation, and storage, consisting of both Capital Expenditures (CAPEX) and Operating Expenditures (OPEX). CAPEX covered the costs associated with equipment, installation, utilities, instrumentation, yard improvements, service facilities, land and harbor, engineering, supervision, construction, and contingencies, and they were estimated using the Aspen HYSYS Economy Analyzer. OPEX included the operational and maintenance expenses, payroll, raw materials, laboratory costs, plant overhead, depreciation, and interest expenses, ensuring a comprehensive assessment of the total costs. The output of both models was the net cash flow discounted to obtain: NPV, IRR, and PBP.

TABLE III. TECHNO-ECONOMIC PARAMETERS

Parameters	Value
Project lifetime	20 years
Revenue tax	30%
Depreciation	10%
Discount factor	10%
Inflation	2.75%
Interest	7.90%
Equity	40%
Loan	60%
USD-IDR exchange rate	R. 16,000.00
Amine MDEA price	\$ 2,600/tCO_2
Water price	\$ 1.2/tCO_2
Carbon tax	\$ 10/tCO_2
Carbon credit price	\$ 18/tCO_2

III. RESULTS AND DISCUSSION

A. *Model Validation*

The SS model aimed to validate the reliability and accuracy of the simulation results obtained in this research. A comparison of the current findings with the reference results (Table IV) indicated that the model performed well, with a deviation of less than 2.5%. Similarly, the CA simulation results were compared with the real case data (Table V). The current model demonstrated good agreement, with the highest deviation of 2.37%.

TABLE IV. SS MODEL VALIDATION RESULTS

	References	Model	Deviation
CO_2 in export gas	7.90%	5.53%	2.37%
Hydrocarbon in export gas	88.57%	90.63%	2.06%
CO_2 in rich CO_2	92.49%	90.72%	1.77%
Hydrocarbon in rich CO_2	5.19%	7.10%	1.91%
Total hydrocarbon loss	8.86%	6.59%	2.27%

TABLE V. CA MODEL VALIDATION RESULTS

	References	Model	Deviation
CO_2 in sweet gas	36.55 mol%	37.25 mol%	2.37%
H_2S in sweet gas	0.013 mol%	0.010 mol%	2.06%
Hydrocarbon in rich amine	0.26 mol%	0.21 mol%	1.91%
Rich amine temperature	72.84 °C	70.88 °C	2.27%

B. *Exergy Analysis*

Generally, higher exergy values indicate greater energy within a flow or system. Based on Figure 3, which illustrates the CA process, Field Y exhibited the highest total exergy of 416.13 MW, compared to 375.20 MW for Field X and 373.09 MW for Field Z. This high energy value was primarily due to its greater molar flow rate and methane-rich composition (33,699.64 kg/h). In contrast, non-combustible components, like CO_2 and N_2, reduce exergy by diluting the energy content. The total mass flow of natural gas was also influenced by the CO_2 content, with its higher values increasing the gas density, and thus the mass flow. However, the operating pressure also plays a crucial role. For example, although Field X exhibited the highest mass flow of 49,282.35 kg/h, Field Y -with the highest operating pressure of 51.34 bar- maintained a relatively high mass flow despite its lower CO_2 content. When comparing the total exergy between CA and SS across the three fields, as shown in Figure 3, SS exhibited higher values in Field Y, whereas CA performed better in Fields X and Z. he methane-rich composition and high pressure in Field Y provided ideal conditions for SS, which relied on rapid expansion and cooling for separation, leading to increased exergy consumption. In contrast, Fields X and Z with higher CO_2 levels made CA a more energy-efficient solution. These differences in total exergy highlighted how the gas composition and pressure conditions could influence the efficiency and suitability of each separation technology across different fields.

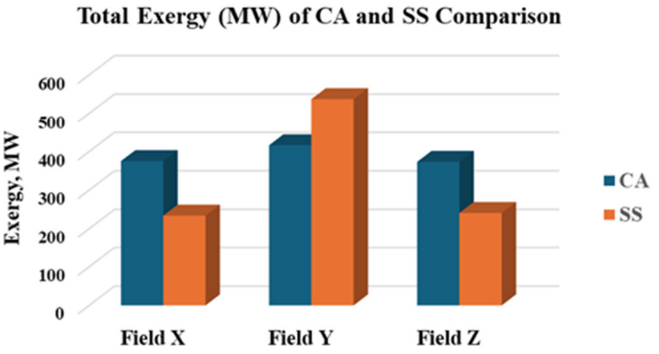

Fig. 3. Total exergy of CA and SS - comparison diagram.

Considering the exergy efficiency data for both CA and SS across Fields X, Y, and Z (Figures 4 and 5), significant insights into process suitability and energy utilization were observed. Field X, with the highest CO_2 content, exhibited the highest energy demand for CA, with a total exergy input of approximately 133.22 MW, leading to an exergy efficiency of around 70%. The SS process, however, demonstrated superior performance in Field X, achieving a higher efficiency of 74.01% with a much lower total exergy input of 32.93 MW, indicating that SS is more suitable for handling high CO_2 levels with lower energy consumption. Similarly, Field Z, which had a moderate CO_2 content, showed better efficiency with SS at 70.64% compared to CA, which also required a higher total exergy input. In contrast, Field Y, characterized by high pressure and methane-rich composition, presented a unique case, where CA displayed the lowest efficiency (due to lower released exergy), while SS, although performing better, had the lowest efficiency compared to its performance in other fields at 65.90%. This suggested that neither method was optimally suited for Field Y, likely due to the low CO_2 content and higher operating pressures, which introduced additional irreversibility.

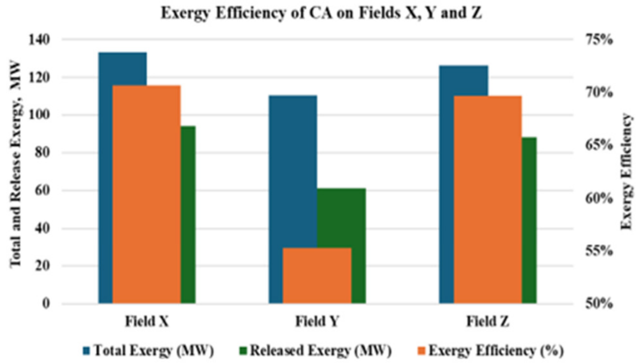

Fig. 4. Exergy efficiency of CA.

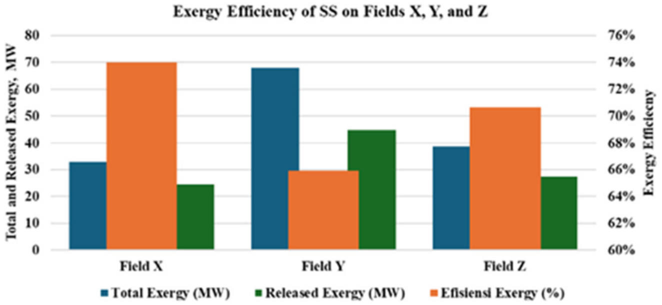

Fig. 5. Exergy efficiency of SS.

C. Duty Analysis

Figure 6 illustrates the total duty of both methods. Among the three fields, it is obvious that Field Y (CA diagram) had the lowest total duty at 42.05 MW, despite its highest molar flow rate. This value is due to the higher operating pressure of 51.34 bar, which enhances the CO_2 removal efficiency and reduces the reboiler energy demand.

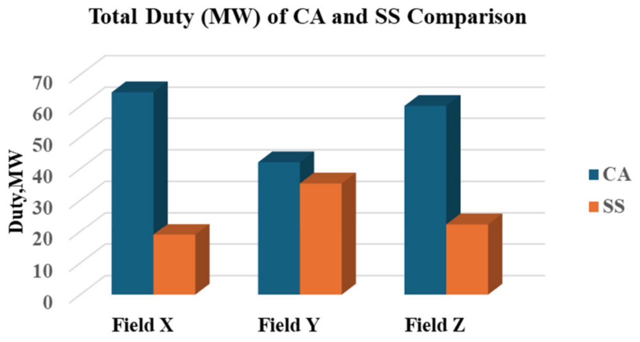

Fig. 6. Total Duty of CA and SS comparison diagram.

Additionally, the CO_2 mass flow in Field Y at 2,564.63 kg/h was significantly lower than in Field X at 37,969 kg/h and Field Z at 21,649 kg/h, leading to lower solvent regeneration requirements. High CO_2 levels in the gas feed increase the solvent flow rates and energy consumption, as seen in Field X, where a 1410 m³/h solvent flow rate corresponded to a peak reboiler duty of 30.13 MW. The case studies confirmed that the absorption of more acid gas required higher regeneration of energy. Comparatively, SS demonstrated lower overall duty than CA across all three fields, indicating superior energy efficiency. SS achieved separation through high-speed gas flow, eliminating the need for the energy-intensive chemical reactions and regeneration steps required in CA. In contrast, CA's high duty was mainly due to the substantial energy demand of the regeneration process, where the reboiler in the distillation column consumed significant energy to separate CO_2 from the MDEA solvent for reuse.

D. CO_2 Process Performance

The performance comparison between the CA and SS processes served as the final indicator to assess the feasibility of these methods. The graph for CA in Figure 7 showed that the methane recovery rates for the three fields were exceptionally high. Specifically, Field X had a recover rate at 99.63%, Field Y at 99.59%, and Field Z at 99.78%. These values surpassed the methane recovery rates of the SS models in Figure 8, making CA greater in this aspect. For the CO_2 removal rates, the CA model exhibited varying values: 41.44% for Field X, 85.13% for Field Y, and 60.26% for Field Z. In terms of the pressure recovery rate, the CA model outperformed the SS model, with rates of 86.02% for Field X, 95.44% for Field Y, and 83.93% for Field Z.

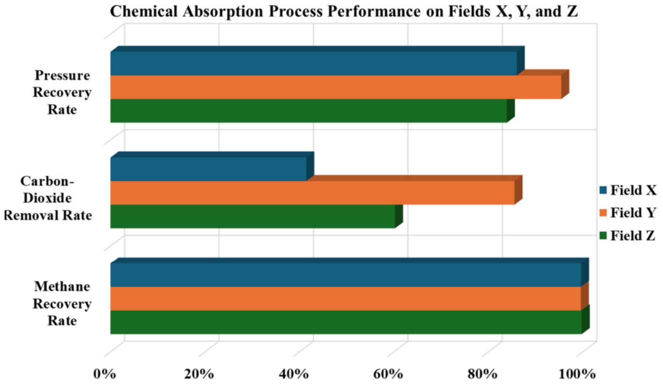

Fig. 7. CA CO_2 capture process performance.

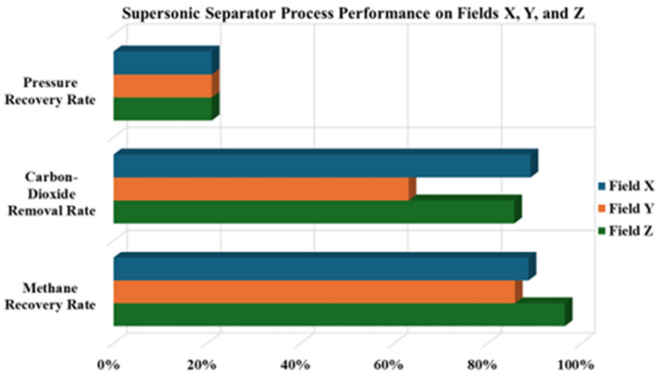

Fig. 8. SS CO_2 capture process performance.

Overall, SS demonstrated a better CO_2 absorption performance, except in Field Y. This difference occurred due to the CA process using MDEA, which effectively removed CO_2 in bulk quantities of natural gas. This further allowed Field Y to achieve the highest CO_2 removal rate due to its high molar flow of 50 MMSCFD. Additionally, the CO_2 absorption was influenced by the absorber pressure in Field Y, due to the highest pressure gained from the enhanced CO_2 removal efficiency. In this study, absorber pressure was set to match the operating conditions of each field. At higher CO_2 concentrations, the dew point temperature of the gas mixture increased, allowing CO_2 to condense at higher temperatures, improving the SS efficiency. This means that the required cooling for phase transition was more easily achieved compared to the low CO_2 content, where condensation demanded much lower temperatures that may not always be reached in SS. Additionally, more CO_2 molecules at high concentrations led to the formation of larger droplets, which were easier to separate due to their higher inertia. These droplets, once formed, were effectively removed from the gas stream by centrifugal forces, improving the overall removal efficiency. Conversely, when the CO_2 content was low, fewer condensation nuclei were formed, resulting in smaller droplets that may not separate efficiently, ultimately reducing the performance of the SS.

E. Sensitivity Analysis

Figure 9 presents the diagram of CA lean MDEA molar flow versus the CO_2 removal rate. It is obvious that with the increase of lean MDEA molar flow, the CO_2 removal rate also raised. The highest lean MDEA value was observed at 120 MMSCFD achieving the highest CO_2 removal rate, particularly in Field Y. This indicated that CA worked more effectively in fields with low CO_2 content in natural gas. However, in Figure 10, SS produced more scattered results compared to CA. The CO_2 removal rates varied across fields, with 96.66% in Field X, 45.66% in Field Y, and 96.29% in Field Z. Although the variations were minimal, about 0.001%, they can translate to a significant molar flow difference of 216,768 SCFD, impacting the environment. Therefore, optimizing the input molar flow was essential. The optimal raw gas molar flow rates in SS for high CO_2 removal efficiency were 20 MMSCFD for Field X, 35 MMSCFD for Field Y, and 30 MMSCFD for Field Z. Field Y exhibited the lowest CO_2 removal rate of 45% due to its low input concentration of approximately 2.34%.

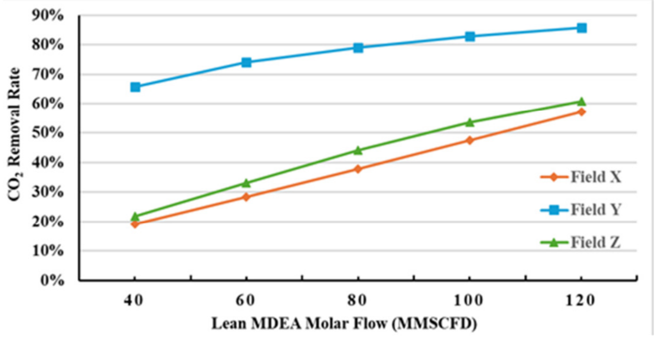

Fig. 9. CA-lean MDEA molar flow (MMSCFD) vs CO_2 removal rate (%).

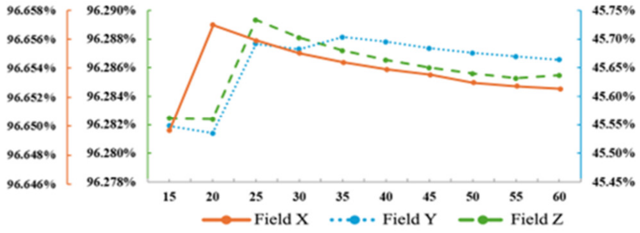

Fig. 10. SS-raw gas molar flow (MMSCFD) versus CO_2 removal rate (%).

F. Economic Analysis of the CO_2 Capture Process

Table VI presents the economic results of both CO_2 capture processes. CA offered a shorter PBP of 4 years and a higher IRR of 25.66%, with lower CAPEX of \$ 39,166,688 and OPEX of \$ 6,911,768, generating annual sales of \$ 20,346,292 and an NPV of \$ 51,996,220. In contrast, SS had a longer PBP of 5 years and a lower IRR of 24.42% but delivered significantly higher profitability, with an NPV of \$ 176,773,577, annual sales of \$ 72,488,729, and greater CAPEX of \$ 145,307,703 and OPEX of \$ 25,642,536. While CA was cost-effective and suited for faster returns, SS was more economically viable for long-term projects with a focus on maximizing profitability. For projects emphasizing scalability and returns, SS was the optimum option despite its higher upfront and operational costs, whereas CA was preferable for cost-sensitive operations with quicker returns as a priority.

TABLE VI. ECONOMICAL ASPECT CALCULATION RESULTS

Economic parameters	Unit	CA	SS
PBP	Year	4	5
IRR	%	25.66%	24.42%
NPV	USD	\$ 51,996,220	\$ 176,773,557
CAPEX	USD	\$ 39,166,688	\$ 145,307,703
OPEX	USD	\$ 6,911,768	\$ 25,642,536
Sales/year	USD	\$ 20,346,292	\$ 72,488,729

The cumulative and net cash flow analyses are presented in Figures 11 and 12, revealing that the CA method had a steady but slower growth in the cumulative cash flow, reflecting its lower CAPEX and smaller annual net cash flow. CA achieved payback within 4 years and continued generating modest profits over 20 years. In contrast, SS demonstrated a steeper cumulative cash flow curve due to its significantly higher annual net cash flow, despite its higher initial costs and a 5-year payback period. Over the long term, SS offered superior profitability and scalability, as evidenced by its larger cash flow margin compared to CA.

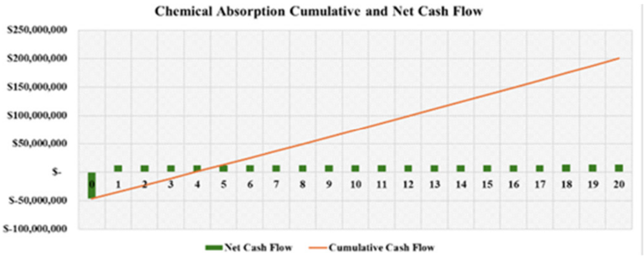

Fig. 11. Cumulative and net cash flow of CA.

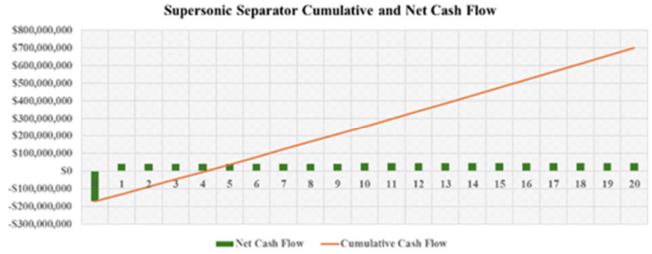

Fig. 12. Cumulative and net cash flow of SS.

IV. CONCLUSIONS

A natural gas processing plant model implementing SS and CA was simulated in Aspen HYSYS to evaluate the exergy efficiency, total duty, CO_2 removal performance, and sensitivity to operating conditions. The analysis highlighted that SS demonstrated superior CO_2 removal efficiency, particularly in CO_2-rich fields, such as Field X with 0.5973 CO_2 mole fraction and Field Z with 0.3545 CO_2 mole fraction, where it achieved exergy efficiencies of 74.01% and 70.64%, respectively. In methane-rich Field Y, with a high molar flow of 50 MMSCFD and elevated absorber pressure of 51.34 bar, CA using MDEA proved more effective due to enhanced CO_2 removal under these conditions. The efficiency of SS was closely related to the CO_2 concentration, as higher levels facilitated the phase separation through increased dew point temperature and larger droplet formation, improving the centrifugal separation. In contrast, lower concentrations reduced the condensation efficiency, limiting the SS performance.

From an economic perspective, CA offered a quicker return on investment with a 4-year payback period, a higher IRR of 25.66%, and lower costs with CAPEX of $ 39.17 million and OPEX of $ 6.91 million, making it a cost-effective choice for short-term operations. SS, despite its higher initial investment and a longer payback period, delivered greater long-term profitability, with an NPV of $ 176.77 million and annual sales of $ 72.49 million. These findings suggested that CA was preferable for short-term, cost-sensitive projects, while SS was more suitable for long-term operations seeking higher profitability and scalability. Overall, SS proved to be the optimal choice for CO_2-rich natural gas streams, whereas CA remained advantageous in methane-rich environments, where absorption-based separation was more efficient.

The novelty of this study lied in the integrated exergy and economic evaluation of SS and CA within a unified simulation framework, specifically tailored for diverse gas field compositions. The contributions of this work were twofold: (1) it provides process engineers with a robust decision-making tool for selecting the most suitable CO_2 removal method based on both thermodynamic and economic criteria, and (2) it highlights the underexplored potential of SS technology for long-term profitability in high-CO_2 fields, bridging a gap in current industrial practice and academic research.

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