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DECARBONIZING A THAI COAL POWER PLANT: EFFECT OF FLUE GAS LOADS ON CARBON CAPTURE PERFORMANCE AND ECONOMICS

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Abstract:
The objectives of this study are to evaluate the technical and cost implications of retrofitting post-combustion Carbon Capture and Storage (CCS) in existing coal-fired power plants in Thailand, with a special focus on the Mae Moh plant managed by the Electricity Generating Authority of Thailand (EGAT). We undertake a detailed analysis using AspenPlus simulation models to determine the optimum capture cost per ton of CO_2 and to examine the effects of various flue gas loads on CO_2 capture performance and cost-effectiveness. The research reveals a key operational insight: as the flow rate of flue gas increases, the cost to capture a ton of CO_2 decreases, indicating economies of scale in CCS operations. Furthermore, the study explores the potential for integrating solar photovoltaic (PV) technology as a renewable energy source, which shows promise in lowering Thailand's power sector emissions and operational costs. By comparing the levelized cost of electricity (LCOE) for solar PV against conventional coal-fired power generation and considering the country's favorable geographic and climatic conditions, solar PV emerges as an economically viable and environmentally sustainable alternative. The findings of this research aim to inform strategic energy policy decisions in Thailand, advocating for a transition to more sustainable energy systems and emphasizing the balance between environmental responsibility and economic feasibility.

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1. INTRODUCTION

Coal is considered to have a relatively low cost. Its energy price is much cheaper than oil and natural gas [1, 2]. Coal plays a crucial role in Thailand's energy mix since coal power plants provide a major fraction of the nation's power supply. However, despite its economic advantages, the use of coal has detrimental effects on the global climate due to greenhouse gas emissions (GHG), as well as the emission of toxic and carcinogenic particles produced during combustion. Consequently, many countries worldwide have implemented strict emission regulations [3].

Replacing coal with environmentally friendly fuels like electricity from renewable sources such as photovoltaic (PV), water (hydroelectric power), and wind power offers significant environmental benefits. It reduces greenhouse gas emissions, improves air quality, and conserves natural resources [4]. Additionally, transitioning to renewable energy sources fosters job creation,

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economic growth, and resilience to climate change, contributing to a more sustainable and environmentally friendly energy system [5].

Thailand was in the top 25 emitters of GHG worldwide and among the top ten countries most affected from long term climate risk. The power industry is the top greenhouse gas emitter . The Electricity Generating Authority of Thailand (EGAT) is the state-owned power utility under the Ministry of Energy, responsible for electric power generation and transmission for the entire country as well as bulk electric energy sales. EGAT has a strong determination to prevent and control the environmental impacts, especially emissions to air such as CO_2. EGAT runs and operates a 2,400 MW lignite-fired power plant at Mae Moh, Lampang. So far, EGAT – Mae Moh power plant helped reduce carbon emission for 1.5 million tons by improving efficiency of its power plant units. It is currently working to do more.

CCS technology can play a crucial role in GHG reduction and low carbon economy development for Thailand [6] . CCS and low-carbon technology concepts are relatively new to the country. There is an urgent need for solutions in dealing with carbon emissions [7, 8]. EGAT is assessing the feasibility of a post-combustion carbon separation system to capture CO_2 from exhaust gases, enabling existing power plants to be retrofitted with minimal changes. This method separates CO_2 into a concentrated stream for easy compression, transportation, and storage. The advantage of this approach lies in its ability to integrate into existing setups without significant modifications, preserving and potentially enhancing operational capacity. The system's placement at the end of the process chain, between the flue gas treatment devices and the stack.

There is a significant body of research focused on simulating carbon capture in power plants. For instance, Aromada et al. [9] reported a CO_2 capture cost of 67 €/tCO_2 for an amine-based CO_2 absorption and desorption process, simulated in AspenHYSYS V.10, which achieved an 85% CO_2 removal rate under specified conditions for power plants. Similarly, Kheirinik et al. [10] found the cost of avoiding CO_2 emissions to be 124.7 £/tCO_2 at a 230 MW coal-fired power plant equipped with post-combustion CO_2 capture technology. Another study [11] used the AspenPlus program to simulate a CO_2 capture plant for the flue gas of a 673 MWe coal-fired power plant and found the capture cost (at a 90% CO_2 capture rate) to be 44.71 £/tCO_2. Bonalumi et al. [12] utilized AspenPlus for simulating a CCS system integrated into a 550 MW coal-fired power plant, revealing a capture cost of 51.62 €/tCO_2.

For CO_2 separation from flue gas, a monoethanolamine (MEA) solution is often deployed [13]. In most pilot-scale works on the MEA solvent, Notz et al. [14] gave a complete description with respect to carbon separation with MEA solutions. The design method and concept employed are of great interest that numerical simulation of relevant processes is conducted especially for technical and economic analysis of the MEA-based units. However, most studies considered only full load of flue gas stream. It is essential to consider part loads of flue gas since this may be initially implemented on an existing plant for engineers and operators to gain more experience with CCS. Futhermore, technology is kept secret because all operate on a for-profit basis, Due to a lack of information, a decision regarding the implementation of the CCS system cannot be made.

The objectives of this study were to analyze the technical and cost aspects of retrofitting the designed capture plant at various flue gas loads and to assess their impact on carbon capture performance and economics. Additionally, the study aims to provide important and useful information for decision-making in CCS system implementation and to assist other relevant ongoing research.

2. METHODOLOGY

2.1 Modeling of Capture Process

Post-combustion carbon capture is about removal of CO_2 in exhaust gas with chemical absorption, and subsequent thermal stripping [11, 15]. In the research modelling, the AspenPlus RadFrac model was used for simulation of the absorption and stripping processes in the MEA-based capture plants. The process flow diagram is depicted in Fig. 1. The reaction kinetics and thermodynamic model proposed by Zhang et al. [16, 17] were employed. The rate equations (equations 1-4) for MEA-CO_2 absorption are presented below. The reaction rate was calculated using the power law expression, incorporating the pre-exponential factor and activation energy constants. The transport property models for gas and liquid phases (e.g., density, viscosity, mass transfer coefficient) are summarized and presented in our previous work [18].

$$MEA + CO_2 + H_2O \rightarrow MEACOO^- + H_3O^+ \quad (1)$$

$$HCO_3^- \rightarrow MEA + CO_2 + H_2O \quad (2)$$

$$CO_2 + OH^- \rightarrow HCO_3^- \quad (3)$$

$$HCO_3^- \rightarrow CO_2 + OH^- \quad (4)$$

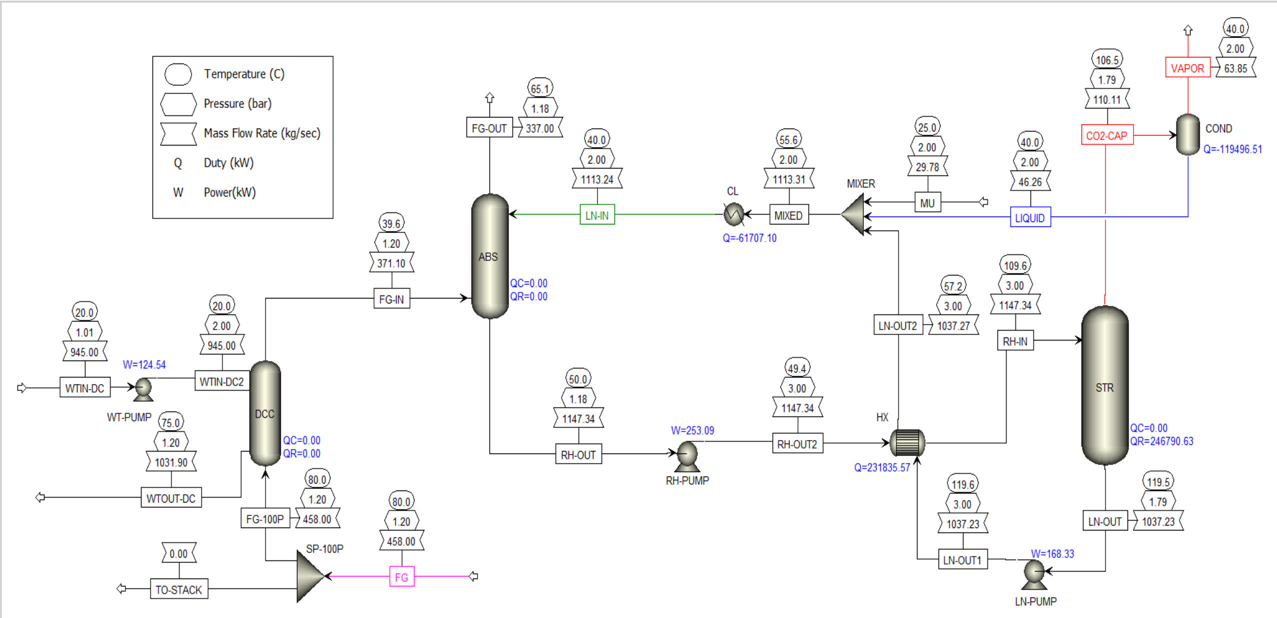


Fig. 1. Simulation process diagram of MEA-based carbon capture plant for EGAT coal-fired plant (CASE I, 100% of flue gas flow rate)

2.2 Model Development and Validation

The determination of the column dimensions (absorber and stripper sizing) was based on two criteria: (i) maximum allowable pressure loss and (ii) maximum acceptable capacity (approximately 80% of the flooding velocity). The length was determined using the height equivalent to a theoretical plate (HETP) as recommended on the research by Agbonghae et al. [11].

The models of absorber and desorber columns, which were validated against relevant experimental work [14] using Sulzer Mellapak 250Y packing structure, demonstrated satisfactory agreement. Subsequently, these validated models were utilized in up-scaling studies with an anticipated uncertainty of 10% or less. The dimensions of absorber and stripper columns were proposed for the desorber reboiling ability at 0.90 carbon capture efficiency and 30 percent by weight MEA concentration.

This work focuses on deploying an amine-based CO_2 capture technology to a 300 MW power generation unit of EGAT coal-fired plant in Lampang, Thailand. Table 1 depicts the compositions and conditions of flue gas, as well as other data adopted for design case studies. The operation expenditure (OPEX) and the capital investment expenditure (CAPEX) of the capture unit were established by the AspenPlus Economic Analyzer. The costs assumed for Thailand were adopted from those in the Economic Analyzer. It was noted that the CAPEX and OPEX were anticipated to be higher for actual retrofits, particularly when the equipment and auxiliaries must be installed in compliance with relevant standards. For example, they must be installed based on a hazard and operability (HAZOP) study [11]. Additionally, location factors that affect the overall cost, such as adverse weather conditions (e.g., rain, snow, low temperatures), waiting time, and costs for temporary facilities, must also be considered [19].

The case studies are itemized in Table 2 for variable loads of 100, 50, and 10% flue gas. The best available design was the one with the lowest OPEX. More economic assessment was also conducted for the annualized total cost (TOTEX) in Eq.(5). Calculation was set for 20 years (n = 20) of the service life and interest rate of 10 % (i = 0.1), Eq.(6):

$$TOTEX = OPEX + QEX + A.CAPEX \quad (5)$$

$$A.CAPEX = CAPEX\left(\frac{i(1+i)^n}{(1+i)^n - 1}\right) \quad (6)$$

where A.CAPEX and QEX are the annualized capital expenditure and the thermal energy expenditure, respectively.

Table 1. Conditions and information for the case studies

List	Value	Unit
Conditions of flue gas (FG)		
Temperature	80	°C
Flow rate (actual O_2)	458	kg/s
Pressure	1.2	kPa
Gas velocity	19.66	m/s
Composition		
Carbon dioxide (CO_2)	15.3	%
Moisture (H_2O)	21.96	%
Oxygen (O_2)	5.3	%
Nitrogen (N_2)	57.44	%
Simulating conditions		
Calculation	Rate-based model	-
The flood velocity	80	%
Max pressure loss per unit height	20.83	mmH_2O/m
MEA conc. without CO_2	0.3	mol CO_2/mol MEA
CO_2 capture rate	90	%
Cross Heat ex. temperature	110	°C
Cross Heat ex. temperature approach, hot end	10	°C
ΔP of Cross Heat ex.	0.1	bar
Lean amine cooler ΔP	0.1	bar
Discharge pressure of lean amine pump	3.0	bar
Efficiency of lean amine pump	0.75	-
Discharge pressure of rich amine pump	3.0	bar
Efficiency of rich amine pump	0.75	-
Cooling water temperature	20	°C
Absorber		
Number of stages	20	stages
Aspen Plus block	RadFrac model	-
Method for mass transfer coefficient	Bravo (1985)	-
Reaction number	(1), (2 for absorber), (3), (4)	-
Flooding method	Wallis	-
Method for interfacial area	Bravo (1985)	-
Film resistance options	Discrxn	-
Method for heat transfer coefficient	Chilton and Colburn	-
Top pressure	1	atm
Flow model	Counter current	-
Lean MEA inlet temperature	~40	°C
Desorber (STR)		
Number of stages	20	stages
Aspen Plus block	RadFrac model	-
Method for mass transfer coefficient	Bravo (1985)	-
Reaction number	(1), (2 for stripper), (3), (4)	-
Flooding method	Wallis	-
Method for interfacial area	Bravo (1985)	-
Film resistance options	Discrxn	-
Method for heat transfer coefficient	Chilton and Colburn	-
Condenser temperature and pressure	40, 2	°C, bar
Flow model	VPlug	-
Economic assumption (ref.: May, 2020)		
Electricity cost	77.5	\$/MWh
Cost of cooling water (in UK)	0.0396	\$/m^3
Plant equipment metallurgy	316L stainless steel	-

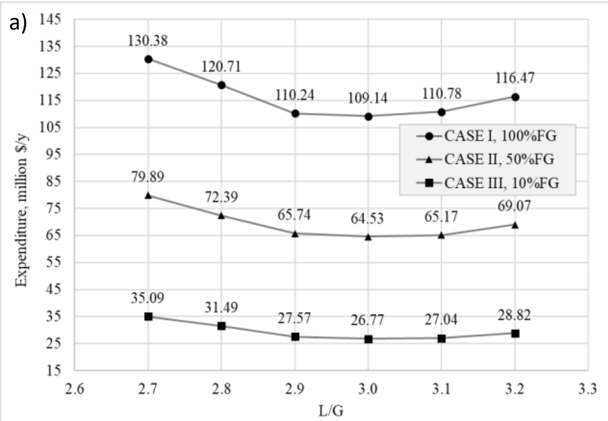
Table 2. Case studies for simulation

L/G	LN-IN (kg/s)	Absorber Height (m)	Absorber Diameter (m)	Stripper Height (m)	Stripper Diameter (m)	Spec. Reboiler Duty ($MJkg^{-1}CO_2^{-1}$)	CO_2 captured (%)
Case I, 100%FG							
2.7	1,001.95	49.10	13.77	16	8.41	3.53	89.92
2.8	1,039.05	26.00	14.05	16	8.57	3.66	89.98
2.9	1,076.16	14.75	14.15	16	8.81	3.79	89.96
3.0	1,113.27	10.67	14.28	16	8.88	3.92	89.99
3.1	1,150.38	9.21	14.33	16	9.03	4.05	89.97
3.2	1,187.49	8.48	14.36	16	9.10	4.17	89.96
Case II, 50%FG							
2.7	501.43	49.10	9.71	16	5.94	3.53	89.95
2.8	520.00	26.00	9.92	16	6.05	3.66	90.01
2.9	538.57	14.75	10.05	16	6.18	3.79	90.03
3.0	557.14	10.66	10.07	16	6.30	3.92	89.96
3.1	575.71	9.21	10.14	16	6.38	4.05	90.01
3.2	594.28	8.48	10.15	16	6.49	4.17	89.97
Case III, 10%FG							
2.7	100.25	49.10	4.35	16	2.73	3.53	89.93
2.8	103.96	26.00	4.45	16	2.71	3.66	90.00
2.9	107.67	14.88	4.50	16	2.77	3.79	90.07
3.0	111.38	10.54	4.53	16	2.82	3.92	89.93
3.1	115.10	9.22	4.52	16	2.82	4.05	89.92
3.2	118.81	8.42	4.56	16	2.86	4.17	89.97

3. RESULTS AND DISCUSSION

The simulated MEA-based carbon capture plants which could be fitted to a power station of the Mae Moh plant were studied. The best available designs in this work (at L/G = 3.0) are listed in Table 3 The optimum lean loading for a commercial power plant was about 0.2 mol/mol for absorber and stripper columns. The optimum L/G ratio for the coal power plant was determined to be 3.0 for a CO_2 concentration of about 15%. The cost evaluation of the capture unit is shown in Figs. 2 and 3.

In cases of 100%FG, 50%FG, and 10%FG, the annualized total costs (TOTEX) indicated in Fig. 2a were \$109.14 million, \$64.49 million, and \$26.78 million per year, respectively. The capture cost per ton of CO_2 shown in Fig. 2b was \$54.90, \$61.90, and \$134.68, respectively. These findings highlight the trade-offs between capture rate, total costs, and capture cost per ton of CO_2. They also underscore the importance of carefully considering both financial and environmental factors when making decisions about carbon capture technologies and policies.



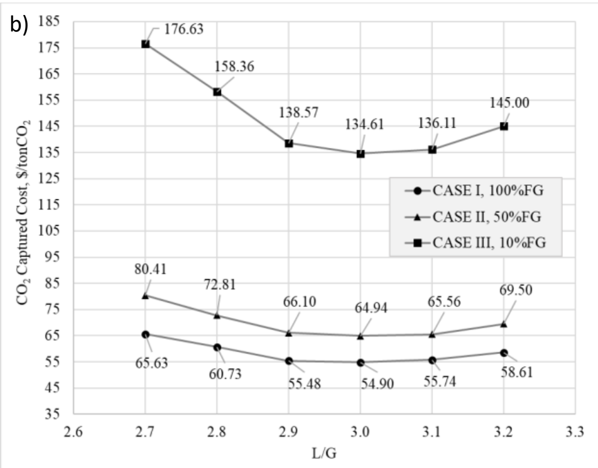


Fig. 2. a) TOTEX; b) CO_2 capture cost of coal-fired power plant

Table 3. Major findings for design of absorber and desorber (STR) columns

Lists	Data			Unit
	Case I, 100%FG	**Case II, 50%FG**	**Case III, 10%FG**	
Overall plant size	300	300	300	MWe
OPT lean CO_2 loading	0.200	0.200	0.200	mol/mol
OPT rich CO_2 loading	0.467	0.466	0.466	mol/mol
Flow rate of flue gas	458	229	45.8	kg/s
Flow rate of flue gas after DCC (FG-IN)	371.09	185.71	37.13	kg/s
CO_2 captured at 90% rate	63.0	31.5	6.3	kg/s
	1,988,037	993,668	198,844	tCO_2/year
Plant efficiency degraded	23.03	11.57	2.30	%
Power consumed from the plant	69.10	34.70	6.91	MWe
Plant equipment metals	316L stainless steel	316L stainless steel	316L stainless steel	-
Absorber				
Absorber packing	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y	-
Number of absorbers	1	1	1	-
OPT absorber diameter	14.28	10.07	4.53	m
OPT absorber height	10.67	10.66	10.54	m
Desorber (STR)				
Desorber packing	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y	-
Number of desorber	1	1	1	-
OPT desorber diameter	8.88	6.30	2.82	m
OPT desorber height	16	16	16	m
Desorber packing	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y	-
Reboiler temperature	119.55	119.82	119.58	°C
Reboiler duty	246,790.63 (68.55)	123,351.74 (34.46)	24,684.04 (6.86)	kWth (MWe)
Specific reboiler duty	3.92	3.92	3.92	MJ/kgCO_2
Condenser				
Condenser duty	119,496.51	59,477.73	11,557.00	kWth
Specific condenser duty	1.897	1.888	1.834	MJ/kgCO_2
Cross HX				
Duty	231,835.57	116,005.63	24,684.04	kWth
Rich amine inlet/outlet temp.	49.4/ 109.6	49.6/ 109.8	49.5/ 111.2	°C
Lean amine inlet/ outlet temp.	119.6/ 57.2	119.8/ 57.4	121.2/ 57.3	°C
Required exchanger area	30,921.70	15,466.10	3,206.44	sqm
Average U (Dirty)	0.85	0.85	0.85	kW/sqm-K
UA	26,283.48	131,461.94	2,725.47	kJ/sec-K
LMTD (corrected)	8.82	8.82	8.74	°C
Lean amine cooler				
Duty	61,707.09	31,286.89	6,220.82	kW
Lean amine pump				
Duty	168.33	73.77	13.68	kW
Rich amine pump				
Duty	253.09	111.81	22.35	kW
DCC water pump				
Duty	124.54	54.71	10.95	kW
Economic results				
CAPEX	123.089	70.86	23.24	M$
A. CAPEX	14.458	8.32	2.73	M$/year
OPEX	48.111	32.89	19.39	M$/year
QEX	46.572	23.28	4.66	M$/year
TOTEX	109.142	64.49	26.78	M$/year
Total cost per CO_2 captured	54.90	64.90	134.68	$/ton$CO_2$
Total cost per gross MWh	41.50	24.52	10.18	$/MWh

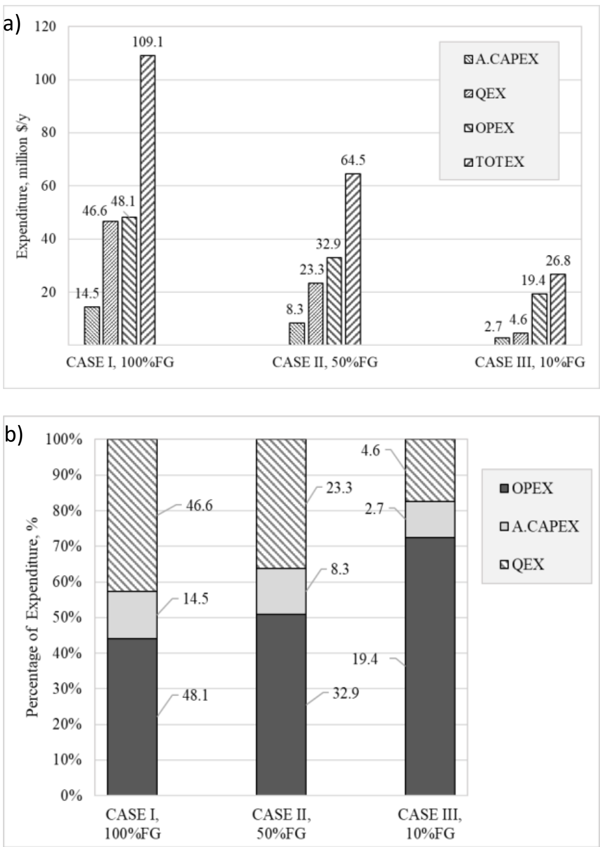


Fig. 3. a) Relative expenditures between cases b) Proportion of each expenditure

When looking at the capture cost per ton of CO_2, there are some interesting observations. Despite the decrease in total costs as the capture rate decreases, the capture cost per ton of CO_2 increases. This suggests that while capturing a smaller percentage of emissions is less expensive overall, it becomes relatively more costly on a per-ton basis. The flue gas load significantly affected CO_2 capture cost. Adopting a higher load led to a lower cost of capture. Additonally, the optimum case was at full flue gas load, resulting in 41.50 $/MWh of the total cost per gross plant size and the degraded efficiency of power plant was by about 23%. Figs. 3a and 3b illustrate that as the percentage of flue gas managed decreases from 100% to 10%, there is a corresponding reduction in various forms of expenditure, including capital, thermal energy, and operating costs. This observation suggests that strategies for reducing flue gas are financially advantageous in this context. Notably, the most significant reduction occurs in thermal energy expenditure, implying that managing flue gas potentially through heating or cooling processes represents a considerable energy and cost factor. Furthermore, the proportion of operating expenses (OPEX) increases as the percentage of flue gas managed diminishes. This trend may indicate a baseline level of operational costs that are incurred regardless of the flue gas volume, encompassing staffing, maintenance, and other fixed expenses.

The graph (Fig. 4) indicates the relationship between the flow rate of flue gas (in kilograms per second) and the cost of capturing CO_2 (in $/ton$CO_2$), including data points from this study (labeled as CASE I, CASE II, and CASE III) and various literature sources [11, 13, 15, 16]. The dashed line represents a fitted curve that shows a general trend of decreasing CO_2 capture cost with increasing flue gas flow rate. The mathematical relationship is given by the equation on the graph, where the cost is proportional to the flow rate raised to a power of -0.299. The negative exponent indicates an inverse relationship, meaning as the flow rate increases, the cost to capture a ton of CO_2 decreases. Moreover, the coefficient of determination (R^2 = 0.9317) is very close to 1, indicating that the curve fits the data well and that the flow rate of flue gas is a good predictor of the cost of CO_2 capture in these cases.

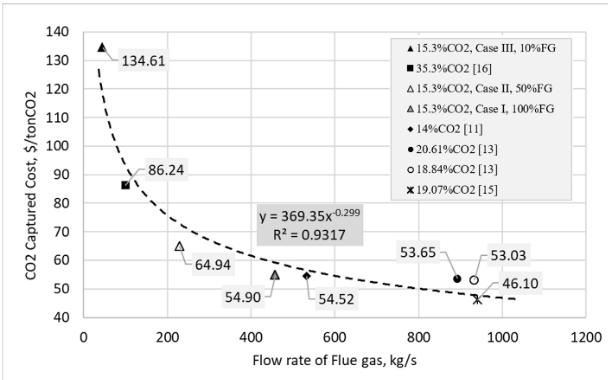


Fig. 4. Effect of flue gas flow rate, comparison with literature

In addition to optimizing the flow rate, employing more affordable alternative energy sources presents another strategy for cost reduction, as depicted in Fig. 5. The potential and suitability of each region play a crucial role in determining the global weighted-average leveled cost of electricity (LCOE) for renewable power generation, as indicated in references [20, 21]. The cost associated with CO_2 capture reflects the cost-effectiveness of carbon capture technologies. However, this cost is not directly relevant for renewable sources, given their lack of CO_2 emissions during electricity generation. For coal-fired power plants, the CO_2 capture cost ($54.90/ton$CO_2$) significantly elevates the overall expense, rendering it far less competitive compared to renewable alternatives. According to the data presented, solar photovoltaic (PV) emerged as an economically viable and environmentally sustainable option for electricity generation in Thailand. It boasts a competitive LCOE without the burden of CO_2 capture costs. Additionally, Thailand's geographical and climatic conditions favor solar energy production, potentially leading to an even lower effective LCOE for solar PV. Thus, a solar photovoltaic power plant is not merely beneficial for its reduced environmental impact but also for its long-term cost-saving potential, potentially lowering annual total expenditures by approximately 11.29% or $12.32 million.

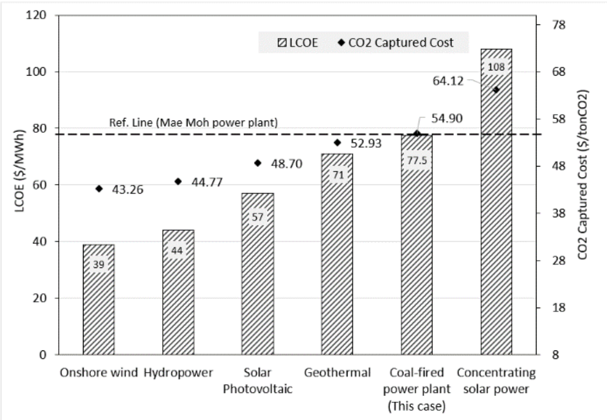


Fig. 5. Comparison of LCOE and CO_2-captured cost for each alternative energy source

4. CONCLUSION

The research undertaken presents a comprehensive analysis of the integration of CCS technology into the Mae Moh coal-fired power plant in Thailand. The study's simulation models, based on the AspenPlus program, reveal a decrease in total costs associated with carbon capture as flue gas loads decrease. However, this is contrasted by an increase in the capture cost per ton of CO_2, emphasizing the cost-benefit trade-offs inherent in CCS technology. The study notably identifies the economic advantage of full flue gas load scenarios in achieving lower CO_2 capture costs and emphasizes the importance of evaluating operational and capital expenditures when considering CCS retrofitting.

Moreover, the comparative analysis of renewable energy sources underscores the economic and environmental potential of solar PV for Thailand. With an LCOE significantly lower than the coal-fired baseline and absent the need for CO_2 capture, solar PV stands out as a sustainable energy solution that aligns with Thailand's climate goals and economic interests. The suitability of Thailand's climate for solar energy further enhances the appeal of PV systems, presenting an opportunity to reduce annual total expenditures while contributing to the global fight against climate change.

In conclusion, the findings advocate for a strategic approach in transitioning from coal to renewable energy sources in Thailand, with solar PV identified as a leading candidate. This transition not only promises environmental benefits but also offers economic incentives, positioning Thailand to meet its emission reduction targets and foster a low-carbon economy. The study's insights into CCS costs and renewable energy economics provide a valuable resource for policymakers and industry stakeholders in navigating the complexities of energy transition strategies.

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Conflicts of Interest

The authors declare no conflict of interest.

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