World Journal of Advanced Research and Reviews
eISSN: 2581-9615 CODEN (USA): WJARAI
Cross Ref DOI: 10.30574/wjarr
Journal homepage: https://wjarr.com/

(RESEARCH ARTICLE)

Check for updates

Carbon capture at the Maria Gléta 2 thermal power plant in Benin: Technical and economic aspects

Gildas David Farid Adamon [1, *], Djonoumawou Mèmèvêgni Grâce Floriane Chidikofan [2], Bernard Noukpo Tokpohozin [3], Eric Laurel Hounguevi [2], Sètondji Juste Acaluce Tossa [1] and Cyriaque Bosco Mitokpe [4]

[1] *National Higher Institute of Industrial Technology, National University of Sciences, Technologies, Engineering and Mathematics, Abomey, Benin.*
[2] *National Higher School of Energy and Process Engineering, National University of Sciences, Technologies, Engineering and Mathematics, Abomey, Benin.*
[3] *National Higher Institute of Preparatory Classes for Engineering Studies, National University of Sciences, Technologies, Engineering and Mathematics, Abomey, Benin.*
[4] *Laboratory of Electrotechnical Telecommunications and Applied Computing, University of Abomey-Calavi, Abomey-Calavi, Benin.*

World Journal of Advanced Research and Reviews, 2024, 24(03), 3247-3259

Publication history: Received on 16 November 2024; revised on 26 December 2024; accepted on 28 December 2024

Article DOI: https://doi.org/10.30574/wjarr.2024.24.3.3969

Abstract

Carbon capture, use and storage (CCS) technology, particularly post-combustion capture, has established itself as a key solution in strategies to reduce CO_2 emissions from thermal power plants. The present work aims to study different combinations of solvents to identify the one which allows an efficient CO_2 elimination process on the one hand and to carry out a technical and economic analysis of the entire process on the other hand on the Maria-Gléta 2 thermal power plant with a capacity of 127 MW in Benin. A model of the CO_2 capture process was produced using Aspen Hysys version 11 software and simulated based on the weight combinations of the solvents mon ethanolamine (MEA) and methyl diethanolamine (MDEA). The investment and operating costs of the system were estimated. It appears that the mixture of 30% MEA and 10% MDEA is energetically and economically profitable. The results obtained in this work offer promising prospects for the energy industry in the fight against climate change.

Keywords: ASPEN Hysys; Capture; Carbon; Thermal power plant; Maria-Gléta 2; Post combustion

1. Introduction

The emission of carbon dioxide (CO_2) is considered one of the main causes of global climate change. Electricity production from fossil fuels is the main CO_2 emitting sector (1). Thermal power plants, primarily on fossil fuels such as coal, natural gas and oil, are among the largest contributors to CO_2 emissions globally. In 2019, they represented around 42% of energy-related CO_2 emissions. The Maria Gléta 2 thermal power plant in Benin produces 585 g/kWh of CO_2 on gas and 650g/kWh of CO_2 on heavy fuel oil. Producing on average 87.23 kWh, it releases 441 t/year of CO_2 into the environment per year. Its emissions alone represented 5% of the country's emissions in 2021 (2). Given their significance in the energy transition, many countries are striving to limit their use in favor of renewable energies and cogeneration to enhance efficiency and lower carbon emissions.

To reduce footprints, carbon capture, utilization and storage (CCS) technology has emerged as a key solution in decarbonization strategies (3) (4) (5). This technology makes it possible to capture the CO_2 produced during the combustion of fossil fuels and then transport it to storage sites to prevent it from entering the atmosphere. Beyond

* Corresponding author: Gildas David Farid Adamon

reducing emissions, captured carbon can become a valuable resource for various industrial sectors, contributing to a circular carbon economy. CO_2 can be used in construction materials, the production of synthetic fuel and chemicals or in agriculture (6) (7).

CCS in thermal power plants relies on several techniques (Figure 1), including post-combustion capture, pre-combustion capture, and oxy-combustion capture (8) (9) (10).

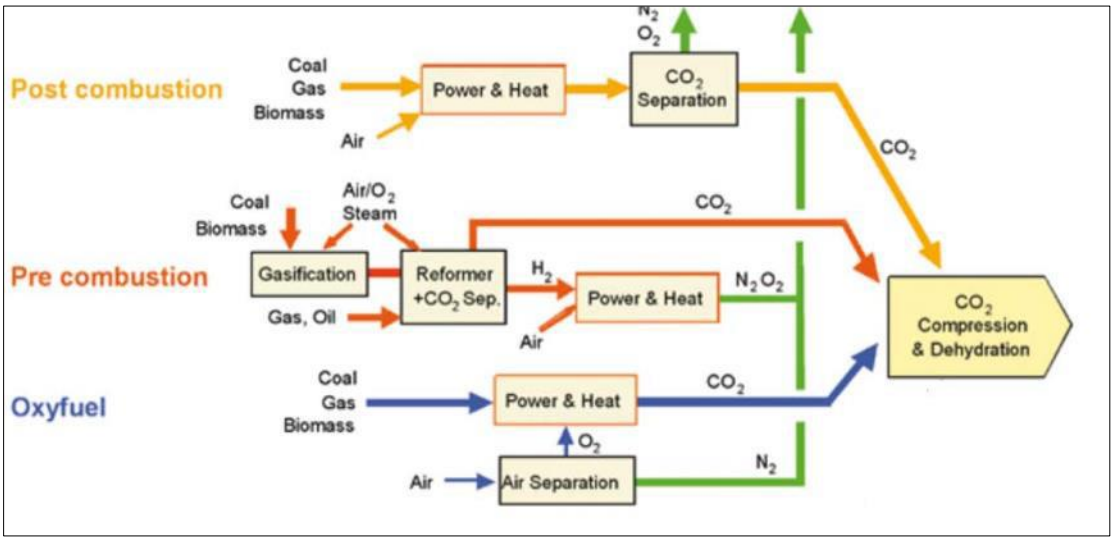

Figure 1 Classification and generic schematics for carbon capture technologies (11)

Although representing significant potential for reducing the carbon footprint of thermal power plants, these technologies require continuous improvements to be economically viable and minimize their environmental impacts. The cost of installing CCS technologies in a thermal power plant is very high, with estimates varying between $60 and $120 per tonne of CO_2 captured (12). This figure includes the cost of materials (CAPEX), labor, and operating costs (OPEX) related to maintenance, additional energy required for CO_2 capture and transport. Furthermore, integrating carbon capture units into thermal power plants substantially increases water consumption for cooling and chemical processes. In some cases, the water consumed can double compared to a plant without CCS.

This challenge is especially critical in water-scarce regions, where it can lead to conflicts with other essential uses, such as agriculture and domestic consumption (13).

Used after combustion, post-combustion capture makes it possible to capture the carbon dioxide (CO_2) contained in the fumes leaving the boiler using chemical solvents. These solvents capture CO_2 and release it during their regeneration. The main difficulty is the energy required for solvent regeneration, which reduces the efficiency of the plant by around 20-30% (14). Research has focused on improving solvents to reduce this parasitic load (8). In oxy-combustion technology, combustion takes place with pure oxygen instead of air, producing exhaust gases mainly composed of CO_2 and water vapor, which makes it easier to capture carbon dioxide (CO_2). However, this method requires expensive equipment for oxygen separation, further increasing the total cost of CCS technology. The pre-combustion capture approach consists of gasifying the fossil fuel to produce a mixture of H_2 and CO_2. The CO_2 is captured before combustion, and the dihydrogen (H_2) is used to produce electricity. The main challenge here is the complexity of the equipment required for gasification and gas separation, which increases initial and maintenance costs (8). As a result, post-combustion capture systems are among the most commonly used in thermal power plants.

Alkanolamines are the most frequently used solvents for CO_2 absorption (15). These include primary amines, such as Monethanolamine (MEA) (3), secondary amines, such as Diethanolamine (DEA), tertiary amines, such as Methyl Diethanolamine (MDEA) (16), as well as cyclic amines, notably Piperazine (PZ) (17). Primary and cyclic amines are distinguished by high reaction enthalpy and reaction rate with CO_2, while tertiary amines offer high absorption capacity and low regeneration cost (14). Therefore, the development of amine mixtures has led to improved performance of the CO_2 absorption process compared to pure amine solvents (18) (19) (20).

Several researchers have studied the use of mixed solvents for flue gas treatment. Idem et *al.* (21) tested MDEA/MEA and MEA solvents for thermal power plants, while Zhao et al. (22) evaluated the PZ/MDEA blend for coal-fired power

plants. Tan and Chen (23) investigated the application of PZ/MEA in packed-rotary column, while Tobiesen et al. (24) utilized the same mixture for treating blast furnace gases. These works highlight the strong potential of mixed amines to reduce energy consumption in carbon capture applications. Additionally, researchers like Hosseini-Ardali et al. (25) and Dubois and Thomas (26) concentrated on process simulation and optimization to further reduce the energy consumption associated with mixed amine absorption. However, these studies remain focused on the energy aspect, without offering a complete analysis or evaluation of the entire process.

The main objective of the present work is to study different combinations of solvents to identify the one that allows an efficient CO_2 elimination process on the one hand and to carry out a technical-economic analysis of the entire process. For this purpose, Aspen HYSYS version 11 was used to model the capture process. A basic scenario where the solvent is composed of 30% MEA was defined (27) after choosing the equipment with the input and output flows associated with each of them. The results of this scenario were compared to MDEA and its mixture with MEA.

2. Material and methods

2.1. Presentation of the thermal power plant

Located in Maria Gléta in the Municipality of Abomey-Calavi, approximately 20 km from downtown Cotonou, the Maria Gléta 2 power plant (Figure 2) is a 127 MW dual-fuel power plant. It is made up of 7 MAN 18V60DF engines with a unit power of 18.5 MW, a 161 kV evacuation station expandable to 400 MW capacity, a 161 kV interconnection station with 400 MW capacity, a connection system to the gas network and a 3 km access road. It covers approximately one-third (1/3) of the country's peak-hour demand.

Figure 2 Maria Gléta 2 thermal power plant

2.2. Specifications and process simulation

The simulation started by selecting the properties of the components involved in the process. This stage involves selecting the substances to be used. Next, a set of parameters was defined to structure the program. In this work, the focus is on amines and their mixtures. The process involves defining the equipment as well as the incoming and outgoing flows for each of them. To assess the impact of using alternative solvents and their mixtures, it is essential to first establish a feasible base case.

2.2.1. Process description of a standard process

Figure 3 shows a typical process for CO_2 capture using an amine absorbent. The system includes a low temperature absorption column, where carbon dioxide is absorbed effectively and efficiently from the flue gases using CO_2-free MEA. After undergoing partial heating in a cross-flow heat exchanger by the high-temperature CO2-free MEA exiting the stripper, the CO2-rich MEA enters the stripper column, where carbon dioxide is thermally separated from the amine. The reboiler provides heat to the stripper via low pressure steam, and the CO_2 separated from the MEA is released into the upper section of the stripper. In the present study, the captured CO_2 is released for future use in an agricultural greenhouse.

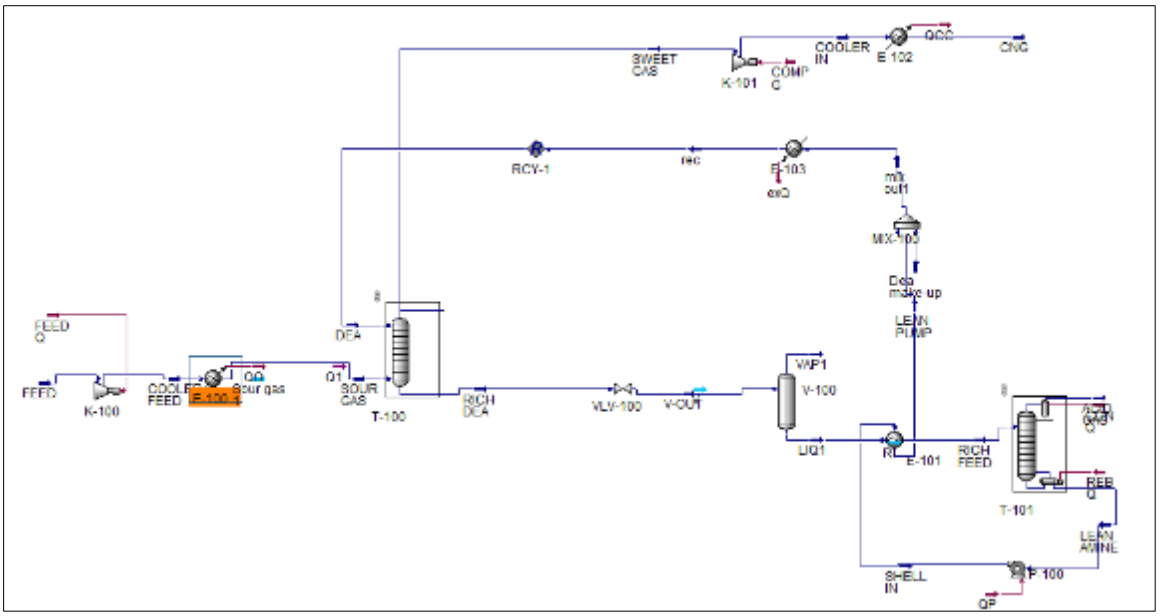

Figure 3 Process flow diagram of a standard amine-based CO_2 capture process from Aspen

2.2.2. Specifications and simulation of base case CO2 capture process

The base case for this work is defined from the work of Øi, (28) where an optimized process with 30% MEA solvent makes it possible to eliminate CO_2 from the combustion gas. The removal efficiency is 85% and the minimum approach temperature is 10°C in a lean atmosphere. The specifications for the base case are given in the Table 1, 2 and 3. base case are given in the Table 1, 2 and 3. The composition of the exhaust gas at the entrance to the capture process is collected in the control room of the Maria Gléta 2 thermal power plant.

Table 1 Exhaust gas composition

Composition	Molar fraction
CO_2	0.29
O_2	0.21
H_2O	0.12
SO_3	0.0659
SO_2	0.065
NO	0.072
NO_2	0.1771

Table 2 Base case solvent composition (25)

Composition	Molar fraction
CO_2	0.0169
O_2	0.0005
H_2O	0.7676
MEA	0.3

Table 3 Gas and solvent parameters at the equipment inlet.

Settings	Values	Units
Inlet flue gas temperature to be treated	500	°C
Flue gas temperature after cooling	40	°C
Pressure of inlet combustion gases to be treated	100	kPa
Flow rate of combustion gases at the inlet	9.663	Kmol/h
Content in the inlet gas	0.29	%
Water content in inlet gas	0.12	%
Lean amine temperature before and after the pump	40	°C
Amine pressure before rich pump	1.202	kPa
Amine pressure after rich pump	1.202	kPa
Lean amine pressure to absorb	1.202	kPa
CO_2 content in lean amine	0.0169	%
Number of stages in the absorber	10	-
Number of stripper stages	36	-
Reboiler temperature	165	°C

2.2.3. Specifications to another solvent and blends

Another solvent, MDEA, along with its blends such as MEA+MDEA, has been employed to simulate the standard removal process. The same base case specifications have been utilized for these processes. The simulated cases are summarized in the table below. All scenarios achieve a removal efficiency of 85% with a minimum approach temperature difference of 10°C. All simulated processes are grouped into seven classes:

- Removal process with 30% by weight of MEA amine mixtures;
- Removal process with 35% by weight of MEA amine mixtures;
- Removal process with 30% by weight amine mixtures of MEA and 5% MDEA;
- Removal process with 40% by weight of MEA amine mixtures;
- Removal process with 35% by weight amine mixtures of MEA and 5% MDEA;
- Removal process with 30% by weight amine mixtures of MEA and 10% MDEA;
- Removal process with 45% by weight of MEA amine mixtures.

All simulations were performed using Aspen HYSYS version 12. The main goal is to find amine mixtures that provide lower regeneration energy to reduce total disposal facility costs.

2.3. Sizing of main captation equipment

2.3.1. Absorption/desorption column

In the carbon capture and utilization process, the absorption column and the desorption column constitute the major equipment. The absorption column is designed to allow intimate contact between the gas containing carbon dioxide (CO_2) and the absorbing solvent and separate it from the rest of the exhaust gas. The desorption column releases the carbon dioxide (CO_2) previously captured by the solvent in the absorption column. Characteristic parameters such as gas volume flow, number of stages, stage height, column height and construction material are from Aspen Hysis.

The diameter and total packing volume of the column are calculated as follows (Eq1 and 2):

$$D = \sqrt{4.\frac{\dot{V}}{\pi.V_{gaz}}} \text{.....(1)}$$

where

D : column diameter ; $\dot{V}$: Volumetric flow rate; V_{gaz} : gas velocity

$$V_{emp} = \frac{\pi D^2}{4} . h_{\text{stage}} . N_{\text{stage}} \quad \text{..... (2)}$$

N_{stage} : Number of stages; h_{stage} : height of stages

2.3.2. Lean/rich heat exchanger

The lean/rich heat exchanger is involved in both the absorption and desorption processes. It is designed to maximize the thermal efficiency of the carbon capture process. It allows the transfer of heat from the rich gas, loaded with CO_2, to the lean gas, less concentrated in CO_2. This heat transfer is essential to heat the lean gas in the desorption column and thus facilitate the release of CO_2 from the solvent.

The heat exchange units were sized based on the heat exchange areas calculated from the thermal functions. The overall heat transfer coefficient of 500 W/(m².K), was specified (27). Its size is determined by equations 3 and 4:

$$\boldsymbol{S} = \frac{\boldsymbol{Q}}{\boldsymbol{U}.\Delta \boldsymbol{T_{lm}}} \text{ ..... (3)}$$

$$\Delta T_{lm} = \frac{\Delta T_{out} - \Delta T_{in}}{ln\frac{\Delta T_{out}}{\Delta T_{in}}} \text{ .....(4)}$$

With S: total air of the heat exchanger; Q: Heat exchanged; U: Heat exchanger coefficient; ΔT_{lm}: Logarithmic average temperature difference in °C; ΔT_{out}: Difference between the hot heat flow and the cold heat flow at the outlet ($T_{hot,in}$-$T_{cold,in}$) ; ΔT_{in}: Difference between the hot heat flow and the cold heat flow at the input ($T_{hot,out}$-$T_{cold,out}$) ; $\Delta T_{out} \neq \Delta T_{in}$. These settings come from Aspen Hysis.

2.3.3. Reboiler

The reboiler, a type of heat exchanger located at the base of the desorption column, provides the heat necessary for the process. It was sized following the same previous approach (Eq 3 and 4). The overall heat transfer coefficient of 800 W/ (m². K), was specified (27).

2.3.4. Condenser

The condenser is another type of heat exchanger where the gas phase of the substance cools and transforms into the liquid phase. It was sized using equations 3 and 4. The overall heat transfer coefficient of 1000 W/ (m². K), was specified (27).

2.3.5. Lean Amine Cooler

The lean amine cooler, also known as the lean amine heat exchanger, primarily serves to cool the lean amine mixture before it is reused in the CO_2 absorption process. The required heat transfer area for the cooler is determined using formulas 3 and 4. The overall heat transfer coefficient of 800 W/ (m². K) has been specified (27).

2.3.6. Pump

The pump is used to circulate the amine (or other solvent) through the system, including both the absorption and desorption column. Its characteristics (power, volume flow, pressure height) are determined by Aspen Hysys. It was specified as a centrifugal pump with an adiabatic efficiency of 75% (29).

2.3.7. Compressor

It is used to boost the pressure of gases released during the carbon capture process. Its power, volume flow, and inlet and outlet pressures are determined using Aspen Hysys, while its adiabatic efficiency is sourced from the literature (29).

2.3.8. Separator

A vertical separator was chosen to separate the two-phase flow leaving the desorption column. The sounder-Brown approach is applied for sizing (27).

$$V_{gmax} = K_S \sqrt{\frac{\rho_L - \rho_G}{\rho_L}} \quad \text{.....(5)}$$

$$D_{min} = \sqrt{\frac{{}^{4}/_{\pi}\, Q_a}{F_g * V_{gmax}}} \quad \text{..... (6)}$$

$${}^{L}/_{D_{min}} = 2.5 \quad \text{..... (7)}$$

With V_{gmax}: The maximum speed ${}^{m}/_{S}$; K_S: Sizing parameter ${}^{m}/_{S}$; ρ_L: Density of the liquid phase ${}^{Kg}/_{m^3}$; ρ_G: Density of the gas phase ${}^{Kg}/_{m^3}$; Qa (m^3/s) : gas flow rate at the actual flowing condition and Fg: fraction of cross section area available for gas flow; D_{min} : diameter and L: length. Parameter values are taken from Aspen Hysys and the literature (Ali et al., 2019).

2.3.9. Sizing of greenhouse

The current concentration of CO_2 in the atmosphere is 426 ppm (parts per million) while that recommended in a greenhouse is 1200 ppm (30).

$$CO_{2_{ppm}} = \frac{V_C}{V_t} \times 10^6 \quad \text{.....(8)}$$

With $CO2_{ppm}$: Concentration of CO_2 in the air, measured in parts per million; V_C: Volume of CO_2 produced, m^3 and V_t: Total air volume, m^3.

The gas flow rate at the plant outlet is 4200 m^3/h. CO_2 represents 30% of this gas, the gas flow rate of CO_2 is 1260 m^3/h. The additional concentration of CO_2 necessary to reach 1200 ppm is 774 ppm and the estimated volume of the greenhouse is 1,658,914.72 m^3. With a greenhouse 5 m high, the surface area of the greenhouse will be 331,782.94 m^2 or 33 ha. The total area of the plant site being 20 ha, the allocation of half seems appropriate for greenhouses, i.e. 10 ha.

2.4. Process economic evaluation

The main economic measure considered in the present work is the annualized total cost (TAC), of the CO2 capture process which combines the annualized investment cost (ACC) and the operating cost (AOC). Calculations are based on dimensions obtained from simulation in Aspen Hysis V12. The cost estimation procedure follows a similar approach to that of Øi et al (28).

2.4.1. Investment cost

Investment costs were estimated using the Enhanced Detailed Factor (EDF) method (29) (27). The total cost of capital is the sum of direct costs (CO_2 capture and use equipment, assembly, piping, electrical equipment, instrumentation, civil engineering, steel and concrete, insulation) and indirect costs (administration, engineering, contingencies and commissioning).

The acquisition costs of each capture equipment were determined using the Aspen In-Plant Cost Estimator version 11 tool based on the equipment sizing parameters for the base case. Depending on the construction material, a material factor was applied to the different equipment. Stainless steel (SS316) has been specified for all equipment. Welded equipment has a material factor of 1.75, machined equipment has a material factor of 1.3 and glass-reinforced plastics 1 (29). A traditional factorial method for cost estimation is based on an array of factors multiplying the cost of purchasing each type of equipment unit. In a detailed factorial method, the total factor for each type is the sum of contributions from, for example, plant, electricity, instrumentation, administration, etc. Since the costs obtained in Aspen In-Plant Cost Estimator version 11 are based on 2021 data, they have been updated for 2023 using the Chemical Engineering Plant Cost Index (CEPCI).

Twenty (20%) percent of the total cost is added to account for unlisted equipment such as direct contact cooler, mixer and control valve. All these costs are added the cost of installing the greenhouse. Capital expenditures were annualized based on the discount rate and lifetime (29). The lifespan is set at 21 years. The discount rate is assumed to be 7.5%.

2.4.2. Operating cost

Operating costs correspond to expenses related to the operation and management of the system. They are subdivided into fixed and variable costs. Fixed costs are expenses that are virtually constant from year to year and do not vary widely with changes in the rate of production. These costs mainly include maintenance costs. The factor method is adopted to calculate the maintenance cost over its lifespan, set at 21 years. They are taken as a percentage (4%) of the CAPEX (29).

Variable costs encompass electricity, steam, water, and solvent expenses. They are calculated simply as the sum of the product of the annually consumed quantity of each utility and its unit price. Unit prices for solvents are taken from the literature. The price of electricity is that applied by the Maria Gléta 2 thermal power plant, which is $0.073. The annual operating time is set at 8760 hours.

3. Results and discussion

3.1. Equipment dimensions

The results obtained are presented in Table 4.

Table 4 Dimensions of main equipments

Settings	Symbol	Units	Specification	Source
Absorption column				
Package volume	V_{emb}	m^3	70.7	Calculated
Column diameter	D	m	3	Calculated
Construction equipment			SS316	Hysys
Desorption column				
Package volume	V_{emb}	m^3	12.66	Calculated
Column diameter	D	m	1.27	Calculated
Construction equipment			SS316	Hysys
Heat exchanger				
Total air	S	m^2	391×10^3	Calculated
Logarithmic mean temperature difference	ΔT_{lm}	°C	90.55	Calculated
Manufacturing equipment			SS316	Hysys
Reboiler				
Logarithmic mean temperature difference	ΔT_{lm}	°C	80.38	Calculated
Total air	S	m^2	13×10^3	Calculated
Manufacturing equipment			SS316	Hysys
Condenser				
Logarithmic mean temperature difference	ΔT_{lm}	°C	40,2	Calculated
Total air	S	m^2	696.517	Calculated
Manufacturing equipment			SS316	HYSYS
Lean amine cooler				

Logarithmic mean temperature difference	ΔT_{lm}	°C	95.28	Calculated
Total air	S	m^2	21.659×10^3	Calculated
Manufacturing equipment			SS316	HYSYS
Pumps				
Power	P	KW	1.331x10^5	HYSYS
Volume flow	Q_v	$l/_S$	793.055	HYSYS
Compressor at the inlet of the capture cycle				
Power	P	W	2.352×10^6	HYSYS
Volume flow	Q_v	$l/_S$	1188.88	HYSYS
Compressor at the outlet of gases released from CO_2				
Power	P	W	1,427×10^6	HYSYS
Volume flow	Q_v	$l/_S$	403.055	HYSYS

A conventional process consisting of an absorber, an economizer and a stripper, and operating with a 30% solution of my ethanolamine (MEA) as the reference solvent; was notably installed on the industrial pilot of the European CASTOR project, operated in Esbjerg in Denmark, on a power plant of the company DONG Energy. It appears from this project that with a gas flow rate of 150 m^3 /h it is necessary to have an absorber 17 meters high and 1.1 meters in diameter and a desorption column 10 meters high and 0.8 meters in diameter (31). Likewise, a feasibility study on the installation of a capture process, based on MEA and sized to recover 5,800 tons of CO_2 per day, from a 600 MW liquid natural gas power plant was carried out. It appears from this study that it is necessary to have an absorption column that would have a diameter of 4.7 meters and a height of 44 meters. As for the regeneration column, its height would be limited to 25 meters (13).

Table 5 compares the dimensions of the absorber and regeneration column from these studies with those of the current work.

Table 5 Comparison of the dimensions of the absorber and the regeneration column

Source	**Height (m)**	**Diameter (m)**	**Mass flow rate of CO_2 (g/h)**	**Volume flow rate of the formed (m^3/h)**	**Volume of the column**
Absorber					
Present works	50	3	4×$\mathbf{10^6}$	4260	353.43
(31)	10	0.8	-	150	16.15
(13)	25	4,7	241 666,66	-	763.37
Regeneration column					
Present works	20	1.27	4×$\mathbf{10^6}$	4260	25.33
(31)	17	1.1	-	150	16.15
(13)	25	-	241 666,66		-

The small difference in the size of the desorption column can be explained by the fact that the desorption column receives the CO_2-rich solvent from the absorption column. The flow rates at the inlet of the desorption column are therefore more stable and require columns whose sizes vary less. The absorption columns receive smoke from a source outside the capture system such as a gas plant or a factory. The flow rate at the entrance of the absorption column fluctuates significantly, which in turn affects the required capacity of the absorption column to handle it.

On the other hand, the study of the table shows that the mass flow of CO_2 of Amann and Bouallou (13) is 16.55 times that of the current work. However, the absorber is only 2.16 times larger in volume. This small difference in size can be explained by the old age of the project given that it was implemented in 2004. Reducing the size of the absorption columns is also one of the key points of Amann and Bouallou (13). As for the desorption column, although its diameter is not mentioned in the project, its height of 25 m is relatively close to that of 20 m of our work. This confirms our observation made above that the size of the desorption column is less influenced by the flow rate of gas treated than the absorber. The method used for sizing can therefore be considered reliable.

3.2. Energy consumed

There are two main sources of energy expenditure. This pertains to the thermal energy required for regeneration and the electrical energy needed to power the various components of the process.

The simulation revealed that the heat obtained during the cooling of the exhaust gases is greater than that necessary for regeneration. Thus, this expense item will be eliminated because the heat recovered from this cooling can be redirected for reuse in the reboiler. The study focused on the impact of different mixtures on the electrical performance of the system. Table 6 presents the results for the various concentrations tested compared to the base scenario.

Table 6 Electrical energy consumed for each mixture

Solvent (% by weight)	**Electrical energy consumed [10^4 kWh]**	**Improvement compared with standard base scenario [%]**
30 % MEA (basic scenario)	1.49	-
35% MEA	1.407	5.57
30 % MEA+ 5 % MDEA	1.419	4.765
40% MEA	1.99	-33.55
35% MEA+5% MDEA	1.468	1.4765
30 % MEA+ 10 % MDEA	1.376	7.65
45 % MEA	1.542	-3.49

It appears that the mixture of 30% MEA + 10% MDEA is the least energy consuming.

3.3. Economic analysis

The cost of installing the capture system is estimated at USD 313.687.140,67 for the base scenario. Figure 4 illustrates the cost distribution (in dollars) for the other analyzed scenarios.

After accumulating the data, we observed that the different mixtures of solvents result in different annualized operating expenses. The highest is the mixture consisting of 40% MEA with an annualized OPEX of $46 980 704.48, an increase of 21.57% compared to the base case whose OPEX is $38, 644, 540.54. The mixture consisting of 30% MEA + 10% MDEA has the lowest OPEX with a value of $37, 224, 171.16. This mixture therefore allows a reduction in the operating cost of the plant by 3.67%. Adopting this mixture will save $29, 827, 756.98 over the 21 years of operation of the plant.

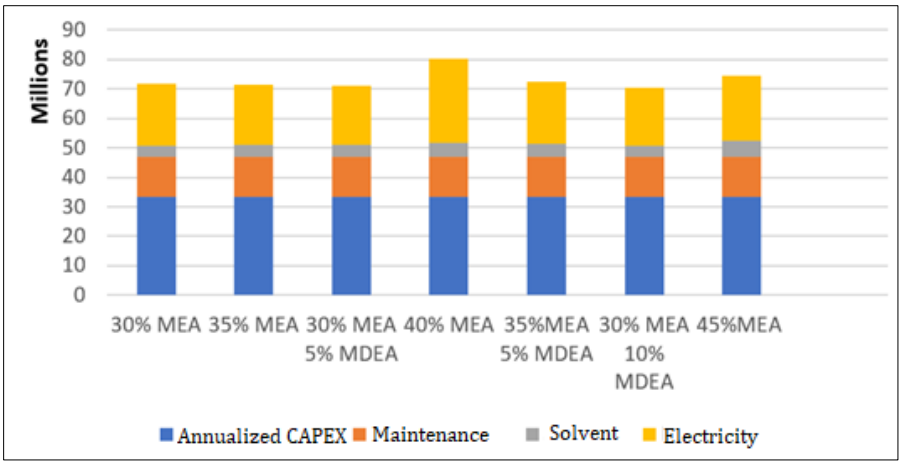

Figure 4 Distribution of total costs of the different scenarios

It thus emerges from this study that the solvent composed of 30% MEA and 10% MDEA is the most economical.

4. Conclusion

This work aimed to study different combinations of solvents to identify the one that allows an efficient CO_2 elimination process at the Maria Gléta 2 thermal power plant in Benin. The various characteristics of the CO_2 capture system were determined. The simulation made it possible not only to predict the behavior of the CO_2 capture system but also to identify optimization strategies with the Aspen Hysys software, showing that the solvent mixture consisting of 30% MEA and 10% MDEA in bulk is less energy intensive and more economical. The results obtained in this work offer promising prospects for the energy industry. This information is crucial in a context where reducing carbon dioxide emissions plays a central role in the fight against climate change.

Compliance with ethical standards

Acknowledgments

Thanks to the people and authorities of the Maria Gléta 2 power plant who made this study possible.

Disclosure of conflict of interest

The author(s) declares no conflict of interest.

References

[1] European Commission. Joint Research Centre. CO2 emissions of all world countries: JRC/IEA/PBL 2022 report. [Internet]. LU: Publications Office; 2022 [cité 6 déc 2024]. Disponible sur: https://data.europa.eu/doi/10.2760/07904

[2] https://fr.countryeconomy.com/energie-et-environnement/emissions-co2/benin. Bénin - Émissions de CO2. 2022.

[3] Liu G, Sun S, Sun H, Zhang Y, Lv J, Wang Y, et al. Integrated CO2 capture and utilization: A promising step contributing to carbon neutrality. Carbon Capture Science & Technology. 2023; 7:100116.

[4] González-Varela D, Hernández-Fontes C, Wang N, Pfeiffer H. State of the art and perspectives of the CO2 chemisorption in ceramics with its simultaneous or subsequent chemical transformation. Carbon Capture Science & Technology. 2023; 7:100101.

[5] Anika OC, Nnabuife SG, Bello A, Okoroafor ER, Kuang B, Villa R. Prospects of low and zero-carbon renewable fuels in 1.5-degree net zero emission actualization by 2050: A critical review. Carbon Capture Science & Technology. 2022; 5:100072.

[6] Allison J. Regenerative Organic Farming. Canada; 2023 p. 3.

[7] Arrouays D, Balesdent J, Germon JC, Jayet PA, Soussana JF, STENGEL P. Stocker du carbone dans les sols agricoles de France ? Synthèse du rapport d'expertise. 2020.

[8] Eldardiry H, Habib E. Carbon capture and sequestration in power generation: review of impacts and opportunities for water sustainability. Energ Sustain Soc. 2018;8(1):6.

[9] Haukås A. L. Automatization of Process Simulation and Cost Estimation of CO2 Capture in Aspen HYSYS. [Master thesis]. [Porsgrunn]: University of South-Eastern Norway; 2019.

[10] Fagerheim S. Process simulation of CO2 absorption at TCM Mongstad [Master thesis in Energy and Environmental Technology]. [Porsgrunn]: University of South-Eastern Norway; 2019.

[11] Oreggioni G. Design and simulation of pressure swing adsorption cycles for CO2 capture [PhD thesis]. University of Edinburgh; 2015. 185 p.

[12] Ezeh A, Kissling F, Singer P. Why sub-Saharan Africa might exceed its projected population size by 2100. The Lancet. 2020 ;396(10258):1131-3.

[13] Aman JM. Etude de procédés de captage du CO_2 dans les centrales thermiques [Thèse de doctorat]. [Paris (France)]: École Nationale Supérieure des Mines de Paris; 2008, 190p.

[14] Borhani N.T, Wang M. Role of solvents in CO2 capture processes: The review of selection and design methods. Renewable and Sustainable Energy Reviews. 2019; 114:109299.

[15] Liang Z., Rongwong W., Liu H., Fu K., Gao H., Cao F., Zhang R., Sema T., Henni A., Sumon K., Nath D., Gelowitz D., Srisang W., Saiwan C., Benamor A., Al-Marri M., Shi H., Supap T., Chan C., Zhou Q., Abu-Aahra M., Wilson M., Olson W., Idem R., Tontiwachwuthiku P. Recent progress and new developments in post-combustion carbon-capture technology with amine-based solvents. International Journal of Greenhouse Gas Control. 2015; 40:26-54.

[16] Feng Z, Cheng-Gang F, You-Ting W, Yuan-Tao W, Ai-Min L, Zhi-Bing Z. Absorption of CO2 in the aqueous solutions of functionalized ionic liquids and MDEA. Chemical Engineering Journal. 2010;160(2):691-7.

[17] Yuan Y, Rochelle GT. CO2 absorption rate and capacity of semi-aqueous piperazine for CO2 capture. International Journal of Greenhouse Gas Control. 2019; 85:182-6.

[18] Aghel B, Janati S, Wongwises S, Shadloo MS. Review on CO2 capture by blended amine solutions. International Journal of Greenhouse Gas Control. 2022; 119:103715.

[19] Mazari SA, Si Ali B, Jan BM, Saeed IM, Nizamuddin S. An overview of solvent management and emissions of amine-based CO2 capture technology. International Journal of Greenhouse Gas Control. 2015; 34:129-40.

[20] Meng F, Meng Y, Ju T, Han S, Lin L, Jiang J. Research progress of aqueous amine solution for CO2 capture: A review. Renewable and Sustainable Energy Reviews. 2022; 168:112902.

[21] Idem R, Wilson M, Tontiwachwuthikul P, Chakma A, Veawab A, Aroonwilas A, et al. Pilot Plant Studies of the CO 2 Capture Performance of Aqueous MEA and Mixed MEA/MDEA Solvents at the University of Regina CO 2 Capture Technology Development Plant and the Boundary Dam CO 2 Capture Demonstration Plant. Ind Eng Chem Res. 2006;45(8):2414-20.

[22] Zhao B, Liu F, Cui Z, Liu C, Yue H, Tang S, et al. Enhancing the energetic efficiency of MDEA/PZ-based CO2 capture technology for a 650 MW power plant: Process improvement. Applied Energy. 2017; 185:362-75.

[23] Tan CS, Chen JE. Absorption of carbon dioxide with piperazine and its mixtures in a rotating packed bed. Separation and Purification Technology. 2006;49(2):174-80.

[24] Tobiesen FA, Svendsen HF, Mejdell T. Modeling of Blast Furnace CO 2 Capture Using Amine Absorbents. Ind Eng Chem Res. 2007;46(23):7811-9.

[25] Hosseini-Ardali S.M., Hazrati-Kalbibaki M, Fattahi M, Lezsovits F. Multi-objective optimization of post combustion CO2 capture using methyldiethanolamine (MDEA) and piperazine (PZ) bi-solvent. Energy. 2020; 211:119035.

[26] Dubois L, Thomas D. Comparison of various configurations of the absorption-regeneration process using different solvents for the post-combustion CO2 capture applied to cement plant flue gases. International Journal of Greenhouse Gas Control. 2018; 69:20-35.

[27] Aromada S. A., Karunarathne S, Eldrup NH, Orangi S, Madan FF, Fajferek KG, Sæter, N.T., Bahri, S., Øi, L.E. Simulation and Impact of different Optimization Parameters on CO2 Capture Cost. In The First SIMS EUROSIM Conference on Modelling and Simulation, SIMS EUROSIM 2021, and 62nd International Conference of

Scandinavian Simulation Society, SIMS 2021, September 21-23, Virtual Conference, Finland, [cité 6 dec 2024]. Pp 309-16. Disponible sur: https://ecp.ep.liu.se/index.php/sims/article/view/360,

[28] Øi L. Aspen HYSYS simulation of CO2 removal by amine absorption from a gas based power plant. SIMS2007 Conference. 2007;

[29] Ali H, Eldrup NH, Normann F, Skagestad R, Øi LE. Cost Estimation of CO_2 Absorption Plants for CO_2 Mitigation – Method and Assumptions. International Journal of Greenhouse Gas Control. 2019; 88:10-23.

[30] Muntean M, Guizzardi D, Schaaf E, Crippa M, Solazzo E, Olivier JGJ, et Vignati, E. Fossil CO2 emissions of all world countries [Internet]. 2022 [cité 7 mars 2024]. Disponible sur : https://fr.countryeconomy.com/energie-et-environnement/emissions-co2

[31] Neveux T. Modélisation et optimisation des procédés de captage de CO_2 par absorption chimique, [PhD thesis]. [France] : Université de Lorraine ; 2018, France, 230p.