Investigation of *Alkanol-Amine* Solvents and their Blends for CO_2 Removal from Natural Gas using Aspen-Hysys

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ABSTRACT: The removal of carbon dioxide (CO_2) from natural gas is vital towards meeting pipeline sales gas specifications and evading operational complications during the liquefaction of natural gas. Therefore, the removal of CO_2 from natural gas is necessary for the efficient utilization of natural gas and for the reduction of global CO_2 emission. It is also vital for the effective liquefaction process in the liquefied natural gas project A common and widespread technique used at natural gas plants in Nigeria is the removal of carbon dioxide (CO_2) from natural gas through chemical absorption using alkanolamine solutions. In this research, an amine sweetening process is simulated using Aspen HYSYS V10 with a typical Nigerian natural gas composition. The simulation is used to investigate four different kinds of amines and their blends (mixed amines). The investigated amines are Monoethanolamine (MEA), Diethanolamine (DEA), Diglycolamine (DGA) and Methyldiethanolamine (MDEA) while the blends are MDEA + MEA, MDEA + DEA and MDEA + DGA. Results obtained from the simulation show that the mixed amine "MDEA + MEA" with lean amine strength of 11% MEA and 39% MDEA, absorbs 99.97% of CO_2 present in the gas and hence, amine blends absorb carbon dioxide from natural gas better than the individual amines. It was also concluded that increasing the composition of the primary or secondary amine while decreasing the composition of the tertiary amine in the lean amine solution (amine blend) led to an increase in the amount of CO_2 being absorbed. The study provides useful information on the absorption of CO_2 using alkanolamine solvents and their blends in a standard amine sweetening plant.

KEYWORDS: Aspen Hysys, amines, CO_2 emission, liquefaction, natural gas

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I. INTRODUCTION

Nigeria is one of the most populous countries in Africa that has amply various energy resources and its gas reserves are ranked globally as the ninth largest with about 182 trillion cubic feet of gas (Nwaoha & Wood, 2014). The discovery of natural gas in Nigeria was secondary as the exploration was aimed at the discovery of crude oil, therefore, prior to 1999, natural gas produced alongside crude oil were flared and not utilized (Ubani & Goodnesss, 2016). From a global perspective, gas flaring is a major cause of significant environmental problems and also a waste of valuable energy source that could serve as a source of employment to many and, revenue to the country (Hassan & Kouhy, 2013).

The sustainability of the environment and utilization of natural gas for socioeconomic benefit is on course in Nigeria through the successful utilization of natural gas that could have been flared in the form of Compressed Natural Gas (CNG), Liquefied Natural Gas (LNG), and Liquefied Petroleum Gas (LPG) (Otene *et al*., 2016). Nigeria is rapidly growing as the second fastest LNG producer in the world with a capacity of 22 million tons per annum (Agbonifo, 2016). Presently, about two-third of thermal power for electricity generation in Nigeria is derived from natural gas (Kamil et al, 2021).

Natural gas must be treated to certain quality specifications in order to meet up with market specification (Grande *et al*., 2017), ensure the reduction of potential greenhouse gas (GHG) emissions (Dong *et al*., 2017) and reduce the possible operational problems that may occur in the plants or during the gas transmission (Zahid *et al*., 2017). Carbon dioxide (CO_2) and hydrogen sulphide (H_2S) are the two major contaminants in natural gas due to their corrosiveness, toxicity and lack of heating value (Taemeh *et al*., 2018). Natural gas reserves in Nigeria contain little or no sulphur content, (Ubani & Goodnesss, 2016) and therefore the major focus is on the removal of CO_2 to negligible concentration levels which must be performed before the gas can be sold or utilized (Nwaoha *et al.*, 2017). The specification of CO_2 in natural gas for pipeline and the production of LNG is less than 3 mol % and 50 ppm respectively (Quek *et al*., 2021).

The most effective, efficient and commercially established separation technique widely used in the energy industries for the recovery of CO_2 from natural gas is the chemical absorption process with the use of alkanolamine solvents (Abdulsalam *et*

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al., 2019). Due to the selectivity of tertiary amines towards H_2S and the degradation products of the primary and secondary amines, mixed amines or amine blends are created to combine the advantages of the solvents and enhance the removal of CO_2 from natural gas (Ghanbarabadi & Khoshandam, 2015).

This study considers the efficiency of four different alkanol-amines and their blends in the removal of CO_2 from natural gas obtained from a gas reserve in Nigeria. The aim of this study is to simulate amine sweetening process using Aspen HYSYS V10 with a typical Nigerian natural gas composition.

II. METHODOLOGY

A. Process Configuration

A gas sample from a gas refinery located in Nigeria with composition as shown in Table 1 is sent into a separator to separate the gas from any liquid entrained in it. The gas contains some components that are not defined on HYSYS therefore information from the plant as regarding these components is used to define these components on HYSYS; Table 2. The gas is further sent into an absorber where the amine solvent or blend is used to absorb CO_2 from the gas with the possibility of attaining gas purity greater than 90%. The four amine solvents (MDEA, MEA, DEA, & DGA) and their blends (MDEA+MEA, MDEA+DEA and MDEA+DGA) were investigated using their respective lean amine strength range as shown in Table 3. The amine and acid gas mixture from the absorber was pumped into a regenerator so the solvent can be recirculated after it is cooled.

Table 1: Reservoir gas composition.

Component	Mole %	Component	Mole %
H_2S	0	C_8*	0.19
CO_2	0.56	C_9*	0.08
N_2	0	C_{10}*	0.05
C_1	95.88	C_{11}*	0.04
C_2	0.86	C_{12}*	0.04
C_3	0.33	C_{13}*	0.03
i-C_4	0.18	C_{14}*	0.03
n-C_4	0.42	C_{15}*	0.03
i-C_5	0.29	C_{16}*	0.02
n-C_5	0.3	C_{17}*	0.02
C_6*	0.28	C_{18}*	0.02
C_7*	0.32	C_{19}*	0.02
		C_{20}+*	0.01

B. Process Simulation

1) Component selection

The component list was created by selecting the components in Table 3 on Aspen HYSYS. The pseudo components (C_6* - C_{20}*) were defined on HYSYS using the properties given from the gas refinery in Table 4.

2) Fluid package basis selection

The "Acid Gas – Chemical Solvents" fluid package was selected as the appropriate property. The package supports all the amines and components needed for this research study and handles all the chemical reactions and thermodynamic calculations involved in the plant.

3) Process flow diagram (PFD)

In this study, a typical natural gas treatment facility was simulated using design data and parameter for a typical acid gas sweetening model. A model from AspenTech was used as a guideline for simulating the plant for using the component and compositions of natural gas from a refinery located in Nigeria. The following steps were used to carry out the simulation.

The process simulation began with the definition of the 'Gas' stream by specifying the conditions (temperature, pressure, and molar flow rate) and composition (Table 3) on the worksheet. The 'lean amine solution' stream was defined in the simulation by specifying the conditions (temperature, pressure, and standard ideal liquid volume flow). The composition for the lean amine stream (amine and water) was specified according to the lean amine strength for the respective amine

Table 2: Reservoir gas composition – Characterization properties of pseudo components.

Component	Molecular weight (g/mol)	Density (kg/m³)	Critical temperature (°C)	Critical pressure (bara)	Acentric factor	Normal boiling point (°C)	Critical volume (m³/kmol)
C_6*	86.17	664	262.66	28.81	0.29	68.75	0.37
C_7*	96	738	320.42	28.58	0.33	91.95	0.48
C_8*	107	765	198.28	26.6	0.37	116.75	0.49
C_9*	121	781	218.59	24.32	0.41	142.25	0.53
C_{10}*	134	792	389.98	22.6	0.45	165.85	0.57
C_{11}*	147	796	514.06	21.13	0.49	187.25	0.63
C_{12}*	161	810	539.11	19.96	0.53	208.35	0.68
C_{13}*	175	825	563.06	19.03	0.57	227.25	0.72
C_{14}*	190	836	587.17	18.15	0.61	246.45	0.78
C_{15}*	206	842	611.31	17.33	0.65	265.85	0.85
C_{16}*	222	849	634.65	16.65	0.7	282.85	0.92
C_{17}*	237	845	654.85	16.01	0.73	299.85	0.99
C_{18}*	251	848	673.8	15.56	0.77	312.85	1.06
C_{19}*	263	858	690.38	15.28	0.79	324.85	1.11
C_{20}+*	368.21	863	603.22	16.11	1.215	422.09	1.732

Table 3: Recommended lean amine strength in water.

Amine	Weight%
MEA	10 – 20
DEA	25 – 35
DGA	50 – 60
MDEA	40 – 50
MDEA + MEA	MDEA (39 – 49); MEA (1 – 11)
MDEA + DEA	MDEA (39 – 49); DEA (1 – 11)
MDEA + DGA	MDEA (39 – 49); DGA (1 – 11)

Table 4: Plant simulation parameters.

Gas	
Temperature	25 °C
Pressure	6900 kPa
Molar Flow	1250 kmol /hr
Lean Amine	
Temperature	35 °C
Pressure	6850 kPa
Std Ideal Liq Vol Flow	43 m^3/hr
Absorber Column	
Number of stages	20
Top Pressure	6850 kPa
Bottom Pressure	6900 kPa
Top Temperature	40 °C
Bottom Temperature	70 °C
Weir Height	0.025 m
Weir Length	1 m
Tray Volume	0.5655 m^3
Tray Diameter	1.2 m
Valve	
Outlet stream Pressure	620 kPa
Heat Exchanger	
Tube Side ΔP	70 kPa
Shell Side ΔP	70 kPa
Heat Exchanger mode	Exchanger Design (Weighted)
Tube Side Outlet Temp.	95 °C
Distillation Column	
Number of stages	18
Type of Condenser	Overhead
Feed Stage	4
Damping Factor	0.4
Solving Method	Modified HYSIM Inside-Out
Condenser Pressure	190 kPa
Condenser ΔP	15 kPa
Reboiler Pressure	220 kPa
Reboiler Temperature	125 °C
Tray 1 Temperature	100 °C
Efficiency (CO_2)	0.15
Efficiency (H_2S)	0.8
Overhead rate Estimate	75 kmol/hr
Reflux Ratio estimate	1.5
Condenser column Temp.	50 °C
Reboiler Column duty	1.3e^7 kJ/hr
Mixer	
Pressure Assignment	Equalize All
Outlet's Std Ideal Liq Vol Flow	43 m^3/hr
Cooler	
Pressure Drop	35 kPa
Pump	
Outlet Temperature	35 °C

solvent as shown. A valve and separator were modelled to reduce the pressure of the 'Rich amine solution' stream to a pressure close to the operating pressure of the regenerator column and flash off the residue gas from the rich amine solution respectively.

A heat exchanger is modelled to heat the amine solution stream coming from the separator before it is introduced into the regenerator. The regenerator was modelled as a distillation column in the simulation environment and the process conditions (number of stages, condenser pressure, reboiler pressure, reboiler temperature, condenser temperature, tray 1 temperature, inlet stage, overhead rate, reflux ratio, reboiler duty and the pressure drop in the condenser) were specified.

The distillation column has 18 stages excluding the condenser and reboiler. The component efficiency for CO_2 for the 18 stages and the condenser are in Table 5 (obtained from the GPSA engineering data book, 14th edition). Each amine was compared with their respective lean amine strength range.

A separator operator was introduced into the simulation environment to separate any liquid or free water entrained in the gas before it is sent to the absorber.

Table 5: Results from sensitivity analysis on MEA.

Lean amine strength	Amount of CO_2 in the raw gas	Amount of CO_2 in the sweet gas	Amount of CO_2 absorbed
10%	0.0056	1.23405E-06	0.005598766
11%	0.0056	9.56351E-07	0.005599044
12%	0.0056	7.83288E-07	0.005599217
13%	0.0056	6.88501E-07	0.005599311
14%	0.0056	5.98429E-07	0.005599402
15%	0.0056	5.87848E-07	0.005599412
16%	0.0056	5.38921E-07	0.005599461
17%	0.0056	5.28935E-07	0.005599471
18%	0.0056	5.21157E-07	0.005599479
19%	0.0056	5.16165E-07	0.005599484
20%	0.0056	5.15289E-07	0.005599485

The amine contactor column was modelled as an absorber operation column where the feed at the top stage and bottom stage were the 'Lean amine solution' stream and the 'Raw gas' stream (coming from the separator column) respectively. The process conditions of the column (top pressure, bottom pressure, number of stages, top temperature estimate and bottom temperature estimate) were also specified. The property package used in this study requires the trays in the contactor column to be modelled as real as possible. This was done by modelling the specific efficiency of CO_2 on a tray-by-tray basis and the tray dimensions were supplied to enable this feature. The weir height, weir length and diameter were specified according to the AspenTech model to enable the calculation of the efficiency by estimating the height of the liquid on the tray and the residence time of vapour in the liquid. The internals of the absorber were also automatically specified using HYSYS.

The 'Sweet Gas' comes out of the absorber through the top of the column and the 'Rich amine solution' stream through the bottom of the absorber. The rich amine solution stream is further sent to a distillation column where the amine and CO_2 are separated with the application of heat so that the amine solvent can be recycled for absorption.

Reboiler were specified along with the damping factor which is also a requirement for the column. Usually, the damping factor required for amine regenerators has a value between 0.25 and 0.5 but 0.40 was specified in this simulation because it provided a faster and more stable convergence.
The 'CO_2' goes out through the overhead stream of the distillation column while, the separated lean amine solution known as the 'Regen bottoms' stream comes out at the bottom of the column. The 'Regen bottoms' stream was introduced into the heat exchanger to cool the stream down.

Water is lost in the absorber and regenerator's overhead streams and a mixer is modelled to combine the 'Lean amine from HX' stream (the cooled down stream coming from the heat exchanger) with a fresh stream that contains only water ('Water' stream) at the same pressure.

III. RESULTS AND DISCUSSION

A. Absorption of Carbon Dioxide with Monoethanolamine (MEA)

The results for the sensitivity analysis performed on the composition of MEA is recorded in Table 5. The composition of MEA in the lean amine was varied according to the lean amine strength recommended by the GPSA handbook (14^{th} edition). From the results recorded, MEA is capable of treating the gas to the required specification of 50 ppm. The amine solvent (MEA) approximately absorbed all of the carbon dioxide present in the natural gas.

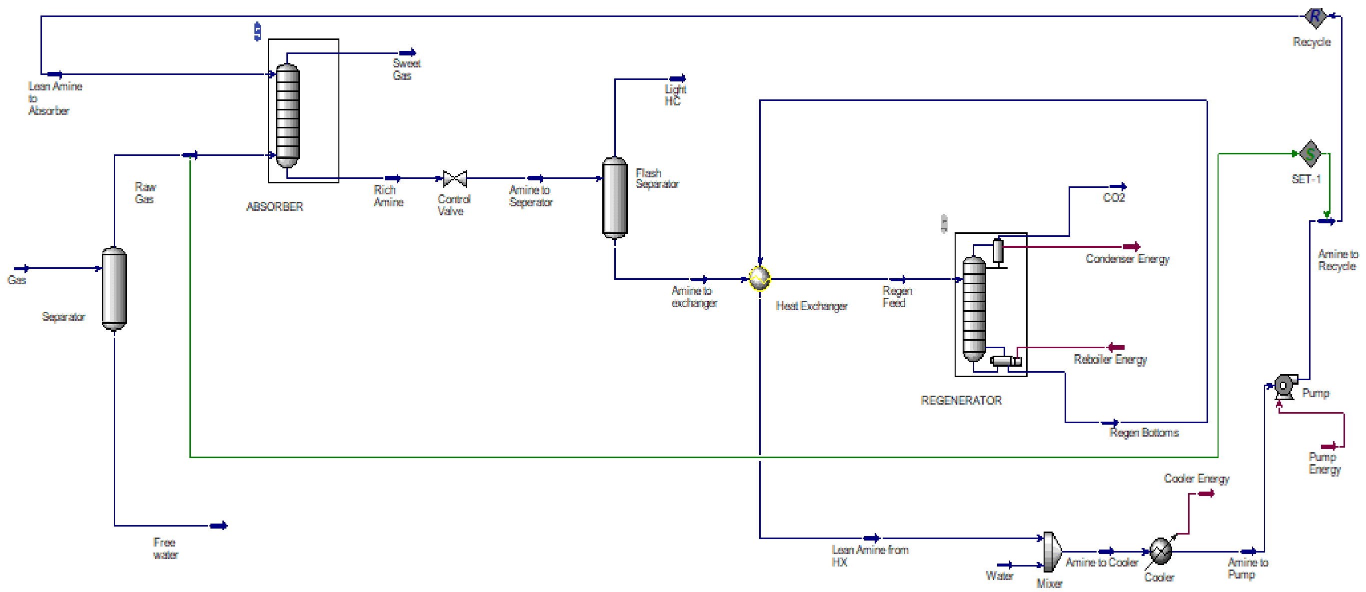

Figure 1: Process flow diagram (PFD).

This is to make up for the water that is lost by adjusting the flowrate of the water to achieve the lean amine circulation rate. The 'Amine to cooler' stream was further cooled down by modelling a cooler and the cooled stream was pumped back to the absorber (contacting column) by modelling a pump.
A set operation was modelled to set the pressure value of the "Sour Gas" stream in relation with the recycled lean amine solution ('Amine to recycle' stream). A recycle operation was also modelled to replace the lean amine solution stream with the recycle amine solution stream. The contactor and regenerator ran until the recycle loop converged. After the convergence, the results were analysed. The alkanolamines were investigated by replacing them in the properties section on HYSYS and their compositions were also varied in the simulation environment.

The Process Flow Diagram (PFD) built in the simulation environment is shown in Figure 1.

The relationship between the lean amine strength of MEA and the amount of carbon dioxide being absorbed is shown in Figure 2. The plot shows that as the concentration of the MEA in the lean amine increased, the amount of carbon dioxide left in the sweet gas also reduced.

B. Absorption of Carbon dioxide with Diethanolamine (DEA)

The results for the sensitivity analysis performed on the composition of DEA is recorded in Table 6. The composition of DEA in the lean amine was varied according to the lean amine strength recommended by the GPSA handbook (14^{th} edition). From the results recorded, DEA is capable of treating the gas to the required specification of 50 ppm. The relationship between the lean amine strength of DEA and the amount of carbon dioxide being absorbed is shown in Figure 3. The plot shows that as the concentration of the DEA in the lean amine increased, the amount of carbon dioxide left in the sweet gas also reduced.

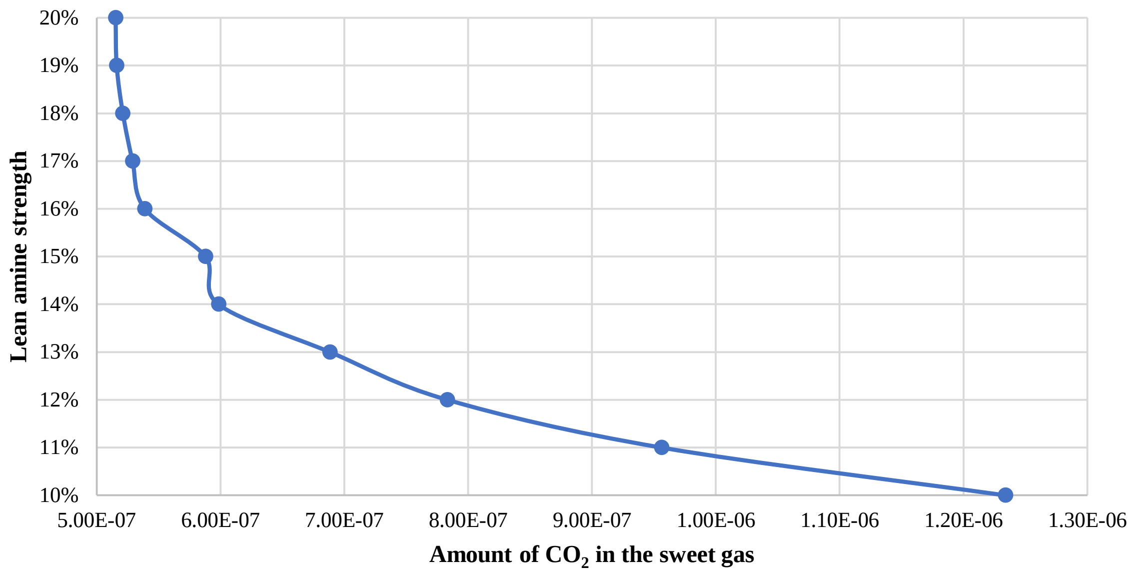

Figure 2: Plot of the lean amine strength against the amount of CO_2 in the sweet gas.

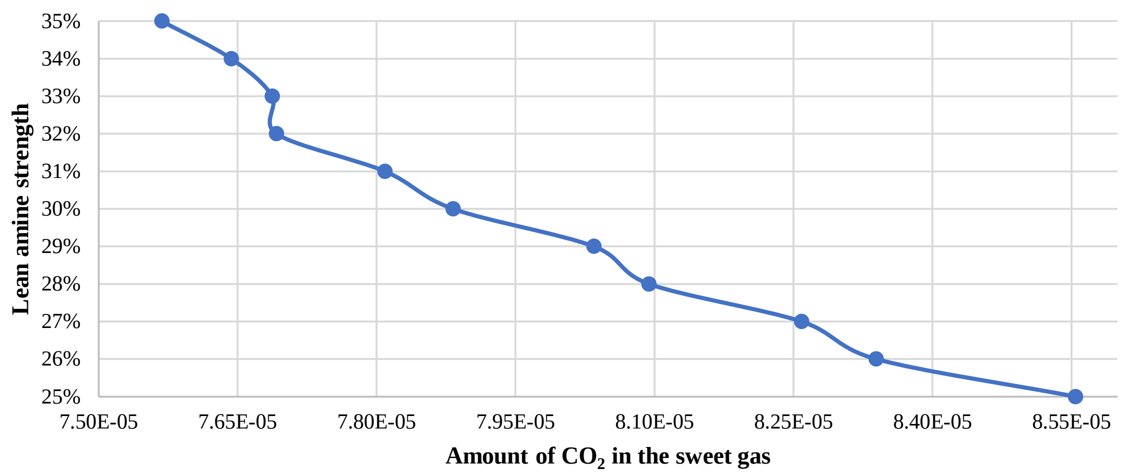

Figure 3: Plot of the lean amine strength of MEA against the amount of carbon dioxide left in the sweet gas.

Table 6: Results from sensitivity analysis on DEA.

Lean amine strength	Amount of CO_2 in the raw gas	Amount of CO_2 in the sweet gas	Amount of CO_2 absorbed
25%	0.0056	8.55436E-05	0.005514456
26%	0.0056	8.33902E-05	0.00551661
27%	0.0056	8.25854E-05	0.005517415
28%	0.0056	8.09387E-05	0.005519061
29%	0.0056	8.03435E-05	0.005519657
30%	0.0056	7.88253E-05	0.005521175
31%	0.0056	7.8088E-05	0.005521912
32%	0.0056	7.69176E-05	0.005523082
33%	0.0056	7.68722E-05	0.005523128
34%	0.0056	7.64303E-05	0.00552357
35%	0.0056	7.56819E-05	0.005524318

Table 7: Results from sensitivity analysis on DGA.

Lean amine strength	Amount of CO_2 in the raw gas	Amount of CO_2 in the sweet gas	Amount of CO_2 absorbed
50%	0.0056	3.85163E-07	0.005599615
51%	0.0056	3.47403E-07	0.005599653
52%	0.0056	3.13195E-07	0.005599687
53%	0.0056	2.79713E-07	0.00559972
54%	0.0056	2.58051E-07	0.005599742
55%	0.0056	2.30238E-07	0.00559977
56%	0.0056	2.04627E-07	0.005599795
57%	0.0056	1.81287E-07	0.005599819
58%	0.0056	1.5985E-07	0.00559984
59%	0.0056	1.40852E-07	0.005599859
60%	0.0056	1.23711E-07	0.005599876

C. Absorption of carbon dioxide with diglycolamine (DGA)

The results for the sensitivity analysis performed on the composition of DGA is recorded in Table 7. The composition of DGA in the lean amine was varied according to the lean amine strength recommended by the GPSA handbook (14th edition). From the results recorded, DGA is capable of treating the gas to the required specification of 50 ppm. The relationship between the lean amine strength of DGA and the amount of carbon dioxide being absorbed is shown in Figure 4. The plot shows that as the concentration of the DGA in the lean amine increases, the amount of carbon dioxide left in the sweet gas also reduces.

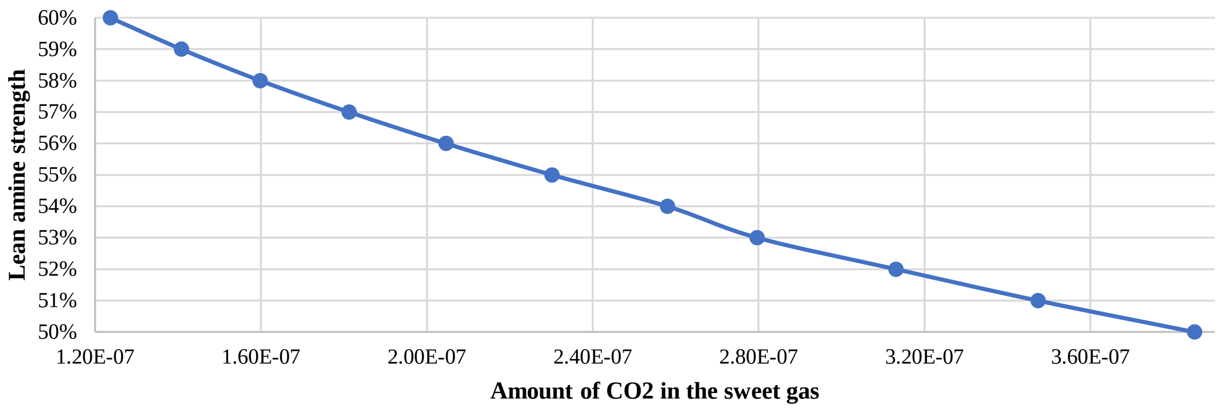

Figure 4: A plot of the lean amine strength of DGA against the amount of carbon dioxide left in the sweet gas.

D. *Absorption of Carbon dioxide with Methyldiethanolamine (MDEA)*

The results for the sensitivity analysis performed on the composition of MDEA is recorded in Table 8. The composition of MDEA in the lean amine was varied according to the lean amine strength recommended by the GPSA handbook (14th edition). From the results recorded, MDEA is not capable of treating the gas to the required specification of 50 ppm.

The relationship between the lean amine strength of DEA and the amount of carbon dioxide being absorbed is shown in Figure 5. The plot shows that as the concentration of the MDEA in the lean amine increased, the amount of carbon dioxide left in the sweet gas also increased.

E. *Absorption of carbon dioxide with methyldiethanolamine (MDEA) and monoethanolamine (MEA)*

The mixed amine (MDEA based amine with a primary or secondary amine) solution was created by making a 50:50 percent amine-water solution.

The sensitivity analysis was performed by varying the concentration of MEA from 1% to 11% while the remaining amount was balanced with MDEA. This is because the second amine in the mixture generally comprises less than 20%. The results for the sensitivity analysis performed on the composition of MDEA and MEA is recorded in Table 9. From the results, it is observed that the (MDEA and MEA) solution is capable of treating the gas to the required specification of 50 ppm. It was also observed that when the concentration of MEA was increased in the mixed amine, the mixed amine was able to absorb more carbon dioxide.

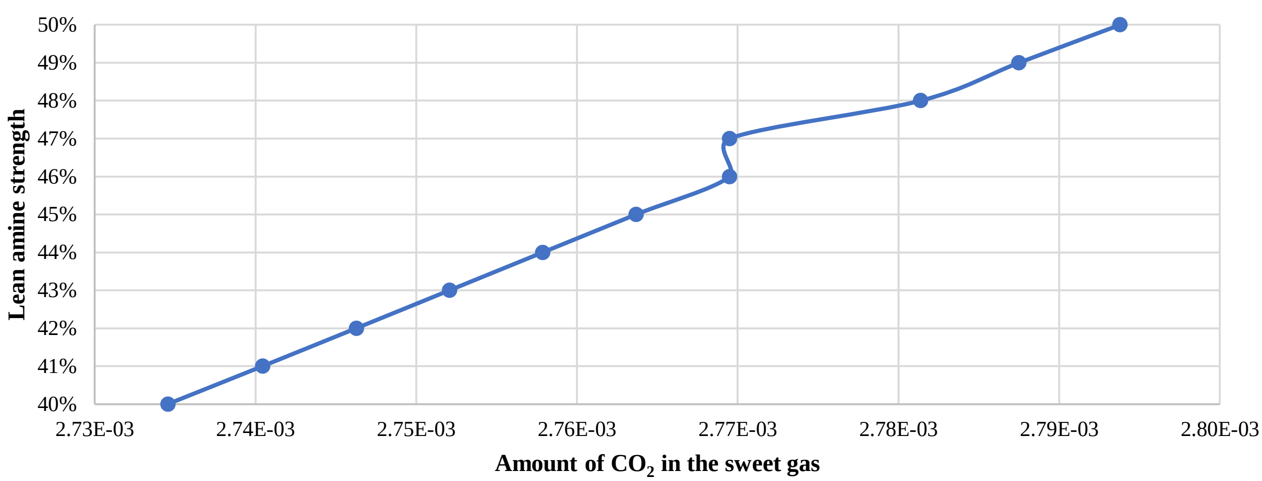

Figure 5: Plot of the lean amine strength of MDEA against the amount of carbon dioxide left in the sweet gas.

Table 8: Results from sensitivity analysis on MDEA.

Lean amine strength	Amount of CO_2 in the raw gas	Amount of CO_2 in the sweet gas	Amount of CO_2 absorbed
40%	0.0056	0.00273455	0.00286545
41%	0.0056	0.002740452	0.002859548
42%	0.0056	0.002746279	0.002853721
43%	0.0056	0.002752078	0.002847922
44%	0.0056	0.002757872	0.002842128
45%	0.0056	0.002763678	0.002836322
46%	0.0056	0.002769497	0.002830503
47%	0.0056	0.002769497	0.002830503
48%	0.0056	0.002781381	0.002818619
49%	0.0056	0.002787495	0.002812505
50%	0.0056	0.002793785	0.002806215

Table 9: Results from sensitivity analysis on MDEA and MEA.

Lean amine strength		Amount of CO_2 in the raw gas	Amount of CO_2 in the sweet gas	Amount of CO_2 absorbed
MDEA	MEA			
49.00%	1.00%	0.0056	0.000635264	0.004964736
48.00%	2.00%	0.0056	7.12827E-05	0.005528717
47.00%	3.00%	0.0056	2.4514E-05	0.005575486
46.00%	4.00%	0.0056	1.32103E-05	0.00558679
45.00%	5.00%	0.0056	7.67412E-06	0.005592326
44.00%	6.00%	0.0056	5.14697E-06	0.005594853
43.00%	7.00%	0.0056	3.70435E-06	0.005596296
42.00%	8.00%	0.0056	2.80671E-06	0.005597193
41.00%	9.00%	0.0056	2.2245E-06	0.005597776
40.00%	10.00%	0.0056	1.8336E-06	0.005598166
39.00%	11.00%	0.0056	1.57185E-06	0.005598428

The relationship between the lean amine strength of MDEA and the amount of carbon dioxide being absorbed is shown in Figure 6(a) while the relationship between the lean amine strength of MDEA and the amount of carbon dioxide being absorbed is shown in Figure 6(b). The plots show that as there is an increase in concentration of MEA in the lean amine, there is also a reduction in the amount of CO_2 left in the sweet gas and for MDEA, as there is an increase in the concentration of MDEA, there is also an increase in the amount of CO_2 left in the sweet gas.

F. Absorption of Carbon dioxide with Methyldiethanolamine (MDEA) and Diethanolamine (DEA)

The results for the sensitivity analysis performed on the composition of MDEA and DEA is recorded in Table 10. From the results recorded, the (MDEA and DEA) solution will treat the gas to the required specification of 50 ppm when there is a further increase in the concentration of DEA as it was observed that when the concentration of DEA was increased in the mixed amine, the mixed amine was able to absorb more carbon dioxide.

The relationship between the lean amine strength of MDEA and the amount of carbon dioxide being absorbed is as shown in Figure 7(a) while the relationship between the lean amine strength of MDEA and the amount of carbon dioxide being absorbed is shown in Figure 7(b). The plots show that, as there is an increase in concentration of DEA in the lean amine, there is a reduction in the amount of CO_2 left in the sweet gas and for MDEA, as there is an increase in the concentration of MDEA, there is an increase in the amount of CO_2 left in the sweet gas.

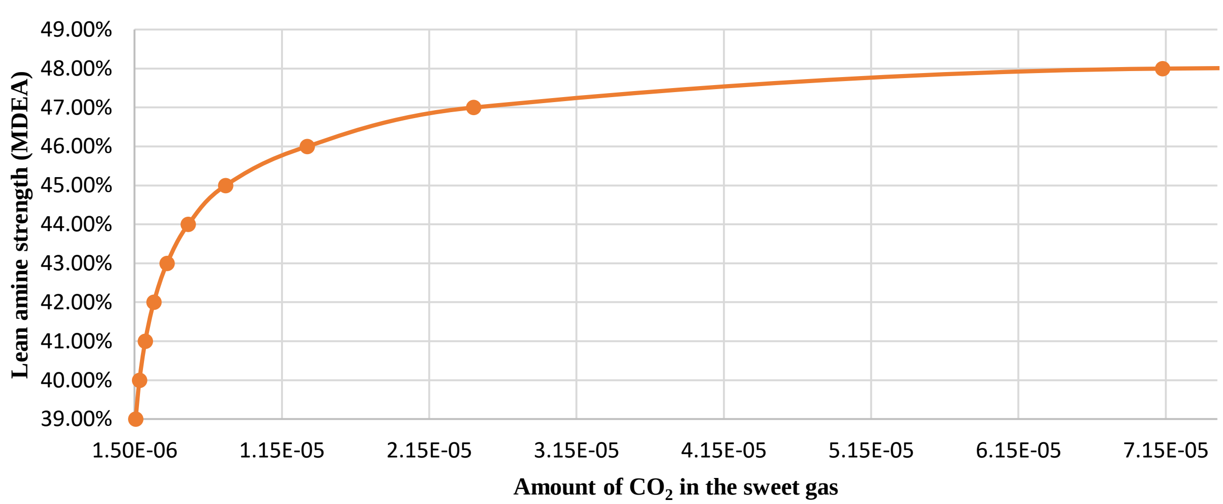

Figure 6(a): Plot of the lean amine strength of MDEA in MDEA + MEA against the amount of carbon dioxide left in the sweet gas.

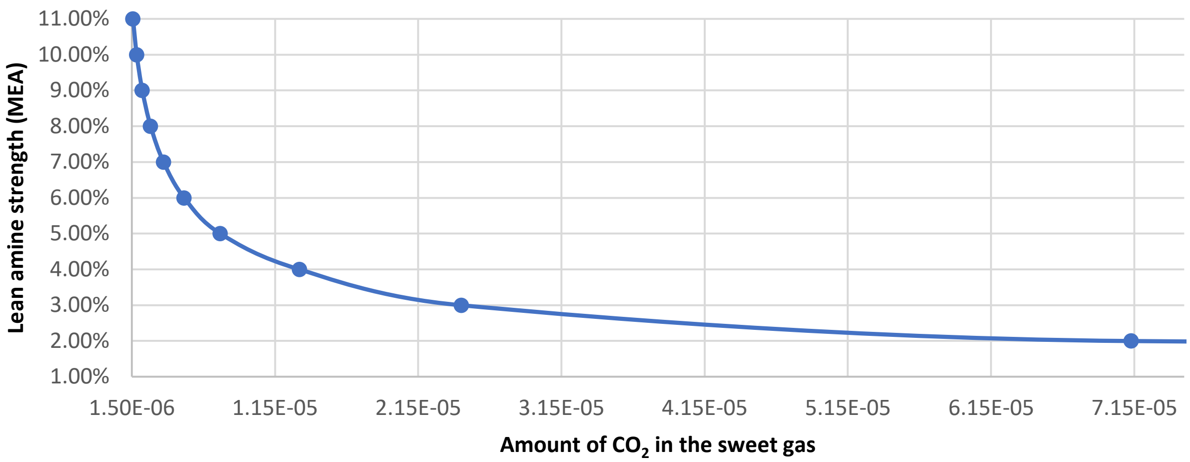

Figure 6(b): Plot of the lean amine strength of MEA in MDEA + MEA against the amount of carbon dioxide left in the sweet gas.

Table 10: Results from sensitivity analysis on MDEA and DEA.

Lean amine strength		Amount of CO2 in the raw gas	Amount of CO2 in the sweet gas	Amount of CO2 absorbed
MDEA	**DEA**			
49.00%	1.00%	0.0056	0.001969029	0.003630971
48.00%	2.00%	0.0056	0.001406932	0.004193068
47.00%	3.00%	0.0056	0.000923208	0.004676792
46.00%	4.00%	0.0056	0.000661719	0.004938281
45.00%	5.00%	0.0056	0.000565069	0.005034931
44.00%	6.00%	0.0056	0.000384578	0.005215422
43.00%	7.00%	0.0056	0.000350027	0.005249973
42.00%	8.00%	0.0056	0.000265925	0.005334075
41.00%	9.00%	0.0056	0.000206467	0.005393533
40.00%	10.00%	0.0056	0.000200922	0.005399078
39.00%	11.00%	0.0056	0.0001625	0.0054375

G. Absorption of carbon dioxide with methyldiethanolamine (MDEA) and diglycolamine (DGA)

The results for the sensitivity analysis performed on the composition of MDEA and DGA is recorded in Table 11. From the results recorded, the (MDEA and DGA) solution can treat the gas to the required specification of 50 ppm. It was observed from the obtained results that the (MDEA and DGA) solution absorbed almost all the carbon dioxide. The relationship between the lean amine strength of MDEA and DGA and the amount of carbon dioxide being absorbed is shown in Figure 8(a) and 8(b) respectively. Figure 8(b) show that as there is an increase in concentration of DGA in the lean amine, there is a reduction in the amount of CO_2 left in the sweet gas and for MDEA, as there is an increase in the concentration of MDEA, there is an increase in the amount of CO_2 left in the sweet gas (Figure 8(a)).

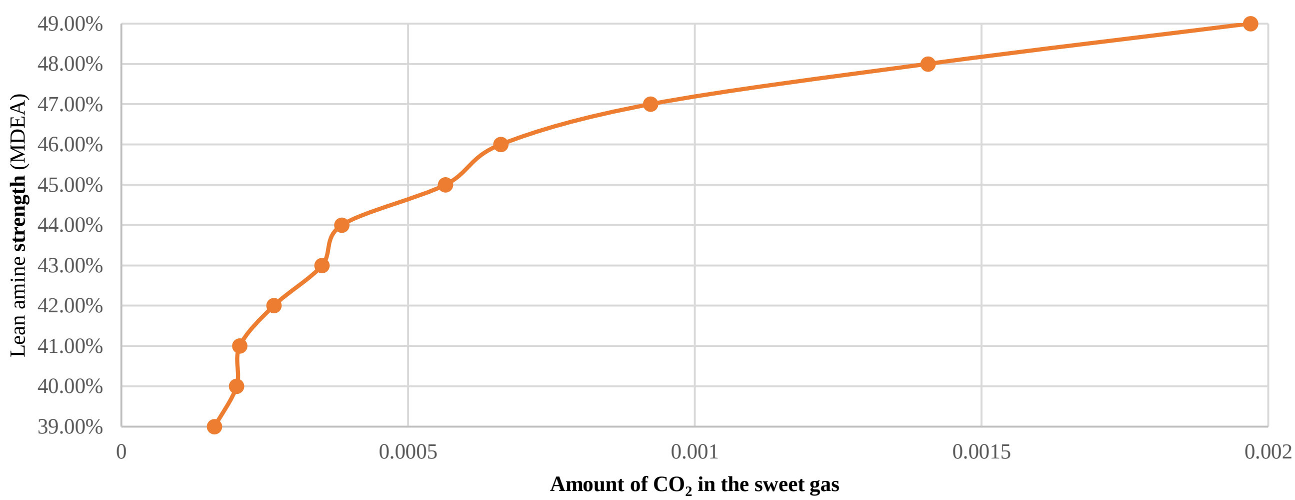

Figure 7(a): Plot of the lean amine strength of MDEA in MDEA + DEA against the amount of carbon dioxide left in the sweet gas.

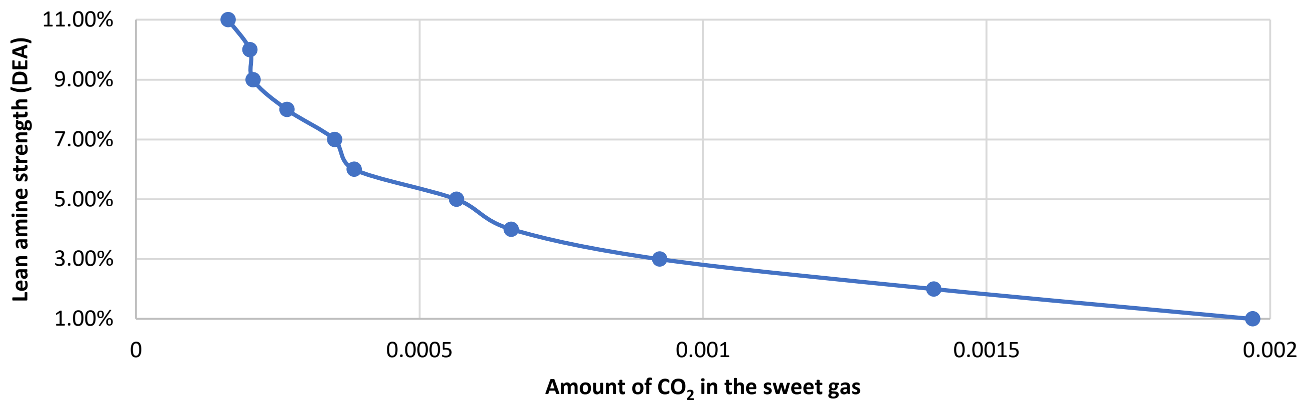

Figure 7(b): Plot of the lean amine strength of DEA in MDEA + MEA against the amount of carbon dioxide left in the sweet gas

Table 11: Results from sensitivity analysis on MDEA and DGA.

Lean amine strength		Amount of CO_2 in the raw gas	Amount of CO_2 in the sweet gas	Amount of CO_2 absorbed
MDEA	**DGA**			
49.00%	1.00%	0.0056	0.001369111	0.004230889
48.00%	2.00%	0.0056	0.000527355	0.005072645
47.00%	3.00%	0.0056	0.000190754	0.005409246
46.00%	4.00%	0.0056	8.0777E-05	0.005519223
45.00%	5.00%	0.0056	4.12581E-05	0.005558742
44.00%	6.00%	0.0056	2.40065E-05	0.005575994
43.00%	7.00%	0.0056	1.69278E-05	0.005583072
42.00%	8.00%	0.0056	1.21671E-05	0.005587833
41.00%	9.00%	0.0056	9.37398E-06	0.005590626
40.00%	10.00%	0.0056	7.79259E-06	0.005592207
39.00%	11.00%	0.0056	6.3238E-06	0.005593676

H. Percentage of carbon dioxide absorbed by each of the solvents

The effect of each of the investigated alkanolamine solvent or amine blend on the gas being treated is evaluated by comparing the percentage of CO_2 absorbed by each of the solvents at the various composition investigated. The result is recorded in Table 12 and 13 respectively.

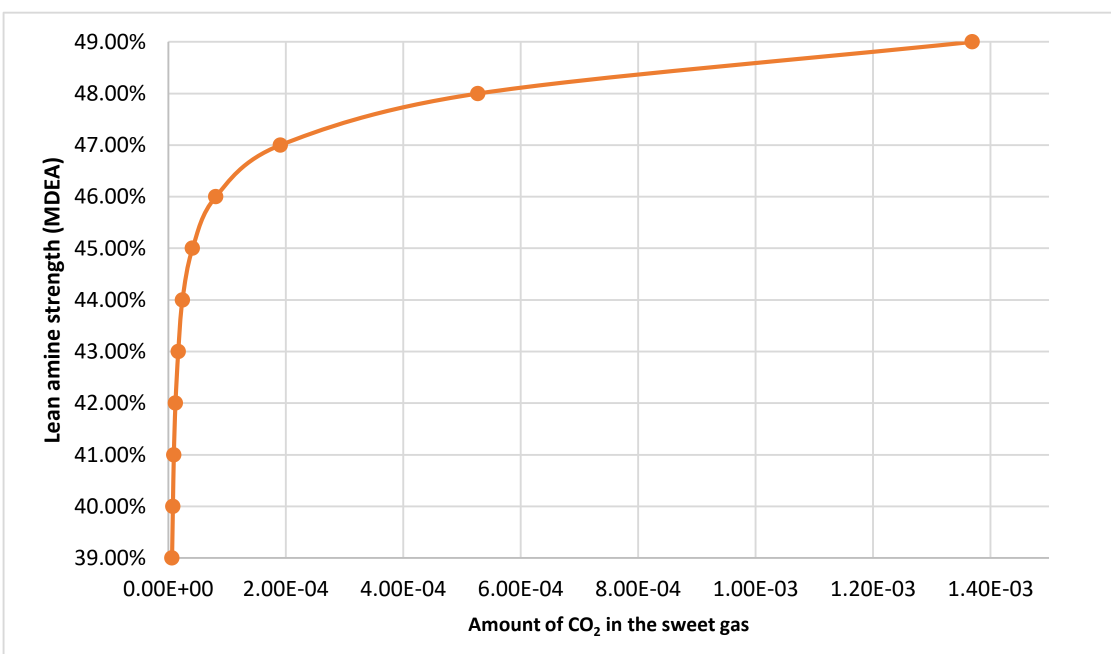

Figure 8(a): Plot of the lean amine strength of MDEA in MDEA + DGA against the amount of carbon dioxide left in the sweet gas.

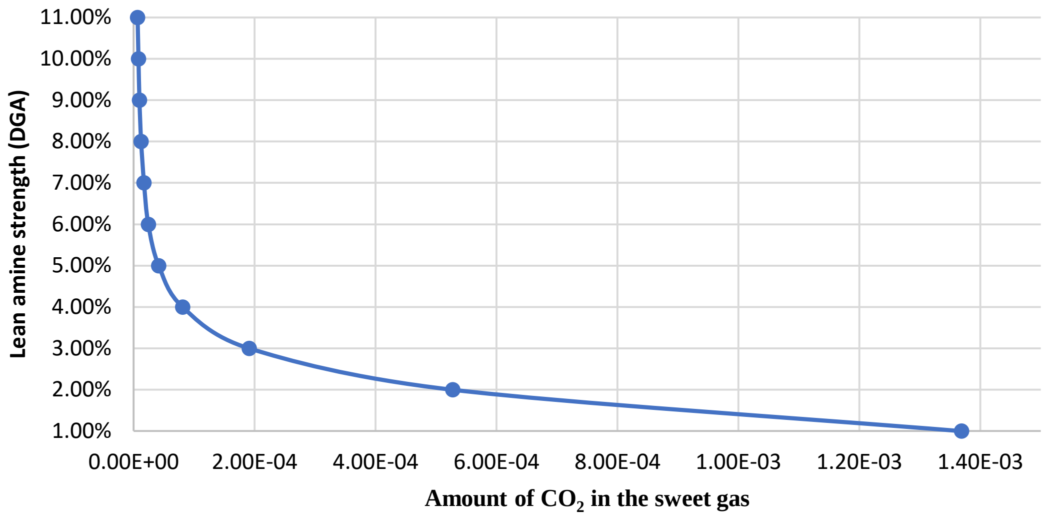

Figure 8(b): Plot of the lean amine strength of DGA in MDEA + DGA against the amount of carbon dioxide left in the sweet gas.

Table 12: Percentage of carbon dioxide absorbed by the amines.

MEA		DEA		DGA		MDEA	
Lean amine strength	%CO2 absorbed	Lean amine strength	%CO2 absorbed	Lean amine strength	%CO2 absorbed	Lean amine strength	%CO2 absorbed
10%	99.97796341	25%	98.4724353	50%	99.99312209	40%	51.16874128
11%	99.98292229	26%	98.51088903	51%	99.99379637	41%	51.06335771
12%	99.98601271	27%	98.52526068	52%	99.99440723	42%	50.95931159
13%	99.98770534	28%	98.55466601	53%	99.99500512	43%	50.85575169
14%	99.98931376	29%	98.56529515	54%	99.99539195	44%	50.75228354
15%	99.98950272	30%	98.59240461	55%	99.99588861	45%	50.64861046
16%	99.99037642	31%	98.60557133	56%	99.99634595	46%	50.54468875
17%	99.99055474	32%	98.62647102	57%	99.99676274	47%	50.54468875
18%	99.99069362	33%	98.62728136	58%	99.99714554	48%	50.33247824
19%	99.99078277	34%	98.63517263	59%	99.99748479	49%	50.22329825
20%	99.99079841	35%	98.64853793	60%	99.99779087	50%	50.11098953

Table 13: Percentage of CO2 absorbed by the amine blends.

MDEA + MEA			MDEA + DEA			MDEA + DGA		
Lean amine strength		$\%CO_2$ absorbed	Lean amine strength		$\%CO_2$ absorbed	Lean amine strength		$\%CO_2$ absorbed
MDEA	MEA		MDEA	DEA		MDEA	DGA	
49.00%	1.00%	88.65599166	49.00%	1.00%	64.83877286	49.00%	1.00%	75.55158603
48.00%	2.00%	98.72709488	48.00%	2.00%	74.87620635	48.00%	2.00%	90.58295165
47.00%	3.00%	99.56224992	47.00%	3.00%	83.51414662	47.00%	3.00%	96.59368326
46.00%	4.00%	99.76410198	46.00%	4.00%	88.18359678	46.00%	4.00%	98.55755382
45.00%	5.00%	99.8629622	45.00%	5.00%	89.90947578	45.00%	5.00%	99.26324854
44.00%	6.00%	99.90808981	44.00%	6.00%	93.13253752	44.00%	6.00%	99.57131315
43.00%	7.00%	99.93385097	43.00%	7.00%	93.74951314	43.00%	7.00%	99.69771759
42.00%	8.00%	99.94988016	42.00%	8.00%	95.25133791	42.00%	8.00%	99.78272965
41.00%	9.00%	99.96027686	41.00%	9.00%	96.31308515	41.00%	9.00%	99.83260753
40.00%	10.00%	99.96725713	40.00%	10.00%	96.41211201	40.00%	10.00%	99.86084662
39.00%	11.00%	99.97193119	39.00%	11.00%	97.09821112	39.00%	11.00%	99.88707503

IV CONCLUSION

The study simulated the design of a standard CO_2 capture plant using Aspen HYSYS V10. The thermodynamic package "Acid Gas – Chemical Solvents" available in Aspen HYSYS reasonably predicted the CO_2 capture process using amine solvents and its blends. A detailed sensitivity analysis has been performed to analyse the effect of various amines on the absorption of CO_2 from the absorber. The amines were analysed at different concentrations within their respective lean amine strength range to find out the concentration at which it absorbs the most CO_2.

Absorption with mixed amines was used to enhance the absorption of CO_2 from the gas because tertiary amines (MDEA) are selective towards the acid gas "H_2S" and the degradation products of the primary and secondary amines. The mixed amine utilized less of the primary and secondary amines (MEA, DEA and DGA) and more of the tertiary amine (MDEA) to achieve desired sweet gas specification.

The results showed that the mixed amine "MDEA + MEA" absorbs 99.97% of CO_2 present in the gas with lean amine strength of 11% MEA and 39% MDEA. In this study, the "MDEA + MEA" blend is most suitable for the adsorption of CO_2. The future prospects of this study are expected to focus on finding the preferred mixed amine solvent with consideration for the cost, energy requirement and environmental impact in terms of degradation products and corrosion.

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