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Using Alkanolamines in Acid Gases Removal from Natural Gas: Simulation and Improvement of Sweetening Gas at Mellitah Gas Plant "An Industrial case study"

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A B S T R A C T

Applying alkanolamines absorption technique in removing H_2S and CO_2 gases from natural gas, is effective technology for sweetening of natural gas. Exist of acidic gases in natural gas can contribute in many technical problems such as: corrosion, pollution addition to the lack of the heating value of CO_2 . In this study, the most often utilized amines in the aqueous solution to extract CO_2 and H_2S from the natural gas stream are diethanolamine (DEA) and methyldiethanolamine (MDEA). The Mellitah gas facility was selected as a case study for using the MDEA solution as a solvent for the gas sweetening process. To conserve energy for amine regeneration and solution circulation rate, MDEA is more selective than (mono ethanol amine) MEA and DEA. However, MDEA does not directly react with CO_2, thus a significant amount of CO_2 must be eliminated. In the meanwhile, the Mellitah sweetening unit uses an aqueous solution of MDEA at a 50% concentration to function. On the other hand, using this percentage of amine produces a significant amount of carbon dioxide, which consider highly in comparison with global specifications at 2% of commercial sales. This project firstly applied a 50% wt of MDEA solution by Aspen HYSYS software as a simulator to mimic the Mellitah gas sweetening process. The second step involves putting the suggested enhancement criteria into practice by combining DEA and MDEA and basing it on five situations.

استخدام الألكانولامينات في إزالة الغازات الحمضية من الغاز الطبيعي: محاكاة وتحسين تحلية الغاز بمجمع مليتة "دراسة حالة منشأة صناعية"

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الكلمات المفتاحية:
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المحاكاة

الملخص

تعتبر تقنية الامتصاص باستخدام الامينات لنزع كبريتيد الهيدروجين H_2S و ثاني اكسيد الكربون CO_2 من الغاز الطبيعي , من الطرق الفعالة في تحلية الغاز الطبيعي. ان وجود الغازات الحمضية في الغاز الطبيعي، يساهم بطبيعة الحال في العديد من المشاكل التقنية والمتمثلة في: التآكل والتلوث بالإضافة الى ضعف القيمة الحرارية لغاز CO_2 . في هذه الدراسة، محاليل الامينات المستخدمة في استخلاص CO_2 و H_2S من دفق الغاز الطبيعي هي ثنائي ايثانول امين DEA وميثيل ثنائي ايثانول امين MDEA . في الوقت الراهن , الامين المستخدم كمذيب في معالجة الغاز في مصنع مليتة لتحلية الغاز هو MDEA . ومع هذا, فلاعتبارات استهلاك الطاقة اثناء عملية اعادة انتاج الامين في الوحدة وعملية معدل التدوير فان MDEA يأتي بالأفضلية قبل DEA و MEA احادي ايثانول امين. لكن في المقابل، MDEA لا يتفاعل مباشرة مع CO_2 , وعليه فان مقدار غير قليل من CO_2 يجب التخلص منه. حاليا، مصنع مليتة لتحلية الغاز الطبيعي، يستخدم محلول بنسبة عند تركيز 50% . ولذلك فان هذه النسبة لها الاثر الرجعي على المصنع

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نظرا للكمية العالية الغير متخلص منها من غاز CO_2 والتي تعتبر مرتفعة اذا ما قورنت مع مواصفات السوق العالمية والتي تأتي عند 2%. في هذه الدراسة، وكمرحلة اولى، قام بمحاكاة نفس الظروف في مصنع مليتة لتحلية الغاز الطبيعي باستخدام سوفت وير هايسس. كما قام بعمليات تحسين الاداء تحلية الغاز وذلك بإضافة ال DEA الى ال MDEA بنسب متغيرة في خمس مقترحات في مرحلة لاحقة.

1. Introduction

Natural gas is mostly used as fuel, but it is also a significant supply of elemental sulfur, a crucial industrial ingredient, and hydrocarbons for petrochemical feedstock. With so many environmental benefits over coal and petroleum, natural gas is predicted to become an increasingly popular energy source in the future [1]. Regionally, Libya has significant amounts of natural gas, and one of the main gas suppliers to Europe. Millitah gas plant which located in west of Libya, considers compatible plant of series of units and sweetening unit has crucial status. The plant receive natural gas from the offshore Bahr Essalam oilfield and Wafa field [2]. Geographically, Libyan gas is usually found in deep reservoirs that are either with little to no crude oil or associated with other gases. Associated gas is produced alongside the oil and then separated. This kind of produced gas is called casing head gas, It may also be called oil well gas (dry gas), or dissolved gas [1].

A mixture of hydrocarbon gases that burns easily is called natural gas. Natural gas can also contain ethane, propane, butane, and pentane, however methane is primarily component of the natural gas. Although natural gas has a very variable composition, the Table 1 below describes the normal composition of natural gas in its unrefined state [3].

Table 1: The Composition of Natural Gas [3].

Chemical Name	Chemical Formula	Percentage (%)
Methane	CH_4	70-90%
Ethane	C_2H_6	
Propane	C_3H_8	0-20%
Butane	C_4H_{10}	
Carbon Dioxide	CO_2	0-8%
Oxygen	O_2	0-0.2%
Nitrogen	N_2	0-5%
Hydrogen Sulphide	H_2S	0-5%
Rare gases	Ar, He, Ne, Xe, H_2O	Trace

It is well known that the most significant properties of hydrogen sulfide (H_2S) are, colorless, highly toxic and combustible. Furthermore, the gas is highly corrosive to carbon steel in oil and gas transport pipelines and processing plant equipment where sulfuric acid develops with water, it can induce poisoning, kill humans and animals, and be odorous at low concentrations. Furthermore, natural gas loses heat energy value as it burns as an energy source because carbon dioxide gas corrodes water. Conversely, inorganic gases with strong hydrate forms are carbon dioxide and hydrogen sulfide [4]. Complex mechanisms led to the formation and growth of hydrate during the transportation of natural gas containing a mixture of CO_2 and H_2S impurities. with a range of kinetics and thermodynamics-based mechanisms and techniques. Therefore, in order to produce a methane-rich gas, it is necessary to remove the acid gases (H_2S and CO_2), heavy hydrocarbons, nitrogen, water, and other contaminants. It can therefore be utilized as fuel in a variety of fields. One of the goals of the natural gas processing facility is represented by this treatment procedure [5]. Reducing acid gases, including carbon dioxide (CO_2) and hydrogen sulfide (H_2S), as well as other sulfur species, to low enough concentrations is known as gas treatment or elimination. In order for the plant to continue processing without experiencing corrosion and clogging issues, or to fulfill contractual requirements, this removal procedure is necessary [6].

Adsorption and absorption are the two forms of indirect acid gas removal [5]. The contaminants in the gas are eliminated chemically or physically during adsorption. Acid gases can be absorbed and removed physically by employing physical solvents and chemically by reacting with the gases and using an alkaline solvent, or physically and chemically by utilizing a combination of solvents. However, certain novel CO_2 capture solvents, such as lipophilic amines and biphasic solvents, have been suggested to enhance energy performance [6].

Amine is a well-known solvent in chemical solvents. Ammonia (NH_3) is the basic component found in amines. Different types of amines are created when an organic hydrocarbon group takes the place of one or more hydrogen atoms. An alkaline can take up a proton (H^+) from aquatic solutions. The formation of hydroxide and an alkaline, which are necessary for gas sweetening with amines and also help to lessen pipeline corrosion, resulting from the reaction of water with an amine, (a proton acceptor) [7]. In the natural gas and refinery industries, aqueous amine solutions are typically utilized to eliminate acidic gasses from gas streams, including carbon dioxide and hydrogen sulfide [8]. The following is a classification of alkanolamines [9]: Primary amines: such as monoethanolamine (MEA) and Di-Glycol Amine (DGA), Secondary amines: such as Di-Ethanol Amine (DEA) and Di-IsoPropanol Amine (DIPA). In comparison to other types of amines, the first class is stronger as a base and is more likely to react with CO_2 and H_2S. Indeed, there are some kinetic processes and equilibrium in these chemical solvents. Though at a slower and more limited rate, the tertiary amine and hydrogen sulfide interact instantly. When combined with carbon dioxide, its regarded pseudo - first- order reaction [10].

Typically, physical and chemical absorption into aqueous alkanolamine solutions is used to remove acid gas from natural gas. When designing plants that gasify acid, thermodynamics is a key factor. The behavior of these systems is modeled thermodynamically, taking into account both phase and chemical equilibria. The driving force behind mass transfer, equilibrium compositions, and hence outlet concentrations is quantified by thermodynamics. The system's thermal characteristics and amine volatility are both measured by a consistent thermodynamic model. Predicting heat absorption is crucial to boosting cost efficiency because steam costs account for more than half of the overall plant expenses [11]. Sulfur compounds found in acid gasses are commonly removed using absorbers. Similar systems can extract undesirable substances from a vapor stream and transfer them to the absorption medium through a chemical reaction or a simple solubility ability. For example, absorption may take place in a liquid droplet scattered throughout the gas stream. Following their reaction with the liquid droplet, the supplied compounds will produce a product that is soluble in the liquid. The surface area of the liquid, where the interaction with the vapor phase will occur, and the flow rate, which establishes the duration of contact between the absorption material and the specific component, are critical elements in the absorption process [12].

The MDEA solution is used at a 50% weight percentage in the Mellitah plant's gas sweetening procedure as a solvent. Using MDEA solutions, acid gas removal machines typically have excessive regeneration rates and poor absorption rates as operational issues. In addition to solvent losses, significant amounts of foaming and corrosion also occur. Utilizing unique solvent that designed the DOW business and suggested a naval approach to get around these technological issues. A technical issue arose due to the high acid gas loading in the rich amine, which exceeded the permitted limits, although this solvent was tested in one treatment train at the Mellitah gas plant in 2017 and proved to be an excellent absorbent that absorbed all the acid gases. Nevertheless, a great deal of research has been conducted using the Mellitah gas plant as a case study, with an emphasis on simulating and improving the current process using other kinds of amine solutions. This study will examine potential MDEA-based blends with DEA at various concentrations and look at how the key variables affect the efficiency of the process [13].

Initially, this project will use a 50% wt MDEA solution created by Aspen HYSYS software as a simulator to mimic the Mellitah gas sweetening process. The second step involves putting the suggested enhancement criteria into practice by combining DEA and MDEA and basing it on five situations. In regard to Millitah data, the simulation have been fulfilled, and refer as first scenario. In contrast, the amine strength is 50% in the second and third scenarios, which include 2% and 1% of DEA, respectively, and 40% in the fourth and fifth scenarios, which also include 2% and 1% of DEA. Lastly, determine and pick the ideal blend concentration of DEA amine to improve the Mellitah gas plant's gas sweetening process performance. This will raise the pace at which acid gas is absorbed and reduce the need for reboiler duty during regeneration.

2. Literature Review

In (2024), Mahdi Mohajeri, et. al. [14], introduced an important study, the goal of their study was to create a plant-wide structure for the best possible operation of natural gas sweetening plants. In order to optimize the use of surrogate models, a steady-state simulation of the Khangiran plant was conducted. This led to an achievement of a 17% decrease in energy consumption. To determine the ideal set of controlled variables (CVs), the self-optimizing technique was used. One degree of freedom (DOF) was unrestricted. It was discovered that the regenerator's top-stage temperature provided the best CV for the remaining DOF. Using straightforward classic PIDs, Aspen Plus Dynamics was utilized to analyze the performance of the proposed control structure and compare it to more recent feedback and feedforward MPCs.

In (2022), the simulation findings of a steady-state based on tetraethylamine (TEA) absorption process for natural gas sweetening are attempted to be summarized by M. S. Lawan [15]. In this study, using tetra ethylamine (TEA), carbon dioxide (CO_2) capture simulation was carried out using the UNISIM software tool in order to produce a sweet natural gas product that satisfies normal market requirements. Appropriate hydration levels for optimal absorption precede the anticipated amine weight at the process's 28% loading capacity. The objective is to get a minimum of 97% purity in the removed CO_2 gas and potentially recover the amine solvent at the conclusion of the process cycle. The findings indicate that when feed temperature and flow rate were increased, the CO_2 gas stream grows. The simulation's final outcome is an optimization of the CO_2 gas's 0.036 mole fraction and the solvent TEA amine's complete recovery. To assess the process's success rate, equipment duties related to the cooler and lean pumps were also ascertained. Though it performs better than other solvents, the TEA solvent can still have an impact on the resulting sweet gas's CO_2 content. This resulted in a methane loss to solvent percentage of 0.00104 moles.

In (2022) [16], Chukwu Kelechi, et. al., applied Aspen Hysys version 10 as the commercial process simulator and Peng Robinson as the fluid package, this study aims to quantitatively simulate an existing natural gas sweetening facility. Using methyldiethanol amine, which has a preference for absorption of H_2S over CO_2, one of the common processes found in the natural gas chain was modeled in this dissertation. However, because the natural gas contains very little H_2S, the process parameter was changed for this project in order to increase CO_2 loading. Reviewing the current plant operation and looking into any potential improvement and modification that can result in a decrease in flared waste gases without breaking the sweet contract was required because the plant is still considered new. By doing a sensitivity analysis of the operational parameters (amine circulation rate and concentration simultaneously), the plant's performance was adjusted and a decrease in CO_2 loading in lean amine was observed.

In (2021) [17], Jassim Khanjarm et. al., achieved a research that took into consideration parametric and simulation investigations of the natural gas processing facility of the Missan Oil Company/Buzurgan oil field (in Iraq). Following this plant's simulation and validation, the impacts of solvent concentration, flow rate, and feed temperature were taken into account. Findings indicate that the amount of H_2S and CO_2 in the sweet gas stream increases with feed temperature and flow rate. The impact of combination solvents was then investigated in the following stage. As solvents for physical-chemical mixtures, sulfolane-MDEA was chosen, and as solvent for chemical mixtures, MDEA-MEA. The simulation results demonstrate that employing a combination of solvents can lower the price of the solvent as well as the reboiler duty and cooling duty. Nevertheless, these solvents may have an impact on the concentration of H_2S and CO_2 in the sweet gas. In comparison to other solvents, the system that uses a chemical mixture of solvents can function better.

In (2018), an integrated model based on Aspen HYSYS software was used to simulate a commercial gas sweetening unit using a methyl-di-ethanol-amine (MDEA) solution by Moghadasi, et. al [18]. In the second step, the simulation findings were compared with operational data collected from the South Pars Gas Complex (SPGC) for evaluation purposes. Based on the results of the simulation, power recovery turbines (PRT) apply this energy driving force because of the significant energy potential that was contributed to the pressure difference between the absorber and regenerator columns. The final step involved calculating the loss hydraulic energy and researching recovery techniques.

In (2017), the use of a simulator, Aspen HYSYS software version 8, the gas sweetening procedure at the Mellitah gas plant was examined by Omar [19]. Furthermore, optimization was carried out using two amine blends, utilizing a typical plate weir height of 50 mm: a 40% weight MDEA with a 10% weight DEA blend and a 40% weight MDEA with a 10% weight MEA blend. According to this investigation, the two amine mixes could effectively eliminate the acid vapors from raw natural gas while maintaining the necessary levels of purity. On the other hand, due to its higher amine circulation rate, lower reboiler duty for amine regeneration, and lower amine losses in the sweet gas stream, a 40% MDEA with 10% DEA blend was ideal. Additionally, the sweet gas stream's specifications called for 0.492 ppm H_2S and 0.055% CO_2 at a lean amine temperature of 35 °C and an amine circulation rate of 1200 m³/h. Furthermore, the optimization work demonstrated that, at an amine circulation rate of 1200 m³/h, the CO_2 absorption rate in the 40% MDEA with 10% DEA mix was 2.5 times higher than that of the 50% MDEA solution. It was advised to use a combination of 40% MDEA and 10% DEA to maximize the gas sweetening procedure at the Mellitah gas plant.

3. Research Methodology

3.1 Study Area

3.1.1 (Mellitah Gas Plant)

The Mellitah gas plant is a gas treatment facility situated about 80 kilometers west of Tripoli on the southern shore of the Mediterranean Sea. All necessary utilities, such as gas and steam turbines for power generation, are included in the complex, along with facilities for treating oil and gas, storage tanks for crude oil and products, LPG, and solid sulfur loading (SPM). Essentially, it consists of two plants: the Wafa coastal plant, which processes oil and condensate produced in the Wafa field, and the Mellitah facility, which processes gas and condensate from the Sabratha offshore platform The Mellitah complex is shown in Figure 1, [20].

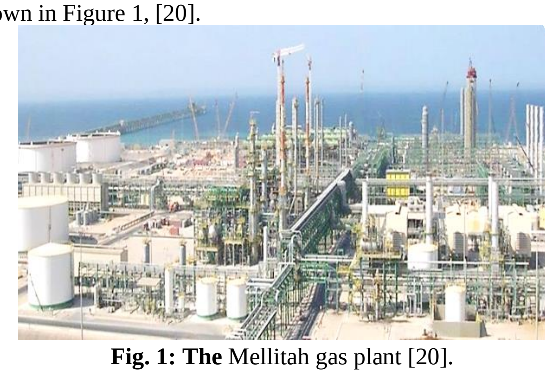

Fig. 1: The Mellitah gas plant [20].

3.1.2 (Mellitah Gas Plant)

Between Gela and Wafa, the Mellitah gas plant processes the output from the Bahr Salam field. It consists of a gas plant, fractionation units, condensate stabilization facilities, and sulfur recovery units. After being cleaned in the Mellitah gas plant, the gas from the platform is mixed with cleaned gas from the Wafa coastal plant and sent all the way to the Mellitah Gas Compressor Station (MGCS) via fiscal metering for eventual export to Italy. Moreover, stabilized condensate and Liquid Petroleum Gas (LPG) production (propane and butane) were transported to the storage tank [20].

3.2 Process Equipment and Description

The Mellitah gas sweetening device is designed to use MDEA as a 50% weight solvent to extract H_2S and CO_2 from raw gas. The amine storage and recovery unit are comprised of three identical absorption trains operating in parallel [20]. As indicated in Table 2, the gas circuit and the amine circuit comprise the major equipment of the gas sweetening unit.

Table 2: Process Equipment in Sweetening Unit in Mellitah gas plant [20].

	Gas Circuit	
1	Raw Gas Filters	51-330 CL001 A/B
2	Feed /Product Gas Exchanger	51-330 HA001 A/B
3	Absorber Inlet Separator	51-330 VA002
4	HP Absorber	51-330 VE001
5	Treated Gas Water Wash Pumps	51-330 PA003 A/B
6	Sweet Gas Trim Cooler	51-330 HA002
7	Sweet Gas KO Drum	51-330 VA001
	Amine Circuit	
1	Rich Amine Flash Drum	51-330 VA003.
2	Rich/Lean Amine Exchangers	51-330 HA006 A÷I
3	Amine Regenerator	51-330 VJ001
4	Regenerator Overhead Condenser	51-330 HC003
5	Regenerator Overhead Trim Cooler	51-330 HA004
6	Regenerator Reflux Drum	51-330 VA005
7	Regenerator Reflux Pump	51-330 PA004 A/ B
8	Regenerator Reboilers	51-330 HA003 A/B/C/D
9	Lean Amine Pump	51-330 PA002 A/B
10	Lean Amine Cooler	51-330 HC004
11	Lean Amine Trim Coolers	51-330 HA005 A/B
12	Lean Amine Storage Tank	51-330 TA001
13	Lean Amine Booster Pumps	51-330 PA008 A/B
14	Lean Amine Circulating Pumps	51-330 PA001 A/B
15	Lean Amine Filtration Package	51-330 XX001
16	Skimming Pot	51-330 VA007
17	Antifoam Injection Package	51-330 XX002
18	Amine Sump Drum	51-330 VA008
19	Amine Sump Pump	51-330 PH007
20	Sump Drum Heaters	51-330 HN 001 A/B

3.3 Process Data and Simulation Setup

3.3.1 Process Data

Plant data and relevant articles were the sources of data that this study examined. Table 3 displays the feed condition and composition. Two millimole % of CO_2 and five parts per million of H_2S are the minimum requirements for the sweet gas stream [20].

Table 3: Feed Conditions and their Compositions [20].

	Condition		
1	Temperature (°C)		30
2	Pressure (kPa)		3950
3	Molar Flow (Kg.mol/h)		14388
	Composition		
	Compounds	Mole %	Molar Flow Rate (kg.mol/h)
1	H_2O	00.02	2.42
2	Nitrogen	04.59	660.63
3	CO_2	15.71	2260.45
4	H_2S	01.29	185.64
5	Methane	70.12	10088.95
6	Ethane	04.46	641.94
7	Propane	01.80	259.23
8	i-Butane	00.40	56.97
9	n-Butane	00.66	95.43
10	i-pentane	00.29	41.83
11	n-pentane	00.28	40.79
12	n-hexane	00.25	35.56
13	n-heptane	00.13	18.16

Table 4 displays the characteristics and state of operation of the primary process equipment in the plant.

3.3.2 Component List and Fluid Package

All the compounds needed for modeling are chosen straight from the Aspen HYSYS software's database because the feed stream reaches the sweetening unit with just pure compounds and no condensate. The acid gas fluid package is used for modeling and estimating thermodynamic properties. The author (Aspen tech producer) highly recommends it for acid gas processing because of its high accuracy and capacity for automatic calculation of the process's primary operating parameters, including amine strength, acid gas loading, recirculation rate, etc.

Table 4: Specifications and Operating Conditions of the Main Process Equipment [21].

Absorption Column	1	Feedstock is sour gas with water
	2	Temperature = 30 °C
	3	Pressure = 3950 kPa
	4	Number of theoretical plates = 30
	5	Column pressure drop = 3.5 kPa
	6	Temperature of lean amine solution = 50 °C
	7	Lean amine solution flow rate = 2.5 of sour gas flow rate
Regeneration Column	1	Number of theoretical plates = 18
	2	Feed is rich amine solution
	3	Feed temperature = 103 °C
	4	Feed pressure = 637 kPa
	5	Bottom pressure = 210 kPa
	6	Column pressure drop = 2 kPa
Heat Exchanger	1	Rich side delta T = 37 °C
	2	Lean side delta T = -50 °C
	3	Shell-side pressure drop = 67 kPa
	4	Tube-side Pressure drop = 59 kPa
Cooler	1	Cooler pressure drop = 30kpa
Pump	1	Discharge pressure = feed gas pressure = 35kpa
	2	Efficiency = 70%
Valves	1	Pressure drops of rich solution in the first expansion valve = 3145 kPa
	2	Pressure drops of rich solution in the second expansion valve = 100 kPa

3.3.3 Simulation Setup

The construction of the base case simulation began with simulating the current plant using the standard AGRU flow sheet and operating conditions. Then, the modification was put into place to reflect the same process conditions of the Melitah complex's acid gas cleaning unit, as indicated in Table 4. The entire plant's process flow sheet, which was represented in the simulator with the primary equipment, was completed as follows:

- **Absorber Column**

To simulate the contactor, Column T-100 with a specification from Table 4 is utilized. At the bottom of the simulation is the sour gas stream (S1) with specs from Table 5, and at the top is the amine solution stream (S2) with specs from Table 6. Figure 2 shows the absorber column.

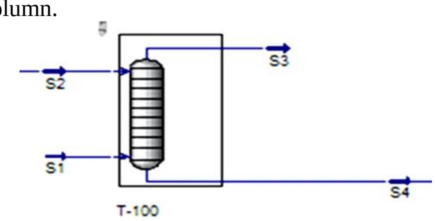

Fig. 2: Absorber Column.

Table 5: Specification of Absorber Column (T-100).

1	Number of Sages (stage)	30
2	Top Pressure (kPa)	3947
3	Bottom Pressure (kPa)	3950

The output streams were computed after the column had converged, with the reach amine leaves as the bottom product (S4) and the sweet gas leaves as the top product (S2).

- **Amine Flasher**

Rich amine stream (S4) is directed to valve 1 (control valve) to lower pressure from 3950 kPa to 805 kPa. It is then flashed into Sep-100, a two-phase separator, to release some of the dissolved gases, hence lowering regeneration energy. Figure 3 shows the amine flasher.

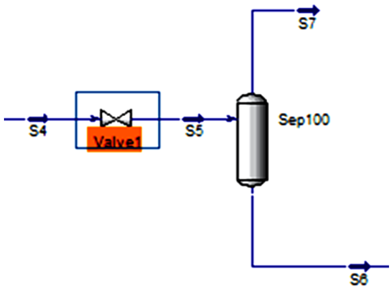

Fig. 3: Amine Flasher.

- **Lean/Reach Heat Exchanger**

The S&T heat exchanger E-100, whose specifications are listed in Table 6, is subsequently used to heat the liquid steam (S6) out of Sep-100 to 104 °C. Figure 4 shows the lean/reach heat exchanger.

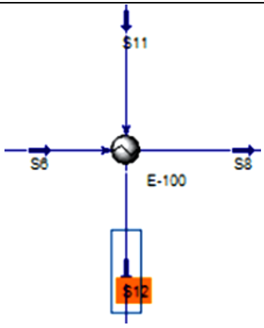

Fig. 4: Lean/Reach Heat Exchanger.

Table 6: Specification of Heat Exchanger (E-100).

	Heat Exchanger	
1	Duty (kJ/h)	2.44x10^8
2	Tube Inlet Temperature (°C)	077.7
3	Tube Outlet Temperature (°C)	104.3
4	Shell Inlet Temperature (°C)	169.9
5	Shell Outlet Temperature (°C)	141.0
	Pressure Drops	
1	Tube Side (kPa)	59.0
2	Shell Side (kPa)	67.0

- **Regeneration Column**

The distillation column T-101, which is used to replicate the regeneration column with the characteristics listed in Table 7, receives the hot amine that exits the heat exchanger (S8). Figure 5 shows the regeneration column.

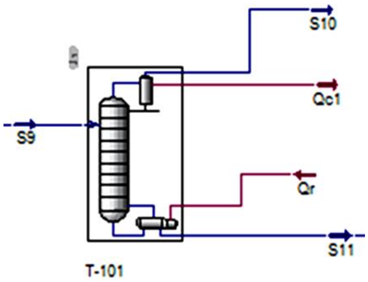

Fig. 5: Regeneration Column.

Table 7: Specification of Regeneration Column (T-101).

1	Number of Trays (Stages)	18
2	Feed Tray (°C)	9.0
3	Reflux Ratio (°C)	0.5
	Pressure	
1	Top Pressure (kPa)	208
2	Bottom Pressure (kPa)	210
	Temperature	
1	Top Temperature (°C)	059.0
2	Bottom Temperature (°C)	169.9
	Flow Rate	
1	Top flow rate (kgmol/hr)	8039
2	Botom flow rate (kgmol/hr)	3.052x10^4

The output streams are computed when the column has converged, with the lean amine leaving as the bottom product (S11) and the acid gas leaving as the top product (S10). The energy demand is also computed. In the lean/reach heat exchanger, the reach amine is heated by the lean amine (S11) since it is hot.

- **Makeup-100**

Makeup-100 is subsequently filled with the lean amine stream (S12) that exits heat exchanger E-100 in order to keep the amine flow rate and amine strength at their starting points. Figure 6 shows the makeup 100. The specifications of (Makeup-100) are listed in Table 8.

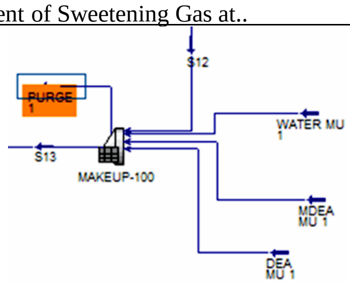

Fig. 6: Makeup -100.

Table 8: Specification of Makeup-100

1	Amine Strength weight percentage) (% wt.)	50
2	Circulation Rate (kgmol/hr)	3.597x10^4

The lean amine (S15), which is recycled back into the absorber column, is compressed to roughly 3950 kPa in pump P-100 after the stream (S13) from the makeup-100 is cooled to 35 °C in cooler E-101 with a pressure drop of 30 kPa. Figure 7: The recycling of amines.

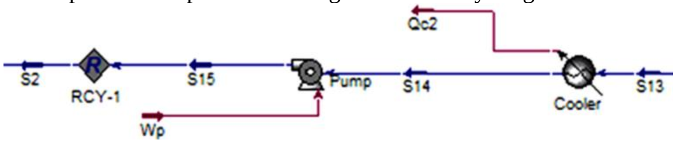

Fig. 7: Recycling of Amines.

The flow sheet begins to be solved as soon as the recycle stream (S2) is connected to the absorber. Eventually, after numerous iterations, the flow sheet is fully converged, as seen in Figure 8.

3.4 Process Enhancement

After the base case is finished, the enhancement technique is used to combine DEA and MDEA to increase the plant's performance. Numerous experiments were conducted to look into the potential applications of the scenarios; Table 9 displays the five situations that were taken into consideration.

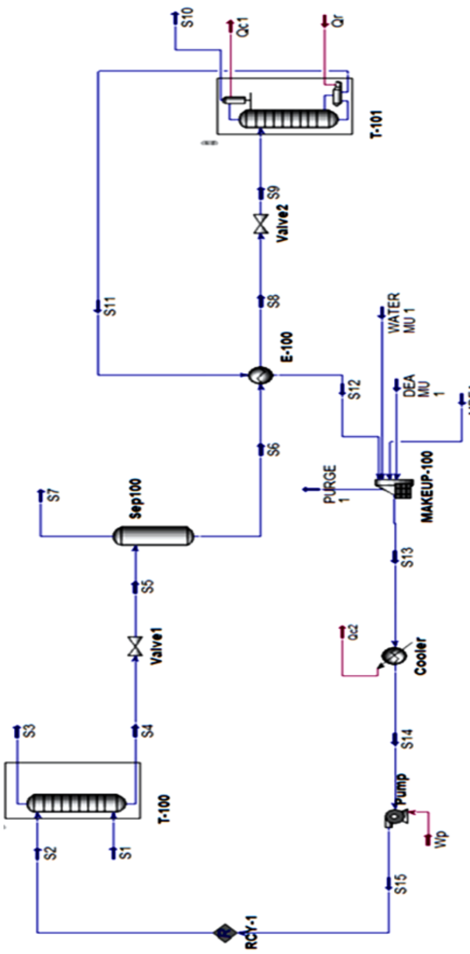

Fig. 8: Complete Process Flow Sheet of the Plant.

Table 9: Considered Scenarios for Enhancement.

	H_2O	MDEA	DEA
Scenario 1	50%	50%	0%
Scenario 2	50%	48%	2%
Scenario 3	50%	49%	1%
Scenario 4	60%	38%	2%
Scenario 5	60%	39%	1%

Scenario 1: A simulation of an existing plant is performed with the actual operating conditions, where the MDEA is used as a solvent with a concentration of 50% wt.

Scenario 2 and 3: The overall concentration is kept at 50% wt., but in this case, the amine blend of MDEA and DEA has been used.

Scenario 4 and 5: The overall concentration is decreased to 40% wt., and again, the amine blend of MDEA and DEA is used and investigated.

The increase is carried out in each case in accordance with the sweet gas's acid gas concentration and the regeneration column's reboiler duty.

4. Results and Discussion

4.1 Overview

In this study, the Millitah plant was simulated by HYSYS and the outcomes showed in (scenario 1). The simulation represent the operation conditions at reality. In regards to simulation outcomes, another fore scenarios were conducted to implement the unit with consideration of reboiler and operating conditions.

4.2 Results of the Base Case (Scenario 1)

Table 10 displays the process dashboard, which shows the primary parameters governing each step of scenario 1's operation.

Table 10: Amine Dashboard for the Base Case (scenario1).

Sweet Gas (S3)		
Molar Flow	1.279x10^4	Kgmol/h
Comp Mole Frac (CO_2)	0.066	
Comp Mole Frac (H_2S)	0	
Lean Amine (S2)		
Amines Flow Rate	3.597x10^4	kgmol/h
Amine Strength	50%	wt.
Acid Gas Loading	6.896x10^-3	mol./mol
Temperature	50	°C
Rich Amine (S4)		
Acid Gas Loading	0.3441	mol./mol.
Regenerator		
Reflux Ratio	0.5	
Reboiler Duty	5.568x10^8	kJ/h
Feed Stream Temperature	103.1	°C

It can be observed that the concentration of acid gases has dropped to less than roughly 1% mol in Table 11 and Figures 9 and 10, which illustrate the effects of the amine flow rate on the CO_2 and H_2S concentrations in the sweet gas and reboiler duty. Because there is more amine that needs to be regenerated when the amine flow rate is increased to four times its typical level, the reboiler duty increases to double.

Table 11: Results of Scenario 1.

Duty (kW)	Mol. Fraction (H_2S)	Mol. Fraction (CO_2)	Flow(kgmol/hr)
232100	0.0017	0.1029	35000
279900	0.0007	0.0702	60000
364300	0.0003	0.0304	100000
407500	0.0002	0.0184	120000
452100	0.0001	0.0106	140000

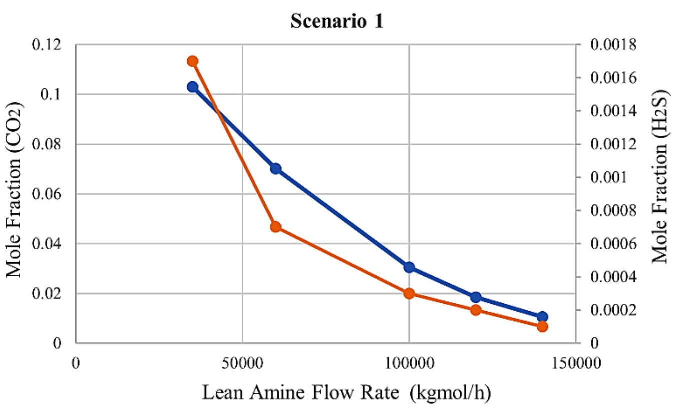

Fig. 9: Effect of Lean Amine Flow Rate on the CO_2 (blue line) & H_2S (orange line) Concentrations (Scenario 1).

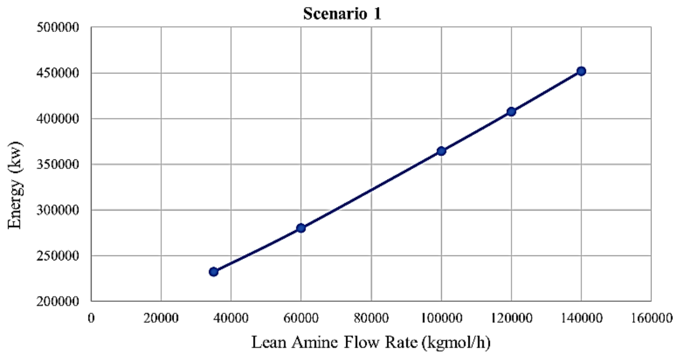

Fig. 10: Effect of Amine Flow Rate on Reboiler Duty (Scenario 1).

4.3. Result of the Different Scenarios

Figures 11–13 illustrate how the amine flow rate affects the acid gas concentration and reboiler duty for each scenario, and it is evident that the outcomes behave similarly in each one.

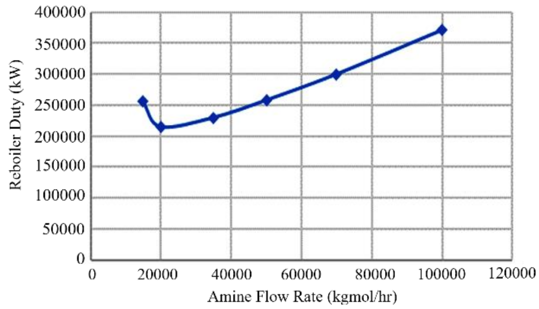

Fig. 11: Effect of Amine Flow Rate on Reboiler Duty (Scenario 2).

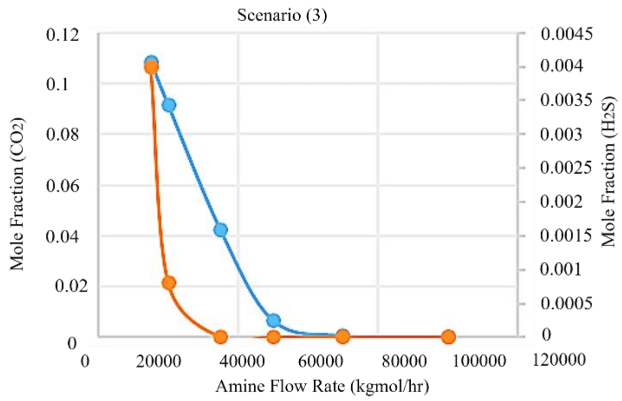

Fig. 12: : Effect of Lean Amine Flow Rate on the CO_2 (blue line) & H_2S (orange line) Concentrations (Scenario 3).

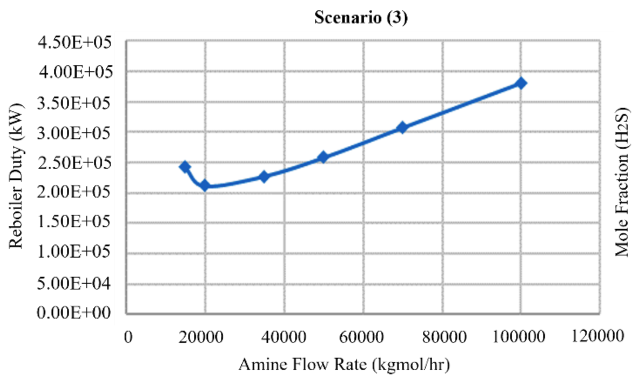

Fig. 13: Effect of Amine Flow Rate on Reboiler Duty (Scenario 3).

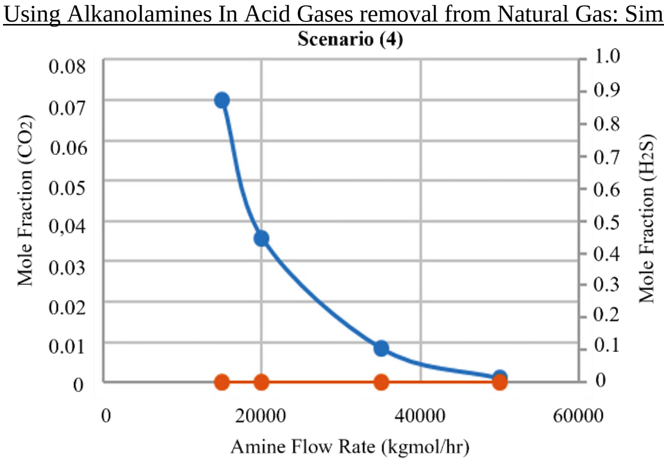

Fig. 14: Effect of Lean Amine Flow Rate on the CO_2 (blue line) & H_2S (orange line) Concentrations (Scenario 4).

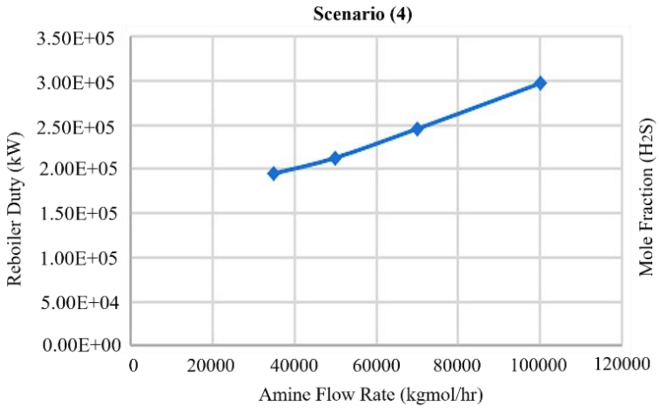

Fig. 15: Effect of Amine Flow Rate on Reboiler Duty (Scenario 4).

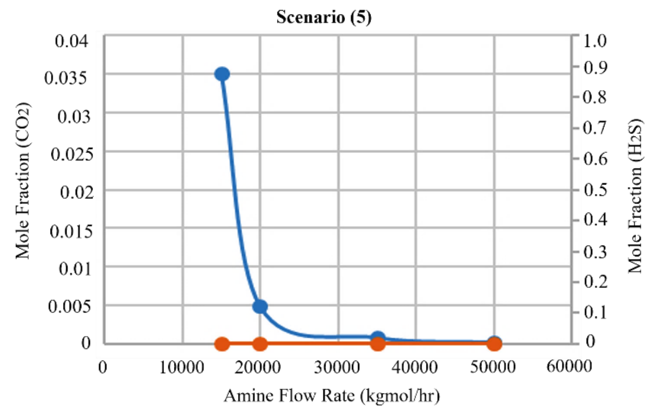

Fig. 16: : Effect of Lean Amine Flow Rate on the CO_2 (blue line) & H_2S (orange line) Concentrations (Scenario 5).

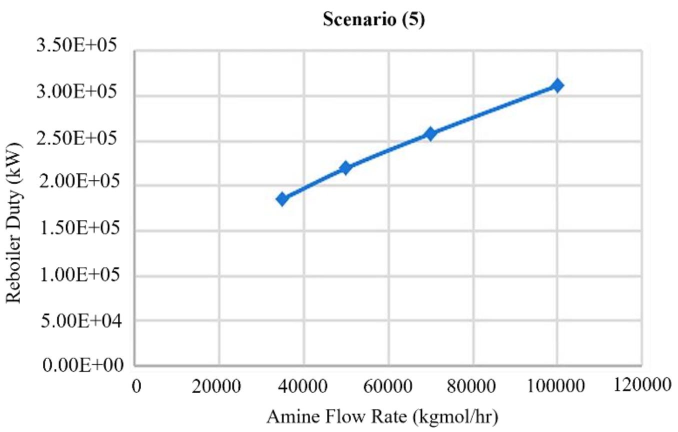

Fig. 17: Effect of Amine Flow Rate on Reboiler Duty (Scenario 5).

To gain more insight and clarity regarding the impact of DEA addition on absorption rate and reboiler duty, DEA concentrations of 1% and 2% were studied at 50% and 40% amine strengths. The amine flow rate was fixed at 3.5 x 10^4 kgmol/h. The findings are displayed in Table 11 and Figure 12. Table 12 and Figure 18 shows the comparison at a fixed amine flow rate. Figure 17 shows the comparison between reboiler duty for different scenarios.

Table 12: Comparison at Fixed Amine Flow Rate.

	CO_2 (Mole Fraction)	H_2S (Mole Fraction)	Reboiler Duty (kW)
Scenario 1	0.1029	0.0017	2.32x10^5
Scenario 2	0.0737	0.0000	2.3x10^5
Scenario 3	0.0423	0.0000	2.28x10^5
Scenario 4	0.0701	0.0000	1.95x10^5
Scenario 5	0.0350	0.0000	1.86x10^5

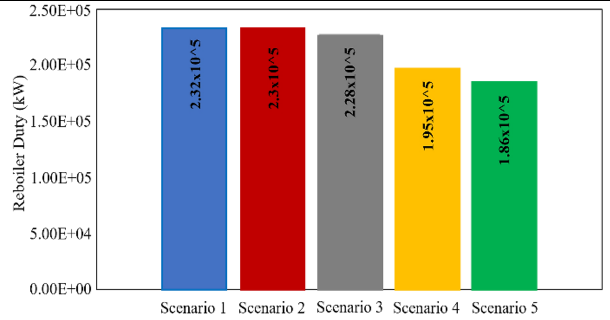

Fig. 18: Reboiler Duty for Different Scenarios.

It is evident from Table 12 and Figure 18 that the best cases are those 4 and 5, in which the amine strength was 40% rather than 50% and the heat duty needed for regeneration was less than that of scenario 1 (the base case), scenario 2, and scenario 3. Additionally, these results are consistent with earlier simulation studies that have been published in the literature [19]. In this study, mixing different amines, such as MDEA and MEA/DEA blends, was found to increase CO_2 absorption when a blend of 40% MDEA and 10% DEA was used as opposed to only 50% MDEA. In contrast, the operation was the primary emphasis of this work's optimization.

The scenario with the 40% amine strength and 2% DEA percentage turned out to be the most favorable one. This is predicated on Figure 19, which illustrates the CO_2 concentration in various system situations using an amine strength of 40% depending on the CO_2 content of the sweet gas.

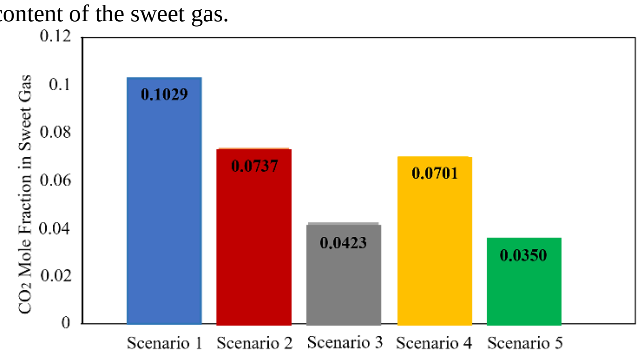

Fig. 19: Concentration of CO_2 in Different Scenarios.

4.4 Column Profiles

During the simulation of distillation columns, one of the most crucial outcomes that needs to be verified is the temperature profile along the column, where the vapor-liquid equilibrium in each stage is calculated step-by-step; additionally, it serves as an indicator for column convergence and validation of results. Figures 20 and 21, respectively, display the temperature profiles for columns T-100 and T-101.

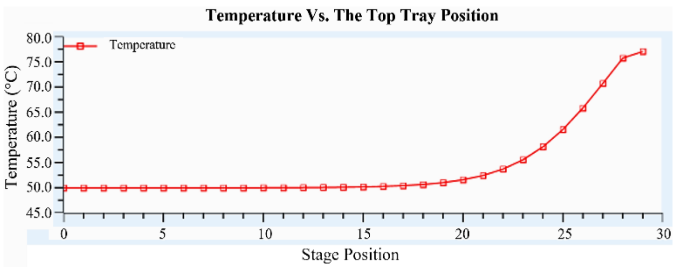

Fig. 20: Temperature Profiles for the Absorber Columns T-100.

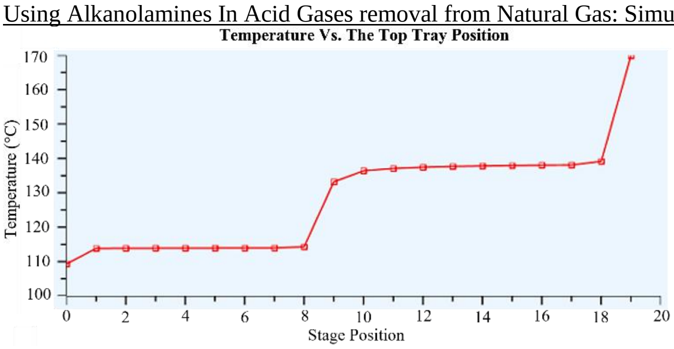

Fig. 21: Temperature Profiles for the Absorber Columns T-101.

The pressure profiles for the regeneration column T-10 and absorber column T-100 are depicted in Figures 22 and 23. In order to prevent hydraulic issues like flooding and weeping, the pressure drop in these columns must remain within the allowed range in order to maintain smooth vapor flow upward and liquid flow downward.

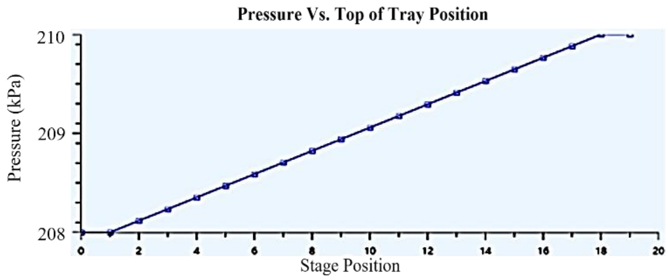

Fig. 22: Pressure Profiles for the Regeneration Columns T-100.

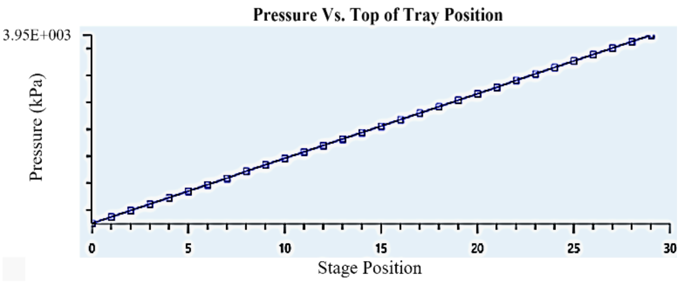

Fig. 23: Pressure Profiles for the Absorber Columns T-100.

5. Conclusions

The use of aqueous solutions containing MDEA as blends in the gas-sweetening units of Mellitah Complex has been studied for carbon dioxide (CO_2) absorption using the process simulation program "Aspen HYSYS V.11." Based on the amine strength and DEA fraction as an activator, five scenarios were created for the process enhancement. The outcomes were compared to the standalone MDEA solution at 50% wt concentrations (Scenario 1). Based on the CO_2 content in the sweet gas and the reboiler duty in the regeneration column, the best possible scenario was selected and enhanced.

The outcomes demonstrate that, at varying amine flow rates and regeneration tasks, all scenarios were capable of meeting the process requirement. With the lowest heat duty for regeneration, scenarios 4 and 5 were the best. Additionally, scenario 5, which has the lowest CO_2 concentration in the sweet gas and where the ratio of process improvement in the fifth scenario reached 89.67% in CO_2 and 94.12% in H_2S, is determined to be the optimal scenario based on an analysis of the absorption rate.

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