The effect of some design parameters in natural gas purification unit by using Aspen HYSYS simulation

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ABSTRACT

More recently, the demand for energy has increased to meet the growing need for it because of the continuous development in all areas of life. The importance of the subject must be achieved by focusing on the sources of this energy, including the energy produced by natural gas, which has increased interest in manufacturing in recent years, which is a clean source of energy compared to the energy produced from crude oil, for example, we find that Libya came in the center The eighth in the Arab reserves of 1.5 trillion cubic meters, according to data from the OAPEC, the reserves of OPEC countries of proven natural gas represents 27% of the global reserve. The natural gas industry is considered one of the most important oil industries. The industry is undergoing several stages, the most important of which is the phase of removing H2S gas and CO2 from natural gas components due to problems such as environmental pollution and corrosion of operating equipment. The aim of this study is to increase the concentration of CH4 and natural gas purification by Diethanolamine (DEA) from these pollutants, which were discussed in this study using the Aspen HYSYS program to simulate the steady state of typical natural gas composition of this phase by changing several parameters Design and operation such as operating temperature, gas flow rate, diameter and number of trays for absorption column. In order to achieve the best results of the degree of purity of methane after the purification phase where a rate of about 1245 kgmole/h (25 MMSCFD) reached a purity of 93% for methane and the number of trays 20, including a space of 0.5 m. When comparing the results obtained for pure methane and acid gases after the purification process, it was consistent with the actual and typical results applied as well as the rest of the design parts of the purification column.

Keywords: Aspen Hysys,Tray Spacing, Gas flow rate

1. Introduction

Acid gas removal is an important process in various branches of the hydrocarbon processing industry, primarily in natural gas processing and refining. Acid gas removal is also an essential part of other processes, such as coal gasification where carbon dioxide, hydrogen sulfide, carbonyl sulfides and other contaminants need to be removed. Acid gas is defined as gas containing significant amounts of contaminants, such as hydrogen sulfide (H_2S), carbon dioxide (CO_2), and other acidic gases. Sour gas is gas contaminated with H_2S. This term comes from the rotten smell due to sulfur content [1]. Thus, “gas sweetening” refers to H2S removal, because it improves the odor of the gas being processed, while “acid gas removal” refers to the removal of both CO_2 and H_2S.Acid gas removal is an important process in various branches of the hydrocarbon processing industry, primarily in natural gas processing and refining.

Natural gas mainly consists of a large quantity of methane along with heavier hydrocarbons such as higher alkanes and alkenes; moreover, in the raw state, it often contains a considerable amount of non hydrocarbons, such as nitrogen and the acid gases (carbon dioxide and hydrogen sulfide). A natural gas stream is approximately two-mole percent (mol %) sour. It means for every 100 kg moles of gas 2 kg moles of hydrogen sulfide (H_2S) are present in it[2]. Due to these facts, sales gas is required to be sweetened to contain no more than a quarter grain H_2S per 100 standard cubic feet (4 parts per million) and to have a heating value of no less than 920 to 980 Btu/SCF, depending on the contract [3]. There are many treating processes available for the removal of acid gases from natural gas. These processes include Chemical solvents, Physical solvents, Adsorption Processes Hybrid solvents and Physical separation (Membrane) [4]. In the past few years, amine solvents for the removal of acid gases have received increased attention. In this process, the acidic components react with an alkanolamine absorption liquid via an exothermic, reversible reaction in a gas/liquid contactor. In the following process step the acidic components are removed from the solvent in a regenerator, usually at low pressure and/or high temperature [5].Monoethanolamine (MEA), diethanolamine (DEA), diisopropanolamine (DIPA) and N-methyl diethanolamine (MDEA) are widely accepted alkanolamines for industrial operations [6]. Today, computer-aided process simulation is nearly universally recognized as an essential tool in the process industries. Indeed, simulation software plays a key role in process development to study process alternatives, assess feasibility, preliminary economics, interpret pilot-plant data, process design to optimize hardware and flow sheets, estimate equipment, operating cost, investigate feedstock flexibility, and plant operation to reduce energy use, increase yield and improve pollution control [4]. In the present paper, the use of amine diethanolamine (DEA) has been investigated by using the software ASPEN-HYSYS.

2. Materials and Methods

2.1 Diethanolamine

This process employs an aqueous solution of diethanolamine (DEA). DEA will not treat to pipeline quality gas specifications at as low a pressure as will MEA. Among the processes using DEA is the SNPA-DEA process developed by Societe Nationale des Petrolesd' Aquitaine (today Total) to treat the very sour gas which was discovered in Lacq France in the 1950s. The original patents covered very high acid gas loading of 0.9 to 1.3 moles per mole of amine.

This process is used for high pressure, high acid gas content streams having a relatively high ratio of H_2S/CO_2. The original process has been progressively improved and Total through Prosernat is now proposing high DEA solution concentrations up to 40 wt% with the high acid gas loading together with corrosion control by appropriate design and operating procedures [7,8].

2.2 Process Description

Figure 1 describes the typical complete acid gases removal cycle (sweetening cycle)which plugged in Aspen HYSYS library and used for natural gas. A typical acid gas treating facility is simulated. A water-saturated natural gas stream is fed to an amine contactor. For this process, Diethanolamine (DEA) at a strength of 28 wt% in water is used as the absorbing medium. The contactor consists of 20 real stages. The rich amine is flashed from the contactor pressure of 6895 to 620 kilo Pascal to release most of the absorbed hydrocarbon gas before it enters the lean/rich amine exchanger. In the lean/rich exchanger, the rich amine is heated to a regenerator feed temperature of 93°C. The regenerator also consists of 20 real stages. Acid gas is rejected from the regenerator at 49°C, while the lean amine is produced at approximately 124°C. The lean amine is cooled and recycled back to the contactor [9].

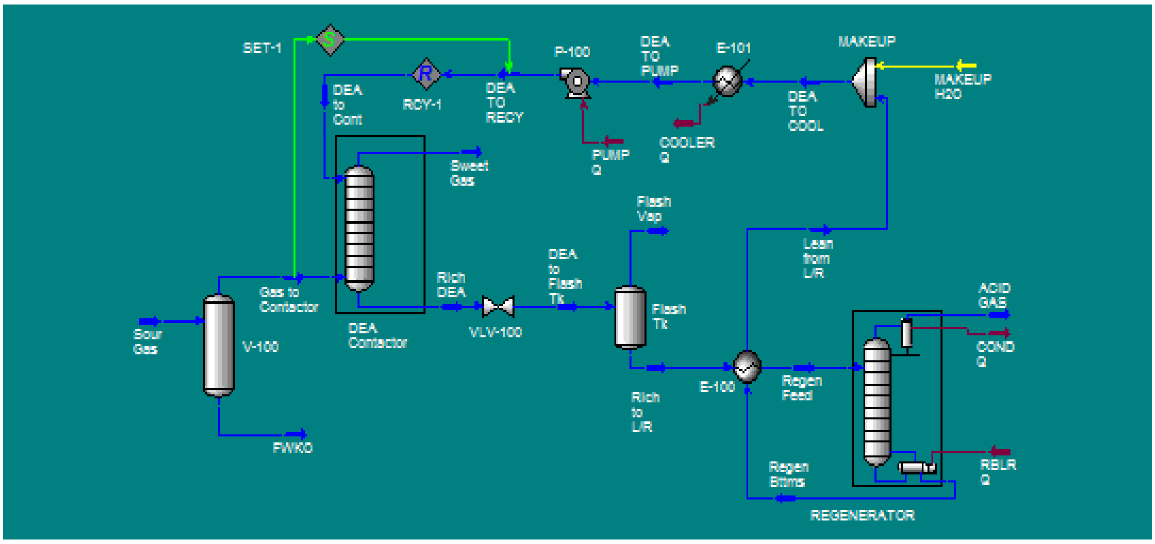

Figure 1. Schematic Process Flow Diagram for an Amine gas treating plant

The absorber column (Contactor) was selected from Aspen HYSYS model pallet as shown in Figure 2 which has the internal construction containing 20 stages, each stage consists of one tray as having construction looks like a sieve. The acid gas fluid package which contains DEA is also selected [10].

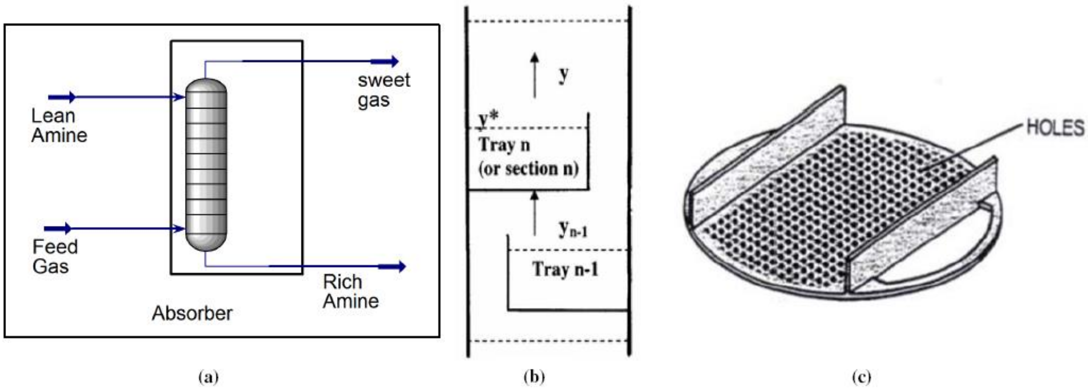

Figure 2. (a) The absorber column (b) Absorber column internal lay out [11] (c) Absorber column tray (sieve) construction [10]

3. Theory and Calculation

Steady state simulation through Aspen HYSYS is an important tool used for the simulation of different process including acid gas sweetening plant. The data was simulated through Aspen HYSYS and then the efficiency removals of acid gas were validated with the plant data. The feed gas conditions and composition for ammine solvent is shown in Table 1, Table 2 and Table 3 respectively [9]. In the case of Aspen HYSYS, the fluid package selected was acid gas -chemical solvent. The acid Gas property package was developed with the Peng-Robinson equation-of-state for vapor phase and the electrolyte non-random two-liquid (eNRTL) activity coefficient model for electrolyte thermodynamics [12]. The property package contains the eNRTL model parameters and other transport property model parameters identified from regression of extensive thermodynamic and physical property data for aqueous amine solutions [13].

The incoming sour gas contains 9.3% CO_2 and 3.0% H_2S. For an inlet gas flow rate of 25 MMSCFD, a circulating solution of approximately 28 wt.% DEA in water removes virtually all of the H_2S and most of the CO_2. A typical pipeline specification for the sweet gas is no more than 2.0 vol.% CO_2 and 4 ppm (volume) H_2S [9].

Table 1: Condition of the Sour gas

Sour gas	
Temperature	30°C
Pressure	6895 kpa
Molar Flow rate	25 MMSCFD

Table 2: Sour gas composition data

S.no	**Components**	**Mole Fractions**
1	N_2	0.002303
2	CO_2	0.093408
3	H_2S	0.030120
4	C_1	0.716616
5	C_2	0.060731
6	C_3	0.021075
7	i-C_4	0.007766
8	n-C_4	0.008662
9	i-C_5	0.005191
10	n-C_5	0.004449
11	n-C_6	0.007972
12	n-C_7	0.037077
13	H_2O	0.004630

Table 3: Conditions and composition of feed solvent (DEA to Contactor)

Temperature	35°C
Pressure	6860 kpa
Mass fraction of DEA	0. 280109
Mass fraction of Water	0.718039
Std ideal liquid vol. flow	43.154 m^3/h
Mass fraction of CO_2	0.001819
Mass fraction of H_2S	0.000033

The Concentrations of acid gas components in an amine stream are typically expressed in terms of amine loading—defined as moles of the particular acid gas divided by moles of the circulating amine. The Spreadsheet in HYSYS is well-suited for this calculation. Not only can the loading be directly calculated and displayed, but it can be incorporated into the simulation to provide a "control point" for optimizing the amine simulation. Also for convenience, the CO_2 and H_2S volume compositions for the Sweet Gas stream are calculated.

4. Results and Discussion

The simulation cycle was run to ensure that Aspen HYSYS absorption was converted to achieve the best number of absorption stages and to determine the appropriate diameter of the absorbance column. All numerical simulation conditions for temperature, pressure and feed flow rates of gas cycle removal are the result of many simulations run in simulations In order to obtain the highest purity of methane from natural gas. Table 4 shows the result of the final composition of natural gas after the completion of the purification process.

Table 4: Sweet and Sour gases composition

S.no	Components	Typical Sweet gas Mole Fractions [14]	Aspen HYSYS Product Mole Fractions	Typical Feed Sour gas Mole Fractions [9]
1	N_2	0.01 – 0.05	0.001712	0.002303
2	CO_2	0.01 – 0.02	0.002193	0.093408
3	H_2S	< 0.01	0.000001	0.030120
4	C_1	> 0.85	0.928323	0.716616
5	C_2	0.03 – 0.05	0.041807	0.060731
6	C_3	0.01 – 0.02	0.009805	0.021075
7	i-C_4	< 0.01	0.002702	0.007766
8	n-C_4	-	0.002989	0.008662
9	i-C_5	-	0.001392	0.005191
10	n-C_5	-	0.001172	0.004449
11	n-C_6	-	0.001571	0.007972
12	n-C_7	-	0.005092	0.037077
13	H_2O	-	0.001712	0.004630

By observing the following results in Figures (3,4). The Wier Height and Tray Diameter effect are evident on the fraction of CH_4 and CO_2 produced by the purification process in the absorption column. By increasing the concentration of CH_4both Wier Height and Tray Diameter are increasing, and for CO_2 the Wier Height and Tray Diameter are decreasing.

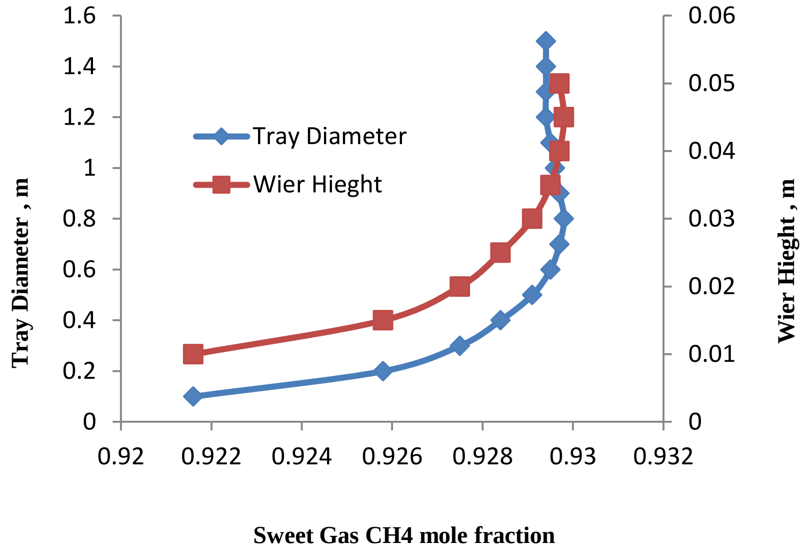

Figure 3. Effect of Tray diameter and Wier Heighton final product CH4

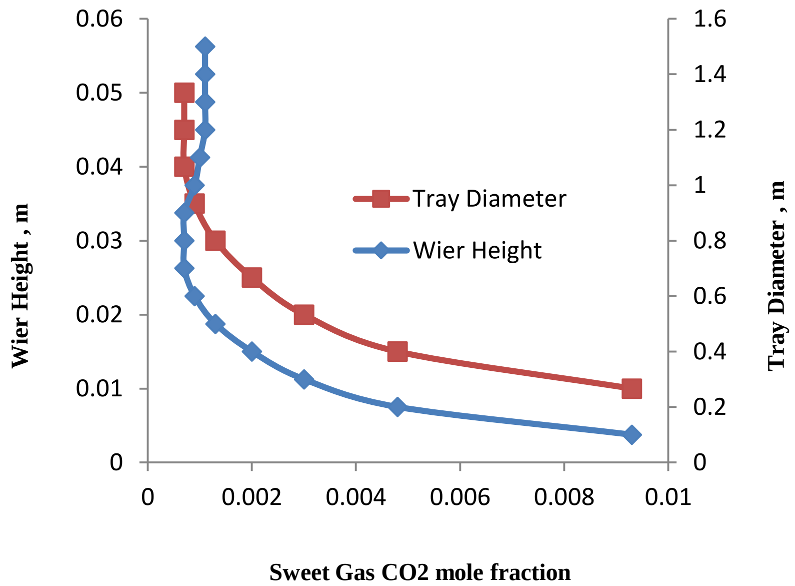

Figure 4. Effect of Tray diameter and Wier Heighton final product CO_2

In Figure (5,6,7) we observe the effect of the Tray position on the purity of methane. The high concentration of gas is in the top tray and the concentration is reduced at the bottom tray as well as for the solvent DEA. For H2S and CO2 the highest concentration is at the bottom of the bottom column tray.

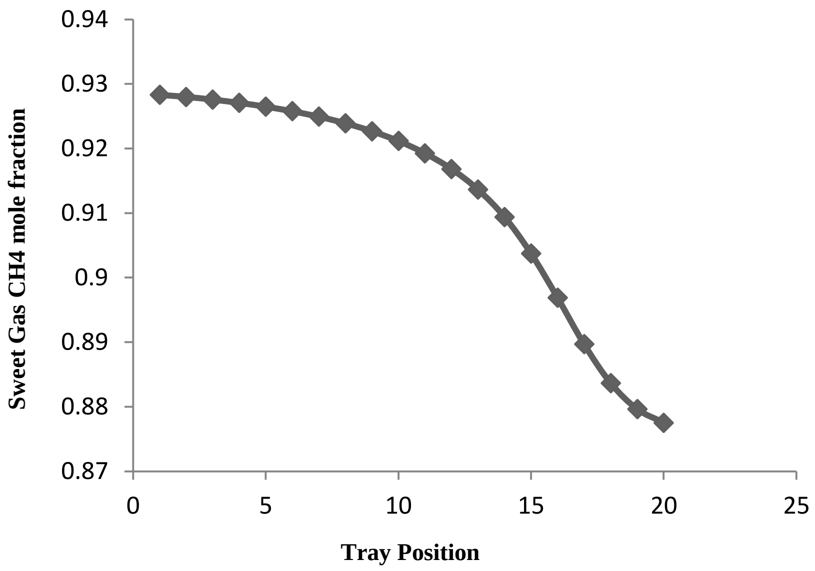

Figure 5. Effect of Tray Position on final product CH_4

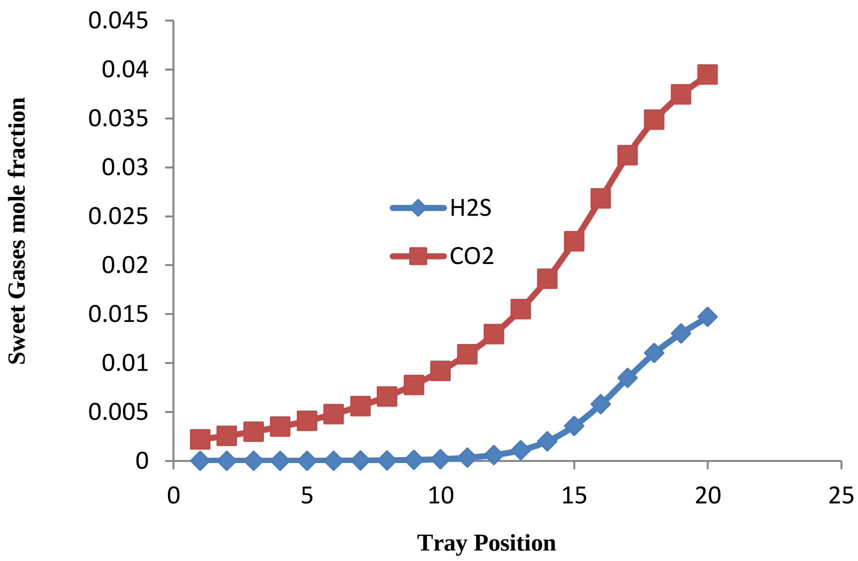

Figure 6. Effect of Tray Position on final product H_2S and CO_2

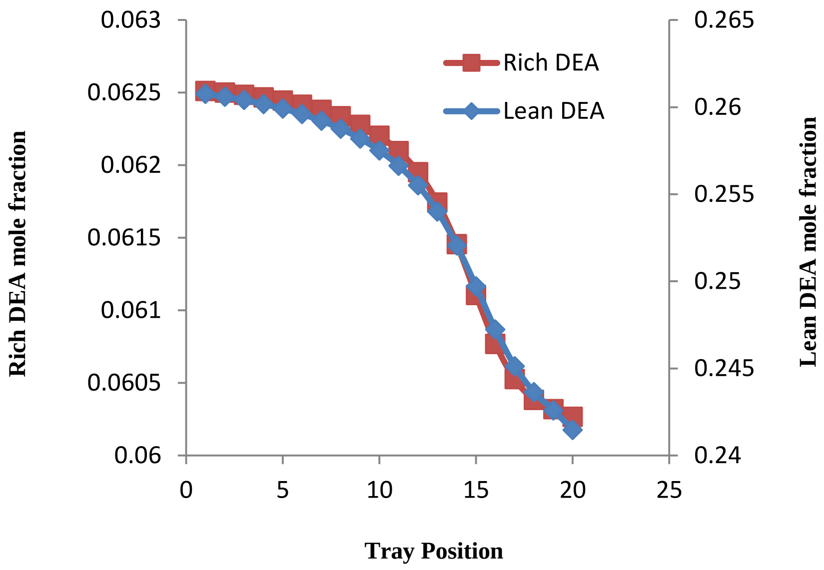

Figure 7. Effect of Tray Position on final product Rich DEA and Lean DEA

5. Conclusions

The Aspen HYSYS program was designed to achieve the best number of absorption stages in addition to determining the appropriate diameter of the absorbance column and wier height to achieve the highest purity of methane from natural gas. The optimal conditions for the process of natural gas treatment were the concentration of the adsorption of 0.24 and 20 trays with a tray diameter of 1.5 and Wier Height of 0.05 m. Under these conditions, the optimum absorption pressure for pure methane with 93% purity of natural gas is 6895 kpa and the CO_2 content H_2S and sour acid 0.093408 and 0.030120 respectively, the temperature of 30°C, the pressure of 6860 kpa, the flow rate of 25MMSCFD DEA amine solvent was used to remove CO_2 and H_2S simultaneously.

6. Acknowledgment

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