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EFFECT OF USING A NEW GAS SPLITTING TECHNIQUE ON THE PERFORMANCE OF AMINE SWEETENING PROCESS AT REDUCED NATURAL GAS PRESSURES

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Abstract:

Throughout the duration of any natural gas reservoir, its pressure declines which directly affect the amine sweetening efficiency, so relevant techniques are used nowadays to overcome this problem such as drilling new wells, modifying process parameters that will increase power/heat consumption, using amine blends and re-design the conventional gas sweetening process. The present study aims to find a new solution or modification to the basic amine sweetening process using Aspen HYSYS to overcome the pressure reduction phenomenon. The proposed solution was based on the idea of splitting the raw natural gas entering the absorber into two streams, one entering from the normal bottom tray and the other fed to the middle tray, in order to allow a better sour gas/amine contact area, consequently a better absorption without consuming higher energy. After simulating the conventional amine sweetening process, along with its modified version utilizing Aspen HYSYS, the findings revealed that the modified split gas flow technique increases effectively the absorption of hydrogen sulphide from natural gas by a factor ranging from 53% to 72% compared to the normal amine sweetening process but this applies only at certain feed gas flow rates. At high pressure, both techniques are delivering on-spec. sweet gas, but when pressure is reduced only the modified solution can produce on-spec. sweet gas at relatively feed gas flow rates while the conventional process failed to maintain the H_2S concentration below the maximum allowable limit.

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Keywords:

Natural Gas Sweetening, MDEA, Aspen HYSYS, Amine Treatment

Introduction

Natural gas is a naturally formed mixture of hydrocarbon gases predominantly composed of methane (CH_4), containing different concentrations of ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), as well as inert gases such as nitrogen (N_2). It is generated by the anaerobic breakdown of organic matter over geological timescales and is typically found in subsurface reservoirs, either associated with petroleum or in isolated gas fields (Speight, J. G. 2019). The increasing demand for cleaner natural gas has driven significant advancements in gas processing technologies. A key challenge in natural gas processing is the removal of acidic components, particularly hydrogen sulfide (H_2S) and carbon dioxide (CO_2), which can lead to pipeline corrosion and diminish the heating value of the gas (Pellegrini, L. A., 2021). The amine-sweetening process, a widely used method for acid gas removal, operates under various pressure conditions, which significantly influence its performance. Recently, reduced pressure conditions in natural gas reservoirs have posed challenges to the efficiency of the amine-sweetening process. If the absorber column pressure drops due to a decline in reservoir pressure, the partial pressure of H_2S will also decrease, leading to a reduction in the rich amine loading (moles of H_2S/moles of amine) will get reduced (Jon, S., Gudmundsson, P.). Traditional methods struggle to maintain high removal efficiencies at these lower pressures, leading to increased operational costs and potential process inefficiencies (Abdulrahman, R. K., (2012). The present study investigates a new modification to the basic amine sweetening process simulated with Aspen HYSYS, where the raw natural gas entering the absorber was split into two streams with the same composition, one entering from the normal bottom tray and the other fed to the middle tray. By comparing the performance metrics of the traditional and modified processes, this study seeks to offer insights into potential improvements in natural gas sweetening operations by analyzing the impact of reduced natural gas pressures on the efficiency of the amine-sweetening process, the performance improvements achieved through the application of the new gas-splitting technique, the operational benefits and potential cost savings associated with the enhanced process. By addressing these objectives, the current study contributes to the development of more efficient and cost-effective techniques for natural gas sweetening, ensuring improved adherence to environmental regulations and enhancing the efficiency of overall gas processing operations.

Literature Review

To overcome these challenges, several techniques are proposed most of them focusing on amine blend in which achieving a constant concentration of different types of amines is very difficult during the operation (Jamekhorshid, A., 2021). Bae et al., (2011) focused on splitting the amine entering the column into two streams; namely lean amine and semi-lean amine to reduce the re-boiler heat duty under normal process conditions. However, they did not investigate the impact of amine splitting during NG pressure declines. Implementing this approach reduced the re-boiler heat duty but required additional heat exchangers and pumping power, resulting in higher capital and operating costs. Zhu et al. (2022) used multiple gas feed to the absorber column with different compositions coming from different wells and revealed better acid gas removal and lower energy consumption compared to a conventional sweetening process. Practically, the idea of multiple gas feed from different

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wells is difficult to apply since NG in each well would travel in separate pipelines, consequently, the cost would increase especially when the reservoir is far away from the treatment plant such as deep water gas reservoirs. Therefore NG gathered from all wells and travelled in a single pipeline having the same composition and sent to the treatment plant (Zheleva, N., 2016), so this study will use the multiple gas feed concept with the same feed gas composition and will analyze the impact of reducing the process pressure on the sweetening performance.

Conventional Gas Sweetening Process Description

The feed gas flows into the sour gas filter coalescer, where entrained liquid hydrocarbons are removed to prevent foaming in the sour gas absorber. The sour gas then exits from the top of the coalescer and proceeds to the sour/sweet gas heat exchanger (shell and tube type) where it is heated with the gas stream from the top of the absorber. A typical amine sweetening process is provided in (Figure 1). The heated gas then enters the base of the absorber and passes upwards through the column where it meets a counter-current stream of lean amine solution. The absorber is a tray column (Figure 2) containing 20 trays (Kohl, A., 1997). H_2S is absorbed by the amine which leaves the base of the tower as a rich amine solution. Sweet gas exits from the top of the absorber and passes through the sour/sweet gas exchanger where it is cooled before entering the sweet gas knock-out drum. Rich amine is sent to the rich amine flash drum where dissolved gases are separated and released, rich amine then passes through the lean/rich amine exchanger where it is heated with a counter-current flow of hot lean amine from the amine regenerator. The heated rich amine is directed to the amine regenerator which it enters on tray 5. The regenerator is a tray column containing 24 trays in which H_2S and other contaminants (i.e. CO_2, mercaptans, etc.) are removed from the rich amine by the stripping gas produced in the steam-heated regenerator re-boiler (Mushtaq, F., 2022; Hameidi, R., 2018).

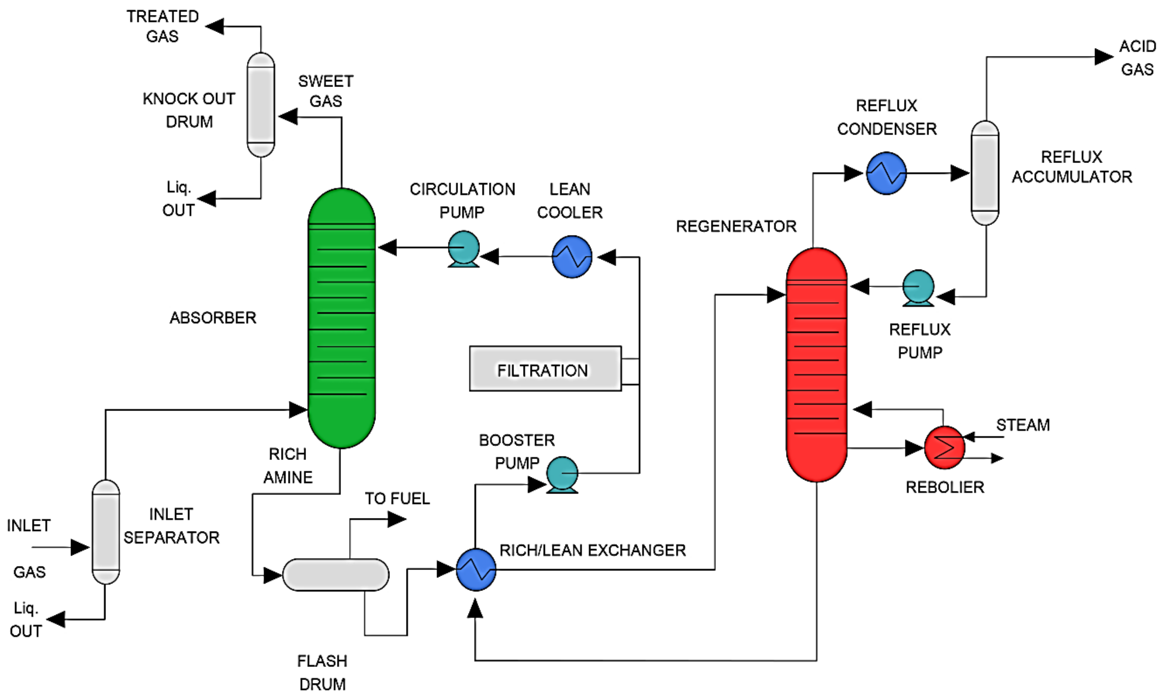

Figure 1: Typical Amine Sweetening Process

Source: Zhu Et Al. (2022)

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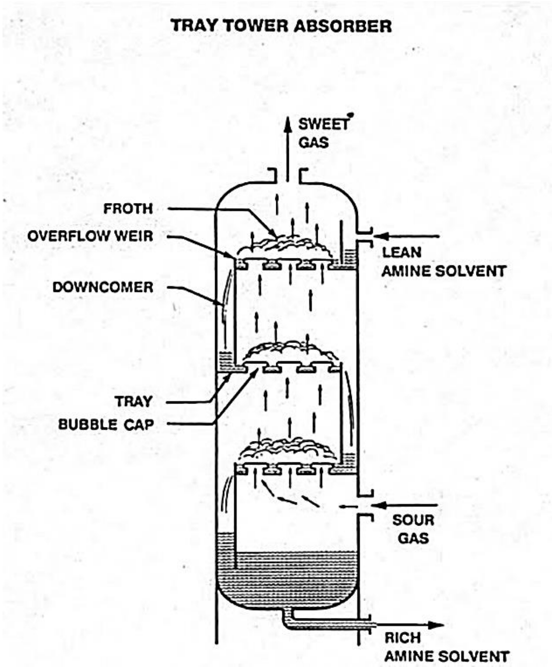

Figure 2: Absorber Column - Tray Type

Source: Speight, J. G. (2007)

The regenerator overhead gas passes to the condenser where it is cooled to 49°C before entering the reflux. The acid gas exiting the reflux drum is directed to the sulfur recovery unit (SRU) where the H_2S and other sulfur compounds are recovered and converted into sulfur. Liquids separated in the reflux drum are pumped by the reflux pump to the top of the regenerator. The lean amine solution exits the bottom of the regenerator, is cooled in the lean/rich amine exchanger, and is subsequently pumped by the lean amine booster pump to the lean amine air cooler. The amine solvent requires continuous filtration to avoid any accumulation of heavy hydrocarbons and amine degradation products which are the primary causes of foaming inside the two columns. A portion of the circulating lean amine stream (about 15 % mass flow) is fed to the lean amine filtration package. The filtered lean amine is then blended back into the main flow and the total stream is transported to the sour gas absorber by the lean amine pump.

Effect of Pressure on Absorption Performance

As shown in Table 1, the absorption capability increases by increasing the operating pressure. This is due to a better gas/liquid contact area as a result of increasing the force exerted on the molecules, so the MDEA absorbs more H_2S molecules compared to a low-pressure process where the distance between the molecules is higher, consequently a lower contact area and absorption performance (He, J., 2021). Such an effect may be explained according to Henry's law in Equation (1) which indicates that the quantity of gas dissolved in a liquid is directly proportional to its partial pressure (Glasstone, S., & Lewis, D. 1960):

$$C = K_H \times P \qquad (1)$$

Where; **C** represents the solubility of a gas at a specific temperature in a given solvent, $\mathbf{K_H}$ is Henry's constant, and **P** denotes the gas's partial pressure. On the other hand, the regeneration of the rich amine solution needs a reduction of pressure and high temperatures to release and

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separate the acid gases from the rich amine that circulates back again as lean amine (Abotaleb, A., 2022).

Table 1: Effect of Pressure on Absorption Performance

Absorber Pressure (Barg.)	H_2S Concentration in Sweet Gas (ppm)
80	2.8
70	3.2
60	4.1
50	17
40	163.8

Case Study

A deep NG reservoir in the Mediterranean Sea, Egypt is taken as the case study where all gas wells are collected in a gathering offshore platform and sent to the onshore treatment plant for acid gas removal and dew point control. The H_2S content in the sweet gas must be below 4 ppm, using 45% MDEA solution as the solvent (Rao, S., 2023). The composition of the feed NG and the operating conditions of the primary equipment are presented in Table 2 and Table 3, respectively.

Table 2: Feed Natural Gas Composition

Component	Composition Mole %
Hydrogen Sulphide (H_2S)	0.041
Carbon Dioxide (CO2)	0.87
Nitrogen (N_2)	0.147
Methane (CH_4)	98.161
Ethane (C_2H_6)	0.469
Propane (C_3H_8)	0.08
Iso-Butane (i-C_4H_{10})	0.081
Normal Butane (n-C_4H_{10})	0.026
Iso-Pentane (i-C_5H_{12})	0.034
N-Pentane (n-C_5H_{12})	0.018
N-Hexane (n-C_6H_{14})	0.073

Table 3: Operating Conditions

Parameter	Typical Value
Inlet gas pressure	80 bar gauge.
Inlet gas temperature	25°C
Inlet gas flow	330 MMSCFD
Absorber stages	20 trays
Absorber top pressure	75 bar gauge
Absorber bottom pressure	80 bar gauge
Regenerator stages	24 trays
Re-boiler temperature	130°C
Lean amine booster pump inlet pressure	1 bar gauge
Lean amine pump inlet pressure	6 bar gauge
Flash drum differential pressure	73 bar gauge
Regenerator inlet temperature	95°C
Regenerator top pressure	1.2 bar gauge

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Regenerator bottom pressure	1.7 bar gauge
Condenser temperature	49°C
Amine circulation rate	75000 kg/h

Proposed Modification to the Conventional Gas Sweetening Process

The proposed solution shown in (Figure 3) is based on the idea of splitting the raw NG entering the absorber into two streams, one enters below the normal bottom tray, and the other is fed below tray number 16 (from top to bottom). This can enhance the absorption performance due to several reasons Towler, G., Sinnott, R., (2012) & Zhu et al. (2022):

1. Improved Gas-Liquid Contact: By introducing gas at different points in the absorber, the contact between the gas and the absorbing liquid is improved. This ensures a more even distribution and reduces the chances of channeling, which is when gas or liquid bypasses portions of the packing or trays, leading to inefficient absorption.
2. Enhanced Mass Transfer: Dividing the gas stream and introducing it at various levels enhances the mass transfer surface area and extends the interaction time between the gas and the absorbent. This allows for more efficient absorption of contaminants from the gas.
3. Reduced Flooding and Foaming: Introducing the gas at multiple points can help in managing the vapor and liquid traffic within the absorber, reducing the risk of flooding (where liquid accumulates and restricts gas flow) and foaming (which can reduce the efficiency of gas-liquid contact).
4. Gradient Utilization: Feeding gas at different points creates concentration gradients along the height of the absorber. This means that different sections of the absorber can operate at different conditions optimized for the specific absorption taking place in that section.
5. Operational Flexibility: Having multiple feed points allows for better control and optimization of the absorber's operation. It provides the flexibility to adjust the flow rates and distribution based on the feed gas composition and operating conditions.
6. Improved Absorbent Utilization: The absorbent can be more effectively utilized because it can interact with the gas at different stages, ensuring that the absorbent's capacity is maximized before it exits the absorber.

By implementing this approach, the overall performance of the absorption process can be significantly enhanced, leading to better contaminant removal and more efficient operation of the gas processing unit.

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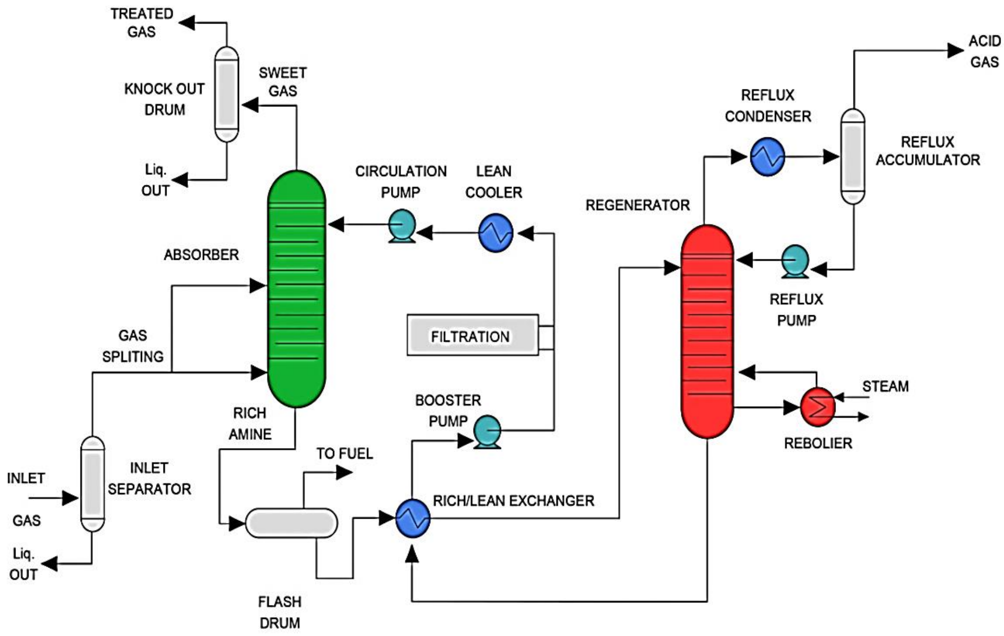

Figure 3: Gas Splitting Amine Sweetening Process

Source: Author

Methodology

Two main cases are simulated using Aspen HYSYS, the first one (Case A; Figure 4) is the conventional amine sweetening process and the second case (Case B; Figure 5) is the modified solution as mentioned earlier with exactly the same parameters as the first case (Table 3). The second step in the current study is to lower the pressure and examine the absorption performance in both cases.

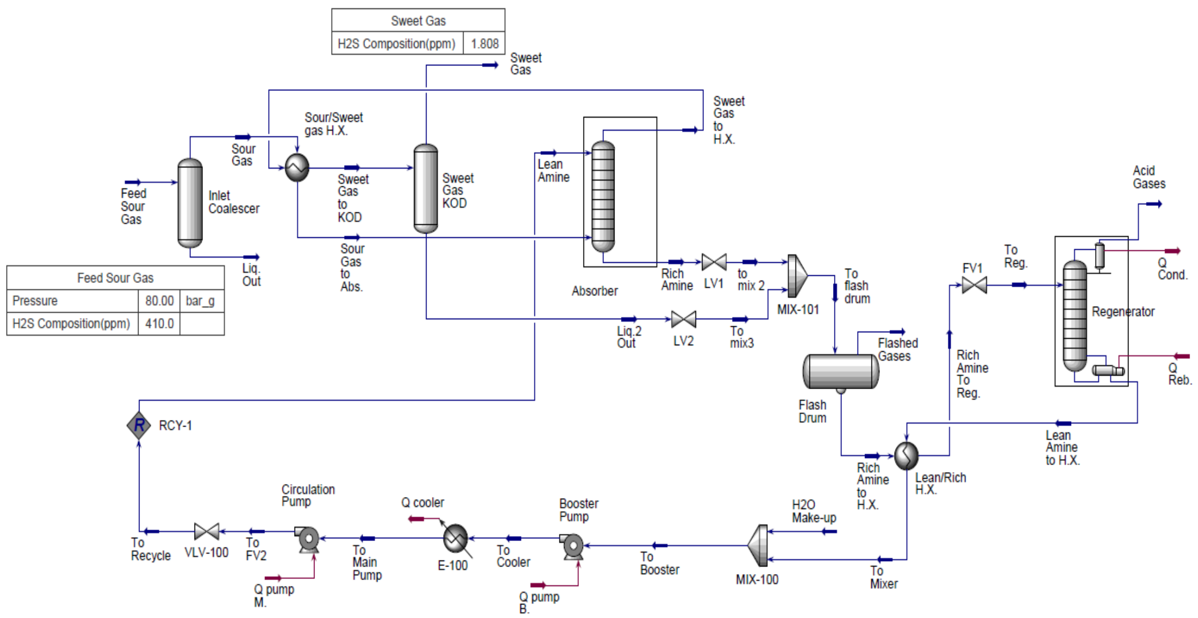

Figure 4: Simulation of the Conventional Amine Sweetening Process (Case A)

Source: Author

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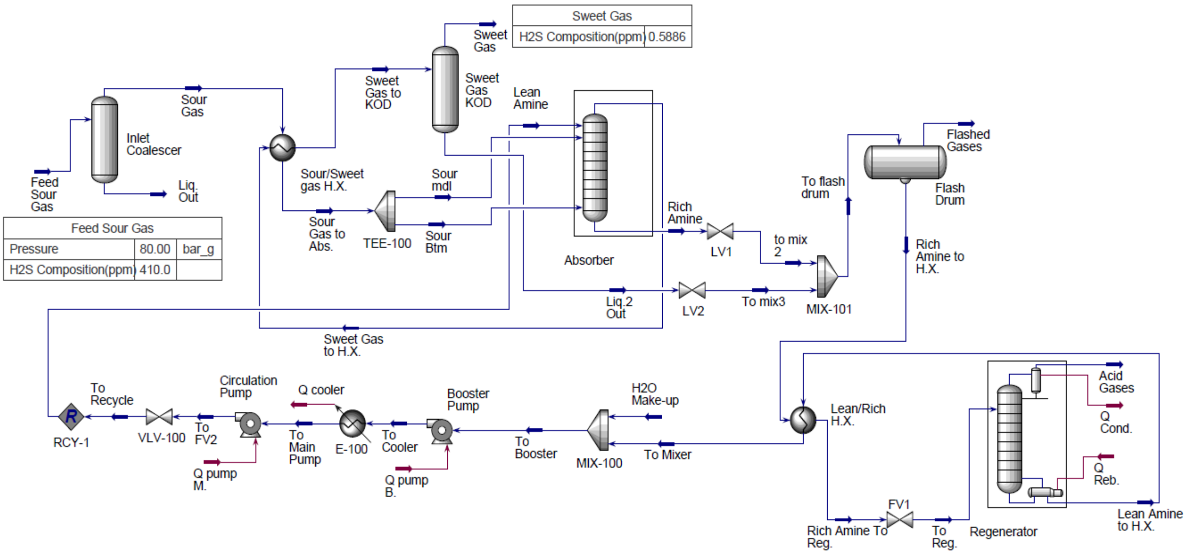

Figure 5: Simulation of the Modified Amine Sweetening Process (Case B)
Source: Author

Chemical Reactions

During the sweetening process, Equations (2) and (3) show the mechanism of the equilibrium-based reactions between H_2S and aqueous MDEA solution (Pacheco, M., & Rochelle, G., 1998).

$$MDEA + H_2O \leftrightarrow MDEAH^+ + OH^- \quad (2)$$
$$MDEA + H_2S\ (aq.) \leftrightarrow MDEAH^+ + HS^- \quad (3)$$

Results and Discussion

Figures 6, 7, and 8 show that for a given feed gas pressure and flow rate, the proposed modification produced an H_2S concentration in the sweet gas significantly lower than that found in the conventional sweetening process without consuming any extra energy due to the reasons mentioned earlier in this report. At high pressures, the feed gas flow rate had minimal impact on the absorption capacity of MDEA solutions and both models delivered on-spec. sweet gas (H_2S concentration lower than 4 ppm). However, at reduced pressures, the absorption capacity of both models decreases especially for the conventional sweetening process resulting in the production of off-spec. sweet gas. Figure 9 justifies the utilization of the gas splitting technique at reduced NG reservoir pressures and relatively low feed gas flow rates (< 400 MMSCFD).

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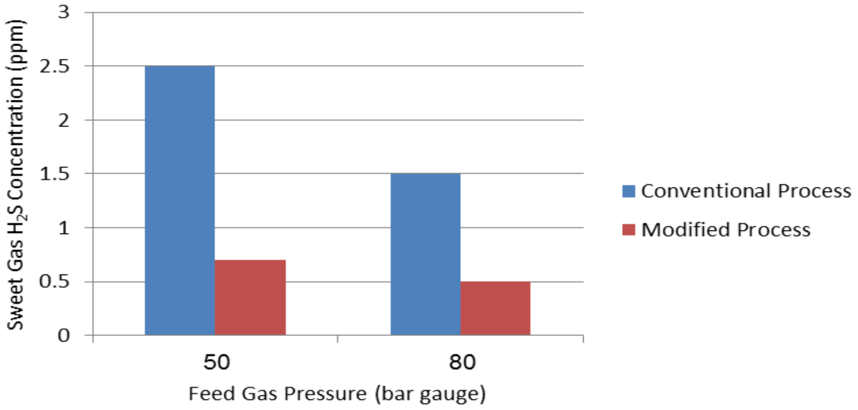

Figure 6: Performance of Conventional and Modified Process at Gas Flow Rate 300 MMSCFD

Source: Author

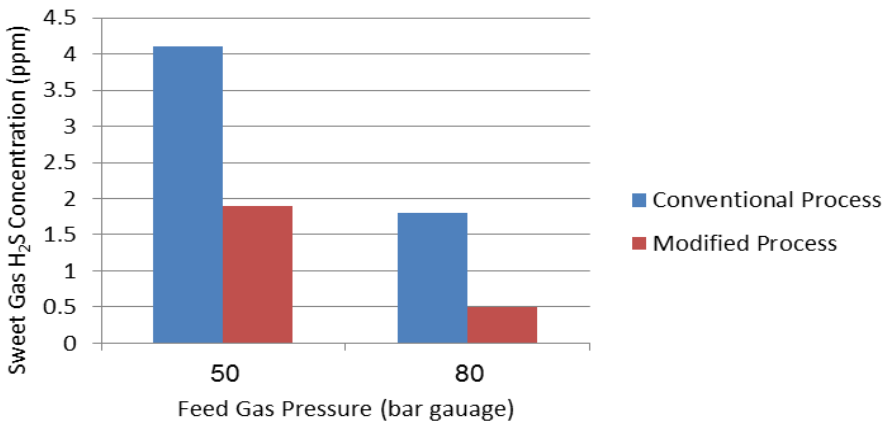

Figure 7: Performance of Conventional and Modified Process at Gas Flow Rate 330 MMSCFD

Source: Author

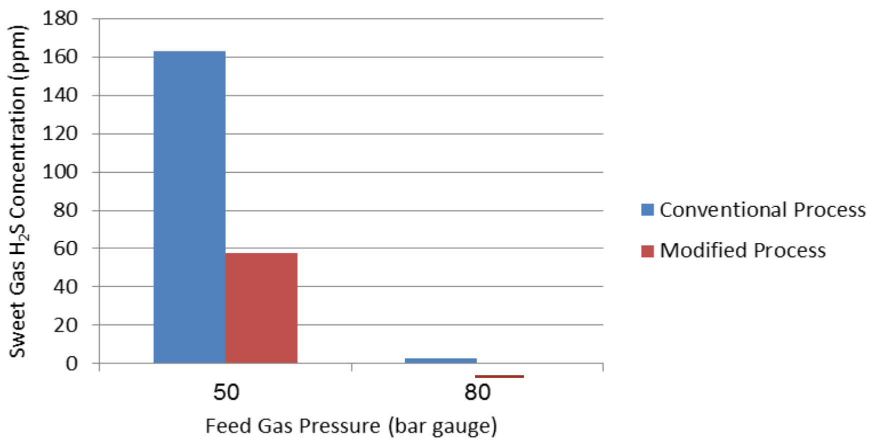

Figure 8: Performance of Conventional and Modified Process at Gas Flow Rate 400 MMSCFD

Source: Author

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Figure 9 shows the percent reduction of the H_2S concentration in the sweet gas resulting from the use of the gas-splitting sweetening technique at high and low pressures. The percent reduction was calculated by the Equation (4):

$$\%\,reduction = \frac{H_2S\ conc._{conventional\ process} - H_2S\ conc._{modified\ process}}{H_2S\ conc._{conventional\ process}} \times 100 \qquad (4)$$

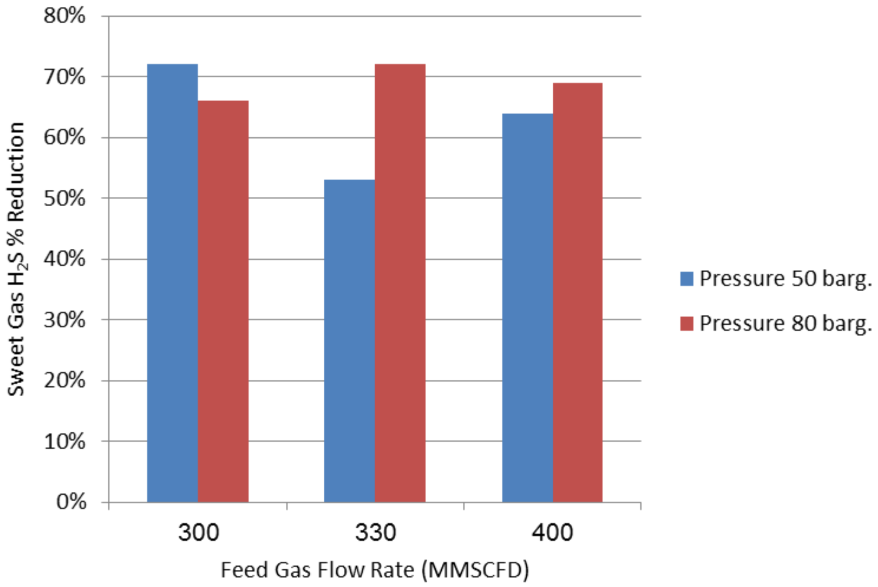

Figure 9: Percentage Reduction of H_2S Concentration in Sweet Gas Using the Modified Process for Different Feed Gas Pressures and Flow Rates

Source: Author

Conclusion

After simulating the normal (conventional) sweetening process and the proposed modification using Aspen HYSYS, then reducing the process pressure, the following outcomes were revealed:

1. The modified split gas flow technique increased the removal of hydrogen sulfide from natural gas by a factor ranging from 53% to 72% compared to the normal amine sweetening process but this applies only at certain feed gas flow rates and using methyl di-ethanol amine (MDEA) as the solvent.
2. At high pressures, both techniques delivered on-spec. sweet gas (H2S concentration < 4 ppm).
3. At reduced pressures, only the modified solution can produce on-spec. sweet gas at different sour gas feed rates while the conventional process failed to maintain the H2S concentration below the maximum allowable limit.
4. The gas splitting technique is a cost-effective alternative (just a second pipeline for gas split flow to absorber) compared to other solutions in which extra energy will be consumed or new equipment must be installed.
5. During the pressure decline phase of natural gas reservoirs, employing the suggested solution enables effective operation of the process at lower pressures without the need for gas compressors typically used during this phase. This approach can lead to

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significant savings in both capital and operating costs, especially when there are no pressure restrictions on the downstream sales gas network or consumers.

6. By using the modified solution, it can be easily switched to the conventional amine process by closing the middle feed stream and allowing all the flow to enter only from the bottom streamline. This can be implemented by installing a manual or flow control valve.

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