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Design and Analysis of an MDEA-Based Natural Gas Purification System: Process Simulation and Economic Assessment

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Abstract:
Natural gas purification is a critical process to meet environmental standards and enhance the fuel's usability. Methyl Diethanolamine (MDEA) has proven to be an effective and economical solvent for removing acid gases such as carbon dioxide (CO_2) from natural gas streams. This study aims to design and analyze a purification system capable of treating 27905.43 Nm^3/h of natural gas using an MDEA absorption-regeneration cycle. The study included process simulation in ASPEN HYSYS v11.0, design of major equipment, and a feasibility assessment of the system's economic performance. The purification system includes an absorber, regenerator, lean/rich heat exchanger, separator, and booster pump, all designed based on material and energy balances. Key results indicate that 72,628 kg/h of MDEA solution is required to achieve a CO_2 removal efficiency exceeding 98%. The absorber, utilizing 25 sieve trays, was designed to optimize solvent contact for efficient gas absorption. The lean/rich heat exchanger was optimized for energy efficiency, showing a heat transfer area of 241.28 m^2 in ASPEN HYSYS calculations. Additionally, economic analysis estimated a fixed capital investment of $5.7 million, with an operating cost of $8.14 million per year. The payback period for the project was determined to be 1.74 years, demonstrating strong economic feasibility. This study highlights the technical and economic viability of using MDEA-based absorption for CO_2 removal, providing insights into process optimization and cost efficiency for large-scale natural gas purification plants.

Keywords: Natural Gas Purification, MDEA, AGR, Acid Gases, Amine.

I. INTRODUCTION

As natural gas purification methods become more sophisticated, the global energy landscape is undergoing a transformative shift toward renewable energy sources [1]. As nations strive to reduce greenhouse gas emissions and dependency on fossil fuels, integrating clean energy solutions has become imperative [2,3]. Technologies such as solar, wind, and bioenergy are gaining traction due to their sustainability and minimal environmental impact [4]. Natural gas stands as a cornerstone of global energy supply, surpassing an annual production rate of 4,000 billion cubic meters. Despite its significance, natural gas often harbors impurities, notably acid gases like carbon dioxide (CO_2) which can detrimentally impact its quality and functionality. The elimination of these acid gases proves pivotal to guaranteeing the safe and effective utilization of natural gas, particularly in sectors such as transportation, power generation, and industrial processes [5].

Amidst a plethora of methods available for acid gas removal, the utilization of Methyl Diethanolamine (MDEA) has emerged as a prominent choice, drawing attention for its exceptional selectivity, efficiency, and environmental friendliness. MDEA, an alkanolamine-based solvent, exhibits a remarkable capacity for CO_2 absorption, rendering it a preferred solution in gas

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purification endeavors. Noteworthy for its cost-effectiveness, this approach not only facilitates the capture of acid gases but also enables their subsequent recovery and reuse, thus curbing environmental repercussions [6].

The integration of MDEA in natural gas purification processes assumes a critical role in elevating gas quality, mitigating corrosive impacts on pipelines and equipment, and ensuring alignment with stringent environmental mandates. This scholarly exploration delves into the intricate mechanisms, advantages, and hurdles linked to the adoption of MDEA for natural gas purification [7].

The purification of natural gas from acid gases such as CO_2 is crucial in the gas industry. Amines, particularly Methyl Diethanolamine (MDEA), are widely used for this purpose due to their high efficiency in selectively absorbing acid gases. MDEA's advantages include low energy consumption and high solvent regeneration efficiency, making it economically viable for large-scale gas processing. However, challenges remain, such as solvent losses, degradation, and the impact of impurities [8].

In general, gas purification involves the removal of vapor-phase impurities from gas streams. The processes which have been developed to accomplish gas purification vary from simple once-through wash operations to complex multiple-step recycling systems. In many cases, the process complexities arise from the need for recovery of the impurity or reuse of the material employed to remove it. The primary operation of gas purification processes generally falls into one of the following five categories like absorption into a liquid, adsorption on a solid, chemical conversion to another compound, permeation through a membrane as shown in Figure 1 [9].

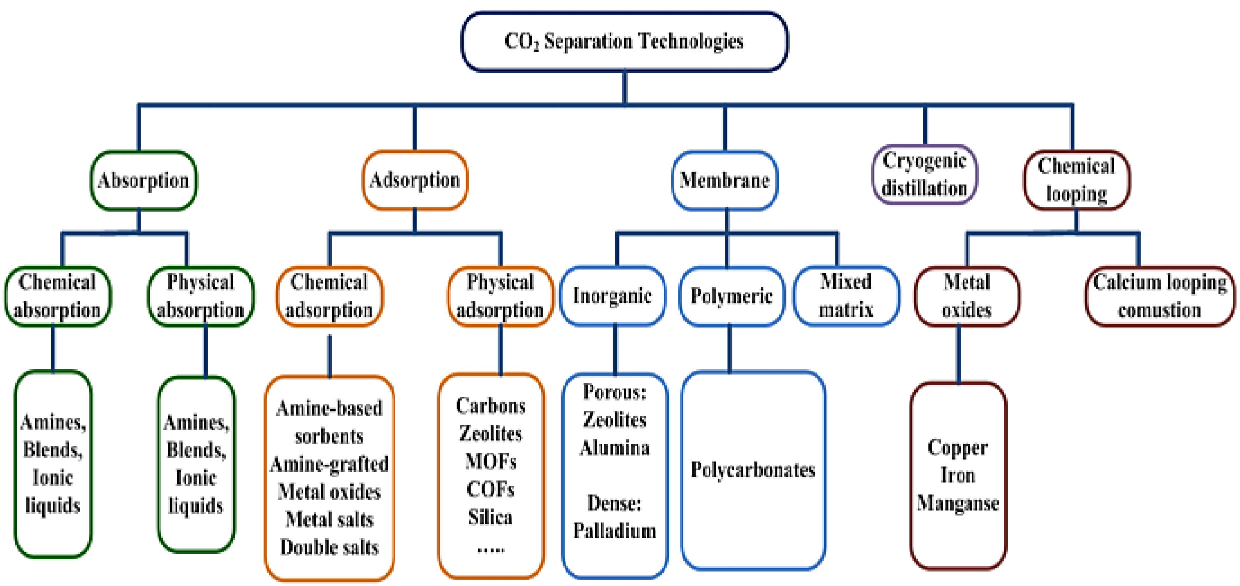

Figure 1: Different technologies used for CO_2 Separation Technologies from Natural Gas.

Absorption is the process of transferring a component from a gas phase to a liquid phase in which it is soluble, playing a crucial role in gas purification. It is widely used in industrial applications to remove impurities from gas streams. The reverse process, known as stripping, involves the transfer of a dissolved component from the liquid phase back into the gas phase. Among gas purification techniques, absorption stands out as the most significant operation due to its effectiveness and broad applicability [10].

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Adsorption is the process of selectively concentrating one or more components of a gas on the surface of a microporous solid. In this process, the gas-phase components that adhere to the solid surface are referred to as the adsorbate, while the microporous solid itself is known as the adsorbent. The forces that hold the adsorbate on the adsorbent are weaker than chemical bonds, allowing for desorption— the release of the adsorbed components—by increasing the temperature or decreasing the partial pressure of the gas, similar to the stripping process in absorption. However, when the adsorbed component undergoes a chemical reaction with the solid, the process is termed chemisorption, and desorption typically becomes irreversible [11].

Chemical conversion is a fundamental operation in various industrial processes, encompassing both catalytic and noncatalytic gas-phase reactions, as well as the interaction of gas-phase components with solid materials. It plays a crucial role in transforming raw materials into desired products through chemical reactions. Additionally, the reaction of gaseous species with liquids or solid particles suspended in liquids is considered a specialized form of absorption and is typically analyzed within that context [12].

Membrane permeation is an emerging technology in gas purification that utilizes polymeric membranes to separate gases through selective permeation. In this process, specific gaseous components dissolve into the membrane material on one side and are transported across due to a concentration gradient. This gradient is maintained by creating a high partial pressure of the key gas components on one side of the membrane and a low partial pressure on the other. Although membrane permeation currently plays a relatively minor role in gas purification, its application is expanding rapidly due to its efficiency and potential for cost-effective separation [13].

Before selecting a gas purification process, several key factors must be considered to ensure efficiency and compliance with operational and environmental requirements. These factors include the type and concentration of impurities present in the gas, along with its hydrocarbon composition. The temperature and pressure conditions of the sour gas also play a crucial role in determining the most suitable purification method. Additionally, the required outlet gas specifications, the volume of gas to be processed, and the selectivity needed for acid gas removal must be evaluated. Other important considerations include specifications for residue gas, acid gas, and liquid products, as well as the overall costs associated with capital investment, operational expenses, and royalties. Finally, adherence to local environmental regulations is essential to ensure sustainable and compliant gas processing operations [14].

For offshore gas sweetening, size and weight are additional important considerations. When removing CO_2 offshore, it's important to note that the acid gas from the sweetening system will either need to be flared or re-injected into the reservoir, depending on customer requirements [15].

Technology selection can be complex, as shown in Figure 2, which provides an overview of the process selection based on feed and outlet acid gas concentrations.

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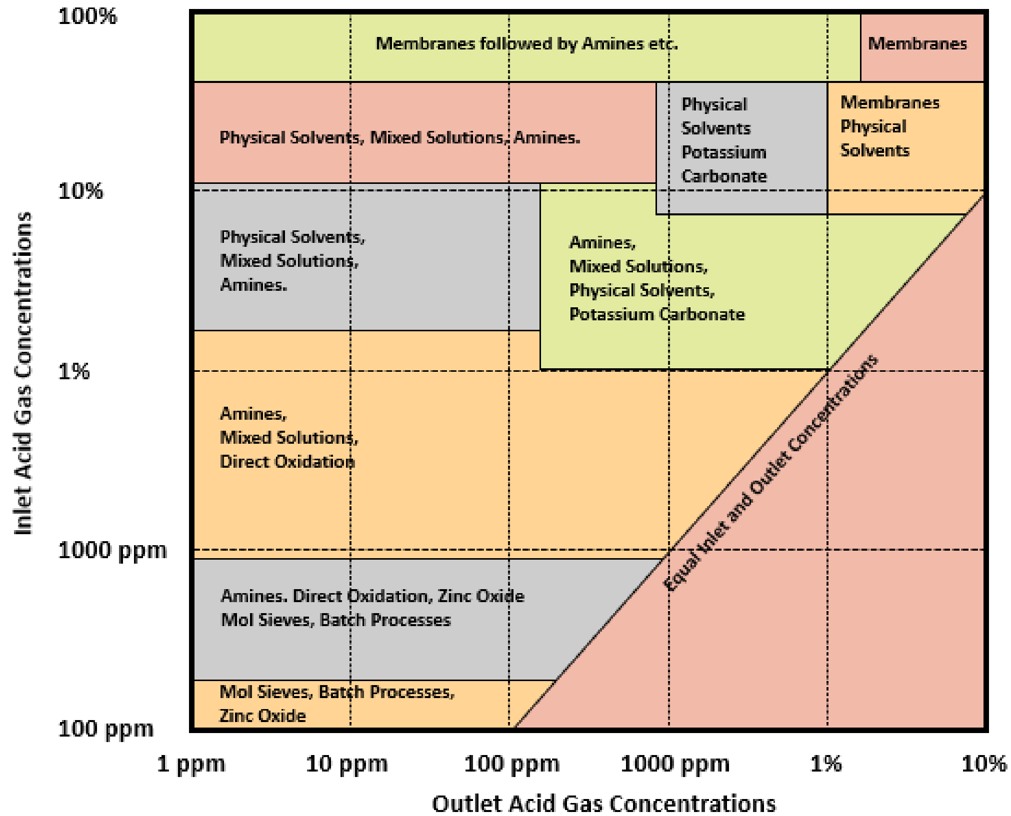

Figure 2: Matrix for Choosing Acid Gas Removal Technologies.

II. Methodology

A comprehensive approach was developed to assess the efficiency of using MDEA for natural gas purification. Process simulation and optimization were carried out using Aspen HYSYS V11, with economic analysis conducted using Aspen Process Economic Analyzer V11. Data organization and calculations were performed using [16] where the process description for N.G. Purification Unit from Acid Gases by MDEA is shown in Figure 3.

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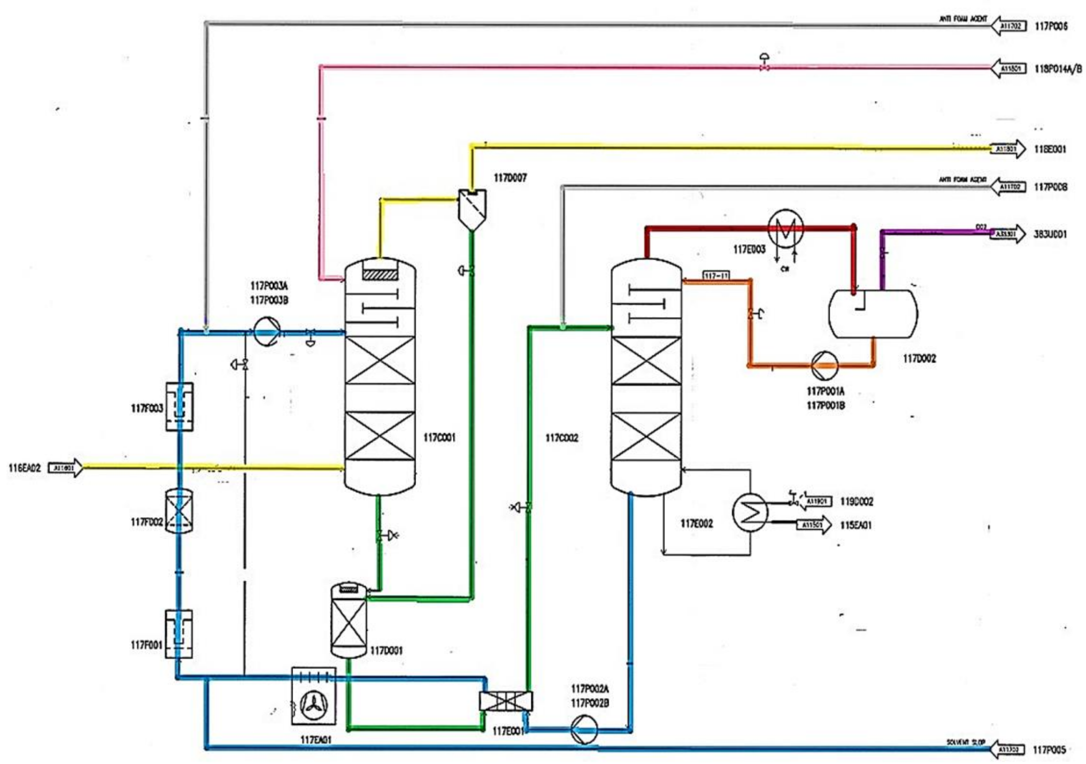
Lean MEDA	Rich MEDA	Condensate	Natural Gas	CO_2	Fresh Water	CO_2 + Condensate	Anti Foam



ITEM	117 F003	117P001A/B	117P002A/B	117P003A/B
DESCRIPTION	Side Stream Cartridge Filter II	Stripper Reflux Pump	Booster Pump	HP Solvent Pump
ITEM	117E003	117EA01	117F001	117F002
DESCRIPTION	Stripper Condenser	Solvent Air Cooler	Side Stream Cartridge Filter I	Charcoal Filter
ITEM	117D006	117D007	117E001	117E002
DESCRIPTION	Process Cond. KO Drum	Treated Gas KO Drum	Solvent Heat Exchanger	Stripper Reboiler
ITEM	117C001	117C002	117D001	117D002
DESCRIPTION	Absorber Column	Stripper	HP Flash Drum	Stripper Reflux Drum

Figure 3: PFD For typical CO_2 Removal Unit.

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The BASF MDEA® process for sour gas removal is used. The process is an absorption process which uses piperazine activated MDEA, an amine solution, which selectively absorbs CO_2 contained in the product gas. Traces of H_2S, which may be present due to sulfur contained in the propane feed, is also removed [17].

Compressed process gas from unit 116 with a temperature of about 70°C is admitted to the bottom of the Absorber Column 117C001. The absorbent (i.e. the lean solution) is admitted to the top of the Absorber Column, having a pressure of 32 kg/cm² abs and a temperature of approx. 63.5°C. It scrubs CO_2 and potential traces of H_2S out of the ascending gas [18].

The virtually CO_2 free product gas from the Absorber Column top is routed to the Fractionation Unit 118 after knockout of potential liquid carry over in Treated Gas KO Drum 117D007 [19].

The rich solvent leaving at the bottom of the Absorber Column at a temperature of approx. 70°C is flashed in the HP Flash Drum 117D001 operated at about 3 kg/cm² abs. Flash gas from 1170001, which includes small amounts of co-absorbed hydrocarbons, is routed back to Process Condensate KO Drum VIII 115D004. Then, it is recompressed in Unit 116 and reprocessed in the Absorber Column to minimize losses of Natural gas. The partially degassed rich solvent is preheated by Solvent Heat Exchanger 117E001 and fed to the Stripper 117C002 [20].

CO_2 rich gas is obtained as overhead product at a temperature of approx. 45°C and a pressure of about 1.9 kg/cm² abs while the lean solvent is pumped back at a temperature of approx. 125.6°C from the bottom of the Stripper to the Absorber Column [21].

Overhead vapors are partially condensed in the Stripper Condenser 117E003 and sent to the Stripper Reflux Drum 117D002. Condensed liquid is returned as Stripper reflux via the Stripper Reflux Pump 117P001A/B. The vapor phase containing CO_2 is routed to Auxiliary Boiler, where it is combined with the combustion air to be incinerated in the burners. Inflammable components in the vapors and traces of H_2S are to be burned in the boiler furnace [22].

The lean solvent obtained as bottom product of the Stripper is pumped by the Booster Pump 117P002A/B and cooled to approx. 101.5°C in the Solvent Heat Exchanger 117E001 against the rich solvent from the Absorber Column bottom. The lean solvent is further cooled to about 65°C in the Solvent Air Cooler 117EA01 and returned to the Absorber Column top by means of the HP Solvent Pump 117P003A/B [23].

A slip stream of the lean solvent is routed via the Side stream Cartridge Filters I & II 117F001 & 117F003 and the Charcoal Filter 117F002 to prevent the enrichment of heavier components in the solvent circuit [24].

Anti Foam Agent is continuously added from the Anti Foam Storage Drum 117D004 to the Absorber Column 1170001 using Anti Foam Dosing Pump 117P006 and also to the Stripper Column 117C002 using Anti Foam Dosing Pump 117P008 [25].

III. Results and Discussions

CO_2 removal is essential for ensuring natural gas quality and compliance with environmental standards. Various purification methods exist, with chemical absorption using solvents like MDEA being highly effective. Aspen HYSYS v11 enables efficient modeling and optimization of these systems. Figure 4 presents a simulation of a CO_2 removal unit, highlighting its design and performance.

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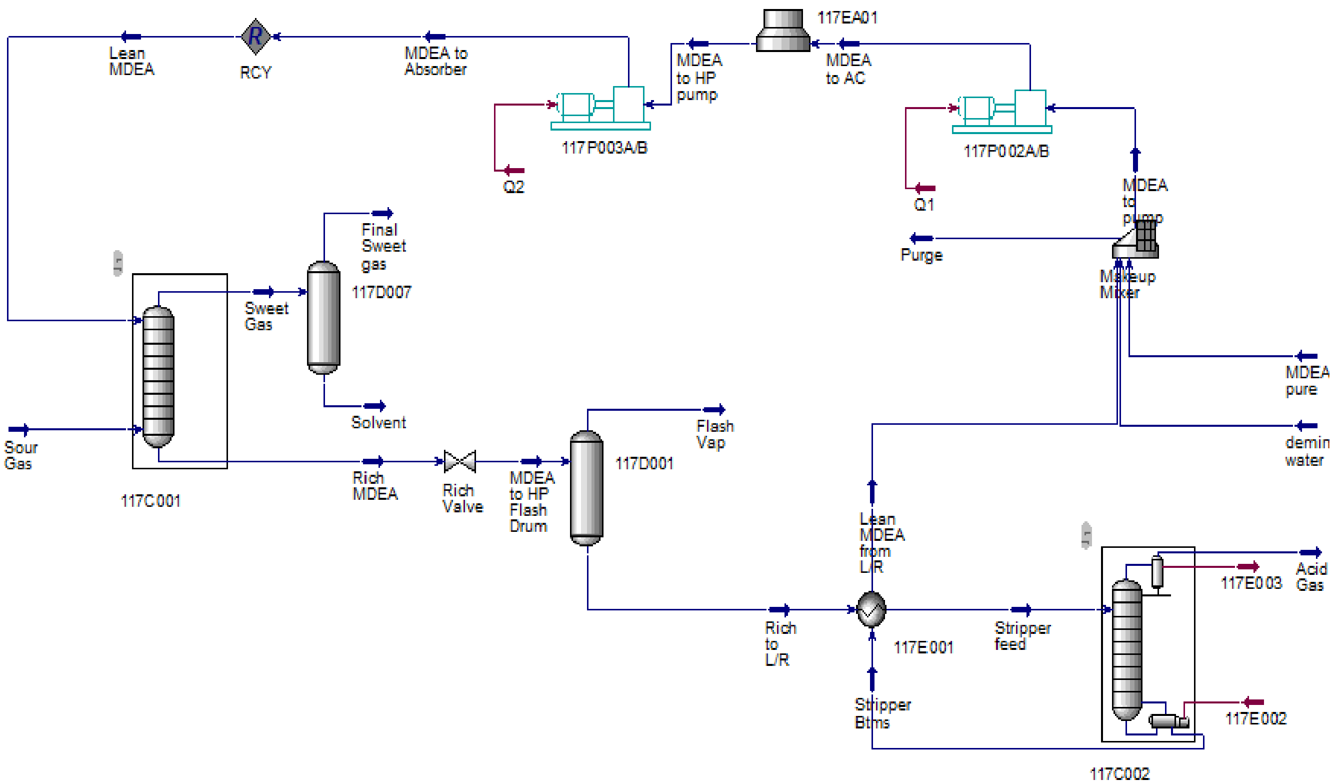

Figure 4: CO_2 Removal unit simulation using Aspen Hysys v11.

In this section, the design of Separator 117D001, Lean/Rich Heat Exchanger 117E001, Pump 117P002A/B, and Absorber 117C001.

HP Flash Drum is Two phase vertical separator, we used manual calculations and Aspen Hysys to make the design [26]. The design of the separator 117D001 is a critical aspect of the gas purification process, ensuring efficient phase separation and optimal system performance. Key parameters such as pressure, temperature, and capacity influence its effectiveness in removing impurities. Table 1 outlines the essential design parameters for separator 117D001, providing insight into its operational specifications.

Table 1: Design parameters for Separator 117D001.

Parameter	Manual Calculations	Aspen Hysys Calculations
Type	Vertical vessel	Vertical vessel
Diameter of separator	1.5 m	1.372 m
Length of separator	6 m	7.5 m
Height of Liquid in separator	3 m	4.2 m
Capacity of separator	11 m^3	12.42 m^3
Retention time	3 minutes	5 minutes
Material type	Carbon steel	Carbon steel
Slenderness ratio (SR)	3.739	3.515

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Lean/Rich Heat Exchanger 117E001 is shell and tube heat exchanger, we used manual calculations and Aspen Hysys to make the design. Figure 5 illustrates the inlet and outlet streams of the heat exchanger, highlighting the heat transfer process critical for energy efficiency in the CO_2 removal system. Proper heat exchanger design ensures effective temperature control, optimizing the absorption-regeneration cycle. Table 2 presents the design parameters for the Lean/Rich Heat Exchanger 117E001**,** along with a comparison between manual calculations and Aspen HYSYS simulations, providing validation of the design accuracy and efficiency.

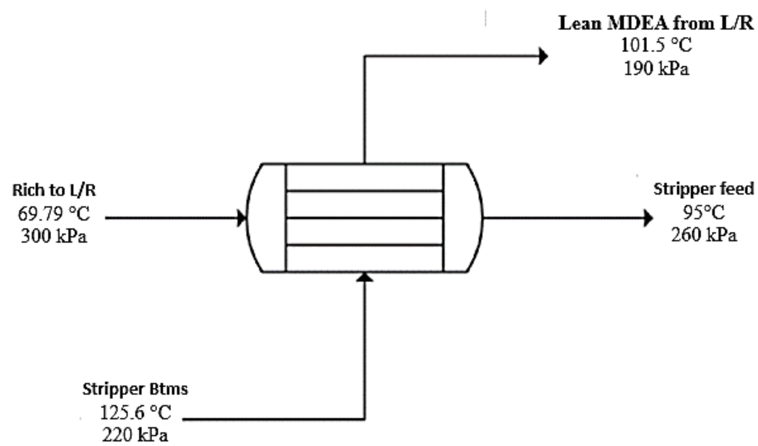

Figure 5: Illustrates the heat exchanger inlet and outlet streams.

Table 2: Design parameters for Lean/Rich Heat Exchanger 117E001.

Parameter	Manual Calculations	Aspen Hysys Calculations
Type	Shell and tube	Shell and tube
Heat Transfer area	260.88 m^2	241.28 m^2
Number of passes	4	4
Total number of tube	692	640
Diameter of shell	0.7366 m	0.7391 m
Inlet diameter of tube	0.016 m	0.018
Outlet diameter of tube	0.02 m	0.02 m
Length of tube	6 m	6 m
Overall heat transfer coefficient	237.1 $W/m^2.C$	310 $W/m^2.C$
Fouling factor (Rd)	0.0012	0.0012
Total pressure drop (shell side)	29.058 kPa	30 kPa
Total pressure drop (tube side)	16.2 kPa	20 kPa

Booster Pump 117P002A/B is an Axial flow centrifugal pump. The selection and design of pumps play a vital role in maintaining the required flow rates and pressure levels in the gas purification process. Table 3 presents the design parameters for Pump 117P002A/B, ensuring efficient circulation of the solvent within the system. Proper pump design is crucial for maintaining process stability and optimizing energy consumption.

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Table 3: Design parameters for Pump 117P002A/B.

Parameter	Manual Calculations
Type	Axial flow centrifugal pump
The liquid Velocity (u)	2.6 m/s
Friction factor	0.31
Head loss	10.7 m
Total Pump head	81.5 m
Power	20.8 kW

The absorber plays a crucial role in CO_2 removal by facilitating gas-solvent interaction. Table 4 outlines the design parameters for Absorber 117C001, ensuring efficient gas purification and solvent utilization.

Table 4: Design parameters for Absorber 117C001.

Parameter	Manual Calculations
Types of trays	Sieve tray
Theoretical number of trays	20
Efficiency of trays	0.7
Actual number of trays	25
Diameter	2 m
Height	34 m

Equipment spacing was essential to provide safe locations of the utilized equipment across the plant. For example, if an explosion happens and equipment spacing is not considered, it may affect other equipment and cause other severe problems. The required tables for equipment spacing were obtained. The spacing is demonstrated in Figure 6.

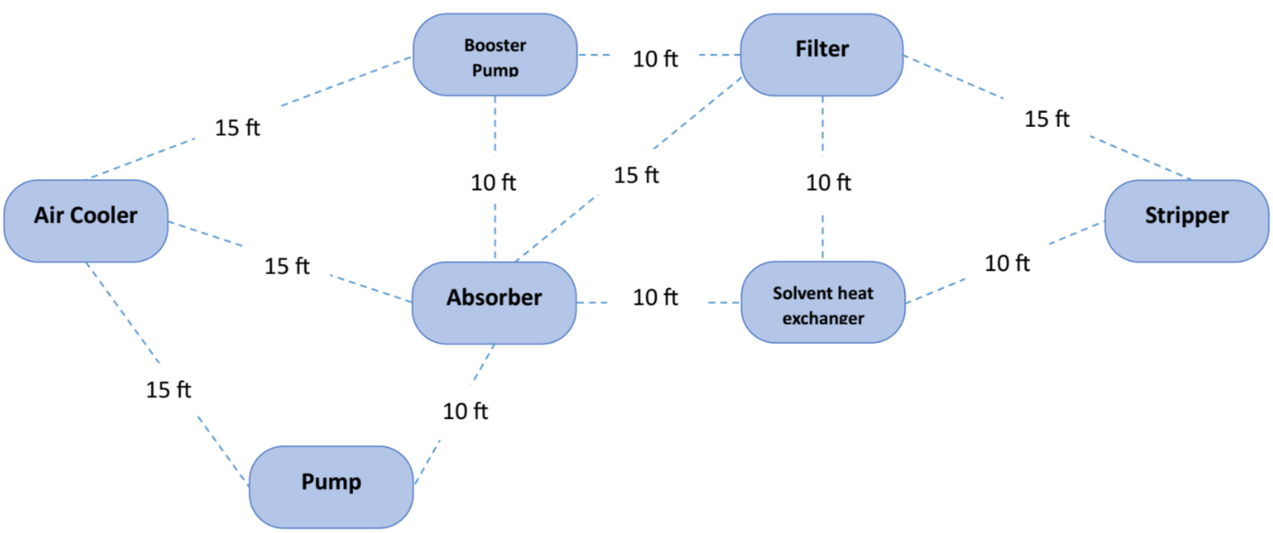

Figure 6: Equipment spacing of Acid Gas Removal plant.

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In the overall plant layout, careful consideration should be given to equipment spacing, the administrative area, and the identification of potential areas for future expansion. Additionally, it was crucial to consider the wind direction and intensity when determining the orientation of the plant. Figure illustrates the importance of this aspect. To gather information about the wind patterns, it would be advisable to analyze the wind atlas, or wind rose specifically for that region. This analysis will provide valuable insights for positioning equipment and structures strategically ensuring optimal safety measures and minimizing the dispersion of pollutants. Figure 7 Illustrate the plant layout [27].

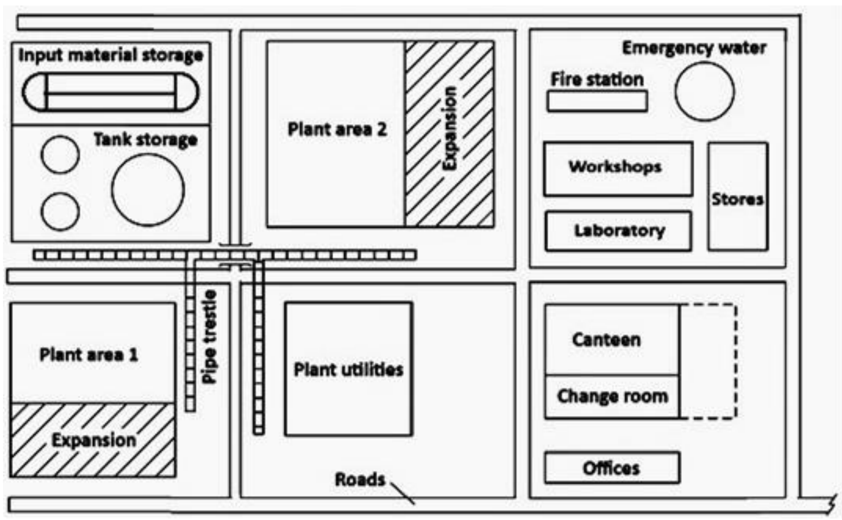

Figure 7: Plant layout for Acid Gas Removal.

Figure 8 shows the wind rose for Port Said, Egypt**,** highlighting prevailing wind directions and speeds, which are crucial for environmental assessments and emission dispersion analysis.

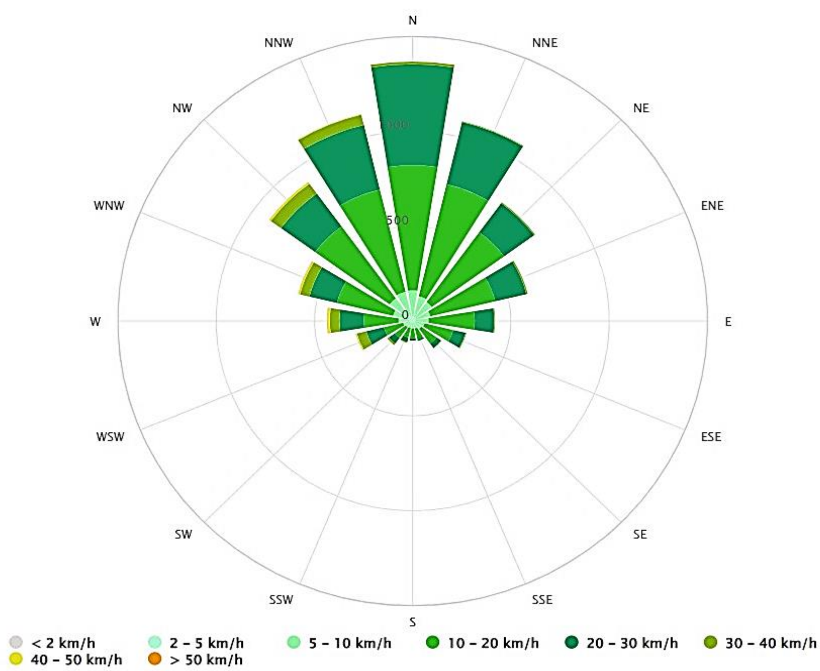

Figure 8: Wind rose of Port Said – Egypt.

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The following sites have been taken into consideration: Damietta Port, East Port-Said industrial zone, October industrial zone, 15 May industrial zone, Alex industrial zone. The following reasons have been used as a basis for choosing the best area: location, according to the marketing area, raw material supply, transport facilities, availability of labor, availability of utilities: water, fuel, power, availability of suitable land, environmental impact, and effluent disposal, local community considerations, climate, and political and strategic considerations. As a result, one can assume that the Port-Said industrial zone was the most optimum for acid gas removal plants [28].

After the design of process equipment, the cost of each piece of equipment is now evaluated as a first step in estimating the cost required for plant erection. Aspen Hysys (process simulation software) can help in estimating equipment costs by modeling the process and providing detailed cost analysis based on the input parameters and process conditions. This software can streamline the cost estimation process and provide more accurate results compared to manual calculations. The calculation steps can be found elsewhere. The calculation results are shown in Table 5 [29].

Table 5: Cost estimation for Acid gas removal plant.

Parameter	Cost Estimation Result	
	Aspen Hysys calculations	Manual calculations
Total Capital Cost [USD]	5,661,710	5,661,710
Total Operating Cost [USD/Year]	8,139,750	8,139,750
Total Raw Materials Cost [USD/Year]	0	4,069,875
Total Product Sales [USD/Year]	0	11,395,650
Total Utilities Cost [USD/Year]	6,276,140	6,276,140
Desired Rate of Return [Percent/'Year]	20	20
P.O. Period [Year]	0	1.74
Equipment Cost [USD]	939,700	939,700
Total Installed Cost [USD]	2,281,200	2,281,200

The Cumulative Cash Flow Curve, shown in Figure 9**,** illustrates the recovery of the initial capital investment over time. The red marker highlights the payback period of 1.74 years, indicating the point where the cumulative cash flow reaches zero, signifying full investment recovery. This analysis is crucial for evaluating the project's financial feasibility and return on investment.

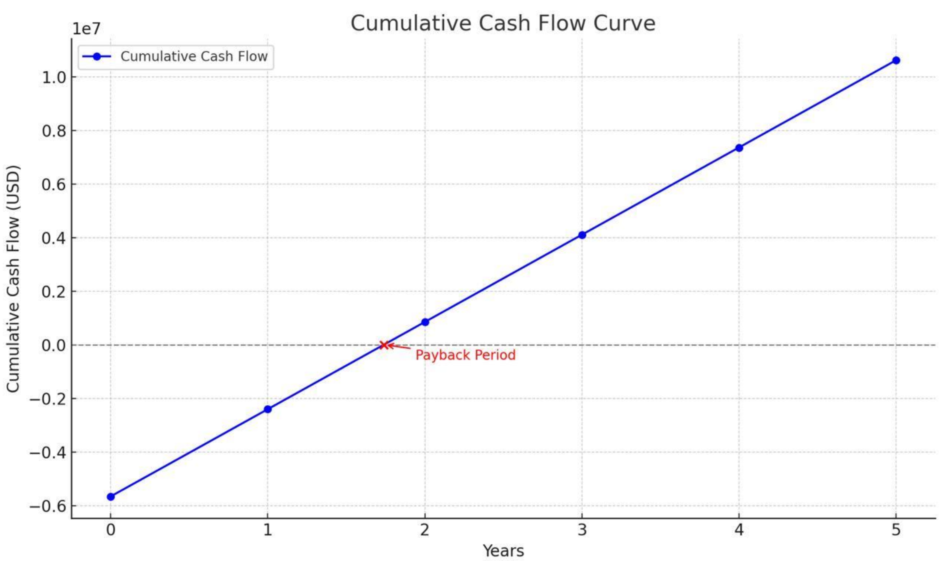

Figure 9: Cumulative Cash Flow Curve.

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A **HAZOP study** systematically identifies potential hazards and operational issues, ensuring process safety, reliability, and regulatory compliance which is shown below in Table 6.

Table 6 HAZOP Study.

Deviation	Causes	Consequences	Existing Provisions	Questions	Recommendations & Actions
High Pressure in Absorber	Overfeed of CO_2, malfunctioning control valve, blocked exit pipe, ineffective pressure control	Risk of rupture, excessive energy consumption, possible leaks	Pressure relief valves, pressure sensors, relief system	Is the relief system sufficient for all potential pressure spikes?	Implement automatic shutdown if pressures exceed safe limits.
Low Pressure in Absorber	Leak in absorber, valve failure, poor gas feed, equipment malfunction	Reduced CO_2 absorption efficiency, process downtime	Low-pressure alarms, backup supply of gas	Are there backup systems if pressure drops below setpoint?	Regular pressure calibration and failsafe systems.
Absorber Flooding	Excessive liquid flow, improper control of liquid-gas ratio, high gas flow rate	Poor CO2 absorption, inefficient operation, possible flooding in downstream units	Flow meters, liquid level control, automated shutdown	Are flow rates and liquid levels being monitored in real-time?	Implement dynamic flow control to prevent flooding.
Low CO_2 Capture Efficiency	Incorrect chemical dosing, improper absorber design, flow imbalance, poor contact time in absorber	Reduced CO_2 removal efficiency, process inefficiency	Absorber design, chemical injection control system	How is CO_2 capture monitored in real-time?	Improve monitoring of chemical dosing and optimize absorber design.
High Temperature in Stripper	Overheating of reboiler, improper temperature control, excessive steam flow	Loss of stripper performance, risk of damage to equipment, excessive steam consumption	Temperature sensors, automated control system	Are temperature setpoints adjusted based on operation conditions?	Add redundancy in temperature control and ensure correct steam management.
Low Temperature in Stripper	Cooling failure, Insufficient reboiler heat flow rate mismatch	Incomplete CO_2 removal, process instability, reduced Stripper efficiency	Temperature sensors, automatic adjustment systems	Does the system Prevent low temp. extremes?	Review stripper heating and cooling system design for reliability
Booster Pump Failure	Mechanical failure, cavitation, seal leak, excessive system pressure	Process instability, reduced flow rate, higher operational costs	Backup pumps, cavitation detection, system alarms	How often are booster pumps inspected and maintained?	Implement vibration analysis and predictive maintenance.
HP Pump Failure	Mechanical failure, seal leaks, cavitation, blockage, inadequate maintenance	Reduced pressure, loss of flow, process interruptions	HP pump alarms, backup pumps, routine inspection	How does the system recover from a pump failure?	Add redundancy in pumps and ensure periodic performance checks
Inlet Separator Overfilling	Blocked drain, malfunctioning level sensors, incorrect pressure differential, high feed rate	Liquid carryover, loss of efficiency, potential damage to downstream equipment	Level control systems, automatic	Are separator levels monitored continuously?	Implement alarms for high-level conditions and regular maintenance.

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			shutoff valves, overflow protection		
Outlet Separator Malfunction	Incorrect pressure control, clogged lines, pump failure, inconsistent liquid-gas separation	Inconsistent separation of CO_2, reduced product quality, flooding of downstream units	Level sensors, separator control systems, pressure relief devices	Are outlet separator pressure and level setpoints optimized?	Implement redundant separation controls and regular calibration.
Flash Tank Pressure Drop	Valve failure, pump malfunction, leak, improper flash conditions	Loss of CO_2 separation efficiency, process upset	Flash tank pressure relief valves, flow monitoring, automated controls	How does the system respond to pressure drops in the flash tank?	Add redundant pressure sensors and design for faster response times.
Flash Tank Overpressure	Blockage, malfunctioning control valve, overfeeding of fluids	Risk of rupture, loss of process control, potential environmental hazards	Pressure relief valves, automatic shutdown systems	Is the flash tank overpressure detection system properly calibrated?	Review overpressure protection systems and increase redundancy.
Heat Exchanger Fouling	Inadequate cleaning, build-up of contaminants, scaling, high operational temperature	Reduced heat transfer efficiency, increased energy usage, overheating	Routine cleaning schedules, temperature control systems	How frequently is the heat exchanger cleaned?	Develop a more efficient cleaning schedule based on operational data
Heat Exchanger Leak	Corrosion, improper maintenance, mechanical failure, thermal stresses	Loss of heat transfer, risk of damage to downstream equipment, safety hazards	Leak detection systems, maintenance schedule, pressure relief systems	Are all connections and seals checked for leaks regularly?	Add more advanced leak detection sensors and schedule more inspections.
Air Cooler Overheating	Blocked cooling fins, malfunctioning fans, inadequate ambient airflow, pump failure	Inefficient cooling, increased system temperature, potential equipment failure	Air cooler maintenance schedule, high temperature alarms	Is the airflow across the cooler monitored regularly?	Enhance airflow monitoring and automate cooler fan control.
Air Cooler Fan Failure	Electrical failure, mechanical failure, incorrect fan speed	Poor heat dissipation, increased pressure on other cooling components	Backup fans, regular motor inspections, system alarms	Are fans inspected periodically for wear and tear?	Implement real time motor condition monitoring for the fans.
Excessive Vibration in System	Pump or compressor imbalance, piping resonance, loose equipment	Equipment damage, process inefficiency, safety concerns	Vibration monitoring systems, inspection routines	How is vibration monitored across the system?	Install vibration sensors and schedule routine checks.
CO_2 Leaks from Connections	Poor sealing, corrosion, pipe joint failure, pressure cycling	Safety hazards, environmental impact, loss of CO_2	Leak detection systems, pressure monitoring	Are pipe connections and seals inspected regularly?	Improve maintenance checks on seals and enhance leak detection.

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Layers of Protection Analysis (LOPA) is a semiquantitative risk assessment method used in the process industry to evaluate and mitigate hazards. It bridges the gap between qualitative approaches like HAZOP and fully quantitative risk assessments by systematically analyzing hazard scenarios and assessing protective measures. LOPA identifies initiating events, estimates their frequency, and evaluates independent protection layers (IPLs) based on their probability of failure on demand (PFD). The combined PFD values determine the mitigated risk, which is compared to predefined risk tolerance criteria. This methodology is particularly effective for high-risk scenarios, ensuring compliance with safety standards while optimizing efficiency. This document applies LOPA to the Acid Gas Removal Unit (AGRU) to assess key hazard scenarios, their causes, consequences, and mitigation strategies [30].

Hazard Scenario 1 was assumed to be loss of Amine Circulation which occur when the amine circulation system fails, leading to H_2S breakthrough in the treated gas and potential release to downstream units or the atmosphere. This issue can arise due to failure of the amine circulation pump, malfunction of the control valve, severe foaming caused by contamination or improper operation, or insufficient lean amine supply due to a process upset. The consequences of this failure include elevated H_2S concentrations in sales gas, making it off-spec, toxic exposure risks for personnel, violations of environmental regulations, and potential overloading of the flare system due to the diversion of untreated gas. Initiating Event (IE) & Frequency for loss of Amine Circulation is shown in Table 7.

Table 7 Initiating Event (IE) & Frequency for loss of Amine Circulation.

Initiating Event	Frequency (per year)	Source
Amine circulation pump failure	0.1 (1 in 10 years)	OREDA, CCPS Guidelines
Control valve malfunction	0.2 (1 in 5 years)	Industry standard data
Severe foaming event	0.5 (1 in 2 years)	Historical plant performance

For the analysis, the most frequent initiating event is considered 0.5 per year (severe foaming). Independent Protection Layers (IPLs) & PFD for loss of Amine Circulation is shown in Table 8.

Table 8 Independent Protection Layers (IPLs) & PFD for loss of Amine Circulation.

Protection Layer (IPL)	Type	PFD
Basic Process Control System (BPCS)	Prevention	10^{-1}
High H_2S Alarm & Operator Response	Prevention	10^{-1}
Safety Instrumented System (SIS)	Prevention	10^{-2}
Relief & Flare System	Mitigation	10^{-2}

Risk Calculation was measured assuming a tolerable risk of 1×10^{-5} per year, the mitigated frequency of 5×10^{-7} per year is acceptable. To mitigate the risk of amine circulation loss and H_2S breakthrough, several recommendations should be implemented. Online monitoring for H_2S breakthrough in the treated gas should be established to provide real-time detection and early warning of any deviations. Installing a standby amine pump with an automatic switchover mechanism ensures continuous circulation in case of primary pump failure. Additionally, enhancing operator training will enable a swift and effective response to alarms, minimizing potential hazards. Lastly, optimizing foaming control through the proper use of anti-foaming agents will help prevent operational disruptions caused by severe foaming.

Hazard Scenario 2 was assumed to be lean Amine Cooler Failure which occurs when the lean amine cooler malfunctions, resulting in high amine temperatures that reduce H_2S absorption efficiency and cause gas breakthrough. This failure can be triggered by a cooling water supply issue, such as a pump trip, valve malfunction, or fouling, as well as a heat exchanger tube rupture leading to contamination. Other potential causes include air cooler fan failure in air-cooled systems or fouling and scaling inside the cooler. The consequences of this failure include H_2S breakthrough, leading to off-spec treated gas, corrosion

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in downstream equipment due to excessive CO_2, an increased flare load if untreated gas is diverted, and potential environmental and safety hazards. The Initiating Event (IE) & Frequency for lean Amine Cooler Failure is shown in Table 9.

Table 9 Initiating Event (IE) & Frequency for lean Amine Cooler Failure.

Initiating Event	Frequency (per year)	Source
Cooling water pump failure	0.1 (1 in 10 years)	OREDA, CCPS Guidelines
Heat exchanger tube rupture	0.05 (1 in 20 years)	Industry data
Fouling or scaling in cooler	0.2 (1 in 5 years)	Historical plant data

The most frequent initiating event is selected: 0.2 per year (cooler fouling). Independent Protection Layers (IPLs) & PFD for lean Amine Cooler Failure is shown in Table 10.

Table 10 Independent Protection Layers (IPLs) & PFD for lean Amine Cooler Failure.

Protection Layer (IPL)	Type	PFD
Basic Process Control System (BPCS)	Prevention	10^{-1}
High-Temperature Alarm & Operator Response	Prevention	10^{-1}
Safety Instrumented System (SIS)	Prevention	10^{-2}
Online H_2S Analyzer & Auto-Diversion	Mitigation	10^{-2}

The mitigated frequency **(2×10^{-7} per year)** is well within the tolerable risk limit of **1×10^{-5} per year**.

To mitigate the risks associated with lean amine cooler failure, several recommendations should be implemented. Increasing redundancy in the cooling system, such as adding standby pumps or fans, ensures continuous operation in case of equipment failure. Regular chemical cleaning should be conducted to prevent fouling and maintain efficient heat transfer. Implementing predictive maintenance through online heat exchange monitoring can help detect early signs of performance degradation, allowing for proactive intervention. Additionally, installing real-time lean amine temperature monitoring with early alarms will provide immediate alerts to prevent excessive temperature rise and ensure optimal H_2S absorption efficiency.

Hazard Scenario 3 was assumed to be Gas Line Leak or Rupture which occurs when a rupture or leak in the treated gas line leads to the release of H_2S, posing serious safety and environmental risks. This failure can be caused by overpressure due to control valve malfunction, corrosion from wet CO_2 or H_2S leading to wall thinning, mechanical damage from external impact or vibration, or localized stress caused by hydrate formation. The consequences of such an event include the release of toxic H_2S gas, resulting in potential fatalities, fire or explosion hazards if hydrocarbons are present, environmental violations, production downtime, and supply disruptions to downstream units. The Initiating Event (IE) & Frequency for Gas Line Leak or Rupture was shown in Table 11.

Table 11 The Initiating Event (IE) & Frequency for Gas Line Leak or Rupture.

Initiating Event	Frequency (per year)	Source
Control valve failure (overpressure)	0.1 (1 in 10 years)	OREDA, CCPS Guidelines
Corrosion-induced failure	0.2 (1 in 5 years)	Pipeline integrity data
Mechanical damage	0.05 (1 in 20 years)	Historical industry data

The most frequent initiating event is selected: 0.2 per year (corrosion-induced failure). The Independent Protection Layers (IPLs) & PFD for Gas Line Leak or Rupture is shown in Table 12.

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Table 12 Independent Protection Layers (IPLs) & PFD for Gas Line Leak or Rupture.

Protection Layer (IPL)	**Type**	**PFD**
Basic Process Control System (BPCS)	Prevention	10^{-1}
High-Pressure Alarm & Operator Response	Prevention	10^{-1}
Safety Instrumented System (SIS)	Prevention	10^{-2}
Pressure Safety Valve (PSV) & Flare System	Mitigation	10^{-2}
Pipeline Integrity Monitoring	Prevention	10^{-1}

The mitigated frequency **(2×10^{-8} per year)** is significantly below the tolerable risk limit of **1×10^{-5} per year**.

To mitigate the risks associated with gas line leaks or ruptures, several measures should be implemented. Increasing the frequency of pipeline corrosion inspections using advanced ultrasonic testing will help detect early signs of wall thinning and prevent failures. Installing leak detection systems, such as acoustic or gas detectors along the pipeline, will provide real-time monitoring and immediate alerts in case of leaks. Regular maintenance and timely replacement of control valves will reduce the risk of overpressure-related failures. Additionally, implementing a predictive maintenance program for pipeline integrity will enhance reliability by identifying potential issues before they escalate into critical failures. Train personnel for quick isolation and emergency response to leaks [31].

IV. Conclusion

In conclusion, the study on natural gas purification from acid gases using MDEA has shed light on crucial aspects of gas treatment processes. Initially, a comprehensive literature review was conducted to understand the principles of MDEA-based purification. Subsequently, a detailed process description was outlined, emphasizing the efficiency and effectiveness of MDEA in removing acid gases from natural gas streams. Furthermore, through the utilization of process simulation software such as "Aspen Hysys" and manual calculations, the purification process was analyzed and optimized for maximum efficiency. The comparison between simulation results and manual calculations highlighted the reliability and accuracy of the chosen methodology, showing a minimal error margin.

Plant considerations, including equipment spacing, layout design, and site selection, were meticulously evaluated to enhance operational efficiency and safety.

Moreover, a cost estimation was conducted to determine the economic feasibility of natural gas purification using MDEA. To enhance future research endeavors, a focus on process optimization is recommended to further reduce production costs and enhance the overall sustainability of the purification process. In essence, the study on natural gas purification from acid gases by MDEA provides valuable insights into the advancements and challenges in gas treatment technologies, paving the way for further research and development in the field of natural gas processing.

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