

PURIFICATION OF ASSOCIATED GASES UNDER FIELD CONDITIONS

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Abstract

The article considers the issue of extraction of aggressive components from the associated gases produced from the oil and gas wells. The presence of hydrogen sulfide and CO₂ in the gas causes corrosion of equipment and pipelines on the one hand, and pollution of the environment, the emergence of technogenic risks on the other. A 15% aqueous solution of monoethanolamine has been proposed as an absorbent for H₂S and CO₂ capture.

Keywords: dry gas, hydrogen sulfide, absorption, absorbent, sodium hydroxide, technogenic risks

I. Introduction

The presence of a wide range of aggressive components, such as hydrogen sulfide (H₂S) and carbon dioxide (CO₂), during the transportation of associated gases produced by the Oil and Gas office can lead to corrosion of equipment and pipelines, environmental pollution, deteriorating gas quality and thus lead to technogenic risks. The combustion of these gases produces sulfur dioxide, which is a major threat to wildlife.

In addition, hydrogen sulfide is a valuable raw material for the production of elementary sulfur, which is widely used in industry. CO₂ is considered a ballast in the gas and increases its transportation costs. The presence of CO₂ in the gases in some cases complicates its processing. Thus, the formation of hydrate compounds during the processes of deep cooling of the gas causes certain problems. Therefore, both from economic and environmental points of view, the extraction of aggressive components from the gases in the mining environment is of great importance and, as a result, serves to reduce technogenic risks.

II. Methods

Thus, during the preparation of associated gases for transportation, physical absorption, combined processes, i.e. chemical and physical absorbents, oxidation and adsorption processes are used to remove aggressive components.

The choice of process for the purification of associated gases from aggressive components depends mainly on the composition of the raw gas and the parameters of energy resources. In world practice, absorption processes are mainly used to purify large volumes of hydrocarbon gases before transportation. Other purification methods, such as oxidation and adsorption, are commonly used to purify small amounts of associated gas streams. The following requirements are set for absorbents used in industry: high absorbency, low vapor pressure, chemical and thermal stability under operating conditions, low viscosity, low heat capacity, non-corrosive, selective and non-toxic properties. Absorption capacity and viscosity determine the cost of

electricity consumed for the circulation of the absorbent. The more stable the absorbent and the lower the saturated vapor pressure, the lower its loss. Based on the corrosion properties, the requirements for the materials of the gas treatment plant equipment are determined.

In the world practice, amine processes take the leading place in the field of purification of gases from aggressive components. In this process, ethanolamines, monoethanolamine (MEA), diethanolamine (DEA), triethanolamine (TEA), diglicolamine (DGA), etc. are used as absorbents to purify gases from H₂S and CO₂. The most commonly used of these amines are mono- and diethanolamines. Triethanolamine is not widely used due to its low absorption properties. Other amines are used for selective removal of aggressive components. [1,2]. Pure amines are highly viscous liquids with a high freezing point. However, their aqueous solutions have low viscosity and low freezing point (below – 10°C). Therefore, in industry, aqueous solutions of ethanolamines are used as absorbents in the process of purification of gases from aggressive components by absorption [3,4]. The concentration of amines in solution can vary widely. Thus, this value is selected based on the results of research and in terms of corrosion control. One of the important indicators of gas treatment plants is the consumption of amines. Thus, the cost of absorbents is very high, and the absorbent expenses are the majority of operating costs.

In some cases, very small amounts of hydrogen sulfide and other sulfur compounds are found in the gases produced in some oil and gas fields of the country. However, some oil and gas companies have high levels of hydrogen sulfide in their gases. The presence of hydrogen sulfide causes corrosion of equipment and pipelines during the preparation of gases for transportation on one hand, pollution and poisoning of the environment on the other hand. The component composition of the gas is shown in Table 1.

III. Results

Concentrations of CO₂ and H₂S up to 10.1308 g/m³ in the associated gases lead to corrosion of the transport system and process equipment and reduce the efficiency of transport processes and the quality of transported products.

Table 1: *The component composition of the gas*

№	Components	%, weight
1	2	3
1	Methan	96,57
2	Ethan	1,59
3	Propane	0,21
4	n-butane	0,06
5	i-butane	0,08
6	n-pentane	0,03
7	i-pentane	0,05
8	hexane	0,03
9	N ₂	0,21
10	CO ₂	1,16
11	O ₂	0,01
	Total:	100
	Density	0,700kg/m ³
	H ₂ S	10,1308g/m ³

Therefore, the extraction of CO₂ and H₂S from these gases is of great importance. The process of purification of gases from hydrogen sulfide by the absorption method consists of 2 blocks - absorption and regeneration (desorption) blocks of saturated 15% aqueous solution.

A 15% aqueous solution of monoethanolamine is used as an absorbent.

Some properties of a 15% aqueous solution of monoethanolamine are given below.

- Thickness, kmol/m ³	2,5
- Boiling point, °C	118
- Freezing temperature, °C	- 5 ⁰
- Viscosity, at 40°C, 10 ³ Pa·S	1,0
- Vapor pressure at 40°C, kPa	7,4

The basic technological scheme of the proposed device for purification of gases by absorption method is given in Figure 1. Dry gas containing H₂S, obtained in the absorption and gas fractionation section, enters the absorber 1 with pressure P = 1.1 ÷ 1.4MPa, temperature t = 40°C through line I for purification from hydrogen sulfide. To remove H₂S from the gas, a 15% aqueous solution of monoethanolamine from capacity 3 is supplied to the upper part of the absorber by means of line N-1 / 1,2 pump. The purified gas in the absorber passes through 2 separators and is released from the monoethanolamine particles it carries with it and is sent to the pipeline of "Azerigaz" PU for further processing through line II. Monoethanolamine solution saturated with hydrogen sulfide from 1 absorber is supplied to line 4 with line IV. The hydrogen sulfide-saturated MEA solution is pumped through the N-2 / 1,2 pump to the inter-pipe area of 7 heaters for regeneration, where it is heated to 90°C and then enters line 8 through the VII desorber.

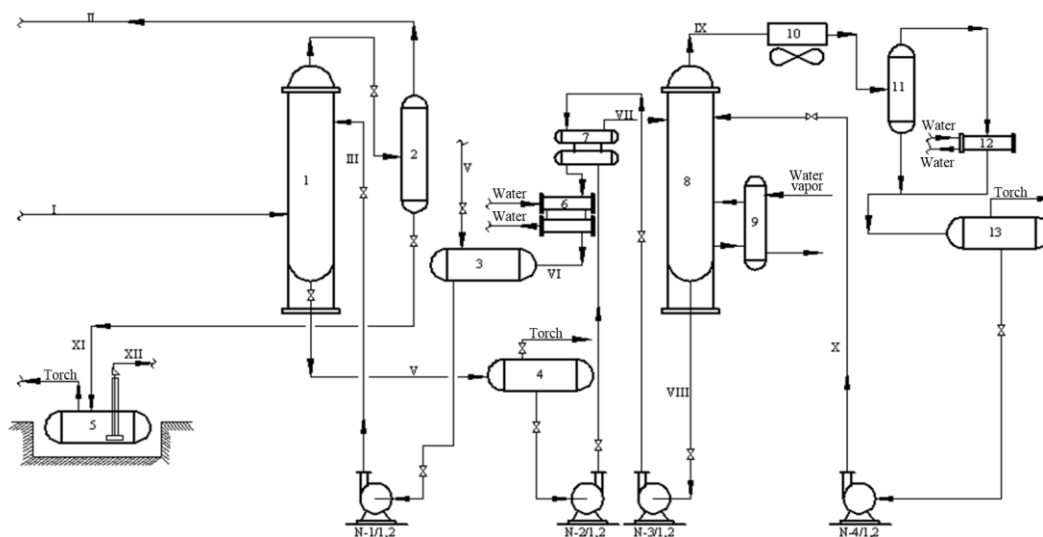


Figure 1: Schematic diagram of the H₂S gas purification plant.

1- absorber; 2,9,11- separator; 3- capacity for regenerated (pure) MEA; 4- capacity for saturated MEA; 5- drainage capacity; 6,12- water coolers; 7-heat exchanger; 8- desorber; 9- evaporator; 10- air cooler; 13- capacity.

I- dry gas; II- purified gas; III- absorbent (15% aqueous solution of MEA); IV- saturated MEA solution; V- freshly prepared 15% MEA solution; VI- regenerated MEA solution; VII-steam-gas phase; VIII- desorber irrigation; IX- liquid drainage capacity in separators; X- liquid 4 capacity.

The temperature in the bottom of the desorber is 120°C, and at the top is 110°C. The heat of the lower part of the desorber 8 is provided by water vapor at a pressure of 1.0 MPa by means of an evaporator 9. Hydrogen sulfide and water vapor from the top of the column are condensed in

air condenser-coolers 10 and being cooled enter separator 11, and then additionally cooled in cooler 12 enter capacity 13. The separated gas phase (H₂S) is transferred to the torch, and the liquid phase is fed to the upper part of the desorber by line X by means of the pump N-4/1,2. Monoethanolamine solution regenerated from desorber 8 is supplied to the pipeline area of heat exchangers 7 through line VIII by means of pump N-3/1,2. Here, it is cooled to 62°C, enters water cooler 6 and then it is cooled to 40°C. From there it is fed to capacity 3.

In order to maintain the required level of circulating MEA solution in the purification process of gases from hydrogen sulfide, fresh MEA solution is added to the system periodically along the V line. Technological reports were made to determine the performance and operating modes of the main apparatus of absorption and desorption processes. During the report, the amount of raw gas was assumed to be 11000nm³/h.

The summarized data of the technological reports are given in Tables 2, 3 and 4.

Table 2: Column type devices

Name	Working conditions					The height of the column, m	The diameter of the column, m	Number of plates, pcs.	Type of plates	The distance between the plates, m
	Location on height	t, °C	P (abs), MPa	Consumption, t/h						
				liquid	steam					
Gas absorber	up down	40 45	1,3 1,3	- 15,2	11,3 -	18,8	1,2	21	Valved, single-flow plate	0,6
Desorber for regeneration of MEA solution	up down	110 120	0,2 0,2	- 10	0,44 -	18,8	1,2	21	Valved, single-flow plate	0,6

Table 3: Separators

Name	The environment	Consumption, t / hour	Working conditions		Basic dimensions			Time of gas presence in the separator, min.
			t, °C	P (abs), MPa	Capacity, m ³	Diameter, m	Height, m	
1	2	3	4	5	6	7	8	9
Gas separator	Purified gas	11,324	40	1,3	4,0	1,2	4,4	0,22
Sour gas separator	Sour gases	0,184	40	atm	6	1,2	5,2	0,22

Table 4: Heaters and refrigerators

Name	The direction of flows	The environment	Consumption, kg / h	Temperature		Heat load kcal / hour	Heat transfer coefficient (K), kcal / m ² hour ⁰ C	Surface area, (F), m ²
				At the inlet	At the outlet			
1	2	3	4	5	6	7	8	9
Heater of saturated MEA solution	pipe area	Regenerated MEA solution	10000	120	67	534665	200	41x2=82
	inter-pipe area	Saturated MEA solution	10182	40	90			
Water cooler of regenerated MEA solution	pipe area	Water	29000	29	40	320000	150	101x2=202
	inter-pipe area	Regenerated MEA solution	10000	67	35			
Water vapor condensate and H ₂ S mixture water cooler	pipe area	Water	153,5	29	35	921	50	3,5
	inter-pipe area	hydrogen sulfide	184	40	35			
Air condenser cooler	pipe area	Water vapor	445	110	40	150000	6,8	848
		hydrogen sulfide	184,096					

The application of this device will reduce the amount of hydrogen sulfide in the gas to 0.001%.

IV. Conclusions

The presence of hydrogen sulfide in the composition of gases leads, on the one hand, to corrosion of equipment, pipelines, and on the other, to pollution and poisoning of the environment and, as a consequence, to the emergence of technogenic risks.

It was proposed to use the absorption process to remove hydrogen sulfide from the gas.

A 15% aqueous solution of monoethanolamine was suggested as absorbent.

Application of this device will allow to reduce the amount of H₂S in the gas to the amount required by the regulatory documents.

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