KLM Technology Group

Project Engineering Standard

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PROCESS DESIGN OF GAS TREATING UNITS

(PROJECT STANDARDS AND SPECIFICATIONS)

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SCOPE

This Project Standards and Specifications is intended to cover the minimum process requirements, criteria and features for accomplishment of process design of gas treating Units.

The basic principles for process design of main equipment, piping and instrumentation together with guidelines on present developments and process selection are considered as the main objectives throughout this standard.

REFERENCES

Throughout this Standard the following dated and undated standards/codes are referred to. These referenced documents shall, to the extent specified herein, form a part of this standard. For dated references, the edition cited applies. The applicability of changes in dated references that occur after the cited date shall be mutually agreed upon by the Company and the Vendor. For undated references, the latest edition of the referenced documents (including any supplements and amendments) applies.

1. ASTM (American Society for Testing And Materials)

   ASTM A 516/ A 516/ M Grade B

   ASTM A 106, Grade B

   ASTM A 333

   ASTM A 234, Grade WPB

   ASTM A 105, Grade LF2

   ASTM A 350, Grade LF2

2. NACE (National Association of Corrosion Engineers)

   NACE Standard MR 0103-2003 "Standard Material Requirements-Material Resistant to Sulfide Stress Cracking in Corrosive Petroleum Refining Environments”

3. ASME (American Society of Material Engineering)

   ASME B 16.20 “Material Gaskets for Pipes, Flanges, Ring Joint, Spiral Wounded & Jacketed”

DEFINITIONS AND TERMINOLOGY

Absorption - Absorption is a separation process involving the transfer of a substance from a gaseous phase to liquid phase through the phase boundary.

Acid Gases - Acid gases are impurities in a gas stream usually consisting of CO2, H2S, COS, RSH and SO2. Most common in natural gas are CO2, H2S and COS.

Acid Gas Loading - Acid gas loading is the amount of acid gas, on a molar or volumetric basis, which will be picked up by a solvent.

Adsorption - Adsorption is a separation process involving the removal of a substance from a gas stream by physical binding on the surface of a solid material.

Antifoam - Antifoam is a substance, usually a silicone or long-chain alcohol, added to the treating system to reduce the tendency to foam.

Degradation Products - Degradation products are impurities in a treating solution which are formed both reversible and irreversible side reactions.

Liquefied Petroleum Gas (LPG) – Any material having a vapor pressure not exceeding that allowed for commercial propane composed predominantly of the following hydrocarbons, either by themselves or as a mixtures: propane, propylene, butane (normal butane or isobutane) and butylene, as a by-product in petroleum refining or natural gasoline manufacture.

Mercaptan - Mercaptan is a hydrocarbon group (usually a methane, ethane, or propane) with a sulfur group (-SH) substituted on a terminal carbon atom.

Normal cubic meters (Nm^3) - Refers to capacity at Normal Conditions (101.325 kPa & 0°C) and relative humidity of 0 percent.

Pressure Relief Valve - A generic term applied to relief valves, safety valves and safety relief valves. A pressure relief valve is designed to automatically recluse and prevent the flow of fluid.

Residence Time - Residence time is the time period in which a fluid will be contained within a certain volume.

Selective Treating - Selective treating is preferential removal of one acid gas component, leaving other acid components in the treated gas stream.

Sour Gas - Sour gas is any gas stream which contains acid gas components.

Steric Hinderance - Steric hinderance is chemically attaching a bulk molecule (such as benzene) to the hydrocarbon chain of an amine to inhibit CO2 reacting to form a carbonate.

Sweet Gas - Sweet gas is a gas stream which has acid gas components removed to an acceptable level.

Threshold Limit Value (TLV) - Threshold limit value is the amount of a contaminant to which a person can have repeated exposure for an 8 hour day without adverse effects.

SYMBOLS AND ABBREVIATIONS

SYMBOL/ABBREVIATION	DESCRIPTION
ANSI	American National Standard Institute.
ASTM	American Society for Testing and Materials.
CO2	Carbon Dioxide.
COS	Carbonyl Sulfide.
CS2	Carbon Disulfide.
DCS	Distributed Control System.
DEA	di-Ethanolamine.
DETA	di-Ethylamine.
DIPAM	di-Isopropylamine.
DN	Diameter Nominal, in (mm).
DGA	di-Glycolamine.
ESD	Emergency Shut-Down.
FOB	Free On Board.
GPSA	Gas Processors Suppliers Association.
HCN	Hydrogen Cyanide.
H2S	Hydrogen Sulfide
HP	High Pressure.
ID	Inside Diameter, in (mm).
L	liter.
LP	Low Pressure.
LPG	Liquefied Petroleum Gas.
MEA	mono-Ethanolamine.

MDEL	Methyl di-Ethanolamine.
max.	maximum.
min.	minimum.
NACE	National Association of Corrosion Engineers.
OD	Outside Diameter, in (mm).
Oper.	Operating.
OVHD	Overhead.
ppmm	parts per million by mass, in (mg/kg).
ppmv	parts per million by volume, in ($\mu m^3/m^3$).
SS	Stainless Steel.
TEMA	Tubular Exchanger Manufacturers Association.
TLV	Threshold Limit Value.
WC	Water Column, in (mm).
ρ (rho)	Gas density at operating conditions, in (kg/m^3).

UNITS

This Standard is based on International System of Units (SI) except where otherwise specified.

GAS SWEETENING UNITS

General

Acid gas constituents present in most natural gas streams are mainly hydrogen sulfide (H2S) and carbon dioxide (CO2). Many gas streams, however, particularly those in a refinery or manufactured gases, may contain mercaptans, carbon sulfide or carbonyl sulfide.

The level of acid gas concentration in the sour gas is an important consideration for selecting the proper sweetening process. Some processes are applicable for removal of large quantities of acid gas, and other processes have the capacity for removing acid gas constituents to the parts per million (ppm) range. However, the sweetening process should meet the Pipeline Specification.

Process Selection

1. General
   a. The selection of a solvent process depends on process objectives and characteristics of the solvents, such as selectivity for H2S, COS, HCN,

etc., ease of handling water content in feed gas, ease of controlling water content of circulating solvent, concurrent hydrocarbon loss or removal with acid gas removal, costs, solvent supply, chemical inertness, royalty cost, thermal stability and proper plant performance for various processing techniques.

b. The choice of the process solution is determined by the pressure and temperature conditions at which the gas to be treated is available, it’s composition with respect to major and minor constituents, and the purity requirements of the treated gas. In addition, consideration should be given to whether simultaneous H 2S and CO2 removal or selective H2S absorption is desired.

c. In general the gas treating process can affect the design of entire gas processing facilities including the methods used for acid gas disposal and sulfur recovery dehydration, absorbent recovery, etc.

d. For an appropriate process selection, the following factors should be considered for evaluation and decision making as a general approach to all sour gas sweetening treatment installations:
   - air pollution regulations regarding H2S removal;
   - type and concentration of impurities in sour gas;
   - specification of treated gas (sweet gas);
   - temperature and pressure at which the sour gas is available and at which the sweetened gas should be delivered;
   - volume of the gas to be treated;
   - hydrocarbon composition of sour gas;
   - selectivity required for acid gas removal;
   - capital cost and operating cost;
   - liquid product specifications (where application).

e. An accurate analysis of the sour gas stream should be made by the Company showing all of the impurities including COS, CO2 and merchaptans should be included in the project specification. These impurities shall in particular have significant effect on process design of the gas treating and down stream facilities.

f. The selectivity of a sweetening agent is an indication of the degree of removal that can be obtained for one acid gas constituent as opposed to another. There are sweetening processes which display rather marked selectivity for one acid gas constituent. There are cases where no selectivity is demonstrated and all acid gas constituents will be removed.

g. The selectivity of sweetening agent may be made on the basis of operating conditions. Only rarely will natural gas streams be sweetened at low pressures. However there are processes which are unsuitable for removing acid gases under low pressure conditions. Other sweetening agents may adversely be effected by temperatures, and some lose their economic advantage when large volumes of gas are to be treated.

   The feasibility and desirability of sulfur recovery can also place considerable limitation on the selectivity of sweetening process. Removal of H2S to produce contractually sweetened gas is a difficult thing and emphasis should be placed on those processes which have major potential application for sweetening of natural gases.

2. Chemical reaction processes

   a. General

      Chemical reaction processes remove the H2S and/or CO2 from the gas stream by chemical reaction with a material in the solvent solution. The alkanolamines are the most generally accepted and widely used of the many available solvents for removal of H2S and CO2 from natural gas streams due to their reactivity and availability at low cost.

      The alkanolamine processes are particularly applicable where acid gas partial pressures are low or low levels of acid gas are considered in the sweet gas. The alkanolmines are clear, colorless liquids that have a slightly pungent odor. All except tri-Ethanolamine are considered stable materials, because they can be heated to their boiling points without decomposition. Tri-Ethanolamine decomposes at below its normal boiling point.

   b. mono-Ethanolamine (MEA)

      i) MEA should commonly be used as a 10 to 20% solution in water. The acid gas loading should usually be limited to 0.3 to 0.4 moles acid gas per mole of amine for carbon steel equipment.

      ii) MEA itself is not considered to be particularly corrosive. However, its degradation products are very corrosive. COS, CS2, SO2 and SO3 can partially deactivate MEA, which may essentially require to be recovered with a reclaimer.

      iii) Since MEA is primary amine, it has a high pH. This enables MEA solutions to produce gas containing less than 6 mg/Sm^3 (¼ grains H2S per 100 Scu.ft) of acid gas at very low H2S partial pressures.

      iv) The heat of reaction for CO2 in MEA is about 1930 kJ/kg of CO2 (460 kcal/kg of CO2). The heat of reaction for all amines is a function of loading and other conditions. It varies by only 117 to 138 kJ/kg (28 to

33 kcal/kg) up to about 0.5 mole/mole of total acid gas loadings. Above this loading, the heat of reaction varies considerably and should be calculated as a function of loading.

v) MEA will easily reduce acid gas concentrations to Pipeline Specifications (generally less than 6 mg H2S/Sm^3 gas (0.25 grains per 100 Scu.ft). By proper design and operation, the acid gas content can be reduced as low as 1.2 mg H2S/Sm^3 gas (0.05 grains per 100 Scu.ft).

c. di-Ethanolamine (DEA)

i) DEA is commonly used in the 25 to 35 mass percent range. The loading for DEA is also limited to 0.3 to 0.4 mole/mole of acid gas for carbon steel equipment.

ii) When using stainless steel equipment, DEA can safely be loaded to equilibrium. This condition can be considered for carbon steel equipment by adding inhibitors.

iii) The degradation products of DEA are much less corrosive than those of MEA. COS and CS2 may irreversibly react with DEA to some extent.

iv) Since DEA is a secondary alkanolamine, it has a reduced affinity for H2S and CO2. As a result, for some low pressure gas streams, DEA can not produce Pipeline Specification gas. However, certain design arrangement such as split flow may be considered to fulfill the specified requirement.

v) Under some conditions, such as low pressure and liquid residence time on the tray (of about 2 seconds), DEA will be selective toward H2S and will permit a significant fraction of CO2 to remain in the product gas.

vi) The heat of reaction for DEA and CO2 is 151 kJ/kg of CO2 (360 kcal/kg of CO2) which is about 22% less than for MEA.

d. di-Glycolamine (DGA)

i) DGA is generally used as 40 to 60 mass percent solutions in water. The reduced corrosion problems with DGA allow mole per mole solution loadings equivalent to MEA in most applications even with these high mass percentage.

ii) For gas streams with acid gas partial pressures, absorber bottoms temperatures as high as 82°C and above can occur. This will reduce the possible loading.

iii) DGA has a tendency to preferentially react with CO2 over H2S. It also has a higher pH than MEA and thus can easily achieve 6 mg H2S/ Sm^3