University of Mosul

College of Petroleum & Mining Engineering

Technology of natural gas

Lecture 4

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2. ***Heating Value***

This is necessary so that the consumer can properly set his firing equipment. Most pipeline companies give a bonus for increased BTU content above 1000/SCF.

3. ***Hydrocarbon Dewpoint***

This specification is necessary to prevent the condensation of liquid hydrocarbons in pipelines transmitting gas to markets or in the lines feeding consumers. When a deep cut extraction plant straddles a pipeline some distance down the line, this specification is not too important as long as free liquids do not form and remain in the transmission lines.

4. ***Water Content***

This specification is necessary to prevent condensation of liquid water in the pipelines as the presence of free water is conducive to the formation of hydrates. The specification of 14 lbs of water/MMSCF is equivalent to a dew point of $+18^{o}F$ ($-9\ ^{o}C$). As the lowest buried pipeline temperature that has been measured in operating conditions is $+25\ ^{o}F$ ($-\ 4\ ^{o}C$) this specification gives a reasonable degree of safety.

5. *H_2S Content*

This specification is explained in the previous section.

6. *Mercaptan Content*

This specification is explained in the previous section.

7. *Total Sulphur*

This specification is also set for the same reason as the mercaptan specification; that is, to control the foul-smelling compounds. These can be, besides mercaptans, thiophenes, and disulfides. Also, sulfur compounds can be a catalyst poison in some reactions involving natural.

8. *CO_2 Content*

This was discussed in the previous section.

9. *O_2 Content*

This is not an important specification as 0 is not normally present. It is a hold-over from manufactured gas specifications.

10. *Delivery Temperature*

This is set, sometimes, to have consistent metering and also to protect pipeline coatings.

11. *Delivery Pressure*

This is s et so that the pipeline company can properly design their system.

The higher, the better for the pipeline company.

1.6 *Definitions*

It is desirable to define several of the terms that will be used in the book.

Some of the main ones are as follows:

Raw Gas (natural gas)	Untreated gas form/ or in the reservoir
Pipeline gas or Residue Gas or Sales Gas	Gas that has the quality to be used as a domestic or industrial fuel. It meets the specifications set by a pipeline transmission company and/or a distributing company
Sour Gas	Gas that contains more than 1 grain of H_2S/100 SCF. Generally much more than this.
Sweet Gas	Gas in which the hydrogen sulphide content is less than 1 grain per 100 SCF.
Wet Gas	Gas that contains more than 0.1 gallons (U.S.) of condensate per 1000 CF of gas.
Dry Gas	Gas that contains less than 0.1 gallons of condensate per 1000 CF of gas.
g. p. m. for a gas	Gallons of liquid per 1000 CF of gas. This can be US or Imperial Gallons.
Rich Gas	Gas containing a lot of compounds heavier than ethane, about 0.7 US gallons of C3+ per 1000 CF of feed to an absorption unit.
Lean Gas	Gas containing very little propane and heavier - or the effluent gas from an absorption unit.
Pentanes +	The pentane and heavier fraction of hydrocarbon liquid.
Condensates	The hydrocarbon liquid fraction obtained from a gas stream containing essentially pentanes
Natural gasoline	is a natural gas liquid with vapour pressure ermediate between natural gas (drip gas) and condensate (LPG) and has a boiling point within the range of gas line and typical gravity of natural gas line is around 8 API
Lean Oil	Absorption oil sent to an absorber.
Rich Oil	Absorption oil containing absorber material. The effluent from an absorber.
Lean Solution	stripped sweetening solution
Rich Solution	A sweetening solution containing absorbed acid gases.

1.7 *General Processing Schemes*

The steps in processing a raw, sour, rich natural gas saturated with water are shown schematically. The raw gas in the reservoir is assumed to be at 4000 psig (28,000 kpa) and 150 °F (65 °C). It is brought to the surface via the tubing in the well where it is reduced in pressure to the operating pressure of the gas gathering line (normally less than 1440 psi) (10,140 kpa) This is for the use of 600 psi ANSI fitting valves. Since the gas cools, when it is reduced in pressure, some of the water of saturation condenses out. This is conducive to hydrate formation.

Similarly as the gas is transmitted to the processing plant, if the distance is more than two miles, the gas will cool to ground temperatures of +25°F (-4°C) to 30 °F (-1 °C) and water will also condense out. This, of course, 'will be conducive to formation of hydrates which will plug the pipelines. Therefore, at the well site hydrate prevention processes have to be used. These are either the heating of the gas to keep it above its hydrate point or the dehydration of the gas to remove the water. The gas is then transmitted to the processing plant via a pipeline. The flow will be generally two phase.

ANSI: American National Standards Institute

Standard Terminology for Valves and Fittings

Upon entering the plant, the gas enters a separator where the liquids are dropped out. The gas is then sent to a sweetening unit where the acid gases are removed; generally by a sweetening agent such as monoethanol amine (MEA), diethanol amine (DEA), sulphinol, and others. The gas leaving the sweetening unit is now sweet, but is still saturated with water vapour and still contains a considerable amount of heavy hydrocarbons.