NATURAL GAS LIQUID RECOVERY

BACHELOR OF TECHNOLOGY
IN
GAS ENGINEERING

Submitted to:

Dr. Srihari
Dean, College of Engineering
University of Petroleun & Energy Studies

Submitted by:

Gursimran Singh Ralhan
R040206023

Sanjay Singh
R040206052

Under the guidance of

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Mr. Pradeep Joshi
(Associate Head Department of Petroleum and Earth Science)
University of Petroleum & Energy Studies

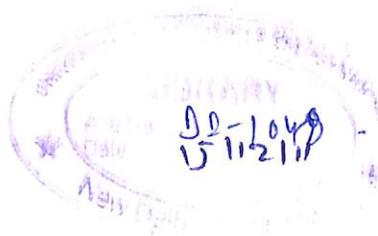**COLLEGE OF ENGINEERING STUDIES**
UNIVERSITY OF PETROLEUM AND ENERGY STUDIES
DEHRADUN – 248001
UTTARAKHAND
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ABSTRACT

Natural gas processing consists of separating the various hydrocarbons and fluids from the pure natural gas, to produce what is known as 'pipeline quality' dry natural gas. Major transportation pipelines usually impose restrictions on the make up of natural gas that is allowed into the pipeline. That means that before the natural gas can be transported it must be purified. While the ethane, propane, butane and pentane must be removed from natural gas, this does not mean that they all are 'waste products'.

In fact, associated hydrocarbons known as 'natural gas liquids' (NGLs) can be very valuable by products of natural gas processing. NGLs include ethane, propane, butane, iso butane and natural gasoline. These NGLs are sold separately and have a variety of different uses ; including enhancing oil recovery in oil wells, providing raw materials for oil refineries or petrochemical plants, and as sources of energy. In additionto processing done at wellhead and at centralized processing plants, some final processing is also sometimes accomplished at ' straddle extraction plants'. These plants are located on major pipeline systems. Although natural gas that arrives at these straddle extraction plants is already of pipeline quality , in certain instances there still exist small quantities of NGLs, which are extracted at the straddle plants.

The actual practice of processing natural gas to pipeline dry gas quality levels can be quite complex, but usually involves four main processes to remove the various impurities:

- Oil and condensate removal
- Water removal
- Separation of natural gas liquids
- Sulfur and carbon dioxide removal

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ABBREVATIONS

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ABBREVATIONS

AGN: American Gas Association

ANSI: American National Standard Institute

API: American Petroleum Institute

ASME: American Society of Mechanical Engineers

CCOE: Chief Controller of Explosives

NGLs: Natural Gas Liquids

SRK: Soave Redlich Kwong

EOS: Equation of State

GSP: Gas Sub-cooled Process

CRRP: Cold Residue Reflux Process

RSVPL: Recycle Split Vapor Process

IPGCL: Inderprastha Power Generation Corporation Limited

TEG: Tri Ethyl Glycol

DEG: Di Ethylene Glycol

TGTU: Tail Gas Treating Unit

LTX: Low Temperature Separator

CHAPTER-1

INTRODUCTION

1.1. INTRODUCTION

Natural gas, as it is used by consumers , is much different from the natural gas that is brought from underground up to the wellhead. Although the processing of natural gas is in many respects less complicated than the processing and refining of crude oil, it is equally as necessary before its use by end users.

The natural gas used by consumers is composed almost entirely of methane. However, natural gas found at the wellhead, although still composed primarily of methane, is by no means as pure. Raw natural gas comes three types of wells: oil wells, gas wells, and condensate wells. Natural gas that comes from oil wells is typically termed 'associated gas'. This gas can exist separate from oil in the formation (free gas), or dissolved in the crude oil (dissolved gas). Natural gas from gas ands condensate wells, in which there is little or no crude oil, is termed 'no associated gas'. Gas wells typically produce raw natural gas by itself, while condensate wells produce free natural gas along with a semi-liquid hydrocarbon condensate. Whatever the source of the natural gas, once separated from crude oil (if present) it commonly exists in mixtures with other hyudrocarbons; principally ethane, propane, butane, and pentanes. In addition, raw natural gas contains water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds.

1.2. NATURAL GAS ORIGIN AND HISTORY

The discovery of natural gas dates from ancient times in the Middle East. Thousands of years ago, it was noticed that natural gas seeps ignited when

lightning and created "burning springs". In Persia, Greece or India, people built temples around these "eternal flames" for their religious practices. However they did not recognize the energy value of natural gas. It was done in China around 900 BC. The Chinese drilled the first known natural gas well in 211 BC. In Europe, natural gas was unknown until it was discovered in Great Britain in 1659 although it was not commercialized until about 1790. In 1821 in Fredonia, United States, residents observed gas bubbles rising to the surface from a creek. William Hart, considered as America's "father of natural gas", dug there the first natural gas well in North America. Throughout the 19th century, natural gas was used almost exclusively as source of light and its use remained localized because of lack of transport structures, making difficult to transport large quantities of natural gas through long distances. There was an important change in 1890 with the invention of leak proof pipeline coupling. However, existing techniques did not allow for gas going further than 160 km. and it was mostly flared of left in the earth. Transportation of natural gas to long distances became practical in the 1920s as a result of technological in pipelines. It was only after World War II that the use of natural gas grew rapidly because of the development of pipeline networks and storage systems.

In the early days of oil exploration, natural gas was often an unwelcome by-product, as natural gas reservoirs were tapped in the drilling process and workers were forced to stop drilling to let the gas vent freely into the air. After the oil shortages of the seventies, natural gas has become an important source of energy in the world. The gas industry has been highly regulated for many years mainly as it was regarded as a natural monopoly. In the last 30 years there has been a move away from price regulation and towards liberalization of natural gas markets. These movements have resulted in greater competition in the market and in a dynamic and innovative natural gas industry. And because of technological advances gas can be better explored, extracted and transported to

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consumers. Innovations also help to improve natural gas applications and create new ones. Natural gas is increasingly used for power generation, fertilizer and transportation.

Natural Gas is a vital component of the world's supply of energy. It is one of the cleanest, safest, and most useful of all energy sources. While commonly grouped in with other fossil fuels ands sources of energy, there are many characteristics of natural gas that make it unique.

1.3. What is Natural Gas ?

Natural gas is colorless, shapeless, and odorless in its pure form and it is lighter than air. It is gaseous at any temperature over $- 161^0$ C. When it is at its natural state, it is not possible to see or or smell natural gas. For safety reasons a chemical odorant that smells a little like rotten eggs, Mercaptan, is added to natural gas so that it can be smelled if there id s gas leak. Natural gas is a mixture of light hydrocarbons including methane, ethane, propane, butanes and pentanes. Other compounds found in natural gas include CO_2 helium, hydrogen sulfide and nitrogen. The composition of natural gas is never constant. The primary component of natural gas is methane (typically 90%), which has a simple hydrocarbon structure composed of one carbon atom and four hydrogen atoms (CH_4). Methane is highly flammable, burns easily and completely and emits very little air pollution. Natural gas is neither corrosive nor toxic, its ignition temperature is high and it has a narrow flammability range making it an inherently safe fossil fuel compared to other fuel sources. In addition, because of its specific gravity of 0.60, which is lower than that of air (1.00), natural gas rises if escaping, thus dissipating from the site of any leak. Natural gas is found throughout the world in reservoirs deep beneath the surface of the earth and floor of the oceans. It forms as pockets of gas over crude oil deposits or is trapped in porous rock formations. Natural gas can be found in oil

deposits, as associated natural gas, although non-associated natural gas is often found without the presence of oil. When natural gas is cooled to a temperature of approximately -260^{0}F at atmospheric pressure, it condenses to a liquid called liquefied natural gas (LNG).

1.4. Typical Characteristics of Natural Gas

Typical Composition of Natural Gas

Methane	CH_4	70-90%
Ethane	C_2H_{60}	0-20%
Propane	C_3H_8	0-20%
Butane	C_4H_{10}	0-10%
Carbon Dioxide	CO_2	0-8%
Oxygen	C_2	0-0.2%
Nitrogen	N_2	0.5%
Hydrogen sulfide	H_2S	0.5%
Rare Gases	A, He, Ne, Xe	trace

1.5. Advantage of Natural Gas

- Installation of ash precipitators and other equipment for pollution control are not required.

- Risk of breakdown in fuel supply due to order processing delays to replenish fuel inventory is eliminated.

- No storage yard required as gas is directly delivered at the end of pipe.

- Energy spent for heating up the fuel oil is saved. This saving is significant in the case of LSHS.

- Natural gas is more cleaner and environment friendly fuel than coal and petroleum products.

CHAPTER -2

NATURAL GAS PROCESSING

2.1   What is Natural Gas Processing ?

Natural gas processing consists of separating all of the various hydrocarbons and fluids from the pure natural gas, to produce what is known as 'pipeline quality' dry natural gas. Major transportation pipelines usually impose restrictions on the make-up of the natural gas that is allowed into the pipeline. That means that before the natural gas can be transported it must be purified. While the ethane, propane, butane, and pentanes must be removed from natural gas, this does not mean that they are all ' waste products'.

In fact, associated hydrocations, known as 'natural gas liquids' (NGLs) can be very valuable by products of natural gas processing. NGLs include ethane, propane, butane, iso-butane, and natural gasoline. These NGLs are sold separately and have a variety of different uses; including enhancing oil recovery in oil wells, providing raw materials for oil refineries or petrochemical plants, and as sources of energy.

While some of the needed processing can be accomplished at or near the wellhead (field processing), the complete processing of natural gas takes place at a processing plant, usually located in a natural gas producing region. The extracted natural gas is transported to these processing plants through a network of gathering pipelines, which are small diameter, low pressure pipes. A complex gathering system can consist of thousands of miles of pipes, interconnecting the processing plant to upwards of 100 wells in the area. According to the American Gas Associatio's Gas Facts 2000, there was an estimated 36,100 miles of gathering system pipelines in the U.S. in 1999.

In addition to processing done at the wellhead and at centralized processing plants, some final processing is also sometimes accomplished at 'straddle extraction plants'. These plants are located on major pipelines systems. Although the natural gas that arrives at these straddle extraction plants is already plants is already of pipeline quality, in certain instances there still exist small quantities of NGLs, which are extracted at the straddle plants.

There are a great many ways in which to configure the various unit processes used in the processing of raw natural gas. The block flow diagram below is a generalized, typical configuration for the processing of raw natural gas from non-associated gas wells. It shows how raw natural gas ios processed into sales gas pipelined to the end user markets.

2.2. Extraction of Natural Gas By-Products:

It also shows how processing of the raw natural gas yields these byproducts:

- Natural gas condensate
- Sulfur
- Ethane
- Natural gas liquids (NGL): propane, butanes and Cs+ (which is the commonly used term for pentanes plus higher molecular weight hydrocarbons).

Raw natural gas is commonly collected from a group of adjacent wells and is first processed at that collection point for removal of free liquid water and natural gas condensate. The condensate is usually then transported to an oil refinery and the water is disposed of as wastewater.

The raw gas is then pipelined to a gas processing plant where the initial purification is usually the removal of acid (hydrogen sulfide and carbon

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dioxide). There a many processes that are available for that purpose as shown in the flow diagram, but amine treating is the most widely used process. In the last ten years, a new process based on the use of polymeric membranes to dehydrate and separate the carbon dioxide and hydrogen sulfide from the natural gas stream is gaining acceptance.

The acid gases removed by amine treating are then routed into a sulfur recovery unit which converts the hydrogen sulfide in the acid gas into elemental sulfur. There are a number of processes available for that conversion, but the Claus process is by fair the one usually selected. The residual gas from the Claus process is commonly called tail gas and that gat is then processed in a tail gas treating unit (TGTU) to recover and recycle residual sulfur-containing compounds back into the Claus unit. Again, as shown in the flow diagram, there are a number of processes available for treating the Claus unit tail gas. The final residual gas from the TGTU is incinerated. Thus, the carbon dioxide in the raw material gas ends up in the incinerator flue gas stack.

The next step in the gas processing plant is to remove water vapor from the gas using either the redeemable absorption in liquid triethylene glycol (TEG), commonly referred to as glycol dehydration, or a Pressure Swing Adsorpiton (PSA) unit which is regenerable adsorption using a solid adsorbent. Other newer processes requiring a higher pressure drop like membranes or dehydration at supersonic velocity using, for example, the Twister Supersonic Separator may also be considered.

Mercury is then removed by using adsorption processes (as shown in the flow diagram) such as activated ccarbon or regenerable molecular sieves.

Nitrogen is next removed ands rejected using one of the three processes indicated on the flow diagram:

Cryogenic process using low temperature distillation. This process can be modified to also recover helium, if desired.

Absorption process using lean oil or a special solvent as the absorbent.

Absorption process using activated carbon or molecular sieves as the adsorbent. This process may have limited applicability because it is said to incur the loss of butanes and heaver hydrocarbons.

The next step is to recover of the natural gas liquids (NGL) for which most large, modern gas processing plants use another cryogenic low temperature distillation process involving expansion of the gas through a turbo-expander followed by distillation in a deemphasizing fractionating column. Some gas processing plants use lean oil absorption process rather than the cryogenic turbo-expander process.

The residue gas from the NGL recovery section is the final, purified sales gas which is pipelined to the end-user markets.

The recovered NGL stream is processes through a fractionation train consisting of three distillation towers in series: a dethanizer, a depolarizer and a debutanizer. The overhead product from the deethanizer is ethane and the bottoms are fed to the depropanizer. The overhead produced from the product from the depropanizer is propane and the bottoms are fed to the depropanizer. The overheads product from the depropanizer is a mixture of normal and isobutene, and the bottoms product is a C_5 + mixture. The recovered streams of propane, butanes and C_5 + are each "sweetened" in a Merox process unit to convert undesirable mercaptans into disulfides and, along with the recovered ethane, are the final NGL by-products from the gas processing plant.

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2.3 Flow Diagram
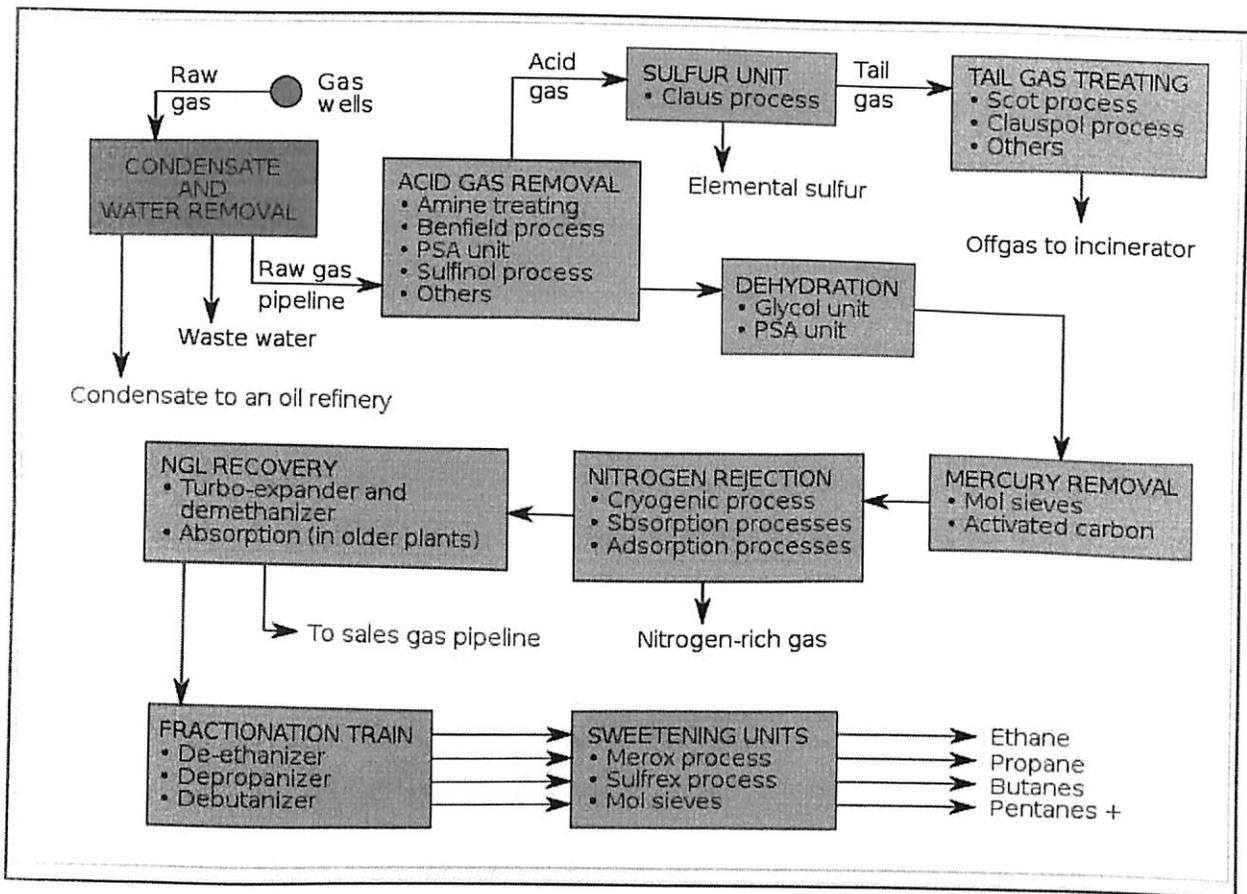
2.3. Processing of Natural Gas

The actual practice of processing natural gas to pipeline dry gas quality levels can be quite complex, but usually involves four main processes to remove the various impurities :

- Oil and Condensate Removal.
- Water Removal
- Sulfur and Carbon Dioxide Removal
- Mercury Removal
- Nitrogen Rejection
- Separation of Natural Gas Liquids

In addition to the four processes above, heaters and scrubbers are installed, usually at or near the wellhead. The scrubbers serve primarily to remove sand and other large particle impurities. The heaters ensure that the temperature of the gas does not drop too low. With natural gas that contains even low quantities of water, natural gas hydrates have a tendency to form when temperatures drop. These hydrates are sold or semi-solid compounds, resembling ice like crystals. Should these hydrates accumulate, they can impede the passage of natural gas through values and gathering systems. To reduce the occurrence of hydrates, small natural gas fired heating units are typically installed along the gathering pipe wherever it is likely that hydrates may form.

2.4.1. Oil and Condensate Removal

In order to process and transport associated dissolved natural gas, it must be separated from the oil in which it is dissolved. This separation of natural gas from oil is most often done using equipment installed at or near the wellhead.

The actual process used to separate oil from natural gas, as well as the equipment that is used, can vary widely. Although dry pipeline quality natural gas is virtually identical across different geographic areas, raw material gas from different regions may have different compositions and separation requirements. In many instances, natural gas is dissolved in oil under ground primarily due to the pressure that the formation is under. When this natural gas and oil is produced, it is possible that it will separate on its own, simply due to decreased pressure; much like opening a can of soda pop allows the release of dissolved carbon dioxide. In these cases, separation of oil and gas is relatively easy, ands the two hydrocarbons are sent separate ways for further processing. The most basic type of separator is known as a conventional separator. It consists of a simple closed tank, where the force of gravity serves to separate the heavier liquids like oil, and the lighter gases.

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In certain instances, however, specialized equipment is necessary to separate oil and natural gas. An example of this type of equipment is the Low-Temperature Separator (LTX). This is most often used for wells producing high pressure gas along with light crude oil or condensate. These separator use pressure differentials to cool the wet natural gas and separate the oil and condensate. We gas enters the separator, being cooled slightly by a heat exchange. The gas then travels through a high pressure liquid "knockout', which serves to remove any liquids into a low-temperature separator. The gas then flows into this low-temperature separator through a choke mechanism, which expands the gas as it enters the separator. This rapid expansion of the gas allows for the lowering of the temperature in the separator. After liquid removal, the dry gas then travels back through the heat exchanger and is warmed by the incoming wet gas. By varying the pressure of the gas in various sections of the separator, it is possible to vary the temperature, which causes the oil and some water to be condensed out of the wet gas stream. The basic pressure- temperature relationship can work in reverse as well, to extract gas from a liquid oil stream.

2.4.2. Water Removal

In addition to separating oil and some condensate from the wet gas stream, it is necessary to remove most of the associated water. Most of the liquid, free water associated with extracted natural gas is removed by simple separation methods at or near the wellhead.

However, the removal of the water vapor that exists in solution in natural gas requires a more complex treatment. This treatment consists of 'dehydrating' the natural gas, which usually involves one of two processes: either absorption, or adsorption. Absorption occurs when the water vapor is taken out by a

dehydrating agent. Adsorption occurs when the water vapor is condensed and collected on the surface.

Glycol Dehydration

An example of absorption dehydration is known as Glycol Dehydration. In this process, a liquid desiccant dehydrator serves to absorb water vapor from the gas stream. Glycol, the principal agent in this process, has a chemical affinity for water. This means that, when in contact with a stream of natural gas that contains water, glycol will serve to ' steal' the water out of the gas stream. Essentially, glycol dehydration involves using a glycol solution, usually either diethylene glycol (DEG) or triethylene glycol (TEG), which is brought into contact with the wet gas stream in what is called the 'contractor'. The glycol solution will absorb water from the wet gas. Once absorbed, the glycol particles become heavier and sink to the bottom of the contactor where they are removed. The natural gas, having been stripped of most of its water content, is then transported out of the dehydrator. The glycol solution, bearing all of the water stripped from the natural gas, is put through a specialized boiler designed to vaporize only the water out of the solution. While water has a boiling point of 212 degrees Fahrenheit, glycol does not boil until 400 degrees Fahrenheit. This boiling point differential makes it relatively easy to remove water form the glycol solution, allowing it be reused in the dehydration process.

As new innovation in this process has been the addition of flash tank separator condensers. As well as absorbing water from the wet gas stream, the glycol solution occasionally carries with it small amounts of methane and other compounds found in the wet gas. In the past, this methane was simply vented out of the boiler. In addition to losing a portion of the natural gas that was extracted, this venting contributes to air pollution and the greenhouse effect. In

order to decrease the amount of methane and other compounds that are lost, flash tank separator-condensers work to remove these compounds before the glycol solution reaches the boiler. Essentially, a flash tank separator consists of a device that reduces the pressure of the glycol solution stream, allowing the methane and other hydrocarbons to vaporize (flash). The glycol solution then travels to the boiler , which may also be fitted with air or water cooled condensers, which serve to capture any remaining organic compounds that may remain in the glycol solution. In practice, according to the Department of Energy's Office of Fossil Energy, these systems have been shown to recover 90 to 99 percent of methane that would otherwise be flared into the atmosphere.

Solid Desiccant Dehydration

Solid desiccant dehydration is the form of dehydrating natural gas using adsorption, and usually consists of two or more adsorption towers, which are filled with a solid desiccant, Typical desiccants include activated alumina or a granular silica gel material. Wet natural gas is passed through these towers, from top to bottom. As the wet gas passes around the particles of desiccant material, water is retained on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the bottom of the tower.

Solid desiccant dehydrators are typically more effective than glycol dehydrators, and are usually installed as a type of straddle system along natural gas pipelines. These types of dehydration systems are best suited for large volumes of gas under very high pressure, and are thus usually located on a pipeline downstream of a compressor station. Two or more towers are required due to the fact after a certain period of use, the desiccant in a particular tower becomes saturated with water. To 'regenerate' the desiccant a high temperature

heater is used to heat gas to a very high temperature. Passing this heated gas through a saturated desiccant bed vaporizes the water in the desiccant tower, leaving it dry and allowing for further natural gas dehydration.

2.4.3. Sulfur and Carbon Dioxide Removal

In addition to water, oi, and NGL removal, one of the most important parts of gas processing involves the removal of sulfur and carbon dioxide. Natural gas from some wells contains significant amounts of sulfur content, is commonly called 'sour gas'. Sour gas is undesirable because the sulfur compounds it contains can be extremely harmful, even lethal, to breathe. Sour gas can also be extremely corrosive. In addition, the sulfur that exists in the natural gas stream can be extracted and marketed on its own. In fact, according to the USGS, U.S. sulfur production from gas processing plants accounts for about 15 percent of the total U.S. production of sulfur.

Sulfur exists in natural gas as hydrogen sulfide ($H_2 S$), and the gas is usually considered sour if the hydrogen sulfide content exceeds 5.7 milligrams of $H_2 S$ per cubic meter of natural gas. The process for removing hydrogen sulfide from sour gas is commonly referred to as 'sweetening' the gas.

The primary process for sweetening sour natural gas is quite similar to the processes of glycol dehydration and NGL absorption. In this case, however, amine solutions are used to remove the hydrogen sulfide. This process is known simply as the 'amine process' or alternatively as the Girdler process, and is used in 95 percent of U.S. gas sweetening operations. The sour gas is run through a tower, which contains the amine solution. This solution has an affinity for sulfur, and absorbs it much like glycol absorbing water. There are two principle amine solutions used, monoethanolamine (MEA) and diethanolamine (DEA). Either of these compounds, in liquid form, will absorb

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sulfur compounds from natural gas as its passes through. The effluent gas is virtually free of sulfur compounds, and thus loses its sour gas status. Like the process for NGL extraction and glycol dehydration, the amine solution used can be regenerated (that is , the absorbed sulfur is removed), allowing it to be reused to treat more sour gas.

Although most sour gas sweetening involves the amine absorption process, it is also possible to use solid desiccants like iron sponges to remove the sulfide and carbon dioxide.

Sulfur can be sold and used if reduced to its elemental form. Elemental sulfur is a bright yellow powder like material, and can often be seen in large piles near gas treatment plants, as is shown. In order to recover elemental sulfur from the gas processing plant, the sulfur containing discharge from a gas sweetening process must be further treated. The process used to recover sulfur is known as the Claus process, and involves using thermal and catalytic reactions to extract the elemental sulfur from the hydrogen sulfide solution.

In all, the Claus process is usually able to recover 97 percent of the sulfur that has been removed from the natural gas stream. Since it is such a polluting ands harmful substance, further filtering, incineration, and 'tail gas' clean up efforts ensure that well over 98 percent of the sulfur is recovered.

Gas processing is an instrumental piece of the natural gas value chain. It is instrumental in ensuring that the natural gas intended for use is as clean and pure as possible, making it the clean burning and environmentally sound energy choice. Once the natural gas has been fully processed, ands is ready to be consumed. It must be transported from those areas that produce natural gas, to those areas that require it.

2.4.4. Separation of Natural Gas Liquids

The removal of natural gas Natural gas coming directly from a well contains many natural gas liquids that are commonly removed. In most instances, natural gas liquids (NGLs) have a higher value as separate products, liquids usually takes place in a relatively centralized processing plant, and uses techniques similar to those used to dehydrate natural gas.

There are two basic steps to the treatment of natural gas liquids in the natural gas stream. First, the liquids must be extracted from the natural gas. Second, these natural gas liquids must be separated themselves, down to their base components.

2.4.5. Mercury Removal from Natural Gas

Mercury has been detected at low trace levels-typically below 100 micrograms per standard cubic meter (ug/Nm^3)- in natural gas worldwide. Some fields, including some in the United States, have relatively high amounts of Hg. But in most fields, Hg contamination is not a problem.

Mercury must be removed below detectable level of 0.01 ug/Nm^3 – to avoid mercury-induced corrosion in the aluminum heat exchangers in liquefied natural gas (LNG) and natural gas liquid (NGL) extraction plants, and to prevent several additional failures, including poisoning of catalysts used in olefin processes, personal safety hazards, and waste disposal difficultie. Mercury can exist in natural gas as organ metallic and inorganic compounds, and in the elemental from, depending on the origin of gas. The elemental form can be found in either vapor or liquid phase. If a decision is made to remove

mercury, one approach is to use solid beds of Hg absorbents (such as carbon impregnated with sulfur) in sufficient quantities to absorb the expected mercury for a reasonable time period (typically, a years or two).

The amount of material to be disposed of is relatively large compared to the Hg removed, and other compounds may affect the absorption material, resulting in its premature saturation. The organ metallic and inorganic compounds drop into the liquid phase in any fractionation of a natural gas stream if Hg has not been removed upstream. This can result in a quality problem for these products. Liquid mercury can be created when solid elemental Hg, aggregated in cold spots in heat exchangers, is warmed up during maintenance or shutdown operations. Its pressure can cause stress cracking in welds and piping. The Hg content of natural gas delivered to customers through the pipeline system is not itself an environmental hazard at the typical levels found in the United States.

2.4.6. Mercury Removal from Flue Gas

Mercury emissions are a major problem in coal-fired electric utility units. Each year, such power plants in the United States emit about 52 tons of mercury. The U.S. Environmental Protection Agency(EPA) has recently identified mercury as the toxic substance of the greatest concern among all the air toxics emitted from power plants. The agency is expected to propose mercury emission standards by December 2003, with promulgation following a year later. Such standards would dramatically limit mercury emissions from coal-fired power plants by 2008. Currently, no single control method exists of removing all mercury species (i.e. Hg^0, $HgCl_2$) from flue gases. Existing carbon injection based mercury control methods are extremely expensive and inefficient, producing large quantities of solid waste contaminated with mercury. Recent cost estimates based on carbon injection technology range from$5,000 to $70,000 per pound of mercury removed.

2.4.7. Nitrogen Rejection Process

A cryogenic process to more efficiently separate nitrogen from a nitrogen containing hydrocarbon stream wherein the separate recovery of natural gas liquids is increased and the final nitrogen removal from natural gas is accomplished at lower than conventional pressures. The nitrogen-methane separation column is driven by a closed loop heat pump circuit that utilizes a nitrogen methane mixture.

CHAPTER-3
NGL EXTRACTION

3.1. NGL Extraction

There are two principle techniques for removing NGLs from the natural gas stream: the absorption method and the cryogenic expander process. According to the Gas Processors Association, these two processes account for around 90 percent of total natural gas liquids production.

3.2. The Absorption Method

The absorption method of NGL extraction is very similar to using absorption for dehydration. The main difference is that, in NGL absorption, an absorbing oil is used as opposed to glycol. This absorbing oil has an 'affinity' for NGLs in much the same manner as glycol has an affinity for water. Before the oil has picked up any NGLs, it is termed lean' absorption oil. As the natural gas is passed through an absorption tower, it is brought into contact with the absorption oil which soaks up a high proportion of the NGLs. The 'rich' absorption oil, now containing NGLs, exists the absorption tower through the bottom. It is now a mixture of absorption oil, propane, butanes, pentanes, and other heavier hydrocarbons. The rich oil is fed into lean oil stills, where the mixture is heated to a temperature above the boiling point of the NGLs, but below that of the oil. This process allows for the recovery of around 75 percent of butanes, and 85 – 90 percent of pentances and heavier molecules from the natural gas stream.

The basic absorption process above can be modified to improve its effectiveness, or to target the extraction of specific NGLs. In the refrigerated oil absorption method, where the lean oil is cooled through refrigeration, propane recovery can be upwards of 90 percent, and around 40 percent of ethane can be

extracted from the natural gas stream. Extraction of the other, heavier NGLs can be close to 100 percent using this process.

3.3. The Cryogenic Expansion Process

Cryogenic processes are also used to extract NGLs from natural gas. While absorption methods can extract almost all of the heavier NGLs, the lighter hydrocarbons, such as ethane, are often more difficult to recover from the natural gas stream. In certain instances, it is economic to simply leave the lighter NGLs in the natural gas stream. However, it it is economic to extract ethane and other lighter hydrocarbons, cryogenic processes are required for high recovery rates. Essentially, cryogenic processes consist of dropping the temperature of the gas stream to around -120 degrees Fahrenheit.

There are a number of different ways of chilling the gas to these temperatures, but one of the most effective is known as the turbo expander process. In this process, external refrigerants are used to cool the natural gas stream. Then, an expansion turbine is used to rapidly expand the chilled gases, which causes the temperature to drop significantly. The rapid temperature drop condenses ethane and other hydrocarbons in the gas stream, while maintaining methane in gaseous from. This process allows for the recovery of about 90 to 95 percent of the ethane originally in the gas stream. In addition, the expansion turbine is able to convert some of the energy released when the natural gas stream is expanded into recompressing the gaseous methane effluent, thus saving energy costs associated withj extracting ethane.

The extraction of NGLs from the natural gas stream produces both cleaner, purer natural gas, as well as the valuable hydrocarbons that are the NGLs themselves.

3.4. Natural Gas Liquids Recovery

Those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods in gas processing or cycling plants. Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as lease condensate, natural gasoline, and liquefied petroleum gases. Natural gas liquids include natural gas plant liquids (primarily ethane, propane, butane, and isobutene; see Natural Gas Plant Liquids) and lease condensate (primarily pentanes produced from natural gas at lease separators and field facilities).

The Petroflux process combines mechanical refrigeration an absorption effect by using a refluxing heat exchanger. Feed gas is cooled by cross exchange with cold sales gas and enters a cold separator. Vapor from the cold separator flows to the refluxing heat exchanger. Cooling is provided by external heat exchanger.

A simple flow diagram for a Petroflux process is shown.
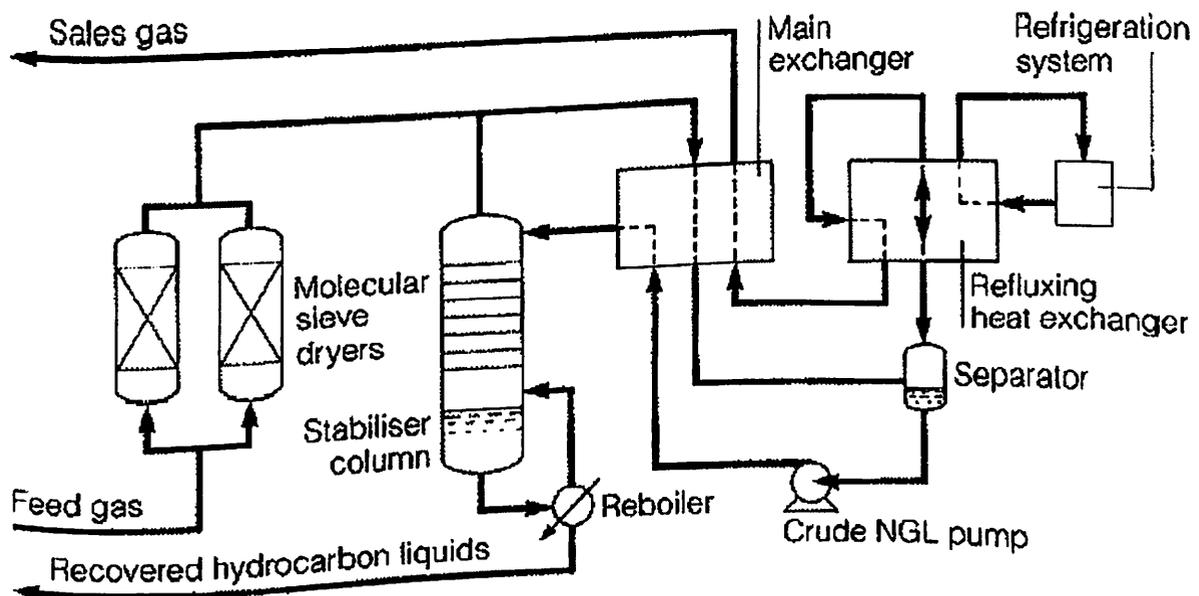
3.5. Expandor Processes

Expandor processes are the preferred process for deep NGL extraction. These process are relatively simple, compact, can achieve ethane recoveries of 99% (Propane 99% +), and halve the lowest capital cost.
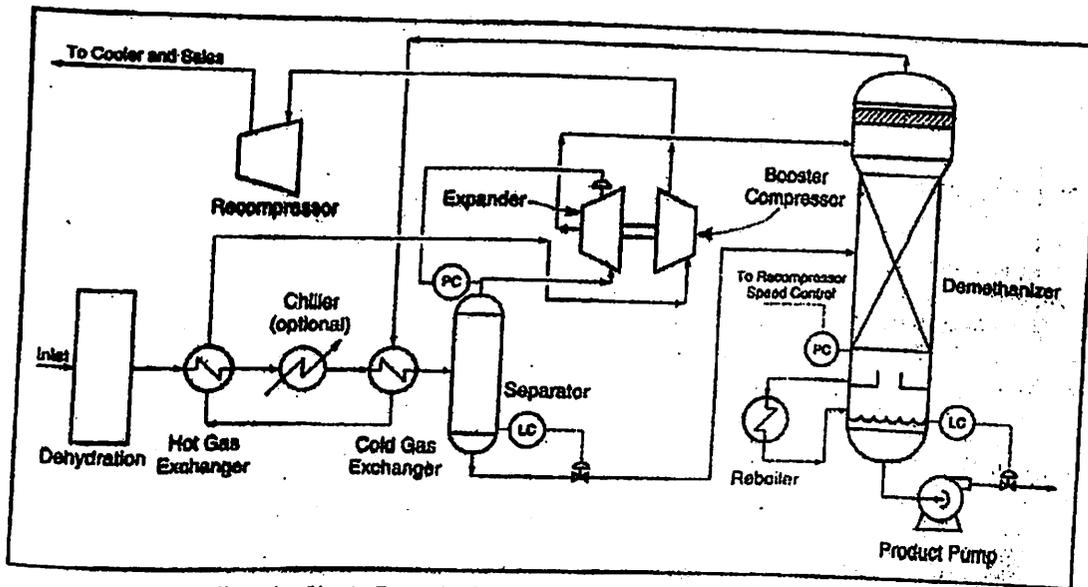
Flow Sheet for Simple Expander Plant

The design of turboexpandcer has evolved further for four reasons:

1. Increase ethane recovery.

2. Increase CO_2 tolerance of the process.

3. Increase propane recovery during period of ethane rejection.

4. Improved energy efficiency.

The different type of NGL recovery process are :

1. Gas sub cooled process.

2. Cold residue reflux process.

3. Split vapor steam process.
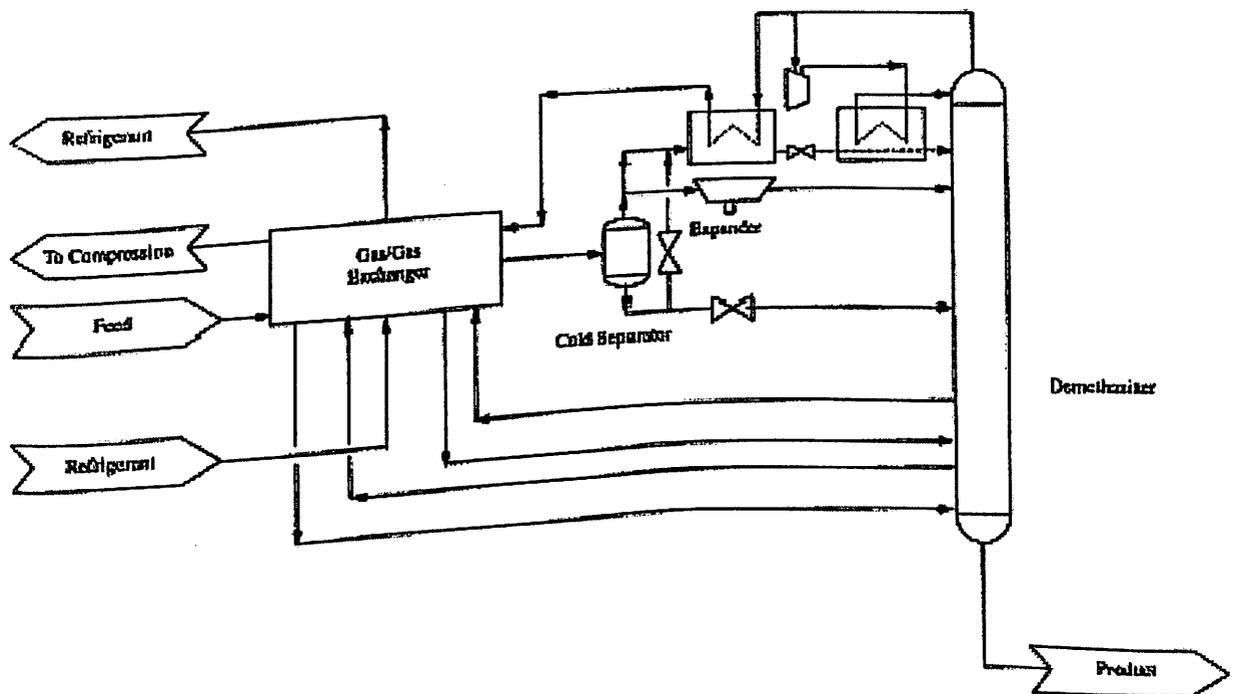
3.5.1. Gas Subcooled Process:

In this process, a portion of the expandor feed, say 20 to 30% is by passed around the expander and sub cooled by heat with the demethanizer over head. The high pressure subcooled dense fluid is then expanded across a value in to the top of the demethanizer. The temperature of this stream can be very cold (< -100° C) and increases NGL recovery. It is also more CO_2 tolerant.

One of the limitation of the GSP process is that the cooled feed contains C_2, C_3 & C_4 components.
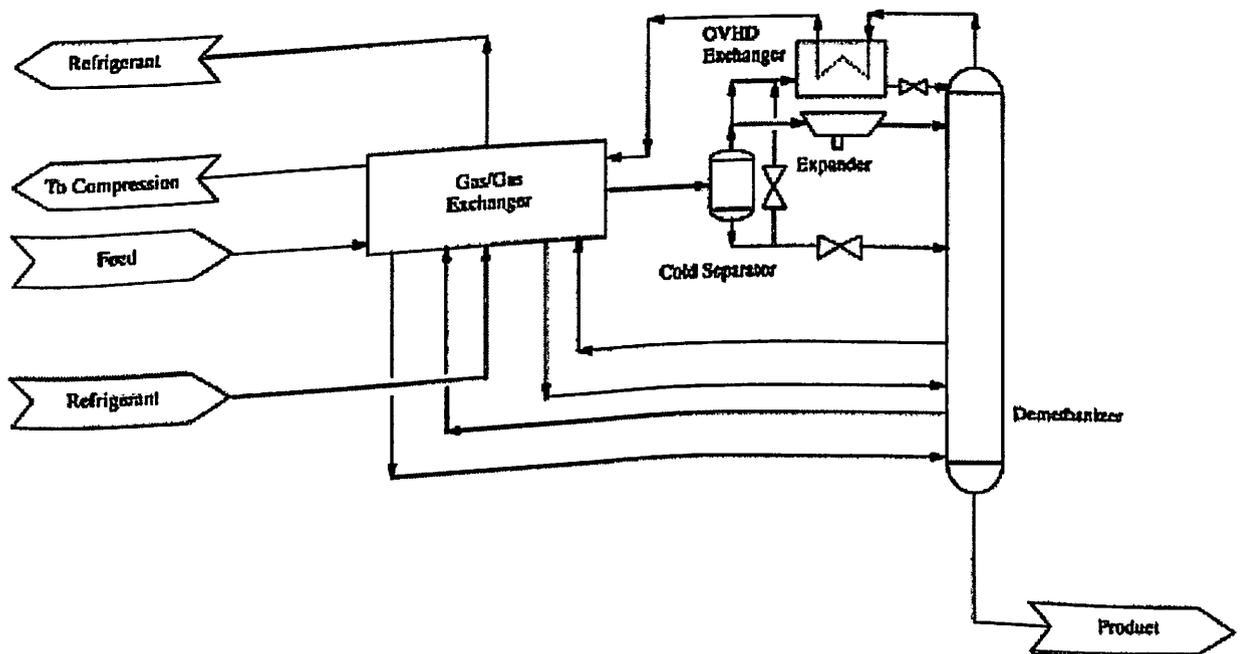
3.5.2. Cold residue reflux process:

The primary advantage of this process is that the subcooled split flow fees is used to condense reflux. In ethane recovery mode, the condensed reflux stream is nearly puree methane. This allows higher ethane and propane recovery. The condensed reflux methane stream is fed to the top of the tower with slightly warmer split vapor stream fed below. Ethane recoveries in excess of 99% are claimed for CRR process and propane recoveries above 99% can be achieved

3.5.3. Recycle Split Vapor Process:

This is s simpler and less expensive version of CRR process in this process a portion of high pressure recompressed sales gas stream is subcooled, flashed to tower pressure and fed to the demethanizer top as a reflux stream. This process is effective in achieving high ethane recoveries, but require more power than CRR process for a give ethane recovery.

CHAPTER -4
MAIN COMPONENTS OF NATURAL GAS LIQUID RECOVERY PROCESS

4.1. Turboexpander

The heart of a turbo expender is a composite metal shaft that has a compressor wheel attached to one end of the shaft and an expander wheel attached to the other end of the shaft. Each wheel is contained completely separate from the other.

A sealing system along the common shaft is used to prevent the process fluids present at each wheel from coming in contact from leakage along the shaft. The sealing systems are usually both mechanical and hydraulic in nature although some systems use a gas (seal gas) purge. The advantage of using as gas seal system is that sealing fluids do not leak into and accumulate in downstream equipment.

In an ethylene production plant, a high pressure, low temperature mixture of hydrogen and methane gas from the demethanizer overhead stream is passed through the expander side of a turbo expander. As the gas passes through the expander side, work is performed because at the other end of the expander-compressor shaft is a compressor wheel that is compressing purified product hydrogen gas for distribution to costomers. Because the expanding demethanizer overhead gas is performing work to compress hydrogen, and is experiencing a large pressure drop across the expander wheel, two important things happen. One is that the expended gas drops in temperature (loses energy) anywhere from 50 to 75 degrees F (28 to 42 K). The other is that some of the gas loses so much energy that it changes to liquid. If one is trying to separate hydrogen from methane, it is vital that a portion of the

expanded gas is liquefied. It usually takes at least two steps of expansion/work to liquefy all of the methane in the stream. During this two-stage expansion /work process, the gas pressure may drop from 515 psia to 40 psia (35 atm to 2.7 atm) and the temperature may drop from- 150^0) F to - 260^0 F (172 K 111 K).
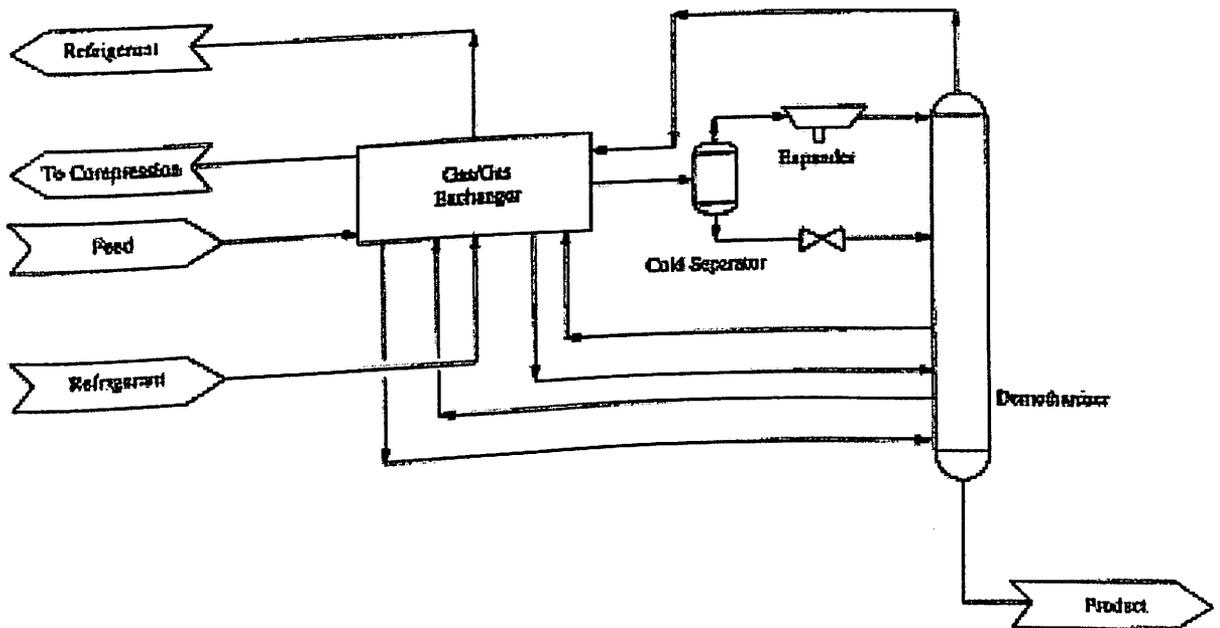
Once the hydrogen and methane are separated, both stream are usually sent to a cold box (a large aluminum block heat exchanger) to use the extremely cold temperatures to finish cryogenically treating the main cracked gas stream (see ethylene production).

We a turboexpander is not in operation it is still necessary to cool the demethanizer overhead stream by dropping if from a higher pressure to a lower pressure. While the turbo expander via a control value that is also known as a Joule-Thomson (J-T) valve. This valve is named after two scientists who discovered that, it a gas undergoes a drop in pressure at it flows through an orifice such as the opening in a valve (adiabatically, meaning without adding or subtracting heat), the gas temperature will drop. Even though the gas does dorp in pressure and become colder in flowing

through the J-T valve, none of the gas is liquefied because the gas is not performing work such as compressing a gas in the turboexpander. Thus, the turbexpander is critical in the separation of hydrogen from methane because just dropping the gas pressure through a J-T valve is insufficient to cause the gas to liquefy.

4.2. Natural Gas Liquid Fractionators

Fractionators, are used to purify the raw natural gas extracted from under ground gas fields and brought up to the surface by gas wells. The processed natural gas, used as fuel by residential, commercial and industrial consumers, is almost pure methane and is very much different from the raw material gas.

Raw natural gas typically consists primarily of methane (CH_4), the shortest and lightest hydrocarbon molecule. It also contains varying amounts of :

- Heavier gaseous hydrocarbons : ethane ($C_2 H_6$), prepane ($C_3 H_8$), normal butane (n-$C_4 H_{10}$), isobutene (i-$C_4 H_{10}$), pentanes and even higher molecular weight hydrocarbons. When processed and purified into finished by-products, all of these are collectively referred to NGL (Natural Gas Liquids).
- Acid gases: carbon dioxide (CO_2), hydrogen sulfide ($H_2 S$) and mercaptans such as methanethiol ($CH_3 SH$) and ethanethiol ($C_2 H_5 SH$)
- Other gases: Nitrogen (N_2) and helium (He).
- Water; water vapor and liquid water.
- Liquid hydrocarbons: perhaps some natural gas condensate (also referred to as casighead gasoline or natural gasoline) and/or crude oil.

- Mercury: very small amounts of mercury primarily in elementary form, but chlorides and other species are possibly present.

The raw natural gas must be purified to meet the quality standards specified by the major pipeline transmissioin and distribution companies. Those quality standards vary from pipeline to pipeline and are usually a function of a pipeline system's design and the markets that it serves. In general, the standards specify that the natural gas.

- Be within a specific range of heating value (caloric value). For example, in the United States, it should be about 1,035 $\pm$ 5% Btu per cubic foot of gas at 1 atmosphere and 600 F (41 MJ$\pm$ 5% 5% per cubic metrte of gas 1 atmosphere and ^{0}C).

- Be delivered at or above a specified hydrocarbon dew point temperature (below which some of the hydrocarbons in the gas might condense at pipeline pressure forming liquid slugs which could damage the pipeline).

- Be free of particulate solids and liquid water to prevent erosion, corrosion of other damage to the pipeline.

- Be dehydrated of water vapor sufficiently to prevent the formation of methane hydrates within the gas processing plant or subsequently within the sales gas transmission pipeline.

- Contain no more than trace amounts of components such as hydrogen sulfide, carbon, dioxide, mercaptans, nitrogen and water vapor.

- Maintain mercury at less than detectable limits (approximately 0.001 ppb by volume) primarily to avoid damaging equipments in the gas processing plant or the pipeline transmission system from mercury amalgamation and embitterment aluminum and other metals.
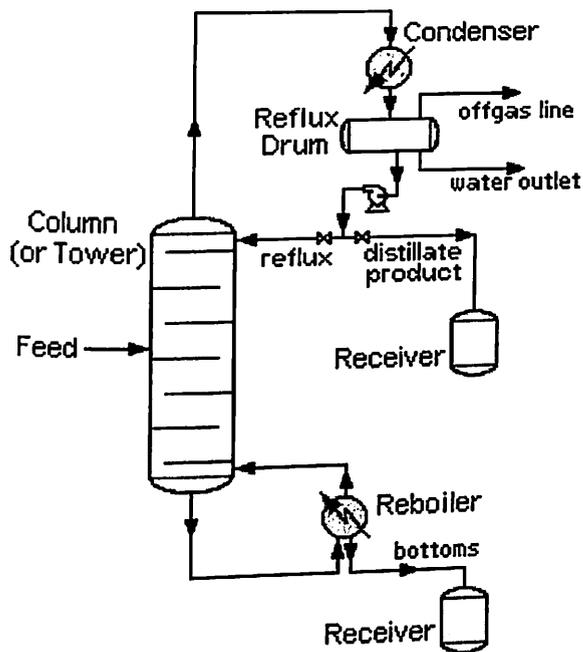
Once NGLs have been recoverd from natural gas stream, they must be broken down into their base components to be useful. That is, the mixed stream of different NGLs must be separated out. The process used to accomplish this task is called fractionation. Fractionation works based on the the different boiling points of the different hydrocarbons in the NGL stream. Essentially, the fractionation occurs in stages consisting of the boiling off of hydrocarbons one by one. The name of a particular fractionator gives an idea as to its purpose, as it is conventionally named for the hydrocarbon that is boiled off. The entire fractionation process is broken down into steps, starting with the removal of the lighter NGL's from the stream. The particular fractionators are used in the removal of the lighter NGLs stream. The particular fractionators used in the following order:

- **Deethanizer** – this separates the ethane from the NGL stream.

- **Depropanizer** – in this step propane is separated.

- **Debutanizer** – this step boils off the butane, leaving the pentanes and heavier hydrocarbons in the NGL stream.

- **Butane Splitter or De-isobutanizer**- this separates the iso and normal butanes.

By proceeding from the lightest hydrocarbon to the heaviest, it is possible to separate the different NGLs reasonably.

CHAPTER 5
COMPONENTS DESIGING

5.1 Designing of turboexpander

Objective:
To extract propane and higher hydrocarbons.
Assuming the pressure drop to 2000kPa from 7000kPa
Inlet gas temp. as 10^0c
We calculate the temp. drop across a valve

Using the P-H diagram of methane
h1@7000kPa and 10^0c=518kj/kg
T2isen=-14^0c
Assuming
Eisen=0.82
Gas flow rate=$1*10^6$std m^3/d
MW=16
Using this information we calculate

- At P1&T1,h1=518kj/kg and s1=9.08kj/kg

- S2=s1,so at P2=2000kPa and s2=9.08

    T2isen=-70^0c h2isen=380kj/kg

- ?hisen=380-518=-138kj/kg

- M=(1.0)(1762)(16)=28190kg/hr=7.83kg/sec

    -W=m?hisenEisen=(7.83)(380-518)(0.82)=-890kw

W=890kw(work is positive)

- $?h_{actual} = 518 + (380 - 518)(0.82) = 405 kJ/kg$

- At $P_2 = 2000$ kPa and $h_2 = 405 kJ/kg$ $T_{2actual} = -60^0C$

Methane
Pressure-Enthalpy Diagram
S = Specific Entropy, kJ/kg - K   T = Temperature, °C
V = Specific Volume, m³/kg
Datum Compound at 0 K and 0 kPa (abs)
H = 0, S+RlnP = 0
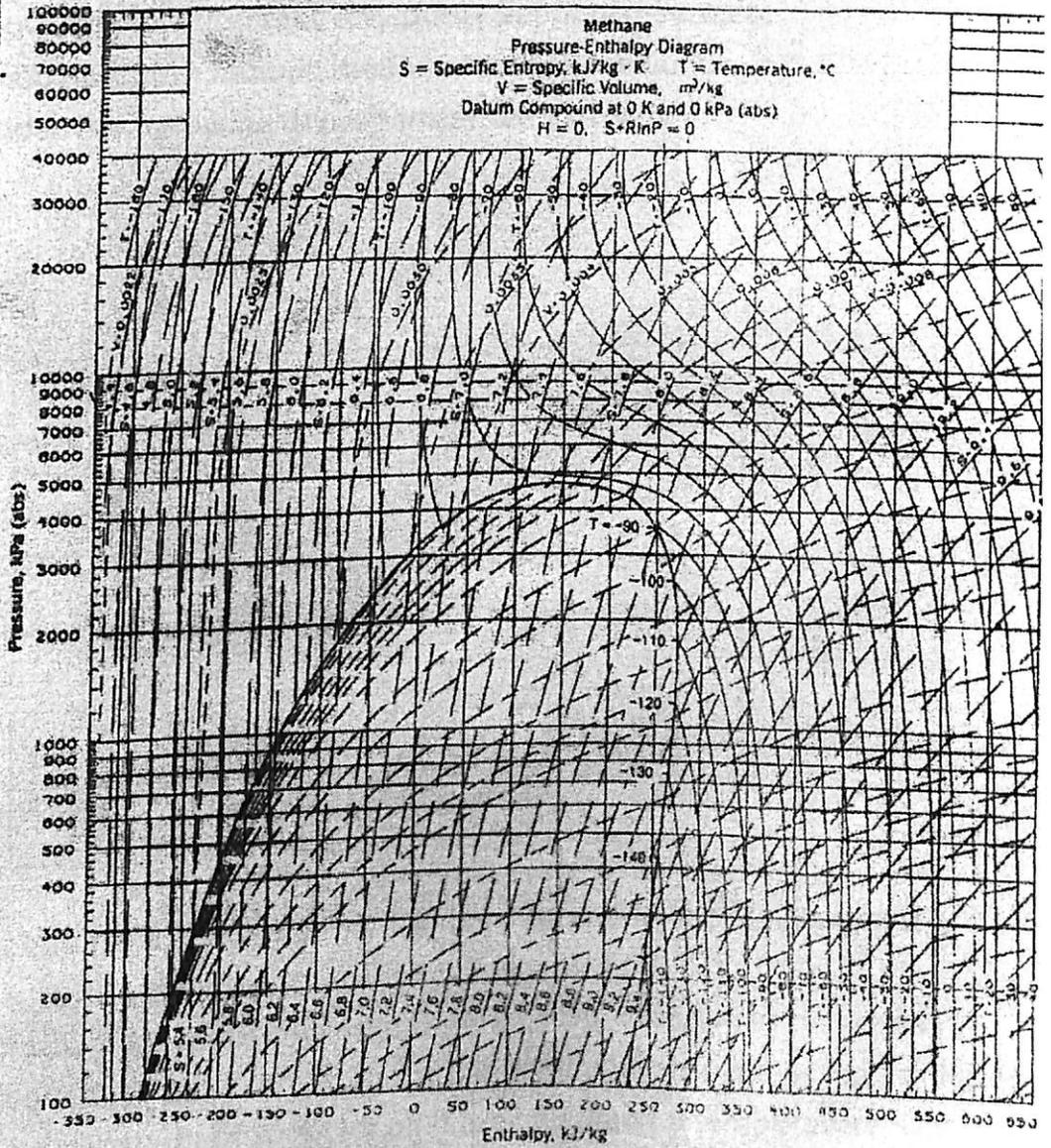
Pressure-Enthalpy Diagram for Methane (SI Units)

5.2 Fractionator Design Consideration

The design of a fractionation column involves the following steps

1. Establish the design basis

- Feed rate ,composition ,condititon(T&P)
- Product specification:recovery,purity,vapor pressure,etc.
- Available utilities: heating medium, cooling medium
  Consider the following depropanizer feed stream

Component	Mol%
C2	1.0
C3	46.0
iC4	10.0
nC4	21.0
C5+	22.0

The feed rate is 1000kmol/hr. The feed condition is 1724kPa and the feed is at its bubble point.

The product specifications require 99% of the propane to be recovered in the distillate product and the composition of propane in the distillate must be minimum of 95%.Hot oil if is available at a temperature. Of 204°c(400°f) for reboiler heat.The condensing medium is air at 35°c(95°f). The design condensing temperature is 49°c(120°f)and is based on approach of 14°c(25°f)

2. Perform a material balance around a column to establish the distillate and bottom product rates compositions.

Products specifications : percentage recovery of C3 in the distillate is 99%

Purity specifications for C3 in the distillate product is 95%
Assume the non-key components do not disturb, eg. All of the C2goes to the distillate , all of the nC4+ goes to the bottoms.

Components	Feed mols	Distillate mols	Mol%	Bottom mols	Mol
C2	10	10.0	2.09	0.0	0.00
C3	460	455.4	95.00	4.6	0.88
iC4	100	14.0	2.91	86	16.52
nC4	210	0.0	0.00	210	40.34
C5+	220	0.0	0.00	220	42.26
	1000	479.4	100.0	520.6	100

Mols of C3 in distillate=(460)(.99)=455.4

Mols iC4 in distillate is calculated by difference as follows,

Tottal distillate mols=(455.4/.95)=479.4

Mols iC4=479.4-455.4-10.0=14.0

3. Determine tower pressure

The tower power is determined from a bubble point or dew point calculation on the distillate product at the condensing temp.

The actual tower pressure is 35-100kPa higher than the calculated accumulated pressure to account for pressure drop through condenser and piping.

Performing bubble point calculation at49^{0}c[120^{0f}]to determine accumulator pressure from SRK EOS

$Z=1+\beta-q\beta(Z-\beta)/(Z+\beta)$

Eq. of state	a(Tr)	s	e	o	?	Zc
SRK(1972)	a_{srk}(Tr;?)	1	0	0.08664	.042748	1/3

Component	Xi,mol%	Ki@49^{0}c&1737kPa	KiXi,mol%
C2	2.09	2.31	4.88
C3	95.00	.985	93.61
iC4	2.91	.520	1.51
	100.0		100.0

Accumulator pressure is1737kPa, therefore we assume a tower pressure 1793kPa.

Now we perform a dew point calculations at 1793kPa to determine top tray temperature.

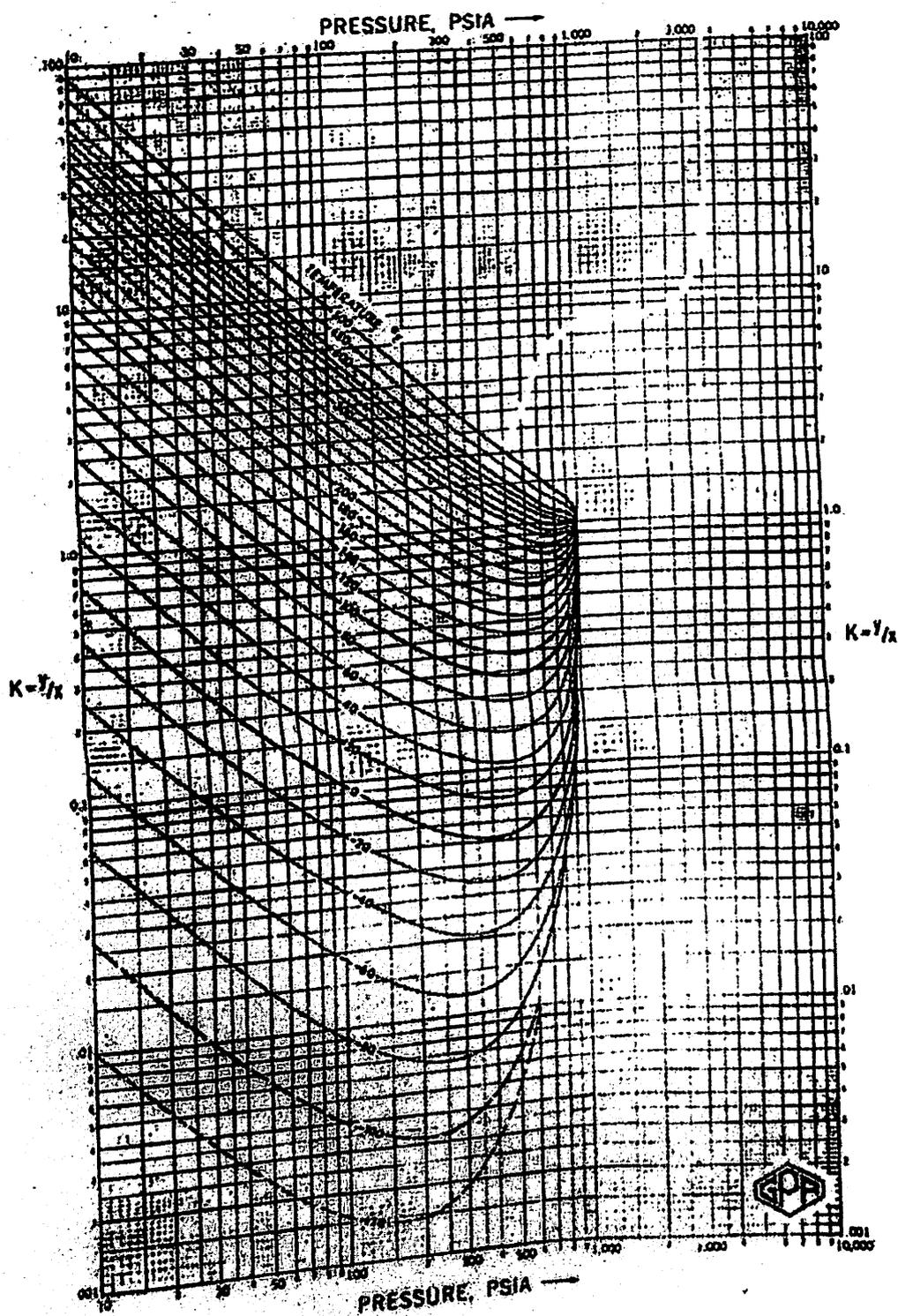| Component	Xi,mol%	Ki@49^{0}c&1737kPa	KiXi,mol%
C2	2.09	2.34	.90
C3	95.00	1.013	93.76
iC4	2.91	0.545	5.34
	100.0		100.0

Top tray is 52^{0}c
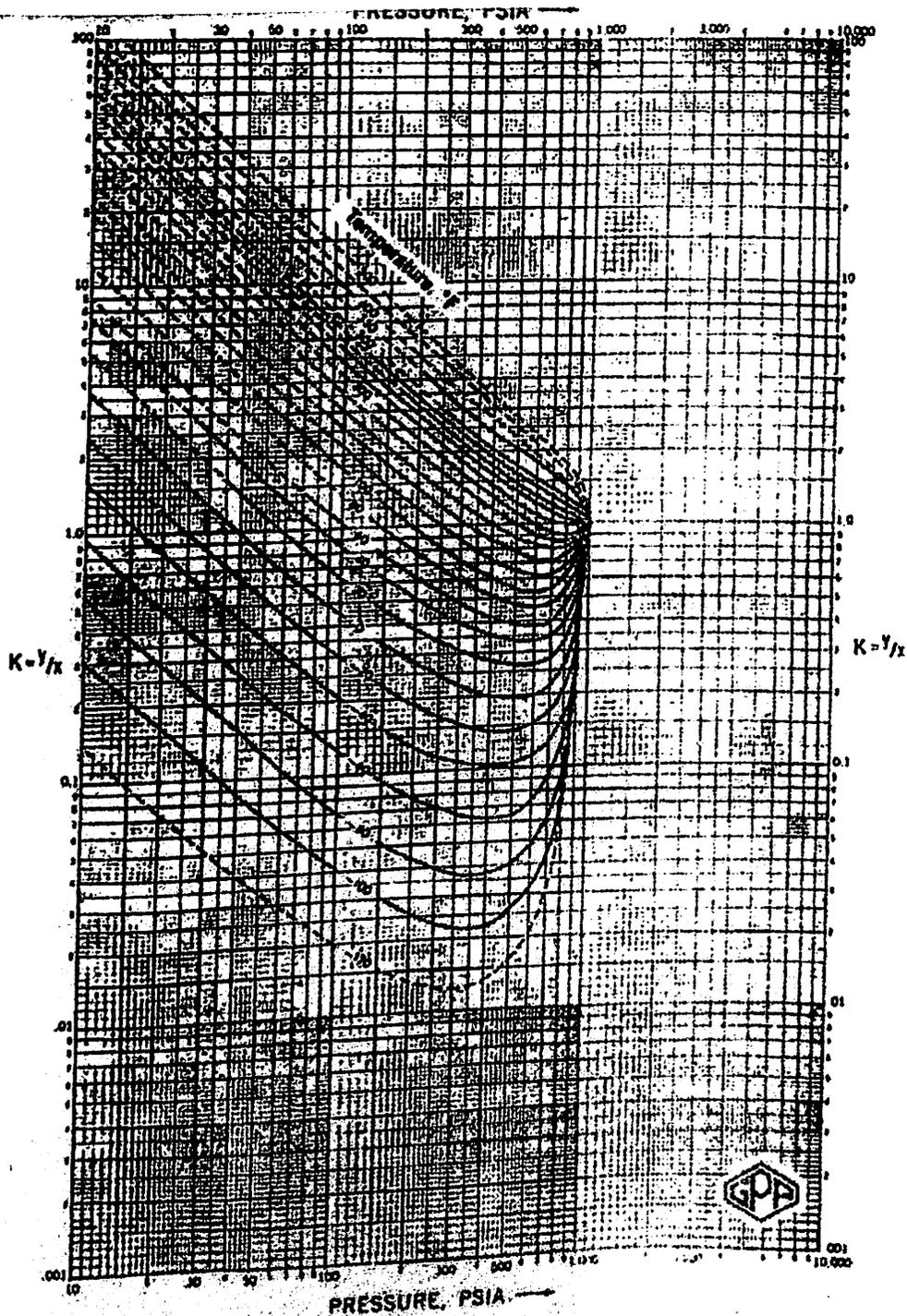
Equilibrium ratio, K, for propane for a convergence pressure of 1,000 psia. (From Engineering Data Book, 1981, courtesy of GPSA.)
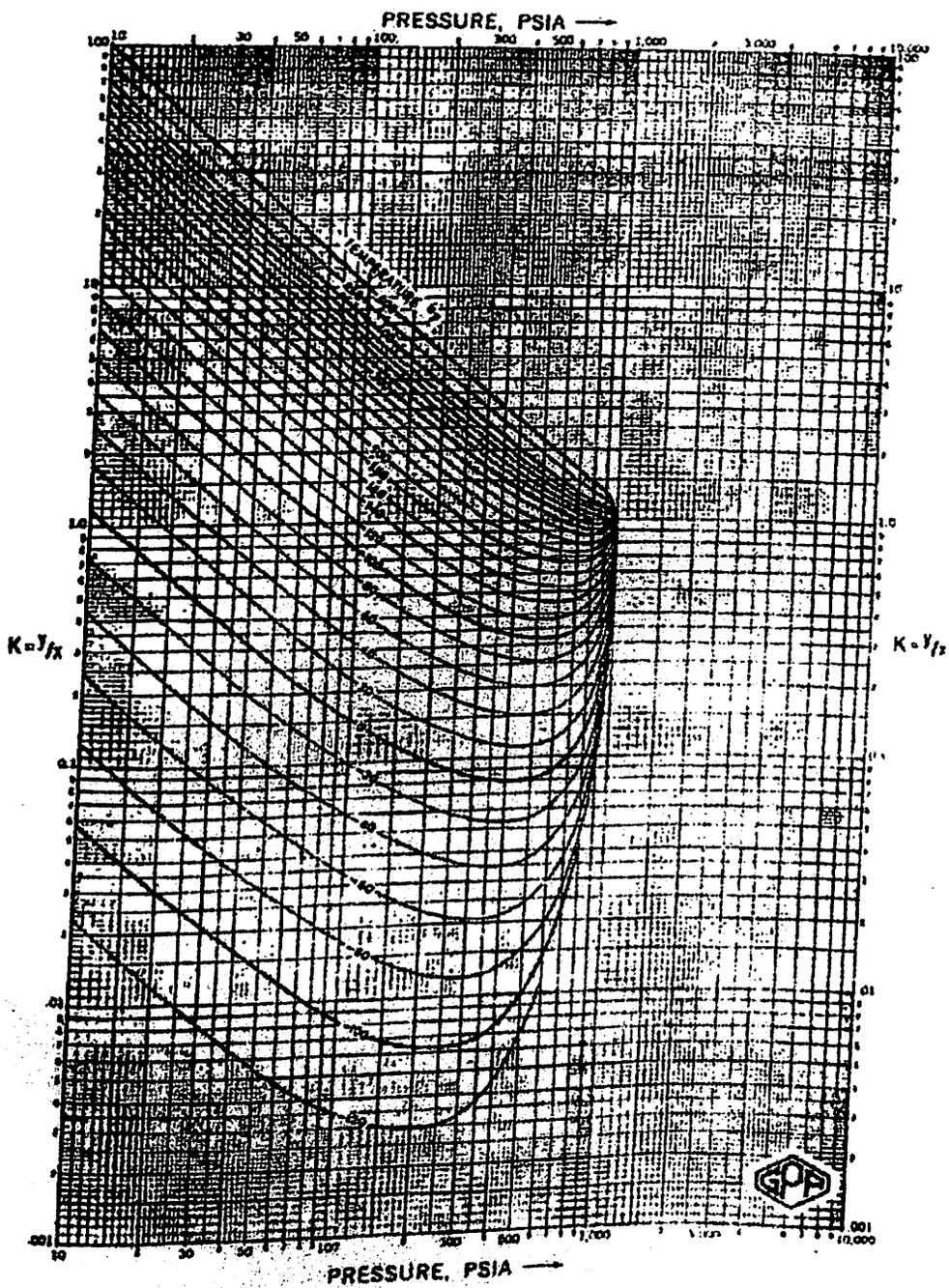
equilibrium ratio, K, for iso-butane for a convergence pressure of 1,000 psia. (From *Engineering Data Book*, 1981; courtesy of GPSA.)
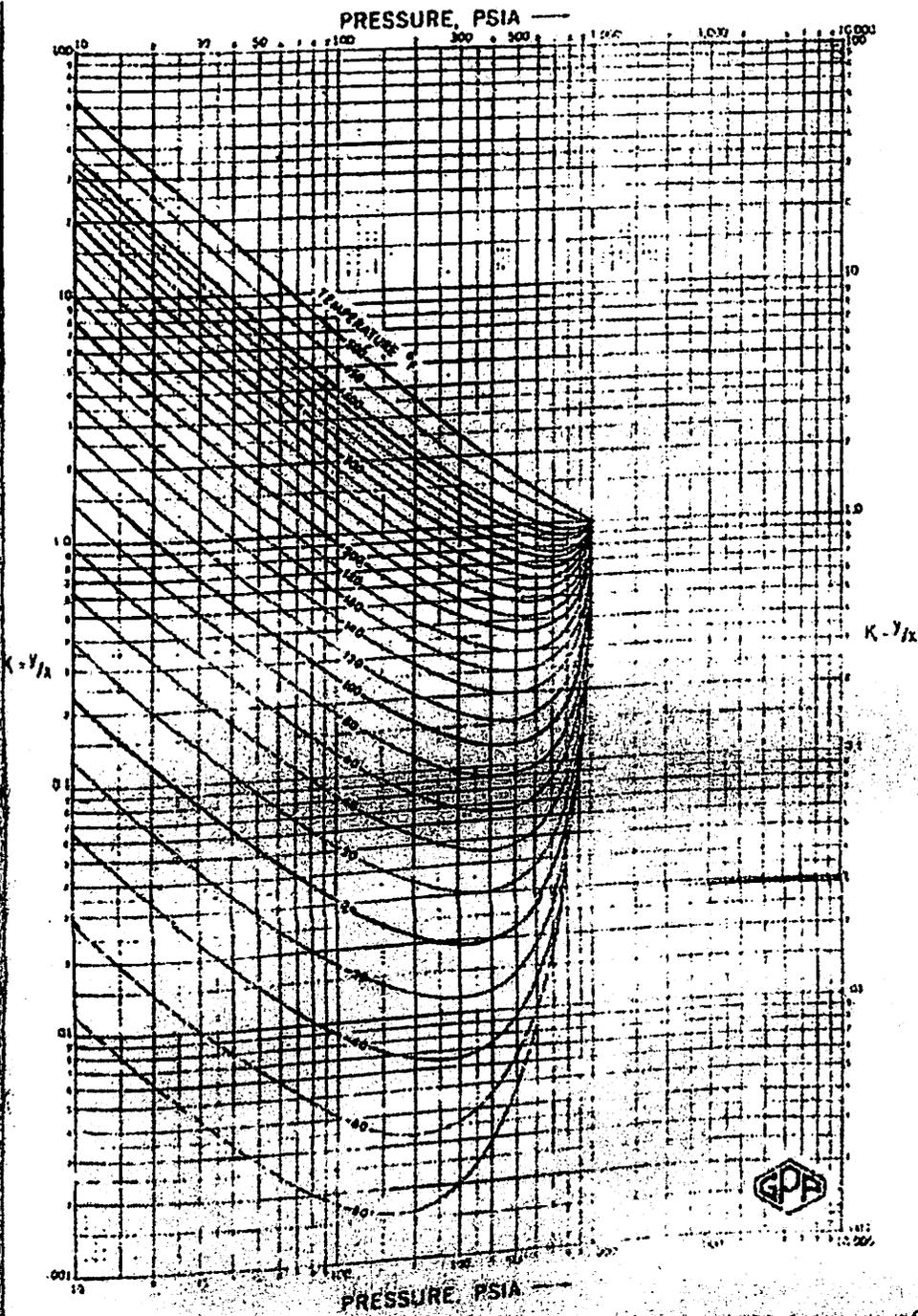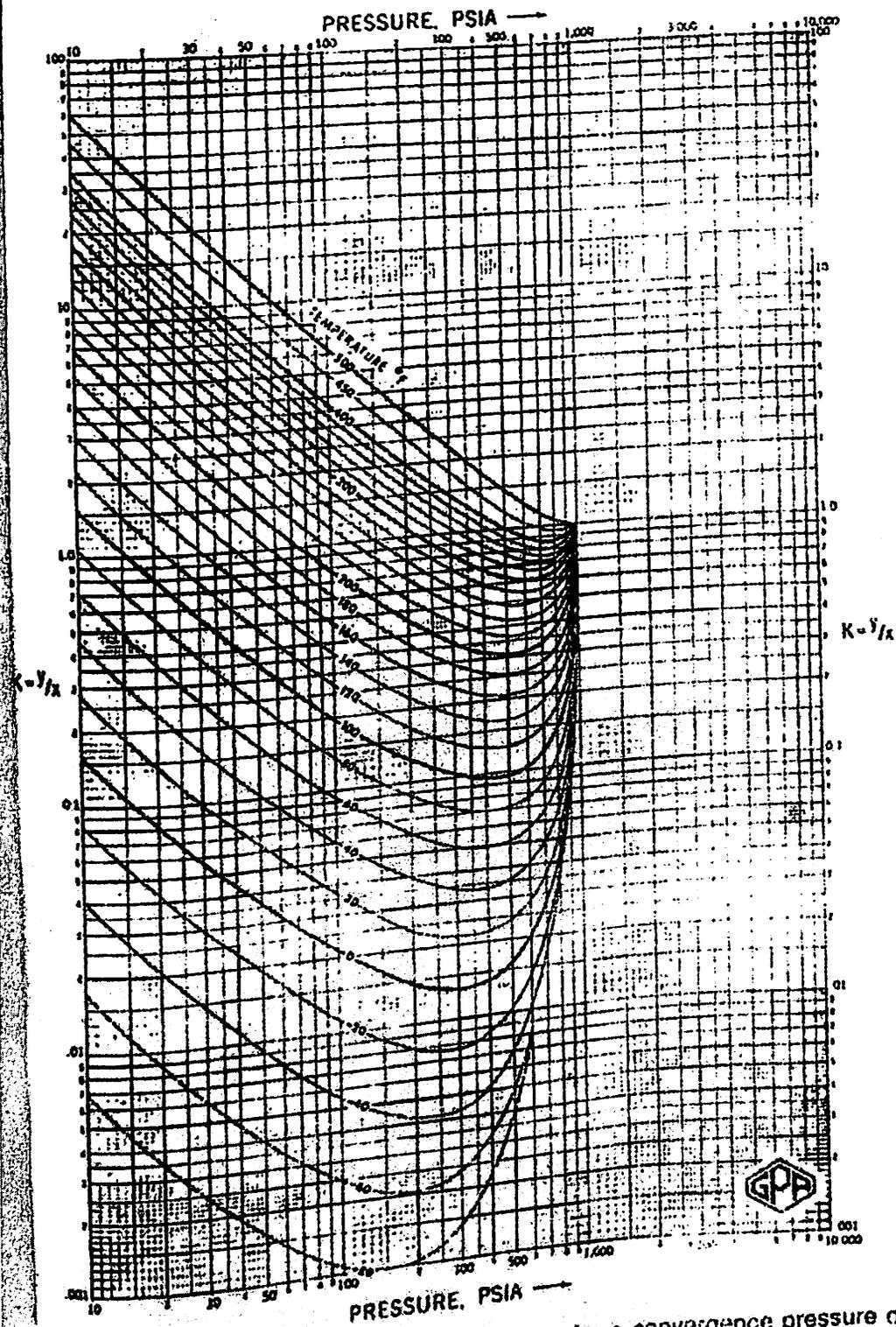
Equilibrium ratio, K, for n-butane for a convergence pressure of 1,000 psia. (From *Engineering Data Book*, 1981: courtesy of GPSA.)

Equilibrium ratio, K, for i-pentane for a convergence pressure of 10,000 psia. (From Engineering Data Book. 1981; courtesy of GPSA.)

Equilibrium ratio. K, for n-pentane for a convergence pressure of 5000 psia. (From Engineering Data Book. 1981; courtesy of GPSA.)

4. Calculate the reboiler temperature

- Reboiler temperature is calculated by performing the bubblepoint calculations on the bottom products at reboiler pressure.
- Assuming a 20kPa pressure drop across the tower, we perform the bubblepoint calculations at 1813kPa on the bottom products to determine the reboiler temperature.

Components	Xi (mol %)	Ki at 134^0C and 1813 kPa	KiXi (mol %)
C_3	0.88	2.31	2.03
iC_4	16.52	1.52	25.19
nC_4	40.34	1.32	53.33
iC_5^+	42.26	0.46	19.44
	100.00		100.00

Reboiler temperature is 134^0C.

5. Determine the reflux ratio and number of theoretical stages required to make the separation.

This steps involves stage to stage calculations inside the column.
Fenske's method for minimum theortical trays
The fenske's equation can be written as:
$$S_m= \log[(X_{Lk}/X_{HK})_D \, (X_{HK}/ X_{LK})]$$

Where:

S_m= minimum number of theoretical plates
X_{LK}=mol fraction of light key component
X_{HK}= mol fraction of heavy key component
a_{avg} = relative volatility at avg. tower temp.
(top tray temp + bottom tray temp)/2

Subscripts:

D = distillate product
B= bottom product

Now applying fenske's equation,
T_1= 52C (top tray temp.)
T_2 = 134(reboiler temp.)
T_{avg}= $(T_1 + T_2)/2$ = (52 + 134)/2 = 93C

At avg. tower conditions

$K_{c_3}= 1.683$

$K_{ic4}= 0.993$

$a_{avg} = 1.683/0.993 = 1.695$

$S_m = \log[(0.950/0.993)(0.165/0.0088)]$

Log 1.695

$S_m = 12.2$

The minimum no. of theoretical trays is 12.2

Underwood methods for minimum reflux

This involves:

$$\sum_{i=1}^{i=n} a_i f_i/(a_i - ?) = F(1-q)$$

$$\sum_{i=1}^{i=n} a_i d_i/(a - ?) = L_m + D$$

where:

? = constant

f_i = mols of component in feed

d_i = mols of component in distillate

q = total heat needed to convert one mol of feed into a saturated vapour divided by the molal latent heat of the feed.

L_m = minimum reflux rate, mols

D = distillate rate, mols

Now using hit trial method, we calculate?

Assuming ? = 1.130

Comp.	Feed Mols	K at 93^0C	a_i	$a_i f_i$	$a_i -?$	$a_i f_i/ a_i -?$
C_2	10	3.437	3.461	34.61	2.331	14.85
C_3	460	1.683	1.695	779.7	0.565	1380.72
iC_4	100	0.993	1.000	100.0	-0.130	-767.63
nC_4	210	0.823	0.829	174.09	-0.302	-576.93
iC_5	220	0.211	0.213	46.86	-0.918	-51.01
	1000					0.00

To calculate L_m

Comp.	Distillate Mols	a_i	$a_i d_i$	$a_i -?$	$a_i d_i/ a_i -?$
C_2	10.0	3.461	34.61	2.331	14.8
C_3	455.4	1.695	771.89	0.565	1366.9
iC_4	14.0	1.000	14.00	-0.130	-107.5
	479.4				1264.2

$1264.2 \; L_m + D$
$D = 479.4$ (from material balance)
$L_m = 1264.2 - 479.4 = 784.8$
Minimum reflux ratio $= (L_m / D) = 784.8/ 479.4 = 1.64$

Actual reflux rate and theoretical stages

Using Gilliland correlation

$Y = 0.75(1 - X^{0.5668})$
Where:
$Y = (S - S_m)/(S + 1)$
$S =$ actual theoretical trays
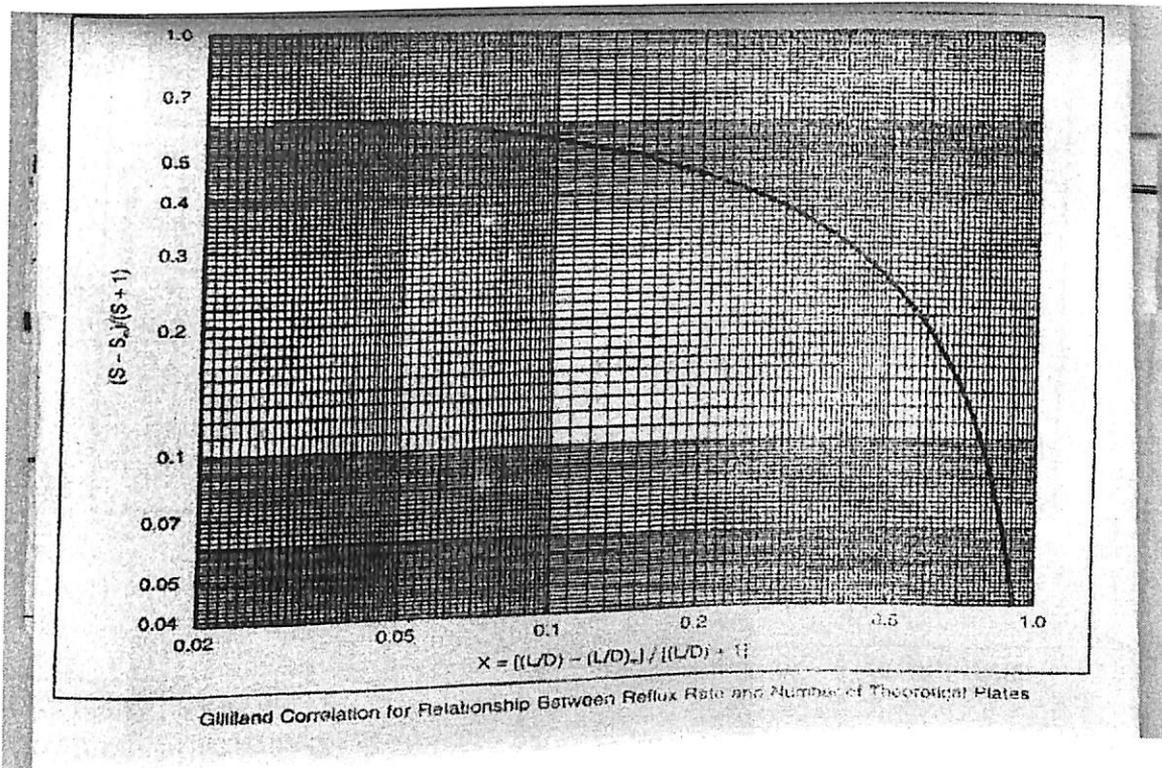$X = [(L/D) - (L/D)_m] /[(L/D) +1]$

The depropanizer considered above to operate at an actual reflux rate 10% above the minimum reflux.

$(L/D) = 1.1(L/D)_m = (1.1)(1.64) = 1.8$
$[(L/D) - (L/D)_m]/[(L/D) + 1] = (1.8 - 1.64)/(1.8 + 1) = 0.06$

From figure,

Gilliland Correlation for Relationship Between Reflux Rate and Number of Theoretical Plates

$(S-Sm)/(S+1)=.06$
From fenske`s eqn.
$Sm=12.2$
$(S-12.2)/(S+1)=.06$
$S=32$
The reboiler is equal to one equilibrium stage ,so far this tower 31 equilibrium stages must be installed in the column proper

6. Convert theoretical stages to actual trays using tray efficiencies

Overall efficiency ,E=no. of theoretical stages/no. of actual trays
To calculate tray efficiency and no.of actual trays required.
$\mu=.088cp$ $a=1.695$
$a\mu=(1.695)(.088)=0.15$
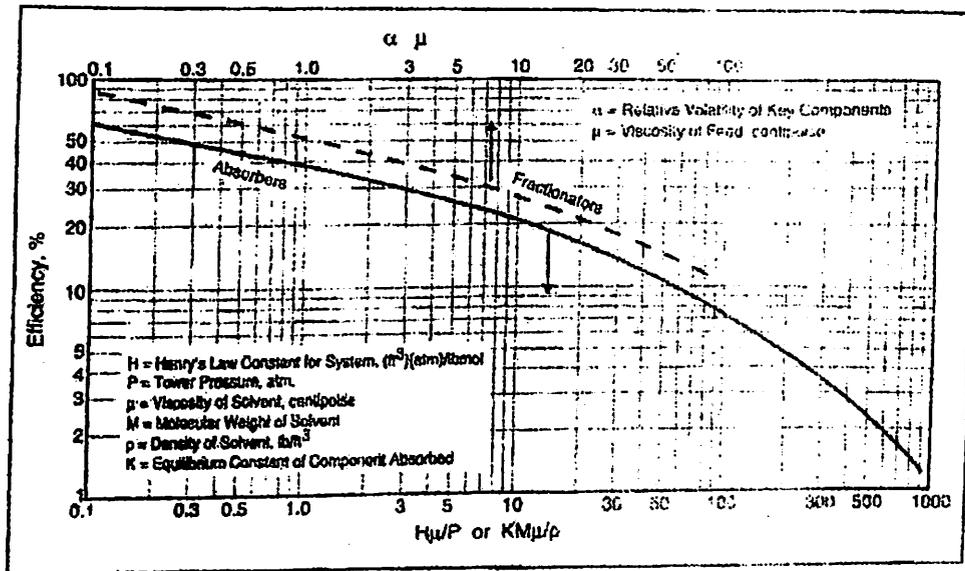from figure,
$E=80\%$
No. of actual trays =(32 theor.Stages-1 reboiler)/.8
=39 acyual trays

α μ

0.1 0.3 0.6 1.0   3   5   10 20 30 50 100

100
50
40
30
20

10

H = Henry's Law Constant for System, (m³)(atm)/lbmol
P = Tower Pressure, atm.
µ = Viscosity of Solvent, centipoise
M = Molecular Weight of Solvent
ρ = Density of Solvent, lb/ft³
K = Equilibrium Constant of Component Absorbed

α = Relative Volatility of Key Components
µ = Viscosity of Feed

Absorbers

Fractionators

Efficiency, %

0.1   0.3 0.5 1.0   3   5   10   30 50 100   300 500 1000

Hµ/P or KMµ/ρ

Correlation for Overall Efficiency of Absorbers and Fractionators

Reflux ratio relative to distillate product ,mol/mol	Operating pressure,psig	No. of actual trays	Reflux ratio	Tray efficiency,%
Demathanizer	200-400	18-26	Top feed	45-60
Deethanizer	375-450	25-35	.9-2.0	50-70
Depropanizer	240-270	30-40	1.8-3.5	80-90
Debutanizer	70-90	25-35	1.2-1.5	85-95
Butane splitter	80-100	60-80	6.0-14.0	90-110
Rich oil fractionators	130-160	20-30	1.75-2.0	Top 67 Bottom50
Rich oil deethanizer	200-400	40	-	Top25-40 Bottom40-60
Condensate stabilizer	100-400	16-24	Top feed	40-60

7. Determine Optimum Feed Tray Location

An empirical correlation is given by equation

$$Log(N/M) = .206 log[(Bxhkf/Dxlkb)(Xlkb/Xhkd)^2]$$

Where;

N=no.of theoretical stges in rectifying section

M= no.of theoretical stges in stripping section

B=bottoms rates,mols

D=distillate rate,mols

Xhkf=composition of heavy key in the feed

Xlkf= composition of light key in the feed

Xlkb= composition of light key in the bottom

Xhkd= composition of heavy key in the distillate

Therefor,

$$Log(N/M) = .206 log[\{(479.4)(.46)/(520.6)(.10)\}\{(.0088/.0291)\}]$$

Log (N/M)=-.0848

N/M=.822

N+M=32;N=14;M=18

Optimum feed tray location is about tray 14.

8. Calculate the condenser and reboiler duties

The over all energy balance around the fractionators is

Qb+Qc=hdd+hb-hff

Where

Qb=reboiler heat load

Qc=condensor heat load

hd=enthalpy of distillate product

hb=enthalpy of bottoms

hf=enthalpy of feed

d,b ,f=rate of flow distillates,bottom and feed streams,resp.

The energy balance for the condenser is

Qc=L(hl-h1)+D(hd-h1)

Where

hl=enthalpy of reflux stream

h1=enthalpy ofvapour from top tray

L=reflux rate

For a total condenser,eq. simplify to

Qc=V1(hd-h1)

V1=Top tray vapour rate=L+D

Now calculating condenser and reboiler duties

F=1000kmol/hr
D=479.4kmol/hr
B=520.0kmol/hr
L=(1.83)(479.4)=862.9kmol/hr
h_f=117.93kj/kg[50.70Btu/lbm]
h_d=41.52kj/kg[17.85Btu/lbm]
h_b=256.56kj/kg[110.30Btu/lbm]
h_1=331.59kj/kg[142.56Btu/lbm]

MWf=57.56
MWd=44.21
MWb=69.86

$Q_c = V_1(h_d - h_1)$
=(479.4+862.9)(44.21)(41.52-331.59)
-17.2*10^6kj/hr=-4782kw
$Q_b = h_d D + h_b B - h_f F - Q_c$
(41.52)(479.4)(44.21)+(256.56)(520.6)(69.89)-
(117.93)(1000)(57.56)-(-17.2*10^6)
=20.62*10^6kj/hr=5728kw[19.51$0^6$Btu/hr]

CHAPTER 6

CONCLUSION

Due to clean burning characteristics and ability to meet stringent enviornmental requirements, the demand of natural gas has increased considerably over the past few years. Projections reflect a continued increase for the next several years. However, it is a clean burning methane rich gas that is in demand as opposed to the typical raw gas that exists in nature, which often includes additional components such as heavier hydrocarbons and other impurities. The NGL recovery column is often required to operate at a relatively high pressure (typically above 550 psig) in order conserve refrigeration compression horsepower requirements. Although refrigeration horsepower is conserved utilizing a high pressure column, separation efficiency is often significantly reduced to less favourable operating conditions, i.e lower relative volatility. Utilization of deethanizer overhead as reflux to the heaviest removal column improves separation efficiency while maintaining higher column pressures for efficient and economical utilization of mechanical refrigeration. For high propane recovery, the deethanizer overhead flux configuration requires less specific power and results in improved project economics when compared to configurations using lean methane reflux or no reflux to the heaviest removal column. NGLs include ethane propane butane iso butane and natural gasoline. Through careful process selection and heat integration, the integrated NGL facility results in lower specific power consumption and increased NPV as compared to non-integrated facilities.

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