May
2009

Gas Processing At Titas Gas Field

A weekly training on gas processing under industrial attachment

Training on Glycol Dehydration, LTS with & without Glycol Injection Plant

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ON
NATURAL GAS PROCESSING
IN
TITAS GAS FIELD

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APPROVAL

This is two to certify that the project work entitled “Natural gas processing “ completed in ”Titas gas field” has been successfully completed by the authors for their partial fulfillment of the requirements’ for the degree of B.Sc(ENGG.) in CHEMICAL ENGINEERING &POLYMER SCIENCE from the department of CEPS,SUST.

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ACKNOWLEDGEMENT

Thanks to Almighty Allah who is merciful to all and good things that happened and is being happened by HIS wish for the successful completion of the internship program and submission of this report.

Thanks to petro bangla & BGFL authority for giving us the opportunity for attending the internship program here.

We would like to express our gratitude to our respected supervisor NOOR-A-ALA, ASSISTANT PROFESSOR, DEPARTMENT OF CHEMICAL ENGINEERING &POLYMER SCIENCE, SHAHJALAL UNIVERSITY OF SCIENCE & TECHNOLOGY for suggesting us the topic and for helping us so much

Thanks to our supervisor MD.MAMUN AZAD & ALI MUKTAZER for their continuous guidance and suggestions.

Thanks to every member from every department for their cooperation. Special thanks to each member of the TITAS GAS FIELD (section A) because without their inspiration this training wouldn’t be successful.

ABSTRACT

The objective of this report is to describe the different processes and equipments involved in the Titas gas field under BGFL. This is a report of the weekly training program attended by the requirement of industrial attachment after completion of 3rd year 2nd semester in the Department of Chemical Engineering & polymer Science, Shahjalal University of Science and Technology.

The present work includes not only the general system of natural gas processing but also how the plant work. Different chapter gives different views of natural gas processing. This report contains the description of processes and equipments involved in the wellheads, gathering lines, production headers, high pressure separators, gas filter, sales gas metering, gas dehydration system, utility water system, instrument and utility air system, flare system, fire water and foam system in the Titas gas field .

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Introduction

The largest gas field of Bangladesh Titas which holds about 50% of country's proven gas reserve is now struggling for life on life support at Intensive Care Unit. We can not figure out which other single resource has made more contribution to Bangladesh economy than this prolific gas field over the years. Starting from 1968 till now this gas field is making silent massive contribution to Bangladesh economy. It still produces about 22% of the total national supply. 2 of its 16 gas wells have ceased to produce for different reasons. It produces about 400 MMCFD. It is also very strategically located on national Gas Grid. This gas field is more than double the size of Bibiyana which now produces 600+ MMCFD. Bangladesh is now struggling – sweating and bleeding for energy crisis induced by gas supply problems.

Titas field was candidate for 3D seismic survey since 2005. Now in a leaking gas field it will not be wise to do that. Drilling of new well can also be risky as no one knows whether some gas sands are charged from leakage. This situation is really alarming and demands immediate national attention.

This is emergency, this is crisis .Unfortunately we do not have contingency planning or any crisis management plan. Natural Gas at this moment is our life blood. Titas is lifeline of Bangladesh Gas Energy. As once grasshopper of Bangladesh Gas sector like to appeal to Prime Minister Sheikh Hasina for urgent action to redress Titas field situation. Arranging 100Million dollar to save life of Titas field must not be a problem.

Brief History On Titas Gas Field

Company's Name: Titas Gas Field Company Ltd.
(A company of Petrobangla)
Location: Bramhanbaria
There was total 16 gas well in Titas Gas Field. At present 14 wells are on the production & remaining 2 wells are closed.
In this gas field there are two types gas well vertical & deviated.

Brief information of different wells

Well No.	Spud-in Date	Completion Date	Well Type	Drilled Depth(ft)	Production String	Production casing	Present Status
Titas#1	1st June 1962	1st November 1962	Vertical	12325	4.5”	7” & $9^5/_8$”	Production
Titas#2	22nd November 1962	6th January 1963	Vertical	10574	5” & 4.5”	7”	Production
Titas#3	3rd August 1969	8thSeptember1969	Vertical	9315	4.5”	7”	Production
Titas#4	14th September 1969	30th October 1969	Deviated	9350	5” & 4.5”	7”	Production
Titas#5	5th October 1980	6th January 1981	Deviated	10805	4.5”	7” & $9^5/_8$”	No Production
Titas#6	7th May 1983	11th October 1983	Vertical	10072	4.5”	7”	Production
Titas#7	1st December 1984	17th march 1985	Deviated	11006	4.5”	7”	Production
Titas#8	25thMay 1985	28thSeptember 1985	Deviated	11760	4.5”	7”	Production
Titas#9	11trh September 1987	20th January 1988	Deviated	11893	4.5”	7”	Production
Titas#10	14thFebruary 19	29th May 1988	Deviated	12139	4.5”	7”	Production
Titas#11	10th February 1990	27th April 1990	Vertical	10462	3.5”	7”	Production
Titas#12	17th June 1999	22nd August 1999	Deviated	9875	4.5”	7” & $9^5/_8$”	Production
Titas#13	27th August 1999	2nd December 1999	Deviated	11490	4.5”	7” & $9^5/_8$”	No Production
Titas#14	7th December 1999	11th March 2000	Deviated	11007	4.5”	7” & $9^5/_8$”	Production
Titas#15	3rd February 2006	15th May 2006	Vertical	10446	4.5”	7” & $9^5/_8$”	Production
Titas#16	7th August 2005	17th December 2005	Deviated	11673	4.5”	7” & $9^5/_8$”	Production

Natural Gas of Bangladesh

Background

Bangladesh is one of the world's poorest and most densely populated countries. Not only is it highly vulnerable to natural disasters such as cyclones, flooding and drought, it is also associated with civil unrest, political instability and widespread corruption – all of which can be viewed as a deterrent to the country's attractiveness as an E&P destination.

Natural gas is the only significant source of commercial energy, and accounts for almost 75% of commercial energy consumption. The largest gas consumers are the power and fertilizer industries, which account for around 70% of daily production. Current supply capacity of 1,450 MMcf/d, however, is insufficient to meet the projected growth in demand; gas consumption, currently at 1,400 MMcf/d, is expected to grow at a rate of 10% per annum.

Some 23 onshore / offshore exploration blocks were delineated ahead of the First Licensing Round in 1993. Six PSCs were awarded in the round: Cairn Energy-Holland Sea Search (Block 15, Block 16), Occidental (Block 12, Block 13 & 14), Okland-Rexwood (Block 17 & 18) and United Meridian Corporation (Block 22). A highly protracted Second Licensing Round was launched in 1997, and a further four PSCs were eventually awarded to Shell-Cairn Energy-Bapex (Block 5, Block 10), Tullow-Chevron-Texaco-Bapex (Block 9) and Unocal-Bapex (Block 7).

Although many of these companies have subsequently left, following a number of asset swaps and company acquisitions in recent years, IOCs present today are Cairn Energy, Chevron, HBR Energy, Niko Resources, Okland-Rexwood, Tullow and Total (see Figure 1). The latter is currently awaiting government approval for a 60% stake in Block 17 & 18.

Exploration activity has predominantly been conducted in the eastern onshore, with the west and the offshore remaining relatively under-explored. Only 110 exploration wells have been drilled to date – 65 of which are New Field Wildcats, with only 13 being drilled in the offshore. A total of 25 discoveries has been made, giving overall a highly impressive 38% success rate.

However, exploration has been stagnant in recent years, since IOCs effectively placed a moratorium in the late 1990s, pending the development of a local gas market and a decision by the Bangladeshi Government on the politically-sensitive issue of gas export to India. The government has long been reluctant to come up with a policy on gas export, choosing not to commit itself to gas supply contracts whilst reserve estimates remain uncertain. A decision was subsequently made to retain the current gas reserve for domestic use and fulfill the rising domestic gas demand.

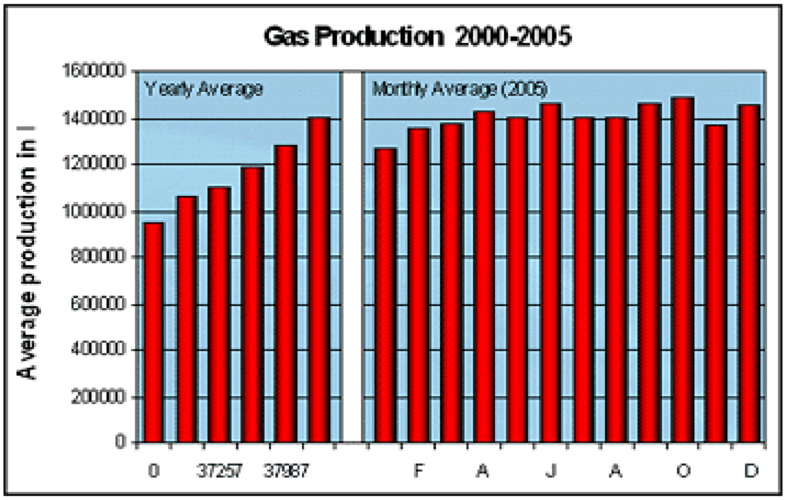

Figure: Gas production 2000 to 2005.

Current / Future Production

Bangladesh is currently producing 1,400 MMcf/d and 3,500 bc/d (Fig 2). Oil production from the Sylhet Field ceased in 1994. The three state-owned companies – Bangladesh Petroleum Exploration & Production Company Ltd (Bapex), Bangladesh Gas Fields Company Ltd (BGFCL) and Sylhet Gas Fields Ltd (SGFL) – are responsible for around 950 MMcf/d from eleven fields, with three IOCs – Cairn Energy, Chevron and Niko Resources – responsible for 450 MMcf/d from four fields. Of the two offshore discoveries made to date, only one has been developed – the Sangu Field, discovered by Cairn Energy on Block 16 in February 1996, and currently producing 150 MMcf/d.

Production levels are expected to increase significantly in the near future, when Chevron (already the country's leading foreign producer with its Jalalabad and Moulavi Bazar fields) brings the Bibiyana Field onstream. Bibiyana, discovered by Occidental on Block 12 in July 1998 prior to its asset swap with Unocal the following year, is the country's largest single site of natural gas to date, with recoverable reserves of 2.4 Tcf. It is expected to contribute an additional 250 MMcf/d to the national grid from late 2006. National production should increase to 500 MMcf/d by the end of 2008 – the three state-owned companies also planning to undertake gas augmentation projects (aimed at delivering an additional 300 MMcf/d) on the Bakhrabad, Habiganj, Kailas Tila, Narshingdi, Shabazpur and Titas fields over the next five years. Figure 3 shows demand and supply projections to 2030.

Tullow is undertaking a long-term production test on its Bangora 1 discovery on Block 9; first gas commenced in May 2006 and stabilised at a gross flow rate of 50 MMcf/d. The well represents Tullow's first production in Bangladesh and production rates are expected to increase with the completion / tie-in of Bangora 2 and the drilling of additional appraisal wells.

Gas Reserve / Undiscovered Resource Potential

A number of studies conducted in recent years on natural gas reserve and undiscovered resource potential have all concluded that Bangladesh has a mean undiscovered gas resource of at least 32 Tcf. The two most widely recognised studies are the United States Geological Survey (USGS) / Petrobangla Study (2001), which declared the mean undiscovered resource potential to be 32.1 Tcf, and the Hydrocarbon Unit / Norwegian Petroleum Directorate (NPD) Study (2001), which declared the mean undiscovered resource potential to be 41.6 Tcf. Both of these studies, however, only took into account offshore acreage out to a water depth of 200m.

Although the remaining recoverable (2P) gas reserve is estimated to be 14.4 Tcf (July 2005), it is understood that there is significant field growth potential, as most of the state-owned gas fields have not yet been fully appraised.

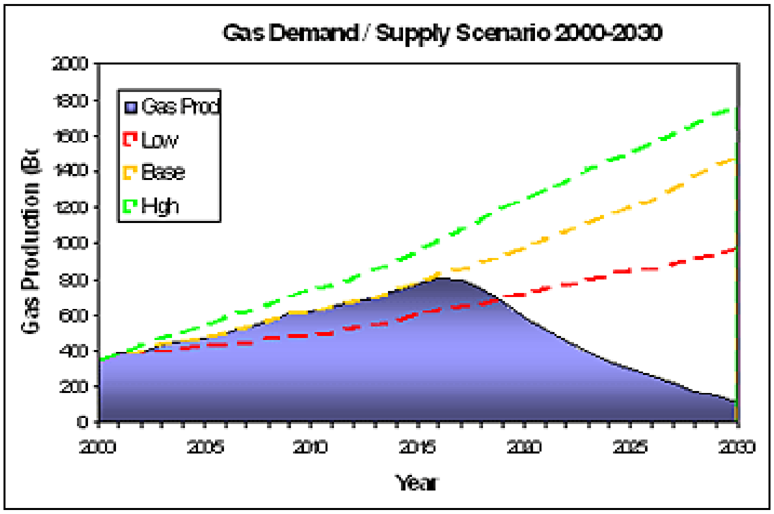

Figure: Gas demand and supply scenarios to 2030.

WELL SPUD-IN

There are two types of well spud-in:

(1) Vertical Well
(2) Deviated Well

Well is spud-in through the drilling. For well spud-in two types of equipment are used.

(1) Cable tools
(2) Rotary rig

The first one is now- a-days generally not used. The second one is used all the places. For well spud-in in Titas gas field rotary rigs was used.

Drilling is done step by step.

Spud-in Well

It consists of following steps,

1. Drilling
2. Casing
3. Cementation the casing
4. Perforating casing
5. Logging of wells
6. Drill stem testing

Drilling

Now a day's drilling is generally done by rotary rigs. A engine drive the draw works. The draw works consists of a hoisting drum around which is spooled steel cable .the steel cable is strung around the sheaves of the crown block and a traveling block, which raises & lowers the drill string. The drill string is made up of the swivel & Kelly, drill pipe, drill collars & the bit. The drill collars have a heavier wall than the drill pipe to give additional weight on the bit. The Kelly is square shaped so that, as it moves downward through the rotary a rotary table, the entire drill string is rotated .the rotary table is driven by a draw works.

The engine also powers a slush pump which pump mud out of the mud tank. The mud then flows up the annular space & is vented out the casing into a trough & then shale shaker. From the shale shaker the mud flows back to the mud pit, and the cycle is repeated.

A Casing Program

It is a part of the plane for drilling a well. Figure shows a well with the casing & set into producing formation. A second smaller casing may be set up to protect drilling from mud loss in a vugular zone or sallow production zone. The production casing is set on the top of the producing zone or, as in fig- is bottomed in or bellow the producing zone

Cementation The casing

Cementation the casing seals the pipe to rock & prevents oil or gas from flowing up the annulus. After the drilling mud has been circulated to clean the wellbore, the casing is placed in the well joint by joint. The casing head is piped to cement truck pump, which are prepared to mix dry cement with water in jet mixer & pump the slurry down the inside of the casing. A calculated volume of cement slurry I is used to bring the annulus level to as high as desired, into an intermediate casing or to surface. When this amount cement has been pumped into the casing, a movable plug is placed on top of the cement & pumped to near the bottom of the casing with mud or water.

Problem arises when the cement slurry breaks into formation instead of coming up the annulus. Also mixing of cement with mud provides channel where oil 7 gas may displace the fluids & move up the annulus. The top of the cement outside the casing may be located by temperature measurements after a short set period or cement bond logs.

Perforation of Casing

Perforating casing has become a routine tool in completing or recompleting wells. When the cement has set on a well drilled through the producing horizon, a perforating gun is lowered into the casing, normally full of or water mud, and bullets are shot through the casing. This method of completion protects the formation face & facilities plug back or recompletion.

Logging Of Wells

Logging of wells was once done by drillers, who maintained a record; known as driller's logs, of activities, events, depths, drill rates, etc., when drilling wells. Electric log Is introduced by running electrodes on insulated conducting cables into wellbores after drilling & before casing was set. Electric log receive signals from the sonds & transmit them to recorders at the surface to give the electrical resistivity & the self potential of the formations. Wells with the casing in place use neutron & gamma ray logs, in which neutron & gamma ray beams penetrate the steel; this may repeated over a period of years to detect gas accumulation & movement.

Drill Stem testing

It is a technique for testing the productivity of a formation before setting the productive casing . The drill pipe is removed, the bit is replaced by the drill stem testing equipment, including pressure gauges, & this is floated back into the mud-filled wellbore. The tool is placed opposite the productive horizon at the bottom of the well, and packers seal off annulus from the formation. The pipe is rotated to open the formation of low pressure inside the drill pipe. A strong productive formation will flow through the drill pipe, which is equipped to flare gas. The pipe is then rotated back to close off the formation and buildup pressure are recorded. The result include time for gas to surface, and the amount of liquid, oil and/or water in the withdrawn drill pipe.

Natural Gas Processing

Natural gas processing plants, or fractionators are used to purify the raw natural gas extracted from underground 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 natural gas.[2]

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_2H_6), propane (C_3H_8), normal butane ($n\text{-}C_4H_{10}$), isobutane ($i\text{-}C_4H_{10}$), 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_2S) and mercaptans such as methanethiol (CH_3SH) and ethanethiol (C_2H_5SH).

Water: water vapor and liquid water.

Liquid hydrocarbons: perhaps some natural gas condensate (also referred to as casinghead gasoline or natural gasoline) and/or crude oil.

Mercury: very small amounts of mercury primarily in elemental 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 transmission 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 ± 5% Btu per cubic foot of gas at 1 atmosphere and 60 °F (41 MJ ± 5% per cubic meter of gas at 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 or 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 equipment in the gas processing plant or the pipeline transmission system from mercury amalgamation and embrittlement of aluminum and other metals.

Types of Raw Natural Gas Wells

Raw natural gas comes primarily from any one of three types of wells:

- Crude oil wells
- Gas wells and
- Condensate wells.

Natural gas that comes from crude oil wells is typically termed associated gas. This gas can exist separate from the crude oil in the underground formation, or dissolved in the crude oil.

Natural gas from gas wells and from condensate wells, in which there is little or no crude oil, is termed non-associated gas. Gas wells typically produce only raw natural gas, while condensate wells produce raw natural gas along with a very low density liquid hydrocarbon called natural gas condensate (sometimes also called natural gasoline or simply condensate).

Raw natural gas can also come from methane deposits in the pores of coal seams. Such gas is referred to as coal bed gas and it is also called sweet gas because it is relatively free of hydrogen sulfide.

Unit Operations in a Natural Gas Processing Plant

There are a great many ways in which to configure the various unit processes used in the processing of raw natural gas. Processing of the raw natural gas yields these byproducts:

- Natural gas condensate
- Sulfur
- Ethane
- Natural gas liquids (NGL): propane, butanes and C_5+ (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 gases (hydrogen sulfide and carbon dioxide). 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 far the one usually selected. The residual gas from the Claus process is commonly called tail gas and that gas 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 natural 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 regenerable absorption in liquid tri-ethylene glycol (TEG), commonly referred to as glycol dehydration, or a Pressure Swing Adsorption (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 carbon or regenerable molecular sieves.

Nitrogen is next removed and 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.
- Adsorption 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 demethanizing 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 depropanizer and a debutanizer. The overhead product from the deethanizer is ethane and the bottoms are fed to the depropanizer. The overhead product from the depropanizer is propane and the bottoms are fed to the debutanizer. The overhead product from the debutanizer is a mixture of normal and iso-butane, 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

GAS PROCESSING
AT
TITAS
GAS FIELD

HP Separator

The High Pressure(HP) separator produces three streams; gas, condensate, and produced water. The separated gas is routed to the dehydration, metering and export. The condensate is sent for stabilization, storage and offloading. The produced water passes directly to produced water storage tanks where any associated condensate may be skimmed off and recycled to the condensate storage tanks through the slop oil tank.

Gas Dehydration

Gas from the HP separators will be dehydrated to sales gas quality using TEG in a conventional contactor tower. The TEG is regenerated by means of a direct-fired reboiler supplied from the plant fuel gas system.

Fire Water

Firewater is supplied on site via an underground ring main. Firewater is used via one of four fixed monitors or three hose reel foam sets positioned around the plant. One of two 100% duty firewater pumps supplies the ring main with water from a 5000 bbl capacity firewater tank. The firewater tank is filled from an on site bore. The firewater system is made live before hydrocarbon is introduced into the plant.

HP Flare

The PSVs (Pressure Safety Valves) and blow down valves (manual and automatic) are connected to the High Pressure flare system which safely disposes of relieved or vented gasses by flaring.

Tank Flare

The tank flare provides safe disposal means for gasses evolved in the on site storage tanks.

Closed Drain

The closed drain system is used for draining hydrocarbons from pressurized sources to the flare knock out drum (V-401). The liquids from the K O drum is pumped back into the condensate storage tanks.

Open Drains

The hydrocarbon open drain system collects the hydrocarbon drains. The drains from condensate storage tanks, the hydrocarbon drain from the produced water storage tanks and drain from the HP Flare K O drum will be routed to the underground drain tank. The hydrocarbon and water are separated in this tank and are sent to the condensate storage and water tanks, respectively.

The surface water collected from the bunds around the storage tanks and process equipment at different parts of the plant will be sent to an API separator. The water from the API separator will be discharged to the nearby creek and the oil will be pump.

Titas Process Description

Gas Processing

The main task of gas processing is separation of gas from condensate (Liquefied hydrocarbon) & water & completely drying the gas obtained from gas well.

There are four processes of gas processing:

(1) Glycol dehydration
(2) LTS(Low Temperature Separation) with glycol
(3) LTS(Low Temperature Separation) without glycol
(4) Silica gel plant

In Titas gas field preceding three processes are used of above four. Three process descriptions are given below:

Glycol dehydration

Dehydration of natural gas with glycol solutions is attractive because of the reliability of the operation, the simplicity of the equipment & the relatively low cost of chemicals & utilities. Proper design & operation of dehydration is of particular importance because of the rigid pipeline specifications especially in winter region which result from the low ground temperatures at which gas must be transported during the winter months.

ABSORPTION

In typical dehydrator, dry lean glycol & wet gas are contacted counter currently in a tower with dry gas exiting from the top of the absorber, and water laden rich glycol coming out at the bottom.

It is extremely important to see that the gas entering the absorber is clean & free of liquids before it enters the glycol absorber. Free liquids especially heavy hydrocarbon liquids can contaminate & foul the glycol. Dirty or contaminated glycol can't be tolerated in these units because of the extremely high levels of purity required by the process. Dirty glycol can prevent attainment of low dew points.

In a trayed glycol absorber, the lean glycol is cooled prior to injection on the top tray by heat exchange with the dry gas leaving the tower. On the top tray the cool lean glycol is maintained at the proper depth by a weir which acts as a dam in holding back the glycol before it spills over the downcomer onto the tray bellow.

Rising gas comes into intimate contact with the glycol as it flows across the tray, trough the bubbles caps, which consists of inverted cups located above the risers, trough which the gas enters from bellow the tray7 is dispersed into the liquids by means of slots around the rim of the caps. As the gas flows from tray to tray while ascending through the column, it comes contacts with , and give up water to the wettest glycol, and the driest gas at the top of the column contacts the driest glycol, permitting attainment of the desired dew point & making the most efficient use of water carrying ability of the glycol.

Gas is from the flowing up the downcomers by a seal pan at the foot of the downcomer which maintain a liquid cover over the open end of the downcomer. In a trayed tower, it is always necessary to initiate glycol flow before gas flows starts so that the seal pans will be charged with liquid, otherwise gas will flow up the downcomer & downflow of liquid will be impeded or stopped. Foam in the downcomer can also interface with tower operation , and for this reason special foam fences are used adjacent to the weirs on each tray to hold back foam & keep it out of the downcomer.

Increase in gas flow cause such a high pressure drop that liquid will cease, and the tower will flood. The presence of foam including impurities tends to cause flooding at a lower than normal gas throughput. Rich glycol, after picking up approximately 6% of its own weight in water, flows to the bottom of the tower where it accumulates to a depth of several inches on the chimney tray.

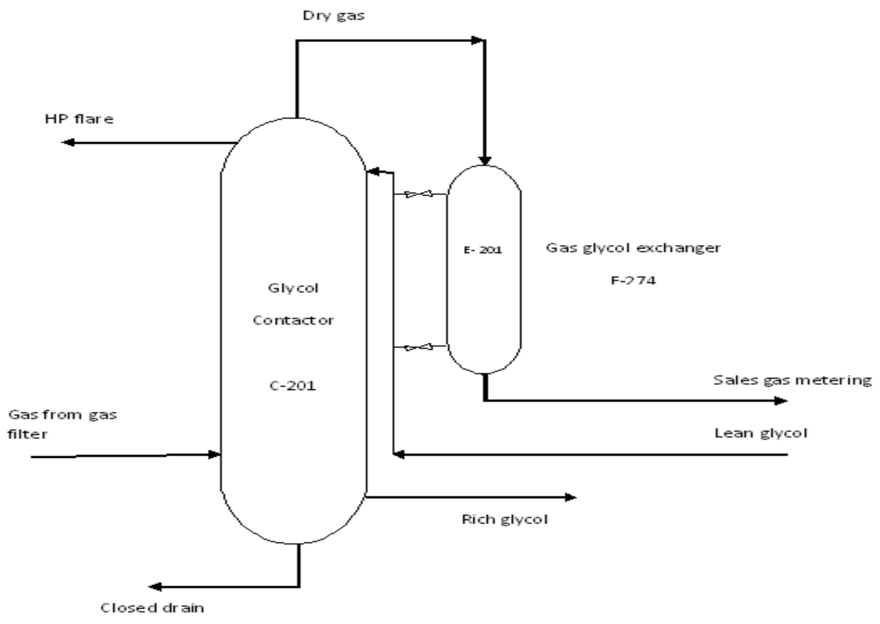

Figure: Process Flow Diagram of Glycol Contactor with a Single Pass Shell & Tube Gas/Glycol Heat Exchanger

After leaving the absorber, the rich glycol is partially preheated by hot lean glycol before flowing to the flash tank & filter. The glycol recovery occurs in two stages. After one stage of heating , the rich glycol at approximately 175^0F, enters the flash tank where dissolved vapors are flashed off.

Typically this vapor is about 1 SCF/gallon of glycol. Partial heating is beneficial to this process, and this reduces the tendency to foam in the flash tank. In the flash tank entrained droplets of hydrocarbon liquid rise to the surface of the liquid where they accumulate as a hydrocarbon layer which can be manually skimmed off through the 1" skim valve as necessary, (to be checked daily).

The degassed warm glycol is then filtered to remove particulate matter. A side stream off the filtered glycol is diverted through a charcoal filter where trace amount of hydrocarbon liquid are removed. The filtered stream then goes to the reflux condenser in the still column, where the rich glycol serves to cool the overhead vapors & provides reflux. After the reflux condenser, the rich glycol goes to the second stage of the glycol – glycol exchange before it enters the still column.

Rich glycol serves as a coolant for the regeneration equipment, first to cool the overhead vapors in the still column & provide reflux liquid, and secondly to cool the lean solution to a reasonable temperature for pumping.

REGENARATION

In the regenerator, reboiling of the glycol takes place at atmospheric pressure, and the temperature maintained in the reboiler establishes the concentration of the TEG(tri ethyl glycol) that is attained thermally. The design calls for 400^0F, which will thermally regenerate the glycol to a concentration of 99.1% which represents the maximum concentration attainable by thermal regeneration alone.

Gas stripping is required for concentration exceeding 99.1%. The regeneration equipment on this unit is designed to regenerate lean TEG to a final concentration of 99.7%(wt). The high concentration is necessitated by the low dew point requirements of the process. The glycol is concentrated in two steps to 99.7%. The first step is thermal regeneration which concentrates the solution to 99.1%, followed by hot gas stripping whereby hot dry gas is used to pick up final traces of water in the glycol. A multistage countercurrent stripper is used to bring the hot glycol into intimate contact with dry stripping gas & bring the final concentration to 99.7%. The introduction of warm, dry stripping gas in contact with the glycol removes water from the glycol & increases the concentration. The amount of stripping gas is normally 2 to 3 standard cubic feet per gallon of glycol.

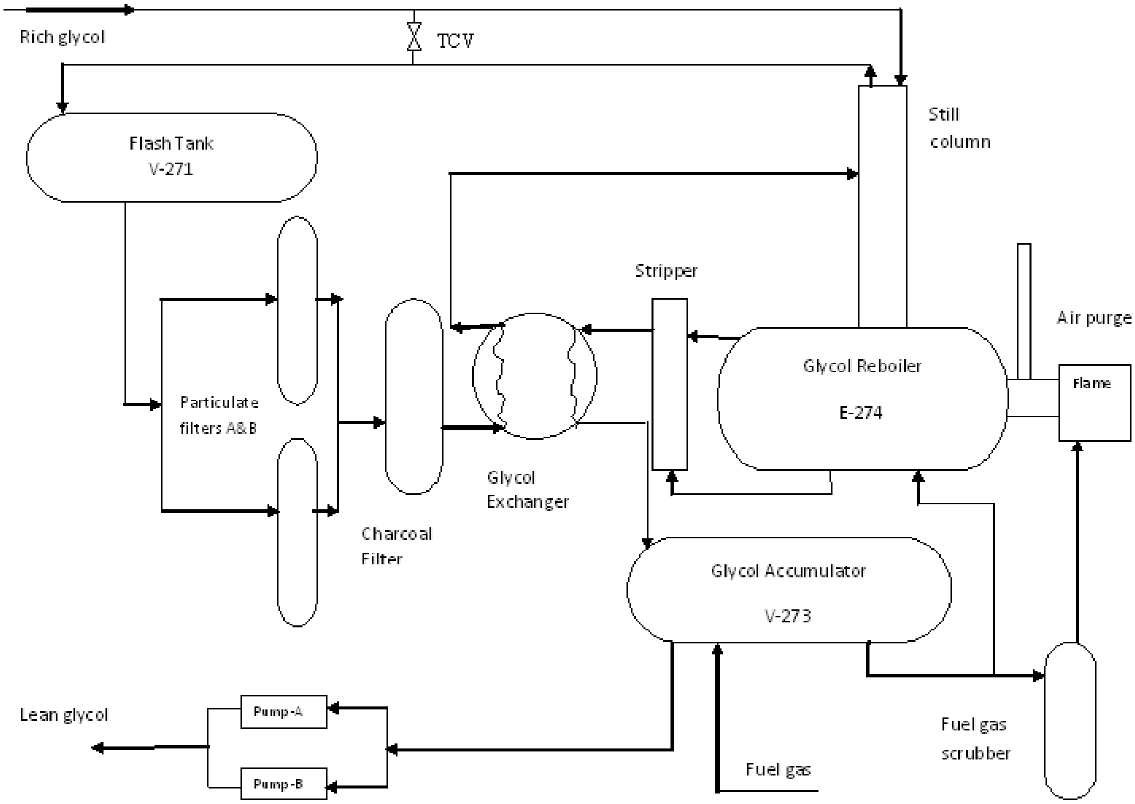

Figure: Process Flow Diagram of TEG Regeneration Skid

Lean hot glycol at 99.1% enters the stripper at 400^0F, and exit at about 383^0F. The 17^0F loss is due to mainly to energy absorbed in the gas phase when water is transferred from the glycol to the gas phase. Lean glycol at 99.7% then flows from the accumulator to the glycol - glycol exchange where it is cooled prior to pumping.

In the still column vapors rising from the hot glycol in the thermal regeneration step flow through a simple packed distillation column where the hot vapor, which is initially rich in glycol vapor is separated from water vapor, which is discharged overhead. Water leaden strip gas vapors rising from the top tray of the stripper section are likewise very rich in glycol vapors. These vapors combine with the hot reboiler vapors, and the combined stream is separated into water & glycol in the still column. Partial condensing of overhead vapors by means of a cooling coil at the top of the column generates reflux liquid which establishes the correct temperature gradient in the still above the feed nozzle. Approximately 25% of the overhead should be condensed asreflux, and the overhead temperature should be within a few degrees of the local boiling point of water. The boiling point of glycol & water are widely separated, so the operation of the still column is not sensitive to minor upsets or variations in condition.

At the completion of regeneration, the fully concentrated hot lean solution over flow to the accumulator below the reboiler. Submergence of the lower end of the overflow pipe isolates the accumulator from the wet reboiler vapor. From here the wet lean solution flows through the accumulator where it exchanges heat with incoming rich glycol as mentioned previously, and flows to the suction inlet of the glycol circulation pump.

Gas Dehydration By LTS With Glycol

For dehydration of natural gas low temperature & absorption with glycol can combindly be used. In this process water is removed through absorption with glycol at low temperature. In this processing gas obtained after condensate separation in gravity separator is passed through a cooler. Air is passed as cross flow arrangement around the flow pipe gas passes. Temperature of gas is lowered in air cooler before entering the glycol absorption column. In absorption column gas enters the column through the bottom section. It is important to see that the gas entering the absorber is clean & free of liquids before it enters through the glycol absorber. Free liquids especially heavy hydrocarbon can contaminate or foul the glycol. The lean glycol is cooled prior to injection on the top t ray. Glycol is sprayed from the top tray of absorption column may be used. In natural gas processing generally tray type absorption column is used. Rising gas comes into intimate contacts with the glycol as it flows across the tray, through the bubble caps.

The pressure of gas in the absorption column is also maintained by decreasing the gas flow rate through the absorption column. Because as gas flow is measured, the hang up of glycol in the tower increases, causing an increase in the pressure drop across the contacting section. Further increase in gas flow eventually will cause such a high pressure that liquid (glycol) down flow will cease.

As gas flows from tray to tray while ascending trough the column it comes into contacts with progressively drier glycol. Thus the wettest gas comes in contact with, and gives up water with wettest glycol and driest gas at the top of the column contacts the driest glycol permitting attainment of the desired dew point & making the most efficient use of water carrying ability of glycol. Thus appropriately complete separation of water vapor is done in absorption column through LTS with glycol process.

The rich glycol after picking up approximately complete water from gas, flows to the bottom of the tower where it accumulates. From this accumulation tank rich glycol is pumped for regeneration by filtration & stripping section.

Gas Dehydration By LTS Without Glycol

In this process gas is dried by removing water from gas by lowering temperature & increasing pressure in some extent of the processing gas. But it sometimes causes problem in processing, because at very low temperature & pressure gas may form ice of hydrate which may blocks the flow of gas through the pipe. Hence pressure and temperature are maintained at constant values. This process is poor in performance & is expensive. Hence this process is used very hardly. In this process water is separated by cooling the gas through the shell and tube heat exchanger.

In this process the gas is first passed through the air cooler before entering the shell and tube heat exchanger. The gases is cool for water separation in two steps by two types of shell and tube heat exchanger one – Gas – Liquid heat exchanger and Gas –Gas heat exchange. At first the gas enters gas -gas heat exchanger where processed gas leaving the liquid- gas heat exchanger as coolant is passed through the tube side and processing gas is passed through the shell side counter current. Gas pressure is maintained the lowering the gas flow in some extent. The processing gas cools & some water separates in this heat exchanger.

In the second step relatively dry gas is passed through the liquid-gas heat exchanger. In this exchanger liquid water is used as coolant which is passed through the shell side & processing gas is passed through the tube side. Most of the water is separated from the gas in this heat exchanger. The liquefied water with small extent of condensate accumulate together in the bottom of heat exchanger is indicated by a level meter.

Finally the dehydrated dry gas leaves the liquid-gas heat exchanger.

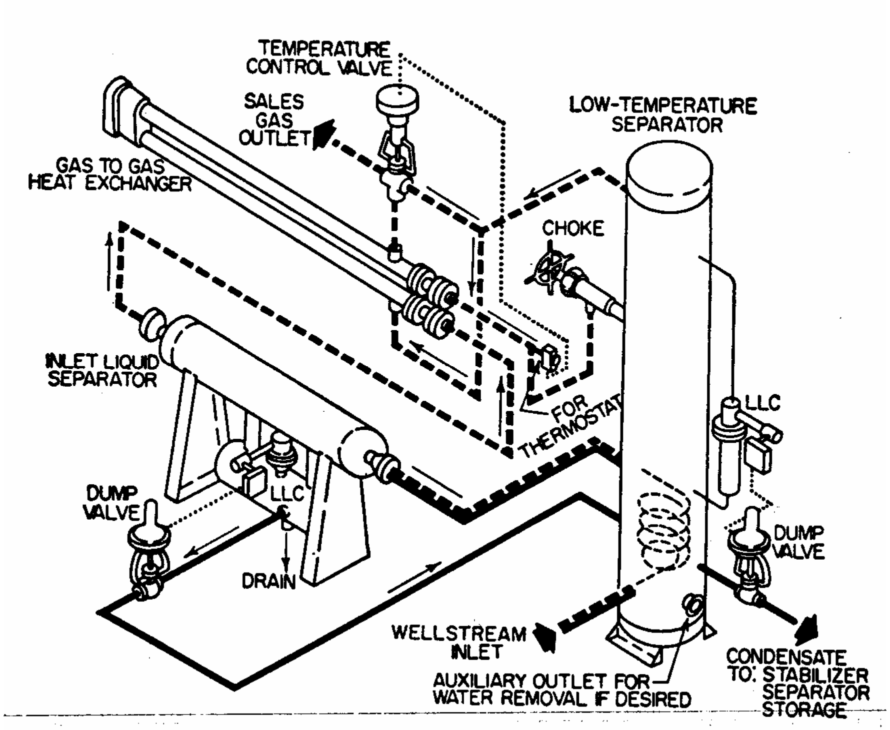

Figure: Typical LTS system without hydrate inhibitor (Reprinted from Petroleum Engineering Handbook, Third Printing

Gas composition obtained from the well head (Titas Gas Field)

Component	Mole %
Nitrogen (N_2)	0.38
Sulfur (S)	0.00
Carbon dioxide (CO_2)	0.43
Methane (CH_4)	96.77
Ethane (C_2H_6)	1.79
Propane (C_3H_8)	0.40
Iso-butane (C_4H_{10})	0.10
Normal butane (C_4H_{10})	0.08
Iso- pentane (C_5H_{12})	0.03
Normal pentane (C_5H_{12})	0.02
Hexane (C_6H_{14})	0.00

RESERVIOR WATER ANALYSIS

Component	**Concentration in Separator(ppm)**	**Concentration in LTS Separator (ppm)**
Iron (Fe)	-	-
Chlorine (Cl)	**300**	**6700**
Calcium (Ca)	**40**	**30**
Magnesium (Mg)	**50**	**40**

P^H of water obtained in separator: 7.6

GAS FLOW RATE AND WELL HEAD PRESSURE (D.W.T. reading)

Well No.	Flow Rate (MMscf/day)	Well Head Pressure (psig)
Well # 1	26	1780
Well # 2	33	1840
Well # 3	Closed	Closed
Well # 4	32	1948
Well # 5	33	1860
Well # 6	34.50	1840
Well # 7	33	1916
Well # 8	19	1616
Well # 9	20	1600
Well # 10	19	1400
Well # 11	24	2020
Well # 12	23	1700
Well # 13	30	1968
Well # 14	Closed	Closed
Well # 15	32	1848
Well # 16	32	1875

Condensate

Condensate includes higher hydrocarbon generally c_3 hydrocarbon to c_{10}hydrocarbon. In Titas gas field the condensate obtained contains c_2 to $c_6$hydrocarbon. This entire hydrocarbon has to separate from the well gas. These higher hydrocarbons are separated through the flash separator & condensate separator.

The general properties of condensate are given as bellow:

Tests	Methods	Results obtained in Flash separator	Results obtained in condensate separator
1.Specific gravity at 60^0F	ASTM D-1298	0.8230	0.820
2.API Gravity at 60^0F	ASTM D-287	40.43	41.06
3.Flash point, ^{0}F	ASTM D-93	<60	<60
4.Water content, %wt	ASTM D-4377	-	-
5.Kinematic viscosity at 100^0F	ASTM D-445	1.56	1.52
6.Absolute viscosity at 100^0F	ASTM D-445	1.28	1.24
7.reid vapor pressure at 100^0F	ASTM D-323	3.22	3.44
8.Doctor test	IP-30	-ve	-ve
9.Pour point, ^{0}C	ASTM D-97	-	-
10.Aniline point, ^{0}C	ASTM D-611	40.0	37.0
11.Diesel index	IP-21	42.0	40.48
12.Sulfur content, %wt	IP-63	-	-
13.Copper strip corrosion at 100^0F	ASTM D-130	1a	1a
14.Smoke point, mm	ASTN D-1322	-	-
15.Cloud point,		-	-
16.Cetane index	ASTM D-976	-	-

Condensate is pumped to the storage tank. This condensate is further processed to separate into two fractions. In Titas gas field condensate obtained from gas separation is separated into motor spirit (MS) & high speed diesel (HSD) by distillation in still column.

The properties of motor spirit & high speed diesel

High Speed Diesel (HSD)

Test	Methods	Results
1 .Specific Gravity at 60^{0}F	ASTM D-1298	0.8310
2. API Gravity at 60^{0}F	ASTM D-287	38.78
3. Flash Point; ^{0}F	ASTM D- 93	100
4. Kinematic Viscosity at 100^{0}F; cst	ASTM D-445	1.64
5. Absolute Viscosity at 100^{0}F; cp	ASTM D-445	1.36
6. Aniline Point; ^{0}C	ASTM D-611	43.0
7. Diesel Index	IP-21	42.4
8. Cetane Index	ASTM D-976	-
9. Copper strip corrosion at 100^{0}F	ASTM D-130	1b
10. Smoke Point; mm	ASTM D-1322	-
11. Pour Point; ^{0}C	ASTM D-97	-
12.Sulfur Content; %wt	IP-63	-

Motor Spirit (MS)

Test	Methods	Results
1 .Specific Gravity at 60^{0}F	ASTM D-1298	0.7630
2. API Gravity at 60^{0}F	ASTM D-287	53.95
3. Water Content; %wt	ASTM D-4377	-
4. Reid Vapor Pressure at 100^{0}F; psi	ASTM D-323	5.4
5.Doctor Test	IP-30	-ve
6. Octane Number		-
7. Copper Strip Corrosion at 100^{0}F	ASTM D-130	1a
8. Sulfur Content; %wt	IP-63	-

Gas composition (Product specification) of Titas Gas Field Company

Component	**Mole %**
Nitrogen (N_2)	1.65
Sulfur (S)	0.00
Carbon dioxide (CO_2)	0.37
Methane (CH_4)	95.32
Ethane (C_2H_6)	1.5
Propane (C_3H_8)	0.49
Normal butane (C_4H_{10})	0.22
Normal pentane (C_5H_{12})	0.08
Hexane (C_6H_{14})	0.07
Heptane plus (C_7H_{16})	0.31

[This data is given for well No. 12]

Wellheads and Flow lines

The wellheads and flow lines are designed to facilitate, monitor and control the production of well stream fluids to the CPP.

Most equipment in the wellhead system has been designed to process 75 MMscfd of fluid. The gathering lines and manifolds have been designed for 150 MMscfd, as they will be connected to two wellheads.

A choke valve regulates the flow rate from the wellhead. Choke valves at the Moulavi Bazar 2 and 3 wells is manually operated. The wells at Moulavi Bazar 4 and 6 is hydraulically operated choke valves. The well sites are unmanned and powered from thermoelectric generators (TEGs) with a battery back up. The well sites are controlled from the CPP control room but can be operated locally should the need arise.

The wellheads consist of a wellhead assembly including choke valve, and associated facilities for high/low pressure protection, flow measurement, a temporary pig launcher, methanol injection, sand probes and corrosion inhibitor injection.

The wellhead configuration is called Xmas tree. The name and operation method of the valves in the Xmas tree is mentioned in the table below.

Table 01: Name and Operation Method of the Valves in Xmas Tree MB-2/3

Name	Operation method
Lower Master Valve (LMV)	Manual
Master Valve (MV)	Hydraulic
Wing Valve (WV)	Pneumatic
Choke Valve	Manual
Swab Valve (SV)	Manual

MB-2 wellhead has Surface controlled Sub-surface Safety Valve (SCSSV) which is hydraulic controlled.

Joule-Thomson Valve

The Joule-Thompson Expansion (Constant Enthalpy) systems use the refrigeration effect that results from a pressure drop taken on a high pressure well stream. This expansion occurs across a choke and the resulting refrigeration effect is dependent on the temperature of the upstream side of the choke, the pressure differential across the choke, and the amount of liquid formed. For obtaining the maximum removal of liquids from the gas stream for a given pressure differential and sales-gas pressure, the lowest possible temperature within reasonable limits should be attained in the separator. This in turn means the lowest possible temperature upstream of the choke.

HP Separation

A typical high-pressure separator designed to overcome irregularities in separating efficiency, and localize any excess pressure close to safety devices. This separator consists of a cylindrical chamber with a cover which, in addition to openings to admit the un-separated mixture and let separated gas out, comprises an elongated first cylinder, projecting downwards inside the chamber and containing a concentric inside cylinder, with which it forms an annular space, into the top of which a mixture supply pipe opens tangentially. The top of this first cylinder consists of a connector attached to the cover and which contains an opening providing communication between the inside of first cylinder and a safety device.

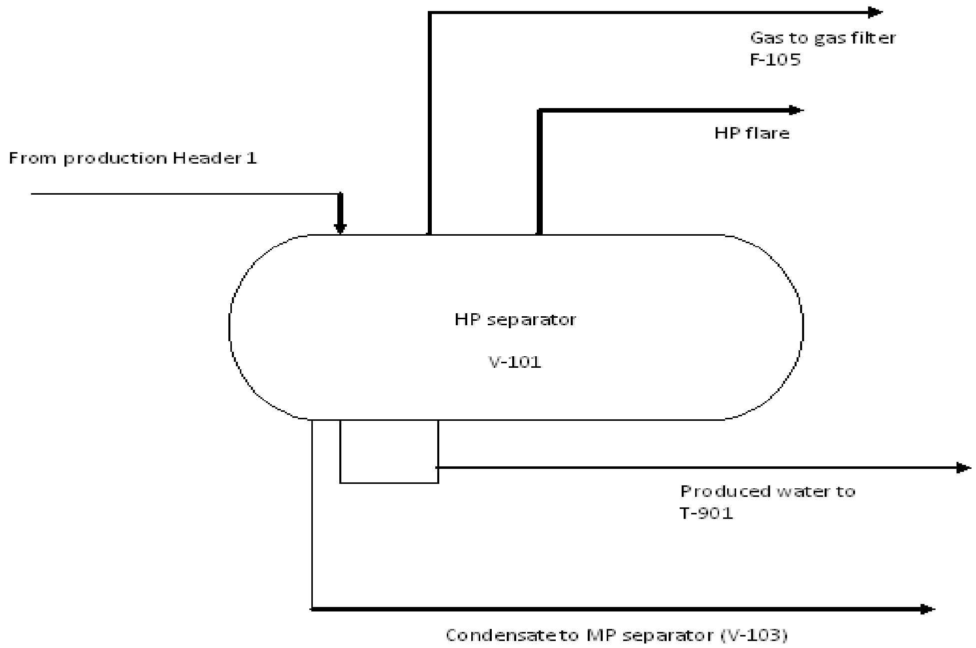

Figure: Flow Arrangements of High Pressure Separator (V-101)

The inlet separation system in MBGP is designed to separate produced water and condensate from the process gas before it passes to the Gas Dehydration System. The HP Separators are horizontal three-phase separator vessels that separate bulk liquid from the process gas. The liquid produced in the HP separators is separated into water boot and oil compartment and passed to either the Produced Water Tanks or the Condensate Stabilization system.

A demister pad is set vertically at top half of the cylindrical vessel for impingement of water and condensate vapor.

Gas Filter

After bulk liquid separation, the Gas Filter Separator (F-105) further separates any water mist or droplets from the gas stream. This uses a filter membrane to coalesce drops from the gas stream. From the filter separator, the water-saturated gas is passed to the Glycol Contactor. Gases from the HP separators pass through the gas filter separator to remove fine particles and liquid droplets.

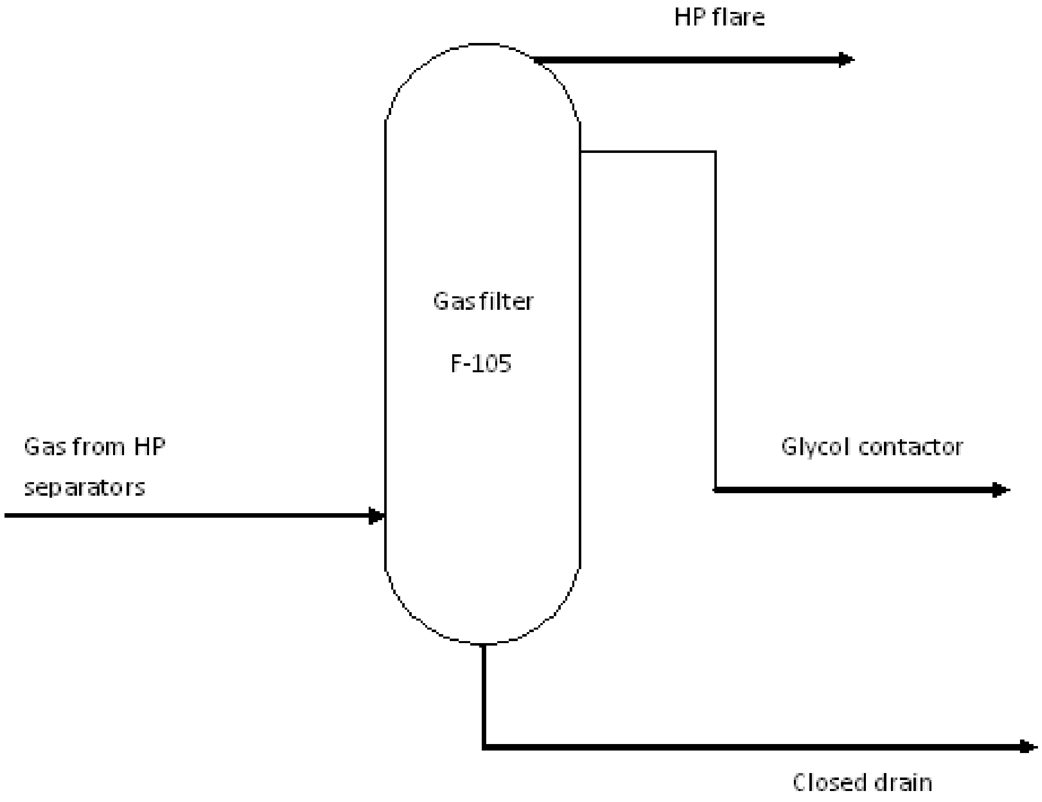

Figure: Flow Arrangements of Gas Filter

Lean glycol enters at the top of the Glycol Contactor after passing through the Gas/Glycol Heat Exchanger. The exchanger lowers the temperature of the lean glycol stream to reduce the carry over losses and reduces possible foaming problems. The glycol flows down through the tower where it contacts the gas in the packing. After contacting the gas, the lean glycol becomes rich with water and falls on the bottom of the tower, where it flows out of the contactor to the regeneration skid when a set level is obtained.

Condensate Storage

The purpose of condensate storage is to provide complete stabilization of the produced condensate and storage of the condensate for export. Two condensate storage tanks receive and store condensate from the MP separator. Stabilization of the condensate to atmospheric pressure occurs in the storage tanks.

Condensate from the HP separator passes to the MP separator where it is flashed to 65 psig from where it passes into the condensate storage tanks T-110 and T-111. The condensate tank being filled is selected manually by altering the valves on the common inlet header of the two tanks. The condensate level in the storage tanks may be read locally or on the control system. There are high and low alarms on the level indication. Each tank has a high level trip which causes a plant process shutdown.

Both condensate storage tanks are gas blanketed to exclude oxygen thereby preventing the build up of an ignitable atmosphere within the tank. The blanket gas is supplied via the tank flare header, which connects the condensate storage tanks to the tank flare header, which connects the condensate storage tanks to the tank flare to allow disposal of evolved hydrocarbon gasses. The tanks are provided with subsurface foam injection from the foam package. The tanks inlet and outlet nozzles are provided with stainless steel bellows to accommodate tank movements. The tanks are also provided with lightening protection.

Condensate from storage is loaded into road tankers using the condensate pumps P-110/111. The pumps are controlled manually.

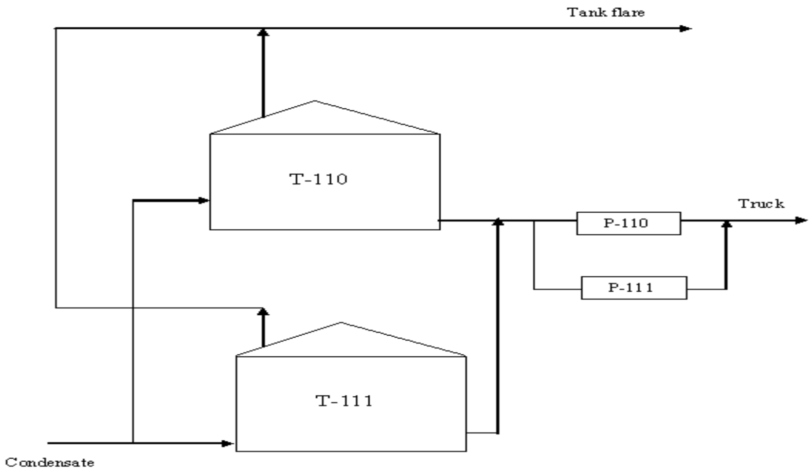

Figure: Flow Arrangements of Condensate Storage Tanks

Flare System

The purpose of the flare system is to safely dispose of relieved gas from pressure safety valves and from manual and automatic blow down operations. The purpose of the flare knock out drum is to remove droplets larger than 600µm from the relieved gases before it passes to the flare stack. The flare knock out drum also acts as a receiver for the closed drain system, which is connected to it. Gases evolved from the draining will go to flare whilst liquid will be pumped away by pump. The HP flare is sized to dispose 182 mmscfd of vented gas. Included in the flare package is the flare stack, tip, seal, pilot burners and ignition panel.

The HP flare KO drum pump is a centrifugal pump. Its purpose is to pump away separated and drained liquids from the HP flare KO drum into the condensate tanks. In case of malfunction of this pump there are connections upstream and downstream of it for connection of a portable pump. Relieved gas enters the flare header from the PSV or blow down valve. It flows to the flare knock out drum where any entrained liquid droplets are separated by gravity, before passing on to the flare stack. Gas travels up the flare stack and is ignited either by the pilot lights or by the flame already in existence at the flare tip. The pilots are supplied with fuel gas and always keep burning. The pilots are ignited and monitoreusing the flare ignition panel.

Tank Flare

The purpose of the tank flare is to dispose of any gasses evolved in any of the condensate storage tanks. The produced water storage tanks are connected to this flare system to prevent air ingress inside the tanks which gives rise to corrosion. Tank flare includes air assist fan and flare pilot ignition package.

All four storage tanks at the Moulavi Bazar gas plant are blanketed with fuel gas and connected to the tank flare by a common header. The tank flare header is constantly purged by fuel gas, this ensures that the flare header itself remains oxygen free and that the storage tanks are always blanketed with gas to prevent ingress of oxygen and subsequent production of an ignitable mixture and giving rise to corrosion problems.

The tank flare has a combustion air assist fan, delivering air to the flare tip to ensure smokeless operation, as heavier hydrocarbons are likely to be evolved from the condensate storage tanks. Gas evolved in the condensate storage tanks are disposed of in the tank flare. This is because of some flashing of the condensate passing from the MP separator at 65psig to the storage tank at almost atmospheric pressure.

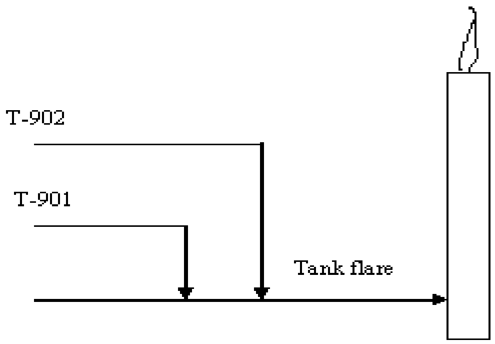

Figure: Flow Arrangements of Tank Flare System

The two air compressors act in lead and lag mode with the lead and lag compressors being selectable by the operator. The air compressor turn on in response to pressure switches, the lead compressor turning on at around 125psig, the lag compressor turning on at around 115psig, both turn off at 135psig. Compressed air passes from the compressors to the wet air receiver where entrained water is knocked out. The water in the wet air receiver is automatically drained to the floor pan under the air compression system. The wet air is passes through the prefilters which also drain automatically to the floor pan. Following the prefilters the air stream then splits between utility air and instrument air. The utility air stream exits the compressor into the desiccant air driver. The desiccant air driver removes moisture to a dew point of -40°C by adsorption process. Two vessels containing desiccant are installed. They operate alternately on-stream or regenerating. Regeneration is achieved by depressurization of the desiccant bed sweeping adsorbed moisture out. The dry air then passes to the instrument air receiver then to the plant instrument air headers

Drain System

The closed drain system collects the drained hydrocarbon from the pressurized vessels and directs them to the flare knock out drum. The liquid from the knock out drum is pumped to the condensate storage tanks. The system consists of manual drain valves and piping connected to closed drain header. All the drain valves are CSC to prevent accidental drain of pressurized equipment. To drain a pressure vessel or piping, the system has to be depressurized to the flare first to reduce the pressure to near atmospheric, then only the drain valves can be operated.

The drains from the condensate storage tanks and condensate from the dirty produced water tank is routed to the open drain system. Surface water from different parts of the plant with potential hydrocarbon contamination will be sent to the underground API separator.

The open drain system consists of the underground drain tank, API separator, water pump, slop oil pump, skimmed oil pump and all the piping and valves. The drain tank is provided with vertical baffles to separate hydrocarbon liquids from the water. The hydrocarbon liquid overflows the internal baffle into an oil compartment, from which is pumped by P-411 to the condensate tank. There is a level transmitter in this compartment, which starts and stops the pump. The separated water underflows an internal baffle into water compartment from

TEG
DEHYDRATION
PROCESS
DESCRIPTION

Dehydration

Dehydration is the process of removing water from a gas and/or liquid so that no condensed water is present in the system. Dehydration is generally preferred, if economically feasible, because it prevents water from condensing in the system.

Importance of Dehydration

- To meet sales outlet gas specification
  (Maximum 7 lb_m/mmscf specified by Petrobangla)
- Excessive water can lead to pipe corrosion and hydrate formation

Different Ways of Dehydration

Natural gas is commercially dehydrated in one of three ways.

1. Absorption
2. Adsorption
3. Condensation

Glycol dehydration is the most common dehydration process used to meet pipeline sales specifications and field requirements. Adsorption processes are used to obtain very low water contents. Condensation process is commonly used as a dehydration process when moderate levels of refrigeration are employed or in pipeline transportation.

Absorption is done by using Glycol solutions as absorbent. Adsorption is carried out by Molecular sieve, Silica Gel or activated alumina. Refrigeration with Glycol or Methanol injection leads to Condensation process.

MBGP follows TEG glycol dehydration process which is carried out by a Glycol Contactor (absorber) of capacity 150 mmscfd.

Selection Criteria of Glycols

- Hygroscopic (affinity to water)
- Noncorrosive
- Non volatile
- Easy regeneration to high concentration
- Insoluble in liquid HC
- Unreactive with HC,CO_2 & S compounds

Types of Glycols

1. MEG (Mono Ethylene Glycol)
2. DEG (Di Ethylene Glycol)
3. TEG (Tri Ethylene Glycol)
4. TREG (Tetra Ethylene Glycol)

TEG is the most common glycol used in absorption systems. MEG is most common glycol which is injected. All glycols are hygroscopic, which means that they have affinity for water. In MBGP TEG is used.

Advantages of TEG Over Other Glycols

- High thermal stability, decomposition temperature is 404 F
- Could be regenerated easily
- Less carry over loss
- Moderate cost

DEG is cheaper and it works as inhibitor as well as absorbent. But compared to TEG, it has more carry over losses due to lower dew point depression. Besides, its regeneration to higher concentration is very difficult.

TEG has less carry over losses but it is more expensive and viscous.
In recent years some of the units have employed propylene glycol (PG). PG is the least toxic glycol and has a lower affinity for aromatics, but PG has a much higher vapor pressure than TEG and a much lower flash point.

Basic Glycol Dehydration Unit

Contactor

MBGP is using a glycol contactor for gas dehydration. It applies the principles of absorption. Where raw gas is charged at the bottom of the vessel and liquid absorbent is sprayed at the top. Contact between the gas and liquid occurs at trays or packing, where water is absorbed by the absorbent. Lean glycol absorbs water and become rich solution with water. TEG is valuable, thus it must be recovered.

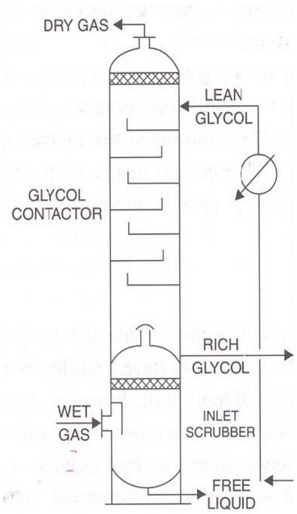

Figure: Simplified flow diagrams for a glycol dehydration unit

Regeneration skid

Regeneration skid consists of many types of equipment which helps to regenerate lean solution from rich solution. They are-

- Three way valve
- Flash tank
- Particulate filters
- Charcoal filter
- Glycol/Glycol heat exchanger
- Reboiler with still column
- Accumulator
- Glycol circulation pump
- Fuel gas scrubber

Process Description of Gas Dehydration

Glycol Contactor

Raw gas enters the contactor at bottom after it passes through the HP separators and Filter separator. The gas flows upward through the tower inlet nozzle where it is contacted by lean tri-ethylene glycol while passing through structured packing. The glycol absorbs most of the water that is entrained in the process gas. The process gas then flows through the Gas/Glycol heat exchanger where it undergoes countercurrent heat exchange with lean glycol entering the contactor. After passing through the heat exchanger, the gas then flows through the sales gas meter run.

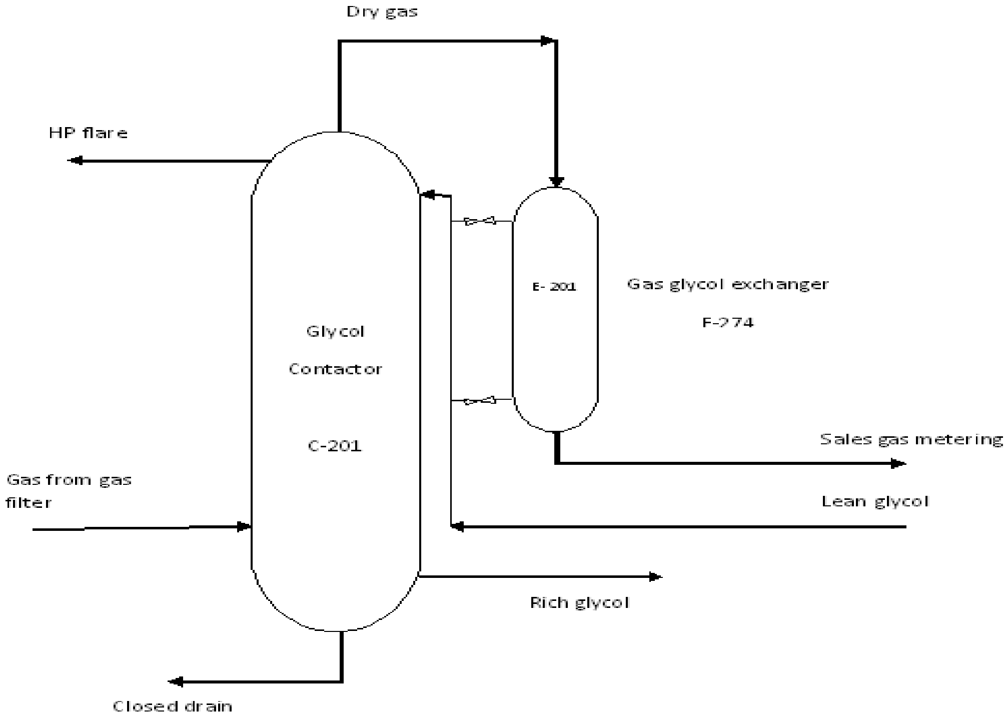

Figure: Process Flow Diagram of Glycol Contactor with a Single Pass Shell & Tube Gas/Glycol Heat Exchanger

Lean glycol enters at the top of the Glycol Contactor after passing through the Gas/Glycol Heat Exchanger. The exchanger lowers the temperature of the lean glycol stream to reduce the carry over losses and reduces possible foaming problems. The glycol flows down through the tower where it contacts the gas in the packing. After contacting the gas, the lean glycol becomes rich with water and falls on the bottom of the tower, where it flows out of the contactor to the regeneration skid when a set level is obtained.

Regeneration Skid

Rich glycol from glycol contactor is sent to the TCV, if the temperature is above 255 F it is directly sent to the flash tank of the regeneration skid; otherwise it flows through the coil in the top of the still column, where it is heated before entering flash tank (V-271). In the flash tank absorbed hydrocarbons in the glycol are flashed off and burned as fuel gas in the reboiler. The rich glycol then flows under level control through the particulate filters A and B and the Charcoal filter where contaminants are removed and hydrocarbon liquids are absorbed. After filtration, the rich glycol flows through the Glycol/Glycol heat exchanger (Plate and Frame Type), where it is partially heated up from the Lean Glycol solution. It is then fed to the reboiler for regeneration. In the reboiler the rich glycol enters the still column and flows down to the main body of the reboiler where additional hydrocarbons and water are boiled off to regenerate lean glycol. Next the glycol flows into the stripping column where dry NG is bubbled through the packed bed of the column to enable the glycol purity to 99.7%. Then the glycol stream flows into the accumulator and is then pumped back to the contactor by a reciprocating pump through the Gas/Glycol heat exchanger.

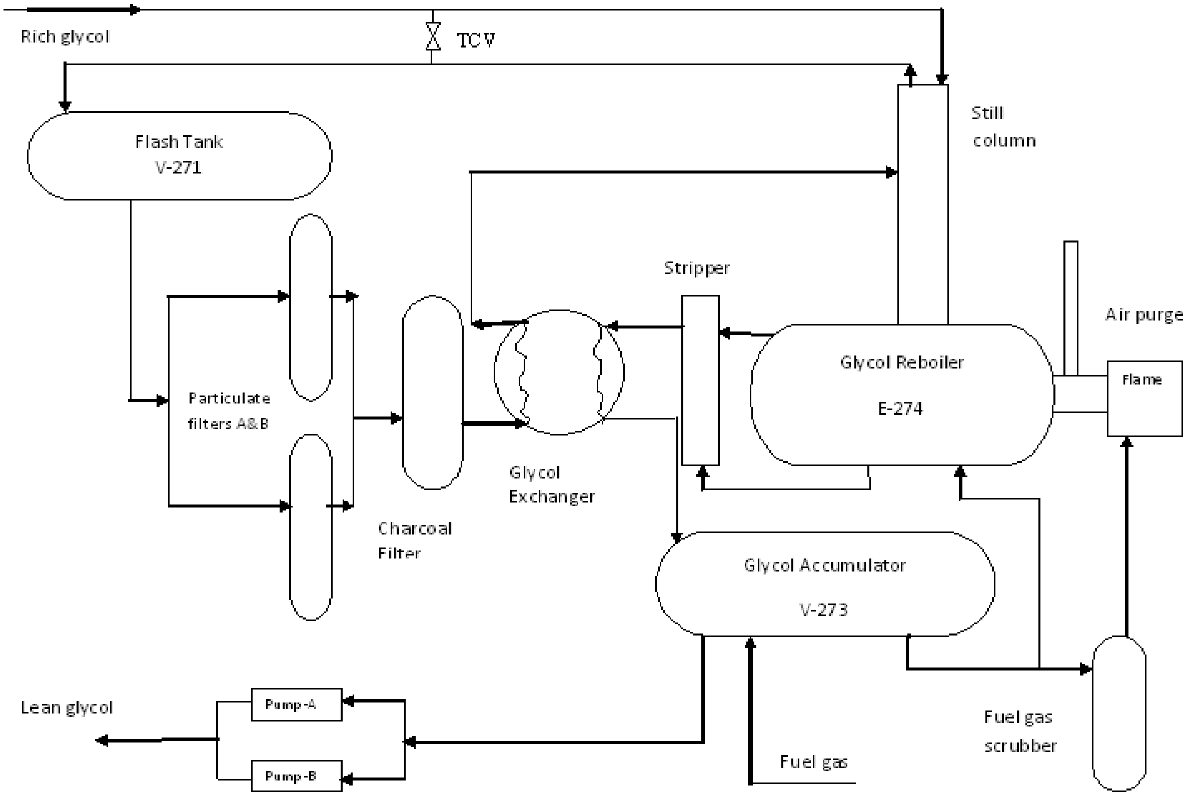

Figure: PFD of Glycol Regeneration Skid

Major Equipments in the Regeneration Skid

The purpose and functions of the equipments involved with the regeneration skid is discussed below:

Reboiler

Heat input to the regenerator is provided in the reboiler. The heat source is usually direct fired with the fire tubes immersed in a glycol bath. Other heat sources include hot oil, steam or electric resistance heating.

In any event, the temperature of the glycol in the reboiler must not exceed 204°C (400°F) due to the degradation of TEG at higher temperatures. However, in order to maintain the glycol bath at a temperature slightly below 204°C, it is necessary to maintain the heat transfer surface at a temperature above this value. MBGP has fired tube reboiler which uses dry gas as fuel and its flux rate is 6000Btu/hr-ft^2.

The reboiler duty depends on

- TEG circulation rate
- The efficiency of the rich-lean TEG exchanger
- The reflux ratio
- Stripping gas rates
- Effectiveness of the insulation

The reboiler duty should always be sized based on circulation pump capacity, not the expected circulation rates.

Still Column

The still column is the fractional portion of the regenerator. The column is packed or trayed. MBGP has structured packed still column. The still column is sized based on standard packed tower sizing correlations. The reflux rate should be minimum required to maintain the still over head temperature at the boiling point of water for the partial pressure of water at the top of the regenerator. Reflux is normally supplied by using the rich glycol stream circulating through a condensing coil inserted in the top of the still column. Using the rich glycol stream is the preferred method for cost, simplicity and energy efficiency.

Rich/Lean Glycol Heat Exchanger

This is a basic heat exchanger. Its efficiency has a direct effect on reboiler heat load. In MBGP, we are using a plate type cross flow heat exchanger. Plate type heat exchangers are preferred, as they are more compact, lighter and cheaper. They are, however, susceptible to plugging and fouling if the rich glycol is not well filtered.

Lean Glycol Cooler

A final glycol cooler is required so that the lean glycol entering the top of the contactor is cooled to within 5-10°C of the gas entering the top tray. Otherwise gas at the top will gain heat and its saturation capacity will increase and it will escape from the contactor with some excess water. MBGP is using a Shell and Tube heat exchanger as a lean glycol cooler. Lean solution is passed through a spiral tube and gas is passed through the shell side.

Particulate filters

Two particulate filters are connected in parallel, one leading and other lagging, downstream of the flash tank to filter out foreign materials, dirt. Good filtration is critical; the full flow type is preferred. A cloth fabric element that is capable of reducing solids to about 100 ppm by weight is preferred. Filter size in properly designed filtration system should be 5-10 µm. removal of solids reduces corrosion, plugging and deposits in the reboiler, heat exchanger and increases overall

Design of Glycol Contactor

The design of the contactor depends on two parameters:

- Gas rate which determines the contactor diameter, and
- Number of contacts, which determine the contactor height

Contactor Internals

Two types of internals are used in glycol contactor

- Trays (usually bubble cap)

- Packing (usually structured)

The internal of the glycol contactor C-201 is structured packing

Advantages Packing Internals

- Lower pressure drop

- Can be manufactured from various materials- metallic, ceramic, plastic

- More adaptable to corrosive environments

- Less subject to packing

- Less liquid hold up in tower

Liquid distributor is required in tall towers

Advantages Structured Packing

Structured packing is preferred over random packing because of its

- higher capacity

- better turndown

- superior performance at low liquid rates

Factors Determining Amount of Water Removal

1. Lean glycol concentration
2. Glycol circulation rate
3. Number of contacts in contactor

CONTROL SYSTEM

Control Objective and Concepts

The objective of a control system is to prevent deviation of a process variable from a standard. To accomplish this objective the control system manipulates an energy or material balance. This balance can be summarized in the equation:

$$\text{In} - \text{Out} = \text{Accumulation}$$

The controlled variable is usually the accumulation term e.g., level, pressure, temperature etc. During transient or unsteady state condition In ≠ Out and the accumulation variable changing.

Several factors affect the ultimate control system selected to accomplish the control objective. These include:

1. Nature of the response of the controlled variable for a given change of the manipulated variable.
2. Control stability conditions.
3. Importance of maintaining controlled variable at constant value.
4. System cost and complexity.
5. Penalties incurred due to poor control.

Valve Petitioners:

The basic mechanism for using a valve positioner or volume booste is:

1. When a split is required.
2. When a maximum loading pressure greater then the instrument signal is required.
3. When the best positive control is desired for certain systems i.e., minimum overshoot and the fastest recovery from disturbances.

Level measurement and control

Measurement and control of liquid level is an integral part of both plant and field processing. A number mechanism is used. Those prevalent in oil and gas production and processing are:

1. Mechanical or pneumatic operated calce actuaed by a float
2. Control valve actuated by a Dpcell.
3. Control valve actuated by a displacement “float”.

Pressure Regulation and Control:

All pressure regulators are similar in principle, the specification of type being depend on the process requirements, pressure drop, variation flow rate, limitation of the loading device, and the maximum pressure . In either of these services pressure is regulated by of control of flow rate.

There are three major pressure control applications:

1. Pressure protection of equipment .
2. Control of pressure as part of the control of phase and fluid composition specification.
3. Letdown of pressure to control of the pressure or flow of the fluid to the next equipment module, e.g., fuel gas or compression pressure suction

SAFETY

Safety is the term consisting of some precautionary measures that are observed by people at the of performing a job inside the plant with the help of some machine or equipment designed in such manner that can check the accident to be happened with an ultimate view to achieve the possible higher productivity.
Safety is the condition of being safe; freedom from danger, risk or injury.

Responsibility of safety

The head of the establishment is ultimately responsible for safety. However, as he cannot check everything personally, the supervisory personnel are also held responsible. So safety is everyone's job.

a. Responsibility of the management:
   - Giving the necessary instructions.
   - Taking the necessary actions.
   - Providing the necessary means.
   - Maintaining the necessary supervision.

b. Responsibility of the employees are:

   - To obey safety rules.
   - To use the safety facilities provided by the authority.

Accident

An accident is an unintentional event resulting from an unsafe act or unsafe situation. In other words industrial accidents are end product of unsafe act and unsafe condition. Industrial accidents may be divided in two general classes:

a. Machinery accident: This type of accident is caused by inadequate safeguards of machines.
b. Non machinery accident is caused due to personal reasons such as age, physical weakness, inexperience and carelessness or for the plant conditions.

Causes of industrial accidents

There are several causes leading to industrial accidents. A single or more causes cumulatively may lead to industrial accidents. The causes can be studied in the following manner.

1. Unsafe condition

    - Effective tools
    - Congestion of work place
    - In adequate warning system
    - Fire and explosion hazards
    - Poor house keeping
    - Excessive noise
    - Poor ventilation
    - Ergonomics
    - Radiation explore
    - Inadequate support or guard
    - Chemical hazard
    - Electrical hazard
    - Mechanical hazard
    - Ionization hazard

2. Unsafe acts

    - Operating at improper speed
    - Using defective equipment
    - Making safety device inoperable
    - Failure to ware personal protective equipment
    - Operating without authority
    - Using equipment improperly
    - Use of alcoholic beverages
    - Use of drugs

Safety management

- T-Card system.
- OMS standard
    - Emergency /Drills
    - Locate and read emergency response station bill
    - Locate your master point
    - Recognize the emergency alarm sound
- Personal protective equipment (PPE)
- Locate and read the genera safety rules
- Work permit, lock out or tag out system
- Hazard identification / near miss incident reporting system
- Hazards and precautions

    Hydrocarbons – pressure, flammability / fire / explosion, toxicity
    - Chemical
    - Electrical
    - Noise
    - Working at height

- ➢ Vehicles using/ speed limit with in gas plant area
- ➢ Smoking / non smoking areas
- ➢ Attend general safety meeting whenever possible
- ➢ Participate on good housekeeping

Personal protective equipment (PPE)

Personal protective equipment (PPE) means all equipment (including clothing affording protection against weather) which is intended to be worn or held by a personal at work and protects him against one or more risks to his health.

Purpose of PPE

- To protect the people on working place
- To maintain safe operation of the plant
- To reduce the accidents
- To enhance the awareness of process safety

Equipments:

PPE can be divided into the following classes-

1. Head protective equipment :
    a. Hard hat
    b. Welding helmet
2. Eye protective equipment:
    a. Safety glasses
    b. Safety goggles
    c. Face shield
    d. Gas welding goggles
3. Ear protective equipment :
    a. Ear plugs
    b. Ear defender
    c. Thermal suit
4. Respiratory protective equipment :
    a. Dust mask
    b. Half face mask
    c. Full face mask
5. Hand protective equipment
    a. Riggers gloves
    b. Thermal gloves
    c. Latex gauntlets
6. Foot protective equipment
    a. Safety shoes
    b. Safety boots
    c. Welding boots
7. Skin protective equipment
    a. Boiler suit
    b. PVC wet suit
    c. Thermal suit

Fire Fighting System

The purpose of the fire fighting system at Titas gas field is to protect people and the asset in the event of potential of a fire or a fire in the plant, apply cooling to tanks or vessels or equipment subject to flame impingement of radiant heat resulting from a fire. The fire water system consists of two diesel driven pumps, which supply an underground ring main.

The underground ring main encircles most of the plant to provide firewater to four monitors and three foam/water hose reel sets. The monitors are positioned to allow coverage of the storage tanks and major equipment on the plant including. The foam/water hose reel sets are placed primarily to provide coverage of the tank bund areas to provide foam cover for spills if required.

The firewater main is normally pressurized to 80psig by the utility pumps. The main firewater pumps are activated manually or pressure switch detection when the ring main pressure falls below the specified pressure. The firewater pump are diesel engine driven and are started by air. Each firewater pump is run for a minimum of 15 minutes once a week to prove the function of the system, which is achieved via the test line allowing the firewater to return to the tank.

Commissioning and start up safety

During start -up be prepared for hazards not encountered in a normal operating facility. Be prepared by anticipating and knowing the effects of your actions, by insisting on good housekeeping and being familiar with and using protective gear where required.

Hazards may be encountered when performing any of the following activities.

Charging chemicals

- Check equipment into which chemical is to be charged.
- Wear protective gear as required for the chemical to be handled.
- Keep others away – post warning signs
- If chemical is unloaded from a truck, check unloading connections for tightness and ensure grounding cable is connected
- Be familiar with the location and operation of the nearest safety shower, check to ensure the safety shower is working.

Purging

- The plant is purged and then pressurized with hydrocarbon gas.
- Smoking must be prohibited in the plant before purging commences.
- All sources of ignition such as open fires, welding, vehicles and cellular telephones must either not be allowed or must either not be allowed or must be tightly controlled.
- Access to areas where purging takes place must be restricted to essential personnel.
- The fare pilots must be lit when purging.
- Initial purging must be done at atmospheric pressure.
- Purge each line separately and keep track of purged lines by color coding on the p&IDs

Operating & maintenance safety

Think

Safety is to a large extent common sense. Before doing anything, think about whatyou are going to do. Plan every step before doing it, plan what to do, where to do it , how to do it . Think of the possible consequences and be prepared for them if they happen.

Safety and fire equipment

All personnel should be familiar with the location of safety equipment and portable fire extinguishers and should be completely familiar with their proper usage and application to different types of fire.

Preparation for Maintenance

- Before work on equipment, vessels or popping is attempted, the item must be isolated, depressurized and purged.
- Wear ear protection when noise levels are high. use proper tools.

- Use correct tools and equipment and qualified personnel for the particular job at hand.

Test before proceeding

- Use test equipment before proceeding. use snifters or voltmeters to detect gases or live electrical circuits, respectively.

Ground equipment

- Ground all equipment before using it. This includes loading trucks.

Use correct protection

- Use correct fuses, breakers and relief valves.

Keep out of restricted area

- The flare stack area is restricted and fences. Personnel should keep away from this area unless permitted.

Tag valves, switchers or levers.

- Tag valves, switchers or levers that closed temporarily for protection.

Check before re-starting

- Do a careful visual check of equipment for any tools or omissions before re-starting after maintenance.

Follow instructions

- Follow all safety operating procedures listed in individual equipment manuals.

Good house keeping

- Good house keeping is a basic part of accident and fire prevention.
- Keep the plant clean and tidy.
- Floors, stairs,p;atforms and steps should be kept clean and free of rools and othe loose material. Care should be taken to keep the working area orderly during repair jobs or during commissioning work.
- Oil spills must be cleaned up immediately and only approved solvents used for cleaning-never gasoline.

Protection and first aid

- Wear chemical and protective gear when handling methanol.
- In case of skin or eye contact, wash with plenty of water.
- Do not step into spills, clean them up immediately.

Safe work practices

- Stop work and report leaks immediately
- Eliminate sources of ignition use Hot work procedures
- Ensure equipment for gas detection and explosibility is tested and calibrated before use.
- Extinguish gas fires by stopping flow of gas.

CALCULATION

Material Balance for Condensate Separator Section

The general material balance equation is:

Input Output Rate of Rate of rate of
flow rate – flow rate + generation – consumption = accumulation)

Since no reaction occurs in the process, rate of generation & rate of consumption will be zero in above equation.

Also since the process is continuous, so the rate of accumulation will be zero.
Hence for gas processing above equation reduced to,

Input flow rate – output flow rate = 0

Or,Input flow rate = Output flow rate

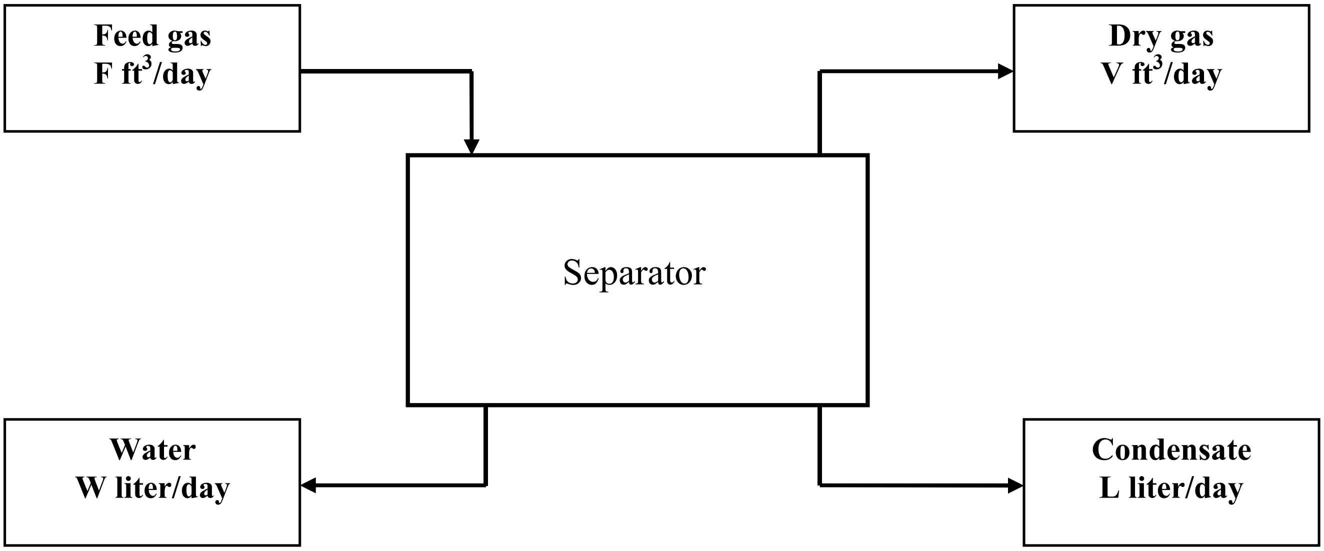

Figure: Schematic view of separation

Overall balance: $F = V + L$
For each component: $Fz_i = Vy_i + Lx_i$

Where , F= total moles of feed / day
V= total moles of gas leves the separator/day
L= toal moles of condensate separate / day
z_i= mole fraction of i component in feed stream
yi= mole fraction of i component in the outlet gas stream
x_i=moles of i component in condensate

Basis:

Feed rate 24 MMscf/D (for Titas well #5)

Feed condition: Temperature = 120^0F
Pressure = 1860 psig

Outlet gas condition: Temperature = 98^0F
Pressure = 1000 psig

We know from the state equation of gas,

$$P_iV_i/ T_i = P_oV_o/ T_o$$

Where suffix 'i' & 'o' indicate the input & output condition respectively.

Hence we get the flow rate of gas leaving the separator,

$$\begin{aligned} V_o &= P_iV_iT_o/ T_iP_o \\ &= (1860\times24\times98)/ (120\times1000) \\ &= 36.6\times10^6 \text{ MMscf/D} \end{aligned}$$

Hence, outlet gas flow rate from separator, $V = 36.6\times10^6$ MMscf/D

We have the following data for material balance,

Well Head Gas Composition

Component	Mole %
Nitrogen (N_2)	0.40
Sulfur (S)	0.00
Carbon dioxide (CO_2)	0.44
Methane (CH_4)	95.07
Ethane (C_2H_6)	2.79
Propane (C_3H_8)	0.73207
Butane (C_4H_{10})	0.3203
Pentane (C_5H_{12})	0.107
Hexane (C_6H_{14})	0.0276
Heptane (C_7H_{16})	0.0504
Octane (C_8h_{18})	0.055

Gas Composition Of Gas Leaving The Separator

Component	Mole %
Nitrogen (N_2)	0.40
Sulfur (S)	0.00
Carbon dioxide (CO_2)	0.44
Methane (CH_4)	96.483
Ethane (C_2H_6)	1.83
Propane (C_3H_8)	0.48
Butane (C_4H_{10})	0.21
Pentane (C_5H_{12})	0.07
Hexane (C_6H_{14})	0.018
Heptane (C_7H_{16})	0.033
Octane (C_8h_{18})	0.036

ter

Condensate Composition

Component	Mole %
Ethane (C_2H_6)	2.7
Propane (C_3H_8)	9.34
Butane (C_4H_{10})	8.22
Pentane (C_5H_{12})	34.52
Hexane (C_6H_{14})	21.32
Heptane (C_7H_{16})	17.63
Octane (C_8h_{18})	6.27

Calculation:

Material balance on pentane,

$$24\times10^{6}\times0.107 = V\times0.07 + L\times34.52$$

$$2.568\times10^{6} = 0.07V + 34.52L \ldots\ldots\ldots\ldots\ldots\ldots \quad (1)$$

Now balance on Hexane,

$$24\times10^{6}\times0.0276 = V\times0.018 + L\times21.32$$

$$0.6624\times10^{6} = 0.018V + 21.32L \ldots\ldots\ldots\ldots\ldots\ldots(2)$$

From equation (1) we have,

$$V= 36.6857 \times 10^{6} - 493.143L$$

Substituting value of V in equation (2),

$$0.6624\times10^{6} =0.018\times(36.6857\times10^{6}- 493.143L) + 21.32L$$

Or, $0.6624\times10^{6} = 0.660343\times10^{6} - 8.8765L + 21.32L$

Or, $12.44L = 2057$

Or, $L = 165.3ft^{3}/D = 4.68m^{3} /D= 4680.8L/D$

Water separation calculation

$= (183.31 - 25)$ lb/ MMscf ×24MMscf/ D

$= 3799.2$lb/D

$= 1723.3$L/D

$= 1.723m^{3}/D$

$= 60.83\ ft^{3}/D$

Amount of water separated= $60.83\ ft^{3}/D$

What glycol circulation rate (m^3/h [gpm]) would you recommend for a contactor operating at the following condition?

Contactor temperature= 80^0F
Contactor pressure= 500 psia
Dew point specification= -22^0F
Gas volume= 91 MMscf/d
Glycol concentration= 99.9%

Solution:

From the water content chart (Fig 1), the water content of the inlet gas & outlet gas are:

W_{in} at 80^0F and 500 psia = 56 lb/MMscf

W_{out} at -22^0F and 500 psia = 1.2 lb/MMscf

Water removed = (56 – 1.2) = 54.8 lb/MMscf

Water removed per hour = (54.8 lb/MMscf) (91 MMscf/day) (1day/24 hours)
= 208 lb H_2O/hr

$\Delta W/W = 54.8/56 = 0.979$

From Fig 2:
At $\Delta W/W = 0.979$ and TEG concentration = 99.9%,

The TEG circulation rate required is: 16 liters TEG/kg H_2O removed.

Actual circulation rate in gpm:

$$\left(\frac{1.8\ gal\ glycol}{lb\ H_2O\ removed}\right)\left(\frac{208\ lb\ H_2O}{hour}\right)\left(\frac{1\ hour}{60\ min}\right) = 6.2\ gpm$$

Blow Down & Purge:

Occasions occur when it is necessary to blow down & purge a gas line. This is a special case of unsteady state flow.
One may estimate the blow down time by some simple equations.
For the critical flow case (when the ratio of the higher pressure to lower pressure is larger than two):

$$t = \left(\frac{BV}{C_d A_v}\right)\left(\frac{\gamma}{zT}\right)^{0.5} \ln\left(\frac{P_1}{P_2}\right)$$

Notation	**SI**	**FPS**
t= Blowdown time	S	Sec
B= Constant	0.09	5.3
V= Actual system volume	m^3	ft^3
C_d= Valve discharge coefficient	-	-
A_v= Blowdown valve area	m^2	in^2
γ= Gas specific gravity	-	-
z= Average gas compressibility factor	-	-
T= Average gas temperature	K	^{0}R
P_1= Initial system pressure	Kpa	Psia
P_2= Final system pressure	kpa	psia

Thermodynamic description of Joule-Thompson Process:

Consider a sample of gas initially at P_1, V_1 and T_1 was forced into a system at constant pressure P_1. The gas came out of the system at P_2, V_2 and T_2. The system is insulated such that Δq=0. The work has two terms, work done on the system to force the gas through the system and the work done by the system on the surroundings as it came out the other side of the plug.
The total work is:

$$w = -P_1(0 - V_1) - P_2(V_2 - 0)$$

$$= P_1V_1 - P_2V_2$$

Since Δq =0, the change in internal energy of the gas is, ΔU= Δq+w

$$= 0 + P_1V_1 - P_2V_2$$

$$= P_1V_1 - P_2V_2$$

The enthalpy is then given by,

$\Delta H= \Delta U+\Delta (PV)= P_1V_1-P_2V_2 +P_2V_2- P_1V_1= 0$

So Joule-Thompson's effect (Throttling process) is a constant enthalpy process.

Co-efficient of Joule-Thompson's effect, μ_{JT} can be defined as,

$$\mu_{JT} = \left(\frac{\partial T}{\partial P}\right)_H$$

$$\Rightarrow \left(\frac{\partial T}{\partial P}\right)_H = -\frac{\left(\frac{\partial H}{\partial P}\right)_T}{\left(\frac{\partial H}{\partial T}\right)_P}$$

$$\Rightarrow \mu_{JT} = -\frac{\left(\frac{\partial H}{\partial P}\right)_T}{c_P}$$

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