# SOUR GAS PROCESSING

## in ONGC Hazira
## & in two complexes abroad

BY


# SAMIR MAITI

# What is sour gas ?

**Ans :**

Sour gas is natural gas or any other gas containing significant amounts of Hydrogen sulfide ($H_2S$).

Generally, natural gas that contains more than 4 ppm (by volume) of Hydrogen Sulphide ($H_2S$) is commonly referred to as "sour gas”.

**Why do need to remove $H_2S$ from the sour gas ?**

**Ans:**

- Because of safety, environmental or corrosion considerations, it is normally desirable to remove $H_2S$ from the sour gas.
- Sour gas, due to presence of $H_2S$ in it, causes corrosion of the equipment, piping etc.
- Sour gas, due to presence of $H_2S$ in it, also causes sulphide stress corrosion cracking, particularly in pipelines.

- Industries (which use natural gas as it's feed e.g. Fertilizer plants) use catalyst in it's processes. Presence of more than specified amount of sulfur compound will damage / spoil the performance of the catalyst.
- Sour gas production in oil pipelines can lead to the production of elemental sulfur, which in turn can lead to plugging of the tubing.

- $H_2S$ is highly toxic gas and can cause serious injury and death at relatively low concentrations. At higher concentrations the odour can no longer be detected by human beings and the inability of human beings to detect its presence is a major risk factor.

## 3 sour gas processing complexes to be discussed in this presentation:

- Oil & Natural Gas Corporation Ltd i.e ONGC's Hazira Gas Processing Complex in SURAT, GUJARAT , INDIA

- CHEVRON & PETRO CHINA's joint venture CDB project in Sichuan province, CHINA near Chengdu city.

- World famous KASHAGAN project developed as a joint venture by World famous organisations like ROYAL DUTCH SHELL, EXXON MOBIL, ENI, TOTAL, CNPC, INPEX etc near Atyrau city in KAZAKHSTAN


ONGC
making tomorrow brighter
OIL AND NATURAL GAS CORPORATION LIMITED
HAZIRA PLANT SURAT
सुरक्षा
ONGC 50

- Sour gas from these Offshore fields / platforms is transported in 2 trunk lines (of approximately 230 Kilometres each) from Arabian sea offshore to Hazira complex.

These trunk lines are:

- 42 ” sub sea trunk line from South Bassein
- 36” sub sea trunk line from Bombay High offshore

- A few subsea pipelines from Tapti Bassein, Panna Mukta field etc join the above trunk lines

**Main operation units in Hazira Gas Processing Complex (in short HGPC) are:**

- Gas Terminal with Slug catcher
- Sulfur Removal Unit or Gas Sweetening Unit (**GSU**)
- Gas Dehydration Unit (**GDU**)
- Dew Point Depression Unit (**DPD**)
- Sulfur Recovery Unit (**SRU**)
- Incinerator
- LPG recovery unit (**LPG**)
- Condensate Fractionation Unit (**CFU**)
- Kerosene Recovery Unit (**KRU**)

# Associated Units / Offsite are:

- Fuel gas system
- Flares
- Spheres for LPG, Propane
- Tank farm for Natural Gasoline Liquified (NGL), Naphtha, Superior Kerosene Oil (SKO), Aviation Turbine Fuel (ATF), High Speed Diesel (HSD), Heavies etc
- Road tankers loading
- Rail wagon / tankers loading
- Ship Tanker loading
- Liquid & Solid Sulfur handling and dispatch
- Caustic wash unit

# Utilities plants

- Raw water treatment  to supply service water, drinking water, make up water
- Air Compressors house for supplying plant air & Instrument air
- N2 plant and inert gas plant to supply inert / blanketing gas
- Boiler House to supply steam ---High Pressure (HP) steam, Medium Pressure (MP) steam and Low Pressure (LP steam)
- Fire water system
- Cooling water system
- Waste water treatment
- Produced water system
- Chemicals handling & injection system
- Electrical Co-generation plant for producing power & steam together

## Products of HGPC:

- Sweet natural gas to Gas Authority of India Ltd (GAIL) of it's 1730 Kms Hazira – Bijaypur - Jagdishpur (HBJ) trunk line and it's branches of 1600 Kms to supply gas to National Thermal Power Corporation (NTPC) , Indian Farmers Fertizers Co-operative Ltd (IFFCO), National Fertilisers Ltd (NFL), Indo Gulf Fertilizers, Tata Chemicals, Chambal Fertilizers etc

- Sweet lean gas to local consumers like KRIBHCO, Reliance (Hazira), ESSAR, L & T, Gujarat gas etc
- LPG to IOCL, BPCL & HPCL terminals here
- NGL
- Superior Kerosene Oil (SKO)
- Aviation Turbine Fuel (ATF)
- Naphtha
- High Speed Diesel (HSD)
- Heavy cut
- Sulfur as Sulfur pellet / bulk Sulfur

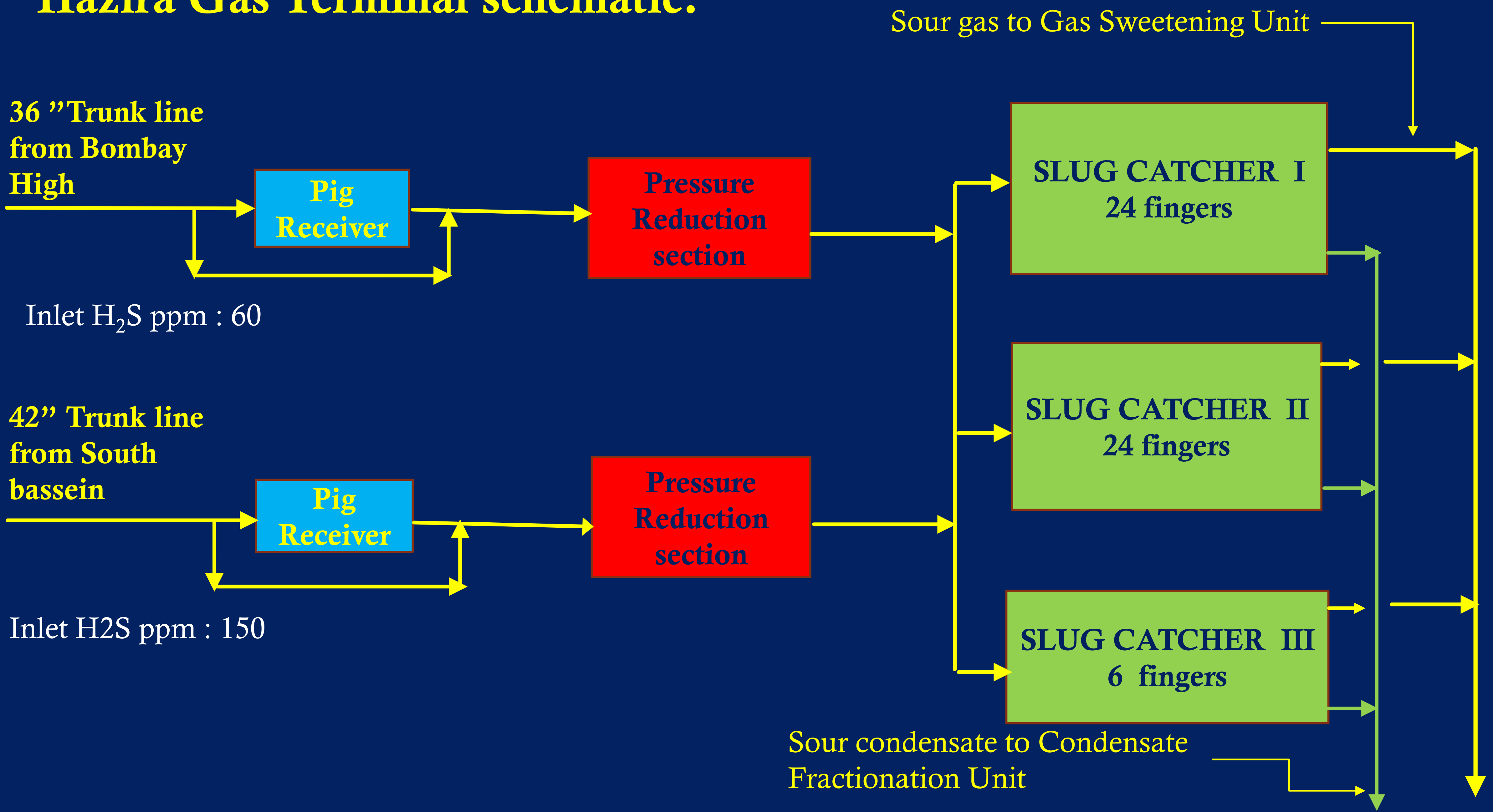
# Hazira Gas Terminal:

- Hazira terminal sour gas inlet pressure : Approx 62 $Kg/cm^2$ g
- Due to long distance travelling through sub sea Trunk lines, part of heavy hydrocarbon components in the gas gets condensed & flow along with gas.

**<u>What is slug ?</u>** A slug is a large quantity of gas or liquid that exits in the pipeline. Under certain operating conditions gas and liquid are not evenly distributed throughout the pipeline, but travel as large plugs with mostly liquids or mostly gases through the pipeline. These large plugs are called slugs.

- For this reason, HGPC has 3 Slug catchers at Gas Terminal.
- Slug Catcher separates gas & condensate and also store sour condensate here. Sour gas is sent to Sulfur Removal Unit and sour condensate is sent to Condensate Fractionation Unit.
- In Hazira, at present sour gas is processed approx 45 million standard cubic meter per day and approx 8000 m3 sour condensate per day.

# Hazira Gas Terminal schematic:



**In Hazira Gas Terminal schematic (in last presentation slide) :**

You can see,

- Sour gas coming in 36” Trunk line and 42” Trunk line, bypass pig receivers during normal operation, pressure is reduced to desired pressure and then enters into Slug catcher where gas & free liquid get separated.

- Slug Catchers are set of parallel pipe fingers of 48 inch diameter and approx. 500 in length. Pipes are mounted with two slopes first at 5% and second at 0.5% thus having separation & collection zone.

- Gas comes out through primary & secondary risers and sent to Gas sweetening unit.

- Liquid is stored in the lower part (at the fag end) of the Slug catcher.

- Total liquid storage capacity is approx 25000 m3 there. Sour condensate is sent to Condensate fractionation unit at specified rate for further processing.

View of a typical (not HGPC) Slug Catcher

## In a typical Slug Catcher schematic (in last presentation slide) :

We can see

- Inlet gas pipe is buried; coming out from under ground, rising up and then bifurcating into two and then further bifurcating and joining to fingers of a Slug catcher.

- As I mentioned earlier, Hazira Phase I & II Slug catchers have 24 fingers in each and Slug Catcher III has 6 fingers.

- The liquid is stored in the fag end of the Slug Catcher.

# Composition of sour feed gas in HGPC:

$H_2S$ : Design 1185 ppm max ; Actual: 150 ppm

- $CO_2$: 8.5%
- C1: 78%
- C2: 7%
- C3: 4%
- C4: 1.7%
- C5: 0.4%
- C6: 0.13%
- C7: 0.08%
- C8: 0.05%
- $H_2O$: Saturated

# Sulfur Removal Unit :

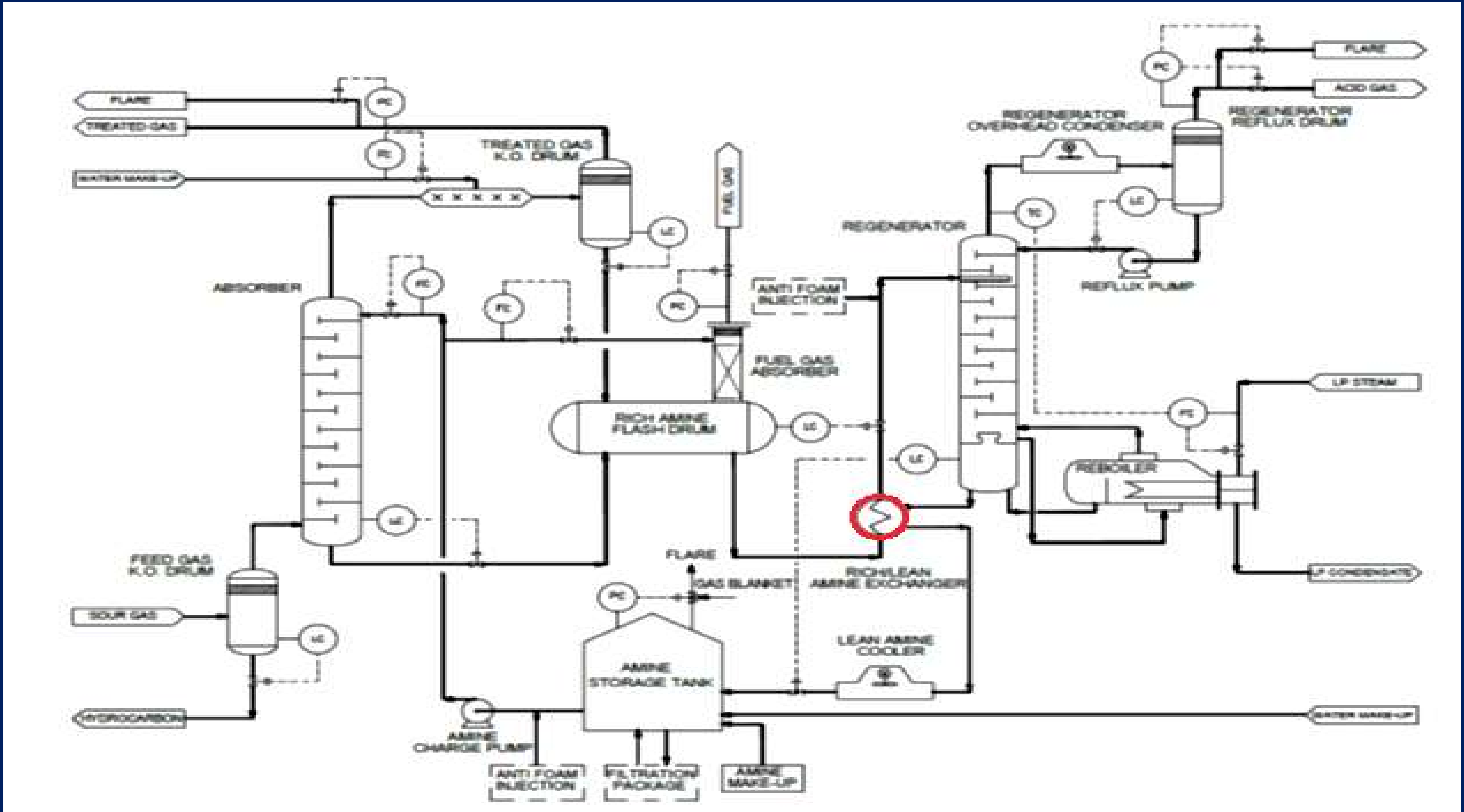
- Sulfur species are removed in this unit and gas becomes sweet (specification: max 4 ppm $H_2S$) to make it suitable for industrial use. For this reason, this unit is also called as Gas Sweetening Unit .

- Sour gas is treated with Amine (MDEA i.e. Methyl Di Ethanol Amine which is the best solvent for Hazira purpose) in one Absorption Column for selective removal of $H_2S$ & other Sulfur species to make it sweet gas (within allowed specification of 4 ppm H2S).

- Rich Amine (i.e. Amine + absorbed $H_2S$ & other Sulfur species + $CO_2$) is flashed to remove dissolved hydrocarbons
- Rich amine is then regenerated in Regenerator using low pressure steam.
- Acid gas (i.e. all Sulfur species and $CO_2$) leaves from Regenerator top passes through a condenser and enters to a Reflux drum. Reflux liquid is sent back to Regenerator and Acid gas is sent to Sulfur Recovery Unit.

- Hot lean Amine is cooled and then cold lean Amine is pumped back into the Absorption Column.

# Typical Gas Sweetening Unit Schematic (not HGPC):



**In the Gas Sweetening Unit schematic (previous slide), we can see,**

- At left hand side bottom, sour gas feed enters into Main absorber bottom section. Amine is fed at Main absorber top. When the gas rises, $H_2S$ is absorbed by the solvent.

- Rich amine then passes through flash drum where dissolved hydrocarbon along with some H2S get removed (using a side stream of MDEA solvent in the Flash gas Absorber) and the gas is sent to Fuel gas system.

- Then rich amine enters into Rich Amine and Hot Lean Amine Plate / Plate Heat exchanger where rich Amine gets heated and lean amine gets cooled.

- Lean Amine gets further cooled in Lean Amine cooler and enters to tank .

- Rich amine is regenerated in Regenerator. Regenerator overhead vapour is condensed. Sour liquid (mainly water) is sent back to Regenerator as Reflux and Acid gas is sent to Sulfur Recovery Unit.

## Sulfur Removal Unit additional information:

- MEA (Mono Ethanol Amine) or DEA (Di Ethanol Amine) are not used here, as both of them remove almost entire $CO_2$ along with $H_2S$ .
- Removal of entire $CO_2$ (from sour gas / sweet natural gas) is not desired in some projects.
  For ONGC Hazira, % of $CO_2$ in sweet gas had been decided as max 4% which might be due to downstream sweet natural gas consuming Fertilizer plants (producing Urea) like KRIBHCO, IFFCO, NFL, Tata Chemicals, INDO GULF Fertilizers etc.

**Note**:

% of $CO_2$ in sweet gas is decided/determined/designed based on use of gas in downstream consumers.

In ONGC Hazira,% $CO_2$ is 4%, in CDB project it's 3% and in Kashagan project it's 0.005%.

- MDEA solution is used for selective removal of $H_2S$ & other Sulfur species and at the same time, limit $CO_2$ co-absorption.

- Formula of MDEA (Methyl Di Ethanol Amine) is : CH3 –N (C2H4OH)$_2$

# Sulfur Removal Unit additional information contd →

- Main Absorber has 14 valve trays and Regenerator has 21 valve trays.

**Note:**

Tray column is preferred in comparison to packed column for the type of service here :

- Tray column offer **higher capacity** (here both sour gas and Amine solution have high flow rates), **less expensive** and **easier maintenance than packed column.**
- In a plate tower, the **liquid and gas are contacted in stage-wise manner on the trays**; while **gas-liquid contact is continuous in a packed column**. There are always some uncertainty to maintain good liquid distribution in a packed tower.
- The major disadvantages of packed towers are:
    1. They have a narrower operating range than tray towers.
    2. A packed tower must have a larger diameter than a tray tower to handle the same feed rate.

- Amine solvent flow in Main absorber:@ 200-230 $m^3$/hr (depending on the requirement)
- There are 5 Remote Operated Valves (ROVs) to change entry point of solvent.
- Lean Amine / Rich Amine exchanger is a Plate Heat Exchanger with 500 plates.

# Gas Dehydration Unit :

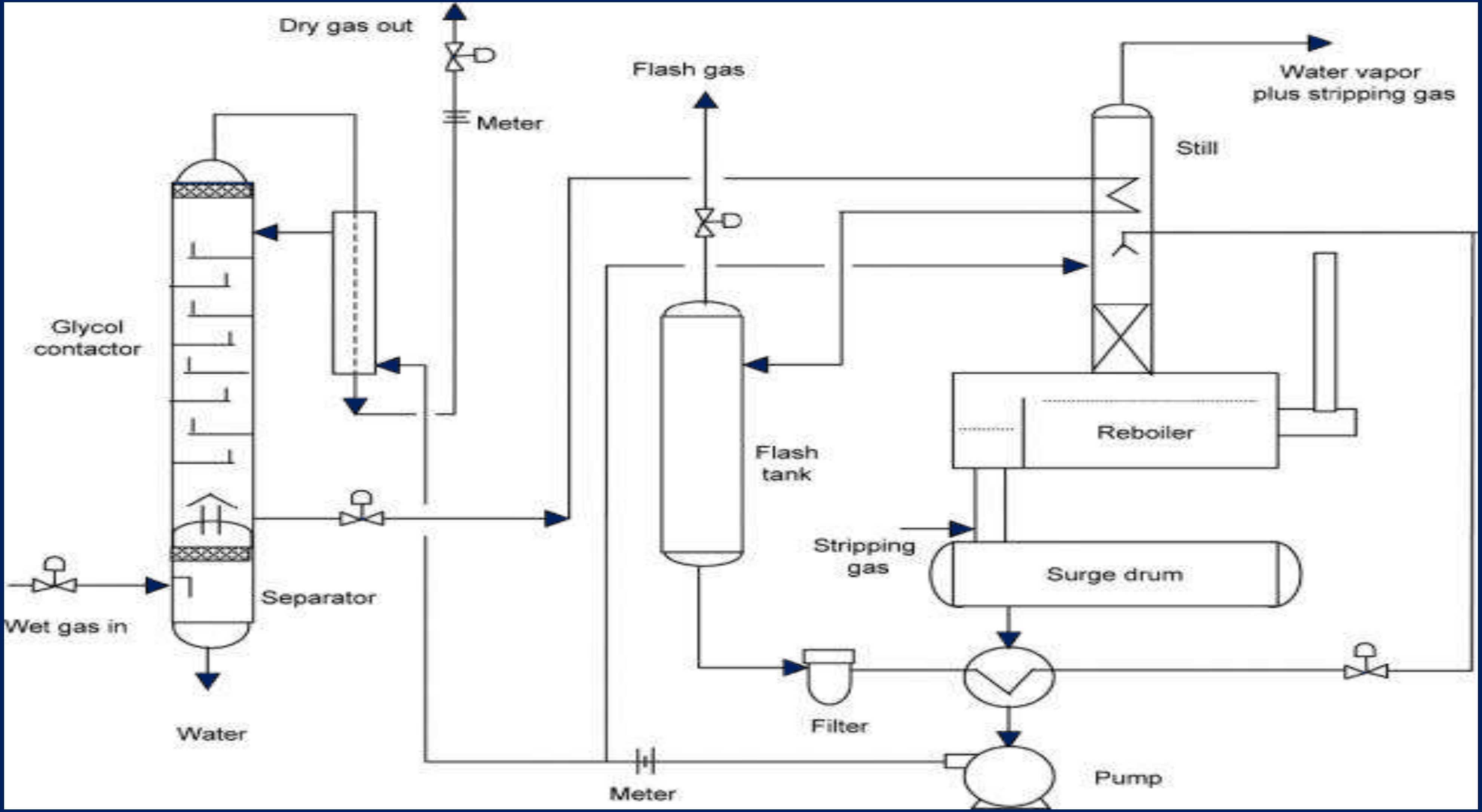
- To meet the water dew point criteria in sales gas, wet sweet gas from GSU is treated with lean glycol (TEG) to remove water from the wet gas in one Absorption Column.

- Tri Ethylene Glycol or TEG is the best solvent among all glycols.

- Rich Glycol from bottom of the Absorber is then flashed to remove any dissolved hydrocarbons.
- Rich glycol is then regenerated in Regenerator using medium pressure steam.

- Lean Glycol is cooled and then pumped back into the TEG Absorption column.

# Typical Gas Dehydration Unit Schematic (not HGPC):



**In Gas Dehydration Unit Schematic (in previous slide), we can see,**

- At left hand side bottom wet sweet gas feed enters into TEG absorber bottom section. TEG is fed at TEG absorber top. When the gas rises, water is absorbed by the TEG solvent.
- Dry gas comes out from TEG absorber top.
- Rich TEG solvent then passes through flash drum where dissolved hydrocarbon gets removed and sent to fuel gas system.
- Then rich TEG enters into Rich TEG and hot lean TEG Plate / Plate Heat exchanger, where rich TEG gets heated and lean TEG gets cooled.
- Rich TEG is regenerated in Regenerator and stored as lean TEG in surge drum.
- Lean TEG is pumped into TEG absorber.

# Gas Dehydration Unit additional information:

- TEG (Tri Ethylene Glycol) formula : $\mathbf{HOCH_2\,(CH_2CH_2O)_2\,CH_2OH}$
- TEG Absorber has 9 valve trays
- TEG Solvent flow : @ 5 to 6 $m^3$/hr
- Among all the Glycols, TEG is preferred because:
  - It is more hygroscopic,
  - comparatively less price,
  - less loss and
  - more regeneration ability

- $H_2O$ content in product gas specification: Max 50 kg/ $m^3$ (Hazira low pressure case) ; Water Dew point : - 11 deg C

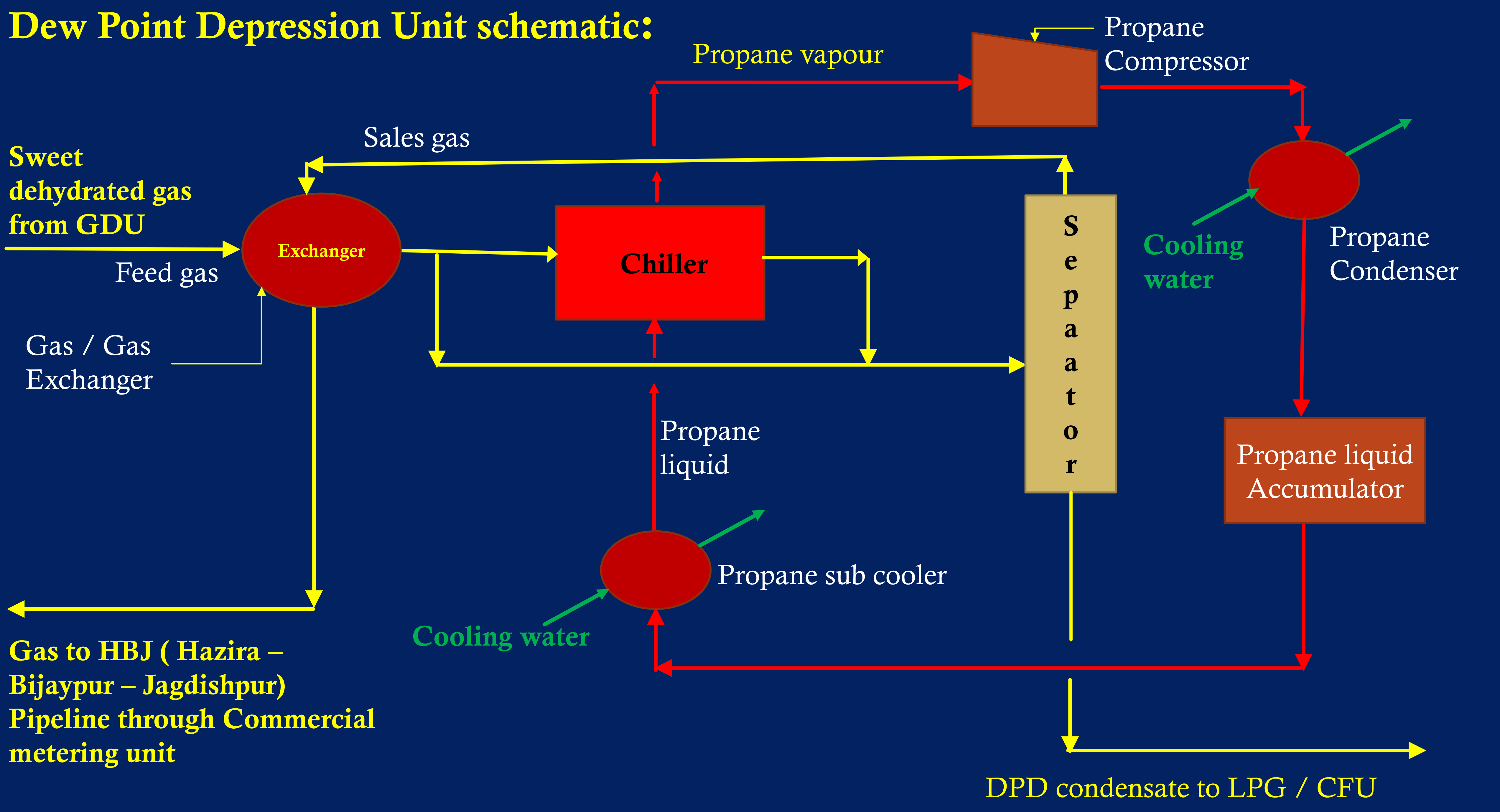
## Dew Point Depression Unit :

- To meet the Hydrocarbon Dew point criteria (+ 5 deg C at line pressure) in sales gas, dehydrated gas from Gas Dehydration Unit is chilled to remove heavier hydrocarbons.

- Dry gas, meeting specification of water dew point and hydrocarbon dew point, is sent as sales gas to GAS AUTHORITY OF INDIA LIMITED (GAIL) in it's HBJ pipeline. GAIL distributes gas through it's big gas pipeline network.

- Chilling medium, used in this unit, is Propane liquid.

# Dew Point Depression Unit schematic:



**In the Dew Point Depression Unit schematic, we can see,**

- Sweet dehydrated gas enters into Gas / Gas exchanger where feed gas is cooled to approx 12 deg C but sales gas temperature gets increased almost to ambient temperature.

- The cold feed gas is then sent to a Chiller where feed gas is cooled to + 5 deg C . The heavier liquid gets separated in the Separator & sent to LPG recovery or Condensate Fractionation Unit.

- In the Propane Chiller, Propane liquid gets vaporized getting the latent heat of vaporization from the feed gas.

- The Propane vapour is compressed and cooled using cooling water at ambient condition.

- Liquid propane is sent back to Chiller through Accumulator and sub cooler.

**Commercial metering station of Gas:**

- Sales gas with water and H.C. dew point within specification is supplied from Commercial metering station to 36” 1730 Kms of HAZIRA – BIJAYPUR – JAGDISHPUR (H-B-J) pipeline of GAIL.
- Commercial Metering Station has parallel flow meters – generally 1 or 2 meters are able for measurement of entire flow of sales gas and other meters are kept as stand-by.

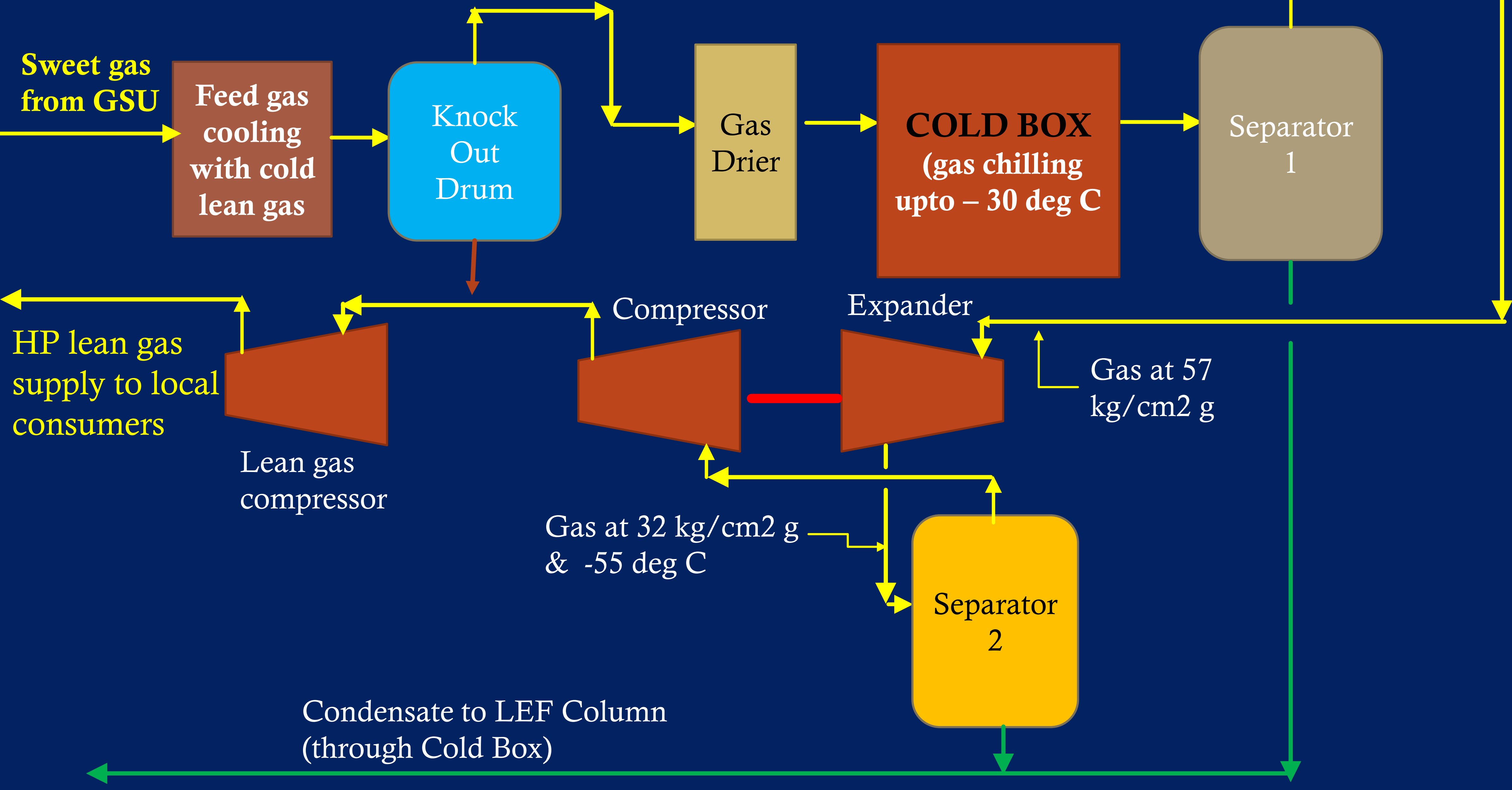
- Each meter is calibrated periodically, generally in every fortnight.

# One typical Commercial Metering station
(not ONGC Hazira photo)

# LPG Recovery unit in Hazira:

- Wet Sweet gas is filtered & dried in Molecular sieve Gas dryer and then chilled in Chiller & in Expander.
- The gas, separated in Separator, is compressed & sent to Consumers as lean gas.
- The separated liquid is fractionated to strip of remaining light ends gas.
- The bottom liquid is then fractionated in another Fractionator to produce LPG from top and NGL from bottom.
- Sometimes part of LPG is fractionated in another column to produce Propane.

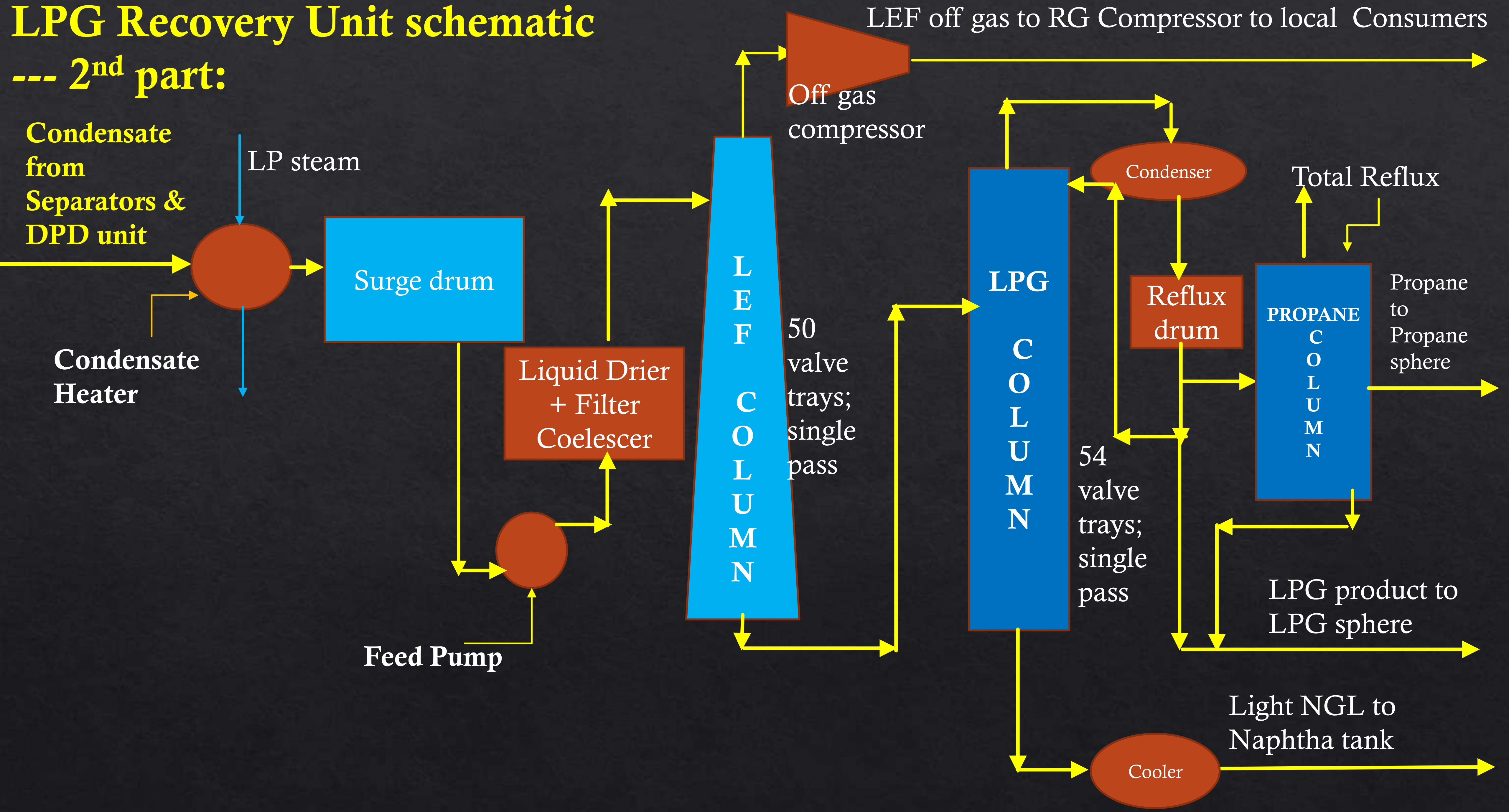
# Schematic of LPG Recovery Unit :



**In the LPG plant schematic (previous slide), we can see,**

- Sweet wet gas from GSU entering from the left is cooled to knock off any water and liquid in a Knock Out Drum. Then the gas is sent through Gas filter and a molecular sieve gas drier.
- Dried gas is sent through Cold box where other cold streams also enter. Feed gas is cooled to MINUS 30 deg C in cold box.
- The hydrocarbon liquid is separated in Separator 1 and sent to LEF i.e. Light Ends Fractionator Column.
- The cold gas from Separator -1 top at 57 Kg/cm2g pressure is then sent through Expander part of Turbo Expander which reduces the gas pressure to 32 Kg/cm2g & -55 deg C temperature.
- The chilled gas is sent to Separator 2 and the hydrocarbon liquid separated is sent to LEF Column.
- Gas from Separator -2 top is compressed in Compressor part of Turbo Expander to 38 Kg/ cm2g and then is further compressed to 47 kg/cm2g in Lean gas compressor.
- Lean gas is sent as sales gas to local consumers like KRIBHCO Fertilizers, Reliance, Gujarat gas etc.

# LPG Recovery Unit schematic --- 2nd part:



**In the LPG plant schematic 2nd part (previous slide), we can see,**

- The hydrocarbon liquid combined stream (from Separator 1, Separator 2 and DPD unit condensate) is pumped to LEF column through Liquid Drier and Coalescer.

- LEF column has 50 valve trays, single pass.
- LEF Column off gas is compressed in Residue Gas Compressor and lean gas is sent to local consumers.

- LEF bottom hot liquid is sent to LPG Column.

- LPG Column has 54 valve trays, single pass.

- LPG column top product is LPG product, which is sent to LPG sphere. When Propane sphere stock comes down, Propane is produced by operating Propane Column.

- LPG column bottom product is cooled. It is lighter NGL, so it is sent to Naphtha tank.

# Specification of LPG at HGPC:

- Composition => C3 :C4 = 50:50 ( by weight)
- Reid Vapour Pressure (RVP): 16.5 Kg/ $Cm^2$ max at 65 deg C
- Volatility (Weathering): +2 to -2 deg C

- HGPC LPG typical composition (vol %):
  - C2: 0.9 %
  - C3: 55.9%
  - iC4: 18.1%
  - nC4: 24.5%
  - iC5: 0.6%
  - nC5: 0.1%

# Specification of NGL from LPG plant at HGPC:

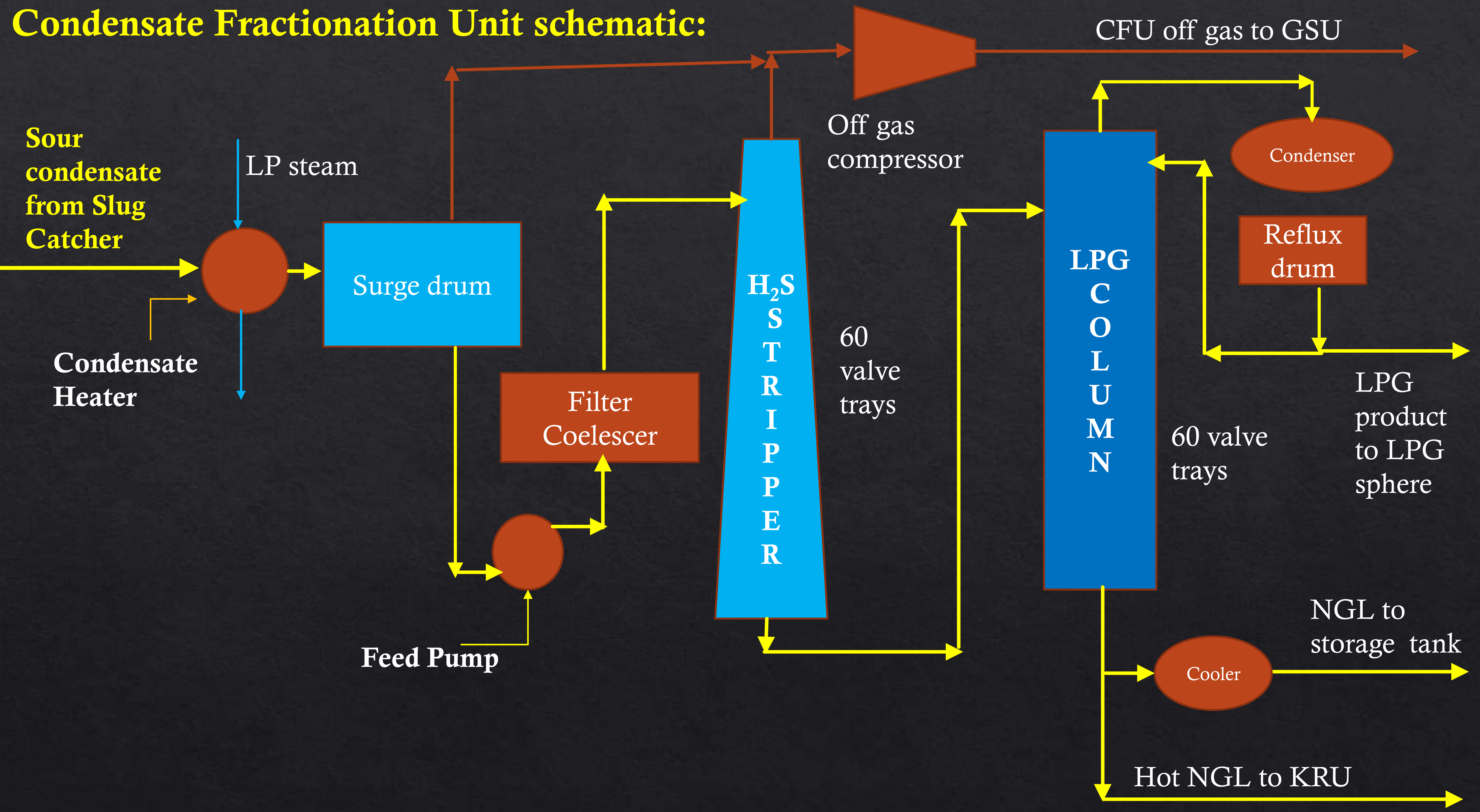
- **RVP: 0.9 Kg/ Cm2 max at 40 deg C**

- **NGL (from LPG plant) sent to Naphtha tank typical composition:**
  - nC4: 0.03%
  - iC5: 24.1%
  - nC5: 26.2%
  - C6: 22.1%
  - C7: 14.7%
  - C8: 9.2%
  - C9: 2.4%
  - C10: 0.8%
  - C11+: 0.5%

# Condensate Fractionation Unit (CFU):

- Natural gas condensate (stored in Slug catcher) contains about 300 ppm of H2S.
- This liquid is fractionated in a Stripper Column from where light gases along with $H_2S$ are stripped off.
- The sweet condensate is then fractionated in LPG Column from where LPG comes out from top and NGL comes out from bottom
- LPG is sent to LPG sphere.
- Hot NGL is sent to KRU.
- If KRU is under shut down (for some reason ), cold NGL is sent to NGL tank

# Condensate Fractionation Unit schematic:



In the **CFU schematic**,
we can see, sour condensate enters from Left hand side.

- Sour condensate is first preheated to avoid hydrate formation. After preheating, sour condensate enters in surge drum which is basically a 3-phase separator. Here hydrocarbon liquid, water and off gas get separated at the vessel pressure.

- Then the hydrocarbon liquid is pumped through Filter coalescer (to remove any remaining water) and sent to stripper column.

- Stripper column has 60 valve trays. Stripper operates at approx 18 to 25 kg/cm2g. MP steam is used in Stripper Kettle type Reboiler.

- Stripper off gas combined with surge drum off gas is compressed and sent to GSU.

- Stripper bottom hot liquid (having $H_2S < 4$ ppm) is sent to LPG Column.

# CFU schematic continued ---→

- LPG Column has 60 valve trays. HP steam is used in LPG Column Reboiler.
- LPG Column top pressure is chosen as 9 $kg/cm^2$ g to keep overhead condensing temperature at 43 deg C, so that cooling water can be used in the overhead condenser.
- Reflux is maintained as required and LPG product is sent to LPG sphere. If LPG is little sour, provision is there to send it through Caustic wash unit and then to LPG sphere.
- Hot NGL is sent to Kerosene Recovery Unit. If KRU is not operating for any reason, cold NGL is sent to NGL tank.

# Composition of Hazira complex NGL from CFU at HGPC:

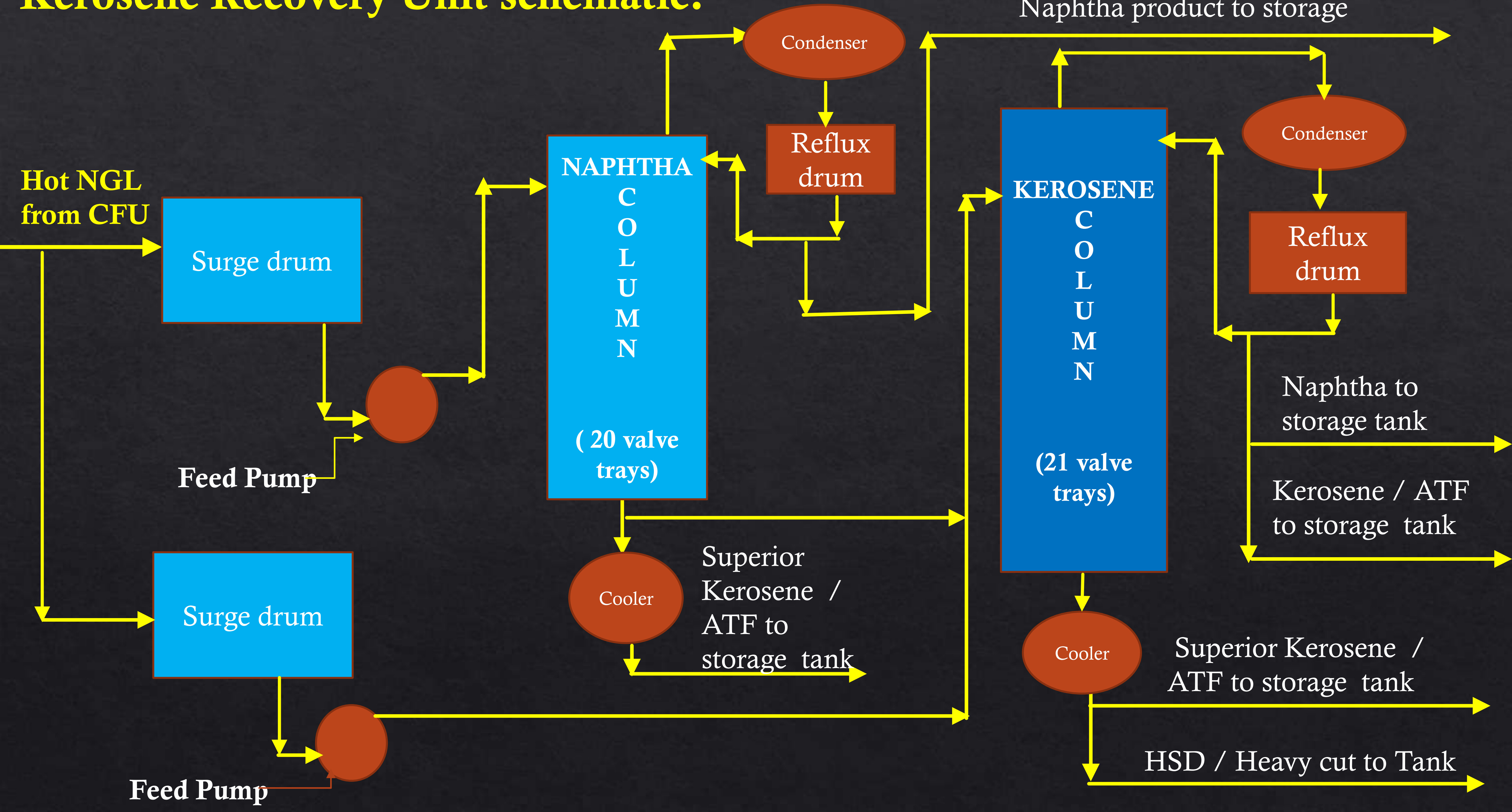
➢ **Typical composition of NGL sent to Kerosene Recovery Unit:**

- nC4: 0.05%
- iC5: 9.2%
- nC5: 10.7%
- C6: 14.8%
- C7: 17.1%
- C8: 20.5%
- C9: 10.6%
- C10: 6.4%
- C11: 7.3%
- C12: 3.3%
- C13 +: balance
- Free water : NIL

## Kerosene Recovery Unit in Hazira Complex :

- Kerosene Recovery Unit has two Fractionating columns i.e. Naphtha Column & Kerosene Column .
- KRU can be operated in series or in parallel based on the feed NGL Final Boiling Point (FBP).
- When the FBP of the NGL feed is greater than 290°C, then the two columns are planned to be operated in series mode.
- When the FBP of the feed NGL is less than 290°C parallel mode of operation is planned under which the second column shall be used for the same service as the first column.
- The products are Naphtha, Superior Kerosene, Aviation Turbine Fuel, High Speed Diesel and Heavies.
- Different products have different storage tanks.
- Based on NGL feed, operation mode is decided and based on the analysis of products, products are diverted to different product tanks strictly maintaining specification.

# Kerosene Recovery Unit schematic:



## Sulfur Recovery Unit (SRU) in HGPC:

- $H_2S$ in Hazira Acid gas : 7000 ppm.
  In my presentation later, we will see, $H_2S$ ppm in CDB project is 563,000 ppm and in Kashagan project, it is 760,000 ppm.

- In Hazira SRU, $H_2S$ is absorbed and oxidized in Absorber- Oxidizer where different catalytic agents like LOCAT and other solutions are added.

- $H_2S$ is converted into molten Sulfur and gets settled at the bottom of the settling section.

- Sulfur Recovery Unit's most popular technology CLAUS process & SCOT process (HGPC has different technology) will be discussed in next sections.

- As $H_2S$ ppm in Hazira Acid gas is less, in HGPC, LOCAT based SRU is suitable.

# CDB sour gas processing project, CHINA

## CDB sour gas project in CHINA:

- CDB project in Sichuan province, CHINA (near Chendgu city / Chongqing city) has been developed by two world famous companies --- CHEVRON and PETRO CHINA.

- The sour gas from onshore well head is processed in gathering stations (including glycol treatment to reduce water content and make Water Dew point of the sour gas – 10 deg C).

- Then the dry sour gas is transported through 20” 36 Kms trunk line to CDB sour gas processing complex near Nanba town of China.

- As the sour feed gas transported from gathering station is dry, there is no requirement of Slug catcher there.

## Main Units in CDB sour gas project are:

- Gas Terminal  without any Slug catcher here

- Sulfur Removal Unit
- 
- Gas Dehydration Unit

- Sulfur Recovery  Unit  ( CLAUS process)

- Tail Gas Treatment Unit  (SCOT process)

and

- Liquid & Solid Sulfur handling and dispatch

**Sulfur Removal Unit in CDB project:**

- CDB Sulfur Removal Unit is quite similar to Hazira Complex of ONGC

- Sour gas is treated with Sulfinol- M solvent (which is a mixture of 50 wt% MDEA + 15 wt% Sulfolane + 35 wt% Water). Sulfolane is used here to absorb Carbon disulphide and Carbonyl Sulfide.

- Inlet sour feed gas $H_2S$ content : >10 wt % = 100,000 ppm
- Inlet sour feed gas $CO_2$ content : Approx 7.5 wt %

- Allowed $H_2S$ ppm in sweet gas in this project : 14 ppm(by vol) max
- Allowed $CO_2$ in sweet gas in this project : Max 3% (by vol)

- Main absorber total number of tray : 22
- Main absorber solvent entry feed tray : 16,18,20 & 22

# CDB Sulfur Removal Unit & Gas Dehydration Unit:

- Wet treated gas (i.e. sweet gas) typical composition ( by volume) :
  - $H_2S$ : 0.0005% (5 ppm by vol) ; Specification: 14 ppm (by vol) max
  - $CO_2$: 0.8 - 2% (by vol) ; Specification: 3% (by vol) max
  - C1: 97.8%

Acid gas composition (by volume):
  - $H_2S$ : 56.3%
  - $CO_2$: 39.3%

- **CDB Gas Dehydration Unit (GDU):** It is exactly same as ONGC Hazira Gas Dehydration Unit.

## Sulfur Recovery Unit in CDB project:

This CDB Sulfur Recovery project is different from ONGC Hazira SRU.

- As the CDB SRU follows Claus process, the unit is also called Claus Unit. Most of the Sulfur Recovery Unit in the World, where $H_2S$ concentration in Acid gas is high, follow this Claus technology.
- In Claus Unit, Acid gas is passed through Furnace and Reactors where most of the $H_2S$ gets converted to elemental Sulfur .
- Elemental Sulfur gets drained into Sullfur Pit.

**Detailed Claus process:**

- Here, Acid gas is mixed with air, to convert 1/3 rd of the $H_2S$ in the acid gas to $SO_2$ .
- $H_2S$ combusts with air to form $SO_2$ :: $H_2S + 1.5\ O_2 \dashrightarrow SO_2 + H_2O$

The Furnace is operated air lean to control H2S to SO2 ratio to approx 2:1

- The Claus Reaction: $2\ H_2S + SO_2 \longrightarrow 3\ S + 2H_2O$

- Claus Unit consists of mainly 4 sections:
  1) **Feed gas section** : Acid Gas KOD, Main Air blowers etc. Combustion air is supplied by the Air blowers.
  2) **Thermal stage**:
     - Acid gas mixed with air is burnt at approx 1000 deg C to maintain a stable flame
     - Hot process gas passes through Waste Heat Boiler and generates MP steam.
     - Then, process gas passes through 1st Sulfur Condenser to condense elemental Sulfur vapours.
     - Condensed liquid Sulfur passes through Sulfur lock and sent to Sulfur pit.
     - About 70% of $H_2S$ is converted into elemental Sulfur in this stage.

# Detailed Claus process contd --→

3) **Catalytic stage:** This section consists of 1st Reheater, 1st Reactor, 2nd Sulfur Condenser, 2nd Reheater, 2nd Reactor, 3rd Sulfur Condenser and two Sulfur locks

- $H_2S$ is further converted to elemental S in 1$^{st}$ reactor (containing 99.9% Titanium Oxide) : 82% of S present in feed gas is recovered.
- Process gas is condensed and liquid S goes to S - pit.
- In 2$^{nd}$ reactor (containing 99.7% Aluminium Tri Oxide), approx. 93% of the S (originally present in the feed acid gas) is recovered.
- Process gas is condensed and liquid S goes to S - pit.
- The process gas after 3$^{rd}$ Condenser is called Tail gas (containing 0.7% $H_2S$) is sent to Tail Gas Treatment Unit (TGTU).
- LP steam is generated during Sulfur condensation in each condenser.

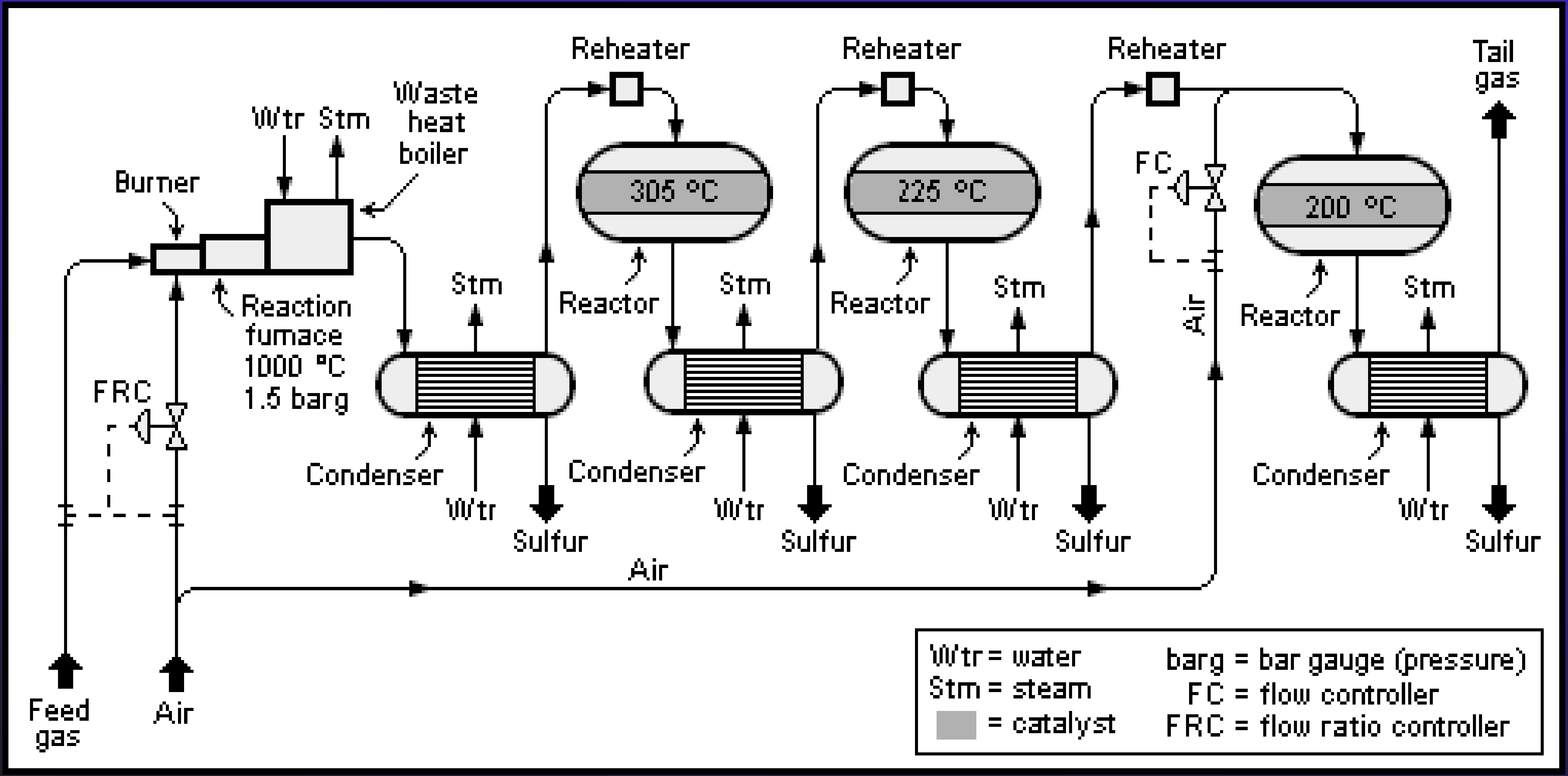
## Detailed Claus process contd --→

4) **Sulfur Degassing section :** This section consists of Sulfur Pit with pit steam coils, Air spargers and Sulfur pumps

- S produced in Claus unit contains 300 ppm $H_2S$. Specification of $H_2S$ in Sulfur product is <10 ppm $H_2S$. So, $H_2S$ ppm in Sulfur product is reduced using stripping air. Off gas is sent to Incinerator.

- SRU produces 2 Tonnes of elemental S (with <10 ppm $H_2S$) per day per train. CDB project has 3 SRU trains.

# Typical (not CDB project) Sulfur Recovery Unit (Claus Process) Schematic :



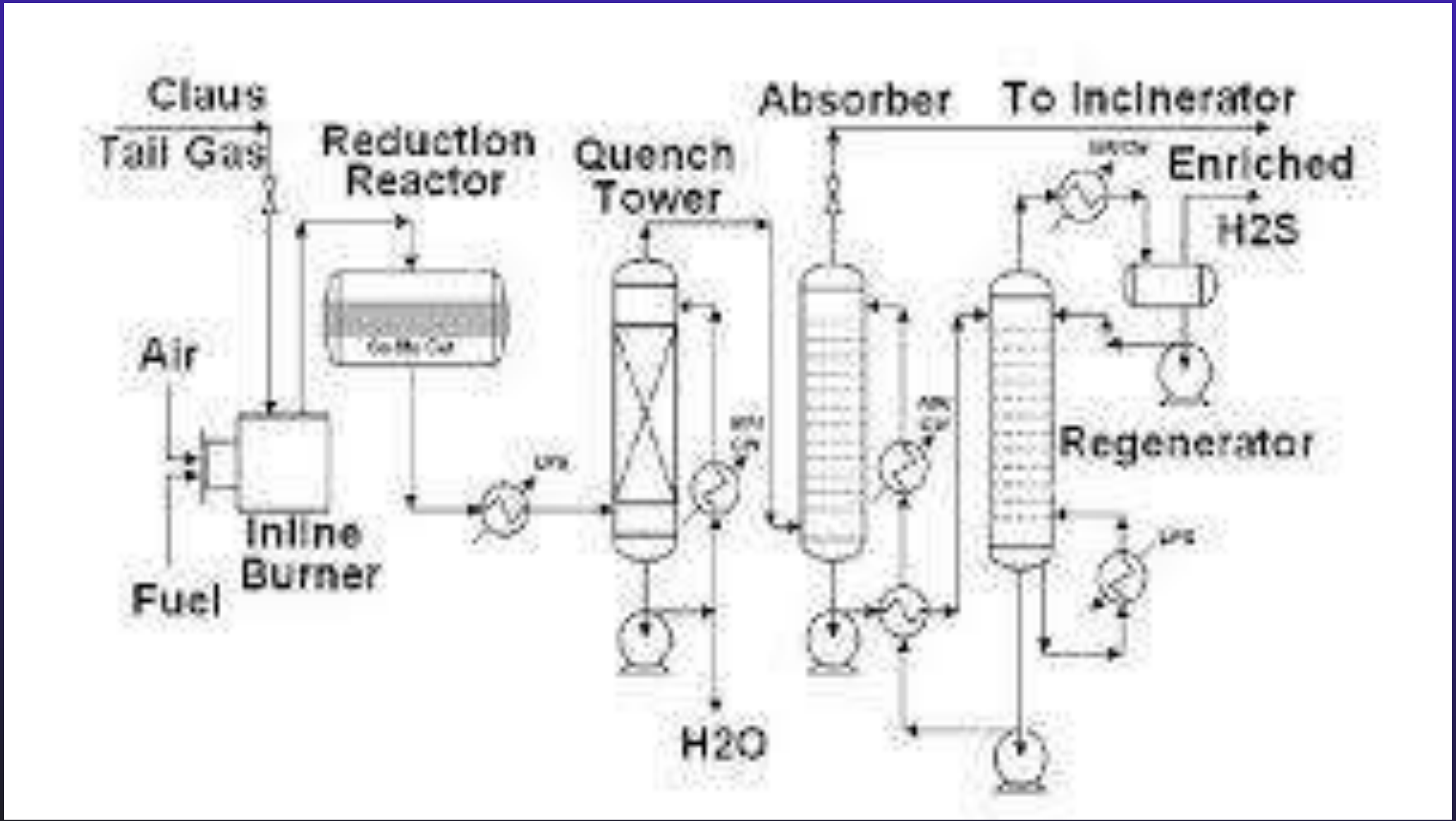
# Tail Gas Treatment Unit (SCOT unit) in CDB project:

- TGTU uses Shell Claus Off-gas Treatment (SCOT) process to convert all remaining sulfur compounds to $H_2S$ followed by absorption of $H_2S$ from process gas using Amine solvent before venting the tail gas through Incinerator.

- $H_2S$ containing Amine solvent is sent to Sulfur Removal Unit to remove $H_2S$ from the Amine solvent.
- TGTU consists of SCOT burner, SCOT Reactor , SCOT waste heat boiler, Quench tower , SCOT Absorber and Incinerator. Over 99.5% of remaining $H_2S$ in tail gas is absorbed here.

- In Incinerator, all the Sufur species in the tail gas (from SCOT Absorber) is burnt into $SO_2$ before venting into atmosphere strictly following environmental norms & guidelines.

# Typical TGTU (SCOT Process) Schematic (not CDB project):



# Sulfur Forming Plant:

- Molten Sulfur product from S - pit (in SRU) is pumped to storage tanks in Sulfur forming plant
- Liquid Sulfur solidifies at 119 deg C and becomes extremely viscous as it's temperature approaches 160 deg C.
- Liquid Sulfur is therefore stored and pumped at approx 140 deg C at which temperature it's viscosity is relatively low (7.4 cP). This is achieved by steam jacketing all equipment & piping.

# Kashagan sour gas & crude oil project, KAZAKHSTAN

# A few bullet points on Kashagan project :

- Kashagan is a high pressure – high $H_2S$ content project .

- The big Kashagan project comprises:
  - Kashagan offshore on man-made artificial island in Caspian sea

  - Two 28” diameter 99 Kms (each) sour gas & sour oil trunk line from Kashagan offshore to Onshore Processing Facility (OPF)

  - Kashagan Onshore Processing Facility with 3 Oil processing plants, 2 Gas processing plants and 2 Sulfur processing plants .

# Main Units in Kashagan onshore complex :

- Oil processing, storage & export
- Gas processing including:
  - Gas inlet facilities with Slug catcher
  - Gas Sweetening Unit
  - Gas Dehydration Unit
  - Hydrocarbon Dew Point control , De-Ethanization
  - Sales gas Compression & gas export
  - NGL treating, fractionation
  - LPG de-marcaptanisation and LPG storage
- Sulfur Recovery Unit ; Sulfur handling, storage & dispatch
- Tail Gas Treatment Unit + Incinerator
- Utilities & support system
- Power generation

## Typical composition (by Volume) of sour feed gas in Kashagan project:

$H_2S$ : Design: 12 -17% ; Actual: 15% approx = 150,000 ppm (Refer Note 1)

- $CO_2$: 4 - 5%
- C1: 68%
- C2: 7%
- C3: 3%
- C4: 1.3%
- C5: 0.4%
- C6: 0.2%
- C7: 0.13%
- N2: 1%
- $H_2O$: saturated

Note 1: CDB project, Feed gas $H_2S$ ppm is 100,000 and Feed gas $H_2S$ ppm in ONGC Hazira it is just 150 ppm.

# Salient features of Kashagan Sulfur Removal Unit :

- Sour gas is treated with 40% (by wt) solution of DEA (Di Ethanol Amine)
- DEA partially removes COS & $CS_2$ and also $CO_2$.
- $H_2S$ content is reduced from 16 % to 0.004% (4 ppm) by vol
- $CO_2$ content is reduced from 5 % to 0.005% by vol
- Based on Kashagan design requirement, high loading and double split flow DEA process has been developed by Totalfina.
- Double split flow permits a reduction in size of the upper section of the Absorber and a substantial reduction of Regenerator steam consumption.
- Amine Contactor has 34 trays
- Two locations of Amine feed (double split flow):
  - At middle ($15^{th}$ tray): Semi lean Amine (Note 1) removes bulk of Acid gas
  - At top ($5^{th}$ tray): Lean Amine to achieve $H_2S$ specification of sweet gas
  - Water wash at the top of the Absorber to reduce Amine carry over

Note 1: Semi lean Amine is obtained from $16^{th}$ tray of the Regenerator column and then cooled.

# Gas Dehydration Unit in Kashagan project:

- To meet the water dew point criteria in sales gas and also to prevent ice & hydrate formation in Dew point control / Turbo expander section, wet sweet gas is sent through Gas Dehydration Unit.

- At first gas is sent through inlet Separator and through LP steam heated dried Feed Superheater to eliminate any chance of entering any free liquid into the molecular sieve drier.

- The drier contains beds of molecular sieve solid desiccant material onto which the water vapour is adsorbed.

- The water content of the gas is reduced from approx. 0.1% ( mol%) to 1 ppmw

# Gas Dehydration Unit in Kashagan project contd -→

- A slip stream of dry gas is compressed and used to regenerate the driers one by one through an automatic process. When one drier goes under regeneration, other regenerated drier comes into line first through the automatic process.

- Though molecular sieve Alumino silicate driers are costly than Glycol units, but these desiccant driers are more effective for:
    - Very low water dew point requirement
    - Simultaneous control of water and Hydrocarbon dew point

# Dew point control / Turbo expander unit:

- Dried gas is cooled (using a few cold streams)to  - 13 deg C
- The hydrocarbon liquid is separated in a Low Temperature Separator and sent to De-Ethanizer
- The cold gas at – 14 deg C and 56 barg pressure is sent through Expander part of Turbo  Expander which reduces the gas pressure to 15 bar g  & - 64 deg C temperature.
- The chilled gas is sent to Liquid Hydrocarbon Recovery Unit for LPG and C5+ recovery.
- Gas from De-Ethaniser overhead enters in Compressor part of Turbo Expander and compressed to 19 barg and sent to Sales gas compressor section.

# Liquid Hydrocarbon recovery and LPG treatment unit:

- Liquid recovered in Low temperature Separator in Turbo Expander inlet section is sent to Liquid Hydrocarbon Recovery Unit for LPG and C5+ recovery.

- Dried chilled gas from Turbo Expander ( at 15 bar g & - 64 deg C temperature) is sent to De-ethaniser pre-flash drum for further liquid recovery.

- De-Ethaniser overhead gas is sent to Turbo Expander Compressor and then sent to Sales gas compressor.

# Liquid Hydrocarbon recovery and LPG treatment unit contd -→

- De-Ethanizer bottom liquid is sent through Mercaptan Removal package to remove Mercaptan using UOP licensed Merox process.
- Hydrocarbon liquid after Merocx treatment is sent to LPG Column to get LPG as top product and C5+ liquid as bottom product.
- LPG product is sent to LPG storage bullet.
- C5+ product liquid is blended with crude oil.

# Kashagan sales gas specification :

- Gross heating value: 32.5 to 45 $MJ/m^3$
- Wobbe Index : 41.2 to 54.5 $MJ/Nm^3$

**Note:** Wobbe index is an indicator of the interchangeability of different fuel gases such as Natural gas ( W. I : 39 – 45 $MJ/Nm^3$), LPG (W.I : 73.5 – 87.5 $MJ/Nm^3$) . If two fuel gases have identical Wobbe Indices, their energy output will also be identical.

- Hydrocarbon Dew point (at export pressure): - 10 deg C
- $H_2S$ ppm : Max 7 $mg/Nm^3$ = Max 4 ppm by vol
- Water : 1 ppm (by wt) max
- Mercaptan : 16 $mg/Nm^3$ max

# Sales gas Compression and Export Gas Pipeline :

- Sales gas is compressed by 2 stage centrifugal compressor
- LPG from LPG bullet is injected into sales gas.
- A gas chromatograph on the sales gas outlet ensures meeting sales gas specification.
- Export gas is transported through 24” diameter 90 Kms length pipeline from Kashagan onshore plant to 3 numbers of 48” Pipeline of the Central Asia Centre Pipeline (CAPC) transportation system.
- The 24” sales gas pipeline is API5L X60 carbon steel , buried with triple polypropylene coating and impressed current cathodic protection.

# Sulfur Recovery Unit & Tail Gas Treatment Unit :

Kashagan Acid gas typical composition (by vol):

- $H_2S$ : 76% approx.
- $CO_2$: 17% approx.
- $H_2O$: 6 – 7 %
- Hydrocarbon: 0.2%

- Kashagan Sulfur Recovery unit has same process as CDB project CLAUS unit discussed earlier

- Also, Kashagan **Tail Gas Treatment Unit** is almost similar like CDB project SCOT unit.

# Thank you