DESIGN OF AN OFFSHORE FACILITY FOR SEPARATION OF SOUR CRUDE AT HIGH TEMPERATURE AND HIGH PRESSURE

A Report

submitted

by

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BACHELOR OF TECHNOLOGY

In

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Under the guidance of

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CERTIFICATE

This is to certify that the thesis titled **DESIGN OF AN OFFSHORE FACILITY FOR SEPARATION OF SOUR CRUDE AT HIGH TEMPERATURES AND HIGH PRESSURES** submitted by **AKSHAY ARORA (R820211002), ASHISH BHARDWAJ (R820211007)** and **SHREYA SINGH (R820211035) ,** to the University of Petroleum and Energy Studies, for the award of the degree of **BACHELOR of TECHNOLOGY** in Applied Petroleum Engineering with specialization in Gas Engineering is a bonafide record of the project work carried out by them under my supervision.

Mr. R. P. Soni

Professor

Head of the Department

Date: April, 28 2015

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ACKNOWLEDGEMENTS

This project would not been possible without the helping hand of our guide, **Prof R .P. Soni**. When we look at it now and from where we began, we have travelled a long distance. And all this while, one thing that was constant was Sir's presence and his thoughtful insight. He offered us the perfect opportunity to explore various avenues. He let us closely observe the short comings that we faced and never once revealed any of the details, despite of being aware of the industrial set up. We were left in the open under the sun to look out for all plausible scenarios and provide judiciously for them. This got us the sense of uniqueness and made us appreciate our doing even more.

The project in very unique in itself and has carefully brought to light all that we happened to learn in our undergraduate studies and see those concepts apply in real life. It marvels us as to how we designed the platform from the very scratch. It is a hard earned work, and Sir made sure we were never alone in this battle. We developed an Engineer's brain and are truly grateful to sir for this.

And for him, we just wish to say "your stories inspire our innovative thinking "

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We shall always remain indebted.

ABSTRACT

The offshore industry faces unique needs and complex challenges. With increasing safety regulations and environmental and geographic guidelines, offshore platform construction requires solutions that can produce a safe, efficient, and cost-effective offshore platform structure. To optimize the life cycle of the offshore platform, the technology in place must support concept and design processes, as well as best practices for information management throughout the life of the project.

The project will focus on Western Offshore where a Production Platform Module will be designed for specific production rates, GOR and other parameters. This will include an assembly of Heat Exchangers for cooling fluids from Manifold to a vertical separator. The vertical separator will be deployed for separation of Gas and condensates. All these equipments have to be in accordance with API Guidelines like RP 14 C while maintaining space limitations.

The deliverables for the project will include:

- Design of Heat Exchanger, Vertical Separator including Material Selection & Pressure Calibrations
- Piping Connections for desired flow rates
- General Arrangement Drawing for equipment layout & spacing

EXECUTIVE SUMMARY

A preliminary literature survey of offshore production facilities for separation of gas and condensate feeds is carried out. Various methods deployed for separation are studied and the most suitable one is chosen, as per the constraints of incoming feed, space and economics.

Careful equipment selection of the processing facility is done after weighing the advantages and disadvantages of each. Furthermore, process equipment design of the units is studied and sizing is carried out.

The primary foot sizing of the platform after consultation with the mentor was done; these are further improvised to incorporate the suggested changes in terms of changing the selected equipment type.

Following this, a rough process flow diagram was prepared. Several recommendations and corrections provided by the mentor helped in drafting the final version of the Processing facility, this helped in re-evaluating the operating philosophy of the plant.

While conceiving the design of the platform, yet another tool which comes handy is the General Arrangement Design. As the work began on this front, the operational philosophy became all the more clear and now the detailed sizing of equipments could be started with. The material of construction of each of these units was also carefully suggested taking into regard the complexities of high temperature high pressure and presence of acidic impurities.

To ease the flexibility in the calculation side of the plant, demo calculators in excel were made. Pressure drops across the equipments and overall pressure drop of the plant was also estimated.

On having done these, and after the approval of the mentor, the general arrangement drawing was finalized. The next step was to conceptualize the platform in the appearance of isometric drawings and three – dimensional modeling.

1. INTRODUCTION

1.1 Overview

Natural gas, as provided to the end users is much different from what is received at the wellhead from reservoirs. And therefore it requires large amount of processing and refining to be sent out for final use.

The natural gas sent out for end use is essentially methane; however natural gas occurs as mixtures and carries various components such as ethane, propane, butane and other contaminants. The raw gas obtained at the wellhead can flow in from three kinds of reservoirs, namely – oil, gas and condensate well. Oil reservoirs can provide gases that may exist in the free state or can be dissolved in the crude, referred commonly as associated gas. While gas obtained from condensate or gas wells, carries very little or almost no amount of crude, this is referred commonly as 'non – associated gas'. Condensate wells also produce a little amount of semi – liquid hydrocarbons, known commonly as condensates. These are usually dissolved and present n gaseous state and are usually of low density.

Contaminants present in natural gas, as mentioned above make the processing of natural gas even more complex. Acidic contaminants such as hydrogen sulfide (H_2S) and carbon – dioxide, nitrogen, helium etc reduce profit margins gravely and processing facilities catering to such feeds require capital intensive designing.

The feed to the plant is received at elevated temperatures and pressures. This increases design complexities further. And more so, the controls and pressure handling of equipments will need even more caution and care.

The processing facility being referred here is to be set up in offshore conditions. So the project is faced by increased complexity, especially in regard to space and the exposure to water, brings along challenges of mitigating corrosion too. For a typical new oil or gas facility, 50 to 60 percent of the costs are related to material. It is certain that use of ineffective materials can result in the loss of millions of dollars on an average capital project. The design thereby involves careful selection of material of construction from acidic gases and water too.[i]

1.2 Objective

In a number of engineering disciplines, optimization is common. The objective thus remains to not only find a way of doing it but suggesting the best way of doing it.

This project aims at designing of an offshore separation facility for condensate and sour gas mixed feed at high temperatures and high pressures.

The deliverables involves the following

- Careful selection of equipments
- Technical design of equipments, (as per standards of API)
- Proper material selection (involving Corrosion Resistant alloys, and standards from ASME, Class 1500 and NACE – MR – 01- 75/ SIO -151-56, API VT -2)
- Estimating the foot print
- Suggesting maintenance operations
- General Arrangement Drawing
- Economic Evaluation
- HAZOP
- Generation of isometrics and 3D views

The project does not involve a few factors in its scope of work. Some of them being - incoming gas at manifold, P&ID, E&ID, mechanical designs.

2. LITERATURE SURVEY

2.1 Processing Natural Gas

Natural gas processing consists of separating all of the various hydrocarbons and fluids from the pure natural gas, to produce what is known as ‘pipeline quality’ dry natural gas. Major transportation pipelines usually impose restrictions on the make-up of the natural gas that is allowed into the pipeline. Associated hydrocarbons, known as ‘natural gas liquids’ (NGLs) are valuable by-products of natural gas processing. These NGLs are sold separately and have a variety of different uses; including enhancing oil recovery in oil wells, providing raw materials for oil refineries or petrochemical plants, and as sources of energy.

While some of the needed processing can be accomplished at or near the wellhead (field processing), the complete processing of natural gas takes place at a processing plant, usually located in a natural gas producing region. The extracted natural gas is transported to these processing plants through a network of gathering pipelines, which are small-diameter, low pressure pipes. A complex gathering system can consist of thousands of miles of pipes, interconnecting the processing plant to upwards of 100 wells in the area.

Additional processing is done at the wellhead and at centralized processing plants. The actual practice of processing natural gas to pipeline dry gas quality levels can be quite complex, but usually involves four main processes to remove the various impurities:

- Oil and Condensate Removal
- Water Removal
- Separation of Natural Gas Liquids
- Sulfur and Carbon Dioxide Removal

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

2.2 Oil and Condensate Removal

In order to process and transport associated dissolved natural gas, it must be separated from the condensates (in this case) which are present along with. This separation of natural gas from condensates is most often done using equipment installed at or near the wellhead.

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

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

2.3 Sour Feeds

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

Sulfur exists in natural gas as hydrogen sulfide (H_2S), and the gas is usually considered sour if the hydrogen sulfide content exceeds 5.7 milligrams of H_2S per cubic meter of natural gas. The process for removing hydrogen sulfide from sour gas is commonly referred to as 'sweetening' the gas. And this part is however out of the scope of work of this project.

2.4 Separating condensates from raw natural gas

There are literally hundreds of different equipment configurations for the processing required to separate natural gas condensate from a raw natural gas. The schematic flow diagram to the right depicts just one of the possible configurations.

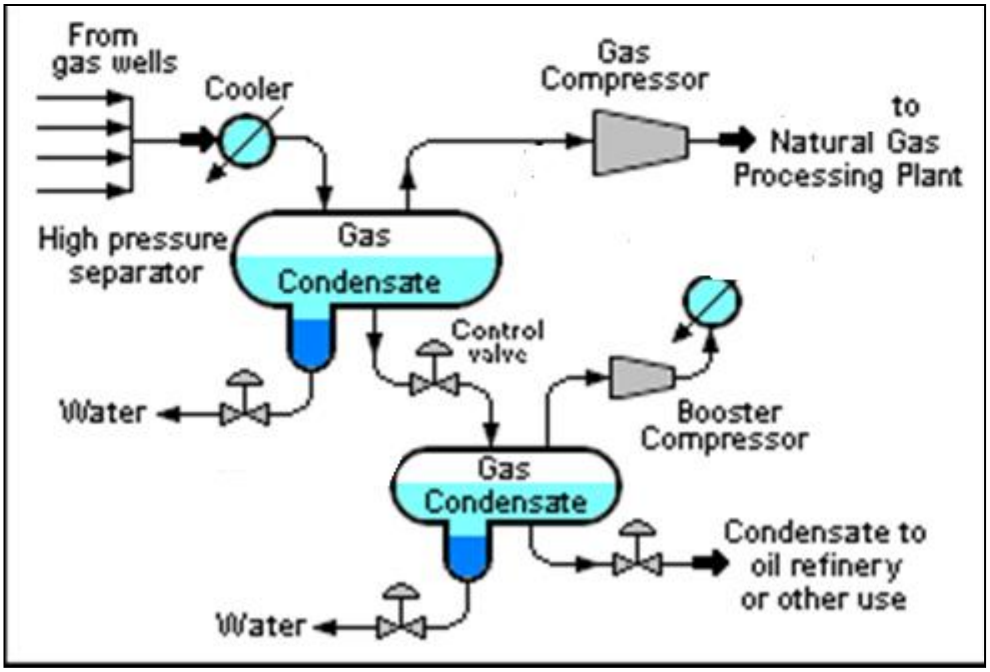

Fig1. Schematic of separation of condensates from natural gas

The raw natural gas feedstock from a gas well or a group of wells is cooled to lower the gas temperature to below its hydrocarbon dew point at the feedstock pressure and that condenses a good part of the gas condensate hydrocarbons. The feedstock mixture of gas, liquid condensate and water is then routed to a high pressure separator vessel where the water and the raw natural gas are separated and removed, if required. The raw natural gas from the high pressure separator is sent to the main gas compressor.

The main gas compressor raises the pressure of the gases from the high and low pressure separators to whatever pressure is required for the pipeline transportation of the gas to the raw natural gas processing plant. The main gas compressor discharge pressure will depend upon the distance to the raw natural gas processing plant and it may require that a multi-stage compressor be used.

At the raw natural gas processing plant, the gas will be dehydrated and acid gases and other impurities will be removed from the gas. Then, the ethane (C2), propane (C3), butanes (C4), and pentanes (C5)—plus higher molecular weight hydrocarbons referred to as C_{5+}—will also be removed and recovered as byproducts.

The water removed from both the high and low pressure separators may need to be processed to remove hydrogen sulfide (H_2S) before the water can be disposed of underground or reused in some fashion.

Some of the raw natural gas may be re-injected into the producing formation to help maintain the reservoir pressure, or for storage pending later installation of a pipeline.

2.5 Treating Raw Natural Gas – Condensate Feed

The wells on a lease or in a field are connected to downstream facilities via a process called gathering, wherein small-diameter pipes connect the wells to initial processing/treating facilities. Beyond the fact that a producing area can occupy many square miles and involve a hundred or more wells, each with its own production characteristics, there may be a need for intermediate compression, heating, and scrubbing facilities, as well as treatment plants to remove carbon dioxide and sulfur compounds, prior to the processing plant. All of these factors make gathering system design a complex engineering problem.

Non-pipeline-quality production is piped to natural gas processing plants for liquids extraction and eventual delivery of pipeline-quality natural gas at the plant tailgate. A natural gas processing plant typically receives gas from a gathering system and sends out processed gas via an output (tailgate) lateral that is interconnected to one or more major intra- and inter-state pipeline networks. Liquids removed at the processing plant usually will be taken away by pipeline to petrochemical plants, refineries, and other gas liquids customers. Some of the heavier liquids are often temporarily stored in tanks on site and then trucked to customers.

Various types of processing plants have been utilized since the mid-1850s to extract liquids, such as natural gasoline, from produced crude oil. However, for many years, natural gas was not a sought after fuel. Prior to the early 20th century, most of it was flared or simply vented into the atmosphere, primarily because the available pipeline technology permitted only very short-distance transmission. It was not until the early 1920s, when reliable pipe welding techniques were developed, that a need for natural gas processing arose. Yet, while a rudimentary network of relatively long-distance natural gas pipelines was in place by 1932, and some natural gas processing plants were installed upstream in major production areas,12 the depression of the

1930s and the duration of World War II slowed the growth of natural gas demand and the need for more processing plants.

After World War II, particularly during the 1950s, the development of plastics and other new products that required natural gas and petroleum as a production component coincided with improvements in pipeline welding and pipeline manufacturing techniques. The increased demand for natural gas as an industrial feedstock and industrial fuel supported the growth of major natural gas transportation systems, which in turn improved the marketability and availability of natural gas for residential and commercial use. Consequently, as the natural gas pipeline network itself became more efficient and regulated the need for more and better natural gas processing increased both the number and operational efficiencies of natural gas processing plants.

The raw natural gas and condensate feed is processed at the processing platform. The well fluid from various Wells/ Well Platforms / Subsea Manifold reaches the process complex via subsea pipelines and two risers (24" each) and is further processed in more than one train. Each Train will normally consist of a Production Manifold (out of scope of the project) , Well fluid heater, Inlet Separator, coolant cooler, coolant tanks and sea water lifting pumps and coolant pumping Pumps. Well Fluid is received in the Production Manifold is dozed with corrosion inhibitors to promote corrosion inhibition program. Then it is cooled in well fluid cooler with sweet water at ambient conditions by flowing it through a shell and tube heat exchanger, with the well fluid on the tube side and sweet water on the shell side. This cooling enables better separation of gas and condensates in Inlet Separator. The Well Fluid from Well fluid cooler reaches the Separator. The gas is then sent out through a pig launcher of 36" and 42". The liquids are further sent for processing. The report further talks about the equipments utilized in the processing.[ii]

3 METHODOLOGY

3.1 Process Circuits

The designing of this separation facility is rather complicated because of presence of mixed feed, sour conditions and to add to it the high temperatures and high pressures. This designing had to be done from the very scratch. After the initial literature survey regarding natural gas processing and the procedures adopted, the next step was to identify the equipments that needed to be chosen for the efficient suggestion as picked up from the literature survey.

The process of separating natural gas and condensates i.e. the sour feed here, can essentially be understood in two circuits. Circuit one can be thought of as a train that cools the incoming crude and circuit two re-circulates the coolant.

Circuit 1

The feed at the processing facility reaches at a temperature as high as 70 ^{0}C and at a pressure of about 100 kg/cm$^{2.}$ This needs to be cooled before it is sent out for further treatment. The sour crude is made to pass through an exchanger or also known as the well fluid cooler to reduce the temperature of the feed to roughly about 35 ^{0}C. The feed is cooled using sweet/treated water. The outlet of the well fluid cooler drops the temperature of the feed to 35 0C and it is then sent out through the piping to the inlet of a separator for extracting the natural gas and condensates. The natural gas is collected at the top of the column and the natural gas liquids also known as the condensates are recovered from the bottom. The natural gas liquids thus collected as sent out for further processing in the facility, while the gas from the top is sent out to the trunk lines of 36” and 42”.

Circuit 2

This cycle essentially is about cooling the coolant, i.e. the sweet water. The objective being to re - attain the temperature of the coolant and to pump it back for continued usage. The outlet of the well fluid cooler leaves the water at raised temperatures of about 40 ^{0}C , this is cooled using sea water by making use of another heat exchanger.

So at this stage we can ascertain the types and number of equipments required for the entire processing facility.

The feed being large of about 10 MMSCMD (though the design of the platform has been up scaled to 12.5- 15 MMSCMD to meet larger quantities) will require an array of equipments for treatment.

These can be enlisted as below:

For Circuit 1

- Well fluid cooler
- Separator, along with internals

For Circuit 2

- Expansion Tank
- Heat Exchanger/Coolant Cooler
- Coolant pumping pumps
- Sea water lift pumps
- Storage Tank for coolant

3.2 Equipment Selection

The previous section of the chapter covered the processing aspect of the facility, in this section we will mostly be emphasizing on the areas pertaining to selection of equipments and the rationale behind it. The consequent chapter will take into account the sizing of the chosen equipments (from here) to evolve the detailed design, these can be later taken up to the mechanical designers and manufacturers to ensure the suitable supply of the equipment.

3.2.1 Well Fluid Cooler

A well fluid cooler can be understood as heat exchangers, having the feed and sweet water as the operating fluids. The most suited heat exchanger configuration for this kind would be a shell and tube heat exchanger. The feed is sour and corrosion problems may occur, so it is made to pass through the tube side and the sweet water is made to flow in the shell side. The feed loses heat and vaporizes the water on the shell side, and increases it temperatures. Because the heat duty of the entire process s very large, we would prefer going with a parallel arrangement of two heat exchangers and preferably double mounted to reduce the size and add compactness to it. Thus the final well fluid cooler assembly would comprise of two double barrel heat exchangers.

3.2.2 Feed Separator

The feed after having being cooled is passed on to the separator inlet nozzle through pipes of 6” diameter. The feed has a GOR of about 2500, and thus the condensates content is fairly low. Owing to the constraints to offshore environments and suitability of the feed, a two phase vertical separator would be the most suitable of all possible configurations, as it would take the least space and can handle large volumes of gaseous phase with ease.

The internals of the two phase separator will essentially include baffles, mist extractors, vortex breakers amongst others.

Note: While making a selection of the equipments, it should be borne in mind that no complex equipments requiring large amounts of ancillary equipments must be chosen, as the technology easy turns obsolete and maintenance of such equipments is difficult. And if the processing facility is to be installed for a long span of time say five or seven years, such operations of high maintenances need to be kept to a minimum.

3.2.3 Expansion Tank

An expansion tank is very essential and inevitable in a heat transfer fluid system. This is so because when the fluids are heated there is an expansion in the volume of the fluids, as much as thirty percent increase. So an expansion tank in the system enables the fluid with the space to allow fluid expansion or extraction.

It also serves as a point for venting moisture and low boiling components. Sometimes it can also act as a reservoir for fluid that is kept at a temperature lower than the fluid temperature, which is being circulated. It also provides a positive head to the suction line in the circulation pump. The preferred design of expansion tank in this facility, here the drop leg diameter is kept same as the return header.

It would require a large amount of instrumentations but with proper expansion tank operation, one can help ensure that the system runs safely and provides the low maintenance operation that one should expect from a heat transfer fluid system.

3.2.3 Coolant Cooler

To cool the sweet water, a gasketed plate type heat exchanger is most suited. This is because plates are attractive when material costs are high and these are easier to maintain. Plate heat exchangers are more flexible; it is easy to add extra plates and are more suitable for highly viscous materials. Fouling tends to be significantly less in plate heat exchangers.

3.2.4 Coolant Tank

Coolant tank can be simply understood as tank acting as a reservoir for storage of coolant i.e. sweetened water. The sweet water will be taken up from coolant tanks and pumped to the heat exchanger the tank will also receive cooled sweet water after passing through gasketed plate heat exchanger or the coolant cooler.

3.2.5 Coolant pump

As the heat exchanger for cooling the feed will be an assembly of two double - barrel shell and tube exchangers placed in parallel, the coolant pumps would be used in two plus one philosophy. Meaning, two pumps will separately cater to the loads for the heat exchangers and each would have a back up of the pump, common in both the loops in case one of them fails. The pump will essentially will centrifugal as the requirements are of larger flow rates and moderate heads. The deliverables after the design of the pump are the power requirement and delivered head. The design of the pumps is carried out in the report, using references from API670, API 610 and API682.

3.2.6 Vapor Compression

Vapor compression desalination is a distillation process where the evaporation of sea or saline water is obtained by the application of heat delivered by compressed vapor. The effect of compressing water vapor can be done by two methods.

The compression is mechanically powered by something such as a compression turbine. As vapor is generated, it is passed over to a heat exchanging condenser which returns the vapor to water. The resulting fresh water is moved to storage while the heat removed during condensation is transmitted to the remaining feedstock.

Marine Vapor Compression

Seawater is pumped into an evaporator, where it is boiled by a heating coil. Vapor produced is then compressed, raising its temperature. This heated vapor is used to heat the evaporator coils. Condensate from the coil outlet provides the fresh water supply. Both the fresh water production and the waste brine from the evaporator are led through an output cooler. This acts as a heat exchanger with the inlet seawater, pre-heating it to improve efficiency. The plant may operate at either a low pressure or slight vacuum, according to design. As the evaporator works at pressure, not under vacuum, boiling may be violent. To avoid the risk of priming and a carry - over of saltwater into the vapor, the evaporator is divided by a bubble cap separator

Some of the highlights of marine compression systems are as mentioned below

Produces potable drinking water and high-quality distilled water, the packaged units are completed with minimum field installations. They have superior energy efficiency over other means and offer large vapor compression capacity of as large as 15,000 gallons per hours.
The fabrication involves corrosion resistant materials like 90/10 copper nickel, titanium, inconel and monel. Class 150 ANSI flange connections are provided. This is also best suited as it is space friendly, offers smaller footprint and easy operation and maintenance.
Thus the sweet water being utilized in the well fluid cooler is provided by either boats o vapor compression making use of water through the available portable water systems on the separation facility, as explained above. Naturally a small amount of the water will be lost and some of the water will be evaporated. Fresh water make-up line is supplied to the tower basin to compensate for the loss of evaporated water, the loss water and the draw-off water.

3.2.7 Sea Water Lift Pumps

Seawater is used in many circuits in offshore processing plants and therefore it is an important fluid in processing. Seawater is pumped up to the platform, where it is then filtered and cleaned. Thus designing of sea water lift pumps is also crucial to provide reliable and efficient performance. These are usually low pressure systems and high circulation rates as they have to provide for large heat needs. Newer technologies are being brought to enhance the operating efficiency at minimal costs.

3.2.8 Products of separation

The gas is collected at the top, and is sent for further gas processing through two pipelines by means of pig launcher into trunk lines of 36” and 42”. The riser carrying the raw gas at the beginning runs straight across the platform and thus carries the processed and separated gas for further use. The condensates are recovered from the base of the separator and processed ahead. Pig launcher and pig receiver shall be equipped with an interlock system to prevent opening of isolation valves around the launcher when the launcher door is open. Flexible hose for purging with inert gas shall be available. Local pressure monitoring shall be provided for pig launchers and pig receivers. When frequent pigging is necessary, pressure monitoring and pig detector alarm for launcher and receiver may be required. Pig trolley and lifting arrangement shall be considered. Space for transportation and handling of pigs to/from pig launcher and pig receiver shall be provided. Drain/vents Pig receivers/launchers shall be connected to flare, vent and drain system with hard piping. Pig receivers and launchers shall be provided with a small bore valve and vent (typical ½") to verify that the system is completely de-pressurised prior to opening the door.

This completes the process circuit of the raw natural gas.

3.3 Process Flow Diagram

This section attends to the preparation and presentation of the process flowsheet, also known as the process flow diagram (PFD). The flowsheet is the key document in process design. It shows the arrangement of the equipment selected to carry out the process, the stream connections, stream flow rates and compositions, and the operating conditions. It is a diagrammatic model of the process. The flowsheet is used by specialist design groups as the basis for their designs. These include piping, instrumentation, and equipment design and plant layout. It is also used by operating personnel for the preparation of operating manuals and operator training. During plant startup and subsequent operation, the flowsheet forms a basis for comparison of operating performance with design.

The flowsheet is drawn up from material balances made over the complete process and each individual unit operation. Energy balances are also made to determine the energy flows and the utility requirements. Most flowsheet calculations are carried out using commercial process simulation programs. The process simulation for this facility was carried out in various stages and revisions were continually made.

3.3.1 Process flow Diagram Phase I

Therefore after going through the concerned literature and the selection of equipments the equipments were logically arranged in a sequence and a rough flow diagram was decided. It is as shown below. It roughly shows the sketch of the fluid flow across the facility.

Suggestions and Corrections

To do : intricately design the process equipments

To find: suitable metallurgy

To incorporate: vessel internals

To consider: instrumentation and gauges for level, temperature and pressure

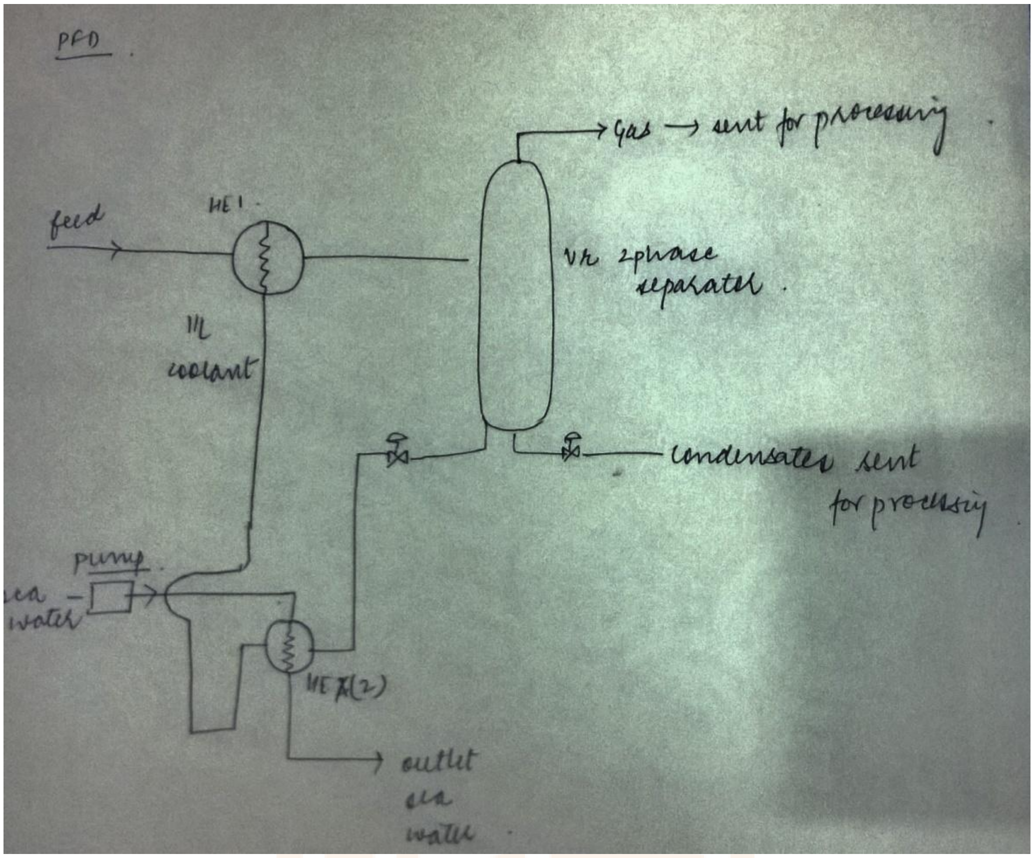

Fig 2- Process Flow Diagram – Phase 1

3.3.2 Process Flow Diagram - Phase II

On further analysis and to incorporate the suggestions from phase 1, the following process flow diagram was pulled up.

This PFD took into account the various process flow parameters such as flow rates, pressures, inlet outlet temperatures, liquid/gaseous levels and was more accurately designed.

Also to bring to notice, this particular revision had a lot many types of equipment besides a basic well fluid cooler and a separator like – expansion tank, pumps, coolant tanks, vapor compressors etc.

Suggestions:

At this stage, a lot many corrections from previous iteration were incorporated. Of the things which remained were as follows:

- Material selection for equipment fabrication
- Instrumentation

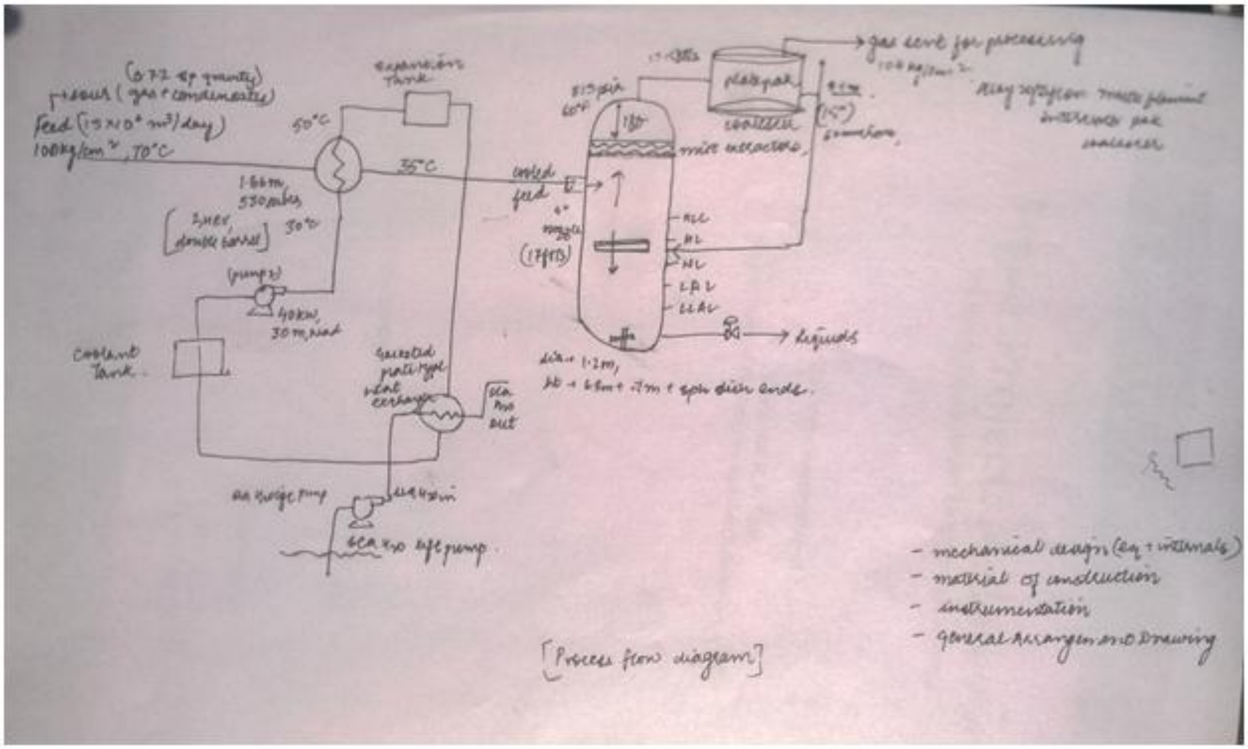

Fig 3 – Process Flow Diagram – Phase II

3.3.3 Process Flow Diagram – Phase III

In this revision, the operating philosophy was addressed. Also the hand drawings were now made using softwares like Edraw to enable a better picture of the situation. The third stage of PFD revision is as attached here:

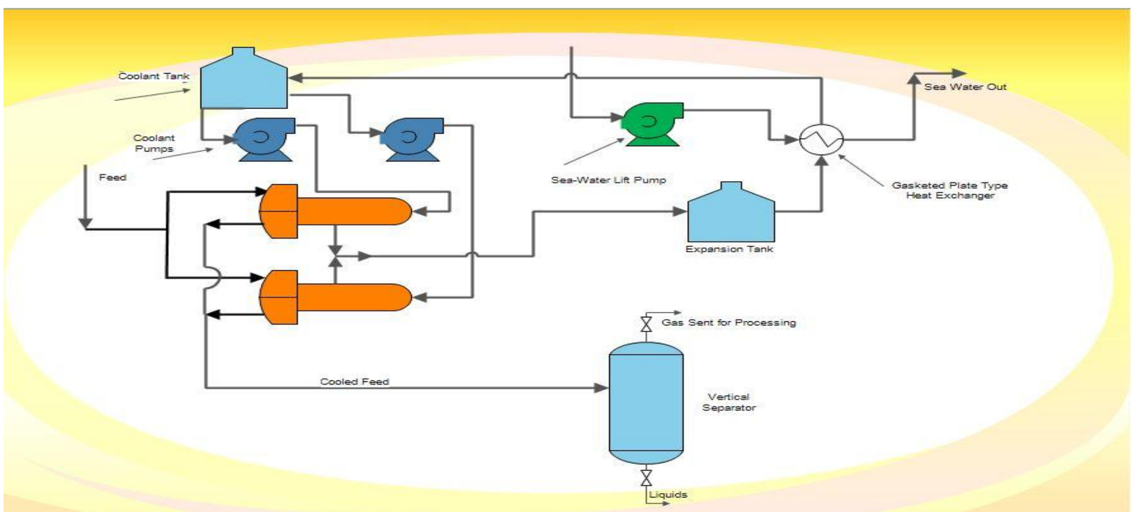

Fig 4 – Process Flow Diagram – Phase III

3.3.4 Process Flow Diagram – Phase IV

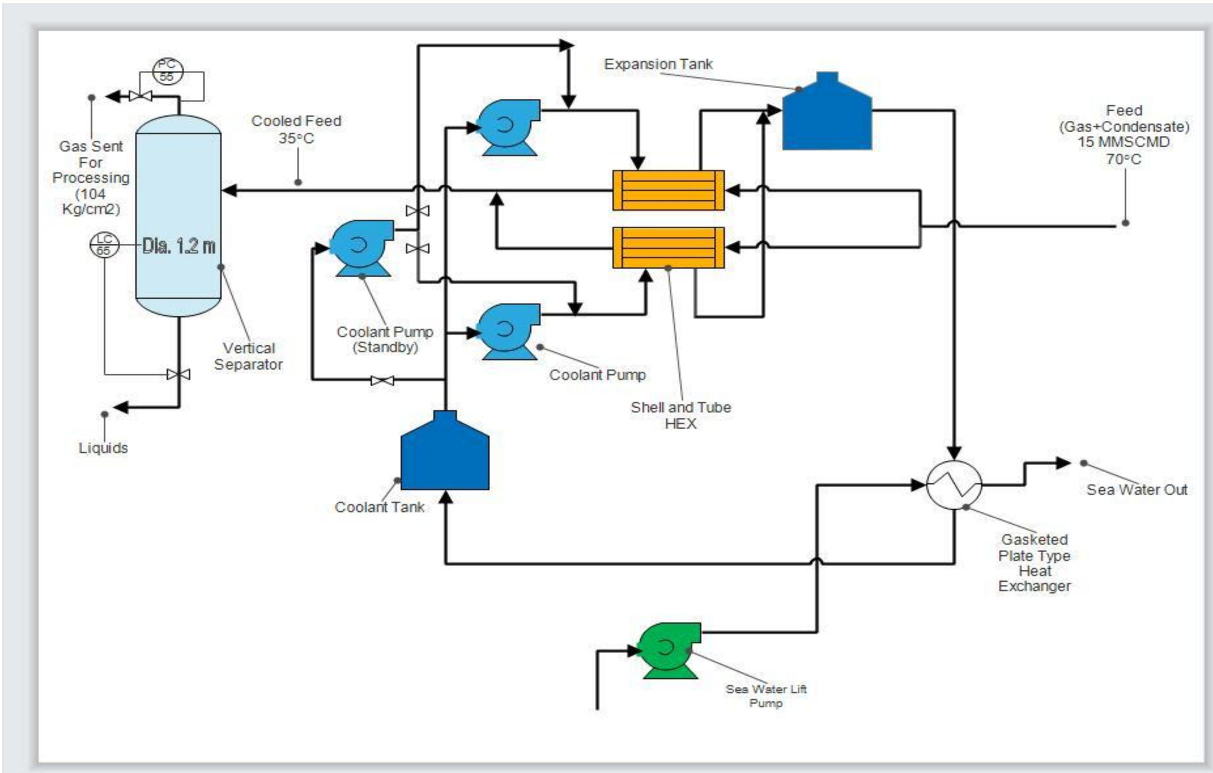

Fig 5 – Process Flow Diagram – Final Version

As shown above is the finalized process flow diagram of the offshore separation facility.

This includes all the possible equipments to be used, stresses on the operating philosophy – of using two double barreled shell and tube heat exchangers in parallel, thereby needing two pumps for each. Not shown here is the stand by pump for pumping coolant to the heat exchanger. This stand by pump is made available in the loops of both the pump circuits, to be utilized when the main pumps are set off. The flow sheet also represents the instrumentation and usage of valves proposed.

3.4 General Arrangement Drawing

The separation facility can be visualized better with the help of an elevation diagram or a general arrangement design.

It consists of three floors, the cellar deck which is the bottom- most of all, this holds above it the middle deck and the top deck is above this. In between the top deck and the middle deck a mezzanine deck is provided. The further expansion of the deck led to the installation of a pig launching facility at the top of the top deck.

The cellar deck receives the feed through the well fluid lines and discharges it into the manifold. The deck has provisions for installations of two risers of 24" diameter. It houses the two coolant pumps that provide sweet water for feed cooling. The deck also hold the sea water lift pump for provision of sea water for various utilities like cooling and drinking water purposes.

On the middle deck of the facility, the two phase vertical separator is provided. The control room for the facility is also housed on the middle deck along with the coolant tank- which acts as a reservoir for holding coolant. it also has space for the coalescer if need persists.

The mezzanine deck has the coolant cooler – a gasketed plate type exchanger and a metering skid.

While on the top deck, the well fluid cooler is placed. Above this is the area for pig launcher and the 42" trunk line.

The gas is provided by the riser to the manifold and is taken all the way up to the well fluid cooler on the top deck, the cooled feed is fed to the separator on the middle deck. The condensates are recovered at the floor and sent out for further processing and the gas is sent to the 36" trunk line after passing through the metering skid at the mezzanine deck and the 42" line on the newly installed line. The coolant is cooled on the mezzanine deck and is pumped by the centrifugal pumps on the cellar deck by sea water, which lifts water from the sea using a sea water lift pump installed at the cellar deck too.

The cellar deck is about 50m x 35m in area and about 18.4 m above the sea level. the middle deck is 27.5 m above the sea level and around 40m x 40m, followed by top deck at 34.7 m above the sea level and about 30m x 30m. The pig launcher on the top most deck is at 45 m from the sea level and is 20m x 20m in area.

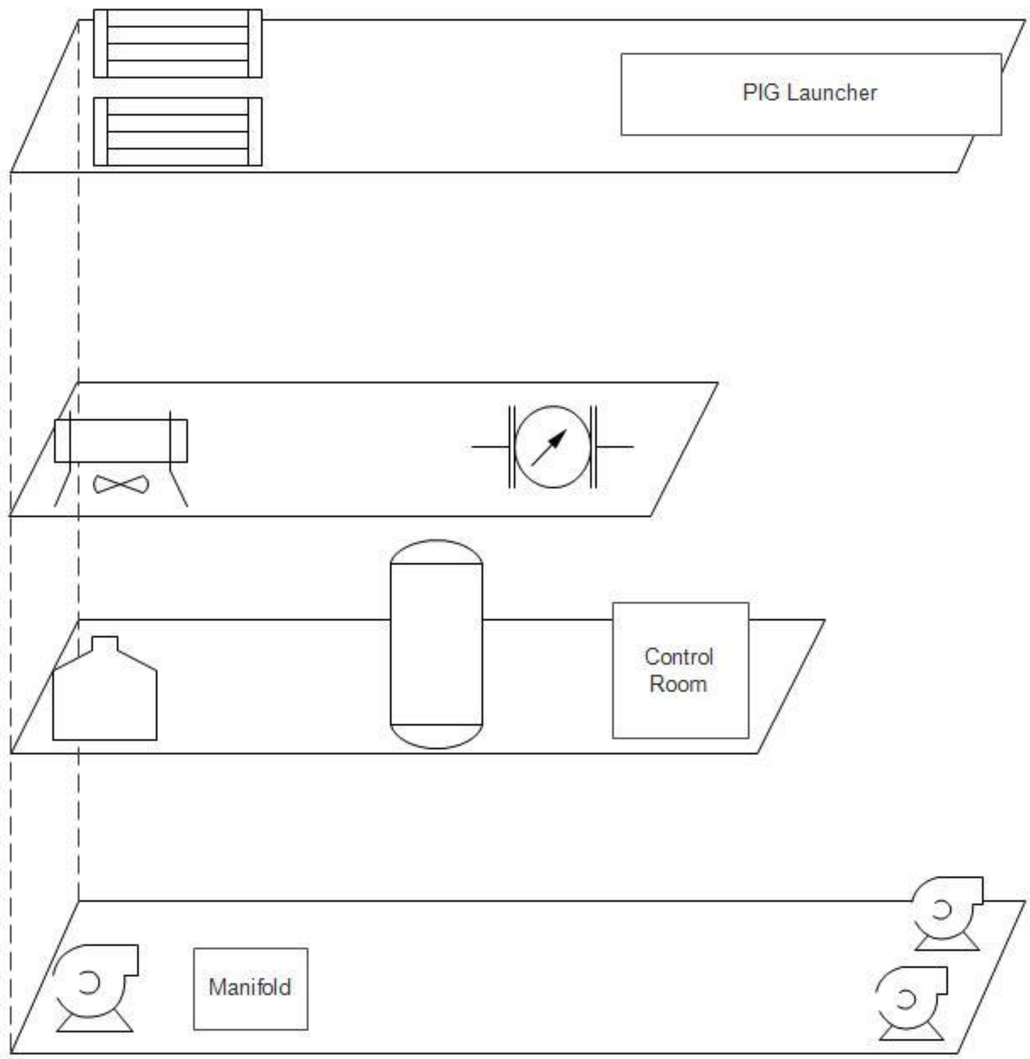

Fig 6 – Elevation drawing of the platform

Note: Due to constraint of time, the general arrangement drawing of the platform could not be computerized and thus is not shown here.

4 EQUIPMENT SIZING CALCULATIONS

Before individually taking to equipment sizing, it is imperative to note the given input parameters, these are as shown:

4.3 Input data – Raw Natural Gas

GOR	2500 cubic meter/cubic meter
Flow rate	15million cubic meters
Specific gravity	0.8296
Specific heat of fluid	2.3 kJ/kg ^{o}C
Inlet temperature of feed	70 ^{o}C
Outlet temperature of feed	35 ^{o}C
Cooling water, inlet temperature	30 ^{o}C
Sea water, inlet temperature	27 ^{o}C
Operating pressure	100 kg/sq cm
Maximum allowable pressure drop	5 kg/sq cm

4.2 Problem Statement

To design an offshore separation facility for sour crude feed at high temperature high pressures, starting from the scratch. The following steps will be adopted

- After the selection of equipments, process design of the equipments
- Consult with the mentor and re-iterate if foot size if too large
- Careful selection of materials of construction, once the sizing of equipments has been approved taking into regard corrosion tendencies and high operating temperature and pressures
- Calculate the foot size of all the equipments
- Identify the plausible locations of each of these equipments for a general arrangement drawing
- Generate isometric drawing and form a three dimensional model of the designed platform
- Carry out the ball park economic evaluation of the platform

4.3 Well Fluid Cooler Sizing

As mentioned above a well fluid cooler can be understood as shell tube exchanger with the sour feed as the tube side fluid and sweet water as the shell side fluid.

4.3.1 To estimate the mass flow rate of the coolant.

Input parameters are as follows:

Feed, inlet temperature = 70 ^{0}C

Feed, outlet temperature= 35^{0}C

Coolant, inlet temperature= 25^{0}C

Coolant, outlet temperature= 40^{0}C

Volumetric flow rate= 15 * 10^6 m^3/ day = 173.611 m^3/s

GOR= 2500

Density of feed = 0.96

Specific heat of feed = 2.3 kJ/kg K

Therefore, mass flow rate of coolant = density*volumetric flow rate

= 0.96*173.611

= 170.496 kg/s

Heat Duty of the exchanger becomes = mass flow rate*Specific heat* Temperature difference

= 170.496*2.3*(75-35)

= 15685.65 kJ /s

As the exchangers are in parallel, heat duty gets halved for each unit;

Therefore for each shell and tube exchanger, Heat Duty = 7842.82 kJ /s

Likewise, mass flow rate of coolant = 87.14 kg /s

Calculating the log mean temperature difference LMTD = $\Delta T_1 - \Delta T_2 / \ln (\Delta T_1/\Delta T_2)$

= 10.82

Calculating correction factor F,

Estimating the value of R = 1.86

Estimating the value of S= 0.358

From graph, Value of F comes out to be = 0.776

Corrected Temperature difference = 0.776*

= 8.39

Calculating the area of heat exchange = Heat Duty / (Overall ht. transfer coeff *Corrected Temp)

= 7842.824/(4000*8.39))

= 2335.305 m^2

Assuming the tube diameter to be = 2.5 inches or 0.0635 mm

And a tube length of = 18 m

No of tubes = Area/ (π*d*l)

= 2335.305/ (3.14*0.0635*18)

= 530 tubes

Bundle Diameter = 2.5 (530/ π*0.0635^2)^(1/2.207)

= 1596 mm

Shell Diameter = 84 mm + 1596 mm

Shell Diameter = 1.66 m

16 baffles at a distance of 1.15 m, and about 25% cut

After making tedious calculations for tube side and shell side the overall pressure drop across the shell and tube exchanger comes out to be 0.39 psi.

Now the dimensions of the well fluid cooler have been obtained of about 1.66 m and the pressure drop of roughly about 0.39 psi.

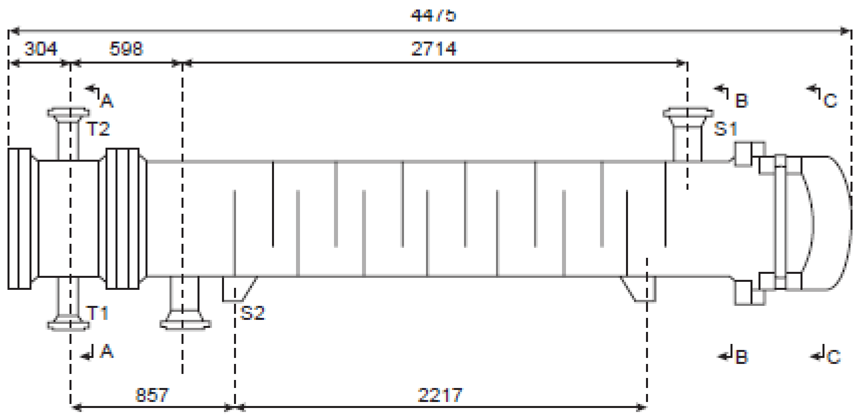

Fig 7 – representative shell and tube well fluid cooler

Structural Mounting

Structural support must be adequate so that exchangers will not settle and cause strains on piping connections. Shell and tube heat exchangers must be mounted on elevated support legs, which in turn should be anchored to housekeeping pad with anchor bolts. In general, suspension of heat exchangers from piping or structure above must be avoided. Shell-and tube heat exchangers must be installed on saddle supports. One end of the shell fasteners shall be left loose to allow proper expansion compensation of the shell

The following support saddle options can be adopted:

- Fabricated of material similar to shell.
- Fabricate foot mount with provision for anchoring to support.
- For project with seismic restraint requirements as determined by Structural Engineer. Fabricate attachment of saddle supports to pressure vessel with reinforcement strong enough to resist heat-exchanger movement during seismic event when heat-exchanger saddles are anchored to building structure

Note - It is also strongly recommended that a low cracking pressure direct acting relief valve be installed at the heat exchanger inlet to protect it from pressure spikes by bypassing oil in the event the system experiences a high flow surge. Nozzles for chemical flushing should be located on the heat exchanger or on the piping near to the heat exchanger to minimize chemical consumption (volume to be flushed). It shall be possible to isolate the exchanger by removing the removable spools, by inserting blinds or by the use of valves. It shall be possible to drain out all chemicals after a "cleaning in place" operation. Nozzles for chemical cleaning and vent/drain can be combined. It shall be possible to drain and vent all heat exchangers.

4.4 Gasketed Plate Type Heat Exchanger Design

Gasketed plate heat exchanger is the next generation of large plate heat exchangers designed for central cooling systems. Its space-saving design and innovative features means that less raw materials are used to achieve higher heat transfer efficiency than comparable units.

Other benefits include

- *Lower investment costs*
- *Higher heat transfer efficiency*
- *Flexible and compact*
- *Low maintenance costs*

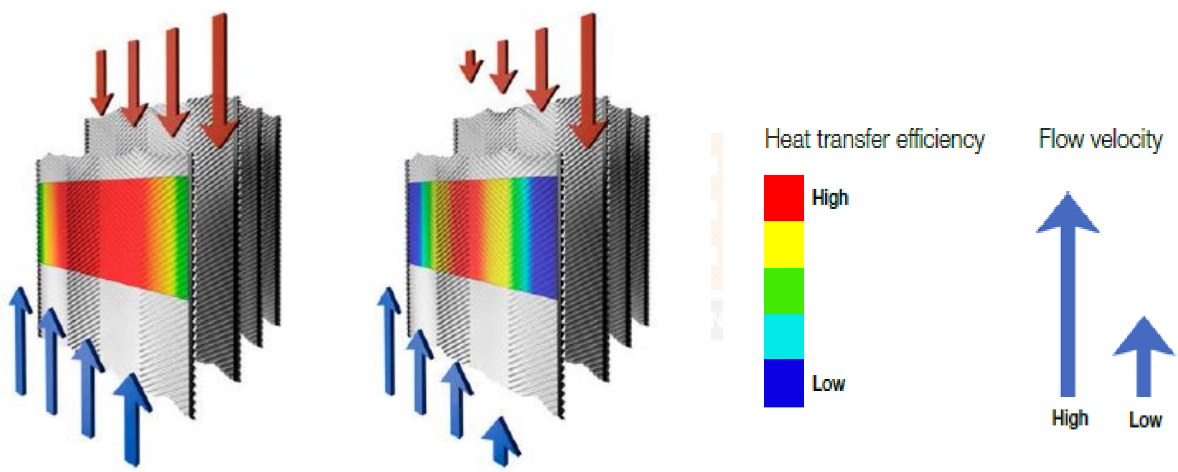

Fig 8 – heat transfer in plate type exchanger Vs conventional plates

The design of gasketed heat exchanger is in accordance to the flow rates of the coolant of about 170 kg/s , as obtained from the well fluid cooler calculations. The heat duty remains the same, the sizing calculations are made and the dimensional drawing is pulled up .

Material of construction

- The plates are made of stainless steel Alloy 304, Alloy 316, Titanium,
- Frame/pressure plate of mild steel, coated with water-based epoxy paint
- Gaskets from Nitrile, EPDM
- Connection - Carbon steel, rubber linings Metal lined: Stainless steel Alloy 316, Titanium

The heat exchanger has been made to tolerate pressures as high as 0.6 MPa and to withstand temperatures of about 140 ^{0}C, all the connections are standard 350mm / 14” and the sizing estimates are as shown in the dimensional drawing shown below:

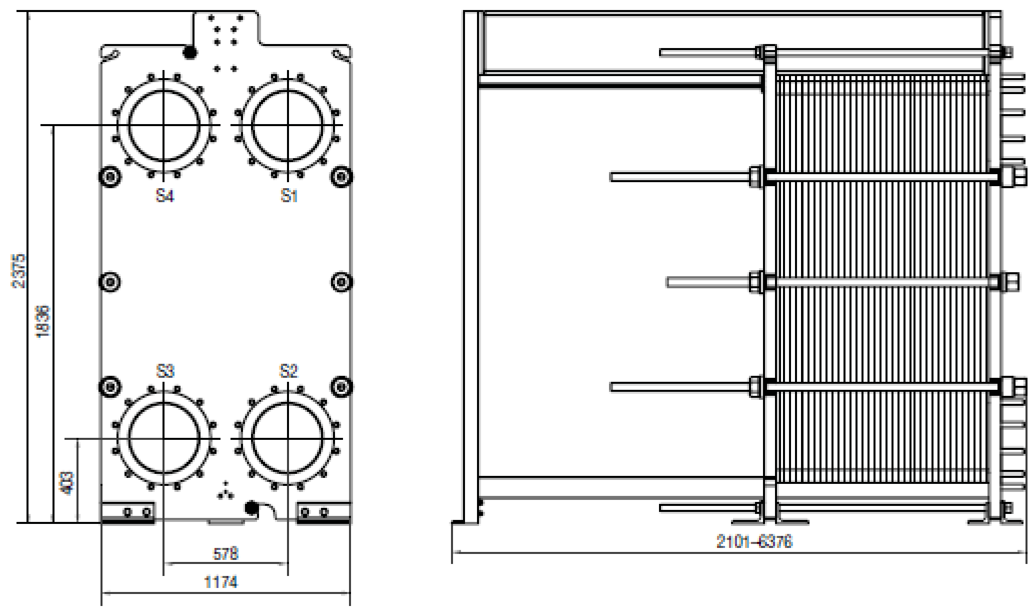

Fig 9 – dimensional drawing of gasketed plate type eat exchanger

Length (including the casing enclosure) = 2.1 m

Width (including the casing enclosure) = 1.17m

Height of the exchanger = 2.375 m

4.5 Two Phase Vertical Separator Sizing

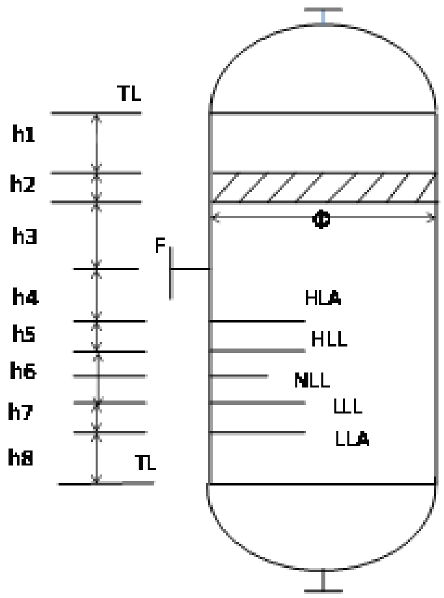

Fig 10 –Two - phase vertical separator

The operating parameters considered were

- Operating Pressure = 815 psia
- Operating Temperature ^{0}R= 520
- Gas flow rate =529.51 bbl/day
- Gas density =0.04777237 lb/ft^3
- Actual volume flow =15 MMSCMD

1. Vapor-liquid settling velocity: $V_{s=}K((\rho_L-\rho_V)/\rho_V)^{1/2}$=0.003616(D/C)$^{1/2}(\rho_L-\rho_V)/\rho_V)^{1/2}$

= 0.43 m/s

2. Derating%=85

Maximum velocity $\mathbf{V_{m=}0.85 \times V_s=0.3655}$ **m/s**

2 Drum flow area= Actual volumetric flow/Max.velocity(V_m)

=**1.1309 m^2**

3. Calculated drum diameter Φ=1.2 m=1200 mm

Selected Diameter =1200mm (rounded to nearest 50mm)

4. Required liquid hold-up times

h_5=200 mm

h6=350 mm

h_7=150 mm

5. Mesh pad: Yes

Thickness=150 mm

6. Height Calculation

Φ=1200 mm

h_1:15% of Φ=180 mm

h_2: mesh pad = 150 mm

h_3: 50% of Φ=600 mm

With mesh $h_1+h_2+h_3$=930 mm

h_4:400mm +d/2=450.8 , d=inlet nozzle

h_5: 1800mm

h_6: 3500mm

h_7: 1200mm

h_8: 1500mm

For dry vessel

$h_6+h_7+h_8$=6270mm

the separator would be provided with spherical dished ends, given the inside radius comes out to be 12oo mm, the crown radius of 1200 mm can be chosen and standard tables can be referred for calculating the height of the dished ends using formula as shown below

Outside dishing end height ho = $R_o - (R_o - D_o/2)*(R_o + D_o/2 - 2R_o)$

Length comes out to be = 1038 mm

Therefore total vessel height = 2*1038 + 5124

Total Vessel Height=7200 mm

7. Wall Thickness

Design pressure P= 815 psia

Diameter D=1200 mm

Corrosion allowance C=3 mm

Stress=15700 psia (for C.S)

Efficiency=0.85

t= (P×D/(2×S×E-1.2P)) +C

Thickness = 1.26 inches

8. Vessel Weight

t= 1.26 inches	Shell weight=14028 kg
L= 7.2m	Head weight (t $\times D^2 \times 20$) =8248.2 kg
D=1.2m	**Total Weight=22276.2 kg**

Vertical separators are supported only at the base by means of bottom skirts, unlike the horizontal separators. Thus walls of vertical separators are somewhat thicker than similarly designed horizontal separators that are supported by saddles.

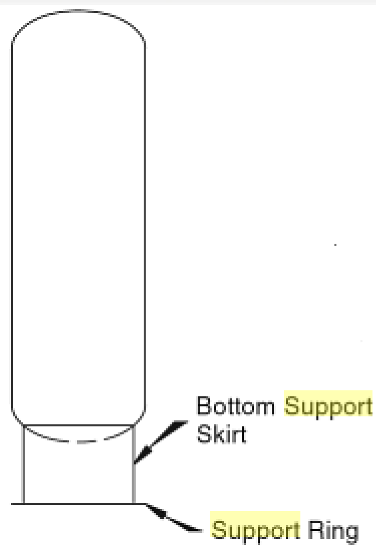

Fig 11- support systems for vertical separators

Vessel Internals

Inlet Nozzle

The erosional velocity is calculated to ensure no dislodging of the nozzle occurs, using API 14RE relation, V= C/(ρ^0.5)

Inlet nozzle velocity = 76.219 m/s

The nozzle will be sized at 4 inches, each pore opening of about 30 mm.

Mist Extractors

The coalescer design calculated as shown below:

V_t = 1.78*10^(-6) (difference in specific gravity)*d^2/μ

= 17.115 ft/s

Volume of the coalescer unit = 164*2751792*0.0013/(0.2*250*250)

= 3259.34 cu. Ft

This can be tweaked to get the combination of height and diameter of coalescer unit, which most suitably comes out to be 68" and about 1.12 m in height.

Vane type Mist Extractors

The re-entrainment point is a function of gas velocity, as well as other physical properties, e.g., vapor density, liquid density, and liquid surface tension. The re-entrainment point is also highly sensitive to the geometry of the chevron. A chevron with superior liquid draining capability and optimum chevron blade spacing can be operated at a higher re-entrainment point, yielding a higher capacity. The difference between droplet penetration and re-entrainment is often confused. Droplets that penetrate the chevron are too small to be effectively removed by impaction. On the other hand, re-entrained droplets are generally quite large and originate from droplets that have coalesced on the chevron blades. At high gas velocities, a chevron can have a removal efficiency of 100% and, simultaneously, re-entrain extensively. Conversely, at low gas velocities, the chevron may not re-entrain but has insufficient removal. Optimal chevron performance is achieved at a gas velocity that is as high as possible but not so high that it yields re-entrainment.

In arriving at an optimal design, it is often necessary to make a compromise between removal efficiency on the one hand and pressure drop and plugging tendency on the other.

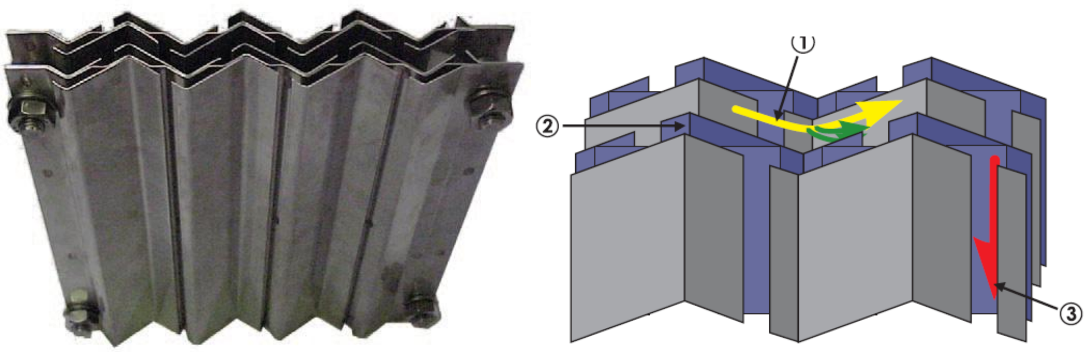

Fig 12 – vane type mist extractors

How the mist extractor works:

1. Double pocket hooks direct the collected liquid (green arrow) away from the main gas stream (yellow arrow).

2. The collected liquid (green arrow) flows into separate channels (purple).

3. The separate channels move the liquid away from the gas (red arrow). Because the liquid is now isolated from the gas stream and less subject to re-entrainment, gas velocities can be more than doubled in both horizontal and vertical gas flow configurations.

Materials of Construction - Stainless steel, carbon steel, nickel – based alloys, titanium

The separators and the vessel internals have been designed as per API 14 RE

Initially it was thought to have knitted mesh type mist extractors, but it was eventually realized that frequent choking of the mesh type extractors could induce a back pressure on the separator system, causing the alarms to go off and in turn shut off the entire system. More so mesh type extractors would require frequent maintenance on account of flooding and this would require venting out the separator, purging it with nitrogen and flushing in air for maintenance personnel to enter – this would just add on the downtime. From investment point of view, this step was very crucial, as mesh type extractors would need a coalescer assembly followed by the separation at the column, this would not only involve costs of setting up a coalescer unit and its maintenance but also involve operational troubles as the coalescer on over loading would lead to shutting down of the entire separation facility.

4.6 Expansion Tank

Although an easy-to-forget component in a thermal fluid heating system, the expansion tank is vitally important to reliable system operation.

The expansion tank serves four distinct and equally important roles in the thermal fluid system:

- Ensuring that the system is completely flooded.
- Serving as the reservoir for the heat transfer fluid to expand into as the fluid heats up.
- Separating water and other non-condensable species from the fluid on startup.
- Controlling the environment between the heat transfer fluid and the atmosphere.

Ensuring That the System Is Completely Flooded: It is important that the thermal fluid system be completely flooded with fluid. Any bubbles will affect the performance of the pump, can cause overheating in the heater coil, and can negatively affect heat transfer in the heat users. To this end, the expansion tank should be located at the highest point in the system.

If design constraints prevent the proper location of the expansion tank, it can be located lower, even at grade, but the tank must be pressurized with nitrogen (or other inert gas) to provide enough pressure to force the fluid to the high point. It should be noted that systems with low-mounted expansion tanks may not be as easy to fill or de-gas as systems with properly located tanks.

Expansion Reservoir (Sizing the Expansion Tank): Choosing the heat transfer fluid is the single most important decision made in specifying a new system. Here is one reason why: Depending on the temperature of the system and the heat transfer fluid chosen, the fluid can expand in volume from as little as 20 percent to more than 35 percent. The owner needs to have the following information to properly estimate the required size of the expansion tank.

- The thermal fluid to be used and its coefficient of thermal expansion.
- Minimum (startup) temperature.

- Maximum (design) temperature.
- Total volume of the thermal fluid system.

With this information, the total expansion of the thermal fluid, in gallons, can be calculated. Ideally, one would want the expansion tank to be about one-quarter full with the system ready to start up and about three-quarters full with the system at full design temperature.

Placement of the tank is important. It should be positioned on the main circulation loop on the suction side of the pump. In this location, it helps ensure that the pump has flooded-suction conditions, which makes system filling and de-gassing much more efficient.

Controlling the Environment at the Fluid-to-Atmosphere Interface : The owner, or his outside resource, must evaluate the thermal fluid chosen to determine what environmental controls need to be installed on the expansion tank. The evaluation should consider properties of the fluid properties to make a proper determination.

Standards of construction/design

In order to have traceability of the materials and procedures used to construct the tank, the expansion tanks need to be constructed in accordance with ASME Section VIII, Division 1 of the pressure vessel code. This requirement results in a tank constructed with materials and weld materials traceable to a national standard, and with welds made by a certified welder.

Instrumentation and Appurtenances

The expansion tank is a component of the thermal fluid system and, as such, needs to be operated. As a minimum, the fluid level in the expansion tank should be recorded daily to monitor the fluid inventory. The level device can be as simple as an armored gauge glass or as sophisticated as an electronic level transmitter, but the fluid level should be monitored. Decreases can indicate loss of fluid due to leaks or volatility. Increases can indicate contamination from leaking heat exchangers, the process or other sources.

A low level switch (shown in the figures as LSLL) is installed on the tank and is connected to the heater shutdown circuit. This safety reduces the possibility of running the expansion tank out of fluid and allowing the heater run without fluid.

If the tank has an inert gas blanket, the pressure of the gas blanket should be monitored. If the inert gas blanket has a discrete source such as a high pressure gas bottle or a dewar of liquid gas, the inventory of the inert gas should be recorded as well.

Calibration of the pressure-relief valve (PRV) should be included in the facility's mechanical-integrity program. The pressure-relief valve should be removed and calibrated periodically.

In addition, a simple pressure gauge (mounted on a connection on the top of the tank) and temperature indicator (mounted in a thermo well located low on the tank to ensure that the liquid temperature -- rather than the gas -- is being measured) are a good idea. In addition, more sophisticated users will install extra instrumentation and will monitor expansion tank conditions remotely in a control room or at a process control panel.

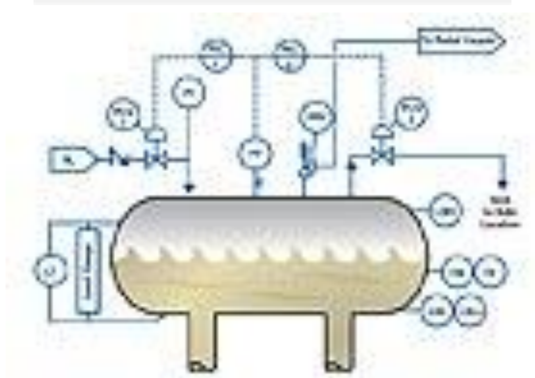

Fig13 – expansion tank and associated instrumentation

Sizing

$$\mathbf{V_{et} = k\ V_w\ [\{(V_1/V_o)-1\} / (P_a/P_o)-(P_a/P_1)]}$$

Where P_a – atmospheric pressure

P_o – system initial pressure, psia

P_1 – system operating pressure, psia

K – safety factor, usually 2

V_{et} – required expansion tank volume, gallons

V_w – water volume in tank, gallons

V_o – specific volume at initial temperature, cu ft/ lb

V_1 - specific volume at final temperature, cu ft/lb

V_{et} = 2* 88* 10^3 * 219.96/1000 * ((14.7/52)-(14.7/49))

= 19122.7 gallons

The expansion tank volume comes to be about 19122.7 gallons.

4.7 Coolant Pumping Pump

Note: The pumps have been designed as per the centrifugal codes - API 670, API 610 and API 682 codes for shaft sealing.

Two of such units will be required to pump the coolant for two heat exchangers, since the flow rates will be larger and pressure head nominal, centrifugal would be the most suitable of all configurations.

Mass flow rate of coolant = 88 kg/s

Inside diameter of pipe = 20 cm, = 0.20 m

Cross sectional area = π*0.2*0.2/4

= 0.0324 m^2

Flow velocity = mass flow rate/ cross sectional area*density

= 0.0518 m/ s

Viscosity = 0.00089

Reynolds Number = ρ*v*d/ μ

= 1000*0.0518*0.20/0.00089

= 11827.85

Absolute roughness for SS = 0.000015

Wetted perimeter = π*outside diameter

= 0.6383 m

Hydraulic Radius = Cross sectional Area/ (4*wetted perimeter)

= 0.0127 m

k/dh = absolute roughness/hydraulic radius

= 0.000015/ (0.0127)

= 0.001181

Friction factor from moody's chart based on Reynolds's number and k/dh = 0.022

Major losses in pipeline = friction factor*10/hydraulic radius*density*velocity^2/ 2

= 23.245 Pa

Head losses = 0.0023m

Operating pressure In bar = 3.926

Total Head = 40.029m

Volumetric flow rate = 6048 m^3 /hr

Flow rate in gallons per minute = 26.63

These calculations are repeated for varying mass flow rates to generate the system curve of the pump.

The curve generated is then superimposed over the pump characteristic curves of industrially available pumps.

The two curves are superimposed to attain the operating point for optimum pump performance.

The curves for the particular facility have been attached in the annexure for reference.

4.8 Sea Water Lift Pumps

These pumps are essentially used to provide for the water to be sweetened and to cool the coolant. They are low pressure pumps but require larger volumetric flow rates

Power requirement of Pumps

The power requirement, P_h (KW) of pumps is given by

$$P_h = \text{Discharge} * \text{density} * g * h / \text{efficiency} * 3.6 * 10^6$$

Where

Efficiency is assumed to be 0.8, h is the differential head in m and discharge s in m^3/hr and density in kg/m^3

Pumps	**Differential Head**	**Density**	**Discharge**	**P_h**
Lifting Pump	72m	1020 kg/m^3	478.5 m^3/ hr	126 KW
Coolant Pumping	46m	1000 kg/ m^3	319 m^3 / hr	40 KW

4.9 Coatings

It is strongly recommended that all standard products be coated with a normal base coat of oil base air cure enamel paint. The enamel paint is applied as a temporary protective and esthetic coating prior to shipment. While the standard enamel coating is durable, the use does not warranty it as a long term finish coating. It is strongly suggested that a more durable final coating be applied after installation or prior to long-term storage in a corrosive environment to cover any accidental scratches, enhance esthetics, and further prevent corrosion. Special Coatings options include - Air-Dry Epoxy, and Heresite (Air-Dry Phenolic) coatings at additional cost.

4.11 Making Connections

The processing platform so far has been discreetly talked about, these equipments will now be required to put together. In all cases of joining of dissimilar metals, isolation joints will be furnished. All high pressure systems to be made of Class1500 and low pressure of class 150. The line connection across various equipments, well fluid lines etc will be provided with valves. All the valves employed will essentially be ball types and all times remain positively isolated so that they can be disengaged in case of emergency and work over, and ensure safety at all times as this is a high pressure high temperature system.

4.12 Welding

The welding operations in the processing platform take place in the following order.

First the root is welded using TIG. This is followed by the welding of the pass. The filler is provided next. The last to do is capping, i.e. the last bead of a groove weld, it can be made with a weave motion back and forth, or with stringer beads tied into each other. It is done by grinding of stress relieved material. These welds are now radio graphed, in case the capping is not as per the requirement, the process is re done.

4.13 Flange Connections

All flanges, a protruding rim, edge, rib, or collar, as on a wheel or a pipe shaft, used to strengthen an object, hold it in place, or attach it to another object will be ring joints and not gasketed.

4.14 Mountings

All mountings will be provided with isolation valaves, especially on the shell side with 100 per cent redundancy. Also the flanges of these mountings will be coated with liners and protected against corrosion.

4.15 Hydo Testing , Pre- Commissioning

Start-up

- Special consideration should be given to restart after a complete de-pressurization, especially if the injection wells are far from the compressor, i.e. subsea wells.
- If blow down valves are to be used in a start-up sequence, the blow down valves shall be designed with sufficient actuator force to close against maximum operational differential pressure.

Commissioning requirements

- Piping shall be fitted with high point vents and low point drains.

4.16 General Maintenance

Maintenance may be performed during operation since components are supplied with back up. Positive isolation is required for main equipment during maintenance.

Maintenance for heat exchangers

- Plate heat exchanger may need to be repaired/ overhauled onshore. Installation shall facilitate access for transportation.

Inspect the heat exchanger for loosened bolts, connections, rust spots, corrosion, and for internal or external fluid leakage. Any corroded surfaces should be cleaned and recoated with paint.

- Shell side: In many cases with clean hydraulic system oils it will not be necessary to flush the interior of the shell side of the cooler. In circumstances where the quality of hydraulic fluid is in question, the shell side should be disconnected and flushed on a yearly basis with a clean flushing oil/solvent to remove any sludge that has been deposited. For severe cases where the unit is plugged and cannot be flushed clean with solvent, the heat exchanger should be replaced to maintain the proper cooling performance.

- Tube side: In many cases it will be necessary to clean the tube side of the heat exchanger due to poor fluid quality, debris, calcium deposits, corrosion, mud, sludge, seaweed, etc. To clean the tube side, flush with clean water or any good quality commercial cleaner that does not attack the particular material of construction. With straight tube heat exchangers you can use a rod to carefully push any debris out of the tubes.

- Zinc anodes are normally used to reduce the risk of failure due to electrolysis. Zinc anodes are a sacrificial component designed to wear and dissolve through normal use. Normally, zinc anodes are applied to the water supply side of the heat exchanger. Depending upon the amount of corrosive action, one, two, three, or more anodes can be applied to help further reduce the risk of failure. American Industrial Heat Transfer, Inc. offers zinc anodes as an option, to be specified and installed at the request our customers. It is the responsibility of the customer to periodically check and verify the condition of the zinc anode and replace it as needed. Applications vary due to water chemical makeup and quality, material differences, temperature, flow rate, piping arrangements, and machine grounding. For those reasons, zinc anodes do not follow any scheduled factory predetermined maintenance plan moreover they must be checked routinely by the customer, and a maintenance plan developed based upon the actual wear rate.

Isolation and sectioning

- Valves shall be located to enable maintenance on system main units. Double block and bleed shall be installed on pig launcher inlet and outlet.

Safeguarding and shutdown

Platform isolation valve shall be installed downstream export pump and as close to riser as possible

4.17 Safety requirements

In designing the separation and stabilization system, the following safety aspects apply as a minimum:

- The separators hold large quantities of hydrocarbons in liquid and gaseous phase. Fire protection insulation on the vessels in order to ensure their integrity in the event of a fire shall be considered.
- Relief cases to be considered for sizing of relief valves shall include fire relief, blocked outlet, and gas blowby.
- During a process or emergency shutdown, the system should be segmented by use of actuated isolation valves. It is normal practice to treat each separator as an individual section and isolation valves

4.18 Wash drain

These can be run along the platform, so as to assist maintenance jobs. Instead of going for a shut – in and work over, the wash drain can be coupled into the equipments through inlet nozzles, the vessels and equipments can be cleaned and the platform can be revived in two hours and can be brought online. Shutting the facility even for a few hours can not only take time and affect the economics by millions of dollars, but is also a labor intensive and risk taking operation. All equipments will be required to be vented and drained, purged, de pressurized and then also requires man power to lower into vessels for maintenance operations, with equipments such as vertical separators, and this is a very tedious job. Hence provision of wash lines is highly recommend

4.19 HAZOP

A hazard and operability study is a systematic procedure for critical examination of the operability of a process. When applied to a process design or an operating plant, it indicates potential hazards that may arise from deviations from the intended design conditions. The technique was developed by the Petrochemicals Division of Imperial
Chemical Industries (see Lawley, 1974), and is now in general use in the chemical and process industries.
The term operability study should more properly be used for this type of study, though it is usually referred to as a hazard and operability study, or HAZOP study. This can cause confusion with the term hazard analysis or process hazard analysis (PHA), which is a similar but somewhat less rigorous method. Numerous books have been written illustrating the use of HAZOP. It can be used to make a preliminary examination of the design at the flowsheet stage, and for a detailed study at a later stage, when a full process description, final flow sheets, P and I diagrams, and equipment details are available. An ‘‘asbuilt’’ HAZOP is often carried out after construction and immediately before commissioning a new plant.

5 Economic Evaluation

5.1 Cost Estimation

Estimating cost for a project depends on the amount of design detail available, the accuracy of the cost data available, and the time spent on preparing the estimate. In the early stages of a project, only an approximate estimate will be required, and justified, by the amount of information available.

In this section of the report, we would be essentially trying to ascertain the ballpark or the class five estimates of the project. The accuracy of such stage is roughly 30 -50 %

The most commonly used method of estimating cost of any project in the chemical and petroleum industry is by taking into account previous costs. Also what could be done is estimate the entire volume of the metal used in the construction, say for e.g. separator weighs 22704.2 kg and the well fluid cooler weighs around 1754 kg, all such weights can be estimated.The next step would be to add up all the weights and look up for an economic empirical relation that would involve the weight of construction metal and the pricing, this will help us estimate the fixed capital investment.

Once the fixed capital investment has been made, all other costs such as Outside Battery Limits, expansion costs, personnel charges, and other utilities can be ascertained as some fixed percentage of the fixed capital investment.

Various relations such as Lang factor and other factorial methods can be used.These help to provide a very basic economic estimate.

As the design stage gets intricately developed, closer estimates can be made. The figure below shows the effect of design on project costs.

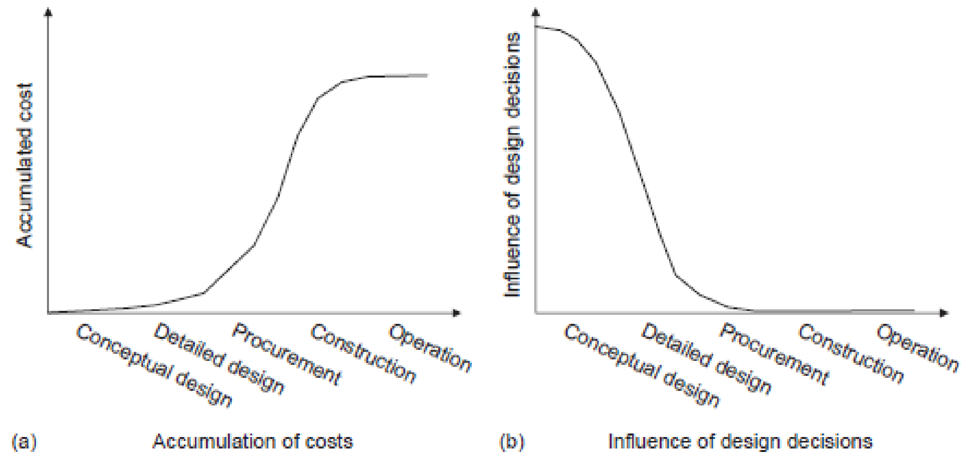

Fig 14 – effect of design on project costs

5.2 Cost Optimization

One of the most important aspects of any economic evaluation is to optimize the costing. In this project over the course of time, we aimed at choosing the most suitable equipment so as to not only optimize the operational efficiency but also take into account the economic efficiency.

Economic efficiency can be understood as

΄H= worth/cost *100

This aims at increasing the cost of the process by minimizing the cost of investment.

As an instance, our separation facility wanted the coalescer to be provided, this would increase my investment.

To increase the worth of our investment, we kept looking for better ways. And in this manner, we came across vane type mist extractors. These not only reduced our liquid carry over to less than 0.1 microns but also removed the need of coalescer. This saved us the investment cost and also the operational hiccups and maintenance charges.

Likewise the separator was around 7.2m high, this would require servicing, so instead of going for a shut down each time, we provided for a caged ladder and a semi circular arc for easy access, this saved us costs again and enabled improved efficiency of operation.

Hence the separation facility has been designed keeping into view the economics as well

6 Learning's and Discussions

The project successfully provides the process design of the separation facility. It accounts for all the designs of the equipments like well fluid cooler, coolant cooler, separator, coolant pumps and sea water lift pumps.

It can thus be understood since the flow rates to this facility are high; the facility would require an assembly of two double barreled heat exchangers to be operating in parallel. These in turn would require two centrifugal pumps operating at 40 kW power and delivering a head of 46m.the operating philosophy will require the use of a stand by pump made available for use at all times in case the main pumps fail.

The sea water lift pumps delivering a head of 72 m with a discharge of 478.5 m3 /hr and a head of about 72 m can be used. Pumps of such capacity are readily available in the industry.

All the concerned materials for fabrication have been suggested in the report, these are strictly as per the recommendations from NACE – MR – 01-75/ ISO – 151 – 56

As the feed is sour, use of corrosion resistant alloys has been strongly vouched for. All equipments have been suggested with a corrosion allowance thickness to ensure longevity of life to delay plant shut off on account of corrosion.

The general arrangement drawing or the elevation drawing has been also been furnished to help understand the concept of the platform in a more vivid manner.

The designing of the separation facility was conceived from the very beginning and various literatures were read to proceed with the design. Only the relevant material has been reflected in the report. In the absence of availability of the necessary material suitable assumptions were made. The project does not take into account the piping and instrumentation of the platform.

As a way ahead to this project, the isometric drawing and three dimensional designing of the project can be done, as owing to the time constraints these could not be delivered.

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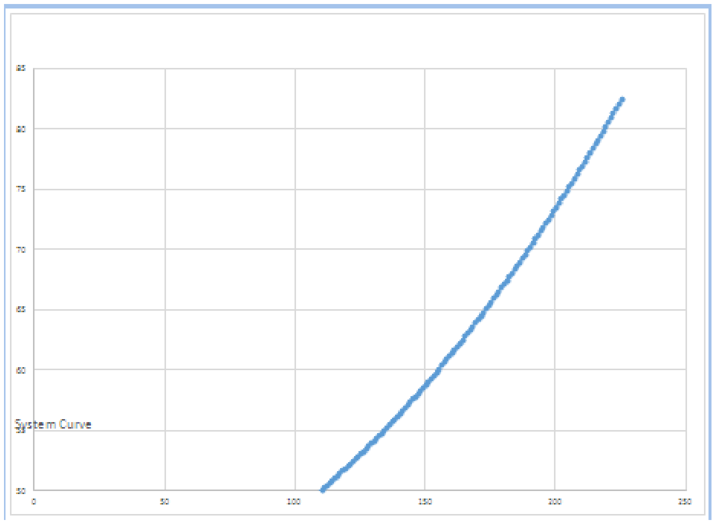
8 Appendix and Annexures

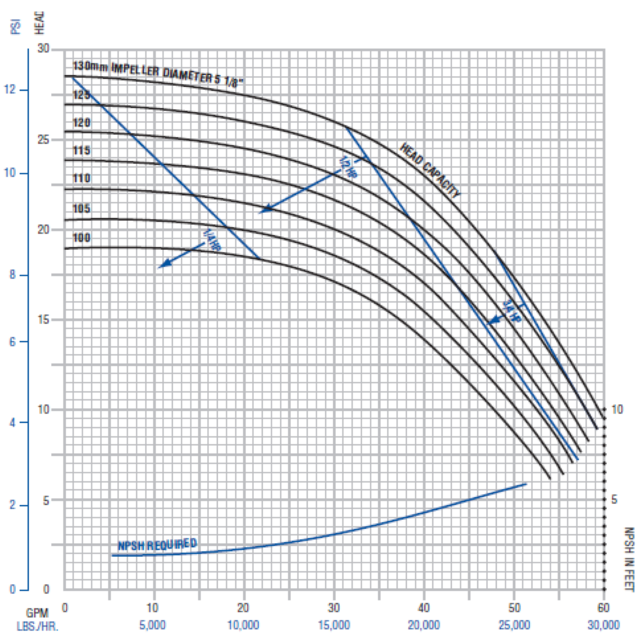
Codes and Standards

Codes/Standards	**Title**
API 662	Plate Heat Exchangers for General Refinery Services
API 660	Shell and Tube Heat Exchangers for General Refinery Service
ASME Sec VIII	Boiler and Pressure Vessel Code— Pressure Vessels
API 610	Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries
API 6D	Specifications for Pipeline valves
API Specs 12J	Specifications for Oil and Gas Separators
API RP-14E	Design and Installation of Offshore Production Platform Piping Systems
NACE MR0175	Petroleum and Natural Gas Industries - Materials for use in H2S Containing Environments in Oil and Gas Production - Part 3: Cracking Resistant CRAs (Corrosion Resistant Alloys) and other Alloys
NACE MR0103	Materials Resistant to Sulphide Stress Cracking in Corrosive Petroleum Refining Environments
API 620	Design And Construction For Large Welded, Low-Pressure Storage Tanks
ASME Code, Sec II, Part A, SA-193, Grade B7M	Internal bolting of ferritic material.
ASME Code, Sec II, Part B, SB-359	Tubes of copper alloy

Coolant Pump : System Curve



Pump Characteristics by manufacturer



Material Of Construction

Sea Water Lift Pump-

Materials used in seawater pumps depend upon many factors that include seawater quality, material limitations and processing characteristics, material cost and availability. High alloys stainless steels have been used for seawater pumps.

Cu-Ni alloys such as Monel(R) and the aluminium and Ni-Al bronzes provide good general and localised corrosion resistance in water.

Biological activity in seawater often creates costly production disruptions due to fouling at system intakes within pumps and pipelines. To avoid marine fouling the conventional method to control biological growth and damage is through chlorination of the water in the circulation system.

Pumps handling seawater have been constructed from austenitic cast irons such as Ni-resist, Cu-Ni, Monels(R), aluminium-bronzes.

Epoxy polyamide paint.

Class 150 bolting and flange material

Compressed asbestos fibre gasket

Coolant Tank –

Coolant Storage Tanks are one of the most important and useful equipments which are used for a much wider and comprehensive range of utilities for industrial and laboratory utilities. These coolant tanks are very much useful and helpful in cooling down the heated and warm fluid materials in a very reliable and efficient manner to the desirable temperatures. These coolant tanks are used for a wide range of manufacturing units being used for the production of various kinds of chemicals and metallic equipments. We are not only manufacturing but also are supplying these coolant tanks to our clients in different parts of the country.

Tanks that have been lined with baked phenolic or epoxyphenolic coatings have been used, as have fibreglass reinforced plastic tanks and stainless steel tanks. Aluminum has been used at low temperatures (about 104°F or 40°C, maximum), but is not recommended where the aluminum container is heated. Zinc or galvanized iron is not recommended, and copper or copper alloys may cause product discoloration. Galvanized iron and tin or tinned steel should not be used.

Coating of epoxy or polyamide

Materials of Construction *			
Item No.	**Name of Part**	**Bronze Fitted**	**Standard All Iron**
1	Casing	Cast Iron	Cast Iron
2	Impeller	Bronze	Cast Iron
6	Pump Shaft	Sae 1045 Steel	Sae 1045 Steel
7	Casing Wearing Ring	Cast Iron	Cast Iron
11	Packing Box Cover	Cast Iron	Cast Iron
13	Packing	Garlock 8913	Garlock 8913
14	Shaft Sleeve	Bronze	18-8 Stainless Steel
16 - 18	Ball Bearing	Steel	Steel
17	Split Gland	Cast Iron	Cast Iron
19	Frame	Cast Iron	Cast Iron
22	Bearing Lock Nut	Steel	Steel
26	Impeller Screw	Steel	Steel
29	Lantern Ring	Teflon	Teflon
30	Washer Gasket	Rulon	Rulon
32	Impeller Key	Steel	Steel
33	Bearing Housing	Cast Iron	Cast Iron
38	Sleeve Gasket	Rulon	Rulon
40	Deflector	Bronze	Bronze
51	Grease Retainer	Cast Iron	Cast Iron
73	Gasket	Treated Fiber	Treated Fiber
204	Adjusting Lock Nut	Steel	Steel
270	Impeller Washer	Stainless Steel	Stainless Steel
272	Impeller Screw "O" Ring	Buna Rubber	Buna Rubber

* Also available in other materials including ductile iron and all bronze.

Mechanical Specifications All Dimensions In Inches					
		Fig. 4166 Sizes			
PUMP	Suction	4	6	6	8
	Discharge	4	4	6	6
	Maximum Impeller Dia.	12	12	12	12
	Maximum Size Solids	$\frac{11}{16}$	$\frac{7}{8}$	$1\frac{5}{16}$	$\frac{7}{8}$
	Volute Wall Thickness	$\frac{3}{8}$	$\frac{7}{16}$	$\frac{1}{2}$	$\frac{1}{2}$
	Impeller Eye-Square Inch	11.0	26.0	28.3	28.3
	Wt. Pump Only - Brz. Ftd.	270	285	320	350
SHAFT	Dia. at Impeller	$1\frac{5}{8}$			
	Dia. Under Sleeve	$1\frac{5}{8}$			
	Dia. at Coupling	$1\frac{3}{8}$			
	Bearing Centers	10			
	Shaft Sleeve, O. Dia.	$2\frac{3}{8}$			
	Maximum H.P. / 100 Rpm	12.5			
PACKING BOX	Packing Box Inside Dia.	3.0			
	Packing Box Depth	$3\frac{1}{16}$			
	Packing - No. Rings - Size	$5\frac{7}{16}$ Sq.			
	Lantern Ring Width	$\frac{5}{8}$			
LIMITS	Maximum Working Pressure	150 psi[1]			
	Maximum Hydro, Pressure	225 psi[1]			
	Maximum Suction Pressure	50 psi[2]			
	Maximum Operation Temperature	250°			

[1] With Standard 125# Flanges.
[2] Suction pressure plus head developed by pump must not exceed maximum working pressure.

Shell and Tube Heat Exchanger-

Tubing used in exchangers is made from low carbon steel, stainless steel, Hastelloy, **Inconel.**

Tube sheets usually constructed from a round, flattened sheet of metal. Tube sheets are typically manufactured from the same material as tubes, and attached with a pneumatic or hydraulic pressure roller to the tube sheet. A layer of alloy metal bonded to the surface of a low carbon steel tube sheet would provide an effective corrosion resistance without the expense of manufacturing from a solid alloy.

The shell is constructed either from pipe or rolled plate metal. For economic reasons, low carbon steel, cupro-nickel is the most commonly used material.

Bonnets / end channels are typically fabricated or cast.

Expansion Tank – Outer body cold rolled steel. *Water chambers:* Top chamber is 100% butyl rubber, lower water chamber is copolymer polypropylene. *Connection* Welded steel / Stainless Steel.

Coating of grey primer

Plate Type Heat Exchanger –

Frame plate
Mild steel, Epoxy painted

Nozzles
Carbon steel
Metal lined: Stainless steel, Titanium
Rubber lined: Nitrile, EPDM

Plates
Stainless steel Alloy 316/Alloy 304, Titanium, Alloy 254 SMO,
Alloy C276

Gaskets (Clip-on, glued)
Nitrile, EPDM, Viton®

CLASS 150 – FLANGE INFORMATION

Nom. Fig. Size Inc. (mm)	Bolting No. x Dia. Inc	A/F Inc.	Torque lbf.ft (Nm) Bolt Lubricant Copperslip (μ=0.1)	Torque lbf.ft (Nm) Bolt Lubricant Molycote 1000 (μ=0.13)
1/2 (15)	4 x 1/2	7/8	20 (30)	25 (35)
3/4 (20)	4 x 1/2	7/8	25 (35)	30 (40)
1 (25)	4 x 1/2	7/8	30 (40)	35 (50)
1-1/2 (40)	4 x 1/2	7/8	40 (55)	50 (70)
2 (50)	4 x 5/8	1-1/16	75 (100)	95 (130)
3 (80)	4 x 5/8	1-1/16	75 (100)	95 (130)
4 (100)	8 x 5/8	1-1/16	75 (100)	95 (130)
6 (150)	8 x 3/4	1-1/4	120 (165)	150 (205)
8 (200)	8 x 3/4	1-1/4	120 (165)	150 (205)
10 (250)	12 x 7/8	1-7/16	175 (240)	220 (300)
12 (300)	12 x 7/8	1-7/16	180 (245)	230 (310)
14 (350)	12 x 1	1-5/8	295 (400)	370 (500)
16 (400)	16 x 1	1-5/8	240 (325)	300 (405)
18 (450)	16 x 1-1/8	1-13/16	415 (565)	520 (705)
20 (500)	20 x 1-1/8	1-13/16	415 (565)	520 (705)
24 (600)	20 x 1-1/4	2	575 (780)	725 (985)
30 (750)	28 x 1-1/4	2	360 (490)	455 (615)
36 (900)	32 x 1-1/2	2-3/8	630 (855)	800 (1085)
42 (1070)	36 x 1-1/2	2-3/8	-	-
48 (1220)	44 x 1-1/2	2-3/8	-	-

Flange Rating: ANSI B16.5, Class 150

Flange Materials: ASTM A105, ASTM A182 grades F50 and F51, ASTM A350 grades LF2 and LF3, ASTM A694 grade F52

Bolting Materials: ASTM A193 grades B7 and B7M, ASTM A320 grades L7, L7M and L43

Gasket Type: Compressed Asbestos Fibre

Service Temperature Range: Minus 101 thru' plus 400°C (Per Piping Class)

CLASS 1500 – FLANGE INFORMATION				
Nom. Flg. Size Ins. (mm)	Bolting No. x Dia. ins	A/F Ins.	Torque lbf.ft (Nm)	
			Bolt Lubricant Copperslip (μ=0.1)	Bolt Lubricant Molycote 1000 (μ=0.13)
1/2 (15)	4 x 3/4	1-1/4	65 (90)	80 (110)
3/4 (20)	4 x 3/4	1-1/4	85 (115)	105 (145)
1 (25)	4 x 7/8	1-7/16	140 (190)	175 (240)
1-1/2 (40)	4 x 1	1-5/8	260 (350)	330 (445)
2 (50)	8 x 7/8	1-7/16	160 (215)	200 (270)
3 (80)	8 x 1-1/8	1-13/16	395 (535)	500 (675)
4 (100)	8 x 1-1/4	2	575 (780)	730 (990)
6 (150)	12 x 1-3/8	2-3/16	770 (1040)	980 (1325)
8 (200)	12 x 1-5/8	2-9/16	1295 (1755)	1645 (2230)
10 (250)	12 x 1-7/8	2-15/16	2000 (2710)	2550 (3455)
12 (300)	16 x 2	3-1/8	2125 (2880)	2710 (3670)
14 (350)	16 x 2-1/4	3-1/2	3040 (4120)	3890 (5270)
16 (400)	16 x 2-1/2	3-7/8	4190 (5680)	5370 (7280)
18 (450)	16 x 2-3/4	4-1/4	5585 (7570)	7170 (9720)
20 (500)	16 x 3	4-5/8	7280 (9870)	9350 (12675)
24 (600)	16 x 3-1/2	5-3/8	11600 (1570)	14920 (20230)

Flange Rating: ANSI B16.5, Class 1500

Flange Materials: ASTM A105, ASTM A182 grades F50 and F51, ASTM A350 grades LF2 and LF3, ASTM A694 grades F52, F60 and F65

Bolting Materials: ASTM A193 grades B7 and B7M, ASTM A320 grades L7, L7M and L43

Gasket Type: Spiral Wound and Ring Joint

Service Temperature Range: Minus 101 thru' plus 400°C (Per Piping Class)

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https://www.intergraph.com/oilgas/eng_schem.aspx[i]

[ii] http://naturalgas.org/naturalgas/processing-ng/

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