MAJOR PROJECT REPORT

On

Process Design for Oil & Gas Separation for Offshore Platform

UNDER THE MENTORSHIP OF

Mr. R. P. Soni

SUBMITTED BY

Shivam Saxena
Enrolment Number: R870211032
E-mail address: *shivamsaxena45@gmail.com*

Siddharth Gusain
Enrolment Number: R870211034
E-mail address: *gusain.siddharth93@gmail.com*

Siddharth Gulati
Enrolment Number: R870211035
E-mail address: *gulatisiddharth3@gmail.com*

Dr. Pushpa Sharma	**Dr. D.K Gupta**
Professor	**Professor**
Course Coordinator	**Head of the Department**

B. Tech. Applied Petroleum Engineering with Specialization in Upstream (2011-15)
Department of Petroleum Engineering and Earth Sciences

University of Petroleum and Energy Studies, Dehradun

April 2015

CERTIFICATE

This is to certify that this project report titled **"Process Design for Oil & Gas Separation for Offshore Platform"** submitted to **University of Petroleum and Energy Studies, Dehradun** is a bonafide record of work done by **Mr. Shivam Saxena, Mr. Siddharth Gusain and Mr. Siddharth Gulati** under my supervision from **"September 2014"** to **"April 2015"**.

Mr. R. P. Soni
Professor
Department of Petroleum Engineering and Earth Sciences

Dr. Pushpa Sharma
Course Coordinator
B. Tech. Applied Petroleum Engineering (Upstream)

Dr. D.K Gupta
Head of the Department
Department of Petroleum Engineering and Earth Sciences

Place: Dehradun

Date:

TABLE OF CONTENTS

ACKNOWLEDGEMENTS

"One looks back with appreciation to the brilliant teachers, but with gratitude to those who touched our human feelings. The curriculum is so much necessary raw material, but warmth is the vital element for the growing plant and for the soul of the child." – Carl Jung

This quote makes a distinction between teachers who effortlessly transfer knowledge to kindle learning among their students and mentors who implant wisdom and lessons that one never forgets for life. The authors feel privileged to have had Mr. R. P. Soni as their mentor who throughout the project timeline not only made sure that they learned technical nuances pertaining to the project topic but also contributed to the grooming and betterment of professionalism and other necessary life skills. The authors shall always remain indebted to him.

Gratitude is due towards Dr. Kamal Bansal, Dean - College of Engineering Studies and Dr. D. K. Gupta, HOD – Department of Petroleum Engineering and Earth Science, for providing the authors with the opportunity to undertake such a project and have a learning experience. The authors also express sincere thanks to Dr. Pushpa Sharma, Course Coordinator – Applied Petroleum Engineering with Upstream Specialization, for her constant support and motivation during the project tenure.

Last but not the least, the authors thank their friends, Prajwal, Pradeep, Meghna, Carvi and Himanshi for their regular help without which the project would not have been possible.

Shivam Saxena, Siddharth Gusain and Siddharth Gulati

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 an offshore scenario where a Production Platform Module will be designed for specific production rates, GOR and other parameters. This will include a Heat Exchanger for heating fluid in between Manifold and Separator. After Heat Exchanger, a three phase separator will be deployed for separation of Oil, Gas & Water. All these equipment have to be in accordance with API Guidelines while maintaining space limitations.

The deliverables for the project will include:

- Design of 3-Phase Separator including Material Selection & Pressure Calibrations
- Piping Connections for desired flow rates

EXECUTIVE SUMMARY

The project work dealt with understanding the process behind the designing of separation facility for separation of oil, gas and water in an offshore scenario. The authors were allowed independence in terms of working and multiple designs were prepared and discussed with the mentor. Based on the industrial insight and experience of the mentor, the designs were modified at regular intervals.

Once a design was approved, the mathematical calculations based on design relations were made by the authors to size various equipments that are to be used. These fittings were carefully chosen in accordance with the space constraints on the deck.

The flow of oil, gas and water between the equipment will be through pipelines which have also been designed by the authors under the guidance of the mentor.

The report deals with only the process designing part of the facility involving a three phase separator and its pipelines for flow.

I. INTRODUCTION

Oil and Gas is produced from reservoirs not separately but together along with water, other gases like hydrogen sulphide, carbon dioxide etc. but these impurities are not of economic value instead they hamper the quality of the final product that is the crude and the natural gas. Hence, post production, there needs to be a facility to remove these impurities from oil and gas and also to bring the quality of the final product to the desired quality. To do these things production facilities are put in place. The main separation is done between oil, gas and water. The main purpose of the production facility thus is separation of the production into three phases namely oil, gas and water and either sell them or dispose them in an environmentally suitable manner. Separators are the most important constituents of the production facility, they are divided into many sub-categories like vertical and horizontal (based on their geometry and shape) or two-phase and three-phase (based on the number of phases they separate). Separators are nothing but mechanical devices that separate the gas in the mixture from the liquids and the water from the oil-water emulsion. This process removes enough light hydrocarbons with appropriate vapour pressure which defines the volatility to bring the final product close to being marketable.

The gas which is acquired by separation process needs to be treated and compressed for sale. Compression is done typically by engine driven reciprocating compressors, large integral reciprocating compressors and in large facilities, turbine driven centrifugal compressors are used. Glycol dehydrators are used to remove moisture from the gas to improve its quality. Sometimes the hydrocarbon dew point needs to be lowered, this is done by removing heavier hydrocarbons. Gas needs to be “sweetened” also sometimes to remove H_2S and CO_2 if these contaminants are present in quantities larger than the limit set by the party who is buying the gas. For sweetening extra equipment needs to be added to the production facility.

The oil and water emulsion produced also needs to be treated to remove the water from the oil and make the oil as pure as possible. The contracts between the producers and the purchasers set a limit on either BS&W (basic sediment and water) or salt content in the crude. The salt content is removed by dilution with clean water and then removing that water from the emulsion formed. The most common limits are 0.5%-3% BS&W and 10 to 25 pounds of salt per thousand barrels.

For emulsion treatment heater treaters are used to remove water droplets and get oil with very low percentage of water. Oil treating can also be done by settling in gun barrel tanks.

Production facilities must also provide for accurate measurement and sampling of crude oil. This can be either automatic or manual. Automatic is done using LACT (Lease Automatic Custody Transfer) or manually by gauging in a calibrated tank.

The water which is the most uneconomical of the three phases is disposed off overboard in most offshore conditions after being treated or it can be disposed via evaporation from pits on onshore locations. Water must first be treated to remove droplets of oil before it is reused or disposed.

II. GENERAL LITERATURE SURVEY

Shallow Water Production Systems:

- **Gravel Islands**

Man-made gravel islands are used year-round in water depths of up to fifty feet and can support large drilling rigs and oil and gas production equipment. Several tons of gravel is placed on the seafloor to create the island. The islands may be left to erode naturally or dredged to a depth that allows for vessel navigation when production is completed. Gravel islands are typically strengthened with concrete, rock or steel sheet piles to resist the impact of ice.

- **Steel Jacket**

A typical fixed steel platform consists of large pipe legs and tubular steel cross bracing that form a “jacket”. This jacket is supported by piles driven into the seafloor to transmit wave, wind, current or ice forces into the ground. These piles support a deck that contains a drilling rig, the crew’s living quarters and production facilities.

Jackets are usually used in shallow to medium water depths and are intended for long-term use. Steel jacket platforms can operate in up to 1,400 feet of water and withstand hurricanes and winter storms.

- **Gravity-Based Structures**

Gravity based structures are big structures and have a heavy mass to support large facilities in water depths of up to 1,000 feet. Theses can also be designed to resist severe arctic conditions, such as multi-year ice and even icebergs in shallow waters and in depths of up to around 200 feet. Gravity-based structures (GBSs) can be made of steel or concrete, and provide support for heavy drilling rigs and production equipment. They function similarly to gravel islands and jacket structures, but can be used in deeper water than gravel islands and can resist ice much better than jacket structures. They effectively act as steel or concrete islands.

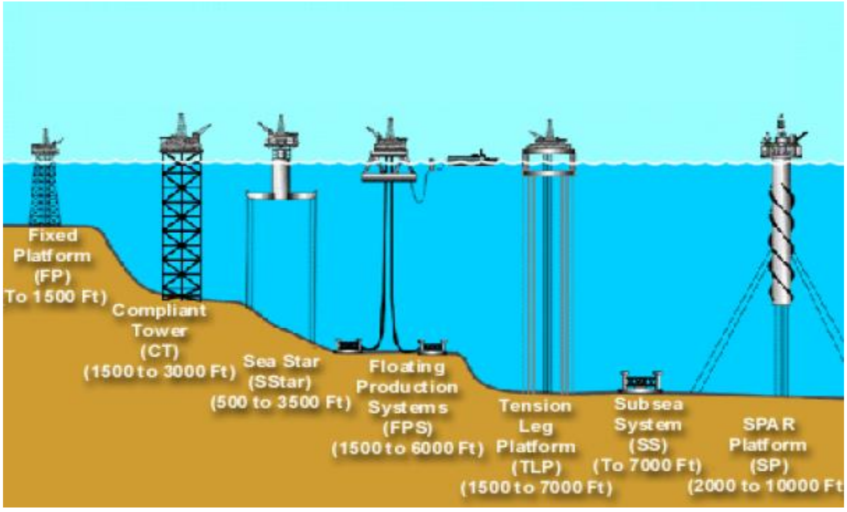

Figure 1: Offshore Production Platforms, Image from Petrowiki

FPSO:

Remote offshore locations lacking infrastructure of subsea pipelines and conventional production facilities are most viable for FPSO operations. Initially storage tankers were being converted for this purpose but now dedicated FPSOs are being built around the world following their success.

Most if not all separation and treating of the oil takes place on board of the permanently moored vessel of the FPSO. The produced gas from the FPSO is used both as fuel as well as for reinjection.

Challenges in Offshore Conditions:

Offshore oil and gas production is more challenging than land-based installations due to the remote and harsher environment. Much of the innovation in offshore petroleum sector concerns overcoming these challenges, including the need to provide very large production facilities. Production and drilling facilities may be very large and a large investment, such as the Troll A platform standing on a depth of 300 meters.

Another type of offshore platform may float with a mooring system to maintain it on location. While a floating system may be lower cost in deeper waters than a fixed platform, the dynamic nature of the platforms introduces many challenges for the drilling and production facilities.

The ocean can add several hundred meters or more to the fluid column. The addition increases the equivalent circulating density and down hole pressures in drilling wells, as well as the energy needed to lift produced fluids for separation on the platform.

The trend today is to conduct more of the production operations subsea, by separating water from oil and re-injecting it rather than pumping it up to a platform, or by flowing to onshore, with no installations visible above the sea. Subsea installations help to exploit resources at progressively deeper waters—locations which had been inaccessible—and overcome challenges posed by sea ice such as in the Barents Sea. One such challenge in shallower environments is seabed gouging by drifting ice features (means of protecting offshore installations against ice action includes burial in the seabed).

Offshore manned facilities also present logistics and human resources challenges. An offshore oil platform is a small community in itself with cafeteria, sleeping quarters, management and other support functions. In the North Sea, staff members are transported by helicopter for a two-week shift. They usually receive higher salary than onshore workers do. Supplies and waste are transported by ship, and the supply deliveries need to be carefully planned because storage space on the platform is limited. Today, much effort goes into relocating as many of the personnel as possible onshore, where management and technical experts are in touch with the platform by video conferencing. An onshore job is also more attractive for the aging workforce in the petroleum industry, at least in the western world. These efforts among others are contained in the established term integrated operations. The increased use of subsea facilities helps achieve the objective of keeping more workers onshore. Subsea facilities are also easier to expand, with new separators or different modules for different oil types, and are not limited by the fixed floor space of an above-water installation.

When an offshore deposit is ready for production, either a drilling platform is converted into a production platform or a production platform is installed above the well. After extraction, the natural resources are taken from the well directly to the mainland by pipeline or are loaded into tankers at the oil production platform. Old tankers or purpose-built ships are often used as floating production storage and offloading (FPSO) units; they float from one production platform to the next.

Apart from the above mentioned problems, the accommodation of various equipments along with platform's sustenance, prove to be extremely challenging. Onshore facilities have the abundance of land to establish plot space for every equipment. Due to the limited space available on the production platform, equipment need to be designed in a precise manner which involves careful measurements to occupy as little space as possible. The plot space approved for every equipment on the platform also includes the safety margin which has to be kept in mind while designing a separator.

Vessel Orientation:

A separator can be classified into vertical, horizontal, and spherical shape. Every shape has its own advantages. The vertical separator occupies less operating area. The horizontal separator can handle foaming crudes better and is more economical for handling large volumes of gas. The spherical separator is easier to install and is more compact and adaptable for portable use.

The choice between horizontal or vertical type of vessel primarily depends upon following process requirements:

• Relative vapour and liquid load
• Plot area availability
• Economics
• Special considerations

Horizontal vessels are most economical for normal oil-water separation, especially when there might be presence of emulsions, foam, or high gas-liquid ratios. Vertical separators work best in low gas-oil ratio (GOR) applications and where there is solids production.

Factors Affecting Separation:

Characteristics of the flow stream greatly affect the design and operation of a separator. The following factors must be determined before separator design:

• Gas and liquid flow rates (minimum, average, and peak)
• Operating and design pressures and temperatures
• Surging or slugging tendencies of the feed streams
• Physical properties of the fluids such as density and compressibility
• Designed degree of separation (e.g., removing 100% of particles greater than 10 microns)
• Presence of impurities (paraffin, sand, scale, etc.)

• Foaming tendencies of the crude oil
• Corrosive tendencies of the liquids or gas

Design Considerations:

The following must be considered in designing separator vessel:

- The volumes of the dished heads are negligible as compared with the volume of the cylinder.
- The length/diameter (L/D) is considered to be acceptable when it is between about 3/1 and 8/1 unless specially stated.
- The interface need not be at the centerline of the horizontal vessel. The feed enters at the end of separator just above the vapor-liquid interface, which should be at least 10 inches from the bottom and at least 16 inches from the top of the vessel.

Separator sizing must satisfy several criteria for good operation during the lifetime of the producing field:

- Sufficient time should be given to allow the immiscible gas, oil, and water phases to separate by gravity
- Sufficient time should be provided to allow for the coalescence and breaking of emulsion droplets at the interface of oil and water
- In the gas space, sufficient volume should be provided to accommodate for the rise in the liquid level resulting from the increase in liquid flow rate
- Removal of solids should be accounted for
- The separator should accommodate for the variation in the flow rates of oil, gas, and water without adversely affecting separation efficiency.

Instrumentation Requirements:

- The outlet needs to be equipped with a temperature indicator, preferably placed on the top of outlet line.
- Every vessel needs to be equipped with a pressure sensor. Tall vessel columns should be avoided as they would hinder in the clear sight of the gauges.

III. SPECIFIC LITERATURE SURVEY

Pipe Coating: All pipes will be dual coated. The first layer will be a primer followed by a layer of paint. These will form a protective coating against corrosion and damage.

Insulation of Piping: All piping will be insulated by glass wool layer to prevent heat loss.

Corrosion under Insulation: In an insulated piping scenario, water may seep into insulation and become trapped. This might result in wetting and corrosion of the metal. Carbon steel corrodes in the presence of water due to the availability of oxygen. So CUI prevention will have to be considered.

Figure 2: Corrosion under Insulation, Image from North County Mechanical Insulators Website, http://www.ncmiinc.com/corrosion-under-insulation

Welding & Radiographic Inspection:

Welding is a process in which two metals are joined together by heating to suitable temperatures with or without the use of a filler metal.

Heat required for the process is sourced from:

1. Electric Arc
2. Electric Resistance
3. Flame
4. Laser
5. Electron Beam

Most of the field pipeline welding processes are done with the use of a filler metal, without the application of pressure and use electric arc for heat generation.

Electric Arc Welding:

Electric arc welding is done by creating an electric arc between the base metal and the electrode. The arc is created by a welding power supply and heats the metals and the welding point, joining them. The welding power supply can be either Direct Current or Alternating Current and the electrodes can be either consumable or non-consumable. The welding region is usually protected by a shielding gas, vapour or slag.

Electric arc welding processes can be manual, semi-automatic or fully automatic. The power supply needed for the generation of the electric arc is generally classified as constant voltage or constant current power supplies. The voltage of the power supply is related to the length of the arc and the current is related to the heat generated by the arc.

Types of Electric Arc Welding:

- **Shielded Metal Arc Welding**

Shielded Metal Arc Welding (SMAW) or Manual Metal Arc Welding (MMAW) is one of the most common arc welding techniques. An electric arc is generated between the base metal and a consumable electrode rod. The electrode is selected in such a way that it is compatible with the base material being welded and is covered with a flux which gives out vapours which eventually serve as a shielding gas for the process. The electrode is also provided with a layer which protects the welding region from atmospheric contamination. SMAW proves very effective as the electrode itself acts as the filler metal thereby making the use of an additional filler metal redundant. It is a very versatile process which does not require a high level of operator expertise and requires inexpensive equipment.

- **Gas Metal Arc Welding**

Gas Metal Arc Welding (GMAW) is a process in which a consumable wire is constantly fed to the welding area. This wire acts as both the filler metal and electrode. A shielding gas, generally inert is flowed around the wire to protect the welding area from atmospheric contamination. This process generally uses constant voltage power supplies. Due to the mechanism, where the electrode is fed continuously for welding, this method provides high welding speeds. The complicated equipment required for this process makes less versatile than SMAW. This technique is generally used for steels.

- **Flux Core Arc Welding**

Flux-cored Arc Welding (FCAW) is a variation of the GMAW method. The wire used in this process is thin metal tube which is filled with flux materials. Sometimes, the use of a shielding gas is required, but generally, the flux itself is relied upon for protection from atmospheric contamination. It delivers high welding speeds and portability.

- **Submerged Arc Welding**

Submerged Arc Welding (SAW) is a high productivity welding process in which an arc is struck beneath a covering layer of granular flux. One of the most important features of this technique is that the slag comes off itself after the welding process and removes the need to chip it away manually. Also, the arc quality is very good because of the flux covering over the metal wire. This process is widely used for large industries.

- **Gas Tungsten Arc Welding**

Gas tungsten arc welding (GTAW) is a manual welding process that uses a non-consumable electrode made of tungsten, an inert or semi-inert gas mixture, and a separate filler material.

Especially useful for welding thin materials, this method is characterized by a stable arc and high quality welds, but it requires significant operator skill and can only be accomplished at relatively low speeds. It can be used on nearly all weldable metals, though it is most often applied to stainless steel and light metals. It is often used when quality welds are extremely important, such as in bicycle, aircraft and naval applications.

Radiographic Testing:

Radiographic Testing (RT), or industrial radiography, is a nondestructive testing (NDT) method of inspecting materials for hidden flaws by using the ability of short wavelength electromagnetic radiation to penetrate various materials.

Since the amount of radiation emerging from the opposite side of the material can be detected and measured, variations in this amount of radiation are used to determine thickness or composition of material. Penetrating radiations are those restricted to that part of the electromagnetic spectrum of wavelength less than about 10 nanometers.

The beam of radiation is directed to the middle of the section under examination and is normal to the material surface at that point, except in special techniques where known defects are best revealed by a different alignment of the beam. The length of weld under examination for each exposure is kept such that the thickness of the material at the diagnostic extremities, measured in the direction of the incident beam, does not exceed the actual thickness at that point by more than 6%. The specimen to be inspected is placed between the source of radiation and the detecting device, usually the film in a light tight holder or cassette, and the radiation is allowed to penetrate the part for the required length of time to be adequately recorded.

The result is a two-dimensional projection of the part onto the film, producing a latent image of varying densities according to the amount of radiation reaching each area.

After this visual examination, the operator will have a clear idea of the possibilities of access to the two faces of the weld, which is important both for the setting up of the equipment and for the choice of the most appropriate technique.

Pre-commissioning Activities:

Pre-commissioning is generally considered to include the preparation and integrity verification of any system or structure upon completion of construction / installation and prior to commissioning. In relation to flow-line systems, these are often laid dry and include the facility to perform pre-commissioning activities. As part of the pipe lay process, the initiation and laydown heads may include suitable connections to allow launch and receipt of pre-loaded pigs. Other systems where pipeline end terminations or similar are installed these also generally allow for the provision and connection of subsea pig launchers and receivers to assist in pre-commissioning. Pre-commissioning includes all or a combination of operations to allow the pipeline or system to be cleaned, internally gauged, pressure tested and dewatered and / or dried. Sometimes there can be a final operation to prepare the pipeline for product by introducing an inert nitrogen blanket in preparation for hydrocarbon production, however this is often considered to be a commissioning activity.

Common Pipeline Pre-commissioning Activities:

- Flooding / filling
- Cleaning
- Progressive cleaning
- Preservation/Gauging/Caliper/Internal geometry checking
- Testing/Integrity Testing/Hydro-testing/Pressure Testing/Factory Acceptance Testing
- Leak Testing
- Dewatering
- Conditioning
- Drying
- Nitrogen filling, inerting or purging
- Nitrogen packing

Pigging Overview:

Many of the above pipeline operations are performed using pipeline internal gauges (pigs). Pig design and product choice is highly variable depending on pipeline design like line length, ID changes, bend radius, tees, wyes, and test pressure and its application or intended use. The available technologies are extensive and ever-changing; the range of products available from many of these suppliers is extensive and products can be highly technical.

Pigs are normally used to remove debris, provide an interface or ensure a tight seal between any chosen propelling and filling medium. For example, most pipelines are laid in a dry condition and therefore contain only air in their initial ‘as laid’ state. To ensure that a successful filling, cleaning, gauging and testing operation can be performed, the use of mechanical pigs is essential. Depending on the filling and cleaning specification, single or multiple pigs (pig trains) can be used.

Figure 3: Various Pig Types, Image from Contract Resources Website, http://www.contractresources.com/content/services/general-pigging

Hydro-testing Overview:

In order to comply with the design code and industry standards, all pipelines and subsea systems associated with pipelines are hydro-tested and the pressure held for approximately 24 hours. The basis of this test is to ensure that the integrity of the system is complete, and that its pressure retaining capabilities exceed the intended operating parameters of the pipeline or system. A common specification for the testing pressure is 1.25 or 1.5 times the design pressure of the pipeline. The hold period of 24 hours allows sufficient time for even small leaks to be evident as a pressure drop. Other factors that can affect the pressure in the pipeline such as temperature change and elevation are also considered. The use of valves to isolate a system is generally avoided as this increases the leak potential increases significantly.

Figure 4: Hydro-Testing of Pipeline, Image from Process Chemicals Website, http://www.processchemicals.com.au/

IV. DESIGN OF PROCESS LAYOUT

A general offshore production facility has been shown in the image below. Various operations like treatment, compression, injection, disposal etc have been shown.

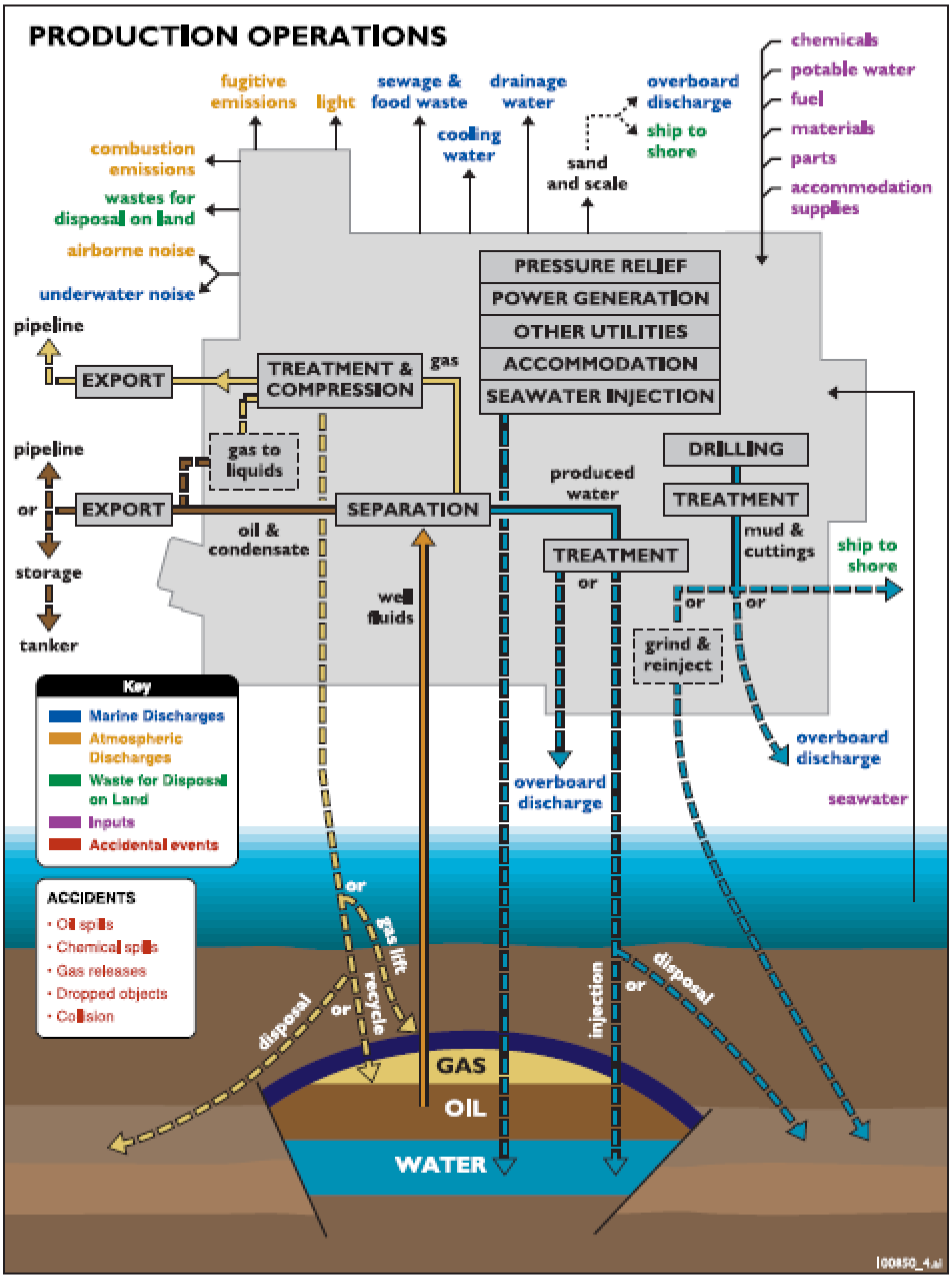

Figure 5: Offshore Production Operations, Image from "An Overview of Offshore Oil and Gas Exploration and Production Activities", August 2001

The layout for the separation process for the project was designed by the authors. The facility includes flow of fluids from manifold to a heat exchanger for heating the fluid. The heated fluid moves from heat exchanger to a three phase horizontal separator where separation into three fractions takes place. The oil, gas and water then move to respective locations.

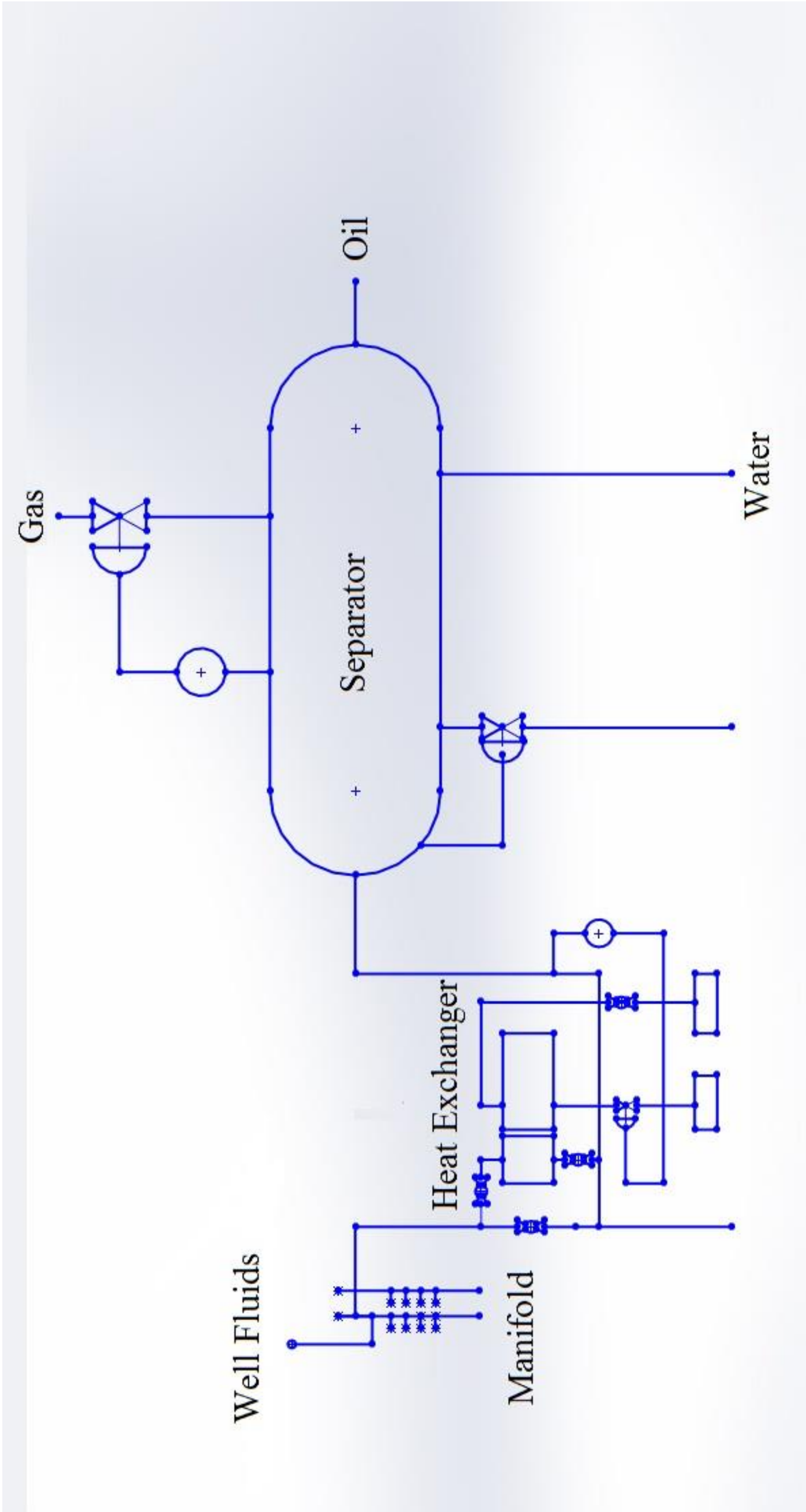

Figure 6: Facility Layout Designed by Authors

V. DATA PROVIDED

The design of the project and associated calculations are based on the following data:

Property	**Value**	**Unit**
Oil Flow Rate	10000-15000	BOPD
Water Flow Rate,	3000-10000	BOPD
Gas Oil Ratio	147-1000	M^3/M^3
Temperature	45-90	°C
Pressure	20	Kg/Cm^2
H_2S Concentration	10000	Ppm
Water Concentration	<1	%
Crude Oil Temperature at Entry	30	°C
Treating Temperature	90	°C
Viscosity	0.58	Cp
API Gravity	42.5	°API
Droplet Size	300	Micron
Equivalent Length Manifold to Heat Exchanger	120	M
Equivalent Length Heat Exchanger to Separator	75	M
Equivalent Length Oil Line	65	M
Equivalent Length Water Line	60	M
Equivalent Length Gas Line	40	M

VI. DESIGNING OF THREE PHASE HORIZONTAL SEPARATOR

Three Phase Horizontal Separator Sizing Calculations:

$$\mathbf{V_t = 0.0119 \left\{\left(\frac{\rho_o - \rho_g}{\rho_g}\right)\left(\frac{D_m}{C_D}\right)\right\}^{0.5}} \text{ ....} \textbf{Eqn. 1}$$

Where;

V_t = Terminal Settling Velocity of Droplet, ft/sec

ρ_o = Density of oil, lb/ft^3

ρ_g = Density of gas, lb/ft^3

D_m = Droplet Size, micron

C_D = Drag Coefficient

$$\mathbf{Re = 0.0049 \left\{\frac{(\rho_g \times D_m \times V_t)}{\mu_o}\right\}} \text{ ....} \textbf{Eqn. 2}$$

Where;

Re = Reynolds Number

ρ_g = Density of gas, lb/ft^3

D_m = Droplet Size, micron

V_t = Terminal Settling Velocity of Droplet, ft/sec

μ_o = Oil Viscosity, cp

$$\mathbf{C_D = \frac{24}{Re} + \frac{3}{Re^{0.5}} + 0.34} \text{ ....} \textbf{Eqn. 3}$$

Where;

C_D = Drag Coefficient

Re = Reynold's Number

Assuming C_D = 0.34

Iteration One:

$$V_t = 0.0119 \left\{\left(\frac{50.766 - 1.198}{1.198}\right)\left(\frac{300}{0.34}\right)\right\}^{0.5}$$

V_t = 2.273

$\mathrm{Re} = 0.0049\ \left\{\frac{(1.198\ \mathrm{X}\ 300\ \mathrm{X}\ 2.273)}{0.017}\right\}$

Re = 235.464

$\mathrm{C_D} = \frac{24}{235.464} + \frac{3}{235.464^{0.5}} + 0.34$

C_D = 0.63

Similarly,

Iteration Two:

V_t = 1.670

Re = 172.99

C_D = 0.70

Iteration Three:

V_t = 1.109

Re = 114.88

C_D = 0.82

Iteration Four:

V_t = 1.464

Re = 151.65

C_D = 0.74

Iteration Five:

V_t = 1.541

Re = 159.63

C_D = 0.72

Taking C_D as 0.72

$$\mathbf{dL_{eff} = 420\ \left(\frac{TZQ_g}{P}\right)\left(\frac{\rho_g}{\rho_o - \rho_g} X\ \frac{C_D}{D_m}\right)^{0.5}} \text{ ……………………………………………………...Eqn. 4}$$

Where;

d = Vessel Internal Diameter, inches

L_{eff} = Effective Length of Vessel where separation occurs, ft

T = Operating Temperature, °R

Q_g = Gas Flow Rate, MMscfd

P = Operating Pressure, psia

Z = Gas Compressibility

C_D = Drag Coefficient

D_m = Droplet Size, micron

$\rho_l = \text{Density of liquid, lb/ft}^3$

$\rho_g = \text{Density of gas, lb/ft}^3$

$$dL_{eff} = 420\ \left(\frac{654 \text{ X } 0.84 \text{ X } 95.39}{299.1}\right)\left(\frac{1.198}{50.766 - 1.198} \text{X } \frac{0.72}{300}\right)^{0.5}$$

dL_{eff} = 560.436

$\mathbf{d^2L_{eff} = 1.42\ (Q_w\ X\ t_{rw} +\ Q_o\ X\ t_{ro})}$ **……………………………………………….Eqn. 5**

Where;

d = Vessel Internal Diameter, inches

L_{eff} = Effective Length of Vessel where separation occurs, ft

Q_w = Water Flow Rate, bpd

t_{rw} = Retention Time for Water, min

Q_o = Oil Flow Rate, bpd

t_{ro} = Retention Time for Oil, min

$$d^2L_{eff} = 1.42\ (10000 \text{ X } 2 + 15000 \text{ X } 2)$$

d^2L_{eff} = 71000

Solving dL_{eff} and d^2L_{eff} simultaneously for values for d & L_{eff}

D	**L_{eff}**	**L_{eff}**
200	2.80	1.775
100	5.60	7.10
110	5.09	5.86
120	4.67	4.93
130	4.31	4.20
127	4.41	4.40

d = 127 in = 10.58 ft

L_{eff} = 4.4 ft

$$\frac{\mathbf{A_w}}{\mathbf{A}} = \frac{\mathbf{0.5\ (Q_w\ X\ t_{rw})}}{\mathbf{Q_w\ X\ t_{rw} + Q_0\ X\ t_{ro}}} \quad \text{...}\textbf{Eqn. 6}$$

Where;

A_w = Cross Sectional Area of Water, ft^2

A_o = Cross Sectional Area of Oil, ft^2

Q_w = Water Flow Rate, bpd

t_{rw} = Retention Time for Water, min

Q_o = Oil Flow Rate, bpd

t_{ro} = Retention Time for Oil, min

A = 2 (A_o + A_w)

$$\frac{\mathbf{A_w}}{\mathbf{A}} = \frac{\mathbf{0.5\ (39\ X\ 2)}}{\mathbf{58.5\ X\ 2 + 39\ X\ 2}}$$

$$\frac{A_w}{A} = 0.2$$

$$\boldsymbol{\beta} = \frac{\mathbf{h_o}}{\mathbf{d}} \quad \text{...}\textbf{Eqn. 6}$$

where;

β = Coefficient for Horizontal Separators

h_o = Height of Oil Layer

d = Diameter of the vessel, in

$\beta = 0.24$

$$\mathbf{L_{ss}} = \frac{\mathbf{4}}{\mathbf{3}}\ \mathbf{L_{eff}} \quad \text{...}\textbf{Eqn. 7}$$

L_{ss} = 5.89 ft

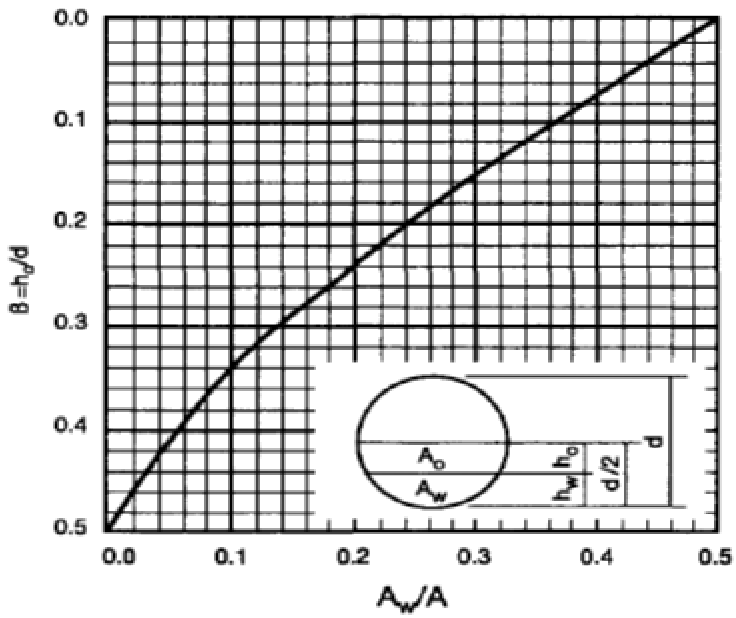

Figure 7: Coefficient β for Horizontal Separator, Image from Surface Production Operations Volume 1, 2nd Edition by Ken Arnold & Maurice Stewart

Three Phase Horizontal Separator Design:

The entire system is of Class 300 type except for the manifold which is class 900 type.

Inlet Diverter: Hemispherical Baffle Plate Type which will provide a change in the direction and velocity of the fluids entering and thus separate the gas and liquid. The design of the baffles is governed by impact-momentum load. The advantage of a hemispherical baffle type inlet diverter is that it creates less disturbance than plates or angle iron which helps in cutting down on re-entrainment and emulsifying problems.

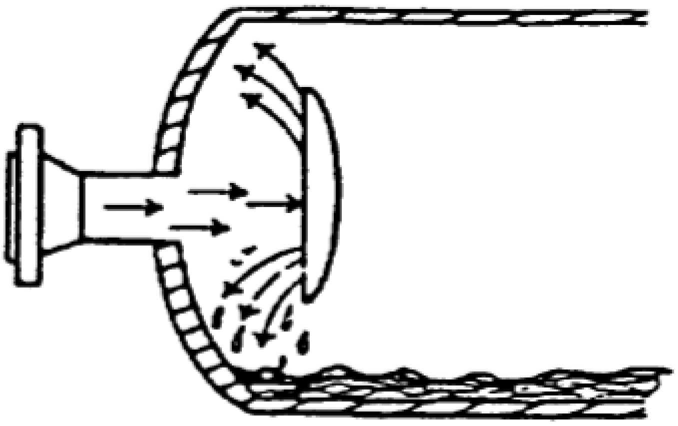

Figure 8: Hemispherical Baffle Plate Type Inlet Diverter, Image from Surface Production Operations Volume 1, 2nd Edition by Ken Arnold & Maurice Stewart

Mist Extractor: Wire Mesh Pad Type Mist Extractor is made up of finely woven mats of stainless steel wire wrapped to form a tightly packed cylinder. The liquid droplets impinge on the matted wires and coalesce. Its effectiveness depends largely on the gas velocity. If the velocity is too high, the liquids knocked out will be re-entrained. If the velocity is low, the vapour just drifts through the mesh element without the droplets impinging and coalescing.

Figure 9: Wire Mesh Pad Type Mist Extractor, Image from Surface Production Operations Volume 1, 2nd Edition by Ken Arnold & Maurice Stewart

Level Control Logic:

Level	**Response**
Hi Hi	Shut Down
Hi	Alarm
Lo	Alarm
Lo Lo	Shut Down

Float Type Level Indicators will be used which will be fitted with level transmitters. Other than this, gauge glasses in positive isolation will be used for external reading of levels.

Pressure Control Logic:

Level	**Response**
Hi Hi	Shut Down
Hi	Alarm

Material of Construction of Separator: Normal Carbon Steel

Material of Construction of Piping: Normal Carbon Steel – Electric Resistive Weld Type

Internal Coating: The separator will be epoxy coated internally to prevent corrosion.

A Hot Oil Expansion Loop will be provided as the oil being processed is heated to a temperature of 90° C.

VII. MULTIPHASE LINE SIZING

From Manifold to Heat Exchanger:

$$\boldsymbol{\rho_m = \frac{(12409 \text{ X } SG \text{ X } P) + (2.7 \text{ X } R \text{ X } S \text{ X } P)}{(198.7 \text{ X } P)+(R \text{ X } T \text{ X } Z)}} \text{ ……………………………………………………...} \textbf{Eqn. 8}$$

Where;

ρ_m = Density of Mixture, lb/ft^3

P = Operating Pressure, psia

R = Gas/Liquid Ratio, ft^3/bbl

T = Operating Temperature, °R

Z = Gas Compressibility Factor

$$\rho_m = \frac{12409 \text{ X } 54.93 \text{ X } 363.09+2.7 \text{ X } 5610.36 \text{ X } 1.198 \text{ X } 363.09}{198.7 \text{ X } 363.09+56310.36 \text{ X } 546 \text{ X } 0.84}$$

$$\rho_m = 9.81 \text{ lbm/ft}^3$$

$$\mathbf{W = 3180 \text{ X } Q_g \text{ X } S + 14.6 \text{ X } Q_l \text{ X } SG} \text{ ………………………………………………} \textbf{Eqn. 9}$$

Where;

W = Rate of Flow of Mixture, lbm/hr

Q_g = Gas Flow Rate, MMscfd

S = Specific Gravity of Gas at standard conditions

Q_l = Liquid Flow Rate, bpd

SG = Specific Gravity of Liquid

$$W = 3180 \text{ X } 95.54 \text{ X } 1.198 + 14.6 \text{ X } 25000 \text{ X } 54.93$$

$$W = 20413423 \text{ lbm/hr}$$

$$\mathbf{d^5 = \frac{3.4 \text{ X } 10^{-6} \text{ X } f \text{ X } L \text{ X } W^2}{\rho_m \text{ X } \Delta P}} \text{ ……………………………………………………………} \textbf{Eqn. 10}$$

Where;

d = Internal Diameter of Pipe, inches

f = Moody Friction Factor

L = Length of Pipe, ft

W = Rate of Flow of Mixture, lbm/hr

ρ_m = Density of Mixture, lb/ft^3

ΔP = Pressure Drop, psi

$$\mathbf{f = \frac{2\ X\ \Delta P\ X\ d}{L\ X\ \rho_m\ X\ V^2}} \text{ ……………………………………………………………………………Eqn. 11}$$

Where;

f = Moody Friction Factor

ΔP = Pressure Drop, psi

d = Internal Diameter of Pipe, inches

L = Length of Pipe, ft

ρ_m = Density of Mixture, lb/ft^3

V = Velocity of Flow, ft/sec

Substituting f in Eqn. 9

$$\mathbf{d^4 = \frac{2\ X\ 3.4\ X\ 10^{-6}\ X\ W^2}{{\rho_m}^2\ X\ V^2}} \text{ …………………………………………………………………Eqn. 12}$$

Solving Eqn. 12 for values of d at different flow velocities:

Velocity, V (ft/s)	**Diameter. D (inches)**
10	23.29
20	16.47
30	13.44
40	11.64
50	10.41

The diameter value of 16.47 inches was selected for flow velocity of 20 ft/sec.

$$\mathbf{t = t_c + t_{th} + \left[\frac{P\ X\ d_o}{2\ X\ \{(S\ X\ E)+(P\ X\ Y)\}}\left(\frac{100}{100-T_{ol}}\right)\right]} \text{ ………………………………………Eqn. 13}$$

Where;

t = Required Wall Thickness of Pipe, inches

t_c = Corrosion Allowance, inches

t_{th} = Thread/Groove Depth, inches

P = Internal Pipe Pressure, psi

d_o = Pipe Outside Diameter, in

S = Allowable Stress for Pipe Material, psi

E = Longitudinal Weld Joint Factor

Y = Factor (0.4 for Ferrous Materials below 900 °F)

T_{ol} = Manufacturers' Allowed Tolerance

Thread Allowance for Pipe Wall Thickness Calculations ANSI B 31.3

Nominal Pipe Size (in.)	t_{th}
¼–⅜	0.05
½–¾	0.06
1–2	0.08
2½–20	0.11

Figure 10: Thread Allowance Values, Image from Surface Production Operations Volume 1, 2nd Edition by Ken Arnold & Maurice Stewart

Basic Allowable Stress for Grade B Seamless Pipe, psi

Temperature, °F	ASTM A106	API 5L
−20 to 100	20,000	20,000
200	20,000	19,100
300	20,000	18,150
400	20,000	17,250
500	18,900	16,350
600	17,300	15,550
650	17,000	15,000

Figure 11: Basic Allowable Stress Values, Image from Surface Production Operations Volume 1, 2nd Edition by Ken Arnold & Maurice Stewart

$$t = t_c + t_{th} + \left[\frac{P \text{ X } (d_i + 2t)}{2 \text{ X } \{(S \text{ X } E) + (P \text{ X } Y)\}} \left(\frac{100}{100 - T_{ol}}\right)\right]$$

$$t = 0.12 + 0.11 + \left[\frac{348.39 \text{ X } (16 + 2t)}{2 \text{ X } \{(20000 \text{ X } 0.85) + 348.39\}} \left(\frac{100}{100 - 12.5}\right)\right]$$

t = 0.42 inches

Standardizing the line size:

NPS18, SCH30

DN450

ID: 17.126 inches, OD: 18 inches

Thickness: 0.437 inches

From Heat Exchanger to Separator:

$$\boldsymbol{\rho_m = \frac{12409 \text{ X SG X P} + 2.7 \text{ X RSP}}{198.7 \text{ X P} + \text{RTZ}}}$$ ………………………………………………………………**Eqn. 8**

$$\rho_m = \frac{12409 \text{ X } 54.93 \text{ X } 306.86 + 2.7 \text{ X } 5610.36 \text{ X } 1.198 \text{ X } 306.36}{198.7 \text{ X } 306.86 + 56310.36 \text{ X } 654 \text{ X } 0.84}$$

$$\rho_m = 6.92 \text{ lbm/ft}^3$$

$$\mathbf{W = 3180 \text{ X } Q_g \text{ X S} + 14.6 \text{ X } Q_l \text{ X SG}}$$ ……………………………………………………**Eqn. 9**

$$W = 3180 \text{ X } 95.54 \text{ X } 1.198 + 14.6 \text{ X } 25000 \text{ X } 54.93$$

$$W = 20413423 \text{ lbm/hr}$$

$$\mathbf{d^5 = \frac{3.4 \text{ X } 10^{-6} \text{ X f X L X } W^2}{\rho_m \text{ X } \Delta P}}$$ ……………………………………………………………...…….**Eqn. 10**

$$\mathbf{f = \frac{2 \text{ X } \Delta P \text{ X D}}{\text{L X } \rho \text{ X } V^2}}$$ ……………………………………………………………………………...**Eqn. 11**

Substituting f in Eqn. 9

$$\mathbf{d^4 = \frac{2 \text{ X } 3.4 \text{ X } 10^{-6} \text{ X } W^2}{\rho_m{}^2 \text{ X } V^2}}$$ ……………………………………………………………...……….**Eqn. 12**

Solving Eqn. 11 for values of d at different flow velocities:

Velocity, V (ft/s)	**Diameter. D (inches)**
10	27.73
20	19.61
30	16.01
40	13.86
50	12.40

The diameter value of 16.01 inches was selected for flow velocity of 30 ft/sec.

$$\mathbf{t = t_c + t_{th} + \left[\frac{P \text{ X } d_o}{2 \text{ X } \{(S \text{ X } E) + (P \text{ X } Y)\}}\left(\frac{100}{100 - T_{ol}}\right)\right]}$$ ………………………………………**Eqn. 13**

$$t = t_c + t_{th} + \left[\frac{P \text{ X } (d_i + 2t)}{2 \text{ X } \{(S \text{ X } E) + (P \text{ X } Y)\}}\left(\frac{100}{100 - T_{ol}}\right)\right]$$

$$t = 0.12 + 0.11 + \left[\frac{306.86 \text{ X } (16 + 2t)}{2 \text{ X } \{(20000 \text{ X } 0.85) + 306.86\}}\left(\frac{100}{100 - 12.5}\right)\right]$$

t = 0.39 inches

Standardizing the line size:

NPS18, SCH30, DN450

ID: 17.126 inches, Thickness: 0.437 inches, OD: 18 inches

VIII. SINGLE PHASE LINE SIZING

Oil Line from Separator to Surge Vessel:

For flow velocity of 10 ft/sec:

Iteration One:

Assuming d = 15 inches

$$\mathbf{Re} = \frac{\boldsymbol{\rho} \mathbf{\ X\ V\ X\ d}}{\boldsymbol{\mu}} \quad \text{..........Eqn. 14}$$

where;

Re = Reynolds Number

ρ = Density of fluid, g/cc

v = Velocity of flow, cm/sec

d = Internal diameter of pipe, cm

μ = Viscosity of fluid, cp

$$\mathrm{Re} = \frac{0.8132 \text{ X } 304.8 \text{ X } 38.1}{0.017}$$

Re = 555505.53

From the Moody Friction Factor Chart

f = 0.014

$$\mathbf{d^5} = \frac{\mathbf{11.5\ X\ 10^{-6}\ X\ f\ X\ L\ X\ Q_l{}^2\ X\ SG}}{\boldsymbol{\Delta}\mathbf{P}} \quad \text{..........Eqn. 15}$$

where;

d = Internal diameter of Pipe, inches

f = Moody Friction Factor

L = Length of Pipe, ft

Q_l = Liquid Flow Rate, bpd

SG = Specific Gravity of Fluid

ΔP = Pressure Drop, psi

$$\mathrm{d^5} = \frac{11.5 \text{ X } 10^{-6} \text{ X } 0.014 \text{ X } 213.2 \text{ X } 15000^2 \text{ X } 50.76}{28.44}$$

d = 6.72 inches

Iteration Two:

d = 6.72 inches

Re = 249023.85

f = 0.015

d = 6.81 inches

Similarly for flow velocity of 20, 30, 40 and 50 ft/sec.

Velocity, V (ft/sec)	Diameter, d (inches)
10	6.81
20	6.62
30	6.55
40	6.49
50	6.44

Standardizing the line size:

NPS 8, SCH 60

ID: 7.813 inches, Thickness: 0.406 inches, OD: 8.625 inches

Water Line from Separator to Effluent Treatment Plant:

For flow velocity of 10 ft/sec:

Iteration One:

Assuming d = 5 inches

$$\mathbf{Re = \frac{\rho \, X \, V \, X \, d}{\mu}} \quad \text{……………………………………………………………………..}\mathbf{Eqn.\ 13}$$

$$Re = \frac{1.06 \text{ X } 304.8 \text{ X } 12.7}{0.35}$$

Re = 11834.07

From the Moody Friction Factor Chart

f = 0.034

$$\mathbf{d^5 = \frac{11.5 \text{ X } 10^{-6} \text{ X } f \text{ X } L \text{ X } {Q_l}^2 \text{ X } SG}{\Delta P}} \quad \text{…………………………………………………………}\mathbf{Eqn.\ 14}$$

$$d^5 = \frac{11.5 \text{ X } 10^{-6} \text{ X } 0.034 \text{ X } 196.8 \text{ X } 10000^2 \text{ X } 62.42}{7.11}$$

d = 9.17 inches

Iteration Two:

d = 9.17 inches

Re = 21704.5

f = 0.025

d = 8.67 inches

Iteration Three:

d = 8.67 inches

Re = 20538.9

f = 0.026

d = 8.67 inches

Similarly for flow velocity of 20, 30, 40 and 50 ft/sec.

Velocity, V (ft/sec)	Diameter, d (inches)
10	8.67
20	8.41
30	8.27

40	8.07
50	8.07

Standardizing the line size:

NPS10. SCH 60

ID: 9.750 inches

Thickness: 0.5 inches

OD: 10.750 inches

CONCLUSION

As discussed earlier, the facility design by the authors was approved by the mentor. The sizing calculations have been done based on standard relations. A margin of size has been kept in the flow lines to account for pigging and standardization of material so that maintenance issues don’t exist. The horizontal separator size also has been checked by the mentors and approved to be fitting in the deck area constraints on the offshore platform. The construction activities and pre commissioning activities have also been studied by the authors. The compiled report was shown to the mentor and approved.

CONVERSION FACTORS USED

1 BOPD = 0.0039 ft^3/min

1 Bbl = 0.1589 m^3

1000 m^3/day = 0.04 MMSCFD

1 kg/cm^2 = 14.22 psi

1 g/cm^3 = 62.4279 lb/ft^3

1 m^3 = 6.28 bbl

1 m = 3.28 ft

REFERENCES

Chakrabarti S. K., "Handbook of Offshore Engineering", Vol. I. 2005.

Arnold K., Stewart M., "Surface Production Operations Design of Oil-Handling Systems and Facilities", Vol. I, 1998.

Devold H., "Oil and Gas Production Handbook, An introduction to Oil and Gas Production", 2009.

"Gas/Liquid Separators – Type Selection and Design Rules", Shell Manual, 2007.

Web resources from Petrowiki