TWO PHASE GAS-LIQUID PIPELINE DESIGN

By

NURUL EZWEEN BINTI HASBI

DISSERTATION

Submitted to the Petroleum Engineering Programme
In Partial Fulfillment of the Requirements
for the Degree
Bachelor of Engineering (Hons)
(Petroleum Engineering)

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MAY 2011

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TRONOH, PERAK

May 2011

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and the original work contained herein have not been undertaken or done by unspecified sources or persons.

NURUL EZWEEN BINTI HASBI

ACKNOWLEDGEMENT

First and foremost, I would like to give thanks to the Almighty who made all things possible. I also owe my deepest gratitude to my helpful supervisor namely Associate Professor Aung Kyaw who have greatly helped me in giving opinions, suggestions and advices as well as his continuous encouragement during the progression of this project. I am heartily thankful to him whose encouragement, guidance and support from the initial to the final level enabled me to develop an understanding of the subject.He inspired me greatly to work in this project as well as his determination to motivate me contributed tremendously to my project. The supervision and support that he gave truly help the progression and smoothness of the project. Associate Professor Aung Kyaw has not only been one of the best lecturers I have ever encountered, he has consistently proven himself to be committed to the academic success of his students and has raised the caliber of my research. I am grateful to Associate Professor Aung Kyaw for his ability to convey complex concepts and always be cheerful, helpful, encouraging, and supportive, both personally and professionally.

I am indebted to my many of my colleagues to support me upon the completion of this project. Foremost, I recognize the intellectual and moral support of my colleague. Oliver Marcus Lim, who is my coursemate have been a vey good company throughout my journey doing this project. His help of finding the PIPESIM software was really helpful, especially when I was facing the difficulties in learning and understanding the software. I am honored to call Oliver a mentor and friend. He provided a critical eye of scientific integrity and rigor to my research.

I would like to thank to the course coordinators for giving me such opportunity to explore creativity and innovativeness through this course in UTP. Lastly, I offer my regards and blessings to all of those who supported me in any respect during the completion of the project.

ABSTRACT

Pipelines are the most common way of transporting oil or gas in oil and gas industry. A pipeline is all parts of the physical facility through which liquids or gases such as crude oil and natural gas are moved, usually over long distances between a producing region and a local distribution system. A pipeline is like any other flowline. The main differences are that pipelines are long and continuously welded, they have a minimum number of curves, they have no sharp bends, and they are most often either buried or otherwise inaccessible due to their location over the majority of their length. These differences mean that small sections of pipeline are not easily removed for maintenance and consequently great care is taken to prevent problems arising in the first place. A pipeline is extremely expensive to lay, and in the case of offshore pipelines, costs in the order of several million pounds per subsea mile have been encountered. Maintenance on pipelines is also expensive but this expenditure is necessary since, regardless of the expense, pipelines frequently form the most efficient and cost-effective method of transporting the quantifies of oil or gas produced. Multi-phase transportation is currently receiving much attention troughout the oil and gas industry. The combined transport of hydrocarbon liquids and gases can offer significant economic savings over conventional, local, platform based separation facilities. Much of fluid data used to design two-phase pipeline have been determined experimentally and through test made in operationg two-phase pipelines. Two-phase pipeline design is a subject on which research and testing continue, and sophisticated computer programs can predict flow conditions and pressure drop more accurately. A number of different correlations have been developed for two-phase pipeline design. Pipe flow simulation is used to optimize and verify design and to throw light on various operational issues and also for training engineers and operators. This paper is an approach to minimize the operation and maintenance cost by selecting the optimum pipeline size and sizing a slug catcher between the outlet of the pipeline and the processing equipment. PIPESIM is used to run the simulation and compute the complex calculation involved in designing the pipeline size and sizing the slug catcher.

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CHAPTER 1: INTRODUCTION

1. PROJECT BACKGROUND

Two-phase pipelines have been built and operated successfully, though the simpler approach is to use two single-phase pipelines with one transporting liquids and the other gas. However, in some applications, the construction of two pipelines along the same route is the least economic solution. The most common application of two-phase pipelines is offshore, where pipeline construction costs are high. In this application, the two-phase pipeline is the most economical approach eventhough it is more difficult to design and operate.

Much of data used to design two-phase pipeline have been determined experimentally and through test made in operationg two-phase pipelines. Two-phase pipeline design is a subject on which research and testing continue, and sophisticated computer programs can predict flow conditions and pressure drop more accurately.

Nowadays, many computer softwares were developed containing some of the methods for predicting pressure drop in two-phase flow. The softwares employ accurate methods for predicting phase behavior, physical properties and can be used to calculate pressure drops for horizontal, inclined and vertical phases. The softwares can be used to solve test cases for many types of flow, varying the diameter, roughness, composition, overall heat transfer coefficient, angle of inclination, and length. The softwares can be a steady-state or transient, multiphase flow or single phase flow simulator for the design and diagnostic analysis of oil and gas production systems. The software tools such as PIPESIM can be use to model multiphase flow from the reservoir to the wellhead as well as analyzing the flowline and surface facility performance to generate comprehensive production system analysis. This paper is an approach to the design two-phase pipelines using PIPESIM.

In this paper, for the case study 1, the pipeline transports natural gas from source to the destination about 104.44 miles away. After the liquid is separated from the natural gas , the gas flows through a solid desiccant dehydrator and then to the pipeline. Due to the high content of H_2S and CO_2 (25.6 and 9.9 mole %, respectively) and to prevent corrosion and hydrate formation, the gas has been dehydrated before entering the pipeline. The design gas flow rate for the pipeline is 180 MMSCF/D. This paper is an approach to the design of optimum pipeline size for the designed pipeline flow rate. The pipeline was divided into 14 segments according to the number of up-hills and down-hills in the line. The pipeline was simulated by PIPESIM. For pressure drop calculation, the Beggs and Brill method with the original liquid hold up correlation was chosen when running the simulation.

For case study 2, the fluid flows down a riser from the satellite platform to the seabed, along a 5 miles pipeline, and up a riser to the processing platform. The fluid inlet pressure at satellite platform will be 1500 psia and the fluid inlet temperature at satellite platform is 176°F. Design liquid flowrate i5 10000 STB/d with minimum arrival pressure at processing platform of 1000 psia. In offshore oilfield development projects using subsea tieback/riser, severe riser slugging is of great concern, particularly for flowlines with downward slope at the riser base. Subsea tieback has been increasingly used in the development of deepwater oil and gas fields. In a typical subsea production system, produced fluids flow through a wellbore, a subsea flowline and a riser. Flow patterns in the production flowlines and risers may be in stratified flow, slug flow, or annular flow. A flow regime of particular concern and may cause the most damage to topsides equipment is the severe riser slugging. It is crucial to size a slug catcher to avoid the damage to topsides equipment.

2. PROBLEM STATEMENT

Multiphase flow of gas and low loads of liquids occurs frequently in natural gas gathering and transmission pipelines for both onshore and offshore operations. As gas moves through a pipeline its pressure and temperature change due to the frictional loss, elevation change, acceleration, Joule-Thompson effect, and heat transfer from the surroundings. Due to pressure and temperature change, liquid and solid (hydrate) may also form in the line which in turn affects the pressure profile. Modeling and simulation of multiphase system, even under steady-state condition, is complex. There are a few tools designed specifically for modeling and analysis of complex multiphase systems such as PipePhase, PipeSim, OLGA, etc. Under this case study, the problem is to:

- **TO SELECT THE OPTIMUM PIPELINE SIZE**

  The calculation of pressure losses and flow rates depends on pipeline size. Pipeline size required, in turn, depends on pressure loss and volume. So it is often necessary to make a preliminary choice of pipeline size before detailed calculations are made on flow rate and pressure drop. Knowing the flow rate required and assuming a reasonable pressure drop based on experience, the experienced designer can choose a likely pipe size as a starting point. Then, calculation of pressure drop and flow capacity can be made assuming that size and weight of pipe. After these calculations are made, a change in the pipe size may be needed to meet requirements dictated by operating pressure. Using PIPEsim, these choices can be evaluated rapidly and the correct design selected. Sensitivity analysis on pipeline diameter should be done by using PIPEsim to determine the optimum pipeline size that will allow the design flowrate to maintain design arrival pressure. To do the sensitivity analysis, the complex calculation of pressure drop and flow capacity will be compute by PIPEsim. Large pipeline diameter is not economical and required longer installation time therefore it is important to select the optimum pipeline diameter.

- **SLUG CATCHER SIZING**

  The computer software also can be used to screen the pipeline for severe riser slugging by identifying which flow regime is the flow in and designing for one in a thousand 5lug. Pipelines that transport both gas and liquids together, known as two-phase flow, can operate in a flow regime known as slug flow or intermittent flow. Under the influence of gravity liquids will tend to settle on the bottom of the pipeline, while the gases occupy the top section of the pipeline. Under certain operating conditions gas and liquid are not evenly distributed throughout the pipeline, but travel as large plugs with mostly liquids or mostly gases through the pipeline. These large plugs are called slugs. Slugs exiting the pipeline can overload the gas/liquid handling capacity of the plant at the pipeline outlet, as they are often produced at a much larger rate than the equipment is designed for. Therefore, if slug flow is expected in the pipeline, it is necessary to size a slug catcher.

3. SIGNIFICANT OF PROJECT

Internal diameter (ID) of the pipeline has significant effect on the pressure drop in the pipeline so it will effect the pressure at the outlet end. The ID of pipeline can effect the performance of the pipeline system. The ID of the pipeline was varied in order to observe the performance of the pipeline with different ID.

[4]Other than that, in oil & gas field development, interfiled pipelines widely used to transfer well fluid from Satellite wellhead (SW) to Center Processing Platform (CPP) for pretreatment, conditioning and processing. Partial conditioned gas and partial stabilized condensate will then transfer to onshore plant via pipeline for further processing. Partial conditioned gas and partial stabilized condensate travel through long distance pipeline will experience frictional loss and heat loss to ambient. These results change in equilibrium state and lead to condensate formation for partial conditioned gas and flashing in partial stabilized condensate. Two phase gas-liquid flow along pipeline will leads to unavoidable non-stable operation, as example, the slugging flow[4].

4. OBJECTIVES

The objective of this project is to optimize the design of two phase pipeline which in this case, the design of gas pipeline with the presence of liquid when the gas pressure and temperature change due to the frictional loss, elevation change, acceleration, Joule-Thompson effect, and heat transfer from the surroundings as gas moves through a pipeline. This paper emphasizes the sensitivity analysis on pipeline diameter to select the optimum pipeline size. The important parameters that will be vary is the **diameter of the pipeline** in selecting the optimum pipeline size. Other than that, the computer software will model the two phase pipeline and if the fluid flow within certain flow regime and indicates the slug formation in the pipeline, the sizing of slug catcher is necessary because as slug approaching receiving facilities, slug size will grow and large slug arrived at first receiving facilities will seriously overload the liquid handling capacity and may lead to tripping of receiving facilities. To size a slug catcher, there are 2 important parameters that will be required to size a slug catcher namely:

- **One over thousand slug length**
- **Volume swept by pig (liquid by sphere)**

For the case study 1, two phase pipeline will be modeled to do the sensitivity analysis on pipeline diameter to select the optimum pipeline size. For the second case study, two phase pipeline will be modeled to do the sensitivity analysis on pipeline diameter to select the optimum pipeline size and to size a slug catcher if the fluid flow within certain flow regime and there is indications of the slug formation in the pipeline.

5. SCOPE OF STUDY

The general scope of study for the two phase pipeline design is to understand the basic key design term such as pipe diameter, pipe length, the temperature, pressure and any other fluid properties and other variables considered in designing liquids or natural gas pipelines. The basic key design terms can be used to calculate pressure drop and flow capacity. Learning on the theories of gas pipeline transmission and understanding in the basic key design term is essential as the knowledge from the theories will be implemented in the PIPESIM software. Other that that, it is crucial to know the steps in building a multiphase pipeline model and learn the procedure of conducting the PIPESIM software. The understanding on all parameters will help the engineers to design the pipeline. The understanding in phase flow behaviour in gas pipeline also essential as the need to determine the flow regime to perform mathematical correlation. There are few correlation developed for different fluid phase condition and the correlation for complex pipeline system can be perform by Pipesim in short time and greatly easing the design process.

6. RELEVANCY OF THE PROJECT

This paper is an approach to optimize the pipe diameter of natural gas pipeline to meet the customer's required arrival pressure and temperature where two phase flow is predicted to occur in the pipeline system. This paper is also an approach to design of slug catcher size in order to minimize the cost for operation and maintenance. Slugs exiting the pipeline can overload the gas/liquid handling capacity of the plant at the pipeline outlet, as they are often produced at a much larger rate than the equipment is designed for. Large slug arrived at first receiving facilitiy will seriously overload the liquid handling capacity. Large slug may leads to tripping of receiving facilities therefore the slug catcher can be used to temporary store the intermittent slug and treated it after the slugging period in order to avoid this situation.

7. FEASIBILITY STUDY

The Gantt chart prepared serves of how this study evolves and move through the end of project. Simulation of the natural gas pipeline, case study 1 started from end of end of May, while the case study 2 for the slug catcher size design started from middle of June, and both simulations were done in the first week of August.

CHAPTER 2: LITERATURE REVIEW

[4]Even to discuss the basics of pipeline design, it is necessary to be familiar with how key physical properties of fluids affect pipeline design. It is important to remember that the term fluid includes both liquids and gases. The effect of these parameters varies with the fluid, compressibility does not significantly affect the flow of liquids, for instance, and differences in viscosity among different gases may not greatly affect the flow of natural gas. Most of the following fluid properties and other variables are considered in designing liquids or natural gas pipelines are:

- **PIPE DIAMETER.** The larger the inside diameter of the pipeline, the more fluid can be moved through it, assuming other variables are fixed.

- **PIPE LENGTH.** The greater the length of a segment of pipeline, the greater the total pressure drop. Pressure drop can be the same per unit of length for a given size and type of pipe, but total pressure drop increases with length.

- **SPECIFIC GRAVITY AND DENSITY.** The density of a liquid or gas is its weight per unit volume. Density can be given in different units: In English units, it is in pounds of mass per cubic foot (lb_{mass}/ft^3); in the SI (International) metric system, units are kilograms per cubic meter (kg/m^3). The specific gravity of a liquid is the density of the liquid divided by the density of water, and the specific gravity of a gas is its density divided by the density of air. The specific gravity of air, therefore, is 1, and the specific gravity of water is 1.

- **COMPRESSIBILITY.** Because most liquids are only slightly compressible, this term is usually not significant in calculating liquids pipeline capacity at normal operating conditions. In gas pipeline design, however, it is necessary to include a term in many design calculations to account for the fact that gases deviate from laws describing ideal gas behavior when under conditions other than standard, or base, conditions. This term supercompressibility factor is more significant at high pressures and temperatures. Near standard conditions of temperature and pressure (60°F and 1 atm, for example), the deviation from the ideal gas law is small, and the effect of the supercompressibility factor on design calculations is not significant.

- **TEMPERATURE.** Temperature affects pipeline capacity both directly and indirectly. In natural gas pipelines, the lower the operating temperature, the greater the capacity,assuming all other variables are fixed. Operating temperature also can affect other variables are fixed. Operating temperature also can affect other terms in equations used to calculate the capacity of both liquids and natural gas pipelines. Viscosity, for example, varies with temperature. Designing a pipeline for heavy crude is one case in which it is necessary to know flowing temperature accurately to calculate pipeline capacity.

- **VISCOSITY.** The property of a fluid that resists flow, or relative motion, between adjacent parts of the fluid is viscosity. It is an important term in calculating line size and pump horsepower requirements when designing liquids pipelines.

- **POUR POINT.** The lowest temperature at which an oil will pour, or flow, when cooled under specified test conditions is the pour point. Oils can be pumped below their pour point, but the design and operation of a pipeline under these conditions present special problems.

- **VAPOR PRESSURE.** The pressure that holds a volatile liquid in equlibrium with its vapor at a given temperature is the vapor pressure. When determine for petroleum products under specific test conditions and using a prescribed procedure, it is called the Reid vapor pressure (RVP). Vapor pressure is an especially important design criterion when handling volatile petroleum products, such as LP-gas. This minimum pressure in the pipeline must be high enough to maintain these fluids in a liquid state.

- **REYNOLDS NUMBER.** This dimensionless number is used to describe the type of flow exhibited by a flowing fluid. In stream-lined or laminar flow, the molecules move parallel to the axis of flow; in turbulent flow, molecules move back and foth across the flow axis. Other types of flow are possible, and the Reynolds number can be used to determine which type is likely to occur under specified conditions. In turn, the type of flow exhibited by fluid affects pressure drop in the pipeline. In general, a Reynolds number below 1000 describes streamlined flow; at Reynolds number between 1000 and 2000, flow is unstable. At Reynolds numbers greater than 2000, flow is turbulent. some references recommend, however, that flow be assumed laminar at Reynolds numbers of up to 2000 and turbulent at values above 4000. In this case, flow is considered unstable at Reynolds numbers between 2000 and 4000.

- **FRICTION FACTOR.** A variety of friction factors are used in pipeline design equations. They are determined empirically and are related to the roughness of the inside pipe wall.

Other properties of the fluid and pipe may be used in specific calculations, but these are the basic terms used to determine pressure drop and flow capacity. Many system variables are interdependent. For example, operating pressure depends, in part, on pressure drop in the line. Pressure drop, in turn, depends on flow rate, and maximum flow rate is dictated by allowable pressure drop.

Several pressure term are used in pipeline design and operation. Barometric pressure is the value of the atmospheric pressure above a perfect vacuum. A perfect vacuum cannot exist on the earth, but it makes a convenient reference point for pressure measurement.

Absolute pressure is the pressure of a pipeline or vessel above a perfect vacuum and is abbreviated psia. Gauge pressure is the pressure measured in a pipeline or vessel above atmospheric pressure and is abbreviated psig. standard atmospheric pressure is usually considered to be 14.696 lb/in^2, or 760 mm of mercury, but atmospheric pressure varies with elevation above sea level. Many contracts for the purchase or sale of natural gas, for instance, specify that standard, or base, pressure will be other than 14.696 lb/in^2.

Formulas describing the flow of fluids in a pipe are derived from Bernoulli's theorem and are modified to account for losses due to friction. Bernoulli's theorem expresser the application of the law of conservation of energy to the flow of fluids in a conduit. To describe the actual flow of gases and liquids properly, however, solutions of equations based on Bernoulli's theorem require the use of coefficients that must be determined experimentally.

The theoretical equation for fluid flow neglects friction and assumes no energy is added to the systems by pumps or compressors. Of course, in the design and operation of a pipeline, friction losses are very important, and pumps and compressors are required to overcome those losses. so practical design equations depend on empirical coefficients that have been determined during years of research and testing.

The basic theory of fluid glow does not change. But modifications continue to be made in coefficients as more information is available, and the application of various forms of basic formulas continues to be refined. The use of computers for solving pipeline design problems has also enhanced the accuracy and flexibility possible in pipeline design.[4]

1. COMPUTER MODELS

[4]Accurate prediction of physical and thermodynamic properties is pre-requisite to successful pipeline design. Pressure loss, liquid holdup, heat loss, hydrate formation, and wax deposition all require knowledge of fluid states.

In flow assurance analyses, the following two approaches have been used to simulate hydrocarbon fluids:

- "black-oil" model: defines the oil as liquid phase that contains dissolved gas, such as hydrocarbons produced from the oil reservoir. The "black-oil" accounts for the gas that dissolves (condenses) from oil solution with a parameter of R, that can be measured from the laboratory. This model predicts fluid properties from the specific gravity of the gas, the oil gravity, and the volume of gas produced per volume of liquid. Empirical correlations evaluate the phase split and physical property correlations determine the properties of the separate phases.

- Composition model: for a given mole fraction of a fluid mixture of volatile oils and condensate fluids, a vapor/liquid equilibrium calculation determines the amount of the feed that exists in the vapor and liquid phases and the composition of each phase. It is possible to determine the quality or mass fraction of gas in the mixtures. Once the composition of each phase is known, it is also possible to calculate the interfacial tension, densities, enthalpies, and viscosities of each phase.

The accuracy of the compositional model is dependant upon the accuracy of the compositional data. If good compositional data are available, selection of an appropiate EOS is likely to yield more accurate phase behaviour data than the corresponding "black-oil" model. This is particularly so if the hydrocarbon liquid is a light condensate. In this situation complex phase effects such as retrograde condensation are unlikely to be adequately handled by the "black-oil" methods. Of prime importance to hydraulic studies is the viscosity of the fluid phases. Both "black-oil" and compositional techniques can be inaccurate. Depending on the correlation used, very different calculated pressure losses could result. With the uncertainty associated with viscosity prediction it is prudent to utilise laboratory measured values.

GOR may be defined as the ratio of the measured volumetric flow rates of the gas and oil phases at meter conditions (ambient conditions) or the volume ratio of gas and oil at the standard condition (14.7 psia, 60°F) with unit of SCF/STB. When water is also present, the watercut is generally defined as the volume ratio of the water and total liquid at standard conditions. If the water contains salts, the salt concentrations may be contained in the water phase at the standard condition.[4]

2. HYDROCARBON FLOW

[4]The complex mixture of hydrocarbon compounds or components can exist as a single-phase liquid, a single-phase gas, or as a multi-phase mixture, depending on its pressure, temperature, and the composition of the mixture. The fluid flow in flowlines is divided into three categories based on the fluid phase condition,

- **SINGLE-PHASE**; black oil or dry gas transport flowline, export flowline, gas or water injection flowline, and chemical inhibitors service flowlines such as methanol, glycol lines and etc.
- **TWO-PHASE**; oil + released gas flowline, gas + produced oil (condensate) flow line.
- **THREE-PHASE**; water + oil + gas (typical production flowline).

The flowlines after oil/gas separation equipment generally flow single phase hydrocarbon fluid, such as transport flowlines and export flowlines, while in most cases, the production flowlines from reservoirs have two or three-phase, simultaneously, and the fluid flow is then called multi-phase flow.

In a hydrocarbon flow, the water should be considered as a sole liquid phase or combination with oil condensates, since these liquids basically are insoluble in each other. If the water amount is small enough that it has little effect on flow performance, it may be acceptable to assume a single liquid phase. At low velocity range, there is considerable slip between the oil and water phase. As a result, the water tends to accumulate in low spots in the system. This leads to high local accumulations of water, and thereby a potential for water slugs in the flowline. It may also cause serious corrosion problems.

Two phase (gas/liquid) models are used for black oil system even when water is present. The water and hydrocarbon liquid are treated as a combined liquid with average properties. For gas condensate systems with water, three-phase (gas/liquid/aqueous) models are used.[4]

3. TWO-PHASE PIPELINE DESIGN

[4]The design of two-phase pipeline to handle both gas and liquids involves calculations similar to those used for a single-phase pipeline. The goal in both cases is to determine pipe size, flow capacity, pressure drop, and other flow parameters.

The key difference is that pressure drop is much more difficult to determine when both gas and liquids are flowing in the same pipeline. And some pipelines carry a two-phase, multicomponent stream (gas, oil, and water). Flow of the two phase can take several forms, and presure drop can vary widely, depending on flow conditions. Changes in elevation over the route of two-phase line are much more significant than single-phase pipeline.

Besides pressure drop, liquid holdup is an important consideration in the design of a two-phase pipeline. Holdup refers to the fraction of the pipeline occupied by liquid at any point in the line and is a function of liquid and gas flow within the pipeline. In bubble flow, free gas is present as bubbles in a continuous liquid phase. At the other extreme is mist flow, in which the gas phase is continuous and liquid droplets are entrained in the gas. Between these two extremes are other types of flow, including stratified, wavy, and slug flow. In slug flow, at low flow rates, liquid can occupy the entire cross section of the pipeline at poits in the line. This is likely to occur on uphill portions of the pipeline. This type of flow can produce liquid slugs that exit the pipeline intermittently. Because of ths, it is often necessary to include equipment to catch thes slugs of liquid at the end of the pipeline to prevent damage to processing or other facilities.[4]

4. MULTIPHASE FLOW

[3]As in the multiphase flow in vertical pipe, in horizontal pipe there are distinct flow regimes. In horizontal flow there are divided up into 3 main types, Segregated Flow, Intermittent Flow and Distributive Flow. Segregated Flow is divided up into Stratified, Wavy and Annular Flow. Intermittent Flow is divided up in to Plug and Slug Flow. Distributive Flow is divided up in to Bubble and Mist Flow.

- Segregated flow is further classified as being stratified smooth, stratified wavy (ripple flow), or annular. At higher gas rates, the interface becomes wavy, and stratified wavy flow results. Annular flow occurs at high gas rates and relatively high liquid rates and consists of an annulus of liquid coating the wall of the pipe and a central core of gas flow, with liquid droplets entrained in the gas.
- The intermittent flow regimes are slug flow and plug (also called elongated bubble) flow. Slug flow consists of large liquid slugs alternating with high-velocity bubbles of gas that fill almost the entire pipe. In plug flow, large gas bubbles flow along the top of the pipe.
- Distributive flow regimes include bubble, mist ,and froth flow.[3]

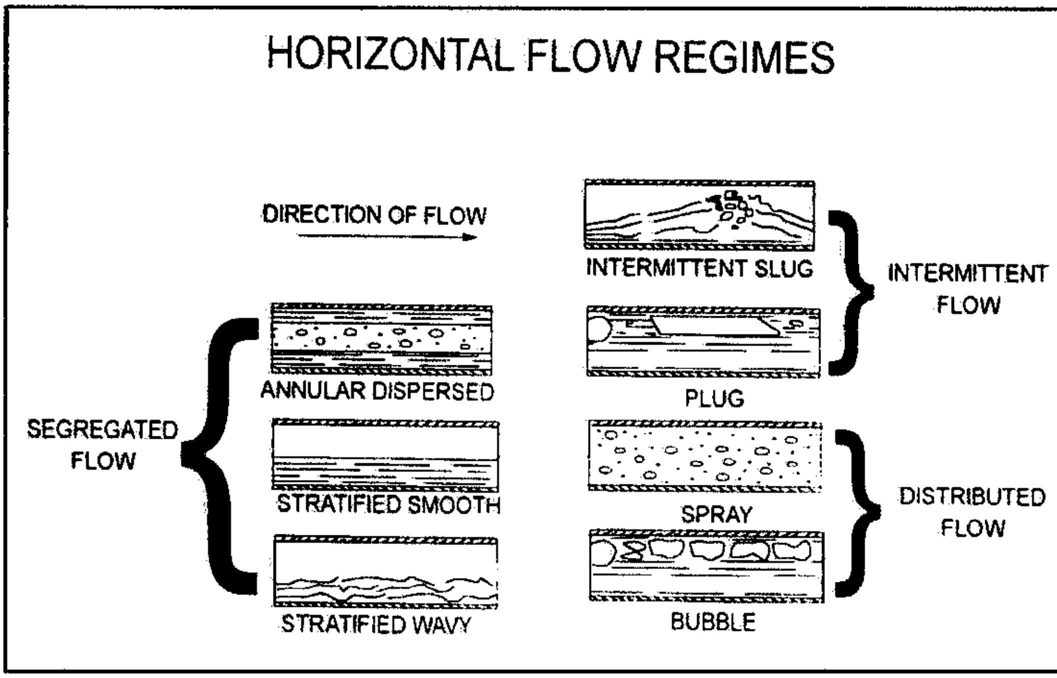


Figure 1: *Horizontal Flow Regimes*[3]

5. BEGGS AND BRILL METHOD

[3]The Beggs and Brill method works for horizontal or vertical flow and everything in between. It also takes into account the different horizontal flow regimes. This method uses the general mechanical energy balance and the average in-situ density to calculate the pressure gradient. The following parameters are used in the calculations.

$$\boxed{N_{FR} = \frac{u^2}{gD}}$$

$$\boxed{\lambda_l = \frac{u_l}{u_m}}$$

$$\boxed{L_1 = 316\lambda_l^{0.302}}$$

$$\boxed{L_2 = 0.0009252\lambda_l^{-2.4684}}$$

$$\boxed{L_3 = 10\lambda_l^{-1.4516}}$$

$$\boxed{L_4 = 0.5\lambda_l^{-6.738}}$$

Determining flow regimes

- Segregated if $\lambda_l < 0.01$ and $N_{FR} < L_1$ or $\lambda_l > 0.01$ and $N_{FR} < L_2$

- Transition if $\lambda_l \geq 0.01$ and $L_2 < N_{FR} < L_3$
- Intermittent if $0.01 \leq \lambda_l < 0.4$ and $L_3 < N_{FR} \leq L_1$ or $\lambda_l \geq 0.4$ and $L_3 < NFR \leq L4$
- Distributed if $\lambda_l < 0.4$ and $N_{FR} > L_1$ or $\lambda_l \geq 0.4$ and $N_{FR} > L_4$

For segregated, intermittent and distributed flow regimes use the following:

$$\boxed{y_l = y_{10}\psi}$$

$$\boxed{y_{10} = \frac{a\lambda_l^b}{N_{FR}^c}}$$

With the constraint of that $y_{10} \geq \lambda_1$

$$\boxed{\psi = 1 + C[(\sin 1.8\theta) - 0.333\,(\sin^3 1.8\theta)]}$$

$$\boxed{C = (1 - \lambda_1)\ln\left(d\lambda_l^e N_{vl}^f N_{FR}^g\right)}$$

Where a, b, c, d, e, f and g depend on flow regimes and are given in the following table

BEGGS AND BRILL HOLDUP CONSTANTS				
FLOW REGIME	a	b	c	
Segregated	0.98	0.4846	0.0868	
Intermittent	0.845	0.5351	0.0173	
Distributed	1.065	0.5824	0.0609	
	d	e	f	g
Segregated uphill	0.011	-3.768	3.539	-1.614
Intermittent uphill	2.96	0.305	-0.4473	0.0978
Distributed uphill	No correction, $C = 0, \psi = 1$			
All regimes downhill	4.70	-0.3692	0.1244	-0.5056

For transition flow, the liquid holdup is calculated using both the segregated and intermittent equations and interpolating using the following:

$$\boxed{y_l = Ay_l(Segregated) + By_l(Intermittent)}$$

$$\boxed{A = \frac{L_3 - N_{FR}}{L_3 - L_2}}$$

$$\boxed{B = 1 - A}$$

$$\boxed{\bar{\rho} = y_l\rho_l + y_g\rho_g}$$

$$\boxed{\left(\frac{dP}{dl}\right)_{PE} = \frac{g\bar{\rho}sin\theta}{g_c 144}}$$

The frictional pressure gradient is calculated using:

$$\boxed{(\frac{dP}{dl})_F = \frac{2f_{tp}\rho_m u_m^2}{g_c D}}$$

$$\boxed{f_{tp} = f_n\frac{f_{tp}}{f_n}}$$

$$\boxed{\rho_m = \rho_l\lambda_l + \rho_g\lambda_g}$$

The no slip friction factor f_n is based on smooth pipe $(\frac{\varepsilon}{D} = 0)$ and the Reynolds number, $N_{Rem} = \frac{\rho_m u_m D1488}{\mu_m}$ where $\mu_m = \mu_m\lambda_l + \mu_g\lambda_g$

$f_{tp}$the two phase friction factor is

$$\boxed{f_{tp} = f_n e^s}$$

where $S = \frac{\ln x}{-0.0523+3.182\ln x-0.8725(\ln x)^2+0.01853(\ln x)^4}$ and $x = \frac{\lambda_l}{y_l^2}$.

Since S is unbounded in the interval $1 < x < 1.2$, for this interval

$$S = \ln(2.2x - 1.2)$$

6. SLUG CATCHER SIZING

Slug catchers should be sized to dampen to a level that can be handled by downstream processing equipment. Before dynamic models of the topsides facilities are available, the level of acceptable surging is unknown and designers are often forced to make assumptions vis-a-vis surge volumes, such as designing for the 'one in a thousand' slug.

Surge volume for gas condensate requirements are determined from the outlet liquids rates predicted in the ramp-up, startup, and pigging cases. The required slug catcher size is dependant on liquid handling rate, pigging frequency, and ramp-up rates. An iterative process may be required to identify optimum slug catcher size, pigging frequency, liquid handling rate, and acceptable ramp-up rates. For this optimization, the results of the simulations should be presented as surge volume requirements as a function of liquid handling rate for representative ramp-up rates and pigging frequencies.

7. SEVERE RISER SLUGGING

Severe riser slugging is likely in a pipeline system followed by a riser under certain conditions. The elements leading to severe riser slugging are:

- The presence a long slightly downward inclined pipeline prior to the riser.
- Fluid flowing in the stratified or segregated flow regime (as opposed to the usual slug or intermittent flow regime).
- A slug number (PI-SS) of lower than 1.0.

The PI-SS number can also be used to estimate the severe riser slug length from the equation:

SLUG LENGTH = RISER HEIGHT / PI-SS NUMBER

2. PROJECT ACTIVITIES FLOW

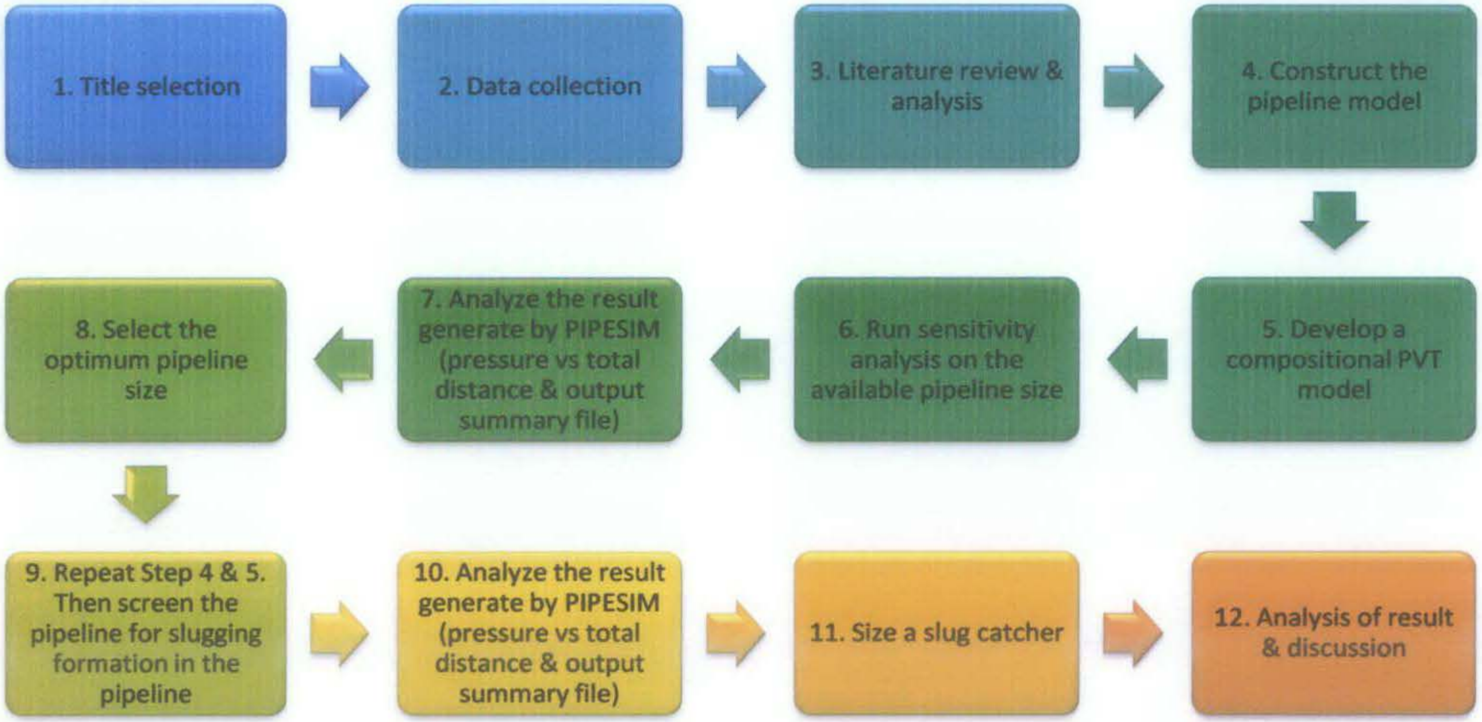


Figure 2: *Project activities flow*

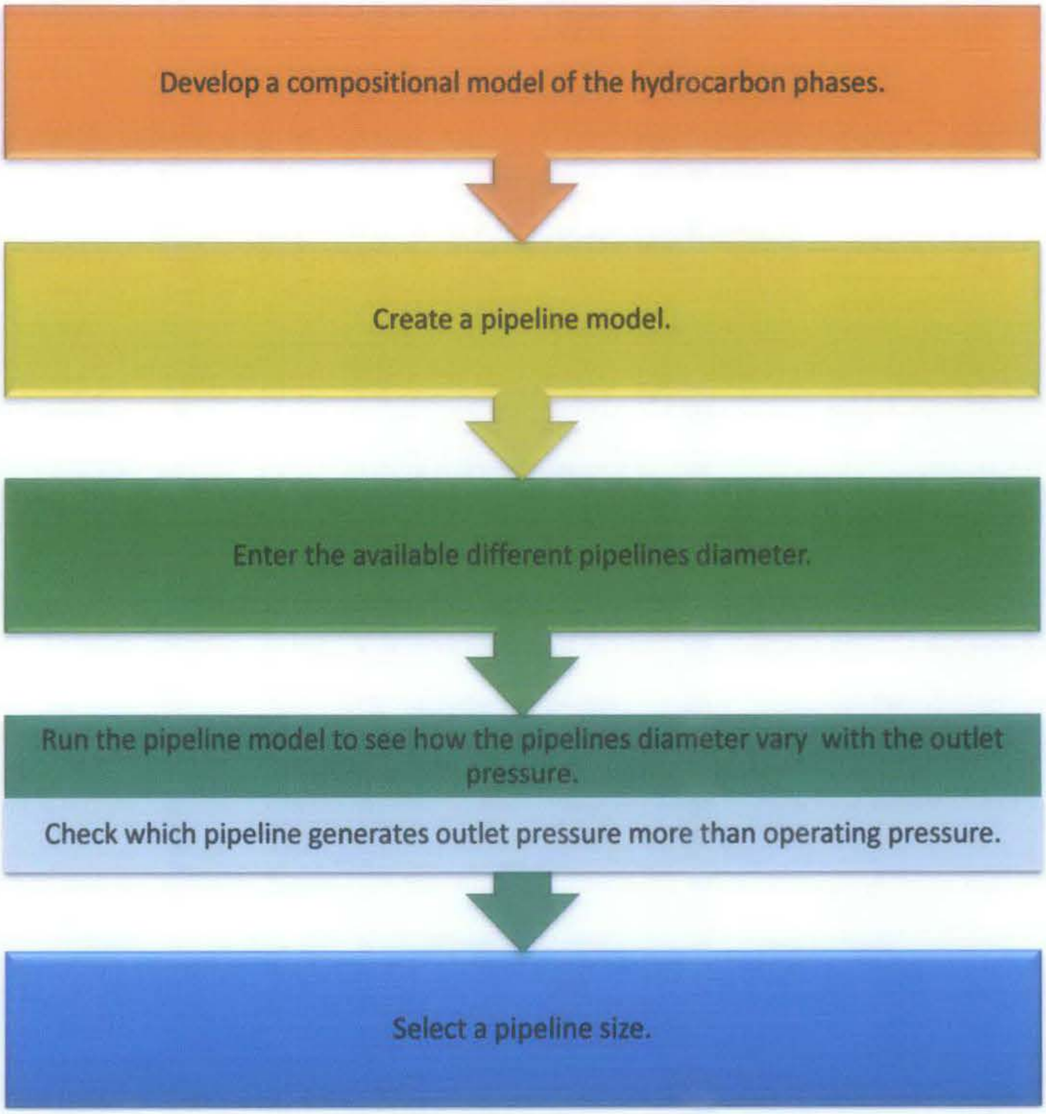


Figure 3: *Project Methodology Case Study 1*

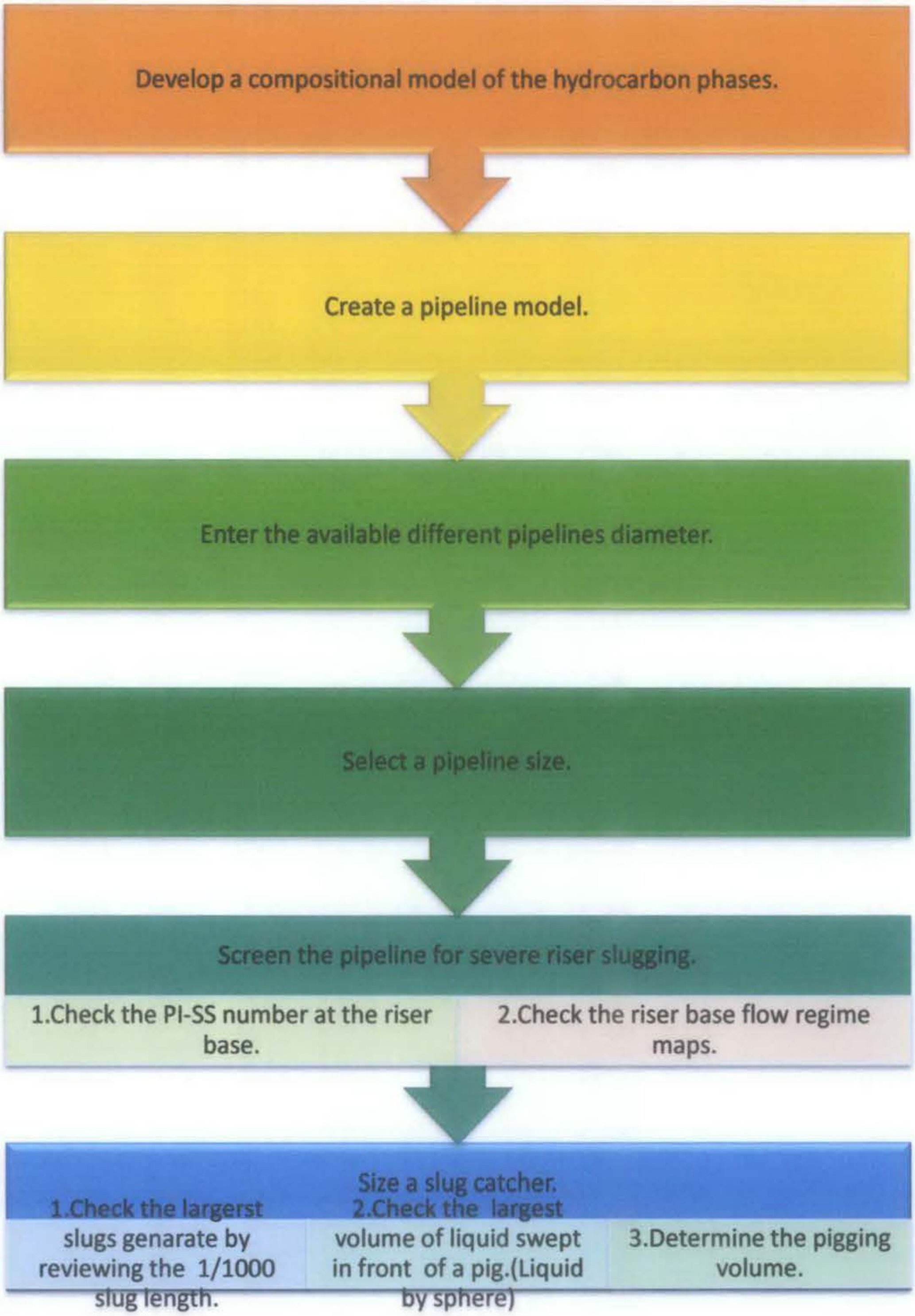


Figure 4: *Project Methodology Case Study 2*

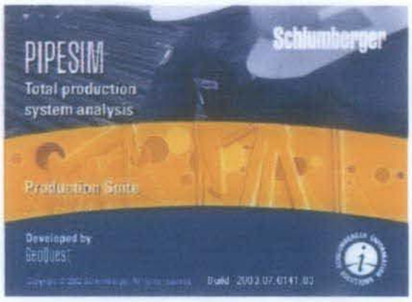
3. KEY MILESTONE (GANTT CHART)

		MAY	JUNE					JULY				AUGUST				SEPTEMBER		
No	**Activities /Week**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17 - 19**
1	Pipesim Exercise							MID-SEM BREAK									STUDY WEEK	EXAMINATION WEEK
2	Pipesim Case Study																	
3	Progress Report Submission																	
4	Pre-EDX																	
5	EDX																	
6	Final Oral Presentation																	
7	Delivery of Final Report to External Examiner																	
8	Submission of Hardbound Copies																	

Activities done   Incoming Activities

Table 1: *Project Gantt chart*

4. PIPESIM



I. Steady-State Multiphase Flow Simulation (PIPESIM)

[5]PIPESIM software is a steady-state, multiphase flow simulation software that can be used to design and analyze of oil and gas production systems. The multiphase flow of hydrocarbon from the reservoir to the wellhead can be modeled by using PIPESIM software tools and also analyzes flowline and surface facility performance to generate comprehensive production system analysis as well. With advanced modeling algorithms for nodal analysis, PVT analysis, gas lift, and erosion and corrosion modeling, PIPESIM software helps engineers to optimize the production and injection operations.[5]

II. PIPESIM Flow Assurance

[5]PIPESIM production system analysis software offers the industry's most comprehensive steady-state flow assurance workflows, both for front-end system design and production operations. Specific flow assurance modeling capabilities include:

- erosion prediction for sand-laden fluids
- CO2-induced corrosion prediction
- emulsion handling
- hydrate prediction including mitigation with inhibitors
- slug characteristics and pigging operations
- wax and asphaltenes prediction
- time-dependent wax deposition

- liquid loading prediction
- detailed heat transfer modeling.

[5]PIPESIM can be used to identify and predict flow assurance issues and develop mitigation strategies. Fluid flow can be modeled accurately using industry-standard multiphase flow correlations and advanced heat transfer models in this simulator software. PIPESIM also offers the accurate characterization of fluid behavior and predict hydrate, wax, and asphaltene formation using a wide variety of black-oil and compositional fluid models. Prediction on rates of erosion and corrosion assess the pipeline integrity. Furthermore, PIPESIM assess the operational risk from wax deposition along flowlines over time and determine liquid-handling capacities at the processing facility by modeling slug flow and pigging operations. The benefits of PIPESIM:

- Models multiphase flow from the reservoir through the production facilities to your delivery point
- Addresses complex production networks and captures the interactions between wells, pipelines, and process equipment
- Performs a comprehensive sensitivity analysis at any point in your hydraulic system using multiple parameters
- Simulates your field production system to improve production, make better decisions, and maximize your asset value
- Links with HYSYS process simulator for an integrated sand face to process facility analysis

CHAPTER 4: RESULTS AND DISCUSSION

1. CASE STUDY 1

The design gas flow rate for the pipeline is 180 MMSCF/D. The pipeline length and elevation at inlet are shown in **Table 2.** The ambient temperature is assumed to be 60 °F (15.6 °C). The fluid inlet pressure is 1165 psia (8032 kPa) with 95 °F (35 °C) inlet temperature. The required outlet pressure is 750 psia. The pipeline is buried under ground; with an approximate overall heat transfer coefficient of 1 Btu/hr-ft2-°F (5.68 W/m2-°C) was assumed. Due to the high content of H_2S and CO_2 (25.6 and 9.9 mole %, respectively) and to prevent corrosion and hydrate formation, the gas has been dehydrated before entering the pipeline.

Segment length for pipeline		
Segment No	Length (miles)	Elevation at inlet (ft)
1	7.09	1740.00
2	4.84	672.57
3	6.40	1197.51
4	3.10	688.98
5	0.62	1410.76
6	7.77	862.86
7	9.94	295.28
8	14.93	426.51
9	7.34	196.85
10	9.46	98.43
11	9.94	55.77
12	9.94	49.21
13	9.94	19.69
14	3.11	36.09

Table 2: *Pipeline length and elevation at inlet*

Composition and condition of pipeline	
Component	Mole %
H_2S	25.6

N_2	0.2
CO_2	9.9
C_1	62.9
C_2	0.7
C_3	0.2
iC_4	0.06
nC_4	0.09
iC_5	0.04
nC_5	0.05
C_6+	0.26
Total	100

Table 3: *Composition and condition of pipeline*

PROPERTIES OF C6+

SpGr = 0.7

Molecular Weight = MW = 107.8

Normal Boiling Point = NBP= 233.8°F

Critical Temperature = TC = 536.7 °F

Critical Pressure = PC = 374.4 psi

Acentric Factor = 0.3622

I.D.(")	Wall thickness (")	Roughness (")
16	0.5	0.001
18	0.5	0.001
20	0.5	0.001
24	0.5	0.001

Table 4: *Available pipeline sizes*

SELECTION OF OPTIMUM PIPELINE ID

By using the wizard feature in the Pipesim, this pipeline model is constructed. The source pressure is 1165 psia with 95°F fluid temperature. The pipeline was divided into 14 segments according to the number of up-hills and down-hills in the line. The pipeline ID, wall thickness, roughness, overall heat transfer coefficient and elevation data and was entered for detailed pipeline description.

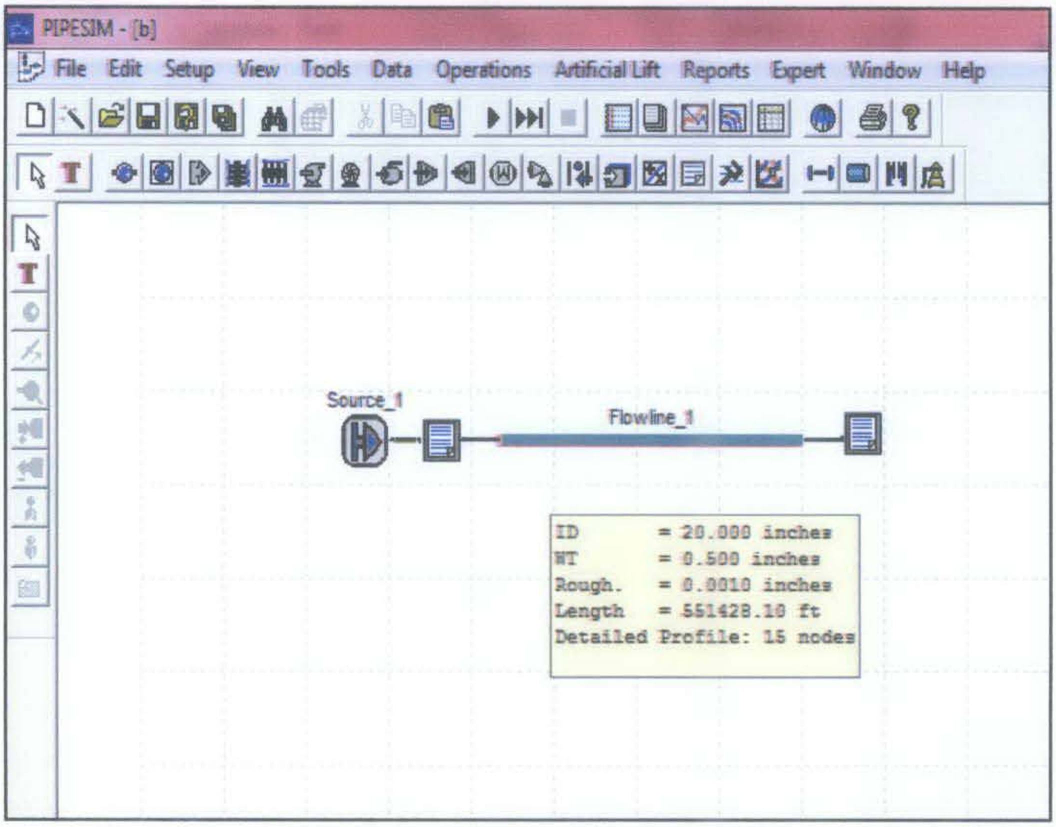


Figure 5: *Constructed pipeline model CASE STUDY 1*

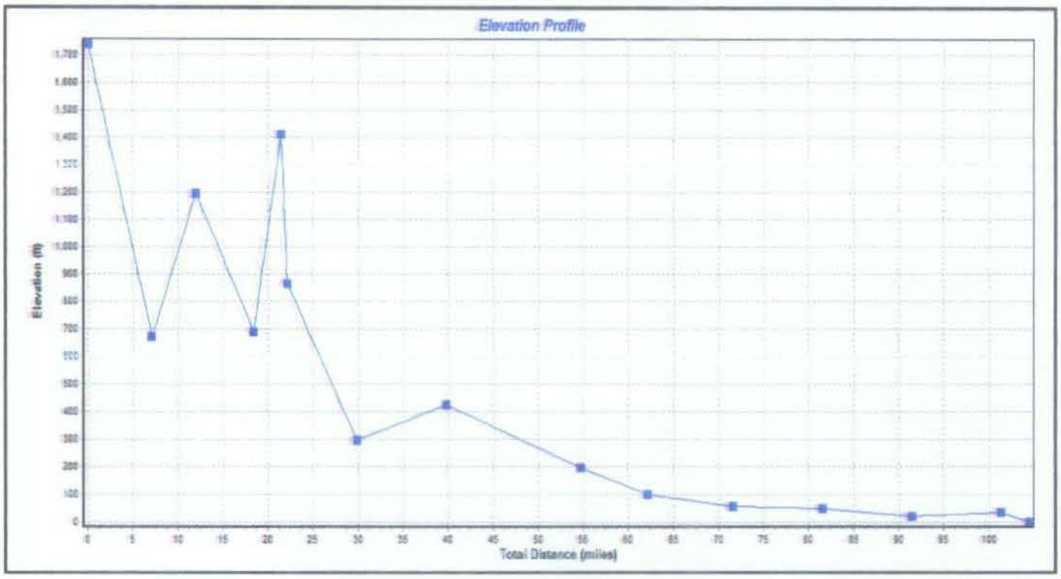


Figure 6: *Pipeline elevation profile*

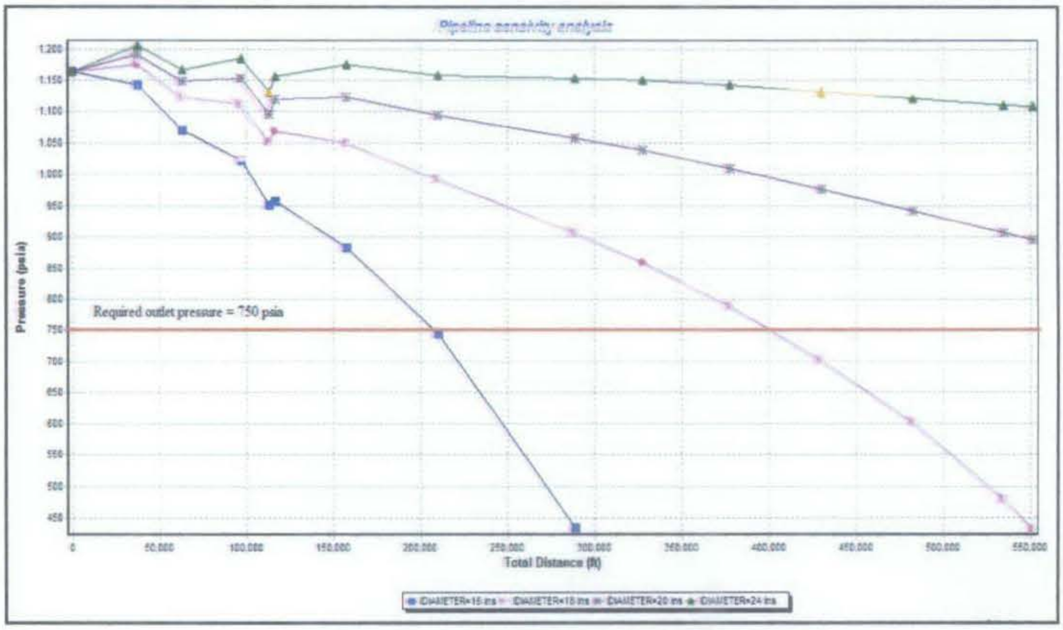


Figure 7: *Pipeline diameter sensitivity analysis*

Required outlet pressure = 750 psia

PIPELINE ID	16"	18"	20"	24"
OUTLET PRESSURE	< 750 psia	< 750 psia	>750 psia	> 750 psia

Table 5: *Pipeline diameter & outlet pressure case study 1*

Figure 6 is the graph plot for sensitivity analysis on 4 available pipeline size which are 16", 18", 20" or 24" ID. Note that the calculated outlet pressure for 16" and 18" pipeline will become less than required outlet pressure for the operation before fluid reach the destination. 20" and 24" ID pipeline will be the suitable pipeline. It can be seen that a 20" is the smallest pipeline size that will satisfy the arrival pressure condition of at least 750 psia. The optimum pipeline size selected is 20".

Case 1 :IDIAMETER=16 ins

FLOWLINE Flowline_1

	Dist. (feet)	Elev. (feet)	Horiz. Angle (deg)	Vert. Devn. (deg)	Pres. (psia)	Temp. (F)	Mean Vel. (ft/s)	Pressure Drop (psi) Elev.	Pressure Drop (psi) Frictn.	Liquid Flow (bbl/d)	Free Gas (mmscfd)	Densities (lb/ft3) Liquid	Densities (lb/ft3) Gas	Slug Number (PI-SS)	Flow Pattern
1	0.0000	1740.0	-1.63	88.37	1165.0	95.000	15.330	0.0000	0.0000	0.0000	180.000	.00010	6.1858		GAS
2	37435.	672.57	-1.63	88.37	1142.3	80.714	14.676	-46.91	69.659	395.25	179.607	37.658	6.4223	125.26	B/B SEGREGATED
3	62990.	1197.5	1.177	88.82	1070.5	68.979	15.052	28.800	42.976	795.89	178.794	37.922	6.2222	31.72	B/B SEGREGATED
4	96782.	688.98	-.862	89.14	1022.5	63.286	15.584	-21.60	69.528	940.30	178.540	38.148	5.9945	16.26	B/B SEGREGATED
5	113150	1410.8	2.525	87.47	950.87	57.222	16.654	42.258	29.387	1511.8	176.975	39.609	5.5499	8.49	B/B SEGREGATED
6	116424	862.86	-9.50	80.50	958.24	58.379	16.604	-21.19	13.824	1297.2	177.593	39.244	5.5888	9.62	B/B SEGREGATED
7	157450	295.28	-.793	89.21	882.61	55.753	18.355	-20.95	96.552	1557.5	176.818	40.616	5.0257	5.82	B/B SEGREGATED
8	209933	426.51	.1433	89.86	744.63	50.554	22.486	5.8857	132.03	1639.6	176.502	42.851	4.0857	4.14	B/B SEGREGATED
9	288763	196.85	-.167	89.83	433.92	39.853	42.004	-5.162	315.54	761.17	179.133	43.023	2.2232	6.79	B/B DISTRIBUTED

**** Case no. 1: Calculated pressure is too low (0 psia) in section 9 ******

******* CASE TERMINATED ********

Table 6: *Output table for 16" pipeline*

Case 2 :IDIAMETER=18 ins

FLOWLINE Flowline_1

	Dist. (feet)	Elev. (feet)	Horiz. Angle (deg)	Vert. Devn. (deg)	Pres. (psia)	Temp. (F)	Mean Vel. (ft/s)	Pressure Drop (psi) Elev.	Pressure Drop (psi) Frictn.	Liquid Flow (bbl/d)	Free Gas (mmscfd)	Densities (lb/ft3) Liquid	Densities (lb/ft3) Gas	Slug Number (PI-SS)	Flow Pattern
1	0.0000	1740.0	-1.63	88.37	1165.0	95.000	12.113	0.0000	0.0000	0.0000	180.000	.00010	6.1858		GAS
2	37435.	672.57	-1.63	88.37	1175.6	81.166	11.215	-47.67	37.028	386.12	179.623	37.557	6.6415	127.90	B/B SEGREGATED
3	62990.	1197.5	1.177	88.82	1123.0	70.054	11.235	30.245	22.373	793.38	178.780	37.721	6.5879	31.68	B/B SEGREGATED
4	96782.	688.98	-.862	89.14	1111.7	65.977	11.164	-23.33	34.620	928.92	178.514	37.761	6.6161	16.33	B/B SEGREGATED
5	113150	1410.8	2.525	87.47	1051.2	59.268	11.632	46.215	14.269	1248.8	177.768	38.373	6.3148	10.15	B/B SEGREGATED
6	116424	862.86	-9.50	80.50	1068.4	61.441	11.519	-24.20	7.0893	1042.7	178.316	37.931	6.3993	11.84	B/B SEGREGATED
7	157450	295.28	-.793	89.21	1049.7	60.487	11.743	-24.99	43.653	1054.6	178.306	38.014	6.2756	8.46	B/B SEGREGATED
8	209933	426.51	.1433	89.86	991.80	57.660	12.447	7.2644	50.621	1516.7	176.979	39.213	5.8703	4.34	B/B SEGREGATED
9	288763	196.85	-.167	89.83	906.78	55.922	13.960	-8.856	93.855	1619.4	176.649	40.285	5.2175	2.96	B/B SEGREGATED
10	327518	98.430	-.146	89.85	859.26	55.196	15.036	-3.441	50.952	1544.8	176.848	41.068	4.8463	2.76	B/B SEGREGATED
11	377467	55.770	-.049	89.95	788.16	54.096	16.891	-1.356	72.434	1378.2	177.301	42.428	4.3214	2.73	B/B SEGREGATED
12	429950	49.210	-.007	89.99	701.99	52.900	19.325	-.1848	86.318	1294.0	177.462	42.580	3.7816	2.56	B/B SEGREGATED
13	482434	19.690	-.032	89.97	600.73	51.249	23.346	-.7121	101.92	1025.5	178.233	42.668	3.1455	2.95	B/B SEGREGATED
14	534917	36.090	.0179	89.98	480.29	49.856	30.490	.43811	119.91	652.08	179.359	42.641	2.4257	4.32	B/B SEGREGATED
15	551338	0.0000	-.126	89.87	431.12	49.101	34.419	-.5742	49.691	600.73	179.479	42.762	2.1508	4.60	B/B SEGREGATED

Table 7: *Output table for 18" pipeline*

Case 3 :IDIAMETER=20 ins

FLOWLINE Flowline_1

	Dist. (feet)	Elev. (feet)	Horiz. Angle (deg)	Vert. Devn. (deg)	Pres. (psia)	Temp. (F)	Mean Vel. (ft/s)	Pressure Drop (psi) Elev.	Pressure Drop (psi) Frictn.	Liquid Flow (bbl/d)	Free Gas (mmscfd)	Densities (lb/ft3) Liquid	Densities (lb/ft3) Gas	Slug Number (PI-SS)	Flow Pattern
1	0.0000	1740.0	-1.63	88.37	1165.0	95.000	9.8111	0.0000	0.0000	0.0000	180.000	.00010	6.1858		GAS
2	37435.	672.57	-1.63	88.37	1191.9	80.763	8.9125	-48.12	21.180	407.32	179.575	37.512	6.7676	120.80	B/B SEGREGATED
3	62990.	1197.5	1.177	88.82	1148.0	69.824	8.8387	31.304	12.671	816.68	178.726	37.640	6.7814	30.66	B/B SEGREGATED
4	96782.	688.98	-.862	89.14	1153.0	66.483	8.6487	-24.20	19.216	939.97	178.478	37.624	6.9178	16.07	B/B SEGREGATED
5	113150	1410.8	2.525	87.47	1096.2	59.674	8.9378	48.857	7.8780	1198.5	177.926	37.997	6.6651	10.52	B/B SEGREGATED
6	116424	862.86	-9.50	80.50	1119.1	62.522	8.8222	-25.57	2.7221	1051.5	178.273	37.735	6.7693	11.70	B/B SEGREGATED
7	157450	295.28	-.793	89.21	1122.4	62.233	8.7767	-26.75	23.459	1063.8	178.248	37.724	6.8032	8.33	B/B SEGREGATED
8	209933	426.51	.1433	89.86	1093.9	59.446	8.9480	7.8696	20.638	1254.5	177.767	38.116	6.6511	5.20	B/B SEGREGATED
9	288763	196.85	-.167	89.83	1058.2	58.732	9.3028	-10.40	46.018	1387.5	177.376	38.547	6.3814	3.38	B/B SEGREGATED
10	327518	98.430	-.146	89.85	1039.2	58.477	9.5145	-4.312	23.355	1419.9	177.276	38.721	6.2342	2.91	B/B SEGREGATED
11	377467	55.770	-.049	89.95	1010.1	58.008	9.8564	-1.814	30.939	1476.8	177.101	39.013	6.0101	2.42	B/B SEGREGATED
12	429950	49.210	-.007	89.99	976.49	57.582	10.296	-.2679	33.826	1499.7	177.021	39.333	5.7490	2.10	B/B SEGREGATED
13	482434	19.690	-.032	89.97	942.15	57.349	10.807	-1.151	35.490	1464.8	177.106	39.653	5.4778	1.93	B/B SEGREGATED
14	534917	36.090	.0179	89.98	906.85	57.150	11.395	.83318	34.461	1404.3	177.266	40.041	5.1982	1.84	B/B SEGREGATED
15	551338	0.0000	-.126	89.87	895.98	57.159	11.595	-1.292	12.161	1370.1	177.360	40.163	5.1110	1.83	B/B SEGREGATED

Table 8: *Output table for 20" pipeline*

Case 4 :IDIAMETER=24 ins

	Dist. (feet)	Elev. (feet)	Horiz. Angle (deg)	Vert. Devn. (deg)	Pres. (psia)	Temp. (F)	Mean Vel. (ft/s)	Pressure Drop (psi) Elev.	Frictn.	Liquid Flow (bbl/d)	Free Gas (mmscfd)	Densities (lb/ft3) Liquid	Gas	Slug Number (PI-SS)	Flow Pattern
FLOWLINE Flowline_1															
1	0.0000	1740.0	-1.63	88.37	1165.0	95.000	6.8133	0.0000	0.0000	0.0000	180.000	.00010	6.1858		GAS
2	37435.	672.57	-1.63	88.37	1205.6	79.129	6.0510	-48.69	8.1272	479.50	179.419	37.477	6.9150	101.75	B/B SEGREGATED
3	62990.	1197.5	1.177	88.82	1167.8	68.254	5.9599	32.975	4.8220	885.64	178.582	37.580	6.9775	28.10	B/B SEGREGATED
4	96782.	688.98	-.862	89.14	1185.6	65.791	5.7761	-25.03	7.1861	985.62	178.378	37.530	7.1894	15.26	B/B SEGREGATED
5	113150	1410.8	2.525	87.47	1130.5	59.377	5.9473	52.192	2.9553	1310.7	177.621	38.017	6.9449	9.58	B/B SEGREGATED
6	116424	862.86	-9.50	80.50	1156.6	62.323	5.8641	-26.68	.52202	1087.3	178.188	37.613	7.0699	11.28	B/B SEGREGATED
7	157450	295.28	-.793	89.21	1176.1	62.824	5.7528	-28.13	8.6253	1084.1	178.188	37.556	7.2078	8.15	B/B SEGREGATED
8	209933	426.51	.1433	89.86	1158.0	59.916	5.7877	8.4694	9.6561	1190.0	177.970	37.658	7.1522	5.46	B/B SEGREGATED
9	288763	196.85	-.167	89.83	1153.1	60.030	5.8244	-11.37	16.296	1161.9	178.047	37.624	7.1101	4.02	B/B SEGREGATED
10	327518	98.430	-.146	89.85	1149.9	59.993	5.8443	-4.851	8.0468	1162.3	178.046	37.638	7.0857	3.53	B/B SEGREGATED
11	377467	55.770	-.049	89.95	1141.6	59.724	5.8875	-2.090	10.405	1228.4	177.857	37.813	7.0256	2.88	B/B SEGREGATED
12	429950	49.210	-.007	89.99	1130.9	59.478	5.9491	-.3183	11.024	1284.3	177.696	37.969	6.9458	2.41	B/B SEGREGATED
13	482434	19.690	-.032	89.97	1121.1	59.419	6.0142	-1.416	11.153	1290.2	177.676	38.029	6.8694	2.14	B/B SEGREGATED
14	534917	36.090	.0179	89.98	1110.2	59.302	6.0869	1.0241	9.9266	1309.3	177.618	38.120	6.7845	1.90	B/B SEGREGATED
15	551338	0.0000	-.126	89.87	1108.3	59.398	6.1049	-1.698	3.5651	1282.4	177.693	38.084	6.7675	1.89	B/B SEGREGATED

Table 9: *Output table for 24" pipeline*

From the output summary in **Table 8**, it can be seen that the flow regime for the fluid flow in 20" pipeline is segregated flow. Segregated flow is further classified as being stratified smooth, stratified wavy (ripple flow), or annular. There is no indication of any slugging would occur in this pipeline.

2. CASE STUDY 2

For case study 2, the fluid flows down a riser from the satellite platform to the seabed, along a 5 miles pipeline, and up a riser to the processing platform. The fluid inlet pressure at satellite platform will be 1500 psia and the fluid inlet temperature at satellite platform is 176°F. Design liquid flowrate is 10000 STB/D with minimum arrival pressure at processing platform of 1000 psia. And the maximum turndown is 5000 STB/D.

Composition and condition of pipeline	
Component	Moles (%)
C_1	75
C_2	6
C_3	3
iC_4	1
nC_4	1
iC_5	1
nC_5	0.5
C_6	0.5
C_7+	12

Table 10: *Composition and condition of pipeline*

Pipeline Data	
Height of undulations	10/1000
Horizontal distance	5 miles
Elevation difference	0
Wall Thickness	0.5"
Roughness	0.001"
Ambient Temperature	50°F
Overall Heat Transfer Coefficient	0.2 Btu/hr/ft2/°F

Table 11: *Pipeline Data*

Data for Risers 1 & 2	
Horizontal distance	0
Elevation difference (Riser_1)	-400 ft
Elevation difference (Riser_2)	+400 ft
Inner diameter	10"
Wall thickness	0.5"
Roughness	0.001"
Ambient temperature	50 °F
Overall heat transfer coefficient	0.2 Btu/hr/ft2/°F

Table 12: *Data for Risers 1 & 2*

Pipe thermal conductivity = 50 Btu/hr/ft/°F

Insulation thermal conductivity = 0.15 Btu/hr/ft/°F

Insulation thickness = 1"

Ambient fluid = water

Ambient fluid velocity = 1.64 ft/sec

Burial depth = 0 (half buried)

Ground conductivity = 1.5 Btu/hr/ft/°F

I.D.(")	Wall thickness (")	Roughness (")
6	0.5	0.001
8	0.5	0.001
10	0.5	0.001
12	0.5	0.001

Table 13: *Available pipeline sizes*

SELECTION OF OPTIMUM PIPELINE ID

By using the wizard feature in the Pipesim, this pipeline model is constructed. The fluid inlet pressure at satellite platform will be 1500 psia and the fluid inlet temperature at satellite platform is 176°F. Design liquid flowrate is 10000 STB/D with minimum arrival pressure at processing platform of 1000 psia. The pipeline ID, wall thickness, roughness, overall heat transfer coefficient and elevation data and was entered for detailed pipeline description.

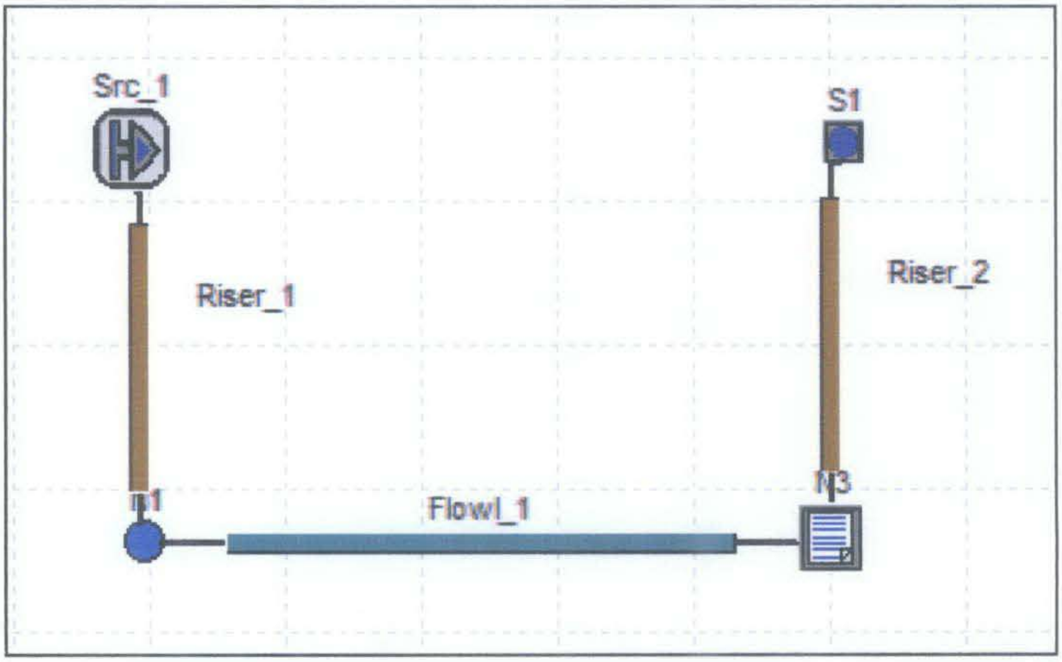


Figure 8: *Constructed pipeline model CASE STUDY 2*

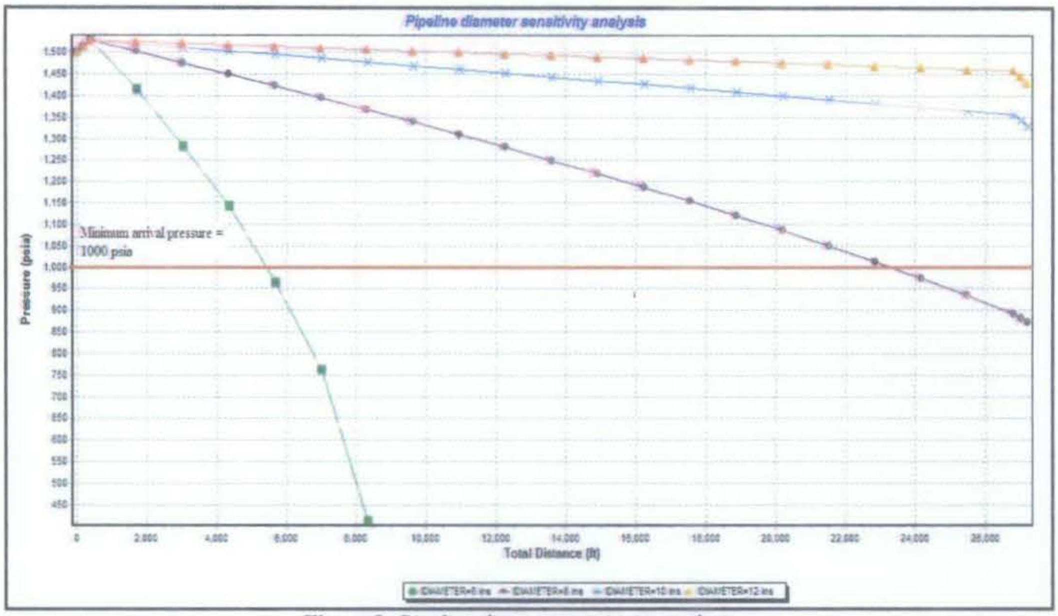


Figure 9: *Pipeline diameter sensitivity analysis*

Minimum arrival pressure = 1000 psia

PIPELINE ID	6"	8"	10"	12"
OUTLET PRESSURE	< 1000 psia	< 1000 psia	> 1000 psia	> 1000 psia

Table 14: *Pipeline diameter & outlet pressure case study 2*

Figure 8 is the graph plot for sensitivity analysis on 4 available pipeline size which are 6", 8", 10" or 12" ID. Note that the calculated outlet pressure for 6" and 8" pipeline will become less than minimum arrival pressure for the operation before fluid reach the destination. 10" and 12" ID pipeline will be the suitable pipeline. It can be seen that a 10" is the smallest pipeline size that will satisfy the arrival pressure condition of at least 1000 psia. The optimum pipeline size selected is 10".

```
Case    1 :IDIAMETER=6 ins


      Dist.    Elev. Horiz. Vert.  Pres.    Temp.    Mean   Pressure Drop  Liquid   Free      Densities    Slug  Flow
                     Angle  Devn.                    Vel.      (psi)       Flow     Gas       (lb/ft3)    Number Pattern
     (feet)  (feet) (deg)  (deg)  (psia)    (F)    (ft/s)  Elev.  Frictn. (bbl/d) (mmscfd)  Liquid   Gas (PI-SS)
RISER Riser_1
Topsides
   1 0.0000  0.0000 -90.0 0.000  1500.0  176.00  16.491  0.0000  0.0000  18609.  64.3446  32.083  5.3674        D/R SLUG
   2 0.0000  -200.0 -90.0 0.000  1514.0  176.52  16.353  -14.30  .26595  18638.  64.2940  32.006  5.4254        D/R SLUG
   3 0.0000  -400.0 -90.0 0.000  1528.2  177.04  16.216  -14.40  .26399  18667.  64.2446  31.929  5.4843        D/R SLUG
FLOWLINE Flowl_1
Riser Base
   4 0.0000  0.0000 .5729 89.43  1527.5  177.04  45.065  0.0000  0.0000  18664.  64.2493  31.932  5.4814        B/B INTERMITTENT 1.4
   5 1320.0  13.200 .5729 89.43  1416.2  172.71  48.260  1.0814  110.02  18412.  64.6707  32.586  5.0240  43.77 B/B INTERMITTENT 1.4
   6 2640.0  0.0000 -.573 89.43  1285.1  168.13  52.895  -.4363  131.42  17959.  65.3956  33.510  4.4991  21.37 B/B DISTRIBUTED 1.5
   7 3960.0  13.200 .5729 89.43  1147.8  163.13  58.921  .91351  136.05  17519.  66.0756  34.403  3.9708  14.46 B/B DISTRIBUTED 1.6
   8 5280.0  0.0000 -.573 89.43  972.20  156.90  69.304  -.3338  175.50  17102.  66.8004  35.210  3.3172  10.88 B/B DISTRIBUTED 1.7
   9 6600.0  13.200 .5729 89.43  778.75  150.14  86.705  .71827  191.99  16363.  68.1169  36.429  2.6218   9.11 B/B DISTRIBUTED 1.9
  10 7920.0  0.0000 -.573 89.43  459.06  137.01  147.58  -.1901  317.28  15142.  69.7822  38.145  1.5379   8.19 B/B DISTRIBUTED 2.5

****  Case no.   1: Calculated pressure is too low ( 0 psia) in section  10  ******
```

Table 15: *Output table for 6" pipeline*

Case 2 :IDIAMETER=8 ins

	Dist. (feet)	Elev. (feet)	Horiz. Angle (deg)	Vert. Devn. (deg)	Pres. (psia)	Temp. (F)	Mean Vel. (ft/s)	Pressure Drop (psi) Elev.	Pressure Drop (psi) Frictn.	Liquid Flow (bbl/d)	Free Gas (mmscfd)	Densities (lb/ft3) Liquid	Densities (lb/ft3) Gas	Slug Number (PI-SS)	Flow Pattern
RISER Riser_1															
Topsides															
1	0.0000	0.0000	-90.0	0.000	1500.0	176.00	16.491	0.0000	0.0000	18609.	64.3446	32.083	5.3674		D/R SLUG
2	0.0000	-200.0	-90.0	0.000	1514.0	176.52	16.353	-14.30	.26595	18638.	64.2940	32.006	5.4254		D/R SLUG
3	0.0000	-400.0	-90.0	0.000	1528.2	177.04	16.216	-14.40	.26399	18667.	64.2446	31.929	5.4843		D/R SLUG
FLOWLINE Flowl_1															
Riser Base															
4	0.0000	0.0000	.5729	89.43	1528.1	177.04	25.339	0.0000	0.0000	18667.	64.2452	31.929	5.4839		B/B INTERMITTENT
5	1320.0	13.200	.5729	89.43	1503.0	173.66	25.555	1.1172	23.964	18725.	64.1127	32.135	5.3849	43.43	B/B INTERMITTENT
6	2640.0	0.0000	-.573	89.43	1476.8	170.38	25.809	-.4889	26.652	18766.	64.0165	32.345	5.2814	20.51	B/B INTERMITTENT
7	3960.0	13.200	.5729	89.43	1451.2	167.14	26.070	1.1076	24.438	18798.	63.9404	32.553	5.1807	13.71	B/B INTERMITTENT
8	5280.0	0.0000	-.573	89.43	1424.5	163.99	26.375	-.4701	27.228	18813.	63.9010	32.769	5.0752	10.04	B/B INTERMITTENT
9	6600.0	13.200	.5729	89.43	1398.4	160.89	26.687	1.0957	25.007	18820.	63.8807	32.986	4.9727	8.02	B/B INTERMITTENT
10	7920.0	0.0000	-.573	89.43	1370.9	157.86	27.051	-.4509	27.915	18807.	63.8986	33.214	4.8650	6.58	B/B INTERMITTENT
11	9240.0	13.200	.5729	89.43	1344.1	154.88	27.422	1.0815	25.684	18786.	63.9351	33.444	4.7606	5.63	B/B INTERMITTENT
12	10560.	0.0000	-.573	89.43	1315.8	151.98	27.853	-.4314	28.733	18743.	64.0126	33.689	4.6505	4.87	B/B INTERMITTENT
13	11880.	13.200	.5729	89.43	1288.2	149.08	28.279	1.0648	26.487	18691.	64.0849	33.940	4.5467	4.33	B/B INTERMITTENT
14	13200.	0.0000	-.573	89.43	1259.0	146.18	28.745	-.4120	29.666	18613.	64.1535	34.216	4.4419	3.86	B/B INTERMITTENT
15	14520.	13.200	.5729	89.43	1230.5	143.33	29.224	1.0478	27.366	18524.	64.2474	34.498	4.3408	3.51	B/B INTERMITTENT
16	15840.	0.0000	-.573	89.43	1200.2	140.50	29.784	-.3930	30.728	18437.	64.3460	34.768	4.2321	3.20	B/B INTERMITTENT
17	17160.	13.200	.5729	89.43	1170.8	137.58	30.336	1.0273	28.398	18440.	64.3037	34.910	4.1264	2.93	B/B INTERMITTENT
18	18480.	0.0000	-.573	89.43	1139.1	134.71	30.992	-.3730	31.963	18428.	64.2965	35.063	4.0117	2.69	B/B INTERMITTENT
19	19800.	13.200	.5729	89.43	1108.5	131.90	31.669	1.0023	29.615	18409.	64.3081	35.217	3.9006	2.50	B/B INTERMITTENT
20	21120.	0.0000	-.573	89.43	1075.4	129.12	32.478	-.3520	33.460	18373.	64.3601	35.386	3.7795	2.33	B/B INTERMITTENT
21	22440.	13.200	.5729	89.43	1043.3	126.39	33.318	.97314	31.121	18329.	64.4324	35.558	3.6624	2.19	B/B INTERMITTENT
22	23760.	0.0000	-.573	89.43	1008.3	123.69	34.331	-.3298	35.321	18262.	64.5545	35.751	3.5340	2.06	B/B INTERMITTENT
23	25080.	13.200	.5729	89.43	974.29	121.03	35.394	.93959	33.004	18185.	64.7012	35.952	3.4098	1.96	B/B INTERMITTENT
24	26400.	0.0000	-.573	89.43	936.89	118.36	36.660	-.3063	37.676	18080.	64.8702	36.184	3.2758	1.86	B/B INTERMITTENT
RISER Riser_2															
Riser Base															
25	0.0000	0.0000	90.00	0.000	936.77	118.36	23.467	0.0000	0.0000	18079.	64.8715	36.185	3.2751		D/R SLUG
26	0.0000	200.00	90.00	0.000	925.84	117.70	23.722	10.525	.40077	18042.	64.9296	36.254	3.2362	1.85	D/R SLUG
27	0.0000	400.00	90.00	0.000	915.01	117.04	23.983	10.425	.40388	18004.	64.9913	36.325	3.1975	1.84	D/R SLUG
Topsides															

Table 16: *Output table for 8" pipeline*

Case 3 :IDIAMETER=10 ins

	Dist. (feet)	Elev. (feet)	Horiz. Angle (deg)	Vert. Devn. (deg)	Pres. (psia)	Temp. (F)	Mean Vel. (ft/s)	Pressure Drop (psi) Elev.	Pressure Drop (psi) Frictn.	Liquid Flow (bbl/d)	Free Gas (mmscfd)	Densities (lb/ft3) Liquid	Densities (lb/ft3) Gas	Slug Number (PI-SS)	Flow Pattern
RISER Riser_1															
Topsides															
1	0.0000	0.0000	-90.0	0.000	1500.0	176.00	16.491	0.0000	0.0000	18609.	64.3446	32.083	5.3674		D/R SLUG
2	0.0000	-200.0	-90.0	0.000	1514.0	176.52	16.353	-14.30	.26595	18638.	64.2940	32.006	5.4254		D/R SLUG
3	0.0000	-400.0	-90.0	0.000	1528.2	177.04	16.216	-14.40	.26399	18667.	64.2446	31.929	5.4843		D/R SLUG
FLOWLINE Flowl_1															
Riser Base															
4	0.0000	0.0000	.5729	89.43	1528.2	177.04	16.215	0.0000	0.0000	18667.	64.2444	31.929	5.4844		B/B INTERMITTENT
5	1320.0	13.200	.5729	89.43	1519.5	173.46	16.158	1.1337	7.5095	18796.	63.9770	32.067	5.4557	43.51	B/B INTERMITTENT
6	2640.0	0.0000	-.573	89.43	1511.8	170.02	16.098	-.4989	8.2481	18919.	63.7301	32.193	5.4304	20.37	B/B INTERMITTENT
7	3960.0	13.200	.5729	89.43	1503.2	166.63	16.053	1.1431	7.4602	19032.	63.5059	32.320	5.4013	13.56	B/B INTERMITTENT
8	5280.0	0.0000	-.573	89.43	1495.5	163.38	16.005	-.4939	8.1985	19139.	63.2990	32.437	5.3757	9.85	B/B INTERMITTENT
9	6600.0	13.200	.5729	89.43	1486.9	160.16	15.970	1.1512	7.4214	19238.	63.1131	32.556	5.3462	7.83	B/B INTERMITTENT
10	7920.0	0.0000	-.573	89.43	1479.2	157.08	15.933	-.4889	8.1602	19332.	62.9416	32.664	5.3202	6.37	B/B INTERMITTENT
11	9240.0	13.200	.5729	89.43	1470.7	154.04	15.908	1.1579	7.3922	19418.	62.7097	32.775	5.2904	5.42	B/B INTERMITTENT
12	10560.	0.0000	-.573	89.43	1463.0	151.12	15.880	-.4837	8.1323	19499.	62.6495	32.878	5.2641	4.65	B/B INTERMITTENT
13	11880.	13.200	.5729	89.43	1454.5	148.17	15.848	1.1637	7.3701	19574.	62.4749	32.984	5.2400	4.10	B/B INTERMITTENT
14	13200.	0.0000	-.573	89.43	1446.9	145.32	15.803	-.4795	8.0989	19646.	62.2817	33.082	5.2228	3.62	B/B INTERMITTENT
15	14520.	13.200	.5729	89.43	1438.4	142.49	15.772	1.1708	7.3348	19709.	62.1091	33.183	5.2016	3.26	B/B INTERMITTENT
16	15840.	0.0000	-.573	89.43	1430.8	139.79	15.737	-.4760	8.0644	19770.	61.9489	33.276	5.1835	2.94	B/B INTERMITTENT
17	17160.	13.200	.5729	89.43	1422.3	137.12	15.717	1.1766	7.3090	19822.	61.8082	33.373	5.1614	2.69	B/B INTERMITTENT
18	18480.	0.0000	-.573	89.43	1414.7	134.57	15.692	-.4723	8.0406	19872.	61.6774	33.462	5.1424	2.46	B/B INTERMITTENT
19	19800.	13.200	.5729	89.43	1406.3	132.03	15.681	1.1814	7.2923	19915.	61.5650	33.555	5.1193	2.28	B/B INTERMITTENT
20	21120.	0.0000	-.573	89.43	1398.7	129.62	15.665	-.4684	8.0265	19956.	61.4606	33.641	5.0995	2.11	B/B INTERMITTENT
21	22440.	13.200	.5729	89.43	1390.2	127.22	15.663	1.1850	7.2841	19989.	61.3738	33.732	5.0756	1.97	B/B INTERMITTENT
22	23760.	0.0000	-.573	89.43	1382.7	124.94	15.656	-.4643	8.0217	20021.	61.2929	33.815	5.0549	1.84	B/B INTERMITTENT
23	25080.	13.200	.5729	89.43	1374.2	122.67	15.663	1.1877	7.2840	20046.	61.2291	33.904	5.0302	1.73	B/B INTERMITTENT
24	26400.	0.0000	-.573	89.43	1366.6	120.51	15.664	-.4601	8.0256	20070.	61.1696	33.985	5.0087	1.63	B/B INTERMITTENT
RISER Riser_2															
Riser Base															
25	0.0000	0.0000	90.00	0.000	1366.6	120.51	15.665	0.0000	0.0000	20070.	61.1699	33.985	5.0085		D/R SLUG
26	0.0000	200.00	90.00	0.000	1351.3	119.82	15.826	15.051	.32323	20004.	61.2877	34.089	4.9470	1.63	D/R SLUG
27	0.0000	400.00	90.00	0.000	1336.0	119.17	15.987	14.923	.32546	19936.	61.3951	34.194	4.8872	1.62	D/R SLUG
Topsides															

Table 17: *Output table for 10" pipeline*

Case 4 :IDIAMETER=12 ins

	Dist. (feet)	Elev. (feet)	Horiz. Angle (deg)	Vert. Devn. (deg)	Pres. (psia)	Temp. (F)	Mean Vel. (ft/s)	Pressure Drop (psi) Elev.	Frictn.	Liquid Flow (bbl/d)	Free Gas (mmscfd)	Densities (lb/ft3) Liquid	Gas	Slug Number (PI-SS)	Flow Pattern
RISER Riser_1															
Topsides															
1	0.0000	0.0000	-90.0	0.000	1500.0	176.00	16.491	0.0000	0.0000	18609.	64.3446	32.083	5.3674		D/R SLUG
2	0.0000	-200.0	-90.0	0.000	1514.0	176.52	16.353	-14.30	.26595	18638.	64.2940	32.006	5.4254		D/R SLUG
3	0.0000	-400.0	-90.0	0.000	1528.2	177.04	16.216	-14.40	.26399	18667.	64.2446	31.929	5.4843		D/R SLUG
FLOWLINE Flowl_1															
Riser Base															
4	0.0000	0.0000	.5729	89.43	1528.1	177.04	11.261	0.0000	0.0000	18667.	64.2445	31.929	5.4843		B/B INTERMITTENT
5	1320.0	13.200	.5729	89.43	1524.1	173.08	11.174	1.1453	2.9294	18831.	63.9108	32.057	5.4759	43.61	B/B INTERMITTENT
6	2640.0	0.0000	-.573	89.43	1521.4	169.29	11.084	-.5018	3.2049	18987.	63.5979	32.170	5.4730	20.32	B/B INTERMITTENT
7	3960.0	13.200	.5729	89.43	1517.3	165.57	11.007	1.1618	2.8859	19133.	63.3133	32.284	5.4641	13.49	B/B INTERMITTENT
8	5280.0	0.0000	-.573	89.43	1514.7	162.02	10.927	-.5007	3.1591	19273.	63.0454	32.385	5.4608	9.76	B/B INTERMITTENT
9	6600.0	13.200	.5729	89.43	1510.6	158.51	10.859	1.1766	2.8474	19403.	62.8034	32.487	5.4515	7.75	B/B INTERMITTENT
10	7920.0	0.0000	-.573	89.43	1508.0	155.17	10.787	-.4995	3.1185	19528.	62.5743	32.577	5.4478	6.28	B/B INTERMITTENT
11	9240.0	13.200	.5729	89.43	1504.0	151.87	10.728	1.1900	2.8134	19644.	62.3692	32.669	5.4381	5.33	B/B INTERMITTENT
12	10560.	0.0000	-.573	89.43	1501.4	148.70	10.656	-.4983	3.0825	19758.	62.1350	32.751	5.4386	4.56	B/B INTERMITTENT
13	11880.	13.200	.5729	89.43	1497.5	145.50	10.585	1.2035	2.7787	19863.	61.8687	32.836	5.4395	4.00	B/B INTERMITTENT
14	13200.	0.0000	-.573	89.43	1494.9	142.46	10.509	-.4989	3.0406	19966.	61.6154	32.910	5.4457	3.52	B/B INTERMITTENT
15	14520.	13.200	.5729	89.43	1491.0	139.46	10.447	1.2173	2.7429	20059.	61.3866	32.988	5.4456	3.17	B/B INTERMITTENT
16	15840.	0.0000	-.573	89.43	1488.5	136.61	10.380	-.4994	3.0030	20151.	61.1673	33.055	5.4509	2.85	B/B INTERMITTENT
17	17160.	13.200	.5729	89.43	1484.5	133.79	10.325	1.2297	2.7112	20233.	60.9709	33.127	5.4497	2.60	B/B INTERMITTENT
18	18480.	0.0000	-.573	89.43	1482.0	131.12	10.265	-.4998	2.9698	20315.	60.7809	33.188	5.4541	2.37	B/B INTERMITTENT
19	19800.	13.200	.5729	89.43	1478.1	128.47	10.217	1.2409	2.6834	20387.	60.6127	33.254	5.4519	2.20	B/B INTERMITTENT
20	21120.	0.0000	-.573	89.43	1475.7	125.96	10.164	-.4999	2.9405	20460.	60.4484	33.310	5.4554	2.03	B/B INTERMITTENT
21	22440.	13.200	.5729	89.43	1471.8	123.47	10.123	1.2510	2.6588	20524.	60.3049	33.371	5.4523	1.89	B/B INTERMITTENT
22	23760.	0.0000	-.573	89.43	1469.4	121.13	10.075	-.4999	2.9148	20589.	60.1628	33.422	5.4550	1.76	B/B INTERMITTENT
23	25080.	13.200	.5729	89.43	1465.5	118.79	10.031	1.2601	2.6372	20653.	59.9957	33.476	5.4550	1.65	B/B INTERMITTENT
24	26400.	0.0000	-.573	89.43	1463.1	116.60	9.9741	-.5005	2.8879	20723.	59.7921	33.517	5.4643	1.55	B/B INTERMITTENT
RISER Riser_2															
Riser Base															
25	0.0000	0.0000	90.00	0.000	1463.0	116.60	14.363	0.0000	0.0000	20723.	59.7926	33.517	5.4640		D/R SLUG
26	0.0000	200.00	90.00	0.000	1446.5	115.89	14.506	16.246	.31423	20666.	59.8874	33.609	5.3965	1.54	D/R SLUG
27	0.0000	400.00	90.00	0.000	1430.0	115.19	14.652	16.109	.31644	20606.	59.9868	33.703	5.3294	1.53	D/R SLUG
Topsides															

Table 18: *Output table for 12" pipeline*

From the output summary in **Table 17**, it can be seen that the flow regime for the fluid flow in 10" pipeline is intermittent flow. The intermittent flow regimes are slug flow and plug (also called elongated bubble) flow. Slug flow consists of large liquid slugs alternating with high-velocity bubbles of gas that fill almost the entire pipe. In plug flow, large gas bubbles flow along the top of the pipe. Because the pipeline system consist of vertical riser, severe slugging could occur in the pipeline riser.

SCREENING THE PIPELINE FOR SEVERE RISER SLUGGING

The screening of the pipeline for severe riser slugging. As claimed in the literature review, the elements leading to severe riser slugging are:

- The presence a long slightly downward inclined pipeline prior to the riser.
- Fluid flowing in the "stratified" or "segregated" flow regime (as opposed to the usual "slug" or "intermittent" flow regime).
- A slug number (PI-SS) of lower than 1.0.

To screen the pipeline for severe riser slugging, the PI-SS number at the riser base for both flowrate cases are checked. It can be seen that the PI-SS number is higher than 1.0 at the riser base in both cases as shown in **Table 19** and **Table 20**. The PI-SS number at the riser base for 5000 sbbl/day is 1.33 and for 10000 sbbl/day is 1.63. In the turndown flowrate case the PI-SS number is 1.33 at the riser base as shown in **Table 19.**

Case 1 :LIQ=5000 sbbl/day

	Dist. (feet)	Elev. (feet)	Horiz. Angle (deg)	Vert. Devn. (deg)	Pres. (psia)	Temp. (F)	Mean Vel. (ft/s)	Pressure Drop (psi) Elev.	Pressure Drop (psi) Frictn.	Liquid Flow (bbl/d)	Free Gas (mmscfd)	Densities (lb/ft3) Liquid	Densities (lb/ft3) Gas	Slug Number (PI-SS)	Flow Pattern
RISER Riser_1															
Topsides															
1	0.0000	0.0000	-90.0	0.000	1500.0	176.00	8.2455	0.0000	0.0000	9304.4	32.1723	32.083	5.3674		D/R SLUG
2	0.0000	-200.0	-90.0	0.000	1517.6	176.51	8.1560	-17.68	.06998	9326.0	32.1342	31.990	5.4405		D/R SLUG
3	0.0000	-400.0	-90.0	0.000	1535.4	177.02	8.0675	-17.83	.06936	9346.9	32.0970	31.899	5.5149		D/R SLUG
FLOWLINE Flowl_1															
Riser Base															
4	0.0000	0.0000	.5729	89.43	1535.4	177.02	8.0672	0.0000	0.0000	9347.0	32.0968	31.898	5.5151		B/B INTERMITTENT
5	1320.0	13.200	.5729	89.43	1532.3	170.24	7.9397	1.1583	1.8892	9493.5	31.8008	32.098	5.5177	43.00	B/B INTERMITTENT
6	2640.0	0.0000	-.573	89.43	1530.8	163.88	7.8170	-.5062	2.0513	9628.4	31.5377	32.269	5.5258	19.71	B/B INTERMITTENT
7	3960.0	13.200	.5729	89.43	1527.8	157.79	7.7116	1.1894	1.8351	9750.2	31.3089	32.429	5.5269	12.94	B/B INTERMITTENT
8	5280.0	0.0000	-.573	89.43	1526.3	152.08	7.6088	-.5069	1.9961	9863.2	31.1043	32.567	5.5338	9.25	B/B INTERMITTENT
9	6600.0	13.200	.5729	89.43	1523.3	146.51	7.5061	1.2164	1.7893	9966.4	30.8760	32.701	5.5460	7.25	B/B INTERMITTENT
10	7920.0	0.0000	-.573	89.43	1521.8	141.24	7.3974	-.5095	1.9434	10063.	30.6407	32.815	5.5707	5.81	B/B INTERMITTENT
11	9240.0	13.200	.5729	89.43	1518.8	136.20	7.3048	1.2444	1.7418	10149.	30.4346	32.926	5.5873	4.88	B/B INTERMITTENT
12	10560.	0.0000	-.573	89.43	1517.5	131.49	7.2137	-.5132	1.8949	10230.	30.2471	33.020	5.6092	4.13	B/B INTERMITTENT
13	11880.	13.200	.5729	89.43	1514.5	126.97	7.1369	1.2686	1.7022	10302.	30.0839	33.113	5.6230	3.61	B/B INTERMITTENT
14	13200.	0.0000	-.573	89.43	1513.1	122.77	7.0601	-.5163	1.8544	10370.	29.9337	33.192	5.6422	3.16	B/B INTERMITTENT
15	14520.	13.200	.5729	89.43	1510.2	118.73	6.9904	1.2895	1.6690	10434.	29.7799	33.268	5.6577	2.83	B/B INTERMITTENT
16	15840.	0.0000	-.573	89.43	1508.9	114.99	6.9083	-.5200	1.8169	10503.	29.5885	33.322	5.6879	2.52	B/B INTERMITTENT
17	17160.	13.200	.5729	89.43	1505.9	111.39	6.8395	1.3113	1.6342	10563.	29.4198	33.380	5.7092	2.29	B/B INTERMITTENT
18	18480.	0.0000	-.573	89.43	1504.7	108.05	6.7700	-.5246	1.7805	10621.	29.2623	33.426	5.7360	2.08	B/B INTERMITTENT
19	19800.	13.200	.5729	89.43	1501.8	104.82	6.7127	1.3305	1.6043	10672.	29.1246	33.477	5.7539	1.91	B/B INTERMITTENT
20	21120.	0.0000	-.573	89.43	1500.5	101.84	6.6537	-.5285	1.7499	10721.	28.9944	33.516	5.7776	1.75	B/B INTERMITTENT
21	22440.	13.200	.5729	89.43	1497.6	98.942	6.6059	1.3471	1.5792	10763.	28.8818	33.562	5.7923	1.63	B/B INTERMITTENT
22	23760.	0.0000	-.573	89.43	1496.4	96.275	6.5556	-.5319	1.7242	10804.	28.7738	33.596	5.8132	1.51	B/B INTERMITTENT
23	25080.	13.200	.5729	89.43	1493.5	93.681	6.5159	1.3615	1.5580	10840.	28.6817	33.637	5.8250	1.42	B/B INTERMITTENT
24	26400.	0.0000	-.573	89.43	1492.3	91.298	6.4728	-.5348	1.7025	10875.	28.5917	33.667	5.8432	1.33	B/B INTERMITTENT
RISER Riser_2															
Riser Base															
25	0.0000	0.0000	90.00	0.000	1492.3	91.298	6.4730	0.0000	0.0000	10875.	28.5919	33.667	5.8429		D/R SLUG
26	0.0000	200.00	90.00	0.000	1470.6	90.406	6.5589	21.608	.08501	10831.	28.6788	33.781	5.7474	1.33	D/R SLUG
27	0.0000	400.00	90.00	0.000	1449.1	89.529	6.6448	21.408	.08571	10788.	28.7575	33.896	5.6547	1.33	D/R SLUG
Topsides															

Table 19: *Output table for 5000 sbbl/day (Turndown flowrate)*

Case 2 :LIQ=10000 sbbl/day

	Dist. (feet)	Elev. (feet)	Horiz. Angle (deg)	Vert. Devn. (deg)	Pres. (psia)	Temp. (F)	Mean Vel. (ft/s)	Pressure Drop (psi) Elev.	Pressure Drop (psi) Frictn.	Liquid Flow (bbl/d)	Free Gas (mmscfd)	Densities (lb/ft3) Liquid	Densities (lb/ft3) Gas	Slug Number (PI-SS)	Flow Pattern
RISER Riser_1															
Topsides															
1	0.0000	0.0000	-90.0	0.000	1500.0	176.00	16.491	0.0000	0.0000	18609.	64.3446	32.883	5.3674		D/R SLUG
2	0.0000	-200.0	-90.0	0.000	1514.0	176.52	16.353	-14.30	.26595	18638.	64.2940	32.006	5.4254		D/R SLUG
3	0.0000	-400.0	-90.0	0.000	1528.2	177.04	16.216	-14.40	.26399	18667.	64.2446	31.929	5.4843		D/R SLUG
FLOWLINE Flowl_1															
Riser Base															
4	0.0000	0.0000	.5729	89.43	1528.2	177.04	16.215	0.0000	0.0000	18667.	64.2444	31.929	5.4844		B/B INTERMITTENT
5	1320.0	13.200	.5729	89.43	1519.5	173.46	16.158	1.1337	7.5095	18796.	63.9770	32.067	5.4557	43.51	B/B INTERMITTENT
6	2640.0	0.0000	-.573	89.43	1511.8	170.02	16.098	-.4989	8.2481	18919.	63.7301	32.193	5.4304	20.37	B/B INTERMITTENT
7	3960.0	13.200	.5729	89.43	1503.2	166.63	16.053	1.1431	7.4602	19032.	63.5059	32.320	5.4013	13.56	B/B INTERMITTENT
8	5280.0	0.0000	-.573	89.43	1495.5	163.38	16.005	-.4939	8.1985	19139.	63.2990	32.437	5.3757	9.85	B/B INTERMITTENT
9	6600.0	13.200	.5729	89.43	1486.9	160.16	15.970	1.1512	7.4214	19238.	63.1131	32.556	5.3462	7.83	B/B INTERMITTENT
10	7920.0	0.0000	-.573	89.43	1479.2	157.08	15.933	-.4889	8.1602	19332.	62.9416	32.664	5.3202	6.37	B/B INTERMITTENT
11	9240.0	13.200	.5729	89.43	1470.7	154.04	15.908	1.1579	7.3922	19418.	62.7897	32.775	5.2904	5.42	B/B INTERMITTENT
12	10560.	0.0000	-.573	89.43	1463.0	151.12	15.880	-.4837	8.1323	19499.	62.6495	32.878	5.2641	4.65	B/B INTERMITTENT
13	11880.	13.200	.5729	89.43	1454.5	148.17	15.848	1.1637	7.3701	19574.	62.4749	32.984	5.2400	4.10	B/B INTERMITTENT
14	13200.	0.0000	-.573	89.43	1446.9	145.32	15.803	-.4795	8.0989	19646.	62.2817	33.082	5.2228	3.62	B/B INTERMITTENT
15	14520.	13.200	.5729	89.43	1438.4	142.49	15.772	1.1708	7.3348	19709.	62.1091	33.183	5.2016	3.26	B/B INTERMITTENT
16	15840.	0.0000	-.573	89.43	1430.8	139.79	15.737	-.4760	8.0644	19770.	61.9489	33.276	5.1835	2.94	B/B INTERMITTENT
17	17160.	13.200	.5729	89.43	1422.3	137.12	15.717	1.1766	7.3090	19822.	61.8082	33.373	5.1614	2.69	B/B INTERMITTENT
18	18480.	0.0000	-.573	89.43	1414.7	134.57	15.692	-.4723	8.0406	19872.	61.6774	33.462	5.1424	2.46	B/B INTERMITTENT
19	19800.	13.200	.5729	89.43	1406.3	132.03	15.681	1.1814	7.2923	19915.	61.5650	33.555	5.1193	2.28	B/B INTERMITTENT
20	21120.	0.0000	-.573	89.43	1398.7	129.62	15.665	-.4684	8.0265	19956.	61.4606	33.641	5.0995	2.11	B/B INTERMITTENT
21	22440.	13.200	.5729	89.43	1390.2	127.22	15.663	1.1850	7.2841	19989.	61.3738	33.732	5.0756	1.97	B/B INTERMITTENT
22	23760.	0.0000	-.573	89.43	1382.7	124.94	15.656	-.4643	8.0217	20021.	61.2929	33.815	5.0549	1.84	B/B INTERMITTENT
23	25080.	13.200	.5729	89.43	1374.2	122.67	15.663	1.1877	7.2840	20046.	61.2291	33.904	5.0302	1.73	B/B INTERMITTENT
24	26400.	0.0000	-.573	89.43	1366.6	120.51	15.664	-.4601	8.0256	20070.	61.1696	33.985	5.0087	1.63	B/B INTERMITTENT
RISER Riser_2															
Riser Base															
25	0.0000	0.0000	90.00	0.000	1366.6	120.51	15.665	0.0000	0.0000	20070.	61.1699	33.985	5.0085		D/R SLUG
26	0.0000	200.00	90.00	0.000	1351.3	119.82	15.826	15.051	.32323	20004.	61.2877	34.089	4.9470	1.63	D/R SLUG
27	0.0000	400.00	90.00	0.000	1336.0	119.17	15.987	14.923	.32546	19936.	61.3951	34.194	4.8872	1.62	D/R SLUG
Topsides															

Table 20: *Output table for 10000 sbbl/day*

Check the riser base flow regime maps in the output file to see if the flow is in the "stratified" or segregated region. It can be seen that flow is in the intermittent (normal slugging) flow regime. The turndown case flow map is shown in **Figure 9**. It can be seen that the segregated region has been avoided and the likelihood of severe riser slugging is reduced.

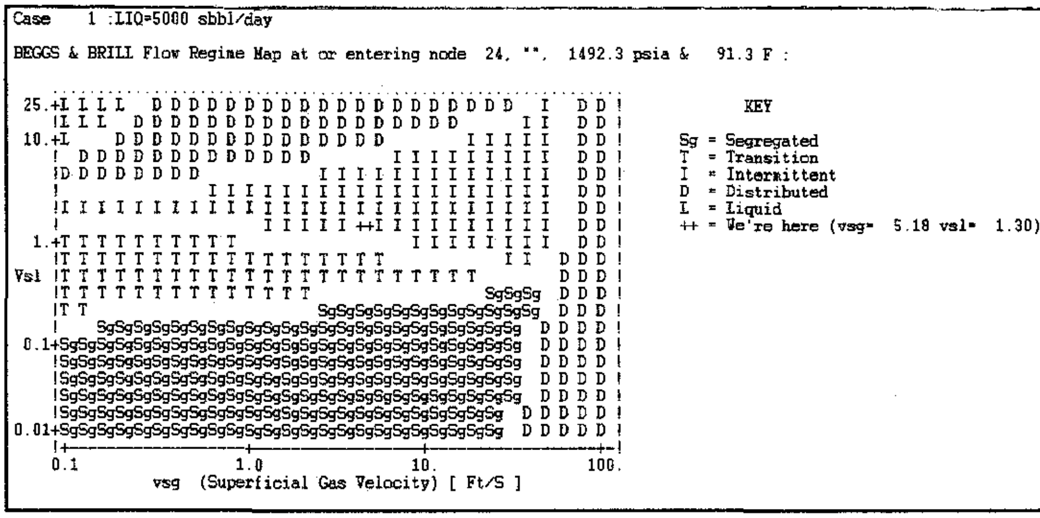


Figure 10: *Case flow map for 5000 sbbl/day (Turndown flowrate)*

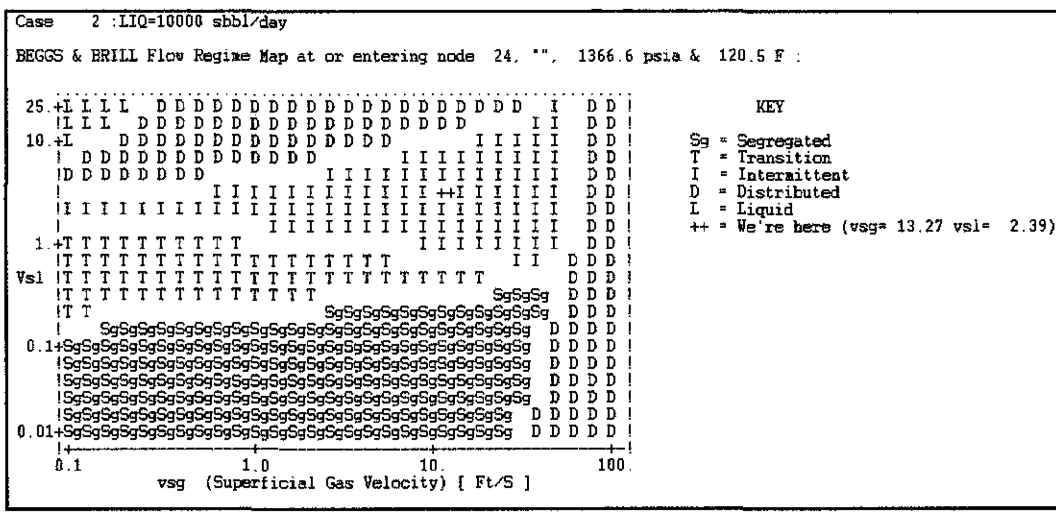


Figure 11: *Case flow map for 10000 sbbl/day*

SIZING OF SLUG CATCHER

In this case study, normal slug flow is expected to be occured. it is necessary to size a slug catcher. The size will be determined by the largest of three design criteria:

- The requirement to handle the largest slugs envisaged (chosen to be statistically the 1/1000 population slug size).
- The requirement to handle liquid swept in front of a pig.
- Transient effects, i.e. the requirement to handle the liquid slug generated when the production flow is ramped up from 5,000 to 10,000 STB/D.

Review the output file as shown in **Table 21** and **Table 22.** As shown in **Table 21,** the 1/1000 slug length for turndown case is 1749.5 ft. As shown in **Table 22,** the

1/1000 slug length for turndown case is 1583.9 ft. It can be seen that the turndown case generates larger slugs.

Case 1 :LIQ=5000 sbbl/day

	Dist. (feet)	Elev. (feet)	Pipe I.D. (ins.)	Mean Slug Length (feet)	Mean Slug Freq (min-1)	1 in thousand Length (feet)	1 in thousand Freq (min-1)	1 in hundred Length (feet)	1 in hundred Freq (min-1)	1 in ten Length (feet)	1 in ten Freq (min-1)	Slug Number (PI-SS)	Flow Pattern
RISER Riser_1													
Topsides													
1	0.	0.0	10.000	-	-	-	-	-	-	-	-		-
2	0.	-200.0	10.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000		D/R SLUG
3	0.	-400.0	10.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000		D/R SLUG
FLOWLINE Flowl_1													
Riser Base													
4	0.	0.0	10.000	-	-	-	-	-	-	-	-		-
5	1320.	13.2	10.000	73.5	0.923	342.9	0.000923	235.7	0.00923	139.4	0.0923	43.00	B/B INTERMITTENT
6	2640.	0.0	10.000	157.0	0.438	732.3	0.000438	503.3	0.00438	297.7	0.0438	19.71	B/B INTERMITTENT
7	3960.	13.2	10.000	195.9	0.356	913.8	0.000356	628.0	0.00356	371.5	0.0356	12.94	B/B INTERMITTENT
8	5280.	0.0	10.000	223.3	0.316	1041.6	0.000316	715.9	0.00316	423.5	0.0316	9.25	B/B INTERMITTENT
9	6600.	13.2	10.000	244.4	0.292	1140.1	0.000291	783.6	0.00292	463.5	0.0292	7.25	B/B INTERMITTENT
10	7920.	0.0	10.000	261.5	0.275	1219.8	0.000275	838.4	0.00275	495.9	0.0275	5.81	B/B INTERMITTENT
11	9240.	13.2	10.000	275.9	0.263	1287.1	0.000263	884.6	0.00263	523.3	0.0263	4.88	B/B INTERMITTENT
12	10560.	0.0	10.000	288.4	0.254	1345.1	0.000254	924.5	0.00254	546.9	0.0254	4.13	B/B INTERMITTENT
13	11880.	13.2	10.000	299.3	0.246	1396.3	0.000246	959.6	0.00246	567.7	0.0246	3.61	B/B INTERMITTENT
14	13200.	0.0	10.000	309.1	0.240	1441.8	0.000240	990.9	0.00240	586.2	0.0240	3.16	B/B INTERMITTENT
15	14520.	13.2	10.000	317.9	0.235	1482.9	0.000235	1019.2	0.00235	602.9	0.0235	2.83	B/B INTERMITTENT
16	15840.	0.0	10.000	325.8	0.230	1519.9	0.000230	1044.6	0.00230	618.0	0.0230	2.52	B/B INTERMITTENT
17	17160.	13.2	10.000	333.2	0.227	1554.1	0.000227	1068.2	0.00227	631.9	0.0227	2.29	B/B INTERMITTENT
18	18480.	0.0	10.000	339.9	0.223	1585.6	0.000223	1089.8	0.00223	644.7	0.0223	2.08	B/B INTERMITTENT
19	19800.	13.2	10.000	346.3	0.220	1615.1	0.000220	1110.1	0.00220	656.7	0.0220	1.91	B/B INTERMITTENT
20	21120.	0.0	10.000	352.1	0.218	1642.6	0.000218	1128.9	0.00218	667.8	0.0218	1.75	B/B INTERMITTENT
21	22440.	13.2	10.000	357.7	0.215	1668.6	0.000215	1146.8	0.00215	678.4	0.0215	1.63	B/B INTERMITTENT
22	23760.	0.0	10.000	362.9	0.213	1692.9	0.000213	1163.5	0.00213	688.3	0.0213	1.51	B/B INTERMITTENT
23	25080.	13.2	10.000	367.9	0.211	1716.1	0.000211	1179.5	0.00211	697.7	0.0211	1.42	B/B INTERMITTENT
24	26400.	0.0	10.000	372.6	0.209	1738.0	0.000209	1194.5	0.00209	706.6	0.0209	1.33	B/B INTERMITTENT
RISER Riser_2													
Riser Base													
25	0.	0.0	10.000	-	-	-	-	-	-	-	-		-
26	0.	200.0	10.000	373.8	0.207	1743.7	0.000207	1198.4	0.00207	708.9	0.0207	1.33	D/R SLUG
27	0.	400.0	10.000	375.1	0.206	1749.5	0.000206	1202.4	0.00206	711.3	0.0206	1.33	D/R SLUG
Topsides													

<u>Table 21</u>: *Output file for 5000 sbbl/day (Turndown flowrate)*

Case 2 :LIQ=10000 sbbl/day

	Dist. (feet)	Elev. (feet)	Pipe I.D. (ins.)	Mean Slug Length (feet)	Mean Slug Freq (min-1)	1 in thousand Length (feet)	1 in thousand Freq (min-1)	1 in hundred Length (feet)	1 in hundred Freq (min-1)	1 in ten Length (feet)	1 in ten Freq (min-1)	Slug Number (PI-SS)	Flow Pattern
RISER Riser_1													
Topsides													
1	0.	0.0	10.000	-	-	-	-	-	-	-	-		-
2	0.	-200.0	10.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000		D/R SLUG
3	0.	-400.0	10.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000		D/R SLUG
FLOWLINE Flowl_1													
Riser Base													
4	0.	0.0	10.000	-	-	-	-	-	-	-	-		-
5	1320.	13.2	10.000	N/A	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	43.51	B/B INTERMITTENT
6	2640.	0.0	10.000	109.3	1.237	509.9	0.001237	350.5	0.01237	207.3	0.1237	20.37	B/B INTERMITTENT
7	3960.	13.2	10.000	162.5	0.837	758.1	0.000837	521.0	0.00837	308.2	0.0837	13.56	B/B INTERMITTENT
8	5280.	0.0	10.000	189.0	0.724	881.5	0.000724	605.8	0.00724	358.4	0.0724	9.85	B/B INTERMITTENT
9	6600.	13.2	10.000	209.5	0.657	977.1	0.000657	671.6	0.00657	397.3	0.0657	7.83	B/B INTERMITTENT
10	7920.	0.0	10.000	226.2	0.611	1054.9	0.000611	725.1	0.00611	428.9	0.0611	6.37	B/B INTERMITTENT
11	9240.	13.2	10.000	240.3	0.578	1120.9	0.000578	770.4	0.00578	455.7	0.0578	5.42	B/B INTERMITTENT
12	10560.	0.0	10.000	252.5	0.552	1177.7	0.000552	809.4	0.00552	478.8	0.0552	4.65	B/B INTERMITTENT
13	11880.	13.2	10.000	263.2	0.532	1227.6	0.000532	843.7	0.00532	499.1	0.0532	4.10	B/B INTERMITTENT
14	13200.	0.0	10.000	272.6	0.515	1271.7	0.000515	874.0	0.00515	517.0	0.0515	3.62	B/B INTERMITTENT
15	14520.	13.2	10.000	281.2	0.501	1311.8	0.000501	901.6	0.00501	533.4	0.0501	3.26	B/B INTERMITTENT
16	15840.	0.0	10.000	289.0	0.489	1348.3	0.000489	926.7	0.00489	548.2	0.0489	2.94	B/B INTERMITTENT
17	17160.	13.2	10.000	296.3	0.478	1382.1	0.000478	949.9	0.00478	561.9	0.0478	2.69	B/B INTERMITTENT
18	18480.	0.0	10.000	303.0	0.469	1413.3	0.000469	971.3	0.00469	574.6	0.0469	2.46	B/B INTERMITTENT
19	19800.	13.2	10.000	309.3	0.460	1442.7	0.000460	991.5	0.00460	586.5	0.0460	2.28	B/B INTERMITTENT
20	21120.	0.0	10.000	315.1	0.453	1470.0	0.000453	1010.3	0.00453	597.7	0.0453	2.11	B/B INTERMITTENT
21	22440.	13.2	10.000	320.7	0.446	1496.1	0.000446	1028.2	0.00446	608.3	0.0446	1.97	B/B INTERMITTENT
22	23760.	0.0	10.000	326.0	0.439	1520.5	0.000439	1045.0	0.00439	618.2	0.0439	1.84	B/B INTERMITTENT
23	25080.	13.2	10.000	331.0	0.433	1544.0	0.000433	1061.2	0.00433	627.8	0.0433	1.73	B/B INTERMITTENT
24	26400.	0.0	10.000	335.8	0.427	1566.2	0.000427	1076.4	0.00427	636.8	0.0427	1.63	B/B INTERMITTENT
RISER Riser_2													
Riser Base													
25	0.	0.0	10.000	-	-	-	-	-	-	-	-		-
26	0.	200.0	10.000	337.7	0.424	1575.1	0.000423	1082.5	0.00424	640.4	0.0424	1.63	D/R SLUG
27	0.	400.0	10.000	339.6	0.420	1583.9	0.000420	1088.6	0.00420	644.0	0.0420	1.62	D/R SLUG
Topsides													

<u>Table 22</u>: *Output file for 10000 sbbl/day*

The liquid swept in front of a pig ("liquid by sphere") was checked as shown in **Table 23**. It can be seen that the turndown case (5000 STB/d) gives the larger volume of 288.772 bbl or 1621.3345 ft^3. The calculated liquid generated when the flow is ramped up from 5000 STB/d to 10000 STB/d is 78 bbl or 437.9375 ft^3. This is the difference in total holdup between the two cases. Therefore the pigging volume of 1621.3345 ft^3 is the determining design case.

	Water Cut (%)	Liquid Flow (bbl/d)	Free Gas (mmscfd)	Pres. (psia)	Temp. (F)	Pressure Losses (psi) Elev.	Frn.	Total	Mixt. Vel. (ft/s)	Liquid Holdup frn.	Liquid Holdup (bbl)	Slug Number (PI-SS)	Flow Pattern
CASE NO. 1	LIQ=5000 sbbl/day												
Topsides	0.0	5000.	32.17230	1500.	176.	0.	0.	0.	8.2	0.2736	0.		D/R SLUG
Riser Base	0.0	5000.	32.09700	1535.	177.	-36.	0.	-35.	8.1	0.2795	11.		D/R SLUG
Riser Base	0.0	5000.	32.09690	1535.	177.	0.	0.	0.	8.1	0.2795	0.		D/R SLUG
	0.0	5000.	28.59170	1492.	91.	8.	36.	43.	6.5	0.2354	665.	1.33	B/B INTERMITTENT
Riser Base	0.0	5000.	28.59170	1492.	91.	0.	0.	0.	6.5	0.2354	0.	1.33	B/B INTERMITTENT
Topsides	0.0	5000.	28.75750	1449.	90.	43.	0.	43.	6.6	0.3432	13.	1.33	D/R SLUG
						15.	36.	51.			689.	Liquid by sphere:	288.772 (bbl)
CASE NO. 2	LIQ=10000 sbbl/day												
Topsides	0.0	10000.	64.34460	1500.	176.	0.	0.	0.	16.5	0.1830	0.		D/R SLUG
Riser Base	0.0	10000.	64.24460	1528.	177.	-29.	1.	-28.	16.2	0.1862	7.		D/R SLUG
Riser Base	0.0	10000.	64.24450	1528.	177.	0.	0.	0.	16.2	0.1862	0.		D/R SLUG
	0.0	10000.	61.16960	1367.	121.	7.	155.	162.	15.7	0.1993	596.	1.63	B/B INTERMITTENT
Riser Base	0.0	10000.	61.16960	1367.	121.	0.	0.	0.	15.7	0.1993	0.	1.63	B/B INTERMITTENT
Topsides	0.0	10000.	61.39510	1336.	119.	30.	1.	31.	16.0	0.1983	8.	1.62	D/R SLUG
						8.	156.	164.			611.	Liquid by sphere:	262.120 (bbl)

Table 23: *Summary file for 5000 sbbl/day & 10000 sbbl/day*

CHAPTER 5: CONCLUSION AND RECOMMENDATIONS

In the case study 1, the task is to find the optimum pipeline size that will allow the design flowrate of gas to be transported from the source to destination whilst maintaining an arrival pressure of not lower than required arrival pressure at the destination. The pipeline sizes available are 16", 18", 20" or 24" ID. PIPEsim allow engineer to select the optimum pipeline ID while minimize the cost and installation time of pipeline. The computation of the pressure drop for each of pipeline size done by PIPEsim to generate important graphs and output results. The pressure temperature profile plot generated by PIPEsim was analyzed to select the most suitable pipeline size that can deliver the fluid at required arrival pressure. From the operation, the 20" or 24" ID can be used to deliver the gas but the 20" pipeline would be the most appropiate size because of the lower cost and installation time. PIPEsim software also can be used to predict the flow pattern in the pipeline. For case study 1, fluid flow pattern falls within segregated flow regime so it is unnecessary to size a slug catcher and cost for installing the slug catcher can be avoid.

In case study two, the pipeline sizes available are 6", 8", 10" or 12" ID. From the operation, the 10" or 12" ID can be used to deliver the gas but the 10" pipeline would be the most appropiate size. The pipeline system in case study two followed by a riser. Prior to the riser, the presence of a long slightly downward inclined pipeline can lead to severe riser slugging. Pipesim predicts the two phase gas-liquid flow along pipeline is in intermittent flow regime. Therefore, the sizing of slug catcher is necessary. Large slug arrived at first receiving facility can overload the liquid handling capacity and may leads to tripping of receiving facilities. Increase liquid handling capacity to handing intermittent large liquid flow may not be cost effective. Thus the slug catcher was designed to temporary store the intermittent slug and it will be treated after the slugging period. The model output in this case study contains the slug information and flow regime maps which is essential for the slug catcher sizing. The pigging volume of 1621.3345 ft^3 is the determining design case for case study 2. The calculated liquid generated when the flow is ramped up is 78 bbl or 437.9375 ft^3.

To improve performance of pipeline and reduce the total cost of the pipeline, other than selecting the optimum pipeline diameter and sizing a slug catcher, the design criteria that can be taken into consideration are:

- Pipe roughness: The flow efficiency vary with the pipe roughness
- Pipeline grade: High grade/low grade, strength & corrosion resistance
- Pipeline length
- Wall thickness of pipeline

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