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Title:

Study of Multiphase Flows and Flow Assurance in Oil and Gas Pipelines

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Finally, we thank all the people they helped in accomplishing our work

Dedication

Praise be to Allah, master of the universe.

Peace and blessings be upon our prophet Mohamed.

To the dearest, closest beings, my parents, through their support, love, patience and advice during long years of study, that they find this modest testimony of all the love that I have for them.

To Mr. BASSAM and Mr. BOUGHENOU best promoters. To all my BENKINI and MOUAIA families without exception.

In everything he helped me from near and far.

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Abstract

Piping systems are considered main tools to transport hydrocarbons with safety method. They are occurred to many problems due to the attack of fluid (high velocity) and change of temperatures or pressures. In addition, other factors may affect on the pipelines such as, external environment actions, fluid reactions, etc. The aim of this final project was to study the flow assurance system of multiphase flows in a piping network using Pipesim software. Two wells were numerically studied and analyzed. The first well is called BRS 28 and the second well is called BRS 30. They are located in Beersheba (Hassi Messaoud city) with a length of 11.163 km and 6.52562 km respectively. The obtained results showed that the hydrates formation and erosion issue were detected as the main problems occur in the piping system, where the corrosion problem and wax deposition were not exceeding the condition of safety factor.

Résume

Les systèmes de canalisations sont considérés comme les principaux outils pour transporter les hydrocarbures avec des méthodes de sécurité. Ils se posent de nombreux problèmes dus à l’attaque du fluide (haute vitesse) et aux changements de températures ou de pressions. De plus, d'autres facteurs peuvent affecter les canalisations tels que les actions de l'environnement externe, les réactions des fluides, etc. Le but de ce projet final était d'étudier le système d'assurance d'écoulement des écoulements multiphasiques dans un réseau de canalisations à l'aide du logiciel Pipesim. Deux puits ont été étudiés et analysés numériquement. Le premier puits s'appelle BRS 28 et le deuxième puits s'appelle BRS 30. Ils sont situés à Beersheba (ville de Hassi Messaoud) avec une longueur de 11,163 km et 6,52562 km respectivement. Les résultats obtenus ont montré que la formation d'hydrates et le problème d'érosion ont été détectés car les principaux problèmes se produisent dans le système de tuyauterie, où le problème de corrosion et le dépôt de cire ne dépassaient pas la condition du facteur de sécurité.

ملخص

تعتبر أنظمة الأنابيب من الأدوات الرئيسية لنقل المواد الهيدروكربونية بطريقة آمنة. لقد حدثت لهم العديد من المشاكل بسبب هجوم السوائل (السرعة العالية) وتغير درجات الحرارة أو الضغوط. بالإضافة إلى ذلك، قد تؤثر عوامل أخرى على خطوط الأنابيب مثل إجراءات البيئة الخارجية، وتفاعلات السوائل، وما إلى ذلك. وكان الهدف من هذا المشروع النهائي هو دراسة نظام ضمان التدفق للتدفقات متعددة الأطوار في شبكة الأنابيب باستخدام برنامج .Pipesim تمت دراسة وتحليل بئرين عددياً. البئر الأول يسمى BRS 28 والبئر الثاني يسمىBRS 30 ، ويقعان في مدينة بئر السبع (مدينة حاسي مسعود) بطول 11.163 كلم و6.52562 كلم على التوالي. أظهرت النتائج التي تم الحصول عليها أن مشكلة تكون الهيدرات والتآكل تم اكتشافها حيث أن المشاكل الرئيسية تحدث في نظام الأنابيب، حيث كانت مشكلة التآكل وترسب الشمع لا تتجاوز شرط عامل الأمان

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List of abbreviations and symbols

CPF: Central Processing Facility

BRS 28: Bir Seba 28

BRS 30: Bir Seba 30

GS: Gathering station

CPL:completion

GTP: National Company for Major Petroleum Works

PVT: pressure Volume Temperature

GOR: gas oil ratio

MD: measured depth

ID: inside diameter

STB/d: stock tank barrels per day

Barg: pressure gauge

Bara: atmospheric

psia: pounds per square inch absolute

Ft/s: foot per second

degC: temperature

Mscfd: thousand standard cubic feet per day

BOPD: barrels of oil per day

BWPD: barrels of water per day

FWHP: flowing well head pressure

FWHT: flowing well head temperature

PH: potential hydrogen

mm/a: millimeters per

sm3/d: standard cubic meters per day

SIM: steady-state multiphase flow simulator

General Introduction

General Introduction

Oil and natural gas are considered as global energy resources. Their production is a challenge due to its high cost and through a complex service operation including network of pipes. Transportation from production sites to end-users also considers an important challenge to the companies. The increasing daily demand for hydrocarbons, such as natural gas and crude oil, highlights the importance of enhancing supply flow. Efficient production methods, particularly utilizing pipelines, are crucial for meeting this growing demand while ensuring cost-effectiveness and safety.

The oil and gas sectors are the backbone of the Algerian economy. According to the latest report issued by OPEC, Algeria held an estimated 12.2 billion barrels of proved crude oil reserves at the beginning of 2023.

Control of flows in hydrocarbon production lines has recently emerged as a key element in the success of petroleum developments. Precipitation and deposition of solids represent a major challenge in oil and gas production. Solids are formed due to inevitable changes in temperature, pressure, and composition of the flow of oil, gas, and water from reservoir conditions to process conditions. The emergence of subsea production and increased exploitation of heavy ores has made flow assurance issues dominant in ensuring the efficient and safe operation of hydrocarbon assets. The main solids that hinder flow assurance are: asphaltene, paraffin wax, natural gas hydrates, naphthene and inorganic scales. Technical, safety and environmental risks associated with sedimentation problems in Close-hole formations, production tubing and wellhead equipment. Flow lines and processing facilities, relevant to decisions made in the oil and gas industry and external regulatory and financial entities. A flow assurance study is essential to ensure optimal and uninterrupted flow of hydrocarbons from the reservoir to the storage or processing site.

The framework of this final project focuses to rely on numerical simulation tools for unsteady multiphase flows to understand the physical phenomena occurring in a crude oil and gas pipelines and thus verify its good sizing.

The requirements for resistance and security in modern societies are becoming increasingly important due to significant growth in recent decades. It is now essential to have access to efficient computer programs, such as PIPESIM, OLGA, or Multiflash, to perform various analyses, including flow calculations in pipes. These tools help reduce design costs by decreasing the time required for each analysis and ensuring accuracy, free from human error. This is especially crucial when the product being transported is a flammable, high-pressure power source. With this in mind, EN-GTP has decided to cooperate with future graduates by studying and improving the designs of the piping systems it develops independently.

This final project is divided into three chapters as follows:

- The first chapter is devoted to the concepts of crude oil and natural gas. It presents the field and environment of study, providing an overview of collection networks and explaining how these resources are transported, stored, and processed.
- The second chapter focuses on the flow assurance study, discussing multi-phase flows and flow assurance, as well as identifying problems encountered in pipelines.
- The third chapter centers on modeling, simulation, and discussion of the main results. Using PIPESIM, we model and simulate the assembly network, interpret the simulation results, and propose solutions to the identified issues.

Finally, this project is ended by conclusions and perspectives.

Chapter 1:
Crude Oil and Natural Gas

1.1 Introduction

Petroleum is composed primarily of hydrocarbons. While nature gas is a mixture of hydrocarbon gases. Additionally, some metals are present at trace levels. Oil and natural gas are the world's major energy sources and play an important role in the global economy. Due to their nature as flammable liquids, their transportation and storage require complex special infrastructure to ensure the safety and efficiency of the process, as flow analyzes inside the tube and pressure losses are an essential step in the design of the network, to avoid problems and ensure the planned life. The condition resulting from the formation of the liquid, the ambient temperature, changes in the form of high tube, various operating patterns and restricting the flow that may occur in the tank or the network component make the flow analysis a very complex task and not only the methods of control and study depends on the location of the facilities, but also on the strategies adopted by construction, assembly and operation companies [1].

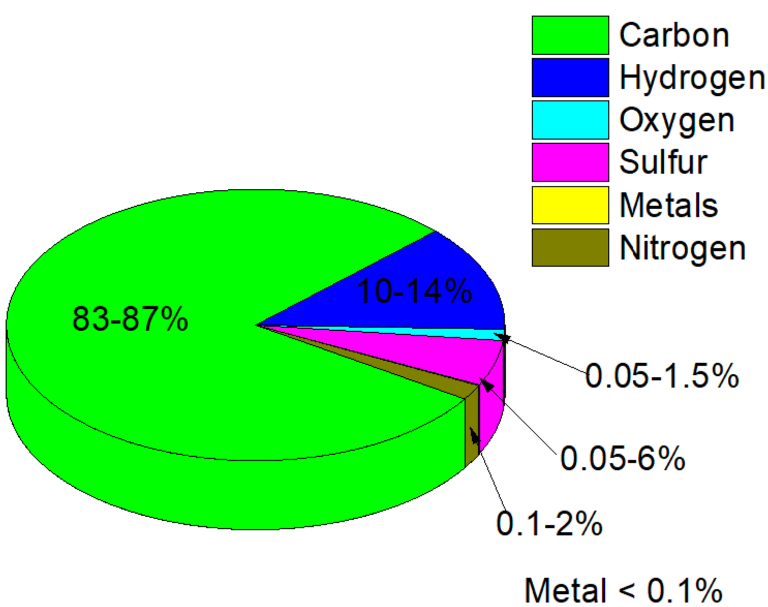

Figure 1-1: Basic elemental composition of crude oil [1].

1.2 Presentation and history of the host company

GTP (National Petroleum Works Company) - a subsidiary of the Sonatrach group, is a large-scale company specializing in the construction, in all trades, of large industrial and pipeline assemblies in different fields mainly hydrocarbons and energy. This Company has succeeded in 50 years of presence on the energy market, develop a broad portfolio of activities by bringing together rich know-how, expertise and skills. Ranking it as a leader in the construction of industrial facilities in all the countries. Indeed, GTP is located at the petrochemical platforms of the north of countries as well as in the oil and gas fields of the south, taking care of the construction of industrial installations intended for production, processing, transport and distribution hydrocarbons.

Table 1-1 presents the historical grow of Algerian GTP company from its creation 1967 up to 2018. In addition, Figure 1-1 shows the evolution of GTP's share capital from 1989 to 2018 [Ref].

Table 1-1: Historical presentation for Algerian GTP company (Source: GTP).

Date	Action
November 15, 1967	Creation of 'ALTRA', Algerian Major Works Company with the association of SONATRACH and the French group UIE (specialized in the construction of surface oil installations) operating in Algeria.
1972	ALTRA becomes a 100% subsidiary of the Sonatrach holding SPP group, upon its acquisition, aftermath of the nationalization of hydrocarbons.
1974	• Algerianization of the company's social capital, prioritizing the training of engineers and construction managers. National institutes such as the IAP and INH of Boumerdès, forming the majority of these managers. • Subsidies for internships and training abroad for their engineers. • Creation of training centers on the national territory, graduating managers and experts from all departments and areas of expertise.

1980	Adoption of the current name “GTP” (*Grands Travaux Pétroliers*) during the restructuring of Sonatrach.
February 19, 1989	Transformation of EN-GTP into a Joint Stock Company – EPE.
June 29, 1997	Recast of the company's statutes, following the law on merchant capital of the State of 1995.
December, 2005	The company becomes a fully public joint stock company, 100% owned by Sonatrach - HOLDING Services Para Pétroliers. (Compared to 51% in 2004 in co-ownership with the public holding company TRAVEN holding the remaining 49%).
2007- 2018	Recording of a real positive peak in the evolution of social capital by GTP head office in Reghaia, with a turnover of 17.43 million dollars

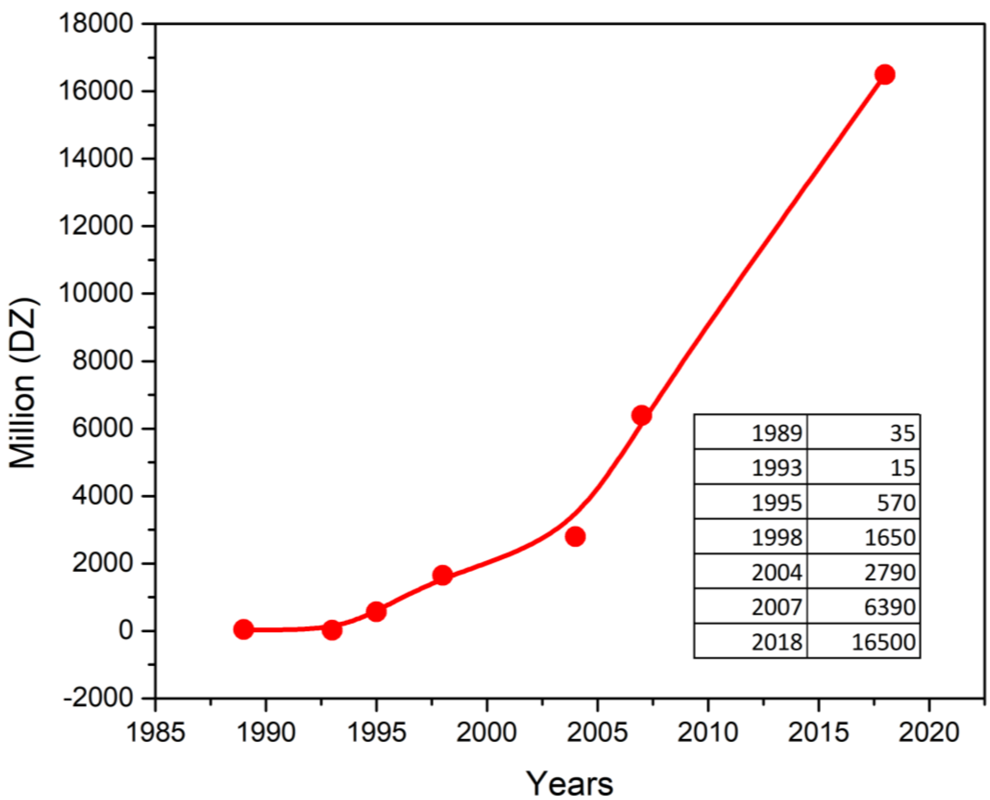

Figure 1-2: Evolution of GTP’s share capital (Source: GTP)

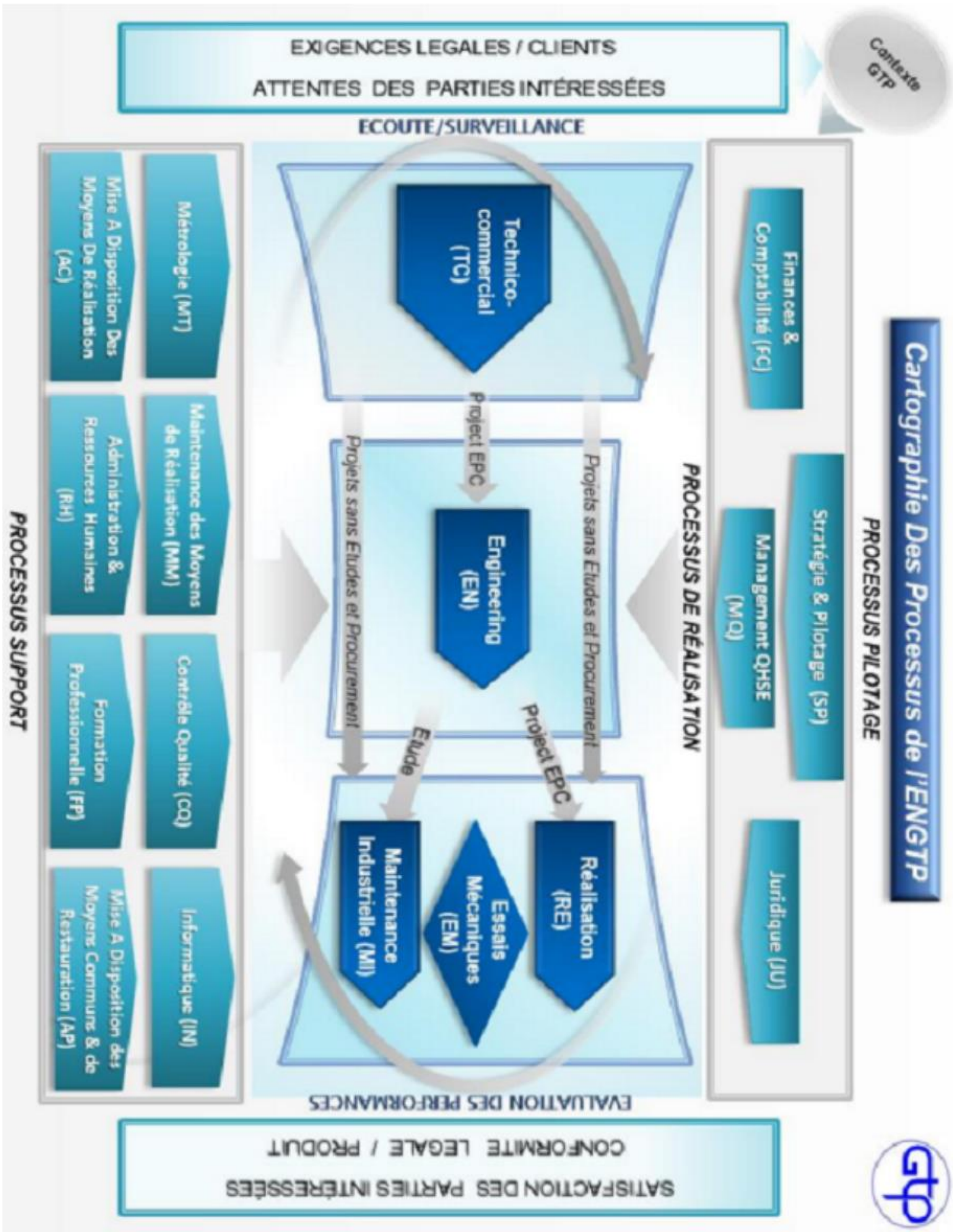

Figure 1-3: Organization chart of the operation and organization of the EN-GTP. (Source: GTP)

1.3 Hydrocarbons

Hydrocarbons are substances composed of carbon and hydrogen. They are important for forming the basis of petroleum and gas. They are also used to involve other compound such as fats and oils. The term 'hydrocarbons' encompasses various connotations due to the broad scope and complex composition of this substance. This includes discussions about gaseous hydrocarbons and the role of bacteria in their biodegradation. Hydrocarbons are further categorized into biogenic and petrogenic origins [2].

Figure 1-4 illustrates the composition of hydrocarbons, which are made up of carbon chains consisting of carbon atoms linked together by covalent bonds. These chains can be straight, branched, or cyclic [3]. Figure 1-5 indicates to the chemical bounds where carbon atoms in hydrocarbons are linked together by single, double, or triple covalent bonds [4].

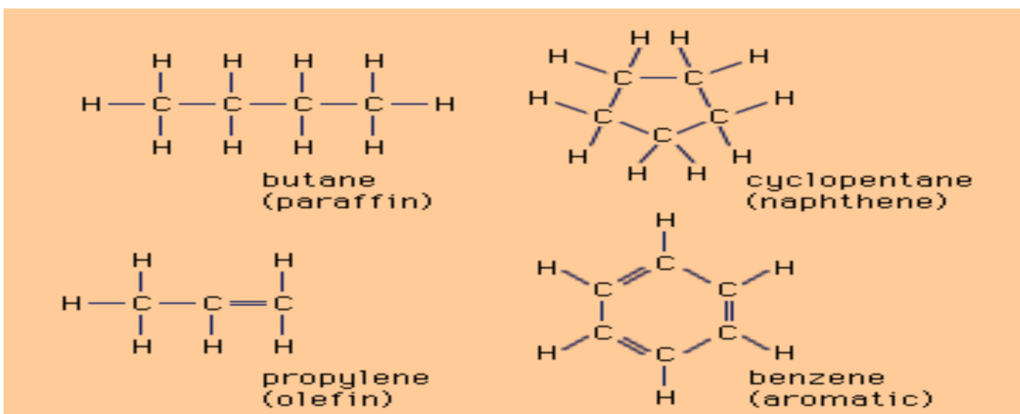

Figure 1-4: types of carbon chains [3].

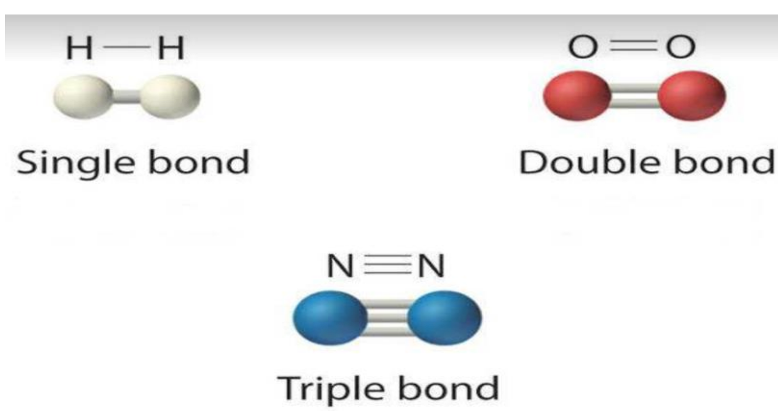

Figure1.5: chemical bonds [4].

1.4 Hydrocarbon properties

The physical state of hydrocarbons varies depending on the length of the carbon chain and the type of bonds present in it. For example, alkanes are gases, liquids, or solids depending on the length of the carbon chain.

Table 1-2: Physical properties of hydrocarbons.

Physical state	**Description**
Color	Pure hydrocarbons have no color.
Odor	Some hydrocarbons have a distinct odor, while others have no odor.
Density	The density of hydrocarbons increases as the number of carbon atoms in the molecule increases.
Boiling Point	The boiling point of hydrocarbons increases as the length of the carbon chain increases.

Table 1-3: Chemical properties of hydrocarbons [3].

Combustion	Hydrocarbons are combustible compounds, as they react with oxygen to produce carbon dioxide and water.
Chemical reactions	Hydrocarbons participate in many chemical reactions, such as addition reactions and substitution reactions

1.5 Transport of hydrocarbons

Hydrocarbon transportation is vital to ensuring that these essential materials reach all parts of the world. This process includes the transportation of oil, natural gas, and their derivative products, such as gasoline, diesel, and kerosene. The process of transporting hydrocarbons occurs through various means, including:

- Pipes: they are the most common means of transporting hydrocarbon over long distances. Extensive networks of pipelines are laid underground or on the surface to transport oil and gas from production fields to refining centers and energy consumption stations.

- Oil tankers: they are used to transport crude oil and its derivative products across seas and oceans. Oil tankers vary in size and capacity, from small tankers that are used to transport crude oil within regional seas, to huge tankers that are used to transport crude oil across oceans.

1.5.1 Hydrate transport within pipes

The raw flows collected at the surface must be transported and shipped to the processing centers. Natural gas isolation stations are considered the first point reached by the oil produced from the wellhead through the X-mas tree. When the flow pipe enters the station, it passes through a choke valve and a check valve (or one-way valve) to prevent the oil from returning in the opposite direction. Pressure gauges or pressure indicators are installed before and after these valves. After this, the crude oil enters the manifold valve complex, which distributes the oil and isolates it based on the oil and gas productivity of each well and the operational capacity: Separator Capacity insulation.

1.5.2 Aggregation network

a) Pipelines

A pipeline is a structure intended for transporting liquid substances (liquids, gases and multiphase mixtures) under pressure and over large distances. It is an industrial system consisting of pipes and accessories (taps, valves, compressors, etc.), often organized in a network called a collecting network. There are two types of pipelines: (i) flow line and (ii) trunk line. Flow line is a part of the pipeline that spans from the mudline at the tree/manifold through to the riser. Trunk line is usually large pipeline diameter compared to other lines in gathering system.

b) Manifold

The production manifold receives preventative effluent from different wells. This device is made up of 2 to 3 transverse lines:

- To select low pressure (LP) wells;
- To select medium pressure (MP) wells;
- To select high pressure (HP) wells.

Its role is to direct the effluent from the wells in the desired directions [5].

Figure 1-6: Manifold

1.5.3 Slug Catcher

Slug catcher sizing is an important flow assurance task that requires designing for the expected worst-case slugging scenario, factoring in a safety margin. Regardless of the type of slugging (Hydrodynamic, Terrain, or Operationally-induced), the surface production facility must be designed to handle these slugs to avoid overloading or overwhelming the gas/liquid handling capacity. Overloading can result infacility shutdowns or spills; the solution is a slug catcher.

A slug catcher is a vessel with sufficient buffer volume to store the largest slugs expected from the upstream system. The buffered liquids can be drained to the processing equipment at a much slower rate to prevent overloading the system. The buffered liquids then can be drained to the processing equipment at a much slower rate to prevent overloading the system.

Table 1-4: Types of slugging.

Type	Description
Hydrodynamic slugs	A property of the stratified flow regime where slugs are formed as a result of the instability of waves at the gas-liquid interface at specific flow rates.
Terrain-induced slugs	Caused by periodic accumulation and periodic purging of liquid at dips along the flowline, for example, severe riser slugging.
Operationally-induced slugs	Created by forcing the system from one steady-state condition to another, for example, ramp-up and pigging.
Central processing facility	They are key link in the technological chain, separating oil from associated gas, water, sand, solvents, and additives.

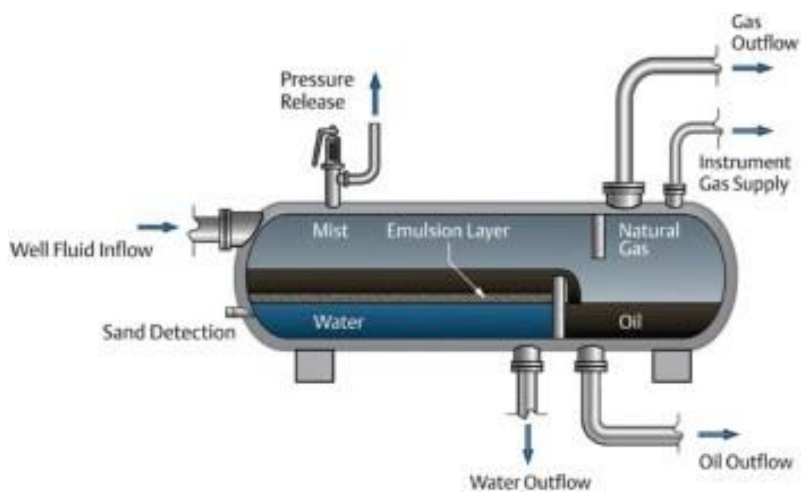

Figure 1-2: Slug catcher [7]

1.6 Hydrocarbon storage

Hydrocarbons, such as crude oil and natural gas, play an important role in the global economy as a major source of energy and chemicals. These materials require careful storage to maintain their quality and ensure safety of use [6]. Gas storage units are structures designed to store large quantities of gases, whether natural or artificial, under high pressure. These units are used in various fields as shown in table 1-5.

Table 1-5: The most important fields used natural gas storage [8].

Field	Role
Industry	To provide fuel and energy to run industrial processes.
Energy	To store liquefied natural gas (LNG) for use as a power source in power plants.
Transportation	To store compressed natural gas (CNG) for use as vehicle fuel.
Medicine	To store medical gases such as oxygen and nitrogen.

Table 1-6: General characteristics of tanks

Characteristics	Importance
Capacity	It varies according to the needs of the population and the type of use.
Materials	• ***Reinforced concrete:*** the most common material for building tanks, and is characterized by its strength and durability. • ***Steel:*** used in building large tanks with high capacity. • ***Plastic:*** used in the construction of small tanks with low capacity.
Shape	• ***Rectangle:*** the most common shape due to its ease of construction. • ***Ring:*** characterized by its ability to withstand high pressures. • ***Square:*** used in small spaces.
Site	Tanks are built in elevated locations to ensure adequate water pressure when distributed.
Design	They must be designed according to specific engineering standards that ensure their safety and bearing capacity Various loads.
Installation	Public tanks must be installed by specialized technical workers.
Maintenance	Public tanks need regular maintenance to ensure their safety and cleanliness.

1.7. Hydrocarbon treatment

Natural gas processing involves a series of production processes in which raw natural gas, extracted from gas wells and brought to the surface using oils, is purified. After treatment, methane gas comprises most of the natural gas content, resulting in properties that are quite distinct from those of raw gas. Processed natural gas serves as a fuel for residential, commercial, and industrial consumption.[9]

1.8. Petroleum processing

The associated gases in oil fields are separated in special devices called "traps" before being sent to the gasoline unit to separate the light condensates, which are often associated with the gases. These condensates are separated by condensation and are known as "natural gasoline". The mixture is then directed into sedimentation tanks, where mechanical impurities are separated through sedimentation.

1.9 conclusion

The flow inside a pipe is influenced by many factors, such as physical and thermal properties (velocity, pressure, temperature, etc.), rheological characteristics (viscosity, shear stress, friction factor, etc.), chemical reactions, geometrical dimensions (length, diameter, thickness, bending, etc.), and other additional parameters or equipment (valve, vibration, etc). These factors impact the overall deliverability of the network. To ensure that the network operates with minimal productivity and environmental barriers while remaining financially viable, a flow assurance study (second chapter) is recommended to save time and money for the parties involved.

Chapter 2:
Flow Assurance study

2.1 Introduction

In general, the role of a production engineer in the oil industry is twofold: to safely and economically design a new production system, and/or, to exploit and optimize an existing one. In either case, the ultimate goal of the production engineer is to maximize profits by optimizing throughput in a safe environment. To achieve this goal, an accurate prediction of flow behavior and characteristics along the production system must be determined as a priority. The three main parameters of flow behavior that the production engineer must predict along the production system on which most aspects of design and operation depend are: Flow regime, Pressure gradient, Liquid volume (hold-up), Prediction of previous flow parameters combined with a good understanding of flow behavior and engineering sense and intuition, can lead to optimal flow, maximum economic profit and safe operation.

2.2 Multiphase flow

The petroleum industry has been dealing with multiphase flow for over a century, although attempts to characterize multiphase flow in a more rigorous mathematical context began in earnest about 60 years ago. Over the past 30 years, however, engineers have increasingly relied on simulation software to model multiphase flow for a variety of applications ranging from front-end design of production systems to real-time optimization of operations. Today, steady-state and transient multiphase flow models are firmly integrated into simulation tools to enable the study of the behavior of the entire production system, from reservoir to separator and beyond [10].

Multiphase flows, that is to say systems in which different fluid phases, or fluid and solid phases, are simultaneously present. Fluids can be different phases of the same substance, such as a liquid and its vapor, or different substances, such as a liquid and a permanent gas, or two liquids. In fluid-solid systems, the fluid can be a gas or a liquid, or gases, liquids, and solids can all coexist in the flow domain [11].

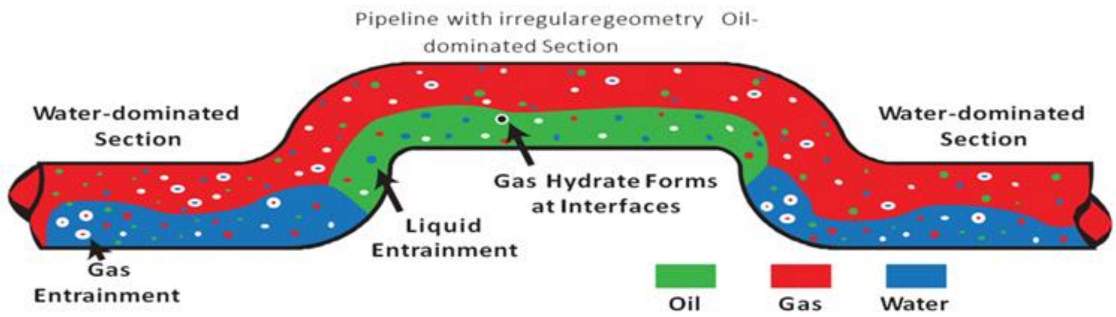

Figure 2-1: Photographic image of a three-phase flow [12].

2.2.1 Multi phase flow configurations

The following combinations are essentially encountered in multiphase flows:

- liquid/liquid (not or barely miscible);
- liquid/gas (or liquid with its vapor);
- divided liquid/solid;
- split gas/solid;

In all these cases, several configurations, each leading to a different treatment of the flow, are possible. For combinations of two fluids, the problem is much more complex: it theoretically involves eight independent dimensionless parameters, which can be reduced in the simplest cases to four or five; also, the domains of existence of the various configurations are not known in all possible cases. These configurations are the subject of a topological classification where we will find them represented, in conduits respectively close to the horizontal and the vertical.

2.2.2 Flow regime

The fluid from the wellbore to the first piece of production equipment (separator) is generally a two-phase liquid/gas flow. The characteristics of multiphase horizontal flow regimes are illustrated in Figure 2.2. They can be described as follows

- **Bubble:** Occurs at very low gas/liquid ratios where the gas forms bubbles that rise at the top of the pipe.
- **Clog:** Occurs at higher gas/liquid ratios where the gas bubbles form moderately sized clogs. As gas/liquid ratios increase, the clogs become more

- **Stratify:** As the gas and liquid flow in separate layers, the energy of the flowing gas stream increases.
- **Wavy:** As reports cause waves in the flowing liquid. continue to increase, the height of the waves
- **Slug:** As gas/liquid ratios increase until the ridges contact the top of the pipe, creating liquid slugs.
- **Spraying:** At extremely high gas/liquid ratios, the liquid is dispersed throughout the flowing gas flow.

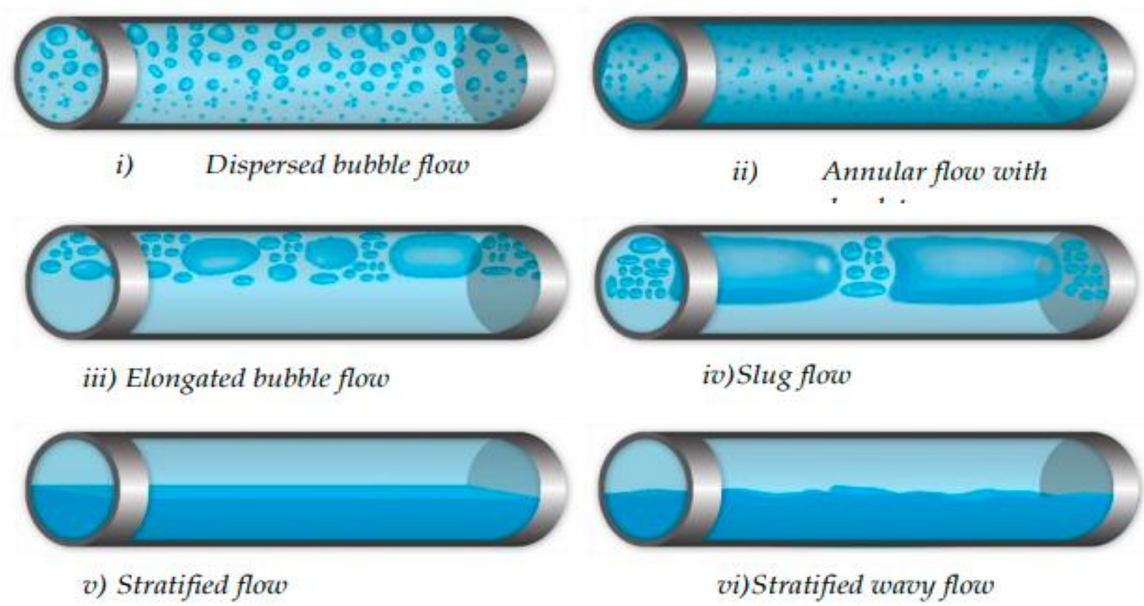

Figure 2-2: Multiphasic horizontal map [13].

Figure 2.2 shows the different flow regimes that could be expected in horizontal flow as a function of the superficial velocities of gas and liquid flow. The superficial speed is the speed that would exist if the other phase were not present. Multiphase flow in vertical and inclined pipes behaves somewhat differently from multiphase flow in horizontal pipes. The characteristics of vertical flow regimes are shown in Figure 2.3 and are described below.

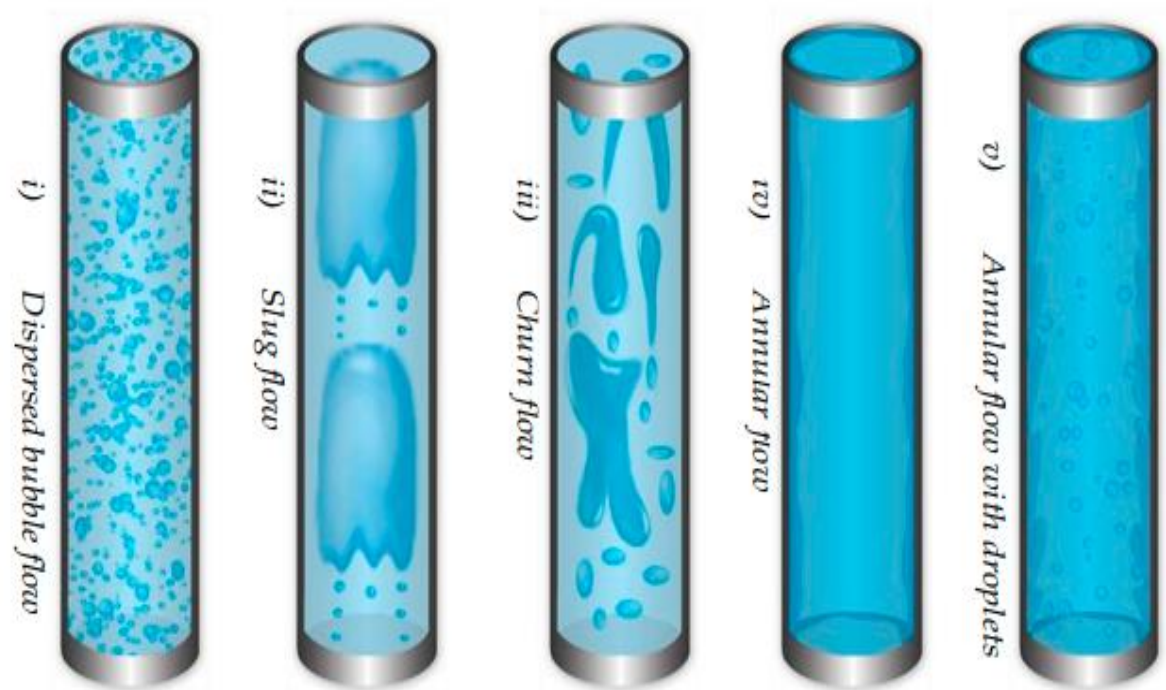

Figure 2-3: Multiphase flow patterns in vertical flow [13].

Bubble: When the gas/liquid ratios are low, the gas is present in the liquid in small bubbles of variable diameter distributed randomly. The liquid moves at a fairly uniform speed while the bubbles rise through the liquid at different speeds, which are dictated by the size of the bubbles. With the exception of the total composite-fluid density, bubbles have little effect on the pressure gradient.

Slug Flow: As gas/liquid ratios continue to increase, the wave height of the liquid increases until the crests contact the top of the pipe, creating liquid slugs.

Transition Flow: The fluid changes from a continuous liquid phase to a continuous gas phase. The liquid slugs virtually disappear and are carried into the gas phase. The effects of the liquid are still significant, but the effects of the gas phase are predominant.

Annular fog flow: The gas phase is continuous and most of the liquid is entrained in the gas. The liquid wets the pipe wall, but the effects of the liquid are minimal because the gas phase becomes the controlling factor.

2.2.3 Multiphase flow pressure drop

The calculation of pressure loss in multiphase flow is very complex and relies on empirical relation to account for phase changes that occur due to changes in pressure and temperature along the flow, velocities relative phases and the complex effects of altitude changes. Table 2-1lists several commercial programs that are available for modeling pressure loss. Because all are based to some extent on empirical relationships, their accuracy is limited to the data sets from which the relationships were designed.

Table 2-1: Hydraulic modeling and flow assurance software

Mutliphase transient simulation	**Mutliphase steady-state simulation**	**Single-phase gas/liquid transient simulation**
OLGA ProFES	Pipeflow, wellflow, PIPEPHASE, PIPESIM-SUITE, GENNET-M, Flosystem, Proposer, Gap, Perform	Pipeline simulator, Winflo, NATASHA PLUS, TLENT, TGNET

2.2.4 Challenge of studying multiphase flows

Pressure losses for single-phase flow in pipes have long been accurately modeled with familiar expressions such as the Bernoulli equation, accurate predictions of pressure loss in multi-phase flow have proven more difficult due to additional complexities. The lower density and viscosity of the gas phase causes it to flow at a higher speed compared to the liquid phase, a characteristic known as slip. This sliding causes frictional pressure losses associated with the shear stresses encountered at the gas/liquid interface, as well as along the pipe wall. Additionally, the highly compressible gas phase expands as pressure decreases along the flow path. Further complicating matters is the variety of physical phase distributions, which impact pressure losses in the flow path. The dominant flow pattern for a specific set of conditions depends on the relative magnitude of the forces acting on the fluids. The forces of buoyancy, turbulence, inertia, and surface tension are greatly affected by relative flow rates, viscosities, and fluid densities, as well as pipe diameter and inclination angle. The complex dynamics of the flow pattern governs slip effects and, hence, variations in liquid hold-up and pressure gradient. Many empirical correlations and mechanistic models have been proposed to predict fluid blockage and pressure loss. Some correlations and models are general, while others apply only to a narrow range of conditions. Many of these approaches begin with a prediction of the flow pattern, with each flow model having an associated method for predicting fluid blockage and frictional pressure loss. In steady state, the gas generally moves faster than the liquid, so it slips past the liquid. For the volume flow to remain constant, the surface area of the pipe occupied by the gas must shrink. This condition results in a higher volume fraction of liquid than if the gas were moving at the same speed, resulting in liquid blocking, as shown in Figure 2-6.

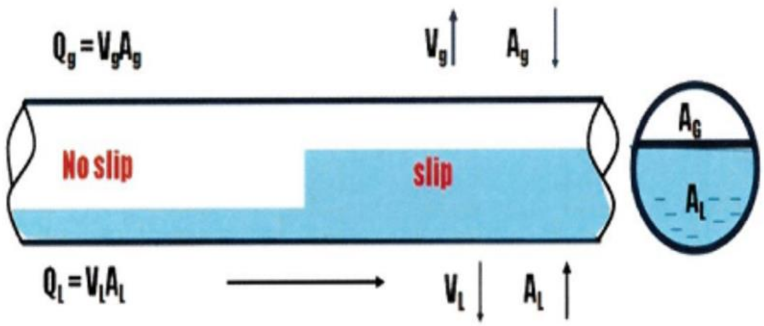

Figure 2-4: Liquid holdup

Liquid blockage is generally the most important parameter in calculating pressure loss. Quantification of liquid blockage is necessary to predict hydrate formation and wax deposits and to estimate the volume of liquid expelled during pigging operations for sizing slug sensors. Prediction of liquid blockage is used to determine a two-phase friction factor from which a pressure gradient is calculated [14].

2.2.5 Modeling of multiphase flows

The most fundamental role of a steady-state multiphase flow model is to provide a relationship between flow rate and pressure change along a single conduit. Combined reservoir inlet performance relationships and downhole equipment models and field the theoretical production (or injection) capacity of the system can be calculated. From this perspective, a number of design workflows can be performed, including Bottom Completion (Reservoir Contact) design behavior:

The top completion design response (piping and artificial lifting systems); The impact and appropriate design of surface equipment and connecting

2.3 Flow Assurance

Flow Assurance works with a cost-effective approach to producing and transporting fluids from the tank to the processing facility. During crude oil production and transportation, knowledge of fluid properties and operating conditions is essential to prevent the formation and deposition of unwanted solids (such as hydrates, waxes, asphaltenes, and scales). Under extreme temperatures and pressures, methane hydrates can crystallize or asphaltenes precipitate in the production pipeline. If not properly controlled, hydrate crystals or asphaltene or wax particles may precipitate and agglomerate to the point of blocking the production pipe. Removing wax or asphalt components in subsea production pipelines can be very expensive and dangerous.

Flow assurance challenges are increasing due to the transition from conventional oil reserves to mature oil fields. As oil fields mature, the water fraction increases. In some cases, operators inject water into mature oil fields to enhance oil recovery. Water-in-crude oil emulsions further complicate flow assurance strategies. The presence of water formation or injection with calcium carbonate can lead to the formation of crusts in certain circumstances. Calcium carbonate scale formation can also clog pipeline equipment and raw material production equipment, making mature oil fields less profitable. Most commercially available anti-caking hydrate inhibitors become less effective as water interruption increases. Finally, the emulsion must be broken to separate the oil and water. Breaking the emulsion via physical or chemical methods can be very expensive, especially for heavy oil emulsions containing emulsion-stabilizing solids such as asphaltenes.

Therefore, it is necessary to study and develop cost-effective flow assurance strategies to control solids and emulsions to reduce economic risks throughout the life of the oil field [15].

2.4 Problems related to Flow Assurance studies

The main flow assurance issues that need to be considered for producing multiphase flow through pipelines and risers in offshore or onshore oil and gas field developments are:

- ✓ hydrates
- ✓ asphaltenes
- ✓ slugging
- ✓ naphthenates
- ✓ scaling
- ✓ corrosion
- ✓ erosion
- ✓ emulsions

2.4.1 Corrosion and erosion

The name “corrosion” comes from the Latin “corroder” which means to corrode or attack. Indeed, corrosion is a degradation of the material or its properties (physicochemical, mechanical, etc.) by chemical or electrochemical interaction with the surrounding environment.

Corrosion therefore refers to the alteration of a material by chemical reaction with an oxidant (mainly dioxygen and the H+ cation). But corrosion can combine with mechanical effects and give rise to stress corrosion and fatigue corrosion; likewise, it intervenes in certain forms of surface wear whose causes are both physicochemical and mechanical.

This definition recognizes that corrosion is a harmful phenomenon because it destroys the material and reduces its properties, making it unusable for its intended application. But from another point of view, corrosion is a welcome phenomenon, even desired, because it destroys and eliminates a number of objects abandoned in nature. Certain industrial processes also involve corrosion (anodizing aluminum, electrochemical polishing, etc.)

Figure 2-5: (a) corrosion, (b) erosion [15].

Table 2-2: Difference between erosion and corrosion [12]

Erosion	**Corrosion**
It is a physical process.	It is a chemical process.
Occurs on the surface of the land.	Occurs on the surface of materials like polymers, ceramics or metals.
Natural agents like water, gravity, wind, causes erosion.	Corrosive agents such as oxygen, sulfates can cause corrosion.
Erosion involves different processes like transportation, weathering, and dissolution.	Corrosion types include pitting, galvanic, crevice, intergranular and selective leaching.
Land reform techniques like terracing or planting trees can prevent erosion.	The preventive measure includes applying a protective layer on the surface of the metals

2.4.2 Scales

Scales can develop in the transport system as a result of water forming deposits, such as crystal growth of insoluble salt or oxides held in the water component. Scale compounds will precipitate out of water when their individual water solubility is exceeded due to incompatibility, reducing the carrying capacity of flow lines and potentially causing blockage, as shown in Figure 2-6. The formation of scale deposits depends on temperature, concentration of scale-forming species, pH, water quality and hydrodynamic conditions.

Figure 2-6: Formation of scale in the pipe.

2.4.3 Hydrates

Gas hydrates are crystalline compounds with a snow-like consistency that occur when small gas molecules come into contact with water at or below a certain temperature. The hydrate formation temperature increases with increasing pressure. Therefore, the hydrate risk is greatest at higher pressures and lower temperatures. When hydrates form inside pipelines, they can form plugs which obstruct flow. In even worse scenarios, where the presence of a hydrate plug was undetected, pipeline depressurization has resulted in the plug being dislodged unexpectedly, resulting in serious injury and even fatalities. These are some of the reasons that hydrates are a serious flow assurance concern.

Figure 2-7 shows a typical gas hydrate curve which is very useful for subsea pipeline design and operations. On the left side of the curve is the hydrate formation region. When pressures and temperatures are in this region, hydrates will form from the water and gas molecules [16].

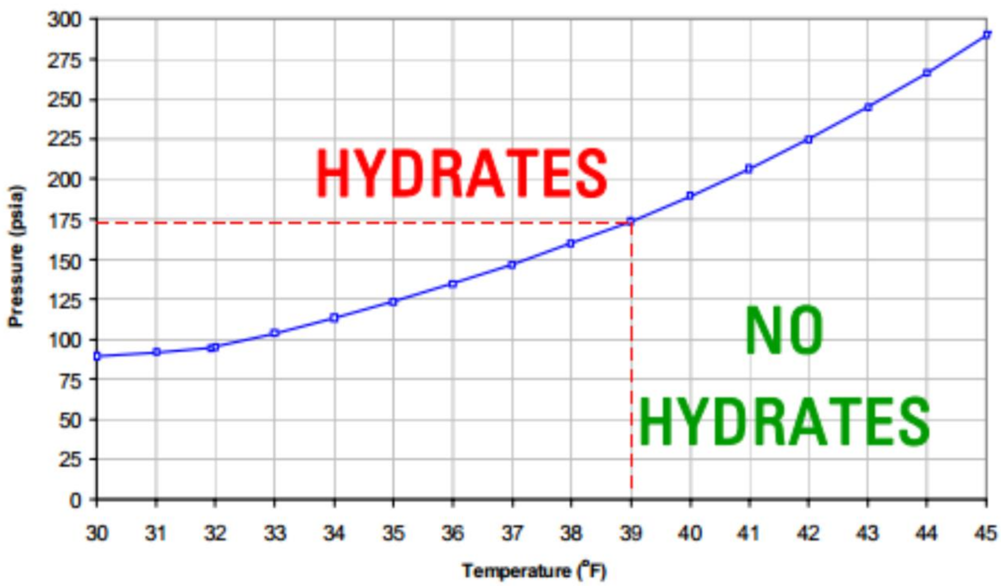

Figure 2-7: Hydrate Curve [16].

Figure 2-8: Hydrates

Many factors impact the hydrate curve including fluid composition, water salinity and the presence of hydrate inhibitors.

a) Hydrate mitigation strategies

Two common strategies to mitigate hydrate formation are thermal insulation and the injection of chemical inhibitors. Thermal insulation carries a higher up-front capital cost, whereas chemical inhibition carries a higher operational cost.

- **Thermal insulation**

The heat transfer between the fluid in the pipeline and the environment surrounding the pipeline is dependent on the temperature gradient and the thermal conductivity of the material between the two:

1) **Input U value:** This option allows the user to define an overall heat transfer coefficient (U value). The heat transfer rate per unit area is calculated based on the pipe outside diameter.
2) **Calculate U value:** This option computes the overall heat transfer coefficient based on the following parameters:
   - ✓ Pipe coatings: Thickness of each pipe coating & K (Thermal conductivity) of the material
   - ✓ Pipe material conductivity
   - ✓ Ambient fluid (Air or Water)
   - ✓ Ambient fluid velocity (The faster fluid flows over the pipe, the greater the heat loss)
   - ✓ Pipe burial depth
   - ✓ Ground conductivity (for flowlines only)

b) Chemical inhibitors

Thermodynamic inhibitors can be used to shift the hydrate line (to the left in the curve shown previously), thereby lowering the hydrate formation temperature and increasing the hydrate-free operating envelope. Examples of inhibitors include methanol and ethylene glycol. The effect of thermodynamic inhibitors on hydrate precipitation can be modeled.

Kinetic and anti-agglomerate inhibitors comprise a category of inhibitors known as Low Dosage Hydrate Inhibitors (LDHIs). These inhibitors do not lower the hydrate formation temperature; instead, they help prevent the nucleation and agglomeration of hydrates to avoid blockage formation [17].

2.4.4 The wax deposit

Wax deposition is a common problem, critical operational challenge and one of the major flow assurance issues in the oil industry worldwide, including both offshore and onshore oil fields. Wax deposition occurs when wax components in crude oil (alkanes with carbon numbers greater than 20) precipitate and deposit on the cold wall of the pipeline when the internal wall temperature falls below the onset temperature wax.

Figure 2-9: Wax deposition plugs in the wellbore on platform

2.4.5 Emulsions

Emulsion formation occurs when two immiscible liquids, such as water and oil, mix to form a continuous phase in which small droplets of the dispersed phase are evenly dispersed. In the context of the oil and gas industry, the formation of emulsions is a common phenomenon that can occur during crude oil production, transportation, or processing

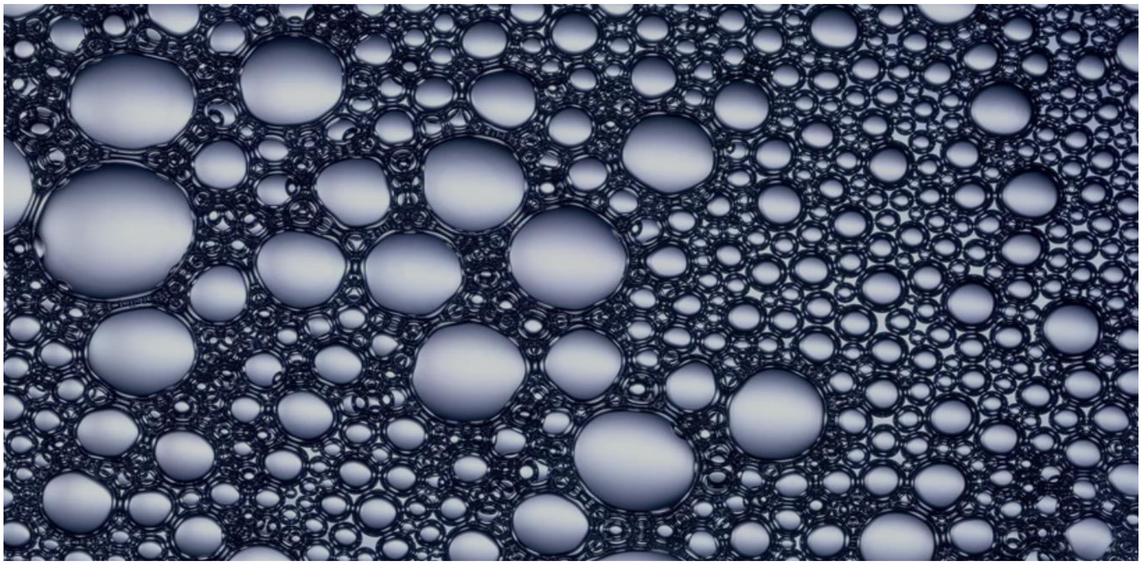

Figure 2-10: Photomicrograph of a water oil emulsion

2.5 Severe terrain and slugging

Slugging is an unstable, cyclical, two-phase phenomenon of gas/liquid spillage induced by pipeline topography. It occurs due to liquid accumulation and blockage at low points in undulated terrain, often in long and large diameter pipelines. Terrain and severe slugging pose serious problems for flow assurance, causing production disruptions, excessive vibration, and valve damage due to water hammer. This phenomenon is common in surface pipelines, corrugated horizontal wells, and extended reach wells, typically under low gas and liquid flow conditions. Severe slugging specifically occurs in pipelines with a slightly downward slope followed by an upward riser, common in offshore production.

Figure 2-11: Terrain slugging [16]

2.5 Permanent regime

Steady-state multiphase flow refers to a situation where flow properties such as velocities and levels of different phases remain stable and do not vary significantly over time. In this type of regime, flow characteristics, such as flow rates, pressures and temperatures. remain relatively constant rather than fluctuating significantly. This permanent regime is often used to model and analyze multiphase flows under stable operating conditions, as opposed to transient regimes where the flow parameters evolve dynamically. Understanding steady state is essential to effectively design and optimize production systems involving multiphase flows.

2.5.1 Software used PIPESIM

The PIPESIM steady-state multiphase flow simulator incorporates the three flow zones in its modeling: multiphase flow, heat transfer and fluid behavior. For over 30 years, the PIPESIM simulator has been continually improved not only by the latest science in these fields, but also the latest innovations in computing, and technologies from the oil and gas industry. The PIPESIM simulator includes advanced three-phase mechanistic models, rigorous heat transfer modeling and comprehensive PVI (Pressure Volume Temperature) modeling options. ESRI-supported GIS maps provide a true spatial representation of wells, equipment, and networks. Networks can be built either on GIS or automatically using a GIS format file. Rapid construction and analysis of well models is accomplished with internal interactive graphical well diagrams. The implementation of a new parallel network solver, which distributes the calculation load across all processors, also led to an acceleration of the simulation [14].

a) Applications

- ✓ Precise modeling of flows over the entire life cycle of a system.

b) Benefits

- ✓ Provides comprehensive and sophisticated sensitivity analyzes of the hydraulic system.
- ✓ Enables rapid construction of well models, with interactive graphical diagrams and existing models in its library

Figure 2-12 : Pipesim 2022.1 software

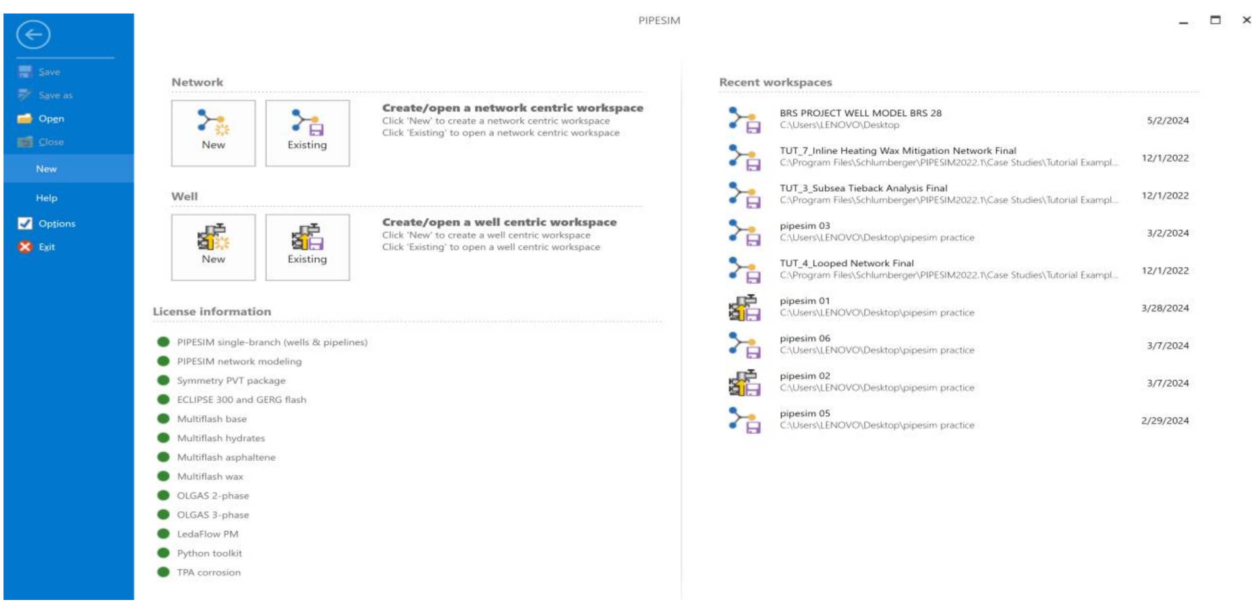

Figure 2-13: Pipesim home screen

c) Features

- ✓ GIS map to create networks and capture pipeline elevation profiles:
- ✓ View consolidated results, including results from multiple simulations;
- ✓ Customizable workspace layout, including entry and breakout panels for easier navigation, as well as a message center to improve workflow.

d) simulation feedback

- ✓ Parallel network solver to distribute computer processing for improvements significant performance;
- ✓ Continuous validation of the model;
- ✓ Creation of an automated network from a GIS format file;

e) System of units

The built-in unit's system allows you to select any variable and define the unit of measurement to use, Thus, the ability to use this feature to modify the system of units to match reports or data provided by a service company or simply customize the system of units to suit personal preferences [14].

f) Types of fluids

PIPESIM can model the following types of fluids:

- ✓ Gas
- ✓ Condensed gas.
- ✓ Liquid.
- ✓ Liquid and gas.
- ✓ Steam.

The fluid can be described by one of the following methods:

- ✓ Fully composition
- ✓ Black oil correlations.
- ✓ Steam tables

The fluid model used will depend on:

- ✓ Properties of fluids in the system.
- ✓ Flow rates and conditions at which fluid(s) enter and exit the system.
- ✓ Data available, etc. [20].

g) Flow correlation

Flow correlations are used to determine pressure loss and maintenance in the system.

Flow correlations are divided into the following section:

- ✓ Single phase
- ✓ Multiphasic - vertical
- ✓ Multiphasic – horizontal

A number of flow correlations have been proposed over the years. In addition to user-provided flow correlations, because user can create and add their own multiphase correlation in PIPESIM via user DLL function [20].

f) The different correlations

The application range of correlations depends on several factors such as: tubing diameter, oil density, GOR, and two-phase flow with or without water-cut.

g) The choice of correlation

For the choice of a best correlation suitable for a certain pipeline we choose the correlations where the application conditions are close to our case and then we will proceed in the following ways to determine the suitable correlation:

* Enter the pipeline data;

* Plot the pressure drop curve; in the pipeline depending on the length of the pipeline by the introduction of a gauge (pressure recorder)

* Plot the pressure drop curve in the pipeline as a function of the length of the pipeline for each correlation;

* The most appropriate correlation is the one which gives the pressure profile in the pipeline close to that measured;

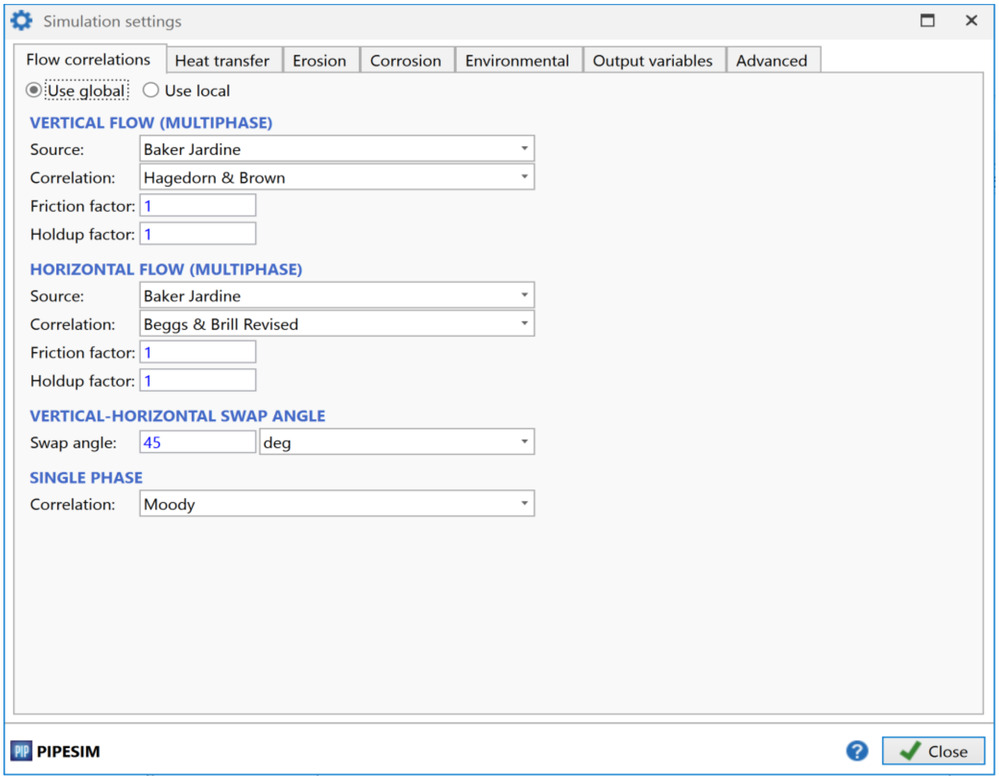

Figure 2-14: Simulation setting (calculation customization window)

2.6 Conclusion

Flow insurance aims to ensure that oil and gas continues to flow. To achieve this goal, flow assurance relies on multiphase flow analysis and the selection and use of production chemicals. Flow assurance engineers typically analyze the flow of oil and gas through wells, production lines, processing facilities and export pipelines. Complex networks of gathering lines feeding main flow lines exist in both onshore and offshore fields, and the analysis to optimize the routing of flows through such networks is equally complex. Software (such as PIPESIM and OLGA) was developed to facilitate and improve the studies carried out on these industrial piping systems.

Chapter 3:

Case study : Modeling, Simulation and Interpretation

3.1 Introduction

The production gathering facilities of the Bir Seba Field Development will include flowlines (linking wells to gathering stations) and trunklines to transport fluids from gathering stations to the Central Processing Facility (CPF). Hydraulic analyses have been performed on the GS systems to size the flowlines. The trunklines are already sized, as detailed in the steady-state flow assurance study report (12 inches).

Flowline sizing is based on a maximum liquid flow rate of 4,000 STB/d per well from a single gathering system at the start of field life, to determine if the pipeline design pressure of 45 barg (667 psia) is exceeded. The flow assurance study was limited to steady-state flow assurance using PIPESIM software.

This chapter explores multiphase flows and flow assurance in oil and gas pipelines using PIPESIM. The analysis was conducted in three steps. The first step involved creating the well model, and the second step involved introducing the fluid. The third step, select the well from Geographic Information System (GIS) map. Figure 3-1 shows the flowchart used in the current work.

3.2 Creating the well model

This process was carried out in several stages, as illustrated in Figure 3-1. In the initial stage, the following dimensions were specified: casing lengths, setting the measured depth (MD) to 1127.76 m, with an internal diameter (ID) of 150.368 mm, a wall thickness of 13.716 mm, and a roughness of 0.0254 mm. The second stage focused on determining the packer depth, set at an MD of 1095.756 meters. During the third stage, the ambient temperature was introduced, starting at 30 °C. At 1112.52 meters depth, the temperature increased to 50°C as shown in Figure 3-2. The fourth stage involved incorporating additional parameters and conditions, thereby contributing to a comprehensive analysis of the well's performance under varying conditions.

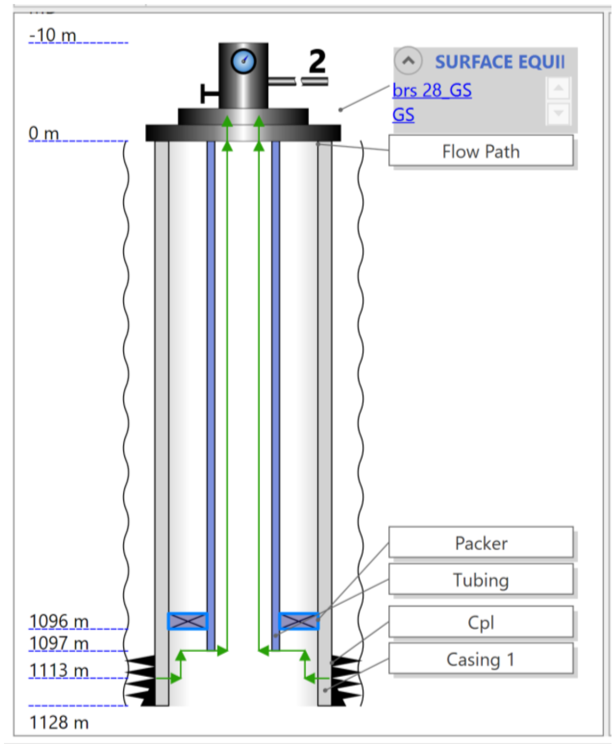

Figure 3-1: Well model

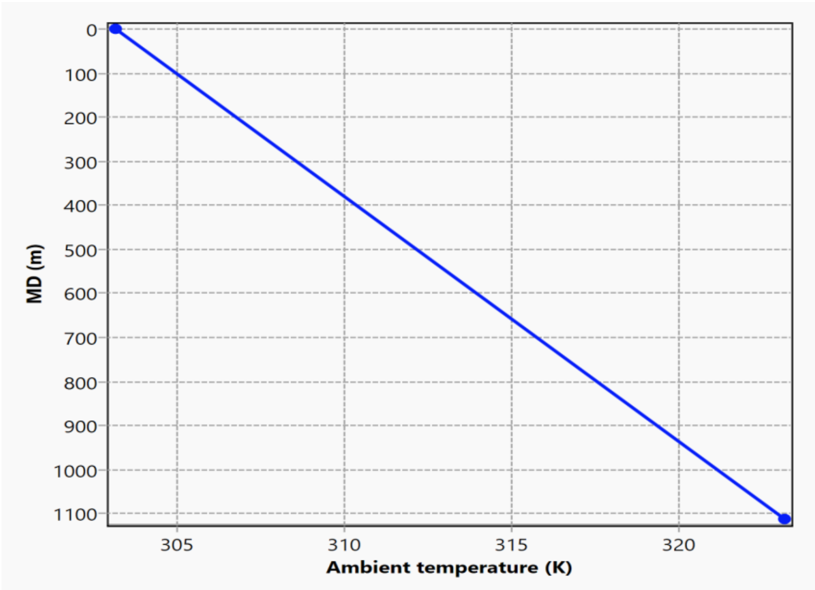

Figure 3-2: Downhole ambient temperature

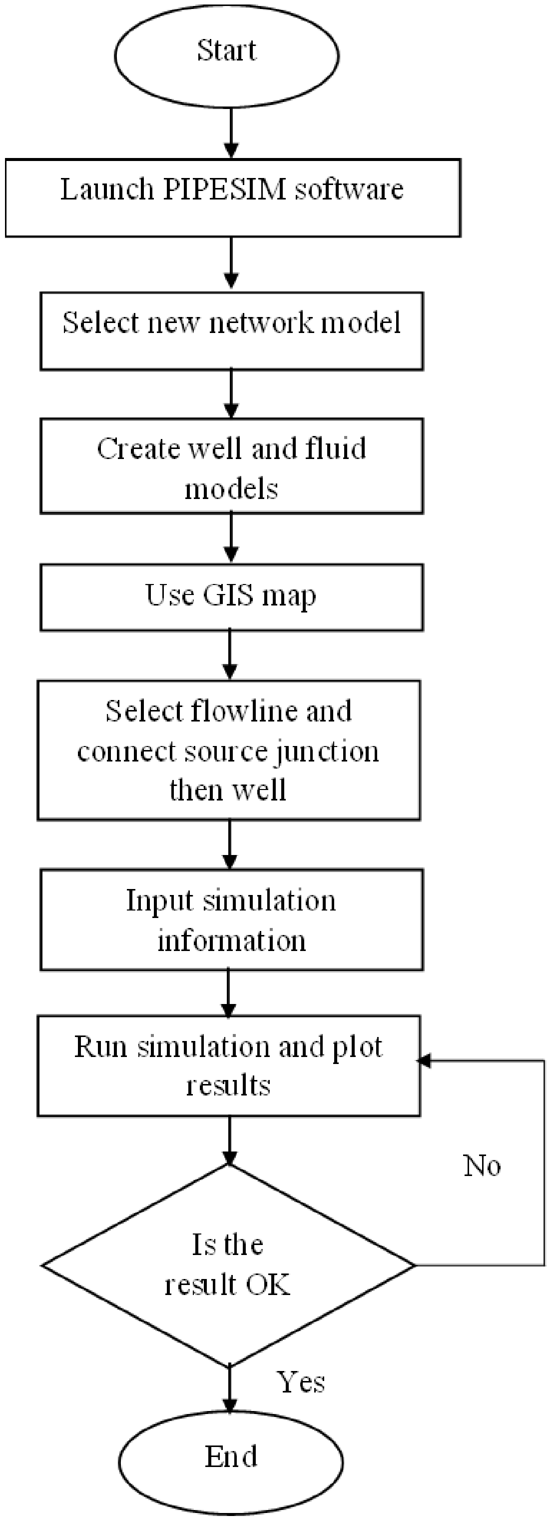

Figure 3-3: Simulation flowchart used in software for current case study.

3.3 Fluid modeling

Black oil fluids are modeled as three phases: oil, gas, and water. The proportions of each phase are defined under stock tank conditions by specifying the gas-to-oil ratio (GOR) and the water cut. Properties at pressures and temperatures other than those at stock tank conditions are determined using appropriate correlations. It is assumed that water remains in the liquid phase. The primary property for determining the phase behavior of hydrocarbons is the solution gas-to-oil ratio, which is used to calculate the amount of gas dissolved in the oil at a given pressure and temperature.

A black oil fluid model was created with a water cut of 33% and a gas-to-oil ratio (GOR) of 875 scf/stb, equivalent to 155.8441 sm^3/sm^3 as presented in Figure 3-4. We introduced this black oil into the completion of the created well of BRS 28 and BRS 30 as indicated in Figure 3-5.

PIPESIM offers full compositional fluid modeling as a more advanced alternative to black oil fluid modeling. In compositional fluid modeling, the individual components (see Table 3-1) that comprise the fluid are specified, and the fluid phase behavior is modeled using equations of state. Compositional fluid modeling is generally regarded as more accurate, especially for systems involving wet gas, condensate, and volatile oils. However, black oil modeling is more commonly used because detailed compositional data is less frequently available to production and reservoir engineers.

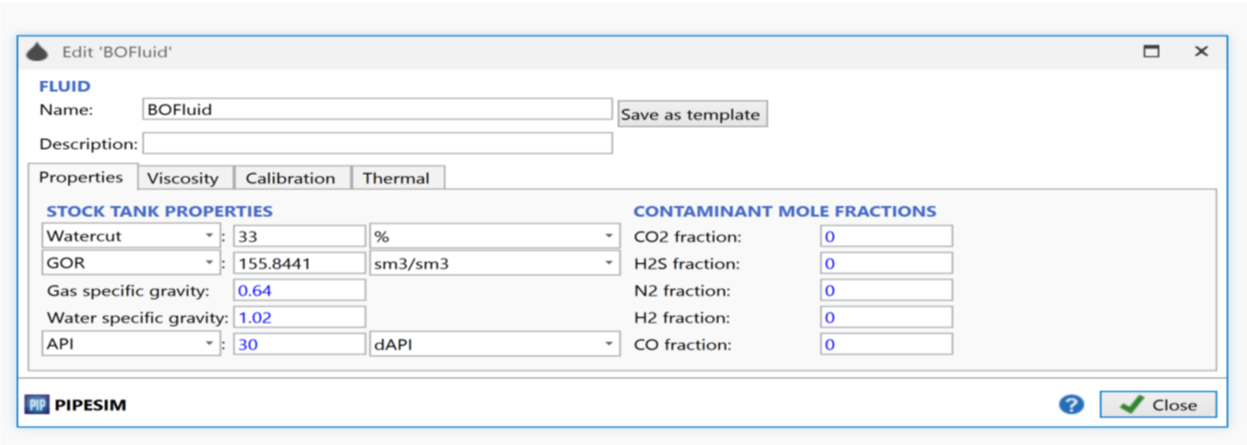

Figure 3-4: Creating a black oil liquid.

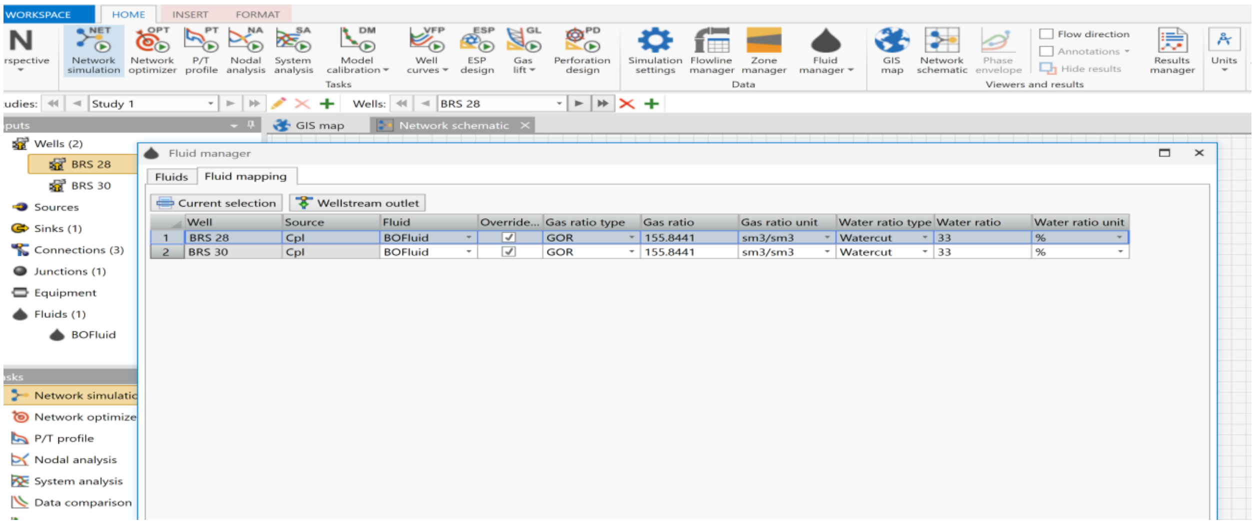

Figure 3-5: Fluid manager black oil.

Introducing liquid ingredients:

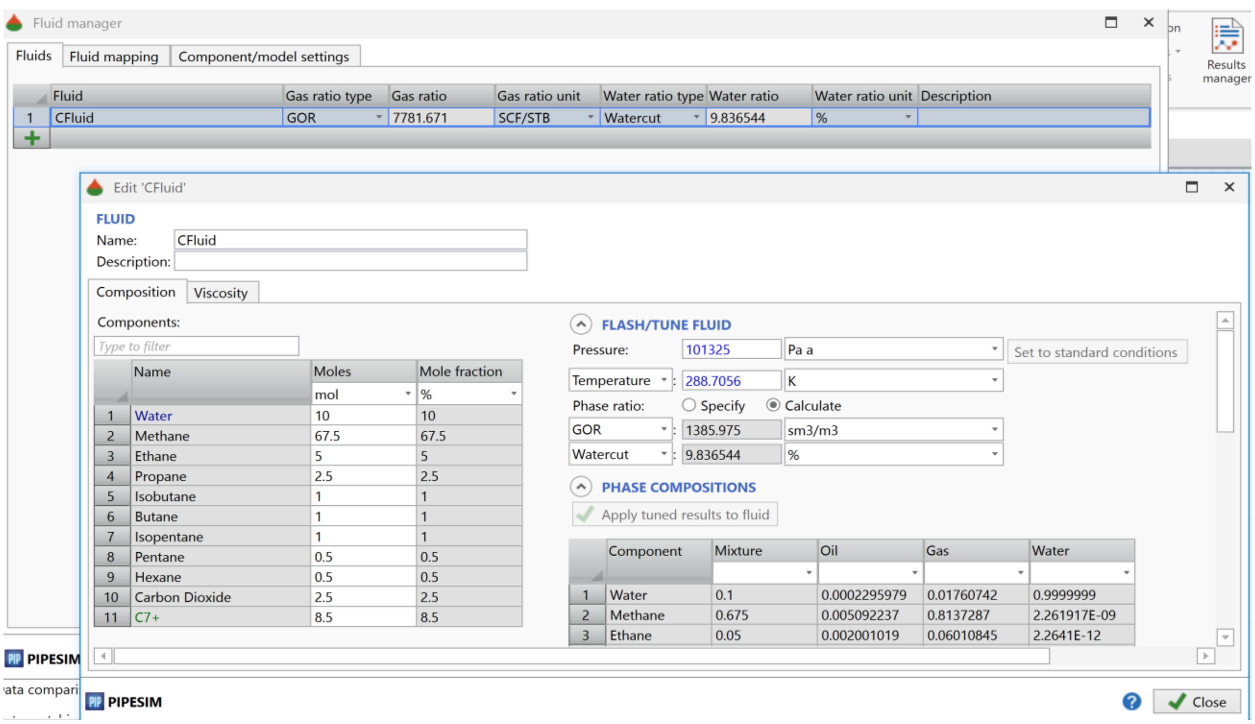

Figure 3-6: Mole fraction of model fluid component.

Table 3-1 : Physical and chemical characteristics for studied emulsion fluid. [give from Sonatrach]

Compound / Phy. prop.	H_2O	CH_4	C_2H_6	C_3H_8	C_4H_{10} (iso)	C_4H_{10} (neo)	C_5H_{12} (iso)	C_5H_{12} (neo)	C_6H_{14}	CO_2	C7+
Molecular Weight	18.01	16.04	30.07	44.09	58.12	58.12	72.14	72.14	86.17	44	115
Boiling point (K)	373.15	111.63	184.55	231.05	261.42	272.65	301.03	309.21	341.88	220	413..07
Specific Gravity	0.999	0.14	0.36	0.51	0.56	0.58	0.62	0.63	0.66	0.83	0.68
Critical temperature (K)	647.3	190.56	305.33	369.85	407.85	425.16	460.45	469.7	507.82	304.12	574.39
Critical pressure (bara)	221.2	45.99	48.71	42.47	36.4	37.96	33.77	33.66	30.18	73.77	20.28
Critical molar volume (m^3/mol)	$5.59 x 10^{-5}$	$9.86 x 10^{-5}$	0.0001	0.0002	0.0002	0.0002	0.0003	0.0003	0.0003	$9.41 x 10^{-5}$	0.0004
Critical viscosity (kg/(m.s))	$5.59 x 10^{-5}$	$9.86 x 10^{-5}$	0.0001	0.0002	0.0002	0.0002	0.0003	0.0003	0.0003	$9.41 x 10^{-5}$	0.0004
Density (kg/m^3)	997.93	145.75	365.71	514.89	561.05	582.54	622.99	628.789	661.42	834.88	681.63

3.4 Geographic Information System (GIS)

The high-resolution elevation data obtained from the GIS map layer provides more accurate calculations of pressure loss and liquid holdup profiles. This enhanced data accuracy helps better predict corrosion hotspots, identify pigging locations, and more effectively manage other pipeline maintenance and safety considerations.

In this section, a Geographic Information System (GIS) is used to capture, store, manipulate, analyze, manage, and present all types of geographical data. The GIS map layer enables the visualization of well networks and surface pipelines within their geographical context. On this map layer, equipment was added (Figure 3-7), and flowlines were digitized to capture their elevation data. The coordinates of well and central processing facility are illustrated in Table 3-2 and Table 3-4, respectively. Gathering station locations are presented in Table 3-3.

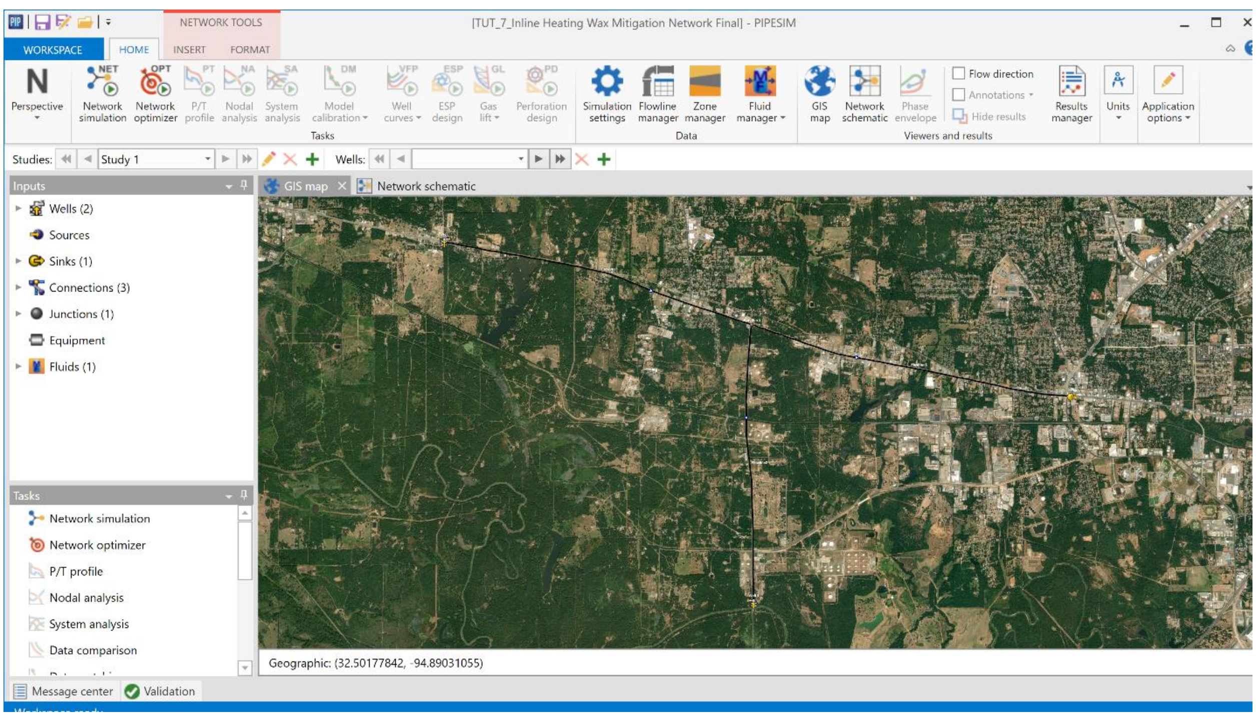

Figure 3-7: GIS map

Table 3-2: Well Coordinates

Well	Latitude (deg)	Longitude (deg)	Elevation (m)	Connected to GS	Flowline Length (km)
BRS 28	32.5966	6.64868	122.48	GS	6,850
BRS 30	32.5764	6.70106	126.71	GS	2,213

Table 3-3: Gathering Station Locations

Gathering station	Latitude (deg)	Longitude (deg)	Elevation (m)	Trunkline Length (Km)
GS	32.564112	6.694715	122.330002	4,7

Table 3-4: Central processing facility Coordinates

Central processing facility	Latitude (deg)	Longitude (deg)	Elevation (m)
CPF	32.5271	6.69673	131.4

3.5 Network and Flow line

The flow lines from BRS28 and BRS30 to the gathering station GS are illustrated in Figure 3-8 and Figure 3-9 respectively. These lines are critical for transporting fluids from the respective wellhead points to the central processing facility, ensuring efficient collection and processing of resources. Additionally, the trunk line from the gathering station to the Central Processing Facility (CPF) is also represented in Figure 3-10, completing the network that facilitates the transport of fluids for further processing and distribution.

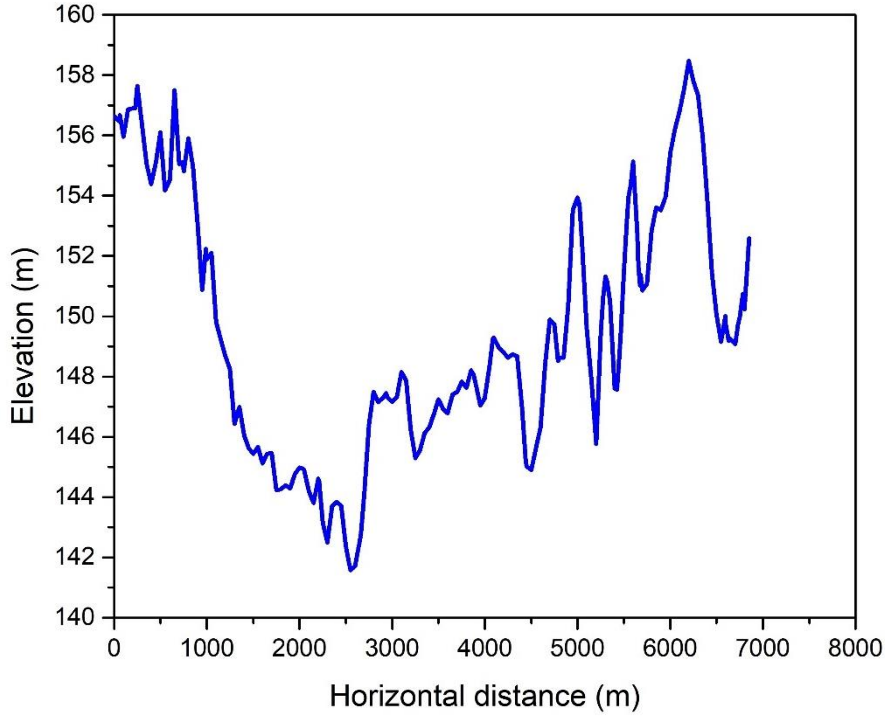

Figure 3-8: Variation of elevation as a function of horizontal distance BRS 28

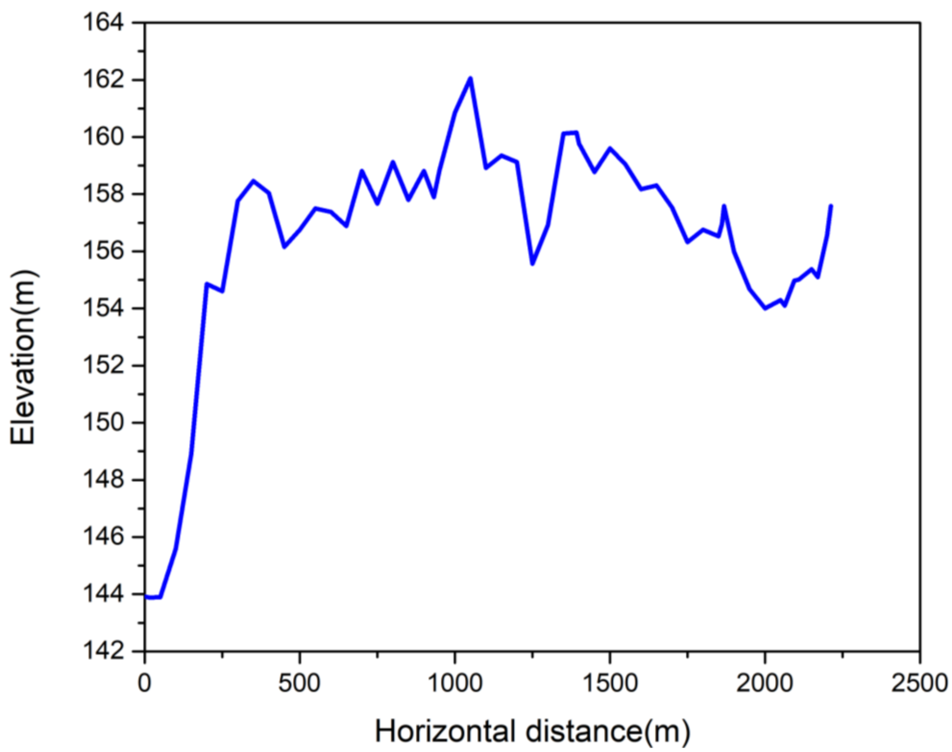

Figure 3-9: Variation of elevation as a function of horizontal distance BRS 30

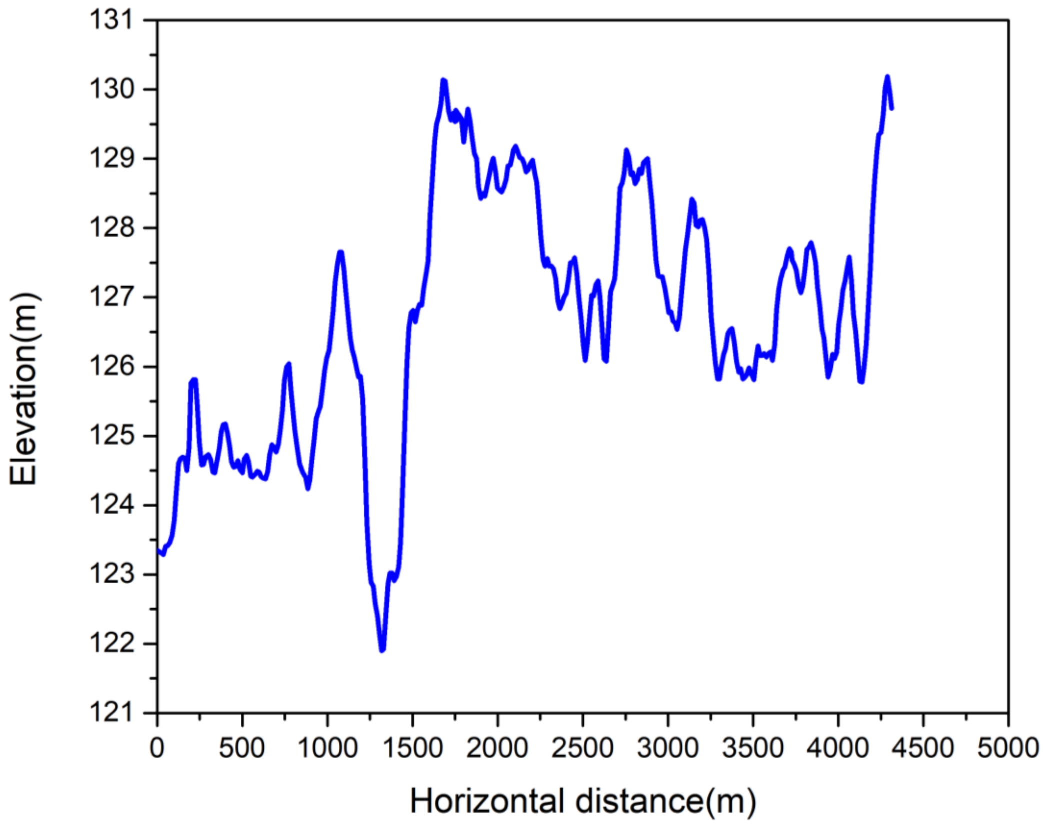

Figure 3-10: Variation of elevation as a function of horizontal distance (Trunk line)

3.6 Design criteria for modeling gathering systems

The detailed basis for this study can be found in Other relevant data and assumptions are as follows:

- 15 barg (233 psia) arrival pressure
- 45 barg (670 psia) design pressure of flowlines / trunklines
- 24 barg (360 psia) minimum FWHP
- Maximum FWHT 50°C (downstream of choke)
- Minimum FWHT 30°C (downstream of choke)
- Maximum ambient soil temperature 55°C
- Minimum ambient soil temperature -5°C
- Soil thermal conductivity = 2.1 W/m/k
- Carbon steel pipe thermal conductivity = 45 W/m/k

- FBE coating thermal conductivity = 0.22 W/m/k
- Maximum flow per well is 4000 STB/d with 1.2 MMscfd gas lift.
- Water cut is calculated from PROCESS & UTILITY DESIGN BASIS as reference: 2000bwpd/6000bopd= 0,33=33%.
- 33% water cut is chosen for existing wells streams from PHASE I (as for flow assurance steady state report of PHASE I).

[Give from Sonatrach]

Table 3-5: Oil modeling data

	MAX	**Normal**	**Minimum**
Liquid (excluding DW)	4,000 BOPD	2,500 BOPD	250 BOPD
Liquid (including DW)	4,157 BOPD	2,657 BOPD	407 BOPD
Gas (excluding gas lift)	3,500 Mscfd	1,275 Mscfd	213 Mscfd
Gas (including gas lift)	5,000 Mscfd	2,475 Mscfd	1,413 Mscfd
Noted:			
Oil	*4,000 BOPD*	*2,500 BOPD*	*250 BOPD*
Water (excluding DW)	*2,000 BWPD*	*600 BWPD*	*0 BWPD*
Water (including DW)	*2,157 BWPD*	*757 BWPD*	*157 BWPD*

Note: GOR=Gas *(Mscfd)* ***/ Liquid*** *(BOPD)****, Water cut= Water*** *(BWPD)* ***/ Water*** *(BWPD)****+ Liquid*** *(BOPD)*

3.7 Methodology

Steady-state pressure, temperature, and liquid hold-up profiles were determined through simulation. The steady-state single and multi-phase flow simulator PIPESIM (Version 2022.1) was used to model the network system. The OLGA-S 3-phase correlation is employed to calculate pressure drops and liquid hold-up. Line sizing is conducted based on evaluating the worst-case pressure drop in the system.

The inlet pressure to the CPF is fixed at 15 barg (233 psia) for all flow conditions. Each flowline was modeled from completion to gathering station, with a maximum flowing wellhead temperature of 49.42°C downstream of the choke. Initial pipeline sizing is based on a maximum liquid flow rate of 4000 STB/d per well from a single gathering system at the start of field life, to determine if the pipeline design pressure of 45 barg (667 psia) is exceeded. The maximum flowline inlet pressure (downstream of the choke) must be less than the available FWHP of 25 barg (360 psia) for each well. The results will lead to recommendations for the line size of the gathering system. For all production scenarios, erosion velocity limits must not be exceeded. The erosional velocity is based on an erosion constant of 100 for ongoing services, which is typical for a carbon steel pipeline with some solids present.

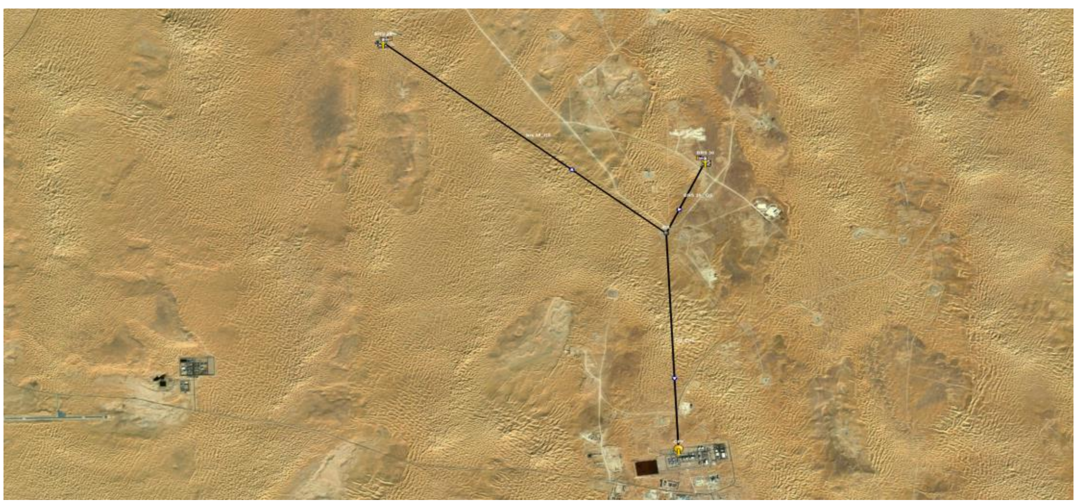

Figure 3-11: PIPESIM Model for sizing the phase 2 BRS NETWORK on GIS MAP Flowlines / Trunklines to CPF

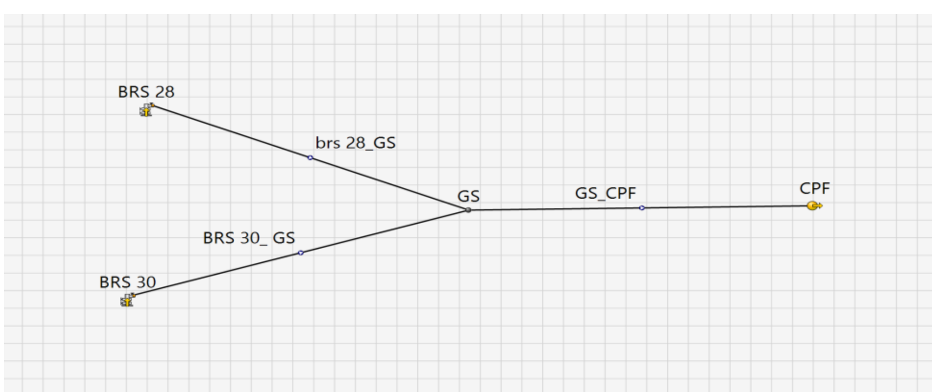

Figure 3-12: PIPESIM Model for sizing the phase2 BRS NETWORK on NETWORK SCHEMATIC Flowlines / Trunklines to CPF

3.8 Steady state operation

The flow behavior of a gas and liquid mixture in a pipeline is more complex than that in single-phase lines. The difference in velocities between the two phases results in slippage between the liquid and gas phases. Variations in pipeline profiles due to topography cause liquids to accumulate at low points (liquid hold-up) and gas pockets at high points. The reduction in flow cross-sectional area in a gas line, due to partial blockage by the liquid phase, invariably leads to additional pressure losses in the pipeline. Furthermore, the intermittent exit of liquid slugs would require additional liquid handling procedures and capacity at the CPF.

3.8.1 Erosional velocity

The liquid and gas mixture velocity is kept below the erosional velocity recommended by API RP 14E. The maximum production velocity is written by the following empirical equation:

$$Ve = \frac{c}{\sqrt{\rho_m}} \quad \textbf{(3-1)}$$

The condition for allowance velocity is defined as:

$$V_{a\max} < V_e \quad \textbf{(3-2)}$$

Where

Ve =The maximum allowable erosional velocity, m/s

ρ_m =The mixture density of fluid in kg/m^3 at flowing conditions of temperature and pressure

c = constant generally known as the c factor; a value of 100 ft/s(lbs/ft3)1/2 is used in this analysis asrecommended for pipelines in continuous service with some solids present in the well streams.

Multiphase pressure losses is defined by the following equation :

$$\left[\frac{\Delta p}{\Delta L}\right]_{Total} = \underbrace{\left[\frac{\Delta p}{\Delta L}\right]_{Z}}_{\substack{elevation \\ \downarrow \\ \rho g \sin\theta}} + \underbrace{\left[\frac{\Delta p}{\Delta L}\right]}_{\substack{friction \\ \downarrow \\ f\frac{\rho v^2}{2D}}} + \underbrace{\left[\frac{\Delta p}{\Delta L}\right]_{a}}_{\substack{acceleration \\ \downarrow \\ \rho v\frac{\Delta v}{\Delta L}}} \quad \textbf{(3-3)}$$

3.8.2 Heat transfer (conduction/convection):

The calculated heat transfer coefficient is made up of four parts:

- ✓ internal fluid film
- ✓ Wax (if present)
- ✓ Pipe wall and surrounding layers
- ✓ External ambient fluid film/ground

The resulting rate of heat flux is given by:

$$Q_{segment} = \left(\frac{1}{h_{internal}} + \frac{1}{h_{wax}} + \frac{1}{h_{pipe\&layers}} + \frac{1}{h_{external}}\right)^{-1} * A_{segment} * \left(T_{segment-average} - T_{ambient}\right) \quad \textbf{(3-4)}$$

3.9 Results and discussion

3.9.1 Line Sizing – 4000 STB/d per Well (Summer case)

The flowline size is based on a maximum production of 4000 STB/d per well and a maximum ambient temperature of 55°C to determine if the flowing pressures exceed 45 barg (667 psia) in the gathering system. The existing trunkline sizes are 12 inches in diameter, as determined from the PHASE 1 steady-state flow assurance report.

The simulation findings, after arbitrarily selecting a flowline size of 6 inches as recommended, alongside the existing 12-inch trunkline size, indicate that the combination of 6 inches for the flowline and 12 inches for the trunkline is acceptable. The flowing pressures for this line size are below the design pressure of 45 barg (667 psia), and the erosion velocity limit is not exceeded (i.e., no erosion velocity issues).

For a 6-inch flowline and 12-inch trunkline, the maximum pressure downstream in the system for BRS28 and BRS30 is 24.46794 bara and 20.54979 bara, respectively. This is below the available FWHP of 25 bara (360 psia) and represents a suitable line size configuration for the gathering system.

Table 3-6: Line Size Combination

Line size combination	
Flowline	Trunkline
6 inch	**12 inch**

Table 3-7: Line Sizing Results for tubing 2.259 in inside diameter

Gathering station	**GS**	
New Wells connected to Gathering station	**BRS28**	**BRS 30**
Flow rate per new well	4000	4000
Ambient T(°C)	55	55
maximum pressure(bara)	24.46	20.54
Maximum erosion	2.19	2.39
Fluid mean velocity (m/s)	15.45	16.99

Arrival Temperature to CPF is 50.22°C. The maximum erosion values at BRS28 and BRS30 are 2.19 and 2.39, respectively. The erosion issue is located in the tubing section of both wells, due to the high velocity of the fluid flowing through the tubing section with an inside diameter of 2.259 inches.

To address the erosion problem, a sensitivity analysis on tubing size was conducted by increasing the diameter to 4 inches. The results are shown in the table below.

Table 3-8: Line Sizing Results for tubing 4in inside diameter

Gathering station	**GS**	
New Wells connected to Gathering station	**BRS28**	**BRS 30**

Flow rate per new well	4000	4000
Ambient T(°C)	55	55
maximum pressure(bara)	21.13	19.15
Maximum erosion	0.51	0.53
Fluid mean velocity (m/s)	4.93	5.42

Arrival temperature at the CPF is 49.09°C. According to the results, the recommended sizes for the tubing and flowline are 4 inches and 6 inches, respectively.

3.9.2 Corrosion assessment

The De Waard Model predicts the corrosion rate of carbon steel in the presence of water and CO_2. This model was primarily developed for use in predicting corrosion rates in pipelines where CO_2 is present in the vapor phase. It has not been validated for high-pressure conditions where CO_2 is entirely in the liquid phase. The corrosion rate is calculated as a function of:

- Temperature
- Pressure
- Mol% CO_2
- Wt% Glycol (Multiflash, Symmetry, and ScaleChem only)
- Liquid velocity
- Pipe Diameter
- pH

$$V_{cor} = \frac{C_c F_s F_G}{\left[\frac{1}{V_r} + \frac{1}{V_m}\right]} \tag{3-5}$$

where :

V_{cor} = Corrosion rate (mm/yr)

C_c = Multiplier to account for inhibitor efficiency or to match field data

F_s =scaling factor to account for degree of coverage by protective scale

F_G = scaling factor to account for glycol reduction effect (if present)

V_r = Highest possible reaction rate

V_m = Mass transfer rate (highest) of the corrosive species

The model considers both the flow-independent kinetics of the corrosion reaction and the flow-dependent mass transfer of dissolved CO_2 using a resistance model. Additionally, it accounts for the effects of protective scale at high temperatures and glycol inhibition. Figure 3-13 shows the upper limits of the corrosion risk index. The results demonstrate that the corrosion risk is high, particularly in the tubing section of BRS 28. A corrosion inhibitor, such as glycol, is required to provide better protection for the pipelines. Maximum corrosion rate is 0.2833531mm/a.

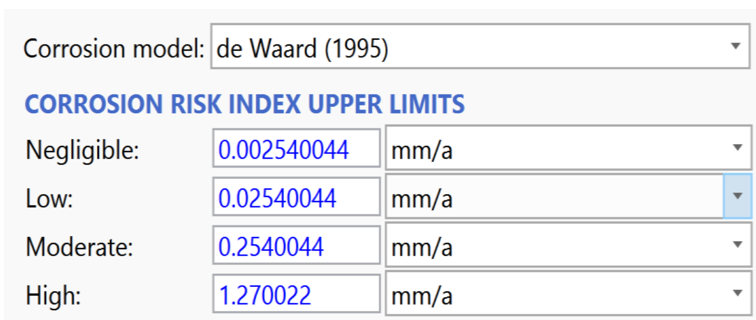

Figure 3-13: corrosion risk index upper limits

3.9.3 WAX (Winter case)

Waxes are complex mixtures of solid hydrocarbons that precipitate (solidify) from crude oils when the temperature drops below the critical wax deposition temperature. They are primarily composed of normal paraffins (n-paraffins), isoparaffins, and naphthenes, if present.

Asphaltenes are defined as the fraction of crude oil that is insoluble in n-alkanes (such as n-heptane or n-pentane) but soluble in aromatic solvents like benzene and toluene. These are extremely complex mixtures whose molecular structure is challenging to determine, as the molecules tend to aggregate in solution. Asphaltenes do not have a specific chemical formula but are generally composed of large aromatic rings containing carbon, hydrogen, sulfur, oxygen, and nitrogen.

Wax deposition may become an issue under extreme winter conditions in small bore and stagnant pipelines. Injection of wax inhibitors may be necessary at appropriate locations. Wax Appearance Temperature: 8°C.

3.9.4 Hydrate study

To better represent the worst-case scenario for hydrate formation, the flow rate has been set to 250 STB/d per well (as longer fluid flow results in greater heat loss), which represents the minimum production rate. Additionally, the ambient temperature has been lowered to -5°C to simulate cold meteorological conditions. The condition for hydrate formation is $(T_{hyd}-T_{fluid})>0$. In addition, low temperature and high pressure are the main reasons for hydrate problem.

Table 3-9: Line Sizing Results for tubing 4 inch and 6 inch flowlines

Gathering station	GS	
New Wells connected to Gathering station	BRS28	BRS 30
Flow rate per new well	250	250
Ambient Temperature (°C)	-5	-5
Maximum pressure (bara)	24.58	22.35
Hydrate sub-cooling delta temperature	11.59	11.08

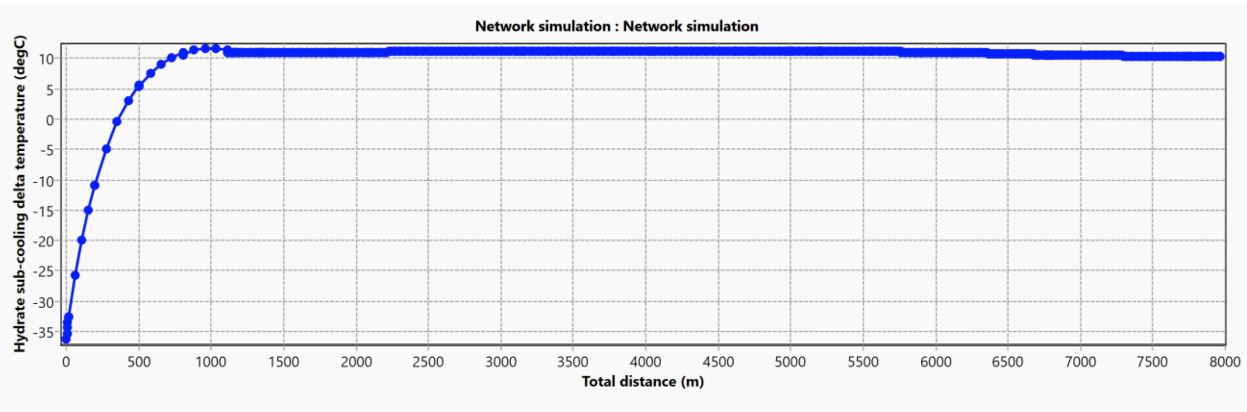

Figure 3-14: variation of hydrate sub-cooling delta temperature as a function of total distance BRS 28-GS.

Table 3-10 indicates that hydrate formation occurs at a distance of 426.56 meters from the completion in the tubing section of the BRS28 well.

Table 3-10: Variation of hydrate sub-cooling delta temperature with total distance BRS 28-GS

Total distance (m)	15.24	198.12	350.52	426.56	1036.16	3153.07	7964.84
Hydrate sub-cooling Delta T (°C)	-32.59	-10.93	-0.45	2.96	11.59	11.21	10.25

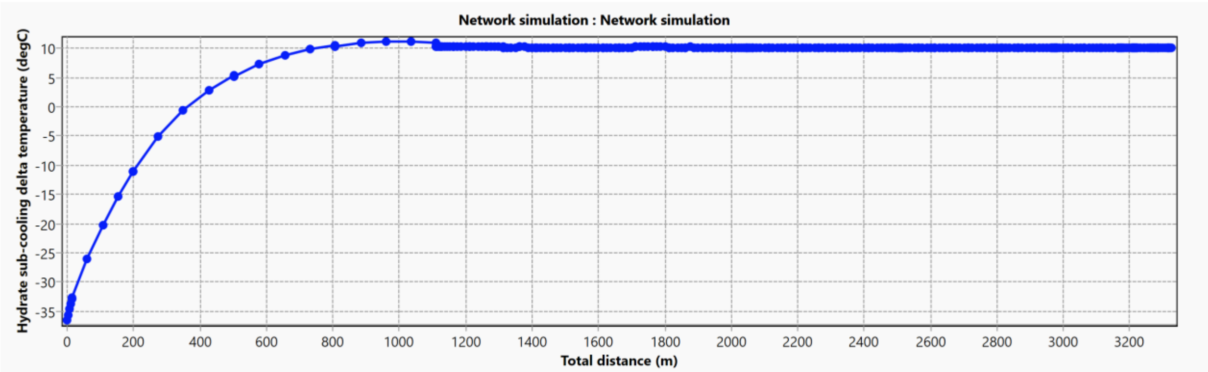

Figure 3-15: Variation of hydrate sub-cooling delta temperature as a function of total distance BRS 30-GS

The table indicates that the hydrate formation is encountered at a distance of 426.56 m from completion in the tubing section of BRS30 well (same as BRS 28).

Table 3-11: Variation in hydrate sub-cooling delta temperature with total distance BRS 30-GS

Total distance (m)	15.24	198.12	350.52	426.56	960.12	2045	3326.5
Hydrate sub-cooling Delta T (°C)	-32.83	-11.19	-0.72	2.68	11.08	10.11	9.95

Table 3-12: Line Sizing Results for trunkline 12 inch

Gathering station	GS
Flow rate per Gathering station (STB/d)	500
Ambient Temperature (°C)	-5
Maximum pressure (bara)	19.36
Hydrate sub-cooling delta temperature	10.10

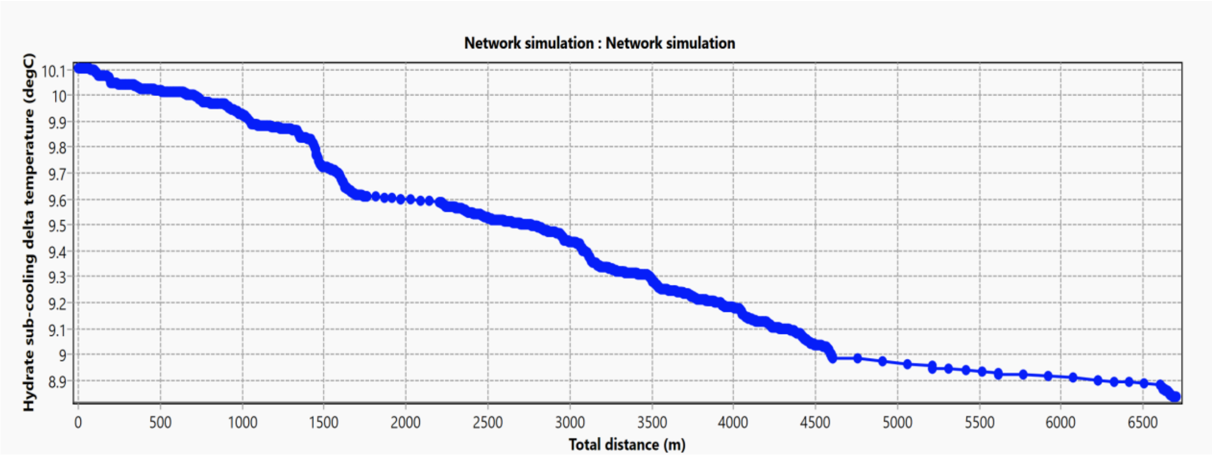

Figure 3-16: Variation of hydrate sub-cooling delta temperature as a function of total distance GS-CPF.

Table 3-13: Variation in hydrate sub-cooling delta temperature with total distance GS-CPF

Total distance (m)	0	27.78	37.13	2410.48	3995.79	4016.62	6704.16
Hydrate sub-cooling Delta T (°C)	10.103	10.104	10.104	9.54	9.18	9.17	8.83

$(T_{hyd}-T_{fluid})>0$: hydrate sub-cooling delta temperature has to be negative along the trunkline.

To overcome the hydrate problem, we add the injector at depth 778 m in both wells as shown in Figure 3-18. We inject an amount of ethanol estimated at 10 sm^3/d. The results are shown in Figure 3-17.

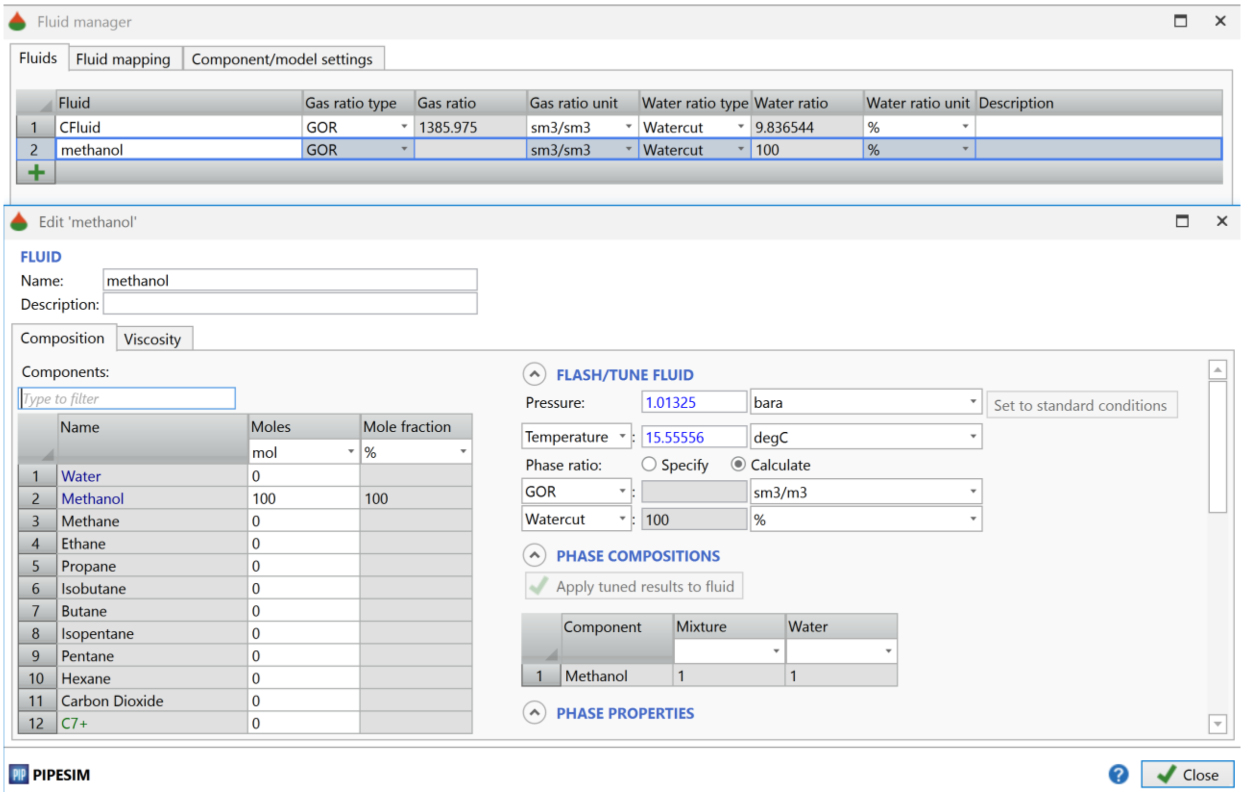

Figure 3-17: created an injection model (Methanol).

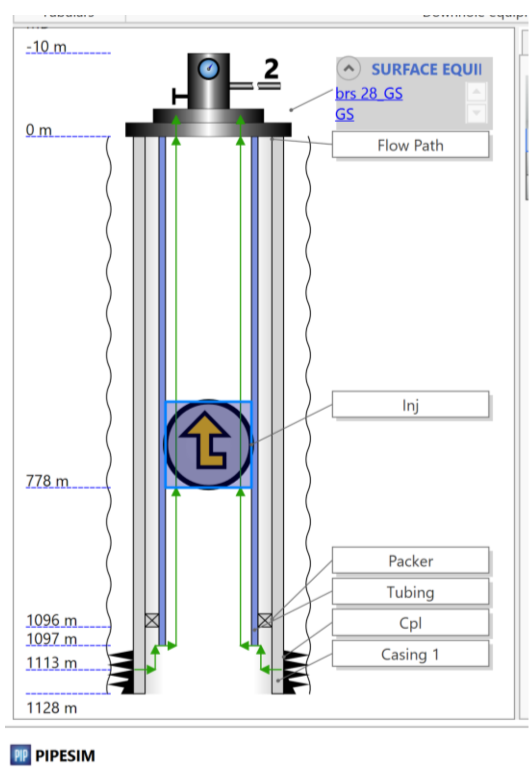

Figure 3-18: Injection depth 1095.756 m at T=20°C

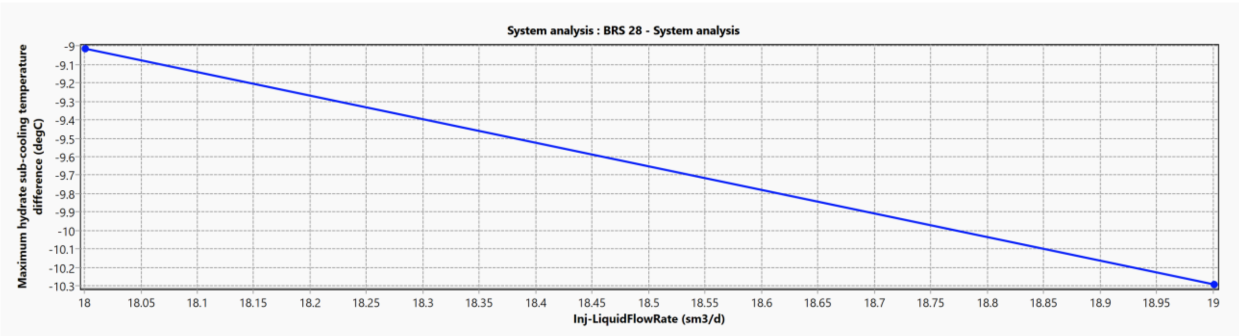

Figure 3-19: Variation of maximum hydrate sub-cooling delta temperature as a function of injection liquid flow rate.

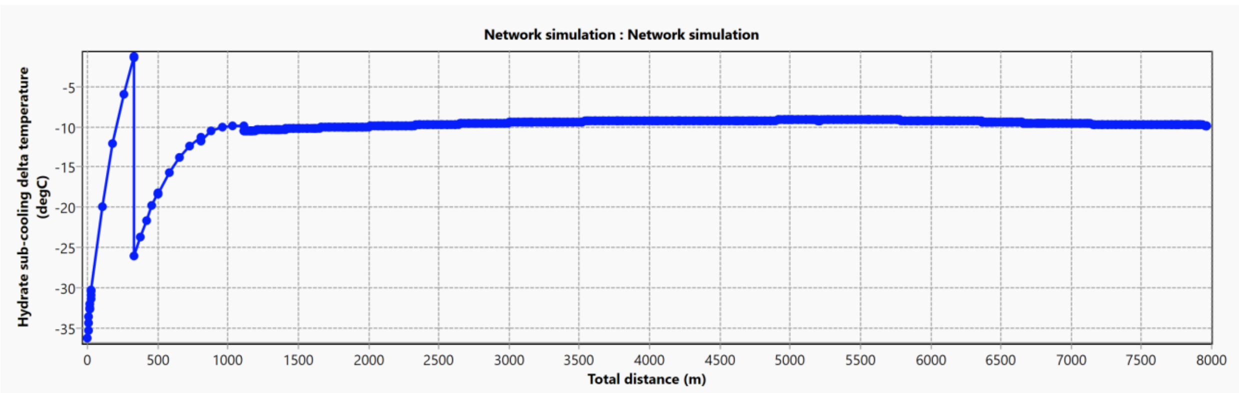

Figure 3-20: Variation of hydrate sub-cooling delta temperature as a function of total distance BRS 28-GS.

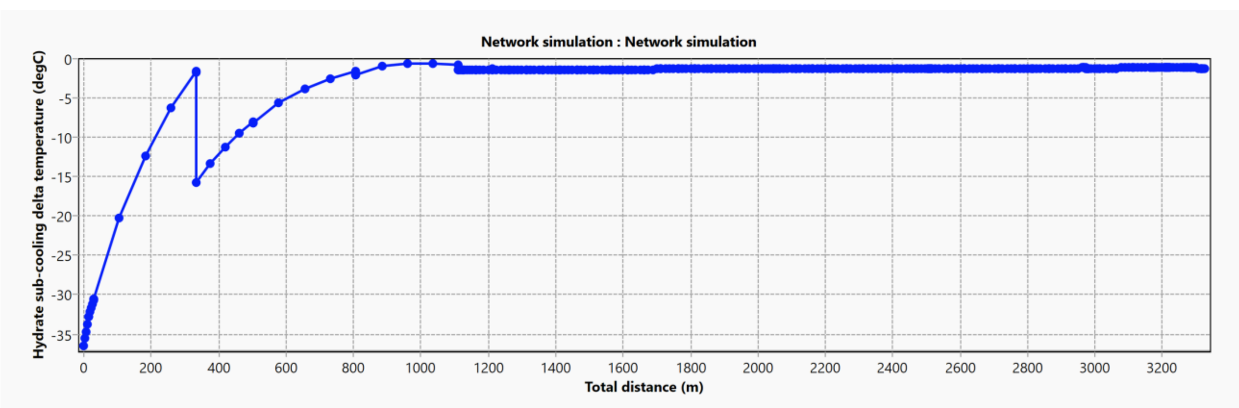

Figure 3-21: Variation of hydrate sub-cooling delta temperature as a function of total distance BRS 30-GS.

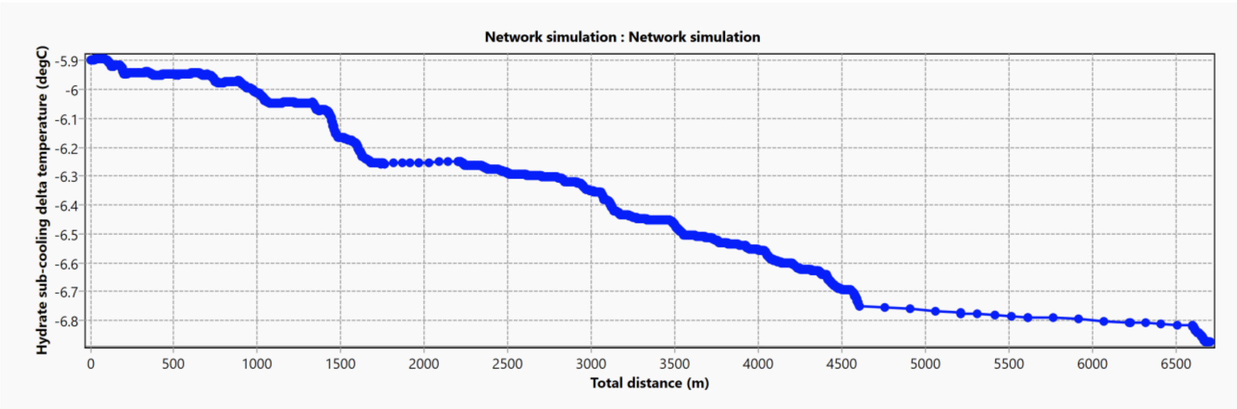

Figure 3-22: Variation of hydrate sub-cooling delta temperature as a function of total distance GS-CPF.

After injecting a hydrate inhibitor, the hydrate sub-cooling delta temperature becomes negative, indicating that T_{hyd} - T_{fluid} is less than zero. The system is now free from hydrate formation.

3.10 Conclusion

In this chapter, the main concepts of the flow assurance study are discussed. The sizing of lines to transport fluids from reservoirs to central treatment facilities is conducted according to design criteria and philosophies. Our study of flow assurance was limited to the steady state.

The modeling steps using the PIPESIM software, a powerful tool for simulations and analyses, were briefly explained. Meteorological and geographical conditions of the site must be accounted for, and the choice of correlations should be made judiciously to ensure accurate calculations. Modeling fluid behavior and selecting the appropriate equation of state are crucial for accurately describing the variations in pressure, volume, and temperature under different conditions.

Data related to wells, reservoirs, and pipelines must be provided, including well depth, pipeline elevations and lengths, material thermal properties, burial depth, and soil data. Once the starting conditions, known as inputs (such as well production data), and the arrival data (such as the pressure at the CPF processing center) have been established, the simulation is initiated. The results are displayed and must be interpreted correctly.

An overview of various problems encountered during the transport of hydrocarbons by pipeline—namely, erosion, corrosion, and the phenomena of deposition, hydrate, and wax formation—was the focus of this project. These issues are essential to consider in the design and conception of the main components of the oil and gas gathering system.

Sizing criteria, such as verification of wellhead pressures and the erosion speed ratio, as well as the limit speeds that should not be exceeded, were examined. These led to the choice of the optimal diameter to ensure the required production. The hydrate phenomenon, which is quite common during production in extreme weather conditions, is a critical case to monitor in flow assurance studies.

Conclusions and perspectives

Conclusions and perspectives

This study allowed us to explore the main aspects of flow assurance under steady-state conditions, including the optimal sizing of the lines connecting the wells to the central processing facility. The flow assurance study also provided insights into the reservoir, which is the source of production, and the potential for routing this production to central processing facilities.

The main results obtained from this study are as follows:

- ✓ The flowline size is based on a maximum production of 4000 STB/d per well and a maximum ambient temperature of 55°C to ensure that the flowing pressures do not exceed 45 barg (667 psia) in the gathering system.
- ✓ The existing trunkline size is 12 inches in diameter, as determined in the PHASE 1 steady-state flow assurance report.
- ✓ Simulation findings, with an arbitrarily chosen flowline size of 6 inches, alongside the 12-inch trunkline size, confirm that this configuration is acceptable. The flowing pressures remain below the design pressure of 45 barg (667 psia), and the erosion velocity limit is not exceeded.
- ✓ For a 6-inch flowline and 12-inch trunkline, the maximum pressures downstream in the system for BRS28 and BRS30 are 24.46794 bara and 20.54979 bara, respectively, which are below the available FWHP of 25 bara (360 psia), indicating a suitable line size configuration for the gathering system.
- ✓ The arrival temperature at the CPF is 42.13°C. The maximum erosion values at BRS28 and BRS30 are 2.19 and 2.39 mm/a, respectively, primarily due to the high velocity of the fluid in the tubing section with an inside diameter of 2.259 inches.
- ✓ A sensitivity analysis conducted by increasing the tubing diameter to 4 inches addresses the erosion issue.
- ✓ The results indicate a high corrosion risk, particularly in the tubing section of BRS 28. The maximum corrosion rate observed is 0.2833531 mm/a.

Conclusions and perspectives

- ✓ A corrosion inhibitor, such as glycol, is necessary to provide better protection for the pipelines.
- ✓ Wax deposition may pose problems under extreme winter conditions in small bore and stagnant pipelines. The Wax Appearance Temperature is 8°C.
- ✓ Injection of wax inhibitors may be required at appropriate locations to manage wax issues effectively.

To better represent the worst-case scenario for hydrate formation, the flow rate has been set to 250 STB/d per well, as longer fluid flow results in greater heat loss, representing the minimum production rate. Additionally, the ambient temperature has been lowered to -5°C to simulate cold meteorological conditions.

Hydrate formation occurs at a distance of 426.56 meters from the completion in the tubing section of the BRS28 well. The table also indicates that hydrate formation is encountered at the same distance in the tubing section of the BRS30 well. After injecting a hydrate inhibitor, the hydrate sub-cooling delta temperature becomes negative, indicating that T_{hyd} - T_{fluid} is less than zero. This adjustment has rendered the system free from hydrate formation.

These findings underscore the importance of considering multiple factors in the design and operation of the gathering system to mitigate risks related to erosion, corrosion wax deposition, and hydrate problem.

As perspective, the corrosion issue and wax deposition can be investigated in the flow of pipeline transport. In addition, fire and cracks are considered serious problems which need to be eliminated. Furthermore, prediction these problems are a challenge for engineers in order to maintain the service flow and production. Limit pressure according to the international codes must be applied and studied.

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