Politecnico di Torino

Corso di Laurea Magistrale in Georesource and Geoenergy Engineering

A.a. 2024/2025

Sessione di Laurea July 2025

Technical Feasibility Study of Cold Flow Using a Transient Multiphase Pipe Flow Simulator

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ABSTRACT

Growing energy demand is pushing oil and gas recovery into challenging subsea environments. A primary flow assurance challenge for these operations, particularly for the long-distance tie-back developments that represent the future of the industry, is the formation of gas hydrates. These crystalline particles form under the high-pressure and low-temperature conditions found in pipelines, creating a significant risk of blockage, especially in cold subsea environments like the Norwegian Continental Shelf. This issue must be addressed as the industry moves toward more sustainable methods that reduce the energy consumption and emissions from offshore production.

In this study, the application of Cold flow technology was evaluated as an energy-efficient flow assurance method for controlling the hydrate formation in offshore hydrocarbon production systems. Traditional methods for hydrate prevention, such as electrical heating, direct insulation, or the use of chemical inhibitors, often lead to high energy consumption, environmental issues and operational complexity—especially in deep water and long tieback developments. In contrast, Cold Flow technology adopts an alternative strategy by allowing the controlled formation of hydrate particles within the produced flow, while simultaneously implementing techniques to prevent their agglomeration and subsequent pipeline blockage. This is achieved through a controlled cooling process, whereby the multiphase mixture is brought into thermal equilibrium with the surrounding seawater temperature, in combination with a seeding technique that facilitates the dispersion of hydrate particles in a stable flow regime.

To assess the performance of this method under real field conditions, a comprehensive simulation model was developed using the commercial advanced transient multiphase flow simulator LedaFlow. The model includes a detailed transport system from the wellhead manifold to the production platform, incorporating essential elements such as boosting pumps, insulation, heating systems to manage pressure and thermal losses. Two field development concepts—Floating Production, Storage and Offloading (FPSO) and subsea tieback—were investigated under two enhanced oil recovery (EOR) scenarios: gas injection and water injection. The simulations accounted for variations in production flow rate, gas-oil ratio (GOR), water cut over a 22-year field life. Key performance indicators such as pressure drop, required boosting pressure, temperature fluctuation, and energy consumption were calculated and compared across the different scenarios.

The case study is based on a representative offshore oil field located on the Norwegian Continental Shelf, providing realistic operating conditions and infrastructure constraints. The advantages and limitations of the concept were identified and discussed, and a comparison was made against alternatives such as pipe insulation, direct electrical heating (DEH) and etc., considering energy consumption during operation. Results from the simulations revealed that Cold Flow offers considerable advantages in terms of energy savings and operational simplicity, particularly in the gas injection case, where lower water cut allows the hydrate particles to remain suspended without excessive risk of blockage. In contrast, the water injection case was not suitable for Cold Flow due to the high water content in the production stream, which led to increased hydrate formation and higher flow resistance due to high viscosity. In such scenarios, separating water at the inlet could improve the feasibility of Cold Flow technology. Furthermore, Cold Flow was shown to reduce the need for complex heating infrastructure or pipe insulation for the long tie-back system, making it a cost-effective and environmentally favorable solution when applied under appropriate reservoir conditions. The results also highlight the limitations of the approach, such as the need for flow conditioning and potential requirement for multiple pumps in some configurations. Overall, the analysis concludes that Cold Flow is a viable and attractive alternative for flow assurance in offshore fields, especially for gas-dominant systems with manageable water production rates.

PREFACE

This thesis, titled represents the culmination of my master's degree program and the dedicated effort over the past months. It is with immense gratitude that I acknowledge the individuals and groups who have supported me throughout this journey.

First and foremost, I extend my deepest appreciation to my supervisor at Politecnico di Torino, Professor Samir Bensaid. His continuous support, insightful guidance, and unwavering encouragement were invaluable at every stage of this research. His expertise helped shape the direction of this work and provided the foundation for its successful completion.

I am also profoundly grateful to my supervisors at NTNU, Professor Milan Stanko,Dr. Heiner Schumann and Dr.Leila Eyni. Their immense support, profound knowledge, and exceptional cooperation were instrumental during my research period in Norway. Their willingness to share their expertise, provide constructive feedback, and engage in fruitful discussions significantly enriched my understanding and propelled this thesis forward. Their guidance was truly indispensable.

Finally, I wish to express my heartfelt thanks to my family. Despite the geographical distance, their constant love, encouragement, and unwavering belief in my abilities provided the strength and motivation needed to pursue and complete my education. To my friends, thank you for your endless cheer, support, and for making the challenges of this academic journey much more enjoyable.

This work would not have been possible without the collective support of these remarkable individuals.

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NOMENCLATURE

AAs	Anti-agglomerants
BHP	Bottom hole pressure
CAPEX	Capital Expenditure
CFT	Cold flow technology
CGC	Compact Glycol Contactors
DEH	Direct Electrical Heating
EHT	Electrical Heat Tracing
EOR	Enhanced Oil Recovery
FPSO	Floating, Production, Storage, and Offloading
GI	Gas Injection
GUI	Graphical User Interface
KIs	Kinetic inhibitors
LDHIs	Low-dosage hydrate inhibitors
MEG	Monoethylene Glycol
NCS	Norwegian Continental Shelf
OPEX	Operational Expenditure
PiP	Pipe-in-Pipe

PP Polypropylene

PU Polyurethane

SOT Save operating temperature

SOEP Sable Offshore Energy Project

TEG Triethylene glycol

THIs Thermodynamic hydrate inhibitors

WAT Wax-appearance temperature

WHP Wellhead pressure

Variables

A Area[m2]

A Empirical constant [-]

D Pipe diameter[m]

$\frac{dP}{dz}$ Pressure gradient along the pipe [Pa/m]

F Darcy-Weisbach friction factor/wall friction [-]

g Gravitational acceleration [m/s^2]

GOR Gas Oil Ratio [Sm^3/Sm^3]

h	Enthalpy of the mixture [J/Kg]
HFT	Hydrate Formation Temperature [°C]
ID	Inner Diameter [inches]
L	Pipe length [m]
P	Pressure [bara]
Pcr	Critical pressure [Pa]
Q	Total production rate [Sm^3/day]
q_wall	Heat exchange between pipe wall and environment [W/m^3]
Re	Reynolds Number [-]
ρ	Fluid density [Kg/m^3]
SG	Specific Gravity [-]
T	Temperature [K]
T_ambient	Ambient temperature [K]
T_fluid	Fluid temperature[K]
Tcr	Critical temperature [K]
θ	Pipe inclination angle [rad or °]
U	Heat transfer coefficient [W/m^2·K]
U	Average flow velocity [m/s]

V	Fluid velocity [m/s]
WAT	Wax Appearance Temperature [°C]
WC	Water Cut [-]
μ	Viscosity [Pa.s]
φ	Solid volume fraction / Viscous dissipation term [-]

CHAPTER ONE

1. Introduction

One of the most common challenges in long deepwater subsea tiebacks is the significant pressure loss and low temperatures encountered by production fluids in the flow line, which can lead to the formation of hydrates and wax deposits. When transporting oil and gas, the formation of gas hydrates and wax deposits poses a major challenge for operations. Gas hydrates are crystalline compounds that form when water molecules trap gas molecules, such as methane, under the high pressure and low temperature conditions common in underwater pipelines. Waxing, on the other hand, occurs when paraffinic components of crude oil precipitate as solid deposits when the oil is cooled below its wax-appearance temperature (WAT). Hydrate and wax formation is one of the important problems in offshore operations which can cause blockage in the pipeline and preventing optimum hydrocarbon production or clog equipment. Conventionally the following techniques are used to avoid hydrate formation:

- Water removal to eliminate one of the key components necessary for hydrate formation
- Injection of thermodynamic inhibitors such as methanol or ethylene glycol to shift hydrate stability conditions.
- Nucleation use of low-dosage hydrate inhibitors to Delay hydrate nucleation and growth
- Maintaining pipeline operating conditions outside the hydrate stability zone by insulation and heating

However, for many production operations, particularly Deepwater field developments, fields with long tie-backs and field developments in the Arctic, the mentioned techniques can turn out to be expensive, impractical, and/or ineffective. For short pipeline distance (less than 10km), insulation and heating can be applied to ensure flow assurance. When the length is extended between 10 to 200 km, other prevention methods for wax and hydrate formation such as chemical injection can be used resulting large increase in CAPEX and OPEX and also environmental issues. Thus, the industry needs improved techniques to tackle flow assurance problems for such challenging conditions. The cold flow technology suggested as a proper substitute to the use of insulation, heating or chemical injection that is able to transport well streams with outflow assurance issues, aims to meet this need.

In this study, a method is introduced which can economically and environmentally beneficial to produce without need for avoiding hydrate formation. It is thus an alternative to costly and high energy consuming methods like pipeline heating of tie-backs. The need for such advances is underlined by the increasing global demand for energy, rising operating costs and the growing importance of environmental sustainability in the industry.

This thesis evaluates the technical and environmental feasibility of Cold Flow technology as an innovative flow assurance strategy for long-distance subsea tie-backs. Using the advanced transient multiphase flow simulator LedaFlow, the study models a synthetic field on the Norwegian Continental Shelf to compare the performance of Cold Flow against conventional methods, including production to a Floating Production, Storage and Offloading (FPSO) vessel and tie-backs utilizing active heating and insulation. The analysis investigates two enhanced oil recovery scenarios—water injection and gas injection—over a 22-year field lifetime to assess key performance indicators such as pressure drop, boosting power, and energy consumption. The study first establishes the theoretical background on hydrate formation and current mitigation techniques, then details the simulation methodology and case parameters. Finally, it presents a comparative discussion of the results to conclude on the viability of Cold Flow as a cost-effective and environmentally favorable solution under specific reservoir conditions

1.1 Background

1.1.1 What are gas hydrates?

Gas hydrates are ice-like solid compounds that contain large amounts of methane. They are formed when natural gas molecules are trapped under high pressure and low temperature in a cage-like framework of a solid lattice of water molecules. This process occurs naturally in deepwater offshore environments, where temperatures are often below 4°C (39°F) and pressures exceed 50 bar (725 psi), creating ideal conditions for hydrate formation. Alongside hydrates, wax deposition presents a similar challenge, particularly when transporting crude oil. Waxing occurs when the paraffinic components of the crude oil precipitate out of the liquid phase as solid deposits. This happens when the oil is cooled below its specific Wax Appearance Temperature (WAT). In the context of offshore oil and gas production, the presence of hydrates and wax pose significant flow assurance challenge. Flow assurance refers to the ability to transport hydrocarbons efficiently through pipelines while preventing blockages and flow restrictions. The agglomeration of these solid particles and wax deposition in the pipelines can lead to partial or complete blockages, disrupting production and potentially causing costly shutdowns or equipment damage. These ice-like solids can form rapidly, resistant to removal and required expensive remediation methods. The prevention and remediation strategies for wax deposition and gas hydrate formation are fundamentally similar, as both challenges are addressed by managing the solid-phase formation within the pipeline.

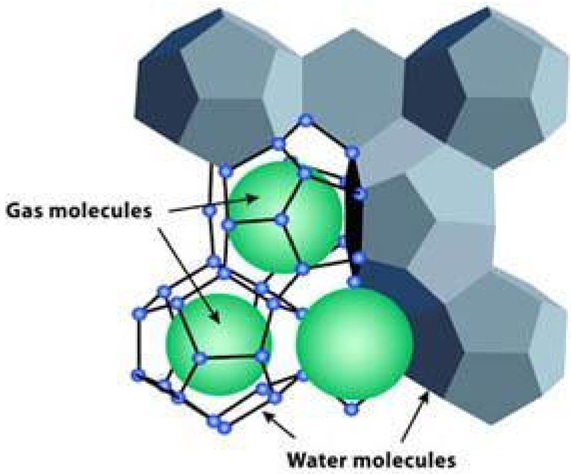

Figure 1.Gas Hydrate Structure [2]

Four factors are necessary for hydrate formation:

1- Presence of Hydrate former which includes small gas molecules such as methane, ethane, and propane
2- Water as the liquid phase
3- High pressure
4- Low temperature

Temperature and pressure conditions depend on gas/liquid and water compositions of the specific fluid.

Hydrate formation is a challenging and a potentially dangerous that can cause flow assurance problems. Some of the industry problems are explained in the following:

1-Production stoppages:

The formation of gas hydrates can lead to the complete or partial blockage of pipelines, resulting in significant production losses. For example, the Sable Offshore Energy Project (SOEP) off the coast of Nova Scotia experienced several unplanned shutdowns due to hydrate blockages in the production pipelines. These blockages required costly interventions to restore normal operations, resulting in significant financial losses and production delays [*3*]

2- Damage to the equipment:

Clogs caused by hydrates can put excessive pressure on pipelines and other equipment, which can lead to mechanical damage. In one notable incident in the North Sea, a hydrate plug caused a rupture in a gas pipeline, resulting in substantial repair costs and environmental problems due to the associated gas leakage [*4*]

3-High Operational Costs:

The need for continuous monitoring and the use of chemical inhibitors such as methanol or glycol to prevent hydrate formation significantly increase operating costs. In the Gulf of Mexico, operators often inject large quantities of inhibitors to control hydrate risk during Deepwater operations. This practice not only drives up operating costs, but also presents a logistical challenge in terms of chemical storage, handling and disposal [*5*]

1.1.2 Techniques to avoid hydrate formation

Any actions avoiding at least one of the four necessary conditions of hydrate formation can be taken into account as a hydrate inhibitor method. In subsea transportation, we have several technologies to achieve flow assurance. In this study some conventional methods have introduced to remediate hydrate particle but the main focus of this study is the investigation of the feasibility of cold flow. For each method some advantages and challenges are mentioned.

1.1.2.1 Direct electrical heating (DEH):

The working principle of Direct Electrical Heating (DEH) involves applying a substantial electric current through the pipeline to generate the necessary heat to raise the fluid temperature, thereby preventing the formation of hydrates. The DEH system consists of a riser cable extending down to the seafloor, a feeder cable running towards the flow line, and a DEH cable that is attached alongside the flow line throughout the heated section. At the distal end, the attached DEH cable is grounded to the steel pipe. Similarly, a return cable is connected to the steel pipe at the proximal end. Consequently, the return current is split between the steel pipe and the seawater. The heat generated per meter (W/m) is due to the electrical resistance in both the steel pipe and the DEH cable, as well as the electromagnetic coupling between the cable and the steel pipe.

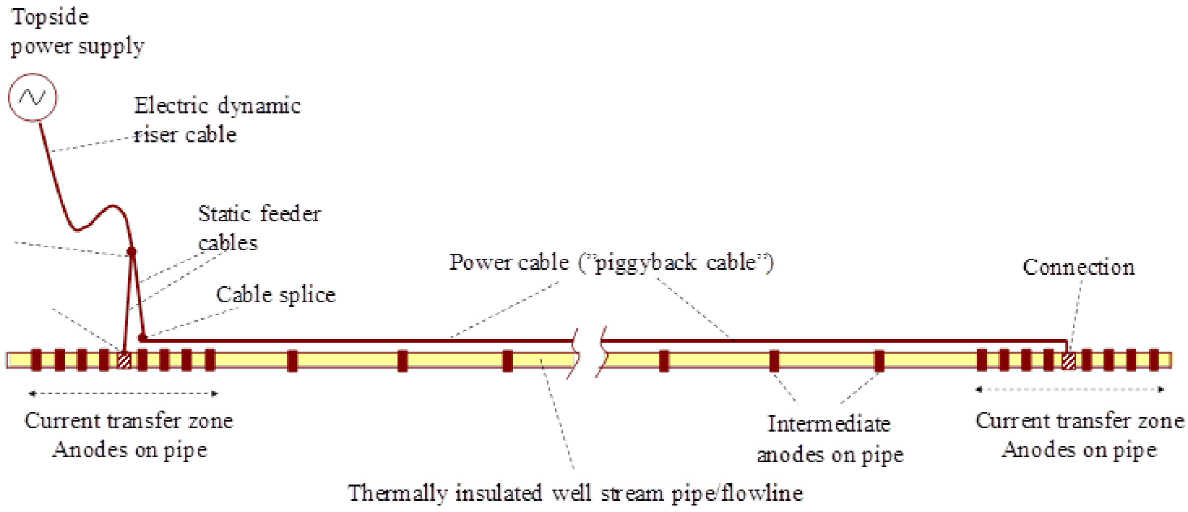

Figure 2. Schematic of DEH System [6]

Direct Electrical Heating (DEH) is considered the most attractive and reliable method for deep water field operations involving transport flow lines. [7] DEH is also suggested for use in long-distance pipelines, spanning 100 to 200 km, and at water depths exceeding 1500 meters. There are no conceptual barriers to using DEH for longer distances if the system is divided into sections. However, increasing the number of sections for longer pipelines will also increase the system's cost. Equinor has been a pioneer in implementing DEH, currently operating approximately 20 installations, primarily in Norwegian waters. [8]A major advantage of DEH systems is their capacity to heat the entire pipeline length. This is essential for both preventing and resolving hydrate blockages. Unlike methods that rely on passive insulation or chemical injection, DEH systems don't have hard shutdown limits, offering greater operational flexibility and reliability

One of the challenges associated with using Direct Electrical Heating (DEH) is corrosion. To combat AC corrosion, sacrificial anodes are included in the system, typically in zones of 50-100 meters near the pipeline ends, where material is intentionally added to corrode over time. Small defects in the pipe or insulation can also lead to localized corrosion. Another issue with DEH is the potential for uneven heating. Differences in electrical properties, mainly magnetic susceptibility, between pipe segments can cause temperature variations of up to 10 °C between adjacent 12-meter pipe segments [9]. Economically, DEH can be very costly for long pipelines due to the higher power energy requirements.

1.1.2.2 Electrical Trace Heating (EHT):

The EHT technology is based on the employment of high performance insulation material in combination with a simple, robust and low power consumption electrical heating system within a compact pipe-in-pipe design. In electric heat tracing (EHT), electrically heated cables are laid along a pipeline. These cables generate heat when an electric current flows through them. The system is controlled by temperature sensors and regulators to keep the pipeline at the required temperature to prevent the formation of hydrates and waxes. As already mentioned, the heating system is composed of copper wires laid between the inner pipe and the insulation material. A schematic of the layout is presented in the figure below.

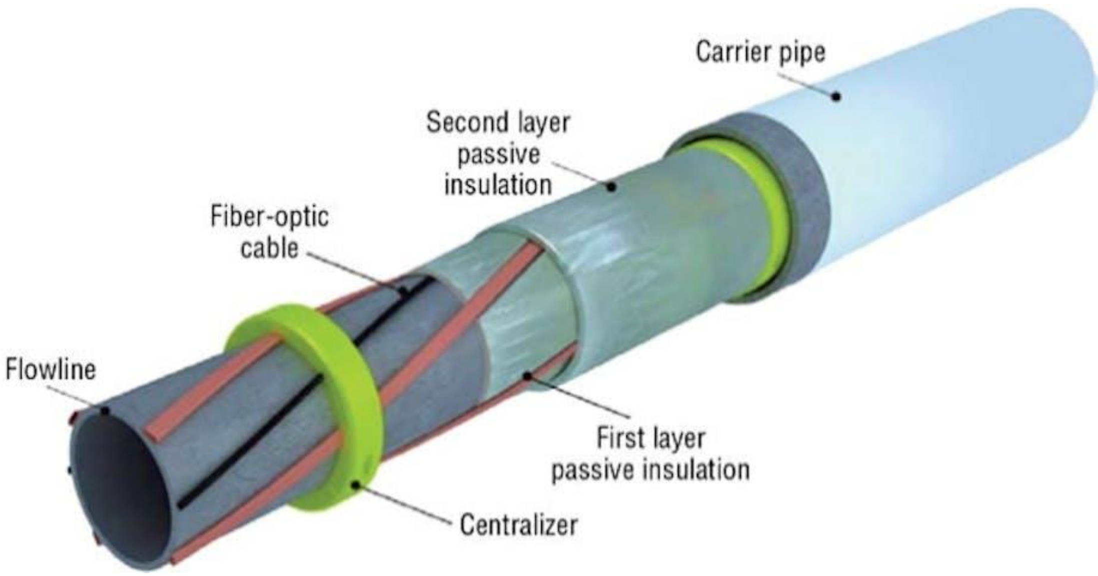

Figure 3 Electric heat tracing (EHT) components[10]

In the EHT technology there is no need for the installation of a return cable for the current because the copper wires are joined in a star configuration. The difference between DEH and EHT is that in the former a current is circulated directly inside the pipe wall, while in the latter electrical cables are laid between the wall of the flow line and the carbon steel layer. This fundamental difference affects their suitability for different operating conditions and environments in the oil and gas industry and influences factors such as cost, energy consumption and system complexity.

The heating efficiency of EHT drops over long distances due to power dissipation. While it may be suitable for short pipelines (typically under 10 km), its performance diminishes in extended subsea tiebacks unless additional power-boosting stations are installed which would raise expenses even further. In addition to this, EHT requires heating cables to be installed along the entire pipeline length, complicating deployment, especially in deep water or hard-to-access areas.

If a fault occurs in submerged or buried sections, locating and repairing damaged cables can be time-consuming and expensive.

1.1.2.3 Prevention with Chemical Injection:

The most common method used to avoid hydrate formation in the pipeline ranging from 10 km to 250 km is chemicals injection [*11*]. Mechanism of Chemical inhibitors is function by either depressing the freezing point of water or altering the interfacial surface tension between hydrate-forming fluids, thus inhibiting the nucleation and growth of crystalline hydrate structures.

Similarly, for wax prevention, chemical inhibitors alter the crystallization characteristics of paraffinic compounds in crude oil, keeping them in a liquid state even at lower temperatures. Injection rates and inhibitor concentrations are carefully controlled based on real-time monitoring of pipeline conditions such as temperature, pressure, and flow rate.

There are two groups of chemical inhibitors: thermodynamic hydrate inhibitors (THIs), and low-dosage hydrate inhibitors (LDHIs)

1.1.2.3.1 Thermodynamic Hydrate Inhibitors (THIs):

These inhibitors function similarly to antifreeze agents in pipeline systems. Methanol and mono-ethylene glycol (MEG) are introduced as the most common THIs which are used in liquid and gas dominated system respectively. The main mechanism of THIs is changing the thermodynamic equilibrium between hydrocarbon and water so the lower temperature and higher pressure are required to form hydrate particles. They interfere with the molecular interactions occurring at the hydrate formation site, thereby preventing the initiation and growth of hydrate crystals. This interference helps maintain the fluid in a uniform liquid state, even in situations where hydrate formation would typically occur [*4*].

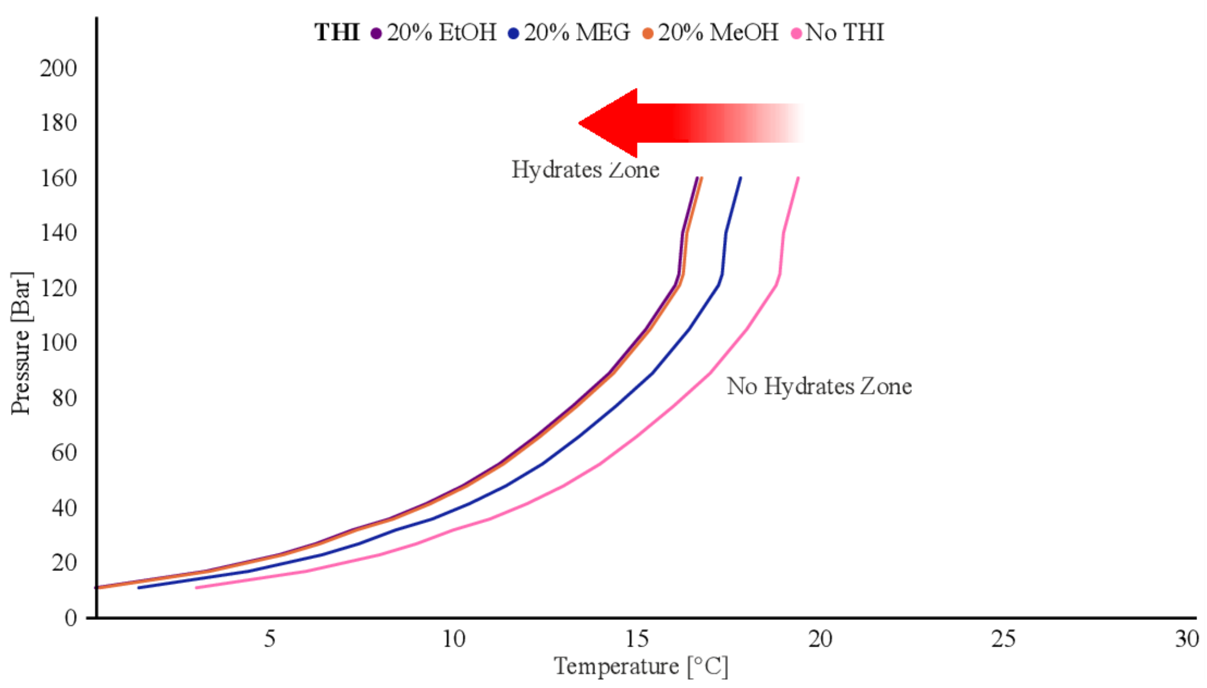

*Figure 4. Shifting Thermodynamic Equilibrium Curve by Adding THI [*12*]*

The main advantage of THIs are their availability and efficiency compared to other conventional method, particularly MEG additives which can be regenerated easily. On the other hand, the drawbacks of this technology for CAPEX and OPEX cannot be neglected. High volume of additives needed to inhabit hydrate particles which means larger storage capacity and injection pumps. In addition to this, Methanol can contaminate the downstream processes since it has high vapor pressure and can be lost easily into any gas phase. Methanol also promotes corrosion problems and reduces the efficacy of some corrosion inhibitors due to the dissolve oxygen in it. Eventually, it should be noted that THIs are toxic and harmful for environment and also they need to be recovered in rather large and expensive topside units.

1.1.2.3.2 <u>Low Dosage Hydrate Inhibitor (LDHI):</u>

Low Dosage Hydrate Inhibitors (LDHIs) are chemicals employed in the oil and gas sector to avert gas hydrate formation within pipelines and processing systems. Over last years, LDHIs have been

developed to tackle the significant drawback of Thermodynamic Hydrate Inhibitors (THIs), high volume requirement. This group of inhibitors require minimal concentrations (typically less than 1% by weight), just a few percent in the produced water, and thus require much lower injection rates compared to This. Besides, LDHIs typically impact the environment less than traditional inhibitors because they are applied in minimal amounts and often possess better biodegradability.
LDHI are divided in two categories: Kinetic inhibitors (KIs) and Anti-agglomerants (AAs).

1.1.2.3.2.1 Kinetic inhibitors (KIs):

Kinetic Hydrate Inhibitors (KHIs) delay the initiation of hydrate formation by extending the induction period. This period varies depending on the specific system, so KHIs are tailored to the needs of each facility. They can extend the time before hydrate formation occurs from several hours to multiple days [*13*]. These inhibitors are typically water-soluble polymers that Slow down the initial nucleation of hydrate crystals, Inhibit the growth of existing hydrate particles and Allow fluids to safely pass through the hydrate risk zone.

1.1.2.3.2.2 Anti-agglomerants (AAs):

Anti-agglomerates are surface active chemicals (surfactants). They allow hydrate crystals to form but prevent them from agglomerating and adhering to pipe walls [*14*]. This means that, they allow hydrates to form, but as tiny, non-adherent particles that are easily dispersed into the liquid hydrocarbon phase, preventing them from sticking together and forming larger, obstructive masses. As the viscosity remains low, this will allow the hydrates formed to be transported with the produced fluids avoiding blockages in pipelines and equipment. AAs do not have sub cooling limitations but have been found to be effective in low to extreme hydrate stable regions, even during extended shut in periods [*15*].LDHIs are used in multiphase, gas condensate, and crude oil production. They can extend the life of wells and its ultimate recovery through higher water production rates from subsea wells and because of continuous flow, the problem of liquid-hold up in gas wells are minimized. They are also capable of delaying water-cut related curtailment, as such, wells may not be shut down because of hydrates or other high water cuts related problems [*16*]. Requirement for manpower is reduced because less stock is needed to be handled. They also save potential cost (CAPEX & OPEX), since lower volumes are required (less than one percent weight) and less pump maintenance resulting from smaller dosing rates. KHIs is now becoming field proven [*17*] And, the absence of sub cooling limitations for AAs.

One of the largest drawbacks with LDHIs is the possibility of pollution since they have not been able to achieve approval, evidenced by Norway's prohibition of their use due to unresolved pollution risks. Beside this, LDHIs requires adequate testing prior to implementation or deployment. For new field development, production fluids may not be readily available for testing. They also lack an established model for the prediction of their effectiveness, thus posing difficulties for field developers in the application of these chemicals [*18*].

Kinetic hydrate inhibitors (KHIs) exhibit time-dependent sub cooling limitations and problematic interactions with other chemicals like corrosion inhibitors causing their effectiveness reduction , while anti-agglomerants (AAs) are restricted to low water cuts due to the continuous hydrocarbon phase that is required and it also has limited experience [*19*]. The cost of the chemical is much higher compared to methanol hence even at low dosage.

1.1.2.4 <u>Wet Insulation:</u>

The most common approach to maintain the temperature of the fluids inside the pipeline, preventing issues like hydrate and wax formation is insulation. This technique involves applying a protective layer of material with a very low heat transfer coefficients material like foam to reduce heat loss from the transported hydrocarbons to the surrounding seawater. By retaining heat, insulation helps keep the fluid temperature above the hydrate formation temperature (HFT) and the wax appearance temperature (WAT)**,** minimizing the risk of solid deposits forming within the pipeline. The selection of insulation material depends on operating conditions such as pipeline depth, fluid temperature, and environmental factors**.** The foam materials typically used include polyurethane (PU), polypropylene (PP), and syntactic foams, which are specifically designed to function effectively under submerged conditions. In this way, we can decrease the heating loss in the protection zones. However, insulation alone is insufficient for maintaining the necessary heat over long distances, particularly in deep water exceeding 200 km. So it should be combined with other hydrate prevention techniques such as chemical injection or pipe heating (typically combined with DEH). This means higher CAPEX and OPEX for providing and maintaining the facilities.

Another disadvantage of this technology is minor damage to the insulation (e.g. cracks or holes made in the laying process) may act as cold fingers, creating local cold spots which can lead to unintended heat loss in specific areas, increasing the likelihood of hydrate formation at those points. Since hydrates can rapidly accumulate and agglomerate under the right conditions, even small defects in insulation can pose a major flow assurance risk**.**

The cost is also substantial, particularly for deep water (insulation rigidity) or long distances (insulation thickness). For very deep-water applications, the needed size of the piping (in order to account for pressure resistance and the thickness to protect against very low temperatures for long distance) may in fact become so large and unwieldy that only a couple of laying vessels with the needed capacities are available world-wide [*20*]. Perhaps the most fundamental limitation of insulation is its inability to prevent hydrate formation during prolonged shutdowns – which must be expected for all major installations. Regardless of insulation thickness, if production is halted for an extended period, the internal fluid temperature will inevitably drop below the hydrate formation threshold. Given that major offshore installations are expected to experience periodic shutdowns—whether for maintenance, operational adjustments, or unforeseen circumstances—there is no practical amount of insulation that can fully eliminate the risk of entering the hydrate formation zone under such conditions.

1.1.2.5 Pipe in pipe:

In recent years, pipe-in-pipe (PiP) solutions and pipeline bundles have been developed as good alternatives to traditional wet insulation techniques, offering superior thermal insulation and enhanced flow assurance for subsea pipelines [*22*]. Unlike conventional single-pipe insulation systems, PiP technology consists of two concentric pipes—an inner pipe that transports production fluids and an outer pipe that provides mechanical protection and houses the insulation material. By isolating the inner pipe from direct exposure to seawater, PiP systems significantly reduce heat loss, helping to maintain fluid temperatures above hydrate and wax formation thresholds.

Beyond thermal benefits, PiP systems also provide increased corrosion resistance, as the outer pipe acts as a barrier against seawater intrusion, thereby extending the pipeline's operational lifespan and reducing long-term maintenance requirements. These advantages make PiP an attractive solution for deep water and Arctic field developments, where extreme conditions pose significant challenges to conventional insulation techniques [*23*].

However, the primary drawback of PiP systems is their high capital expenditure (CAPEX) compared to single-pipe solutions. The double-layered pipe-in-pipe (PiP) design significantly increases project costs and technical challenges across multiple phases. Material costs are inherently higher as the system requires two concentric pipes rather than a single flow line, substantially increasing steel procurement expenses. Fabrication becomes more complex due to the precision engineering needed to maintain consistent annular spacing and ensure optimal thermal insulation performance while meeting structural requirements [*24*]. Installation presents additional difficulties as the combined weight and bulk of the nested pipe system often necessitates specialized laying vessels and more sophisticated deployment techniques compared to single pipe configurations [*24*]. These compounded factors - from material duplication to engineering precision and installation constraints - make PiP systems considerably more capital-intensive than conventional single-pipe solutions, particularly for long-distance subsea tiebacks.

1.1.2.6 Floating Production Storage and Offloading (FPSO):

The Floating Production, Storage, and Offloading (FPSO) system is one of the most popular and easily accessible ways to produce hydrocarbons from deep water oil reserves while mitigating hydrate formation risks. The number of FPSOs in operation worldwide has been increasing in recent years, primarily due to the decline in new onshore oil discoveries over the past two decades and the growing demand for offshore oil development.

An FPSO is a floating vessel positioned near an offshore oil field that serves as a self-contained production facility. It is designed to process, store, and offload crude oil until it can be transferred to a shuttle tanker for transportation to refineries or storage terminals. FPSOs are particularly favorable in remote offshore locations where constructing fixed pipeline infrastructure is either technically unfeasible or economically prohibitive.

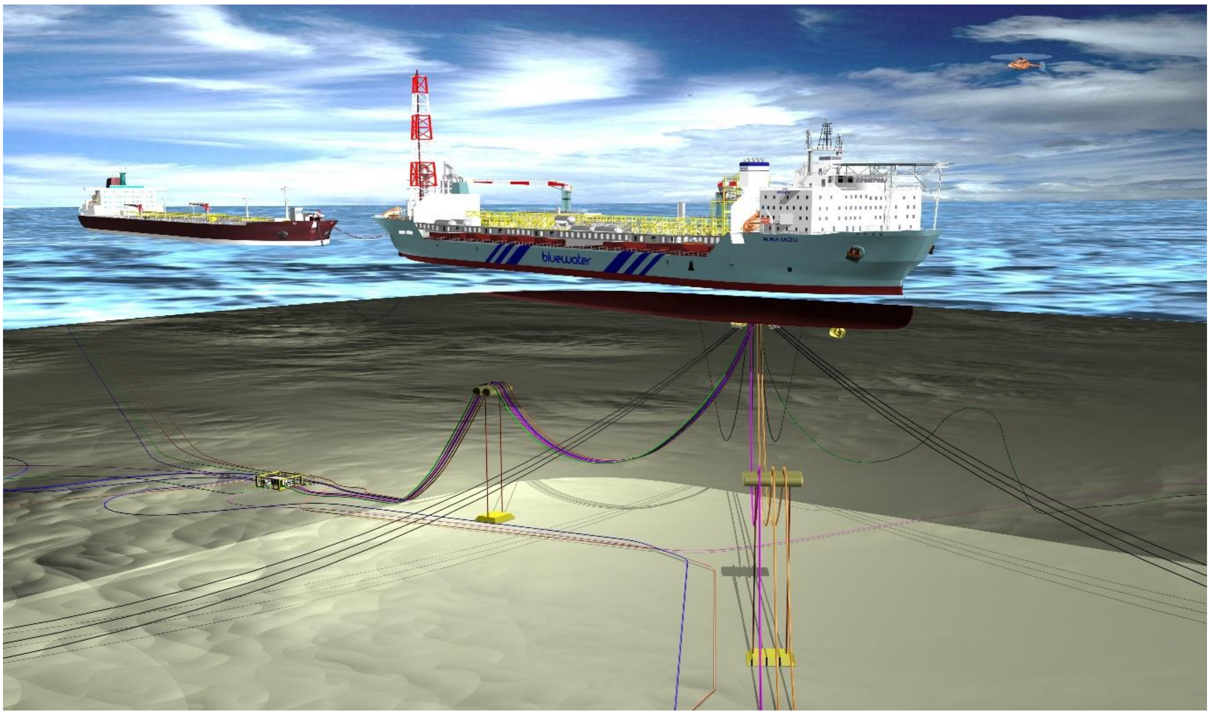

Figure 5. Subsea Tie-back to FPSO unit [25]

Advantages of FPSOs Over Fixed Offshore Platforms:

Compared to fixed offshore oil platforms, FPSOs offer several key advantages. They have Lower capital expenditure (CAPEX) for infrastructure. FPSOs are more economical in deep water areas since they do not require large subsea pipes. They offer significant operational flexibility and mobility compared to fixed platforms, as they can be relocated to new fields once the current reservoir is depleted. This key advantage allows operators to maximize asset utilization and extend the productive life of the floating production system across multiple oil fields. Thanks to their exceptional adaptability to different water depths, FPSOs perform especially well in very deep water situations where fixed platforms are both technically and financially impractical.

Challenges and Cost Considerations of FPSO Deployment:

Despite their advantages, FPSOs may face to significant economic and operational challenges, especially in large-scale developments. One key issue is scaling costs. The more increase in volume production, the more storage is required, often leading to higher vessel charter rates and operational expenses. Additionally, FPSOs rely on shuttle tanker fleets for oil export, which introduces logistical complexities and adds substantial transportation costs. Gas handling poses another limitation—remote locations far from pipeline infrastructure may force operators to reinject associated gas rather than monetize it, resulting in wasted resources unless alternative solutions like gas pipelines or LNG carriers are implemented.

1.1.2.7 Natural gas dehydration:

Natural gas dehydration is one of the methods in flow assurance particularly aimed at preventing hydrate formation during the transportation of gas in subsea pipelines. The primary risk factor for hydrate formation under high-pressure and low-temperature conditions is due to the presence of vapor water in Natural gas extracted from reservoirs**.** If this moisture left untreated, can cause several operational issues, including the formation of gas hydrates and internal corrosion in pipelines**.** Therefore, dehydration processes are critical to ensure safe transportation and efficient utilization of natural gas.

The key design factor for dehydration systems is the target water dew point, which must be sufficiently low to prevent hydrate formation at the coldest anticipated pipeline temperature. Typically, the water content in the gas is reduced to less than 7 lb/MMscf to ensure hydrate-free flow under operating conditions [*26*]

There are three most common methods for natural gas dehydration;1-glycol dehydration (Absorption method) and 2- Solid Desiccant Dehydration (Adsorption Method) 3- membrane separation

1.1.2.7.1 glycol dehydration(Absorption method):

In glycol dehydration**,** a liquid desiccant**,** usually Triethylene Glycol (TEG), is used to absorb the water vapor present in the gas stream. Wet natural gas enters a contactor column where it flows upward while the glycol solution trickles downward, allowing for maximum surface contact. The TEG absorbs the water, resulting in a drier gas stream exiting the top of the tower [*27*].

The TEG is regenerated on-site by heating and removing the absorbed water, making the process cyclic and efficient [28]**.** For offshore applications, compact designs like Compact Glycol Contactors (CGC) are preferred due to space and weight limitations [*28*].

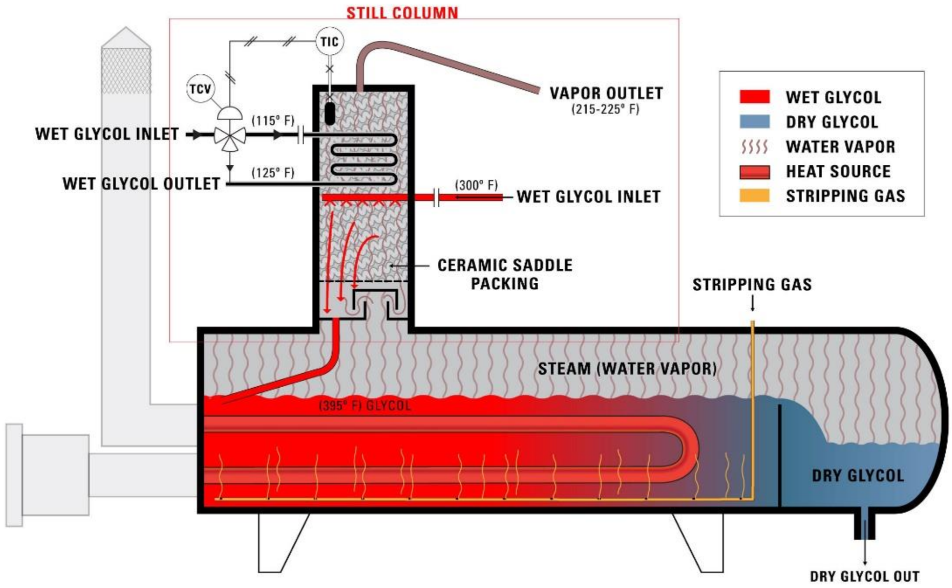

Figure 6. Still column for glycol dehydration [29]

The dehydration unit is usually located topside on the FPSO or offshore platform; however, subsea dehydration modules have been developed to meet the demands of ultra-deep water projects, minimizing topside infrastructure. Subsea dehydration is particularly attractive for fields located far from existing infrastructure where pipeline tie-backs are necessary.

The energy consumption in TEG dehydration systems primarily comes from the heat required to regenerate the glycol in the reboiler. Studies have shown that the heat duty ranges from 3 to 6 MJ per kilogram of water removed, with a typical average of about 5 MJ/kg H_2O [30].This includes the latent heat of vaporization of water and sensible heating of the glycol.

1.1.2.7.2 Solid Desiccant Dehydration (Adsorption Method):

This method is commonly used for extremely low water content — such as in cryogenic processing. In this method, natural gas is passed through fixed beds packed with materials like silica gel, activated alumina, or molecular sieves. These desiccants adsorb the water vapor onto their surfaces until saturation. Regeneration of the desiccants is typically achieved through heating (thermal swing) or by applying a pressure drop (pressure swing).

Solid desiccant systems can achieve very low dew points, making them suitable for processes where extremely dry gas is needed, such as liquefied natural gas (LNG) production [31].

Solid desiccant systems, such as molecular sieves, require higher energy input compared TEG dehydration systems, due to the thermal regeneration of adsorbent beds. The energy requirement for these systems is typically in the range of 10–20 MJ/kg H_2O, making them more energy-intensive than glycol units [*32*].

1.1.2.7.3 <u>Membrane Dehydration:</u>

Another approach is membrane-based dehydration. In this system, natural gas flows through specially designed membranes that selectively allow water vapor to pass through while retaining the dry gas. This method is particularly valuable for offshore applications, where space and weight are limited. Membrane-based dehydration offers advantages such as compact equipment size, lower operational costs, and reduced energy consumption compared to traditional dehydration methods [*33*]. However, membrane systems are generally applied where moderate dehydration is sufficient, as they may not achieve as low a water dew point as solid desiccants can.

Membrane dehydration systems operate using physical separation and typically require compression energy rather than thermal input. As a result, they are significantly more energy-efficient, requiring only about 0.5–1 MJ/kg H_2O [*34*].

The advantages of natural gas dehydration:

1. Reduction in hydrate risk without the need for thermal insulation or active heating.
2. Improved operational flexibility as the system allows variations in gas production rates without significant changes in hydrate risk.
3. Lower capital costs compared to insulated pipelines or pipe-in-pipe systems.

Limitations of dehydration process:

1. Operational complexity due to the need for periodic regeneration of the dehydration medium [28].
2. Maintenance requirements, especially for offshore installations, can increase the long-term operational cost [35].
3. In some cases, residual water in the gas might still allow limited hydrate formation if not properly controlled.

1.1.2.8 Cold Flow:

Flow assurance is a critical challenge in offshore oil and gas production, particularly in deep water fields where long-distance subsea tiebacks are required. Conventional methods to prevent hydrate and wax deposition, such as chemical inhibitors, insulation, and active heating, often result in high operational costs and environmental concerns. In response to these challenges, Norwegian University of Science and Technology (NTNU) in collaboration with SINTEF, introduced one of the most notable method for flow assurance which is called cold flow technology. Unlike traditional methods that aim to prevent hydrate formation The main mechanism of cold flow is based on cooling down of the produced fluid until the ambient temperature(4°C) is reached and allowing all the hydrate particles to form without agglomeration of hydrate particles that can plug the pipeline under controlled condition along the cooling system. This cooler includes one or more parallel pipelines without insulation (ambient sea water cooling) or other mechanisms for thermal or hydrate control (hydrate formation is controlled by flow rate control and seeding) and are imposed at thermodynamic equilibrium with the surrounding seawater. Often a seeding technique is used to form these dry hydrates. Once the hydrates are formed under controlled conditions, they are transported as a slurry through the subsea pipeline. This is a simplified representation of a real cooler. One design as developed by EMPIG AS, Norway, is shown in the Figure 7. It has a curvy shape like in form of spiral and are hold in a cubic cage which make it easier to install on the seabed.(An alternative layout for the cooling unit is presented in Appendix 1)

Figure 7. Cold Flow unit manufactured by EMPIG [36]

The importance of CFT appears in the industry where we have longer distance transfer (greater than 50 km) from the wellhead to the processing facilities on seabed, topside, or to beach (onshore). Successful implementation of Cold Flow for long distances allows big savings, particularly in pipeline costs and heating energy consumption. CFT eliminates the need for costly chemical inhibitors, such as methanol and monoethylene glycol (MEG), thereby reducing both capital and operational expenditures associated with pipeline heating systems, and significantly diminishing energy consumption, which enhances its economic viability in deep water operations. Furthermore, CFT minimizes the chemical footprint inherent in offshore production, mitigating environmental risks related to inhibitor disposal and contributing to a reduction in carbon emissions by eliminating energy-intensive heating systems. Additionally, by maintaining hydrates in a thermodynamically stable, dispersed state, CFT eliminates the risk of abrupt pipeline occlusion and flow interruption, thus enhancing operational safety and reliability in deep water hydrocarbon production.

Cold Flow like other conventional flow assurance methods has some limitation that needs to be considered. Basically, the efficiency of cold flow system depends on the amount of water and gas (in here gas represents hydrate former which includes light hydrocarbons such as methane) which should be used up completely to form hydrate particles. If the production fluid contains high GOR or WC, separation of one phase could be taken. For instance, if the water is dominant phase in inflow, water separation reduces the risk of hydrate formation after cooler. More equipment and high maintenance are also required for water separation.

Another possible challenge is that the oil may become quite viscous at ambient temperature, and this can be further affected by the levels of hydrates, such that the resulting apparent viscosity may become larger than for standard systems and potentially increasing pressure drop and impacting flow efficiency. Moreover, the presence of wax in crude oil can further exacerbate flow resistance, necessitating careful monitoring of fluid properties.

As hydrate particle concentration increases, the viscosity in a slurry increases non-linear, rather exponential. Depending on the fluid system, particle concentrations of maximum 30% seems to be feasible for the concept. For higher concentrations the resulting pressure drop becomes too large and extensive boosting might be required.

Cold Flow Technology (CFT) application in the field has its own difficulties, especially when compared with chemical injection techniques. CFT needs exact operational control to provide the best possible management of hydrate development, even while chemical injection allows for dynamic adjustments to reduce hydrate formation. Moreover, the successful large-scale implementation of CFT necessitates extensive testing, strict validation, and careful adaptation to the diverse and often unpredictable conditions encountered across different reservoir environments.

CHAPTER TWO

2 METHODOLOGY

2.1 LEDAFLOW SIMULATOR AND APPLICATION :

LedaFlow is a dynamic multiphase flow simulator developed for oil and gas production systems which provides detailed transient modeling of multiphase flow (gas, oil, water, hydrate, and solids).This simulator is used to understand the behavior of flow assurance issues such as hydrate and wax formation, especially in long-distance and deepwater subsea tie-backs. In this study,different production scenarios were simulated by Leda flow(version V2.6.260.024) to evaluate the technical feasibility and performance of Cold Flow Technology in comparison with traditional solutions like FPSO, PIP with DEH, and EHT.

Leda flow has some key capabilities to simulate the process of hydrocaron transportation.Since in oil and gas ,multiphase flows are present, it can model the transient multiphase flow. LedaFlow solves the Navier-Stokes equations for each phase (gas, oil, water, solid), using a multi-field model, where Continuous phases are gas, oil, water and Dispersed phases are gas bubbles in liquid, liquid droplets in gas, solid particles (hydrates, wax).It should be noted that it is important for Cold Flow, since hydrate particles remain dispersed as solids in a slurry phase.

Another parameter which is measured and simulated in LedaFlow is transient thermal simulations such as Heat exchange between flow and surroundings,Insulation effects,Joule-Thomson cooling ,Heat generated/absorbed by phase transitions (e.g., hydrate formation is exothermic).This parameter is necessary for comparing insulated systems (PiP, DEH, EHT) with uninsulated cold flow systems using ambient cooling.

The fundamental distinction between LedaFlow and other flow simulation software is LedaFlow's specialization in modelling hydrate and wax formation and transport. LedaFlow models Thermodynamic envelope of hydrate stability,Kinetics of hydrate formation and Particle transport, size distribution, and agglomeration risk. This allows simulation of controlled hydrate formation (as in cold flow) under steady cooling conditions.

In multiphase flow modeling, accurately identifying flow regimes is essential for predicting fluid behavior along the pipeline. In Leda Flow, flow regimes represent the spatial distribution and interaction of different phases, such as gas, oil, and water. For three-phase flow, Leda Flow distinguishes between two primary categories of regimes: gas–liquid and oil–water flow regimes.

Leda Flow separates flow regime analysis into two levels:

- Numerical flow regimes, which determine the selection of the appropriate multiphase flow model used in the simulation.
- Physical flow regimes, which are derived from the numerical solution and provide insight into the actual flow pattern occurring within the pipeline or well.

In this study, based on the well and pipeline geometry and flow conditions, Leda Flow primarily identified stratified wavy and slug flow regimes in horizontal sections of the flow line. As such, Slug Capturing was enabled in the model. This advanced option allows for detailed tracking of hydrodynamic slugs and their interaction with terrain-induced slugs, which is particularly useful in assessing potential flow instabilities and pressure surges that may affect production. By simulating the gas–liquid and oil–water interactions under varying operational conditions, Leda Flow provided reliable predictions for flow assurance design, especially in handling transient behaviors and multiphase transport phenomena.

2.2 GOVERNING EQUATIONS:

Leda Flow works by numerically solving these main equations:

1-Mass conservation (Continuity Equation) for each phase (oil, gas, water)

2-Momentum conservation (Momentum Equation) for the entire flow or separately for each phase

3-Energy conservation (Energy Equation) for fluid temperature and heat exchange

These three main equations are solved across the pipeline.

Momentum Equation:

The pressure in the pipeline (like the wellhead pressure you see in the results) is calculated by solving the momentum equation:

$$\frac{dP}{dz} = -\rho . g . sin(\theta) - f . \frac{\rho . u^2}{2 . D} - (\rho . u) . \frac{du}{dz}$$

Where:

- dP/dz: Pressure gradient along the pipe [Pa/m]
- ρ: Mixture density [Kg/m^3]
- g: Gravitational acceleration [m/s^2]]
- θ: Pipe inclination angle [rad]
- f: Darcy-Weisbach friction factor [-]
- u: Average flow velocity [m/s]
- D: Pipe diameter [m]

Reynolds Number:

To determine the flow regime (laminar, transitional, or turbulent):

$$Re = \frac{\rho v D}{\mu}$$

Where:

- ρ: fluid density [Kg/m^3]
- v: fluid velocity [m/s]
- D: pipe diameter [m]
- μ: dynamic viscosity [Pa.s]

High Reynolds number supports particle dispersion and reduces agglomeration in cold flow.
The wall friction in LedaFlow is based on the analytical laminar friction and turbulent [*37*] models:

$$f_{\text{laminar}} = \frac{16}{\text{Re}}$$

$$\frac{1}{\sqrt{f_{\text{turbulent}}}} = -3.6\log_{10}\left(\frac{6.9}{\text{Re}} + \left(\frac{\varepsilon}{3.7\text{D}}\right)^{1.11}\right)$$

The laminar-turbulent transition occurs around a Reynolds number of 2000:

$$f = \begin{cases} f_{\text{laminar}} & (f_{\text{laminar}} \geq f_{\text{turbulent}}) \\ f_{\text{laminar}}^{W} f_{\text{turbulent}}^{1-W} & (f_{\text{laminar}} < f_{\text{turbulent}}) \end{cases}$$

$$W = \frac{1}{1 + \left(\frac{\text{Re}}{2300}\right)^{20}}$$

Energy Equation:

For temperature, the following energy balance equation is used:

$$d\frac{(\rho uh)}{dz} = -q_{wall} + \Phi$$

Where:

- h: Enthalpy of the mixture [J/Kg]
- q_{wall}: Heat exchange between pipe wall and environment (e.g., seawater) [W/m^3]
- Φ: Viscous dissipation term (usually small) [-]

Heat exchange with the environment causes the fluid temperature to decrease or increase**.**

Heat Transfer Through the Pipe Wall:

For the heat transfer across the pipeline wall (whether it's insulated, PiP, or Cold Flow), this equation is applied:

$$q_{wall} = U\,A\,(T_{fluid} - T_{ambient})$$

Where:

U: Overall heat transfer coefficient [W/m²·K]

A: Heat transfer area [m^2]

T_{fluid}: Fluid temperature [K]

$T_{ambient}$: Ambient temperature (e.g., seawater) [K]

The difference between methods like FPSO, PiP, DEH, EHT, and Cold Flow mainly affects the U value.

Slurry Viscosity (Exponential Model):

$$\mu_{slurry} = \mu_{fluid} \cdot e^{\alpha\phi}$$

Where:

ϕ: solid volume fraction [-]

α: empirical constant (based on particle type/size) [-]

This helps in evaluating flow behavior in cold flow systems, where hydrate solids are dispersed. After hydrates are formed they end up in the oil and/or water phase, changing the physical properties of these phases. The main effect on the flow is a higher pressure drop, due to the increased viscosity of the resulting hydrate slurry.

2.3 Defining Fluid Properties:

Firstly, fluid properties were defined to the Leda flow. To do this, Leda Flow can run using PVT tables (generated by PVTsim), compositional tracking through its internal PVT server GUTS or using Multiflash, black-oil steam and constant properties. According to given data, black – oil model (Vasquez & Beggs), was applied by having the GOR, specific gravity, viscosity and bubble point pressure and temperature, see Table 1 and Figure 8. The Black Oil fluid model is a set of PVT equations that approximately replicate the behavior of well fluids for pressure. The gas fraction provided by the Black Oil correlation is used for the so-called PVT mass transfer, which updates the gas and oil fractions along the pipelines. Water vapor is not part of the Black Oil model, so all water will be in its liquid form.

The specific formulation of the mass transfer in Leda Flow is based on a differential form, which means that we only update the mass fractions of the different phases between cells and in time.

Fluid	SG[kg/m^3]	Viscosity[mPa.s]
Oil	0.75	0.01
Gas	0.83	5

Table 1. fluid properties

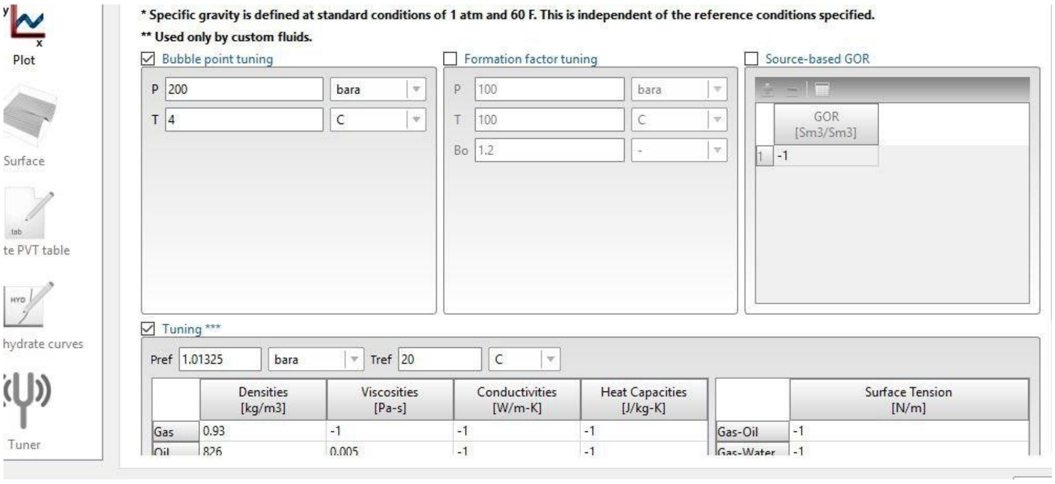

Figure 8. Introducing fluid properties to the Leda flow

2.4 Hydrate curve analysis:

Hydrate curve has been carried out with HYSYS based on given production data (see Appendix 2) . The hydrate formation curve indicates the temperature and pressure envelope safe zone in which the hydrocarbon can be operated to prevent the possibility of hydrate formation. In fact, the following figure shows the stability of natural gas hydrates as a function of pressure and temperature. Hydrates become more stable with increasing pressure and decreasing temperature. In the region to the right of the dissociation curve, no hydrate forms; it is thus safe to work in this area and have no issues with hydrate blockages. The left of the hydrate formation curve is the thermodynamically stable region where hydrates can form.

Hydrate curve:

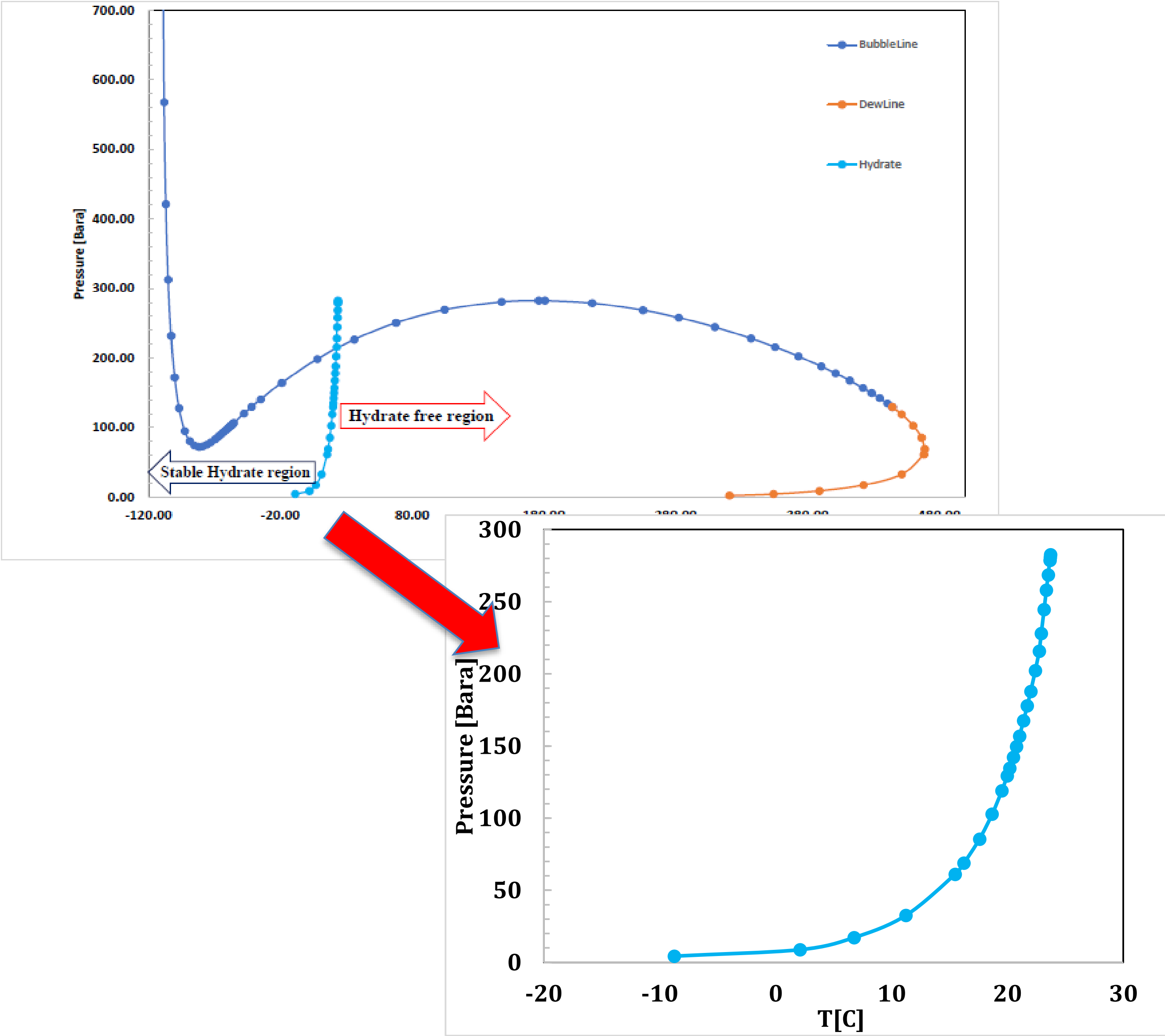

Figure 9. Hydrate curve

According to the Figure 9 and considering our study case with pressure range from 20 to 200 bar there is a risk of hydrate formation on the left side of the hydrate curve (around 20 C). We can calculate Save operating temperature (SOT) from the hydrate data at the highest pressure in our system. This temperature is our critical point for formation of hydrate and we try to avoid it by using different method such as thicker insulation, MEG injection or heating.

CHAPTER THREE

3 *Study Cases:*

It is assumed that the base case for production is a local FPSO. Chemical injection such as MEG was excluded because of its high required amounts, and a significant increase in the water phase viscosity when injected which is unsuitable for a very long liquid dominated flow line. The technical and evaluations of the following development alternatives were conducted:

- production to an FPSO
- a tie-back production over a distance of 100 km to an existing offshore platform using different flow assurance methods such as DEH and EHT
- a tie-back production over a distance of 100 km to an existing offshore platform using cold flow technology followed by transport in an uninsulated, non-heated flow line.

The production data was given from industry partners. Due to confidentiality, no details regarding the origin will be mentioned here. The field studied is located in the far North. Two non-communicating saturated oil reservoirs with gas cap should be produced. The distance between these two oil field centers is 10 km, and the water depth is 400m. A field lifetime of 22 years is planned. Gas injection and water injection have been considered as reservoir recovery methods. In water injection, the drilling injection wells into reservoir and water into that are included in order to encourage the hydrocarbon production.This water injection helps to increase deleted pressure within the reservoir.The water used for injection is usually some sort of brine or could be made up of other sources treated..On the other hand, gas injection is used on a well to enhance waning pressure within the formation. Systematically spread throughout the field, gas-injection wells are used to inject gas and effectively sweep the formation for remaining petroleum, boosting production.The gas is injected into the gas cap of the formation, whereas in water injection, the water is injected directly into the production zone.Apart from advantages of these methods,It should be pointed out that drilling injection wells could be considerably costly particularly in deepwater. Corrosion of surface and sub-surface equipment and formation damage due to the reaction of injected water with the formation water are other drawbacks.

Related production profiles are shown in Figure 10 and Figure 11. Production rate of the first reservoir is 2/3 of the total rate(Production data for both water and gas injection are provided in Appendix 3 and Appendix 4). A constant topside arrival pressure of 20 bar was assumed. The fluid temperature at the wellhead is 80 C.

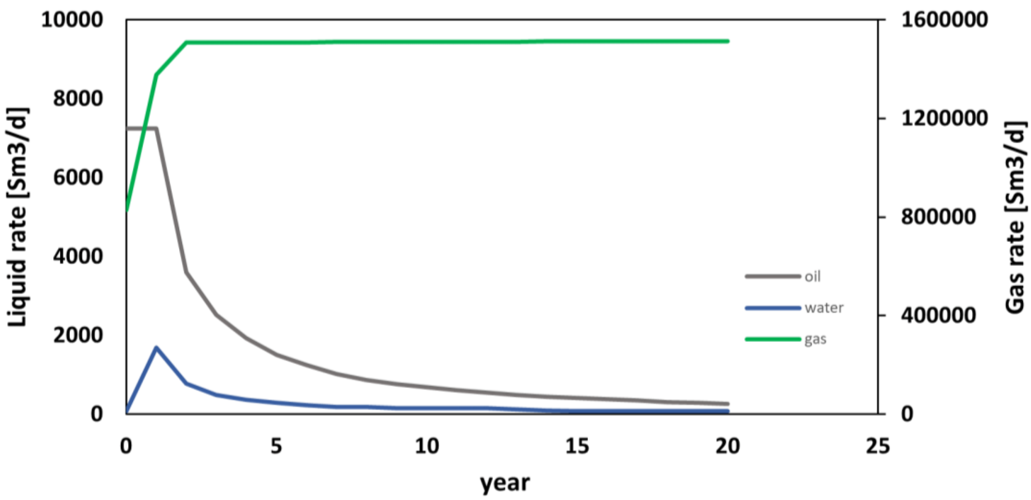

Figure 10. Production profile of Gas injection

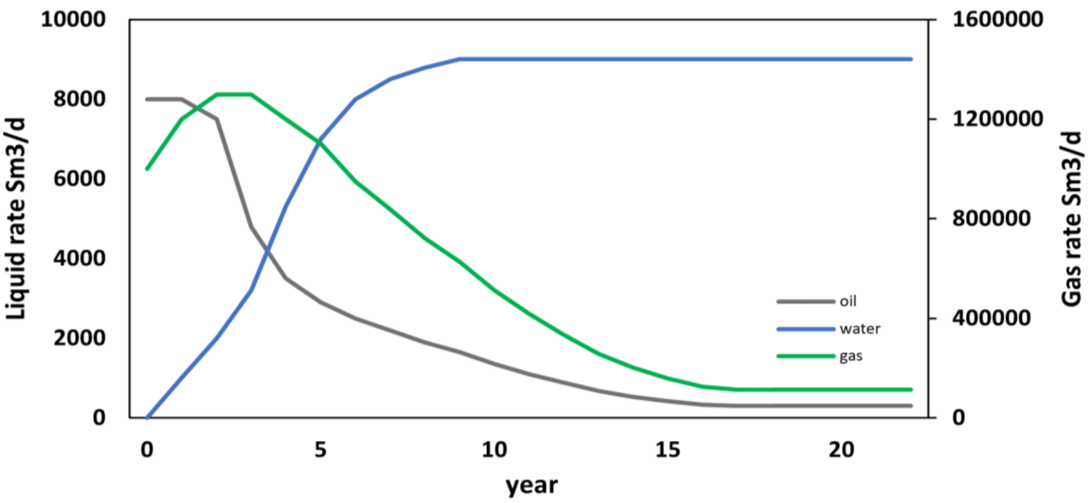

Figure 11. Production profile of Water injection

3.1 **FPSO**

The FPSO is located between the two reservoirs, which are situated 10 km apart. The riser is 388 m high, and a PiP solution was used for all flow lines with a U value of 1W/m^{2}K. Each flow line has an ID of 12 in. The material for all pipes is steel carbon. For each reservoir, flow lines and risers were modeled by Leda flow. After running the model, the pressure in manifolds was calculated.

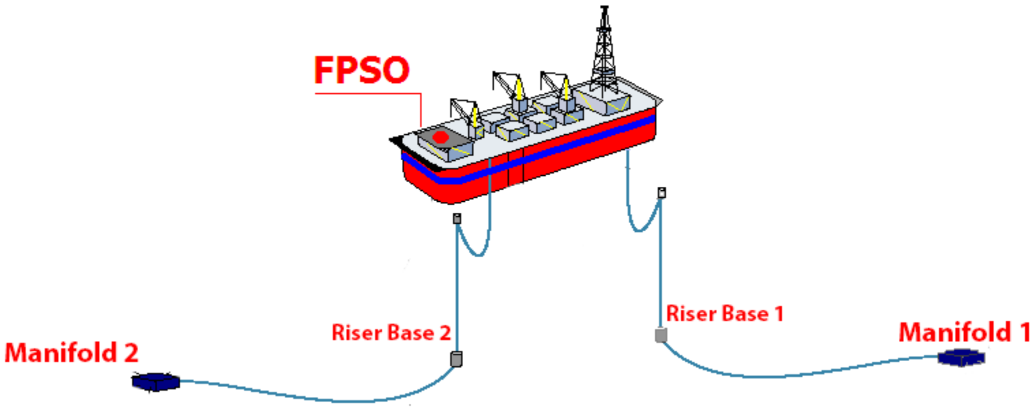

Figure 12. schematic of the FPSO model

One simulation per production year was performed. The required flow line inlet pressure for both depletion strategies was compared, see Figure 13.

At the start, reservoir pressure is high and production begins. The production causes pressure drop around the wellbore because fluids are being extracted faster than natural recharge. Then the Water injection starts to support the pressure and pushes fluids towards the production wells. Over time, injected water sweeps hydrocarbons and helps rebuild pressure in the reservoir. As water cut increases (WC rises from 0% to ~97%), water becomes dominant in the produced fluids. Since water is less compressible than oil or gas, the pressure behavior becomes more stable but shows small fluctuations due to complex multi-phase flow in the reservoir and pipeline.

On the other hand, for Gas injection, it should be noted that the gas is much more compressible than water and it tends to expand and not build pressure as effectively as water. At startup (Year 0), the reservoir is at initial conditions, with production beginning before gas injection fully stabilizes .Then at second production period the Injected gas reaches the wellbore, creating a localized pressure buildup near the well (near-wellbore. This temporarily increases bottom hole pressure (BHP), translating to higher WHP.In the following period of production, The Reservoir pressure gradually declines because Produced hydrocarbons are not fully replaced by injected gas and Gas provides less pressure support compared to water so The pressure stabilizes at a lower value.

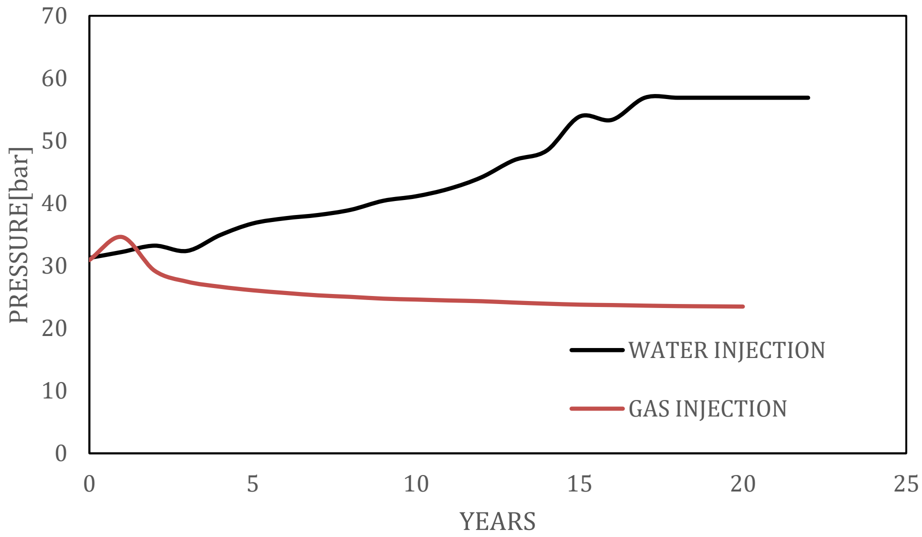

Figure 13.Wellhead Pressure profile on Manifold 1

The following Figure 14 shows the available pressures of manifolds which is acquired by SINTEF. This provided data calculated with a reservoir and well model for the two reservoirs over time. As expected the Second figure shows the pressure drop for Gas injection case was considerable and at the end of the production reaches to the approximately 160 bar.

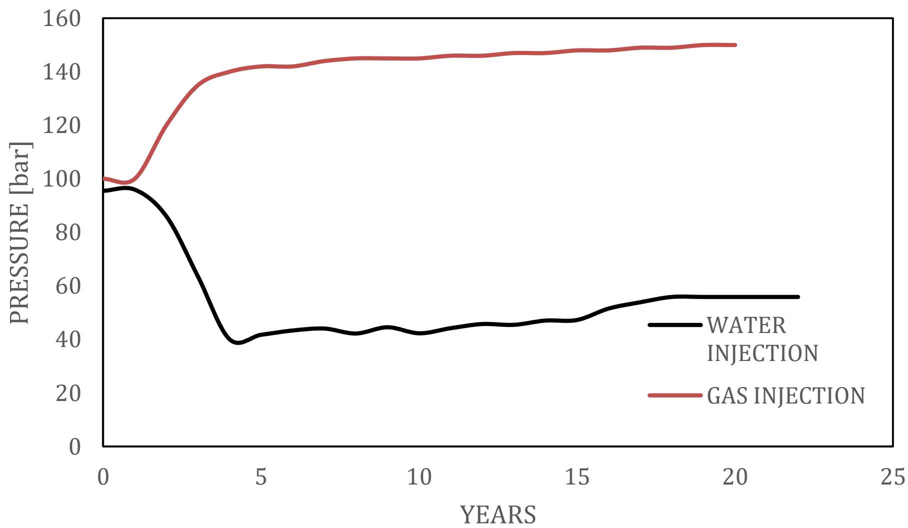

Figure 14. Available pressure which is given by SINTEF

Based on maximum pressure in pipeline the SOT (save operate temperature) was determined to find out the hydrate formation temperature. It is the minimum operating temperature which should be maintained in the pipeline to avoid hydrate or wax formation.

At 160 bar ➔ critical temperature =20.7° C➔ SOT= 21° C

In this study the wax appearance temperature(WAT) is assumed to be at 30 °C based on the lab tests. Since the WAT is higher than SOT, 30° C is considered as governing factor to prevent wax deposition.

The result of simulation shows the arrival temperature profile for water injection case. At first year this temperature stands on 73° C, even though fluid exits the wellhead at 80°C**,** heat loss happens immediately as the fluid moves through flow lines exposed to cold seawater(T=4°C). As production continues, reservoir pressure decreases, and the liquid production fraction increases (more liquids, less gas). Liquids have higher heat capacity than gas, so they retain temperature better. As a result, fluid temperature slightly increases over time as the liquid ratio grows. The observed temperature fluctuations during the mid-life of the water-injection scenario are attributed to the combined effects of increasing water cut and decreasing total production rate. As the water content surpasses 90%, the heat retention capability of the produced fluids diminishes, leading to larger thermal losses and sensitivity to flow regime changes. These dynamic variations in fluid properties and flow conditions are accurately captured by the transient thermal-hydraulic coupling in Leda flow, resulting in the small oscillations observed in the production temperature profile.

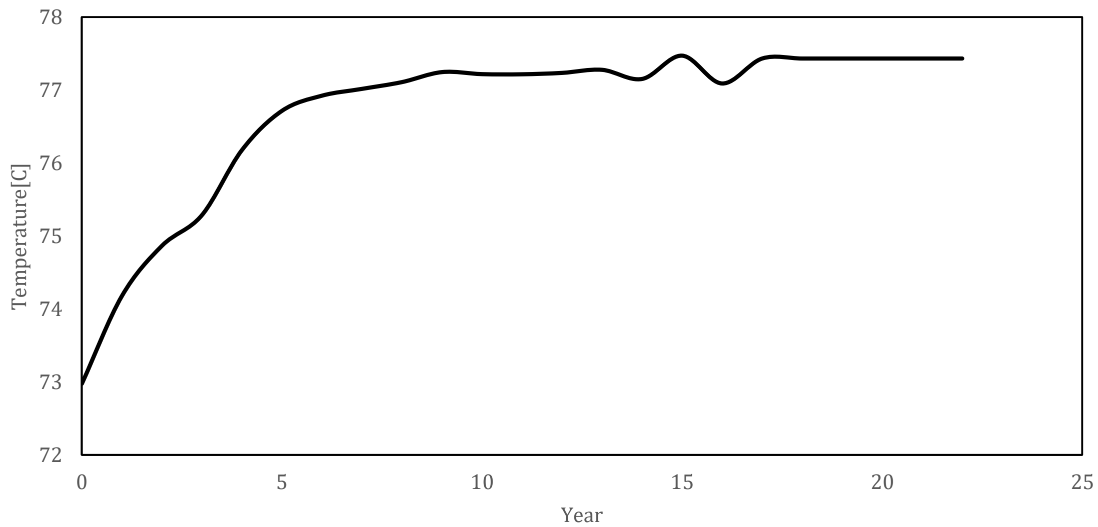

Figure 15. Arrival temperature for water injection

Given that 21° C is the temperature at which hydrate formation occurs, it can be seen clearly from figure above that we are far way form this point by minimum temperature of 73°C.

It was found that production without heating or boosting is possible throughout the lifetime. Despite the good flow performance, construction, moving, and operating the facility are quite expensive and the FPSO case can be assumed to be the most cost-intensive case.

3.1.1 Sensitivity analysis of pipe ID:

In order to determine which diameter is more efficient for transportation three common sizes were selected for this part. Since the effect of diameter is significant on wellhead pressure, a full comparison of the wellhead pressure outputs is presented below Figure 16.

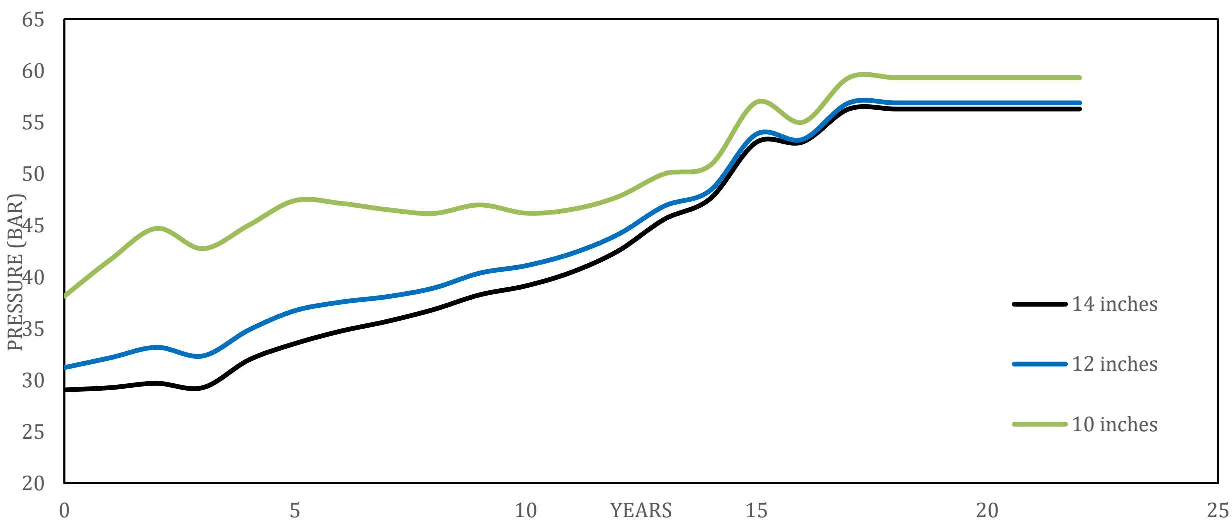

Figure 16. Comparison of pressure profile to determine the optimal ID for piping

According to the figure above and the table in appendix, the smaller the ID, the higher pressure drop in the pipeline will be. High pressure drop results in poor system performance and excessive energy consumption. The pipes with 12-inch and 14-inch showed lower pressure drop. The Graph indicates that both IDs have overlapping pressure profiles maintained almost the same pressure but the 12-inch saves material and installation costs (CAPEX). So 12” pipe ID would be preferred for the modeling cases.

3.2 Tie back

In the tie-back case a 100 km horizontal flow line with 12 in. inner diameter was modeled connecting the two wells to a receiving processing facility (platform). The pipe dimension was investigated in a pre-study concluding that 12 in. is a good compromise with respect to pressure drop and cost. The two manifolds are connected to the flow line at x_1 = 0 km and x_2 = 10 km. For this case I have modeled two different hydrate inhibitor methods:

1-Pipe in pipe with EHT

2-Insulation with DEH

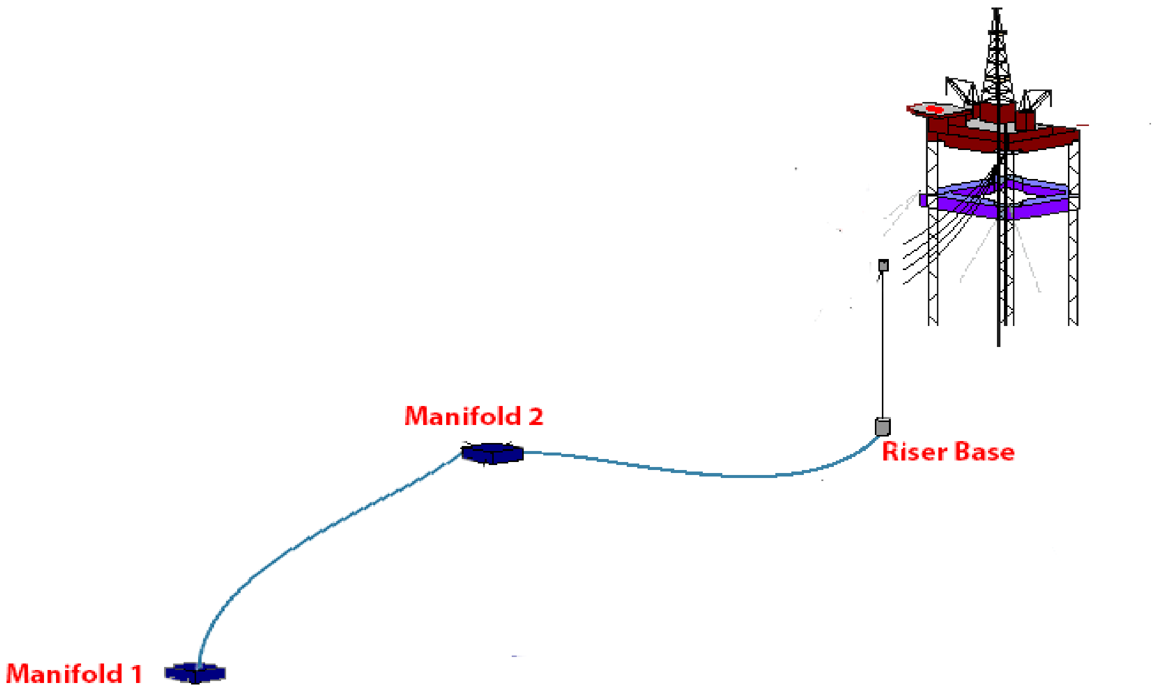

Figure 17. schematic of tie back case

The modeling was divided into two groups, as two different depletion strategies were employed:

3.2.1 Water Injection:

3.2.1.1 Tie back PIP EHT:

In this option, water injection is employed as a depletion strategy alongside PIP (Pipe-in-Pipe) technology to maintain thermal energy within safe operational limits across the system. The purpose of this simulation is to compare the modeled pressure with the available wellhead pressure, thereby assessing the need for booster installation. Subsequently, an evaluation is required to determine whether PIP alone suffices to keep fluid temperatures above wax and hydrate formation thresholds or if supplemental electrical heat tracing (EHT) must be implemented."

At the beginning of production (Year 0), while the production rate was 8,000 Sm^3/day, the pressure increased due to the combined effects of rising water cut (WC) and gas-oil ratio (GOR). By Year 3, however, the production rate declined sharply, causing a temporary drop in the pressure profile. This was followed by a gradual pressure recovery until Year 5, coinciding with a steep rise in both WC and GOR. Beyond Year 5, the pressure decreased steadily as the production rate continued to decline, while the GOR remained constant.

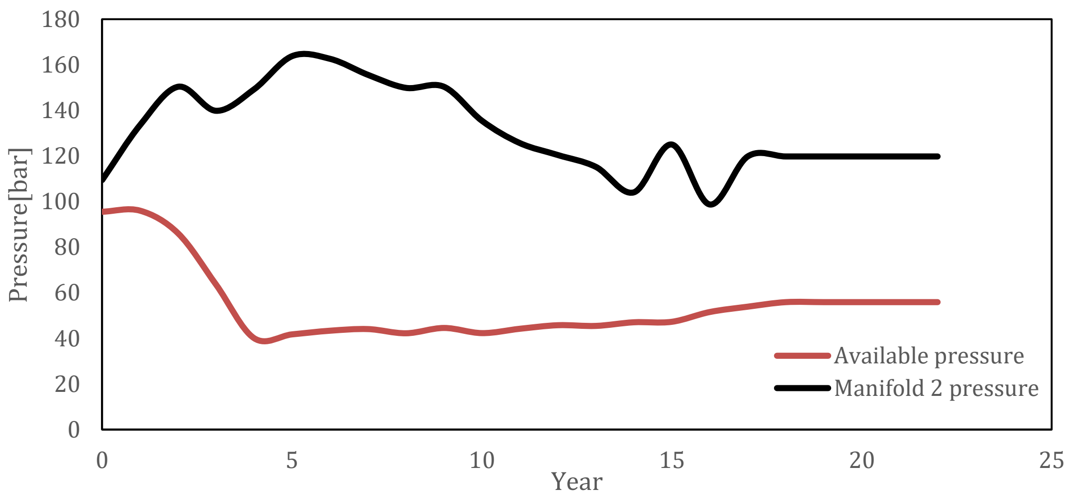

Figure 18. Pressure profile for water injection

The flow line inlet pressure (required pressure) was compared with the available wellhead pressures in the Figure 18. If the wellhead pressure was higher than the available pressure, the required boosting was applied just after the manifold, and the simulation was repeated.

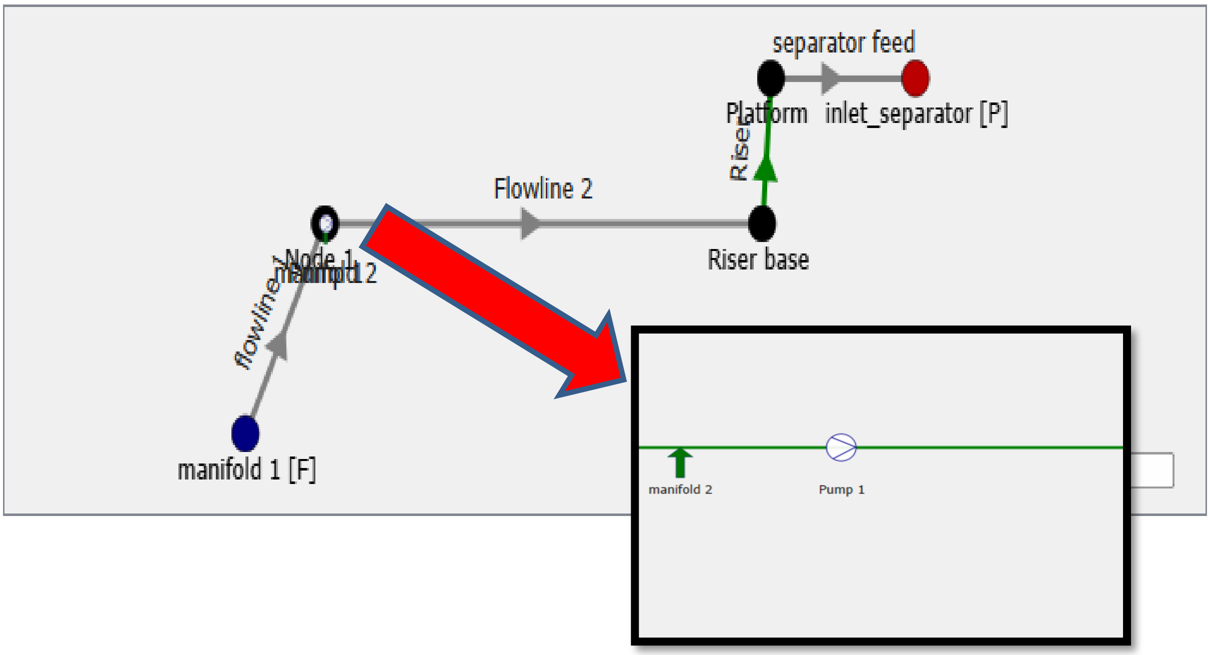

Figure 19. LedaFlow GUI of the tie back model and location of the booster

Regarding the fact that the wellhead pressure was significantly higher than the available pressure, particularly, in year 5, the required boosting was applied. The location of installing a booster pump is just after the connection of the second manifold, see Figure 19.

In the figure below, the pressure difference that a pump needed to compensate is reported. As can be seen clearly, in the beginning of production, oil rate decreased steadily while GOR and WC increased until year 5 with 125 bar. At this point we have the maximum pressure drop before starts to fall. The reason behind this drop is having the low rate of oil production and constant GOR.

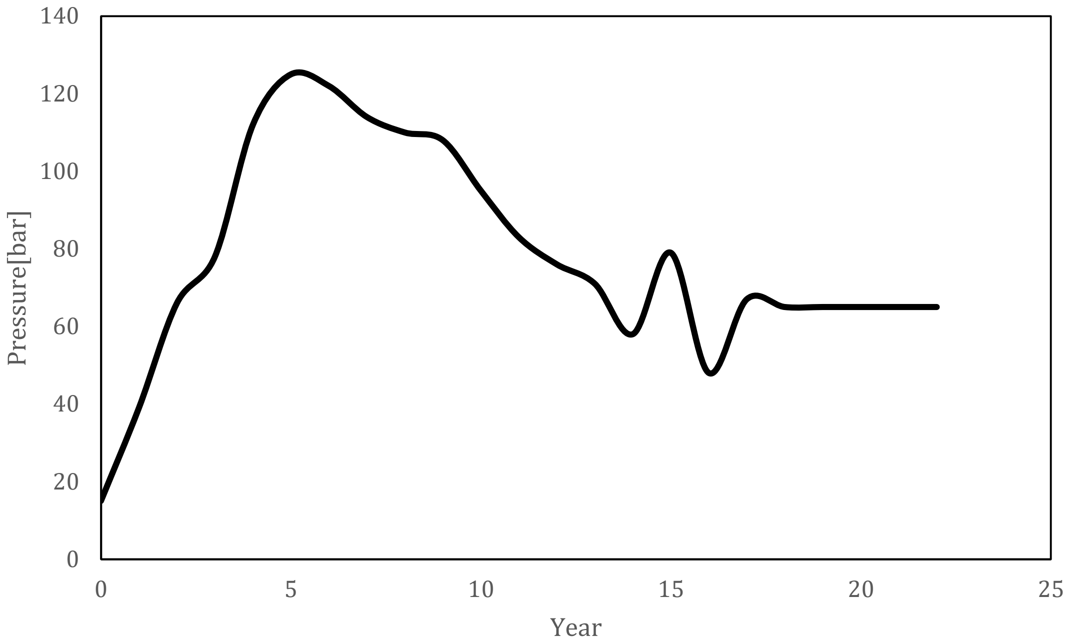

Figure 20. Required boosting pressure drop for water injection case in Tie back PIP EHT

The efficiency of a multiphase pump is strongly dependent on the gas volume fraction. This dependency was considered as shown in the following figure. An efficiency independent of the flow rate was considered. This assumption holds due to the fact that the total flow rate is relatively constant throughout the lifetime of the field (declining oil production is replaced by increasing water production).

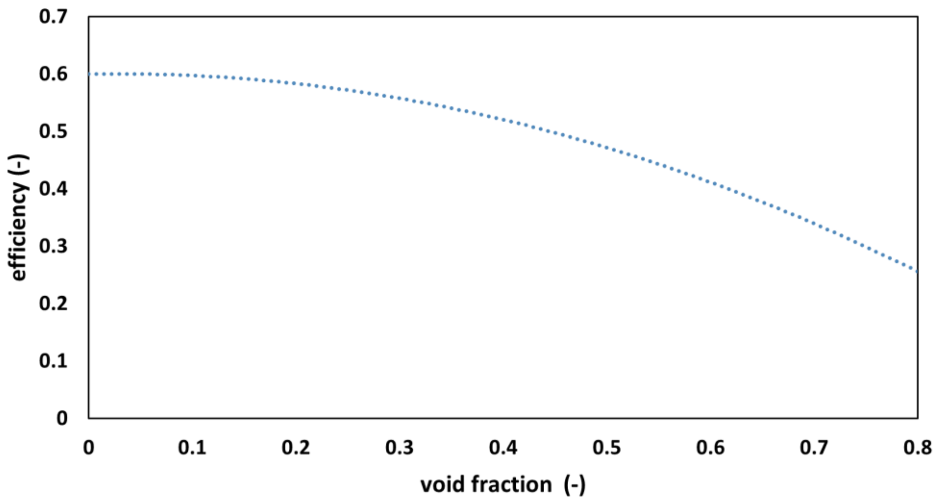

Figure 21. boosting efficiency profile vs gas volume fraction

The arrival temperature profile demonstrates that during the first five years of production, while hydrocarbons remained the dominant phase, the system experienced relatively low heat loss as temperatures increased steadily. However, once water cut exceeded 70%, the temperature profile showed a distinct decline, resulting in greater thermal losses.

Analysis of the arrival temperature data confirms that throughout all production years, fluids are delivered above 40°C. This temperature maintenance ensures that neither hydrate formation nor wax deposition occurs in the pipeline, consequently eliminating the need for electrical heat tracing (EHT) supplementation.

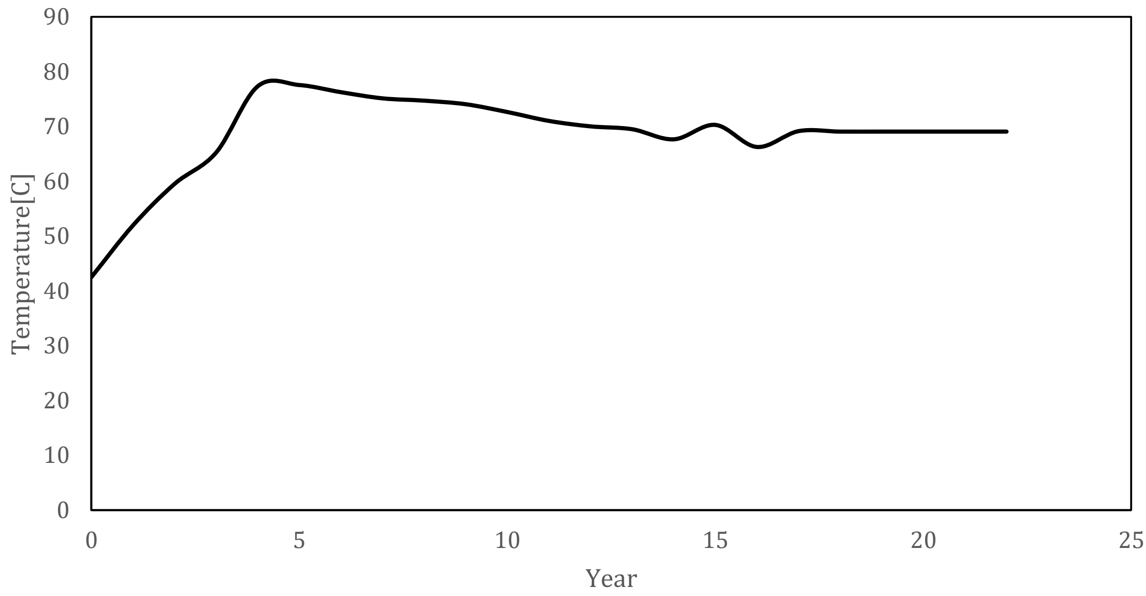

Figure 22. The arrival temperature for water injection case in Tie back PIP EHT

3.3.1.2. Tie back Wet Insulation with DEH:

For this comparative analysis, an alternative model was developed utilizing wet insulation rather than PIP technology to evaluate differential energy losses between the two systems. The selected insulation material consists of foam layers with thicknesses of 93 mm for flow lines and 50 mm for risers, representing standard industrial practice. These dimensions reflect the optimal balance between thermal performance and economic feasibility, as excessive insulation thickness would not only incur prohibitive costs but could also compromise riser stability.

Due to Leda flow's modeling constraints preventing simultaneous simulation of insulation and Direct Electrical Heating (DEH), an equivalent overall heat transfer coefficient (U-value) was calculated for the specified insulation configuration. As demonstrated in the Figure 23, the derived U-value of 2.7 $W/m^2 \cdot K$ was applied uniformly across all pipeline segments to maintain thermal consistency in the analysis.

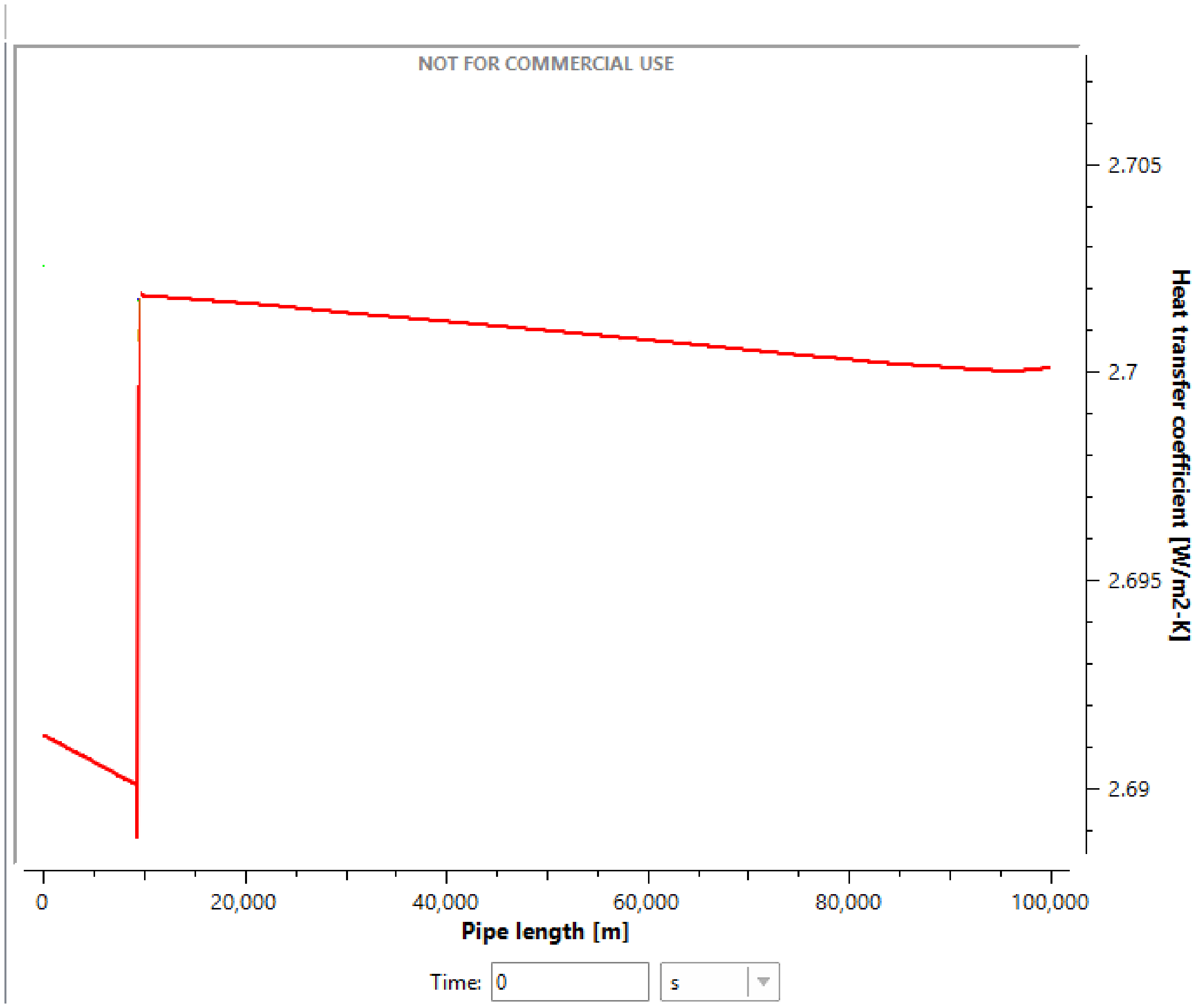

Figure 23. Heat coefficient profile through the pipe line

It is noteworthy that the pressure profiles for both the Pipe-in-Pipe (PIP) and wet insulation systems demonstrate nearly identical behavior. This similarity suggests that, from a hydraulic perspective, the two insulation methods provide comparable pressure maintenance capabilities under the given operating condition.

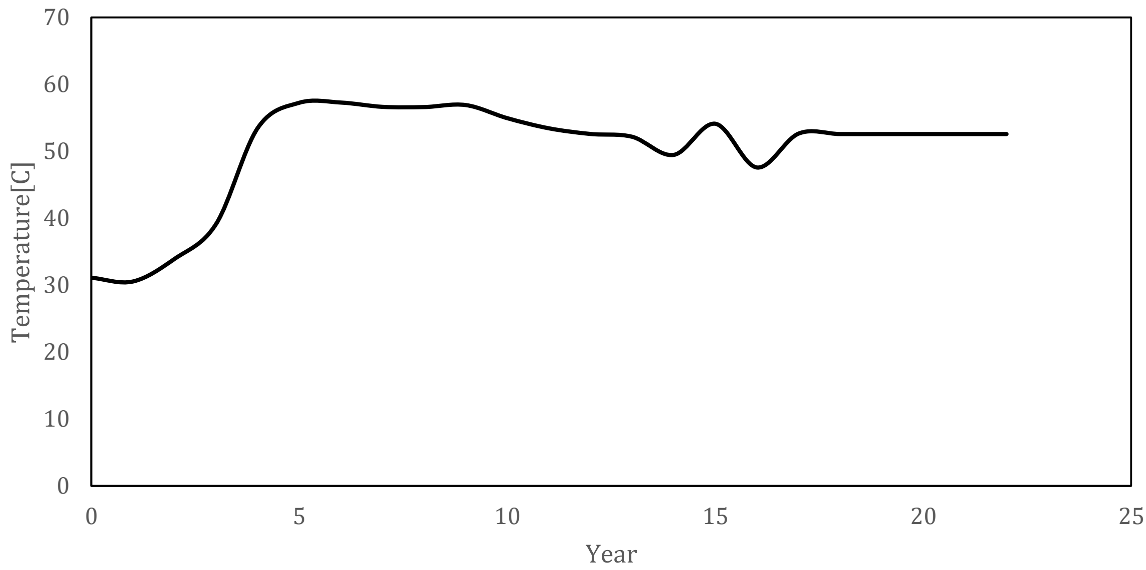

Figure 24. The arrival temperature for water injection case in Tie back wet insulation DEH

Based on temperature profile Figure 24,solid paricles started to form for the first and scond year of production due to heat loss at the end of flowline near the platform. To mitigate this risk, a Direct Electrical Heating (DEH) system was implemented along the entire pipeline length specifically for this initial period. The system was configured with a 60% thermal efficiency rating to balance energy consumption with thermal management requirements.

Through sensitivity analysis, it was determined that power inputs of 5 MW and 2 MW are required to maintain operational parameters within the flow assurance safety envelope. This power range ensures adequate thermal management while optimizing energy efficiency.

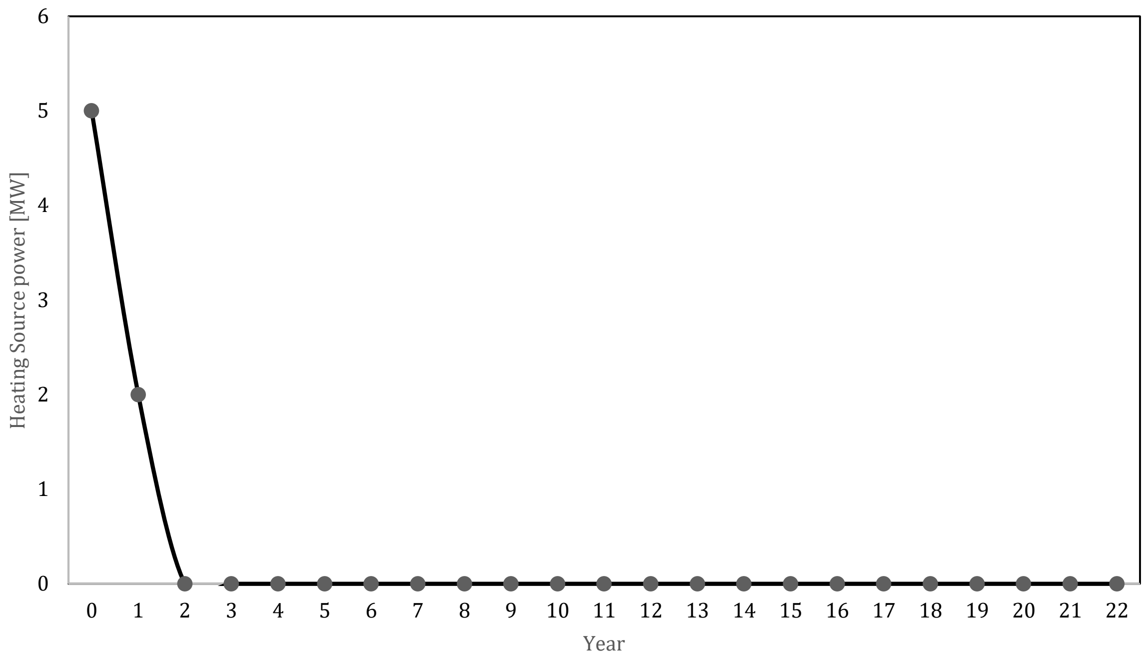

Figure 25. The Required Power for DEH in water injection case

By comparing the results of the PIP and DEH technologies, it can be concluded that PIP is better solution for water injection because of the elimination of active heating infrastructure, resulting in significant capital and operational cost savings, and environmental impact reduction through lower energy consumption.

3.2.2 Gas Injection:

3.2.2.1 PIP with EHT:

For this analysis, a uniform overall heat transfer coefficient (U-value) of 1 W/m²·K was applied to all pipeline segments. In the electrical heat trace system, the heating efficiency was set to 90%, meaning that only 90% of the topside power input is effectively transferred as thermal energy to the pipeline. The heating system was configured to provide constant heat input per unit length (W/m) along the entire flow line.

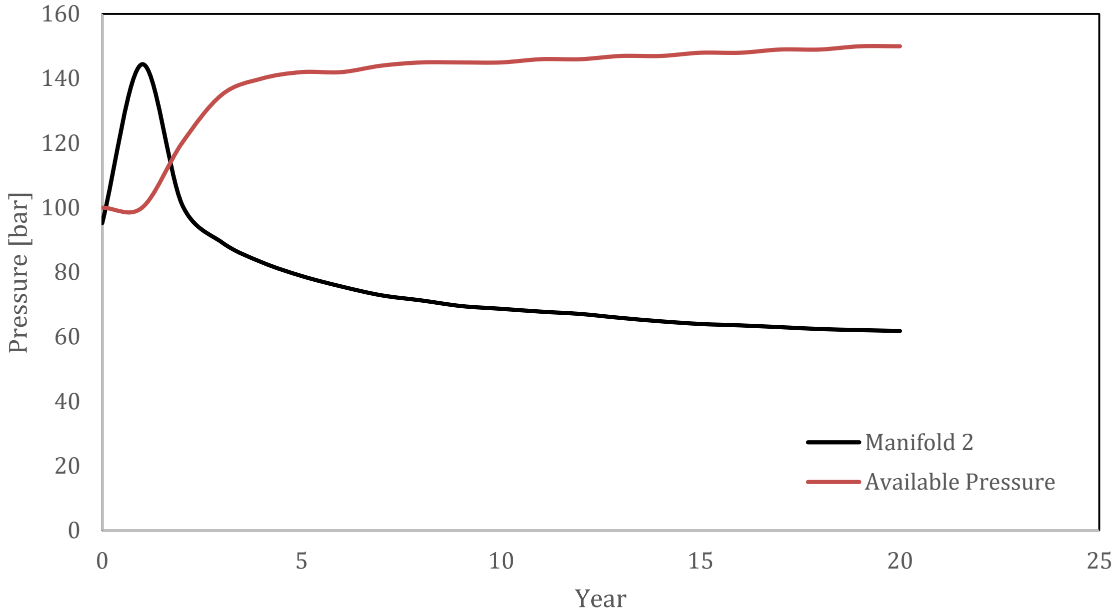

Figure 26. Pressure profile for Gas injection in PIP with DEH

As indicated in Figure 26. The wellhead pressure initially rises during the first 2 years due to effective gas injection support and low water cut (WC <20%), which maintains high reservoir pressure and minimizes frictional losses. After peaking at Year 2, pressure gradually declines as production rates drop and gas-oil ratio (GOR) increases, reducing fluid density while introducing more compressible energy losses. Despite rising GOR (reaching ~1200 Sm^3/Sm^3), late-stage stabilization occurs as gas lift efficiency balances declining liquid rates, though pressure eventually approaches the available pressure limit, signaling near-abandonment conditions. This behavior reflects gas injection's transient benefits—early pressure support followed by gas breakthrough and declining reservoir energy—while highlighting the system's transition from liquid to gas-dominated flow.

In addition to this, the pressure profile shows that the available wellhead pressure for second year of production is considerably higher than required flow line inlet pressure but for the remaining period it is much lower. This is a consequence of the different production profiles with much lower liquid rates and higher gas production leading to both reduced frictional pressure losses and lower static pressure loss in the wells and riser due to a reduced mixture density at high GOR. All cases can be produced by natural flow without boosting except for year 2.

For this specific production year, two mitigation strategies can be evaluated: (1) temporary installation of a booster pump for one year, or (2) moderate adjustment of the production profile through controlled rate reduction. Each approach presents distinct operational and economic trade-offs that require careful analysis

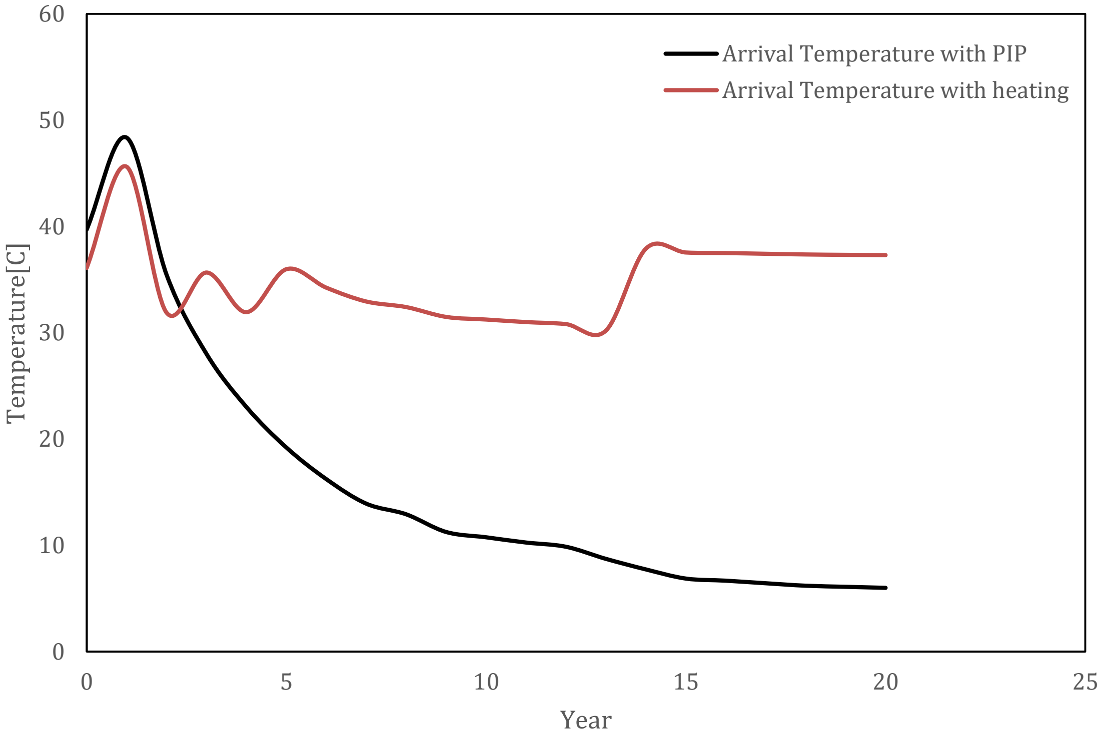

Figure 27. Temperature profile for Gas injection case

Figure 27 compares the arrival temperature profiles with and without Electrical Heat Tracing (EHT). The analysis reveals that without thermal intervention, the system would experience temperatures below hydrate formation thresholds by Year 3, creating a significant flow assurance risk. This thermal deficit could lead to hydrate particle formation and potential pipeline blockage

The Leda flow sensitivity analysis was performed to determine optimal energy requirements for maintaining fluid temperatures above the Wax Appearance Temperature (WAT) of 30°C yielded the following findings: During the initial three years of production, natural thermal conditions remained sufficient to prevent both wax deposition and hydrate formation. However, beyond this period, thermal modeling indicates that supplemental heating exceeding 2 MW becomes necessary to maintain flow assurance Figure 28.

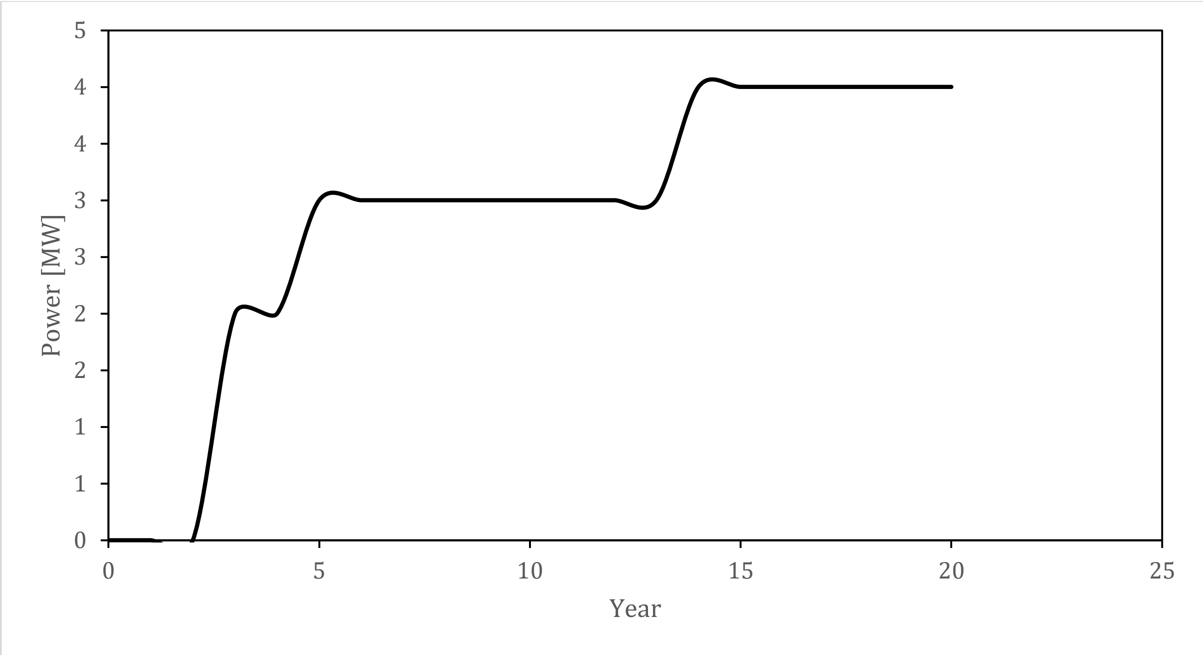

Figure 28. The required power for EHT in gas injection case

3.2.2.2 Wet insulation with DEH:

On this method, pipeline insulation with a U-value of 2.7 W/m²·K was selected. Given the implementation of gas injection as the depletion recovery method—where gas becomes the dominant phase with its inherently lower heat capacity—a greater temperature drop along the pipeline was anticipated. The results demonstrate that, compared to PIP technology, this configuration would lead to earlier hydrate formation and wax deposition risks across all production years if Direct Electrical Heating (DEH) were not implemented. However, by applying DEH to maintain fluid temperatures above the critical thresholds for both wax appearance (30°C) and hydrate formation, all flow assurance risks can be effectively mitigated.

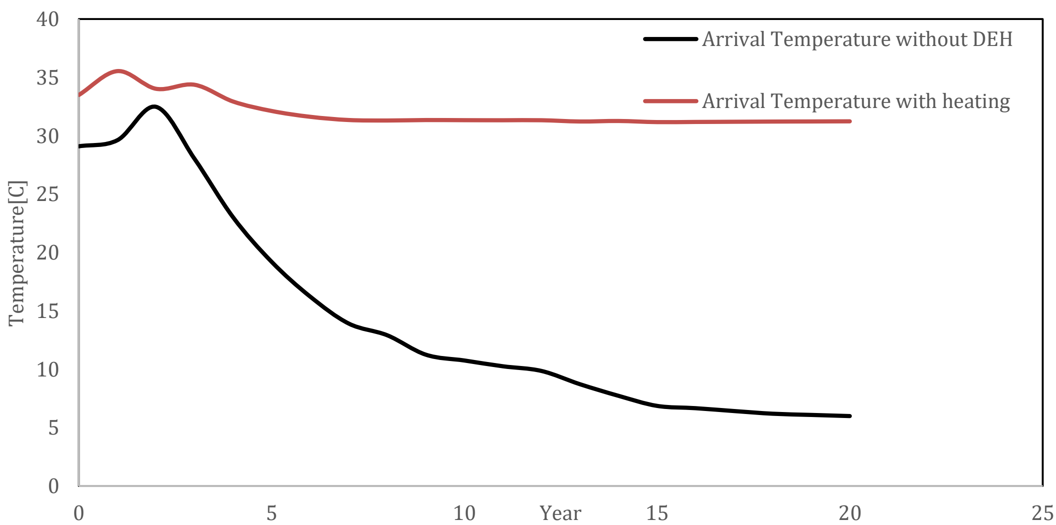

Figure 29. Comparison the arrival temperature using DEH on the pipeline

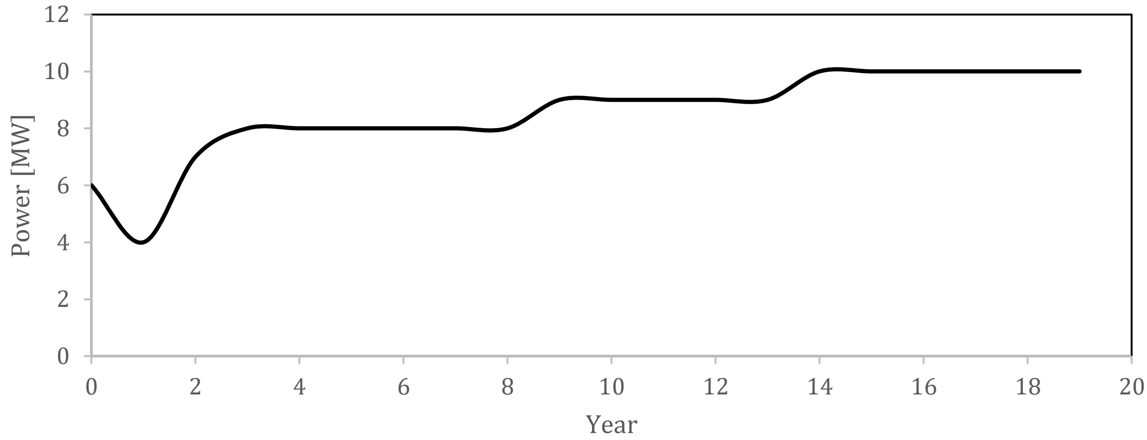

Figure 30. Power consumption for gas injection case in Tie back wet insulation with DEH

Figure 30 shows the power consumption requirements for the Direct Electrical Heating (DEH) system. The analysis demonstrates that DEH represents an energy-intensive solution, demanding a minimum of 4 MW to prevent wax and hydrate formation during the second production year, with requirements escalating to 10 MW by the end of field life. This significant energy demand not only results in substantial operational expenditures but also raises environmental concerns due to the associated carbon footprint.

3.3 Cold flow:

The Cold Flow system implementation follows a similar configuration to the standard tie-back case, with the addition of a cooling unit positioned downstream of the second manifold booster. After cooling unit, the system employs a 100 km uninsulated flow line without any mechanisms thermal control extending to the platform. A critical design constraint requires complete prevention of hydrate and wax formation in the distance between first and second manifold flow line. As the result of analysis demonstrated in the tie-back case where hydrate blockage risks were observed without proper insulation. Consequently, Pipe-in-Pipe (PIP) technology was selected for this specific segment. The cooling unit comprises multiple bare parallel pipes. The number, inner dimension size and the length of these pipe are determined by parametric study in Leda flow. The simulation is repeated until achieving complete water conversion to hydrates. When incomplete solid particle formation occurs, the system parameters are iteratively adjusted with dual optimization criteria: (1) minimizing capital and operational costs while (2) maintaining environmental performance. The adjustment process prioritizes three key factors, in order of importance: technical feasibility, reduction of total pipe count, and minimization of cooler length. It is assumed that after the hydrate formation, there is no possibility of blockage in flow line considering that these particles are basically inert and will not aggregate into larger particles or stick to the pipeline wall.

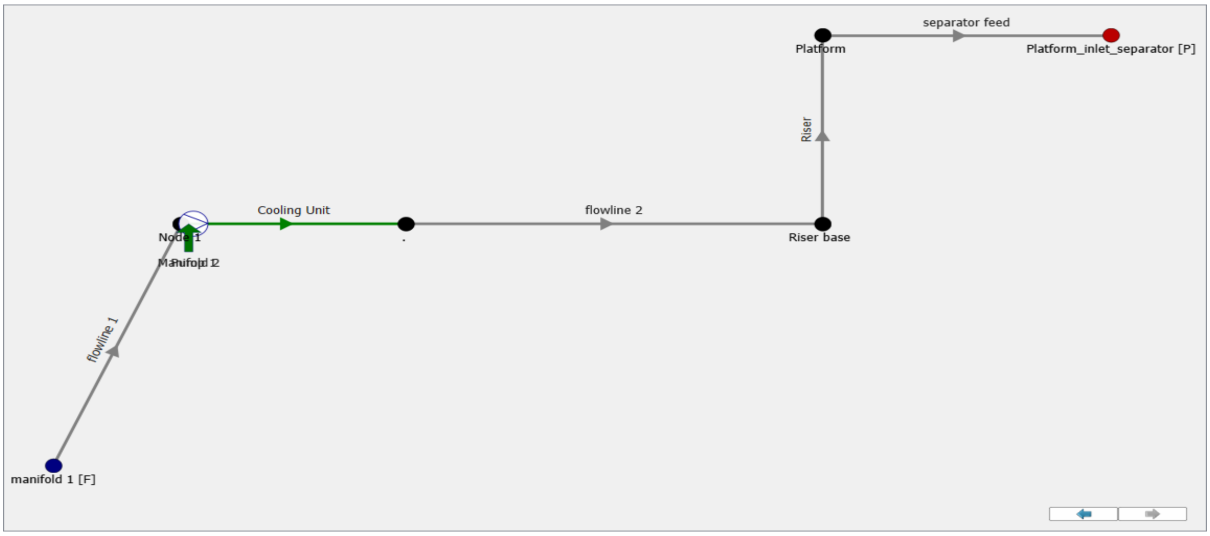

Figure 31. GUI of the cold flow model and location of the booster and cooling unit

To analyze the hydrate parameters such as hydrate volume fraction, the so-called "hydrate transport" option was activated in Leda Flow. This model predicts the hydrate formation forming a hydrate slurry similar to a solid particle flow. This will also lead to a viscosity increase depending on the hydrate particle fraction.

Extensive simulation iterations were conducted to determine the optimal cooling unit configuration that ensures complete hydrate formation prior to the bare flow line segment. Selected results from this optimization process are presented in the Appendix 5.

3.3.1 Water injection:

In this case, where water constitutes the dominant phase and serves as the primary component for hydrate formation, the system design necessitates an extensive cooling unit capacity. This requirement stems from the need to achieve complete water-to-hydrate conversion while maintaining flow assurance throughout the production system

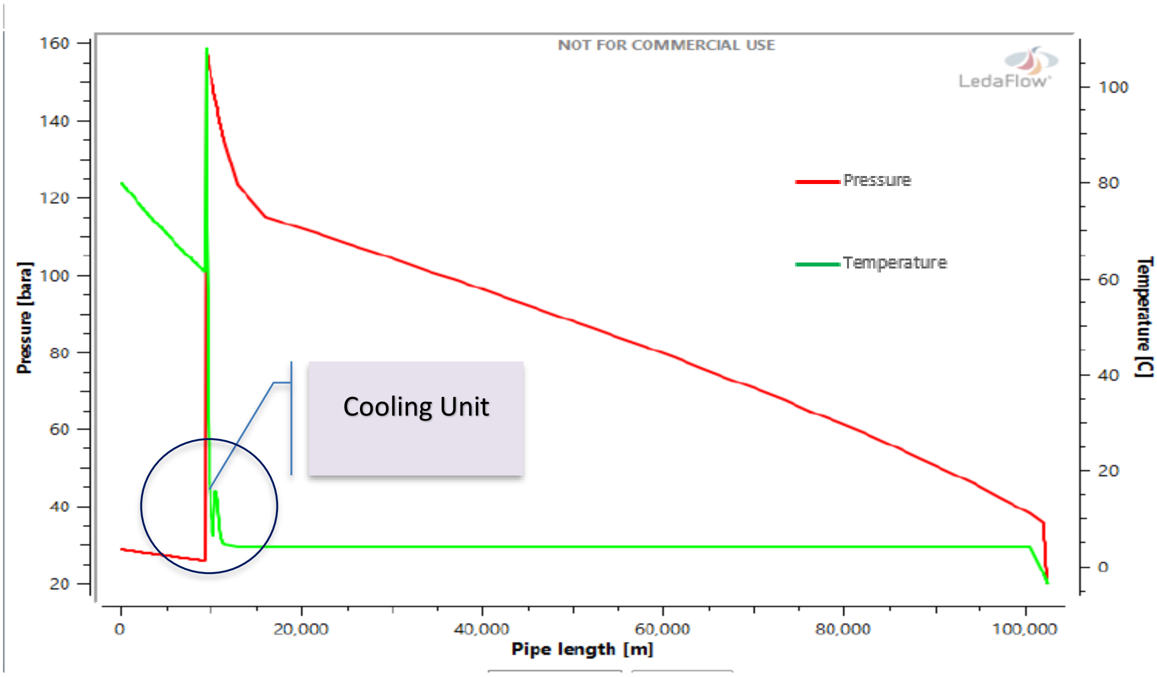

Figure 32. Pressure and temperature profile for water injection case in cold flow technology

The green line represents the temperature change in flow line for the second year of production when the GOR= 125 WC=0.11. It can be seen that the warm fluid with 80° C flows through the flow line which is equipped with PIP to prevent hydrate formation. After passing 10 km the temperature reaches approximately 60 °C where meets the second manifold. There is a sudden increase in temperature because the hydrocarbon flows to the booster. Then in the cooling unit and within the 2 km length it loses the heat energy considerably reaching to ambient temperature,4°C. On the other hand, the pressure trend (red line) shows the small drop in before reaching the second manifold (around 5 bar), sharp increase from 25 to 160 bar across the booster and cooling unit, then gradually declines to 20 bar at the platform arrival point.

Hydrate formation induces a measurable increase in fluid viscosity, which directly impacts system pressure drop. The viscosity profile was evaluated under continuous oil phase conditions, with results demonstrating that post-hydrate formation, the oil phase viscosity remained within the 10-20 cP range.

An additional critical parameter requiring analysis is fluid viscosity. As the solid hydrates are formed, the viscosity of the fluid would be increased which will effect on pressure drop in the system The viscosity profile was evaluated under continuous oil phase conditions. As shown in the Figure 33, after forming all hydrates, the viscosity of fluid in oil phase remained between 10 to 20 CP. The viscosity increase attributable to hydrate formation occurs exclusively at the 10 km mark, coinciding with the location of the cooling unit. The downstream viscosity increase is caused by oil degasification resulting from pressure reduction along the flow line.

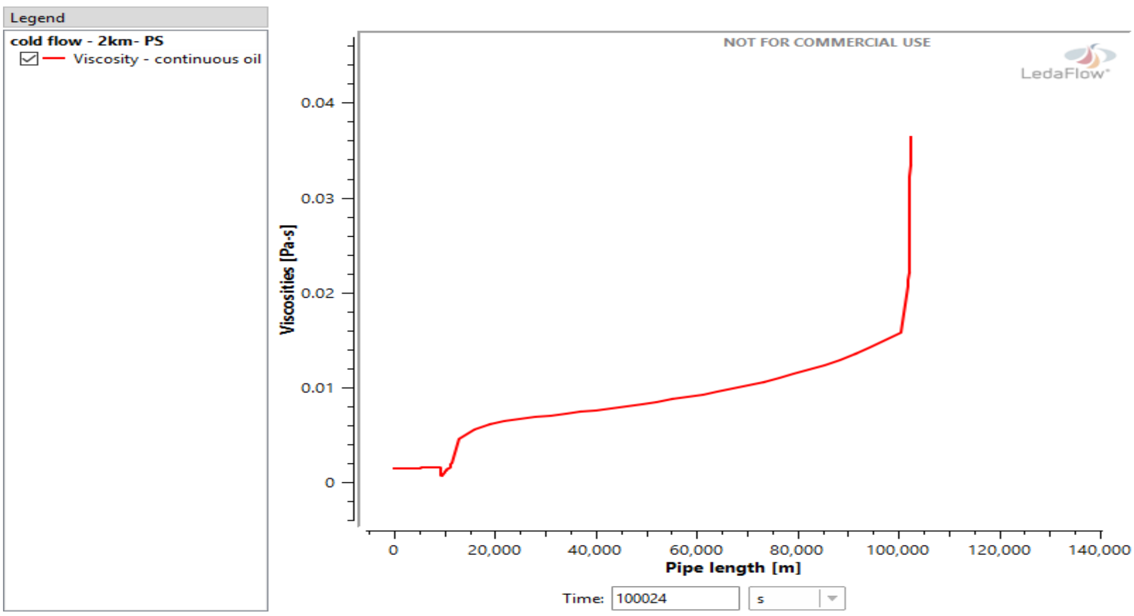

Figure 33. Viscosity profile through the flow line for water injection case in cold flow technology

For the following years, simulations were repeated using identical cooling unit specifications. However, the 2 km length proved insufficient for complete hydrate formation due to increasing water production rates. For example, in Year 5, the hydrate volume fraction reached 0.35 downstream of the cooling unit, indicating incomplete conversion. Subsequent simulations demonstrated a progressive annual increase in hydrate volume fraction throughout the field's production life, culminating in the highest values during late-life production.

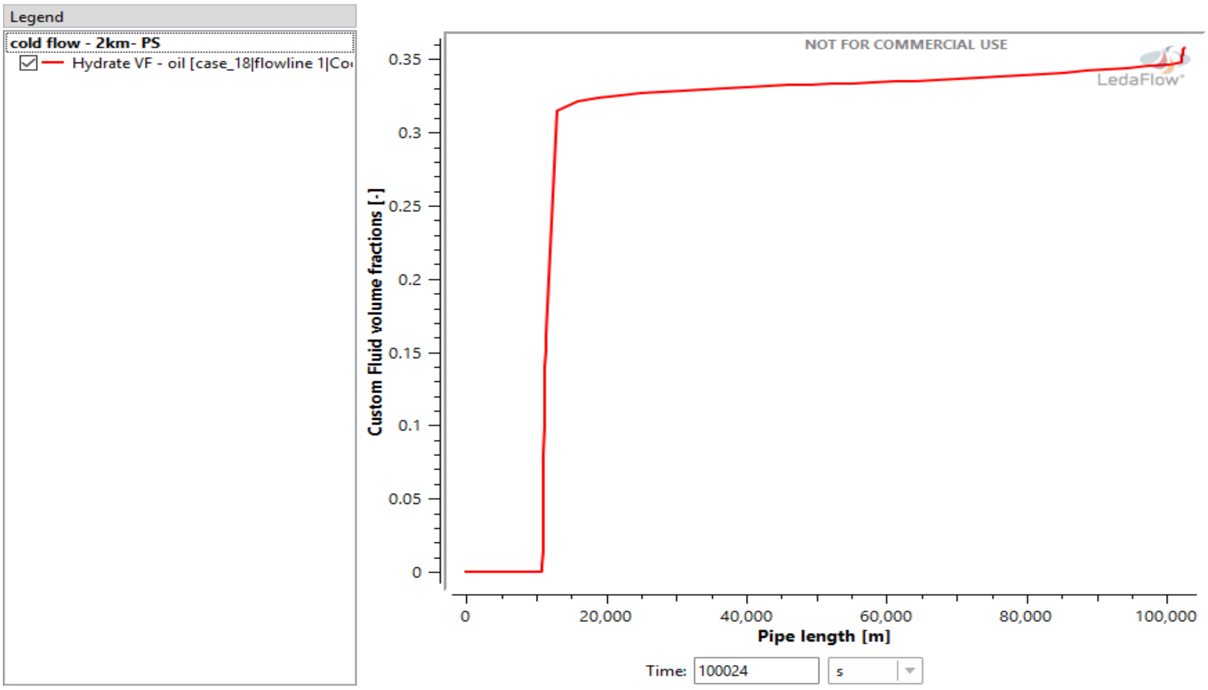

Figure 34. Hydrate volume fraction profile through the flow line for water injection case in cold flow technology

Furthermore, the pressure profile for the same production year (see Figure 32) exhibits a significant pressure drop indicating that more than one booster is required in the system. This elevated pressure loss directly correlates with the increased hydraulic resistance caused by higher hydrate slurry viscosity.

Given the inefficiency of extending cooling pipe length or adding booster pumps (due to both capital and operational energy costs), implementation of subsea bulk water separation emerges as the optimal solution. This approach would reduce inlet pressure requirements, thereby diminishing the need for maximum boosting pressure. Under optimal conditions, it could potentially enable natural flow production without artificial boosting.

3.3.2 Gas injection:

This numerical model utilizes gas injection production data and incorporates a cooling unit with the following specifications: five parallel uninsulated pipes, each measuring 4 inches in internal diameter and 2 km in length. These parameters were optimized through an iterative parametric study conducted in Leda Flow (see Appendix for selected iterations). To prevent hydrate formation in the distance between first and second manifold, Pipe-in-Pipe (PIP) technology with an overall heat transfer coefficient (U-value) of 1 $W/m^2 \cdot K$ was implemented for this flow line.

The second production year was selected as the basis for evaluating this depletion strategy, as it represents the most thermodynamically critical period due to high rate in water production with respect to high oil rate, which leads to have the highest heat capacity. This selection criterion ensures that if the cooling unit successfully achieves complete hydrate formation during this challenging operational phase, flow assurance will be maintained throughout the entire production lifecycle

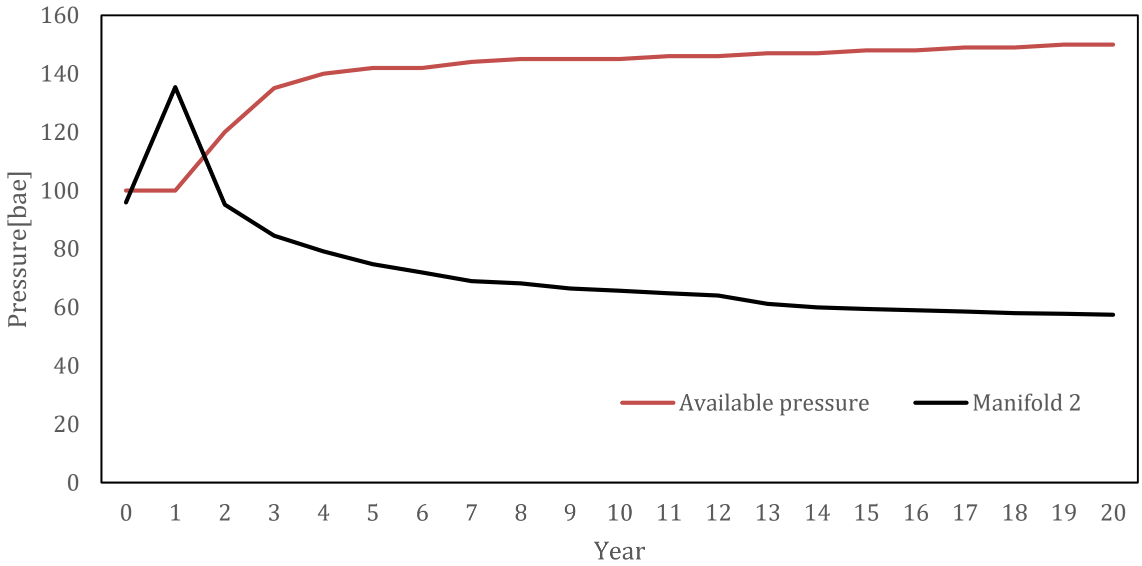

Figure 35. Pressure profile for Gas injection in Cold flow technology

From the figure above, it can be seen that for the second year of production, the simulated pressure exceeded the available wellhead pressure. In contrast, all subsequent years demonstrate simulated pressures consistently below the available wellhead pressure by an average of 60 bar. The combination of high plateau oil production and initial water breakthrough causes significantly higher pressure losses. In subsequent years, both total liquid production and the resulting pressure loss decrease substantially. Therefore, the system requires booster support only during the second production year.

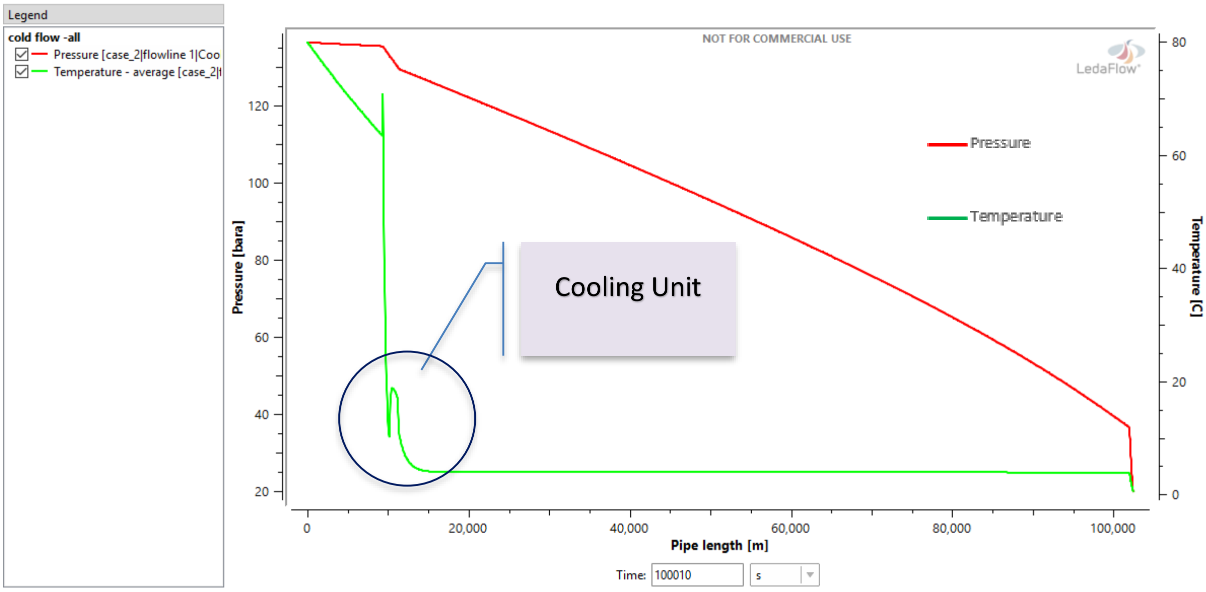

Figure 36. Pressure and temperature profile for gas injection case in cold flow technology

The green line shows the temperature change in flow line for the second year of production when the rate of oil is high, GOR is 190 and WC=0.18. The temperature profile follows a similar trend to the water injection case, though without booster heating, resulting in a maximum pre-cooler fluid temperature of 80°C.

Viscosity of the fluid in continuous oil phase is reported for the second year in Figure 37. Compared to the Water injection case, the viscosity for gas injection is much lower by considering that this is the most critical year and all solid particles are formed. This is mainly because the dominant phase is gas, with low water production.

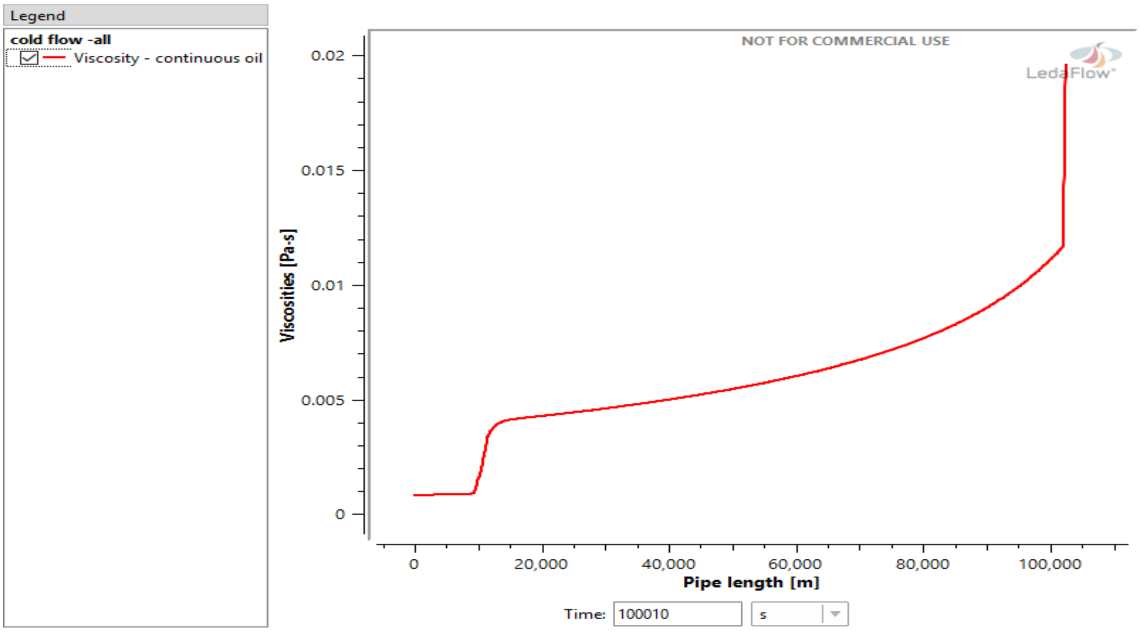

Figure 37. Viscosity profile through the flow line for second year-gas injection case in cold flow technology

The figure below shows the hydrate volume fraction at year 2. Based on the values determined on the figure, it can be observed that the hydrate volume fraction is only 20% for a production year with high gas-oil ratio (GOR) and high water cut (WC) with respect to oil production.

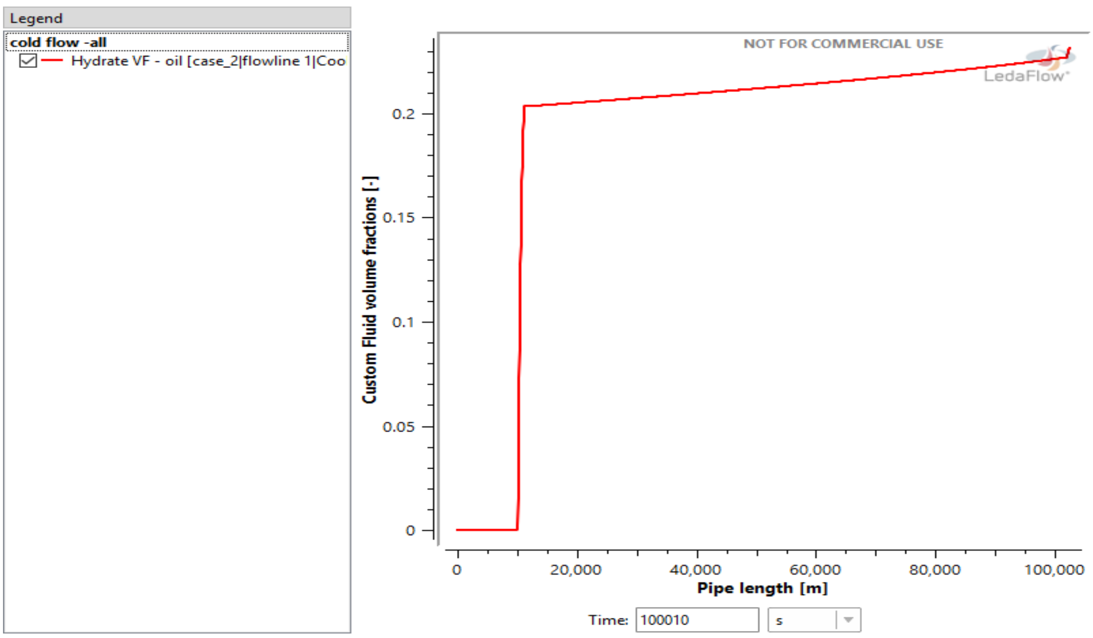

Figure 38. Hydrate volume fraction profile through the flow line for gas injection case in cold flow technology

4. *Results and discussion:*

The purpose of this study is finding the best transport method for a 100 km length pipeline under two different depletion strategies: 1-Water injection 2- Gas injection

These two strategies have been investigated with the following flow assurance methods:

1-FPSO

2-Tie-back wet insulation DEH

3-Tie-back PIP and EHT

4-Cold flow

The optimal solution to tackle hydrates depends on comparing between the results of Leda flow. The comparison is based on analyzing economical evaluation of each hydrate preventing method, as well as their environmental performance and challenges each of them has to face in the offshore field.

4.1 **Water Injection:**

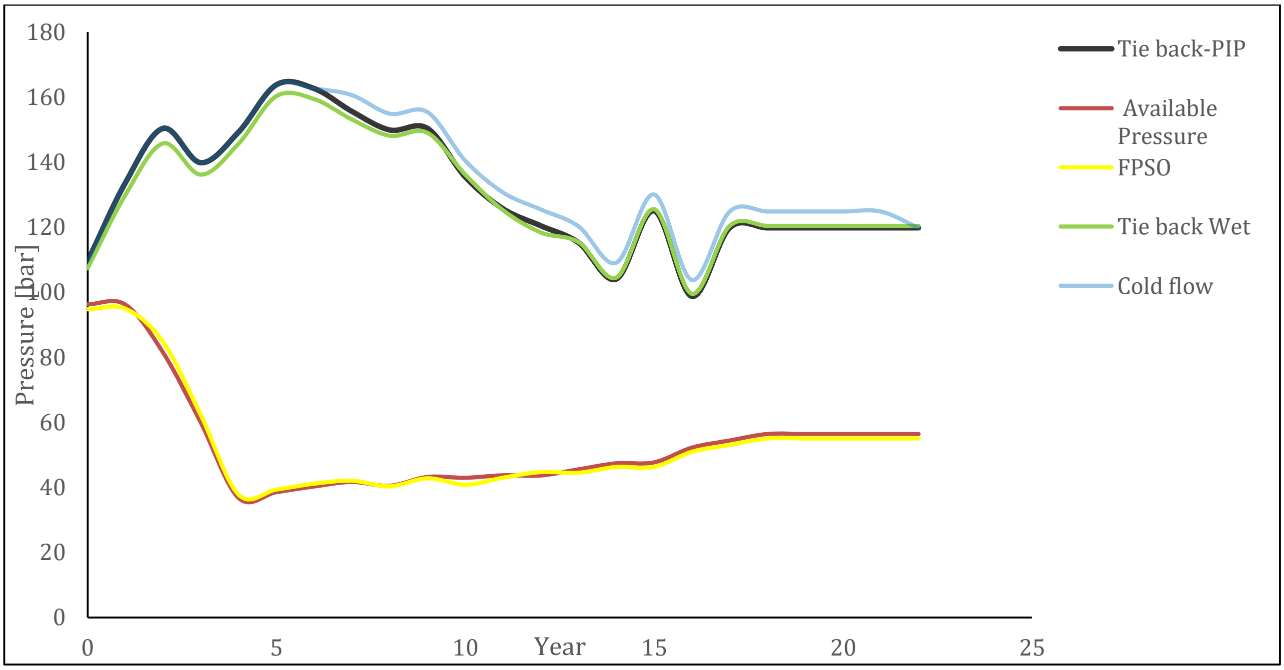

Figure 39. Comparing Pressure profile for water injection case

By examining the required pressure boosting, see Figure 39, it can be observed that only the FPSO case does not require a booster pump, due to the low pressure drop in the flow line resulting from the short distance between the production well and the FPSO platform. However, the overall cost of the FPSO solution could increase as the field size grows, since the required storage capacity would impact the vessel's charter rates.

For the other three flow assurance methods, a pump must be installed after the second manifold to compensate for the pressure difference between the available wellhead pressure and the simulated manifold pressure. Therefore, additional factors such as heat losses and energy consumption must also be considered when determining the most efficient method for water injection.

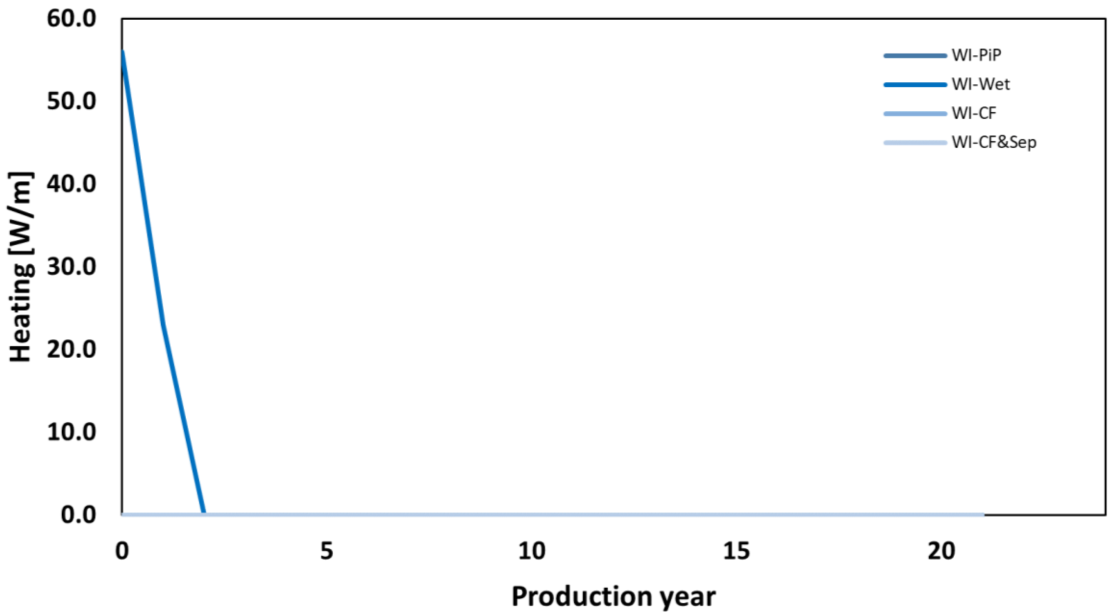

Figure 40. REQUIRED FLOWLINE HEATING RATE FOR WATER INJECTION CASES

For water injection cases the produced water rate is very high and becomes the dominating phase throughout the field's lifetime. Water entering the flow line at 80°C provides a high heat input. In combination with the good PIP insulation, production without heating is possible. For the wet insulation, heating is required in the first two years only until water production starts. Additionally, Cold Flow technology is not practical without modifications due to the high water content in the inflow; hydrates continue to form even after the cooling unit, causing the fluid to become more viscous. This increase in viscosity may require the use of multiple pumps and could potentially block the pipeline, leading to flow interruptions. However, by implementing water separation from inlet flow, Cold Flow technology becomes a highly favorable option for water injection scenarios. It can serve as a suitable alternative to conventional flow assurance techniques, eliminating the need for insulation or active heating systems.

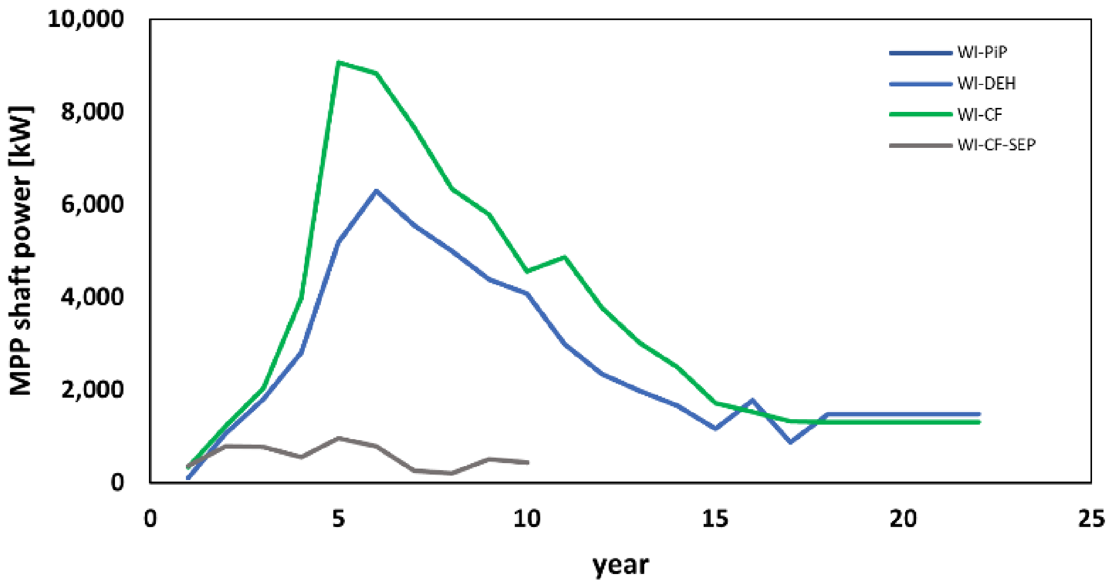

Figure 41. REQUIRED SHAFT POWER FOR THE MULTIPHASE BOOSTING PUMP FOR WATER INJECTION CASES

As the results in Figure 41, for the water injection cases, the power demand will be dominated by the multiphase boosting pump. The required boosting pressure was translated into the power demand under consideration of the pump inlet void fraction (as predicted by Leda Flow) and considering the resulting pump efficiency.

4.2 Gas injection:

On the other hand, in the gas injection case, the dominant phase is gas, and a higher pressure drop in the flow line is expected compared to the water injection scenario. Nevertheless, for all flow assurance methods, production from the well can be achieved without the need for boosting, except during year 2 for the tie-back and cold flow options, where a booster pump is required.

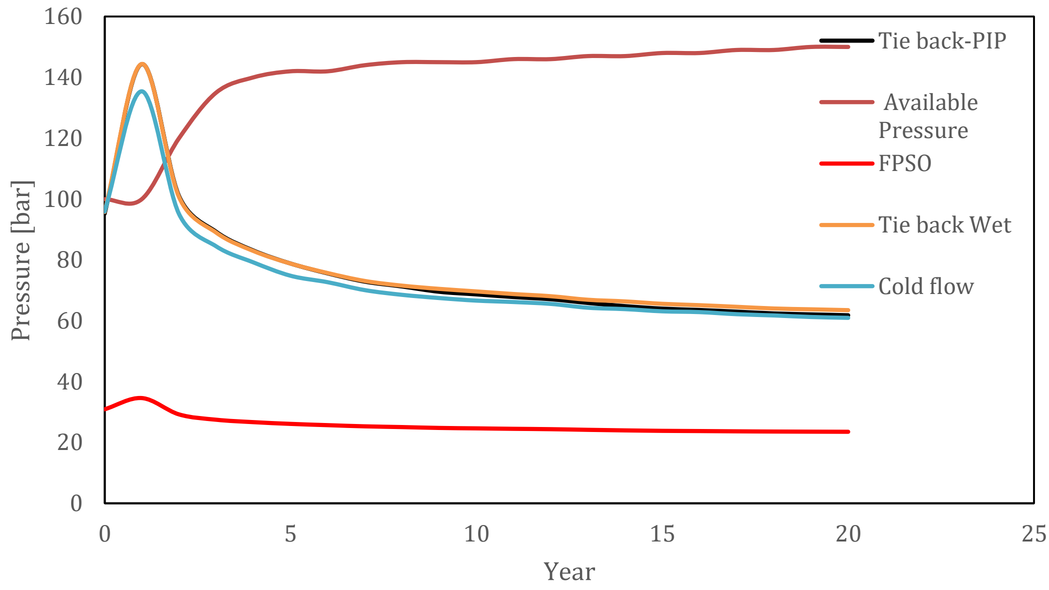

Figure 42. Comparing the Pressure profile for Gas injection cases

The energy consumption of heating is also taken into account in this section. In the following Figure 43 the heat energy required for gas injection is provided. Since, the produced water rate is much less and production is dominated by gas towards the end of the lifetime, higher heating energy is required to maintain temperature above 30 °C because gas contains little heat. From the second year, implementing the heating trace for PIP technic with the maximum of 30 W/m is needed, while in wet insulation, more than three time more heating energy is required to keep the fluid temperature above hydrate and wax appearance. Conversely, Cold flow concept shows its superiority over other methods without using any heating device.

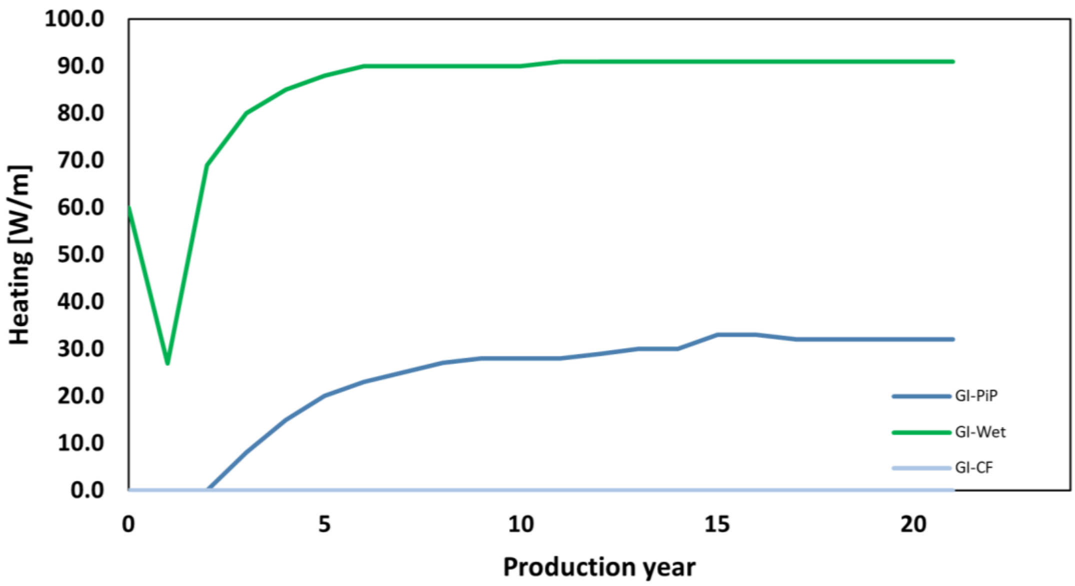

Figure 43. Comparison of Heat energy required on flow assurance methods for Gas injection cases

5 Conclusion:

The objective of this thesis was to evaluate the benefits and feasibility of cold flow technology as an innovative approach to prevent hydrate and wax deposition in deep-water and long-distance production. Flow assurance remains a significant concern in offshore oil and gas operations, with hydrate and wax blockages which result in time-consuming and expensive mitigation and remediation efforts. Traditional flow assurance techniques, such as insulation, chemical injection, and pipeline heating, have proven effective but often come with substantial energy consumption, high operational costs, and environmental concerns. In contrast, Cold Flow Technology presents a promising alternative that mitigates these issues while maintaining operational efficiency.

This study simulated production scenarios for two marginal reservoirs with a high risk of hydrate and wax formation in order to assess the technical feasibility of CFT. As part of the Enhanced Oil Recovery (EOR) strategy, water and gas injection were taken into the consideration with various flow assurance methods. different transportation and production options have been evaluated in this study including production to a Floating Production Storage and Offloading (FPSO) vessel and transport via a 100-km subsea tie-back to an existing processing facility. During the simulations several flow assurance methods were used such as wet insulation with Direct Electrical Heating (DEH), Pipe-in-Pipe (PiP) systems with Electrical Heat Tracing (EHT), and Cold Flow Technology with and without upstream water separation.

The findings indicate that the cold flow technology has proven to be an efficient and feasible alternative solution for hydrocarbon transport in deep water environments to produce the reservoirs for both gas and water injection strategies, without any risk of solid particles blockage and wax deposition compared to conventional options, The advantages and limitations of cold flow were identified and the results showed that that CFT successfully prevents hydrate and wax deposition, eliminating the risk of solid particle blockages. Additionally, the energy demand associated with CFT is significantly lower than that of conventional heating and insulation methods, leading to reduced carbon dioxide (CO2) emissions and a smaller overall carbon footprint. This advantage aligns with the industry’s growing emphasis on sustainable and environmentally friendly solutions.

One of the critical considerations in applying CFT is its effectiveness under different injection strategies. For this production data and in water injection case as a depletion strategy, Cold Flow can be implemented; but, due to the presence of exceeding water, the cooling unit should be extended to more than 2 km and it means higher expenses. So separation of water is proposed to tackle this problem. On the other hand, For the gas injection scenario, cold flow technology was feasible without requiring additional upstream separation, further reinforcing its practicality in specific production conditions.

Despite its evident advantages, one main challenge of cold flow technology is lack of proven track record. Although the cold flow is not new technology, it has yet to be deployed in real-world offshore field operations. Thus, there are always the possibilities of failures during the production that might not have been taken into account under development or have not been revealed under conducting the tests. It could be extremely risky to implement new technologies in the remote environment of arctic without considering all safety aspects.

Nevertheless, despite these uncertainties, Cold Flow Technology remains one of the most attractive concepts for preventing pipeline blockages due to hydrate particles and wax deposition. Its ability to provide a cost-effective, energy-efficient, and environmentally sustainable alternative to conventional flow assurance methods positions it as a transformative innovation in offshore oil and gas production. Moving forward, further research and field trials will be essential to validate its reliability, optimize its implementation, and establish confidence in its operational effectiveness. With continued advancements, Cold Flow Technology has the potential to revolutionize subsea production by enabling longer tie-back distances, reducing operational expenses, and enhancing overall flow assurance strategies in challenging offshore environments.

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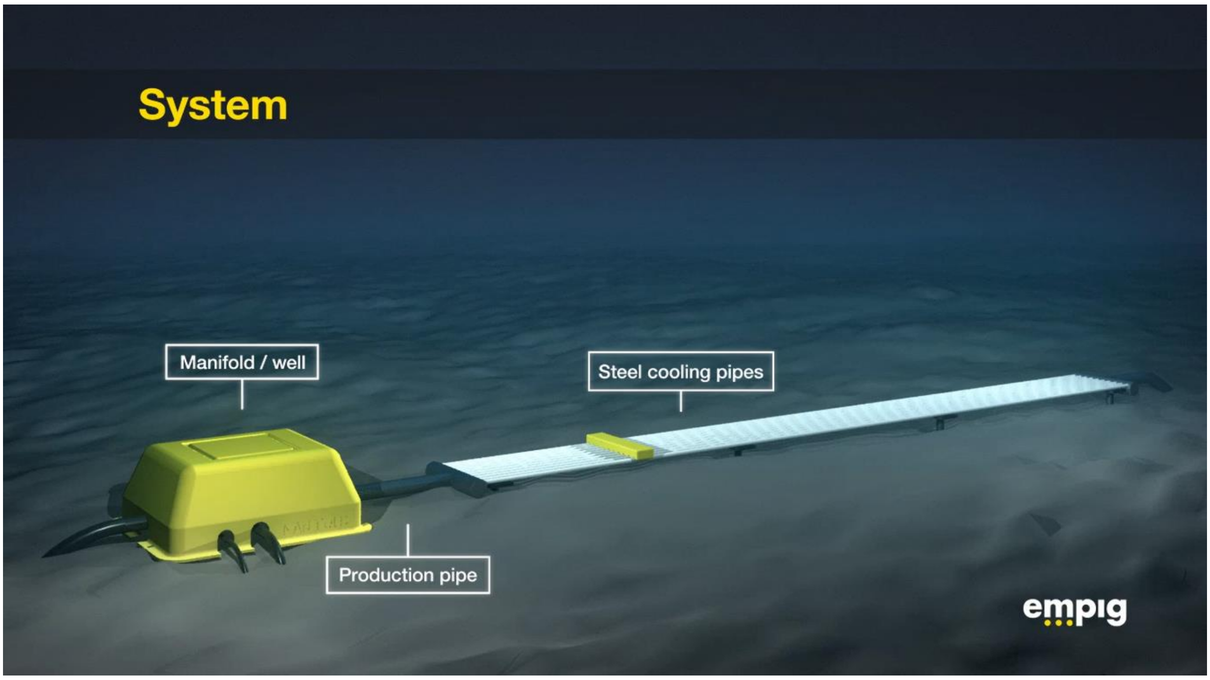
7. APPENDIX

Appendix 1. Different type of cooling unit introduced by EMPIG



Appendix 2. Hydrate table

Bubble point		Dew point		Hydrate	
Pressure	Temperature	Pressure	Temperature	Pressure	Temperature
[bara]	[C]	[bara]	[C]	[bara]	[C]
1738.547	-108.94926	2.0265	320.853183	4.290101	-8.7443544
1134.734	-109.39246	4.2901005	354.321065	8.756124	2.12256791
888.2533	-109.23651	8.7561236	388.959969	17.1686	6.7840106
567.6802	-108.13028	17.168596	422.581112	32.50128	11.2501889
421.1935	-106.81859	32.501284	451.440702	61.02801	15.4975846
312.5069	-105.06922	61.028006	468.349977	68.7973	16.2652873
231.8663	-102.8889	68.797297	468.948997	85.42361	17.6073928
172.0345	-100.2417	85.423608	466.595474	102.6349	18.6967074
127.642	-96.977981	102.6349	460.233236	118.9021	19.5375047
94.70467	-92.548549	118.90213	451.352941	129.2637	20.0034878
80.28545	-88.674309	129.26368	444.471552	134.4745	20.2213855
74.1682	-85.176907			142.0397	20.5208678
72.35545	-81.929776			149.4676	20.7977673
72.32627	-81.425775			156.7605	21.0551935
73.02529	-78.831502			167.445	21.4100291
75.28831	-75.787206			177.8124	21.7326722
78.73233	-72.689301			187.8418	22.0275802
83.26315	-69.385798			202.1925	22.4247408
86.99242	-66.94383			215.6164	22.7564462
89.90503	-65.129446			228.0029	22.9412893
93.30231	-63.076293			244.4142	23.1834241
95.95314	-61.505027			257.981	23.3814183
99.06914	-59.679564			268.5407	23.5341623
101.5346	-58.245206			278.7084	23.6802933
103.4374	-57.141517			282.4519	23.7338104
104.8685	-56.312314			280.5596	23.7067377

TABLE 2.HYDRATE DATA

Appendix 3. Production table for water injection

end of year	qo - field	GOR	WC
[y]	**[Sm3/d]**	**[Sm3/Sm3]**	**[-]**
0	8000	125	0.00
1	8000	150	0.11
2	7500	173	0.21
3	4800	271	0.40
4	3500	343	0.60
5	2900	380	0.71
6	2500	380	0.76
7	2200	380	0.79
8	1900	380	0.82
9	1650	380	0.85
10	1350	380	0.87
11	1100	380	0.89
12	880	380	0.91
13	680	380	0.93
14	530	380	0.94
15	420	380	0.96
16	330	380	0.96
17	300	380	0.97
18	300	380	0.97
19	300	380	0.97
20	300	380	0.97
21	300	380	0.97
22	300	380	0.97

TABLE 3. PRODUCTION PROFILE FOR WATER INJECTION

Appendix 4. Production profile for Gas injection

end of year	qo - field	GOR	WC
[y]	[Sm3/d]	[Sm3/Sm3]	[-]
0	7241.4	114	0.010
1	7241.4	190	0.188
2	3601.1	419	0.178
3	2528.7	597	0.163
4	1928.0	783	0.159
5	1509.3	1000	0.161
6	1243.5	1214	0.155
7	1019.7	1481	0.158
8	871.3	1733	0.179
9	763.3	1979	0.167
10	688.3	2195	0.182
11	613.4	2464	0.200
12	553.3	2732	0.217
13	493.3	3065	0.203
14	445.9	3391	0.184
15	414.5	3650	0.156
16	383.0	3950	0.167
17	344.7	4389	0.182
18	306.5	4938	0.200
19	287.8	5261	0.210
20	269.0	5629	0.222

TABLE 4. PRODUCTION PROFILE FOR GAS INJECTION

Appendix 5. Table for comparison the length, ID and pipe number for cooling unit.

	ID"	Pipe number	Hydrate formation length [km]	HMFR [kg/s]	Pump pressure[bar]	Power [MW]	Max pressure [bar]
1km	3	15	1	16.19	104	8.1	136
		16	1	16.17	105	9.1	135
	4	13	1	16.17	96	8.4	125
		9	1	16.17	93	8.95	122
	5	10	1	16.37	91	7.18	121
		11	1	16.14	90	6.85	121
	7	7	2	16.06	127	11.2	176
		8	1.6	16.11	120	10.3	165
		9	1.6	16.21	116	10.1	158
		10	1.4	16.18	113	9.8	152
2km	3	5	2	16.2	103	7.6	145
		7	1.4	16.18	100	8.6	135
		8	1.3	16.2	100	7.9	131
		9	1.2	16.14	101	7.7	130
		10	1.1	16.26	102	8.1	128
	4	4	2	16.14	95	8.2	128
		5	2	16.17	95	8.6	128
		6	2	16.17	98	8.1	126
		7	1.2	16.05	100	7.8	125
		8	1.2	16.09	103	8.1	124
	5	2	8	0.87	95		137
		3	5	14.6	92		127
		5	1.6	16.16	100	8.6	122
		6	1.2	16.19	104	6.5	120
	6	2	3	16.14	91	7.9	127
		3	2.2	16.23	95	8	123