Hydrates mitigation and remediation in sub-sea flowlines

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ABSTRACT: Hydrate formation in subsea flow lines is a significant challenge for the offshore oil and gas industry. These hydrates, crystalline structures formed by water and gas molecules under high-pressure and low-temperature conditions, can lead to blockages and operational disruptions. Effective mitigation and remediation of hydrates are essential for maintaining continuous production and safeguarding infrastructure.

Mitigation strategies focus on preventing hydrate formation. Thermal insulation of flow lines is a common method, maintaining temperatures above the hydrate formation threshold. Additionally, injecting chemical inhibitors like methanol or glycols into the flow lines can disrupt hydrate formation processes. Advanced flow assurance modelling techniques are employed to predict hydrate formation and design appropriate mitigation measures. These models consider various factors, including pressure, temperature, and fluid composition, enabling tailored solutions for specific operational conditions.

Depressurization is a primary method, reducing pressure to levels where hydrates dissociate back into water and gas. Chemical injection, particularly with thermodynamic inhibitors or kinetic inhibitors, can also dissolve hydrates. Mechanical removal methods, such as pigging, involve sending devices through the flow lines to physically dislodge and remove hydrates.

Effective hydrate management in subsea flow lines ensures safe and uninterrupted operations, reduces downtime, and lowers maintenance costs. By combining robust mitigation strategies, efficient remediation techniques, and advanced monitoring technologies, the industry can enhance production efficiency and maintain the integrity of offshore infrastructure. This comprehensive approach is vital for the sustainability and profitability of subsea oil and gas operations.

CHAPTER 1 INTRODUCTION

1.1 Definition and scope:

Petroleum exploration and production endeavours are currently concentrating on deep and ultra-deep water fields worldwide. Managing flow under conditions where gas hydrates are stable has become a crucial scientific concern. The emergence of gas hydrates in pipelines during oil/gas processing can lead to significant expenses due to heightened pressure loss or blockages. Flow assurance focuses on addressing the risks and challenges stemming from the properties and behaviour of produced hydrocarbons, associated fluids, and solids.

Hydrate accumulation poses one of the most formidable challenges in flow assurance modelling, resulting in pressure losses from the reservoir to pipelines or storage facilities. This issue is primarily driven by variations in temperature, pressure, and the composition of each phase. Hydrates formed by water and hydrocarbon fluids can obstruct pipelines. Additionally, high water cut can induce corrosion, while pressure and temperature fluctuations along the pipeline, along with incompatible water mixing, can lead to scale deposition and flow restriction. Severe slugging within the pipeline can also create operational hurdles for downstream processing facilities.

Engineers are grappling with the task of designing pipelines to ensure the safe and cost-effective transportation of multiphase fluids from the reservoir to downstream processing plants and end-users. This involves identifying, quantifying, and mitigating the various flow risks associated with pipelines, particularly those in sub-sea systems, a practice known as flow assurance.

1.2 Sub-sea Fields:

For many years, deep water exploration remained technologically and economically unfeasible. However, with the surge in oil prices, more companies are now directing investments towards this sector. Following the 2010 disaster, the deep-water gas and oil market is experiencing a resurgence. Total annual expenditure amounts to approximately $35 billion, with a global Capex totalling $167 billion over the past four years.

Water depth is categorized as follows:

1. Shallow Water (0–999 ft)

2. Mid-water (1,000–3,999 ft)

3. Deep water (4,000–6,999 ft)

4. Ultra-deep water (7,000+ ft)

The ocean's depths represent a realm of darkness, high pressure, and cold temperatures. Oceanic temperatures sharply decline with depth, reaching around 4°C at depths of approximately 600 meters.
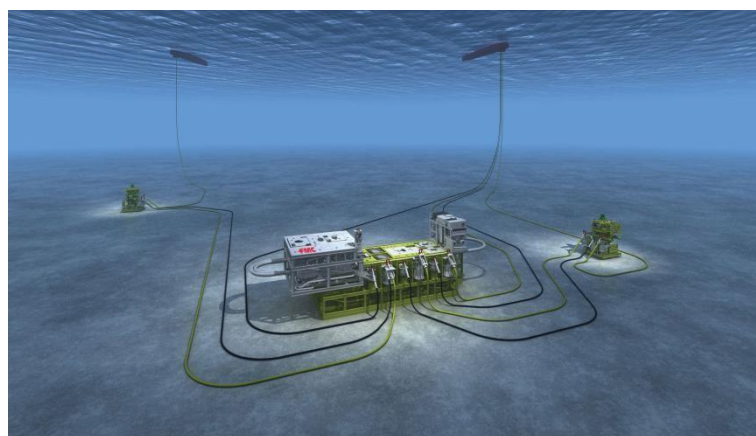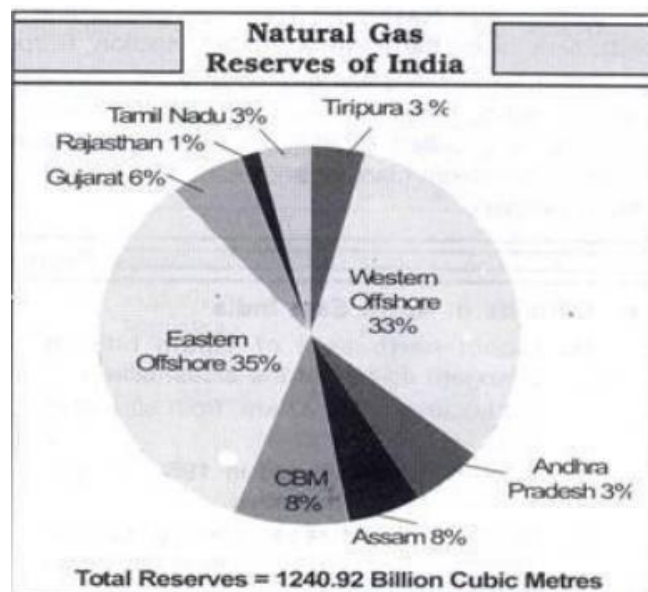
Table 1.1 Natural gas reserves of India

Fig.1.1 schematic diagram of sub-sea oil field.

1.3 Gas hydrates

Gas hydrates are crystalline compounds resembling ice, characterized by three-dimensional water lattices bonded through hydrogen, which capture small gas molecules. These gas molecules, referred to as guests, are enclosed within the water molecules, known as hosts. The interaction between hydrocarbon and water molecules does not involve chemical bonding. Instead, hydrogen bonds allow water molecules to form a cage, wherein the small gas molecules can freely rotate within the available space.
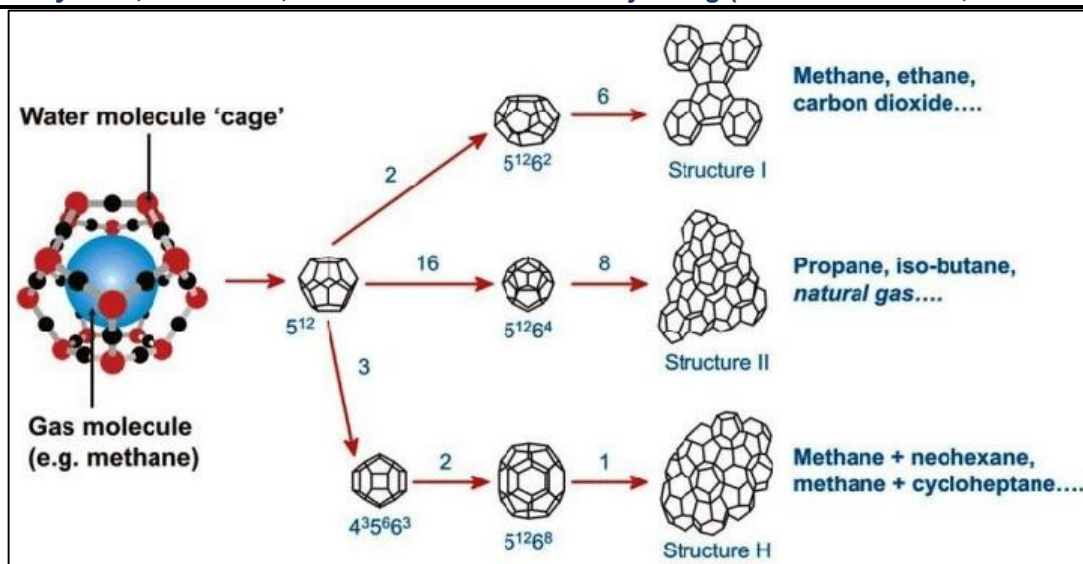
Fig 1.2 Common gas hydrate structures

1.4 Hydrate type and Formers:

1.4.1 TYPE I hydrates

The Dodecahedron, a twelve-sided polyhedron with a typical pentagon on every face, and the Tetrakaidecahedron, a fourteen-sided polyhedron with twelve pentagonal faces and two hexagon faces, are the two different kinds of cage that compose Type I, the most basic hydrates structure. While the latter are referred to by the term giant cages, dodecahedral cages are less large and are called tiny cages. There are 46 water molecule pairs in a type I hydrate. The theoretical formula for the hydrate is X • 5 3/4 H2O, where X defines the hydrate previous, assuming that every cage allows an additional molecule. The hydrate crystal structure gets frequently oversimplified throughout scholarship by showing the dodecahedron as the single unit crystal structure, which is unreliable. These are the specific frameworks that are offered.

	Type I	Type II	Type H
Water Molecules per Unit Cell	46	136	34
Cages per Unit Cell			
Small	6	16	3
Medium	—	—	2
Large	2	8	1
Theoretical Formula†			
All cages filled	$X . 5\ 3/4\ H_2O$	$X . 5\ 2/3\ H_2O$	$5X . Y . 34\ H_2O$
Mole fraction hydrate former	0.1481	0.1500	0.1500
Only large cages filled	$X . 7\ 2/3\ H_2O$	$X . 17\ H_2O$	—
Mole fraction hydrate former	0.1154	0.0556	—
Cavity Diameter (Å)			
Small	7.9	7.8	7.8
Medium	—	—	8.1
Large	8.6	9.5	11.2
Volume of Unit Cell (m³)	1.728×10^{-27}	5.178×10^{-27}	
Typical Formers	$CH_4, C_2H_6,$ H_2S, CO_2	$N_2, C_3H_8,$ $i\text{-}C_4H_{10,}$	See text

† Where X is the hydrate former and Y is a Type H former.

Table 1.2 Hydrates types

Type I formers

Methane, ethane, carbon dioxide, and sulphide of hydrogen are examples of common Type I hydrates formers. Guest molecules can inhabit both small and big cages in CH4, CO2, and H2S hydrates, whereas ethane molecules can only occupy giant cages.

1.4.2 TYPE II hydrates:

Type II hydrates have a far more intricate composition than Type I hydrates. Additionally, Type II hydrates have two different kinds of cages: the Hexakaidecahedron, a sixteen-sided polyhedrons having twelve pentagonal faces and four hexagon faces, and the Dodecahedron, a twelve-sided polyhedron having regular pentagons on each face. Compared to hexakaidecahedral cages, dodecahedral cages are smaller.

Thirty-six water molecules define type II hydrates. The theoretical composition is X 5 2/3H2O, where X is the hydrates former, assuming that each cage accommodates an added molecule. On the other hand, the theoretical composition changes to X17H2O if visitors are limited to the huge cages. As with Type I hydrates, these types of hydrates are non-stoichiometric, meaning that their actual compositions deviate from their theoretical counterparts.

Type II formers

In the case of natural gas, nitrogen, propane, and iso-butane frequently occur in Type II formers. Whereas propane and iso-butane only occupy big cages, nitrogen occupy both large and small cages in Type II hydrates.

1.4.3 TYPE H hydrates:

Type H hydrates are less common than Types I or II and require the presence of a Type H former and a small molecule such as methane in order to form. Three different cage types—the dodecahedron, irregular dodecahedron, and irregular icosahedron—are used to build these hydrates. Three tiny, two medium, and one huge cage make up the crystal unit. Small molecules inhabit the small and medium cages, whereas bigger molecules fill the large cage in type H hydrates, which are invariably found as double hydrates. Y.5X.34H2O is the theoretical formula that takes into consideration the presence of a big molecule Y in the main cage and a tiny molecule X in two smaller cages.

Type H formers

Unlike Type I and Type II hydrates, Type H requires two formers: a bigger Type H forming molecule and a smaller molecule such as methane. Hydrocarbon species including 2-methylbutane, 2,2-dimethylbutane, 2,3-dimethylbutane, 2,2,3-trimethylbutane, 2,2dimethylpentane, 3,3-dimethylpentane, methyl-cyclopentane, ethyl-cyclopentane, methyl cyclohexane, cyclo-heptane, and cyclo-octane are all included in type H formers. Most of these elements are not often present in natural gas.

1.5 Hydrate formation conditions:

Three prerequisites must be met for hydrate formation:
• Adequate water content;
• Low temperature and high pressure;
• Hydrate formers like CH4, C2H4, CO2, and H2S present.

1.6 Four liquid flow models:

'Sloan et al., 2010 present four different models to study hydrate flow models.

1.6.1 Systems dominated by oil:

These systems are common in oil, when surfactants or shear have emulsified water droplets into the oil phase. Turbulence can cause gas to dissolve in the oil phase or scatter in the liquid water phase. Oil holdup at phase interfaces is often greater than 50%, making them difficult to describe and frequently disturbed.

1.6.2 Systems for gas condensate:

Gas condensates, which at reservoir conditions are initially gaseous, change into liquid when reservoir pressure drops. Compared to black oil, these systems have fewer heavy hydrocarbons. Water in the hydrocarbon phase may only disperse at high shear rates before separating a phase that is constantly flowing at the pipe's bottom.

1.6.3 Gas-dominated systems:

This thesis focuses on these systems, which have very little liquid oil and water in them. In the gas phase, liquid can exist as tiny, spherical droplets that can periodically moisten the pipeline's inner wall. Accumulated water at the lower part of the pipeline facilitates hydrate formation and plugging, forming slugs with detrimental consequences.

1.6.4 High-water-cut systems:

Later phases of the development of an oil field, significant water volumes may be produced due to water coning or multilayer channeling. Increased water content elevates the risk of gas hydrate plugging. As water content exceeds 70%, water becomes the continuous phase, with oil dispersed as droplets. Gas dissolved in oil droplets triggers hydrate formation at the oil-water interface.

1.7 Overall project objectives:

The purpose of this study is to improve understanding of how hydrate deposits slough off the pipe walls to generate hydrate plugs in gas-dominated pipelines. The following are the project's goals:

Calculating, using theoretical models, the rate of development of gas hydrate deposits on pipeline/flow line walls over time.

Using suggested theoretical packing models to examine the mechanical properties of hydrate deposits on gas subsea pipes.

Exploring hydrate phase diagrams and identifying methods for mitigating and remedying hydrate formation.

Performing volume calculations for the injection of chemical inhibitors.

CHAPTER-2

LITERATURE SURVEY

2.1 Global activities in deep water:

This section examines the impact of hydrate formation on flow regimes in flow lines as a strategy for flow assurance. The discussion will centre on the characteristics of deepwater oilfields, flow assurance, multiphase pumping, and subsea processing, as well as integrated production modelling. Figure 2.1 illustrates the trend in oil production and price range from 1970 to November 2004. It demonstrates the consistent increase in price compared to the supply of hydrocarbon products worldwide during the specified period. This underscores the necessity for increased exploration in deep waters due to the escalating demand for hydrocarbon products globally.
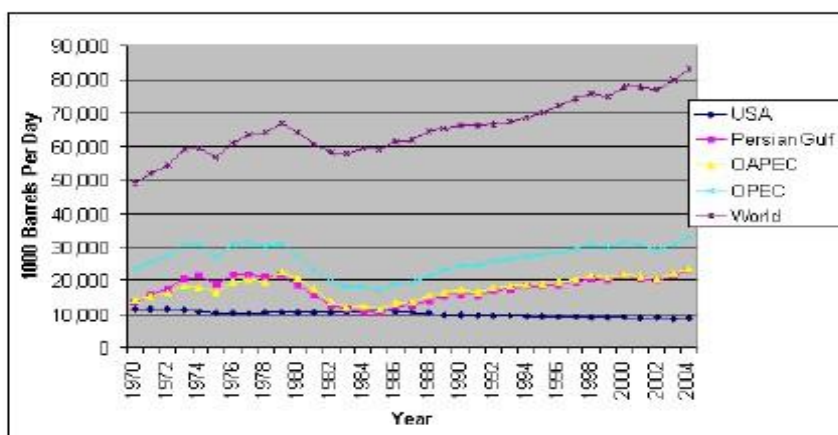

Figure 2.1: Supply of hydrocarbon in M Barrels per day (Amin, 2006)

Exploration and operations in the petroleum industry are focusing on fields in deep and ultra-deep waters across various regions worldwide. This shift is driven by the rising demand and subsequent escalation of oil and gas prices. Such a trend necessitates a comprehensive understanding and strategic planning for production enhancement and flow assurance under increasingly challenging conditions.

The interest in deep-sea drilling programs (DSDP), ocean drilling programs (ODP), and integrated ocean drilling programs (IODP) is shown globally in Figure 2.2 below.

Figure 2.2: World Interest in Deep Sea Oil/Gas. (Ocean Drilling Program, 2007)
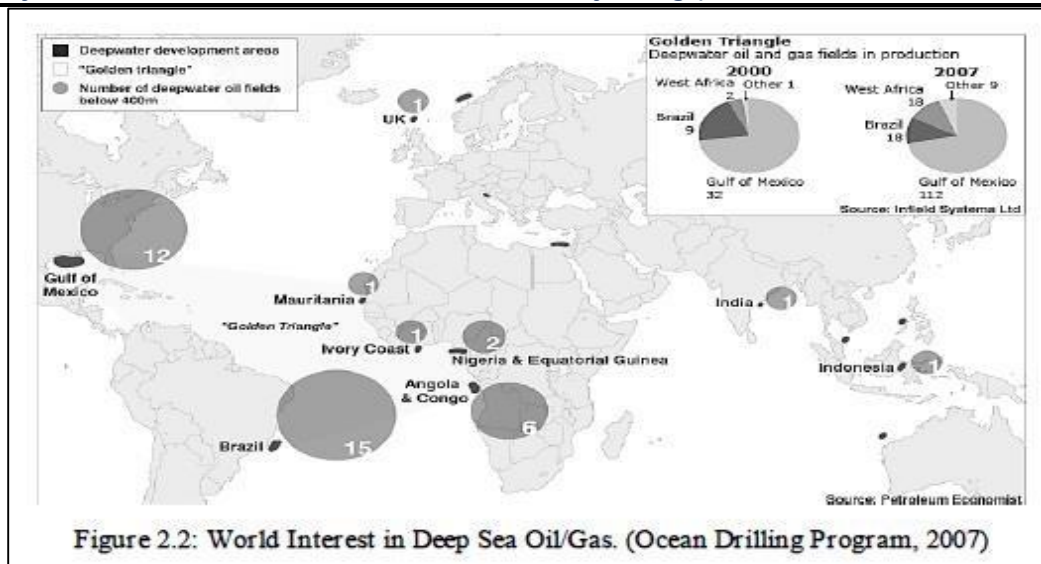
2.2 Gas hydrate challenges

One of the primary challenges confronting producers today is ensuring the uninterrupted flow of oil and gas through intricate and expensive long subsea tiebacks. Potential obstacles may arise from the formation and deposition of hydrates in wells, flow lines, or production facilities, as well as corrosive elements in the flow streams that can damage equipment and pipelines.

In deeper waters, the costs of intervention escalate, and flow assurance becomes a significantly larger component in production economics, particularly for developments in depths of 4000 ft or deeper, connected to shallow-water host facilities located up to 50 miles away (Oil and Gas Journal, 2001).

In deep water, many hydrocarbons accumulate in shallow structures, resulting in wellhead flowing temperatures typically ranging from 110-140°F. To extract these accumulations, designers aim to deliver the well fluid to processing facilities at temperatures above the wax appearance temperature and beyond the hydrate formation range. The accumulation of hydrates can cause significant flow distortion, potentially leading to reverse flow.

As depicted in Figure 2.3, launching pigs through the pipe system may trigger flow line eruptions, posing hazardous risks and causing pollution and continuous leaks along the flow line. This challenge is compounded by the cold sea-bottom temperatures in deep water, often reaching near or below 40°F, even in equatorial waters.
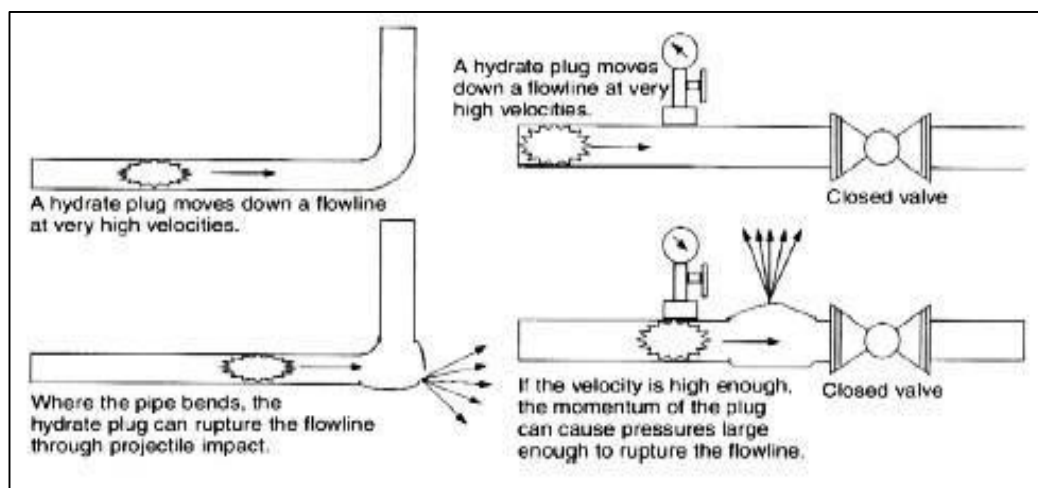

Fig 2.3 Basic Flow Assurance challenges. (Flow Assurance in Oil and Gas, 2010)

Figure 2.4 highlights the issue of hydrate plugs in subsea pipelines and flow lines. Designers face the dilemma of whether to install one or two flow lines to a subsea well or development. While one flow line is less costly, two allow for interventions such as the circulation of pigs and fluids to remove flow impediments.

Fig.2.4: hydrate plug in subsea pipelines/ flow lines

2.3 Characteristics of multi-phase flow:

Multi-phase flow can manifest in various types. Firstly, there is the scenario where a single component exists in two phases, as seen with steam and water. Next, there's the situation where two components, each in a different phase, flow together, such as oil and gas. Finally, there's the case where a mixture of two immiscible liquids, like oil and water, flow together, which should technically be termed single-phase, two-component flow. Multi-phase flows in pipelines are encountered in many scenarios, sometimes intentionally and sometimes not. Examples include:

- **Oil Well Heads:** Here, multi-phase and multi-component flows are evident, with oil, gas, water, sand, and shale all emerging from the wellhead.

- **Cavitation:** High fluid velocities in pumps and valves momentarily draw the vapour phase from the liquid.

- **Leaks in Pipelines:** Ingress of air into a pipeline running at or below atmospheric pressure through leaky seals, glands, gaskets, etc.

- **Cryogenic Fluids:** Liquid oxygen, nitrogen, LNG, or Freon's used in refrigeration systems.

When gas and liquid flow together in a pipeline, conventional single-phase concepts like turbulent or non-turbulent flow and velocity profile are no longer applicable. Instead, a range of flow regimes emerges, depending on the relative ratios of gas and oil and the velocities of each phase relative to each other. The flow regimes vary depending on the pipe's orientation through which the phases flow, with most experience confined to horizontal or vertical flows. Flows at intermediate orientations produce a mixture of the two, while a transition from horizontal to vertical can lead to severe slug flow. Figure 2.5 illustrates the different types of flow regime associated with vertical flow in a gas pipeline.
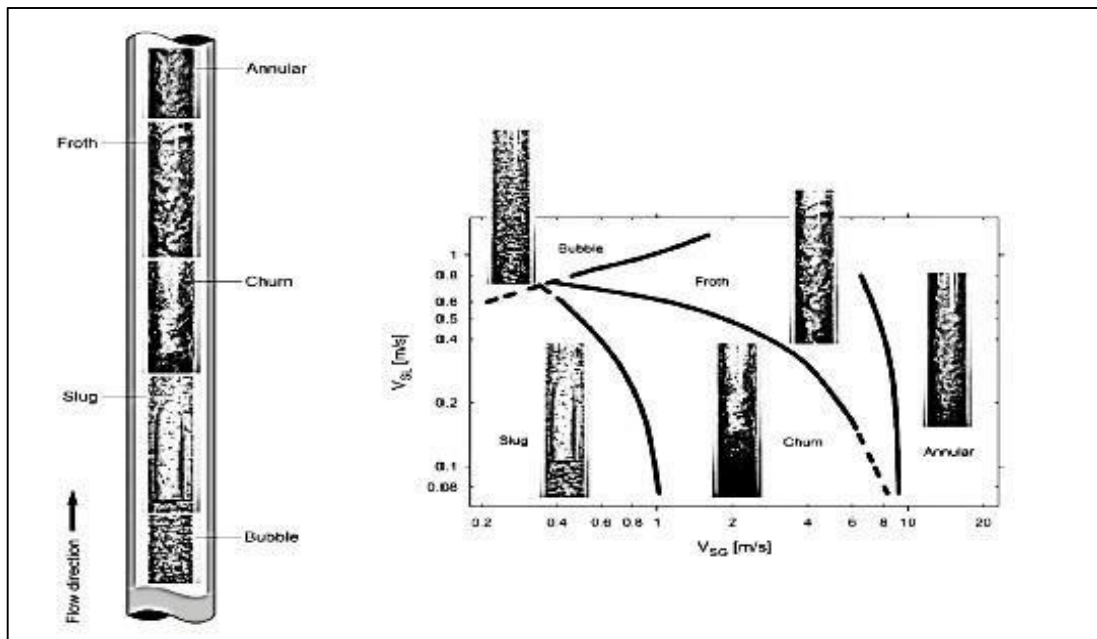

Fig.2.5 (a) Schematic of Flow Pattern (b) Idealized Flow Region ('Flow Assurance in Oil and Gas, 2010')

2.4 Phase envelopes:

The particular hydrodynamic and thermal properties of the production system determine the pressure-temperature (P-T) pathway of production. Figure 2.8 illustrates a phase envelope where the hydrate formation line intersects the envelope along the vapour line, indicating the potential for hydrogen solids formation in the system. However, crossing the envelope does not necessarily imply flow assurance issues because the formation of solids does not automatically lead to deposition or blockages.

According to Turner's (2005) suggested model, hydrates are thought to develop at the interface between gas bubbles entrained in the water phase and/or water droplets entrained in the oil phase of a multiphase flow system that contains water, oil, and gas.

When a plug develops, often as little as 4 vol% of the water turns into hydrates. These hydrate-encrusted water droplets have the potential to aggregate into bigger hydrate masses in the oil phase, increasing the viscosity of the slurry and perhaps forming a clog. In water-in-oil (W/O) emulsions, the surface of the water droplets is a crucial site for hydrate formation and agglomeration. The idea of naturally inhibited oils ('Leporcher, 1998'), which is distinguished by natural surfactants that seem to limit the agglomeration of hydrate particles and permit the transportation of hydrate slurries without plug formation, is another significant feature for both industry and academics.
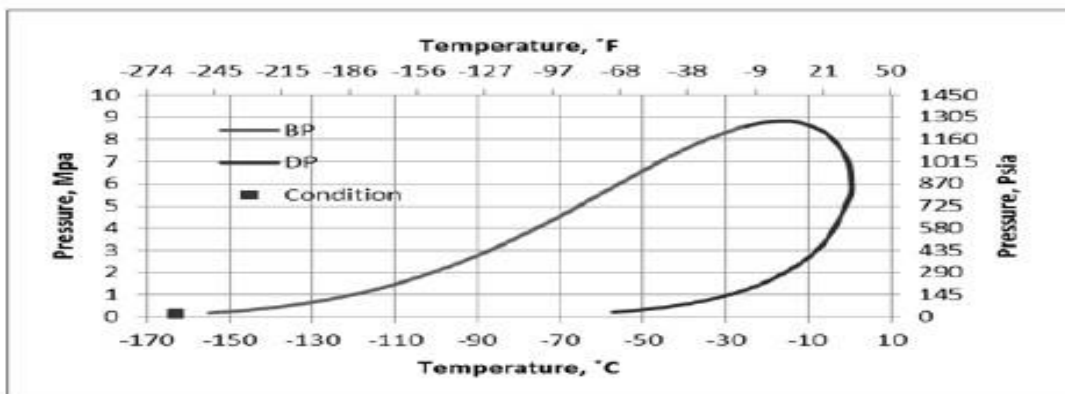

Fig 2.6: Phase Envelope Generated from Flow Assurance Issues. (Sloan, 2005)

2.5 Phase Diagrams Provide Hydrate Classification:

The first to produce a pressure–temperature plot for SO2 hydrate, similar to the one shown in Figure 1.2 for different natural gas components, was Roozeboom (1884, 1885). The symbols H for hydrates, I for ice, V for vapor, and Lw and LHC for the aqueous and hydrocarbon liquid phases, respectively, are used in this image. Every element has a unique phase diagram.
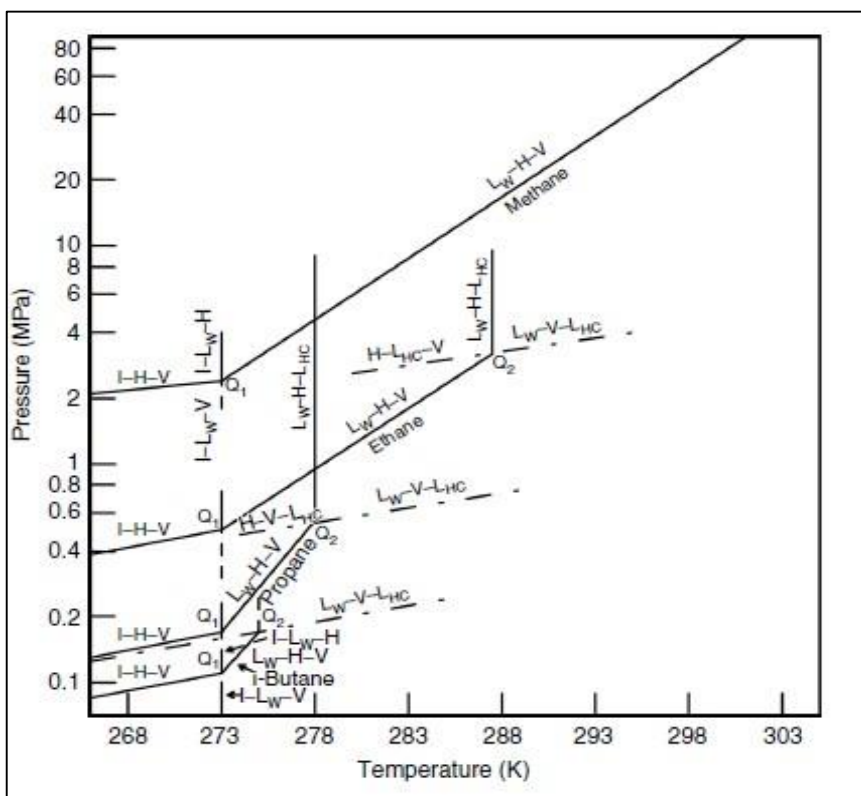
Phase diagrams for a few basic hydrate-forming natural gas hydrocarbons are shown in Figure 2.7. The quadruple points are located in Q1 (lower) and Q2 (upper).

The three phase lines (I–H–V), (Lw–H–V), and (Lw–H–LHC) to the left define the hydrate area, while the phases for liquid water or ice and the guest component as vapour or liquid exist to the right. These three phase lines overlap in Figure 1.2, defining an upper quadruple point Q2 (LW–H–V–LHC) and a lower hydrate quadruple point Q1 (I–LW–H–V). Each hydrate formation has a unique set of quadruple points that offer a quantitative characterization of the constituents of natural gas hydrate. Four three-phase lines connect at each quadruple point (Figure 1.2). Q1 denotes the LW to I transition, showing where, as temperature drops, hydrate production starts from ice and vapour instead of liquid water.

At first, Q2, or about the point where line LW–H–V intersects with the hydrate guest's vapour pressure, was thought to be the highest temperature at which hydrate production from that component could occur. Nevertheless, some natural gas components, such as methane and nitrogen, lack an upper quadruple point, Q2, and as a result, have no upper temperature limit for hydrate formation, as the vapour pressure at the critical temperature may be too low for such an intersection.

2.6 Measurable Variables and Gibbs' Phase Rule:

There are five major categories of variables in phase equilibrium:

1. Tension

2. The temperature

3. The phases' concentrations of gas, liquid, or hydrate

4. Mass or composition

5. Phase quantities

Since all processes involve measurements of pressure and temperature, it is common to talk about phase equilibrium in terms of those parameters. The final two variables on the list, phase quantities and volume/density, are difficult to assess using tools that are readily accessible. Therefore, four parameters are often used to identify hydrate phase equilibria: pressure, temperature, the composition of the water-free hydrocarbon phase, and the composition of the free-water phase (which includes salts, alcohols, and glycols but excludes hydrocarbons).

"How many variables must be specified to obtain a unique solution to the phase equilibrium calculation?" is a crucial topic that has to be addressed. A problem may have an unlimited number of solutions if there are not enough variables given, or it may not have any answers at all if there are too many variables specified.

'Gibbs' Phase Rule' (Gibbs, 1928, p. 96) provides an answer to this question, stated simply for non-reacting systems by the equation:

$$F = C - P + 2$$

Where F is the quantity of intense variables required to define the system C is the total number of system components. P is equal to the number of system phases.

An intense variable is a measured quantity that is unaffected by the phase amount, such as temperature, pressure, or individual mole fractions of a single phase. For instance, although phase masses, volumes, or quantities are extensive variables and not covered by Gibbs' Phase Rule, temperature, pressure, mole fractions, or density are intense variables.

Think about the possibility of free water and methane gas forming hydrates. It may be asked, "At what temperature (T) will hydrates form for a given pressure (P)?" Prior to doing the computation, it is crucial to ascertain if the issue has a single, unique solution or whether it is under-specified, meaning there are an unlimited number of possible answers.

According to the Gibbs' Phase Rule, methane and water are the components (C = 2) and there are three phases (LW–H–V). To produce a unique solution for hydrate formation, just one intense variable (F = 1), such as either temperature or pressure, has to be given.

2.7 Pressure–Temperature Diagrams for different hydrocarbon mixtures:

Diagrams of pressure and temperature are shown in Fig. 2.8. (a) Shows the hydrate region's methane + water or nitrogen + water system. (b) Displays systems with hydrocarbon and water at the upper quadruple points. (c) Showcases multicomponent water and natural gas systems. (d) Shows water + hydrocarbon systems with inhibitors and higher quadruple points.

• The I-H-V line has a smaller P-T slope than the LW-H-V line, and the LW-H-V line is the one of most importance in natural gas systems. Take note of the dearth of data below 273 K resulting from industry avoidance of ice formation issues.

• The I–LW–V line joins the quadruple point to the water triple point (I–LW–VW), designating the transition between water and ice without hydrate formation.

• The I–LW–H line rises vertically from the quadruple point, signifying high pressure increases for modest temperature changes. For all natural gas systems, Q1 is roughly equal to 273 K, hence the I-LW-V line continues practically vertically below Q1 to 0.62 kPa.
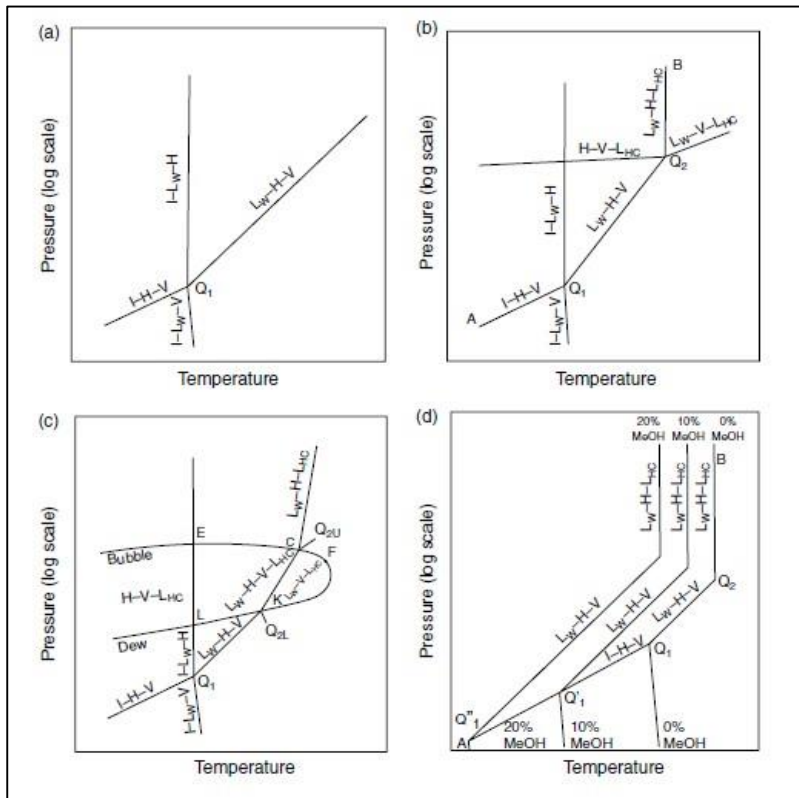
2.8 Hydrate Formation for Three-Phase Conditions of Single Natural Gas Components:

Using P [kPa] = exp(a + b/T [K])

Component	Type	T range (°C)	a	b
Methane	L$_W$–H–V	0 to 25	38.980	−8533.80
Methane	I–H–V	−25 to 0	14.717	−1886.79
Ethane	L$_W$–H–V	0 to 14	44.273	−10424.25
Ethane	I–H–V	−25 to 0	17.511	−3104.54
Propane	L$_W$–H–V	0 to 5	67.130	−16921.84
Propane	I–H–V	−25 to 0	17.156	−3269.65
Isobutane	L$_W$–H–V	0 to 1.5	61.740	−15571.43
Isobutane	I–H–V	−25 to 0	18.950	−3887.32
Carbon dioxide	L$_W$–H–V	0 to 11	44.580	−10246.28
Carbon dioxide	I–H–V	−25 to 0	18.594	−3161.41
Nitrogen	L$_W$–H–V	0 to 25	37.808	−7688.63
Nitrogen	I–H–V	−25 to 0	15.129	−1504.28
Hydrogen sulfide	L$_W$–H–V	0 to 25	34.828	−8266.10
Hydrogen sulfide	I–H–V	−25 to 0	16.560	−3270.41

Table 2.1 Hydrate Formation for Three-Phase Conditions

2.9 Challenges for artificial lifting of gas hydrate reservoirs:

The water has to be evacuated since the accumulated water column might cause the well to experience severe backpressure or perhaps burst. Nevertheless, there are several difficulties in discharging hydrate wells, including low gas-to-liquid ratios and inadequate reservoir energy (GLR). Liquid loading issues are more common in low-pressure reservoirs. Reservoir pressure in hydrate reservoirs can be extremely low due to their relative shallowness, which raises the likelihood of liquid loading.

The production rate of a hydrate well on Alaska's North Slope, as determined by Nodal Analysis, is extremely near to the critical velocity, below which water droplets start to accumulate in the well's bottom. Artificial lift techniques need to be used right from the start of manufacturing.

Low GLRs might make it more difficult to use artificial techniques. It's possible that velocity strings, gas lift, or foam-assisted lift are not cost-effective deliquification techniques. The presence of gas reduces the pumping effectiveness of other pumping techniques. Low reservoir and surface temperatures are another problem. In contrast to traditional gas reservoirs, the majority of hydrate reservoirs are found in permafrost or offshore settings, which have extremely low temperatures. Water vapor may condense and turn into ice at these temperatures, which might result in a choke blockage.
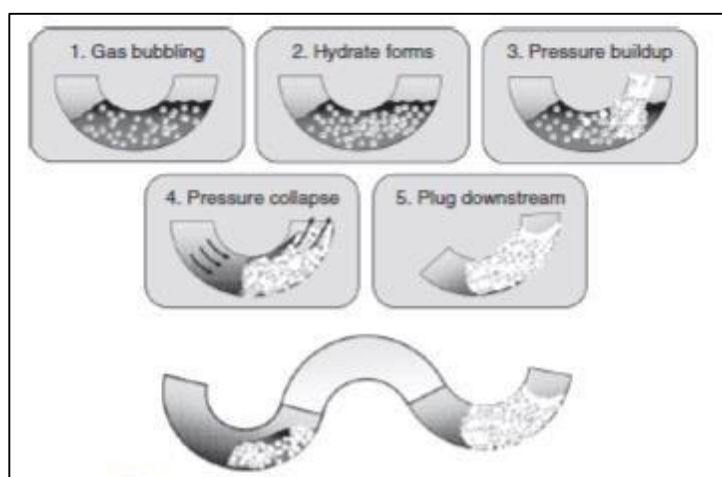
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Fig 2.9 hydrate plugs in bends of flow lines /jumpers.

CHAPTER-3

HYDRATE PLUG DETECTION AND THEIR MITIGATION, REMEDIATIONS

3.1 Introduction:

Hydrate blockages, which frequently result from odd circumstances or human mistake, can appear in a variety of and occasionally surprising places. Prior to taking any action, the issue must be properly analysed. Determining the makeup of the obstruction and the conditions surrounding its creation is a difficulty to investigators. It is often the case that expert collaboration is required. The level of managerial pressure might vary greatly based on the extent of the obstruction and how it affects operations. A plug that has built up immense pressure behind it suddenly releasing may be just as damaging as an artillery shell. Unexpected direction changes or limitations while moving can harm machinery or put life in danger, requiring expensive repairs and downtime. Therefore, until safety issues are addressed, suspected hydration blockages should be handled as unstable.

This chapter is frequently the first that readers consult when handling suspected hydration blockages.

• How to determine whether the obstruction is a hydrate plug.

• Techniques for finding the plug and figuring out its dimensions.

• The alternatives available for effectively removing obstructions.

• Safety measures should be used when clearing hydration plugs.

• The effects of the mechanical characteristics of plugs in various services (oil, gas, and condensate) on cleanup.

• Calculating how long it will take to remove a hydrate clog.

• Managing plugs in a variety of equipment types, including subsea wells, dry tree wells, subsea flow lines, subsea manifolds, trees, and chokes; onshore gas pipelines; subsea processing equipment, valves, and manifold.

3.2 Blockage Identification & Determining Cause of Blockage:

The initial step in addressing any blockage is identifying its nature. Although often apparent to those familiar with the system, it's crucial to confirm what is obstructing flow before proceeding. It's also important to consider any actions or oversights that may have contributed to the blockage. Among the potential reasons for a blockage are:

• Mechanical problems (pigs, broken pipes, construction waste, etc.).

• Scale buildup, which forms slowly.

• Blockage of the artery (slower formation).

• Congealed wax (slow forming).

• Composite obstruction, which forms quickly as a result of chemical reactions brought on by incompatibilities.

• Hydrate formation (rapid formation brought on by process interruptions, hydrate formers, insufficient treatment, etc.).

3.3 Locating blockage:

There are several sophisticated methods for calculating pressure and temperature at various locations along a flow line. Advanced technologies including acoustic hydrophones, Bragg grating pressure sensors, Raman spectroscopy, fiber optics, and Brillouin backscattering are used in these techniques.
As of right now, these methods have only been shown in experimental settings. It is possible to find the location of hydrate plugs in lines above water during depressurization by using infrared sensors to measure the drop in temperature caused by the endothermic heat of dissociation. An intelligent completion system intended for fluid injection into production pipes is shown in Fig. 2.10.
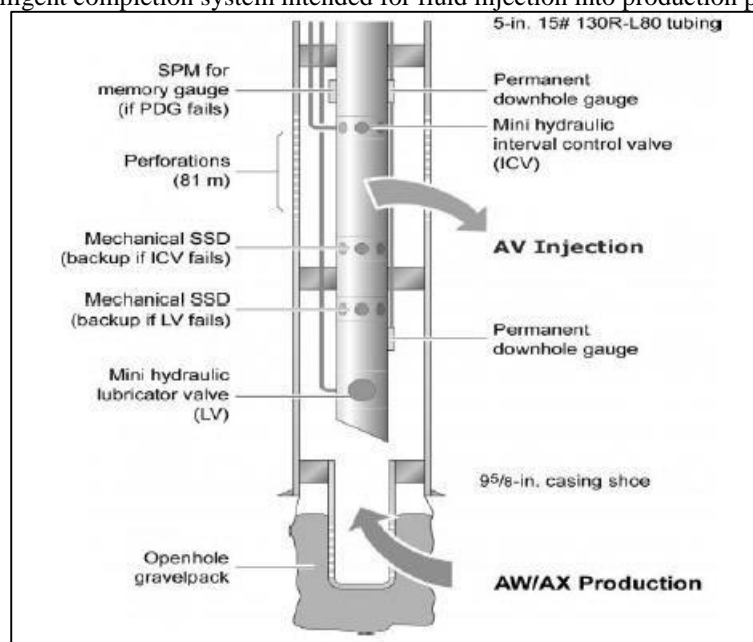

'Fig: 3.1 Selective Intelligent completion schematic facilitating controlled fluid injection

3.4 Blockage removal options:

Hydrate blockages may be removed primarily in four ways: mechanical removal, chemical application, pressure reduction, and heat application. Every technique has benefits and related hazards. The specifics of these choices are provided below.

3.4.1 Pressure method (Depressurization):

In the industry, dissociating hydrates by lowering pressure below the dissociation pressure at room temperature is the most often used technique. When getting chemicals to the blockage site is difficult, this approach is especially recommended. The total elimination of the hydrate plug is the main goal of this strategy. The dissociation process can be sped up and the resultant mixture stabilized for cleanup operations by flooding the system with a thermodynamic inhibitor after pressure communication has been established across the plug or plugs. In subsea settings (4°C), however, it can be challenging to achieve the required pressure decrease. Pressures between 200 and 130 lb/in² are needed, and hydrostatic head in subsea systems may make this difficult.
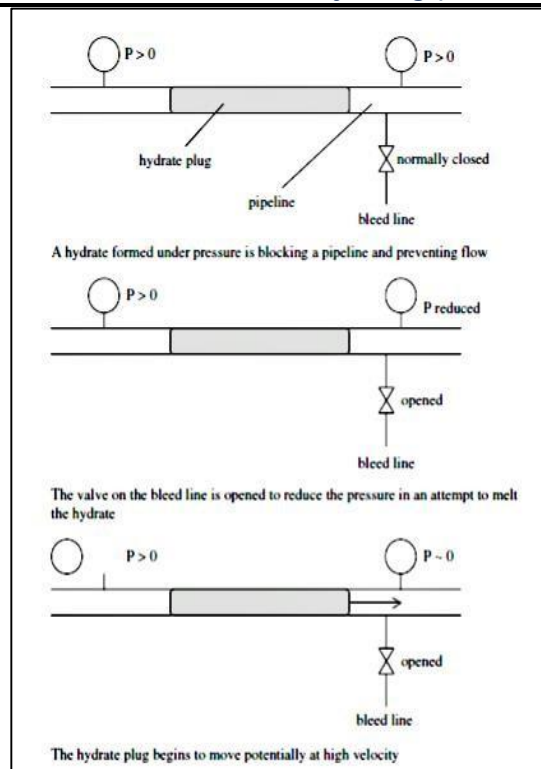
Fig: 3.2 Depressurization of hydrate plug

There are two methods for implementing depressurization: one-sided depressurization (from the wellhead) and two-sided depressurization.

Although one-sided depressurization has its uses, it runs the danger of igniting a partly dissociated plug in the system's low-pressure end. Therefore, before attempting depressurization, a detailed assessment of the plug release risk is necessary. This danger occurs when a closed volume of vapor is trapped by plugs operating at pressures greater than the necessary dissociation pressure. Because it lowers the overall energy in the system and increases the speed at which the plug may be removed, two-sided depressurization is often   recommended.

Knowing the plug's velocity as it enters equipment, elbows, tees, valves, etc., is essential. Plugs next to pipe fittings and equipment present the greatest danger of

The greatest danger of damage is seen in plugs that are close to pipe fittings and equipment. Furthermore, any study should take into account the possibility that liquids flooding the system downstream of the plug might considerably lower plug velocity.

3.4.2 Chemical Method:

It can be difficult to get inhibitors like methanol or ethylene glycol to clog a pipeline without access points close by. Even though plugs are permeable and porous, direct contact is hampered when there is a large gas volume between the plug and the injection sites, particularly when depressurizing the line is not an option in order to promote gas flow through the plug. In order to reach plugs, inhibitors must push aside other line fluids due to density differences; this is most advantageous when the plug is near subsea structures or producing facilities. It is improbable that an inhibitor would reach a blockage in a pipeline without flow when there are elevation changes.

Typically, inhibitors are injected from both sides of a plug to increase the chances of reaching it. Heavy brines with increased density can also help displace hydrate plugs.

Methanol or glycol injection is usually the first attempt, leveraging density differences to move the blocker toward the plug face, with glycol being preferred over methanol due to its effectiveness. Recent advancements suggest that certain gases like nitrogen and helium may act as solvents by permeating and dissociating hydrate plugs, although this method hasn't been field-proven yet. Refreshing is necessary because the chemicals used to dissolve plugs become diluted by water and vapour generated during the Procedure.
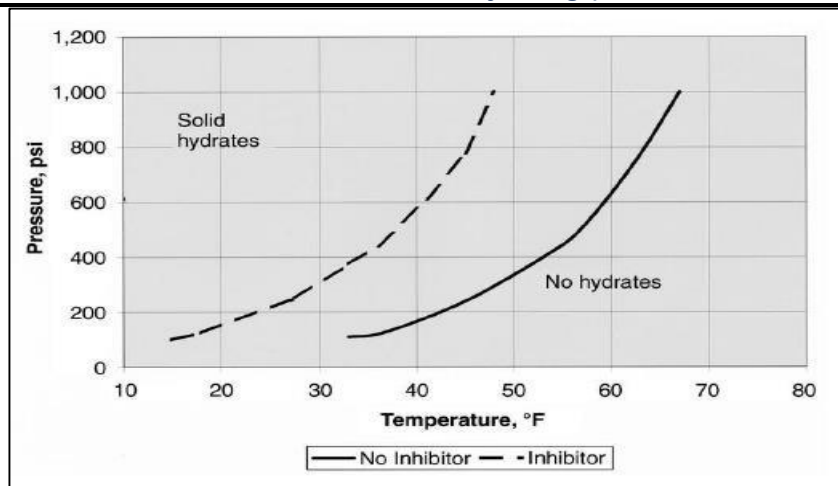
Fig: 3.3. Hydrate Inhibition Monitoring System (hydraCHEK) Methanol

Low-dosage hydration inhibitors (LDHIs) are now employed in various systems; thus, it is important to take into account the efficacy of LDHIs depending on the carrier fluid used. It is important to use caution while using these substances.

	Methanol	Ethylene Glycol (EG)	Diethylene Glycol (DEG)	Triethylene Glycol (TEG)
Flammability				
NFPA[1] Rating	3	1	1	1
Flash point	12°C	111°C	117°C	163°C
method	closed cup	closed cup	closed cup	closed cup
UEL[2] in air	36.5%	15.3%	10.6%	–
LEL[3] in air	6.7%	3.2%	1.7%	–
Toxicity				
LD_{50}[4]	9.54 g/kg	4.70 g/kg	14.80 g/kg	17 g/kg
method	oral rat	oral rat	oral rat	oral rat
description	practically non-toxic	slightly toxic	practically non-toxic	practically non-toxic

Notes on Table 5.6:
[1]NFPA—National Fire Prevention Association (www.nfpa.org). In this rating scheme, 4 is the highest fire hazard and 0 is the least.
[2]UEL—Upper Explosion Limit
[3]LEL—Lower Explosion Limit
[4]LD_{50}—LD stands for "Lethal Dose." LD_{50} is the amount of a material, given all at once, which causes the death of 50% (one half) of a group of test animals. The LD_{50} is one way to measure the short-term poisoning potential (acute toxicity) of a material. In general, the smaller the LD_{50} value, the more toxic the chemical is.

Table 3.1 Properties of various hydrate inhibitor and dehydration

Considerations:
1. To improve reachability, inject glycol at access locations above the hydrate plug rather than methanol or ethanol.
2. For similar purposes, inject ethanol or methanol at access locations beneath the plug.
3. Keep a fluid cushion in place underneath the plug.
4. Make sure the right chemicals are used after dissociation to stop plug reconstruction.
Recommendations:
• At SCSSV, inject ethanol or methanol.
• Inject the tree with glycol.
Possible Risks and Concerns:
   • Hazards to Health, Safety, and Environment (HSE) posed by chemicals.

Hydrate inhibitor	Methanol (MeOH)	Monoethylene glycol (MEG)
Advantages	Easily vaporized into gas For flowline and topside plugs No salt problems	Relatively recoverable For plugs in wells and risers Low gas and condensate solubility
Disadvantages	Costly to recover High gas and condensate losses Poisons molecular sieves, catalysts; downstream problems	High viscosity inhibits flow Boiler fouling, salt precipitation

Table 3.2 Methanol Vs MEG

3.4.2.1 The low-dosage hydrate inhibitors (LDHIs):

We now examine more recent classes of chemical inhibitors called low-dosage hydrate inhibitors (LDHIs), taking into account the previously described elements. These inhibitors differ significantly from conventional thermodynamic inhibitors, which mainly work by lowering the freezing point—a thermodynamic effect—to prevent the formation of hydrates. Examples of these inhibitors include alcohols, glycols, and ionic salts.

The following are some of the main causes influencing the use of LDHIs:
1. A conceptual knowledge of hydrate inhibition that is qualitative.
2. The accessibility of quantitative inhibition predictions derived from current programs.
3. The rising cost of conventional thermodynamic inhibitors and the difficulties in recovering from them.

Kinetic inhibitors and antiagglomerants are the two primary groups into which these contemporary compounds fall.

Table 3.3 Hydrate Inhibitors Vs Price

	Base Price	Adjusted Price			REF
	($US)	$US/gal	$(Cdn)/kg	$(Cdn)/L	
methanol	$532/tonne	1.60	0.53	0.42	1
ethanol	$3.30/USgal	3.30	1.10	0.87	2
EG	$0.63/lb	5.87	1.39	1.55	2
DEG	$0.32/lb	7.00	1.65	1.85	2
TEG	$0.90/lb	8.44	1.98	2.23	2

References: 1. Methanex, March 2008 (www.methanex.com)
2. ICIS pricing, April 2008 (www.icispricing.com)

Notes: Base Price is taken from original source
$1 (US) ~ $1.00 (Cdn) 2007
Price is for pure ethanol
Densities from Table 5.1, except DEG, $\rho = 1120 \, kg/m^3$

3.4.2.1.1 Kinetic Hydrate Inhibitors :(KHIs)

In recent times, a new class of chemicals known as "kinetic inhibitors" or KHIs has emerged. These inhibitors are designed to hinder the crystallization of hydrates, effectively slowing down the process of hydrate formation. While KHIs delay hydrate formation and growth, it's important to note that hydrates can still form given sufficient time, even in the presence of KHIs. Notably, these chemicals can be effective at very low concentrations.

Typically, KHIs under consideration for this purpose are polymers with high molar mass and significant water solubility. Kinetic hydrate inhibitors (KHIs) are primarily designed to stop hydrate blockages from forming for a longer period of time than the free water phase's residence time in the flow line. The effectiveness of KHIs is time-dependent, in contrast to thermodynamic inhibitory substances like methanol and MEG, which are time-independent.
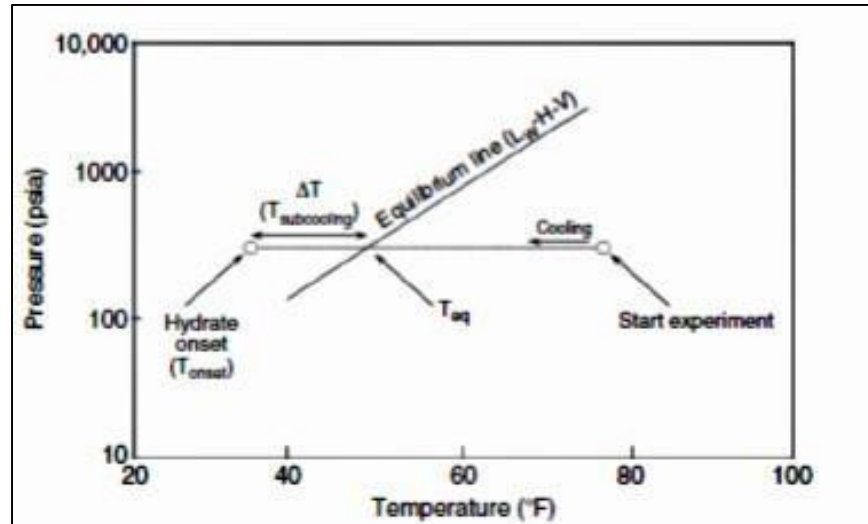

Fig.3.4 Sub cooling temperature chart.

The subcooling temperature chart is another method used to evaluate the efficacy of KHIs. The degree of subcooling (ΔT) that KHIs can attain below the equilibrium temperature for a given pressure is the basis for their evaluation. The subcooling chart sheds light on the efficacy of KHIs and is closely associated with the equilibrium time-independent diagram. The diagonal line divides the hydrate zone from the non-hydrate region, defining the pressure-temperature threshold at which hydrates are stable. In the absence of KHIs, hydrates might develop at greater pressures and lower temperatures, which could result in hydrate blockages.

3.4.2.1.2 Anti-Agglomerants:

Understanding the mechanism behind anti-agglomerants (AAs) requires acknowledging that aggregation is pivotal in blockage formation. Here's a breakdown of the process:
1. In the oil phase, water droplets become trapped.
2. The droplets produce a "hydrate balloon" of water at the contact where they develop a hydrate shell.
3. To aid in aggregation, capillary bridges develop between the hydrated droplets.
When there are enough aggregates, a clog or obstruction forms.
For the hydrated droplets to continue flowing with the oil phase, hydrate aggregation must be prevented. This is especially true under suitable liquid loading circumstances, such as up to 60 vol% loading.
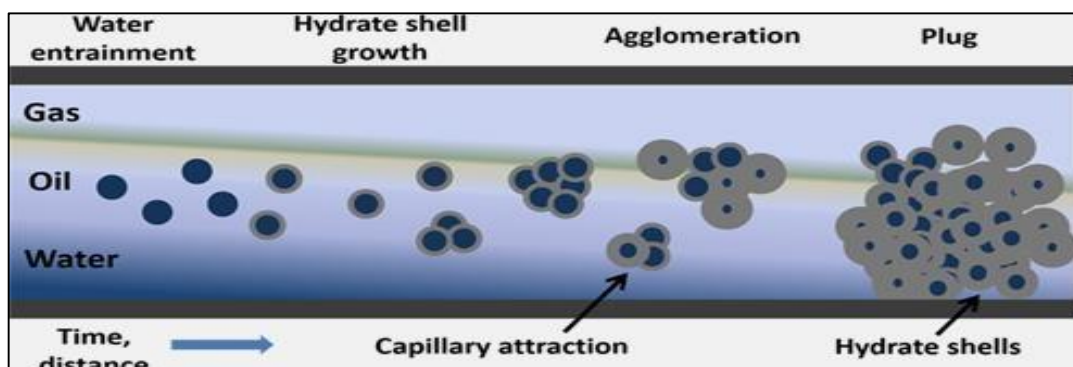

Fig: 3.5 Conceptual picture of hydrate formation in an oil-dominated system

To demonstrate the idea of anti-agglomeration, look at Figure 3.5, where an anti-agglomerant called sorbitan monolaurate (Span-20) has been applied to the surface of a hydrated droplet on the left. As seen on the right side of Figure 3.6, this treatment results in tiny, hair-like protrusions of hydrate into the oil phase, which lowers the attractive forces between particles in comparison to pure spherical particles. As a result, the hydrate particles continue to float in the oil phase. Interestingly, the surface "hairs" in Figure 3.6 are much bigger than the molecules of Span-20. Quaternary ammonium salts, which have one end of the molecule dissolved in the oil phase and the other linked to the hydrate structure, are a common type of anti-agglomerant.

What does Capillarity mean?

Capillarity refers to the phenomenon where a liquid either rises or depresses in small capillary passages, such as those found in porous materials. This action can occur both vertically and horizontally, with the liquid moving upward against gravity, a process also known as capillary action. It involves two types of forces: cohesion, which binds molecules of the same substance together, and adhesion, which causes molecules of different substances to attract each other.

3.4.3 Mechanical methods:

When accessibility permits, mechanical methods—like using coiled tubing—have been effective, particularly in dry tree facilities. Standard lubricator designs may be used to introduce coiled tubing into the well. To break down and spread the plug face, methanol or hot water can be directed against it. In particular, hot water has proven to be useful in delaying hydrate reformation until the well fluids settle once the blockage is removed.

Where access permits, coiled tubing has been used successfully, especially in dry tree facilities. Standard lubricator designs with coiled tubing make it easier to enter the well and stretch it down until the clog is found. Abrupt movement is avoided by keeping the pressure balance on both sides of the plug. On remove and dissolve the clog, hot water or methanol are applied on its face. Hot water has shown to be quite successful, particularly in situations where restrictions on heat transport prevent hydrate reformation until well fluid stability occurs after plug removal. Although drag forces impose constraints, alternative means to draw the coiled tubing deeper into the system than it can be pushed include tractor pig or cup-shaped designs. The hydrate solid phase dissociation and plug removal processes may be greatly accelerated by mechanical augers. By drawing the tubing into the pipe using fluid pressure in the annulus between the production pipe and the coiled tubing, this technology may provide a way to remove hydrate obstructions in the future. The circulation of warm fluids across the hydrate plug is taken into account.

Considerations:

- Apply the proper chemical proportions to avoid reformation after melting the plug. • Ensure accurate knowledge of the position and length of the whole hydrate plug. The following recommendations apply to both options: • To guarantee safe hydrate clean-up, closely monitor the temperature of the pipe wall; do not allow temperatures to rise over the maximum permitted working pressure that corresponds to the dissociation pressure. The hydrate plug may be uniformly heated by gradually increasing the temperature after plug melting begins, which is indicated by a rise in pressure.
- Verify that the discharged gas has clear escape routes. Potential Hazards and Issues: • Local pressures resulting from gas release from hydrate melting may reach pipe bursting pressure if the starting temperature of the pipe wall is higher than that which corresponds to dissociation pressures surpassing the maximum permissible pressure.
- Non-uniform heating of the total plug may impede gas escape, leading to high local pressures, potentially surpassing pipe bursting pressure.

3.4.4 Thermal methods:

Thermal technologies for hydrate clean-up are becoming more and more prevalent as subsea flow line distances and water depths rise. Raising the hydrate plug's temperature over its equilibrium point is the main idea behind thermal methods. Once equilibrium conditions are exceeded, gas is released from the melting hydrate cap. In the vicinity of the hydrate block, pressure is constant if the gas can escape freely. However, isolated high pressures may trap the gas and cause hydrate reformation if there is no clear avenue for gas escape because of uneven heating along the plug's length.

To avoid pressure accumulation, the whole length of the hydrate plug must have a homogeneous temperature distribution. Presumably, pressures close to the hydrate plug may rise to 8000 psia if the plug's temperature reached 85°F without a free gas escape route.

Therefore, precise temperature control is essential for any thermal method. While thermal methods have been intermittently employed without issues, improper procedures have led to pipe bursts and fatalities.
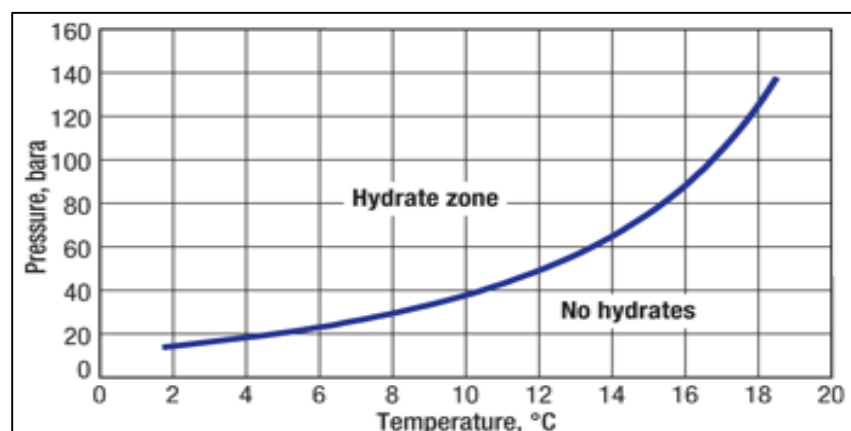
Fig: 3.6 Hydrate stability curve (thermal)

Commonly considered thermal methods during project design include electrical heating, heated bundles, and external hot water tubing. Key considerations during project design include evaluating alternative methods if these thermal approaches are not implemented, ensuring accurate knowledge of the plug's location and length, assessing risks associated with electrical heating, and applying appropriate chemicals post-plug melting to prevent reformation.

Recommendations for safe hydrate remediation emphasize meticulous monitoring of pipe wall temperature to avoid exceeding the maximum allowable working pressure corresponding to dissociation pressure. Temperature can be gradually raised to ensure that the heating medium covers the whole hydrate plug and achieves uniform heating of the pipe wall after plug melting begins, as indicated by an increase in pressure. To reduce the possibility of trapped gas reaching bursting pressure, it is crucial to make sure released gas has an unobstructed path to escape.

3.4.4.1 Heat transfer across the pipeline:

For the purpose of handling hydrate issues, it is essential to forecast the temperature profile along the pipeline. Thermal design of pipelines to prevent hydrate deposition typically involves adding insulation layers. Subsea pipeline insulation costs approximately $1,000,000 per mile to mitigate hydrate formation during offshore operations.

Heat transfer in nature encompasses three modes: conduction, convection, and radiation. A variety of these modalities are involved in heat transport over the pipeline. When there is a temperature differential across the pipeline wall, conduction happens. When there is a temperature differential between the outside surface of the pipeline and the surrounding air (for onshore pipelines) or seawater (for subsea pipelines), convection happens.

Radiation is the method by which electromagnetic energy from the pipeline surface is released. But radiation-induced heat loss pales in comparison to conduction and convection losses, especially when you take into account that the temperature conditions inside the pipeline for hydrate formation usually stay below 10°C.
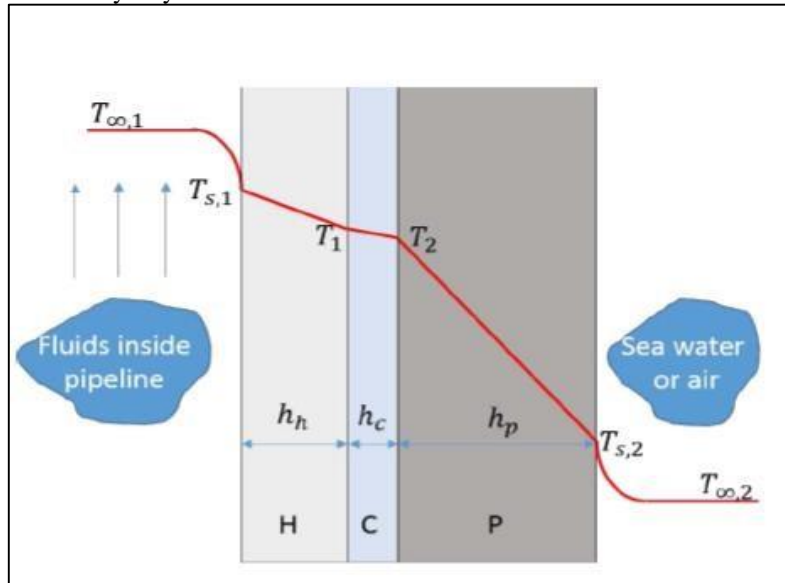

'Fig: 3.7 Heat Transfer across pipeline wall with hydrate deposition (H: Hydrate deposit layer; C: Coating layer; P: Pipe wall)

3.4.4.2 Melting a plug with heat:

Melting a hydrate plug with heat is another method of removing it. Electrical resistance heating and steam spraying are two techniques for applying heat to a line. But use of this approach needs to be done with caution. A potentially dangerous scenario related to this strategy is shown in Figure 3.8.

The plug will release gas and produce liquid water when it melts. One standard cubic meter (Sm3) of gas is produced from one cubic meter of methane hydrate, as explained in detail in Chapter 8. 51.45 kilomoles (kmol) of liquid water are also produced during the melting process; this liquid water takes up 0.927 cubic meters. This suggests that for every 170 Sm3 of released gas, only 0.073 cubic meters are accessible in a limited location.
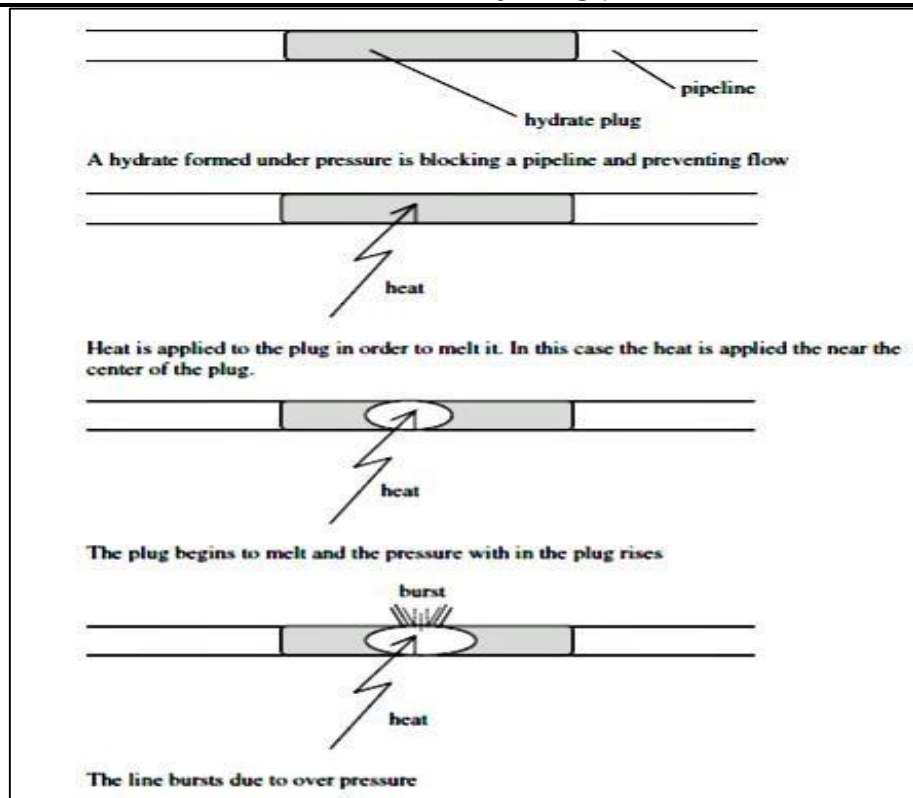
'Fig: 3.8 Scenario for pipeline rupture during the melting of a gas hydrate plug.

The pressure of the released gas can be roughly estimated using the ideal gas law.

$$P1P1 = P2V2 \ (or) \ P2 = P1V1/V2$$

$$P2 = (170*101.325)/0.073 \quad = 236000kpa \ (236Mpa)$$

3.5 Typical Hydrate Mitigation Methods:

In subsea oil production systems, heat preservation is a frequent tactic employed to stop hydrate formation during steady state operation. However, in cases where flow lines are very lengthy or where late-stage production rates are limited, heat retention may not be possible. Low-dosage hydration inhibitors (LDHIs) may be constantly given in such circumstances. Although continuous infusion of methanol (MeOH) has been used, it is still not prevalent. If fluids are not blocked during shutdowns, there is a chance that the system will cool into the zone where hydrate formation occurs.

In these situations, two typical mitigating techniques are frequently used:

1. Applying a blowdown to depressurize the subsea system and lower pressure.

2. Substituting dead oil and/or methanol for living fluids. Sufficient insulation of the system is essential to provide operators sufficient time to complete these displacements. There is a chance that generated fluids will find their way into the hydrate formation zone upon restart. Applying heat—such as electrical heating, heating the flow line with dead crude prior to commencement, injecting LDHIs or thermodynamic inhibitors, or starting the well quickly enough to beat hydrate production—is one way to stop hydrate formation during well initiation. In some subsea gas production systems, when hydrate mitigation through heat preservation is difficult, the latter approach—which is dependent on the kinetics of hydrate formation and entails inherent risks—may be the only practical choice. For long offset gas flow lines, continuous injection of monoethylene glycol (MEG) is a typical technique. MEG is used over MeOH mainly because it is easier to recover and reuse. Usually, export pipes are protected by dehydrating the sales fluids.

CHAPTER-4

INDUSTRIAL PROCEDURES FOR HYDRATES CONTROL

4.1 Introduction:

It's critical to understand that hydration events frequently happen during sporadic or unusual operations, like:

• Initialization

• Restart following an emergency shutdown of operations

• The existence of uncontrolled water as a result of an inhibitor injection or dehydrator malfunction

• Refreshing with flow growth beyond a constraint

Because the system is designed to ensure flow assurance, hydrate plug development usually does not occur during regular flow-line operation. During start-up, shutdown, and steady-state production operations, managing hydrates entails providing appropriate awareness and direction to operations, which consists of four essential components:

1. Robust system architecture

2. Thorough record-keeping of hydrate hazards, mitigation strategies, oversight techniques, and backup plans

3. Dependable operating protocols

4. Operations personnel with sufficient training

4.2 Deep-water system design:

In order to control hydrates, deep-water subsea production oil systems are often built as piggable loops with active or passive heat management.

A looping system makes it possible to:

• Move hydrate-prone fluids after a shutdown;

• Use pigging to manage sand and corrosion; and

• Use intelligent pigging to manage integrity.

After they have warmed up enough, oil systems often don't require constant inhibitor input during start-up. Continuous inhibitor injection is inhibited in mid-to late-life oil wells by a significant water reduction. In contrast, deep-water subsea gas systems usually have bare pipe topologies and, because of their lower starting heat content per unit volume, lesser formation of water, and cooling during pressure drop in the flow line, predominantly use inhibitors rather than heat for hydrate management. Dual-line designs are frequently required for gas because of the periodic pigging and integrity management used for liquid control.

Both oil and gas fields are managed by highly skilled offshore workers. After the design and drawings are complete, operators and engineers work together to create the facility's operating procedures. These protocols cover steady-state, upset, start-up, and shutdown scenarios. Simulators include "full field models," which incorporate topsides process equipment such as export pumps and compressors, as well as reservoir boundary conditions, wellbores, trees, manifolds, flow lines, risers, and boarding chokes. Process and emergency shutdown (PSD and ESD) logic, sensors, and controllers are all included in both topsides and subsea versions.

4.3 Applications:

The hydrates and manufacturing methods covered in previous chapters are the result of much study and experience, some of which is accepted by the industry and some of which is still at the cutting edge of technology awaiting application. Flow assurance engineers need to think about the following issues from a design and operations perspective:

1. In the production system, when and where are hydrates likely to form?

2. What kind of controls can be put in place to stop the production of hydrates?

3. Which system monitoring points show the existence of hydrates?

4. How can a hydrate block be remedied in the production system?

4.3.1 Application 1: Identifying Hydrate Formation Locations A thorough grasp of hydrate thermodynamics is vital for pinpointing potential formation areas within the production system. Alongside hydrocarbons, three crucial elements—cold temperatures, high pressure, and water—are prerequisites for hydrate formation in hydrocarbon production setups. Given the hydrate-forming nature of all deepwater production systems, comprehending the anticipated pressures, temperatures, and water compositions over the field's lifespan via simulation is paramount. A couple of fundamental guidelines to remember include:

- Hydrates won't develop without water.
- Gas systems

4.3.2 Application 2: Prevention Strategies for Hydration In one way or another, all three requirements for hydrate formation are controllable. Although temperature and flow rate usually go hand in hand, especially in gas systems, pressure drops within the system can have a big impact on temperature. Sometimes pressure management in the subsea system can be accomplished by choking the wellhead. There will be variations in both temperature and pressure control over the field's life. But controlling water content is not as simple as controlling pressure and temperature.

4.3.3 Application 3: Keeping an eye on the Hydrate Indicators Monitoring system parameters is essential because of the role that water, high pressure, and low temperatures play in hydrate blockages. This means using chemical injection systems, temperature and pressure transmitters, and water monitoring apparatus (such as three-phase separators with water-cut meters). Downhole and tree pressure (P) and temperature (T) monitoring in wells is standard practice for deep-water settings. Pressure and temperature monitoring are frequently included in subsea systems at commingling places (manifolds) and the top parts of incoming risers. It is possible to compute the pressure and temperature readings between monitoring stations, which highlights the possibility of hydrate obstructions in the manufacturing system.

4.3.4 Application 4: Hydrate Blockage Remediation Strategies In this segment, we'll explore operational strategies for addressing suspected hydrate blockages. Referring to the hydrate location notation depicted in Figure 7.1, we'll delve into effective remediation approaches.
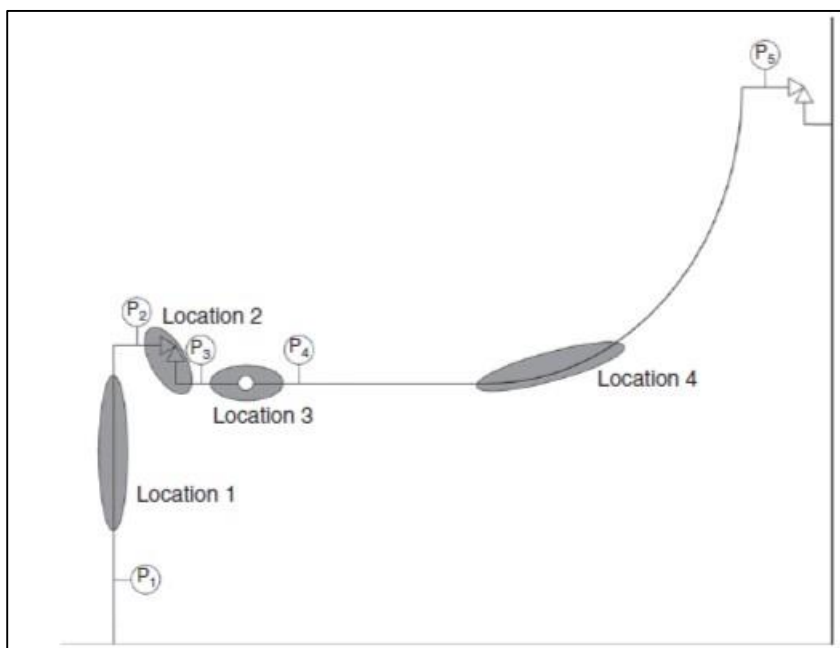

Fig: 4.1 'Subsea system and potential location of hydrate blockage'.

	Location 1	Location 2	Location 3	Location 4
DHP (P_1)	Increase	Increase	Increase	Increase
P_2	Decrease	Increase	Increase	Increase
P_3	Decrease	Decrease	Increase	Increase
SSP (P_4)	Decrease	Decrease	Decrease	Increase
TRP (P_5)	Decrease	Decrease	Decrease	Decrease

DHP, downhole pressure in well; P2, tree pressure upstream of well choke; P3, tree pressure downstream of well choke; SSP, subsea pressure (usually at manifold); TRP, top of riser pressure (upstream of topsides choke).

Table: 4.1 Pressure Response of Hydrate Blockage Forming

Four activities are taken into account: (1) inject chemical; (2) halt flow; (3) decrease flow; and (4) increase flow. These are all covered in the sections that follow.

4.3.4.1 Inject Chemical:

The most suitable course of action is frequently to inject a thermodynamic inhibitor when there are signs of a hydrate blockage occurring. It's crucial to determine the blockage's location beforehand, typically through pressure responses as outlined in Table 7.1 and methods discussed in Chapter 4. Ensuring complete protection of the water in the flow stream requires injecting the inhibitor as near to the obstruction as feasible. There is a possibility to melt any hydrates that may already be in the system by over-injecting chemical.

4.3.4.2 Flow Interruption:

Operators often take the initial action of halting flow upon discovering the development of a hydrate clog. Even though it's occasionally required, stopping the flow must be immediately followed by a system blowdown to lower the pressure below the hydrate threshold. It's crucial to remember that system blowdown in gas-dominant systems may reduce temperatures, which might exacerbate hydrate formation.

4.3.4.3 Flow Reduction:

Reducing flow alone is not likely to clear a hydrate blockage and would potentially cause the system temperature to drop more, which would encourage the production of hydrates. However, by guiding an overprotected water phase toward the limit, lowering flow can support chemical injection attempts.

4.3.4.4 Flow Increase:

Increasing flow or "pushing through" might make sense in some situations. Increasing flow may cause temperatures to rise and may melt any hydrates that may be accumulating. Using this technology requires prudence, particularly in settings where gas predominates.

4.4 Operating Procedures for Hydrate Control:

The operational guidelines function as a thorough explanation of how the production system is supposed to operate. Particular portions of these recommendations should include the following with relation to hydrates:

1. Hydrate Risk Assessment: When and where hydrate-related issues are expected to surface should be clearly documented.
2. Hydration Control Strategy: The appropriate hydration control actions should be specified for various operational conditions. As an illustration:

• Chemical injection at designated sites should be maintained until temperatures surpass the hydrate threshold during start-up operations.
• Chemical injection is not required during steady-state operations where temperatures stay over the hydrate threshold. A time limit should be given in the event of an unscheduled shutdown until the system is vulnerable to hydrates.
3. Monitoring Points and Contingencies: Identify critical monitoring points and outline contingency plans for addressing unforeseen issues.

Operating procedures are typically structured in a modular format tailored to specific operations, such as well start-up, shutdown, testing, and subsea or topsides system operations.
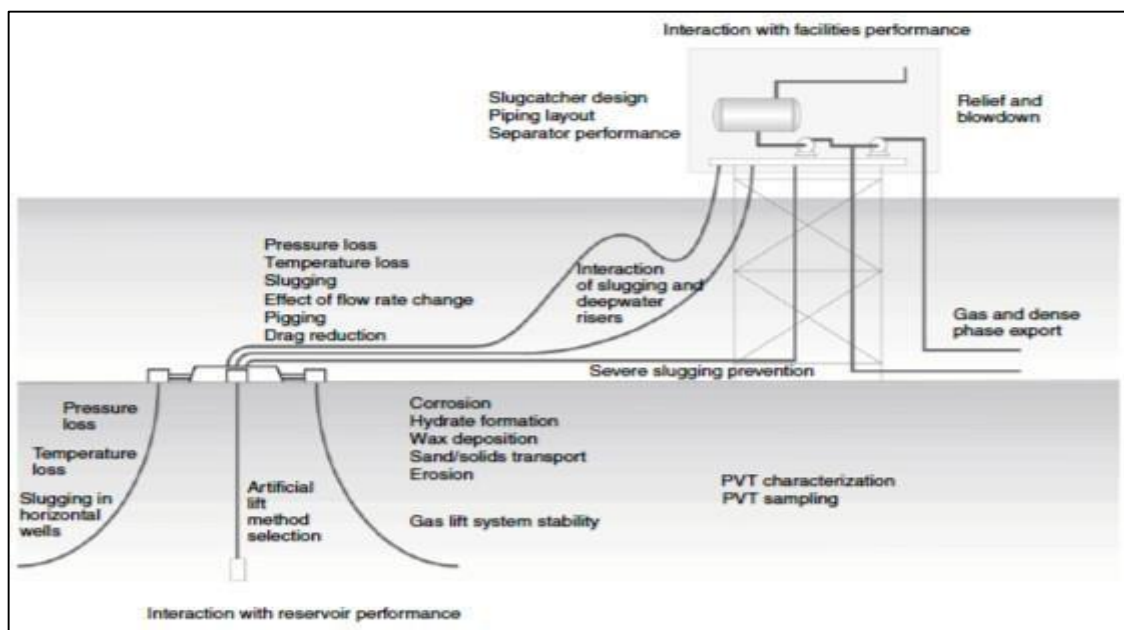

'Fig: 4.2 Typical production systems with some flow assurance problems labeled

Generally speaking, a comprehensive operating process has six parts:

1. Operational Scope: Offers a high-level summary of the activity.

2. Primary Risks: Synopsis's of possible hazards that may arise throughout the procedure.

3. Additional Safety and Environmental Issues: (not covered in detail here).

4. Documentation and References: Modular guidelines including references to pertinent diagrams, such as system-specific process flow diagrams (PFDs) and process and instrument diagrams (P&IDs).

5. Prerequisites: Conditions that must be met for the process to be approved.

6. Procedure: Detailed operating guidelines with integrated monitoring comments that describe variations in pressure, temperature, and flow as well as how to react when these variations deviate from expectations.

CHAPTER-5

CASE STUDY

5.0 Introduction: About Reliance Industries Limited:

Dhirubhai H. Ambani (1932–2002) founded the Reliance Group, which is India's largest private sector company operating in the energy and materials industries. The main firm, Reliance Industries Limited (RIL), with yearly revenues above US$ 66 billion, was rated 158th on the Fortune Global 500 list in 2015, therefore securing its position as the largest private sector organization in India. RIL achieved the 14th position in the Platt's Top 250 Global Energy Company Rankings for that same year. Backward vertical integration, which began with textiles in the late 1970s and progressed into polyester, fiber intermediates, plastics, petrochemicals, petroleum refining, and oil and gas exploration and production, has been the driving force behind Reliance's expansion.

The Group's diverse business includes petrochemicals, textiles, retail, communications, special economic zones, petroleum refining and marketing, oil and gas production, and exploration. With global leadership in key sectors, Reliance is the largest producer of polyester yarn and fiber globally and ranks among the top producers in major petrochemical products. Key companies within the Group include Reliance Industries Limited and Reliance Industrial Infrastructure Limited.

5.1 Krishna-Godavari Basin:

The Krishna-Godavari basin, a pericratonic basin that includes the inter-deltaic areas and the deltaic plains of the Krishna and Godavari rivers, is located on the east coast of the Indian peninsula. Geographically, it extends southeast into the deep seas of the Bay of Bengal, spanning from Kakinada in the northeast to Ongole in the southwest. Quaternary sediments cover a large amount of the onshore basin area. Encompassing around 28,000 square feet. 145,000 sq. km. onshore. Far offshore, the basin is a crucial component of India's Eastern Continental Margin, which was formed when India drifted and rifted away from Antarctica–Australia.

Block KGD6 is planned to be developed in multiple phases, with the initial phase featuring 18 subsea wells clustered around six manifolds, each capable of connecting six wells. These manifolds are further clustered around a Pipeline End Module (PLEM), which connects to two 24" trunk lines for transporting production fluid to a Control and Riser Platform (CRP).

5.2 Development Plan of KG-D6:

Secured by RIL's E&P team through NELP-I bidding, the KG D6 block, also known as Block KGDWN-98/3, is situated in the Krishna-Godavari Basin, Bay of Bengal. Spanning an area of 7500 sq. km, KG-D6 marked Reliance's debut in offshore gas field development and underwater discoveries. It stood as India's largest deposit of natural gas and the world's largest discovery in 2002. The block spans water depths ranging from 400 meters in the northwest to over 2700 meters in the southeast.
The project included the installation of eighteen producing wells at the KG-D6 block, each with pipelines, an onshore terminal, a riser platform, and subsea equipment. In January 2006, Reliance awarded US-based Bechtel the project's overall EPCM contract. This rapid expansion required one of the biggest and most complex underwater installation projects to be completed to date. For the entire subsea production system, Aker Kvaerner Subsea was awarded an engineering, procurement, and construction (EPC) contract for $400 million.
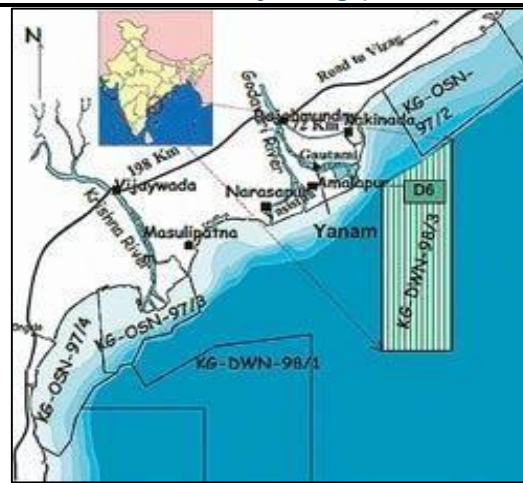
Fig 5.1 Location of KG-DWN-98/3 in India map.

The block comprises two fields: D1D3 and MA. While the D1D3 field primarily yields gas, the MA field produces both oil and gas. The development of the D1D3 field involves subsea wells interconnected with subsea manifolds. Production from these manifolds is directed to a DWPLEM (Deep Water Pipeline End Manifold), with the fluids then transported to the Onshore Terminal through two 24" pipelines via the Control and Riser Platform (CRP).

The MA Subsea System comprises six subsea wells interconnected to a Floating Production Storage and Offloading (FPSO) vessel via flexible risers, a quick disconnect turret, and a swivel. Additionally, this system includes a production manifold with eight slots and two production risers. At the FPSO, gas and oil from the MA field undergo separation using a production separator. The separated oil is stored on-board the FPSO, while the gas is conveyed to the Control and Riser Platform (CRP) through a 24" pipeline, along with gas produced from D1 and D3 fields.

Situated in Gadimoga, the Onshore Terminal functions as a gas processing facility. It receives gas from three 24" pipelines—GTL-1, GTL-2, and GTL-3—from the CRP. Equipped with a dehydration unit, MEG Regeneration Unit, TEG Regeneration Unit, and other facilities, the terminal is designed to remove sand and other undesirable constituents from the gas.

5.3 Subsea Architecture:

```
┌──────────────────────────────┐
│      18 Subsea Wells          │
└──────────────────────────────┘
               ↓
┌──────────────────────────────┐
│      6 Subsea Manifolds       │
└──────────────────────────────┘
               ↓
┌──────────────────────────────────────────┐
│ Deep Water Pipeline End Manifold (DWPLEM)  │
└──────────────────────────────────────────┘
               ↓
      Two 24″ Pipelines
                                          Gas from MA
┌──────────────────────────────────────────┐ ←
│      Control and Riser Platform (CRP)      │
└──────────────────────────────────────────┘
               ↓
      Three 24″ Pipelines
┌──────────────────────────────────────────┐
│            Onshore Terminal                │
└──────────────────────────────────────────┘
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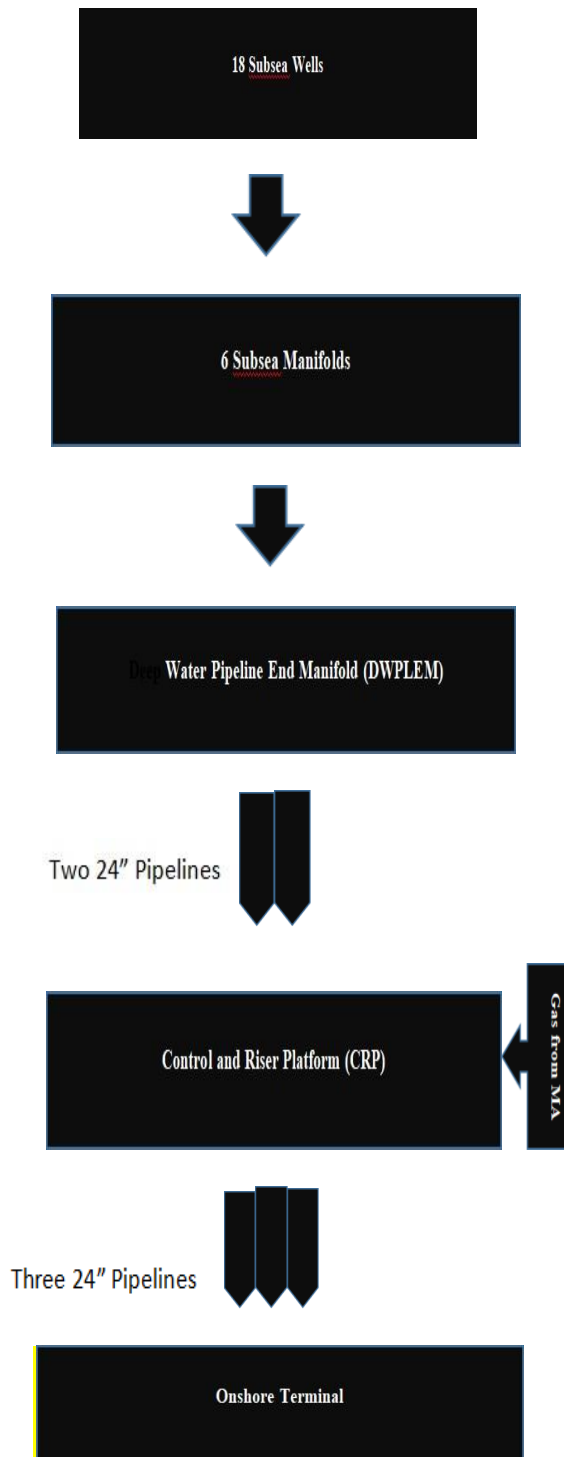
At the KGD6 site, the well/down-hole completion design features an 18 ¾" subsea wellhead system. Each tube bore is equipped with a Dual DHPT gauge for permanent temperature and pressure monitoring. Additionally, a Single Control Subsurface Safety Valve (SCSSV) is situated in the tube bore to perform a single control function. There are a total of 11 5" and 7 7" High-Pressure Christmas Trees (HXTs) present, with a maximum allowable pressure of up to 10,000 psi. Continuous injection of corrosion inhibitor is implemented into the HXTs. The wells are categorized into two channel wells: A channel wells with low water production and B channel wells with high water production
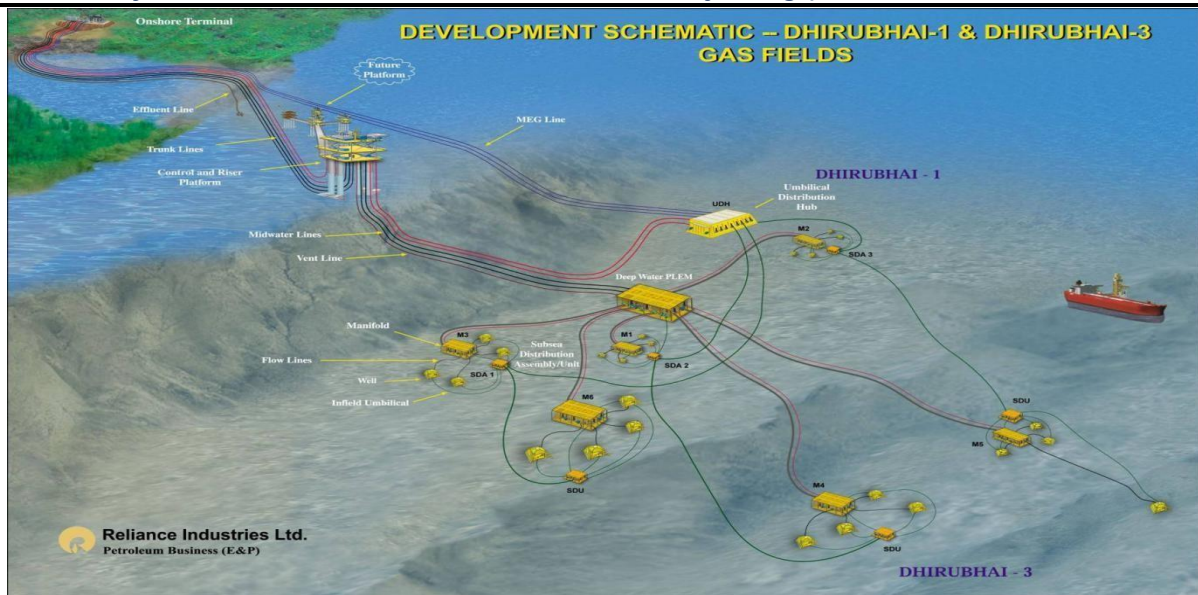
Fig. 5.2 Development Schematic D1 D3 Field

5.4 Production pipelines:

• The Manifolds and Wells are connected by 8" or 10" flow lines.

• Deep Water Pipeline End Manifold (DWPLEM) is reached by 16"–18" deep-water infield pipes that run from the Manifolds.

• The Control & Riser Platform (CRP) is connected to the DW PLEM by two 24" gas trunk lines.

• One pipeline enters from the MA field, and three 24" export pipes connect the CRP to the Onshore Terminal.

5.4 FPSO

In the context of FPSO (Floating Production, Storage, and Offloading), an FPSO installation is a floating facility that is usually built around the hull of an oil tanker that has been transformed. With the use of flexible pipes, it receives crude oil, water, and gasses from subsea oil wells and processes them using hydrocarbon processing equipment. With this idea, oil may now be produced in distant and deep-water locations that would not be commercially viable with existing technologies, such as stationary stacked structures. To further eliminate the need for a pipeline to deliver oil to shore, the FPSO is equipped with an offloading system that transfers crude oil to shuttle tankers for export to refineries, as well as storage space for processed crude oil.

Fig 5.3: FPSO

At a depth of 1200 meters, the FPSO Dhirubhai-1 is situated offshore off the East Coast of India. It now exports over 9 million Standard Cubic Meters of gas to onshore users, with a 60,000 barrel oil production capability. Every day, more than fifty people work on this FPSO. The Dhirubhai-1, which was first transformed in 2008 from an oil tanker into an FPSO, is bound by a long-term contract with Reliance Industries Ltd. that runs until September 2018.

Table 5.1 : FPSO Details

Vessel Type	FPSO
Built	2008 (converted from oil tanker)
Key features	**Water depth:** 1,200 meters at FPSO location **Environment:** Typhoon Conditions **Mooring:** Disconnectable turret **Oil Production Capacity:** 60,000 bopd (80,000 blpd) **Gas Inject. Capacity:** 100 mmscufd (3 million cbm/d) **Gas Export Capacity:** 300 mmscufd (9 million cbm/d)
Yard	Jurong Shipyard, Singapore
Charterer	Reliance Industries, India
Contract Type	Bareboat Contract + Operating Agreement
Charter start	September 2008
Charter End	September 2018

5.6 Challenges in KG-D6

The major flow assurance challenges faced in KG-D6 are listed below:

5.6.1 Liquid Loading:

Production volumes and bottom-hole pressures start to drop as gas wells get older, which lowers production velocity and makes it harder for the liquids to rise to the surface. If the gas production doesn't entirely remove these liquids from the well, they may accumulate down hole and cause the gas to flow erratically, which will reduce production and ultimately cause the well to fail. Surfactants By lowering the liquid density in the well and creating the necessary velocity to raise these fluids to the surface, foaming agents assist to increase production capacity, prolong the equipment's usable life, and cut down on downtime.
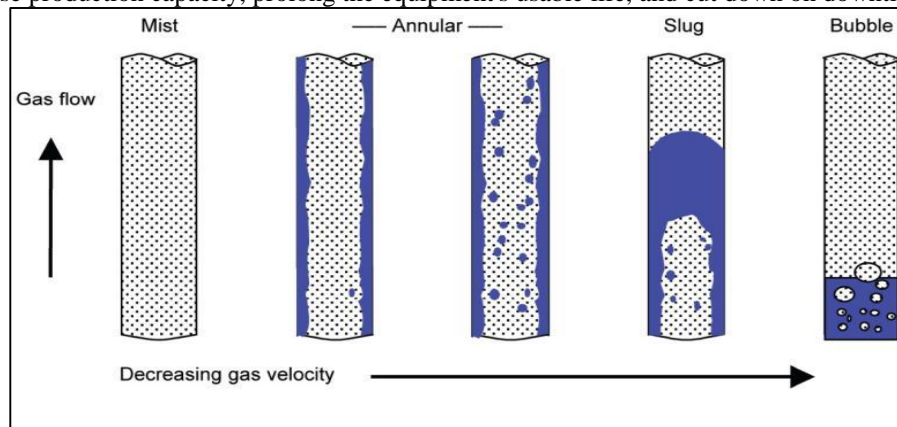
Fig 5.4: flow regimes (Liquid Loading Phenomenon)

Due to the problem of liquid loading gas from DWPLEM to CRP is routed in one 24" pipeline instead of two 24" pipelines so that the gas velocity increases and it escapes from the unstable gravity dominated flow to stable friction dominated flow .In KG-D6 the surfactants and foaming agents are being transported using the chemical inhibitor lines of the umbilical's.

5.6.2 Hydrates Formation:

When free water and natural gas mix at high pressure and low temperature, natural-gas hydrates—which resemble ice—are created. This may happen in oil wells as well as gas and gas/condensate wells. Natural gas hydrates are non-stoichiometric solids made comprised of water molecules forming a mesh cage structure that holds a small number of gas molecules. High pressure and low temperature circumstances cause the elements of hydrates to come into contact, forming a solid structure with diverse kinds of crystals that have densities greater than those of conventional fluid hydrocarbons.

The stability and characteristics of hydrates, which are solid metastable substances, are dependent on temperature and pressure.

Natural gas hydrates are hazardous substances that should be avoided both during the building and maintenance of process facilities, including platforms, pipelines, and other engineering structures. In producing gas wells and pipelines, hydrates can readily develop before the gas has completely dried out. Heated production costs might reach 10–15% as a result of the significant efforts needed to avoid hydrates.

5.7 Hydrate Prevention:

Hydrate formation may be prevented in the following ways:-

- Thermodynamic Inhibition
- Operate outside the hydrate formation region.
- Dehydrating the gas.
- Adding chemical hydrate inhibitors such as MEG and Methanol
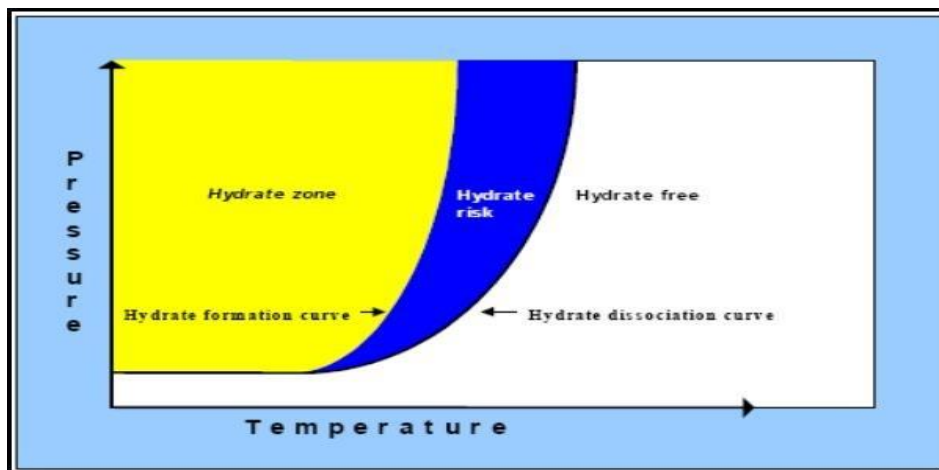- Kinetic Inhibition (Anti-Agglomerates)

Fig 5.5 Hydrate curve

In KG-D6, D1D3 field MEG injection was practised to prevent formation of hydrate in the subsea facilities. The MEG used has a purity of 90%.After conducting many simulations RIL concluded that the production is out hydrate formation zone .Now the production is done without MEG injection however RIL has stored Lean MEG which could be used at the time of intervention

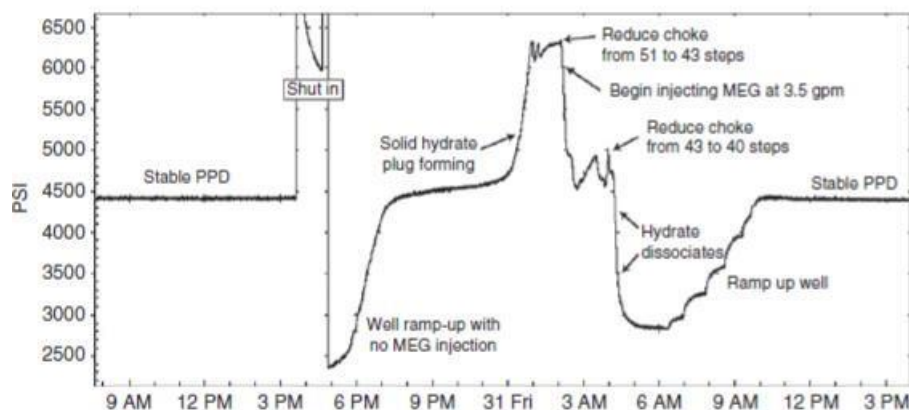## 5.7.1 Background operations:

Table 5.2 Hydrate remediation procedure step-by-step.

Approximately one hour after being turned down, the system in the KG-D6 Field scenario was restarted. Regretfully, the well restart unintentionally did not start the MEG inhibitor. The pressure progressively rose during ramp-up when the system restarted, signaling the development of a hydrate deposit. Hydrate dissociation occurred as a result of the choke rate being lowered and MEG injection being started in reaction to the pressure increase. Following the reduction of pressure, output was boosted via MEG injection at standard pressures, therefore averting hydrate accumulation. Over the 1.4 miles, the temperature dropped from 120F to 44F.

The process of hydrate remediation involved pumping methanol from the D1D3 wellhead and the other wellhead over a 12-day period, totaling around 6500 gallons of methanol. The pressure during the period is shown in Figure A.13, and Table A3 gives a thorough explanation of the hydrate remediation procedure step-by-step.

5.7.2 Hydrate remediation steps:
1. Methanol was periodically injected into the Christmas tree, and pressure bleed off was monitored.
2. An ROV was deployed to close the sled valve of the D1D3 fields.
3. Methanol injection was initiated to the manifold where gas from the D1D3 fields was present.
4. The total estimated methanol injection amounted to 5000 gallons.
5. The choke was opened to allow flow at a rate of 10 MMCFD.
6. Downstream pressure at the manifold immediately increased to over 6000 psi.
7. 1500 gallons of methanol were pumped through the D1D3 fields.
8. Prior to restarting the 24-inch pipeline, all wells were shut in on that flow line.

5.8 Choice of MEG:
- MEG allows for regeneration.
- It possesses lower viscosity, molecular weight, and specific gravity compared to DEG and TEG, thereby offering better fluidity at low temperatures.
- The melting point of MEG (-13.0) is lower than that of DEG (-10.45) and TEG (-7.0).
- MEG is less corrosive.

Fig 5.6 : Reliance Industries (RIL) Onshore Terminal at Gadimoga

CONCLUSION

This dissertation investigates the phenomenon of natural gas hydrate crystals forming in pipelines dominated by gas, employing both numerical and analytical models. The key findings of this study are as follows:

1. Hydrate formation presents a substantial risk to the transportation of fluids in subsea pipelines, potentially leading to pipe and instrument blockages. The hypothesized evolution of plugs in gas-dominated systems comprises five stages: hydrate formation, deposition, sloughing, jamming, and eventual plugging.
2. Hydrate formation typically occurs under conditions of high pressure, low temperature, and in the presence of water and light hydrocarbons (C1 - C4). The composition of fluids significantly influences hydrate formation, with heavier hydrocarbon gas molecules and sour gas molecules facilitating it.
3. In offshore systems, hydrate formation commonly occurs between the subsurface safety valve in the well and the beachhead. Flow assurance engineers are tasked with designing systems to prevent hydrate formation and safely remediating them if they occur.
4. Operating outside the hydrate-stable region by adjusting pressure and temperature through heating, heat conservation, and pressure control is recommended.
5. It is recommended to replace fluids that are prone to hydrate formation with dead fluids in advance of hydrate formation.
6. You can add hydrate inhibitors, such methanol (MeOH) or monoethylene glycol (MEG), to shift the hydration curve to the left.
7. Since liquid water is necessary for the production of hydrates, eliminating water from the hydrocarbon stream is beneficial.
8. Hydrate agglomeration can be avoided by injecting Low Dosage Hydrate Inhibitors (LDHI).

9. Hydrate Inhibitors with Kinetic Low Dosage postpone the development of hydrates.
10. In gas-dominated systems, inhibitors such as methanol and monoethylene glycol must be injected downhole and/or at the wellhead in order to stop hydrate formation due to fast heat loss. Flow rates and prediction software can be used to calculate injection quantities.
11. Inhibitor injection upstream is typical because hydrates can develop from abrupt expansion of gas, such as passing through a valve.
12. Hydrates pose safety hazards due to their density and gas content, potentially causing impact upon dislodging and generating pressure upon dissociation in confined spaces.
13. Upon depressurization of a pipe, hydrates dissociate radially due to temperature gradients, potentially detaching from the wall.

14. Radial plug dissociation may cause plugs to become projectiles, leading to line obstructions or failures downstream.
15. Depressurizing plugs should ideally be done from both sides to account for potential multiple plugs in the line.
16. Single-sided dissociation requires careful consideration and precautionary measures.

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