

Chapter

Managing Paraffin/Wax Deposition Challenges in Deepwater Hydrocarbon Production Systems

Keshawa Shukla and Mayank Vishal Labh

Abstract

The prevention of solids formation and their deposition are major challenges to design and operate any subsea hydrocarbon production systems. One of the most challenging issues is the management of paraffin/wax. As the water depth increases, at the low temperatures of subsea conditions, hydrocarbons may precipitate as wax, which can solidify and restrict the flow. During shutdown of a subsea production system wax gel may form and solidify when a crude oil cools below its pour point causing operational problems from downhole to the processing facilities. The purpose of this chapter is to address the paraffin/wax formation and deposition issues to properly design a subsea production system consisting of pipe-in-pipe flowline and flexible riser under deepwater environment. A field specific example is presented to manage the wax formation/deposition and prevent paraffin/wax deposition risks in an effective way during the normal and the shut-in operations of the subsea production system. This study illustrates that the subsea hardware, such as water stop and equipment valves, along with the flowline, riser and jumper should be sufficiently insulated in order to prevent any cold spots in the production system, and achieve sufficient cooldown time for the shut-in operations.

Keywords: paraffin/wax, subsea production system, hydrocarbons, pipe-in-pipe flowline, flexible riser

1. Introduction

The major flow assurance challenges in the design and operation of a subsea hydrocarbon production system arise mainly due to the reservoir fluid properties, multiphase fluid flow, and solid formation such as paraffin/wax, hydrate, asphaltene, scale, corrosion, emulsion and foam. In particular, the formations of paraffin/wax and hydrate at low temperature and high pressure conditions in a deep water production system are critical to manage when transporting fluids from the reservoirs to the host facilities. The wax present in hydrocarbon fluids is mainly comprised of high molecular weight paraffinic compounds that are crystalline in nature. The wax can drop out of the crude oil at the wax appearance temperature (WAT) and deposit in the subsea systems during the production operations when the fluid temperature is lower than WAT. Below the pour point, the wax can gel and

solidify resulting in restricting the flow and plugging the subsea system. Likewise, the hydrates can form and deposit in the subsea systems when the produced hydrocarbon gas and water mix at low temperature and high pressure (for example, see for review [1–6]).

The cooling down of a subsea production system in a shut-in process is another complex transient heat transfer problem. In this process, the fluid flow stops and heat transfer occurs between the subsea production system and the surrounding environment through the pipe wall, and the system eventually reaches to low ambient seawater temperatures. The rate at which the temperature drops with time becomes important to manage paraffin/wax deposition, hydrate formation and their solidifications in such subsea production systems.

When the operating temperatures are low, the cold spots can appear at inadequately insulated or uninsulated sections of the subsea structures and equipment including jumpers, flowlines, risers, manifolds, field joints, water stops, bulkheads and valves, among other components. Therefore, the subsea production systems should be sufficiently insulated for the wax and hydrate controls during both the normal operation and the shut-in operation. The shut-in operation normally requires a minimum cooldown time. Generally, the cooldown time is the period when the fluid temperature reaches the wax deposition temperature or hydrate formation temperature at the operating pressures during the shut-in operation. During this period the operator has to decide the remedial actions such as to commence chemical inhibition, depressurization and hot oil circulation to prevent plugging of the subsea production systems [1–6]. Note that in this study, the cooldown time is the time when the fluid temperature reaches the pour point in the shut-in operation to prevent wax gelling/solidification in any part of the production system.

In this chapter, a subsea production system is considered typical to the Gulf of Mexico (GoM). The production system consists of a pipe-in-pipe (PIP) flowline, a flexible riser, insulated jumpers, subsea structures and equipment. The flowline, riser and jumpers of this system are adequately insulated so that they can operate above the pour point and WAT during normal operations and provide a minimum cooldown time of 12 h to prevent any cold spots (low temperature conditions) and wax gelling/solidification during the shut-in operations.

The objective of this chapter is to investigate the cooldown time and cold spots (low temperature conditions) of the above assumed production system. The cold spots can arise due to uninsulated or inadequately insulated parts of the subsea structures and equipment, such as water stops and valves, during the shut-in operations.

The rest of the chapter is organized as follows. Section 2 describes the subsea field layout typical to the Gulf of Mexico (GoM). Section 3 describes the properties of the PIP flowline, dry and wet insulations for retaining heat in the subsea production system. This section also describes the design basis and the operating constraints. Section 4 presents the method and procedure employed to perform the cold spot analysis at different locations of the subsea production system. Section 5 presents simulation results for the cooldown time and cold spots of the subsea production system including subsea structures and equipment. Section 6 presents the conclusion of this study.

2. Subsea field description

Figure 1 shows the sketch of a subsea production system typical to the GoM. The system consists of a well with corresponding wellbore and wellhead (WH), four

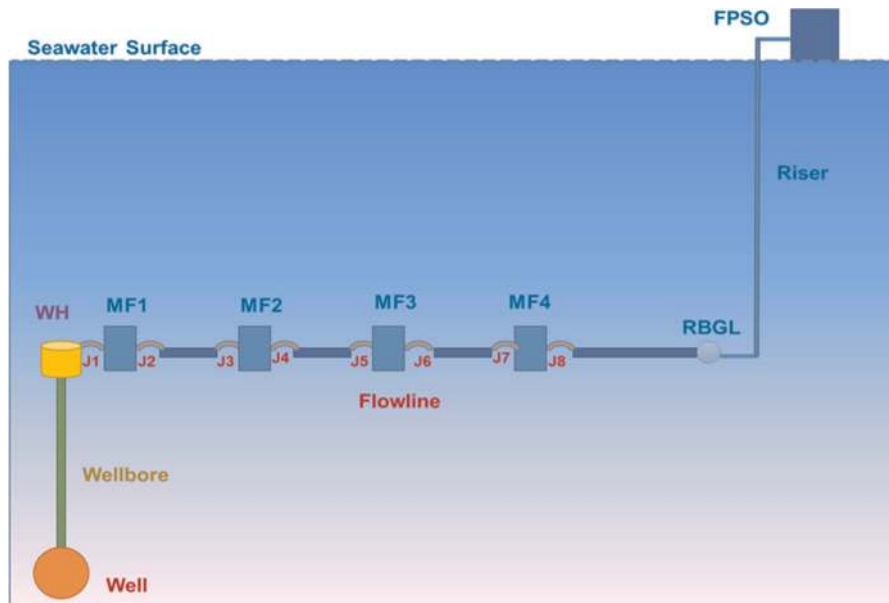


Figure 1.
A Schematic of the subsea production system.

manifolds (MF1, MF2, MF3 and MF4), and eight jumpers (J1–J8). The manifolds are connected to a flowline and a riser leading to a floating production storage and offloading (FPSO) facility. RBGL indicates the location of a riser base gas lift. Practically, the manifold MF1 has production from two wells, while each of MF2, MF3 and MF4 has production from a single well.

The total length of the flowline is approximately 17 km. The wellheads are located in water depth of about 1450 meter. The ambient seabed temperature is approximately 3.5°C. The flowline system consists of (2628.9 mm (8.625-inch) × 3886.2 mm (12.75-inch)) PIP flowline. The riser is a 2133.6 mm (7-inch) flexible riser starting from the riser base. The jumpers have 2628.9 mm (8.625-inch) stainless steel outside diameter (OD) with the glass syntactic polyurethane (GSPU) wet insulation. The subsea hardware such as the water stops is placed at the spacings of 700 meter, and equipment valves are added at the manifolds and RBGL.

3. Design basis and insulation materials

3.1 PIP flowline system and dry insulation

The PIP insulation is a passive non-chemical solution for flow assurance problems and does not need input of work and heat. Heat retention is achieved by surrounding the pipeline with materials that offer a high resistance to heat transfer with low thermal conductivity.

In a PIP system, a pipe is inserted inside another pipe. A dry insulation material, such as aerogel, is placed in the created intermediate annulus and is protected by the outer pipe from hydrostatic pressure and water penetration. Having a low thermal conductivity, aerogel allows the design of pipelines with the overall heat transfer coefficient (U_{ID} -value) significantly low without compromising the overall external dimensions of the PIP system. For the case of a rigid outer pipe, an air gap exists between the outside diameter surface of the insulation and inside diameter of the outer pipe adding to the heat resistance of the system. In the recent past, PIP flowline systems have been used for a number of deep water projects [1–2, 7–11].

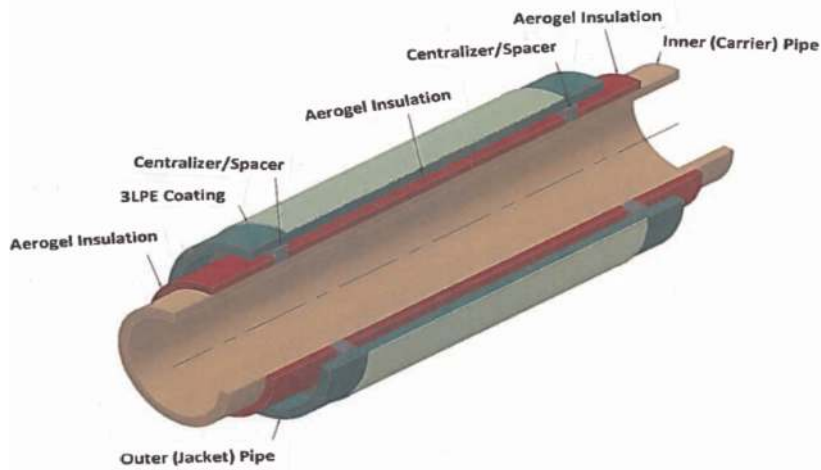


Figure 2.
Pipe-in-pipe insulation section of a pipe.

Figure 2 shows a typical PIP flowline section with the various layers of dry insulation [1].

In this study, the PIP insulation material is considered to be aerogel. The centralizer spacing at every stalk length is set about 2.2 m specified for aerogel thickness requirement for the reeled pipeline. The function of centralizer is to support the inner pipe centralized within the outer pipe to prevent possible damage to the PIP thermal insulation and transfer loads between the inner and outer pipes.

3.2 Wet insulation

Wet insulation does not require any input of energy such as work and heat. For example, glass syntactic polyurethane (GSPU) is the typical subsea wet insulation material. It can be used to retain heat in the jumpers and hardware providing U_{ID} -values greater than $1.0 \text{ W/m}^2\cdot\text{K}$ [1, 12]. The wet insulation is directly coated to steel pipes and placed on the seabed exposed to seawater.

In this study, the GSPU wet insulation is used along with fusion bonded epoxy (FBE) and three-layer polyethylene (3LPE) coatings for jumpers and equipment. Thermal conductivities of GSPU, FBE and 3LPE are 0.16, 0.3 and $0.4 \text{ W/m}\cdot\text{K}$, respectively. **Figure 3** shows the schematic of a typical wet insulated pipe section [2].

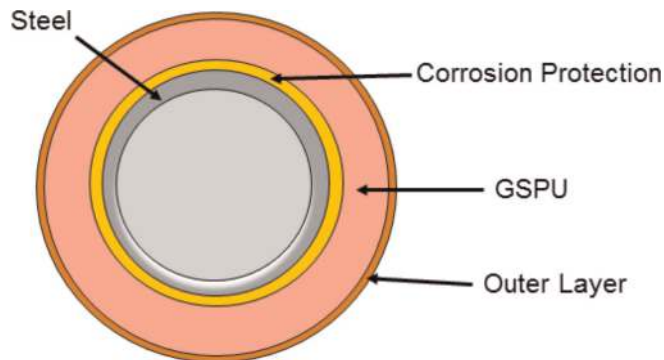


Figure 3.
A wet insulated pipe section.

3.3 Insulation thickness and cooldown time

Here, the PIP flowline insulation consists of 18.3 mm steel, 15 mm aerogel, 18.3 mm air, 19.1 mm steel and 3 mm 3LPE. The riser has the coating of 2133.6 mm flexible pipe. Jumpers are insulated with 1066.8 GSPU.

For the above flowline configuration and insulation, the U_{ID} -values of PIP flowline, flexible riser and wet insulated jumpers are 1.0, 3.5 and 2.9 W/m².K, respectively. These U_{ID} -values yield the required cooldown time of 12 h based on pour point of the waxy crude oil, that is, when the fluid temperature is equivalent to the wax pour point temperature during the shut-in operation.

The U_{ID} -values of water stops and valves are determined using their typical configurations and GSPU insulation as discussed below.

3.4 Crude oil properties

The crude oil comprises of waxy oil, gas and produced water with 33° API gravity. The wax appearance temperature and pour point/wax deposition temperature of the fluid are 29 and 18°C, respectively. The total liquid production is approximately 19,300 STBPD (stock tank barrel per day) with associated gas of 13 MMSCFD (million standard cubic feet per day), equally distributed to five wells. The watercut is approximately 10% by volume and gas to oil ratio (GOR) is 750 SCF/STB (standard cubic feet/standard barrel). The hydrate curve is determined from the fluid composition without any inhibitor. Note that the crude oil was characterized up to C₈₀₊ components and the PVT properties were determined using a multiphase software, PVTsim Nova 3. The composition of C₁₈₊ components was found to be greater than 11 mole%, indicating the presence of wax with wax content of 3–6 wt%.

3.5 Subsea system design constraints

For the assumed design and operation constraints of the jumpers, flowline and riser and their insulations, the required cooldown time should be 12 h for maintaining the fluid temperature above the wax gelling/solidification temperature, i.e., above the wax pour point temperature of 18°C. The normal arrival pressure and the ambient temperature at FPSO are set to be 19 bar and 19°C, respectively. Since the hydrate temperature of the fluid is always lower than the pour point, 12 h cooldown time is sufficient to manage the hydrate deposition during the shut-in operations.

4. Procedure of cold spot and cooldown time analyses

The cold spot and cooldown analyses were performed using the multiphase flow simulator OLGA 2016.2.1. The software uses a finite difference numerical scheme to solve mass, energy and momentum balances for multiphase fluid flow in a pipeline. The model accounts for the energy transfer between adjacent pipe segments, and inner pipe and surrounding. The fluid properties, hydrate dissociation curve and WAT were obtained from PVTsim Nova 3, which is a versatile equation of state modeling software.

The PIP flowline system was shut down via a linear ramp-down of the topsides valve on the facility and flow sources in the flowline closing simultaneously in 45 s. Steady state initial conditions were applied prior to the ramp-down. The cold spots were investigated at water stops and subsea equipment valves locations of the

assumed subsea production system for several cases. However, the results for only two selected operating cases are presented below.

4.1 Case 1: flowline/riser/jumper system without equipment

Case 1 forms the base case providing sufficient insulations to PIP flowline, flexible riser and insulated jumper system without the water stops and equipment valves. In this case, the fluid temperature is always maintained above the wax appearance temperature (WAT) during the normal operations. In this case, the fluid temperature can be maintained above the pour point for up to 12 h (cooldown time) in the shut-in operations. Since the wax deposition issue dominates over the hydrate formation issue in this subsea production operation (that is the hydrate temperatures are always lower than 18°C pour point), only the pour point was utilized in determining the cooldown time.

4.2 Case 2: flowline/riser/jumper system with equipment (water stops and valves)

In this case, a typical equipment such as the water stop was added to the flowline to isolate a section of flooded annulus by preventing water passage to the adjacent PIP sections during installation and normal operations. The actual configuration of a water stop is shown in **Figure 4** [13]. A simplified water stop assembly used in this analysis is shown in **Figure 5**.

The two ends of the water stop consist of Hydrogenated Nitrile Butadiene Rubber (HNBR), which is the expected configuration so long as the middle steel section of the water stop does not touch the carrier pipe during normal operations. The middle part consists of the stainless steel with 3 mm coated 3LPE. This situation may occur if the middle steel section of the water stop touches the carrier pipe during normal operations. The HNBR material has good stability from thermal aging and is suitable for a water stop seal [9].

The water stops were placed at 700 meter intervals of PIP flowline assuming concentric layers surrounding the flowline with three segments of equal length 220 mm and thickness 33.3 mm (annular gap between inner and outer pipes). The



Figure 4.
Water stop configuration (TEKSEAL® Mechanical Clamp).

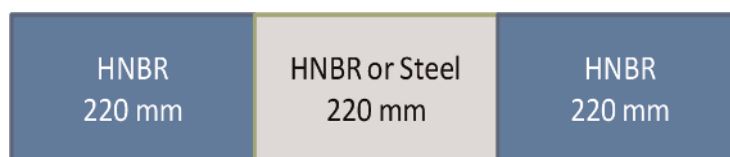


Figure 5.
A simplified water stop configuration.

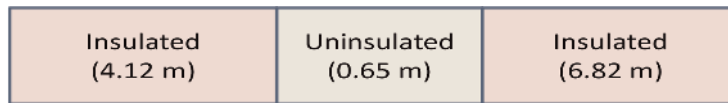


Figure 6.
 A schematic of a valve insulation at RBGL manifold.

water stops were placed in the annulus of inner pipe and carrier pipe without any air gap. The thermal conductivity, specific heat and density of HNBR are 0.24 W/m.K, 0.25 J/kg.K and 1000 kg/m³, respectively. In this study, a conservative case of the water stop configuration has been assumed.

In addition to the water stop, the typical subsea equipment valves were added at the manifolds and RBGL to assess the impact of cold spots on temperature. Such structures are commonly encountered in a subsea field development. The valves were insulated up to the bonnet but uninsulated on the actuator and pressure transmitters. The uninsulated valve section was accounted for by inserting a section of pipe with equivalent length of the valve bonnet diameter into the subsea hardware piping. The uninsulated subsea valve accumulators and pressure transmitters are modeled as cylindrical pipe segments. **Figure 6** shows the schematic of a valve insulation at the RBGL manifold. The similar configuration of equipment valves was assumed at other manifolds. All equipment valves were placed on the main flowline. The insulated sections of the valves used 1066.8 mm (3.5 inch) GSPU.

5. Results and discussions

This section summarizes results for the above two different operating scenarios.

5.1 Case 1: flowline/riser/jumper system without equipment

Figure 7 shows the fluid temperature variation with length of the flowline production system without any water stops and equipment valves. Also shown in the figure are WAT and pour point. The calculated U_{ID} -values of PIP flowline, flexible riser and wet insulated jumper are 1.0, 3.5 and 2.9 W/m².K, respectively.

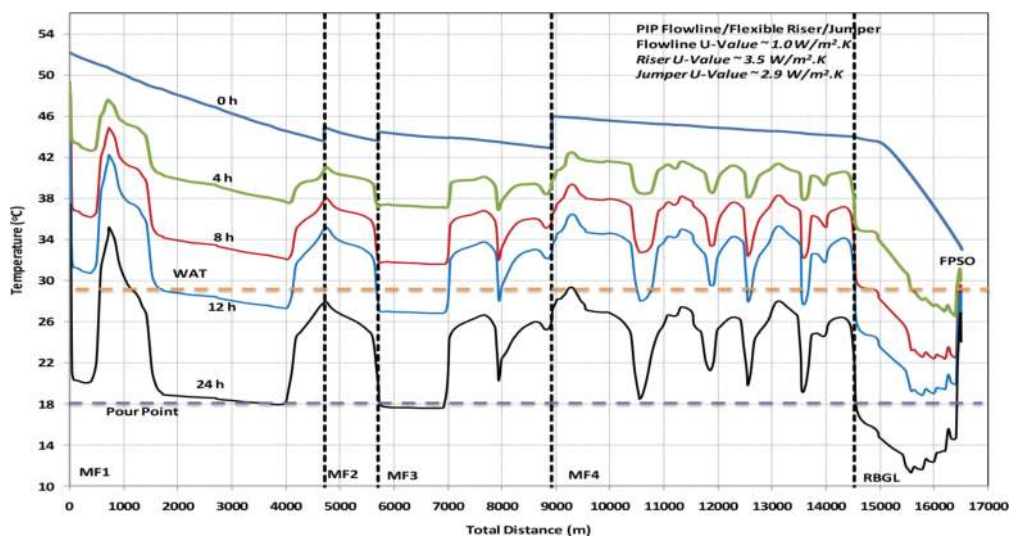


Figure 7.
 Temperature vs. distance of flowline/riser/jumper system during shutdown.

For each shut-in scenario, the lowest fluid temperature lies close to the riser base because of the higher U_{ID} -value (less heat retention) of the flexible riser. Here, 0 h indicates results at steady state, while 4, 8, 12 and 24 h indicate the results for different shutdown times (hour).

Figure 8 shows pressure and temperature conditions for the normal and shut-in operations along with WAT, pour point and hydrate formation conditions. The results for the normal operation (0 h) show that the fluid temperature in the production system remains above WAT (29°C), pour point (18°C) and hydrate temperature. During shut-in operation, the fluid temperature remains above 18°C until 12 h shutdown time. However, the fluid cools below the wax pour point quickly after 12 h shutdown, and the fluid temperature lies in the wax gel region for 24 h shutdown.

The above results suggest that the combination of PIP flowline, flexible riser and wet insulated jumpers yields the cooldown time of 12 h, which can be sufficient to efficiently prevent cold spot (low temperature) problems arising from the wax gelling/solidification in the subsea production system.

5.2 Case 2: flowline/riser/jumper with equipment (water stops and valves)

In this case, the PIP flowline, flexible riser and wet insulated jumper system of Case 1 was assumed to include water stop seal assembly (HNBR with steel) and subsea equipment valves at manifolds and RBGL.

In order to check the overall performance of this system, it is first important to assess the impact of the assumed insulations on U_{ID} -values of water stop and equipment. **Figure 9** shows U_{ID} -values at water stops and equipment valves locations. For water stops the U_{ID} -value is greater than $50 \text{ W/m}^2\cdot\text{K}$, and that for valves the U_{ID} -value is greater than $300 \text{ W/m}^2\cdot\text{K}$. For such extremely large U_{ID} -values compared to those of Case 1 system, the cold spots can be expected at the water stops and equipment valves locations.

Figure 10 shows the temperature variation as a function of length of the production system with water stops and equipment valves for the normal and shut-in operation scenarios. The sections of the pipe near and at the location of water stops and equipment valves are seen to cool much faster than those of the flowline/riser/

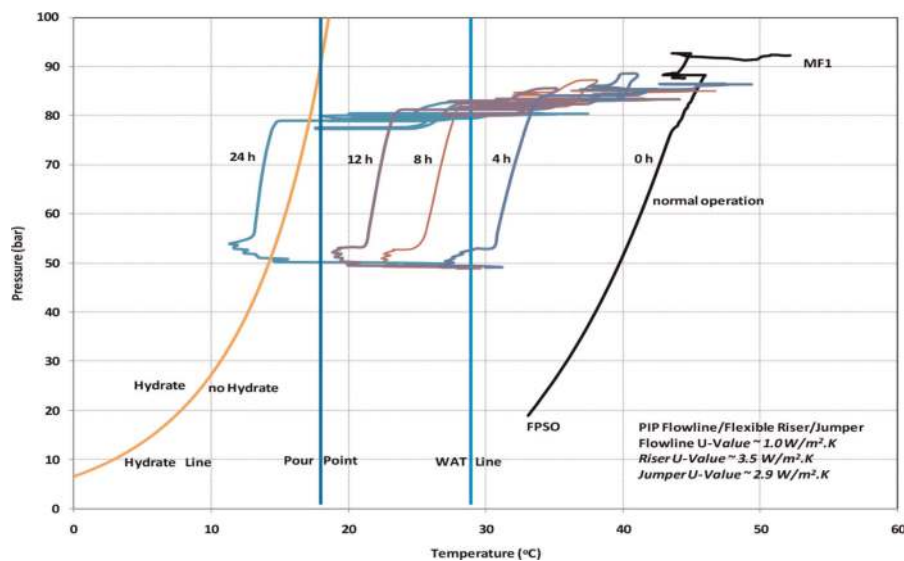


Figure 8.
Pressure vs. temperature of flowline/riser/jumper system during shutdown.

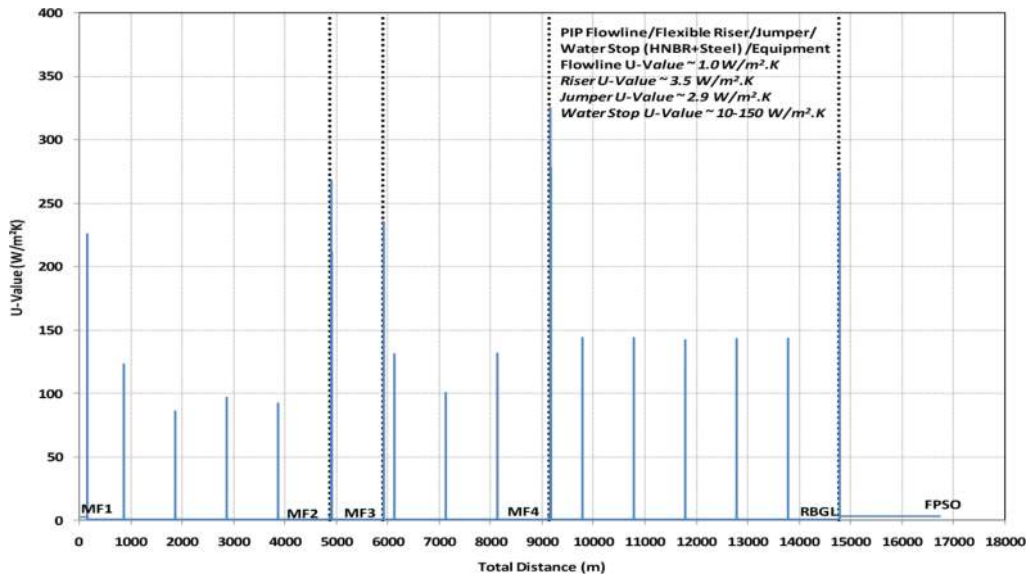


Figure 9.
 U_{ID} -values for flowline/riser/jumper with water stops and valves.

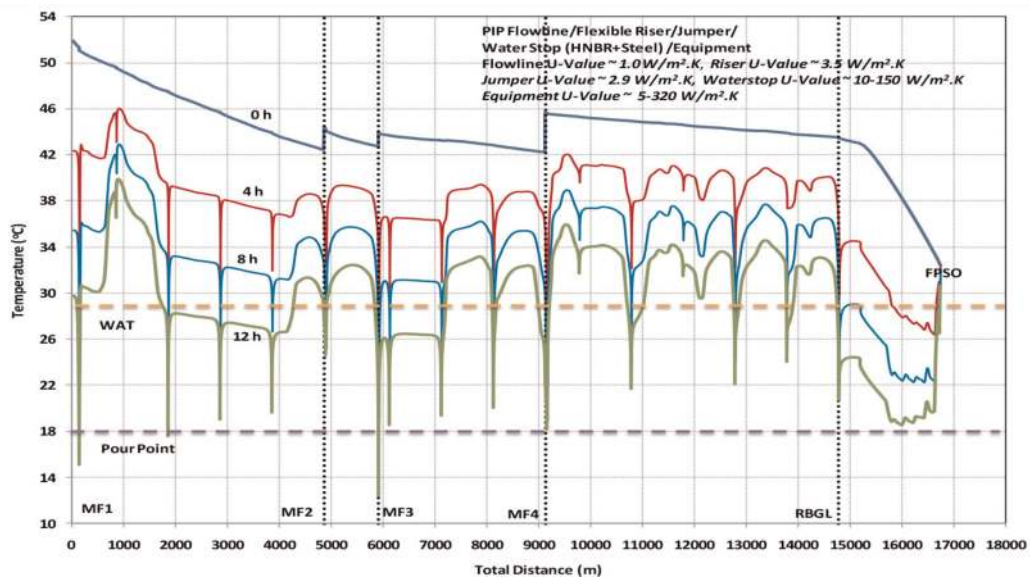


Figure 10.
 Temperature vs. distance of flowline/riser/jumper system with water stops and equipment valves during shutdown.

jumper system. Due to the large U_{ID} -values of the stainless steel, the cooldown temperature at the water stops locations has lowered substantially (large downward spikes in temperature).

Figure 11 shows the variation of pressure with temperature during the shut-in operation. It shows the cooling temperature of the sections of flowline near and at locations of uninsulated and inadequately insulated equipment valves. The cold spots are not seen during normal operations because of the fact that only a small portion of the equipment is uninsulated, still maintaining the sufficient retention of heat. Because of the inadequate insulation of subsea water stops and equipment valves, however, the cold spots appear to yield only 8 h cooldown time, which is much less than the required 12 h cooldown time for shut-in operations. In this case,

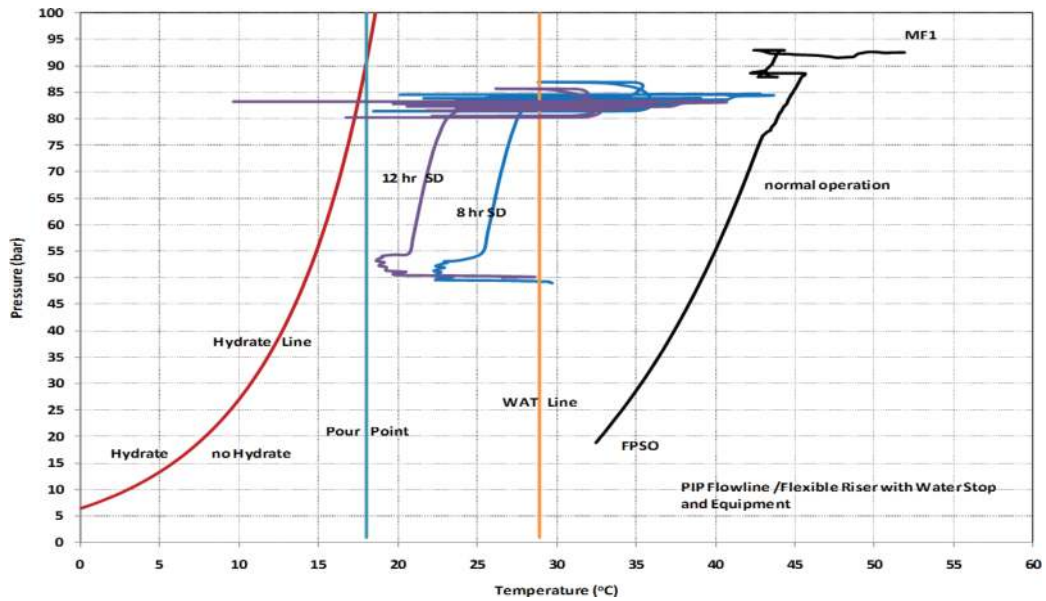


Figure 11. Pressure vs. temperature of flowline/riser/jumper system with water stops and equipment valves during shutdown.

Shut-in operation	Cooldown temperature (°C)	
Time (h)	Case 1: flowline, riser and jumpers	Case 2: flowline, riser and jumpers with water stops/equipment valves
0	43	42
4	37	23
8	32	19
12	27	15
24	18	11

Table 1. Cooling down time and temperature for Case 1 and Case 2 operating scenarios.

8 h cooldown is not sufficient to take remedial actions, especially for unplanned shutdowns. However, if feasible to insulate the entire equipment valve system with 1066.8 mm (3.5 inch) GSPU (without causing any installation and operation issue), it could provide the required cooldown time of 12 h.

Table 1 shows the summary of cooldown time achieved for Case 1 and Case 2 operating scenarios. As the table shows, Case 2 system cools down to 15°C after 12 h cooling time and cannot meet the cooldown time requirement of 12 h for the shut-in operations.

6. Conclusions

The assumed PIP flowline/flexible riser/wet insulated jumper system of the base case provides sufficient insulation for maintaining the fluid temperature above the wax pour point and hydrate deposition temperatures. This system could achieve the required cooldown time of 12 h, which is sufficient to keep the production system

out of the wax gel formation region and avoid any cold spot (low temperature) in the shut-in operations.

When the water stops (HNBR + Steel) and partly insulated equipment valves were added to the PIP flowline/flexible riser/wet insulated jumper system, there appears no major issue of the cold spots during the normal operations. However, for the shut-in operations, the system shows cold spots (low temperature conditions) at the hardware (water stop and equipment valves) locations and can barely yield the cooldown time of 8 h. These results suggest that the uninsulated section of the equipment valves at manifolds should be adequately insulated in order to prevent any cold spots in the production system during the shut-in operations, even though the flowline, riser and jumpers are sufficiently insulated.

It is recommended to insulate the subsea hardware as much as possible. If the subsea structures and equipment cannot be sufficiently insulated due to installation and/or any other manufacturing reasons, it is recommended to manage the shut-in operations in 8 h and take preventive measures for wax gel formation/solidification. Typical actions to control wax deposition/solidification can be to maintain high operating temperature, inject chemical inhibitors, circulate hot oil and prepare for the pigging of the subsea production system. Such actions along with the recent subsea processing technologies can help reduce both capital and operating costs significantly, especially during the shut-in operations.

In the future study, the sensitivity analysis will be performed using different types of the crude oils with varying ratios of paraffinic hydrocarbons relevant to the deep water production systems.

Acknowledgements

Keshawa Shukla would like to thank the Subsea Engineering Program under EASA for investing his time and effort and Petroleum Engineering Department for giving access to the multiphase flow simulators at College of Engineering, Texas A&M University, College Station to contribute this chapter to the book which are gratefully acknowledged. Mayank Labh is a graduate student in Subsea Engineering (EASA) and has partly contributed to this work during his Directed Study. The open access publishing fees for this article have been covered by the Texas A&M University Open Access to Knowledge Fund (OAKFund), supported by the University Libraries and the Office of the Vice President for Research.

Conflict of interest


No potential conflict of interest.

Author details

Keshawa Shukla* and Mayank Vishal Labh
Subsea Engineering, EASA, College of Engineering, Texas A&M University,
College Station, TX, USA

*Address all correspondence to: kpshukla@tamu.edu

IntechOpen

© 2019 The Author(s). Licensee IntechOpen. This chapter is distributed under the terms of the Creative Commons Attribution License (<http://creativecommons.org/licenses/by/3.0>), which permits unrestricted use, distribution, and reproduction in any medium, provided the original work is properly cited. 

References

- [1] Shukla K. Non-chemical products offer effective flow assurance solutions. *Offshore*. April Issue. 2014:120
- [2] Chapman M, Shukla K. Non-chemical solutions enhance flow assurance options. *Offshore*. April Issue. 2012:113
- [3] Al-Safran EM, Brill JP. *Applied Multiphase Flow in Pipes and Flow Assurance*. Oil and Gas Production. Richardson, TX, USA: Society of Petroleum Engineers Press; 2017
- [4] Huang Z, Zheng S, Fogler HC. Wax deposition—Experimental characterization. In: *Theoretical Modeling and Field Practices*. New York: CRC Press, Taylor and Francis Group; 2015
- [5] Firoozabadi, A. *Thermodynamics and applications in hydrocarbon energy production*. New York: McGraw-Hill Education; 2016
- [6] Gudmundsson JS. *Flow Assurance Solids in Oil and Gas Production-Oil and Gas Production*. London: CRC Press, Taylor and Francis Group; 2018
- [7] de Azevedo FB, Solano RF, Manouchehri S, Dolinski A, Denniel S. Design, Fabrication and Installation of the First Ever reeled Pipe-in-Pipe System in Offshore Brazil. *Offshore Technology Conference*, May 4–7, Houston, TX, USA. 2009. p. 19951
- [8] Decrin MK, Nebell F, de Naurois H, Parenteau T. Flow Assurance Modeling using an Electrical Trace Heated Pipe-in-Pipe: From Qualification to Offshore Testing. *Offshore Technology Conference*. May 6–9, Houston, TX, USA; 2013. p. 24060
- [9] Jukes P, Delille F, Harrison G. Deepwater Pipe-in-Pipe (PIP) Qualification Testing for 350°F Service. In: *Proceedings of the 3rd International Offshore Pipeline Forum (IOPF)*, Houston, TX, October 29–30, 2008. p. 922
- [10] Rao V, Mair J, Srisankarajah T, Jones R, Booth P. Pipe-in-Pipe Swaged Field Joint for Reel Lay. *Offshore Technology Conference*. May 6–9, Houston, TX, USA; 2013. p. 24077
- [11] Dixon M. Pipe-in-Pipe: Thermal Management for Effective Flow Assurance. *Offshore Technology Conference*. May 6–9, Houston, TX, USA; 2013. p. 24122
- [12] Ruschau GR, Rogers RH, Woodley SA, Wright EJ. Evaluation and Qualification of Materials for Subsea Insulation Systems. *SPE Annual Technical Conference and Exhibition*, Sep 20–22, Florence, Italy; 2010. p. 131618
- [13] TEKSEAL[®] Mechanical Clamp (Courtesy of Tekmare, Private Communication, 2016)