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Flow assurance below WAT in long tiebacks using wax inhibitors

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Abstract

One of the biggest challenges in offshore oil production in long tieback systems is the wax precipitation due to low seabed temperatures, leading to flowline clogging. This study investigated the flow assurance conditions of an oil from a field situated along the Brazilian coast, with a water depth of 250m and located 60km away from a FPSO vessel, where the seabed temperature is 12°C. The oil's wax appearance temperature (WAT) and gelation temperature (GT) were determined, indicating the feasibility of flow assurance without insulation. Economic analysis revealed a net present value (NPV) of US$589 million with insulation and US$689 million without. Tests with inhibitors showed benefits of softer gel and lower viscosity, aiding wax removal with pigs. Overall, the study highlights the importance of understanding wax behavior and employing appropriate measures for flow assurance in offshore oil production.

Keywords

Petroleum; gelation temperature; yield stress; WAT; waxes; wax inhibitors

Introduction

One of the biggest problems to flow assurance in offshore long tiebacks is the wax precipitation and deposition since the temperature of the seabed can be very low [1,2]. During cooling, paraffins can form a gel in pipelines, resulting in solid-like plugs and completely interrupt the oil flow. To avoid this risk, production is carried out above WAT, which makes the project more expensive and limits the distance from the well to the platform [1]. Studies on paraffinic gels, such as gelation temperature (GT), gel structure and strength at the time of restart, have advanced in flow assurance research [3,4]. It can be shown that depending on the value of GT, flowing temperature can be lower than WAT. Various parameters, including geological data, PVT curves, viscosity, yield stress, well geometry, hydrate formation, wax deposition and economics must be examined before deciding on constructing long tiebacks [1]. Mitigation techniques include pipe insulation, mechanical removal, and the use of wax inhibitors [5] . In recent years, wax inhibitors have emerged as promising tools for mitigating gelation and enhancing crude oil flow. The co-polymers MAC (Maleic anhydride) and EVA (Poly(ethylene-*co*-vinyl acetate) and surfactant ethoxylated are the most reported in literature as wax inhibitors [6–8]. However, the relationship between wax inhibitors and the rheological properties of crude oils, particularly yield stress, remains relatively unexplored. This study investigates a case involving a small field on the Brazilian coast, with a depth of 250m and located 60km from an FPSO vessel, where the seabed temperature is 12°C. The study aims to evaluate the feasibility of constructing a tieback for oil production from this field and its associated limitations, with an economic analysis. It examines the effects of inhibitors on rheological parameters. The inhibitors studied are surfactants based on glycerol ethers and fatty chains with 12 and 16 carbon atoms, called WI-C12 and WI-C16, respectively. And they are compared with the EVA, commonly used polymeric commercial inhibitor, based on poly(ethylene-vinyl acetate), called WI-CX.

Methodology

Experimental Procedure

Rheological assays

Gelation temperature (GT)

Initially, oil samples were prepared with 1000ppm of the inhibitors (WI-C12, WI-C16 and WI-CX). This concentration is typically an effective concentration [9]. The samples with crude oil without inhibitors and in the presence of the inhibitors were initially heated (20 to 60 ºC) in rotational mode and then cooled in oscillatory mode (60 to 5 ºC, at 1 ºC min-1 for the samples with WI-C12 and WI-C16 inhibitors and 60 to -35 ºC, at 1 ºC min^{-1} for the sample with the WI-CX inhibitor). Rotational mode homogenizes the sample and oscillatory mode is used to measure viscoelastic behavior of the gel. The assays were carried out under a shear stress of 0.01Pa. This assay measures the values of G' ang G" as a function of temperature. The GT of the samples was obtained from the crossover of G´ and G'' curves [10]. The measurements were performed in duplicate.

Yield stress

The oil samples were heated to 35 °C and then cooled to 5 ºC in rotational mode. Shear rates from 0.001 to 0.2 s^{-1} were applied every 5 degrees, and an increase in shear stress to a plateau was measured to quantify the yield stress (gel breakage)[11]. Measurements were performed in duplicate.

Wax appearance temperature (WAT) and viscosity

The oil samples were heated (20 to 60 ºC) and then cooled (60 to 5 ºC), at 1 ºC min^{-1} in rotational mode. The WAT was determined as the temperature at which a significant deviation in viscosity was observed. To determine this point more accurately, a graph of Ln viscosity against the inverse of absolute temperature times 1000 was done. The measurements were performed in duplicate. To verify the inhibitors performance in the reduction of viscosity, measurements of viscosity as a function of temperature was studied.

Results and Discussion

Determination of the gelation temperature (GT)

Figure 1 shows the graphs of G' and G'' as a function of temperature for the crude oil without inhibitor The GT is the intersection point between the G' and G'' curves [10]. Table 1 shows the GT values for the oil with the inhibitors. We can see that the values were not significantly affected by the wax inhibitors WI-C12 and WI-C16. Considering the measurement error, we can consider that the GT temperatures were practically equal. However, the oil with the commercial inhibitor WI-CX presented GT at -21.49 ± 0.35 °C.

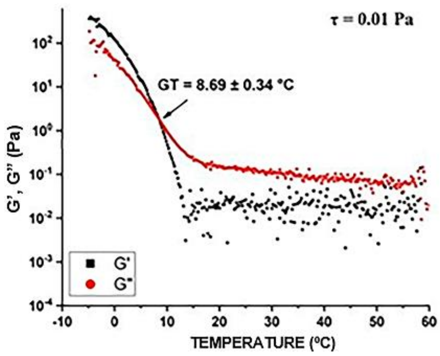

Figure 1. G' and G" as a function of temperature for crude oil without inhibitor at 0.01Pa

Table 1. Gelation Temperature

Wax Inhibitor	GT (˚C)
No WI	8.69 ± 0.34
WI-C12	9.23 ± 0.01
WI-C16	9.01 ± 0.00
WI-CX	-21.49 ± 0.35

Determination of yield stress

A yield stress study was performed from 35 to 5 °C measured every 5 degrees. The yield stress corresponds to the maximum value of the shear stress reaching a plateau. This corresponds to the breaking of the gel [11]. This value can be obtained from the graph of shear stress as a function of shear rate, as seen in Fig. 2a for the oil without inhibitor. Since the difference in scale between 5°C and the other temperatures is large, the figure 2b was plotted to visualize the points from 10 to 35°C. It is possible to see that for the shear rate range analyzed, yield stress occurred at 5°C. This is probably the temperature of gel formation. The other temperatures are above GT, according to the results showed in Tab 1. The yield stress of the oil with wax inhibitors can be seen in Tab. 2. The oil with WI-C12 and WI-C16 presented the same behavior. On the other hand, the oil with WI-CX inhibitor presented curves, in all the temperatures, that almost match the x-axis. There probably was no gel formation at 5 °C, in agreement with the results of the absence of GT at this temperature (Tab. 1). Comparison of the yield stress values at 5 °C show a significant reduction for all inhibitors. The measurements presented an error in the third decimal place, justifying the zero error presented in the table.1. This is an excellent result for the flow of the oil in a long tieback because the presence of wax inhibitors avoids the formation of the gel. Probably the affinity of the ether chain of WI-C12, WI-C16 with the paraffins of this oil, prevent further wax crystal aggregation. The size of linear fatty chains of 16 carbon atoms may also have influenced the performance of this inhibitor compared with 12 carbon atoms. The WI-CX presented the best results compared with the others inhibitors because is a polymer which are normally more efficient than surfactants. Polymers are capable of reaching high molecular weights and copolymers can be tailored to inhibit paraffin. They co-crystallize with paraffins changing the shape of the crystals [6].

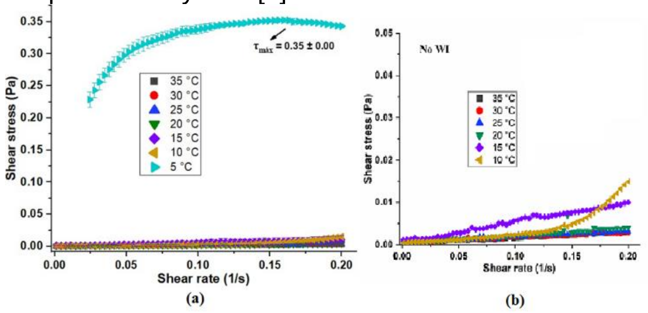

Figure 2. Shear stress as a function of shear rate for oil without inhibitor, (a) from 5 to 35ºC and (b) a zoom from 10 to 35ºC.

Table 2. Yield Stress

Wax Inhibitor	Yield Stress at 5^{0}C
No WI	0.35 ± 0.00
WI-C12	0.04 ± 0.00
WI-C16	0.02 ± 0.00
WI-CX	0.01 ± 0.00

Determination of viscosity and wax appearance temperature (WAT)

The WAT of oil without inhibitors and in the presence of inhibitors can be seen in Tab. 3.

Considering the measurement error, the WAT temperatures with WI-C12 and WI-C16 were practically equal. While with WI-CX, this commercial additive was capable of interfering with the crystallization of paraffin, leading to a reduction in viscosity and WAT. Most likely the polymer interacted with the paraffins since nucleation, delaying the appearance of crystals. The surfactants, however, did not delay the crystal appearance, but decreased their size enough to make the gels softer.

Table 3. WAT

Wax Inhibitor	WAT (^{0}C)
No WI	14.00 ± 0.13
WI-C12	13.53 ± 0.01
WI-C16	14.36 ± 0.90
WI-CX	10.29 ± 0.09

The results in Fig. 3 show that all inhibitors in the oil have significantly reduced the oil viscosity at 5 °C, temperature where the wax gel has already been formed as seen in the GT and yield stress tests. Probably the wax inhibitors helped to form soft gels, consequently with low viscosity.

With these results we can say that both type of inhibitors studied (the surfactants and the polymer) can help the oil to be transported in long tiebacks. However, an economic analysis is important for the decision takers.

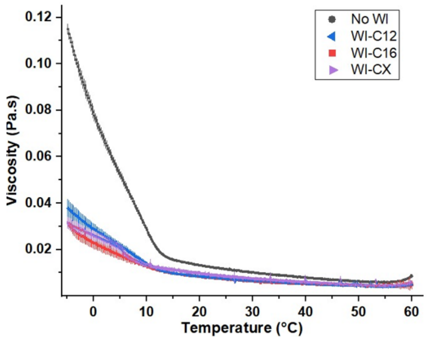

Figure 3. Rheological curve of oil A without inhibitor (No WI), and with WI-C12, WI-C16 and WI-CX inhibitors

Case Study

In this Case Study, three wells have been considered. The wells are connected to a manifold which is connected to a multiphase pump (MPP). From the MPP a 14-inch pipeline transports the oil to the platform. The flowrates from all three wells under these conditions are 19922, 20372 and 20503 bpd for well 1, well 2 and well 3 respectively. Both scenarios with and without the MPP are examined. The MPP increases the fluid pressure by 60 bar and its temperature 10 ^{o}C. The flow simulations determined the temperature that the fluid reaches along the pipeline, depending on the applied insulation, as indicated by the Thermal Exchange Coefficient (TEC). The relationship between the coefficient of heat transfer and TEC is shown in Eq. (1)[12].

$$U = \frac{TEC}{\pi d_i} \quad (1)$$

The lower the TEC the higher the insulation in the pipeline and the more expensive it is. The simulation results indicate that when the TEC ≥1 the fluid temperature reaches the WAT of 14^{o}C at a distance of 60 km in the flowline. For TEC=10, the WAT is reached at a distance of 27 km (Figure 4). As conclusion we can say that only a huge insulation (TEC≤1) can ensure that the fluid temperature remains above the WAT throughout the entire pipeline. However, even with temperature maintenance above the WAT, this system will still necessitate pigging to address operational disruptions, which could potentially reduce flow rates or result in a complete system shutdown. In the latter scenario, the fluids would cool down reaching seabed temperature.

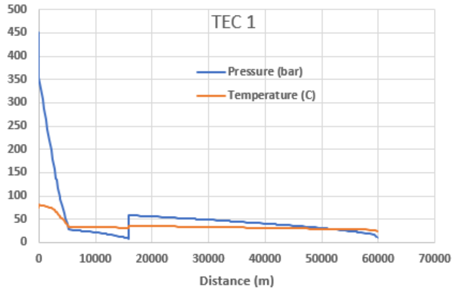

Figure 4. Temperature gradient with multiphase pump for TEC=1

Economic analysis

For the economic analysis the following data was considered: economic life (tf) = 20 years, minimum Rate of Return = 10%/year, oil price = 51 US$/bbl, taxes = 35%, royalties = 10%. The software calculates the cost of the equipment. The economic analysis is determined by the NPV equation (Eq. (2)). The NPVoil [12] is the present value of the revenue, obtained from the production curve. The NPVoil is US$ 4.35 billion.

$$NPV = (1-R)(1-T)NPV_{oil} - CAPEX_{FPSO} - CAPEX_{WELLS} - CAPEX_{SUB} \quad (2)$$

Where NPV = net present value of the system,

NPV_{oil} = net present value of produced oil,

$CAPEX_{FPSO}$= capital cost of FPSO,

$CAPEX_{WELLS}$= capital cost of wells,

$CAPEX_{SUB}$= capital cost of subsea system,

R = Royalties

T = Taxes.

The CAPEX Subsea includes all pipelines, connections and christmas trees.

The table 4 shows the results of the economic analysis. For a TEC = 1, the NPV is US$ 589 million. And for a TEC = 10 (no insulation is used), the NPV is US$ 689 million. Considering the case of this oil, where the WAT is 14^o C, simulations suggest that avoiding the costly TEC=1 insulation is advantageous, leading to a gain of US$ 100 million. In this scenario, the lowest fluid temperature (12°C) remains above the yield stress and gelation temperature (9°C), indicating that wax removal through pigging is feasible, provided aging is prevented. Aging has not been addressed here. It is key to determine pigging frequency.

The above results are for shallow water platforms. In deep waters however, where the seabed temperature is 5°C, wax inhibitors become crucial in averting the high viscosities associated with gel formation. Yield stress tests indicate that without inhibitors, flow restart at this temperature could be jeopardized due to the high energy required. Once again tests with wax inhibitors demonstrate a softer gel formation and lower viscosity, easing wax removal through pigging.

Table 4. Economic Analysis (MM US$)

CAPEX	TEC = 1	TEC = 10
Subsea	867	767
Manifold	25	25
MPP	50	50
Subsea Pig launcher	5	5
Wells	507	507
NPV	589	689

Integrating economic analysis with flow assurance studies enables operators to make informed decisions regarding production strategies and the implementation of preventive measures like wax inhibitors.

Conclusions

This work showed a flow assurance study of an oil from a small field, on the Brazilian coast located 60km from the FPSO. The gelation temperature GT = 9°C is below the WAT = 14°C as well as the seabed temperature of 12ºC. The tests also showed that the gel formed exhibited a yield stress at 5°C. In this scenario, the production of this oil is viable with little pipeline insulation. According to the laboratory tests and the flow simulations, the oil flows adequately through long tiebacks. Wax inhibitors are recommended to prevent paraffin deposition during shutdowns. The tests showed that the presence of wax inhibitors significantly reduced the yield stress and viscosity of oil suggesting that a soft gel was formed instead of a hard gel. The economic analysis showed that the NPV is positive and can be higher if no insulation is used. This study showed that laboratory tests in conjunction with simulation and economic analysis, are essential for decision taking.

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