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# Asphaltene Deposition Case in a Well from Pre-Salt Campos Basin: from Lab to Field

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## Abstract
Oil production activities are strongly dependent on the phase behavior of produced fluids. Among the possible phase changes, those that lead to one or more solid phases appearances presents the greatest risk to oil production. The flocculation of asphaltenes, the major components of the heaviest and most polar fraction of crude oil, can lead to solids formation in several steps of oil production. From the laboratory isothermal depressurization tests at reservoir temperature of a single-phase fluid sample collected from a pre-salt well it was noticed asphaltenic solid formation at pressure above fluid bubble point. The referred well production in a long-term test showed increasing pressure drop at production tubing during time, related to asphaltene deposition. A multifinger imaging run inside the well showed regions with large reduction in the free flow diameter of the production tubing, as well as solid deposition in front of perforations. This work aims to converges risky evaluations based on laboratory results with field behavior of a pre-salt Campos basin well.

## Keywords
Asphaltene deposition; risky evaluation; multifinger imaging

## Introduction
Asphaltenes are the heaviest and most polar compounds of a crude oil, which are soluble in aromatic solvents such as toluene, but are insoluble in n-alkanes of low molecular weight such as n-heptane [1]. In reservoir conditions, oil and gas are confined at high pressure and high temperature. In this case, the several fractions that compose the oil are in thermodynamic equilibrium. As the produced fluids are lift from reservoir to the surface, variations of pressure and temperature occur. Due to these changes, the asphaltenes might tend to form aggregates that can cause several problems for the petroleum industry. A severe example is the free diameter reduction available to flow, which occurs due to the solids deposition on the inner walls of production tubings and flowlines. A comprehensive understanding of the phase envelope of asphaltenes is of utmost importance for oil companies in order to predict and mitigate flow assurance problems caused by the deposition of this fraction in production systems. Light oils with low asphaltene contents, typically ranging from 0.1 to 1.0% by mass, are particularly prone to experiencing asphaltene deposition issues upon fluid depressurization. One way to accomplish this prediction involves laboratory determination of a solid phase appearance from a homogeneous fluid, in which the solid is composed mainly by the asphaltene fraction. This determination can be performed by isothermal depressurization of a single-phase fluid using a high-pressure microscope (HPM).
The HPM enables visual identification of phase changes that occur in live oil during isothermal depressurization or isobaric cooling procedures. This innovative technology has revolutionized the way we evaluate the formation of a second phase from a pressurized single-phase fluid. Prior to the development of the HPM, indirect techniques such as light scattering, gravimetry, and viscosimetry were used to assess these phase changes [2]. However, the HPM provides a direct and more accurate method to visually observe and analyze fluid phase behavior [3].
In this work the assessment of fluid stability with respect to asphaltene precipitation for a sample collected from Well 1 (W1) was carried out in the laboratory using a high-pressure microscope (HPM). The result obtained from live oil isothermal depressurization experiment with W1 sample revealed the existence of an ordinary behavior in which the asphaltene formation was observed above its bubble point, what raised a red flag for potential asphaltene deposition problems in the well throughout its productive life.

### Well 1
W1 is a producer well in the Macabu (MCB) pre-salt reservoir. This reservoir presents a vertical

compositional gradient with fluids with API ranging from 28.5° to 32°, gas oil ratio (GOR) from 130 to 277 std m³/std m³, and saturation pressure ranging from 3800 to 5500 psi. The original static pressure of MCB reservoir is 6830 psi. The asphaltene content in W1 is lower than 0.5% w/w. The reservoir temperature is high, 123 °C, some of these characteristics reported in the literature related with fluids with asphaltene deposition problems.

During W1 long-term production test its maximum flow rate was limited due to low gas flow capacity of the platform test separator, resulting in an oil production of 1400 m³/day. An increasing pressure drop was observed inside its production tubing, as evidenced by the pressure difference between two pressure sensors, installed the first one near the perforations and the second at Xmas tree. The suspicion of asphaltene deposition was confirmed.

## Methodology

In the lab, HPM isothermal depressurization experiment with single-phase sample collected from W1 was carried out at constant reservoir temperature, 123 °C, and followed a stepwise procedure. HPM apparatus contains a solid detection system based on light scattering of a laser light that crosses the fluid. Besides, at each step, a movie and some pictures were collected in order to proceed with image analysis, allowing assess phase equilibria and also giving a particle size distribution, in case of existence of a two or three phase system.

In the field, during well long-term production test it was evaluated the pressure drop between two pressure sensors inside the well. No chemicals for inhibiting asphaltene deposition were injected into the well during this time.

A multifinger caliper profile (PMIT - platform multifinger imaging tool) was run during a rig intervention in W1, allowing assess the asphaltene deposition profile inside its production tubing.

Solid samples obtained during an impression block tool run from perforations up to XMas tree were characterized by solvent extraction in heptane and toluene followed by thermal analysis of residues in order to indicate the nature of the deposit material.

## Results and Discussion

### Lab Results

Figure 1 depicts images obtained during isothermal depressurization of W1 fluid at 123 ºC. As can be observed there were traces of a emerging solid phase at about 5,300 psi. Below this pressure more solids were observed.

The histograms which show the particle size distribution obtained during the isothermal depressurization test performed at 123.0 °C are presented in Fig 2. They are consistent with the visual observations. Below 5,300 psi there was a significant increase in the particle population of the order of 1 to 10 μm, attributed as asphaltene particles formed in the process of isothermal depressurization.

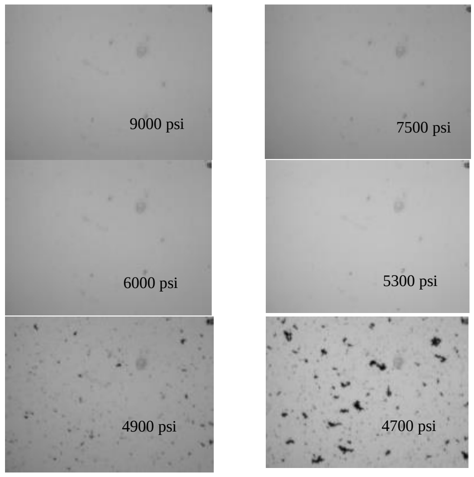


Figure 1. HPM images obtained with a camera equipped with an objective lens 5X during W1 single-phase fluid depressurization at 123 °C. Minimum detectable particle size equals to 2 μm.

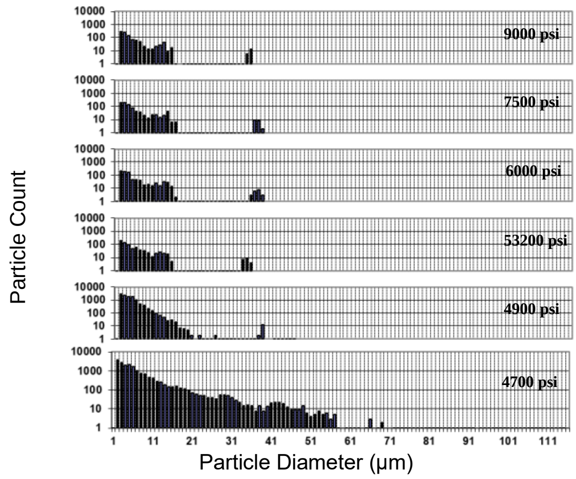


Figure 2. Particles size distribution during depressurization at 123 °C of the W1 single-phase fluid.

Figure 3 depicts the laser transmitted power curve through the sample as a function of pressure obtained by the Solid Detection System during the isothermal depressurization at 123.0 °C.

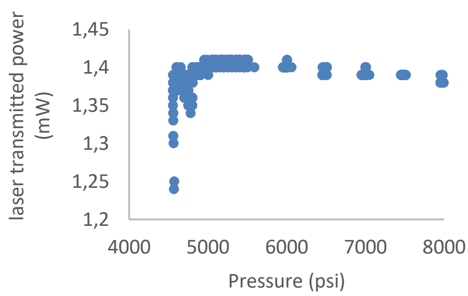


Figure 3. Laser transmitted power at 1550 nm during depressurization at 123.0 °C of the W1 single phase fluid.

A decrease in the laser transmitted power is an indicative of a second phase formation, which may be a dispersed liquid phase, one solid phase (asphaltenes) or a gas phase (bubbles). It is observed in Fig. 3 a slight decrease in transmitted power around 5,000 psi associated with the formation of asphaltene particles.
Summarizing, from the laboratory result it was expected that W1 presents asphaltene deposition into production tubing during oil production.

**Field Observations**
During the long-term production test of well W1, three years producing, an increasing pressure drop was observed in its production tubing, as evidenced by the pressure difference between the PDG (permanent downhole gauge) sensors and the TPT (Temperature and Pressure Transmmitter) of the well. Given the laboratory results presented above, the strongest suspicion of partial obstruction in the production tubing fell on the deposition of asphaltene solids. This suspicion was further reinforced by the correlation between the laboratory results and the observed field behavior, indicating the presence of deposited asphaltenes within the production tubing.
Well W1 suffered a workover with a rig, in which an impression block tool and a platform multifinger imaging tool (PMIT) profiles were run from the perforations to the Xmas Tree. The multifinger profile revealed severe deposition along a length of over 1,600 meters inside the production tubing. When comparing the deposition profile in the wellbore with the profile obtained from the open-hole Production Logging Tool (PLT), it becomes evident that a great amount of the deposited material occurred in the lower-flow contributing perforated intervals (Fig. 4). This observation strongly suggests that the fluid is saturated with asphaltene particles, even at reservoir pressure and temperature.

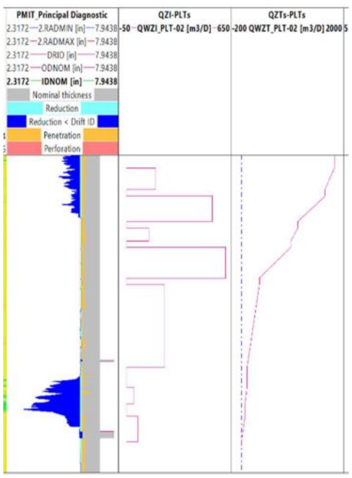

Figure 4. PMIT of W1 run during the Long-Term Production Test indicates larger obstructions aside the perforations. Correlation with PLT results shows that the low contributing flow interval at the base of perforations feeds strongly the asphaltenic material.

The sample retained in the impression block tool run, Fig. 5, was carefully collected and promptly analyzed. Extract results revealed that 41 % of the residue was soluble in heptane (maltenes or solvent – marine diesel oil), 11 % was soluble in toluene (asphaltenes), and 20 % remained insoluble. The thermogravimetric analysis of the remaining insoluble material indicates that it is also asphaltenes, summarizing 31 % of asphaltenes in residue composition – W1 oil contains less than 0.5% of asphaltenes. Unfortunately, due to the production platform's shutdown, xylene soaking could not be performed at that time in order to solve the W1 asphaltene deposition.


Figure 5. Solid sample retained from W1 during impression block tool run.

In an attempt to restart production from W1 after a long platform shutdown, the well exhibited complete blockage below the PDG. After a multidisciplinary evaluation, based on the results and behavior of the deposit assessed by PMIT, it was decided that the best solution was performing high-pressure diesel pumping to push the asphaltene deposits towards the bottom of the well. The pressurization procedure was successfully applied, allowing the well to produce after its execution with expected oil potential.

## Conclusions
This work presented a comprehensive study on asphaltene deposition in a well from the Pre-Salt Campos Basin, from laboratory analysis to field observations. The laboratory tests conducted using a high-pressure microscope (HPM) confirmed the presence of asphaltene formation above the bubble point of the fluid sample collected from the well. This indicated a potential risk of asphaltene deposition throughout the well's productive life.
Field observations further supported the presence of asphaltene deposition, as evidenced by the increasing pressure drop in the production tubing and the solid deposition observed even in front of the perforations. The characterization of the deposited material collected in the impression block tool using solvent extraction and thermogravimetric analysis revealed a significant portion of asphaltenes – 62 times enrichment in comparison with asphaltenes in W1 oil.
The findings of this study highlight the importance of understanding the phase behavior of asphaltenes in order to predict and mitigate flow assurance problems caused by their deposition in production systems. By integrating laboratory analysis and field observations, this work provides

valuable insights into the behavior of asphaltenes in a Pre-Salt Campos Basin well.
Further preventive measures are recommended to effectively manage asphaltene deposition and ensure efficient oil production in similar wells from the same reservoir.

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## Responsibility Notice

The authors are the only responsible for the paper content.

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