Curtailing Asphaltene Deposition in Conventional Oil Reservoirs: Insights from Hassi Messaoud Field, Algeria

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Abstract

The Formation damage caused by asphaltene deposition is a significant challenge in the oil industry. Asphaltene, a naturally occurring molecule found in crude oil, can form solid deposits within reservoir rocks and obstruct the flow of oil through formations. This study aimed to diagnose and treat the asphaltene precipitation problem at the bottom of HMD1, which is a well located in the Hassi Messaoud field in southeastern Algeria. The production rate of the well rapidly decreased while the operating costs increased. Laboratory tests were also conducted to study the properties of the reservoir fluids and the effects of different treatments on asphaltene deposition. To evaluate the performance of the well, Saphir software was utilized, and the results showed that the value of the skin increased from 1.66 to 2.64, which indicated that the formation was damaged by sediment inside the pores. Laboratory tests revealed an unstable asphaltene state with a Colloidal Instability Index (CII) of 3.24. Pipesim software was used to simulate reservoir behavior and predict asphaltene deposition, indicating the well was in the asphaltene precipitation phase when the pressure was between 150 and 190 bar and the temperature was between 75 and 120 °C. The method used in this research contributes to preventing asphaltene formation before it occurs.

Keywords: Asphaltene, Hassi Messaoud, Asphaltene deposit envelope (ADE), Precipitation, Skin, Laboratory tests, Colloidal Instability Index (CII)

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Introduction

The precipitation and deposition of high-molecular-weight components, primarily asphaltene, in the pore spaces of conventional oil reservoirs has been the subject of extensive research. Asphaltene precipitation produces tiny particles that can eventually assemble into aggregates large enough to obstruct the throat of microscopic pores, limiting absolute permeability (A. Fadili, 2009; Nasri & Dabir, 2009; Ghadimi et al., 2019). Asphaltene precipitation and deposition are influenced by a number of factors and parameters, including pressure, temperature, the properties of the involved mixtures, the types and amounts of precipitants, and the characteristics of the porous media, according to experimental and theoretical research (Ali Mohammadi et al., 2019; Fakher et al., 2020). Asphaltene is first soluble in oil and is stable under thermodynamic conditions in reservoirs. Until its equilibrium is disturbed, the asphaltenes in the oil will remain stable. Following this disruption, the asphaltene inside the crude oil solution starts to form solid particles. When the amount of precipitated asphaltene increases, the particles begin to combine and form larger flocculation's, which are more dense than the previously precipitated particles. Since the particles in these dense foci have a high density and will start to accumulate in pipelines, wellbores, and reservoir pores, they could be a major concern (Ali et al., 2019). Asphaltene flocculation is affected by hydrocarbon content, temperature, and pressure. In terms of composition, asphaltenes are deposited immediately after flocculation, and their ability to maintain a stable suspension depends on the relative proportions of paraffins, aromatics, and resins. Asphaltene micelles (aggregates) produce larger asphaltene particles during flocculation, resulting in pore-clogging damage and a decrease in effective permeability (Ariza-León et al., 2014). Most crude oil in Hassi Messaoud is light with a small amount of asphaltene and more likely to cause problems than heavy crude oil because the latter contains many intermediate components, such as resins, which are good asphaltene solvents; however, light crude oil may consist mainly of paraffinic materials, which are poor solvents for asphaltenes. Moreover, the mixing of different crude oil sources can induce asphaltene precipitation and deposition due to the change in its composites. Additionally, the study of the molecular structure of asphaltenes is the key to preventing their precipitation and can help in comprehending their function as well their stability. This characteristic is estimated in crude oil by taking many factors into account. These include the chemical makeup, temperature, and pressure of the fluid. According to several studies, pressure and composition are the main factors that affect the precipitation of asphaltenes, although temperature can also have an impact on the pattern of an oil's asphaltene precipitation (Chandio et al., 2015; Guerrero-Martin et al., 2023). Typically, two different laboratory tests are conducted for asphaltenes:

The total asphaltenes in the oil were determined based on the standardized ASTM method expressed as grams of solids per 100 ml. Oil stability tests that involve flocculation onset titration of the oil with a precipitant such as n-heptane (Zoveidavianpoor et al., 2013). The oil stability test is based on the insolubility of asphaltenes (Guo et al., 2005).

The primary causes of the precipitation and subsequent deposition of asphaltenes are variations in P and T that occur during the upwards flow of oil in the production tubing. Asphaltenes that have been dissolved in oil begin to precipitate and form primary particles as the onset condition is reached. While some primary particles are carried upwards with flowing oil as finely dispersed particles, other primary particles adhere to one another to create asphaltene aggregates of varying sizes or adhere to walls to form asphaltene deposits (Salehzadeh et al., 2021; Vargas et al., 2010).

Therefore, asphaltene precipitation in the pores of oil formations leads to formation damage and wettability alteration. One of the crucial tasks engineers perform daily to plan corrective steps is determining the extent of this formation damage. Identifying skin damage through well-testing activities is the most practical and reliable technique for measuring damage formation (Bellabiod et al., 2022). The removal of asphaltene deposits from oil production facilities can be very costly (Zoveidavianpoor et al., 2013). Thus, predicting the conditions that lead to asphaltene precipitation can aid in reducing these costs and mitigating issues in production facilities. However, preventing asphaltene deposition may not always be possible. Therefore, modelling fluid flow behavior can help in identifying optimal conditions that minimize blockages caused by asphaltene deposition.

This paper focuses on the optimization and diagnosis of irreversible flocculation of asphaltene in reservoirs. The aim is to develop effective strategies and prevent asphaltene-related issues. Laboratory testing, reservoir simulation, and performance evaluation will be employed to understand the asphaltene properties, predict flocculation conditions, and assess formation damage. This study aimed to enhance production efficiency, reduce costs, and extend reservoir lifespan through preventive measures and optimization strategies.

2. Methods

The HMD1 well located in the Hassi Messaoud oil field was selected for studying the problems of asphalt flocculation and deposition after a decrease in production. Both experimental and modelling approaches were used in this study (Figure 1).

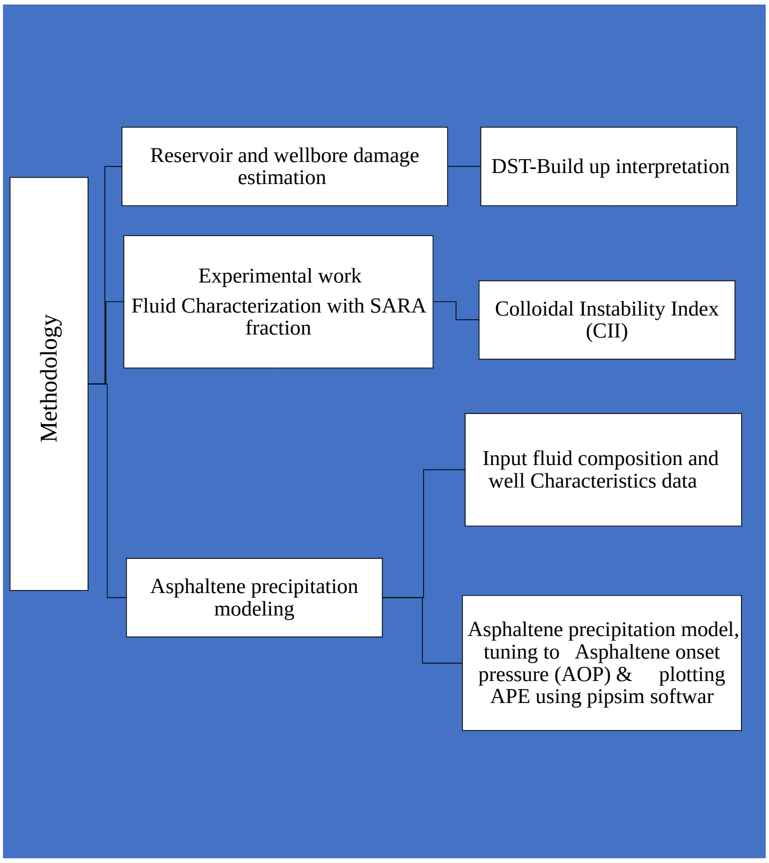

Figure 1. Schematic of the research methodology

2.1 Reservoir data

To model the precipitation of asphaltene, this effort integrated data from experiments and reservoirs. The simulation program retrieves experimental compositional analysis and fluid dynamics data for modelling. For this investigation, oil samples were taken from well HMD1. Table 1 presents the reservoir statistics obtained from the well survey.

Table .1. Reservoir Data.

Parameters	Value
Formation	HMD
Reservoir fluid	Oil
Reservoir pressure, psi	5419
Reservoir temperature, F°	248
Wellhead Pressure, psi	1829
Wellhead Temperature, F°	134
Choke size, inches	32/64
Sample	BHS (live oil)

2.2 Estimation of reservoir and wellbore damage via pressure transient analysis (PTA)

Well test analysis is a crucial technique in the field of reservoir engineering and petroleum production. The method involves analyzing pressure and rate data obtained from well tests to evaluate reservoir properties, assess well performance, and make informed decisions regarding reservoir management.

Well testing using pressure tests provides data on the relationship between formation capacity or permeability thickness (i.e., permeability multiplied by formation thickness) and the formation damage skin factor (S) which is one of the most significant and representative variables for reservoir characterization tests. It is crucial to monitor formation damage using pressure transient well testing to minimize oil formation damage and maximize reservoir performance (Bellabiod et al., 2022). There are various available test types, and each test is intended for a particular level. In the present case study, a drill stem test (DST) was conducted during the appraisal stage and exploration. It uses shut-in data that were obtained from a drill stem test. The Saphir software examines the pressure responses of the shut-ins to determine the details of the reservoir, including permeability and skin factors. A pressure build-up test was conducted on a horizontal well HMD1 for 12 hours on August 25, 2019. Afterwards, the pressure data versus time and flow rate data were used as inputs for Saphir (Ecrin). In addition, properties such as the well radius, thickness of the productive layer, and fluid type were also added to the model.

Saphir, a widely accessible and versatile software package, provides a convenient platform for conducting well test analysis. By utilizing its data manipulation, calculation, and visualization capabilities, Saphir allows engineers and analysts to perform various well-tested analysis techniques efficiently. Saphir is a software that is used in this case study for HMD1 to compare the measured data to the model while considering the whole production history. The interpretation of Saphir is carried out as follows:

The wells were recorded as data (height of reservoir (H), viscosity (μ), porosity (Φ), flow (Q), compressibility factor (Ct), formation volume factor (B), pressure (P), well radius (Rw), and thickness of the zone (THz)) calculated at the average reservoir pressure. The chart below summarizes the process (Figure 2).

The software displays the history plot with both flow rate and pressure after adding the pressure and flow rate data. The buildup process has two stages. However, since the second is longer and backed by the previous one, it serves as the foundation for the interpretation. The pressure difference (psi) between the boundary limit and the wellbore storage and reservoir as a function of DST (hr).

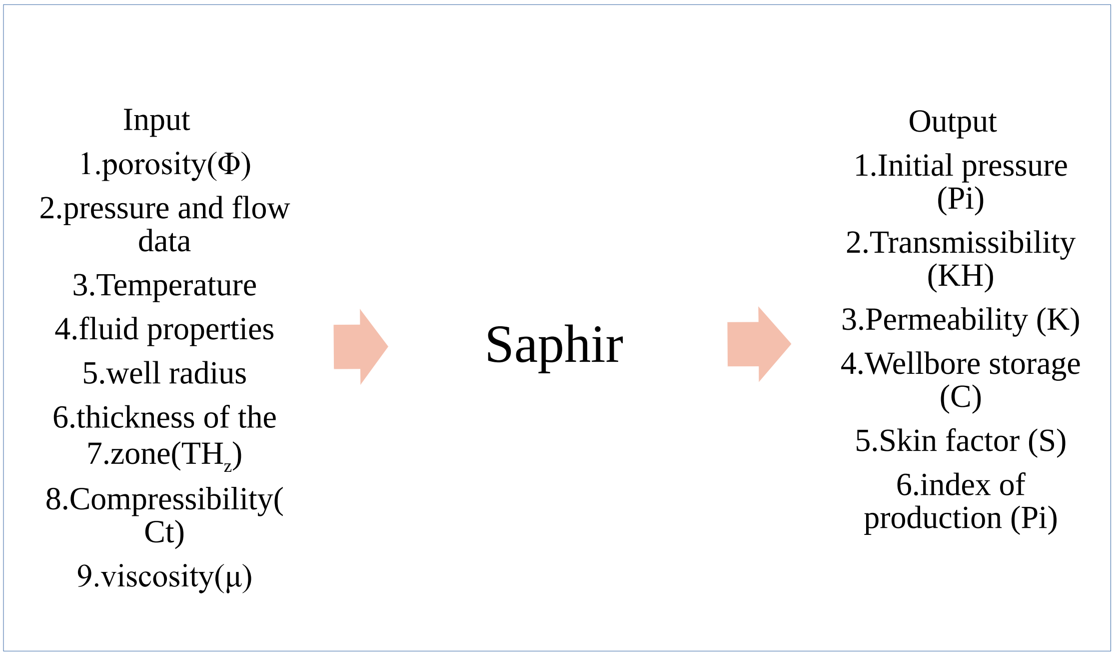

Figure 2. Schematic of Saphir functions

2.3 Investigation of Asphaltene Stability using Experimental Methods

One of the main approaches for compositional analysis of crude oil is SARA fractionation, in which the sample is separated into saturated, aromatic, resin, and asphaltene fractions based on polarity (Karevan et al., 2022; Khalil De Oliveira et al., 2017). The sample was separated into four fractions by selective retention through interactions with the solvent mobile phases and the column stationary phases (Fig. 3). Additionally, SARA analysis can aid in estimating coking, asphalt stability, and fouling tendency as well as crude oil blend tendency and product stability (Rudyk, 2018; Van Beek et al., 2018). The original and common approach used for SARA separation is gravimetric adsorption chromatography (Jewell, 1972). The separation of the asphaltene fraction occurs in the first step of this procedure by adding an excessive amount of an alkane solvent, such as n-pentane, n-hexane, or n-heptane. Maltenes are the portion that has been dissolved in the alkane solvent following deasphalting.

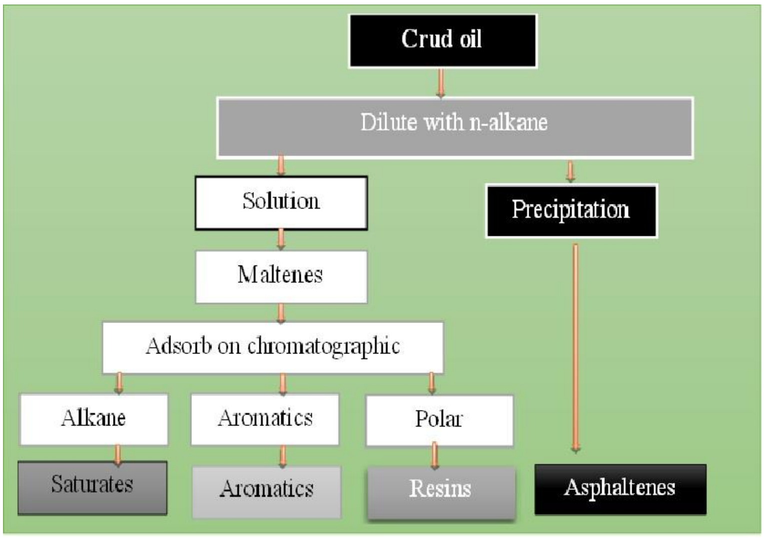

Figure 3. SARA analysis

2.3.2 Colloidal Instability Index (CII)

To quantify the stability of the asphaltenes in the maltenes phase, the colloidal index (CII) was calculated for the asphalt binders using Equation (1) (Siddiqui & Ali, 1999; Wang et al., 2019).

CII = (Asphaltenes in wt % + Saturates in wt %)/(Resins in wt % + Aromatics in wt %) (1)

A lower CII represents a greater stability of the asphaltene micelles in the asphalt binder. In this regard, according to Lesueur (Lesueur, D. 2019), for CII values greater than 1.2, the asphaltene fraction tends to be unstable within the Maltenes matrix. When the CII is between 0.7 and 1.2, the asphaltene stability is uncertain, while for CII values less than 0.7, the asphaltene fraction is stable.

3 Asphaltene precipitation modelling

For the crude oil samples from the Hassi Messaoud oil field, the asphaltene phase envelope was predicted using Pipesim software. This program is used in our case study to specify the well: asphaltene precipitation circumstances by modelling the asphalt deposit envelope (ADE). The asphalt deposit envelope is an effective tool for evaluating the potential and severity of asphalt problems. The ADE indicates the thermodynamic path that must be followed when oil is recovered from the tank to avoid or minimize asphalt problems. If possible, the oil should be kept outside or as far away as possible from the ADE center.

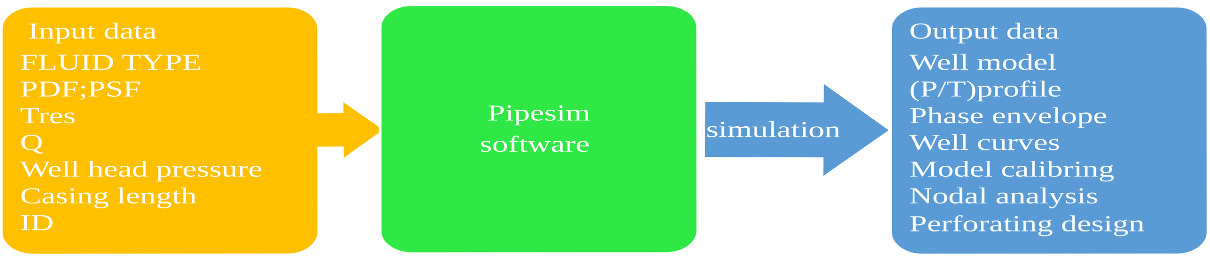

Figure 4. Schematic of the Pipesim functions

3 Results and discussion

3.1 Drill stem test (DST)

Figure 5 represents the pressure difference (psi) as a function of the time DST (hr) in the wellbore storage and reservoir and the limit boundary.

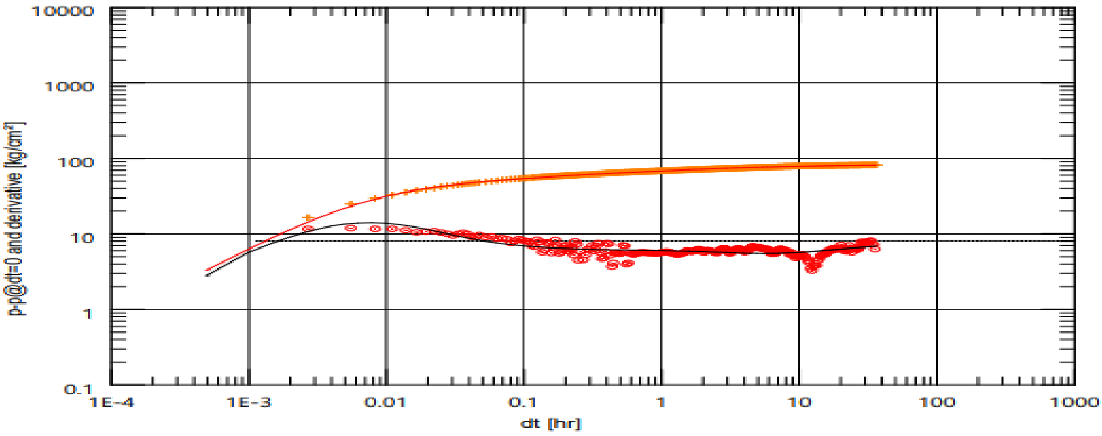

Figure 5. Log-log plot of the Bourdet derivative and pressure extracted from the DST versus time for HMD1

A decrease in radial flow stabilization was observed, which can be explained by an increase in skin factor due to damage to the formation of the skin, and this change needs to be stimulated to confirm that we will use the results of the two methods to determine the changes in skin temperature, permeability, and transmissibility. The table below summarizes the parameters selected for the model.

Table 2. Model of HMD1 well

Model properties	
Wellbore model	Standard model
Well model	Horizontal
Reservoir model	Homogenous
Boundary model	Infinite

The transient test with the possible best model has given the following results:

Table 3. Well test HMD1 output

Property	Pi (kg/cm²)	H utile (m)	K (md)	KH (md.m)	kz/kr	ΔpSkin(kg/cm²)	Skin factor	C(m³.cm²/kg)
Results	358.056	67	2.94	197	0.0168	26.7	1.66	0.00239

3.2 Build up

On a log-log plot, the Bourdet derivative is shown together with the extracted pressure buildup. Three distinct zones are displayed in Figure 6.

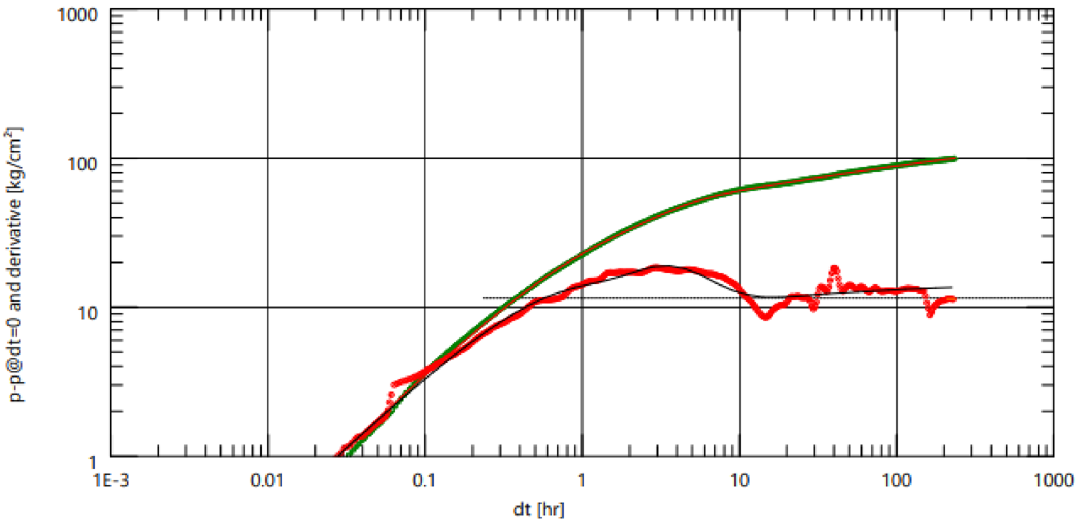

Figure 6. Log-log plot of the Bourdet derivative and extracted pressure buildup versus time

As illustrated by the arrow on the curve in Figure 6, the distance between the horizontal radial flow of the derivative and the Bourdet is less than that during the prior test, indicating that the thickness of the skin decreased. Since the stabilization of the radially flowing middle time zone is known to be inversely proportional to the transmissibility, a lower transmissibility, as in this test, translates to a lower permeability and thus a greater pressure drop. Since the range of the asphalts inside the formation is greater than two feet, this indicates that treatment with the reformat decreased the skin temperature but had no impact on the transmissibility or permeability. The scattered dots turned upwards throughout the late-time zone, and the slope away from the radial flow nearly doubled. The parameters chosen for the model are listed in Table 4.

Table 4. Model of well HMD1

Model properties	
Wellbore model	Changing storage (hegeman)
Well model	Horizontal
Reservoir model	Homogenous
Boundary model	Infinite

The transient test with the possible best model has given the following results:

Table II.5: Well test HMD1 output

Property	Pi (kg/cm^2)	H_{utile} (m)	K (md)	KH (md.m)	kz/kr	ΔP Skin (kg/cm^2)	ΔP skin factor	C ($m^3.cm^2/kg$)
Results	254.88	67	0.40	27	1.71E-4	38.3062	1.67	0.0431

3.4 Investigation of Asphaltene Stability

3.4.1 Colloidal Instability Index (CII)

This method involves the use of Eq. 1, the values of which are given in Table 2: a saturated weight percent of 61.47 wt%, an aromatic weight percent of 14.01 wt%, a resin weight percent of 9.52 wt%, and an asphaltene weight percent of 15. The results showed that there is a chance of asphaltene precipitation (unstable asphaltene) because the CII is 3.24, which is more than 0.9.

$$CII = \frac{Asphaltenewt\%+Saturatewt\%}{Aromaticwt\%+Resinwt\%} = \frac{15+61.47}{9.52+14.01} = 3.24$$

Because CII= 3.24 (i.e., > 1.2), again, there is an asperity problem.

3.5 Asphaltene precipitation modelling

3.5.1 Well design

The model of well HMD 1 is already simulated in the model presented in Figure 7. The model is characterized by a vertical section combined between different sections (tubing from the wellhead to 2984 m) and isolation equipment (packer) and liner 7" from 2980 m to 3357 m. The horizontal section (open hole) extends from 3357 m to 4450 m and is equipped with a crimped and perforated liner.

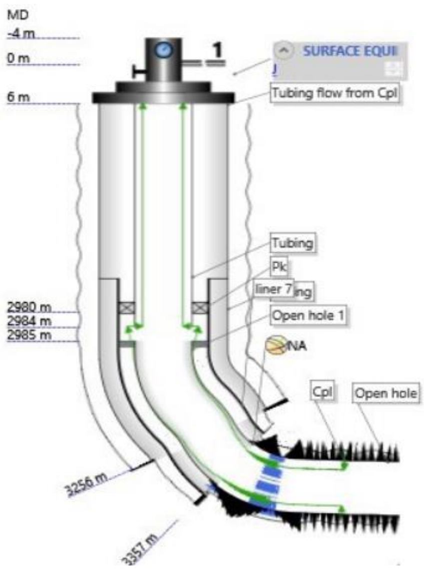

Figure 7. Well HMD 1 design

3.5.2 ADE envelope

This program is used in our case study to specify the well HMD1 asphaltene precipitation circumstances. The latter is a useful tool for determining the likelihood and seriousness of asphalt issues. To prevent or reduce asphalt issues, the ADE shows the thermodynamic path that must be taken when oil is recovered from the tank. If possible, keep the oil outside or as far away from the ADE centre as possible (Figure 8).

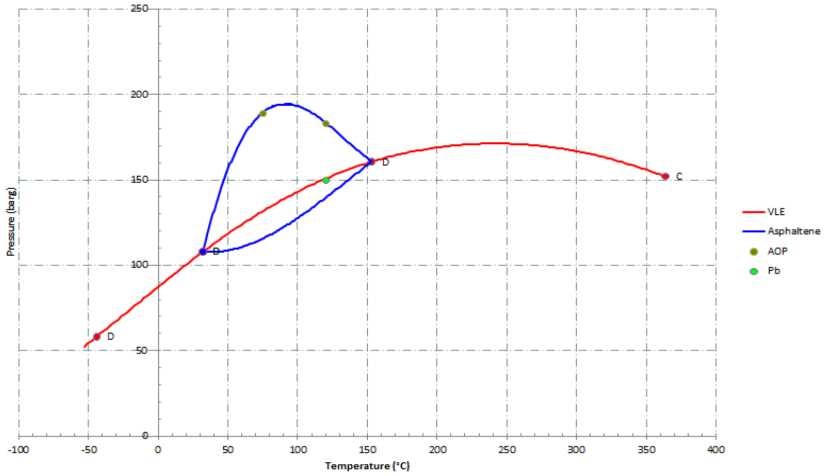

Figure 8. Phase enveloppe

During the deployment isotherm of the reservoir fluid, as long as the pressure does not reach the PAOP (180 bar to 190 bar), the flocculation pressure threshold and amount of asphaltene remain in the liquid phase, and there is no flocculation of the asphalts. Asphaltene instability occurs when the pressure is between the upper onset points (P = 190 bar; T =75 °C) and the bubble point [pressure = 150 bar; temperature = 120 °C]. The substance has two phases, asphalt oil, and, between the bowl point and the lower onset point, there are three phases: gas and oil/asphaltenes. When the tank pressure drops below the lower onset point, the asphalt particles are completely redissolved into the liquid phase, where the fluid is in the diphasic zone (gas-oil). The bubble point is determined under

conditions of pressure (150 bar), temperature (120 °C), and asphaltene at a specific pressure (AOP) (180 to 190 bar), as shown in Figure 6. A well is a candidate for damage caused by asphaltenes because it is in the precipitation zone of asphaltenes when the pressure is between 150 and 190 bar and the temperature is between 75 and 120 °C.

3.5.3 PVT data

All kinds of crude oil contain asphaltenes. The content of these substances does not determine whether they will precipitate. This complex thermodynamic equilibrium depends on the pressure, temperature, and composition of the crude oil components. Many laboratory studies are frequently carried out using reservoir oil samples in a PVT cell, simulating the circumstances that fluids are subjected to during production to determine how these volumetric changes occur. The PVT data obtained in this work for the HMD1 well give the following values in Table 6.

Table 6. Properties of the oil from the HMD1 well mixture

Bubble pressure	P_b	150 kg/cm³
Well storage Pressure	PWS	373 kg/cm³
Temperature	T_r	120°c
The molecular weight of the oil	MW_o	161,61 g/mol
Oil density	ρ_o	0.808 g/cm3
Gaz Oil Ratio	GOR	181.9 sm3/sm3

3.5.4 Nodale analysis

The wellbore and wellhead are the two main node points where the nodal analysis approach is used, and the inflow and outflow performances are extensively examined via sensitivity analysis. Due to the high-pressure decreases that are observed, two nodal locations are selected.

The model was used to simulate well HMD1, and the resulting curves are presented in two axes: pressure at the node analysis point (bar) and stock tank at the node analysis point (sm³/d), as shown in Figure 9.

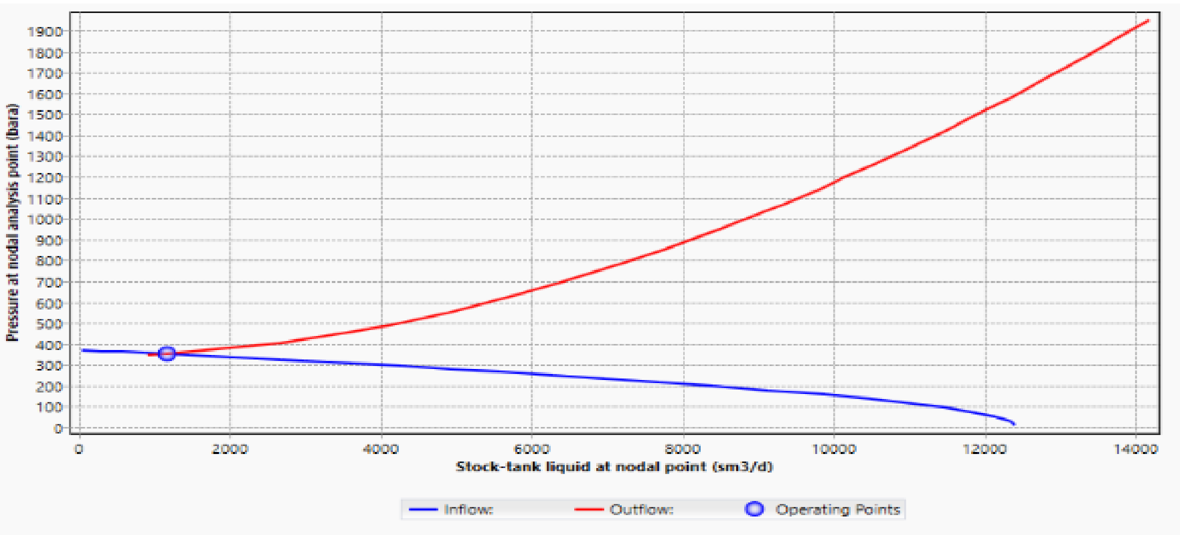

Figure 9. Nodal analyses of the HMD1 well

The nodal analysis yielded Q and PFD values, which were subsequently transferred to the following table (table 7). These values facilitates greater fluid flow, potentially leading to higher production rates.

Table 7. The operation points of HMD1.

Parameters	Flow rate (m³/d)	PDF (kg/cm²)
Fund point	103.3	359.69

4. Conclusion

In summary, the optimization of production in reservoirs with asphaltene precipitation and irreversible flocculation is a critical focus in the oil and gas industry due to the challenges and disruptions it poses to extraction operations. Finding effective strategies to manage and mitigate these issues is of utmost importance. This study highlights the growing significance of simulation as a reservoir engineering tool for justifying investments in the oil and gas sector. The case study specifically identified HMD1 as susceptible to asphaltene damage due to its location in the precipitation zone within the reservoir matrix, emphasizing the need for immediate treatment. During the production phase, a significant pressure drop occurs, prompting the use of well testing as an essential tool for assessing well and reservoir conditions. The best model match was obtained and validated through this process.

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