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Impacts of Asphaltene Deposition on Oil Recovery Following a Water flood - A Numerical Simulation Study

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A B S T R A C T

One of the challenges in extracting oil from unconventional resources is the low primary recovery rate, which is caused by the ultra-small permeability. Investigating gas injection techniques is therefore crucial to producing the trapped oil in shale seams. But the injection procedure may result in asphaltene deposits within the reservoir, which could clog pores and lower oil recovery (OR). While carbon dioxide (CO_2) and gas-enhanced oil recovery techniques have been employed in traditional resources, there has been little research on the utilization of gas injection techniques to improve oil output. In order to ascertain whether the cyclic (huff-n-puff) CO_2 process enhances OR and exacerbates asphaltene precipitation, the possibility of asphaltene deposition close to the oil wellbore during the waterflooding recovery operation is predicted using a thorough Eclipse simulation model. Eclipse 300 was used to create a data file based on the molar weight of asphaltene dissolved in the oil as a function of provided parameters. To guarantee accurate data gathering for the modeling, the simulation was conducted between January 1, 2011, and June 6, 2027. Upon completion of the simulation, it was seen that the block pressure had increased from 2500 psia to over 4500 psia due to a significant increase in the asphaltene deposition fraction from 0.0001 to 0.0006. From the third to the eighth year, the pressure, and the percentage of asphaltene deposition remained constant at 4000 psia and 0.0006, respectively. The block pressure dropped dramatically from 4000 psia to 2500 psia at the end of the eighth year, which led to an increase in the asphaltene deposition fraction from 0.0006 to 0.0016. This illustrates how the deposition of asphaltene is impacted by thermodynamic variations in temperature and pressure, resulting in its obstructing of the porous media within the reservoir. Based on the findings, a thermodynamic imbalance is indicated by the rise in asphaltene deposition when reservoir temperatures shift from low to high at reduced pressure. The findings of this research can serve as a valuable resource for the oil and gas industry in understanding the necessary considerations to avoid asphaltene deposition when performing recovery operations.

Keywords: Asphaltene; Near wellbore; Pressure; Temperature; Water flooding

1. Introduction

Climate change is one of the most concerning topics in our world today. The Carbon Capture Utilization Storage is not the only solution to combat this issue[1,2]. There are many new existing technologies in the campaign to reduce greenhouse gas emissions, such as hydrogen, renewable energy, etc. Along with that, Enhanced Oil Recovery and maintaining the existing operation oil well are also important means of contributing to meeting the world's energy demand and reducing the negative environmental impact. There are many new studies for well remediation[3-6]. Enhanced Oil Recovery, especially with water

flooding, exhibits an economical method with more easy-manipulated processes than others. However, asphaltene precipitation is being emerged as one of the most challenging. It may lead to formation damage, therefore reducing production capacity.

Asphaltene is a high molecular weight compound that can be found in crude oils. Asphaltene precipitation can block the pore throat and plug surface and subsurface equipment during the production process[7] And therefore result in oil production reduction. Many studies have investigated the impact factors on asphaltene precipitation and the impact of asphaltene deposition[8-11].[8]conducted experiments to investigate the influences of pressures and flow rate changes on the asphaltene precipitation[9]. Developed the experimental workflow to simulate the deposit of asphaltene and investigated the impact of the deposit on fluid flow through core floods and relative permeability experiments. The study showed up to 25% absolute permeability reduction[10]. Analyzed the asphaltene aggregation with respect to its colloidal and interfacial activities.[11]found that the effects of ultrasonic waves and microwaves on the permeability of formation. The study confirmed that ultrasonic waves and microwaves would reduce the negative charge of asphaltene and thus result in the reduction of adhesive force between asphaltene and limestone.

During the operations of secondary recovery (waterflooding), crude oil and water are jointly generated. The reservoir rock pores in the hydrocarbon zone are where some of the water is initially found. Additionally, during the waterflooding operation, water is injected into a reservoir. Hydrocarbon reserves must be produced to fulfil the increase in energy demand[12]. According to[13]water injection in petroleum production is very important. The partial miscibility of water and petroleum fluid occurs at high pressures and temperatures. To determine the part that water plays in the deposition of asphaltene, studies into a probable asphaltene-water interaction are important in this situation. These important investigations are only just beginning.

Since a few years ago, conventional waterflooding has been utilized as an improved oil recovery method to extract additional oil from a reservoir. The ongoing need for energy has made it necessary to recover additional oil today. It has been demonstrated that miscible or partially miscible waterflooding is a possible enhanced oil recovery approach for numerous reservoirs. It is generally known that waterflooding may cause asphaltene precipitation, which can block the reservoir and the production machinery by forming a sticky asphalt material. This is frequently attributed to changes in the solubility of heavy components in reservoir oils.

Waterflooding is a term used to describe the practice of injecting water back into a reservoir in the oil business. This is typically done to increase pressure and hence raise production. Onshore and offshore waterflooding wells are used to boost oil recovery from a reservoir that already exists. The recovery factor, which is a percentage that is increased by water injection, maintains a reservoir's production rate for a longer duration. Water is injected into the reservoir to stabilize the pressure, sweep or displace the oil from the reservoir, and drive it toward a well.

The wettability of rock can shift to a state that is more oil-wet when asphaltene is deposited on its surface. Since end point saturations and relative permeability curves are ranked after wettability in the hierarchy of rock-fluid properties, wettability also controls fluid flow during displacement operations. Observable changes in the interfacial tension at the oil-water interface, which is the source of the asphaltene deposition process, may also be linked to the wettability alteration event. Due to the potential for formation, wellbore, and production facility obstruction, asphaltene deposition from reservoir fluids during oil production is a serious problem. A layer of asphaltene may form when extremely unsaturated reservoirs are first depleted. Injection of CO2 or hydrocarbon gases for greater oil recovery may potentially cause it.

Asphaltenes exist in the form of colloidal particles suspended in resin molecules that function as surfactants to keep the colloidal particles in suspension. Depending on how they interact with the crude oil, these colloidal particles may either exist as a single-phase solution or form a distinct phase. When reservoir pressure declines or when light hydrocarbon or other gaseous injectants are supplied, the colloidal suspension may change into a destabilization, causing asphaltene and resin molecules to precipitate out of the oil. Several scholars previously examined the effects of temperature and the molecular weight of the n-alkane precipitants on the onset and amount of asphaltene precipitation in the case of various crude oils. A thermodynamic micellization model is advised for the report of asphaltene precipitation from petroleum fluids. The solubilization of asphaltene polar species by resin bipolar molecules in the micelles is described in detail. The acknowledged structure of the micellization standard Gibbs free energy is straightforward. Regarding asphaltenes, it is assumed that the petroleum fluid is a diluted solution.

[14]described techniques to determine the onset of asphaltene precipitation. They are a gravimetric method, viscosity measurement method, optical microscopy technique, refractive index measurement, interfacial tension measurement method, heat transfer technique, density measurement method, electrical technique, acoustic resonance technique, and light scattering technique.[15,16]proposed a new technique to remediate asphaltene precipitation.[15]introduced nanocomposites for preventing asphaltene, while[16]suggested increasing the natural-state oil resin and oil's aromatic power solvency.

[17]Introduced a generic plot for predicting asphaltene difficulties using PVT data of some crude samples. This method is based on the solubility principle and is a straightforward way to screen the potential for asphaltene precipitation. The De Boer plot's theoretical foundation is a thermodynamic model of asphaltene solubility created by [18] under the presumption that the asphaltene-rich phase contains just asphaltene. Hirschberg has forecast asphalt precipitation using this condensing premise, the modified Flory-Huggins theory, a lumped compositional representation (two or three chemicals), and so on. Because of its negative outlook, this approach ignores the variations in stability between different oils and their asphaltenes.

In 1998,[19]demonstrated that RI measurement can offer precise estimates of solubility parameters, obviating the need for cumbersome calculations. Asphaltene instability forecasts in many of the industrial operations are based on an empirical method that uses these crucial variables. The asphaltene to resin weight percentages ratio was first introduced in 2001 by[20]. Asphaltene in the crude mixture is stabilized by resins acting as a peptizing agent. As a result, for a given oil, the ratio indicates how unstable the oil is.[21]created models for asphaltene precipitation and deposition, and they were later validated using usual experimental data. This was done by adding the asphaltene mass balance equation, porosity, and permeability to a three-dimensional, three-phase black-oil simulator.

[22] studied the precipitation of asphaltenes in two crude oils from Mexico by combining atmospheric titration with n-alkanes and high-pressure isothermal expansion. The same crude oils' live and tank oil sample types were used in the experiments. The statistical association fluid theory for potentials of variable range (SAFT-VR) equation of state (EOS) was used to conduct a fictitious analysis of these systems within the confines of the McMillan-Mayer theory. A reliable forecast of asphaltene precipitation over a wide range of temperature, pressure, and composition intervals can be achieved by matching a single titration curve or two precipitation onset points with this EOS.

Predictions using the De Boer plot have been found to be cautious, according to [23]They introduced the single point ASIST (Asphaltene Instability Trend) approach and generated more precise predictions. The square root of the molar volume of the precipitating agents and the oil solubility parameter at the start of precipitation have a linear relationship, which forms the basis for the ASIST method (n-alkanes). By classifying oils and blends in terms of SARA (saturates, aromatics, resins, and asphaltenes) fractions,[24]reported that a previously developed regular solution model was adapted to predict the onset and amount of asphaltene precipitation from crude oil blends diluted with pure n-alkanes or a mixture of toluene and n-heptane.

There are many studies about asphaltene precipitation during CO_2 flooding[25-27]. The thermodynamics of asphaltene deposition with CO_2 flooding was studied experimentally and numerically[26]. The study tested the influence of pressure and concentration of CO_2 and revealed that the asphaltene precipitation is from 0.25-4% for the concentration of CO_2 from 10-50 % wt.[25] revealed that CO_2 flooding is more favorable for homogeneous reservoirs than for heterogeneous reservoirs.[27]presented the asphaltene precipitation at a molecular level. The study explained the mechanism of asphaltene micelle formation and showed that asphaltene precipitation depends on the reservoir pressure.

These earlier studies, however, were all conducted to corroborate experimental observations and neither of them addressed models of asphaltene deposition near wellbores or examined formation damage brought on by water injection. Due to this restriction, the goal of this research article is to employ a simulation model to predict the occurrence of asphaltene deposition brought on by water injection in a location close to a wellbore. The model is used to produce type curves for crude oil under various in-situ conditions for pressure, time, viscosity, using the composition of the crude oil and other pertinent PVT properties.

Methods

Modelling asphaltene precipitation and its effects on reservoir performance is the goal of the Asphaltene option. There are numerous asphaltene models available now, however there is still no consensus on how to describe asphaltene behaviour. This option for modelling asphaltene behaviour implements a simple but useful dissolution-like model that gives users the freedom to study a wide range of processes associated with asphaltene behaviour. The act of causing the asphaltene particles (fines) to become active is referred to as precipitation. The accumulation of precipitated fines into larger particles, or "flocs," is a process known as flocculation. Deposition describes the mechanical exchange of flocs between oil (a liquid solution) and the solid matrix that formed the reservoir rock. All these processes are interconnected in (**Figure 1**).

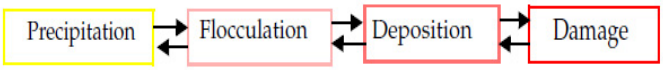

Figure 1: The Asphaltene modeling is decayed into different stages.

Reversibility is indicated by the double arrow (partial or total). The chain of flocculation, deposition, and damage, including the viscosity effect, are all triggered by precipitation. The word ASPHALTE in the RUNPSEC section activates the asphaltene modeling option.

Theory and Characterization

The basis for this model is the weight percentage of asphaltene-originating components that can remain dissolved in the oil as a function of pressure. According to their molar weight (%) in the solution, the components that make up asphaltene can precipitate. By employing the ASPREWG word, the user can specify a percentage restriction based on pressure. This limit can be set against the pressure, temperature, or molar fraction of a specific component using the ASPP1P word. Additionally, this limit can be determined in terms of two variables from the list of molar fraction, pressure, and temperature (Z). Taking into account that the list of parts is 1, 2, … i, i+1,...j,...k,..., N. If component i is the first to precipitate, component j is the last, and component k is the flocs component, then the dissolved fraction of asphaltene is just:

$$W_{adis} = \frac{\sum_{l=i}^{j} m_{wl} x_l}{\sum_{l=1}^{N} m_{wl} x_l} \quad (1)$$

and the total fraction of asphaltene (dissolved and flocs) is calculated as:

$$W_{apre} = \frac{m_{wk} x_k + \sum_{l=i}^{j} m_{wl} x_l}{\sum_{l=1}^{N} m_{wl} x_l} \quad (2)$$

Where m_{wl} is the molecular weight of component l, x_l is the liquid fraction of component l. The excess of W_{adis} with respect to user limit input specified using the keyword ASPREWG is given by the precipitate fraction emerging from the dissolved asphaltene at a known temperature, pressure, or concentration as follows:

Asphaltene Deposition Model

The exchange of flocs between the solution (oil phase) and the rock surface is referred to as deposition. The flocs can bind to the surface of the rock, become trapped inside of porous media due to their size (plugging), or be entrained and returned to the oil phase due to high, local velocities (shear). However, because it is currently believed that they do not contribute to the process, variations in the rock's density are not considered. The following model represents the deposition in the flow direction i:

$$\frac{\partial \varepsilon_i}{\partial t} = \frac{\alpha}{d} \phi C_a + \gamma |F_{oi}| C_a - \beta (|U_{oi}| - U_{cr})^{+} \varepsilon_i \quad (3)$$

where d is the dimension of the problem (1,2 or 3) and: ε_i is the volume fraction of deposit in the i direction of the flow, α is the adsorption or static deposition coefficient, Φ is the current porosity (time t), C_a is the volumetric concentration of the flocs in the oil phase (flowing flocs), F_{oi} is the oil Darcy flux, γ is the plugging coefficient, β is the entrainment coefficient, U_{oi} is the oil phase velocity, A is the section area between connecting cells and U_{cr} is the user input critical velocity. The + sign around the bracket for the entrainment part means that the entrainment will be zero if the velocity $|U_{oi}|$ is smaller than the critical value U_{cr}. The overall volume fraction deposit is the sum of the deposits in each direction i:

$$\varepsilon = \sum_{i=1}^{d} \varepsilon_i \quad (4)$$

The flocs mole fraction that deposits is calculated as:

$$n_a^{dp} = \varepsilon n_a^f \quad (5)$$

and the flocs mole fraction that remains in solution is corrected to:

$$n_a^f = n_a^f - n_a^{dp} \quad (6)$$

The concentration of the flowing part of the flocs is calculated as:

$$C_a = \frac{n_a^f S_o x_a}{b_o} \quad (7)$$

where, b_o is the oil molar density, S_o the oil saturation and x_a the molar fraction of the flocs in the liquid phase. The user-input parameters α, γ, β, and U_{cr} are given using the ASPDEPO keyword in the PROPS section. The core flood experiments should yield these parameters.

Results & Discussion

The performance of asphaltene deposition in a reservoir has been studied using a variety of techniques; however, the "Asphaltene Option" from Eclipse 300 provides modelling and simulation that are extremely accurate. The standard asphaltene option is set up using Eclipse 300's default choice of weight, which essentially represents the percentage of asphaltene's molar weight dissolved in the oil as a function of specified factors. The grid blocks used for this simulation have **10 X 1 X 3** blocks with an average porosity of **0.10**. Along the z-axis, the reservoir thickness remains constant (30 ft). The permeability is identical in the X and Y directions but varied along the Z direction. There are two wells, a producer and an injector, in the corresponding blocks **(1,1,1)** and **(10,1,1)**. With the same tube ID, they are both completed through layer 1**(Figure2).**

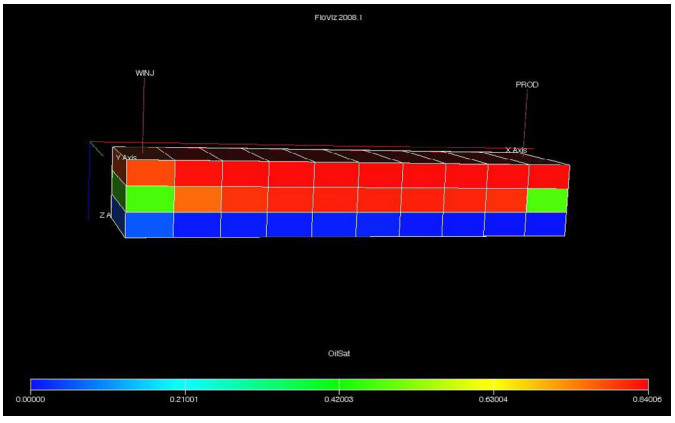

Figure 2: Grid block model used in simulation of asphaltene deposition.

After the simulation has been run numerous times, a comparison between the injector well and producer well is made based on several variables, including the oil reservoir density, oil viscosity, bottom hole pressure, asphaltene net deposition volume fraction, asphaltene precipitation fraction, asphaltene flocculation-dissociation rates, and asphaltene flocculation-dissociation fraction.

Asphaltene net deposition volume fraction vs time is the first comparison. Fig. 3 demonstrates that while the production well essentially remains constant, asphaltene deposition in the injector well dramatically increases. A little after the third year, at **1000 days**, the changes are quite noticeable; from this point forward, the distinction between these two wells is well-known. This discrepancy results from the injector well's pressure changing quickly, approaching **4500 psia**, while the producer well's pressure just touches **4000 psia** at the same time. The pressure variations from the several wells are depicted in Figures10 and 11. This supports the asphaltene thermodynamic theories that predict that every change in pressure will result in an increase in asphaltene deposition**.**

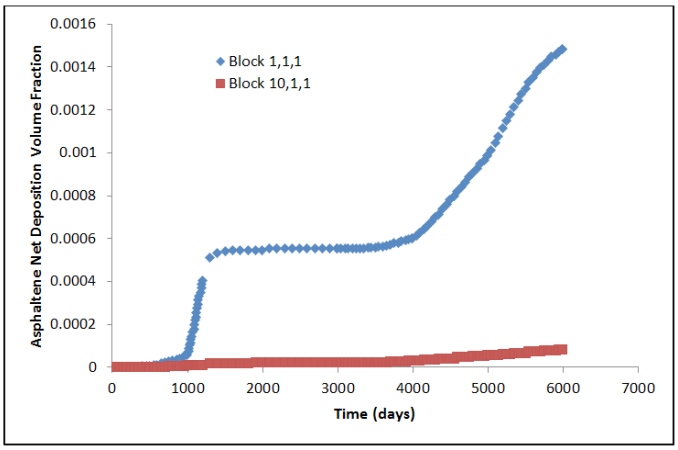

Figure 3: Asphaltene net deposition volume fraction vs time (days).

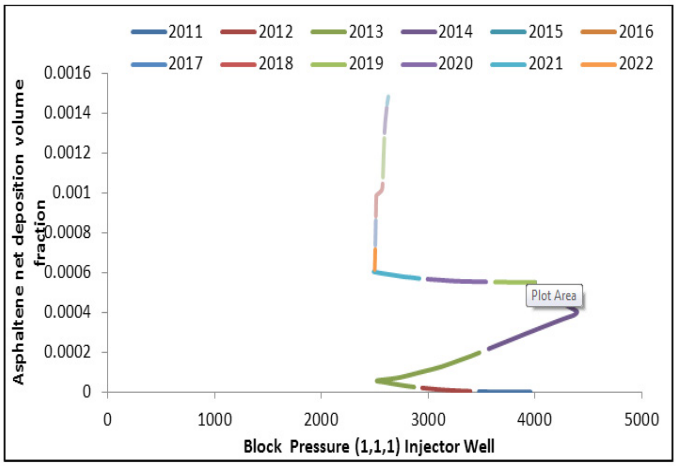

Figure 4: Asphaltene net deposition volume fraction vs block pressure (Injection well).

The asphaltene deposition volume fraction is kept consistent for the first three years by the injector well's constant pressure decline **(Figure 4)**, but in the third and fourth years, the pressure increases quickly, leading to a significant increase in the volume fraction **(Figure 3)**. Even though there are some pressure variations in the fourth and tenth years, the asphaltene deposition remains constant for almost six years. After the tenth year to the sixteenth year, the asphaltene deposition volume fraction increases at the maximum rate; in this final segment, the rate of increase ranges from 0.006 to 0.0015.

According to **(Figure 3)**, the producer well behaves considerably differently from the injector well; as a result, even though the producer well experiences minor pressure variations, the behaviour of the asphaltene deposition volume fraction is nearly constant over the course of the entire period (16 years). The plots suggest that there will be a shift, although it may just be a little one, depending on how the pressure changes affect whether asphaltene deposition rises.

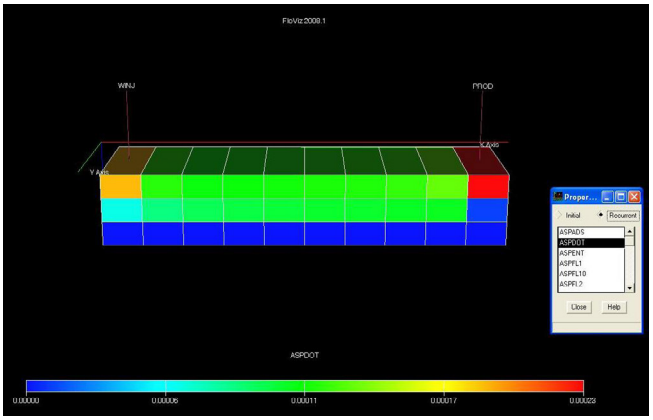

Figure 6: Asphaltene net deposition volume fraction.

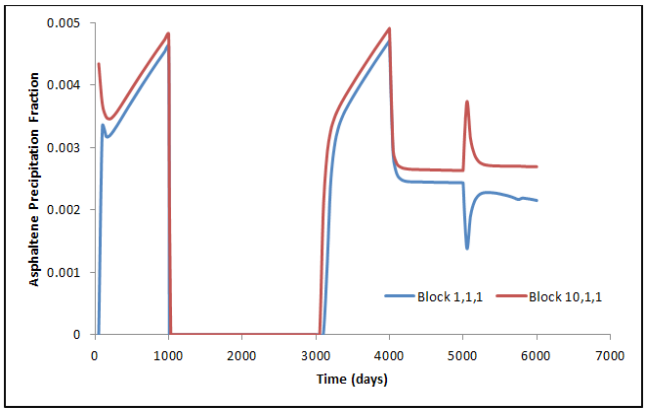

Figure 7: Asphaltene precipitation fraction vs time (days).

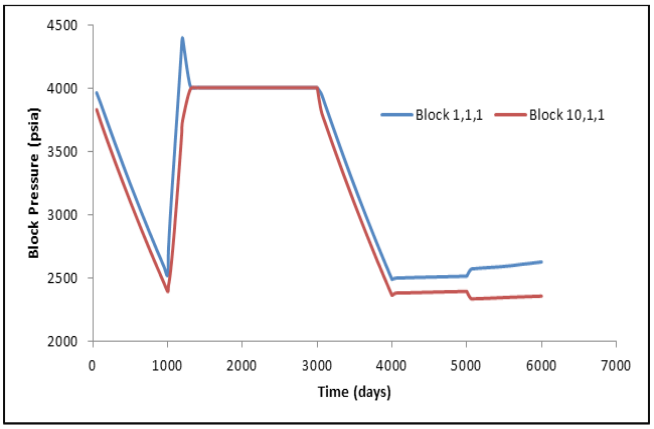

Figure 8: Block pressure vs time (days).

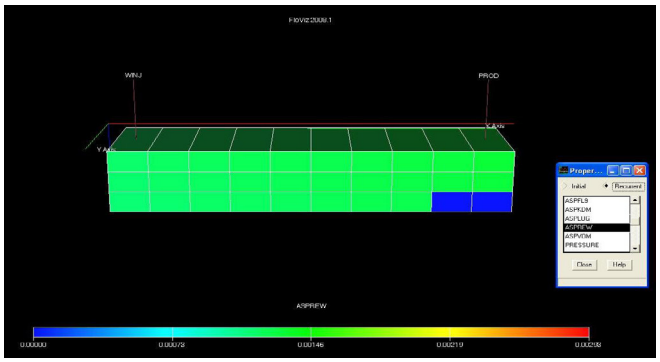

Figure 9: Asphaltene precipitation fraction.

The asphaltene precipitation fraction stabilizes when the pressure remains constant, as may be deduced from **(Figures 7 and 8)**. In this instance, the asphaltene precipitation fraction is equal to zero from the third to the eighth year, and the pressure stabilizes at 4000 psia. Once more, each drop or rise in block pressure destabilizes asphaltene, causing it to precipitate at random values that range from zero to 0.005.

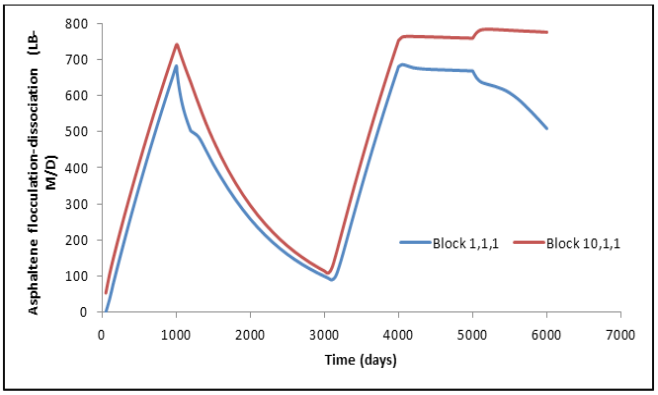

Figure 10: Asphaltene flocculation-dissociation rates vs time.

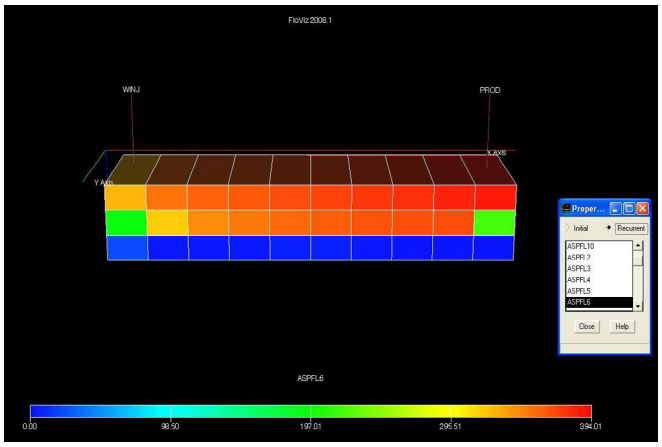

Figure 11: Asphaltene flocculation-dissociation rates.

Because the plots are so comparable, the oil viscosity and density are behaving in a manner that is similar for both wells. In all situations, it appears to be slightly greater in the 11th year near the end of the simulation procedure. The bottom hole pressure at the producer and injector wells is shown in Fig. 20, and it basically depicts how the wells are operating, each at a separate time. Due to the inactivity of both wells between the third and ninth years, certain variables, such as the fraction of asphaltene precipitation, oil viscosity, and oil density, remain constant during this period.

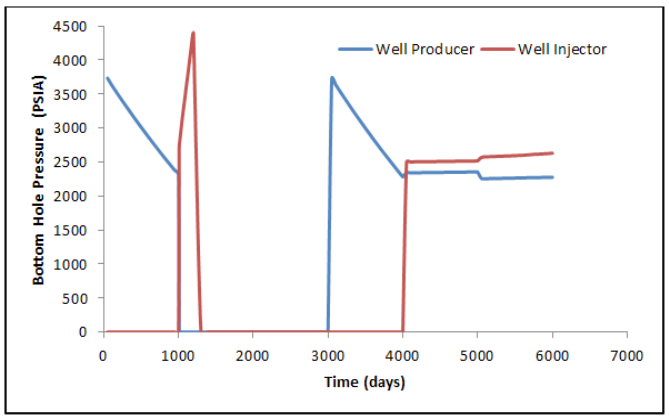

Figure 12: Bottom hole pressure vs time (days).

Finally, the simulation was run at various reservoir pressures of 124 °F, 132 °F, 140 °F, and 160 °F, respectively, with various pressure gradients of 1.6 °F/100ft, 1.8 °F/100ft, 2.0 °F/100ft, and 2.5 °F/100ft. From Fig. 13, it can be inferred that the amount of asphaltene deposition increases quickly as temperature and pressure change (Fig. 14), demonstrating how thermodynamic factors like temperature and pressure affect the asphaltene deposition percentage. In contrast, Fig. 15 shows the producer well at various reservoir temperatures. As reservoir temperatures

drop, more asphaltene is deposited, and as block pressure drops, the asphaltene curves rise sharply from 0.0001 to 0.0035.

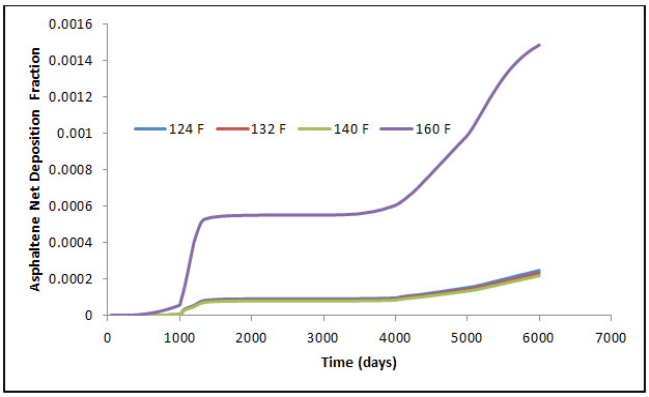

Figure 13: Asphaltene net deposition fraction vs time at different reservoir temperatures (injector well).

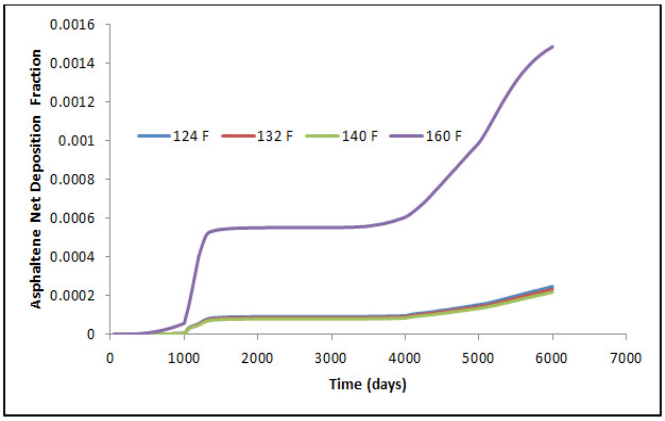

Figure 13: Asphaltene net deposition fraction vs time at different reservoir temperatures (injector well).

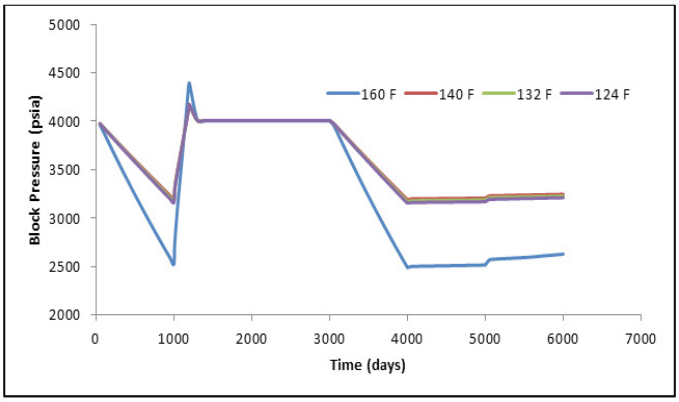

Figure 14: Block pressure vs time at different reservoir temperatures (injector well).

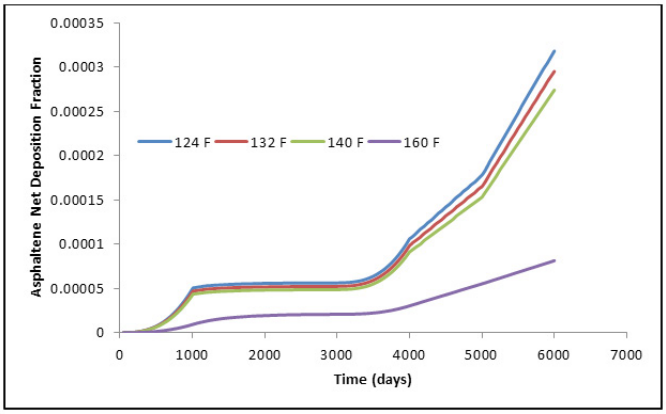

Figure 15: Asphaltene net deposition fraction vs time at different reservoir temperatures (producer well).

From these graphs, it can be concluded that the asphaltene deposition in the wells varies greatly depending on the temperature and pressure. For each situation, a variety of elements operate in various ways, which aids in the research's attempt to understand the behaviour of asphaltenes during the injection and production processes.

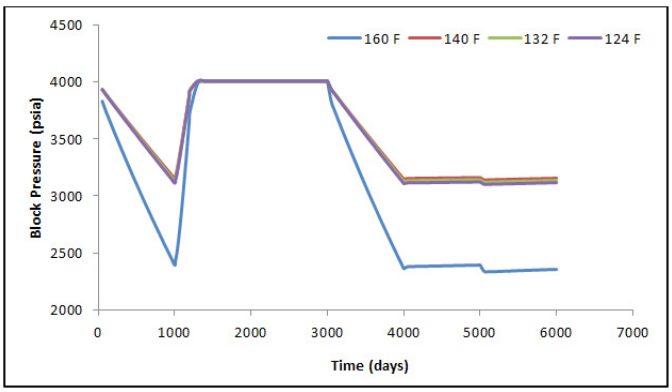

Figure 16: Block pressure vs time at different reservoir temperatures (producer well).

Numerous intriguing findings were made when the simulation on ECLIPSE 300 was complete. According to the theory, thermodynamic changes like temperature and pressure, have an impact on the deposition of asphaltene and cause it to block the porous media in the reservoir. From **(Figure15)**, the asphaltene deposition fraction dramatically increases from 0.0001 to 0.0006. This phenomenon occurs because, during this time (roughly 1000 days), the block pressure (Fig. 16) changes from 2500 psia to almost 4500 psia. Additionally, it is demonstrated that during a five-year period (from the third to the eighth year), both the pressure at 4000 psia and the asphaltene deposition fraction at 0.0006 remain constant. By the eighth year, the block pressure has significantly decreased from 4000 to 2500 psia, increasing the asphaltene deposition fraction from 0.0006 to 0.0016.

The suggested model presented was used to simulate the deposition of asphaltene, with varying results. Depending on how much the injection pressure is changed, any change may result in an asphaltene deposition. The formation damage close to the wellbore is not considered in the simulation findings. To demonstrate how changing reservoir temperatures can affect asphaltene behaviour and demonstrate their inconsistency owing to thermodynamic changes, the simulation was run with various reservoir temperatures. The fundamental cause of asphaltene deposition is the thermodynamic equilibrium, which is affected by both pressure drop and temperature fluctuations.

Conclusions

The summary of this research paper concludes that the stability of asphaltenes can be altered by the influx of water to an oil reservoir with a particular influence of the reservoir fluid's properties. The result revealed that the inclusion of water to an oil reservoir influenced the formation of when the pressure dramatically rises or falls above or below a particular crossover point. Moreso, the maximum asphaltene deposition was recorded at the block pressure of 2400 and 4400 psia. This occurrence caused the two liquid phases coexist in an asphaltic oil system with the increase in the injected water. Lastly, the findings also revealed that asphaltene deposition increased as the reservoir temperatures fluctuate at a reduced pressure. This phenomenon indicates a state of thermodynamic imbalance. The producer

well behaves considerably differently from the injector well; as a result, even though the producer well experiences minor pressure variations, the behaviour of the asphaltene deposition volume fraction is nearly constant over the course of the entire period (16 years) as shown in the simulated result. This suggests that there will be a shift, although it may just be a little one, depending on how the pressure changes affect the occurrence of asphaltene deposition. For further investigations, this work would be extended to experiments. The experimental system should model what the numerical simulation has done.

List of Abbreviations

Latin letters

b_o	oil molar density
C_a	volumetric concentration
d	dimension of the problem
F_{oi}	oil Darcy flux
m_w	molecular weight
n_a^{dp}	flocs mole fraction that deposits
n_a^f	flocs mole fraction that remains in solution
S_o	oil saturation
i	direction of flow
W_{adis}	dissolved fraction of asphaltene.
W_{apre}	total fraction of asphaltene
U_{oi}	oil phase velocity
U_{cr}	user input critical velocity
x	liquid fraction

Greek letters

α	adsorption or static deposition coefficient
ε	the volume fraction of deposit
γ	plugging coefficient
β	entrainment coefficient

Declarations:

Availability of data and material:

The data that support the findings of this study are available on request from the corresponding author.

Competing Interests

The authors declare no competing financial interest.

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Authors' Contributions

MC wrote the Original draft; FB, MC, OO, VN analysed the data; FB, OO, VN, MAZ reviewed and edited the manuscript; FB is also a supervisor for this paper. All authors have read and approved the manuscript.

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