

Prediction of Asphaltenes Deposition in Multiphase Flow Systems through the use of Novel Numerical Modelling

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Abstract

One of the well-known problems encountered in oil flow lines, oil reservoirs and completion strings, causing flow assurance issues, is the deposition of asphaltenes in these areas. The complications aroused due to asphaltenes deposition include, but are not limited to, permeability reduction, wettability reversal, pipeline and well plugging, increased pressure drop and an overall reduction in oil production. The problem is not only severe, but it occurs so abruptly that it can damage the formation in a few days if it proceeds unnoticed. The asphaltenes deposition for a given oil is measured by the use of high-tech and expensive apparatuses, particularly where multiphase flow occurs, which incurs additional costs. Multiphase flow combined with asphaltenes precipitation worsens the situation in well bores and affects the flow of crude oil. This paper presents a numerical modeling approach for prediction of asphaltenes deposition and precipitation in crude oil in multiphase flow by the use of governing equations calculated using finite difference discretization methods. These numerical models belong to the family of front-capturing-models which permit the capture of the depositing front on a fixed mesh. The paper also presents a model for studying the effect of CO₂ injection on asphaltenes precipitation during enhanced oil recovery from the reservoir. The developed numerical models are validated against each other. The parametric effect on deposition of crude oil was modeled and studied against experimental values. The numerical models and resulting simulations were in good agreement with the steady-state solution of the asphaltenes onset curve.

Index terms— numerical modeling, asphaltenes precipitation, multiphase flow, enhanced oil recovery.

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47 Keywords: numerical modeling, asphaltenes precipitation, multiphase flow, enhanced oil recovery.

48 2 Highlights

49 ? A new numerical model for predicting asphaltenes deposition is presented. ? Another model accounts for the
50 effect of CO₂ injection on asphaltenes precipitation. ? The numerical models were in good agreement with a
51 steady-state solution. ? Simulations revealed that asphaltenes become more unstable in the presence of CO₂.
52 I.

53 3 Introduction

54 he shift in oil and gas producing systems to offshore and subsea areas in the past few decades has increased the
55 need to study the fluid properties related to flow assurance problems (Patin, Stanislav, & Ian, 2001). Deposition
56 and precipitation of asphaltenes are one of these potential problems, and it is often catastrophic. The general
57 problems related to asphaltenes precipitation are fouling in extraction facilities and plugging of wells and lines
58 (Hasanvand, Ahmadi, & Behbahani, 2015). To avoid asphaltenes deposition, proper control strategies must be
59 developed from the beginning of production. Either a comprehensive experimental procedure or the development
60 of a prediction model is required to understand the problems before their occurrence. The issue with modeling
61 the prediction of asphaltenes requires a large number of parameters, which makes the model highly complex.
62 The drawback of such a model is that its solution will require more processing power and time to achieve the
63 desired results (Yap, et al., 2012). This effect is further enhanced in the multiphase flow because there are three
64 different phases (i.e., gas, liquid, and solid), that must be incorporated to obtain accurate results. The phases
65 generated in the flow path are due to various reasons such as pressure depletion or a change in the composition
66 of the oil. The generation of the solid phase creates flow assurance problems during primary production of
67 crude oil or in enhanced oil recovery processes involving the injection of CO₂ (Ali, Dahraj, & Haider, 2015).
68 In previous studies, researchers have found some major parameters that affect asphaltenes deposition, such as
69 molecular weight, solubility, temperature, and pressure. Various models have been developed, but they do not
70 account for the effect of asphaltenes deposition on multiphase flow. This paper presents the numerical model for
71 the prediction of asphaltenes deposition under such conditions.

72 Before discussing the previous models developed by various scientists for the prediction of asphaltenes
73 deposition, it must be taken into account that asphaltenes precipitation and deposition is not a reversible process,
74 as indicated by various researchers (Nasrabadi, Moortgat, & Firoozabadi, 2016). The reason T (A)

75 for the irreversibility of the process is the colloidal nature of asphaltenes suspensions, and this was verified
76 by previous experimental observations. Therefore, there is an intense need to understand the possible conditions
77 under which asphaltenes will deposit in the well. Numerical modeling provides an alternative and economical
78 solution in the prediction of asphaltenes deposition, especially at higher temperatures and pressures under
79 multiphase flow conditions (Attar, 2015). The modeling of asphaltenes initially started from the thermodynamic
80 models based on the solubility parameters, leading to multiple descriptions of Statistical Associating Fluid Theory
81 (SAFT). Various researchers have used the experimental results as the basis for the prediction of asphaltenes
82 deposition, but it was found that an optimized numerical model produces more reliable results compared
83 to predictions based on experimental values (Behbahani, Ghotbi, Taghikhani, & Shahrabadi, 2014).

84 The following section describes the various models developed for predicting asphaltenes deposition, leading to
85 the numerical model developed and studied in this paper.

86 4 II.

87 5 The Different Types of Existing Models

88 The various existing models can be classified into two categories: compositional models and mechanistic models
89 (Yap, et al., 2012). The compositional models use various forms of equations of state to predict the phase
90 equilibrium for asphaltenes precipitation, whereas the mechanistic models are based on the formulation of
91 homogeneous liquid hydrocarbon mixtures (e.g., crude oil).

92 6 a) The steric-stabilization model

93 The steric stabilization model was presented by (Leontaritis, Kawanaka, & Mansoori, 1987). The model is
94 based on Nellensteyn's concept of asphaltenes as the solid particles produced in crude oil, which are insoluble
95 and peptized by the resins that are absorbed on their surfaces. According to this model, the asphaltenes are
96 produced when the chemical potential of the resin is higher than the critical value. The compositional value is
97 expressed by the following equation: $\ln \left(\frac{C_2}{C_1} \right) = \ln \left(\frac{C_2}{C_1} \right) + \left(\frac{C_2}{C_1} \right)^2 \left(\frac{C_2}{C_1} - 1 \right) \left(\frac{C_2}{C_1} + 1 \right) \left(\frac{C_2}{C_1} - 2 \right) \left(\frac{C_2}{C_1} + 2 \right) \left(\frac{C_2}{C_1} - 1 \right)$

98 where μ_2 is the difference between the chemical potentials of the resins in solution and in their reference
99 state, R the gas constant, T is temperature, ϕ_2 is the volume fraction of the resins, χ is the interaction parameter
100 between resins and solvents, and r is the ratio of the molar volumes of the resins to the solvent. This model was
101 initially successful in predicting the asphaltenes precipitation up to certain limits of temperature and pressure.
102 However, it was mainly used for data regression. This model has certain limitations.

103 For example, multiphase systems cannot be integrated because of the assumption of a single flowing phase
104 used in this model. Conversion to multiphase flow without modification results in undefined outcomes. For
105 example, as proposed in the model, the presence of any resin on the surface needs to be physically tested. In
106 numerous studies, it has been found that inaccessible asphaltenes fractions are stable in particular solvents (Arya,
107 et al., 2017). Thus, the existence of resins is not an essential requirement for the formation and stabilization of
108 asphaltenes (Subramanian & Simon, 2015). Due to such major drawbacks and no inclusion of multiphase flow,
109 the model does not seem capable of predicting asphaltenes precipitation.

110 7 b) The thermodynamic models i. The Flory-Huggins equation

111 This model is based on the Flory-Huggins equation for polymer solutions which considers the asphaltenes solvated
112 in the liquid medium. This technique differentiates the liquid-solid apart from the vapor-liquid equilibrium during
113 multiphase flow modeling. The procedure follows the vapor-liquid calculations at an initial stage. After that,
114 a modification is used for the liquid phase in which the vapor phase stays unaffected. The limitation of this
115 model is that the solid-vapor equilibrium is not taken into account. Under the action of high pressure and
116 temperature, some gases such as CO_2 affect the asphaltenes precipitation. Thus, the model is missing vital
117 parameters for asphaltenes prediction during multiphase flow. Further work on this model was carried out by
118 Hirschberg and co-workers (Hirschberg & Meijer, 1984). They eliminated any chances for the presence of resin
119 and considered asphaltenes as single dispersed solvated macromolecules (Wu & Prausnitz, 1998). Following the
120 various generalizations for this equation, the highest volume fraction of soluble asphaltenes in the crude oil is
121 expressed as follows: $\phi_2^{\max} = \exp\left(\frac{v_2}{v_1} \left(\frac{1}{\chi} - 1\right)\right)$ (?? ?? ? ? ? ?) (2)

122 where ϕ_2^{\max} is the maximum volume fraction of soluble asphaltenes in the crude, v is the molar volume, χ
123 is the solubility parameter, and a and l refer to the asphaltenes and the liquid medium, respectively.

124 8 ii. Cubic equations of state

125 A few researchers have used the cubic equations of state for predicting the behavior of asphaltenes precipitation.
126 Various forms of cubic equations of state are available and modified. For example, Gupta used a solid phase
127 fugacity with a Peng-Robinson model (?? provides the basis for the numerical model (Jaramillo, Galeana, &
128 Manero, 2006). Nonetheless, as observed in previous models, the selection of molar weights and heteroatom
129 content are critical to being able to present unrelated results. The interaction parameters (i.e., pressure, volume
130 and temperature) must be considered during asphaltenes precipitation because of the changes in the solubility
131 with changes in these major parameters. Nonetheless, these parameters had to be tailored for each n-alkane, and
132 all of the changes in these parameters were applied in all of the equations rather than just considering them to
133 be constant (Stachowiak, et al., 2005). The major issue with the models based on cubic equations of states is
134 that they cannot simulate the upper onset pressure boundary by tuning the model parameters to the lower onset
135 pressure boundary.

136 9 c) The association EOS

137 The most advanced forms of the equation of states include association EOS for predicting phase equilibria
138 based on Statistical Associating Fluid Theory (SAFT). Research has shown that the models based on SAFT are
139 somewhat acceptable to use for predicting asphaltenes precipitation, as evident from the works of (Firoozabadi
140 & Li, 2010), (Wu & Prausnitz, 1998), (Chapman, 1989), (Ting, Hirasaki, & Chapman, 2003), (Ting D. , 2003),
141 and Gil-Villegas (Gonzalez, et al., 2004). The issue with the models based on the associating equation of states is
142 the same as that of cubic EOS. That is, the model takes sufficient time for characterization of the oil, especially
143 the heavy oil, considering all of the parameters that make the model complex. Andersen and Speight explained
144 this in a short and concise manner: "The more realistic the model becomes, the more complex it will be. The
145 complexity as well gives rise to an increase in unknown parameters which in turn will have to be estimated or
146 fitted to the experimental data" (Andersen & Speight, 1999).

147 In the present paper, a new numerical model has been developed using a novel approach to describe flow
148 restrictions in the wellbore and near-wellbore area due to asphaltenes precipitation in multiphase flow. This
149 model is capable of identifying and predicting potential flow assurance problems. In the wellbore numerical
150 model described below, numerical methods (such as implicit finite difference discretization) along with a specific
151 type of black/heavy oil and appropriate Equation of State compositional models are used. The application of
152 Equation-of-State updates the properties and the equilibrium calculations between all of the phases (oil, gas, and
153 asphaltenes).

154 The governing equations of the wellbore model consist of mass conservation of every phase and every
155 component, momentum conservation of the liquid and gas phases, and energy conservation of the mixture of
156 fluids. The governing equations are calculated using finite difference discretization methods. The simulation

157 results indicate that asphaltenes deposition can begin in the middle of the well. Furthermore, they show that
 158 asphaltenes deposition is greatly influenced by CO₂, and the location of deposition is altered to the lower part
 159 of the well in systems containing CO₂.

160 The following section also describes the transport model based on rheological equations of state, a three-phase
 161 interacting system, and correlations for multiphase flow. The prediction model incorporates mass profiles as a
 162 function of pressure and temperature along with changes in the rheological properties of crude oil as it flows
 163 through the pipe.

164 III.

10 Material and Methods

165 A simulation of asphaltenes deposition in the wellbore was performed with a heavy oil sample. In this simulation,
 166 the bubble point pressure of the fluid took place in the middle of the wellbore. Furthermore, the effect of CO
 167 2 on asphaltenes deposition in the same sample was investigated. This simulation, however, can adequately
 168 demonstrate the effect of CO₂ on asphaltenes deposition in the production well. It applies to the discovery of
 169 CO₂ in enhanced oil recovery.

170 The input parameters for this case study were obtained from an Australian oil field. A 2400 m well was
 171 considered in this case study, which is at the primary production stage. The well is located in a reservoir with an
 172 initial pressure of 38 MPa and functioning at a wellhead pressure of 12.9 MPa. The multiphase flow simulation
 173 is carried out for this well to analyze its performance for flow assurance concerns. Figure -1 shows the schematic
 174 of the flow system in the well pipeline. An initial composition of oil is flowing through the pipe of height "h" and
 175 radius "r". The crude oil is a hydrocarbon mixture of "n" number of components. The effects of temperature and
 176 pressure are considered for equalmole fractions of three phases (i.e., liquid, solid, and gas). The crude oil enters
 177 from the bottom of the pipe, which has an inside radius of "r(a)". The multicomponent oil flows through the pipe
 178 at a temperature "T_o" and pressure "P_o". The oil flows in the upward direction, cools along the length of the
 179 pipe, and expands under reduced pressure. The crude oil temperature also changes with the forced convection
 180 heat transfer process. This change in temperature and pressure conditions results in asphaltenes deposition along
 181 the wall of the wellbore pipe. The radius of the pipe at this area reduces to "r(w)". As the layer of asphaltenes
 182 grows, it faces shear removal forces due to the flow of upcoming oil and gas.

183 When the flow of oil "Q_s" is considered as turbulent, the asphaltenes layer is assumed to form a laminar sub-
 184 layer. Three zones are developed under such conditions: a laminar sub-layer, a transition zone, and a turbulent
 185 main. The input parameters for this case study are obtained from an Australian oil field, and are presented in
 186 Table 1. Table 2 shows the composition of the fluid sample and the fluid's characteristics. These tables are used
 187 for better understanding of the simulation applied in this case study.

11 Assumptions for proposed Multiphase Flow model

188 a. The single-dimensional flow was assumed along the length of the well in vertical, horizontal and deviated
 189 inclinations. The assumption is acceptable for pipelines of smaller diameters, as in our case. b. Spatial averaging
 190 and Eulerian time were applied. c. For the cases of the three-phase flow, water-oil slippage was considered and
 191 calculated using the d. The pressure for all of the phases (i.e., liquid, solid and gas) is considered to be the same.
 192 This assumption is considered reliable when the concentration of gas is negligible compared with those of the
 193 liquid and solids during multiphase flow in the pipeline. e. A thermodynamic equilibrium is considered between
 194 the phases. Various approaches such as black oil and compositional approaches were applied to calculate the
 195 fluid properties and state relations.

12 b) Development of the Mathematical Model

196 Based on these assumptions, the flow equations developed for the liquid and gas phases are as follows:
 197
$$\frac{d}{dz}(\rho_o v_o) + \rho_o v_o \frac{d}{dz} \ln \rho_o = \delta \rho_o \frac{d}{dz} \ln \rho_o \quad (3)$$

198
$$\frac{d}{dz}(\rho_g v_g) + \rho_g v_g \frac{d}{dz} \ln \rho_g = \delta \rho_g \frac{d}{dz} \ln \rho_g + \hat{I} \rho_g \frac{d}{dz} \ln \rho_g \quad (4)$$

199 where ρ_o and ρ_g are the oil and gas mass flux terms, and v_o and v_g are the oil and gas mass densities.
 200 Along with an appropriate definition of the interphase transfer term, Equations 3 and 4 result in decreasing
 201 the number of primary unknowns. This approach leads to a faster simulation runtime as well as application
 202 of the state relations using either compositional phase property calculations or black oil property calculations.
 203 The addition of solid particles to the fluid flow results in new sets of mass conservation equations, which are as
 204 follows:
 205
$$\frac{d}{dz}(c_a v_o) + c_a v_o \frac{d}{dz} \ln \rho_o = \delta c_a \frac{d}{dz} \ln \rho_o + m_d \quad (5)$$

206 where c_a is the asphaltenes concentration in the crude oil, δ is the flocculation of solid particles from the
 207 reservoir, and m_d is the deposition rate of the solid particles. Equation 5 is applied to fluids that contain
 208 asphaltenes and cause asphaltenes flow assurance problems. Equation 6 is used for fluids with precipitation
 209 potentials.

210 Here, c_w is the wax concentration in the crude oil. To solve Equations 5 and 6 for asphaltenes and wax
 211 mass conservations, a similar approach for the solution component concentration (mole per volume) at a specific
 212

time is considered. Solving the equation in grid block "i" (the goal of gridding is to transform the model into a discrete system to solve the flow equations), we obtain the following equation:) is obtained, the overall mole compositions of the hydrocarbon phases in the grid block i are updated. The next step involves the flash calculations of the concentration of asphaltenes at a new time step. In Equation 6, the solid deposition rate ΔC_{asph} is used for the old time step. The process can be reiterated using a new deposition rate and new solid concentrations until convergence is achieved. The new concentrations are used for updating the concentrations of fluid species and solid precipitates in grid block i using PHREEQC module, which is a specialized geochemical model (Parkhurst & Wissmeier, 2015) for the reaction among rocks, water and solid precipitates (asphaltenes in our case). The next concern is the evolution of asphaltene deposits, finally resulting in complete clogging of the wellbore. The cross-sectional area of well bore pipe decreased due to solid deposition, resulting in production loss. The cross-sectional area at the new time step is calculated as follows: $A_{i,t} = A_{i,t-1} - \Delta C_{asph} \cdot \Delta t \cdot \pi \cdot r_w^2$. (8)

Equation 8 can follow the progress of solid deposition in each wellbore grid block. The model is used for predicting the decline in the flow of crude oil due to solid deposition.

230 13 c) Effect of CO 2 injection

231 According to (Darabi, 2014), additional flow assurance issues are introduced into the reservoirs and the wellbores
 232 by applications of CO 2 and light hydrocarbon gas injections for the enhanced oil recovery process. Most
 233 conventional oil fields have reported asphaltene deposition as the most challenging issue during the CO 2
 234 flooding process, and there is the need to conduct proper studies of that effect. As evident, the presence of light
 235 components can upsurge the bubble point pressure and the onset pressure of asphaltene in the crude oil. (Vargas,
 236 et al., 2009) Applied PC-SAFT EOS in the description of the impact of light components on the behavior of the
 237 asphaltene phase. As in the case of the asphaltene precipitation modelling approach, the impact of composition
 238 on the asphaltene onset pressure is not rigorously included. Instead, the pressures of different temperatures are
 239 well defined as input variables for use in the process. PC-SAFT EOS may not be recommended for the entire
 240 variety of compositions because the Cubic Equation of State is modified to only one set of compositions for
 241 asphaltene precipitation. This is because it applies to the binary interaction coefficients. To reduce modification
 242 errors for asphaltene precipitation models, experimental values are used for the asphaltene onset pressure. Table
 243 3 shows the onset pressure of the fluid for different molar ratios of CO 2 to oil.

244 14 d) Development of the Computational Model

245 A comprehensive computational model is designed for the evaluation and prediction of asphaltene in wellbores,
 246 as shown in Figure -2. The model incorporates asphaltene prediction with and without injection of CO 2 in
 247 the well. The model starts with defining and inputting the variables that affect asphaltene precipitation. The
 248 assumptions are also included in the next step, which defines the flow of the model. The next step is to update the
 249 temperature and pressure in the loop for evaluating the asphaltene precipitation later on. Equations 2 and 3 are
 250 used to calculate the phase equilibria in the next step. All the physical properties, such as the density, viscosity,
 251 and temperature of crude oil, are determined in this step, and the diameter of the pipe is updated. Equations 5
 252 and 6 are used for evaluating for asphaltene precipitation in the next stage. If precipitation doesn't occur under
 253 the given conditions, the loop is repeated for changed values of temperature and pressure. If asphaltene are
 254 present, further calculations are made for its verification and are matched with the original data obtained from
 255 the Halibut oil field (Australia). If asphaltene are formed, and the nominal diameter of the pipe decreases to a
 256 reduced size, the simulation is stopped, confirming the asphaltene precipitation. If no asphaltene are formed,
 257 the loop is repeated back for the changing temperature and pressure values. After the initial determination of
 258 asphaltene under the given conditions, the effect of CO 2 injection is also studied. This loop can be run or
 259 stopped as required. With the injection of CO 2, the asphaltene mass calculations are made along with changes
 260 in the nominal diameter of the wellbore. Upon confirming the asphaltene precipitation, the loop stops. In
 261 the case of no change in pipe diameter, the loop is repeated to change the CO 2 concentration pressure and
 262 temperature for a new iteration.

263 15 Results and Discussion

264 This study has considered a working example of Tan oil field for the analysis of asphaltene deposition problems.
 265 The data of pressure-temperature profiles was available. The natural fractured reservoir has the pressure of
 266 92.2 MPa and temperature of 160 °C. The average oil produced by this well is 32°API and the average bubble
 267 point pressure is 13.2 MPa. The data of impact of phase behavior on asphaltene deposition Following are the
 268 results from simulations for the developed numerical model. Figure -3 indicates that the maximum asphaltene
 269 precipitation takes place at approximately the bubble point pressure, in which the solubility of asphaltene is at
 270 a minimum. In fact, when gas is released from the crude oil, the asphaltene components increase their stability
 271 and solubility in the oil. As evident, the pressure-temperature (P-T) path at initial conditions, as indicated by
 272 the blue line, shifts from the asphaltene stable zone towards the asphaltene unstable zone. At the same time,
 273 the blue line shifts towards the two-phase region. Therefore, according to this study, it is understandable that the
 274 well can hypothetically experience asphaltene precipitation. Moreover, the study proceeds with the simulations

275 for calculating the asphaltene deposition rate and with measuring the quantity of asphaltene precipitation
276 accumulated in the well. A graph of asphaltene precipitation as a function of depth is plotted for different
277 temperatures. It is expected that more asphaltene precipitation will be evident in the upper part of the well.
278 This is because of the fact that temperature changes drastically in the wellbore, and the temperature of the
279 wellbore is lower in the upper section.

280 The magnitude of asphaltene deposition and the rate of deposition in the wellbore can be obtained through
281 conducting simulation runs for the wellbore. The wellbore's cross-sectional area is considerably changed by the
282 asphaltene deposition within the wellbore, as evident in Figure -5, which displays the profile of the inner radius of
283 the well as a function of time. Evidently, the wellbore's cross-sectional area begins to shrink below 2030 m depth,
284 although a minimum asphaltene thickness is attained at 846 m below the surface. Small dents are observed
285 at the surface of the precipitated asphaltene as a result of the elimination of asphaltene by shear forces. The
286 remnant profiles of asphaltene flocculated in the wellbore are shown in Figure -6. Indeed, the concentration of
287 asphaltene attains a maximum value at 846 m depth, and this behavior substantiates the maximum deposition
288 at that instant. Parameters such as pressure, temperature, and velocity profiles in the wellbore can subsequently
289 change due to the deposition of asphaltene particles. For that reason, it also impacts the volume of fluid
290 influx coming from the reservoir. It is important to note that the bottom-hole is pressurized by asphaltene
291 deposition because of blockage of the wellbore. This pressurization is also contributed to by the rise of frictional
292 forces existing between the surfaces of accumulated asphaltene and the flowing fluid. As a result, asphaltene
293 deposition minimizes the influx from the reservoir through the wellbore.

294 Variations in the fluid temperature inconsistently increase the asphaltene precipitation while reducing the
295 probability of asphaltene sticking on the surface of the well. The variation of pressure at bottom-hole as a
296 function of time is shown in Figure -7.

297 16 Effect of CO₂ on asphaltene deposition

298 This section shows the simulation of the effect of CO₂ on asphaltene precipitation and deposition in the wellbore
299 in general. Additionally, the simulation process targets capturing the condition where CO₂ is extracted in the
300 production well and is combined with the crude oil. In a previous study, Vargas (2009) demonstrated that the
301 presence of light components or impurities in crude oil significantly alters the phase behavior of oil. The author
302 has also claimed that asphaltene loses stability when natural gas or CO₂ is injected with the oil. In Figure
303 ??9, it is clear that the results for the effect of CO₂ on the P-T phase are in accordance with Vargas's claims.
304 Additionally, the input onset pressures as shown in Figure ??9 (c) follow the same trend as the composition of
305 oil after mixing with CO₂ in Table 4. Therefore, more asphaltene accumulated at the bottom of the well when
306 more CO₂ was in the production well.

307 This simulation reveals that CO₂ can indirectly alter the pressure and temperature profiles through varying
308 the velocity fields within the wellbore. As a final point, this section considers the propagation of asphaltene
309 deposition on the surface of the wellbore as illustrated in Figure -12. The presence of CO₂ can cause plugging
310 of the wellbore to occur at a faster rate than if CO₂ is absent, and its presence also moves the maximum plugged
311 cross-section toward the bottom of the well during the deposition process.

312 V.

313 17 Conclusion

314 The asphaltene prediction model was developed based on the finite difference method. The deposition problems
315 in wells with proven records were simulated using the developed numerical model. It was observed from the
316 results that the deposited layer of asphaltene has more thickness at the upper part of the well due to the
317 low temperature and pressure area, favoring the instability of the dissolved asphaltene. It is noted that the
318 maximum asphaltene precipitation takes place near the bubble point pressure. The effects of velocity changes,
319 pipe diameter, and pressure variations were investigated in this paper. It is found that a decrease in velocity
320 decreases the heat exchange rates of the wellbore fluid and surroundings. Blockage in the wellbore increases the
321 bottom-hole pressure with time. Additionally, the effect of CO₂ injection for enhanced oil recovery was studied,
322 and it was found that asphaltene becomes more unstable in the presence of CO₂.

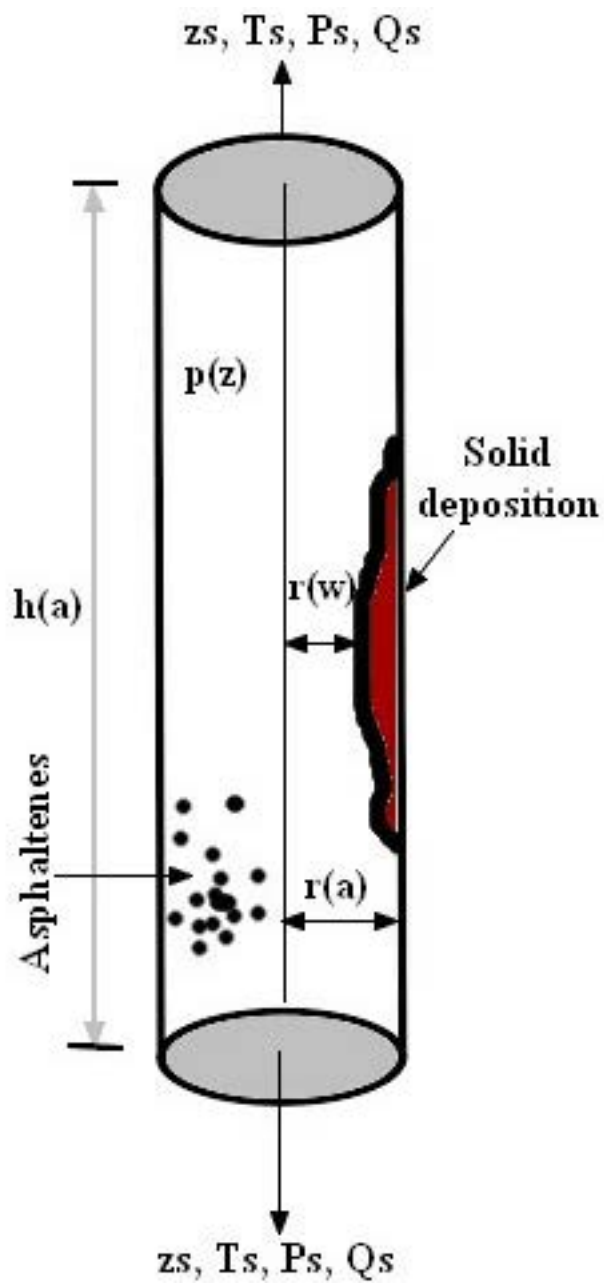
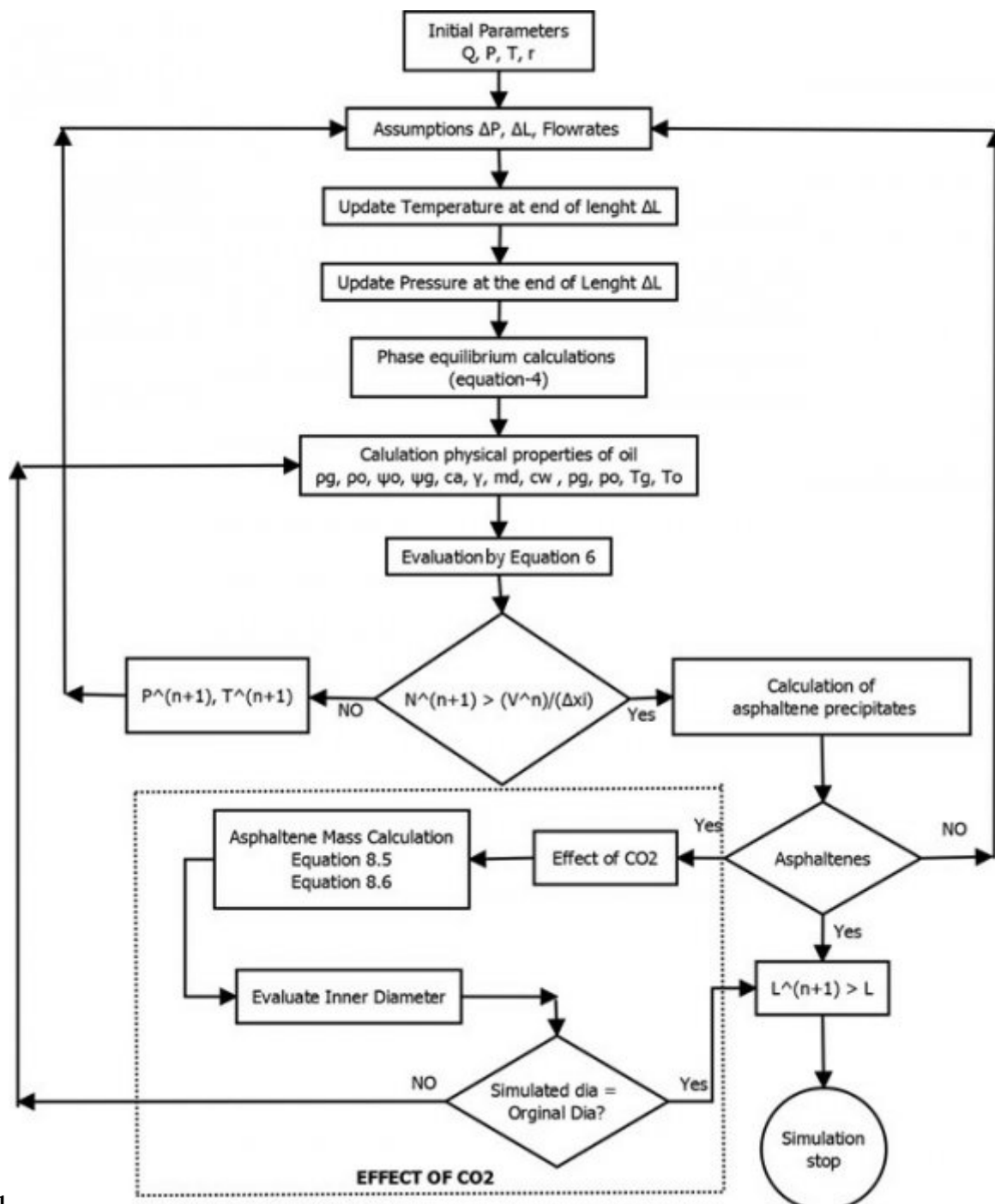
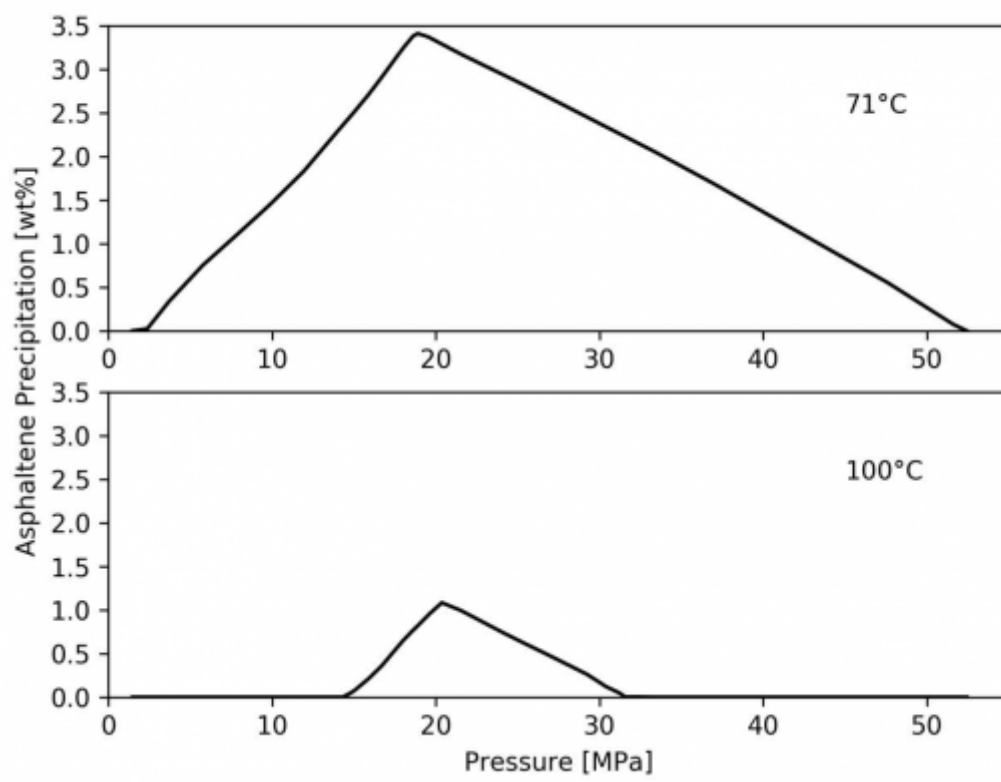


Figure 1:



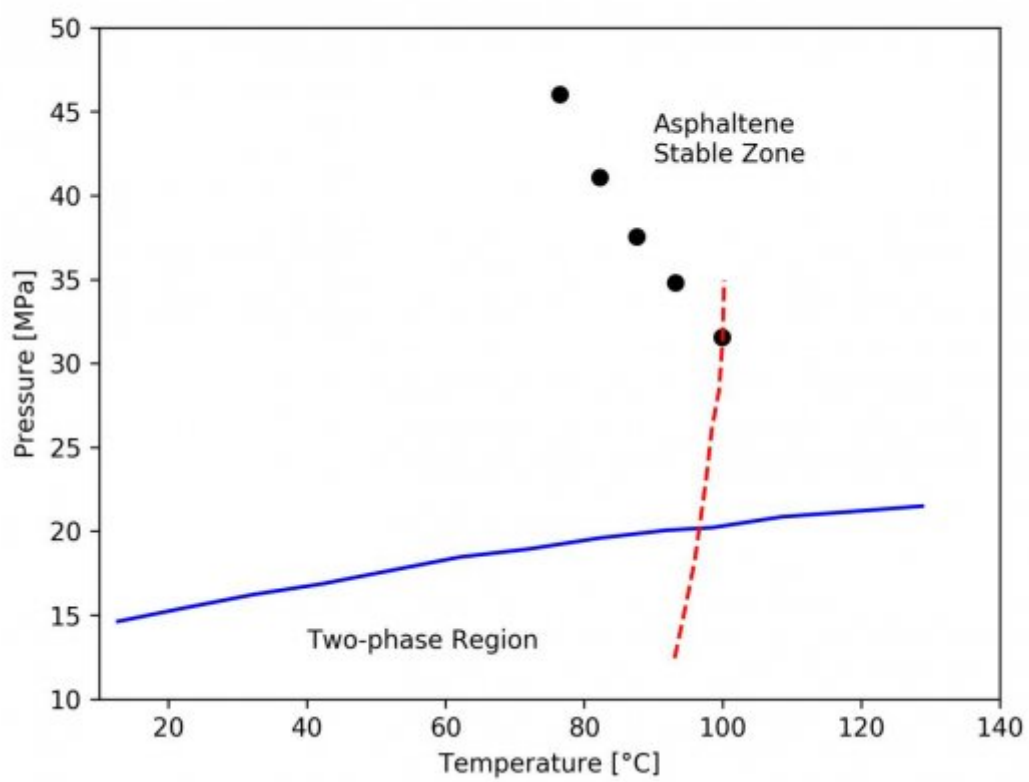
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Figure 2: Figure 1 :



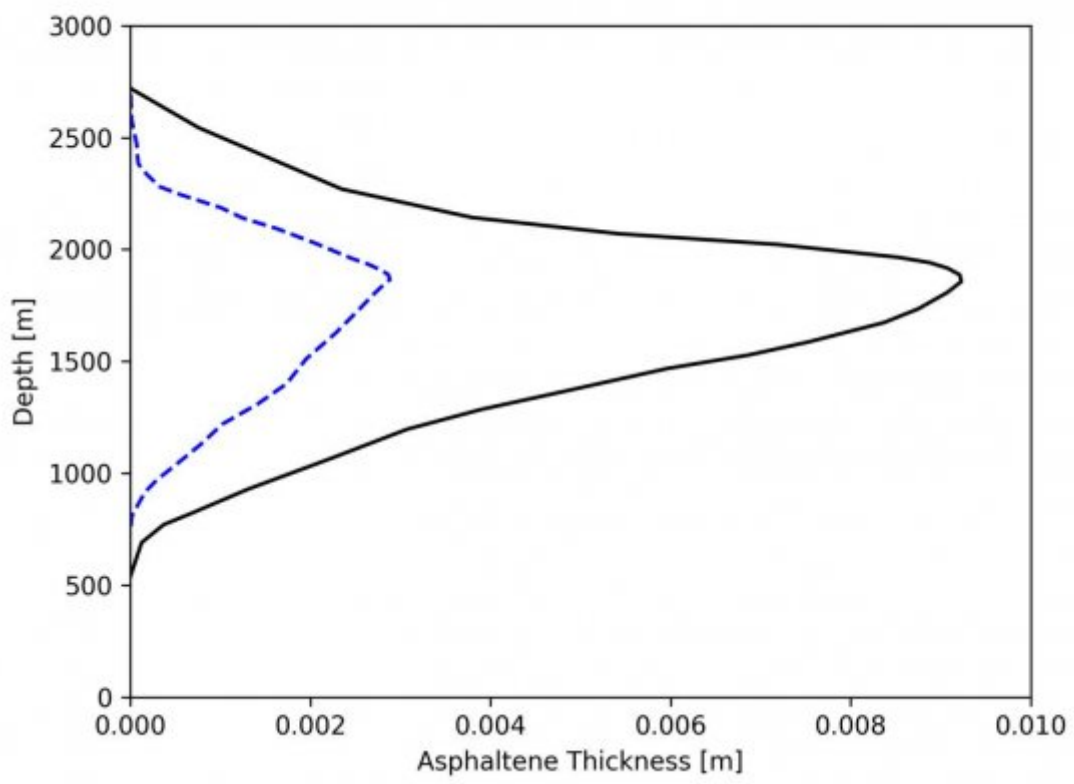
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Figure 3: Figure- 2



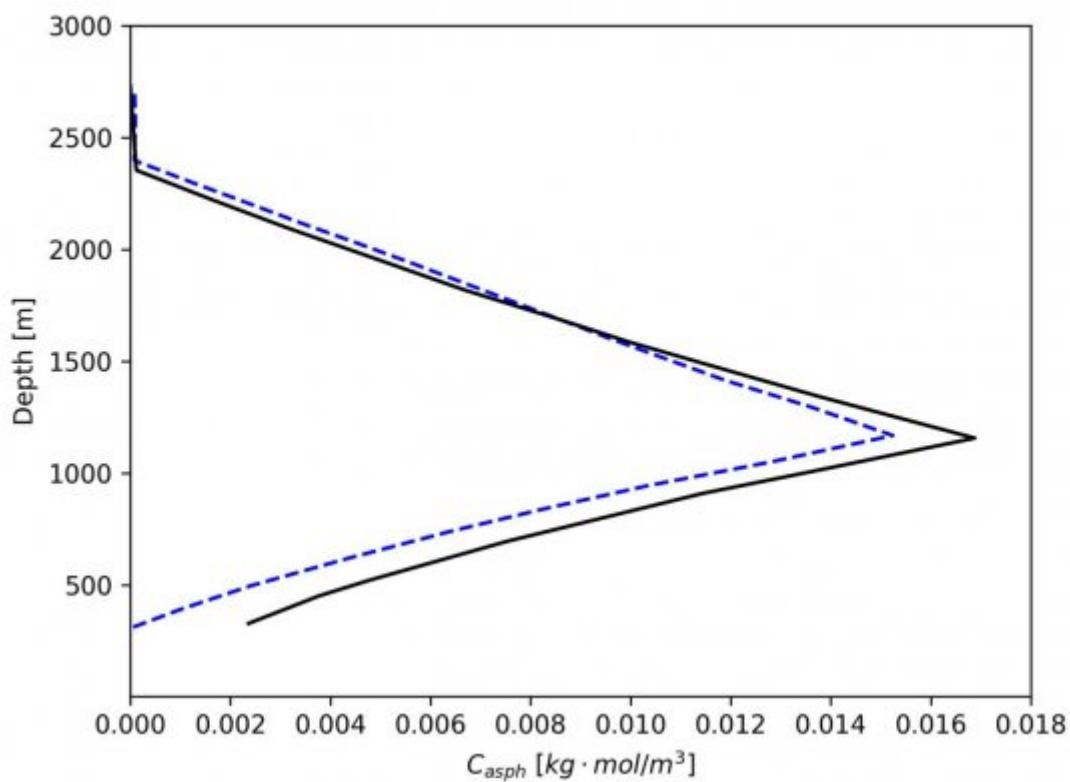
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Figure 4: Figure 2 :



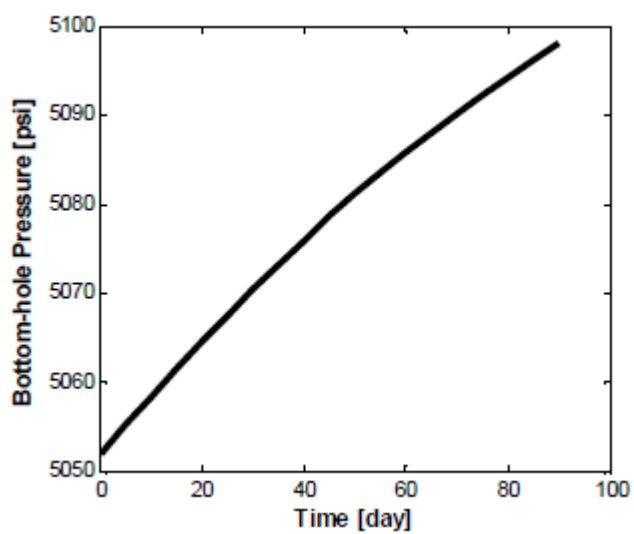
3

Figure 5: Figure 3 :



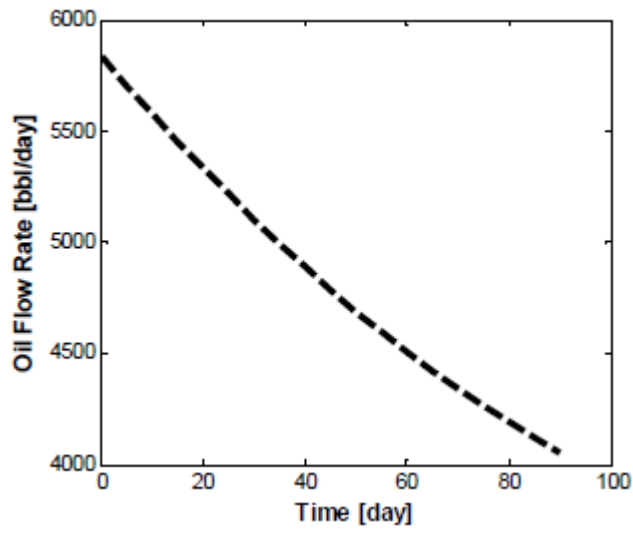
4

Figure 6: Figure 4 :



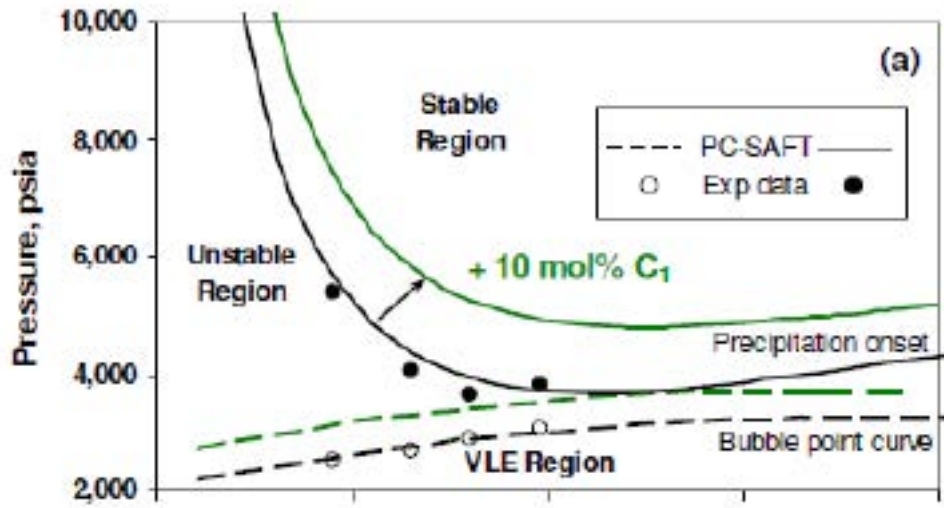
5

Figure 7: Figure- 5



5

Figure 8: Figure 5 :



6

Figure 9: Figure 6 :

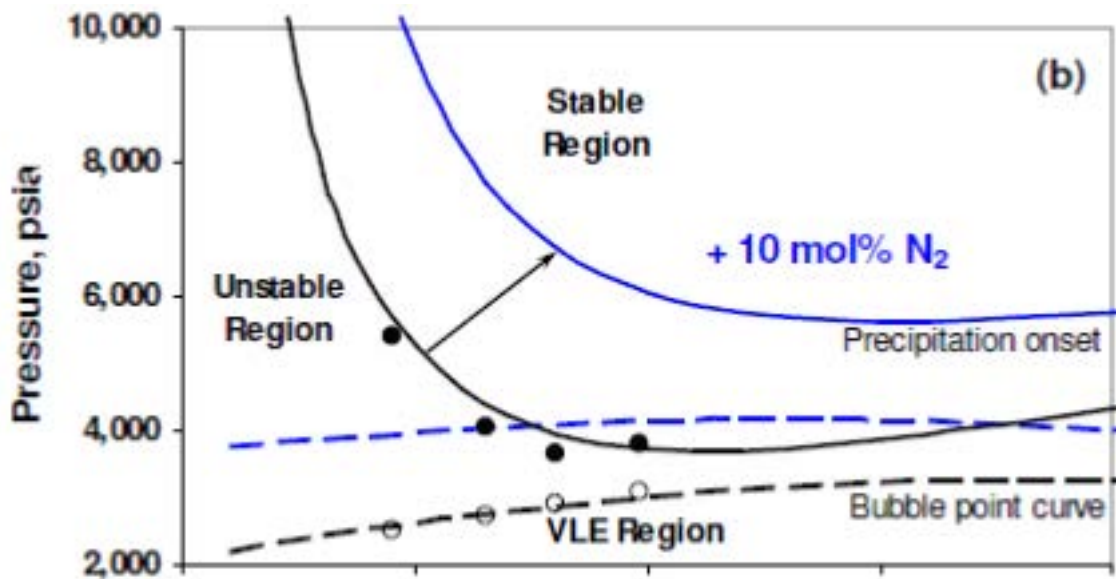


Figure 10: Figure 7 :

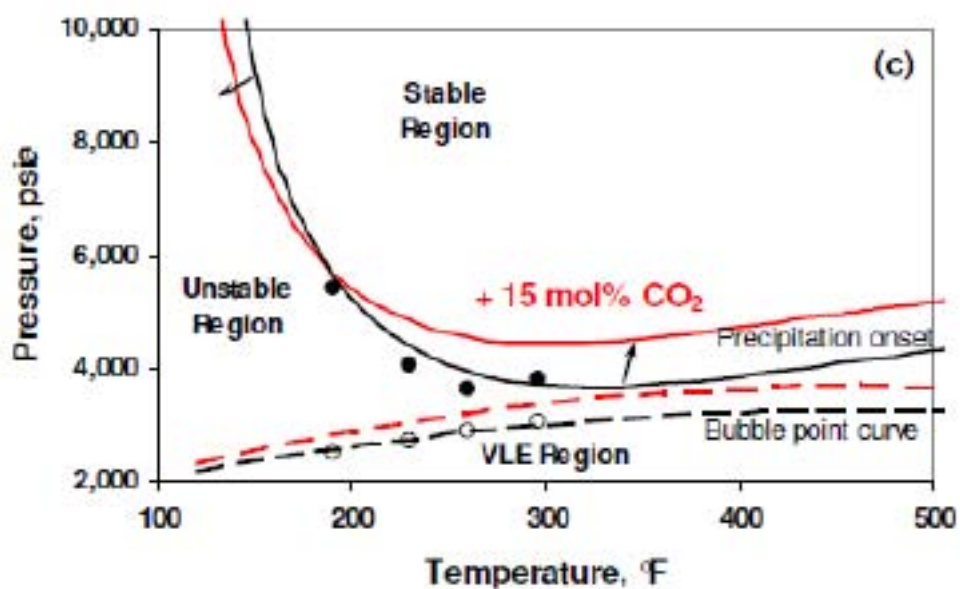
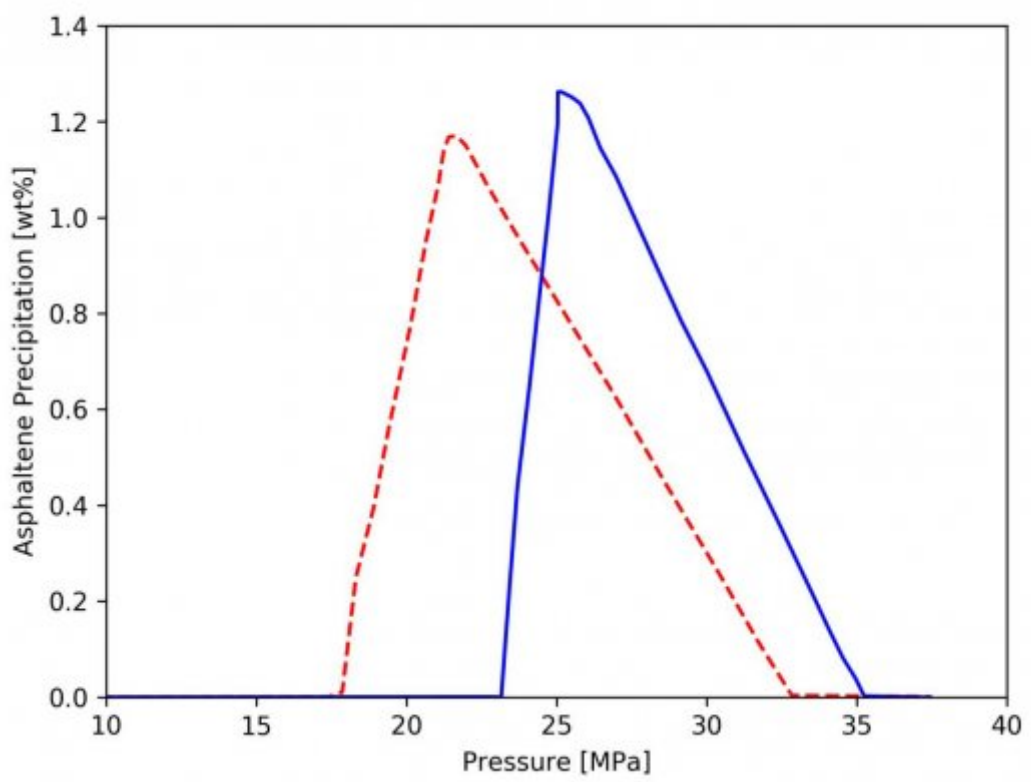
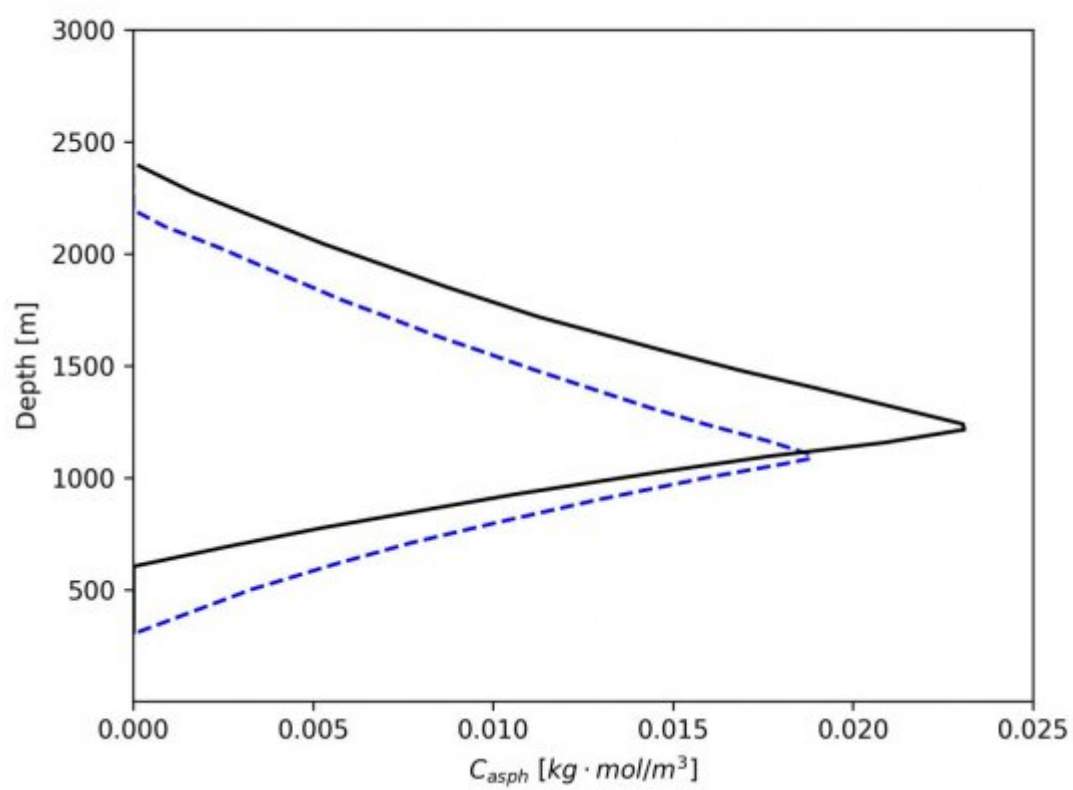


Figure 11: Figure 8 :



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Figure 12: Figure 9 :Figure 10 :Figure 11 :



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Figure 13: Figure 12 :

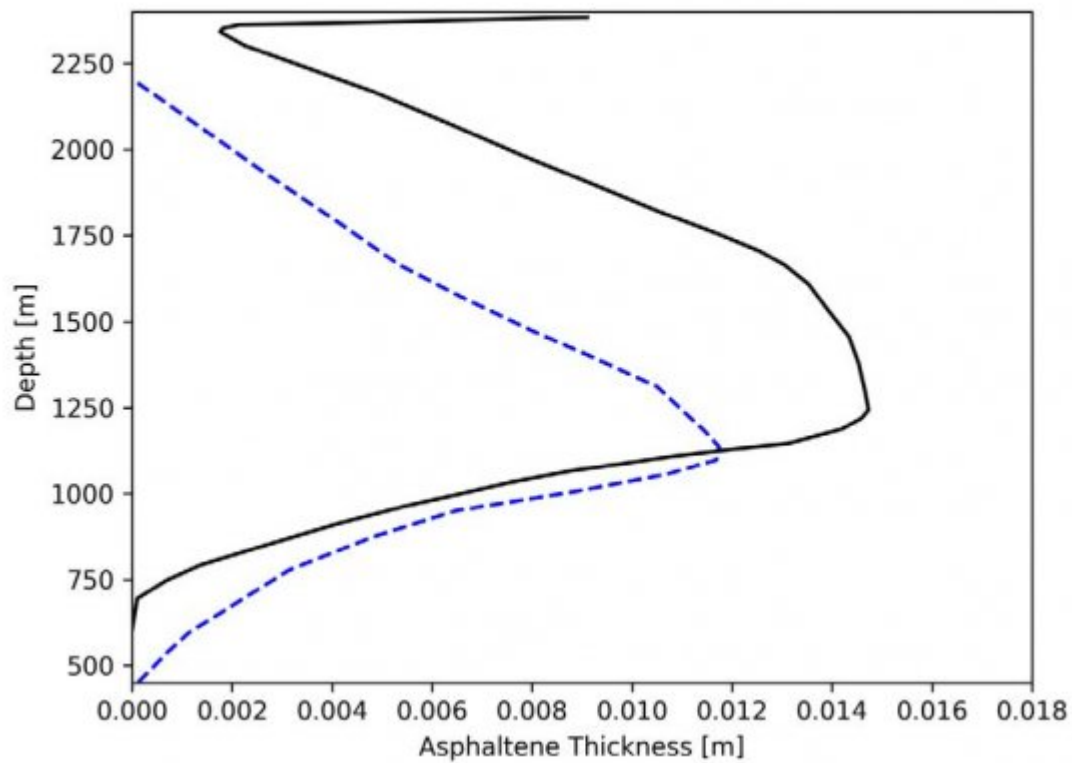


Figure 14:

1

| | | | |
|---------------------------------|------------------------------|------------------------|--------------------------------|
| Well Data | | Reservoir & Fluid Data | |
| Well Height | 2400 m | Net pay zone | 60 m |
| Max. grid size | 15.2 m | Reservoir pressure | 90 MPa -922 Kg/cm ² |
| Top ambient temperature | 15.6 °C | Reservoir temperature | 320°F - 160°C |
| Bottom ambient temperature | 100 °C | | |
| Total heat transfer coefficient | 20.4kJ/m ² .hr.°C | | |
| Tubing ID | 0.070 m | | |
| Wellhead pressure | 12.4 MPa | | |
| Oil productivity index | 2.7m ³ /MPa.m.day | | |

Figure 15: Table 1 :

17 CONCLUSION

2

| Component | Pc (MPa) | Tc (R) | VC (m ³ /kg.mol) | Mw (kg/kg.mol) | Acentric factor | Parachor | Volume shift | Primary composition |
|------------|----------|---------|-----------------------------|----------------|-----------------|----------|--------------|---------------------|
| CO 2 | 7.3780 | 547.56 | 0.09408 | 44.01 | 0.225 | 168.17 | 0 | 0.0246 |
| Cl-CO 2 | 4.6092 | 360.61 | 0.10258 | 17.417 | 0.015127 | 92.19 | 0 | 0.4041 |
| C 3 -C 5 | 3.9517 | 732.89 | 0.23784 | 53.516 | 0.1793113 | 195.33 | 0 | 0.0755 |
| C 6 -C 19 | 2.0092 | 1135.31 | 0.85649 | 164.423 | 0.655007 | 512.21 | 0 | 0.2719 |
| C 20 -C 30 | 1.2094 | 1419.29 | 1.81247 | 340.927 | 1.064023 | 1016.51 | 0 | 0.1064 |
| C 31+ | 0.9871 | 1682.93 | 3.53022 | 665.624 | 1.371778 | 1944.21 | 0 | 0.0774 |
| Asphaltene | 0.9871 | 1682.93 | 3.53022 | 665.6224 | 1.371778 | 1944.21 | 0 | 0.0401 |

Figure 16: Table 2 :

3

| Onset Temperature (°F) -(°C) | 0% CO 2 | 5% CO 2 | 10% CO 2 | 15% CO 2 |
|------------------------------|---------|---------|----------|-----------|
| 100 -37.7778°C | 4600 | | 4770 | 4930 5100 |
| 93 -33.8889°C | 5045 | | 5165 | 5285 5400 |
| 88 -31.1111°C | 5450 | | 5545 | 5640 5735 |
| 82 -27.7778°C | 5960 | | 6000 | 6045 6085 |
| 77 -25°C | 6660 | | 6625 | 6590 6560 |
| 71 -21.6667°C | 7580 | | 7445 | 7310 7170 |
| 66 -18.8889°C | 8650 | | 8430 | 8210 7995 |
| 63 -17.2222°C | 9545 | | 9175 | 8810 8440 |

Figure 17: Table 3 :

4

| Component | 0% CO 2 | 5% CO 2 | 10% CO 2 | 15% CO 2 |
|-------------|---------|----------|----------|----------|
| CO 2 | 0.0246 | 0.07337 | 0.12214 | 0.17091 |
| Cl-C2 | 0.4041 | 0.383895 | 0.36369 | 0.343485 |
| C3-C5 | 0.0755 | 0.071725 | 0.06795 | 0.064175 |
| C6-C19 | 0.2719 | 0.258305 | 0.24471 | 0.231115 |
| C20-C30 | 0.1064 | 0.10108 | 0.09576 | 0.09044 |
| C31+ | 0.0774 | 0.07353 | 0.06966 | 0.06579 |
| Asphaltenes | 0.0401 | 0.038095 | 0.03609 | 0.034085 |

Figure 18: Table 4 :

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