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Effect of Liquefied Petroleum Gas (LPG) on Heavy Oil Recovery Process

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Unconventional heavy oils are high viscosity and low API density which hinders process recovery from the wellbore. The injection of liquefied petroleum gas (LPG) could be an attractive alternative to improve process recovery. However, LPG dosing must be controlled in order to avoid asphaltenes precipitation. This study aimed to evaluate the feasibility of LPG injection to improve recovery of unconventional heavy oils. The study was based on the computer aided engineering using the software CMG (winprop). The physicochemical properties and composition of heavy oil and LPG were adapted from literature. Both fluids came from a Colombian oil field which had wells with average depth of 7900 ft and porosity of 17 %. The result showed that viscosity values decreased as increase in saturation pressure and temperature. It was convenient to keep the pressure under to 850 Kpa during process recovery in order to control asphaltenes precipitation. The minimum asphaltenes precipitation of 4.8 % (w/w) was obtained from heavy oil to GLP ratio of 0.64. The used of LPG showed as an attractive solvent to improve the process recovery for heavy oils. GLP injection throughout the well could be easily implemented since it is produced in situ during oil recovery.

1. Introduction

The economic development and the dramatic population growth have involved a continuous increase in world energy demand. This fact has directly impacted on the availability of petroleum resources, especially conventional oil resources which have been widely exploited owing to its high market value and technically well-established methods of production (Santos et al., 2016). Currently, conventional oil reserves are in constant depletion leading the future of petroleum industry up to unconventional oils exploitation. As fossil fuel will remain to be the main energy source for the coming decades, there is an urgent need to exploit alternative fossil resources (Bayat et al., 2015).

Unconventional oils comprise heavy oil, extra heavy oil and bitumens which are approximately 70 % of total worldwide oil reserves (Bayat et al., 2015). Compared to the production of conventional oils, heavy oils exploitation is more problematic due to its high viscosity and Carbon/Hydrogen (C/H) ratios giving rheological distinctiveness of immobility. The key mechanism for effective recovery of heavy oils has been identified to be the viscosity reduction which in turn improves oil mobility inside the wellbore. Several production techniques beyond conventional methods (e.i primary and secondary) have been developed for the economic heavy oil recovery. Among these methods, thermal injection is recognized as an effective one with high recovery factors up to 70 % of the original oil in place. Typical thermal recovery includes steam-assisted gravity drainage, cyclic steam stimulation and in-situ combustion. However, these technically successful methods are still challenged both economically and environmentally because of high cost of heat supply along with excessive carbon dioxide (CO_2) emission and costly post-treatment and maintenance (Guo et al., 2016).

A tertiary method corresponds to the Enhanced oil recovery (EOR) which implies injection of solvents into the wellbore in order to modify crude rheological properties. The EOR method has gained attention for the effective increase in sweep efficiency and is already applied worldwide in many heavy oil fields (Santos et al., 2016). Light hydrocarbons such as naphtha, liquefied petroleum gas, heptane and CO_2 have been used as solvents for the EOR methods (Guo et al., 2016). Light hydrocarbons are high miscible to heavy oil. They reduce the interfacial tension easing the further sweeping of the crude outside the wellbore (Al-Rujaibi et al.,

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2016). However, the amount of light hydrocarbon injected must be regulated in order to avoid asphaltene depositions into the wellbore. Asphaltene depositions cause serious problems such as clogging the porous formations, porosity and permeability reduction, changes in wettability and pressure drops in the upstream process (Yang et al., 2016). Asphaltenes can precipitate mainly as a result of changes in oil composition after heavy oil to light hydrocarbon mixing (Cho et al., 2016). Aromatics, resins, deasphalted oil and surfactants have been used as solvent to retard asphaltene depositions. However, most applicable inhibitors such as toluene, xylene, benzene and chlorate solvents are flammable, carcinogenic, dangerous for handling and harmful for the environment. In addition, many of those techniques may cause pauses in the production due to dependences on its availability (Gou et al., 2016). Then, as much as possible, it is preferable to control asphaltenes precipitation without consumption of any additional solvent to visbreaker.

Asphaltene precipitation is also influenced by the temperature and pressure which vary throughout the well (Cho et al., 2016). High temperature increases the onset point for asphaltenes precipitation as well as decrease the precipitation yield (Yang et al., 2016). The relationship between pressure and temperature is documented at envelope showed at figure 1, where two curves defined the region exhibiting asphaltene precipitation: upper boundary, above which asphaltene does not precipitate, and lower boundary, below which asphaltene does not precipitate (Gonzales et al., 2016). Nevertheless, asphaltenes precipitation could be avoided controlling the temperature and pressure of the wellbore.

In other hands, the Liquefied Petroleum gas (LPG) seems to be profitable for the EOR compared to other light hydrocarbons. The LPG is mainly composed by 40 % C_3H_8 and 60 % C_4H_{10}, those are hydrocarbons produced in situ after the initial drilling of wells during primary oil recovery. Moreover, LPG has commercial prices 40 % - 60 % lower than other light hydrocarbons. LPG is easy to transport and manage that reduce operative ricks (Raslavičius et al., 2016). Under a miscible gas injection scheme, injection of gas swells the oil, reduces the oil density and viscosity, and hence mobilizes the residual oil that is scattered in the reservoir (Bayat et al., 2015). Moreover, the understanding and modeling of the LPG effect on heavy oil rheological properties is the key for properly designing and optimizing development programs for reservoirs with high concentration of asphaltene. Reservoir simulation is an important tool for predicting performance of asphaltenic reservoirs. The simulation outputs the optimum mixtures ratios of oil/solvent visbreaker and forecasts trouble shooting saving money on experimental assays. This study aimed to evaluate the effect of petroleum liquefied gas on rheological properties of heavy oil using reservoir simulation.

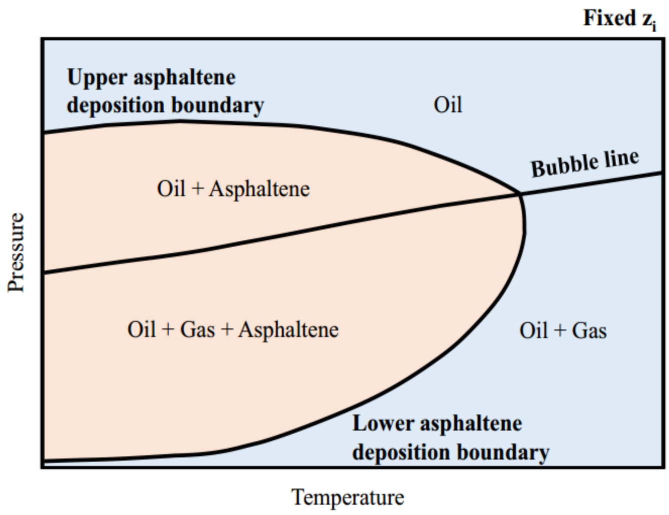

Figure 1: Typical P-T asphaltene precipitation envelope where precipitation occurs only within the region defined between the ADE upper boundary and the ADE lower boundary (Gonzales et al., 2016).

2. Methodology

2.1 Description of crude oil

The elemental composition of crude oil studied was taken and adapted from Cortes et al. (2016). Table 1 shows the crude fractions in terms of their weight and molar composition. According to Table 1, the crude oil corresponded to extra heavy oil composed mainly of heavy fractions from C12 through C46.

Table 1: Molecular characterization of crude oil taken from J.E Cortes, (2016)

Components	Weight fraction	Mole fraction	Components	Weight fraction	Mole fraction
C12	0.009	0.023	C30	0.015	0.016
C13	0.011	0.028	C31	0.019	0.021
C14	0.013	0.030	C32	0.018	0.019
C15	0.017	0.037	C33	0.010	0.011
C16	0.018	0.034	C34	0.010	0.010
C17	0.020	0.037	C35	0.015	0.014
C18	0.021	0.036	C36	0.014	0.013
C19	0.021	0.035	C37	0.009	0.008
C20	0.019	0.029	C38	0.008	0.008
C21	0.023	0.034	C39	0.013	0.012
C22	0.015	0.022	C40	0.012	0.011
C23	0.022	0.031	C41	0.006	0.005
C24	0.021	0.028	C42	0.006	0.005
C25	0.017	0.021	C43	0.011	0.009
C26	0.016	0.019	C44	0.008	0.006
C27	0.018	0.022	C45	0.008	0.006
C28	0.019	0.022	C46+	0.502	0.319
C29	0.016	0.018			

2.2 Description of liquefied petroleum gas (LPG)

The LPG composition was taken from Guerrero (2016). Table 2 shows the composition of the LPG which mostly corresponds to low molecular weight compound. The light components of LPG would decrease the heavy fractions of crude oil by improving the physicochemical properties and the recovery conditions.

Table 2: Molecular composition of liquefied petroleum gas (LPG)

Components	Ethane	Propane	Propylene	I-Butane	N-Butane
Fraction	0.171	0.569	0.002	0.183	0.075

2.3 Thermodynamic description of the wellbore

The thermodynamic behavior of the crude and crude /solvent mixtures was described by development of PVT envelopes using Winprop package of Computer modeling group (CMG) software. The software is equipped with a data base property and equations of state to describe the vapor and liquid phase of the oils. The Lee-kesler model (Eq 1) described the thermodynamic behavior for the vapor phase through estimation of the saturated vapor pressure at a given temperature (T) which the critical pressure Pc, the critical temperature Tc and the acentric factor (ω) are known in data base of the CMG.

$$Z = 1 + B^0 \frac{Pr}{Tr} + \omega B^1 \frac{Pr}{Tr} \quad (1)$$

The Robinson models described the thermodynamic behavior for the liquid phase by estimation of critical conditions and saturation conditions for the crude oil and solvent/crude mixtures inside the well. The Peng-Robison model corresponded to equation 2 where the pressure (p) is related to the temperature (T), ideal gas constant (R) and molar volume (V). It has two pure component parameters *a* and *b*. The parameter *a* is a measure of the attractive forces between the molecules, and *b* is related to the size of the molecules. Both parameters were calculated by the Winprop.

$$p = \frac{RT}{V-b} - \frac{a\alpha}{V(V-b)+b(V-b)} \quad (2)$$

The PVT envelopes were calculated to the conditions described in Table 3, which correspond to the wellbore top and bottom conditions.

Table 3: Thermodynamic conditions of the wellbore

Property	Surface	Wellbore
Temperature (ºC)	23.9	15
Pressure (Kpa)	101.3	2,450

3. Results

3.1 Oil viscosity profile by changes on pressure throughout the wellbore

Figure 2 showed the oil viscosity profile by changes on the well pressure from the bottom to the top. In the figure 2 is clear that cinematic viscosity increased as well as pressure increased inside the wellbore. The highest cinematic viscosity of 939 cP was found at wellbore bottom where pressure was 2450 KPa. Meanwhile the lowest cinematic viscosity of 933 cP was found at the top where the pressure was 101,3 KPa. Nevertheless, it is possible to infer that pressure barely varied the cinematic viscosity as the viscosity gap between the top and bottom of the wellbore was 7 cP. Then, the crude kept as extra heavy oil throughout the whole wellbore. This result is consequent with the statements in Mordi et al. (2014) who developed a mathematical model to predict viscosity throughout the wellbore for oils with API gravities ranging from 6.5 to 9.5. The researchers predicted changes in viscosity between 322 cP and 345.8 cP for a pressure profile of 5173.5 Kpa to 32613 Kpa.

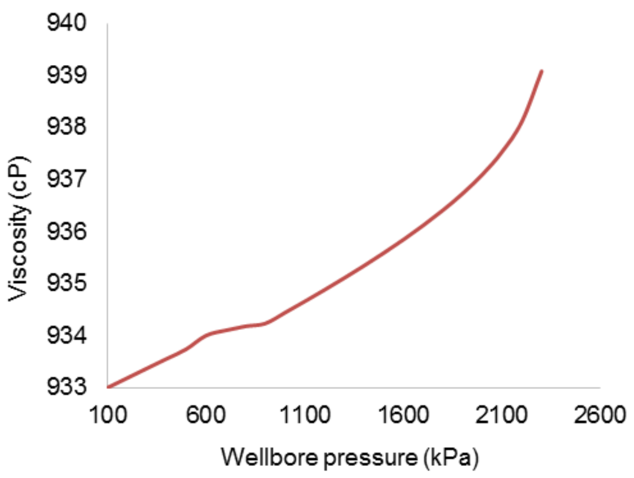

Figure 2: Effect of pressure on cinematic viscosity of the extra heavy oil

3.2 Minimization of asphaltene precipitation

The figiure 3 showed the asphaltene precipitation for difference crude to LPG ratios at top wellbore condicion (see table 3). The asphaltene precipitation was calculated from the top temperature in the wellbore of 23.9ºC. The precipitation of asphaltene presented a parabolic behavior. The miminmun precipition of 9.2% asphaltene was achived for a crude to LPG ratio of O.65 weigth basis. However, the inyection of LPG must be controlled in order to keep the dynamic of the wellbore. The asphatene precipitation increases up to 13% above 0.65 weigth basis and increases up to 14% below 0.65 weigth basis. This behavior can be compared with the result obtained by Moradi et al (2012) who obtain 9.05 % w/w of asphaltene precipitation by injection of methane at a temperature of 324°C. On the other hands, the minimum asphatene precipitation varies with the pressure of the wellbore. Inside the wellbore, the minimum asphatene precipitation increased to 12.5 Kpa for the bottom pressure of 2,450 Kpa. Moradi et al. (2012) also found that asphatene precipitation had a parabolic behaviour for variation in the pressure. Then, the pressure throughout the wellbore must be control to keep the dynamic of the enhanced recovery process.

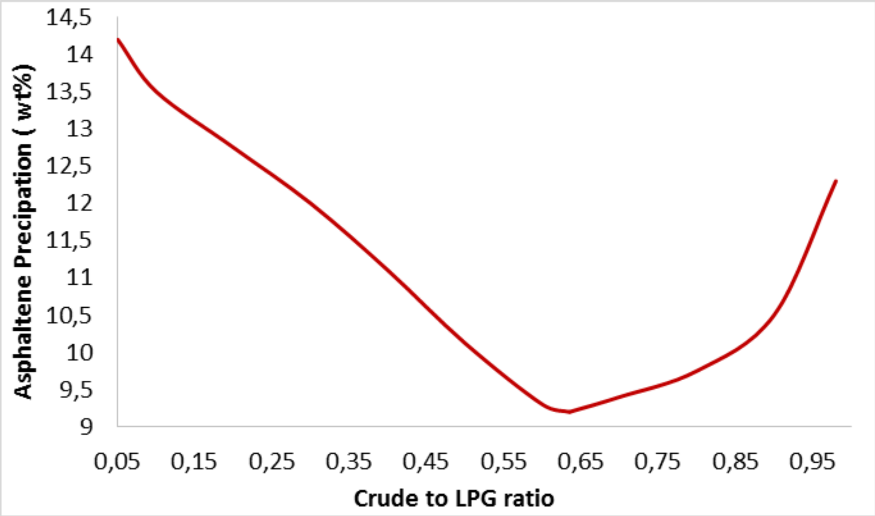

Figure 3: Asphaltene precipitation curve

3.3 Thermodynamic behavior of the crude inside the wellbore.

The phase envelopes shown in Figure 4 consist of a region where fluids occur in a single phase state and a region where they exist as two separate phases. The latter one is enclosed by a bubble point curve and a dew point curve. The bubble point curve marks the PT-conditions where separation of a gas phase from a supercritical liquid phase takes place, while the dew point curve is defined as the PT-area where separation of a liquid phase from a supercritical gas phase occurs. The critical point, located where bubble point and dew point curves meet, characterizes fluid conditions intermediate between those of a liquid and a vapor phase. Nevertheless, the fluid behaves as saturated liquid on the left zone meanwhile the fluid behaves as saturated gas on the right zone right zone. The figure 4a represents the thermodynamic stability of the extra heavy oil. The critical conditions for the extra heavy oil were 2200 Kpa and 750 ºC. The heavy oil behaved mostly as saturated liquid due to thermodynamic conditions throughout the wellbore kept far away from the critical point. On other hands, the figure 4b showed the thermodynamic stability of the optimal mixture of heavy oil to LPG of 0.64 on volume basis. The critical conditions for the optimal mixture were 1650 Kpa and 610 ºC. The injection of LPG into the well decreased the critical conditions for the heavy oil increasing the zone in which liquid and gas coexist together. Then, the optimum mixture of heavy oil to LPG of 0.64 on volume basis will perform thermodynamically into the wellbore as a biphasic liquid-gas mixture.

(a)

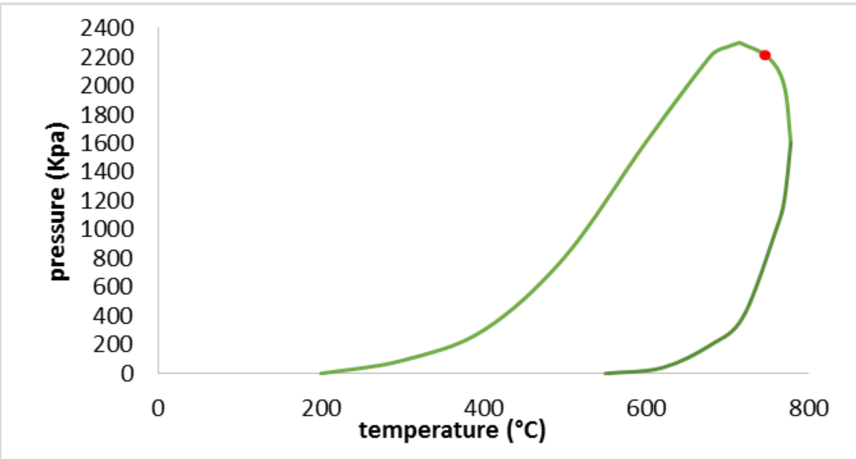

Figure 4a: The phase envelopes for the extra heavy oil (a) and optimal mixture (b)

(b)

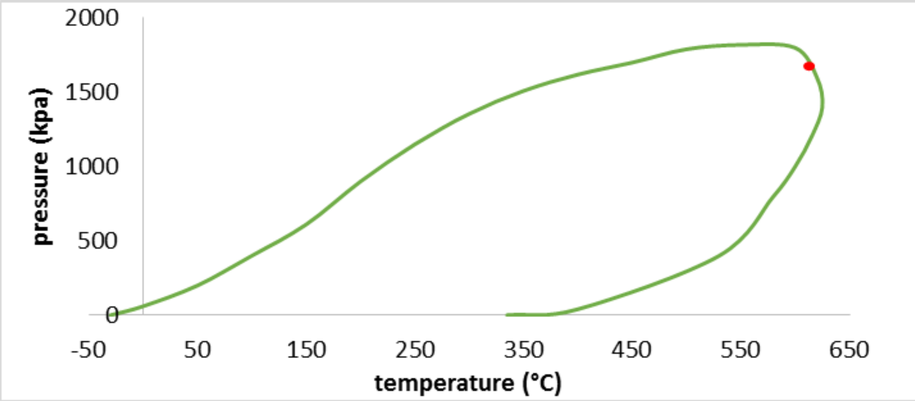

Figure 4b: The phase envelopes for the extra heavy oil (a) and optimal mixture (b)

4. Conclusions

The work analyzed in this document clearly indicates the potential of liquefied petroleum gas as a visbreaker for the enhanced oil recovery of heavy crude. The liquefied petroleum gas can be injected inside the wellbore to create an optimum mixture ratio of 0.64. The optimum ratio allowed a controlled asphaltene precipitation of 9% that can be managed with the pressure of the wellbore. The use of liquefied petroleum gas could improve the economy viability of recovery process.

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