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The Effects of Non-Newtonian Flow on Pressure Losses in Wellbore during Heavy Oil Production

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Abstract
This work evaluates the impact of Non-newtonian flow on pressure gradient during heavy oil production. PROSPER well modeling package was used to built the wellbore model. Fluid model was set up to ensure that the original oil was accurately modeled with Newtonian fluid model, and gradient calculations run at different wellhead pressure, and laboratory data inputted to predict the impact of changing the viscosity model to the Non-Newtonian fluid model and compared with the Newtonian viscosity case. Gradient calculations were carried out at a wellhead pressure of 250psig, 500psig and 1000psig and a liquid rate of 7500 STB/day. The predicted pressure traverses were lower for Non-newtonian model than the Newtonian fluid viscosity model. A pressure of 1705.74psig existed at the bottomhole for the Newtonian viscosity fluid model and 1413.38psi at the bottomhole for the non-Newtonian viscosity model for a wellhead pressure of 250psig. For a wellhead pressure of 500psig, a pressure of 1955.78psig and 1663.43psig existed at the bottomhole for the non-Newtonian viscosity model and Newtonian viscosity fluid model. For 1000psig wellhead pressure, a pressure of 2455.89psig and 2163.65psig for the Newtonian viscosity fluid model and non-Newtonian viscosity model. Increase in the well head pressure results in an increase in bottomhole pressure for both Newtonian and Non-newtonian model with Newtonian model as the highest.

Keywords: Gradient, wellbore, Non-newtonian, model, wellhead, pressure.

I. Introduction

As recoverable reserves of conventional crude oil are decreasing worldwide, heavy oil plays an important role in the energy supply. During heavy oil development, the problem of high-viscosity fluid flowing in the wellbore is apparent. However, high viscosity poses great challenges for the production and transportation of heavy oil. In addition, gas and water are inevitably and concurrently present with the oil in the pipeline flow process; thus, gas-liquid two-phase flow behavior is more complex and difficult to predict (Liu *et al.*, 2020). As oil is produce from wellbore, the fluid properties changes. Mechanistic model develop are based on low viscous oil between (10cp and 110cp) that will not adequately account for heavy oil.

Farsetti *et al.*, (2014) studied high-viscosity gas-liquid two-phase flow in horizontal and inclined pipes through experiments and measured pressure gradient, and bubble frequency in the experiment. By comparing the prediction results of existing low-viscosity models, the existing models showed poor prediction ability for the flow behavior of high-viscosity fluids. Chung *et al.*, (2016) studied the effect of high-viscosity oil (122-560 mPa·s) on oil-gas flow behavior in vertical downward flow, measured the pressure drop and liquid holdup data, and compared the experimental data of gas and water and found that the viscosity has a significant impact on the flow behavior. Al-Ruhaimani *et al.*, (2016) studied high-viscosity oil-gas two-phase flow in a vertical upward pipe and found that the friction pressure gradient of liquid increases with increasing viscosity. In addition, the negative friction pressure drops phenomenon of high-viscosity oil-gas multiphase pipe flow was studied. A number of studies are currently available in the literature on flow pattern and pressure drop, but very few studies tried to understand the effect of some parameters on flow patterns and pressure drop (Angeli and Hewitt, 1998, 2000; Mandal *et al.*, 2007; Sotgia *et al.*, 2008). All of these works have focused on the influence of pipe geometries or materials on either flow patterns or pressure drop.

Previous studies have shown that most multiphase flow models are developed based on the experimental results of low-viscosity fluids, although the flow behavior of high-viscosity fluids is significantly different from that of low-viscosity

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fluids. When these models are used to predict the flow behavior of high-viscosity fluids, they are quite different from the measured data (Al-Safran *et al.*, 2015; Zhang *et al.*, 2012). In addition, research on high-viscosity liquid-liquid two-phase flow has recently begun, but due to the limitations of experimental conditions, the development of this research is relatively slow; therefore, there is no comprehensive model to predict the pressure drop under different flow patterns of high-viscosity liquid. Considering the existing problems, the gas-liquid two-phase flow in the wellbore producing heavy oil production is considered in this research work. The variation of pressure drop in gas-liquid two-phase flow with the change in liquid viscosity is explored.

II. Methodology

2.1 Simulator and Data

PROSPER well modelling software and the following variables as input data were used; Fluid properties data(Solution gas/oil ratio, Gas and oil gravity, and Water salinity), Viscosity model calibration data(Temperature and pressure, Yield stress, Consistency index, Shear thinning index), Deviation survey and geothermal gradient data(Measured depth against true vertical depth, Formation temperature against depth and overall heat transfer coefficient),Downhole equipment data(Casing and tubing setting depth, Internal diameter and wall thickness).

Model configuration option data, Fluid properties data, Fluid properties correlation calibration data, Non-Newtonian viscosity calibration data, Deviation survey and Downhole equipment data are presented in Table 1 to Table 7.

Table 1: Model configuration option data

Property	**Specification**
Fluid type	Oil and Water
Fluid properties calculation method	Black Oil
Separator type	Single-Stage Separator
Well completion type	Cased hole
Flow type	Single branch

Table 2: Fluid properties data

Property	**Value**
Solution GOR	10 SCF/STB
Gas Gravity	0.58
Water salinity	75000 ppm
Oil gravity	12°API
Mole % H_2S	0%
Mole % CO_2	0%
Mole % N_2	0%

Table.3: Fluid properties correlation calibration data

Pressure (psig)	GOR (scf/STB)	Oil FVF (RB/STB)	Viscosity (cP)
170	10	1.025	700

Table 4: Non-Newtonian viscosity calibration data

Temperature (°F)	**Pressure (psi)**	**Yield stress (psi)**	**Consistency index (K)**	**Shear Thinning index (n)**
60	100	0	1	0.9
60	3000	0	1	0.9
120	100	0	0.5	0.95

120	3000	0	0.5	0.95

Table 5: Deviation survey data

Measured Depth (ft)	**True Vertical Depth (ft)**
0	0
1000	1000
2000	2000

Table 6: Downhole equipment data

Type	**Measure Depth (ft)**	**Inside diameter (inch)**	**Roughness (inch)**
Xmas Tree	0	-	-
Tubing	1800	3.4	0.0006
Casing	2000	6.4	0.0006

Table 7: Geothermal gradient data

Measured Depth (ft)	**Temperature (°F)**
0	80
2000	120

2.2 Simulation Approach

Petroleum Experts PROSPER was used to developed the wellbore model. Fluid description, flow type and well completion types, heat transfer calculations were selected and the model configuration presented in Table 1 were enabled. The fluid properties correlations were matched against the laboratory data at 170psig and 120°F.After having a good match on fluid properties and water introduced, an emulsion was formed and the location of the emulsion effect seen in the model was selected from the emulsion occurrence drop down. The well bore configuration was described with the deviation survey shown in Table 4 and the data in Table 5 used for the matching. The geothermal gradient data shown in Table 7 were populated in the temperature input interface and was used to calculate the temperature difference that the fluid experiences as it travels up the well and used in the estimation of heat transfer. An Overall Heat Transfer Coefficient (OHTC) value of 8-Btu/h/ft^2/°F was also entered to account for the heat transfer from the fluid to the surroundings. With the fluid properties and well description entered, the pressure gradient within the well for a given set of conditions was established and was first determined with the fluid treated as a Newtonian fluid data and later with the non-Newtonian data. Gradient calculations were carried out at a wellhead pressure of 250psig, 500psig and 1000psig and a liquid rate of 7500 STB/day. The simulation workflow is shown in Figure 1.

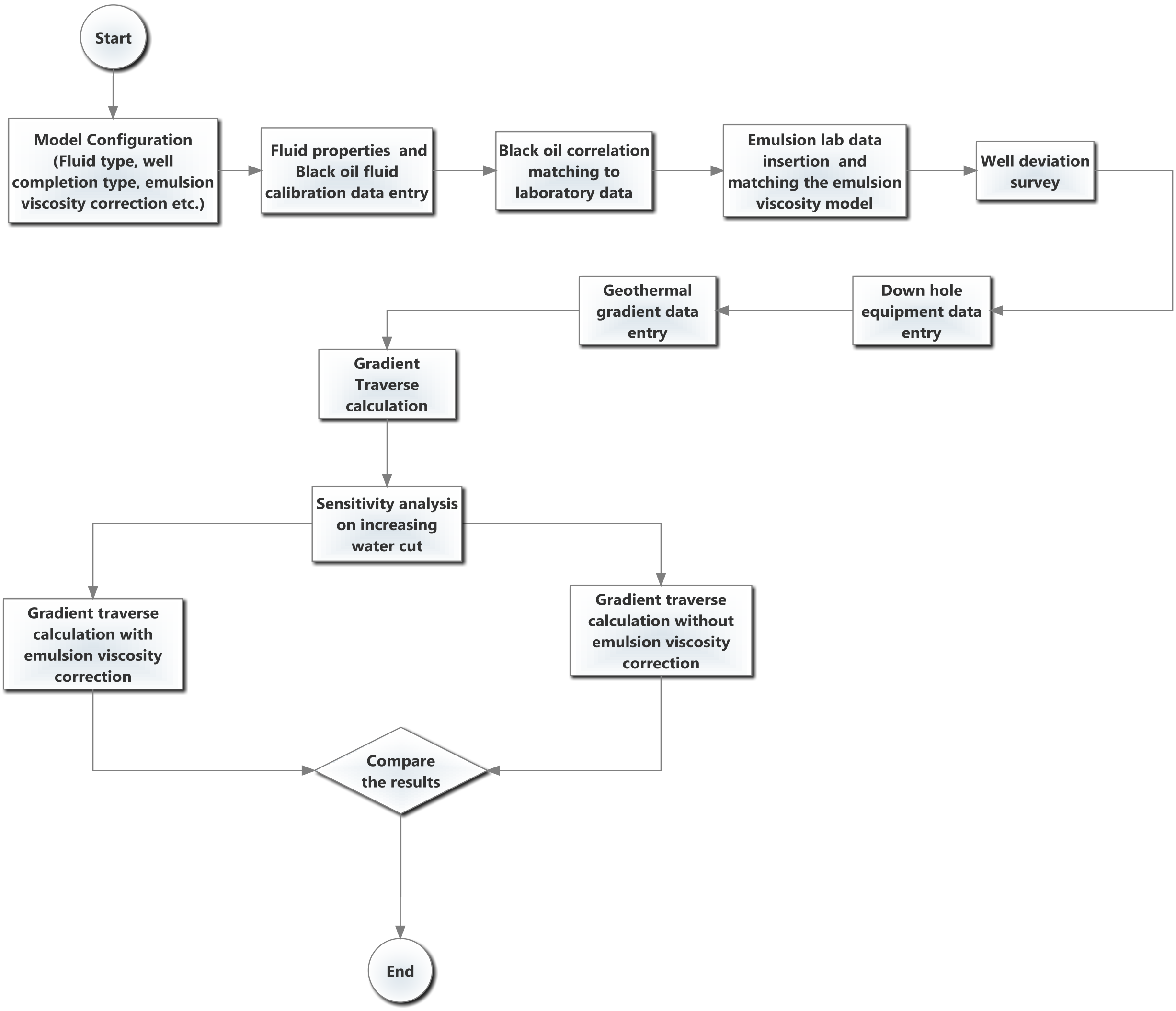

Figure 1: Simulation workflow

III. Results

3.1 Pressure gradient with Newtonian fluid viscosity model

Figure 2 shows the result of the pressure traverses predicted with the Newtonian fluid model along the wellbore for a wellhead pressure of 250psig, 500psig and 1000psig. The results obtained indicated an increase in the pressure traverses as the wellhead pressure increases from 250psig to 500psig and 1000psig. Newtonian fluid viscosity model gave a pressure of 1705.74 psig, 1955.78 psig, and 2455.89 psig respectively at the bottomhole.

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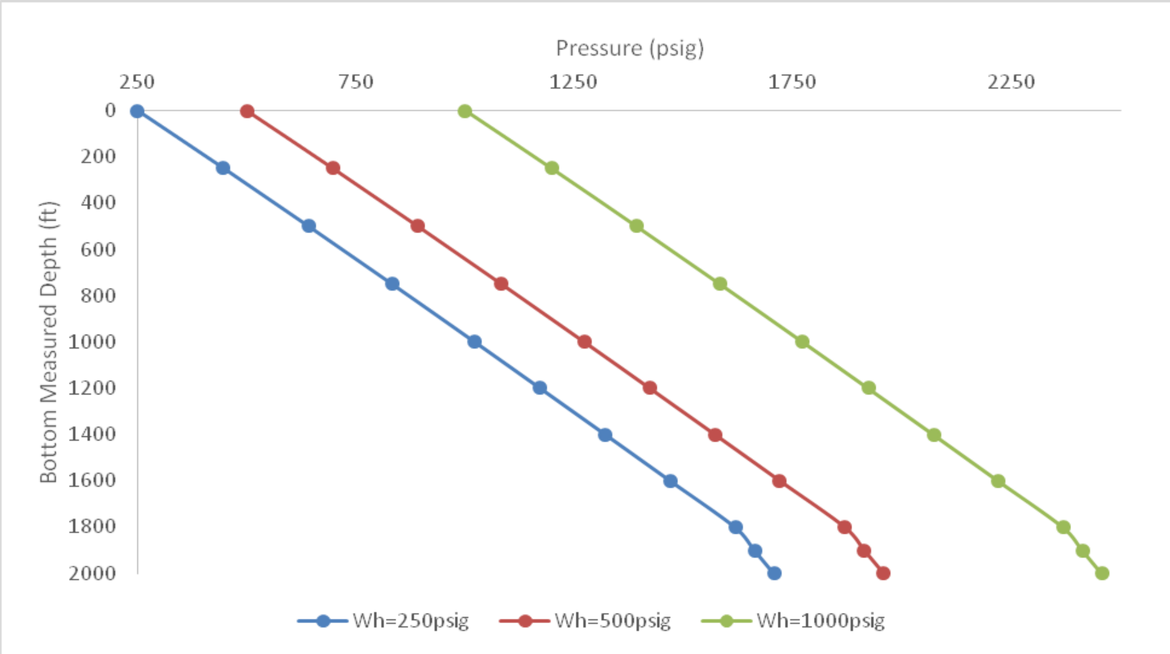

Figure 2: Pressure profile along the wellbore (Newtonian fluid model)

3.2 Pressure gradient with non-Newtonian fluid model

The result of the pressure traverses predicted with the non-Newtonian fluid model along the wellbore for a wellhead pressure of 250psig, 500psig and 1000psig is shown in figure 3. The results obtained indicated an increase in the pressure traverses as the wellhead pressure increases from 250psig to 500psig and 1000psig.Pressure of 1413.38psig, 1663.43psig, and 2163.65psig respectively was obtained at the bottomhole for Non-newtonian fluid viscosity model.

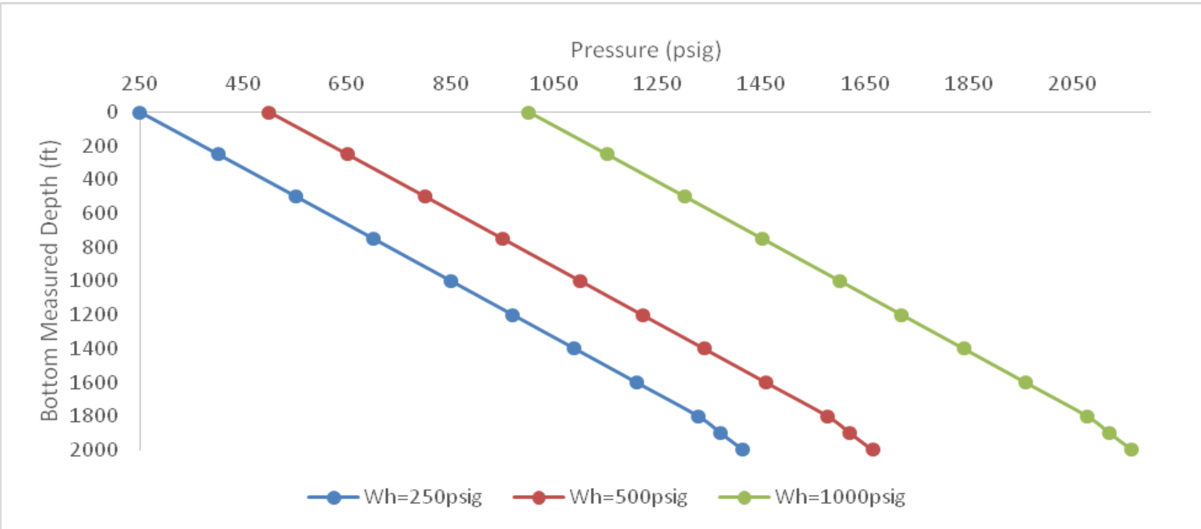

Figure 3: Pressure profile along the wellbore (non-Newtonian fluid model)

3.3. Pressure gradient with Newtonian and non-Newtonian fluid model at 250psig

Figure 4 shows a comparative plot of the pressure gradients predicted with both Newtonian and wellhead pressure of 250psig. Result shows that a pressure of 1705.74psig existed at the bottomhole for the Newtonian viscosity fluid model and 1413.38psig existed at the bottomhole for the non-Newtonian viscosity model for a wellhead pressure of 250psig.

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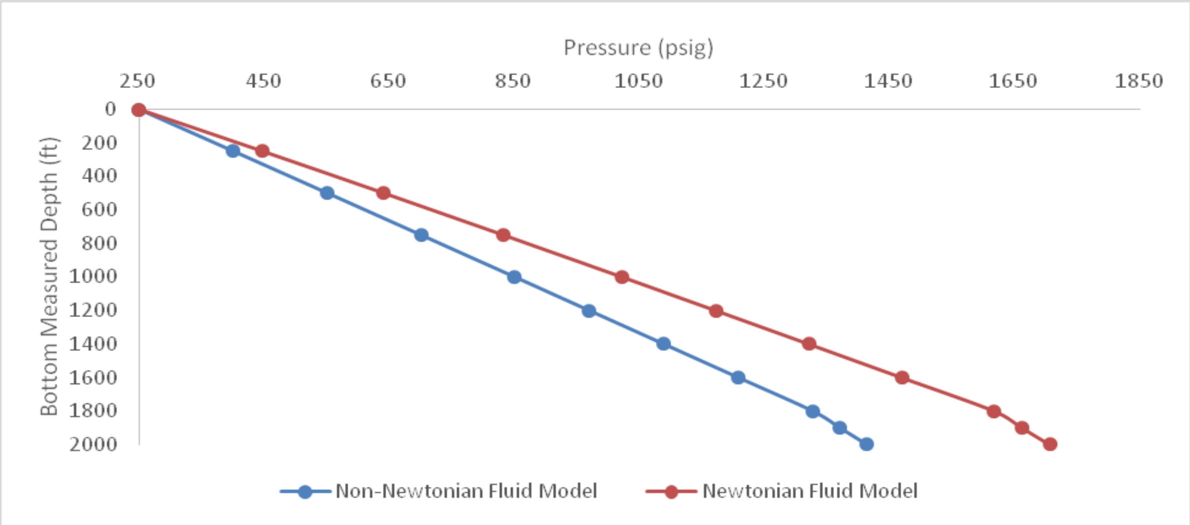

Figure 4: Pressure gradients for both Newtonian and non-Newtonian fluid model at 250psig

3.4 Pressure gradient with Newtonian and non-Newtonian fluid model at 500psig

Figure 5 shows a comparative plot of the pressure gradients predicted with both Newtonian and wellhead pressure of 500psig. Result shows that a pressure of 1955.78psig existed at the bottomhole for the Newtonian viscosity fluid model and 1663.43psig existed at the bottomhole for the non-Newtonian viscosity model for a wellhead pressure of 500psig.

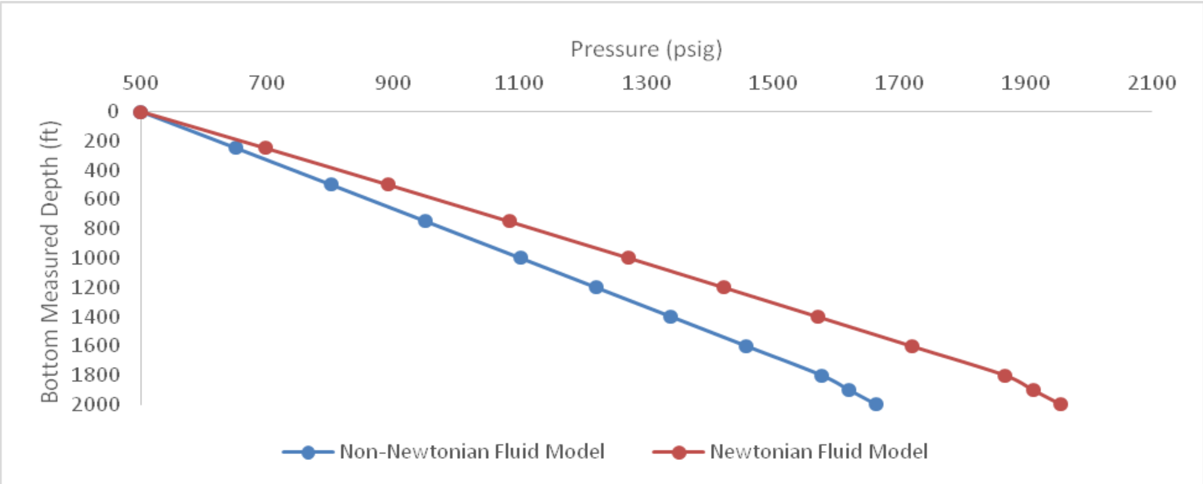

Figure 5: Pressure gradients for both Newtonian and non-Newtonian fluid model at 500psig

3.5 Pressure gradient with Newtonian and non-Newtonian fluid model at 1000psig

The pressure gradients predicted with both Newtonian and Non-newtonian for wellhead pressure of 1000psig is shown in figure 6.Result shows that a pressure of 2455.89psig existed at the bottomhole for the Newtonian viscosity fluid model and 2163.65psig existed at the bottomhole for the non-Newtonian viscosity model for a wellhead pressure of 1000psig.

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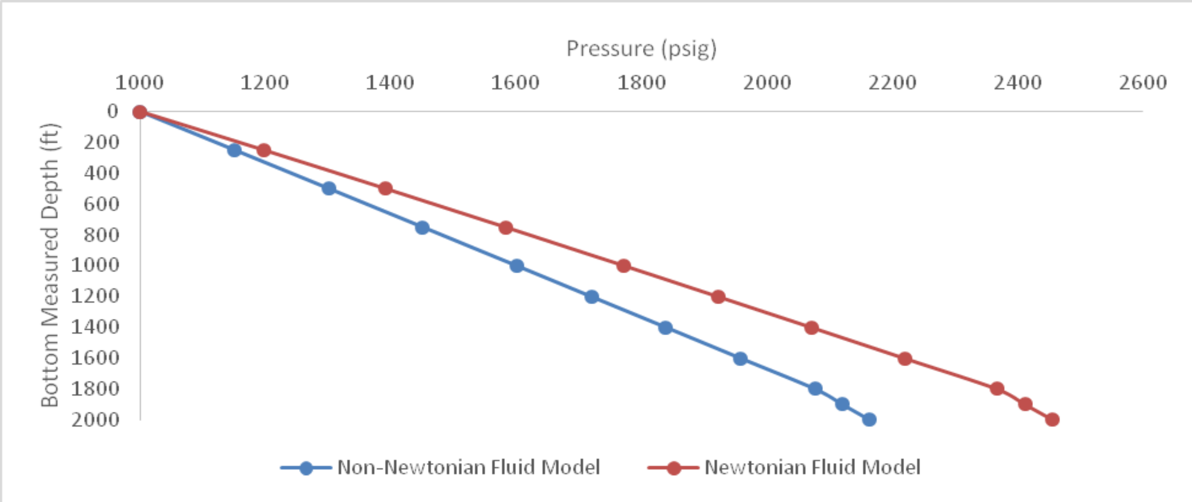

Figure 6: Pressure gradients for both Newtonian and non-Newtonian fluid model at 1000psig

IV. Conclusion

In this work, the effects of non-Newtonian fluid on pressure losses in wellbore during heavy oil production were investigated. A wellbore was built in PROSPER based on fluid properties, and viscosity model. The effect of increasing water on the pressure traverse along the wellbore with and without emulsion viscosity correction were simulated and compared. The non-Newtonian fluid viscosity model has a lower pressure traverses than the Newtonian fluid viscosity model as the pressure increases.

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