Reservoir Simulation Models -Impact on Production Forecasts and Performance of Shale Volatile Oil Reservoirs

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Abstract

Reservoir simulation is an important tool that can be used to simulate as well as predict production from shale reservoirs. The type of reservoir simulation model used, is significant in this process. Black-oil and compositional simulators can be used for reservoir simulation. Blackoil simulations are easier and less time-consuming than compositional simulations. However, how accurate are black-oil simulation results compared to compositional simulation results? Can we afford to jeopardize the accuracy of production forecasts by using easier and less timeconsuming reservoir simulation methods? Can the results be trusted to some extent? Singlephase and two-phase black-oil simulation results as well as compositional simulation results were analyzed and compared in this article.

Index terms— reservoir simulation, black-oil, compositional, production forecasting, volatile oil, unconventional resources â??" shale reservoirs.

1 I. Introduction

hale reservoirs, such as the Eagle Ford and Bakken, have emerged as extremely viable sources of hydrocarbon reserves. They do not produce economic volumes of oil and gas without some Mendeleev University of Chemical Technology, Moscow, Russia as well as MS and PhD degrees in Chemical Engineering from the University of Houston, TX. e-mail: ibukunmakinde@rocketmail.com form of stimulation. There has been a steady increase in productivity of oil and gas from shale plays across the US, due to the emergence of multi-stage hydraulic fracturing and horizontal well drilling technologies. Despite this positive production trend, shale plays have been plagued by relatively low recovery factors in comparison to conventional plays.

This article discusses performance analyses of shale volatile oil reservoirs using different simulation models with the aim of improving production forecasts and overall reservoir management. Why the focus on volatile oils? It is because volatile oils have complex fluid properties that are yet to be fully understood, and the behavior becomes even more complex in shales with nanoscale pores. A better understanding of the fluid properties of volatile oils as well as an appropriate use of reservoir simulation models can help eliminate many errors in reservoir engineering calculations and forecasting. Apart from examining the influence of reservoir simulation models on production performance, **??**akinde and Lee (2016) also investigated the effect of fluid sampling errors on production forecasts.

As a result of the ever-rising global demand for energy, the importance of shale oil and gas research cannot be overemphasized. A better understanding of volatile oil fluid properties will be a major hurdle crossed in the race to further improve recovery in shale reservoirs. This, without doubt, will positively impact the oil and gas industry. Research and studies like this can lead to improved reservoir management and economics as well as provide insight into potential alternative methods to enhance recovery from unconventional shale formations.

2 II. Reservoir Simulation Models

represented by two components -one "component" called oil and the other "component", gas. Here, there is an assumption that produced gas, solution gas, injected and free gas in contact with oil all have the same physical properties. In this model, PVT properties of fluid phases are calculated as functions of pressure only. Therefore, the only inputs necessary for black-oil simulators are tables of PVT properties such as oil formation volume factor (FVF), gas FVF, solution gas-oil ratio, viscosity, etc. as a function of pressure.

However, in compositional models, oil and gas phases are represented as multi-component mixtures. Both phases are made up of different amounts of the same components. For example, ethane can be 45% in the gas phase and 7% in the oil phase. Here, the physical properties of the gases are different and the composition of produced gas varies with time. An equation of state is used in this case instead of simple PVT tables.

3 III. Reservoir Model Description

A reservoir base case model consisting of 8 horizontal wells, with 20 hydraulic fractures spaced 250 ft apart was constructed. The distance between each well is 660 ft, i.e., 330 ft from one well to half adjacent distance of the other. The horizontal well lengths are 5,000 ft. Overall dimensions of the reservoir model are 7,000 ft long, 7,000 ft wide and 250 ft thick. The simulation model is a single porosity system. The fractures are all infinitely conductive. For computational purposes, a fracture width of 2 ft was used. Actual fracture width is about 0.2 inches, but wider fractures make simulation go more smoothly. Fracture permeability is correspondingly reduced to keep the product of width and permeability (of fractures) at an appropriate level. This approach is appropriate because reservoir models with the same fracture conductivity but different fracture widths yield similar results (Alkouh et al., 2012). The initial reservoir pressure is 5,000 psia and the wells produce for 30 years at a minimum bottom hole pressure constraint of 1,000 psia. Figure 1 is a pictorial representation of the base case model after gridding. Tables 1 and 2 show the reservoir data and the model parameters used. Correlations used to generate PVT properties of oil and gas phases, as a function of pressure are shown in Table **??**. Parameters for the Reservoir Basecase Model IV. Single-Phase vs. Two-Phase Black-Oil Simulations 30 years of production was simulated using single-phase (oil) and two-phase (oil and gas) black-oil simulators. The simulations were isothermal and simulation results are for the 8 horizontal wells combined. Figures 2 to 4 show the simulation results comparing single-phase flow with two-phase flow for cumulative oil production, oil recovery factor and average reservoir pressure. There is larger cumulative oil production and oil rate for the two-phase flow than the single-phase flow case. This is likely due to the solution gas drive mechanism in two-phase flow, caused by the presence of the second phase (gas) which is absent in single-phase flow. A higher cumulative oil production correspondingly leads to a higher oil recovery factor for the two-phase flow case. Also, there is lesser pressure drop for two-phase flow compared to the single-phase flow case due to multiphase flow effects. V. Sensitivity Analyses -Single-Phase Flow vs. Two-Phase Flow Comparisons

How do certain parameters affect the production performance of shale volatile oil reservoirs when single-phase and two-phase black-oil simulators are used to simulate production? Are the results comparable or do they differ? Sensitivity studies were carried out with the aid of isothermal single-phase and two-phase black-oil simulations. The parameters studied include fracture spacing, fracture half-length, oil API gravity and critical gas saturation. These parameters were varied with other variables in the base case model kept constant.

4 a) Fracture Spacing -Single-Phase Flow vs. Two-Phase Flow Comparisons

Fracture spacing is an important well completion parameter. The fracture spacing used for the base case model is 250 ft (20 hydraulic fractures). Two other cases were considered -100 ft (50 hydraulic fractures) and 500 ft (10 hydraulic fractures). Figures 5 to 8 show the effect of fracture spacing on cumulative oil production, oil rates, oil recovery factors and average reservoir pressure for single-phase and two-phase flow cases. Simulation results show that closer fracture spacing leads to higher cumulative oil production, higher initial oil rates and higher oil recovery factor for both single-phase and two-phase flow cases. For the oil rate cases, we can observe higher oil rates toward the end of the production period as fracture spacing widens. This is because there is faster drainage of the reservoir with closer fracture spacing, thereby leading to lower oil rates toward the end of the production period in comparison to cases with wider fracture spacing. There is a quicker pressure drop at the beginning of the production period for single-phase flow than for twophase flow cases. Oil recovery factors, cumulative oil production and oil rates are generally higher for twophase flow than for single-phase flow cases.

5 Two-Phase Flow Comparisons

Fracture half-length is the distance from the wellbore to the outer tip of a fracture. Three scenarios were considered here -fracture half-lengths of 100 ft, 200 ft and 300 ft. In the base case model, the fracture half-length is 150 ft. Figures 9 to 12 show the effect of fracture half-length on cumulative oil production, oil rate, oil recovery factors and average reservoir pressure for single-phase and two-phase flow cases. Results show that the larger the fracture half-length, the higher cumulative oil production, oil rate and oil recovery factor for both single-phase and two-phase flow simulations. There is a more rapid pressure drop (that later flattens out) early in the production period for single-phase flow than for the two-phase flow cases. Oil recovery factors, oil rates and cumulative oil production are mostly higher in two-phase flow than the single-phase flow cases. For the single-phase flow cases, the higher the oil API gravity, the higher the cumulative oil production and the initial oil production rates. This is because the higher the oil API gravity, the lighter the oil and the lower the viscosity -indicating higher oil mobility. Likewise, the analyses show that the higher the oil API gravity, the higher the oil recovery factor. Also, the lower the oil API gravity, the slower the rate of decline of the average reservoir pressure and vice versa.

Results of the two-phase flow cases provide a good demonstration of shale volatile oil reservoir behavior. As production occurs and reservoir pressure falls below the bubble point, gases start to build up around the wellbore. With time, the increasing gas saturation starts to hinder oil flow to the wellboreeventually leading to a decline in cumulative oil production. This study illustrates that the higher the oil API gravity, the lower the cumulative oil production. This is shown in Figure 13. The higher the oil API gravity of fluids, the more the lighter components they contain. These lighter components of the fluid contribute to gas saturation around the wellbore, thus decreasing cumulative oil production with time. Table **??** shows actual production forecast data from two-phase black-oil simulations after 30 years of production. This table clearly shows the numerical value of cumulative oil production decline with increasing oil API gravity. Cumulative gas production on the other hand, increases with increasing oil API gravity. Furthermore, Figure 17 shows how average gas saturation increases with increasing oil API gravity. This also corroborates the explanations above on how increasing oil API gravity decreases cumulative oil production. In addition, results from two-phase flow cases show that oil production rates drop with increasing oil API gravity. However, there was an increase in oil recovery factor with increase in oil API gravity, even though above 60°API there was a slight drop in oil recovery factor for the 65°API case. This is shown in Figure 15, indicating that with further increase in oil API gravity above 60°API, oil recovery factor will most likely begin to decline. It is also observed from this study that the average reservoir pressure declines at a faster rate with increase in oil API gravity and vice versa. This is illustrated in Figure 16.

6 d) Critical Gas Saturation -Two-Phase Black-Oil Simulation Cases

In an oil reservoir, gas evolves out of solution when the reservoir pressure drops below the bubble point. The gas is immobile until it reaches a threshold called the critical gas saturation. At and above the critical gas saturation, the gas phase becomes mobile and begins to flow towards the wellbore. Two-phase black-oil simulations were run with critical gas saturations of 2%, 10%, 15% and 20%. A critical gas saturation of 5% was used for the base case model. Figures 18 to 21 show the effect of critical gas saturation on cumulative oil production, oil rate, oil recovery factor as well as average reservoir pressure.

Results indicate that cumulative oil production increases with increase in critical gas saturation. This can be seen in Figure 18. The higher the critical gas saturation, the longer the gas stays in the pore spaces, thus pushing out more oil before it becomes mobile and starts to flow. Oil recovery factor also increases with increase in critical gas saturation. For the case with 20% critical gas saturation, the oil recovery factor is almost 12%, while it is approximately 7% for the case with 2% critical gas saturation. Figure 20 shows this.

In Figure 19, results show that at early times, a constant production rate was observed for the 20% critical gas saturation case, before decline starts to occur. From the graph, it is also observed that oil production rates decline earlier as critical gas saturation decreases. This is because at lower critical gas saturations, evolved gas becomes mobile earlier, leading to earlier decline in oil rate. This phenomenon is vice versa as critical gas saturation gets higher. It also explains why there is a slightly faster decline in average reservoir pressure as critical gas saturation gets lower. This is observed in Figure 21. McCain (1994) suggested that the heavy components in petroleum mixtures have the greatest effect on fluid characteristics. Results of this study, however, show the importance of not only the heavy components, but also of the light components, especially methane. Figure 24 illustrates the effect of fluid composition on cumulative oil production and oil rates. Fluid 5, with the smallest methane composition and relatively high (22.41%) C 7+ composition has the largest cumulative oil production and oil rate whereas Fluid 3, with the largest methane composition and relatively low C 7+ composition (though not lowest -Fluid 4 has the least C 7+ composition), has the smallest cumulative oil production and oil rate. Note that, despite the fact that Fluid 4 has a smaller C 7+ composition than Fluid 3, cumulative oil production and oil rate for Fluid 4 is higher than for Fluid 3. This indicates that the methane composition plays a major role in reservoir performance. Fluids 1 and 2 are similar in composition (methane compositions are almost the same and the C 7+ compositions are slightly different) -they therefore have almost the same cumulative oil production and oil rates. Fluid 2, with a slightly smaller methane composition and slightly larger C 7+ composition, has a slightly higher cumulative oil production and oil rate than Fluid 1. Also, Fluids 5 and 2 have almost the same C 7+ composition (Fluid 5 -22.41% and Fluid 2 -22.59%); however, there is a considerable difference in their methane composition [less -(49.43%) in Fluid 5 than in Fluid 2 -(58.07%)] and results indicate much higher cumulative oil production and oil rate for Fluid 5 than for Fluid 2. The trend generally indicates that the smaller the methane composition, the larger the cumulative oil production and oil rate. This clearly demonstrates the importance of the effect of the methane composition on production performance. The heavy components affect cumulative oil production and oil rates because the larger the heavy component composition in the reservoir fluid, the more it contributes to the oil phase production and consequently increases the cumulative oil production and oil rate. However, results of this study indicated that apart from the heavy components, the methane component has a large role to play as well. Note that the spikes in the oil rate curves are probably artifacts due to the numerical solver (in the software) used for the simulation. However, disregarding the spikes, the trends can be clearly observed.

7 VII. Two-Phase Black-Oil Simulations -Standing Correlation

Separator tests were done on the fluids and the results of the flash calculations were used as inputs for two-phase black-oil simulations. Two stages of separation were used, with the stock tank as one of the separators. Separator pressure and temperature were 400 psia and 100°F, while the stock tank conditions were 14.7 psia and 60°F respectively. The results of the flash calculations are shown in Table ??. This was done to provide a reasonable basis for comparison of the compositional simulation and the black-oil simulation results.

8 Table 6: Flash Calculation Results

First, a case where Standing's correlation was used for bubble point pressure estimates was considered. The simulation results were different from those obtained in the compositional simulations and show no notably observable trends. Figure 25 shows the results for cumulative oil production and oil rates. Fluid 1, in this case, has the largest cumulative oil production and oil rate, while Fluid 5 has the smallest. Incorrect bubble point pressures estimated with the correlations might have led to discrepancies in the results. The inconsistencies in the results for the blackoil simulations are most likely due to inaccurate bubble point estimates using empirical correlations. In Table 7, the approximate bubble point estimates calculated with the Standing and Vazquez-Beggs correlations are shown. Note that the initial reservoir pressure is 5,000 psia. Therefore, the bubble point pressure estimates calculated are higher and lower than the initial reservoir pressure depending on the fluid type considered. Predicted values of bubble point pressure (using correlations) could be in error by 25 percent or more depending on the circumstance (McCain et al., 1998). This definitely affects the accuracy of production forecasts. Simulation results from the compositional and black-oil simulations were compared for each of the fluid samples under consideration. Results generally show greater cumulative oil production and greater oil rates from compositional simulation than from black-oil simulations. Black-oil simulations using Vazquez-Beggs correlation for calculation of most of the oil PVT properties produced results that are closer to the compositional simulation results than black-oil simulations in which Standing's correlations were used. Therefore, we conclude that proper use of correlations or the development of better correlations for black-oil simulations can lead to results that are close to or almost the same as compositional simulation results. Results of cumulative oil production and oil rate Fluid 3 is a near-critical fluid; therefore, an additional simulation was run by modeling it as a gas condensate using modified black-oil (MBO) simulation. MBO simulation of gas condensates takes into consideration the condensate-gas ratio, R v , which is the amount of vaporized oil in gas.

When Fluid 3 was modeled as a gas condensate (using MBO), the result was similar to the original black-oil simulation case (when modeled as a bubble point fluid using Standing's correlation). When modeled as a bubble point fluid using the Vazquez-Beggs correlation, the cumulative oil production is a little closer to the compositional simulation case except toward the end of the production period. This highlights the difficulties inherent in modeling near-critical fluids, especially when using black-oil simulators with illustrates the results for the cumulative oil production and oil rates.

Compositional vs. Two-Phase Black-Oil Simulations -Fluid 3 Cumulative Oil Production and Oil Rate Comparisons X. Conclusions

1. Sensitivity studies done with the aid of single-phase and two-phase black-oil simulators, showed that fracture spacing, fracture half-length, oil API gravity and critical gas saturation are important parameters that affect oil production and oil rates in shale volatile oil reservoirs; 2. From the analyses of the oil API gravity cases, it is obvious that imperfect fluid samples (errors in calculation of fluid properties) can have significant impact on oil recovery estimates;

3. The gas phase in two-phase flow has a considerable effect on oil production in shale volatile oil reservoirs; 4. Results from black-oil simulations are markedly different from compositional simulations.

Compositional simulations are more accurate than two-phase black-oil simulations, while two-phase black-oil simulations are more accurate than singlephase black-oil simulations; 5. Volatile oil production cannot be properly modeled using black-oil simulations (especially when PVT properties are estimated with empirical correlations); 6. Inaccurate bubble point pressures and PVT properties estimated using correlations can have huge impacts oil production forecasts, whereas identification and use of more appropriate correlations for PVT property estimates can lead to production estimates that can be almost the same as those obtained from compositional simulations; 7. Reservoir engineering calculations for volatile oils should treat the reservoir fluid as a multi-component [1]

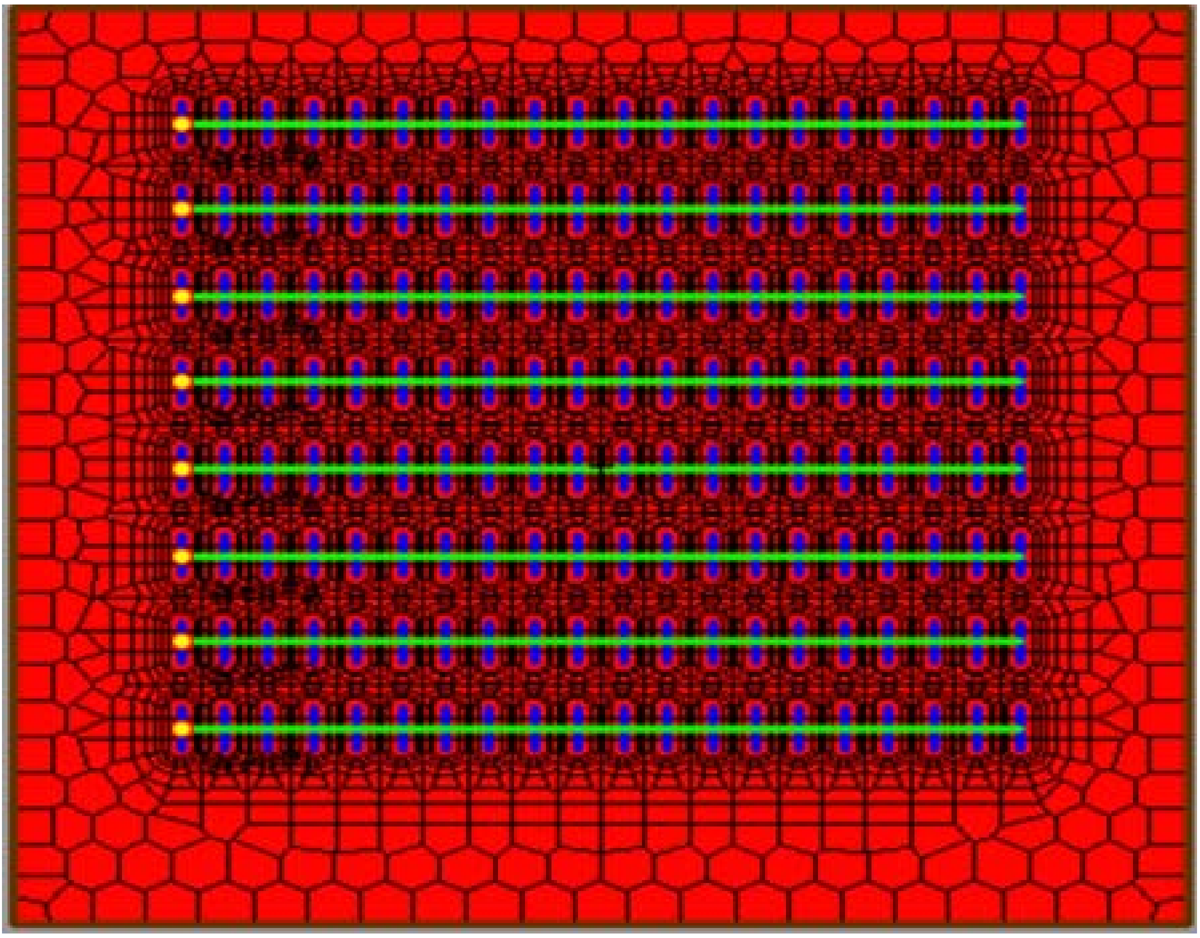

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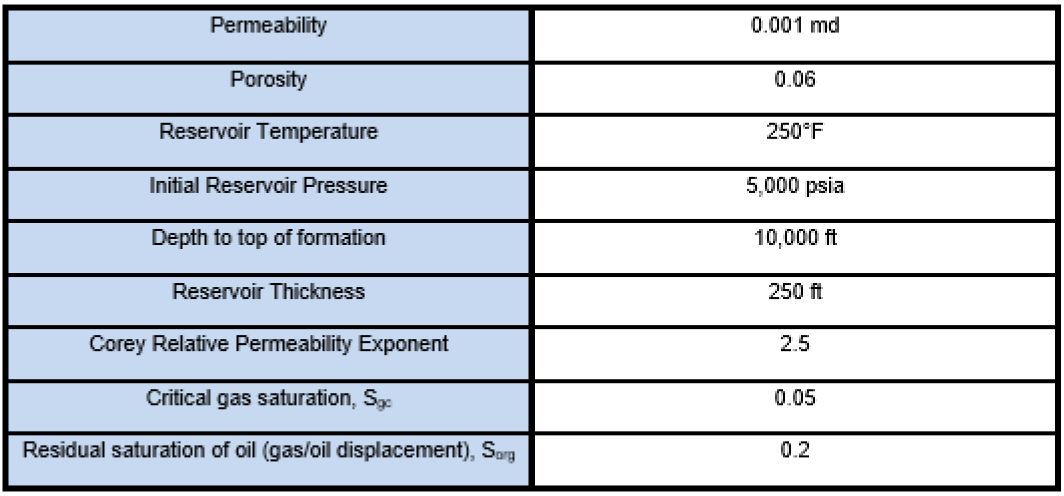
Figure 1: Fig. 1 :



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Permeability	0.001 md
Porosity	0.06
Reservoir Temperature	250°F
Initial Reservoir Pressure	5,000 psia
Depth to top of formation	10,000 ft
Reservoir Thickness	250 ft
Corey Relative Permeability Exponent	2.5
Critical gas saturation, S_{gc}	0.05
Residual saturation of oil (gas/oil displacement), S_{org}	0.2

Figure 2: Fig. 3 :Fig. 4 :

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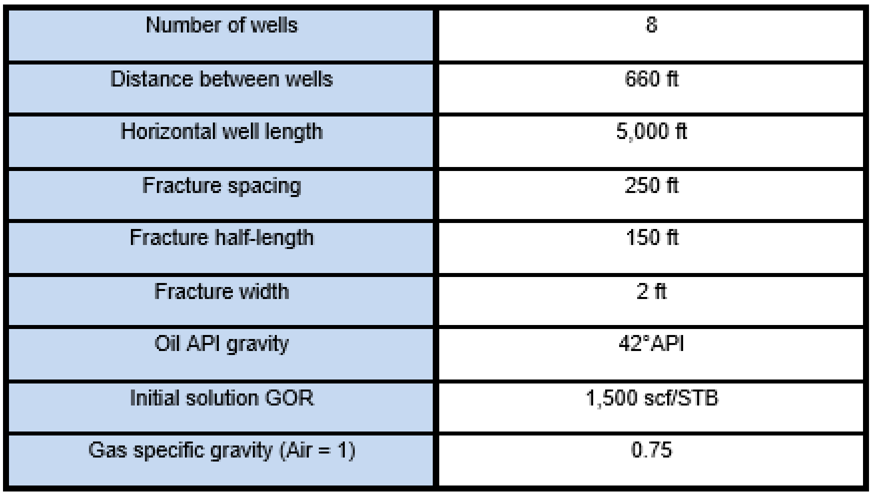

Number of wells	8
Distance between wells	660 ft
Horizontal well length	5,000 ft
Fracture spacing	250 ft
Fracture half-length	150 ft
Fracture width	2 ft
Oil API gravity	42°API
Initial solution GOR	1,500 scf/STB
Gas specific gravity (Air = 1)	0.75

Figure 3: Fig. 2

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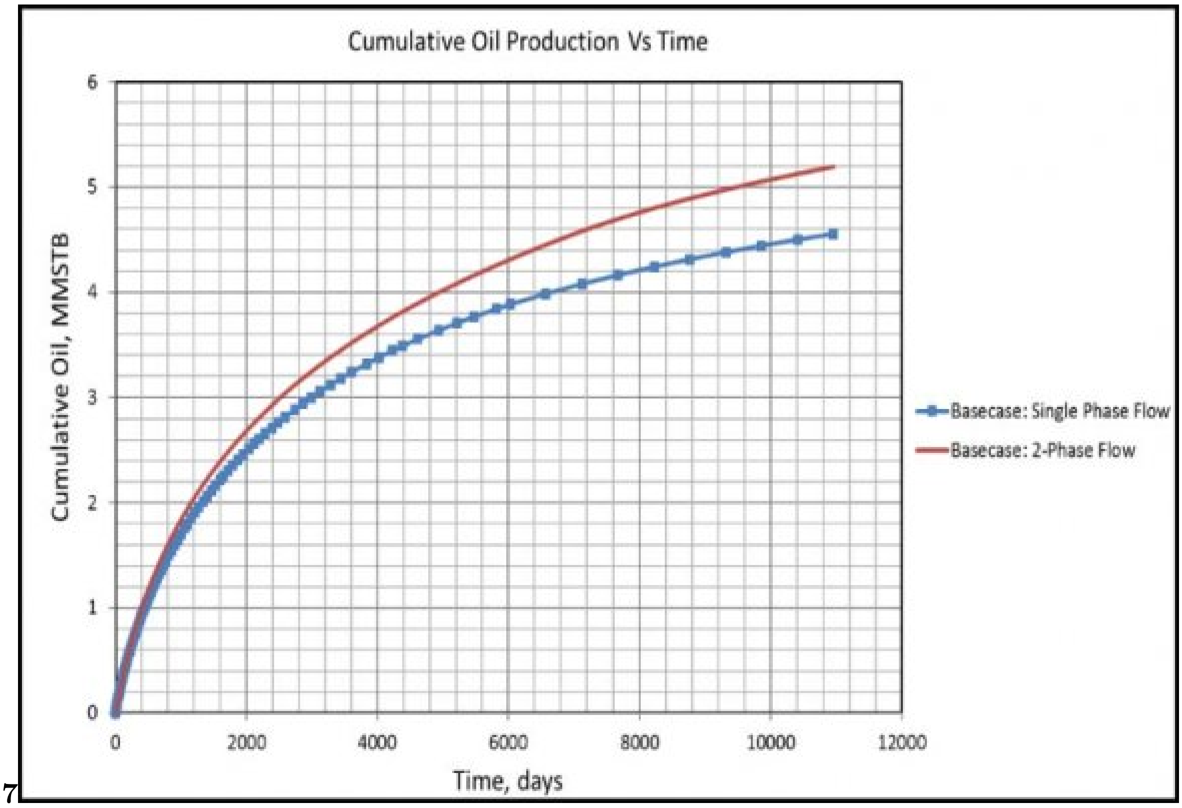

Figure 4: Fig. 5 :Fig. 6 :Fig. 7 :

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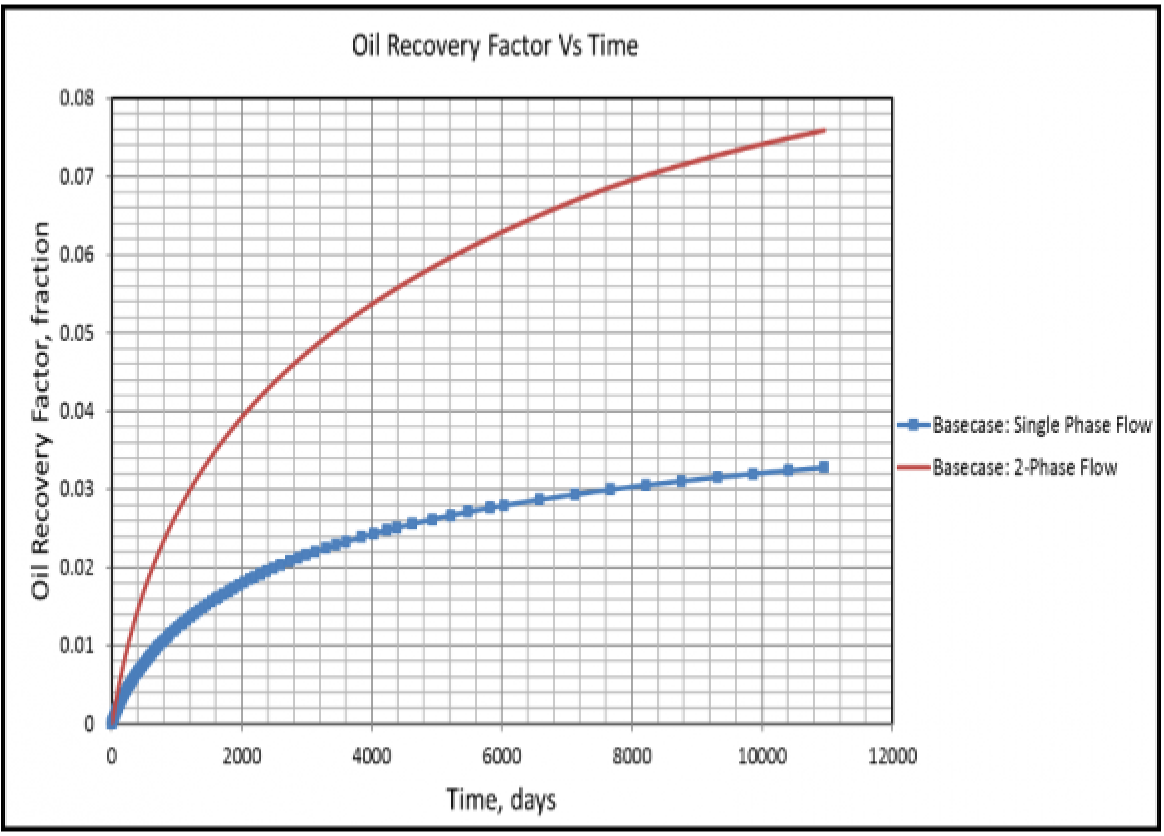

Figure 5: Fig. 8 :

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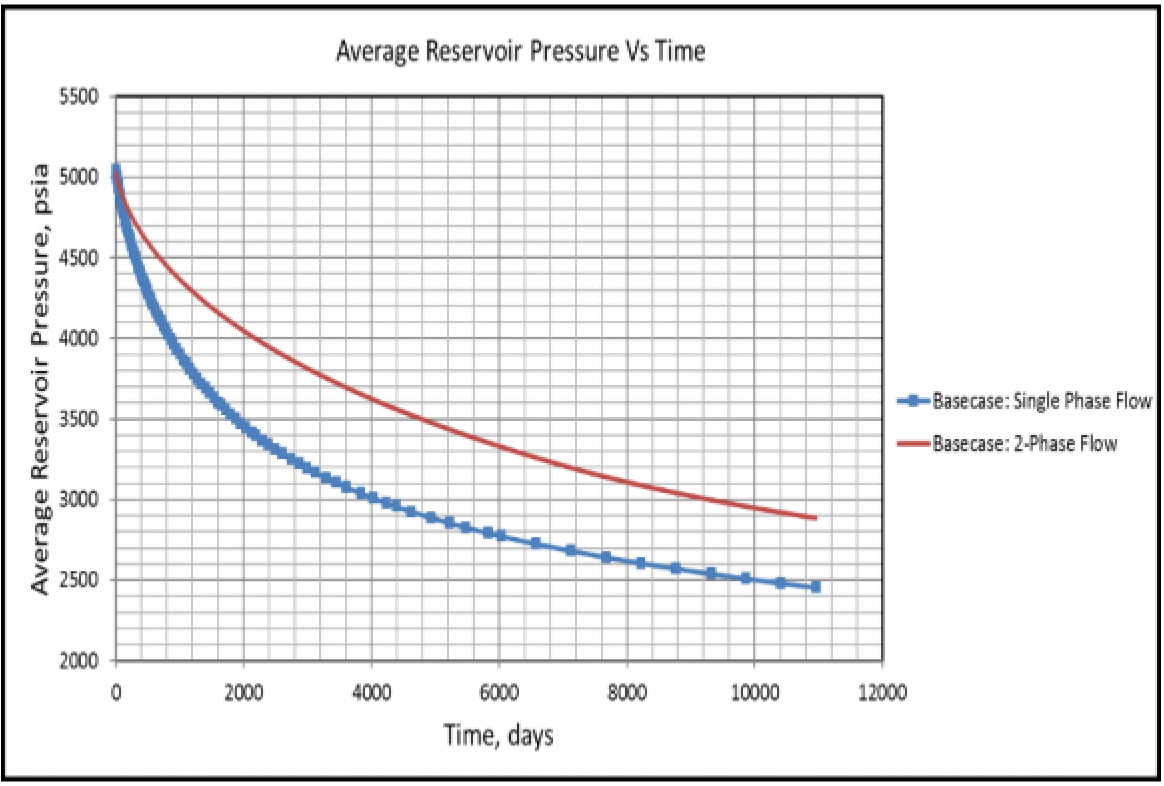

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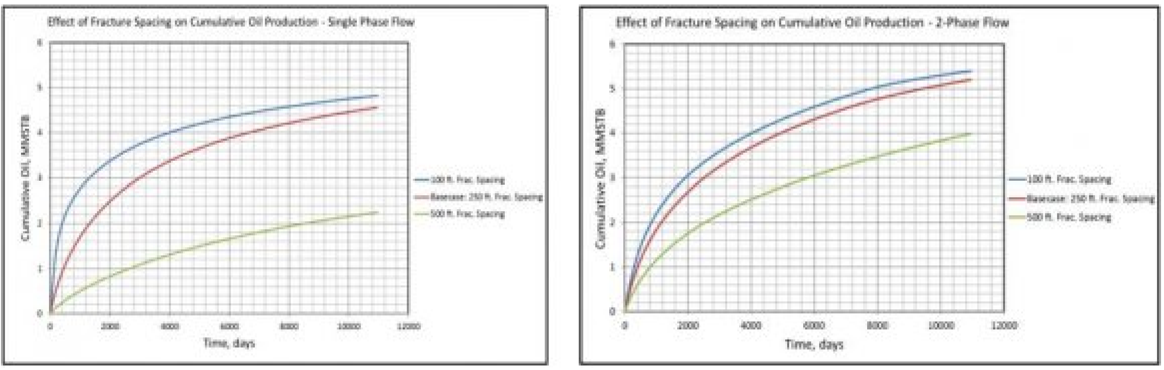

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Figure 7: Fig. 13 :Fig. 15 :

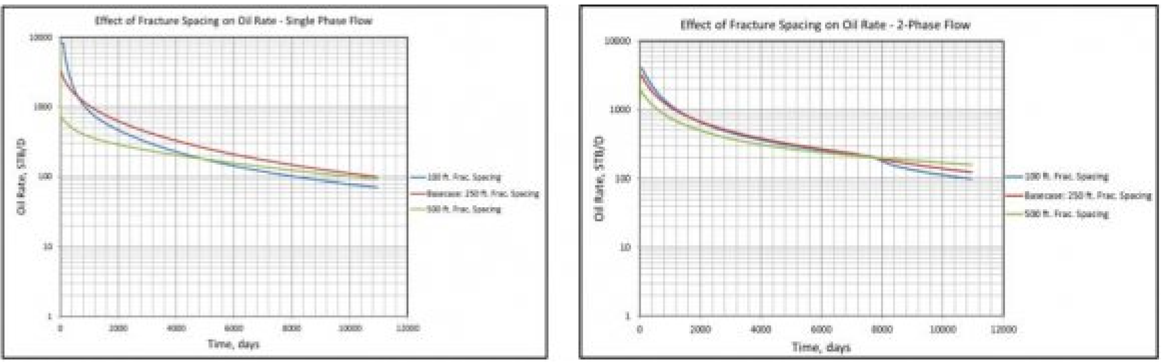

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Figure 8: Fig. 17 :Table 4 :

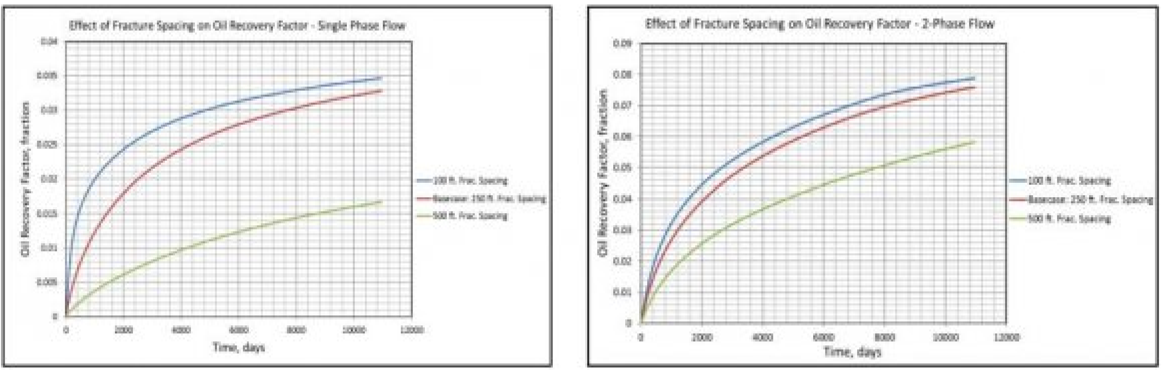

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Figure 9: Fig. 18 :Fig. 19 :

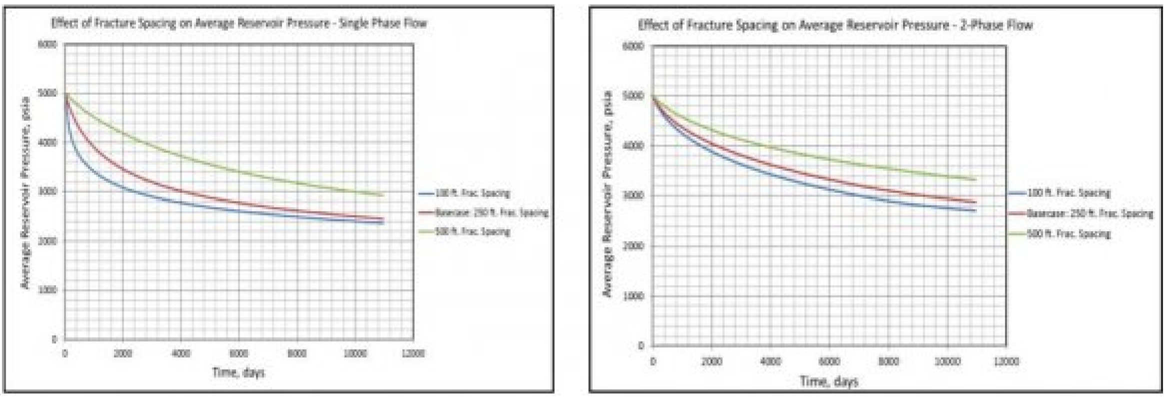

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Figure 10: Fig. 21 :

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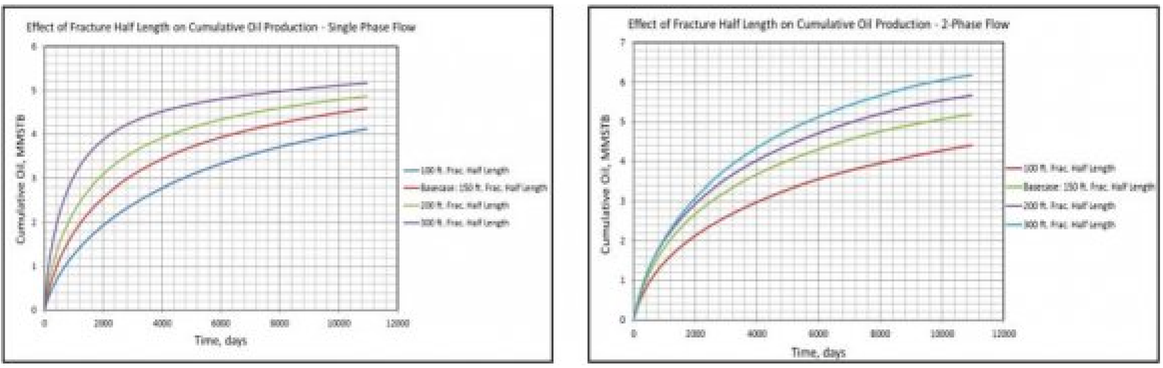

Figure 11: FigFig. 23 :

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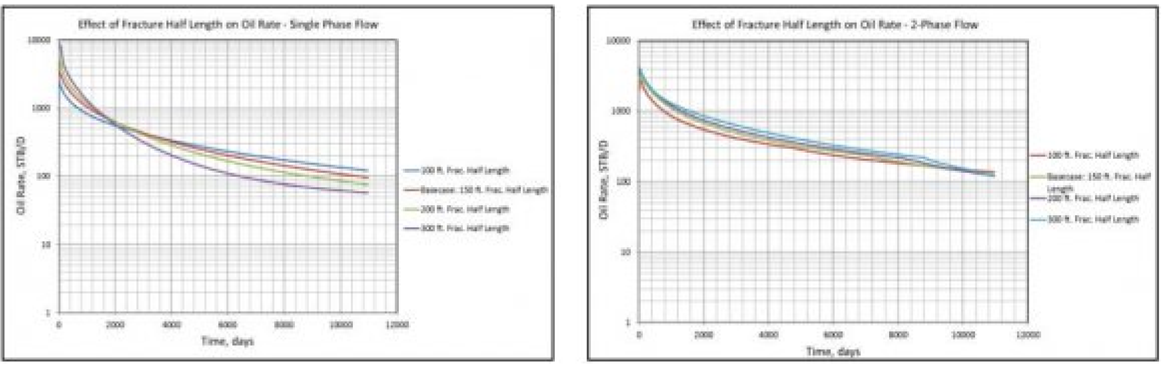

Figure 12: Fig. 24 :

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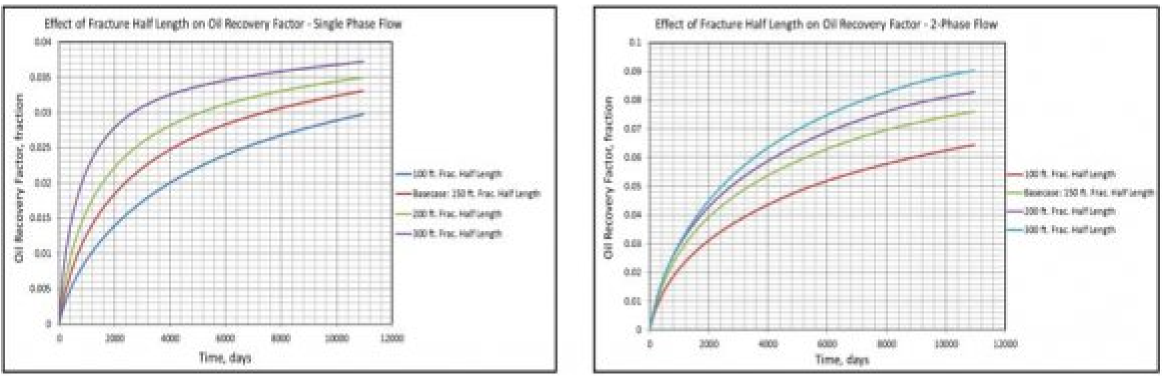
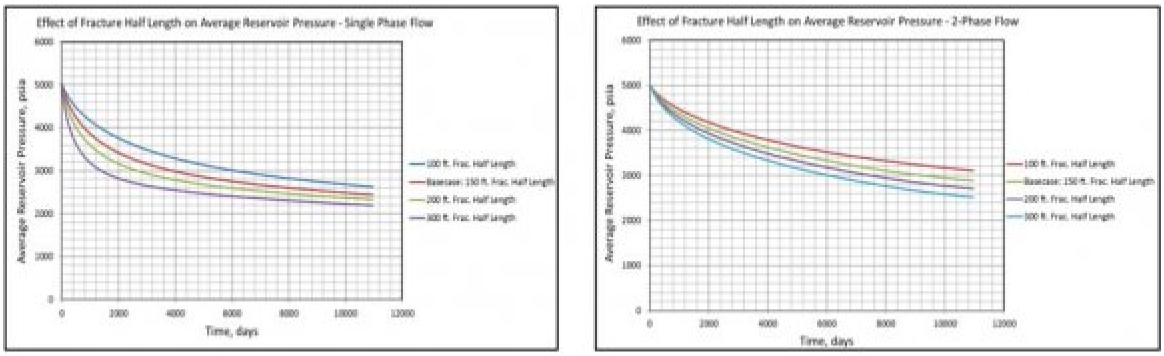


Figure 13: Fig. 25 :



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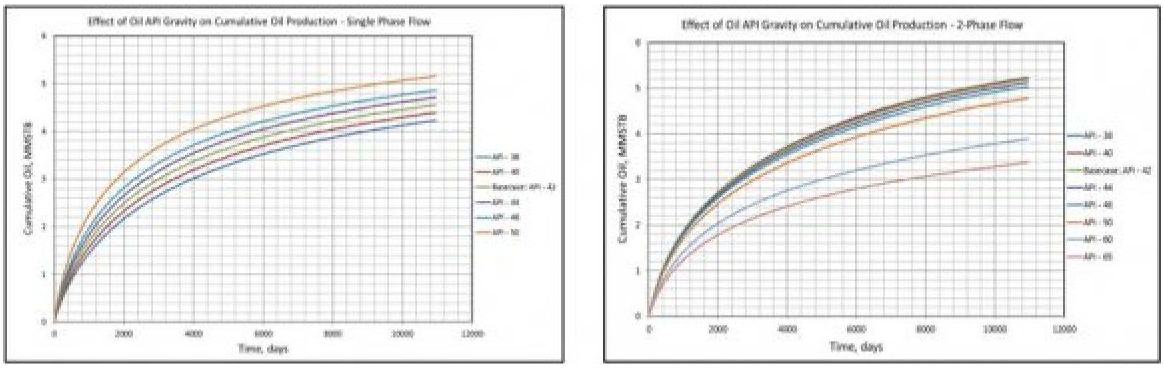

Figure 15:

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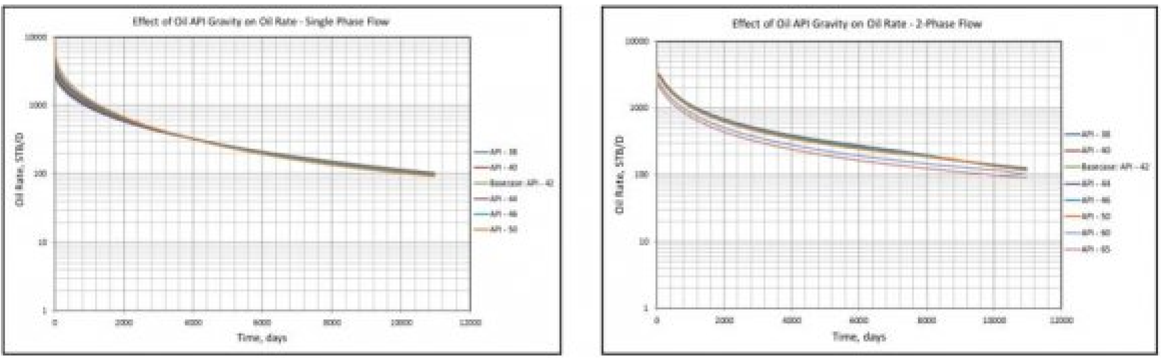

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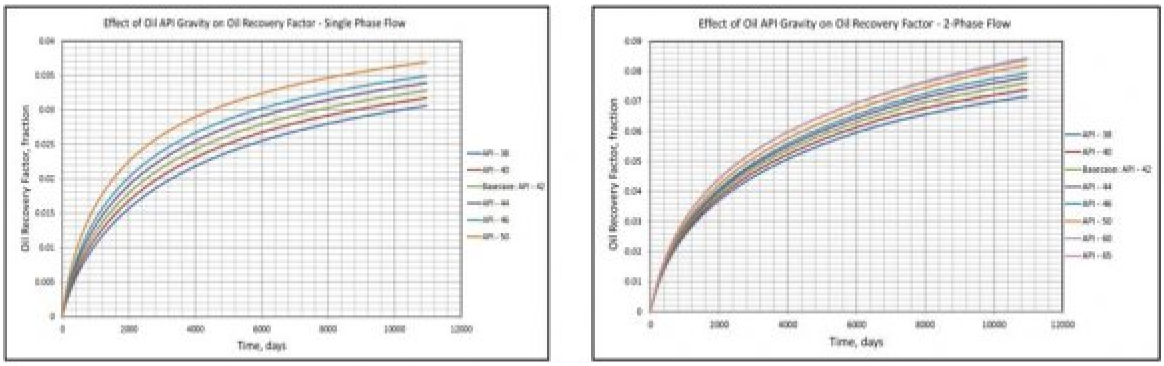


Figure 17: Fig

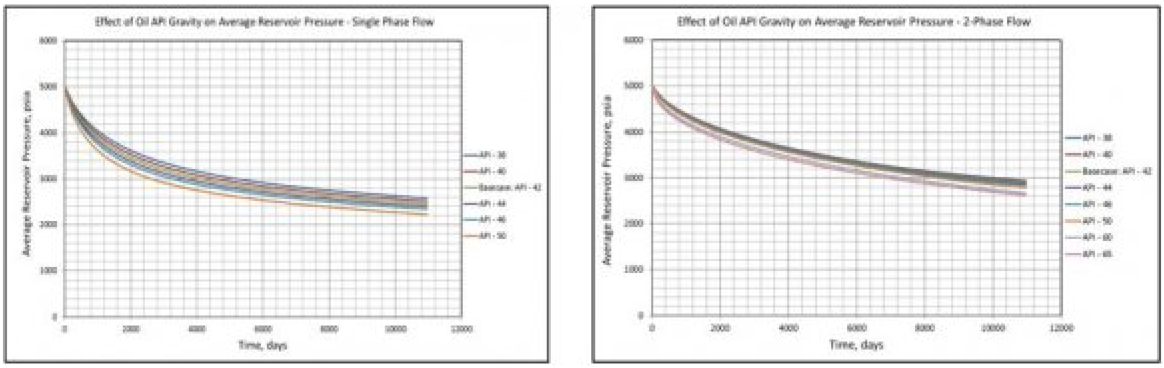
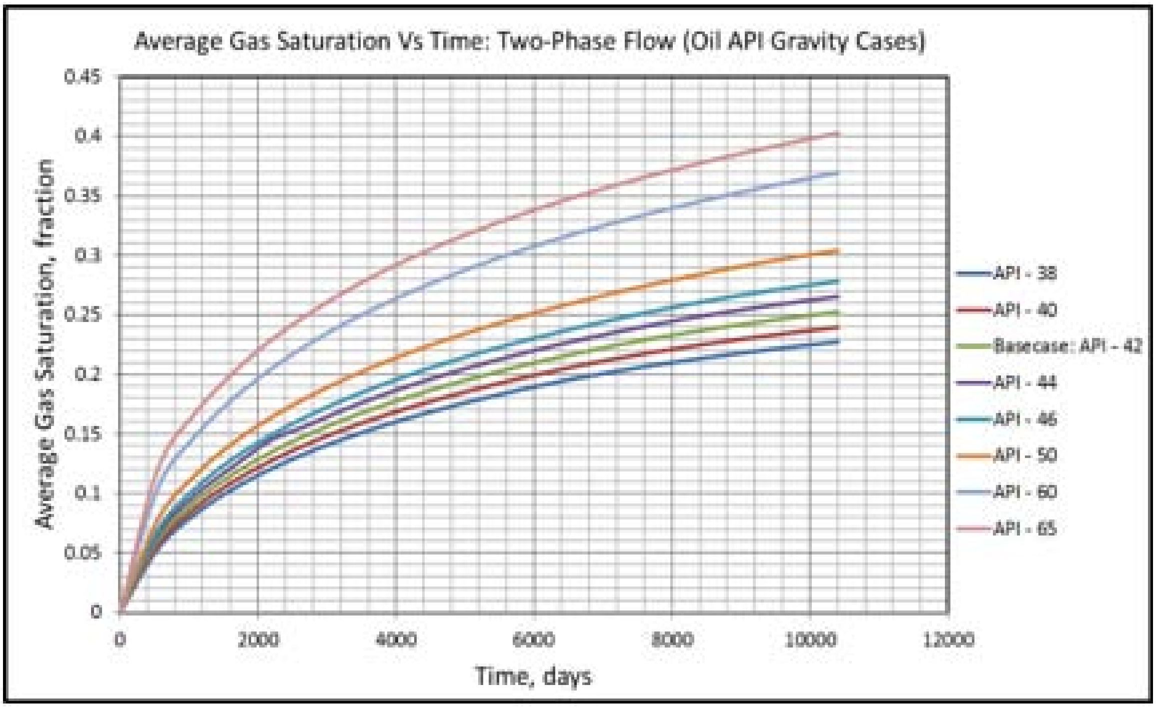


Figure 18:



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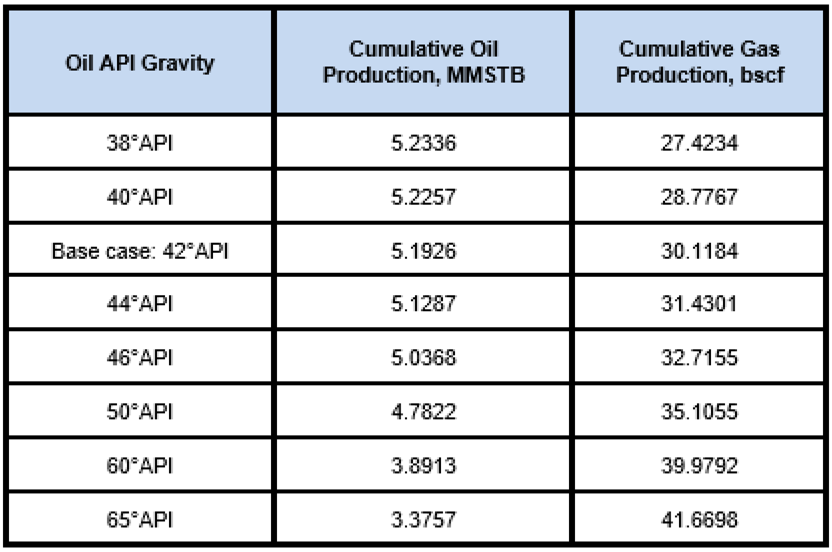

Oil API Gravity	Cumulative Oil Production, MMSTB	Cumulative Gas Production, bscf
38°API	5.2336	27.4234
40°API	5.2257	28.7767
Base case: 42°API	5.1926	30.1184
44°API	5.1287	31.4301
46°API	5.0368	32.7155
50°API	4.7822	35.1055
60°API	3.8913	39.9792
65°API	3.3757	41.6698

Figure 20:

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[Note: 1 Internal correlations within the software]

Figure 21: Table 1 :

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Figure 22: Table 2 :Table 3 :

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Figure 23: Table 5 :

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[Note: IX. Compositional vs. Two-Phase Black-Oil Simulations]

Figure 24: Table 7 :

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