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A number of relative permeability models were present in the literature, which were used to generate relative permeability data for the fluids, present in the porous medium. Some models were more significant to reservoir geology and displacement system (imbibitions and drainage system), while developing the correlations. Similarly, the same is kept in mind while performing reservoir studies. Therefore, in this study different models based on displacement system and formation geology have been compared, while including the effect of fluid saturation distribution/end point saturation in a reservoir. The generated relative permeability data by using these models have been further used to predict the reservoir performance for gas and water-displacement systems. The results based on this study showed that at lower saturations of displacing fluid (gas and/or water), the generated reservoir performance curves based on relative permeability data generated by using Corey and Wylie and Gardner models, gives higher degree of deviation on comparative basis. The behavior of these error or deviation curves for displacing phase is opposite in case of gas and water-oil displacement systems. While in case of displaced phase (oil), generally analogous behavior can be observed for both systems in terms of deviation/ error profiles trends. These reservoir performance curve(s) are of utmost significance in developing reservoir in an appropriate manner and a slight variation in relative permeability data can have a significant impact at macroscopic level. Keywords: Performance prediction;. The number of parameters can hinder the fluid flow and a displacement of one fluid by another in a reservoir. Such parameters involve wettability as of prime importance (Ahmed 2000; Zahoor & Derahman 2013; Zahoor et al. 2011). Wettability, in turn also affects the relative permeability of displacing and displaced fluids, as shown in Figure 1. permeability curve will shift downward (representing lower relative permeability values). However, to keep it simple, in the later discussion regarding flow dynamics and relative permeability models, water will be considered as wetting phaseEFFECT OF GENERATED RELATIVE PERMEABILITY DATA ON RESERVOIR PERFORMANCE PREDICTION Consider a reservoir having a length of 100 ft and an area of 1500 ft2 . Further details of reservoir and fluid properties are given in Table 3. In order to analyze the effect of previously discussed relative permeability models on reservoir performance and prediction; oil, water and gas production rates have been calculated along with gas and water-cut. The production rates have been calculated by using the following set of equations (Ahmed 2000; Gatlin 1960): FIGURE 5. Influence of change in minimum water saturation (0 to 0.1) on relative permeability data FIGURE 6. Effect of minimum water saturation of 0.2 and 0.3 on relative permeability curves TABLE 2. Ranking of correlations based on generated Kr data with reference to fluid system and saturation variation Smin Values Correlation Type Gas-oil displacement system 0.0, 0.1, 0.2, 0.3 Unconsolidated well sorted Unconsolidated poorly sorted Corey model Generates similar Kr Cemented Water-oil displacement system 0.0, 0.1, 0.2, 0.3 Unconsolidated poorly sorted Cemented Unconsolidated well sorted 1411 qg = 111.98 × 10–3 (2) qo = 1.127 × 10–3 (3) qw = 1.127 × 10–3 (4) where q represents flow rate and the subscripts ‘o’, ‘w’ and ‘g’ refers to oil, water and gas. ‘A’ is the area and ‘Z’ stands for gas deviation factor. The water and gas-cut (fw and fg ) have been calculated by using the following equations (Ahmed 2000): f w = (5) and f g = (6) In this study, to highlight and analyze the effect and significance of relative permeability models selection for reservoir performance calculations, the data was used in (2) to (6), corresponding to various saturation values from Figures 4 (gas-oil system) and 6 (water-oil system). The trend of the obtained results in case of gas-oil system for their production rates, gas-cut are shown in Figure 7 with reference to saturation, respectively.]

Permeability is a measure of the ability of a fluid to pass through its porous medium. Permeability is one of important to determine the effective reservoir. Porosity and permeability are two properties describing the reservoir rock capacity with regard to the fluid continence. Moreover, a reservoir rock can be porous without being permeable. For example it is said to be permeable if and only if the pores “communicate”. Hence for explorationists, knowing reservoir rock permeability is a key mile stone because it is important for being used to determine if it really has sufficient commercial accumulation of oil, indeed measuring it is very difficult. The measuring of permeability can differently be understood basing on two different ways. When the porous medium is completely saturated by a single fluid, the permeability will be described ***absolute,***become described as ***effective permeability*** when its porous medium is occupied by more than one fluid

Matrix volume (Vm) can be calculated from the mass of a dry sample divided by the matrix density. It is also possible to crush the dry solid and measure its volume by displacement, but this will give total porosity rather than effective (interconnected) porosity. A gas expansion method can be used: gas in a cell at known pressure is allowed to expand into a second cell containing core where all gas present has been evacuated. The final (lower) pressure is then used to calculate the matrix volume present in the second cell using Boyle’s law (Fig. 2.3). This method can be very accurate, especially for low-porosity rock. Boyle’s law: P1V1 ¼ P2V2 (assuming gas deviation factor Z can be ignored at relatively low pressures) can now be used. Pore space volume (Vp) can also be determined using gas expansion methods. 2.2.3 Variable Nature of Porosity As discussed above, porosity is very variable in its nature, changing over quite small distances within a reservoir; and even if two samples have the same porosity, it does not mean that they will have the same absolute permeability or the same wettability characteristics, which in turn means that they can have very different capillary pressure and relative permeability

forces are balanced at the oilewateresolid contact point, giving the relationship sos sws ¼ sow cos qc [2.15] where sos ¼ the interfacial tension between oil and solid; sws ¼ the interfacial tension between water and solid; sow ¼ the interfacial tension between oil and water; and qc ¼ the contact angle between water and oil at the contact point measured through the water. Wettability will control the distribution of oil and water in the pore space. In water wet systems oil will tend to be found in the centers of pores, while in oil wet systems oil will be retained around the solid grains (see Fig. 2.10). This will of course have a fundamental effect on oil recovery in water flooding. Many examples of porous material have intermediate wettability where the contact angle is close to 90. We can also have short-range variable or “mixed” wettability. Gas will normally be the nonwetting phase with respect to both water and oil. 2.4.1.1 Hysteresis The history of the porous rock (in terms of the history of the phasesd watereoil or gasdthat have occupied the pore space) will have a strong effect on its wettability; this is known as “hysteresis.” Wettability is fundamental in determining capillary pressure and relative permeability

 CONCLUSION AND RECOMMENDATIONS

Variations in minimum saturation of the displaced phase affect the relative permeability data generated by using different models for gas- and water-oil displacement systems. Wylie and Gardner model for cemented formations undergoing gas-oil displacement (drainage) process gives results similar to Corey model. Moreover, in general, the behavior of models proposed by Wyllie and Gardner becomes vice versa based on fluid system (gas and oil-water) for the same formation type. In order to analyze the effect of above discussed relative permeability models on reservoir performance, production rates and displacing fluid (gas and water) cuts have been calculated, which shows that the slight change in relative permeability have significant impact on reservoir performance calculations. This study shows that the deviation in generated production profiles in either displacement system for any particular fluid generally increases with the decrease in its saturation. This can be particularly observed specially in case of gas, which being lighter and having high mobility is least effected by degree of sorting and cementing and the difference in production profile and gas-cut becomes evident at lower gas saturations. Therefore, fluid saturation/end point saturation in a reservoir also affects the reservoir performance apart from pore size distribution (sorting) and degree of cementing, which was earlier a more commonly known and discussed fact in reservoir performance calculations. Therefore, the fluid saturation variations and model selection for reservoir studies should be taken into thorough consideration and need to be critically handled, for better reservoir exploitation and development.