Evaluation of Phase Trapping Damage Using Hydrocarbon Base Fluids

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Abstract: At present, low permeability and tight gas reservoirs have signatures of various problems and significant damages due to their low matrix nature. During the invasion of wellbore fluid in drilling and completion operations, the increment of additional phase saturation dramatic damage to permeability of produced phase. The trapped wellbore fluid causes 80% reduction in the relative permeability of produced phase near the wellbore. The interfacial tension (IFT) and capillary pressure are the dominant factors to control the trapping mechanism and displacement of the trapped wellbore fluid towards production. This study based on the investigation of the phase tapping damage using diesel oil and brine base fluids. The diesel oil was used as base fluids for investigation as hydrocarbon base fluid in comparison with water base that was synthetic brine. The IFT was measured at temperature 60 – 100 C and pressure 800 – 2500 psi ranges to imitate reservoir conditions and then estimate the capillary pressure. The results shows low permeability core samples under unsteady state condition has slightly high value as compared to tight core samples at steady state conditions which showed less severity to damage permeability caused by phase trapping block. SCAL reservoir simulation was also carried out to simulate relative permeability and capillary pressure curves using single 1-D black oil simulator. Further core flooding was required to observe the IFT and capillary pressure effect on phase trapping and validate these simulation outcomes.

Keywords: *Phase trapping, interfacial tenstion, Capillary pressure, low permeability, tight gas reservoirs.*

1. Introduction

Low and tight permeability and porosity resources are considered as unconventional resources. The unconventional resources are difficult to produce; they often need fracture stimulation or steam injections to enhance their recovery. The conventional resources are one third of worldwide oil and gas reserve, the remaining are unconventional resources as shown in Figure 2.1[9, 10]. Note conventional resources make up productivity less than a third of the total.

The worldwide distribution of unconventional gas resources is presented in the Table 2.1[11]. The worldwide distribution of the unconventional hydrocarbons is shown in the Table 2.1. Almost 75% of the world's total unconventional resources are out of North America. According to the assessment, the demand of unconventional reservoirs is continually increasing globally [11].

The recent technology helps to extract possible gas production has recorded for 44% from the unconventional gas. The contribution of shale gas is two-thirds of unconventional gas reserves or technically recoverable gas recorded around 28% [12].

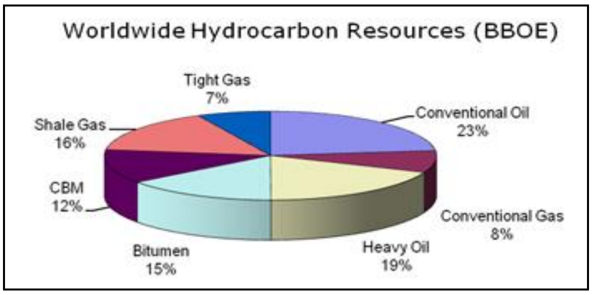

Figure1: Worldwide hydrocarbon resources[9]

While Middle East, Eastern Europe, Eurasia (incl. Russia) are representing to develop 16.6% of unconventional gas, however 61% of region account for conventional gas. All the other regions have more reserves of unconventional gas as compared with conventional gas, shown in Figure 2.2. Because of this demand and supply, development of unconventional gas sources will produce an improvement in worldwide energy and supply [13].

According to growth of population, individual demand increases, currently requirement from rising economies and depleting of oil and gas resources, worldwide need for methane gradually increase approximately 45% to 50% by 2035 [12,14]. The unconventional gas exploration will be thrice around 1600 bcm yearly with latest leading discoveries predicted in Poland, Australia, China, and India. There is an increment of unconventional gas from 14% in 2010 to 32% of gas production by 2035 [15].

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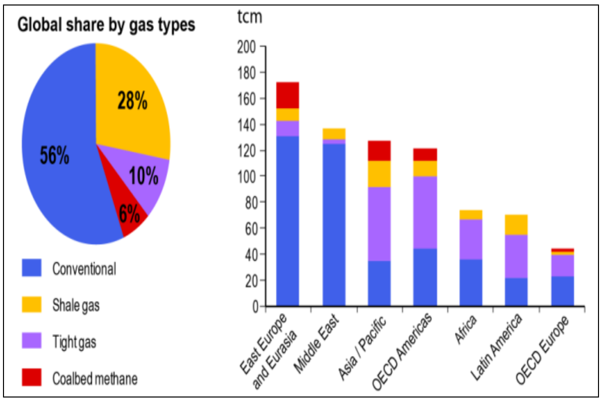

Figure2: Unconventional global distribution regions[12]

2. Low Permeability Reservoirs

The resource triangular is presented for the hydrocarbon types in well manner that can be assigned to various resources classes, shown in Figure 2.3. The positions of the hydrocarbons in the triangle reflected its large quantity, their quality of reservoir and technology needed for improvement [16,17]. As the triangle of gas-resource is going downwards, the reservoirs are more complicated because of its low matrix permeability. The low permeability reservoirs have much more potential than the high quality reservoirs [15,16].

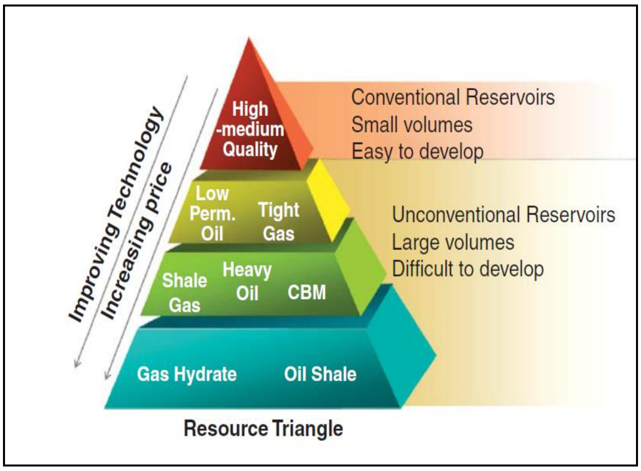

Figure3: Triangle for unconventional resources [17]

3. Tight Gas Reservoirs

According to U.S Government, 1970, the meaning of tight gas reservoir is said to be consider rate of permeability of gas would be less than 0.1 md. The most excellent explanation was given “reservoirs that cannot possible to produce at optimum production rates and also produce economical volumes unless the well is go through stimulation operations such as hydraulic fracturing treatment or enhance production by drilling multilateral or horizontal wellbores [18,19].

Formation Damage during Workover and Completion in Low Permeability Gas Reservoirs

Formation damage is a vast and expansion area which has been explained thoroughly in detail by various authors. In this study, attention has been given towards the system of formation damage which is frequently most effective cause of decreased productivity in tight and low permeability gas reservoirs[M].Figure2.4 shows a schematic of these formation damage system mostly fall in to three categories which are further sub divided[20].

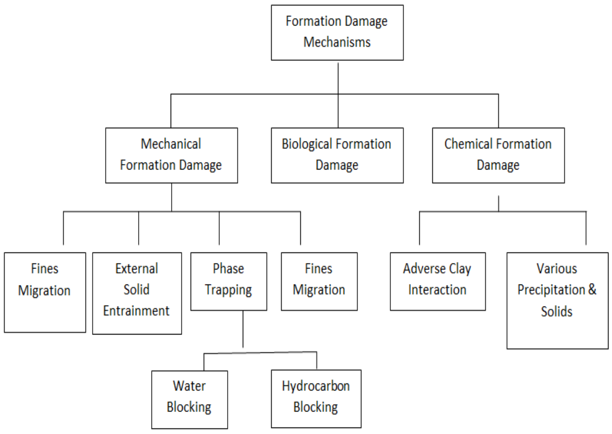

Figure 4: Chain of common formation damage mechanisms[21]

4. Phase Trapping or Retention of Fluids in tight and low permeability reservoirs

Water blocking damage is a kind of phase trapping damage and an important concern though well has successfully fractured completions in tight and low sands. Water blocking effect (water phase trapping) is one of the foremost problems which may cause reduction in productivity near the wellbore. Specific laboratory equipment are required to develop strategy for evaluation and diagnoses problems for given reservoir application. Formations of an average permeability 15md are the best candidates for damage in permeability due to fluid invasion through drilling and fracturing operations. This damage is critical to improve flow efficiency. It is quite difficult to remove formation damage within pore space of tight and low permeability formations.[22,23].

The phase trapping can be defined in another term which said to be unfavourable relative permeability effects. This system of permeability damage is being gradually more recognized as a major problem. Most notably areas are given below [24,25]:

- Water-Based Phase Trapping/Water Blocking
- Hydrocarbon-Base Phase Trapping
- Retrograde Condensate Dropout Trapping
- Water Blocking Damage/Water Phase Trapping

Water blocking damage may be associated with reservoir type either in both oil and gas reservoirs, when the reservoir consists of sub-irreducible initial water saturation. A noticeable objective is required for analyse and estimate its impacts [22,26,27].

These worldwide basins are given below in Table 2.2, which contain sub irreducible initial water saturation[24]. Furthermore, the detail of basins are also documented in the literature for South America, Europe, Asia, Africa and Australia[28,29,].

Table 1: Worldwide basins[22]

United States of America (USA)	Canada Deep basin area
Powder River Basin	Paddy
Green River Basin	Cadomin
DJ Basin	Cadotte
United States of America (USA)	Canada Deep basin area
Powder River Basin	Paddy
Green River Basin	Cadomin
DJ Basin	Cadotte
Permian Basin	

5. Mechanism of Phase Trapping (Water Blocking)

Low permeability and tight gas saturated matrix is the best candidate of the phase trapping issue; basic mechanism of this phenomenon is shown in Fig. 2.5. It can be noticed that the reservoir pore system primarily at a low liquid saturation which allow the maximum cross sectional area to flow within the pore system, and therefore the highest level of permeability[30].

If a water-based fluid is initiated into the system (middle of section in Fig. 2.5), it can be seen that high value of the water saturation in the flushed zone is originated and outcome in some trapped gas saturation[31].

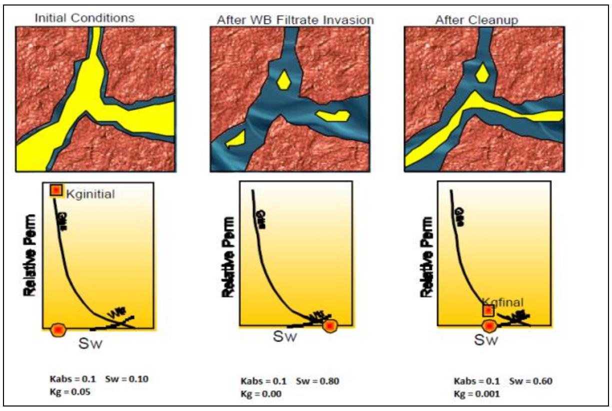

Figure 5: Mechanism of water blocking [29]

For the clean up the well by reversal of gas flow, drawdown caused by produced fluid (gas) is insufficient for tolerate the capillary pressure impacts (Fig. 2.6) It tends large value of liquid’s saturation has trapped in the porous media. Determination of decreasing in permeability value has taken from the construction of the gas-water relative permeability curves within the porous media related with this increased saturation [32,33].

6. Factors which affect the potential of water blocking damage

Various factors are under consideration while discussing phase trapping damage such as capillary pressure, interfacial tension, initial water saturation, rock wettability, type of fluid and its composition.[15, 16]. The interfacial tension between immiscible phases present in the formation can be reduced and consequently the capillary pressure, thus allowing for physical mobilization (by drawdown) of a significant portion of the entrapped phase[10,11]. The high back pressure displacement (HBPD) method was proposed by the scientist in the literature to estimate the initial water saturation and permeability measurement of tight core samples at high pressure and temperature conditions. The consequences of Aqueous phase trapping was concluded with various unfavorable conditions such as reduction in flow rate , increase in retained fluid near the wellbore and different pressure difference between casing and tubing[6, 7].

7. Effect of Capillary pressure on phase trapping damage

Capillary pressure is totally dependent on the Interfacial tensions value and they are directly reliant on to each other. If the forces between reservoir fluid and trapped phase fluid near the wellbore are high; it results increase in capillary pressure which helps to retain the saturation of the trapped fluid. It leads to reduce the permeability near the wellbore and dramatically change in the well productivity. The ultimate purpose is to decrease the capillary forces inside the formation so reservoir drawdown may displace the trapped fluid and keep well back on production with satisfactory production numbers. The mathematical relationship of interfacial tension and capillary pressure is given in the form of following equation[4,5,9].

$$P_c = \frac{2\sigma \cos\theta}{r^2} A \quad (1)$$

Where,
Pc = Capillary forces, psi
σ= interfacial tension, dynes/cm
θ = contact angle, degree
r = throat radius within pore, microns
A= 145 x 10-3 (constant, to convert in psi)

8. Prediction of phase trapping using correlation

The prediction of water trapping damage near the wellbore is very important during various stages of well development. The below equation 2 proposed to estimate the severity of phase trapping damage. The initial water saturation value and average permeability of the rock are required to substitute in the below mathematical relationship [9].

$$APT_i = 0.25\,[\log 10\,(k_a)] + 2.2\,(S_{wi}) \quad (2)$$

Where:
APTi = aqueous phase trap index
ka = uncorrected average formation air permeability (mD)
Swi = initial water saturation (fraction)

9. Methodology

The Interfacial tension meter IFT-700 was used to determine interfacial tension between produced fluid(gas) and trapped fluid(brine, diesel oil) using rising drop method at different temperature and pressure ranges. The phase trapping damage can be controlled by using IFT reducers between trapped fluid and produced fluid. Anton Par Density meter model DMA4500 was used to measure the density of these fluids at high temperature, shown in Table 2. Three fluid system were examined in the design of the experiment which are shown below [1,2,3].

1. Brine-Nitrogen system
2. Diesel oil-Nitrogen system
3. Condensate-Nitrogen system

Table 2: Density of liquids at 80 °C[1]

Fluid	Density
Brine	0.9915
Diesel	0.8198
Condensate	0.7012

The 1-D black oil simulator was chosen to run numerical reservoir simulation. The core data and density of fluid were input in the software. Three samples were chosen for the study. Diesel oil, synthetic brine and condensate sample.

10. Analysis of relative permeability and capillary pressure curves

The relative permeability and capillary pressure curves have been of great importance in evaluation of phase trapping damage. Sendra software 1-D black oil simulator was run to simulate relative permeability and capillary pressure curves at steady-state and unsteady state conditions [10]. It helps in pre-analysis of core flooding experiments and simultaneously visualization of various correlations in case of limited data available. The core properties and fluid properties were inputted into model, shown in the Table 3. The Figures 7,8,9,10 give representation of simulated results of relative permeability Kr, water saturation Sw and capillary pressure Pc using different correlations at steady and unsteady state conditions.

Table 3: Input data for model

Parameter	*Value*
No: of grids in X Direction	100
Core Length, cm	7.7
Core Diameter, cm	3.8
Porosity , Ø , frac	0.16
Permeability, k , md	18 and 0.1
Gas density	0.0199
Brine density @ 80 ºC	0.9915
Diesel density@ 80 ºC	0.8198
Condensate @ 80 ºC density	0.7012

11. Result and Discussion

Figure 9 demonstrated the unsteady state condition using Corey and Burdine correlation to generate relative permeability and capillary curves. The core sample permeability value was entered in the software as 18md that ranges lies in the low permeability reservoirs. The capillary pressure values decreases with increase of water saturation and reduction in relative permeability. The simulated capillary pressure value lies between 5-20psi and constant on most of the region. But the core sample bearing permeability 0.1md which imitate tight gas formations and run simulator using LET-LET primary drainage correlation gives reduction in capillary pressure slowly with decrease in relative permeability, shown in figure 10. It continues to zero value till the water saturation reaches almost 80% under the steady state conditions. The unsteady state condition was run through Sigmund, McCaffery & Bentsen, Asli correlation for core permeability of 18md. It has less impact on the capillary pressure reduction as compared to tight gas formation and ranges lies from 95-15 psi with increase of 75% of water saturation and less value of relative permeability 10%, mentioned in Figure 11. The , Chierici & Skjaeveland correlation run for unsteady state condition for a core sample permeability 0.1md said negligible amount of capillary pressure throughout region of the simulated graph in the Figure 12. At the end, capillary pressure value dramatically becomes zero with increase of water saturation 80% within the formation.

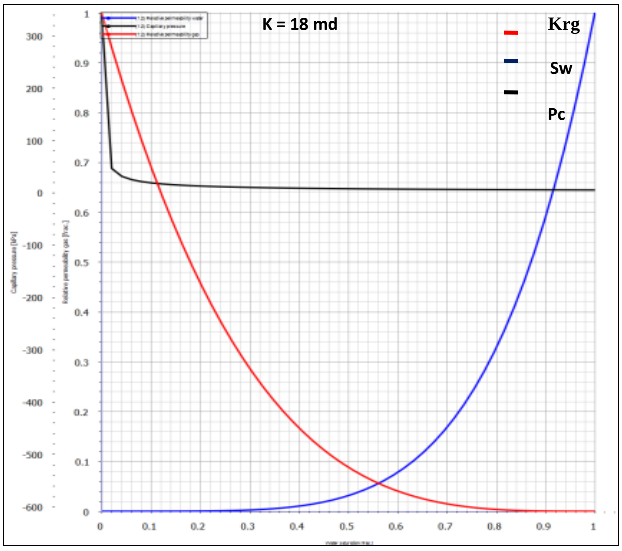

Figure 9: Relative permeability and capillary pressure curves at unsteady state condition, Corey and Burdine correlation

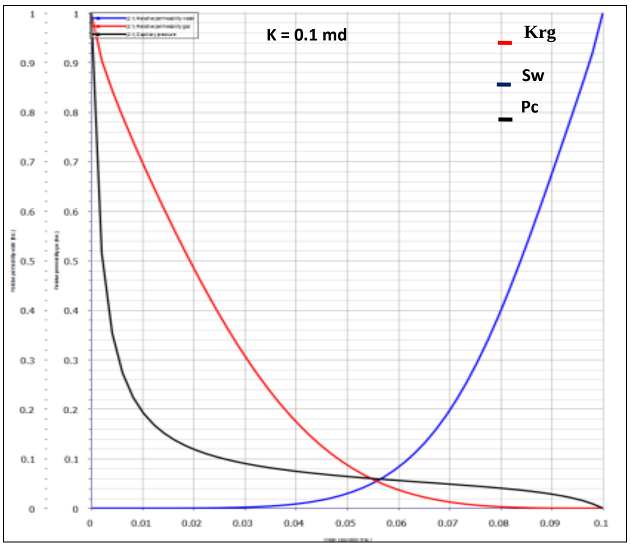

Figure 10: Relative permeability and capillary pressure curves at steady state condition, LET & LET primary drainage correlation

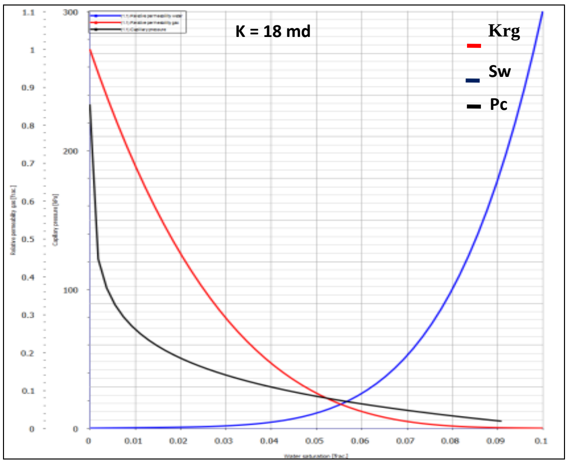

Figure 11: Relative permeability and capillary pressure curves at steady state condition, Sigmund, McCaffery & Bentsen, Asli correlation

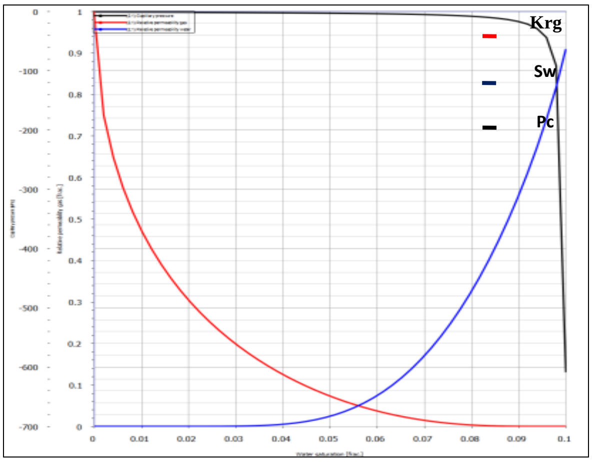

Figure 12: Relative permeability and capillary pressure curves at unsteady state condition, Chierici & Skjaeveland correlation

12. Conclusion and Recommendations

i) The simulated results showed the capillary pressure has high values in the low permeability core samples at unsteady state condition and less amount in the tight core samples under steady state condition using different correlations.

ii) The validation of the simulated results confirms with the core flooding experiments under steady state and unsteady state conditions with core permeability ranges from 18md to 0.1md samples. The reservoir conditions should be maintained at 1800-2500psi and temperature range up to 60C to 100C to imitate actual reservoir environment.

iii) The proper evaluation of the capillary forces and interfacial tension help to understand the phase trapping damage near the wellbore within the tight gas reservoirs.

iv) Furthermore, the effect of flow rate, porosity and permeability of tight core sample can be studied with help of core flooding experiment.

v) The relationship of porosity and permeability with differential pressure drop during the core flooding is also an important factor to better understanding the phase trapping damage in the tight gas reservoirs and optimize the hydrocarbon productivity

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