Evaluation of Petrophysical Properties of an Oil Field and their effects on production after gas injection

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Abstract
This paper presents results of a study conducted to determine and evaluate Petrophysical properties of an Oil Field and their effects on production from this field while under gas injection. To estimate most of petrophysical properties of this oil field, we used well logs. After determining and evaluating petrophysical properties of this field, we describe how these properties affect reservoir quality and EOR strategy.

Introduction
Petrophysical of any oil field include reservoir fluid properties and reservoir rock properties. In other words these properties are divided into static petrophysical properties and dynamic petrophysical properties. Dynamic petrophysical properties are related to reservoir fluid and static petrophysical properties are related to reservoir rock. Petrophysical properties of oil reservoirs affect their ultimate recovery and amount of oil production. These properties include porosity, permeability, viscosity, wetability, fluid saturation, mobility, fracture distribution, drive mechanism, etc.
Reservoir engineering calculations are based on the petrophysical properties of reservoir rocks that contain fluids. First, general lithologic type of reservoir rock and their different petrophysical properties are obtained out. Then we must deal with rock porosity and fluid saturations, which important to reservoir engineering because they are the principal factor involved in determining the amount of oil and gas originally in place. These are various methods of measuring porosity. Then we must deal with permeability, a measure of the ease with which fluid flows through the pore spaces of rock. Absolute, effective and elative permeability are described and their importance and interrelationships pointed out.
Production from any of the oil fields is accompanied by a pressure decline. The rate of propagation of the pressure decline is such that the pressure may be significantly reduced many miles away from a producing well. Therefore to prevent pressure drop due to oil production from a reservoir we must inject gas in the reservoir to be able to at least establish the reservoir pressure. Petrophysical properties of a reservoir affect recovery factors and recovery methods. In this paper, we have studied petrophysical properties of an oil field to determine how these properties affect oil production and ultimate recovery.

Rock Properties and their Effects on Reservoir Quality
The average matrix permeability and therefore the pore type distribution in a reservoir is most important factor in reservoir characterization and EOR planning. The petrophysical properties such as porosity, permeability, saturation and capillary are related to engineering parameter of permeability and saturation. Most of the oil in the fracture is naturally depleted in the first

phase of production. Capillary – trapped oil in the dense area of the reservoir is the main target for EOR phases. Three main classes of rock fabric are found in this reservoir. Class1 rock fabric mainly consists of limestone, dolomitized grainstone and grain dominated dolopackstones. Class2 rock fabric consists of grain dominated packestones, grain dominated dolopackestones and mud dominated dolostones. Class 3 rock fabric consist of mud dominated wakestone and mudstone. Various type of connected pore such as interparticle, inter crystalline, touching vugs and fracture were found in this reservoir, while moldic and separated vugs are the main type of the non-connected pore. Main pocket of the oil were found in the dense non-fractured sector of this reservoir. The layer with well-connected network of micro-intercrystalline inters granular nad vuggy porosity are the best target in the development phases of this reservoir.

The reservoir characterization is the bases of reservoir development. The reservoir properties are mainly consisting of static properties like texture, rock fabric, porosity, permeability etc. and dynamic properties like fluid properties, pressure, temperature etc. Geologists divide the rock type according to their mineralogical composition, grain size and texture while petrophysist classified the rocks on the basis of their petrophysical properties mainly porosities and permeabilities. These parameters make the basis of reservoir characterization. The relation of petrophysical parameters such as porosity, permeability and saturation is the key factor in reservoir characterization. Logs, core analyses and production data, pressure buildup data provide quantitative measurements of petrophysical parameters in the vicinity of the well bore. Studies that relate rock fabric to pore-size distribution, and thus to petrophysical properties are key to quantifying geologic models in numerical terms for input into computer simulation.

In this study on basis of porosity derived from log analysis, porosity and permeability derived from routine core analysis and visual porosity from petrography study, the reservoir were divided into 3 different rock fabric classes. Log data from several wells were analyzed and correlated with core data and petrography data from the same well. Several types of porosity were identified in this reservoir. The main type of porosity are mainly inter granular, inter particle touching vugs and fractures, forming inter connected pore system. Non touching vugs, moldic, chanel and fenestral are other types of porosity. Intergranular porosity is mainly found in grainstone and thinly bedded sandstone with high permeability and good porosity permeability relationship. Vuggy porosity is mainly found in dolostone and some wackestone while moldic porosity are mainly in wackestone packestone rock type. Rock fabric classification based on the petrophysical parameters for this reservoir indicates that: I) Zone one of this reservoir is petrophysically classified as class 3 and 2 rock fabric within the permeability fields of less than 100 micrometers. II) Zone 2 is mainly in class 2 rock fabric with grain dominated pack stone within the permeability field of 20 to 100 micrometers and class one rock fabric within the permeability field of more than 100 micrometers. III) Zone three is mainly classified as class 3 rock fabric within the permeability field of less than 20 micrometers and considers as a pore reservoir. IV) Limestone indicates wide range of porosity permeability relationship as compare to dolostone due to wide range of pore type distribution. VI) Connected pore types in this reservoir are mainly inter granular inter particle, touching vugs and fractures, forming inter connected pore system.

Fluid Injection Problems of this Reservoir

We studied key physical mechanisms and calculation methods for fluid flow in this fractured reservoir. The main matrix – fracture fluid exchange mechanisms described are gravity drainage, capillary imbibition and molecular diffusion. Important issues such as capillary continuity between matrix blocks, reinfiltration of fluids from higher to lower blocks and effect of block shape on flow processes are also addressed simulation studies of water flooding in fractured reservoirs are reported for the purpose of identifying the effects of gravity and capillary forces on oil recovery. Included are studies of effects of capillary continuity and degree of wetting. The results show that for intermediately wetted systems, capillary continuity has a major effect on oil recovery. Laboratory processes involving high pressure gas injection in fractured systems have been studied by compositional simulation. The results show that changes in interfacial tension caused by diffusion may have effects on oil recovery.

The only solution to more representative modeling of flow in fractured reservoirs is more detailed calculations. A multiple grid concept is proposed which may drastically increase the detail of the simulation. Numerical modeling of naturally fractured reservoirs using dual porosity models has been the subject of numerous investigations. In the dual-porosity and dual-porosity / dual-permeability formulations most commonly used to model fractured reservoirs, proper representation of imbibition and gravity drainage is difficult. In some formulations, attempts have been made to represent correct behavior by employing a gravity term and assuming a simplified fluid distribution in the matrix. Despite the efficiency of water flooding in fractured reservoirs, considerable oil will be left behind due to relatively high residual saturations. This residual oil may be a target for high pressure gas injection.

The recovery mechanisms involved in high pressure gas injections in fractured reservoirs are complex and not fully understood. They include viscous displacement, gas gravity drainage, diffusion, swelling and vaporization/stripping of the oil. Inter facial tension gradients caused by diffusion may also play an important role on the overall recovery. Viscous displacement normally plays a minor role, except perhaps in the near vicinity of the wells where the pressure gradients are large. Contrary to conventional reservoirs, diffusion may play an important role in fractured reservoirs. The injection gas has a tendency to flow in the fractured system, resulting in relatively large composition gradients between fracture gas and matrix hydrocarbon fluids. Thus there is a potential for transport by molecular diffusion. This is especially the case in reservoirs with a high degree of fracturing (small matrix block sizes). Diffusion is difficult to model. A problem arises when gas is injected in an under saturated reservoir. The minimum contact saturation between the fracture and matrix grid block will be zero, and no diffusion between the two media will be calculated. With matrix block heights lower than the capillary entry height, no mass transfer between fracture and matrix system will be occur.

Physically, the mechanism for gas entering from the fracture to an under saturated oil would require an ultra-thin contact zone at the fracture / matrix interface. In this zone a small amount of equilibrium gas will exist, and diffusion transfer between fracture and matrix can occur via this zone, as gas-gas diffusion between fracture gas and equilibrium gas in the two phase zone, and as liquid-liquid diffusion between under saturated matrix oil and saturated oil in contact zone.

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The simulated results indicate that the recovery can roughly be divided into three production stages: 1- primary swelling of the oil 2- secondary swelling and vaporization 3- final vaporization of the oil. The initial stage is dominated by swelling of the oil inside the core, due to liquid-liquid diffusion between the under saturated oil inside the core and the saturated oil at the outer surface of the core. The light components of oil (mostly methane) diffuse into the core, while the intermediate oil components from the core diffuse to the outer contact zone. During this stage there is some viscous flow from the center of the core to the fracture, due to swelling of the oil and interfacial tension gradients. The oil produced to the fracture is vaporized by the injection gas and no free oil is observed. The first stage ended when some of the oil within the core first became saturated. This marks the beginning of the second stage m where free gas saturation advances toward the center of the core. As the gas front advances, the gas – gas diffusion will play a more dominant role on the recovery process. During this stage, mainly light-intermediate, and the intermediate components of the oil are vaporized. When the light-intermediate and most of the intermediate components have been recovered, the third stage begins. During the last stage, mostly heavy- intermediate and heavy components are vaporized. This stage is slow compared to the first two stages, but a large additional recovery may be achieved. So we can say that high pressure gas injection may yield high oil recoveries due to reduction in interfacial tension caused by diffusion.

Field Characterization

Fractures

This reservoir has some fair fractures which make connection between the pore volume across and along the reservoir. Generally the most fracture extends in reservoir crest. The good connection at the west shows the fracture consequently where as shale layers in half part of reservoir reduce vertical permeability.

Production Mechanisms

The production mechanisms of this reservoir are as follows: 1- Gravity segregation in fractures 2- Capillary– gravity displacement between matrix and rock cracks in water wet reservoir. 3- Weak water drive near WOC 4- Gas drive 5- Dissolved gas

Average Reservoir Permeability

To determine the average permeability (fracture and matrix permeability), the build up pressure well test was done and ported to eclipse well test software. The following results achieved: 1- Average permeability = 5.62 2- Skin factor = 3.05
Thus the fracture makes the good system grid but there is negative skin effect.

Vertical vs Horizontal Permeability

Since the permeability measurements in the laboratory have been made on core plugs of small size, normally it is not expected that the vertical permeability to be different from horizontal permeability except that the formation is highly laminated. Presence of shale and anhydrite streaks, stylolites and valcilite filled fractures all restrict vertical flow and on the layer sizes common in the simulation models, they will cause a reduction in vertical permeability. A fraction of 0.1 is quite common to be applied to horizontal permeability and use it for vertical permeability.

Grain Density

Grain density has been measured on core samples of wells. The mean and median grain densities are calculated to be 2.809 and 2.800 respectively, which are almost the same due to the symmetry of the distribution. Small frequency of low grain density values is an indication of rare presence of sandstone in the main carbonate reservoir.

Average Reservoir Porosity

Using 15 well logs, average reservoir rock porosity was estimated to be 8.9%.

Water Saturation

Water saturation is a function of porosity and for this reservoir is estimated: Sw = 28 %.

Buble Point

Buble point of this reservoir is constant in a 11oil well PVT data in at 150° C: P_b = 2956.

Fluid Level Contacts

Gas oil contacts in north, south and west of this field is calculated by means of average oil and gas pressure and are 1601, 1601, 1601 sub sea meter respectively. Oil water contacts are 1896, 1886 and 1885 for north, south and west side of reservoir respectively.

Fluid Pressure

Oil pressures according to static pressures are 2481, 2474 and 2456 psi for north, south and west side of reservoir respectively in reference depth of 1800 meter sub-sea. Gas pressure is measured in 1100 meter sub-sea and are 2166, 2161and 2137 psi for north, south and west side of reservoir respectively. Water pressures are measured in 2150 meter sub-sea by static pressure test and are 2930, 2950 and 2950 for north, south and west of this reservoir respectively.

Production Gas Oil Ratio (GOR)

In accordance to the tests which is conducted in this reservoir, the initial gas oil ratio (GOR) of this reservoir was measured to be 700 cubic feet per barrel. Because the reservoir is a saturated reservoir and pressure drop due to oil production from this reservoir the gas oil ratio decreases and now this is 600 cubic feet per barrel. Initial gas oil ratio (GOR) which was measured by PVT tests was 860 cubic feet per barrel of oil.

Rock Type

According to the cores from wells we studied this reservoir rock and depends on porosity, permeability and water saturation, we divided this reservoir into five section by means of petrophysical logs.

Gas Injection in this Field

We inject 400 MMscf/D gas this oilfield to prevent its pressure depletion and to increase pressure of the reservoir. Gas injection in this field is performed by a gas compressor station. The variation of fluid composition with depth in a reservoir is called compositional grading.

As depth increases, the mole fraction of light components decreases, density increases and GOR decreases and accurate characterization of reservoir fluids becomes more critical. In this oilfield, we inject gas to gas cap of the reservoir. This fractured carbonate reservoir is produced under natural depletion mechanisms at the all of its life time. In this reservoir, oil properties vary with depth. The bubble point pressure decreases with depth along with values of oil volume factor and solution GOR (gas–oil ratio). Oil gravity and viscosity increases with depth. Gas injection in this field is done through 6 injection wells. We inject gas to reservoir by these six wells and produce by oil production wells. To have a good injection in naturally fractured reservoir, we must have: a) good design of facilities for gas injection b) good reservoir properties for gas injection.

Field Production Problems

This reservoir is a non homogeneous reservoir and has two gas caps. Its reservoir rock mainly contain of calcite carbonate and dolomite rocks with layers of shale and salt in different parts of reservoir. Depending on the petrophysical data, this reservoir divided into four sections which is separated by shale layers with low porosity from each other. Distribution of shale layers in the reservoir is such that there is a connection between zones vertically. In its production view, this reservoir has divided into three section which are south, north, and south sections of this reservoir is very good but in the west section we have a bad production because of existing a salt and calhore layer and ack of a good fracture system. Oil loss per each barrel of produced oil is .25 and its pressure drop is .87 psi per million barrel of produced oil .because this is a fractured reservoir, an amount of the gas which is injected into the reservoir goes into the empty fractures of oil and goes into the production column of oil wells and come back to the surface with produced oil and cause some producing problems in oil production units and oil pipelines which transports oil from wells to production units.

Two main production mechanisms in this field are solution gas and gas cap gas expansion

Because the reservoir rock in west section is a dense rock, well completion in this section must be open hole. There are some wells in this section which were completed as a cased hole well and this is a cause for insufficient production from this section. Because of a very large numbers of vertical and horizontal fractures in reservoir rock, drilling operations in this formation is generally with high loss and because lack of control facilities to control this loss, well drilling is stopped and we can not reach to predicted depth and can not receive to final purpose of horizontal wells for optimization and longer production from this reservoir.

Conclusions

1- Reservoir of this field is a fractured carbonate reservoir with un uniformly distributed fractures throughout the reservoir 2- The numbers of fractures in crest of reservoir is more than other parts 3- This reservoir is a saturated reservoir and has a gas cap throughout the reservoir. 4- In accordance to PVT tests and oil properties, oil composition throughout the reservoir is the same 5- Oil production from north and south sections are better than west section. 6- To now about 59 % of initial oil reserve of this reservoir has been produced. 7- Oil loss is 25% for each barrel of produced oil. 8- Reservoir pressure drop is 0.87 psi for each one million barrel of produced oil. 9- In most cases production of this reservoir is by means of gravity drainage. 10- Delay in starting gas injection causes a more oil loss and pressure drop.

11- Gas injection in this field must be continued to increase pressure and to prevent pressure drop. 12- Any drilling in this field must be done by under balance drilling technique. 13- Decreasing oil production from this field to let it for compensating energy loss to prevent more oil loss. 14- The reservoir rock permeability is low and to increase oil production we must increase gas injection to maximum capacity and to let the oil in matrix enough time to go to oil column other wise, by increasing oil producing rate, oil column will be decreased and because of a large amount of fractures in this reservoir oil producing wells will connect to gas cap gas injection causes oil column to go down and increasing gas production from oil wells.

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