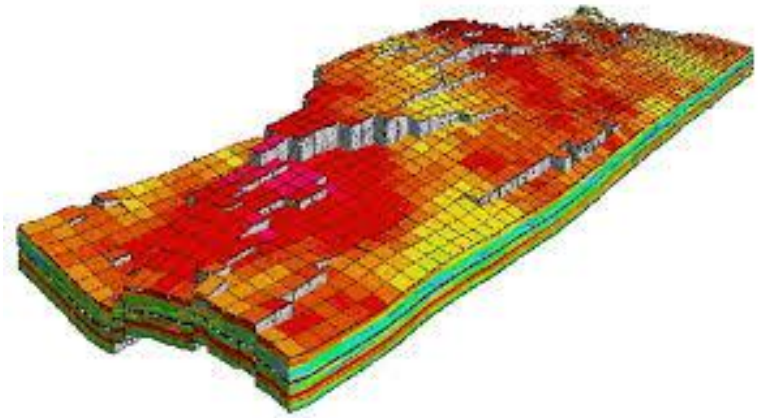
Technical University of Crete
School of Mineral Resources Engineering
MSc in Petroleum Engineering

Diploma Thesis:

'Tracers flow in fractured reservoirs'



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Abstract

This diploma thesis focuses on examining the fluid flow in a fractured reservoir, as well as the simultaneous flow of fracture/matrix systems. Fractured reservoirs have many differences comparing with the conventional ones. A reservoir might be naturally fractured, but also fracturing is a technique that is applied in the subsurface sediments, in order to improve the oil recovery during the production.

In addition, there is an extensive description of the recovery mechanisms of a fractured reservoir, according to the literature, although it is still a complicated issue the way that the fractures contribute to the hydrocarbon recovery and the performance of a reservoir.

Finally, it is mentioned the use of tracers applications in the oil field. Particularly, in this study, tracers are involved to understand and visualize, in some manner, the fluid flow in a fractured reservoir.

Acknowledgments

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Chapter 1:

Introduction

The study of fractured reservoirs is a subject that is described extensively in the literature in the last decades. It was only in the early nineteen fifties, with the important discoveries in the Spraberry trend of West Texas and giant fields in the Middle East that an increasing interest for this type of fields started.

A fractured reservoir is defined as a reservoir, where the fractures have a significant impact on performance and recovery. Such fractures are formed either naturally, during specific events in geological history, or artificially. Fluid flow in fractures is of interest to engineers in many aspects. It is estimated that 25-30 % of the world's total oil output nowadays is from fractured reservoirs.

The evaluation of fractured reservoirs is by processing the observed data, examining the flow behavior towards a well and analyzing reservoir behavior during a field's entire history, through its specific production mechanisms. The impact of gravitational and capillary forces shows that the conventional roles of water-drive or solution gas-drive are completely modified in a fractured reservoir.

The characterization of subsurface formations is a multidisciplinary field that is applied to hydrocarbon bearing zones and subsurface hydrology. The application of reliable tracer transport model approaches is a key issue to derive the hydrodynamic properties of aquifers. In other words, tracer is a tool to investigate the mass transfer in structured porous media.

1.1 Thesis Scope

The scope of the current diploma thesis is to simulate a fractured reservoir in *ECLIPSE* simulator program and also describe the fluid flow in such a reservoir using different tracer models. Tracers are injected in the reservoir through a water injection well. Also, there is an extensive mention to the recovery mechanisms that take place in a fractured reservoir, which are useful to the production procedure, in order to have the best possible hydrocarbon recovery.

1.2 Thesis Overview

The second chapter of this thesis is related to the theory of what does a fractured reservoir mean and the basic parameters of a fractured reservoir, comparing with those of a conventional one. Also, there is a mention of some useful and of great importance properties like wettability, capillary pressure and relative permeability and finally there is an analytical description of the recovery mechanisms, according to the literature.

The third chapter is a description of the way that *ECLIPSE* software simulates a fractured reservoir and the options that are available. The fourth chapter is an application of a fractured reservoir in *ECLIPSE* with the injection of totally nine tracers, through the water injection well. The properties and the characteristics of the matrix/fracture system are denoted separately. The results, concerning the tracers concentration, during the production procedure, are presented in the end of the chapter.

Finally, the fifth chapter refers to the simulation of the same fractured reservoir in *ECLIPSE*, using dual porosity/dual permeability options. The aim is to compare the results of these two different options of simulation in *ECLIPSE*. In appendix 1 and 2 of this thesis, there are the complete codes in *ECLIPSE*, that are used for the above purposes.

Chapter 2:

Theory

2.1 Definition of fractured reservoirs

A reservoir is defined as fractured only if there is a continuous network of fractures throughout the reservoir. In a fractured reservoir two distinct porous media systems are existed. One is the highly permeable fractures that conduct most of the flow and the other is the low permeable matrix, where most of the oil is contained. Since the permeability of the fractures is much higher than the matrix permeability, the fluids will flow towards the well through the fractures and the matrix will feed the fractures with oil and gas.

The evaluation of fracturing is far more complex than the evaluation of porosity and permeability in a conventional reservoir. In fact, the fracturing depends on the pattern of mechanical stresses of the rock material and rock properties. Hence, the results of fracturing, such as fracture openings, size, distribution, orientation, etc, will be related to stresses and type of rock (brittle or ductile), structural conditions, depth (overburden stress), lithology, bed thickness and several other parameters.

The study of the geology of a fractured reservoir requires the study of the relationship between the fracturing process and the geological events, which took place during this phase. This includes the elaboration of a correct theory of fracturing and a valid diagnosis of the features of a fractured reservoir. Rock fracturing will most commonly have a tectonic origin, developing in folded beds or in connection with faulting or joint patterns.

In general, the understanding of the fracturing process has recently progressed from an empirical to a more scientific approach, and therefore, reservoir description and reservoir modeling has benefited.

Fracture detection and evaluation is accomplished during the various operations in both the exploration and production phases of oilfield development. Methods and techniques include operations such as drilling, logging, coring and testing. The best quantitative information concerning fracture parameters is obtained by direct measurement on outcrops and on cores obtained during drilling operations.

2.1.1 Basic Parameters of fractures

The variations in space of fracture characteristics, such as size, orientation and description are so irregular and complicated that the description of such a reservoir is substantially difficult and complicated. Therefore, the study of a fractured reservoir must follow a special pattern, beginning with the examination of local basic characteristics of single fractures, only afterwards continuing with the examination of a multi-fracture system.

Single fracture parameters refer to the intrinsic characteristics, such as opening (width), size and nature of fracture. If the single fracture is associated with the reservoir environment, another essential characteristic is the fracture orientation.

The multi-fracture parameters refer to the fracture arrangement (geometry), which further generates the bulk unit, called the matrix block. The number of fractures and their orientation are directly related to fracture distribution and density. When fracture density is related to lithology, another parameter of particular interest is fracture intensity.

I. Single Fracture Parameters

a. Fracture opening

Fracture opening or fracture width is represented by the distance between the fracture walls. The width of the opening may depend (in reservoir conditions) on depth, pore pressure and type of rock. The fracture opening depends on the lithological-petrographic characteristics of the rock, nature of stresses and reservoir environment.

b. Fracture size

Fracture size refers to the relationship between fracture length and layer thickness, especially if a qualitative evaluation is to be formulated. In this case fractures can be evaluated as minor, average and major.

- minor fractures have a length less than the single layer pay
- average fractures traverse more layers
- major fractures have a very large extension, often tens or even hundred of meters.

c. Nature of fracture

The nature of fractures mainly concerns the state of fractures under observation with reference to opening, filling and wall characteristics and is generally discussed in the following terms:

- opening-open, joint, closed
- filling-mineral, various minerals
- closed by - homogeneous or diffused filling material
- fracture walls-rugose, smooth, polished, creeping

d. Fracture orientation

Fracture orientation is the parameter, which connects the single fracture to the environment. From comparison of the orientation of the various single fractures it follows that all parallel fractures belong to a fracture system. If more intercommunicating systems are recognized in a reservoir, those systems will form the fractured reservoir network.

II. Multi-Fracture Parameters

a. Fracture distribution

In a fracture network, which contains two or more fracture systems, each fracture system will generally be generated by a certain state of stress. Fracture distribution is then expressed by a degree of fracturing factor. This factor will be stronger if there is continuous intercommunication among the fracture systems and if the systems are equivalent to each other. The degree of fracturing will be weaker if the intercommunication among the fracture systems is interrupted and if the fracturing of one system prevails over the other.

b. Matrix block unit (trapped bulk)

The fractures which cut the reservoir rock in various directions, delineate a bulk unit referred to as the matrix block unit or simply the matrix block. Since around any single block a continuum exists, each single block will be hydro dynamically separated from the adjacent blocks. It is thus correct to consider that each bulk unit is, in fact, trapped inside the fracture network. In reality these blocks are in contact through leaning points, but the hydrodynamic communication between blocks remains practically interrupted. The matrix blocks are defined by shape, volume and height, in relation to the fracture system's dip, strike and distribution. The shape of the matrix block is irregular, but for practical work the block units are reduced to simplified geometrical volumes, such as cubes or as elongated or flat parallelepipeds.

c. Fracture density

Fracture density expresses the degree of rock fracturing through various relative ratios. If the ratio refers to the bulk volume the fracture density is called volumetric fracture density. If the ratio refers to the area or to a length the fracture density is called areal or linear fracture density. The volumetric density is a static parameter (similar to the porosity), while the areal and linear densities are associated to direction of fluid flow.

d. Fracture intensity

If a quantitative analysis of fractures has to be carried out, it is necessary to associate the fractures with the lithology, pay and tectonic mechanisms of the layers, which contributed to the formation of the fractures. In order to make the tectonic examination of this problem possible, it is necessary to weight the fracture parameters with the thickness and lithology. Since areal and linear fracture densities and cumulative frequencies are used for the same layers or for similar layers, it is necessary to use another parameter, called fracture intensity, if the pay is very much contrasted.

2.2 Wettability

Wettability is defined as the tendency for one fluid to wet a rock surface in the presence of another fluid. It is a characteristic property of the rock fluid interaction.

In the petroleum section, wettability is associated either with water-wet rocks or with oil-wet rocks. If a rock is completely water-wet, an oil-field core that is submerged into water will be completely filled with water. On the other hand, for a completely oil-wet rock, no water will be imbibed when submerged into water. No rocks are gas-wet, so in order to get gas into the pores of a rock, capillary pressure need to be applied, so that the gas will be forced into the rock. This pressure is equal to the pressure that is needed to force a droplet of oil out of the biggest pore.

2.3 Capillary Pressure Curves

In a fractured reservoir the capillary pressure curve plays a much more important role than in a conventional reservoir. Capillary forces in fractured reservoirs are one of the driving mechanisms, while the role of capillary pressure for a conventional reservoir is more limited. Capillary pressures oppose drainage for a gas-oil system, but might help for a water oil imbibition system.

Capillary pressure is defined as the pressure difference between two immiscible fluids:

$$P_c = P_{nonwetting\ phase} - P_{wetting\ phase} \quad (1)$$

In oil-water systems, water is typically the wetting phase and for a gas-oil system, oil is always the wetting phase.

If a reservoir rock is fully saturated by a wetting phase, the displacement of this phase by non-wetting phase will be related to the capillary pressure magnitude and to the corresponding decrease of the wetting phase saturation. This displacement is called drainage displacement and the relationship between capillary pressure and saturation is known as the drainage capillary pressure curve (figure 1).

Imbibition capillary pressure develops when reservoir rock is saturated with a non-wetting phase, which must be displaced by a wetting phase. For a conventional pore distribution the imbibition capillary pressure is approximately half of the order of magnitude of the drainage pressure and therefore the curve will show a considerable hysteresis between drainage and imbibition displacement of the same rock. An essential characteristic of both curves (drainage and imbibition) for two slightly compressible fluids (oil and water) is the minimum saturation of the wetting phase.

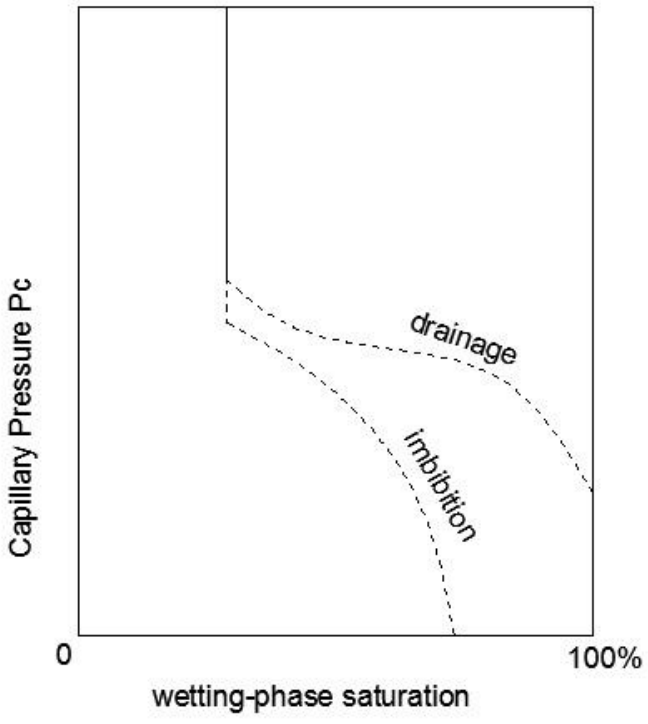

Figure 1: Drainage and imbibition capillary pressure curve

The shape of the drainage capillary curve reflects the homogeneity of the pore size. The capillary pressure curve depends essentially on type of displacement, drainage or imbibition. In the case of a drainage displacement, capillary forces oppose the entrance of a non-wetting phase into the matrix, while in an imbibition displacement capillary forces act as a driving force in displacing a non-wetting phase from the matrix. In a fractured reservoir the relationship between fluid saturating the matrix block and fluid saturating the fracture will determine (during production process) if a drainage or imbibition process takes place. This relationship may be simplified as follows:

MATRIX	FRACTURE	TYPE OF DISPLACEMENT
Oil	Water	Imbibition
Oil	Gas	Drainage
Water	Oil or Gas	Drainage
Gas	Water or Oil	Imbibition

Figure 2: Drainage or imbibition process

The discontinuity of the matrix caused by the fracture network cutting the continuum of the matrix bulk into small individual matrix blocks, explains why the water table is only related to the fracture network. In addition, since the fractures are large channels with negligible capillary forces, the transition zone disappears in a fractured reservoir, and water-oil contact becomes a horizontal plane. On the other hand, capillary and gravitational forces (through the capillary pressure curve and gravitational curve) control the static and dynamic equilibrium of each matrix block. The basic element which relates individual block behavior to reservoir behavior is the water-oil contact in fractures and is called water table level. These water-oil contacts in fractures, together with the oil-water contacts inside the matrix, the last corresponding to displacement front level, are essential reference planes for the evaluation of the driving mechanism of capillary and gravity forces. An analogical situation will take place in the case of a gas-cap for

both gas-oil contacts in fractures and matrix blocks, where the first is called gas-cap table and the second gas displacement front.

2.4 Relative Permeability

Relative permeability is the ratio of the permeability of a fluid at a particular saturation over the permeability of that fluid at 100% saturation. For the oil the formula would take the following form:

$$k_{ro} = k_{oil} / k_{absolut} \quad (2)$$

The relative permeability is one of the most significant parameters used in reservoir simulation, as it is critical in the prediction of the flow rate of a phase in the presence of another.

In a fractured reservoir, evaluation of relative permeability is difficult, since we have a discontinuity in the multiphase flow, when going from matrix to fracture. As relative permeability is one of the key parameters to the recovery versus time curve, this could in a dual porosity simulation be used as a history matching parameter to better match the recorded history or results from a single porosity run. Traditionally, relative permeability in fractures is assumed to be a straight line, only dependent on the fluid saturation.

It is important to mention that capillary pressure, wettability and relative permeability are all linked closely together.

2.5 Recovery Mechanisms

Reservoir engineers often try to predict the future behavior of a fractured reservoir by examining its past history and estimating its future behavior through conventional reservoir approaches and procedures. But, unfortunately, very seldom will the behavior resulting through conventional reservoir calculation procedures match with the real past history of a fractured reservoir. A matching may be obtained only modifying the basic data to a completely unrealistic extent.

Fractured reservoirs can be classified into three different groups. For group one, the bulk of the hydrocarbon resides in the matrix and fracture pore volume is very small in comparison to the matrix pore volume. In group two, most of the hydrocarbon is in the matrix, but fracture pore volume could be as high as 10 to 20%. For group three, more than half of the hydrocarbon resides in the fracture and in some cases, the contribution of the matrix can be negligible. For all three groups, the matrix permeability is often low. The ultimate recovery from fractured reservoirs varies widely from less than 10% to over 60%.

There are fundamental differences between recovery performance of fractured and unfractured reservoirs. Capillary is the main cause of this difference. More specifically, the difference in capillary pressure of matrix and fractures has a significant effect on recovery performance of fractured reservoirs. Figure 3 illustrates the main oil recovery mechanisms of a fractured reservoir.

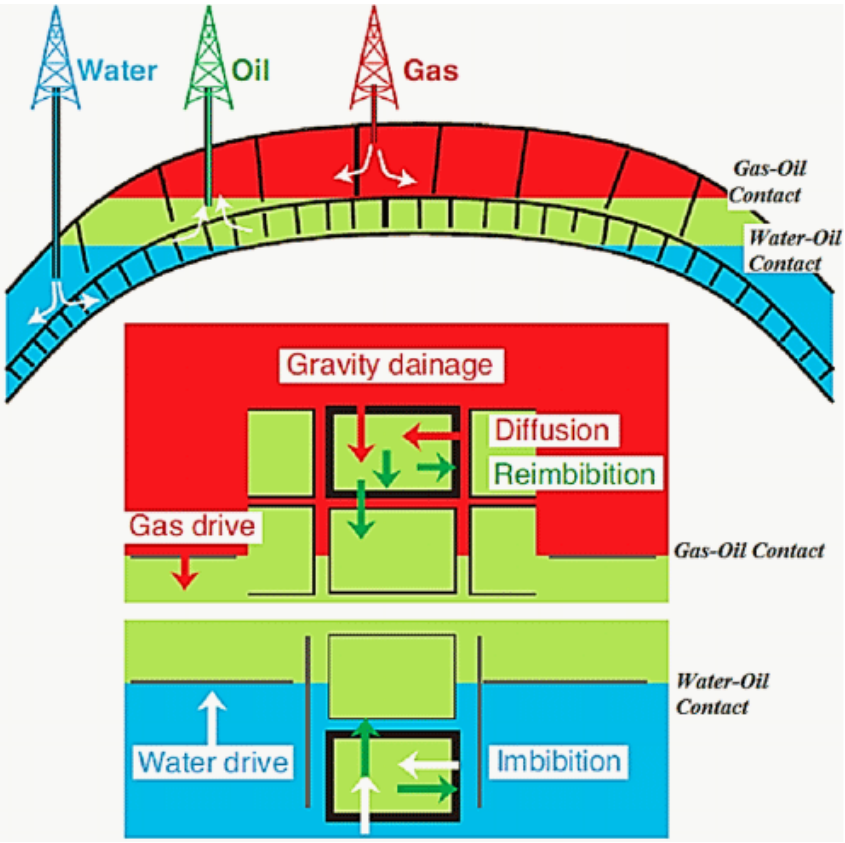

Figure 3: Main drive mechanisms in fractured reservoirs (Journal of Petroleum & Environmental Engineering, April 28,2011)

An analytical presentation of the main recovery mechanisms of a fractured reservoir is presented below.

2.5.1 Convection

Most well to moderately well-fractured reservoirs with enough dissolved gas have uniform fluid properties throughout their thick oil column. This would indicate that because of the temperature gradient, fluid convection exists within fractures, before production commences.

As production begins and reservoir pressure drops, the following processes will occur in the fracture system:

- Gas/oil level drops.

- Oil in the vicinity of the new gas/oil contact releases its extra solution gas and becomes heavier. This may create an extra force to accelerate convection within the fracture.

- Depending on the rate of pressure drop and the convective velocity, free gas released from matrix oil flows to the fracture (gassing zone).

- Oil flows from the fracture to matrix, to replace the voidage created by the release gas, mentioned above.

- Oil flows from matrix blocks to fractures, when gravity drainage takes place, within the matrix blocks in contact with the gas and/or the water invaded part of the fracture system.

- As the heavier oil in the fracture (oil with less gas in solution) comes into contact with matrix oil, which has a higher gas saturation, gas diffuses through the oil phase from matrix to fracture and matrix oil replaces this voidage in the matrix.

- In the oil zone (zone below the gassing zone), oil may flow from matrix to fracture due to the expansion of the oil. This process may be reversed, depending on the PVT characteristics of the matrix fluid, rate of pressure drop and the degree of diffusion.

In studying and analyzing the considerable reservoir history available on several well fractured reservoirs, it was noticed that, as the reservoir pressure declines, the bubble point pressure of the fracture oil, in the area directly beneath the gas cap, almost follows that at the gas oil contact. On the other hand, the oil zone, whose projection on the gas-oil surface is within the vicinity of the gas-oil circle, shows less

bubble point pressure depression, and almost no drop in bubble point pressure, if it is far away from the gas-oil circle.

As the gas cap grew larger, a proportionally greater volume of the reservoir was affected by the above process. This observation associated with reservoir analysis showed that in fact, the convective process in fractures is an important factor in reservoir engineering studies. It should be included in a more accurate form, rather than using an average value of this process for the entire reservoir, during history matching, and then extrapolating it for prediction.

In some fields the convective movement is so strong that shows no vertical temperature gradient within a few hundred feet of the producing formation. Moreover, if the rate of pressure drop is high and/or there is no convection in the fracture under such conditions, the free gas saturation, created in the body of matrix blocks, exceeds the critical gas saturation and floods the fracture oil. The mass transfer between matrix and fracture becomes simply a flow of free gas from matrix to fracture and a flow of oil from fracture to matrix. The consequence of this mechanism is that in short time the gassing zone will cover the entire oil column.

On the contrary, when a fractured reservoir is produced at a reasonably low rate, it creates a small gassing zone, whose size depends on the length of the shortest dimension of the matrix blocks in contact with the fracture. A shorter gassing zone may also be explained by the strong convective action of the liquid in the fracture, and as a result, by the diffusion of gas through the liquid between matrix and fracture.

The main force of having convection in oil reservoirs is essentially the inverse density gradient due to the formation temperature gradient. As the fracture thickness is very small, as compared with other fracture dimensions, and the inverse density gradient is due to the geothermal gradient, the possibility of having convection in a fracture is nil.

The theoretical treatment of convection is a very delicate subject. Often several possibilities may exist for which only laboratory experiments can help to find the correct one. Otherwise, one can reach misleading conclusions.

2.5.2 Diffusion

In fractured reservoirs, where the oil in the vertical fractures convects due to the temperature gradient, the process of diffusion plays an important role. It can transport large volumes of gas from the matrix block within the oil body to the gas cap, as the reservoir pressure drops. Conversely, it can take the gas from the gas cap and leave it in the matrix blocks, as the reservoir pressure increases.

In the first case, the bubble point pressure of the oil in the blocks located in the oil zone reduces, as the reservoir pressure declines. This process is called bubble point pressure depression. Whereas in the second case the bubble point pressure of the oil in matrix blocks located in the oil zone increases, as the reservoir pressure increases. This process is called bubble point pressure elevation.

The process of movement of the molecules (or mass) due to the concentration difference, in an isotropic media, is analogous to the conduction of heat due to temperature difference and to the flux of momentum due to the velocity difference. When the flow is in the x-direction, these can be written mathematically as follows:

$$f = - D \cdot dc/dx \quad (3)$$

$$q = - k \cdot d\,(\rho \cdot C_v \cdot T)/dx \quad (4)$$

$$\tau = - v \cdot d(\rho \cdot V_y)/dx \quad (5)$$

where:

C is the concentration

D is the diffusion coefficient

k is the thermal diffusivity

ρ is the density

$\mathbf{C_v}$ is the heat capacity of the flow medium at constant volume

T is temperature

v is the kinematic viscosity

$\mathbf{v_y}$ is the velocity in the y direction

The diffusion coefficient D is a measurement, which gives the speed at which the molecules of component A can penetrate the component B when these two come into contact with each other under given conditions. The flux f given by the above equation is for a two component system and is under no external forces.

In a hydrocarbon system, the diffusion coefficient is a function of concentration difference of diffusing component, temperature, pressure and interfacial tension between the diffusing component and the diffused medium. The last effect is applicable when diffusion is taking place between gas and liquid phases.

The effect of concentration on the diffusion coefficient varies depending on the nature and conditions of the diffusing components of molecules e.g. for binary gas mixture, it is almost independent of gas concentration at low pressure. In ionic molecules dissolved in water, it reduces as the concentration increases. Whereas, in gas-liquid or liquid-liquid hydrocarbons, the diffusion coefficient increases, as the concentration difference of the diffusing component increases. In general, the diffusion coefficient increases with temperature, due to the higher activity of the diffusing molecules, and reduction of interfacial resistance between the two phases.

Pressure has two contradictory effects on the diffusion coefficient in the hydrocarbon system. The diffusion coefficient decreases as the pressure increases, due to the reduced activity of the diffusing molecules. Whereas, the diffusion coefficient increases due to its reducing effect on the interfacial tension between the diffusing component (gas) and the diffused phase (liquid).

2.5.3 Solution gas drive mechanism

The solution gas drive mechanism plays an important role in oil recovery and in analyzing the past history and future performance of most reservoirs. This is particularly true in the case of fractured reservoirs. This is because the rate of pressure drop in some fractured reservoirs is as low as a few bars per year. Moreover, as the matrix blocks in fractured reservoirs are small compared to the oil column thickness, the segregated gas only has to travel a short distance before it reaches the fracture system. The gas which leaves the matrix blocks in this manner can easily join the gas cap through the high permeability fracture system. Furthermore, the pressure variation between the wellbore and its radius of drainage is normally small and is limited to a very short distance, whereas in sandstone reservoirs it can be fairly large.

A series of solution gas drive experiments are made by varying the rate of pressure drop, using small size permeable cores and fluid, with different bubble point pressure. The volume of free gas saturation, occupying the pores, was measured at the end of each experiment.

Solution gas drive mechanism depends on the rate of pressure drop, diffusion, interfacial tension between gas and oil and the degree of inhomogeneity of reservoir rock.

2.5.4 Gravity drainage and imbibition

Gravity drainage is another important recovery mechanism in oil producing reservoirs. In fractured reservoirs this mechanism plays the major role in hydrocarbon recovery from low permeability matrix blocks when their height is sufficient.

In fractured reservoirs the presence of vertical fractures makes the gas-oil or water-oil contact advance ahead of the corresponding contact in the matrix blocks. It is the difference between the density of the fluids and the elevation of the two contacts that causes the fluid in the block to become unstable and thus hydrocarbons are produced from

the matrix blocks. This drainage process is similar to the free fall gravity drainage by water or gas.

In forced gravity drainage, the rate of injection for the displacing fluid is fixed in advance by the fluid density difference, permeability of the rock and the difference between the fluid contact in matrix and fracture. In this case the rate of fluid displacement is related to the pressure difference acting on each fluid in the matrix block. The pressure difference is due to the difference in fluid densities in fracture and matrix. Whereas, in free fall gravity drainage the displacement is related to the weight of the displaced fluid, which by its nature should move downward.

From the above simple definition it can be noted that to produce a reservoir with one mD permeability, under free fall drainage, takes about 1000 times longer than the same reservoir having one Darcy permeability, if their relative permeabilities were the same. This clearly shows the role of fractures in the low matrix permeability fractured reservoirs, which provide the pressure difference and thus expediting the drainage process. As a result, in free fall gravity drainage and fluid density difference is the cause of oil movement (except in the zone which gas is rather immobile), whereas in a dual permeability reservoir, the density difference between the two phases and the block height are the main cause of the oil displacement.

In laboratory models, when, for instance, gas is slowly injected from the top of a vertically oriented block, while oil is produced from the bottom at a given pressure, the system follows the free fall gravity drainage. Whereas, when the top and bottom sides of the vertical core are connected through a by-pass tube filled with the displacing gas, it produces under forced gravity drainage. Low pressure reservoirs can be produced under forced gravity flow, if the water-oil level is introduced to the atmosphere and the necessary volume of gas is injected from the top.

There is no breakthrough phenomenon in the forced gravity drainage, whereas the free fall gravity drainage can be associated with breakthrough when the rate of injecting gas is larger than a critical value. This is because, when in the forced gravity drainage, the displacing front reaches the capillary equilibrium height, determined by the rock and

fluid properties, the front no longer advances. Therefore, the displacing fluid cannot flow beyond the capillary hold up or, at most, the leading boundary of the matrix block.

As the rate of hydrocarbon displacement by gravity drainage is controlled by the rock and fluid properties, the rate of injection of the displacing fluid is governed by a combination of the above factors and is not at all mandatory. On the other hand, due to high fracture permeability and thus high productivity of the producing wells, in the fractured reservoirs, there is a strong tendency to produce them, as fast as the operation permits. If the withdrawal rates are higher than that of the oil supplied by the matrix blocks due to gravity drainage, then solution gas drive will be the mechanism, which provides the difference between the two.

In partially water-wet rock fractured reservoirs, where imbibition takes place from all sides of the blocks open to the fractures, the gravity drainage process takes much longer to reach the final conditions unlike the same block, when the side boundaries are closed. This is due to the fact that imbibition of water from the side boundaries causes a higher water saturation ahead of the WOC in the matrix block. This higher water saturation gives a lower relative permeability to oil and thus the final water-oil front moves at a slower speed.

It is clear that the maximum potential oil recovery by the gravity drainage mechanism is possible if the production rate, pressure maintenance, proper location of the wells, necessary work-overs, etc are controlled carefully during the life of the reservoir.

2.5.5 Block-to-block process

Block-to-block effect is a process, which has a major effect on the timing of the primary and secondary oil recoveries. It may be thought that by producing a fractured reservoir at a faster rate and thus dropping the GOC and/or raising the WOC contact also at a faster rate, more matrix blocks would undergo gravity drainage sooner. Thus, one can produce the total recoverable oil in a shorter period of time. It is now clear that by dropping the GOC and/or raising the WOC, the oil produced

from the upper blocks is sucked in by the lower draining blocks. This process is called block-to-block effect.

The desaturation of the displaced liquid phase, during drainage, takes place in the following manner:

a) Gas front travels rapidly downwards until it reaches the holdup depth. The displaced phase therefore reaches the capillary pressure profile more rapidly in the lower part, whereas oil saturation at the top of the block, after the initial desaturation, varies slowly due to the reduced oil relative permeability.
b) The drainage performance during the early period is mainly governed by the shape of the capillary pressure curve, whereas the long term recovery is controlled by the shape of the relative permeability curve.
c) When capillary pressure in a block is suddenly reduced while draining, the gas front approaches the new oil saturation profile rapidly owing to the high oil saturation between the two holdup zones. However, a large part of the additional recoverable oil, which is coming from the upper part of the block, will be produced at a much slower rate due to more poor relative permeability than that before the P_c was reduced.

In view of the heavily fractured character of the matrix rock, with several sets of fractures cutting through the rock in different directions, the rock can be said to be divided into a large number of separate matrix blocks, surrounded by narrow, but permeable fractures/fissures. As the permeability of the fracture - fissure network is usually over 1000 times that of the matrix, it is assumed that oil leaving a matrix block as a result of gravity drainage would preferentially flow through this network to the gas-oil contact, rather than flowing through the matrix blocks, which it meets on its way downwards. In this way, matrix blocks in the gas cap would drain quite independently, and the total drainage rate of oil could be obtained by successively adding the individual contributions of all the blocks surrounded by gas.

The crucial feature of this type of reservoir simulator is the single block drainage performance. For a given block, rock and fluid properties, one can easily calculate this performance. In some reservoir simulators,

this performance is even introduced in the form of transfer functions, instead of simulating it internally.

Because of the poor rock quality, the capillary pressure between oil and gas is usually high. This means that the force driving the oil, during the drainage process is reduced to zero. Thus, when this drive ceases, there is still a considerable amount of oil left at the bottom of a block (capillary holdup zone). The physical ultimate recovery, R_u (an important parameter for single block drainage performance) is therefore directly related to the ratio between the capillary hold-up zone (h_c) and the block height (L). So, only high permeability (low capillary pressure) blocks will ultimately produce most of their oil, whereas low permeability blocks retain most of their oil capillary trapped.

Within the production period of a reservoir, most blocks in the gas cap will closely approach their ultimate physical recovery, R_u. The ratio between capillary rise and block height will determine the field recovery. As a consequence of the importance of capillary pressure, the ultimate recovery is very sensitive to the gas-oil interfacial tension, which increases with decreasing pressure. Natural depletion results in decreasing displacement's efficiency, as at a lower pressure, a higher oil saturation will be left behind, while owing to oil shrinkage, it will represent even more stock tank oil. This is the main reason for considering large scale gas injection in the fractured reservoirs to maintain pressure or to increase it to its original value.

2.6 Waterflooding Tracers

Waterflooding and water-based floods are the most widely used secondary and tertiary oil recovery methods. Application of the theory to field operations is hampered by a lack of detailed knowledge about the reservoir and how the fluids move through it. In cases where the water entering the field comes from many different sources, managing the waterflood operation can become difficult. The addition of a tracer to the injected water is the only means of distinguishing between injection water and formation water, or between waters from different injection wells in the same field.

Generally, tracers are added to waterfloods for many reasons and in a variety of circumstances. They can be a powerful tool for describing the reservoir, investigating unexpected anomalies in flow, or verifying suspected geological barriers or flow channels. They can also be used in a test section of the field before expanding the flood.

Flow in most reservoirs is anisotropic. The reservoir structures are usually layered and frequently contain significant heterogeneities leading to directional variations in the extent of flow. As a result, the manner in which water moves in the reservoir can be difficult to predict. Tracers are used in enhanced oil recovery pilot tests to monitor the actual water flow pattern during the test.

The ability to identify the water source is basic to the use of tracers for all the purposes described above. The tracer response as a function of position and time provides a qualitative description of fluid movement that can play a useful part in managing the flood. However, it is also possible to obtain qualitative measure of water movement in the reservoir from the tracer data.

The usefulness of waterflood tracers is based upon the assumption that the movement of the tracer reflects the movement of the injected water. How closely this holds true depends upon how closely the tracer follows the injected water through a formation without significant loss or delay. An ideal water tracer must meet two requirements: it must faithfully follow the path and velocity of the water with which it is injected and it must be easy to identify and measure quantitatively.

To conclude with, in the last fifty years many tracer studies have been reported, in which tracers are used as a tool to improve the reservoir description as follows:

- Volumetric sweep. The volume of fluid injected at an injection well until breakthrough of the traced fluid at an offset producer is a measure of the volumetric sweep efficiency between that pair of wells. Very small volumes injected before breakthrough would indicate the existence of an interwell open fracture and would give an idea of the volume of that channel. Knowledge of channels is important to the sizing of remedial treatment.

- Identification of offending injectors. Problem injection wells can be identified by associating the breakthrough of a specific tracer to its point of injection. At this well, a remedial treatment to seal a channel normally would be applied.
- Directional flow trends. When fluids are injected in a regular pattern and the fluids injected at each well tagged with a different tracer, directional flow trends will be obvious from the repeated early tracer breakthrough at producers in a preferential direction from the injectors. Where directional flow trends are prevalent, the interwell sweep efficiency often can be improved by altering the injection pattern and/or the injection and withdrawal rates at selected wells.
- Delineation of flow barriers. Faults with large displacement along the fault plane and permeability pinchouts can represent barriers to the flow of fluids perpendicular to their axis. Normally, such barriers are detected by bottom hole pressure build-up surveys run in nearby wells. However, the course of these barriers can be delineated further from the production well's response to traced water injection at an array of wells surrounding the producer.
- Relative velocities of injected fluids. When different fluids are injected simultaneously, alternately or sequentially in the same well with each fluid tagged with a different nonadsorbing tracer, the relative velocities of these fluids can be measured from the individual tracer arrival time at offset producers. For example, assume that traced solvents and traced water are injected alternately in the same well. The early arrival of one of the traced fluids at the producing well would indicate that the early arriving fluid had contacted less of the reservoir than the slower fluid. This shows a need to alter one of the fluid injection cycles to achieve more uniform sweep of the reservoir. Similarly, in a micellar flood, in which water is injected sequentially, the overrunning or fingering of one injected fluid through another points out the need for better fluid-mobility control to achieve more uniform sweep by the various injected fluids.
- Evaluations of sweep improvement treatments. Remedial treatments, to correct sweep problems, can be evaluated by comparing the before-and-after-treatment interwell volumetric sweep as determined by tracing.

2.6.1 Passive Tracers

Tracers are classified in passive, when they blindly follow the fluid phase in which they are injected. Field tracers, whether chemical or radioactive, are currently the only feasible, direct means of tracking the movement of injected fluids in a reservoir. In many fields, these information has been crucial for improving injection and production programs. A tracer test is a cost efficient method to obtain important data that allow the analysis of injection and production options.

A passive tracer that labels gas or water in a well-to-well tracer test must fulfill some criteria and have several characteristics such as:

- Have a very law detection limit.

- Be stable under reservoir conditions.

- Follow the phase that is being tagged and have a minimal partitioning into other phases.

- Have no adsorption to rock material.

- Have minimal environmental consequences.

The best example of a passive water tracer is tritiated water (HTO). The HTO will, in all practical aspects, follow the water phase. On the other hand, for gas tracers, there are no known passive tracers. All gas compounds will, to a certain degree, partition between the phases. The most ideal gas tracer is tritiated methane. This gas tracer follows the methane component in the gas phase closely, and the pressure-volume-temperature (PVT) properties of this gas tracer can be found with ordinary PVT calculations.

2.6.2 Partitioning Tracers

As it is already mentioned, non-partitioning tracers are routinely used for flow characterization and source identification. On the other hand, partitioning tracing is potentially applicable whenever a phase boundary, for instance gas-oil, oil-water and water-rock, exists.

Partitioning between phases will slow down the partitioning tracers in a phenomenon known as chromatographic retardation, from which fluid saturations and surface properties can be deduced. Single well tracer testing to determine residual oil saturation constitutes the most common application of partitioning tracers.

So, a partitioning interwell tracer test (PITT) is a method of estimating oil volume and/or oil saturation in the swept zone between a set of injectors and producers in a reservoir. One of the methods for analyzing PITTs is the method of moments, which is based upon calculating the first temporal moment of the tracer concentrations in the produced fluids. It is especially important to know the remaining oil saturation, as accurately as possible, before applying enhanced oil recovery methods. PITTs also provide valuable information on swept volumes between wells, flow paths and breakthrough times.

2.6.3 Adsorption Tracers

Adsorption is a phase transfer process that is widely used in practice to remove substances from fluid phases (gases or liquids). The most general definition describes adsorption as an enrichment of chemical species from a fluid phase on the surface of a liquid or a solid. In water treatment, adsorption has been proved as an efficient removal process for a multiplicity of solutes. Molecules or ions are removed from the aqueous solution by adsorption onto solid surfaces.

In adsorption theory, the basic terms are shown in figure 4.

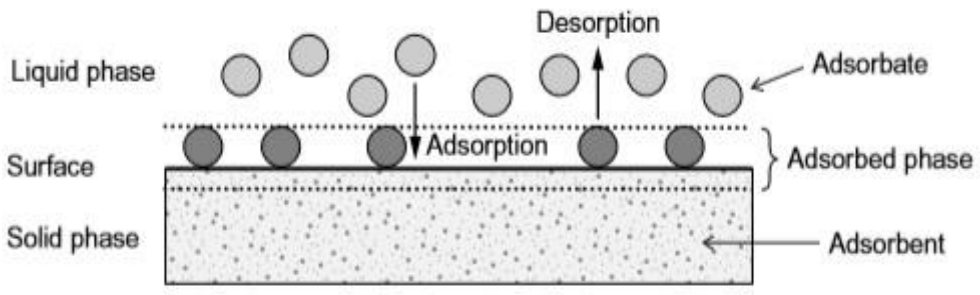

Figure 4: Basic terms in adsorption theory (Adsorption Technology in Water Treatment, Eckhard Worch, 2012)

The solid material that provides the surface for adsorption is referred to as adsorbent, the species that will be adsorbed are named adsorbate. By changing the properties of the liquid phase (concentration, temperature, pH) adsorbed species can be released from the surface and transferred back into the liquid phase. This reverse process is referred to as desorption.

In the oil field especially, adsorption refers to a process wherein a flowing tracer material in the aqueous solution is absorbed on the surface of the reservoir rock. Two limiting cases may exist:

- instantaneous adsorption (equilibrium) and

- time dependent or rate-controlled adsorption (non equilibrium)

For an equilibrium adsorption, the concentration on the rock surface is generally described by the Langmuir isotherm:

$$C_r = a \cdot C / (1+b \cdot C) \quad (6)$$

where a and b are constants related to the ratio of the adsorption and desorption rate constants. The Langmuir equation, however, can be approximated by a linear expression at low concentration levels. Because the tracer concentration levels in most interwell tracer tests are low, the linear relationship of $C_r=a \cdot C$ should provide a useful model for tracer adsorption effects. The effect of adsorption is to retard a tracer response and reduce the level of influent tracer concentrations.

Chapter 3:

Modeling in Eclipse Simulator

3.1 Fractured Reservoirs

Fractured reservoirs consist of two types of porosity and they are often referred to as dual porosity or dual permeability systems. Since a dual porosity system contains two porosity types, a conventional modeling could be hard. That is why many simplified methods to model dual porosity systems are made.

To model such systems in *ECLIPSE*, two simulation cells are associated with each block in the geometric grid, representing the matrix and fracture volumes of the cell. In *ECLIPSE* the porosity, permeability, depth and other characteristics may be independently defined. A matrix-fracture coupling transmissibility is constructed automatically by *ECLIPSE* to simulate flow between the two systems due to fluid expansion, gravity drainage, capillary pressure, etc. This procedure is referred to as 'dual porosity' modeling. If the matrix blocks are linked only through the fracture system, this is considered to be a dual porosity, single-permeability system, since fluid flow through the reservoir takes place only in the fracture network, with the matrix blocks acting as sources. However, if there is the possibility of flow directly between neighboring matrix blocks, this is conventionally considered to be a dual-porosity, dual-permeability system.

In a dual-porosity or dual-permeability run of *ECLIPSE*, the number of layers in the Z direction should be doubled. *ECLIPSE* associates the first half of the grid with the matrix blocks and the second half with the fractures.

3.2 Transmissibility Calculations

The matrix-fracture coupling transmissibility terms that exist between each cell of the matrix grid and the corresponding cell in the fracture grid are proportional to the cell bulk volume. In *ECLIPSE* this relation is expressed according to the following formula:

$$TR = CDARCY \cdot K \cdot V \cdot \sigma \quad (7)$$

where by default:

K is taken as the X-direction permeability of the matrix blocks

V is the matrix cell bulk volume and

σ is a factor of dimensionality, to account for the matrix/fracture interface area per unit volume, that is the size of the blocks in the matrix volume.

Kazemi has proposed the following form for σ :

$$\sigma = 4 \cdot (1/l_x^2 + 1/l_y^2 + 1/l_z^2) \quad (8)$$

where l_x, l_y, l_z are typical X, Y, Z dimensions of the blocks of material making up the matrix volume. Alternatively, as σ acts as a multiplier on the matrix-fracture coupling, it may simply be treated as a history matching parameter.

If the dual porosity but not the dual permeability option is selected, the matrix blocks have no transmissibilities between them. If dual porosity and dual permeability is chosen, the matrix blocks have their normal transmissibilities.

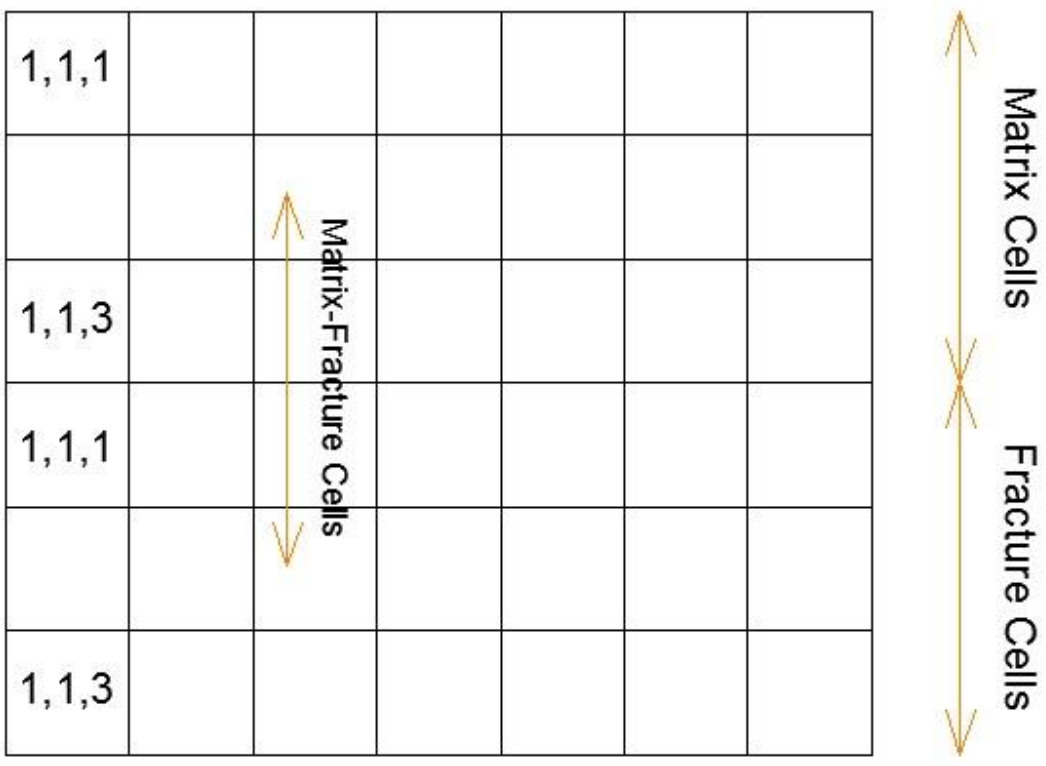

Figure 5: A simple dual porosity, dual permeability system
(Eclipse technical description, 2010)

3.3 Block-to-Block Transmissibility Calculations

In *ECLIPSE*, it is possible to represent re-imbibition from a fracture cell by the matrix cell below it. In this case the transmissibility between the matrix and fracture cells is a conventional spatial one, since the two cells are not superimposed on one another, and the properties of the two cells contribute to the transmissibility between two neighboring fracture cells or two neighboring fracture cells.

Figure 6 shows this new transmissibility on a picture of the two physical cells, that is the matrix and fracture cells occupy the same physical location.

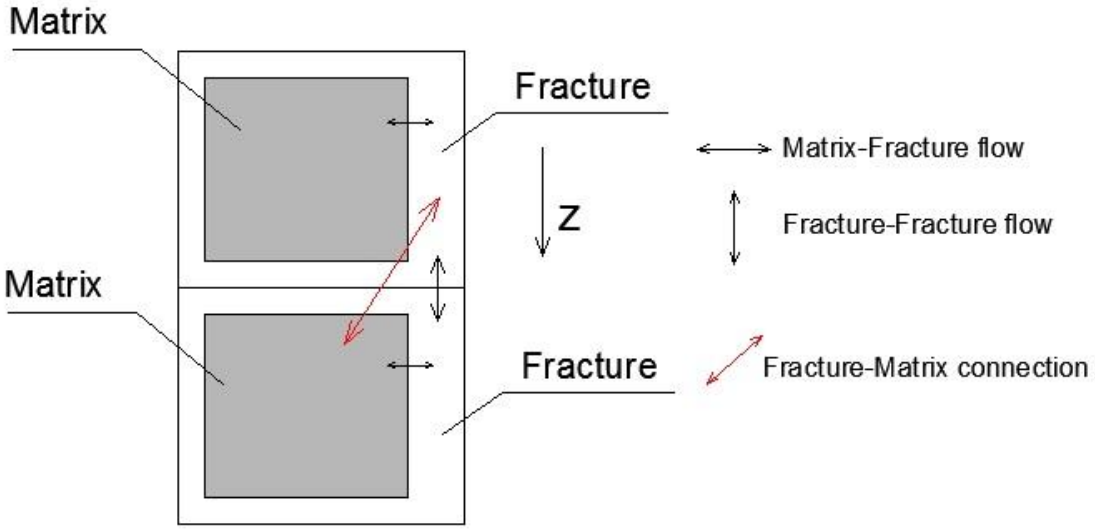

Figure 6: Physical view of the matrix and fracture cells for the block-to-block connection (Eclipse technical description, 2010)

In addition, figure 7 presents the contact between the upper fracture and the lower matrix, where the lower matrix and fracture are shown as single adjacent blocks, but the upper matrix is split in two, one half abutting the lower matrix and one half abutting the lower fracture (not presented in the model but conceptually possible). The upper fracture contacts both lower fracture and lower matrix.

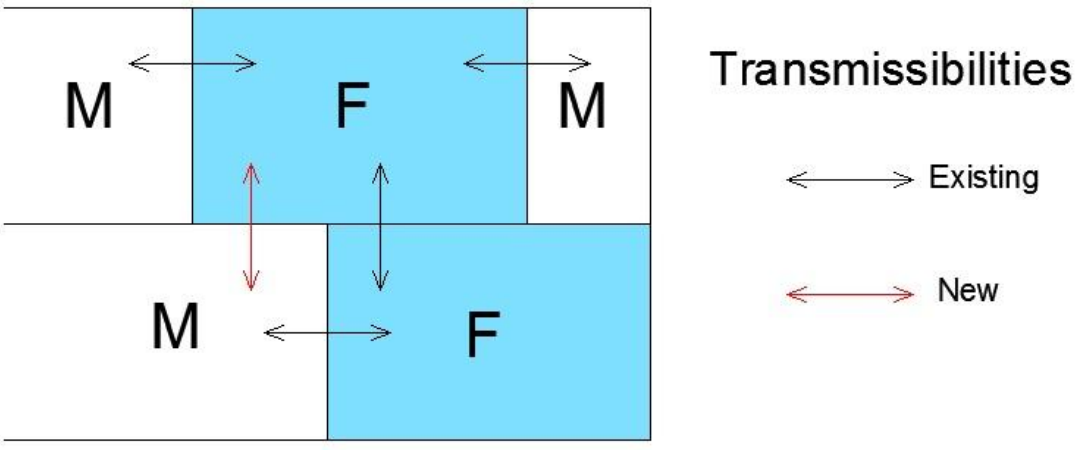

Figure 7: Schematic view of the contacts between the upper and lower cells of the two porosity systems (Eclipse technical description, 2010)

3.4 Recovery Mechanisms

In a dual porosity system, the majority of the oil is contained in the matrix system but the production of oil to the wells is through the high permeability fracture system. In such a system, an injected fluid does not sweep out oil from the matrix block. Production from the matrix blocks can be associated with various physical mechanisms including:

- Oil Expansion
- Imbibition
- Gravity imbibition / drainage
- Diffusion
- Viscous displacement

3.4.1 Oil Expansion

As the pressure drops in the fracture system, oil flows from the matrix to equilibrate the matrix pressure with the surrounding fracture pressure. This production mechanism can be thought of as expansion of the oil within the matrix block, either above the bubble point or by solution gas drive below the bubble point.

3.4.2 Imbibition

In a typical water-wet system the matrix rock has a positive water-oil capillary pressure. If water is introduced into the fracture, the water flows under capillary forces into the matrix system, displacing oil.

The water imbibition process is modeled in *ECLIPSE* by specifying different saturation table numbers for the matrix and fractures cells, respectively. The matrix cells typically have a water-oil capillary pressure, while the fracture cells usually have zero capillary pressure.

In gas-oil systems the oil is the wetting phase and tends to imbibe into the matrix. In practice this means that if the gravity drainage model

is not active then no production occurs from a matrix block when the associated fracture block is full of gas.

3.4.3 Gravity Imbibition / Drainage

Drainage displacement is the process where the non-wetting phase is displacing the wetting phase. This is contrary to the imbibition process where the wetting fluid is displaced by a non-wetting fluid. A common case is gas cap expansion, where gas (non-wetting phase) invades the fractures. For a fractured reservoir, gravity drainage is fully dependent on the block height (or capillary continuity).

Fluid exchange between the fracture and matrix due to gravity is modeled in one of two ways. One method is to consider each of the matrix and fracture cells as separately in vertical equilibrium and then to calculate additional potential, due to differences in contact heights between the matrix and fracture. The other method uses a modification of the discrete matrix model and uses N matrix porosities, where N is user-defined, to create a vertical stack of finely spaced matrix cells, which describe the distribution of properties within a single block of matrix material.

I. Standard Gravity Drainage Model

Figure 8 illustrates a typical block of matrix material containing oil and water. The fractional height of the water table in the fracture is *Xw* and the fractional height of the water displacement front in the block of matrix material is X_w.

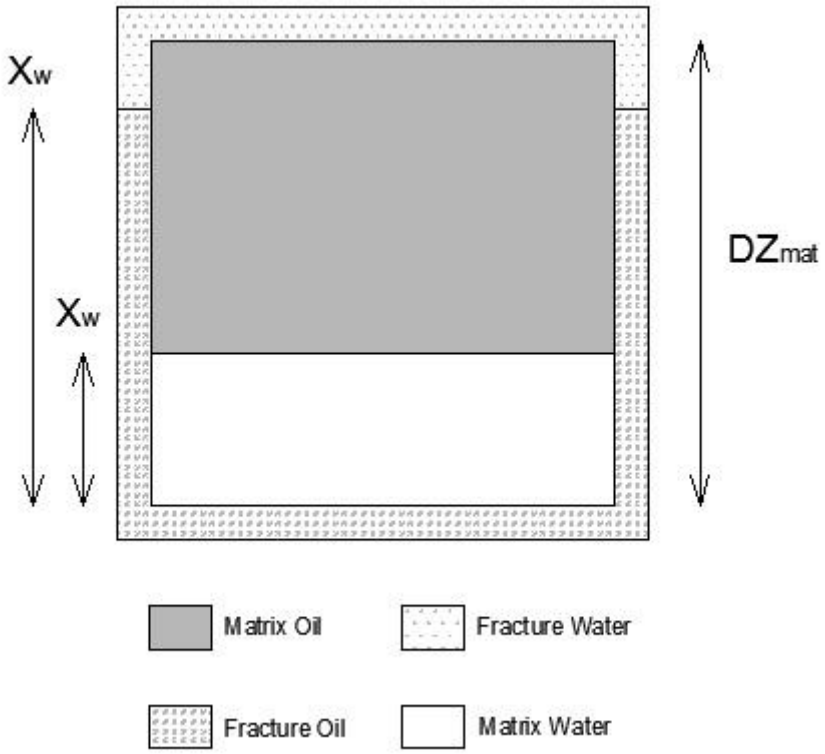

Figure 8: A typical block of matrix material containing oil and water
(Eclipse technical description, 2010)

The pressure difference due to gravity is expressed by the formula below:

$$\Delta P = DZ_{mat} \cdot (Xw - X_w) \cdot (\rho_w - \rho_o) \cdot g \quad (9)$$

where:

ρ_w is the water density

ρ_o is the oil density at reservoir conditions

The flow of oil and gas from a fracture to a matrix cell in a gas-oil system is computed as:

$$F_g = TR \cdot GMOB \cdot [P_{of} \cdot P_{om} + d_{fm} \cdot \rho_g \cdot g + P_{cogf} \cdot P_{cogm} + (DZ_{mat}(X_G - X_g) \cdot (\rho_o - \rho_g) \cdot g) / 2)] \quad (10)$$

$$F_o = TR \cdot OMOB \cdot [P_{of} \cdot P_{om} + d_{fm} \cdot \rho_o \cdot g - (DZ_{mat}(X_G - X_g) \cdot (\rho_o - \rho_g) \cdot g) / 2)] \quad (11)$$

where:

TR is the transmissibility between the fracture and matrix cells

GMOB is the gas mobility in the fracture cell

OMOB is the oil mobility in the fracture cell

$\mathbf{P_{of}}$ is the oil phase pressure in the fracture cell

$\mathbf{P_{om}}$ is the oil phase pressure in the matrix cell

$\mathbf{d_{fm}}$ is the difference in depth between the fracture and matrix cells (usually zero)

ρ_g is the density of gas at reservoir conditions

ρ_o is the density of oil at reservoir conditions

g is the acceleration due to gravity

P_{cogf} is the capillary pressure of gas in the fracture cell (normally zero)

P_{cogm} is the capillary pressure of gas in the matrix cell

II. Alternative Gravity Drainage Model

The matrix-fracture flow is taken to be the sum of three flows from the center of the matrix to the fracture system: one horizontal, one vertically upwards and one vertically downwards, as it is presented in figure 9.

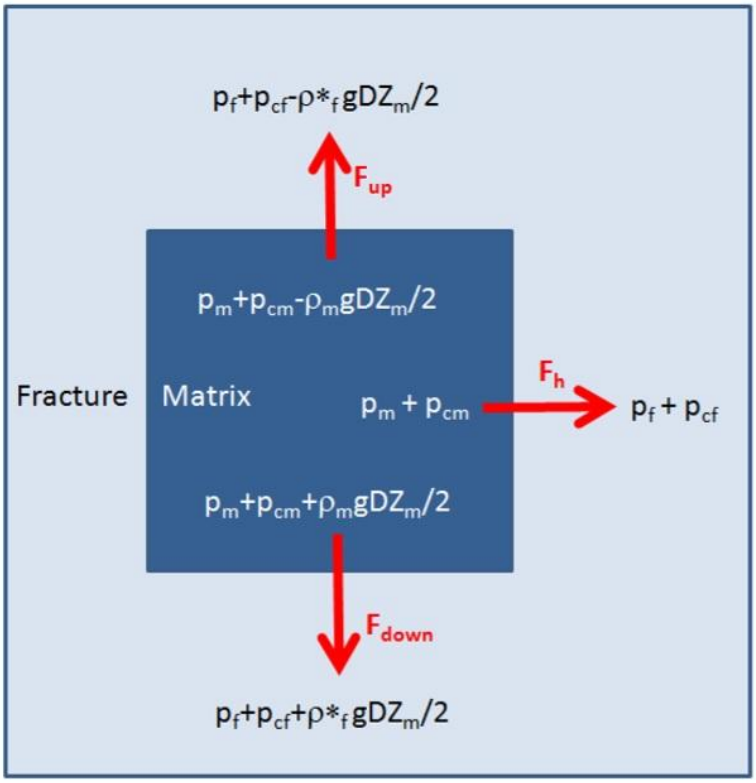

Figure 9: Flows and potentials of an alternative gravity drainage model (Eclipse technical description, 2010)

This formulation allows for different flow paths and hence transmissibilities in the vertical and horizontal dimensions.

The matrix-fracture flow is given by:

$$F = F_h + F_{up} + F_{down} \quad (12)$$

as shown in figure 9.

III. Vertical Discrete Matrix Gravity Drainage Model

The third alternative gravity drainage model uses the discrete matrix model, which provides a number of matrix porosities connected together in a chain, with the outermost connected to the fracture (figure 10).

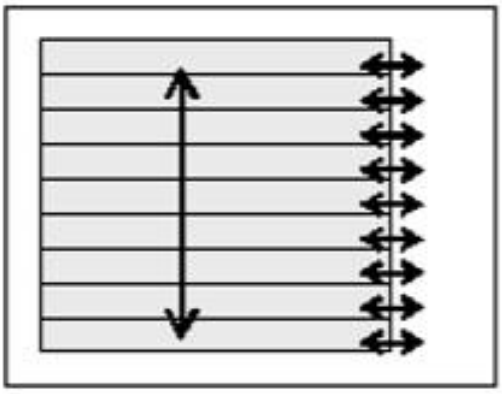

Figure 10: The discretized matrix material block within a fracture cell
(Eclipse technical description, 2010)

3.4.4 Diffusion

Molecular diffusion of gas and oil between the matrix and fracture may be a significant production mechanism for the matrix. Diffusion option is supported by *ECLIPSE* simulator.

3.4.5 Viscous Displacement

Viscous displacement of a fluid is simply the movement of that fluid when a pressure differential is applied. In a dual porosity system, there is a pressure gradient in the fracture system moving the fluid through the fracture, towards the production wells. In many cases this pressure gradient is small, as the fracture system has a very high effective permeability. In these cases it is reasonable to ignore the viscous displacement of fluids from the matrix by the fracture pressure gradient. However, if the fracture system has a more moderate permeability, then flow to and from the matrix caused by the fracture pressure gradient may be expected to act as a significant production mechanism.

3.5 Tracers Options in ECLIPSE

As it is already mentioned, tracers could be any fluid used to track flow. The environmental tracer is an option, which extends the modeling to account for adsorption of the tracer on to the bulk rock, for decay of the tracer over time and for molecular diffusion of the tracer. In *ECLIPSE*, it is possible to model adsorption, decay and diffusion within a single tracer. Actually, the environmental tracer is an extension to the passive tracer tracking model. This option in *ECLIPSE* enables the modeling of contaminants and other substances, as they flow within a host water, oil or gas phase.

As for passive tracers, the flow of an environmental tracer through the porous medium is assumed to have no influence on the flow of the water and hydrocarbon phases or on the flow of other tracers.

Environmental tracers are therefore solved, in a similar fashion to passive tracers, at the end of a time step after the oil, water and gas equations have converged.

For an environmental tracer present in a single phase the governing equation is:

$$d(VSC/B)/dt + d[V\rho_r C^a(1-\Phi)/\Phi]/dt$$

$$= \Sigma[(Tk_\rho/B\cdot\mu)(\delta P-\rho g D_z)C + DFD_c S\delta C] + QC \qquad (13)$$

where:

S is the host phase saturation

C is the flowing tracer concentration

C^a is the adsorbed tracer concentration

ρ_r is the mass density of the rock formation

φ is the porosity

ρ is the host phase density

μ is the host phase viscosity

D_z is the cell center depth

B is the host phase formation volume factor

T is the transmissibility

k_r is the host phase relative permeability

V is the block pore volume

Q is the host phase production rate

P is the host phase pressure

g is the acceleration due to gravity

D_c is the tracer diffusion coefficient

DF is the diffusivity

Σ is the sum over neighboring cells

3.5.1 Adsorption Tracer

Adsorption is treated as an instantaneous effect in the model. The effect of tracer adsorption is to strip tracer from the leading edge of a tracer front. Desorption effects may occur as the tracer concentration decreases.

In *ECLIPSE*, the adsorption model can handle both stripping and desorption effects. An adsorption isotherm is specified, which tabulates the saturated rock absorbed concentration versus the local tracer concentration in solution. As an alternative to tabulating, the isotherm coefficients can be supplied for an analytical isotherm, which allows for dependences of adsorption on rock permeability. There are currently two adsorption models, which can be selected. The first model ensures that each grid cell retraces the adsorption isotherm, as the tracer concentration rises and falls in the cell. The second model assumes that the adsorbed tracer concentration on the rock may not decrease with time and hence does not allow for any desorption. To ensure equilibrium, the initial input tracer concentrations can either partition between the fluid and solid, thereby conserving the total input

concentration in the fluid, or can be honored by adding adsorbed tracer concentration to the rock.

3.5.2 Diffusion in Tracers

The diffusion flow of tracer from cell *i* to a connected cell *j* is given by:

$$F_t = DF \cdot D_c \cdot S \cdot (C_{ci} - C_{cj}) \quad (14)$$

The diffusivity (DF) is analogous to the transmissibility and has the form:

$$DF = (A \cdot \phi) / d \quad (15)$$

where,

A denotes the interface area

d denotes the distance between the cell centers

In a system, where there is significant convection of the tracer, molecular diffusion is likely to be a relatively small effect. Numerical dispersion associated with the discrete approximation of the flow equation is likely to dominate any molecular dispersion. However, the diffusion model is useful when the convection is small. In the limiting case of zero permeability, the only mechanism for flow is by diffusion; this kind of situation may occur when modeling a contaminant initially stored in concrete.

3.6 Partitioned Tracers

Partitioned tracers allow *ECLIPSE* to solve a range of problems that could not be tackled otherwise. For example, if marked gas is injected into a reservoir, it is possible that the marker may dissolve in the water. The partitioned tracer option can model this behavior. With a single phase tracer in, say, the gas phase, *ECLIPSE* solves a conservation equation for the total amount of tracer in a grid block, taking into account the inflow and outflow of gas. With a partitioned tracer, one or

more additional phases can be nominated into which the tracer may also dissolve.

Partitioned tracers are separated in the following two categories:

1. Standard Partitioned tracers

2. Multi-partitioned tracers

A standard partitioned tracer can exist in two phases. For input and output purposes these two phases are regarded as being the 'free' and 'solution' phases. The 'free' phase can be thought of as the reference phase for the tracer. When a standard partitioned tracer is used in conjunction with adsorption, decay and diffusion, it is assumed that these processes happen only in the solution phase.

The multi-partitioned tracer option is an extension and generalization of standard partitioned tracers. A multi-partitioned tracer can partition into any number of phases and have phase specific adsorption, decay and diffusion parameters.

Chapter 4:

A Fractured Reservoir Model

4.1 Description of the reservoir model

In this section, a two dimensional oil fractured reservoir is presented with one production and one water injection well. Totally, nine (9) tracers are injected through the water injection well, in order to examine the role of the tracers in a reservoir and investigate the fluid flow in this fractured reservoir. Figure 11 illustrates this reservoir in Petrel software, while figure 12 shows a schematic presentation of the reservoir.

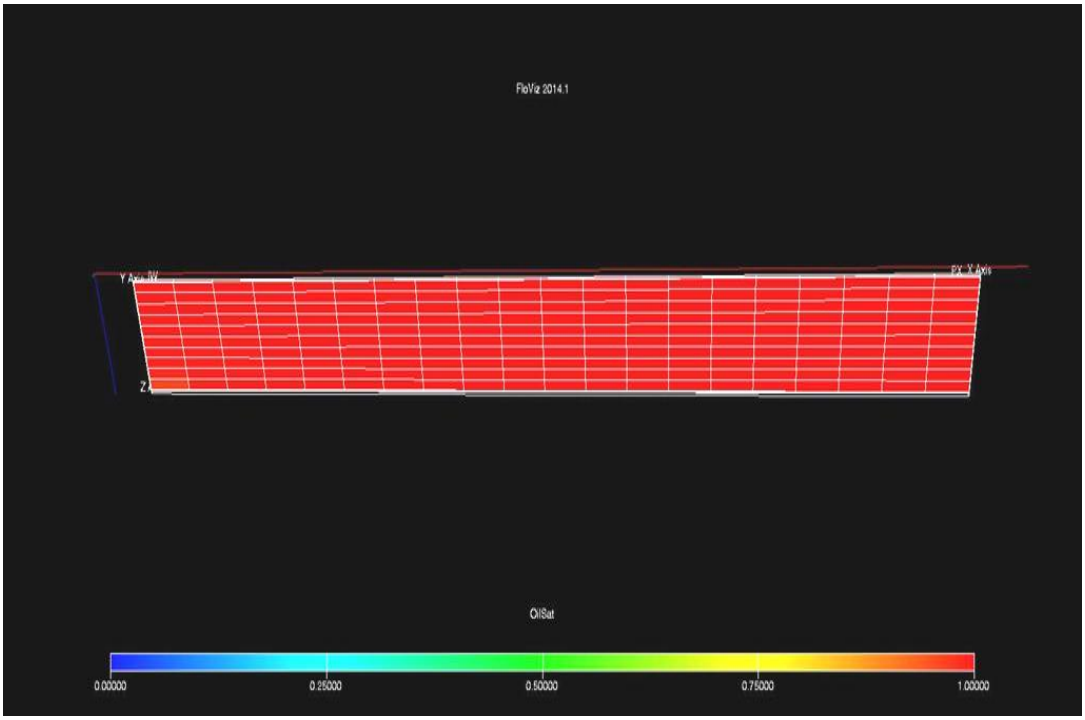

Figure 11: A 2D fractured reservoir in Petrel software

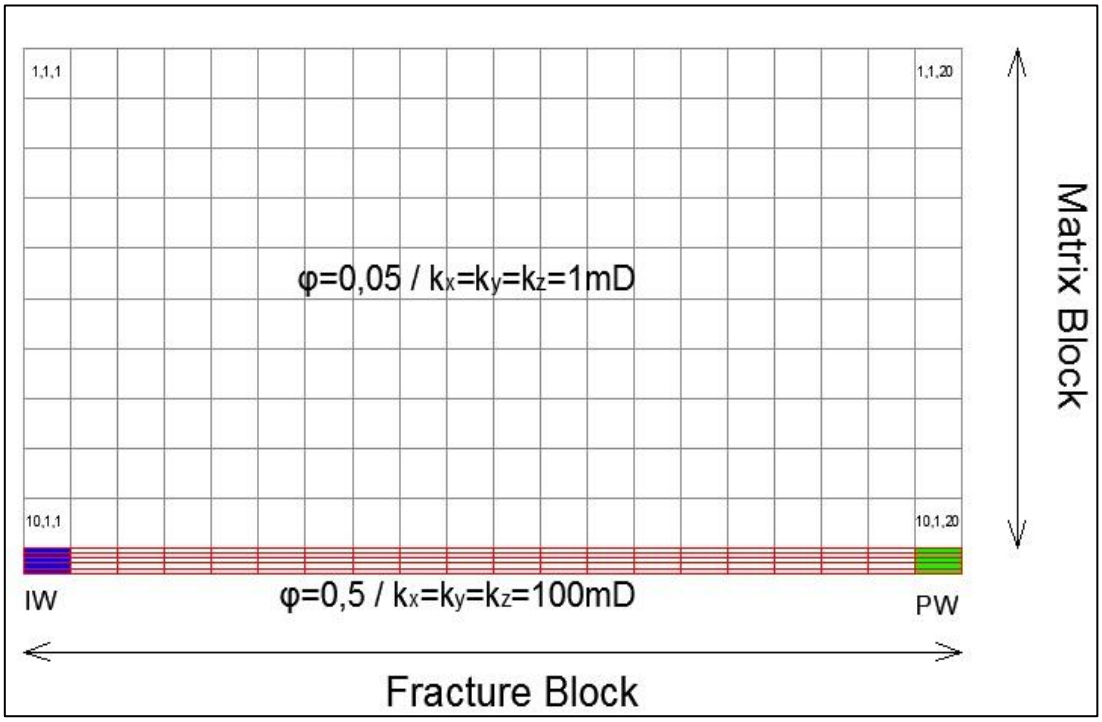

Figure 12: Schematic Presentation of the Reservoir

The above fractured reservoir is simulated in *ECLIPSE 100* and there are two approaches to realize it. The first method, which is described in the current chapter, is to create a matrix grid block and a fracture grid block with different cell parameters (porosity, permeability etc), which are specified by the user (*Appendix 1*). In other words, a normal flow model is performed. The other approach, which is described in chapter 5, is to simulate the fractured reservoir by using dual porosity and dual permeability options of *ECLIPSE* simulator.

The concerned fractured reservoir model consists of 20x1x15 cells in each direction X, Y, Z, respectively. The first ten layers are part of the matrix block and the rest five layers belong to the fracture block. The porosity value of the matrix block is equal to 0.05, while the permeability value for all directions X,Y,Z is equal to the unity. On the other hand, the porosity in the fractured block is equal to 0.5, while the permeability is equal to 100mD. All the other properties of the reservoir, such as the water saturation, the oil and water relative permeabilities, the capillary pressures and the rock properties are specified in the *ECLIPSE* code by the user.

Three similar slugs of three different types of tracers are injected in the concerned reservoir. The first slug of tracers consists of one passive, one partitioning and one adsorption tracer. Also, in all these three tracers, a diffusion behavior is applied. The first slug is injected for one day, in the beginning of the production period, when the matrix block is full of oil. Then, a second slug of tracers, with exactly the same properties, is injected for one day in the middle of the production period, when the oil in the matrix block reaches its half quantity. And finally, a third similar slug of tracers is injected, while approaching the end of the production period.

The reservoir oil saturation, for each time period that the second and the third slug of tracers are injected in the reservoir, is presented in the following figures.

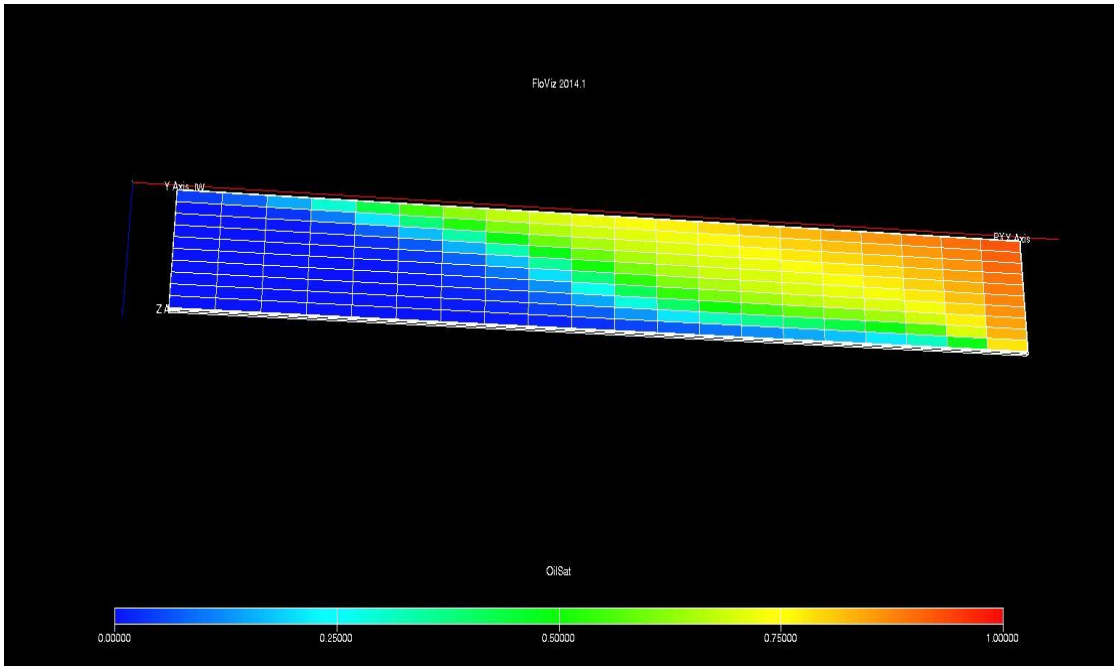

Figure 13: Oil Saturation in the beginning of the injection of the 2nd slug of tracers

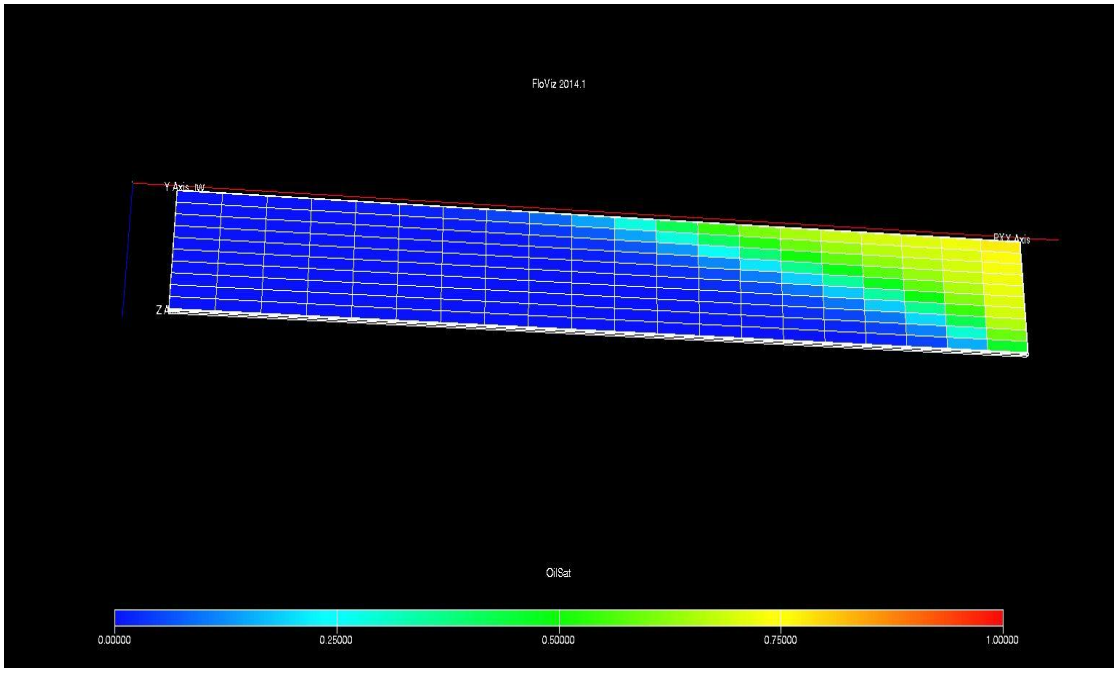

Figure 14: Oil Saturation in the beginning of the injection of the 3rd slug of tracers

4.2 Results - Comments

The following plots (figures 15,16,17 and 18) present the results of the tracers' concentration (for each tracer slug) in the reservoir and the retention times, during the production period.

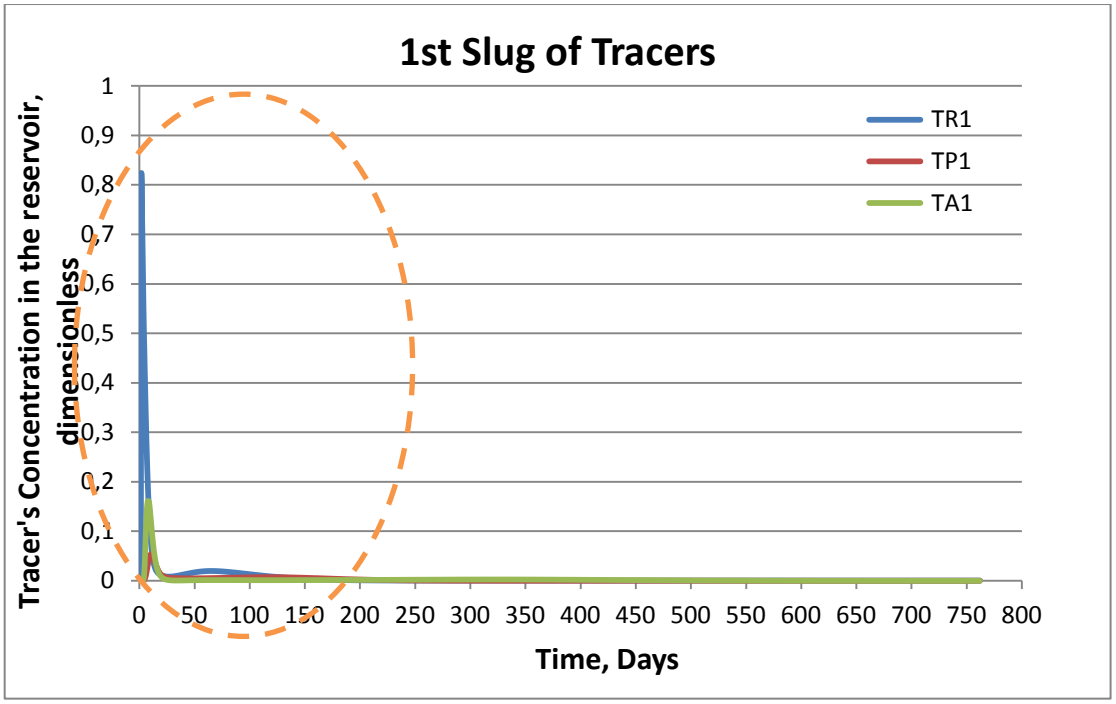

Figure 15: Concentration of the 1st slug of tracers

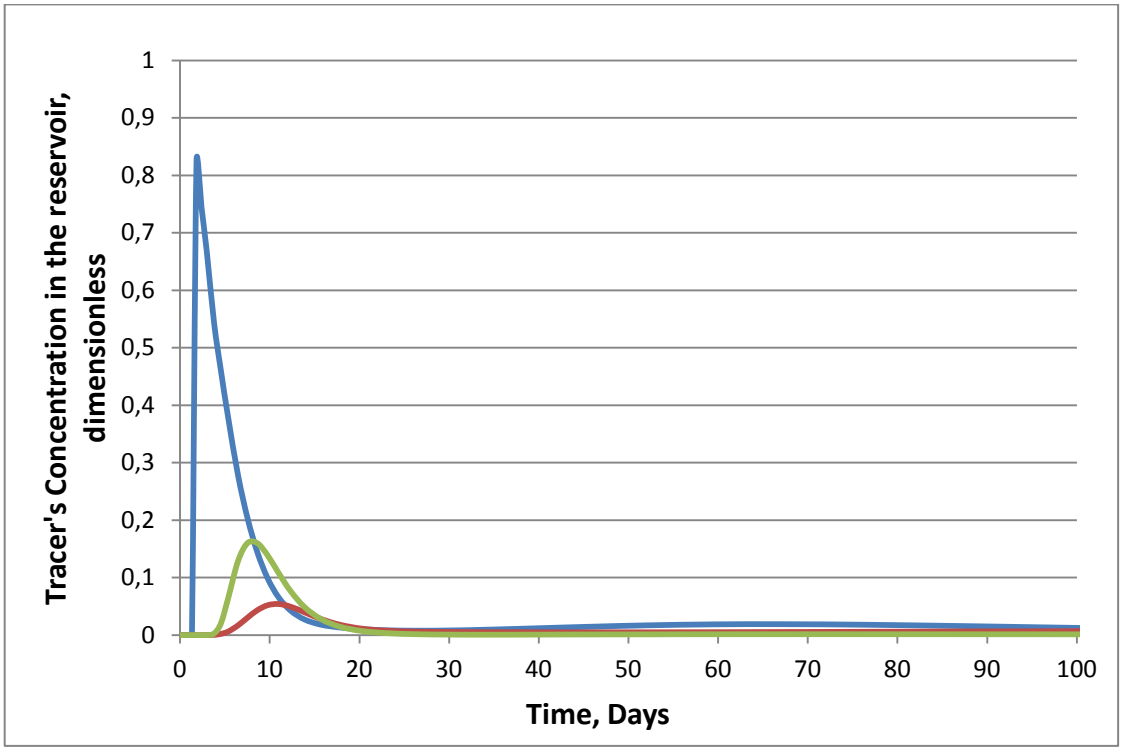

Figure 16: Detailed Presentation for the first 100 days

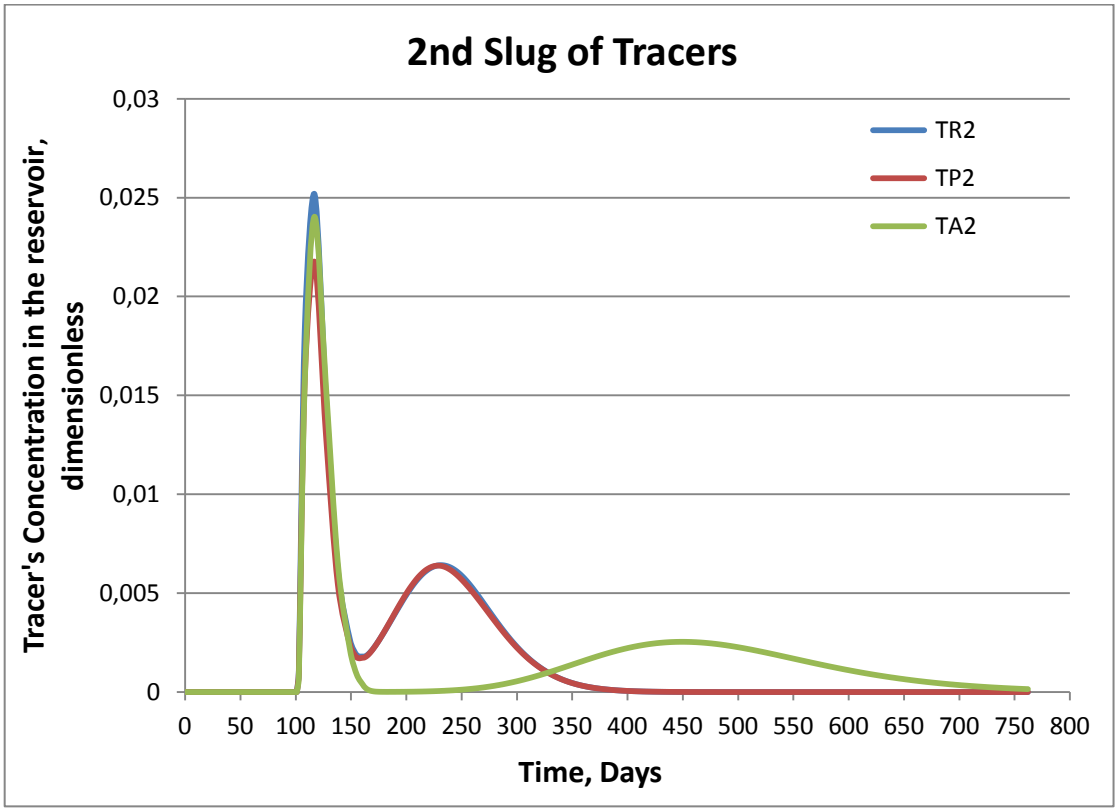

Figure 17: Concentration of the 2nd slug of tracers

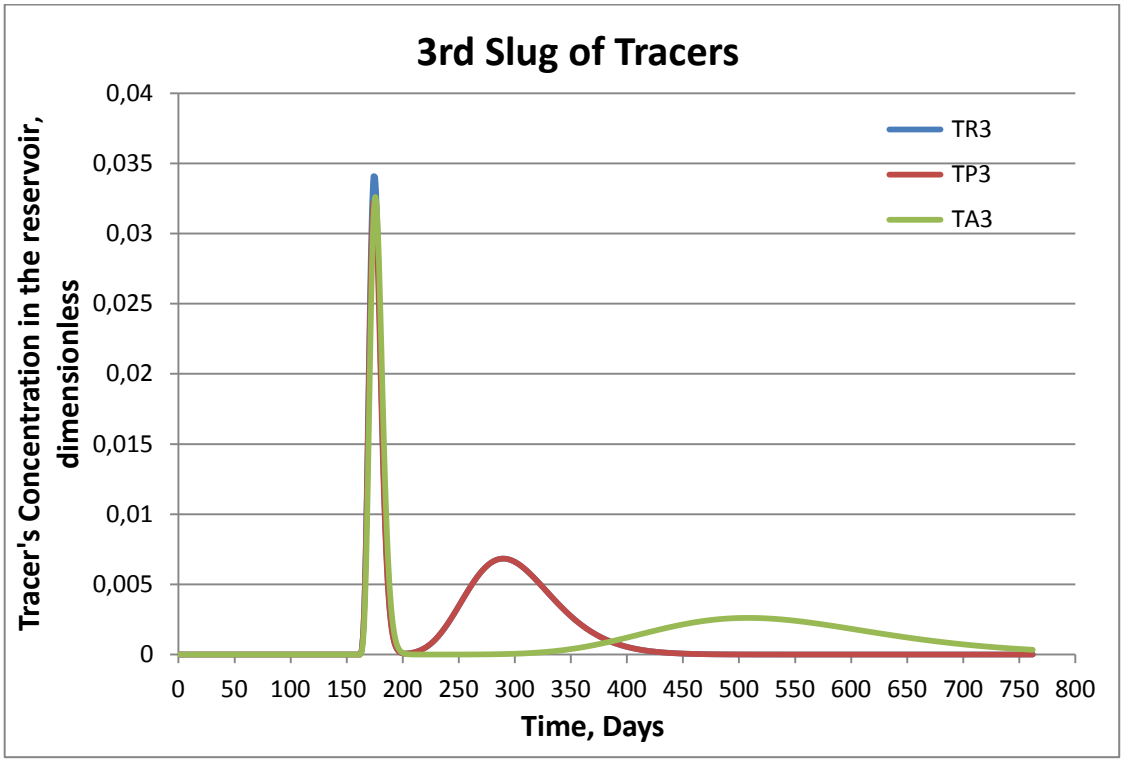

Figure 18: Concentration of the 3rd slug of tracers

Firstly, as it is observed in all diagrams, there are two peak points for each tracer during the production period of the reservoir. The first peak point corresponds to the tracer flowing through the fracture, while the second peak corresponds to the tracer volume flowing through the matrix. Further analysis of the tracer curves leads to the determination of the fracture and matrix swept volumes.

Each tracer is injected through the water injection well in the fracture block, which has higher porosity and permeability values than the matrix block. This explains the fact that the tracer concentration is higher in the fracture block. Then, through the capillary forces, tracers are transferred in the matrix block.

Another useful notation is the time that the peak of the tracers concentration is occurred, which is called retention time. In plot 14, the first peak belongs to the passive tracer and its peak concentration value has a significant difference, comparing with the adsorption tracer, which is the second peak concentration. The tracer that has the highest retention time and the lowest concentration is the partitioning tracer.

It is useful to emphasize that passive tracers just follow the flow of the fluid wherein they are injected. The concentration of the passive tracer is reduced due to dispersion. The higher the reservoir volume swept by the tracer, the higher the dispersion. The concentration of the partitioning tracer is decreased due to dispersion and due to further diffusion in the oil phase, while the adsorption tracers concentration is reduced due to dispersion as well as due to the adsorption on the rock surface.

The retention time between a passive and a partitioning tracer gives information about the oil saturation of the reservoir. In addition, the retention time between a passive and an adsorption tracer gives information about the rock surface in contact with water. All these data are very useful especially, when decisions, concerning the production mechanisms, for the best oil recovery have to be taken by the engineers. That is why tracers are a significant section in the reservoir engineering field.

Analyzing further figure 16, which shows the concentration for the first slug of tracers, which are injected in the beginning of the production period (when the reservoir is full of oil), it is denoted that the passive tracer has the highest concentration with the lowest retention time, while the adsorption tracer's peak, in the fracture block, happens earlier, with higher value than the partitioning tracer's peak concentration.

The highest concentration values belong to the passive tracers, because their dispersion depends only on the reservoir volume that is swept. So, as time goes by, the reservoir volume that is swept by the tracer is higher and as a result the concentration of the passive tracer is reduced accordingly.

On the other hand, the partitioning tracer is dissolved in the oil, which volume is high in the reservoir, because we are in the beginning of the production period. So, the partitioning tracer's concentration is reduced significantly. Moreover, the adsorption tracer's concentration follows a decline, because an amount is absorbed by the reservoir sediments surface.

As the second and the third slug of tracers are injected in the reservoir, it is observed a similar behavior but with peaks of less concentration values. This is something physically expected, as the remaining volume of oil in the reservoir is reduced.

Figures 19, 20, and 21 present the concentrations of each type of tracers and the retention times for the different time period that they are injected in the reservoir. As it is denoted, in the three following plots, the tracers concentration is reduced, depending on the production period that the tracers are injected through the reservoir. This is because of the definition of each type of tracers, as it is already mentioned and given that less oil volume remains in the reservoir.

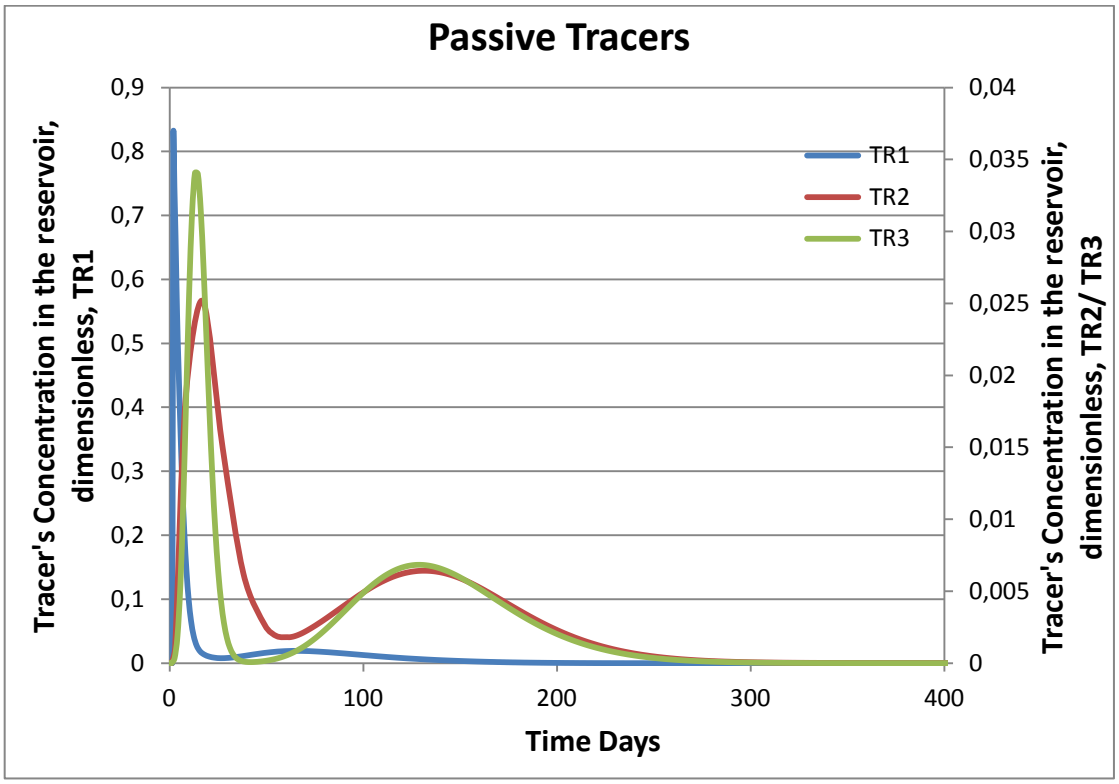

Figure 19: Concentration of the three passive tracers in the reservoir

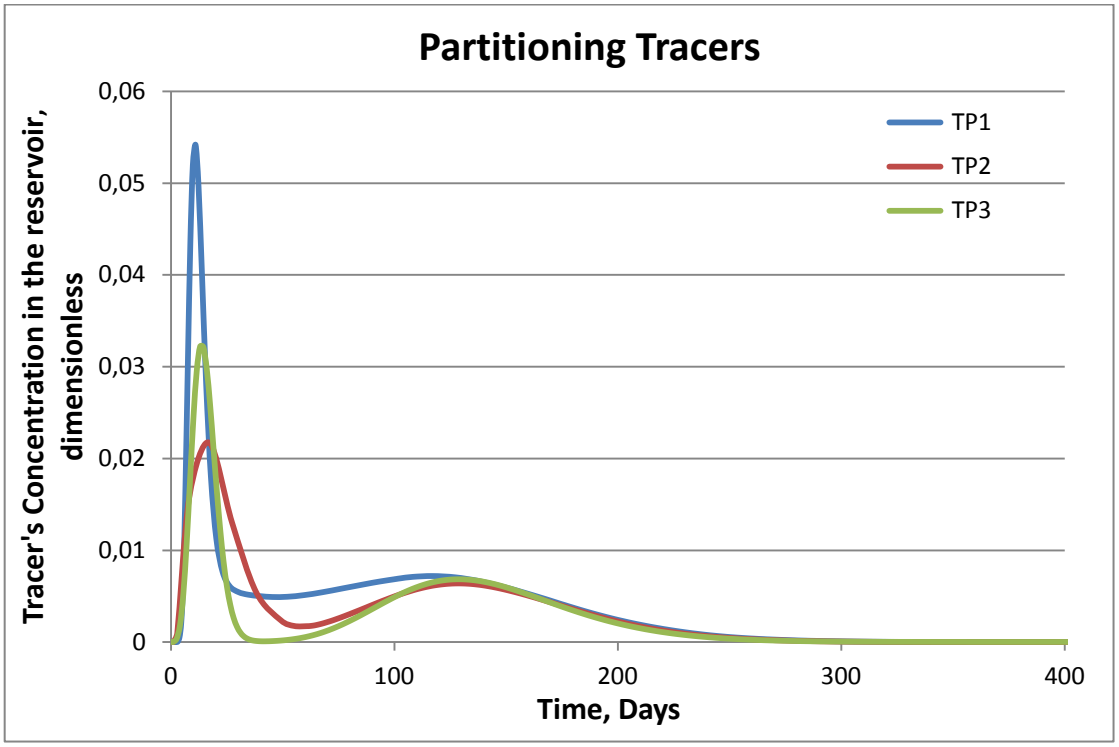

Figure 20: Concentration of the three partitioning tracers in the reservoir

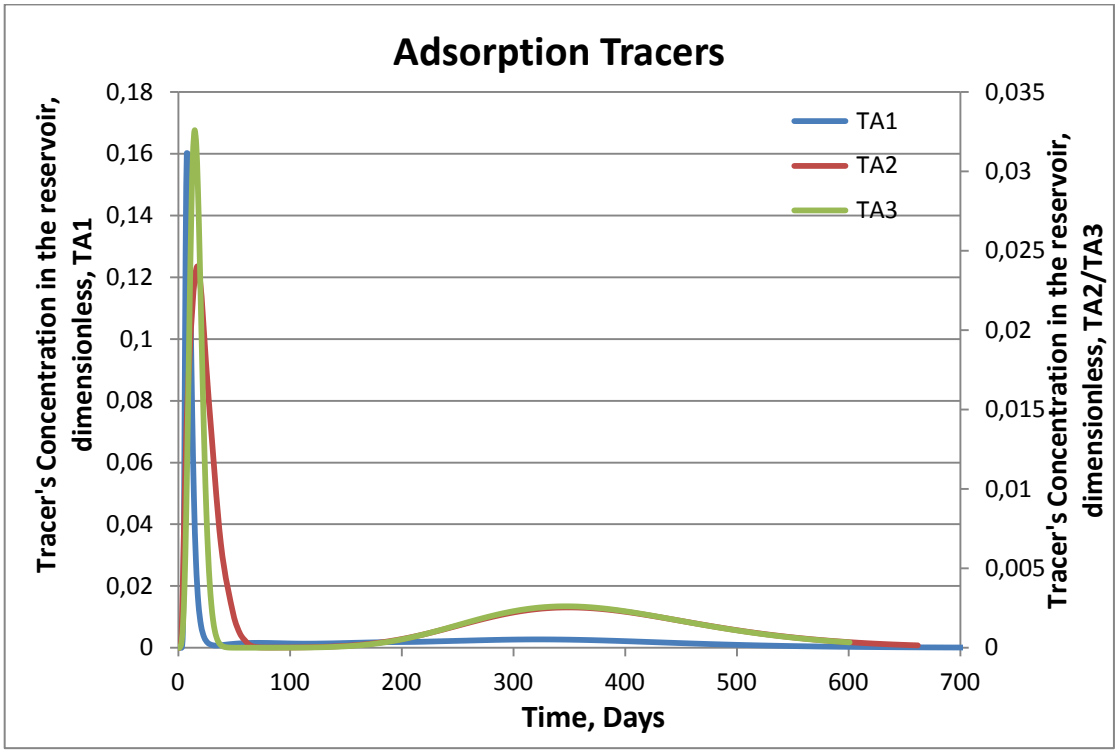

Figure 21: Concentration of the three adsorption tracers in the reservoir

A final observation is that in the matrix block, the tracer's peak concentration is the same for the three tracers of the same type but there are differences in the retention time. This means that the period that the tracers are injected plays a significant role in the outcomes.

Chapter 5:

A Dual Porosity Reservoir Model

5.1 Simulation results of the dual porosity reservoir model

In this chapter, it is presented the modeling of a fractured reservoir, using the dual porosity/dual permeability options of *ECLIPSE*. This type of modeling is widely used when a large reservoir have to be simulated and as a consequence, it is complicated and time consuming to determine the matrix and the fracture block of the reservoir by layers separately.

The properties and the characteristics of the fractured reservoir are the same with those described in the previous chapter 4. So, the purpose is to examine if there are differences in applying during porosity modeling with the normal flow model. The complete code of using dual porosity/dual permeability options in *ECLIPSE* is presented in *Appendix 2*.

The theory of the calculations that are performed in *ECLIPSE* simulator, choosing dual porosity/dual permeability reservoir model are mentioned extensively in chapter 3. The results of this simulation, concerning the concentration of the tracers and the retention times in the fractured reservoir, are presented below in the figures 22, 23 and 24.

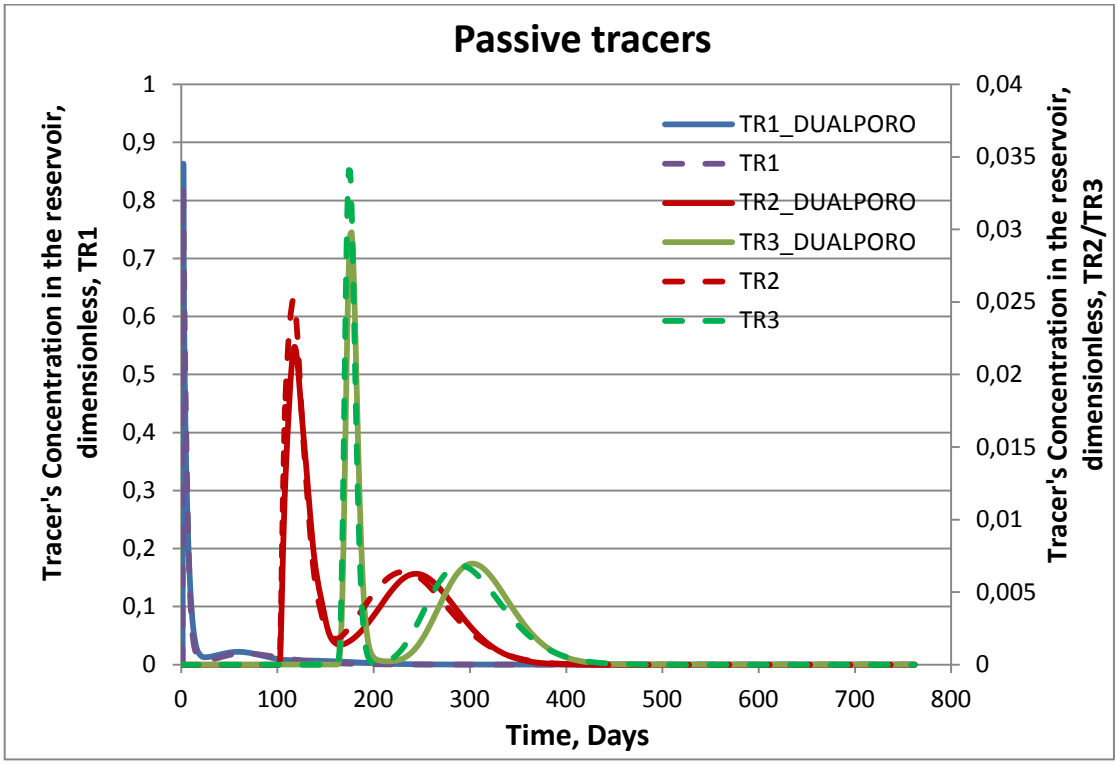

Figure 22: Passive tracers' concentration for the two different simulation options

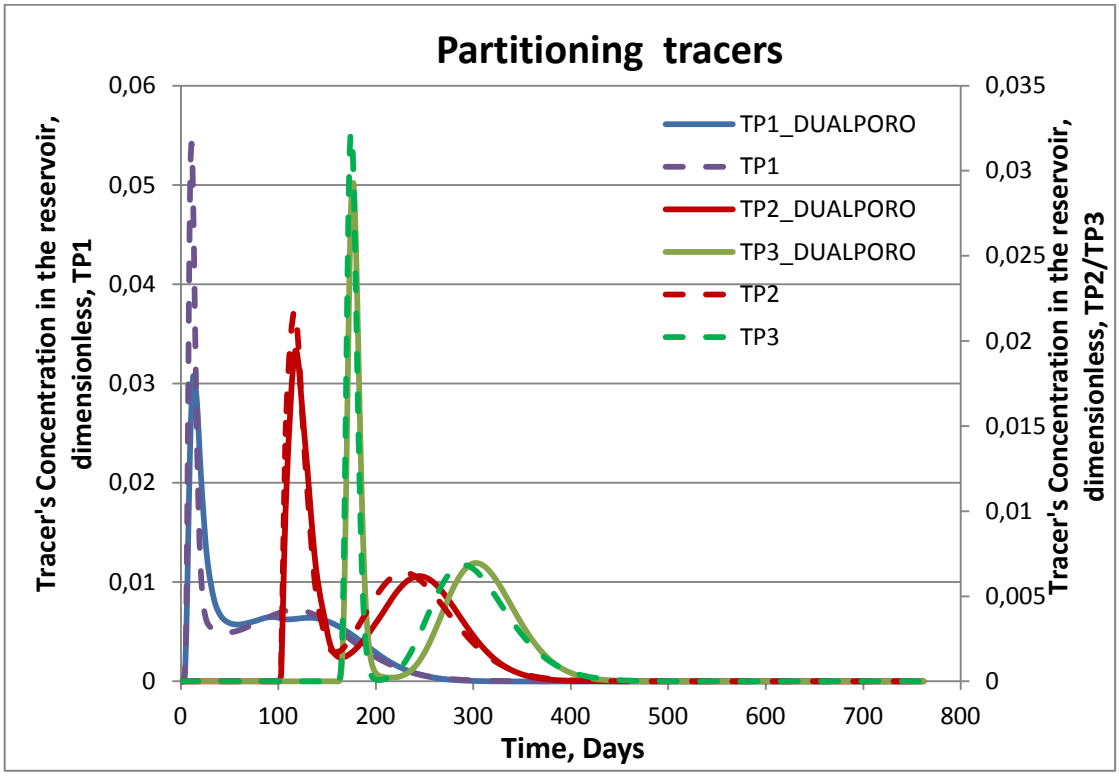

Figure 23: Partitioning tracers' concentration for the two different simulation options

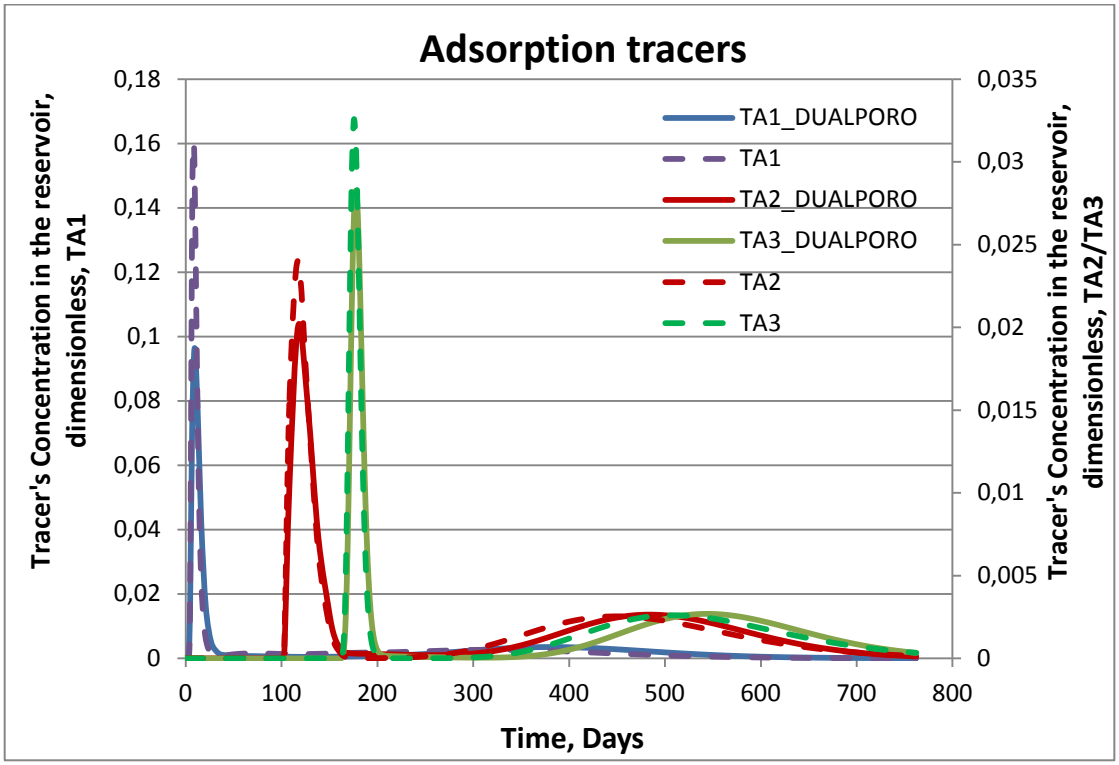

Figure 24: Adsorption tracers' concentration for the two different simulation options

5.2 Comments on the results of the simulation

Comparing the plots with the tracers concentration in the given fractured reservoir, it is obviously deduced that there is a small difference in their values and the retention times, applying the normal flow model and the dual porosity option in *ECLIPSE*. More specifically, the trend of the plots is similar but the absolute values are slightly different in the fractures, while in the matrix block are exactly the same. As for the retention times, in the fracture block they are the same, while in the matrix block are slightly different.

This little divergence in the values of the concentration is due to the simulation of *ECLIPSE* for the dual porosity/dual permeability option. Nevertheless, it is indisputable that dual porosity modeling for a fractured reservoir consists a reliable option in understanding the way that a tracer reacts in a fractured reservoir.

Chapter 6:

Conclusions

The purpose of this thesis is firstly to mention the difference in the flow regimes and the drive mechanisms that exist in a fractured reservoir, comparing with a conventional one. These differences define the production methods that have to be applied in order to have the best possible achieved oil recovery in a fractured reservoir.

Another useful issue is the importance of the tracers application in the reservoir engineering field. Tracers are widely used in the oil industry, as a tool to understand the geology of a reservoir through the monitoring of the tracers concentration in the reservoir and their retention times. Especially, for fractured reservoirs, the monitoring of the tracers flow gives significant information about their structure.

In this thesis, a fractured reservoir is modeled in *ECLIPSE* software applying dual porosity/dual permeability option, while three types of tracers are injected through the reservoir in order to examine their flow and gain information about the reservoir. The definition and the differences of the tracer types are also presented. As it is expected, the properties of the reservoir, such as the permeability, the porosity, the capillary forces, the wettability and the rock properties identify the reservoir and its flow regimes.

Finally, a comparison of the outcomes of the dual porosity/dual permeability model with the normal flow model is presented. It is concluded that there are some slight deviations with the normal flow model but without making the dual porosity model in *ECLIPSE* unreliable for a fractured reservoir simulation.

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Appendix 1

```
-- 2D_RESERVOIR WITH 9 TRACERS

RUNSPEC

TITLE

   2D RESERVOIR_9 TRACERS

DIMENS

   20    1    15  /

OIL

WATER

FIELD

TABDIMS

   2    1   13   25    1   20 /

WELLDIMS

   2   5    2    1 /

START

  1 'JAN' 1990  /

TRACERS  --OIL  WATER  GAS  ENV    FLS

         0     9     0    6   'NODIFF' /

--MULTI PARTITION TRACER

PARTTRAC

3 1 30 /
```

```
GRID    ================================================
INIT
EQUALS
 'DX'     16.4   /   PROPERTIES COMMON TO MATRIX AND FRACTURES
 'DY'     1   /
 'DZ'     3.28    1 20 1 1 1 10 /  MATRIX PROPERTIES
 'DZ'     0.0328   1 20 1 1 11 15 /  FRACTURE PROPERTIES
 'PORO'   0.050    1 20 1 1 1  10  /  MATRIX PROPERTIES
 'PERMX'    1   /
 'PERMY'    1   /
 'PERMZ'    1   /
 'PORO'   0.5    1  20  1  1  11  15  /  FRACTURE PROPERTIES
 'PERMX'  100   /
 'PERMY'  100   /
 'PERMZ'  100   /
 'TOPS'  4000     1  20  1  1  1  1  /
/
ADD
 'PORO'  0.05    1  20  1  1  11  15  /  FRACTURE PROPERTIES
/
RPTGRID                              FIELD   18:07 29 NOV 83
  -- Report Levels for Grid Section Data
  --
  'DX'
  'DY'
```

'DZ'

'PERMX'

'PERMY'

'MULTX'

'MULTY'

'PORO'

'TOPS'

'PORV'

'TRANX'

'TRANY'

'ALLNNC'

/

EDIT

PROPS ==========

--TO OBTAIN CASE WITH NO IMBIBITION, SET CAPILLARY PRESSURES TO ZERO

BOX

1 20 1 1 1 10/

SWOF

-- SATURATION OF WATER AND RELATIVE PERMEABILITIES OF WATER AND OIL

--S_w kr_w kr_o Pco_w

0.0 0.0 0.9 3.0

0.25 0.1 0.5 1.6

0.50 0.15 0.4 1.2

0.60 0.20 0.3 0.7

0.75 0.9 0.0 0.2 / MATRIX

/

ENDBOX

BOX

1 20 1 1 11 15/

SWOF

0.0 0.0 1.0 10.0

0.30 0.4 0.8 6.0

0.60 0.5 0.6 4.0

0.80 0.7 0.5 2.4

1.00 1.0 0.0 1.5 / FRACTURE

/

ENDBOX

PVTW

-- PVT WATER PROPERTIES

--PRESSURE B_w(@ Pref) C_w μ_W (@Pref) Water Viscosibility

-- (psia) (rb/stb) (1/psi) (cP) (1/psi)

4500 1.02 3.0E-06 0.8 0.0 /

PVDO

-- PVT OIL PROPERTIES

-- OIL_PHASE P B_o μ_o

-- (psia) (rb/stb) (cP)

300 1.25 1.0

800 1.20 1.1

6000 1.15 2.0 /

```
ROCK
-- PROPERTIES OF THE ROCK
-- P_ref     C_r
--(psia)  (1/psi)
4500 4E-06 /
DENSITY
--ρ_oil   ρ_w  ρ_g  (@surface conditions)
--   (lb/ft^3)
 52.0000  64.0000   .04400 /
TRACER
 'TR1'  'WAT' /
 'TR2'  'WAT' /
 'TR3'  'WAT' /
 'TP1'  'WAT' 1* 'MULT'  1  /
 'TP2'  'WAT' 1* 'MULT'  1  /
 'TP3'  'WAT' 1* 'MULT'  1  /
 'TA1'  'WAT' /
 'TA2'  'WAT' /
 'TA3'  'WAT' /
 /
--DUE TO THE ACTIVATION OF THE ENV TRACER
TRROCK
-- Adsorption index of the rock   Mass d of rock @reservoir conditions
--       (1 or 2)                        (lb/rb)
```

```
1 0.875 /
/
--MULTI PARTITION TRACERS
TRACERKM
'TP1' STANDARD /
A O /
--PRES  K1(O/A)
  14.7   1.0
  10000  1.0 /
/
TRACERKM
'TP2' STANDARD /
A O /
--PRES  K1(O/A)
  14.7   1.0
  10000  1.0 /
/
TRACERKM
'TP3' STANDARD /
A O /
--PRES  K1(O/A)
  14.7   1.0
  10000  1.0 /
/
--ADSORPTION TRACERS
```

```
TRADSTA1
 .0000  .00000
 0.300  0.0300
 0.500  0.0500
 0.750  0.0750
 1.000  0.1000 /
/
TRADSTA2
 .0000  .00000
 0.300  0.0300
 0.500  0.0500
 0.750  0.0750
 1.000  0.1000 /
/
TRADSTA3
 .0000  .00000
 0.300  0.0300
 0.500  0.0500
 0.750  0.0750
 1.000  0.1000 /
/
--DIFFUSION TRACER DATA
TRDIFTR1
-- (ft^2/day)
3E-5 /
```

```
TRDIFTR2
-- (ft^2/day)
3E-5 /
TRDIFTR3
-- (ft^2/day)
3E-5 /
TRDIFTP1
3E-5 /
TRDIFTP2
3E-5 /
TRDIFTP3
3E-5 /
TRDIFTA1
3E-5 /
TRDIFTA2
3E-5 /
TRDIFTA3
3E-5 /
--TRACTVD
RPTPROPS                          FIELD   15:56 29 NOV 83
  -- PROPS Reporting Options
  --
  'PVTO' 'PVDO' 'PVTW' 'DENSITY' 'GRAVITY' 'SDENSITY' 'ROCK'
/
REGIONS    ================================================
```

SATNUM

200*1 100*2 /

--TRACER

TNUMFTR1

300*1 /

TNUMFTR2

300*1 /

TNUMFTR3

300*1 /

TNUMFTA1

300*1 /

TNUMFTA2

300*1 /

TNUMFTA3

300*1 /

--MULTI PARTITION TRACER

TRKPFTP1

300*1 /

TRKPFTP2

300*1 /

TRKPFTP3

300*1 /

--TRACER

RPTREGS

19*0 1 /

```
SOLUTION  ================================================
EQUIL
4010  3959  6000  0   /
4012  3959  6000  0   /
--TRACER
TVDPFTR1
4000.0   0.0
4033.0   0.0  /
/
TVDPFTR2
4000.0   0.0
4033.0   0.0  /
/
TVDPFTR3
4000.0   0.0
4033.0   0.0  /
/
TVDPFTP1
4000.0   0.0
4033.0   0.0  /
/
TVDPFTP2
4000.0   0.0
4033.0   0.0  /
/
```

TVDPFTP3

4000.0 0.0

4033.0 0.0 /

/

TVDPFTA1

4000.0 0.0

4033.0 0.0 /

/

TVDPFTA2

4000.0 0.0

4033.0 0.0 /

/

TVDPFTA3

4000.0 0.0

4033.0 0.0 /

/

SUMMARY ==========

FOPR

FWPR

FOPT

FWPT

WTPCTR1

/

WTPCTR2

/

WTPCTR3

/

WTPCTP1

/

WTPCTP2

/

WTPCTP3

/

WTPCTA1

/

WTPCTA2

/

WTPCTA3

/

WTICTR1

/

WTICTR2

/

WTICTR3

/

WTICTP1

/

WTICTP2

/

WTICTP3

```
/
WTICTA1
/
WTICTA2
/
WTICTA3
/
 --TRACER
RPTSMRY
1 /
SCHEDULE  ================================================
RPTRST
 BASIC=2 NORST=1 /
WELSPECS
'IW'  'G'   1   1  4033  'WAT'  /
'PX'  'G'   20  1  4033  'OIL'  /
/
COMPDAT                          FIELD   18:10 29 NOV 83
'IW'   1   1   11   15 'OPEN'   2*  .01  /
'PX'   20  1   11   15 'OPEN'   2*  .01  /
/
WCONINJE                         FIELD   18:10 29 NOV 83
'IW','WAT','OPEN','RATE' 1 /
/
```

WCONPROD FIELD 18:11 29 NOV 83

'PX' OPEN LRAT 3* 1 /

/

--TRACER

WTRACER

'IW' 'TR1' 1 /

'IW' 'TP1' 1 /

'IW' 'TA1' 1 /

/

TSTEP

0.1 0.9

/

WTRACER

'IW' 'TR1' 0 /

'IW' 'TP1' 0 /

'IW' 'TA1' 0 /

/

DATES

11 APR 1990 /

/

WTRACER

'IW' 'TR2' 1 /

'IW' 'TP2' 1 /

'IW' 'TA2' 1 /

/

```
TSTEP
 0.1 0.9
/
WTRACER
'IW' 'TR2' 0 /
'IW' 'TP2' 0 /
'IW' 'TA2' 0 /
/
DATES
11 JUN 1990 /
/
WTRACER
'IW' 'TR3' 1 /
'IW' 'TP3' 1 /
'IW' 'TA3' 1 /
/
TSTEP
 0.1 0.9
/
WTRACER
'IW' 'TR3' 0 /
'IW' 'TP3' 0 /
'IW' 'TA3' 0 /
/
```

```
TSTEP

400*1.5

/

END

============================================================
```

Appendix 2

```
-- DUALPORO RESERVOIR WITH 9 TRACERS

RUNSPEC

TITLE

   DUALPORO_RESERVOIR_9 TRACERS

DIMENS

   20   1   16  /

DUALPORO

DUALPERM

OIL

WATER

FIELD

TABDIMS

   2   1   13   25   1   20 /

--GRAVITY DRAINAGE & IMBIBITION FOR DUAL POROSITY RUNS

GRAVDR

WELLDIMS

   2   5   2   1 /

--No OF NON-LINEAR ITERATIONS

NUPCOL

4/

START

  1 'JAN' 1990  /
```

```
TRACERS  --OIL  WATER  GAS  ENV    FLS
         0    9    0   6   'NODIFF' /
--MULTI PARTITION TRACER
PARTTRAC
3 1 30 /
GRID     ================================================
INIT
--NO DUAL POROSITY PERMEABILITY MULTIPLIER
NODPPM
--SPECIFIES BLOCK CORNER TRANSMISSIBILITIES
NEWTRAN
EQUALS
 'DX'     16.4    /    PROPERTIES COMMON TO MATRIX AND FRACTURES
 'DY'     1    /
 'DZ'     3.28     1 20 1 1 1 10 /  MATRIX PROPERTIES
 'DZ'     0.0328   1 20 1 1 11 16 /  FRACTURE PROPERTIES
 'PORO'   0.050    1 20 1 1 1  10  /  MATRIX PROPERTIES
 'PERMX'    1    /
 'PERMY'    1    /
 'PERMZ'    1    /
 'PORO'   0.5     1  20  1  1  11  16  /  FRACTURE PROPERTIES
 'PERMX'  100    /
 'PERMY'  100    /
 'PERMZ'  100    /
 'TOPS'   4000     1  20  1  1  1  1  /
```

```
/
ADD
 'PORO'   0.05     1  20  1  1  11  16  /  FRACTURE PROPERTIES
/
--DUAL POROSITY MATRIX-FRACTURE COUPLING
SIGMA
0.5 /
--VERTICAL DIMENSION OF A BLOCK OF MATRIX MATERIAL
DZMTRX
0.0328 /
RPTGRID                                FIELD   18:07 29 NOV 83
  -- Report Levels for Grid Section Data
  --
  'DX'
  'DY'
  'DZ'
  'PERMX'
  'PERMY'
  'MULTX'
  'MULTY'
  'PORO'
  'TOPS'
  'PORV'
  'TRANX'
  'TRANY'
```

'ALLNNC'

/

EDIT

PROPS ==========

--TO OBTAIN CASE WITH NO IMBIBITION, SET CAPILLARY PRESSURES TO ZERO

BOX

1 20 1 1 1 10/

SWOF

-- SATURATION OF WATER AND RELATIVE PERMEABILITIES OF WATER AND OIL

--Sw krw kro Pcow

0.0 0.0 0.9 3.0

0.25 0.1 0.5 1.6

0.50 0.15 0.4 1.2

0.60 0.20 0.3 0.7

0.75 0.9 0.0 0.2 / MATRIX

/

ENDBOX

BOX

1 20 1 1 11 16/

SWOF

0.0 0.0 1.0 10.0

0.30 0.4 0.8 6.0

0.60 0.5 0.6 4.0

0.80 0.7 0.5 2.4

```
 1.00  1.0   0.0  1.5 / FRACTURE
/
ENDBOX
PVTW
-- PVT WATER PROPERTIES
--PRESSURE   Bw(@ Pref)   Cw     µW (@Pref)  Water Viscosibility
-- (psia)     (rb/stb)  (1/psi)     (cP)         (1/psi)
4500 1.02 3.0E-06 0.8 0.0 /
PVDO
-- PVT OIL PROPERTIES
-- OIL_PHASE P    Bo      µo
--   (psia)    (rb/stb)  (cP)
300   1.25  1.0
800   1.20  1.1
6000  1.15  2.0 /
ROCK
-- PROPERTIES OF THE ROCK
-- Pref     Cr
--(psia)  (1/psi)
4500 4E-06 /
DENSITY
--ρoil   ρw   ρg  (@surface conditions)
--   (lb/ft^3)
 52.0000  64.0000   .04400 /
```

```
TRACER
 'TR1'  'WAT' /
 'TR2'  'WAT' /
 'TR3'  'WAT' /
 'TP1'  'WAT' 1* 'MULT'  1  /
 'TP2'  'WAT' 1* 'MULT'  1  /
 'TP3'  'WAT' 1* 'MULT'  1  /
 'TA1'  'WAT' /
 'TA2'  'WAT' /
 'TA3'  'WAT' /
 /
--DUE TO THE ACTIVATION OF THE ENV TRACER
TRROCK
-- Adsorption index of the rock   Mass d of rock @reservoir conditions
--       (1 or 2)                        (lb/rb)
1 0.875 /
/
--MULTI PARTITION TRACERS
TRACERKM
'TP1' STANDARD /
A O /
--PRES  K1(O/A)
  14.7   1.0
  10000  1.0 /
/
```

```
TRACERKM
'TP2' STANDARD /
A O /
--PRES  K1(O/A)
  14.7   1.0
  10000  1.0 /
/
TRACERKM
'TP3' STANDARD /
A O /
--PRES  K1(O/A)
  14.7   1.0
  10000  1.0 /
/
--ADSORPTION TRACERS
TRADSTA1
 .0000  .00000
 0.300  0.0300
 0.500  0.0500
 0.750  0.0750
 1.000  0.1000 /
/
TRADSTA2
 .0000  .00000
 0.300  0.0300
```

```
 0.500  0.0500
 0.750  0.0750
 1.000  0.1000 /
/
TRADSTA3
 .0000  .00000
 0.300  0.0300
 0.500  0.0500
 0.750  0.0750
 1.000  0.1000 /
/
--DIFFUSION TRACER DATA
TRDIFTR1
-- (ft^2/day)
3E-5 /
TRDIFTR2
-- (ft^2/day)
3E-5 /
TRDIFTR3
-- (ft^2/day)
3E-5 /
TRDIFTP1
3E-5 /
TRDIFTP2
3E-5 /
```

TRDIFTP3

3E-5 /

TRDIFTA1

3E-5 /

TRDIFTA2

3E-5 /

TRDIFTA3

3E-5 /

--TRACTVD

RPTPROPS FIELD 15:56 29 NOV 83

-- PROPS Reporting Options

--

'PVTO' 'PVDO' 'PVTW' 'DENSITY' 'GRAVITY' 'SDENSITY' 'ROCK'

/

REGIONS ==========

SATNUM

200*1 120*2 /

--TRACER

TNUMFTR1

320*1 /

TNUMFTR2

320*1 /

TNUMFTR3

320*1 /

TNUMFTA1

320*1 /

TNUMFTA2

320*1 /

TNUMFTA3

320*1 /

--MULTI PARTITION TRACER

TRKPFTP1

320*1 /

TRKPFTP2

320*1 /

TRKPFTP3

320*1 /

--TRACER

RPTREGS

19*0 1 /

SOLUTION ==========

EQUIL

4010 3959 6000 0 /

4012 3959 6000 0 /

--TRACER

TVDPFTR1

4000.0 0.0

4033.0 0.0 /

/

TVDPFTR2

4000.0 0.0

4033.0 0.0 /

/

VDPFTR3

4000.0 0.0

4033.0 0.0 /

/

TVDPFTP1

4000.0 0.0

4033.0 0.0 /

/

TVDPFTP2

4000.0 0.0

4033.0 0.0 /

/

TVDPFTP3

4000.0 0.0

4033.0 0.0 /

/

TVDPFTA1

4000.0 0.0

4033.0 0.0 /

/

TVDPFTA2

4000.0 0.0

4033.0 0.0 /

/

TVDPFTA3

4000.0 0.0

4033.0 0.0 /

/

SUMMARY ==========

FOPR

FWPR

FOPT

FWPT

WTPCTR1

/

WTPCTR2

/

WTPCTR3

/

WTPCTP1

/

WTPCTP2

/

WTPCTP3

/

WTPCTA1

/

WTPCTA2

/

WTPCTA3

/

WTICTR1

/

WTICTR2

/

WTICTR3

/

WTICTP1

/

WTICTP2

/

WTICTP3

/

WTICTA1

/

WTICTA2

/

WTICTA3

/

--TRACER

RPTSMRY

```
1 /
SCHEDULE ================================================
RPTRST
 BASIC=2 NORST=1 /
WELSPECS
'IW'  'G'   1   1  4033  'WAT'  /
'PX'  'G'   20  1  4033  'OIL'  /
/
COMPDAT                          FIELD   18:10 29 NOV 83
'IW'   1   1   11   15 'OPEN'   2*  .01  /
'PX'   20  1   11   15 'OPEN'   2*  .01  /
/
WCONINJE                         FIELD   18:10 29 NOV 83
'IW','WAT','OPEN','RATE' 1 /
/
WCONPROD                          FIELD   18:11 29 NOV 83
'PX' OPEN LRAT  3* 1 /
/
--TRACER
WTRACER
'IW' 'TR1' 1 /
'IW' 'TP1' 1 /
'IW' 'TA1' 1 /
/
TSTEP
```

```
 0.1 0.9
/
WTRACER
'IW' 'TR1' 0 /
'IW' 'TP1' 0 /
'IW' 'TA1' 0 /
/
DATES
11 APR 1990 /
/
WTRACER
'IW' 'TR2' 1 /
'IW' 'TP2' 1 /
'IW' 'TA2' 1 /
/
TSTEP
 0.1 0.9
/
WTRACER
'IW' 'TR2' 0 /
'IW' 'TP2' 0 /
'IW' 'TA2' 0 /
/
DATES
11 JUN 1990 /
```

```
/
WTRACER
'IW' 'TR3' 1 /
'IW' 'TP3' 1 /
'IW' 'TA3' 1 /
/
TSTEP
 0.1 0.9
/
WTRACER
'IW' 'TR3' 0 /
'IW' 'TP3' 0 /
'IW' 'TA3' 0 /
/
TSTEP
400*1.5
/
END
============================================================
```