Simulation of Water-Oil flow in Naturally Fractured Reservoirs

by

Affaf Yahya Ikram
17055

Dissertation submitted in partial fulfilment of

the requirements for the

Bachelors of Engineering (Hons)

(Petroleum)

FYP II May 2015

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CERTIFICATION OF APPROVAL

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Approved by,

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AP Dr. Mohanad Talib Shukur Ali-Shaikhli

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May 2015

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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Affaf Yahya Ikram

ABSTRACT

One of the major problems in the simulation of Naturally Fractured Reservoirs (NFRs) is calculating the matrix-fracture transfer which governs the dynamic behaviour of the reservoir. Dual Porosity models were introduced to study the flow of fluids through the fracture media. In this research, a reservoir model is simulated with a dual porosity system and compared with a reservoir without a dual porosity system. The results show high permeability and low porosity of fractures in the simulation model whereas the matrix blocks have high porosity and low permeability.

ACKNOWLEDGEMENT

I like to thank my supervisor AP Dr. Mohanad Talib Shukur Ali-Shaikhli for his support and kindness during my research. I acknowledge his helpful and supportive professional advisory role. I am also thankful to Muhammad Ali Buriro (PhD scholar) for his cooperation and technical assistance during my studies.

I am thankful to Universiti Teknologi PETRONAS for providing me with this research opportunity and facilities to complete my studies. I also acknowledge welcoming and valuable support of UTP staff. This journey would not be pleasantly memorable without my friends. I am thankful to Ali Boi, Mr. Awan and Raja Sheb.

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CHAPTER 1
INTRODUCTION

1. PROJECT BACKGROUND

Naturally fractured reservoirs are characterized by the presence of two distinct types of porous media: matrix and fracture. These reservoirs are often called dual-porosity reservoirs due to the different fluid storage and conductivity characteristics in the matrix and fractures (Warren and Root, 1963). Figure 1 below shows a naturally fractured reservoir made up of a composed rock matrix surrounded by an irregular system of natural fractures and vugs. A real, heterogeneous, naturally fractured reservoir is observed to have a characteristic behavior which can be interpreted by the use of an equivalent, homogeneous dual-porosity model like the one shown in the idealized sketch below. Several models have been proposed to represent the pressure behavior in a naturally fractured reservoir. These models differ conceptually only in the assumptions made to describe fluid flow in the matrix. Most dual-porosity models assume that production from the naturally fractured system comes from the matrix, to the fracture, and then to the wellbore (i.e., that the matrix does not produce directly into the wellbore). Furthermore, the models assume that the matrix has low permeability but large storage capacity relative to the natural fracture system, while the fractures have high permeability but low storage capacity relative to the natural fracture system.

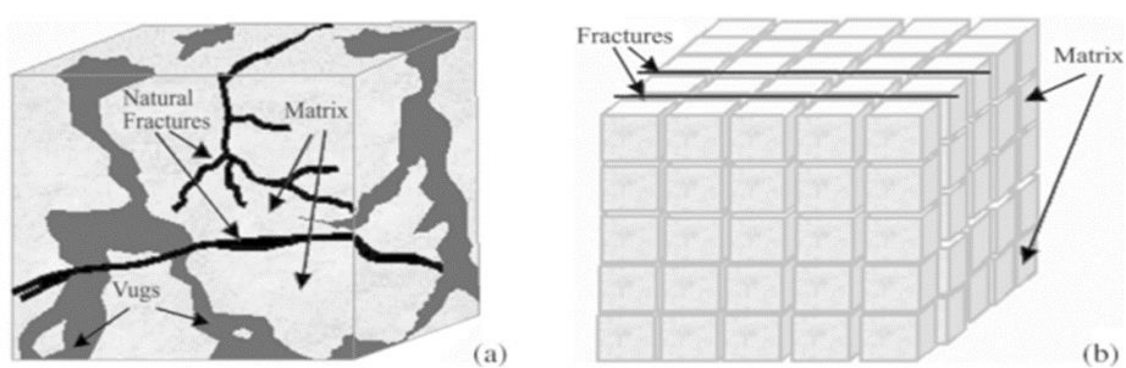

Figure 1. Actual (a) and idealized (b) dual-porosity reservoir model (Warren and Root, 1963)

2. PROBLEM STATEMENT

This research will be particularly conducted for Naturally Fractured reservoirs (NFR). These reservoirs have great hydrocarbon reserves, most of which have not been recovered due to the complications in geology. A huge uncertainty in a number of parameters such as storage capacity, spatial distribution, flow and transport alterations are caused due to the presence of two contrasting media—matrix and fracture. All of the above mentioned parameters affect the reservoir performance at all stages of production life and must be studied and accounted in detail when developing a design for any field operation. Impact on different recovery mechanisms are important at any stage of development therefore, proper characterization and fracture properties should be understood especially for the investment intensive and risky EOR applications. With the help of technology, high risks taken by companies due to higher budgets can be analyzed and reduced. One peculiar feature of NFRs is the risk factor, resulting from the huge difference between an outcome of a proper reservoir management and an outcome of an improper one. That means in the same reservoir, natural fractures can have a positive or a negative effect on its recovery at all stages of its life.

3. OBJECTIVES AND SCOPE OF STUDY

The research of this study will be focusing on objectives as follow:

- To simulate a Dual-Porosity model.
- To compare the flow of fluids in a reservoir with a dual porosity system and a reservoir without a dual porosity system.

CHAPTER 2
LITERATURE REVIEW

Although the research conducted in naturally fractured reservoir cannot be considered an old branch in reservoir geosciences, however our understanding of NFRs showed tremendous progress over recent time, especially in the past two decades. Many books on several aspects from fracture origins to their impacts on reservoir management have been published. To fully grasp the behaviour of NFR, we need to understand the characteristics of these reservoirs and the methods used for modelling.

1. CONVENTIONAL MODELLING OF NATURALLY FRACTURED RESERVOIRS

Dual porosity models are the conventional methods used for the simulation of naturally fractured reservoirs and are widely used in the industry. Barenblat et al. (1960) and Warren and (Warren & Root, 1963) laid the foundation of the dual-porosity model some fifty years ago, also known as the sugar cube model. Numerous modifications to the basic dual-porosity model by various researchers have been done since then. In this technique, NFRs are supposed to comprise of an interconnected fracture system which will give the primary flow paths (with low storage volume and high permeability) and the reservoir rock (or matrix) which acts as the primary source of hydrocarbons (which has high storage volume and low permeability). Therefore, it is the matrix system which has the most of the hydrocarbons, but the production to the wells is provided by the high-permeability fracture system, which shows that it is the interaction in matrix and fracture that controls the flow of the fluids. The NFR is modelled with two overlapping domains: the matrix domain and the fracture domain. The model assume that the matrix has low permeability but large storage capacity relative to the natural fracture system, while the fractures have high permeability but low storage capacity relative to the natural fracture system. A sample model of such reservoir is illustrated in Figure 2.

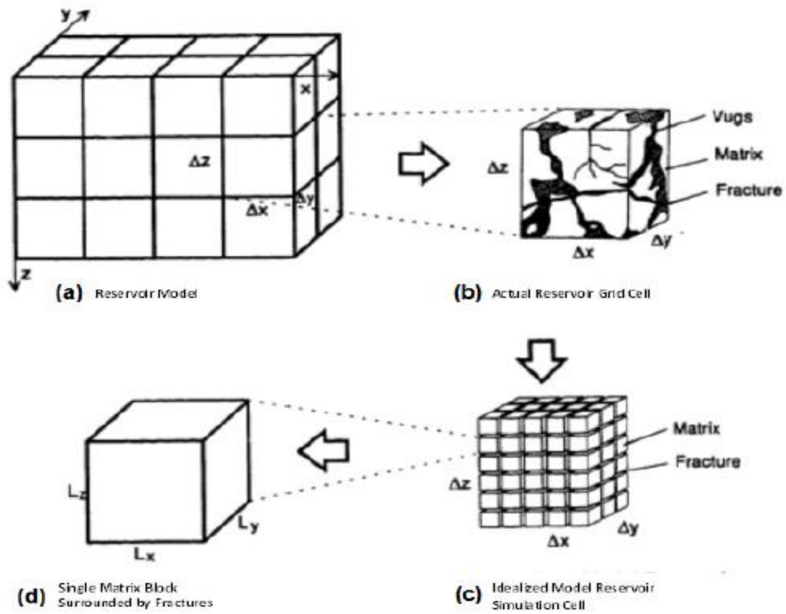

Figure 2. Warren and Root Model (1963)

(Kazemi, Gilman, & Eisharkawy, 1992), (Rossen, 1977), and (Saidi, 1983) further developed the Warren and Root approach to multiphase flow and developed dual porosity simulators. Few years later, (Blaskovich, Cain, Sonier, Waldren, & Webb, 1983), (Hill & Thomas, 1985) and (Dean & Lo, 1986) developed dual permeability models. These models allow for matrix to matrix flow but these reservoirs are modeled as a continuum. Although dual porosity and permeability models have been implemented in many reservoir simulators, fracture uniformity presumed in these models does not conform to outcrop observations, which indicate height, length, aperture, spacing and directionality of natural fractures vary substantially in the sub surface. (Johns & Jalali-Yazdi, 1989) and others further extended dual continuum models to include variable matrix block sizes in order to make these models more realistic. (Moinfar, Narr, Hui, Mallison, & Lee, 2013), however presented examples where the dual continuum approach fails to provide accurate solutions in the presence of large scale fractures and high localized anisotropy. Thus continuum models are especially appropriate for reservoirs with a large number of highly connected, small scale fractures.

2. DISCRETE FRACTURE MODELING

Discrete Fracture Modeling (DFM) is a different type of model for simulating fractured systems. DFMs based on the concept that the fracture planes are individually represented and the fluid flow behaviour can be estimated from the fracture geometries and data on the transmissivity of these individual fractures. This methodology integrates "a forward approach based on geosciences and an inverse approach based on reservoir engineering" using the mapping of fracture planes in 3D space to construct an interconnected fracture network. Average reservoir properties e.g. conductivity, anisotropy and storage capacity are required to perform a field-scale simulation, and therefore, discrete fracture information such as size, orientation, location and spacing are used in building DFMs. Unlike other techniques, DFM depends upon a highly precise fracture network, and is best suitable in conditions where the flow behaviour is dominated by significant fractures without depending on any given type of information. Information regarding geological setting and fractures is not only used to develop the models, but also to constrain the models, making sure that a realistic geological model is developed. The final outputs of DFM are the equivalent fracture parameters which can be used in any fractured reservoir simulator. These parameters consist of effective permeability, fracture porosity and matrix block size.

Discrete Fracture Network related research carried out in over the past few decades has focused on identifying the individual discrete features and karts which provides secrete connections which carry the most important portion of flow. As mentioned above, most DFMs rely on precise structured grids to honour the geometry and location of fracture networks. (Noorishad & Mehran, 1982), (Baca, Arnett & Langford, 1984), (Kim & Deo, 2000) and (Karimi-Fard & Firoozabadi, 2003) developed discrete fracture models based on the finite element method. Similarly, (Monteagudo & Firoozabadi, 2004). (Fu, Yang & Doe, 2005) and (Matthäi, Mezentsev & Belayneh, 2005) employed control volume finite-element methods to develop numerical simulators for multiphase flow in fractured media. Karimi-Fard, Durlofsky & Aziz, 2003) and (Hui & Mallison, 2009) developed DFMs compatible with multiphase reservoir simulators, based in unstructured control volume finite-difference formulation, Also (Li & Lee, 2008) and (Moinfar, Varavei, Sepehrnoori & Johns, 2012) developed embedded discrete fracture models, which use a structures grid to represent the matrix and introduce additional fracture control volumes by computing the intersection of fractures with the matrix guide.

Figure 3 shows a comparison between a Dual Porosity model and a Discrete Fracture Network model. The dual porosity model shows the distribution of fractures as a path between the matrixes and the grids are highly structured. On the other hand, DFN model shows fractures that are spatially distributed and the grids are highly unstructured.

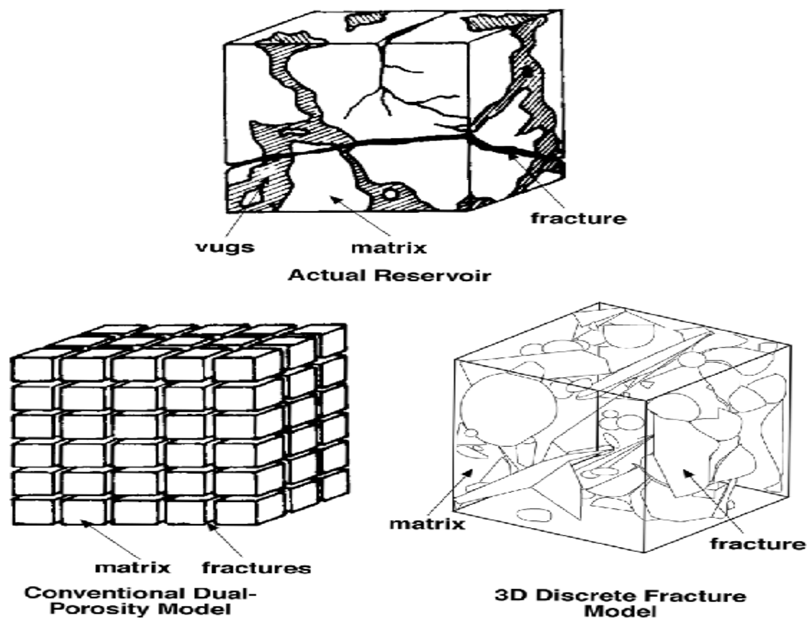

Figure 3. Comparison between a Dual porosity and a DFN model.

CHAPTER 3

METHODOLOGY/PROJECT WORK

1. RESEARCH OVERVIEW

This research project was conducted based on the following activities upon completion of this course.

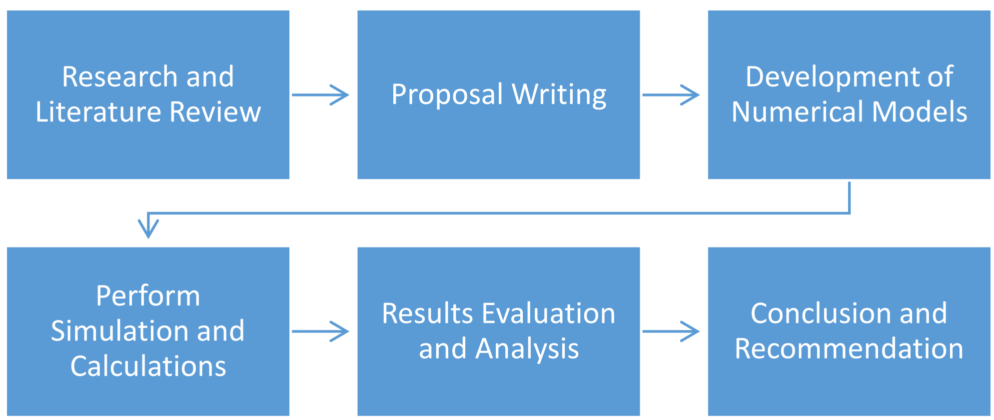

Figure 4. Research Methodology Workflow

2. TOOLS REQUIRED

- Schlumberger ECLIPSE was used to simulate the fractured reservoir using Dual Porosity Method.

3. KEY MILESTONE

For FYP, the following milestone were completed by the end of course.

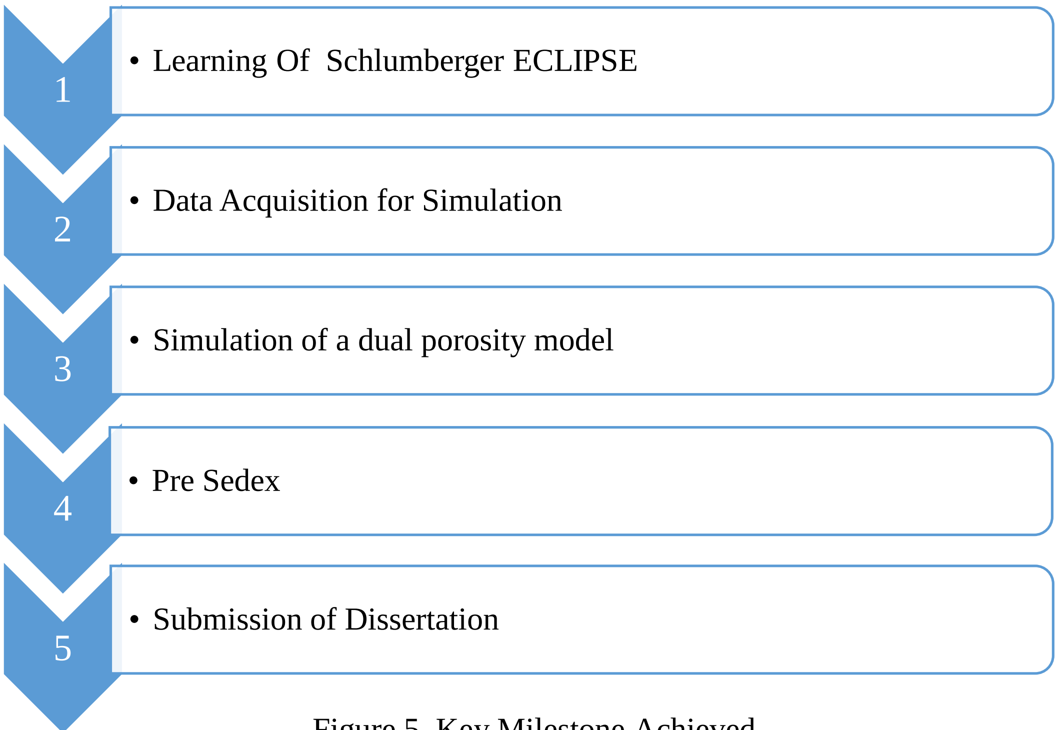

Figure 5. Key Milestone Achieved

4. SIMULATION IN ECLIPSE

Reservoir simulation is defined as the combination of physics, mathematics, reservoir engineering and computer programming to develop a tool for predicting hydrocarbon-reservoir performance under various operating conditions. Reservoir modeling requires the use of simulator. A simulator is a program used to perform material balance calculations to determine pressure and saturation distribution of the reservoir as a function of time.

4.1 Simulation Model Construction

This is a process where all information for describing the reservoir is provided to the reservoir simulator as input data, so it can perform material balance calculation. In constructing a dynamic simulation model using the compositional simulator, the input data are categorized and need to be entered under eight (8) sections in the input data file.

The names of the sections are in a required sequence namely: RUNSPEC, GRID, EDIT, PROPS, REGIONS, SOLUTION, SUMMARY and the SCHEDULE section. Below is the description of the data to be entered in the respective sections.

- **RUNSPEC:** the data specified in this section is used to determine the amount of storage required by the run and includes the units, phase present, number of grid cell, number of PVT and relative K tables, maximum number of wells and start date for the run.
- **GRID:** this is the backbone of dynamic simulation model. Here the amount of data that needs to be specified in this section is usually very large for full field simulation study. It is where property values from the maps are placed on the grid. These data include cell dimension, the depth of each cell, gross thickness, porosity and permeability.
- **EDIT:** this section keep track of the changes made on the rock properties during the history match and also keep original geological model in GRID section.
- **PROPS:** the simulator requires this section and it contains data primarily measured in the laboratory and normally specified as Tables. This includes: oil, water and gas at stock tank conditions, relative permeability curves, capillary pressure data and rock compressibility.
- **REGIONS:** this section is optional, used if there is more than one rock type, oil gravity, oil water contact, bubble point distribution or initial pressure at datum. Also, keywords in this section are used to assign cells to different relative permeability tables, PVT tables or initial conditions.
- **SOLUTION:** this section is used by the simulator to take the first time-step (model initialization). Here pressure and saturations for each grid cell is needed.
- **SUMMARY:** this section is optional because it is used to specify parameter that the user plans to plot.

As discussed previously, in a naturally fractured reservoir, fluids exist in two interconnected Systems:

- The rock matrix, which usually provides the bulk of the reservoir volume.
- The highly permeable rock fractures.

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 etc. of these 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. Dual porosity runs are specified by the keyword DUALPORO in RUNSPEC section, while dual permeability requires the DUALPERM keyword. 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 grids with the matrix blocks, and the second half with the fractures. 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 6 illustrates a simple dual porosity and permeability system.

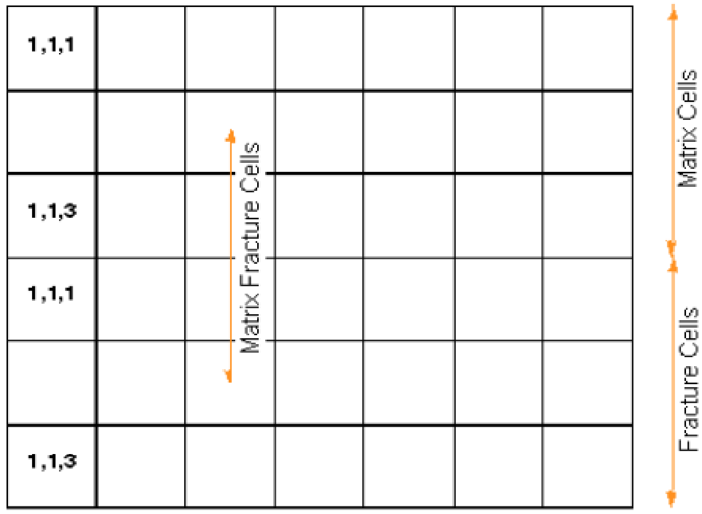

Figure 6. A simple dual porosity, dual permeability system. (ECLIPSE 100)

4.2 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.

4.3 Restrictions on Dual Porosity runs

The following restrictions apply to dual porosity (DUALPORO) runs (except in single porosity regions specified using DPNUM).

- Wells connect only to fracture cells - not to matrix cells.
- Non-neighbor connections (keyword NNC) may not be used with matrix cells. The internal connection of each matrix cell to its appropriate fracture cell is made automatically by ECLIPSE.

- Each active matrix cell must connect with an active fracture cell.

In single porosity regions, there are no active fracture cells. Within these regions, data is only required for the matrix cells; any data for the fracture cells are ignored. Wells should connect to matrix blocks within single porosity regions.

CHAPTER 4

RESULTS AND DISCUSSION

The reservoir is assumed horizontal and rectangular, with height 100 ft. and length 600 ft. For computational simplicity the reservoir is assumed to be uniform in the other direction; consequently, the fracture calculations are two dimensional.

In the RUNSPEC section the reservoir was defined with dimensions of 8 x 8 x 1. Figure 7 shows the grid model for the reservoir.

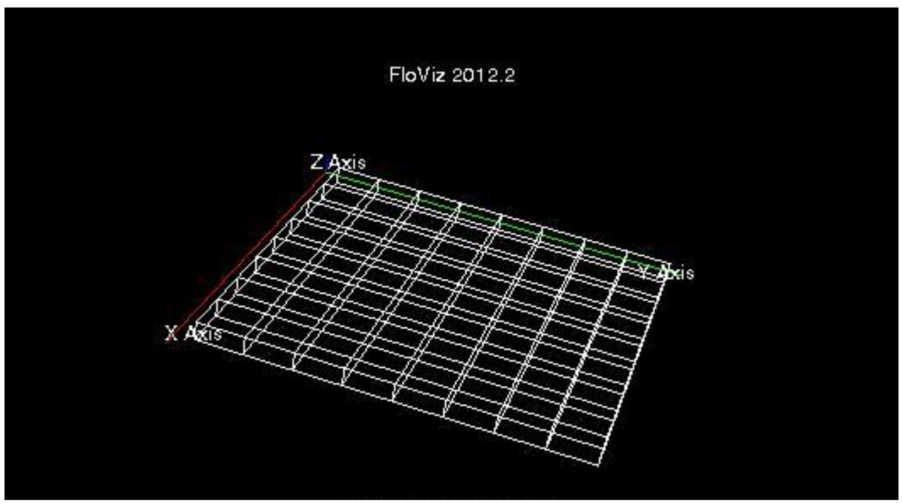

Figure 7. Grid model of an 8x8x1 reservoir

Furthermore, the black oil simulation and dual porosity keywords are entered to prepare the simulator for dual porosity simulation. The fluids to be entered in the data set are water and oil Also, the units to be used are Field units.

The values of porosity for matrix blocks and fractures are assumed to be 0.01 and 0.19. The permeability value for matrix blocks and fractures are 1.0md and 10000md. Therefore accounting for low porosity and high permeability in the fracture cells.

Initially the reservoir contains 75% oil with following properties:

Viscosity = 0.5cp

Density = 0.7 g/cm3

And 25% water with following properties:

Viscosity = 2cp

Density = 1 g/cm3

In the PROPS section, Water relative permeabilities are defined with the SWFN keyword followed by the table below.

Table 1. Water relative Permeabilities

Sw	Krw	Kro
0.0	0.0	4.0
0.1	0.05	1.85
0.2	0.11	0.9
0.25	0.14	0.72
0.3	0.18	0.55
0.4	0.26	0.40
0.5	0.355	0.29
0.6	0.475	0.2
0.7	0.585	0.16
0.8	0.715	0.11
0.9	0.85	0.05
1	1.0	0.0

Oil relative permeabilities are defined with the SOF3 keyword followed by the table below. The SOF3 keyword sets relative permeability of oil in water, and oil in gas at the connate water saturation, as a function of oil saturation.

Table 2. Oil relative permeabilities

So	Krow	Krog
0.0	0.0	0.0
0.1	0.02	0.02
0.2	0.05	0.05
0.3	0.10	0.10
0.4	0.17	0.17
0.5	0.24	0.24
0.6	0.33	0.33
0.7	0.45	0.45
0.8	0.51	0.51
0.9	0.77	0.77
1	1.0	1.0

In the SCHEDULE section, the injection well is specified using the WELSPECS keyword at block (1, 1, 3) perforated at a depth of 4000ft. The production well is placed at block (4,4,3) perforated at a depth of 4000ft. The injection and production rates are set at 200 stb/day after several test runs. Figure 8 shows the position of injection and production wells in the reservoir.

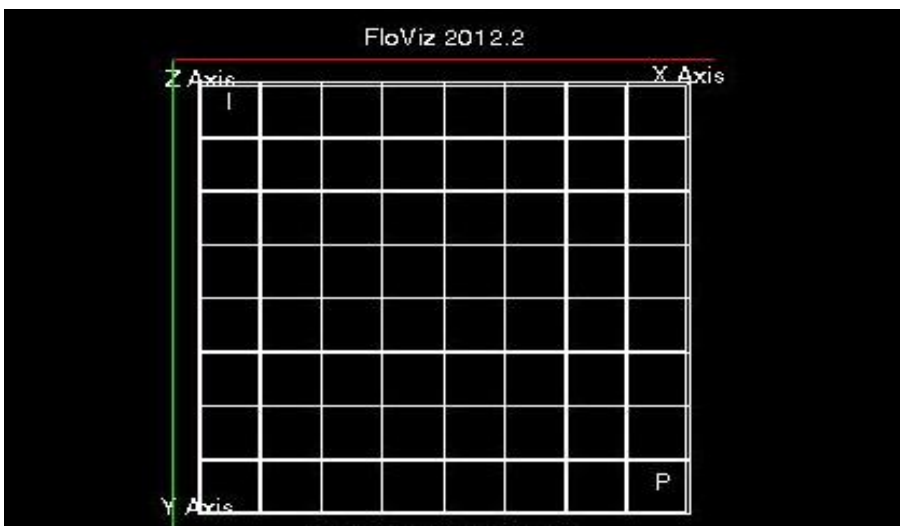

Figure 8. Position of injection and production wells in the reservoir

The 3D reservoir simulation model is shown below at time step 0. The distribution of oil saturation is illustrated. The red grid cells are showing high oil saturation while blue grid cells are showing low oil saturation and high water saturation.

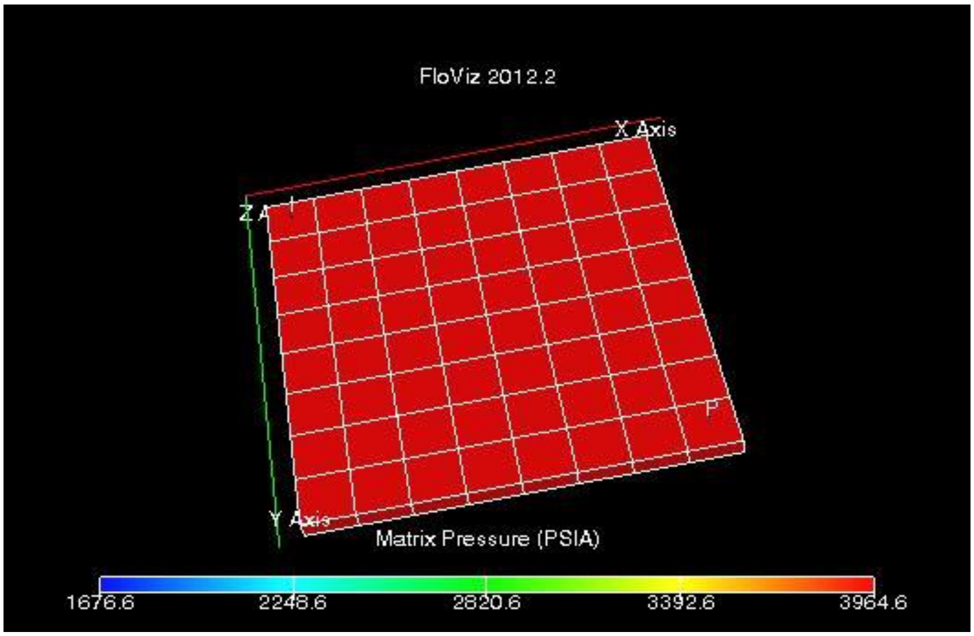

Figure 9. The 3D reservoir simulation model

To analyze the use of Dual porosity keyword in the RUNSPEC section, figure 10 helps us understand the distribution of matrix blocks and fractures. The matrix blocks and fractures were assigned different porosity and permeability values. The flow through matrix blocks is much lower than the flow of fluids through the fracture blocks.

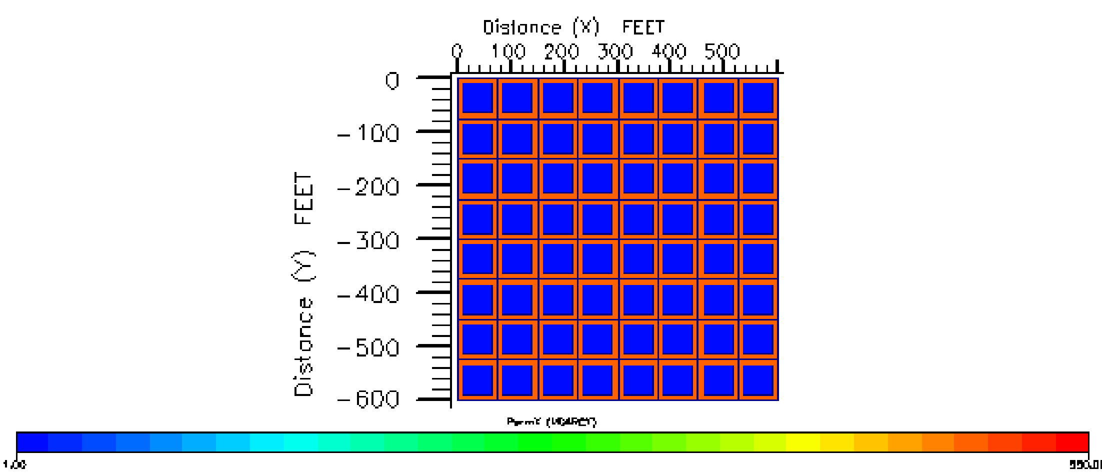

Figure 10. Permeability in matrix blocks and fractures

The blue color of the matrix blocks depicts the low permeability of porous rock therefore the flow from the matrix blocks to the fracture is low. However, the reddish color of the fractures shows that fractures allow fluids to pass through them with ease and hence resulting in higher permeability. Contrary to this, the porosity in the matrix blocks are higher compared to the fractures. Figure 11 shows that porosity distribution in the matrix blocks and the fractures.

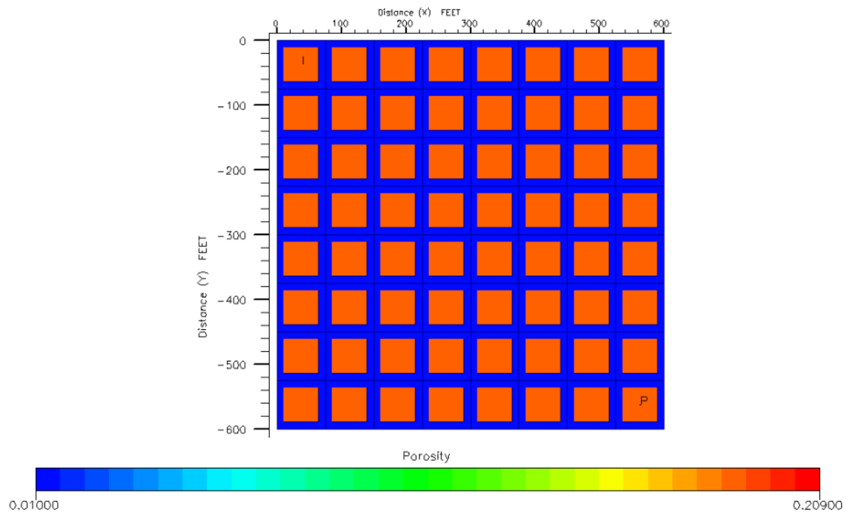

Figure 11. Porosity in matrix blocks and fractures

In the SCHEDULE section, 12 time steps of 100 days each are entered in the data set. As the production begins, the oil saturation in the reservoir decreases near the injection well. Owing to the higher permeability of fractures the oil moves faster from the fractures in to the production well as compared to the flow from the matrix blocks to the fractures. Figure 12 shows the distribution of the oil saturation after 6 time steps to indicate the flow of oil through the fractures.

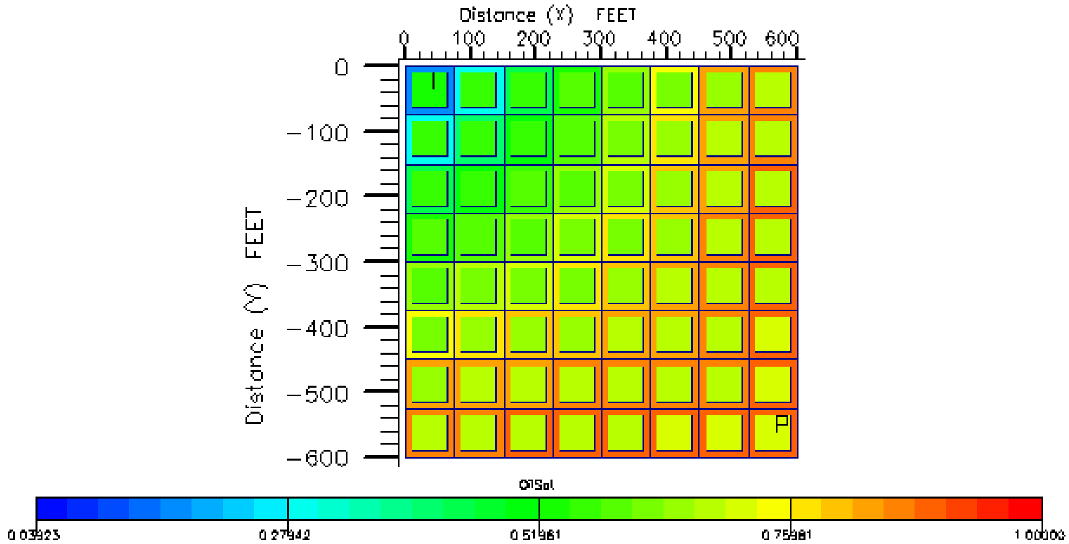

Figure 12. Oil Saturation in matrix blocks and fractures

Furthermore after 1200 days, Field oil production rate (FOPR), Field gas oil ratio and Field water cut is analyzed. Figure 13 shows the graphs obtained after 12 time steps.

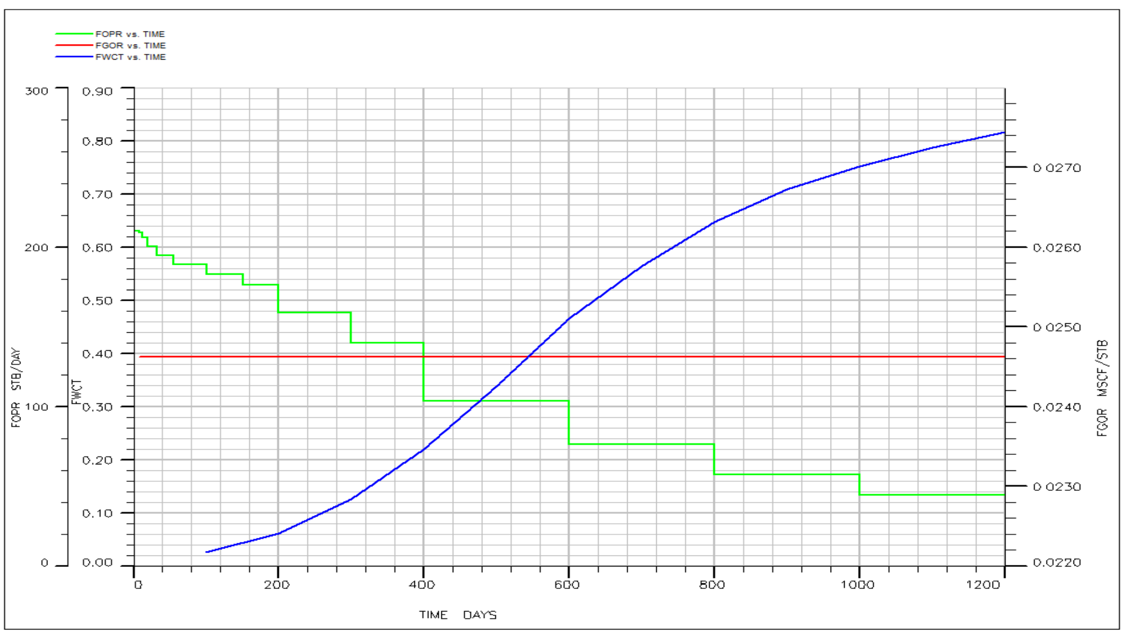

Figure 13. FOPR Vs TIME, FGOR Vs TIME and FWCT Vs TIME of the reservoir

Field gas oil ratio is observed constant at a value of 0.39. The Oil production rate declines while the water cut increases with time. At 1200 days the water cut is observed quite high due to the injection of water and high permeability of fractures. Due to this the oil production rate declines and reached a low value of a 43 STb/day.

After analyzing the flow in Dual porosity Model, a fractured reservoir is compared to an unfractured one, with unfractured one possessing the matrix properties of the fractured one. The difference in response between the two reservoirs is analyzed on the basis of better production rate and pressure gradient. The unfractured model has no dual porosity keyword assigned in the RUNSPEC section.Therefore there are no fractures present in the reservoir, however the matrix blocks have the same properties as in the dual porosity model.

Figures 14 shows the grid blocks of an unfractured model.

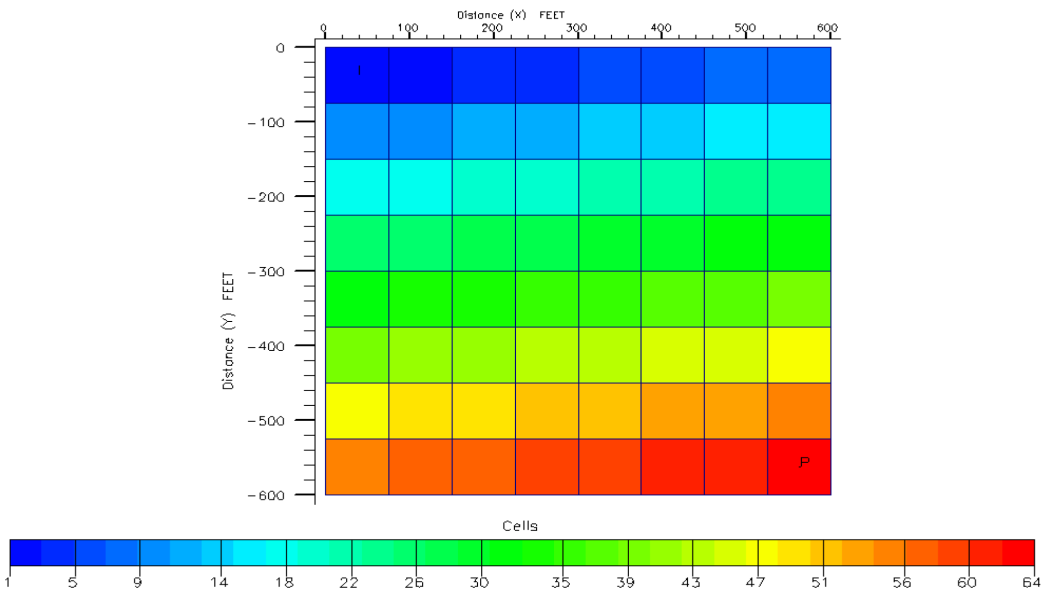

Figure 12. Reservoir model with Dual Porosity

In the figure above, there are so fractures present in the model since there is no dual porosity system. Hence the reservoir has one porous medium present which are the matrix blocks. The permeability distribution in the matrix blocks are constant in both X and Y direction. Figure below shows the permeability distribution of in the reservoir with no dual porosity system.

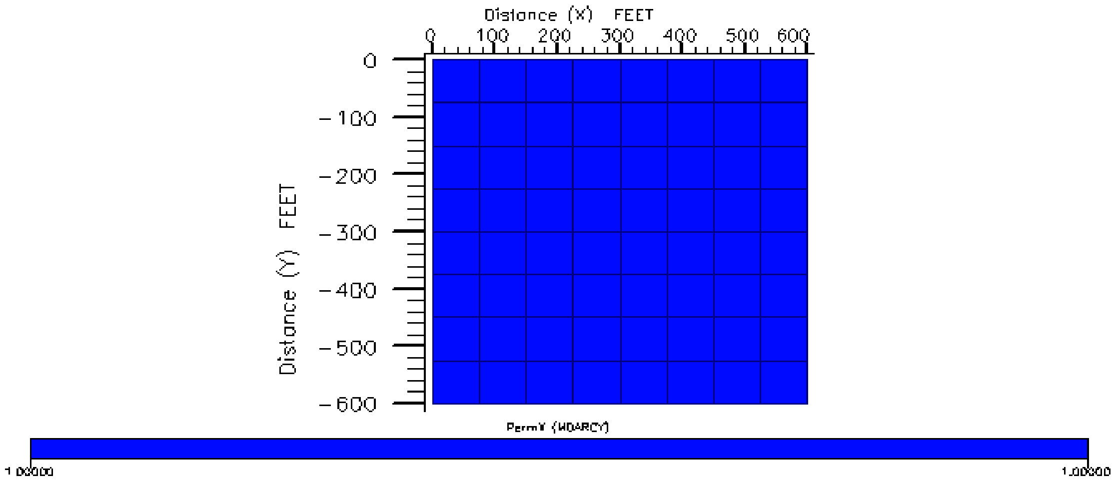

Figure 13. Permeability distribution in the Reservoir with no Dual Porosity

To compare the flow of fluids in both the models, Field oil production rate is analyzed. Figure 16 shows the field oil production rate in both the models.

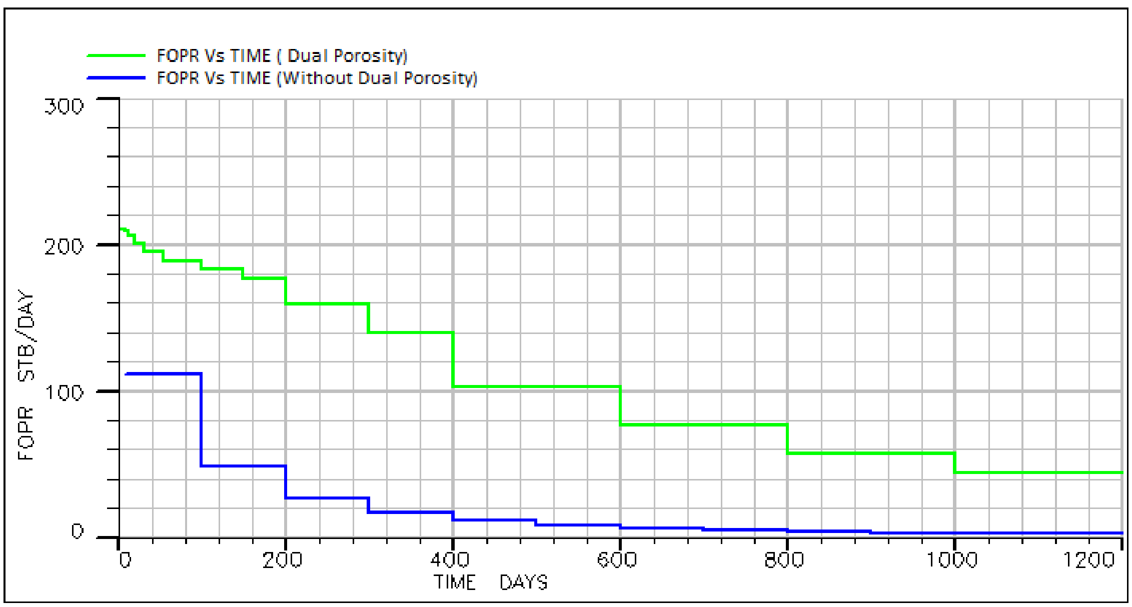

Figure 14. FOPR comparison between a Dual Porosity model and a model with no dual porosity

Since there are high permeability fractures present in the dual porosity model, the oil production is recorded higher than the unfractured model. This is because the fractures ease the path for the oil to flow to the production well. Moreover, the pressure decline is also associated with the flow of the fluids from the porous media to the production well.

Higher the flow, higher the pressure decline in the reservoir. In figure 16, the field pressure decline is observed in the both the reservoir models.

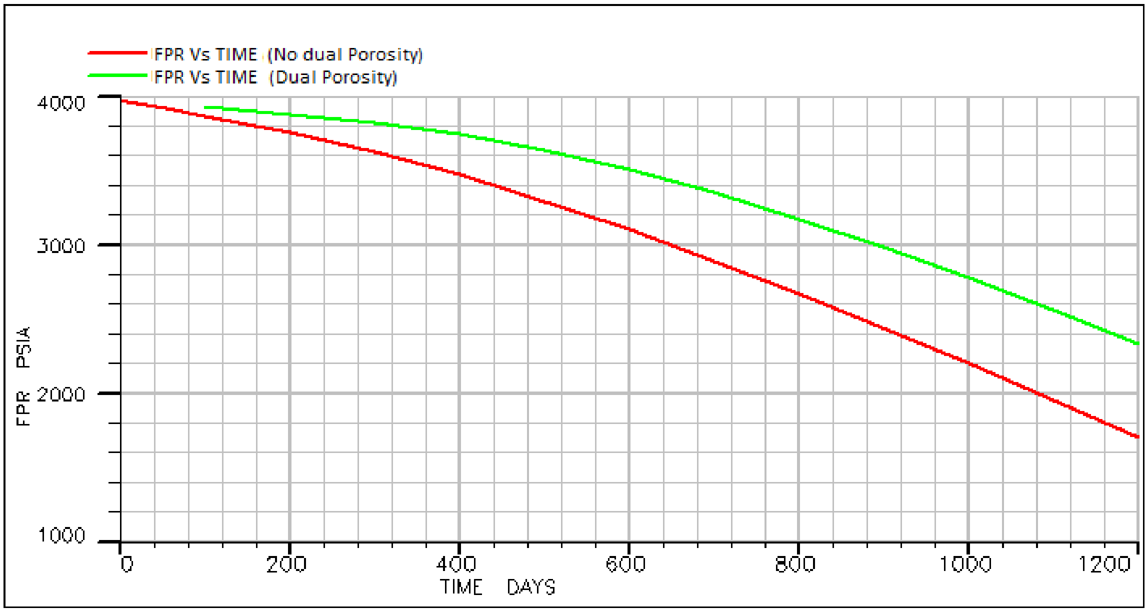

Figure 15. Pressure decline in a Dual Porosity model and a model with no dual porosity

The pressure depletion in the fractures reservoir is faster compared to the unfractured one. As seen in the graph of oil production rate, the fractured reservoir was produced at a higher rate, therefore the pressure decline is faster. On the other hand, the unfractured reservoir due to the low fluid flow tends to maintain a smaller pressure decline.

In light of the results presented above, the dual porosity system is understood and nature of fluid flow in the porous medium is studied. The dual porosity system has higher flow of fluids in the reservoir compared to a reservoir simulated with no dual porosity system.

CHAPTER 5
CONCLUSION AND RECOMMENDATIONS

The simulation of Naturally Fractured Reservoirs (NFRs) compared to the conventional reservoirs has always been a challenging task for the engineers. One of the major problems in the simulation of NFRs is calculating the matrix-fracture transfer which governs the dynamic behaviour of the reservoir. The concept of dual porosity model has enabled the engineers to understand the flow of fluids in the naturally fractured reservoirs. In this research we have simulated a reservoir model with a dual porosity system and a reservoir with a single porosity system. The results obtained showed the fluid flow in both the reservoir. On comparison, we have observed a higher production rate and faster pressure decline with the presence of a dual porosity system. The research is a good step towards understanding the flow in naturally fractured reservoirs.

However, the concept is basic, more advanced techniques have been developed to simulate the fractures. More data are required to fully simulate the natural fractures. Further work can be done using the dual permeability and discrete fractured network modeling to simulate the fractures as close to the real fractures as possible to accurately predict the performance of the reservoir.

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