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Department of Earth Science and Engineering
Centre for Petroleum Studies

Fine Scale Simulation of Fractured Reservoirs: Applications and Comparison

By

Akash Vijayakumar

A report submitted in partial fulfilment of the requirements for the MSc and/or the DIC.

September 2014

DECLARATION OF OWN WORK

I declare that this thesis [*insert full title of thesis*]

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is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

Signature:.....

Name of student:.....

Name of supervisor:.....

Name: Akash Vijayakumar

Title: Fine Scale Simulations in Fractured Reservoirs: Application and Comparison

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It is estimated that more than half the world's remaining recoverable reserves of conventional oil are carbonate reservoirs (*Ahlbrandt et al 2005*), which are mainly naturally fractured reservoirs (NFRs). Natural fractures are macroscopic planer discontinuities that result from stresses exceeding fracture strength of the formation rock (*Stearns and Friedman 1972*). NFRs are profitably produced with poor efficiency in reservoir depletion due to the complexity and the extreme heterogeneities in the reservoir (*Narr et al 2006*). This poses a major challenge for reservoir management and characterization.

Fracture intensity, orientation, size and aperture characterisation is required to simulate representative NFR model (*Bahrami et al 2008*). The purpose of this study is, to examine the use of small-scale simulations where fracture network and matrix blocks are explicitly represented. This will help understand the flow mechanisms in NFRs. The project focuses on two applications, which are fracture-matrix exchange analysis, and well test interpretation. To initiate the project, various test cases are devised to cover the two types of applications. We start with orthogonal single matrix block fracture network model simulated using a standard commercial simulator (*Eclipse 100*). Single matrix block model and multiple matrix blocks (uniform and non-uniform block sizing) model are generated to understand the impact of various reservoir parameters on flow mechanism. A further stage of the study includes the use of a prototype flow simulator (*CSMP++*). The prototype simulator is compared with commercial software by analysing the matrix-fracture flow exchange in a 2D non-orthogonal fracture network. This will help discover the capability of finite volume method and finite element method to simulate flow. Finally, an example is constructed with a complex orthogonal fracture geometry using the two previous simulators and an additional one, for well test analysis to compare discrete fracture network (DFN) model and discrete fracture and matrix (DFM) model.

The study illustrates the importance of the spontaneous imbibition mechanism where the gravity and capillary forces have a significant impact on the matrix-fracture flow exchange. These exchanges are governed by the static fracture or matrix property (fracture aperture, matrix size), and by the dynamic parameters, like the wettability. The overall recovery of the reservoir is a function of these flow exchanges, and small-scale simulations allow the calibration of transfer functions in so-called dual-medium models used for full-field studies. Non-orthogonal case study proves the limitations of finite volume method to simulate irregular cell geometry thus producing spurious flow results compared to finite element method. Well Test analysis proves the numerical method and modelling technique has a significant impact on the time at which the well test signatures that represent reservoir behaviour are recognised. Results show that NFR complex recovery mechanisms can be better understood with small-scale simulation, but also that these simulations must be carefully performed, taking carefully in to account the specificities, advantages and limitations, of the numerical approaches used.

Imperial Supervisor: Prof. Olivier R Gosselin

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Fine Scale Simulation of Fractured Reservoirs: Applications and Comparison

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Abstract

It is estimated that more than half the world's remaining recoverable reserves of conventional oil are carbonate reservoirs which are mainly naturally fractured reservoirs (NFRs). Natural fractures are macroscopic planer discontinuities that result from stresses exceeding fracture strength of the formation rock. NFRs are profitably produced with poor efficiency in reservoir depletion due to the complexity and the extreme heterogeneities in the reservoir (*Narr et al 2006*). This poses a major challenge for reservoir management and characterization.

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Introduction

The understanding of fluid flow behaviour in fractured reservoirs is still at its growing stages in the oil industry; therefore effects of fractures are largely underestimated while making major decisions on reserves (*Bratton et al., 2006*). Most naturally fractured reservoirs are carbonate reservoirs (*Ahlbrandt et al 2005*). This would mean the production behaviour is not solely matrix dominated and the fracture-matrix exchange plays an important role when analysing flow behaviour of NFR using flow simulators.

Natural fractures are macroscopic planer discontinuities resulted from stresses exceeding the fracture strength of the formation rock, which has a significant impact on the flow of fluid due to extreme heterogeneities in the dynamic properties of the reservoir (*Stearns and Friedman 1972*). These heterogeneities lead to complex recovery mechanisms in the reservoir and large contrast of material properties at fine fracture scale level. To get a better understanding on the impact of fractures on the flow behaviour, NFRs are classified based on the relative contribution of storativity and permeability in the reservoir (*Nelson 2001*).

Reservoir modelling plays a crucial role in reservoir management to produce efficiently from hydrocarbon reserves while remaining economically profitable. Full field reservoir models are represented by dual porosity modelling approach, which is a hybrid upscaling approach. However fine scale simulations where each single fracture and each matrix block are explicitly represented (and meshed) are also needed to study the complex flow mechanisms. Due to complex heterogeneities in NFRs, numerical modelling is a major challenge. This is caused by high contrast in permeability and porosity data as well as complex fracture distribution and orientation. These calculations involve both statistical analysis of fracture properties and

detailed knowledge of 3D distribution of fractures in the reservoir (*Nelson 2001*).

All reservoir simulators are driven by a specific numerical method, which acts as the foundation for all flow calculations implemented within the tool. The commonly used numerical methods for flow simulations involve finite volume (finite difference in space when the grid is regular and orthogonal), and various types of finite element method. The 1D time discretisation uses finite difference method. Various commercial and research prototype simulators such as ECLIPSE (*Schlumberger 2013*), INTERSECT, CSMP++ (*Matthäi et al 2004*), IC-FERST, FracMan (*Golder Associates. 2013*), are currently being used for small-scale simulations to understand the flow mechanism in NFRs.

The motivations for detailed small scale simulations are the following: (1) analysis of matrix-fracture exchanges under various recovery mechanisms, and with various static and dynamic parameters (for phenomenological study, and for validation/calibration of transfer function used in dual-medium models), (2) reservoir study for sector model and/or relatively larger features, (3) computation of effective fracture network permeability tensor (upscaling for dual-medium models, or single-medium homogenised), (4) well test interpretation (pressure transient analysis for reservoir characterisation).

The purpose of the paper is to examine small-scale simulations of fractured reservoirs in which the matrix blocks and fractures are explicitly represented, by setting up a series of test cases for application types (1) and (4), by using various simulation approaches, and comparing them when possible (in this study Eclipse, CSMP++ and FracMan are used). After an introduction and review of the main production mechanisms, and the main numerical approaches, the paper is subdivided into three main sections. The first stage involves simulating an orthogonal fracture network system at fine scale to analyse the variation in flow behaviour by varying different fracture and matrix parameters in the reservoir model. This case is performed with a standard commercial simulator (Eclipse), which uses finite volume (FV) numerical method. The model is constructed using single porosity reservoir modelling technique. The purpose of the case is to give a good understanding on the impact of various fracture and matrix parameters on the flow behaviour as well as the overall recovery from the reservoir. Second stage of study involves the use of finite element finite volume (FEFV) method (CSMP++) and finite volume methods by simulating the same non-orthogonal fracture network. The matrix-fracture flow exchange transfer function is used to realize the capabilities of FV using irregular cell geometry in simulation. Last stage of the study involves generating and simulating a complex orthogonal fracture network system with the two previous tools, using a Discrete Fracture and Matrix (DFM) model approach, in addition to, and in comparison with a Discrete Fracture Network (DFN) model approach (FracMan). A well test analysis is performed on the models. This study will allow us to compare the impact of the type of numerical method and modelling technique on representing the flow behaviour in NFRs.

Literature review

This review presented in the following sections, through its references, clearly shows that the flow simulation of fractured reservoirs at the scale of fractures and matrix blocks got an increasing interest for applications, like the definition and calibration of transfer function for dual-porosity models, the computation of effective fracture network permeability tensors, and the interpretation of well tests. Small-scale flow simulation of fractured reservoirs also provides a challenging field of numerical experimentations for novel methods.

Recovery Mechanism

Carbonate reservoirs are difficult to characterize due to the heterogeneities thus requires a detailed understanding of the fluid saturation, pore size distribution, permeability and natural fractures (*Narr et al 2006*). For all the simulators used for analysis the fracture and matrix properties. The main parameters considered for the study involve:

Wettability and capillary forces: Production of oil from naturally fractured reservoirs is normally governed by spontaneous counter-current imbibition of water from the fracture network into the matrix (*Ersland et al. 2010*). The wettability of a reservoir has a significant impact on the recovery efficiency of the reservoir. The case study tests the behaviour of reservoir by using the imbibition Pc curve from residual water saturation to the crossover point of the imbibition curves zero capillary pressure line (water saturation axis). The water-wet system is expected to provide a higher recovery compared to mixed wet system because the capillary forces in the water wet case dominates recovery whereas in mixed wet systems the capillary pressure drive is dependent on saturation, where the early recovery capillary forces act along with gravity (capillary curve is positive), and after exceeding a certain water saturation the forces act against each other until they reach equilibrium at irreducible oil saturation (capillary curve is negative).

Gravity forces*:* The oil and water undergo gravity segregation due to difference in density. In homogeneous medium, oil relative permeability is a key parameter in gravity drainage mechanism (*Hagoort 1980*). Gravity drainage in naturally fractured reservoirs contributes along with the fundamental forces (capillary forces) towards recovery and should be considered when dealing with significant difference in permeability between fracture and matrix systems (*Luan 1994*). For small density contrast the reservoir thickness is a dominant factor to achieve gravity segregation.

This paper gives additional examples of the interest of such simulation for sensitivity study, and also initiates some comparison between different numerical approaches. As mentioned in the introduction section the review only focuses on the **two following main areas of analysis**:

Matrix-Fracture exchange transfer function: The extreme heterogeneities in the model result in large variations in material balance equation within the reservoir model. The interaction between the matrix and fracture is represented by transfer functions (*Kazemi et al. 1976*, *Gautam 2002*). Transfer function and the concept of dual porosity concept were initially

formulated under the continuum method approach. This was further improved by assuming single-phase flow and pseudo steady state **[equation 1]** (*Warren and Root 1963*).

$$T = \sigma \frac{K.kr_\alpha}{\mu_\alpha}(P_\alpha^m - P_\alpha^f) \quad \textbf{[1]}$$

Fluid expansion, viscous forces, capillarity, gravity and diffusion are the main mechanism of recovery (*Abushaikha and Gosselin 2008*). In water wet matrix blocks, water flooding mechanism are preferred recovery mechanism due to spontaneous imbibition from fractures into matrix blocks due to capillary pressure gradient (*Gabitto 1998*), whereas for mixed to oil wet matrix blocks water flooding technique provide lower recoveries as oil is only recovered from fractures and the ratio of the impact of gravity and capillary forces acting on the oil trapped in the matrix blocks. At fine (macroscopic) scale simulations, Quandalle and Sabathier Transfer Function approach is used to describe 3D, multiphase reservoir where the matrix blocks are represented as a three nodes to define viscous, capillary and gravity forces as a function of space **[equation 2]** (*Quandalle and Sabathier 1989*).

$$\phi_{jfx^+} - \phi_{jf\xi_o} = p_{f\xi_o} - p_{m\alpha\xi_o} + K_v\left(p_{fx} - p_{f\xi_o} + \rho g\left(\frac{c_i}{2}\right)\right) + K_g\left(\rho_{jma} - \rho g\left(\frac{c_i}{2}\right)\right) + K_c(P_{cjof\xi_o} - P_{cjom\alpha\xi_o}) \quad \textbf{[2]}$$

Well Test Analysis: This analysis involves measuring bottom hole pressure and transient rate when well is flowing at variable rates. The production data acquired is used to determine reservoir behaviour (*Horne 2000*). Well test can be performed using analytical method where mathematical models are used to relate pressure response to flow rate history. Well test analysis assumes the fluid to obey Darcy's law and fluid and rock properties such as permeability and viscosity is constant. In a reservoir with high permeability contrast the well response show two stabilization lines of the same magnitude, one indicating flow only in fracture region (1st stabilization which is usually obscured due to wellbore storage and skin effects) and then following the minimum curve a 2nd stabilization line indicating fracture and matrix region. This signature is observed at middle time. The length of the stabilization line depends on the production rate and the depth of the dip is a function of the permeability contrast (*Gringarten 1987*).

Analytical solution: NFRs consists of two different medium, on is the fracture network with high permeability and allows fluid to flow into the well and the other is the low permeability matrix block in which oil is present and produces oil into the fractures due to spontaneous imbibition.

Numerical approach/Geological Well Testing: This method is the preferred choice to analyse heterogeneous reservoirs (Robertson et al. 2002) as it is able to model complex reservoir boundaries accurately, reservoir heterogeneities, multi well test and multi phase effect along with standard boundary conditions represented by analytical methods.

Numerical methods

The complexity of fractured reservoirs in terms of geometry and sharp contrasts between flow properties over very short distances provide a challenging field of application for well established numerical methods, and for more novel ones.

Finite Difference Method: Differential quotients replace derivatives to approximate differential operator. The domain of the problem is partitioned by space and time and the solutions are approximated using space and time coordinates. The finite section of the Taylor series represents the truncation error in the numerical method (*Ciarlet and Lions 1997*). The five-point implicit finite difference method is used by Eclipse 100 to mesh the models. It is unable to mesh unstructured models efficiently due to distorted grid orientation (*Khatanair and Peters 1991*).

Finite Volume method: Finite volume method is a discretization technique for solving partial differential equations (**Figure 1b)**). This approach is used for discretising and approximating flow in porous media (*Ciarlet and Lions 1997*). In meshing of flow models the finite volume method, the conservation law is integrated into each individual cell of the mesh. One condition of validity of this method is a consistent approximation of fluxes through the interface by computing the normal pressure gradients, which required the orthogonality between the interface and the segment joining the cell centres of the two adjacent cells. This requires the construction of an ad-hoc grid, or additional points to compute the flux. When using a standard 5-point scheme, with a Cartesian non-orthogonal mesh, the numerical error can be severe. For regular Cartesian orthogonal grid, FV and FD are equivalent.

Finite Element Method: This is a popular method for mechanical models with complex geometry. It is also used in FracMan to simulate NFRs using DFN modelling technique. Finite element method is a node-centred process, which is useful to generate irregular element shapes to simulate flow. This method is computationally less efficient than finite difference method. This degree of inefficiency is dependent on the transmissibility matrices in the reservoir model (*Khatanair and Peters 1991*). This is also a large class of numerical methods with many possible type of elements.

Finite Volume-Finite Element Method: For meshing of models the FVFE approach uses dual mesh constructed by a primal mesh generated by finite element method (*Ciarlet and Lions 1997*). CSMP++ utilizes this approach to construct models where a triangular primary mesh median is used to constructs the duel mesh (*Matthäi et al. 2007*). This method uses finite element nodal basis function for pressure and control volume around the nodes for saturation computation (**Figure 1a)**). For unstructured 2D models, meshing triangular cells is recommended as it can tessellate any planer surface and allows approximation of time dependent variable, over the element by linear interpolation between the nodes (*Voller 2009*). The uncertainty of triangular meshing is dependent on the angle of the triangles, as it is likely to damage the quality of the mesh for flow calculation thus unable to accurately capture the behaviour in the model region (*Voller 2009*). There are many variants

amongst this class on methods: i.e. hybrid methods (*Nick and Matthäi 2011; Bazr Afkan and Matthäi 2011*), overlapping control volumes (*Jackson et al. 2013*), and face-centred control volumes (*Abushaikha 2014*).

Reservoir Modelling Technique

Single Porosity Modelling: This is used to represent NFRs at fine scale (macroscale) level where the permeability and porosity are defined at each point in the model (**Figure 1c)**). In order to represent the heterogeneities in NFRs, the permeability and porosity values are significantly larger than the matrix properties. These rapid variations and discontinuities in the reservoir properties heavily strain the workload of the simulator that reduces the processing speed of the software. For this reason this method is not implemented to analyse highly complex fractured reservoirs (*Douglas and Arbogast 1990*). This method is comparatively less suitable than dual porosity modelling due to larger data requirement and computational time and difficulty in characterising fracture system for field scale simulations (*Ghani 2009*). For orthogonal fracture network systems at fine scale, the single porosity method is used as the base case to capture the flow behaviour between fracture and matrix as well as analyse the results produced by other types of simulator modelling.

Discrete Fracture Network (DFN) Modelling: DFN focus flow only in fracture network system and describes a class of dual continuum model in which matrix porous medium is not represented. The analysis and modelling explicitly incorporates the geometry and properties of discrete features as a central component controlling flow and transport (**Figure 1e)**). This approach provides a 3D framework of discrete features that concentrate flow and transport, and also the flow barriers such as faults and argillaceous layers that provide partial or complete seals. DFN modelling combines deterministic and stochastic discrete fractures to make consistent use of a wide variety of disparate geological, geophysical and production data and provide a quantitative approach to description of the geometry and connectivity of solution features, fractures, and bedding, with their correlations making it a prefer choice over dual porosity method (*Dershowitz et al. 2003*). To generate a DFN model, information on the stratigraphy of the strata, fracture parameter (orientation, height, aperture, spacing) and cross cutting relationships are provided by analysing outcrops and cores (*Jin et al 2014*).

Discrete Fracture and Matrix (DFM) Modelling: This method is based on mixed-dimensional unstructured hybrid-element. The purpose of DFM models is to represent fractures as a 1D line in 2D model or surface of 3D models (**Figure 1d)**). This captures the complex behaviour in flow and transport on individual fractures without specifying properties such as effective permeability for sub-grid scale fractures. It is computationally efficient compared to 3D fracture models due to high-aspect ratio fractures with very small apertures. On the downside, in order to capture all geometrical details of the fracture, a large number of element are required resulting in considerable computational overhead. This is because, DFM resolve the non-linear and multi-scale physics of capillary, gravitational and viscous processes explicitly in each fracture that lead to severe time step limitations (*Geiger et al 2009*). DFM approach use unstructured finite element or finite volume method for spatial discretization (*Journal of Petroleum Technology 2011*). However, there is a large degree of uncertainty associated with the connectivity of fracture networks, the fracture density, and fracture aperture distribution because information on their statistics is generally sparse for real NFR (*Berkowitz 2002*).

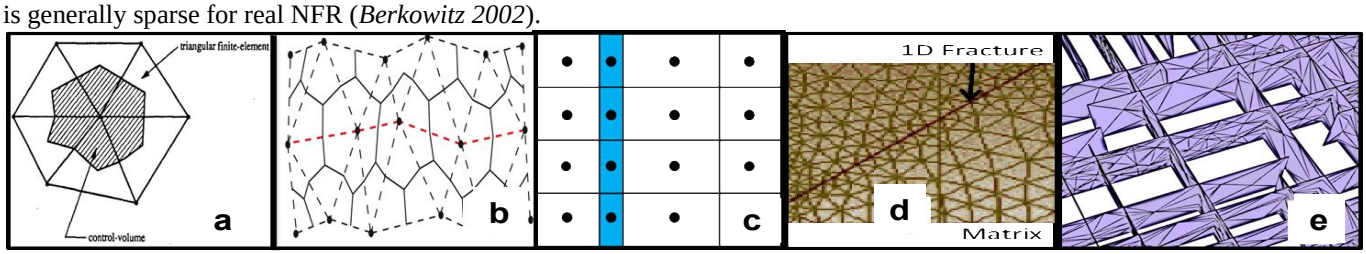


Figure 1: a) Finite Volume Finite Element b) Finite Volume c) Single Porosity Method d) DFM e) DFN

Methodology

Input Modelling Parameters

Static and dynamic parameters for the NFRs are determined by analysing open-hole wireline logs, cores (for routine and specialized core analysis procedures), well test interpretation and reference to analogue fields. Fracture sets for the reservoirs are characterized by integrating geological, geophysical and engineering data. Tools such as ultrasonic and resistivity borehole imaging logs and cores are used to classify fracture sets and determine the fluid and fracture properties in the reservoir such as fracture spacing, orientation, lengths and fracture aperture (*Bratton et al. 2006*). To perform small scale simulations representing carbonate fractured reservoirs, analogue data from various fields are used. The range of measurements used throughout the project for the analysis is given in **Table 1**. To generate the simple Eclipse models to analysis of matrix-fracture exchanges, three wettability cases are used:

1. Water-wet system with high capillary pressure (**Figure 2; Figure 3a)**)
2. Water-wet with no capillary pressure effect (**Figure 2; Figure 3a)**)
3. Mixed wet system with large pore network system which produces the same relative permeability curve as the water wet system (**Figure 2; Figure 3b)**)

Table 1: Matrix and Fracture Properties for the study

Rock and Fluid Properties	
Initial Reservoir Pressure (Bars)	150 - 500
Rock Compressibility (Bars^{-1})	6x10^{-5} – 5x10^{-5}
Oil Formation volume factor (rb/stb)	1 - 1.5 (Medium to Heavy Oil)
Water Formation volume factor (rb/stb)	0.8 – 1.2
Oil Compressibility (Bars^{-1})	4x10^{-5} (Incompressible Fluid)
Water Compressibility (Bars^{-1})	5x10^{-5}
Viscosity (cP)	0.5 (Water); 0.04(Light oil); 1.4 (Heavy oil)
Oil Density (kg/m^3)	600 – 900
Water Density (gm/cc)	1.0 – 1.01
Gas Density (kg/m^3)	1-1.5
Matrix and Fracture Properties	
Matrix Permeability (mD)	0.1 – 50
Matrix Porosity (%)	25
Fracture Permeability (mD)	1000- 5000
Fracture Porosity (%)	100
Fracture aperture (mm)	2-5
Fracture Orientation (degree)	20-90
Fracture length (m)	20-50
Matrix block size (cm)	5 – 10 (*Gomez et al 2002*)

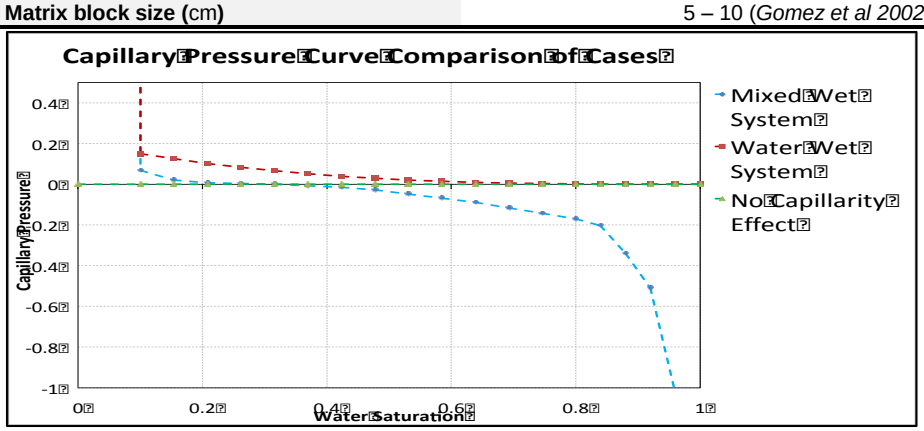


Figure 2: Capillary pressure vs. water saturation: for Wettability case (water-wet with capillarity effect (red dashed line); mixed wet system (blue dashed line) and water wet without capillarity effect (green dashed line))

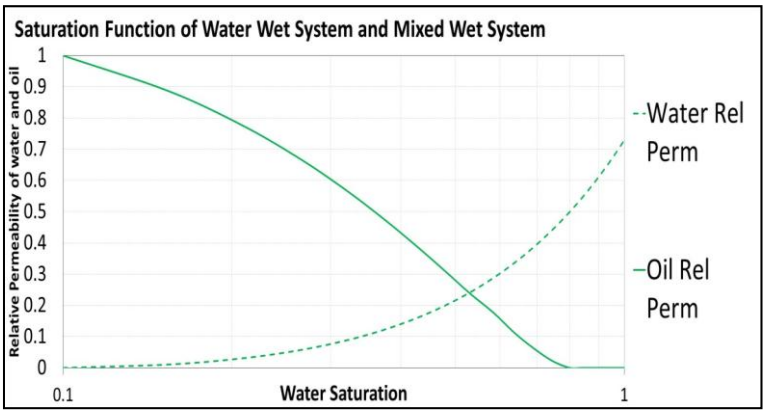


Figure 3: Relative permeability vs. water saturation for water wet and mixed wet systems

Fracture permeability and other dynamic parameters are difficult to obtain for a specific fracture aperture. Therefore, the cubic equation is used to calculate the relative fracture permeability value for a specified fracture aperture **[equation 3]** (*Gomez et al 2002*).

$$Fracture\ Porosity: \phi_f = \frac{(a+h_f)^3 - a^3}{(a+h_f)^3}; Fracture\ Permeability = k_f \propto \frac{a^2}{12} \quad \text{[3]}$$

Model Geometry Construction and Meshing

ECLIPSE 100:

It is finite volume simulator. In time it is always implicit in pressure, and implicit or explicit in saturation. To generate the model at fine scale the matrix and fractures properties are both specified. In Eclipse 100, the resolution of the mesh depends on the matrix blocks and fracture network geometry in the reservoir model. To generate the grid of the reservoir model two approaches are used in this project:

Block Centre Geometry: It is the conventional method used by simulators to construct reservoirs. The transmissibility calculations are performed by linear interpolation between the centre values of the cells (*Schlumberger 2013*). This approach is well suited for orthogonal fracture network as the accuracy of the solutions (approximated by constant grid block centre) and fluxes (approximated on block edges) are the same (*Dawson and Dupont 1991*). This approach uses regular cell geometry (**Figure 4a)**)

Centre Point Geometry: This tool is useful to construct irregular cell geometry (**Figure 4b)**). This makes it the preferred approach to represent fracture network systems in the fine scale for real fields. This approach generates distorted grids to fit fracture orientation and directions, where the non-neighbouring grid transmissibility is computed automatically by the simulator. This gridding method implements point-centred finite volume method where the accuracy between the fluxes and solutions varies depending on the complexity of the model (*Dawson and Dupont 1991*). To generate highly complex reservoir models it is time consuming and difficult to generate the model manually, therefore it is highly recommended to use some software tools, like Python code, to generate the visual geometry of the reservoir and later use a convertor to generate the coordinate file for Eclipse. For the 2D non-orthogonal model generated for this study, initially an excel spreadsheet is generated to specify the distance between the cornor points in each cell. This is then imported into the Eclipse 100 dataset using the COORD and ZCORN function.

Cell Sizing: In order to capture the geological structure of fractures and matrix blocks, it is essential to use relative sizing factor of 100-1000 between matrix cell blocks and fracture cell blocks. This would mean Eclipse dataset follows a DFM approach as the matrix and fracture cells are being constructed.

CSMP++

CSMP is an ANSI/ISO C++ based object-oriented application programmer interface (API) (*Matthäi et al 2004*). The simulator uses finite element-finite volume numerical method to simulate complex geological structures such as fractured reservoirs. To operate CSMP++ various tools such as ANSYS, CAD applications and modelling tools such as Rhino3D are required.

Fracture network geometry construction: For CSMP++, the fracture sets are modelled as 1D lines on a 2D surface of the model (**Figure 4d)**). In order to capture the exact fracture geometry of the fracture system generate in Eclipse 100, one of the two choices need to be implemented:

- For simple fracture models the accurate and clear visual document capturing all the fractures to be analysed is imported into a modelling tool such as Rhino3D to manually create the 1D fracture network using the drawing tool.
- The above approach is not compatible for highly complex NFR models. A convertor is used to generate the geometry coordinates compatible to Rhino3D to generate an accurate fracture network model. In this project the geometry of the Eclipse model is imported to Rhino3D using an in-house college convertor. This convertor (Monty, which is aPython Code) is only capable of generating orthogonal geometries.

Geometry Meshing: CSMP++ use finite volume finite element numerical approach and the geometry are meshed using triangular elements (*Matthäi et al 2004*) using ANSYS (mesher) (**Figure 4e)**) for this study, but other types of elements can be used as well to generate the mesh via ANSYS.

FracMan

It is commercially available software, used for analysis and modelling of heterogeneous and fractured reservoirs. This simulator allows users to visualize fracture systems as well as to test concepts and understand the flow mechanisms of the reservoir. This simulator generates the fracture network using the DFN approach where the fractures are represented as planer polygons. This allows more realistic description of fault patterns, fractures and stratigraphic contacts in fractured rocks (*Golder Associates. 2013*).

Model Meshing: The meshing tool is provided within the software. For the well test analysis, the complex geometry generated in Eclipse 100 is imported into FracMan using a convertor. To generate the mesh and run numerical well test, a pseudo well is inserted at the intersection of connected fractures and specify appropriate meshing element size to accurately capture the fractures. The process involves only generating elements at the fracture planes and the matrix blocks are left unmeshed, this is because the DFN method solely focuses on the geometry and properties of fractures as a central component controlling flow and transport (**Figure 4c)**).

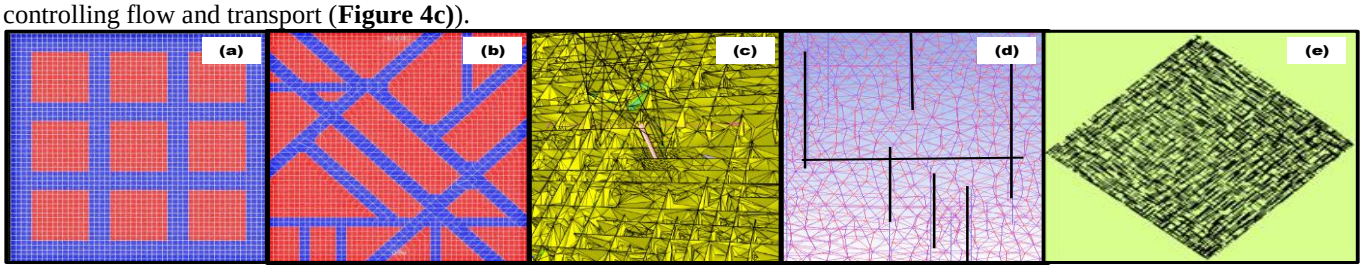


Figure 4: a) Block-Centre Gridding b) Corner Point Gridding c) FracMan Mesh d) ANSYS Mesh e) Rhino3D geometry

Simulation Cases

Matrix-Fracture Flow Exchange on Orthogonal Fracture Model

Eclipse 100 is expected to show representative flow behaviour for orthogonal fracture networks due to the use of regular grids. This allows the numerical simulator to make reliable transmissibility and flow calculations representative of NFR. To get a thorough understanding of flow mechanism, the impact of various reservoir properties on flow, and capabilities of Eclipse 100 relative to FracMan and CSMP++, the following cases are run:

(1) ***Effect of Wettability on Flow Mechanism (Analyse single matrix block and multiple matrix block model)****:* Wettability of the reservoir has a major impact on the overall recovery efficiency. To examine the influence of wettability on the recovery of oil, a single matrix block and a multiple matrix block datasets are generated. In the models, the fractures are modelled to behave as open fractures with a permeability of 5000mD and the matrix are given a lower permeability value of 20mD with porosity of 25%. The cases are modelled in 3D geometry to take gravity drainage into account. The flow exchange between the matrix and fracture for each model is analysed to observe seperately.

(2) ***Effect of matrix block size on Flow Mechanism (Compare uniform matrix block and non-uniform matrix blocks)****:* The size and the location of the matrix block in the reservoir affect the saturation and pressure distribution profile (*Sani et al 2011*). In a 3D model this factor is observed in the higher oil saturation profile for matrix blocks deeper in the reservoir relative to the matrix blocks positions closer to the surface. This case studies the difference in flow response between non-uniform matrix block model and uniform matrix block case. These models are constructed at lab scale with a fracture aperture of 4-6 mm long and the same dynamic property as (1). To test the impact of fracture properties on reservoir simulations, sensitivity tests are performed to analyse the impact of fracture aperture on flow mechanism.

(3) ***Effect of gravity drainage on Flow Mechanism (Analyse Single block, Uniform and non-uniform Multiblock models):*** In this sensitivity case, two models with different reservoir thickness are used to observe the degree of impact caused by gravity drainage on the flow mechanism in NFRs. To visualize a clear impact, the models are generated without capillarity effect.

Matrix-Fracture Flow Exchange on Non-Orthogonal Fracture Model

Effect of fracture orientation (Comparison of CSMP++ and Eclipse 100 non orthogonal models)*:* Eclipse 100 model simulate flow using fully implicit finite volume method, which approximates partial differential equation. In CSMP, the fractures are represented as 1D line whereas ECLIPSE fractures are represented as thin zones of fracture. The simulators are compared using a 2D fracture model consisting of 10 non-orthogonal fractures with permeability of 5000mD and fracture orientation varying from 20-90°. The matrix-fracture flow exchange for both models are analysed to compare the difference between finite volume method and finite element numerical method. In ECLISPE 100 model, various sensitivity analysis cases are run to assess flow behaviour by varying the method of calculating transmissibility and grid resolution of fracture from 5mm to 5µm only near the fracture region. This is to assess the degree of deviation calculated by numerical simulator in Eclipse 100. For verification purposes, a second sensitivity case study is run to compare the impact of fracture length on flow behaviour of the model for Eclipse 100.

Well Test Analysis on Complex Orthogonal fracture Geometry

Well Test Analysis (Compare transient pressure response for complex orthogonal fracture model): Well test analysis is one of the most useful tools used to validate flow simulators and benchmark simulators in terms of calculating reservoir parameters such as the effective permeability. The pressure responses from the Eclipse 100, CSMP++ and FracMan are recorded to perform well test interpretation. This gives the opportunity to compare DFM and DFN modelling methods. For this case a complex 2D orthogonal model (Single phase model) is to be modelled by the three software tools. Within Eclipse 100 sensitivity cases on the change in permeability contrst between the north south and east-west fractures are analysed using the drawdown transient pressure curves. More sensitivity cases are also run to analyse well response in a 2 phase model with peripheral injection drive with varying injection rates and also analyse the change in pressure response due to change in production rate. All the results are viewed graphically on a log-log pressure derivative plot and compared based on well test responses produced for NFRs such as double porosity behaviour, stabilization lines and the calculating the effective permeability of the well behaviour.

Results and Discussion

Matrix-Fracture Flow Exchange on Orthogonal Fracture Model

Effect of wettability on Flow Mechanism (Compare single matrix block and multiple matrix block model)

Table 2: Change in flow mechanism and recovery with change in wettability

Comparison of models			
Parameter	Single Block Model	Uniform Multiblock Model	Non-Uniform Multiblock Model
Number of matrix blocks	1	36	25
Height (cm)	160	155	162
Recovery Efficiency (%)			
Water Wet System	78	78	78
Mixed Wet System	30	30	30

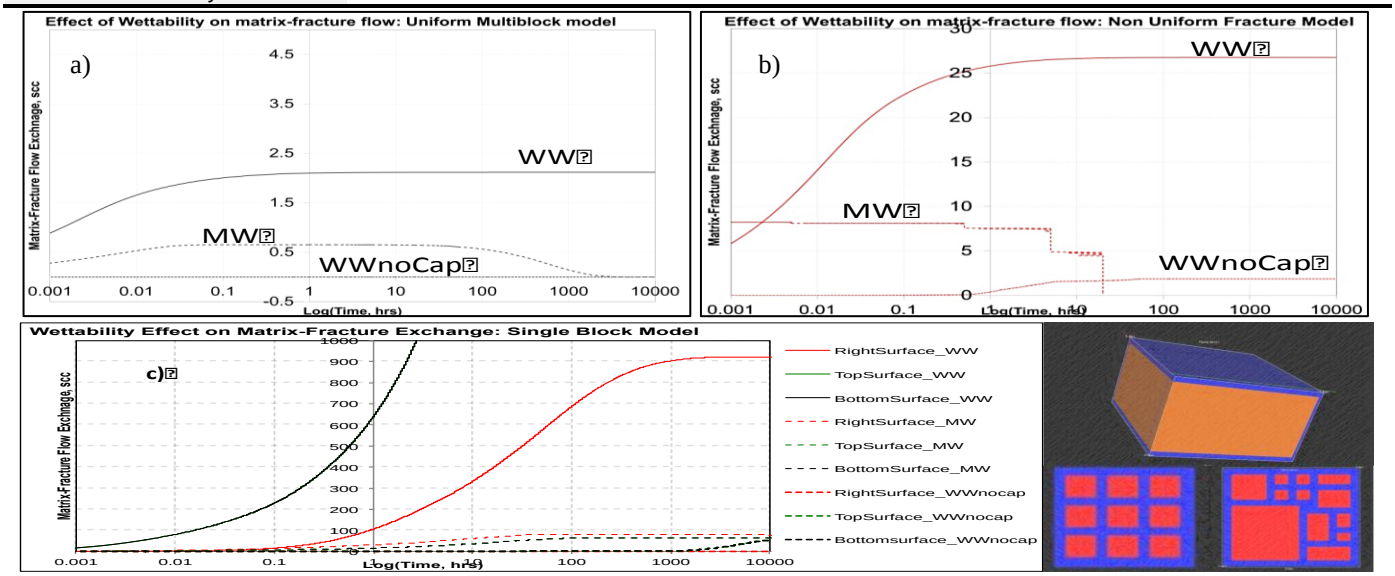


Figure 5: Matrix-Fracture flow exchange against time: Test Impact of Wettability (a) uniform multiblock; (b) non-uniform multiblock; (c) single block model (WW = Water-wet with Capillarity; WWnocap= Water-wet without capillarity; MW = Mixed wet)

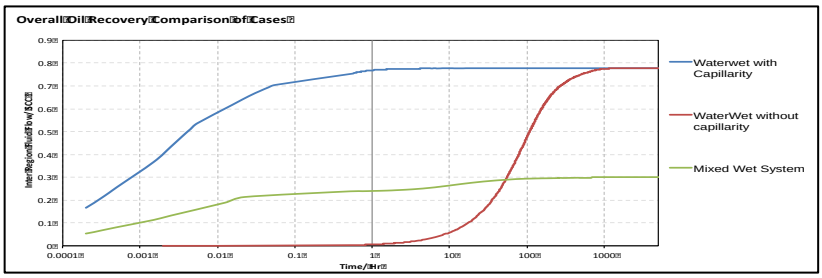


Figure 6: Oil recovery efficiency against time: Impact of Wettability (blue = water-wet with capillarity; red = water-wet without capillarity; green = mixed wet)

The matrix fracture flow exchange and overall recovery efficiency of the reservoir has a significant impact due to wettability. **Figure 3** shows that the hypothetical relative permeability chart constructed for the models are set to be the same. This assumption is made to focus on the effect of capillary pressure forces on the recovery efficiency in the reservoir. This is supported by a small capillary curve for mixed wet system than the water-wet system (**Figure 2**). Though the relative permeability data show the residual oil saturation to be 0.04; the capillarity and gravity drainage effects govern the oil recovery for this test. From **Figure 5** it is observed that capillarity pressure in water-wet conditions has a significant impact on the fracture-matrix exchange. This can be explained by referring to **Figure 1** where it is observed that the capillary pressure curve of a water system with capillary effect is the highest followed by mixed wet system and finally water wet without capillarity effect. This proves that in spontaneous imbibition dominated NFRs, high capillary pressure forces in water-wet system provide a steeper pressure gradient between the fracture and the matrix, thus aiding flow exchange and maintaining higher rate of recovery. The reason for high recoveries (**Figure 6**) in water wet system against mixed wet model can be explained by **Figure 1**, which shows that the water saturation before crossover point for capillary pressure (P_c = 0 bars) for water wet is at 0.75 whereas mixed wet system is at 0.30. The fracture-matrix flow for mixed reservoir is lower as **Figure 2** show that the capillary forces act against gravity after a certain time. This restricts flow, thus reducing the recovery of the oil to 25%. This behaviour is observed by the parabolic behaviour of the matrix-fracture flow in the mixed wet system (**Figure 5(a) and (b)**).

Effect of matrix block size on Flow Mechanism (Compare uniform matrix block and non-uniform matrix blocks)

Table 3: Effect of matrix block size on flow mechanism of NFR

Comparison of Models			
Parameter	**Uniform Multiblock model**		**Non-Uniform Multiblock model**
Number of matrix blocks	36		24
Volume of exchange (cm^3)	6969.60		14910.00
Recovery	78		78
Fracture Aperture (Homogeneous Sensitivity) (mm)			
Multi block model	Original Case	Sensitivity Case 1	Sensitivity Case 2
	6	3	0.006
Fracture Aperture (Heterogeneous Variation) (mm)			
Aperture value	X axis	Y axis	Z axis
	6	0.6	0.3

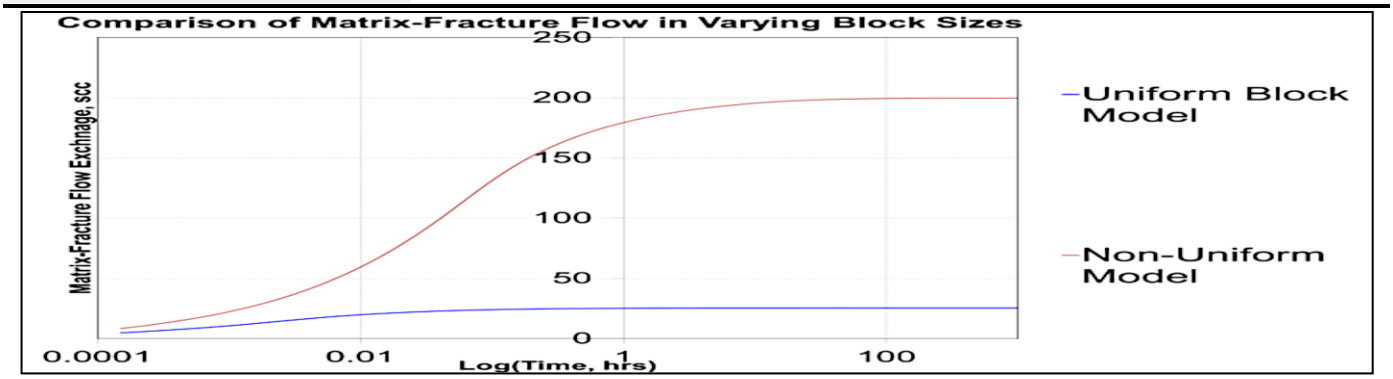
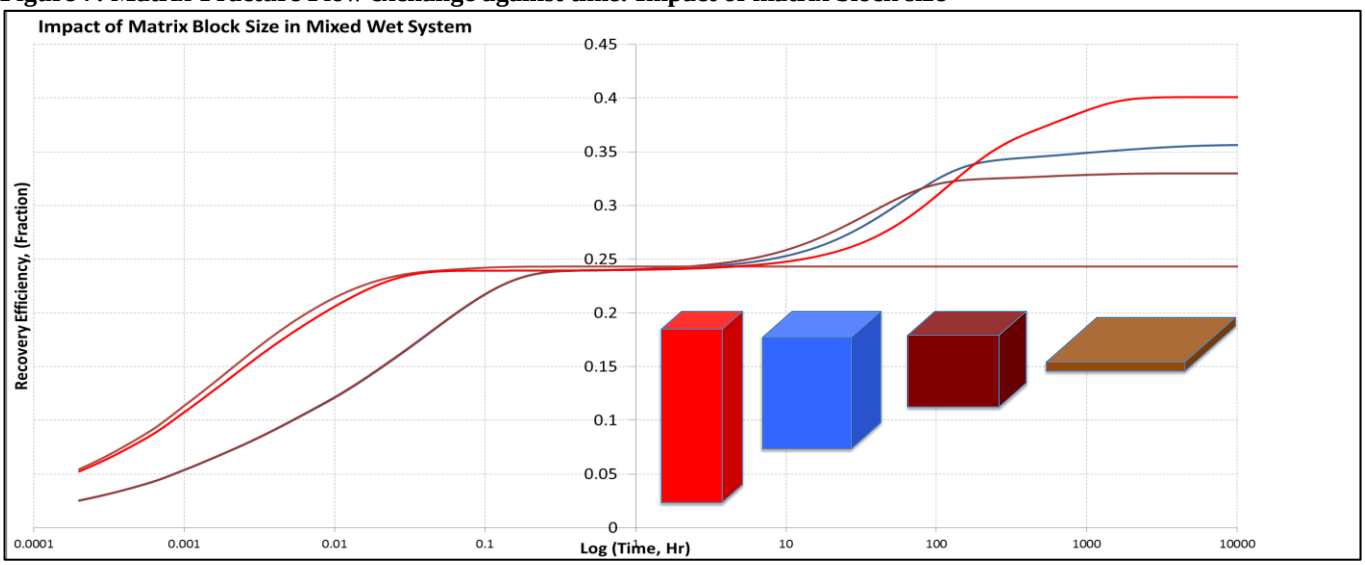


Figure 7: Matrix-Fracture Flow exchange against time: Impact of matrix block size



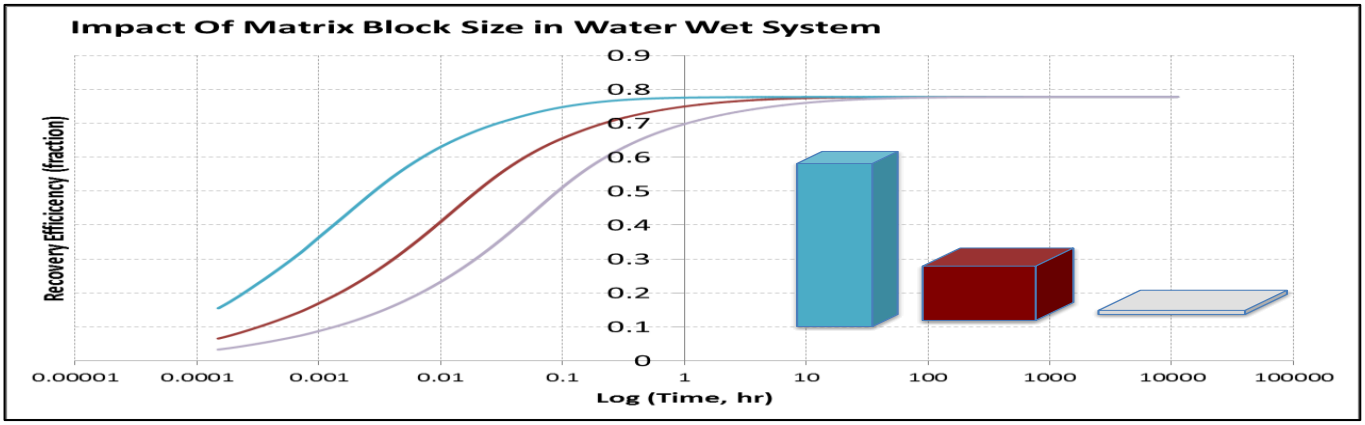


Figure 8: Recovery Efficiency v time: a) Impact of matrix block on Mixed Wet System b) Impact of matrix block size on Water Wet system

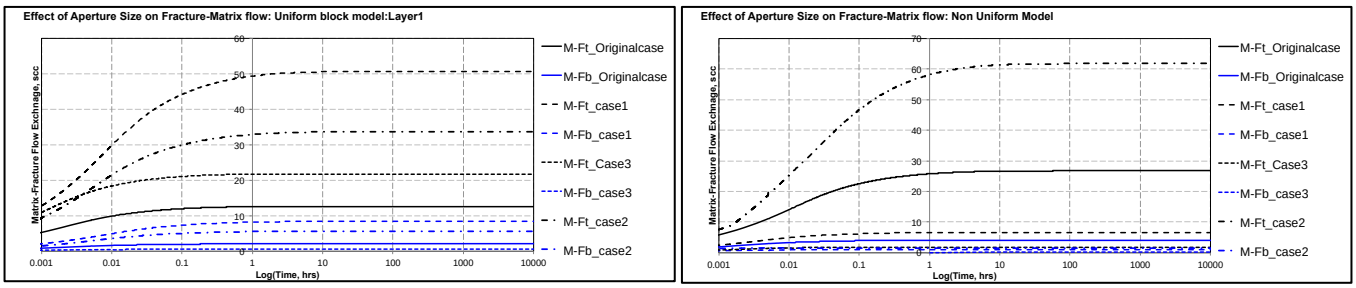


Figure 9: Matrix-Fracture Flow exchange against time: Impact of fracture aperture size in uniform (left) and non-uniform (right) model at water wet conditions. (Case 1 (homogeneous case 1)= dashed and dotted; case 2 (homogeneous case 2) = dashed; case 3 (heterogeneous case) = dotted line; Original model = solid line); (M-Ft = Matrix and top fracture layer interaction [black line]; M-Fb = Matrix and bottom fracture interaction [blue line])

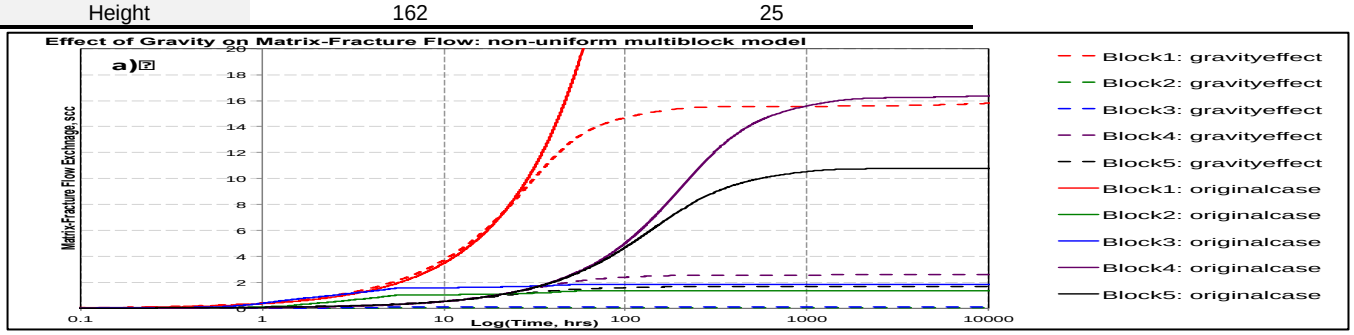
The flow mechanism between the uniform fracture system and the non-uniform system vary due to difference in the surface and volume of exchange available between the fracture and matrix (**Figure 8**). This difference is caused either due to difference in matrix block sizes or difference in number of fractures in the system. The base size of uniform matrix block model is at 20cm^3 (*black solid line*), for this reason the uniform model shows consistent fracture-matrix flow behaviour in every layer. This response is observed, because the model is run at lab scale. Hence there is no significant difference in the pressure distribution in each block throughout the uniform model. In the non-uniform matrix model, due to variation in size of the block, the flow response varies block to block (**Figure 8**). This behaviour proves that the pressure distribution is a function of matrix block size hence affecting the flow mechanism between the matrix and fracture. The second observation made, is that matrix block size only has an impact on the rate of recovery for a water wet system, but the recovery efficiency of the matrix block in mixed wet systems depend on the size of the matrix block. This behaviour in mixed wet is caused because of the difference in gravity forces acting each matrix block. The observation made on the recovery curves show that the rate of recovery in time is a function of block size, as the recovery efficiency rate of small block sizes are faster than the large block (**Figure 8**). This is because the pressure is more confined in a small block, which maintains a larger pressure gradient with the fracture compared to a larger pressure distribution in larger matrix blocks.

The sensitivity analysis cases are run to understand the impact of aperture size on flow and the recovery of the reservoir. The results show that the aperture size plays a significant role in fracture-matrix exchange (**Figure 9**). This is because; the permeability of the fracture network is a function of fracture aperture (cubic law (*Wooten 1989*) – **equation 3**). Therefore, reducing the aperture of a fracture with high pore volume increases the pressure contrast between the fracture and matrix, resulting in an increase fracture-matrix flow. It is observed that the matrix-fracture behaviour in uniform block geometry shows a consistent in flow rate with decrease in aperture size. As an exception, in non-uniform block model the flow rate at original aperture is higher than the 0.6mm. This behaviour is caused due to difference in surface of exchange available in the non-uniform as the results are collected from a large matrix block with a small surface for exchange area with the fractures.

Effect of gravity drainage on Flow Mechanism (Analyse Single block, Uniform and non-uniform Multiblock models)

Table 4: Impact of Gravity Drainage on flow in NFR

Single Phase Model			
Parameter	Original Case	Sensitivity Case 1	Sensitivity Case 2
Height	160	1600	16
Uniform Multiblock Model			
Height	155	34	
Non Uniform Mulitblock model			
Height	162	25	



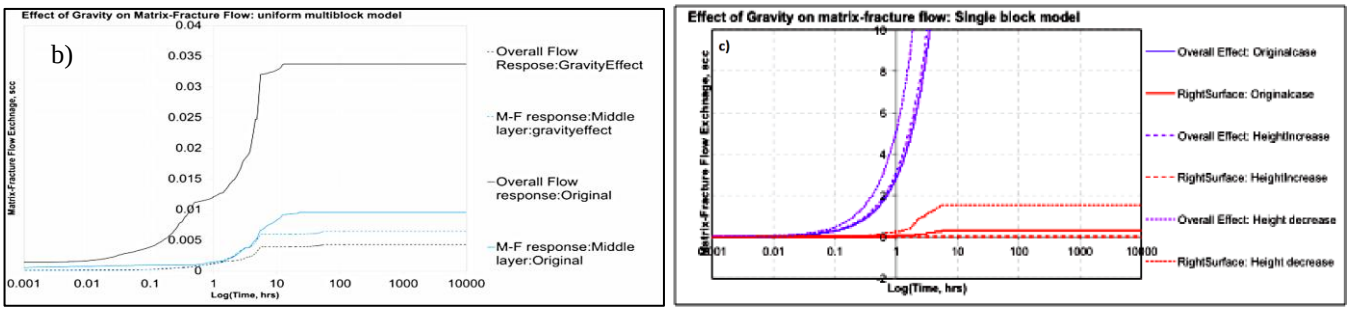


Figure 10: Matrix-fracture flow against time: Impact of Gravity Imbibition in a) uniform b) non uniform c) single block model

The sensitivity run on single block model shows that the matrix-fracture flow exchange between the two cases initially is almost similar, but over time the gap between the two trends increase showing that the reservoir thickness has a direct impact on the gravity drainage effect hence the fracture-matrix flow exchange. The flow response in the multiblock and single block sensitivity cases overlaps until 0.1hrs and later the gravity effect causes a deviation in flow behaviour until stabilization is achieved. The test revealed that the change in stabilization flow exchange rate and the reservoir thickness are directly proportional (**Figure 10**). The rate of flow exchange in thicker reservoir is higher due to greater force acting on the matrix blocks, which is observed by a difference in gradient between the original case and the sensitivity cases (**Figure 10**).

Matrix-Fracture Flow Exchange on Non-Orthogonal Fracture Model

Effect of fracture orientation (Comparison of CSMP++ and Eclipse 100 non orthogonal models)

Table 5: Non-Orthogonal Case Study

Parameter	Original Case	Sensitivity Case 1	Sensitivity Case 2	Sensitivity Case 3
Eclipse 100				
Number of Fractures	10	10	16	16
Aperture Size	5mm	5mm	5 µm	5 µm
Fracture representation	Thin high permeability zones using corner point gridding method			
Transmissibility calculation method	Default case: cell centre (OLDTRAN)	Corner point method (NEWTRAN)	Default case: cell centre (OLDTRAN)	Corner point method (NEWTRAN)
Recovery Efficiency (%)	78	78	78	78
CSMP++				
Number of Fractures	10			
Aperture Size	5 µm			
Fracture representation	1D lines on the 2D surface using Rhino3D and meshing the model using ANSYS			

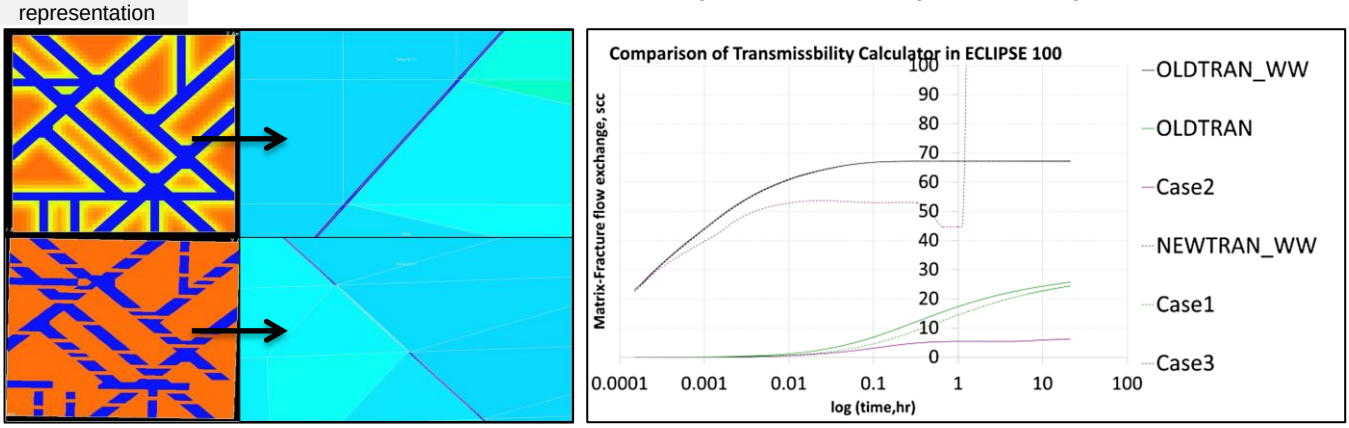


Figure 11: Matrix-fracture flow exchange: Impact of fracture aperture and transmissibility calculator for non-orthogonal fracture model in Eclipse 100 (OLDTRAN calculation = solid lines; NEWTRAN = dashed lines); [case 1 = aperture change with original model; case 2 = use of disconnected fracture network; case 3 = disconnected fracture network with change in aperture size]

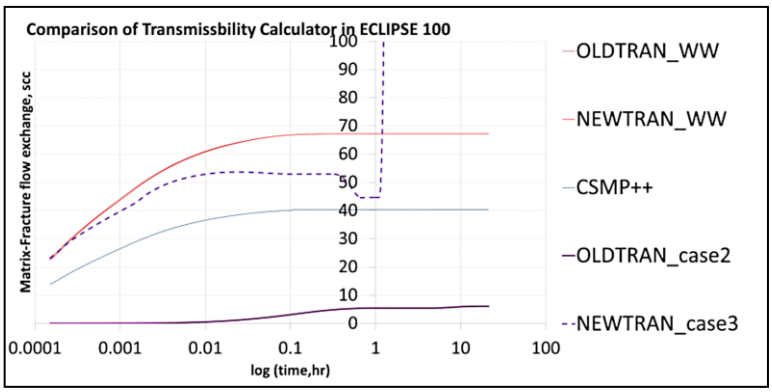


Figure 12: Matrix-fracture flow exchange: Comparison of CSMP++ and Eclipse 100 (OLDTRAN and NEWTRAN)

The non-orthogonal model generated in Eclipse 100 is also validated with the orthogonal case study by comparing the ultimate recovery achieved in the model. For the original model it is noticed that the recovery efficiency in non-orthogonal structures are the same. When introducing change in aperture size in the model. The model is unable to produce coherent results proving that the cell geometry has an impact on flow calculations in Eclipse100. The sensitivity results for the change in aperture size had a significant impact on the model behaviour (**Figure 11**). This is because the finite difference method is unable to cope with large variation in unstructured cell sizes, thus producing highly spurious result at default transmissibility calculator settings.To further understand the capability of Eclipse 100 with non-orthogonal fracture geometry, the transmissibility calculators are altered from default transmissibility calculator (OLDTRAN) (*Schlumberger 2013*) to new type o transmissibility calculator (NEWTRAN) (*Schlumberger 2013*). The OLDTRAN method determins the transmissibility by the product of the distances between the centre point of two adjacent cells and the permeability value assigned to them. Whereas, NEWTRAN calculates the transmissibility by including the distance between the cornor points of the cells, the permeability assigned to the cells and the distance between the centers of the cells. **Figure 11** shows that for the original model, the two methods produced almost identical results, whereas changing aperture size by reducing the size of cells, it is observed that NEWTRAN produce underestimated result compared to OLDTRAN. This is because the OLDTRAN calculator calculates the transmissibility based on the distance between the block centres and NEWTRAN uses the corner points to evaluate the transmissibility indices, therefore there is a higher chance of producing more spurious results due to large variation between fracture cell and matrix cell.

Figure 12 shows that the flow response for the non-orthogonal structure is higher compared CSMP++ when using 6mm aperture size, but Eclipse100 produces underestimated results if aperture size is reduced to 6µm. This is caused because the Eclipse 100 model is simulating the non-orthogonal model using finite difference method. Therefore, CSMP++ is more suitable for irregular cell geometry simulations. This observation supports the theory on literature for benefits of finite element numerical simulation on unstructured grid cells compared to finite difference method (*Matthäi et al 2004; Voller. 2009)*.

Well Test Analysis on Complex Orthogonal fracture Geometry

Well Test Analysis (Compare transient pressure response for complex orthogonal reservoir model)

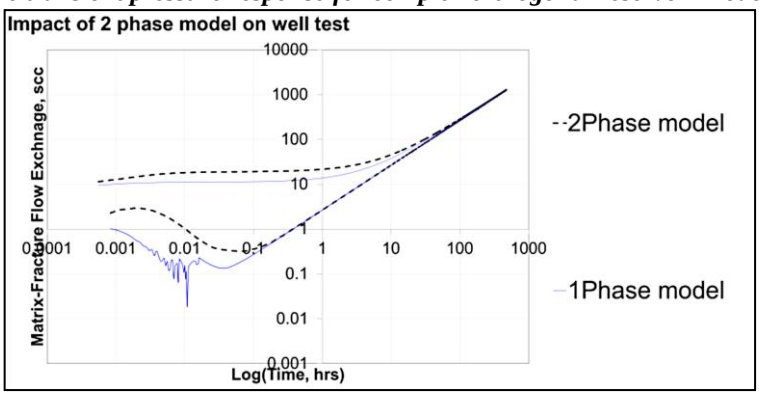


Figure 13: Well Test Analysis: Comparison of 1 phase 1 layer (1P1L = blue line); 2 phase 1 layer (2P1L = black dotted line)

In ECLISPE 100, various sensitivity cases are run to understand the impact of fracture permeability on reservoir behaviour. In this sensitivity case a single producer is used with a production rate at 50m^3/day. For this analysis the base case is set to a fracture permeability of 200,000mD and fracture aperture of 0.1mm. In **Figure 13**, well test analysis is performed on 2 phase and 1phase single block models. The results show that the behaviour of the 2 phase model is overestimated compared to 1 phase model. This is caused due to a change in density of fluid (oil and water) during analysis. For this reason, well test

analysis is not suitable for 2 phase systems. **Figure 13** show that the permeability contrasts between the fracture and the matrix produces a dual porosity response on the transient pressure curve. This is observed by the decrease in the depth of the dual porosity stabilization line as the permeability contrast is reduced from 200,000mD to 5,000mD. The contrast in fracture permeability also impacts the storativity ratio and the interporosity flow, this is observed by the decrease in the depth of the minimum curve as well as the delay in time for the signature (**Figure 13**).

Table 6: Well Test Analysis and understanding reservoir behaviour

ECLIPSE 100: Homogeneous Permeability Variation (Single Producer) for Single and Double Layer model				
Parameter	Original Case	Sensitivity Case 1	Sensitivity Case 2	Sensitivity Case 3
Horizontal Permeability (mD)	200000	5000	20000	500000
Vertical Permeability (mD)	200000	5000	20000	500000

ECLIPSE 100: Non Uniform Permeability Variation (Single Producer and Single Layer model)										
Parameter	Original Case	Case1	Case2	Case3	Case4	Case5	Case6	Case7	Case8	Case9
Horizontal Permeability (mD)	200000	500&20000	500	5000	20000	500000	200000	200000	200000	200000
Vertical Permeability (mD)	200000	200000	200000	200000	200000	200000	500	5000	20000	500000

ECLIPSE 100: Peripheral Drive Mechanism (Single Layer model)				
Parameter	Original Case	Case1	Case2	Case3
Horizontal Permeability	200000	200000	200000	200000
Vertical Permeability	200000	200000	200000	200000
Injection Rate	100	10	50	1000

ECLIPSE 100: Single Producer and 2 Layer model			
Parameter	Original Case	Case1	Case 2
Horizontal Permeability	200000	200000	200000
Vertical Permeability	200000	200000	200000
Production Rate	100	50	1

Comparison of Simulators			
Parameter	ECLIPSE 100	FracMan	CSMP++
Fracture Aperture (mm)	0.1	0.1	0.1
Fracture Orientation	90	90	90
Fracture Permeability (mD)	500000	500000	500000

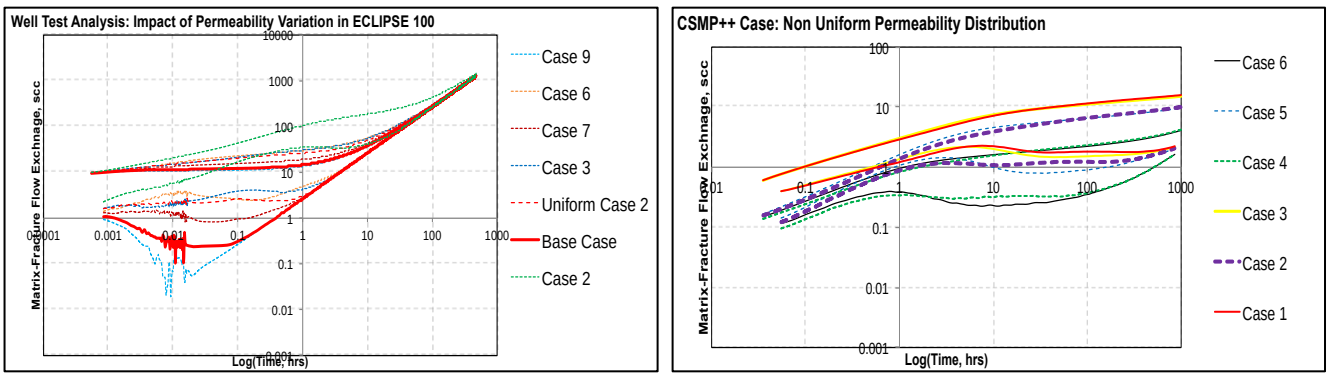


Figure 14: Well Test Analysis: Impact of Fracture Permeability on reservoir behaviour in Eclipse 100 (left) and CSMP (right); [Case 1 – case 9 refer to Non Uniform Permeability variation table; Uniform Case 2 = Homogeneous permeability variation case 2]

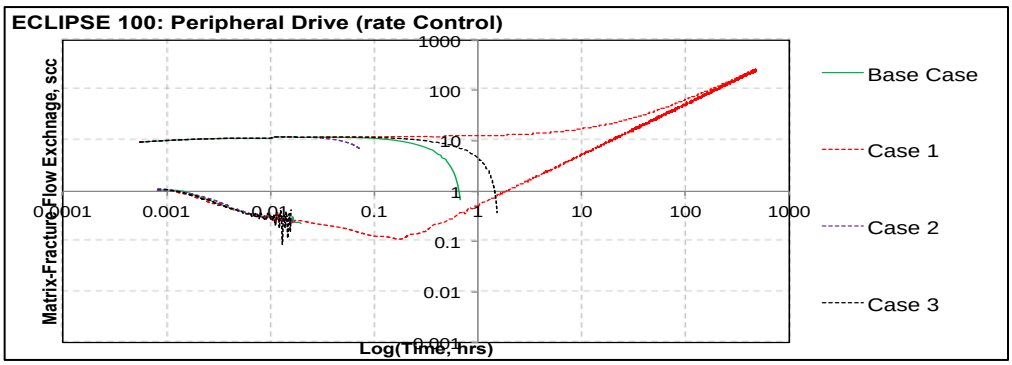


Figure 15: Well Test Analysis: Impact of Injection rate in peripheral drive in a Single phase and single layer model (case 1- case 3 refer to sensitivity cases in Eclipse 100: Peripheral Drive Mechanism (Single Layer model))

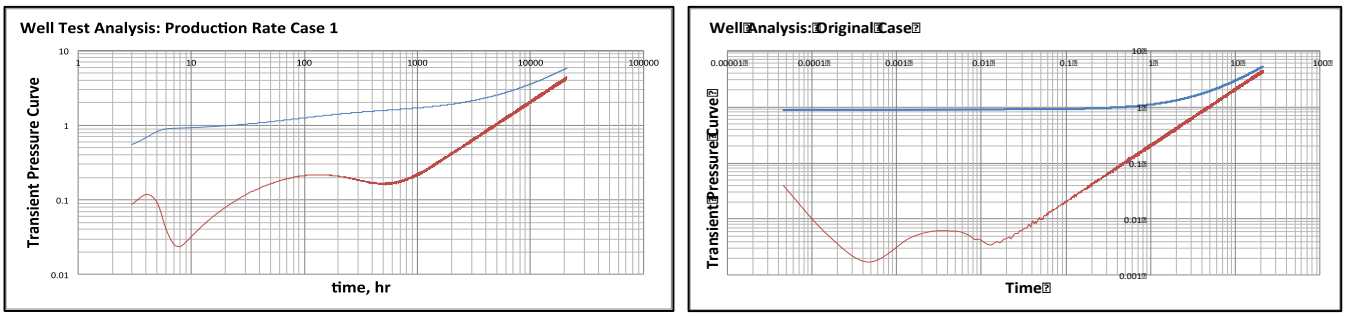


Figure 16: Well Test Analysis: Impact of Producer rate in Single producer, single phase and single layer model

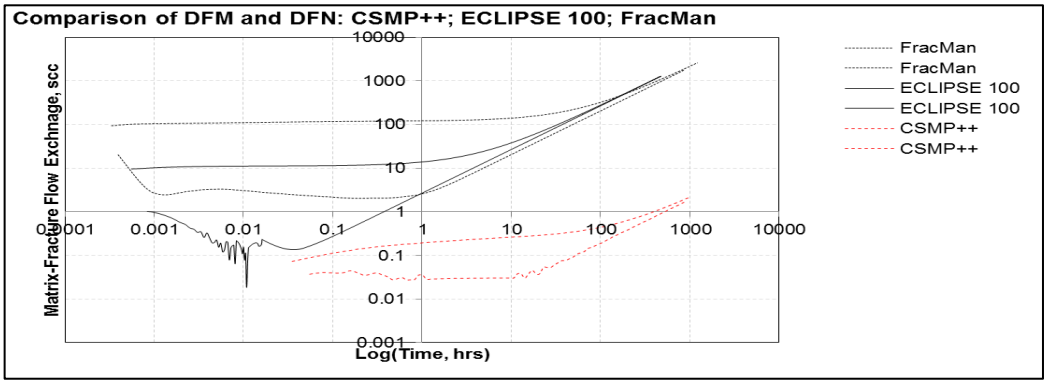


Figure 17: Well Test Analysis: Comparison of Eclipse 100 (solid black line), FracMan (black dotted) and CSMP++ (Red dotted line) for fracture permeability of 500,000 mD and fracture aperture of 0.1 mm. (Legend repeated twice; first one indicate Pressure change curve and second one indicate derivative pressure change curve)

Following the analysis of fracture permeability the injection rate for a peripheral drive system is analysed to understand the well response for a peripheral system under 2 phase system. **Figure 15** indicates shows that increasing the injection rate in the peripheral drive system, will produce a constant pressure response in the derivative time at an earlier time. The next parameter to analyse involved the production flow rate. **Figure 16** showed that 50m^3/day flow rate provided the best results as it provides sufficient time to capture the various reservoir behaviours in middle and late time with disturbances caused due to very short time steps in Eclipse100.

The final stage of the case study involves comparing Eclipse, CSMP++ and FracMan. This case uses a single layer, single phase, with permeability of 500,000mD. For this case Eclipse results is assumed to be the base case model. **Figure 17** shows that FracMan provides a good relation with Eclipse 100, but the results are over-estimated. This behaviour is caused due to the difference in modelling technique, in Eclipse 100 the model follows the DFM technique where the flow interaction between the matrix and fracture is considered as the properties are provided for both mediums. On the other hand, FracMan follows DFN technique, where only the fracture properties are meshed. For this reason during well testing the interaction between the matrix and fracture are not captured, thus producing a higher estimate. The graph also showed CSMP++ provided an underestimated respose relative to Eclipse. This is caused due to the presence of a large wellbore region used to simulate Eclipse and FracMan, whereas in CSMP++ a single 1D line is used to represent the producer well. The other reason for the difference is caused due to the inconsistency of the aperture which due to limited time require further research in future studies.

Conclusion and Recommendation

The flow mechanism in a fractured reservoir is highly complex. Results from the tests confirm that matrix-fracture flow exchanges are highly sensitive to the fracture and matrix properties at fine scale. The first stage of the study also confirmed that the wettability and capillary pressure in the porous medium are the dominant factors controlling the overall recovery efficiency of the reservoir, helping or reducing the gravity driving forces. Changes to fracture and matrix properties such as fracture aperture, matrix size impact the matrix-fracture exchange. It is observed that small fractures apertures and small matrix will have higher flow exchange rate, but these properties do not have any effect on the total recovery efficiency. However the recoverable reserve also depends on the thickness of the matrix blocks, and the fluid density differences, in case of mixed wettability systems. This means that a highly saturated fracture system will have a higher recovery rate due to increased surface for exchange and greater pressure gradient between the matrix and fracture.

Analysis of second stage of the study showed that finite volume method is not efficient to simulate flow for non-orthogonal fracture-set represented by irregular cell geometry. Finite element methods are more suited to this task as they can are able to perform numerical calculations with irregular cell geometry. In terms of the workflow to generate the model, the tools associated to CSMP++ interface are manageable to create the mesh than Eclipse 100. CSMP++ on the other hand require a

drawing tool (Rhino3D for drawing the geometry and ANSYS for meshing the model) where the fractures are represented a 1D lines on the 2D plane making it a convenient process to generate models, even for more complex structures.

Well test analysis of the complex orthogonal fracture geometry provided a detailed analysis on change in reservoir behaviour caused due to changes in mobility ratio and well properties in NFRs. The study proved that for a 2D model, the permeability contrast between the matrix and fracture affects the dual porosity signature as for significantly high contrast the stabilization is low showing a clear change in mobility whereas for lower contrast this difference in reduced and starts to produce a normal radial flow effect in the derivative plot. It is also observed for reservoir behaviour in two-phase and single phase on Eclipse 100 have significant difference, thus proving that well test analysis is unable to cope with 2 phase models. Assuming the well response for Eclipse 100 to be a reference case, FracMan produces overestimates the reponse, this is because in Eclipse, the matrix-fracture properties are explicitly stated (DFM), thus considering the matrix-fracture interaction. Whereas, in FracMan, only the fracture properties are represented in the model (DFN), therefore the well response does not capture the behaviour of matix. On the other hand, the CSMP++ runs performed in this study produce an underestimated response due to difficulty in well region representation comparison between the three models, and inconsistency incurred in specifying the fracture aperture for the limited time frame.

Results produced from the study calls for more research in this field to get a better understanding the fine scale simulation in fractured reservoirs. Further studies on well testing should be performed after resolving the inconsistency issue to get a better understanding of the flow simulation between CSMP++ and Eclipse. Further studies can be performed on 3D non-orthogonal fracture models to compare the capability of FracMan relative to CSMP++ as well as get a deeper understanding on the naturally fractured reservoirs. Furthermore, upscaling case studies could be run in complex orthogonal model to validate the simulators further. Finally, it is also recommended to test other available numerical simulators such as IC-FERST and INTERSECT to extend this study to other available methods to simulateflows in NFRs.

Nomenclature

Symbols

a,b, c	Block size in x,y,z direction
C	Concentration
g	Gravitational constant (9.8 m/s^2)
h_f	Fracture width (ft)
k	Permeability (mD)
kr	Relative Permeability
K_c	Capillary matrix-fracture flow coefficient
K_g	Gravity matrix-fracture flwo coefficient
K_v	Viscous matrix-fracture flow coefficient
p	Pressure
P_c	Capillary Pressure (bar)
t	Time
T	Transfer Function (s^{-1})
α	Block Size
σ	Shape factor (cm^{-2})
ρ	Fluid Density (kg/m^3)
Φ	Porosity
μ	Viscosity (cP)

Subscripts

f	Fracture
i	Cell Index
j	Phase Index
ma	Matrix
o	Hydrocarbon liquid phase
x,y,z	Corresponding Direction
ξo	Centre of centre block (node locaton)

Anonyms

1D	One Dimensional geometry
2D	Two Dimensional geometry
3D	Three Dimensional Geometry
API	Application Programmer Interface
CSMP++	Complex Systems Modelling Platform
DFM	Discrete Fracture and Matrix method
DFN	Dicrete Fracture Network method
FD	Finite Difference Method
FV	Finite Volume Method
FEFV	Finite Element and Finite Volume Method
NFR	Naturally fractured reservoirs

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Appendix

Cases	Eclipse	CSMP++	FracMan
Understand Flow Mechanism of NFRs			
Impact of Wettability and Capillary Pressure	X		
Impact of Matrix Block Size	X		
Impact of Gravity Imibition	X		
Understand Capability of Eclispe			
Impact of Transmisibility calculator	X		
Comparison of 2D models	X	X	
Well Test Analysis			
Analysis of 2 Phase system	X		
Impact of Permeability contrast	X		
Impact of peripheral drive in 2 Phase system	X		
Impact of production rate	X		
Comparion of DFM and DFN	X	X	X

Eclipse Cases	Single Block	Uniform Mulitiblock	Non-Uniform Multiblock	Non-Orthogonal 2D model	Orthogonal 2D model
Understand Flow Mechanism of NFRs					
Impact of Wettability and Capillary Pressure	X	X	X		
Impact of Matrix Block Size	X	X	X		
Impact of Gravity Imibition	X	X	X		
Understand Capability of Eclispe					
Impact of Transmisibility calculator				X	
Comparison of 2D models				X	
Well Test Analysis					
Analysis of 2 Phase system					X
Impact of Permeability contrast					X
Impact of peripheral drive in 2 Phase system					X
Impact of production rate					X
Comparion of DFM and DFN					X

Note: Detailed information of each model is provided in Appendix A2

A1: Literature Review

A1.1: Literature Milestone

Title of Periodical	Year	Title	Authors	Contribution
Advances in Water Resources 51	2012	Pore-scale imaging and modelling	Blunt M.J.; Bijeljic B.; Dong H.; Gharbi O.; Iglauer S.; Mostaghimi P.; Poluzny A and Pentland C	Describes the underlying technology, namely imaging of the pore space of rocks from the nanometre scale upwards, coupled with a suite of different numerical techniques for simulating single and multiphase flow and transport through these images.
SPE 24916	1992	Fine Grid Simulation of Two Phase Flow in Fractured Porous Media	Guzman R.E and Aziz K.	Improve simulation for oil recovery by gaining a better understanding on the importance of matrix/fracture fluid transfer, matrix and fracture two phase flow, and interactions
Advances in Water Resources. Vol(26)	2002	Characterizing flow and transport in fractured geological media: A review	Berkowitz B.	Analyze measurements, conceptual pictures, and mathematical models of flow and transport phenomena in fractured rock systems.
SPE 51347	2000	Numerical Study of Natural Convection and Diffusion in Fractured Porous Media	Kassem Ghorayeb, SPE, and Abbas Firoozabadi, SPE, Reservoir Engineering Research Inst.	Examines the effect of the fracture parameters: fracture aperture (or fracture permeability), fracture intensity, and fracture connectivity on the fluid compositional variation
Golder Associates	2003	Advances in Discrete Fracture network modelling	Dershowitz W.S.; La Pointe P.R and Doe T.W.	Describes recent advances in discrete fracture network (DFN) modeling and analysis.
SPE 93144	2007	Multirate-transfer dual-porosity Modeling of gravity drainage and imbibition.	Di Donato G, Lu H, Tavassoli Z, Blunt M.J.	Describe an approach to model displacement processes in fractured reservoirs
Geological Society London	2007	Numerical simulation of multi- phase fluid flow in structurally complex reservoirs	Matthäi S. K.; Geiger S.; Roberts S. G.; Paluszny A.; Belayneh M.; Burri A.; Mezentsev A.; Lu H.; Coumou D.; Driesner T. and Heinrich C. A.	Describe the use of CSMP++ and has compared the simulator with ECLIPSE 100 in single fracture flow system
SPE 118924	2009	Massively Parallel Sector Scale Discrete Fracture And Matrix Simulation	Geiger S. Huangfu Q.; Reid F.; Matthäi S.K.; Coumou D.; Belayneh M.; Fricke C. and Schmid K.S	Flow simulation of FRACS2000 and reservoir model with the DFM model of CSMP++

A1.2: Critical Literature review

SPE 51347

Numerical Study of Natural Convection and Diffusion in Fractured Porous Media

Author/Organization
Kassem Ghorayeb, SPE, and Abbas Firoozabadi, SPE, Reservoir Engineering Research Inst.

Contribution to Industry/Project
Examines the effect of the fracture parameters: fracture aperture (or fracture permeability), fracture intensity, and fracture connectivity on the fluid compositional variation.
Study the effect of connected and discrete fractures on compositional variation

Objective
Numerical study of natural convection and diffusion in fractured porous media.

Methodology
- Two-dimensional fractured porous media with width b and height is saturated by a binary mixture of C1 (methane)/ n C4 (normal butane).
- Eight different configurations of fractured porous media are used to study the effect of fracture parameters on the variation of composition.
- Numerical runs were performed with different mesh grids either in the matrix blocks or in the fractures.

Conclusion
- Fracture aperture affects compositional variation only when fracture aperture is greater 0.1mm, whereas the fracture convective velocity increases with an increase in fracture aperture.
- The main effect on compositional variation is due to the surrounding fractures. The interior fractures affect the shape of the mole fraction contour lines, but the horizontal compositional variation is not significantly affected by those fractures.
- The fluid flow consists mainly of a loop within the surrounding fracture. Smaller loops occur in the interior connected fractures. The flow velocity within the rock matrix is negligible in comparison to fracture velocity, as expected.

Comment
Examines the effect of the fracture parameters: fracture aperture (or fracture permeability), fracture intensity, and fracture connectivity on the fluid compositional variation. This helped as a validation document to assess what is to be expected from numerical simulation results

SPE 24916

Fine Grid Simulation of Two phase flow in Fractured Porous Media

Author/Organization
R.E Guzman and Khalid Aziz, Stanford U.

Contribution to Industry/Project
- Considers the interaction between capillary and viscous forces
- Considers the influence of capillary imbibition in fractured flow.
- Investigates the validity of assuming injection/production is confined to fractures

Objective
•Consider the effect of FRP (fracture relative permeability) and the conditions in which they become important for flow in fractured porous media
•FRP is important only at low capillary numbers when viscous forces are significant and two-phase flow exists in the fracture. High capillary numbers flow occurs inside the matrix due to strong water imbibition, and the effect of FRP is reduced.
•At high capillary number the water flow is faster in matrix than in fracture. The capillary forces are dominant and water imbibes in the matrix. At low capillary numbers imbibition is weak and most of the water flows faster in the high permeability fracture than in the matrix. Viscous forces are more important in these cases and the high permeability fracture has a large influence
•The improvement of oil recovery due to high imbibition for strongly water-wet matrix is more noticeable at low capillary numbers. The reduction of oil recovery due to water channeling through the fracture is important only at low capillary numbers when imbibition is not very strong.

Methodology
•The fractures are represented as blocks with high permeability and unit porosity. The matrix block size was increased logarithmically from the fracture towards the outer blocks.
•Inlet/outlet boundary conditions: Constant total injection rate and constant production pressure. No capillary end effects were included and their influence is not known for this particular case.
•Effect of Fracture relative permeability on oil displacement are analysed
•Effect of matrix capillary pressure under different wettability conditions
•Effects of matrix/fracture capillary pressure by analysing water cut and oil recovery correlations, followed by comparing different cores

Comment
Improve simulation for oil recovery by gaining a better understanding on the importance of matrix/fracture fluid transfer, matrix and fracture two phase flow, and interactions.

Advances in Water Resources 51

Pore-scale imaging and modelling

Author/Organization
Blunt M.J.; Bijeljic B.; Dong H.; Gharbi O.; Iglauer S.; Mostaghimi P.; Poluzny A and Pentland C.

Contribution to Industry/Project
- Describes the underlying technology, namely imaging of the pore space of rocks from the nanometre scale upwards, coupled with a suite of different numerical techniques for simulating single and multiphase flow and transport through these images.

Objective
Discuss limitations and challenges of pore scale modelling

Methodology
- Discuss Imaging techniques such as X-ray (absorb X-ray to produce 3D representation of rock and fluid. This is doen using a micro-CT scanner); focused ion beams (to produce fine scale image of the rock sample)
- Statistical Reconstruction: based on an analysis of a high-resolution two-dimensional image, three-dimensional representations of the pore space are constructed.
- Modelling method: Direct modelling (lattice Boltzmann method: the motion and collision of particles on a grid are captured by this method); Network modelling
- Analysis of the result

Comment
Provide detailed information relating the capillary pressure forces acting in the system as well as prove experimentally that in small scale fractures the capillary forces are active.

Advances in Water Resources. Vol(26)

Characterizing flow and transport in fractured geological media: A review

Author/Organization
Berkowitz B.

Contribution to Industry/Project
- Consider (i) geometrical characterization of fractures and fracture networks, (ii) water flow, (iii) transport of conservative and reactive solutes, and (iv) two-phase flow and transport
- Examine the physical factors controlling flow and transport behaviour

Objective
Analyze measurements, conceptual pictures, and mathematical models of flow and transport phenomena in fractured rock systems.

Methodology
- Consider (i) geometrical characterization of fractures and fracture networks, (ii) water flow, (iii) transport of conservative and reactive solutes, and (iv) two-phase flow and transport

Comment
Provide information relating the transfer functions and the flow behaviour in NFRs

Golder Associates

Advances in Discrete Fracture network modelling

Author/Organization
Dershowitz W.S.; La Pointe P.R and Doe T.W

Contribution to Industry/Project

- Describes recent advances in discrete fracture network (DFN) modeling and analysis. Investigates the validity of assuming injection/production is confined to fractures

Objective
Highlight trends in DFN modelling such as 1) convergence of DFN and Continuum Methods 2) Increasing Geologic Realism 3) Multiple Immobile zone transport.

Methodology

- Convergence of DFN and Continuum Methods: Analyse development of DFN and EPM models by analysing the three types of integration which include: Layered DFN/EPM model; EPM Implementation of DFN Hydrstructural Models; Nested DFN/EPM model
- Increasing Geologic Realism
- Multiple Immobile zone transport. Analyse diffusive exchange; multirate diffusion and other properties for the study

Comment
Major advances have been made in the development and implementation of hydrostructural models for fracture geometry, and microstructural models, for the immobile zones influencing solute transport. For the project it has given detailed information about discrete fracture nework method and equations used for permeability calculation used in FracMan.

SPE 93144-PA

Multirate-transfer dual-porosity Modeling of gravity drainage and imbibition

Author/Organization
Di Donato G, Lu H, Tavassoli Z, Blunt M.J.

Contribution to Industry/Project
- Describe an approach to model displacement processes in fractured reservoirs
- Discover a matrix/fracture function in dual porosity model that use analytical expressions for average recovery asa function of time for gas gravity drainage and countercurrent imbibiton.

Objective
Highlight the need of core-scale measurement of recovery and use streamline based formulation to accommodate 1D transport equation along streamlines that capture flow.
Methodology
- Discuss streamline formulation in dual porosity simulator
- Investigate Capillary controlled imbibition in single rate transfer functions which is based on semianalytical solutions
- Discuss impact of gravity drainage in fractured reservoir
- Mention the numerical approach for the transfer function

Comment
Gave a good insight on the various transfer functions involved in a fractured reservoir. It also proves that shape factor method are inaccurate to accurate capture the average behaviour

Geological Society London

Numerical simulation of multi- phase fluid flow in structurally complex reservoirs

Author/Organization
Matthäi S. K.; Geiger S.; Roberts S. G.; Paluszny A.; Belayneh M.; Burri A.; Mezentsev A.; Lu H.; Coumou D.; Driesner T. and Heinrich C. A.

Contribution to Industry/Project
- Provide detailed analysis of CSMP++ and SAMG solver

Objective
Generate a workflow to use CSMP++

Methodology
- Feature representation and geological interpretation of the model geometry on CAD
- Hybrid finite elementdiscretization of model geometry
- Discretization of the governing equations using operator spitting in a combined finite element and finite volume framework
- A posteriori mesh adaptation of pressure equation is based on an estimate of discretization error.
- Simulation and then visualise and analyse results
- Upscaling

Comment
Provide detailed analysis of CSMP++ and SAMG solver. It has run cases on single fractures to compare with ECLIPSE 100

SPE 118924

Massively Parallel Sector Scale Discrete Fracture And Matrix Simulation

Author/Organization
Geiger S. Huangfu Q.; Reid F.; Matthäi S.K.; Coumou D.; Belayneh M.; Fricke C. and Schmid K.S

Contribution to Industry/Project

- Simulate multiphase displacement, including viscous, capillary and gravitational forces for highly resolved and geologically realistic models.
- Investigates Discrete fracture and matrix modelling method at high resolution and provide information on dual porosity modelling method

Objective
Analyse DFM and finite element method for field scale simulation of highly complex and geologically realistic models

Methodology

- Discuss the governing equations in the model and understand the concept of finite element method, discussing on the process involved in solving the problem
- Compare finite volume and finite element method
- Discuss the computational power required to simulate such complex models: Inter-processor communication; hardware etc.
- Simulation method is tested on applications: single phase singl component models and multiphase multicomponent model. The results are compared and discussed using conventional well test analysis

Comment
Provide information on DFM and further details on finite element method. This will be used in literature to understand the mathematics involved in solving flow equations

A1.3. Software Workflow
ECLIPSE 100

```
RUNSPEC
-- Start Data File--
        TITLE
        --Name of the Case Study ---
        Uniform MultiBlock Wettability case_Water Wet With Capillarity
        DIMENS
        --Number of Blocks used for the model---
        DX      DY      DZ
        50      50      21
        --Specify the Fluids present in the model---
        OIL
        WATER
        GAS
        --Model Scale Units---
        LAB
        --cm3 Scale---
        START
        --Specify start date---
        01 Jan 2014
        WELLDIMS (Used for only complex orthogonal geometry)
        -- Well number and specification---
GRID
--Generate Model Geometry---
        --Cornor Point Gridding Method (To generate non-orthogonal model only)---
        COORD
        --Define Cornor points of the reservoir model---
        ZCORN
        --Define Point depth of the grid---

        --Block Center Gridding Method (To generate orthogonal fracture model)---
        DXV
        --Grid block sizing in x direction---
        DYV
        --Grid block sizing in y direction---
        DZ
        --Grid block sizing in z direction---
        TOPS
        --Specify the depth of the reservoir surface---

        --Property Spefication----
        PERMX
        --Permeabiltiy in x direction---
        PORO
        --Porosity of cells---
        COPY
        'PERMX' 'PERMY" /
        'PERMX' 'PERMZ' /
        /
        MINPV
EDIT
        MULTIPLY
        'PORV' X1 X2 Y1 Y2 Z1 Z2 'multiplying factor' /
        /
PROPS
 --SaturationFunction---
        SWFN, SOF3
--PVT data---
        -- Matrix static properties: Compressibilty---
        ROCK
         -- Fluid Density: Gas, Oil and Water---
        DENSITY
        -- PVT data of oil---
        PVDO
        -- PVT data of water---
        PV

REGIONS
SOLUTION
SUMMARY
SCHEDULE
```

A2: ECLIPSE Model Simulation

A2.1: Uniform Multi-Matrix block Simulation

Model Specification:

TableA2.1 1: Uniform Multiblock Base Case Reservoir Parameter	
Model Parameters	
Model Grid Size (Cell Count)	50x50x21
Model Grid Size (cm)	10x10x162
Model gridding methodology	Centre – Block Gridding
Reservoir Datum Depth (cm)	15000
Reservoir Pressure (BARS)	400
Number of Matrix Blocks	36
Total surface for exchange (cm^3)	6969.6
Fracture Aperture Size (mm)	8
Matrix Porosity (%)	25
Matrix Permeability (mD)	20
Oil Water Contact for Matrix (cm)	30000
Fracture Porosity (%)	100
Fracture Permeability (mD)	5000
Oil Water Contact for Fracture (cm)	14000
Gas Oil Contact for matrix and Fracture (cm)	13000

PVT Table

TableA2.1 2: Base Case Fluid Properties	
Fluid Properties	
Datum Pressure (BARS)	400
Water Formation Volume Factor	1
Water Compressibilty (BAR-1)	4x10-5
Water Viscosity (cP)	1.4
Viscositivity	0
Water Density (kg/m3)	1000
Oil Formation Volume Factor	1
Oil Compresibility (BAR-1)	4x10-5
Oil Viscosity (cP)	0.5
Oil Density (kg/m3)	897
Gas Density (kg/m3)	1.5

A2.1.1: Water Wet Reservoir Model

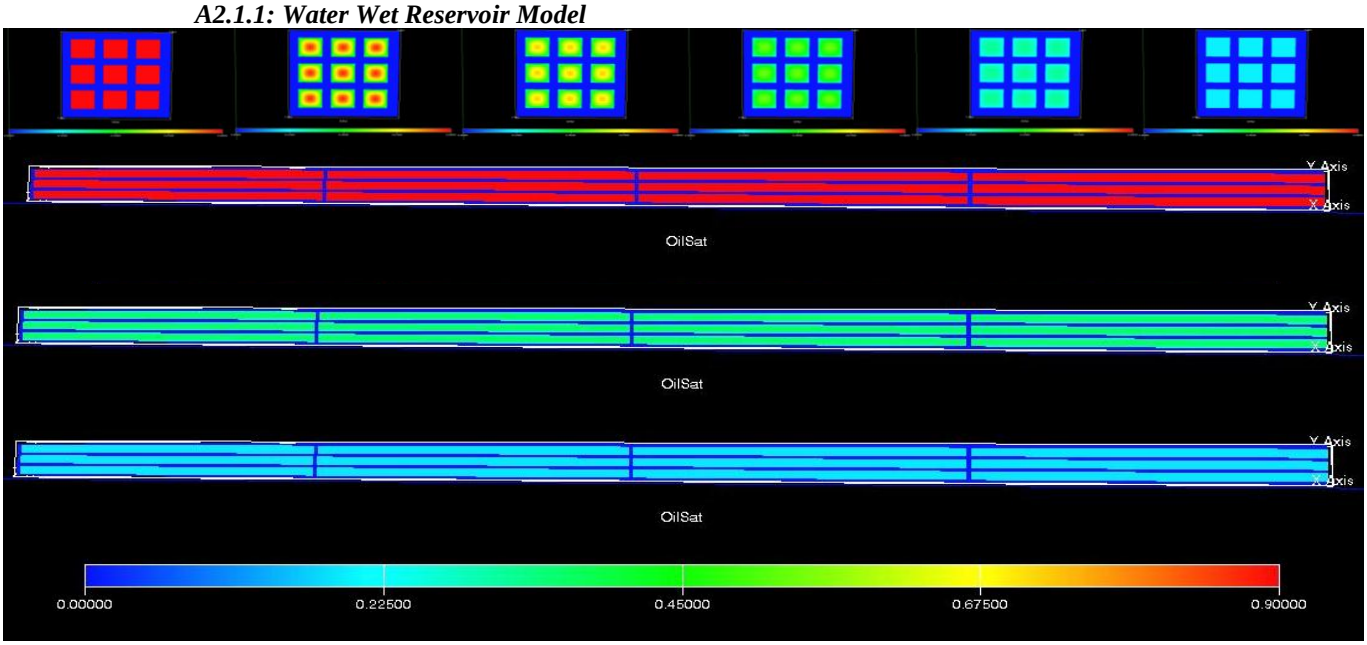

Figure A2.1.1. 1: 3D visual of the flow behaviour in Water Wet Reservoir model with Capillarity Effect and Gravity forces

Matrix – Exchange Flow Exchange

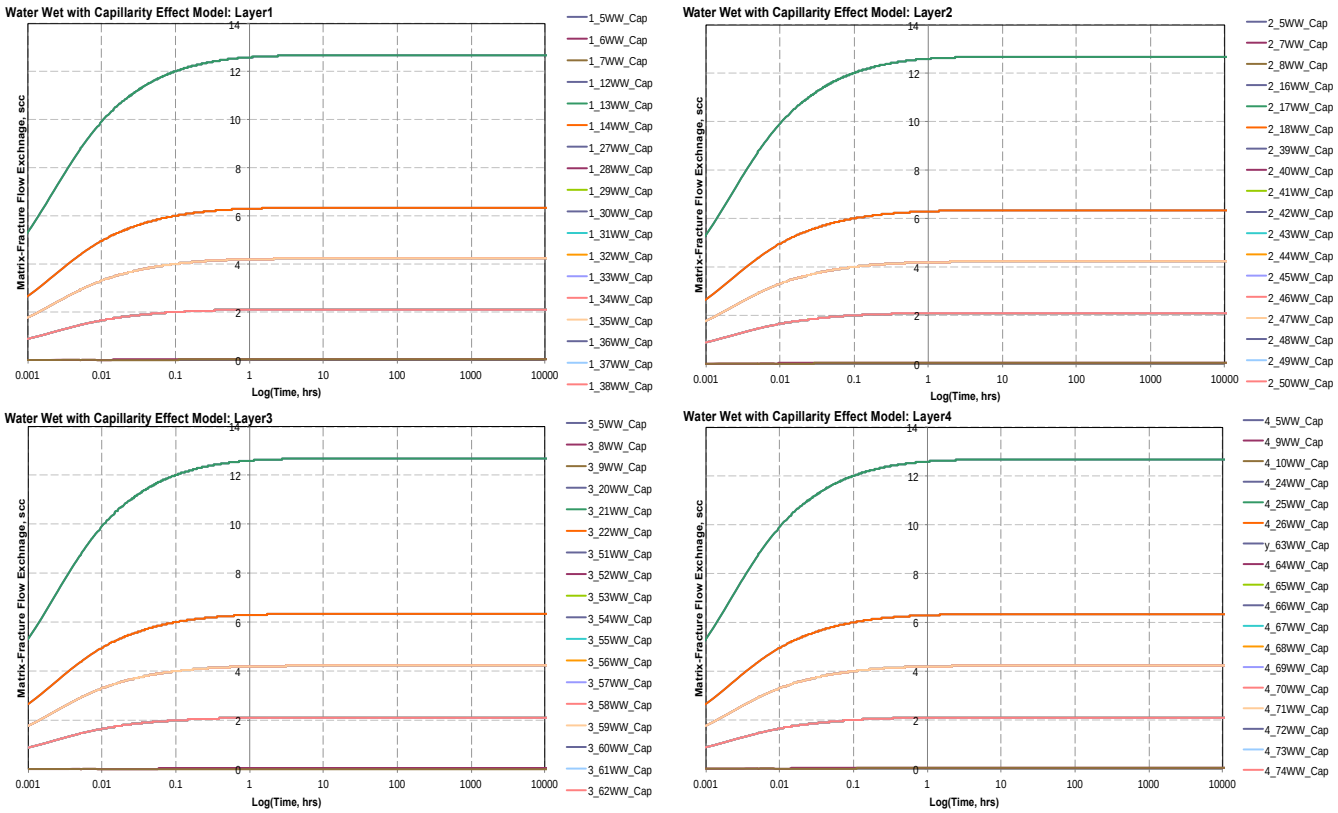

Figure A2.1.1. 2: Matrix-Fracture Exchange behaviour in each layer of the reservoir (1 = Top Layer; each layer has 9 matrix blocks)

A2.1.2: Water Wet Reservoir Model without Capillarity Effect

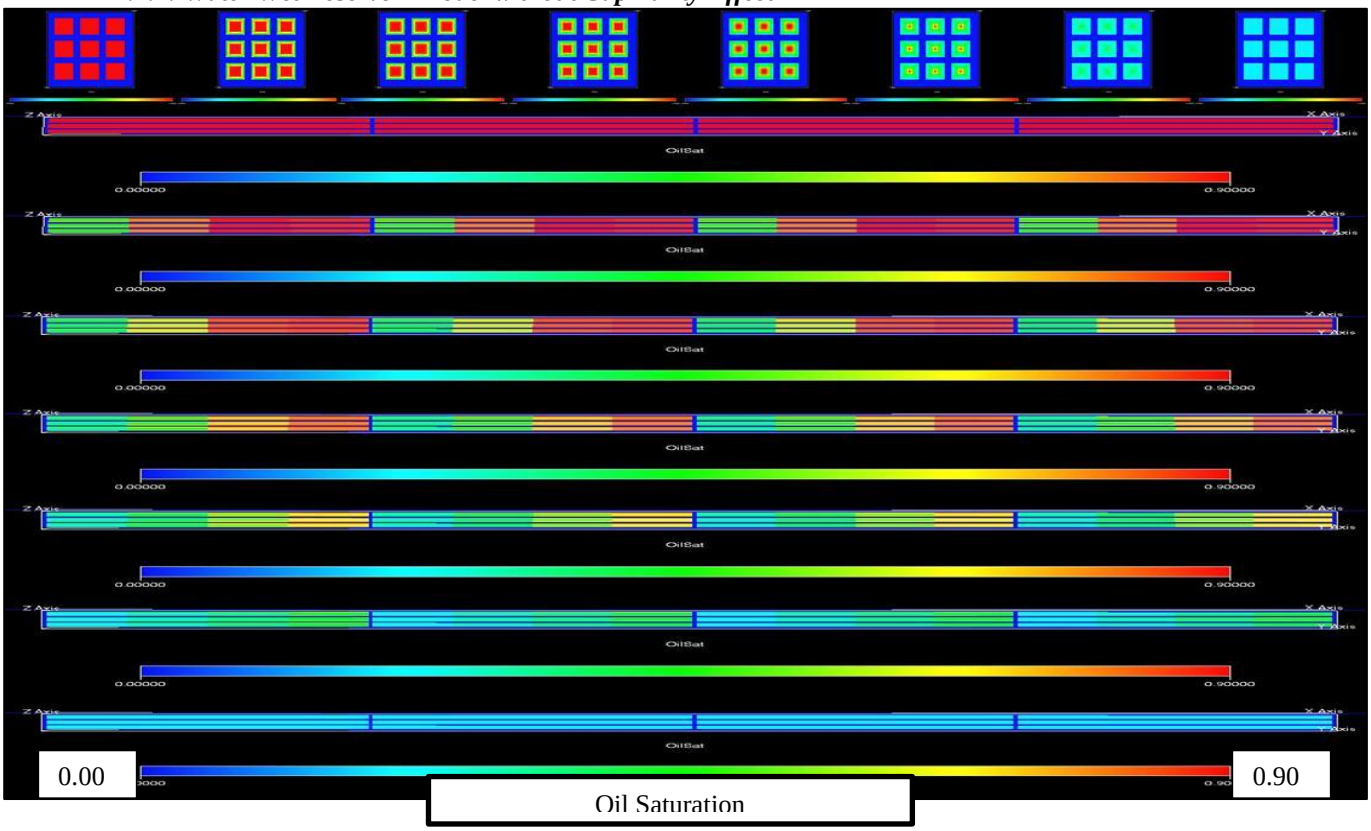

Figure A2.1.2. 1: 3D visual of the flow behaviour in Water Wet Reservoir model with Gravity drainage only

Matrix – Exchange Flow Exchange

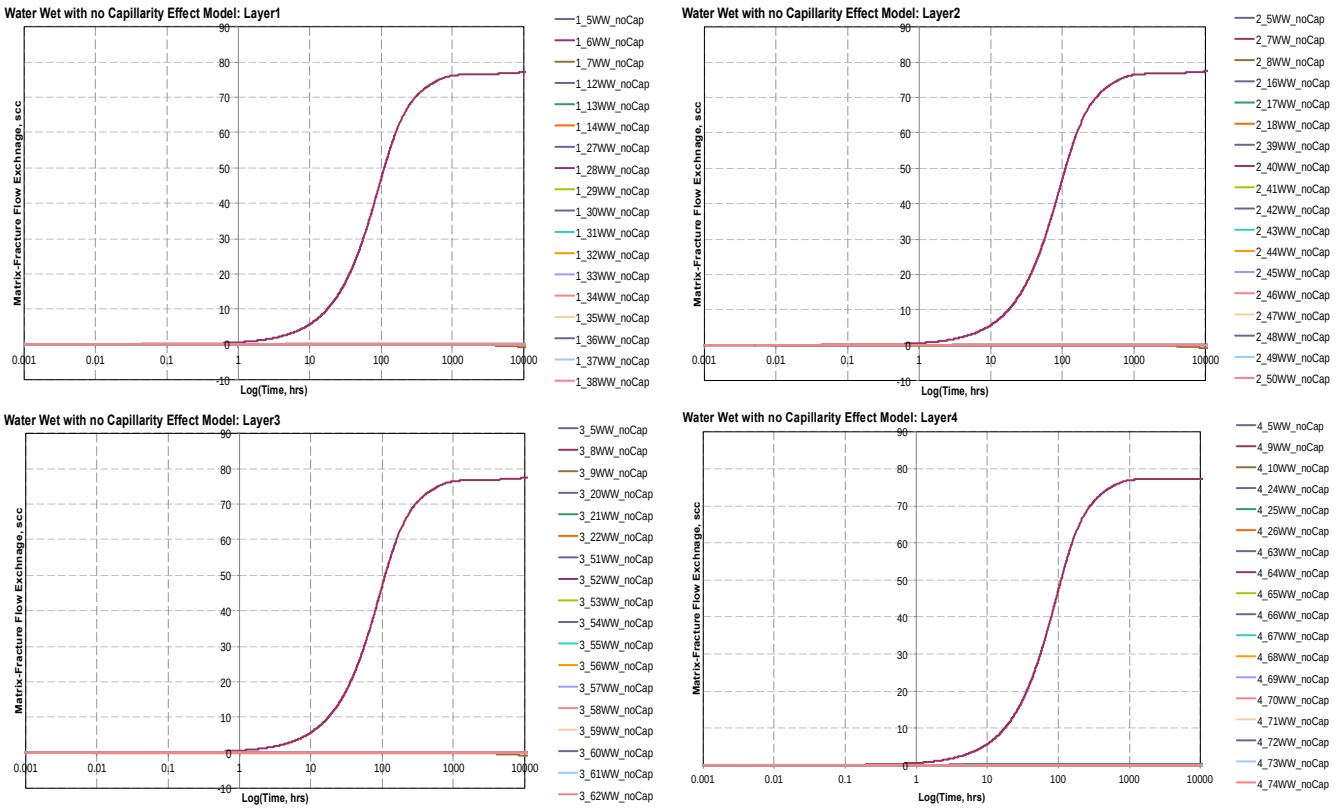

Figure A2.1.2. 2: Matrix-Fracture Exchange behaviour in each layer of the reservoir (1 = Top Layer; each layer has 9 matrix blocks)

A2.1.3: Mixed Wet Reservoir Model

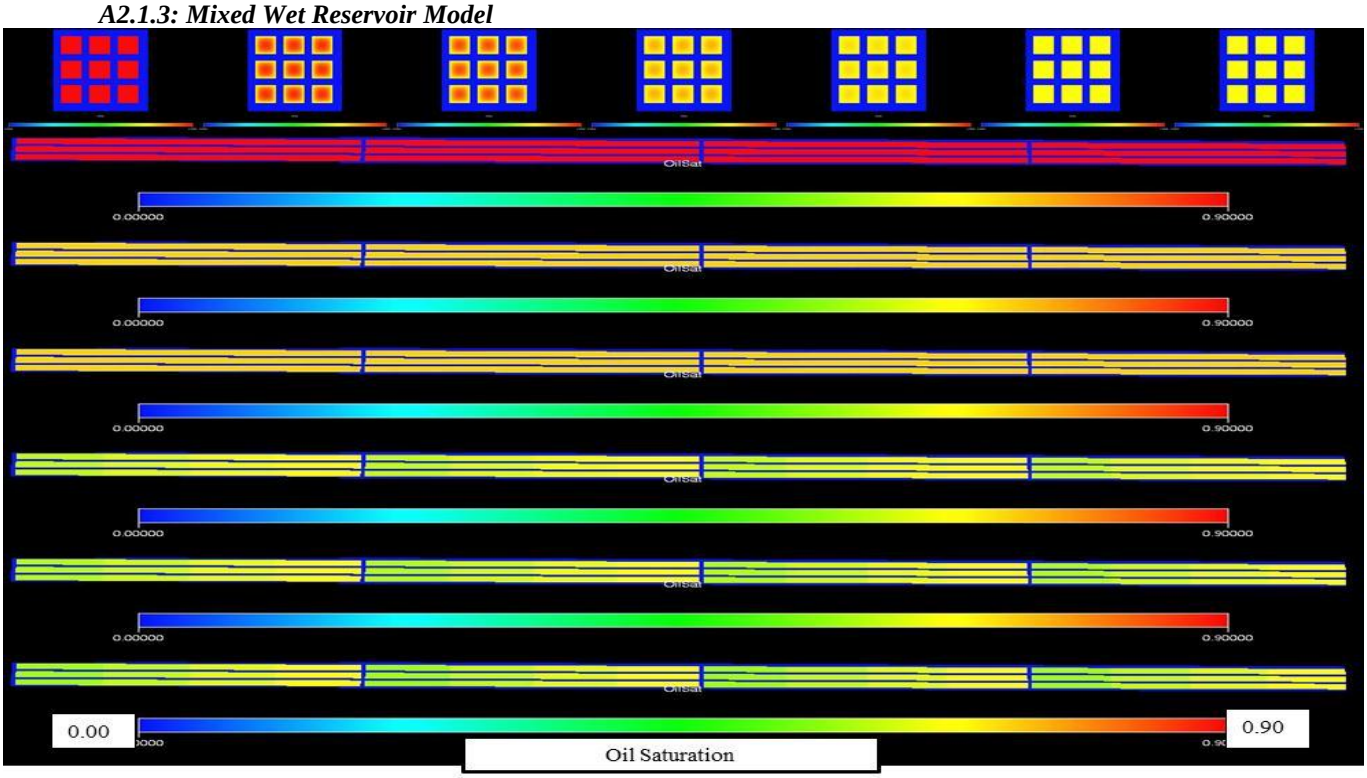

Figure A2.1.3. 1: 3D visual of the flow behaviour in Water Wet Reservoir model with Gravity drainage only

Matrix – Exchange Flow Exchange

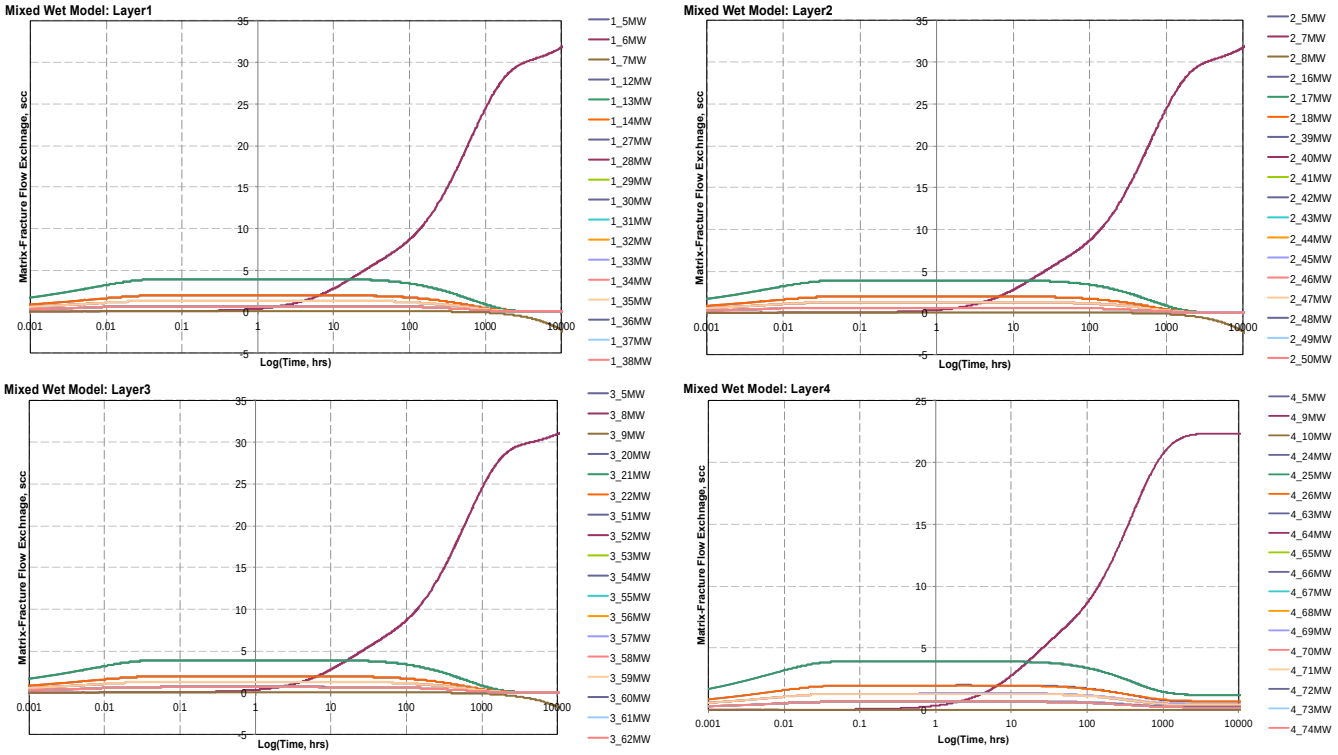

Figure A2.1.3. 2: Matrix-Fracture Exchange behaviour in each layer of the reservoir (1 = Top Layer; each layer has 9 matrix blocks)

A2.1.4: Sensitivity Study in Water Wet Model: Homogeneous Aperture Decrease x2
Matrix – Exchange Flow Exchange

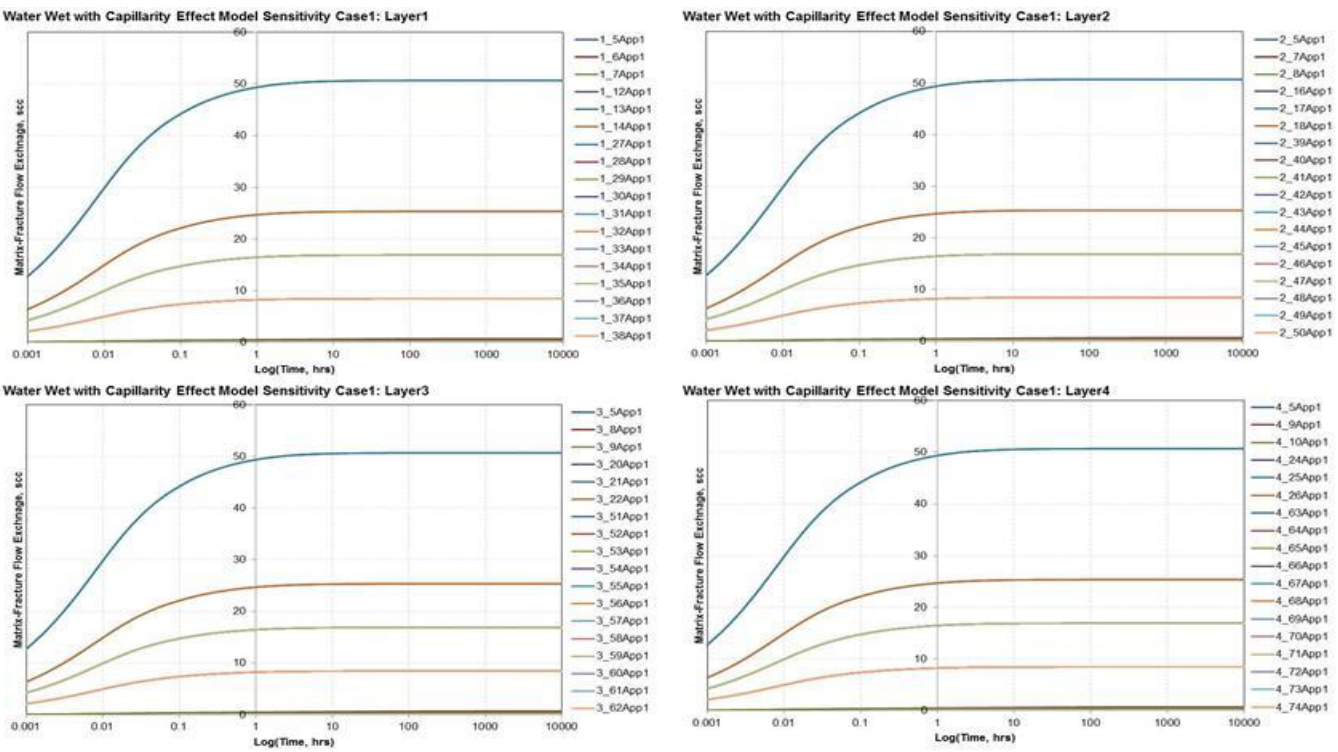

Figure A2.1.4. 1: Matrix-Fracture Exchange behaviour in each layer of the reservoir (1 = Top Layer; each layer has 9

matrix blocks)

A2.1.5: Sensitivity Study in Water Wet Model: Heterogeneous Aperture Sizing (x = x1; y = x0.1; z = x0.05)
Matrix – Exchange Flow Exchange

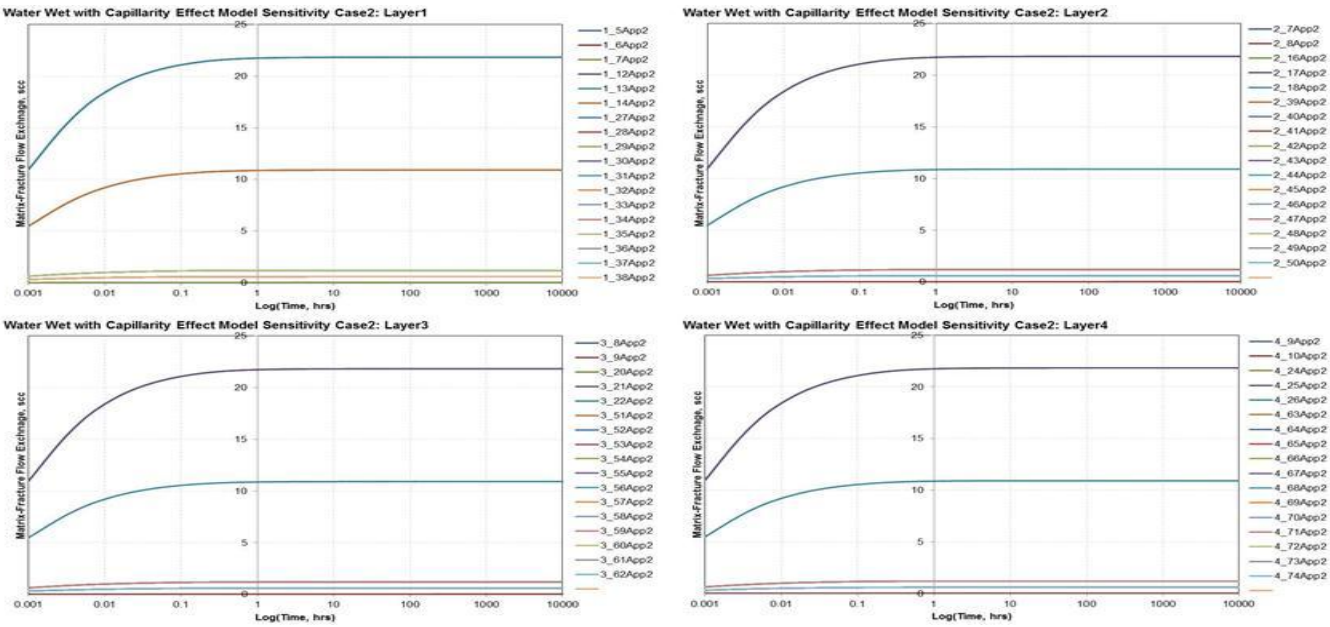

Figure A2.1.5. 1: Matrix-Fracture Exchange behaviour in each layer of the reservoir (1 = Top Layer; each layer has 9 matrix blocks)

A2.1.6: Sensitivity Study in Water Wet Model: Aperture Sizing (x0.001)
Matrix – Exchange Flow Exchange

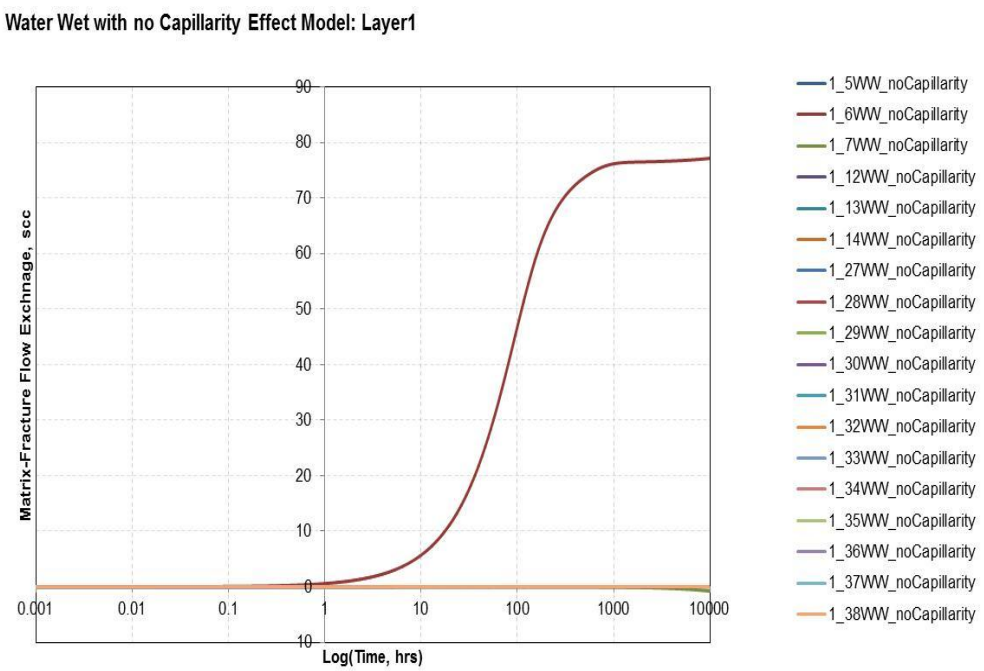

Figure A2.1.6. 1: Matrix-Fracture Exchange behaviour in each layer of the reservoir (1 = Top Layer; each layer has 9 matrix blocks)

A2.1.7: Water Wet Reservoir Model without Capillarity Effect: Sensitivity Study for Gravity Effect

Matrix – Exchange Flow Exchange

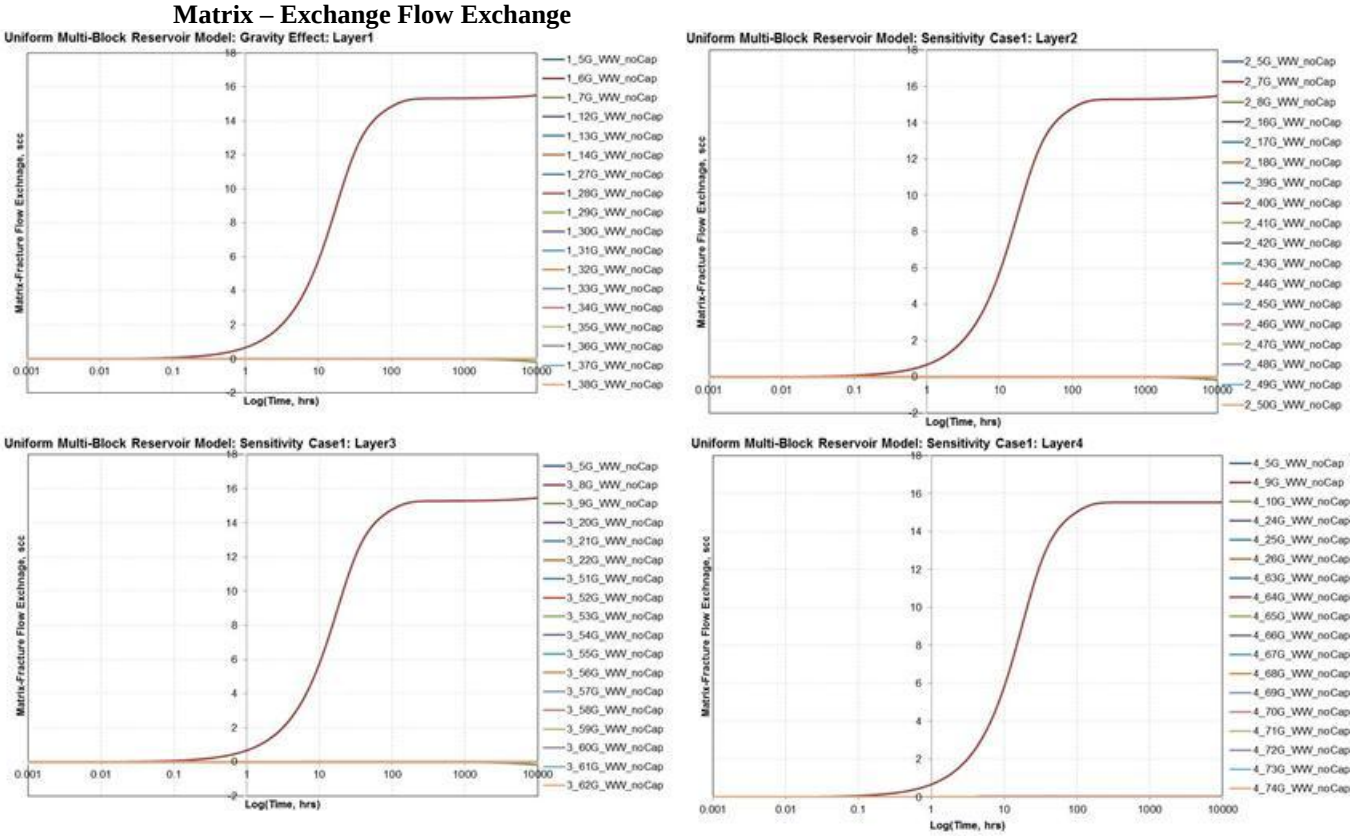

Figure A2.1.7. 1: Matrix-Fracture Exchange behaviour in each layer of the reservoir (1 = Top Layer; each layer has 9 matrix blocks)

A2.2: Non-Uniform Multi-Matrix blocks Simulation

Model Specification:

Table A2.2. 1: Non Uniform Multiblock Base Case Reservoir Parameter	
Model Parameters	
Model Grid Size (Cell Count)	50x50x21
Model Grid Size (cm)	10x10x155
Model gridding methodology	Centre – Block Gridding
Reservoir Datum Depth (cm)	15600
Reservoir Pressure (BARS)	400
Number of Matrix Blocks	25
Total Surface for exchange (cm^3)	14910
Fracture Aperture Size (mm)	8
Matrix Porosity (%)	25
Matrix Permeability (mD)	20
Oil Water Contact for Matrix (cm)	30000
Fracture Porosity (%)	100
Fracture Permeability (mD)	5000
Oil Water Contact for Fracture (cm)	12000
Gas Oil Contact for matrix (cm)	13000
Gas Oil Contact for Fracture (cm)	10000

PVT Table

Table A2.2. 2: Fluid Properties	
Fluid Properties	
Datum Pressure (BARS)	400
Water Formation Volume Factor	1
Water Compressibilty (BAR-1)	4x10-5
Water Viscosity (cP)	1.4
Viscositivity	0
Water Density (kg/m3)	1000
Oil Formation Volume Factor	1
Oil Compresibility (BAR-1)	4x10-5
Oil Viscosity (cP)	0.5
Oil Density (kg/m3)	897
Gas Density (kg/m3)	1.5

A2.2.1: Water Wet Reservoir Model

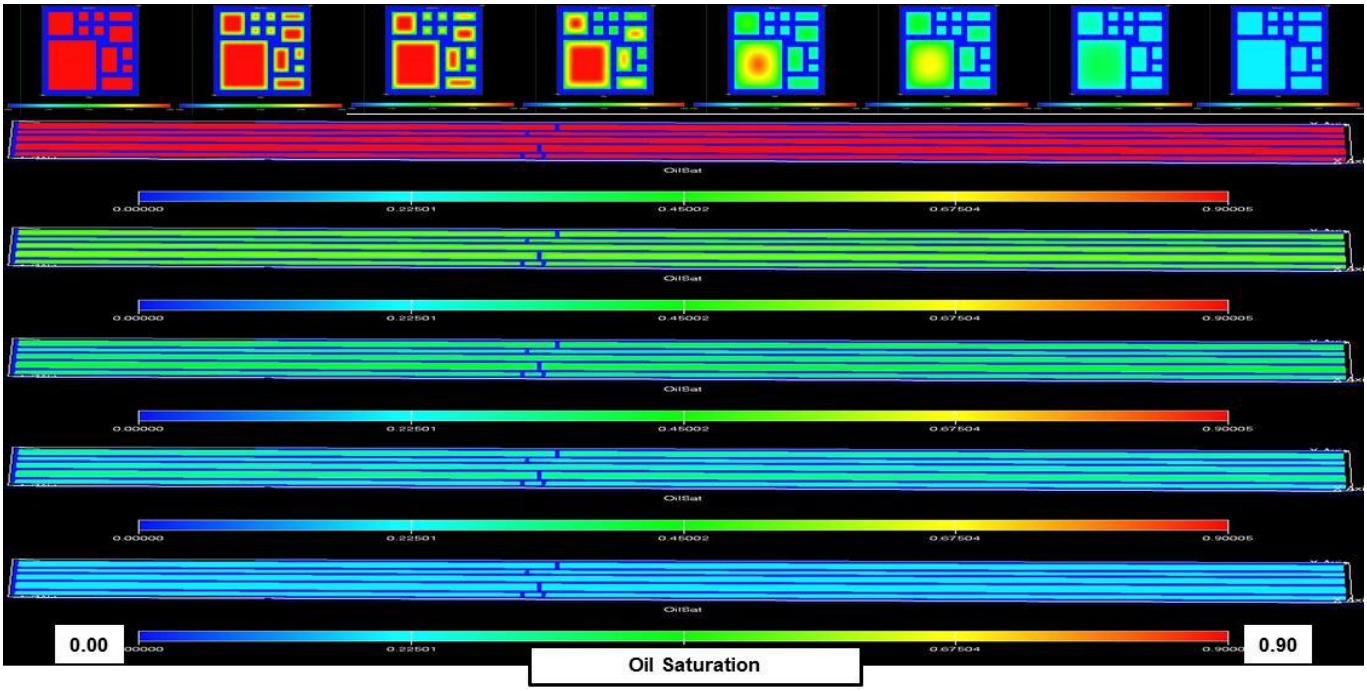

Figure A2.2.1. 1: 3D visual of the flow behaviour in Water Wet Reservoir model with Capillarity Effect and Gravity

drainage

Matrix – Exchange Flow Exchange

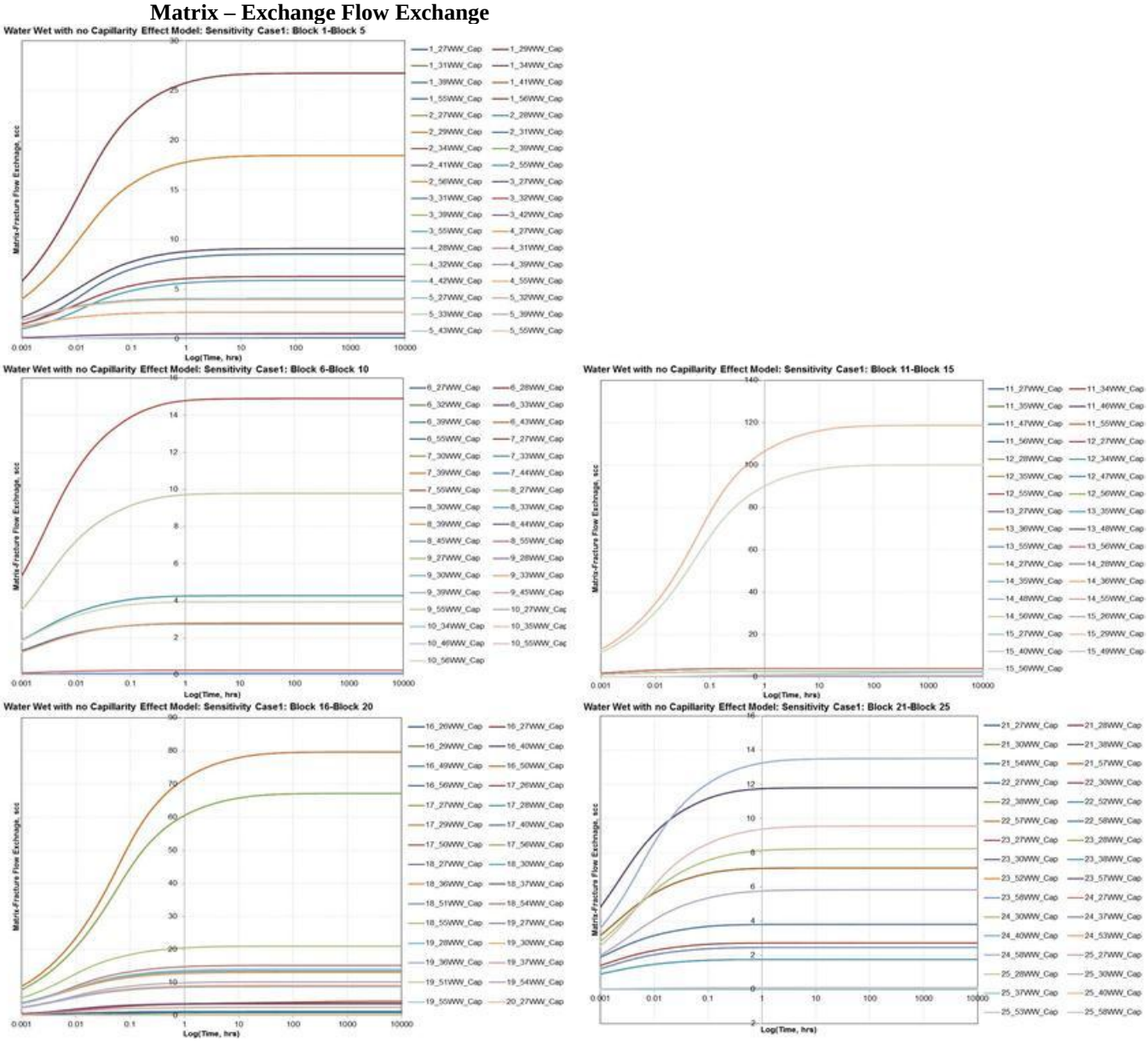

Figure A2.2.1. 2: Matrix-Fracture Exchange behaviour in each layer of the reservoir

A2.2.2: Water Wet Reservoir Model without Capillarity Effect

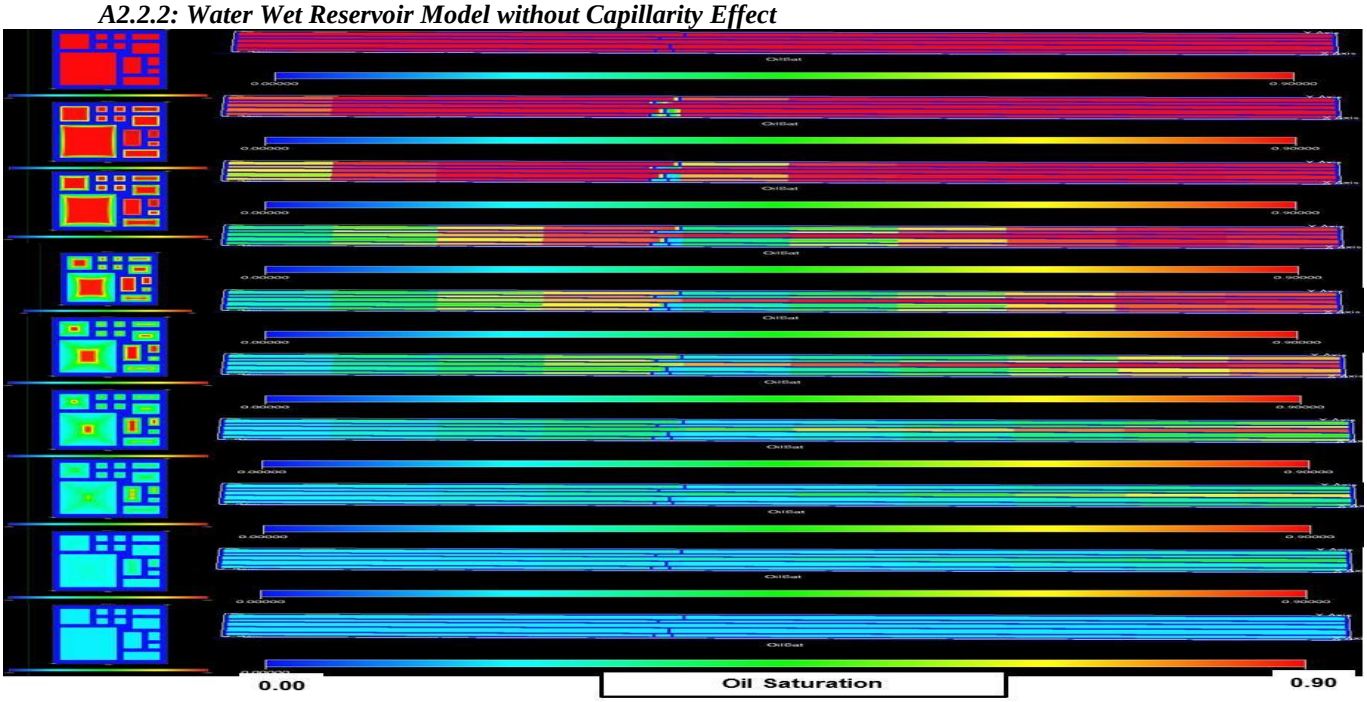

Figure A2.2.2. 1: 3D visual of the flow behaviour in Water Wet Reservoir model with Gravity drainage only

Matrix – Exchange Flow E

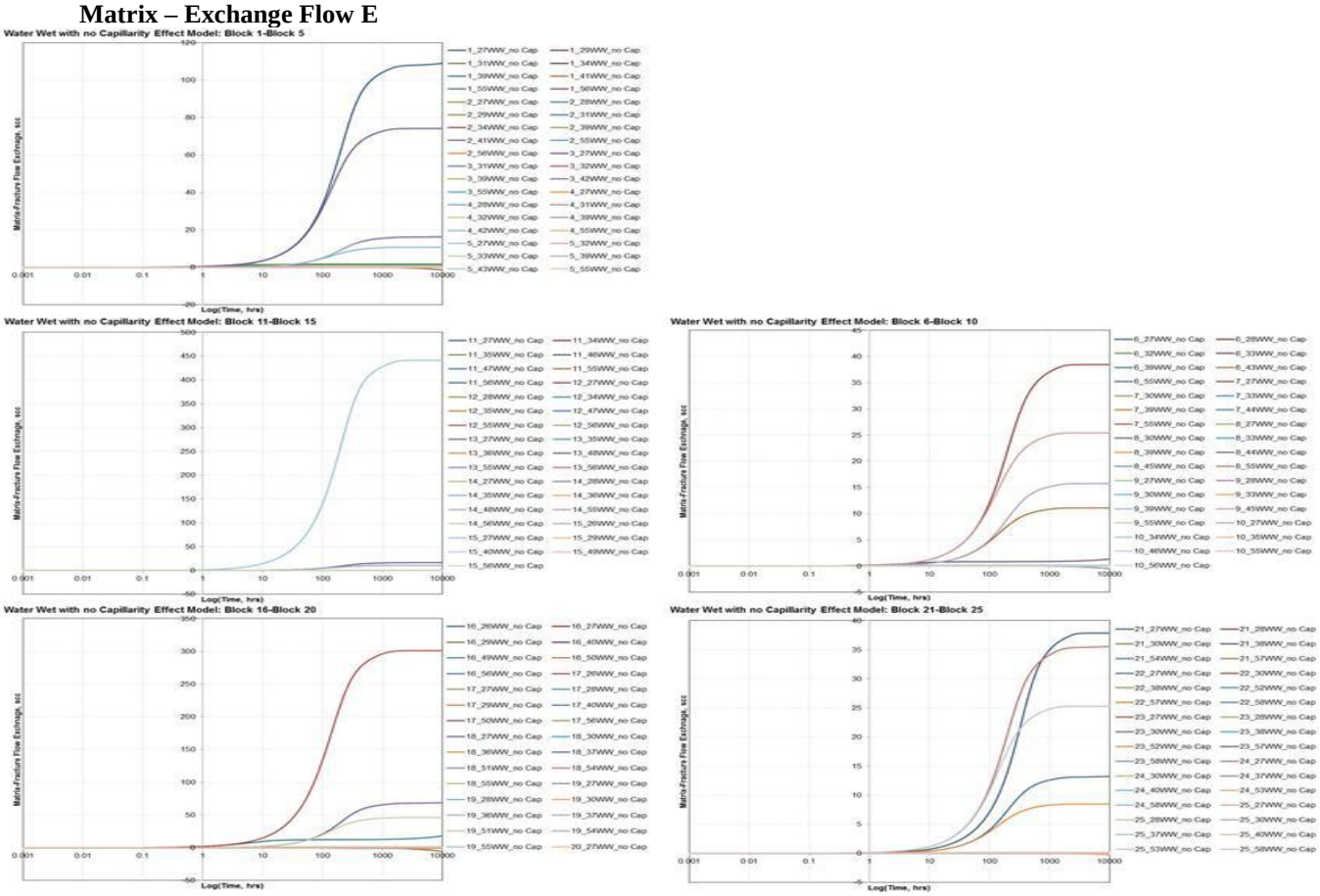

Figure A2.2.2. 2: Matrix-Fracture Exchange behaviour in each layer of the reservoir

A2.2.3: Mixed Wet Reservoir Model

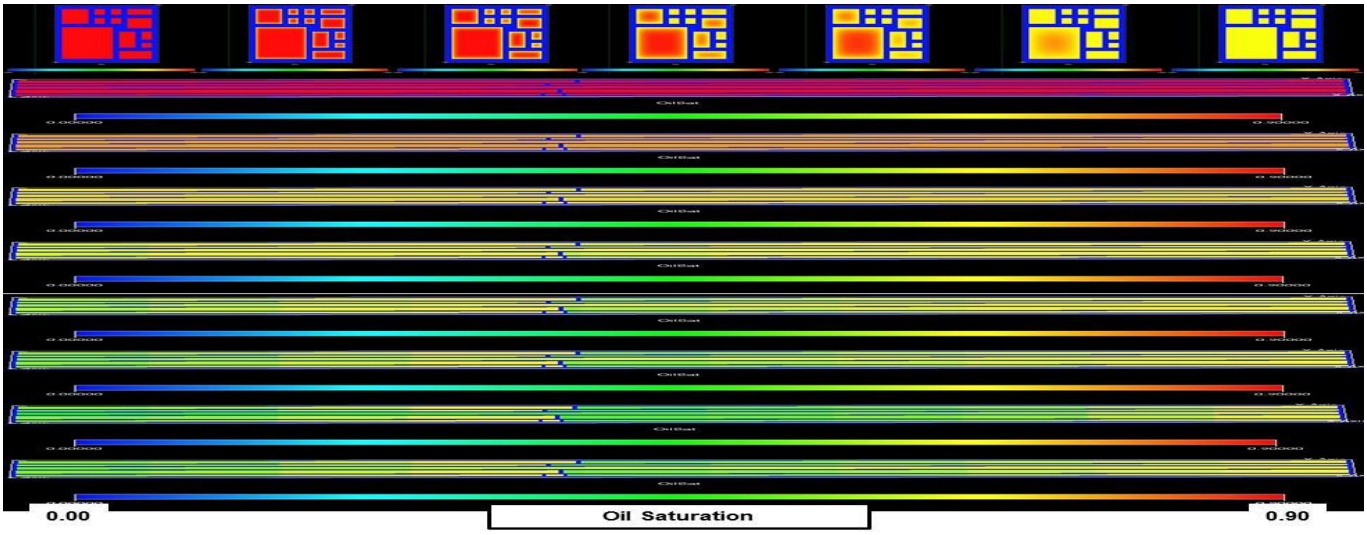

Figure A2.2.3. 1: 3D visual of the flow behaviour in Water Wet Reservoir model with Gravity drainage only

Matrix – Exchange Flow Exchange

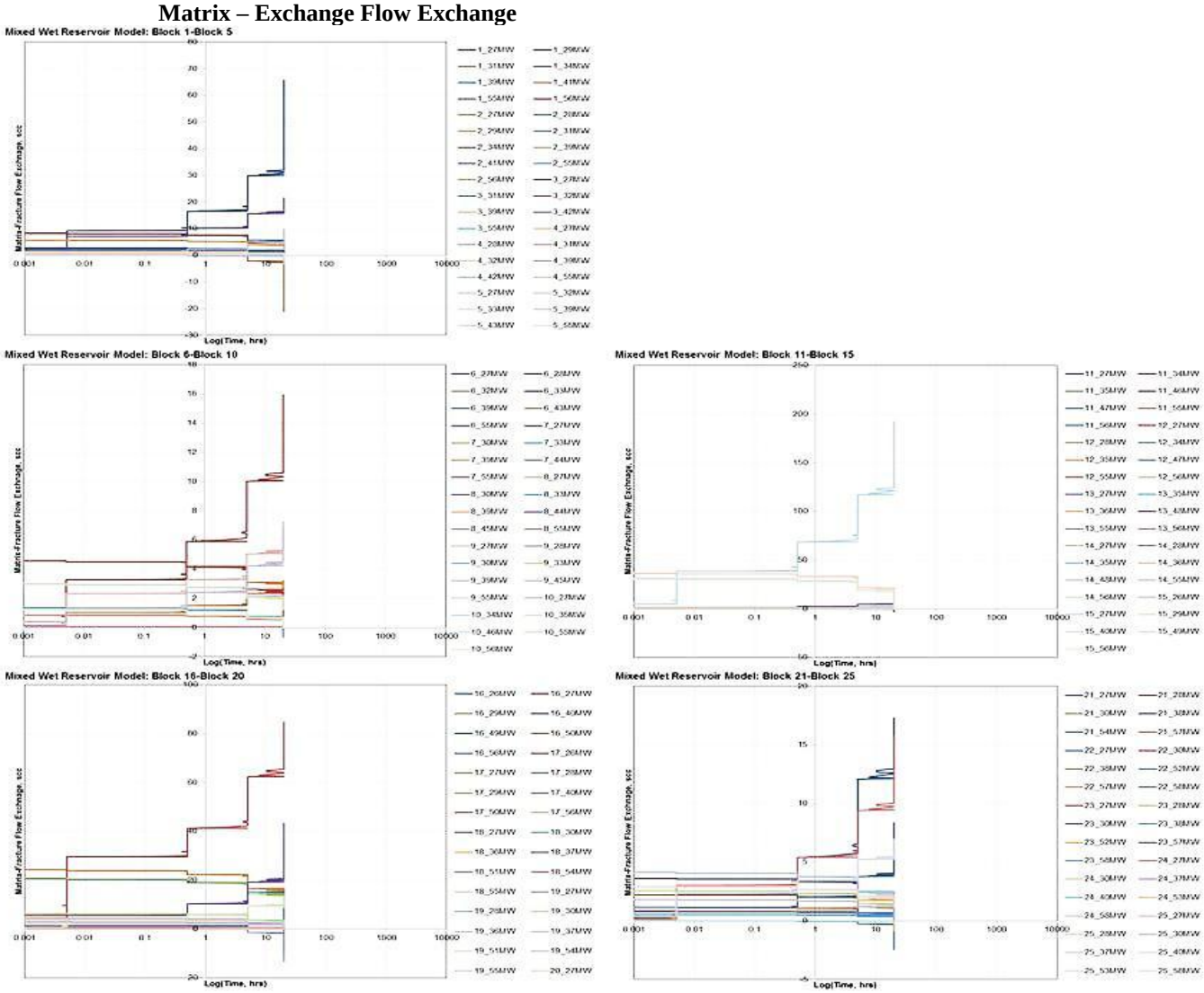

Figure A2.2.3. 2: Matrix-Fracture Exchange behaviour in each layer of the reservoir

A2.2.4: Sensitivity Study in Water Wet Model: Homogeneous Aperture Increase x2

Matrix – Exchange Flow Exchange

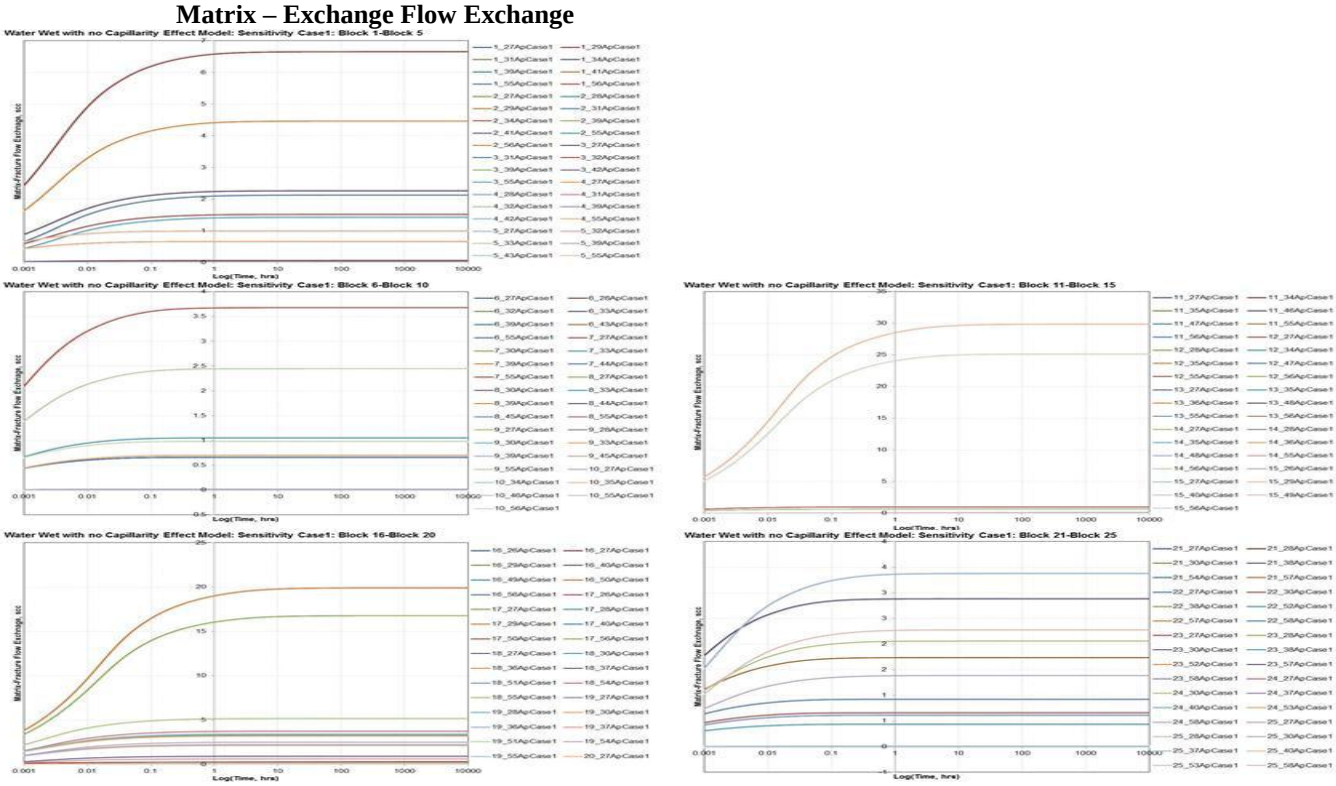

Figure A2.2.4. 1: Matrix-Fracture Exchange behaviour in each layer of the reservoir

A2.2.5: Sensitivity Study in Water Wet Model: Heterogeneous Aperture Sizing(x = x1; y = x0.1; z = x0.05)

Matrix – Exchange Flow Exchange

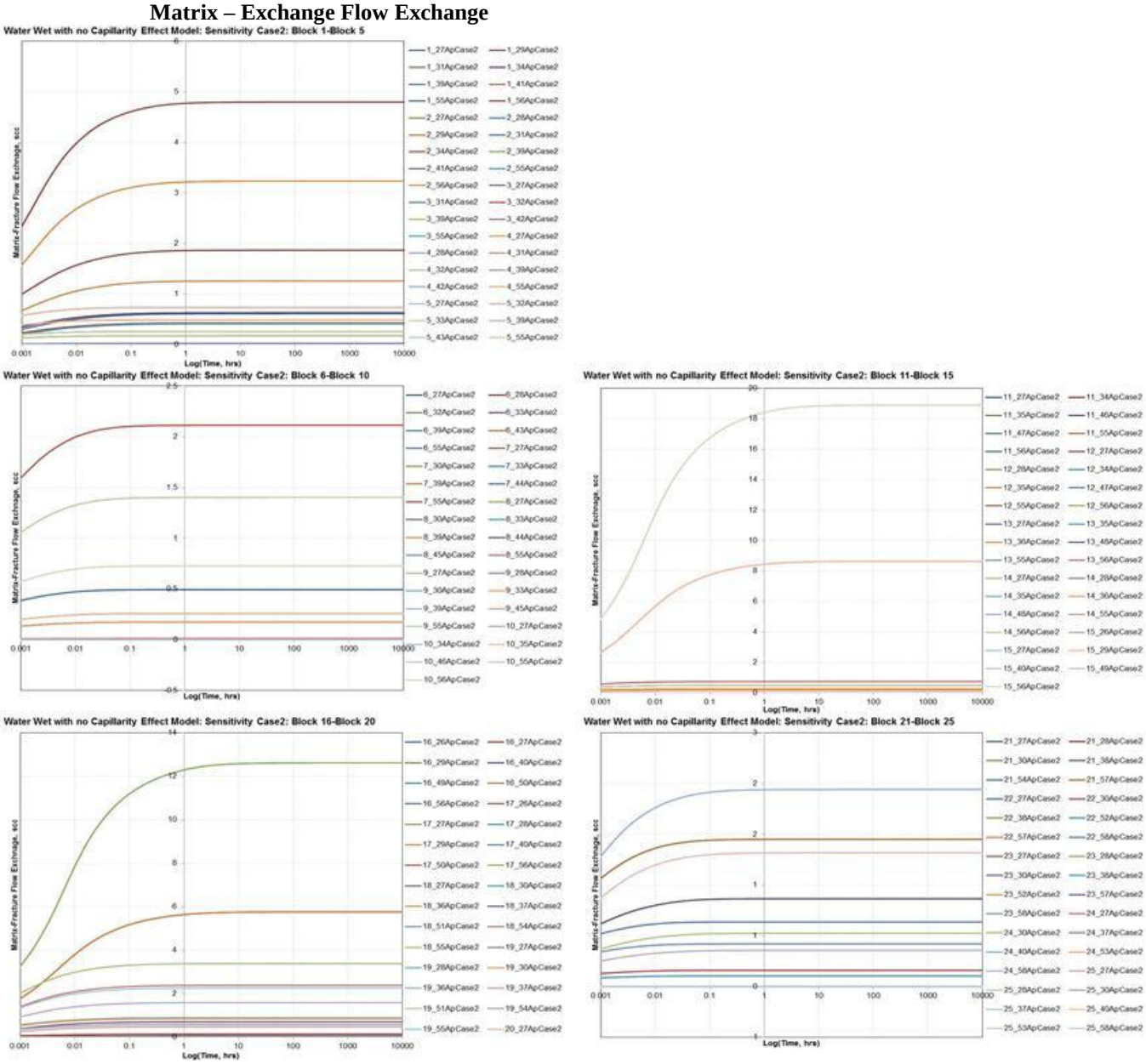

Figure A2.2.5. 1: Matrix-Fracture Exchange behaviour in each layer of the reservoir

A2.2.6: Sensitivity Study in Water Wet Model: Aperture Sizing (x0.001)
Matrix – Exchange Flow Exchange

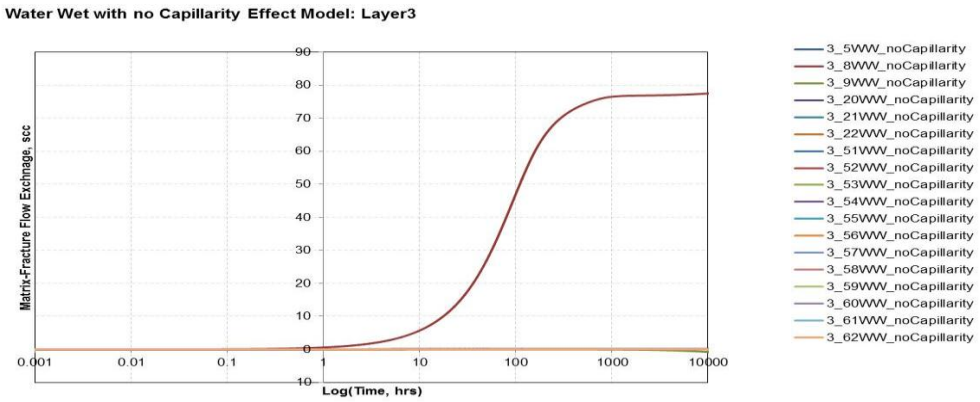

Figure A2.2.6.1: Matrix-Fracture Exchange behaviour in each layer of the reservoir

A2.2.7: Water Wet Reservoir Model without Capillarity Effect: Sensitivity Study for Gravity Effect
Matrix – Exchange Flow Exchange

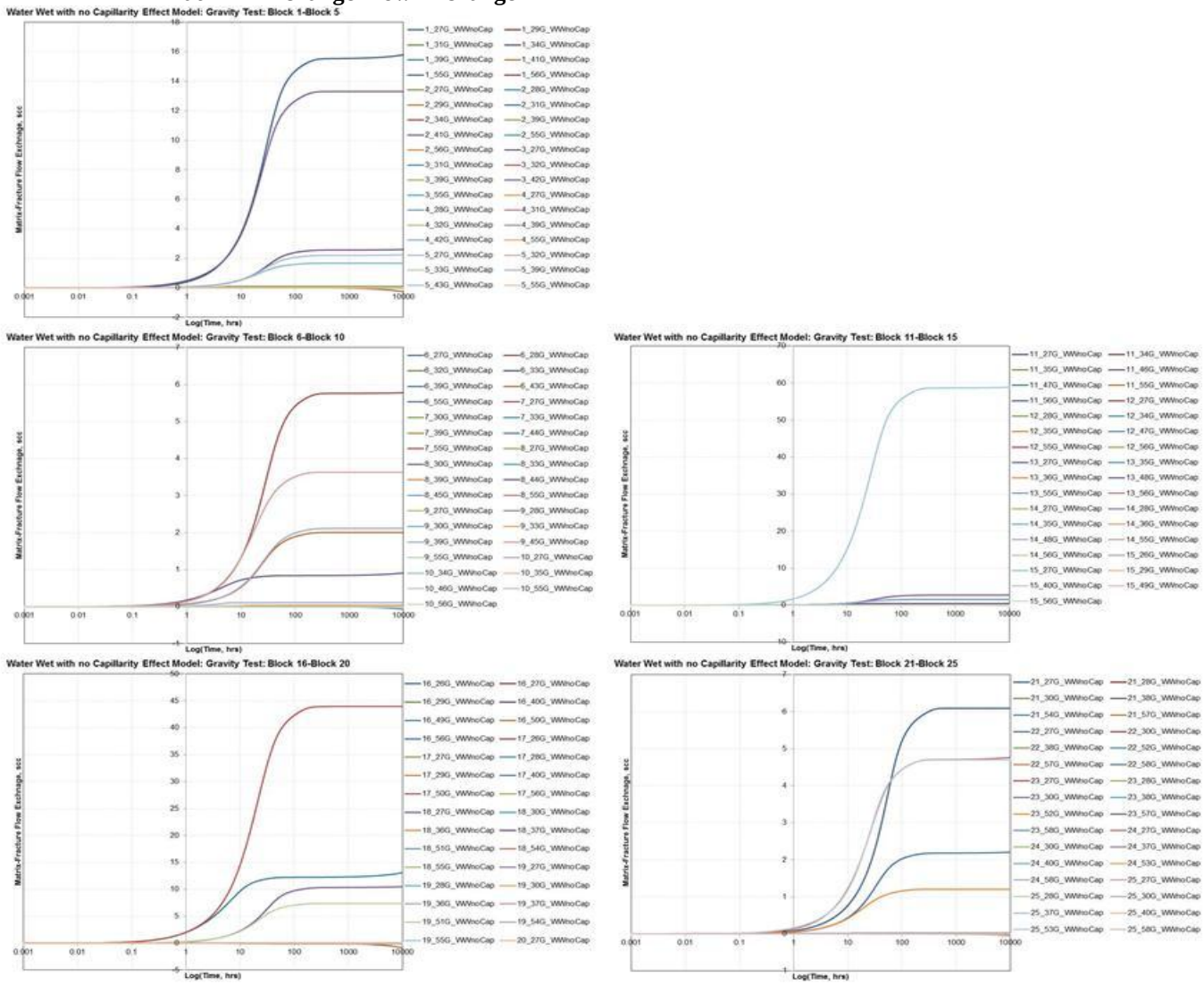

Figure A2.2.7. 1: Matrix-Fracture Exchange behaviour in each layer of the reservoir

A2.3: Single Matrix Block Simulation

Model Specification:

TableA2.1 3: Single block Base Case Reservoir Parameter	
Model Parameters	
Model Grid Size (Cell Count)	12x12x32
Model Grid Size (cm)	25.5x25.5x160
Model gridding methodology	Centre – Block Gridding
Reservoir Datum Depth (cm)	15000
Reservoir Pressure (BARS)	400
Number of Matrix Blocks	1
Total Surface for exchange (cm^3)	87500
Fracture Aperture Size (mm)	5
Matrix Porosity (%)	30
Matrix Permeability (mD)	1
Oil Water Contact for Matrix (cm)	25000
Fracture Porosity (%)	100
Fracture Permeability (mD)	1000
Oil Water Contact for Fracture (cm)	14000
Gas Oil Contact for matrix and Fracture (cm)	13000

PVT Table

TableA2.1 4: Base Case Fluid Properties	
Fluid Properties	
Datum Pressure (BARS)	400
Water Formation Volume Factor	1
Water Compressibilty (BAR-1)	4x10-5
Water Viscosity (cP)	1.4
Viscositivity	0
Water Density (kg/m3)	1000
Oil Formation Volume Factor	1
Oil Compresibility (BAR-1)	4x10-5
Oil Viscosity (cP)	0.5
Oil Density (kg/m3)	897
Gas Density (kg/m3)	1.5

A2.3.1: Water Wet Reservoir Model

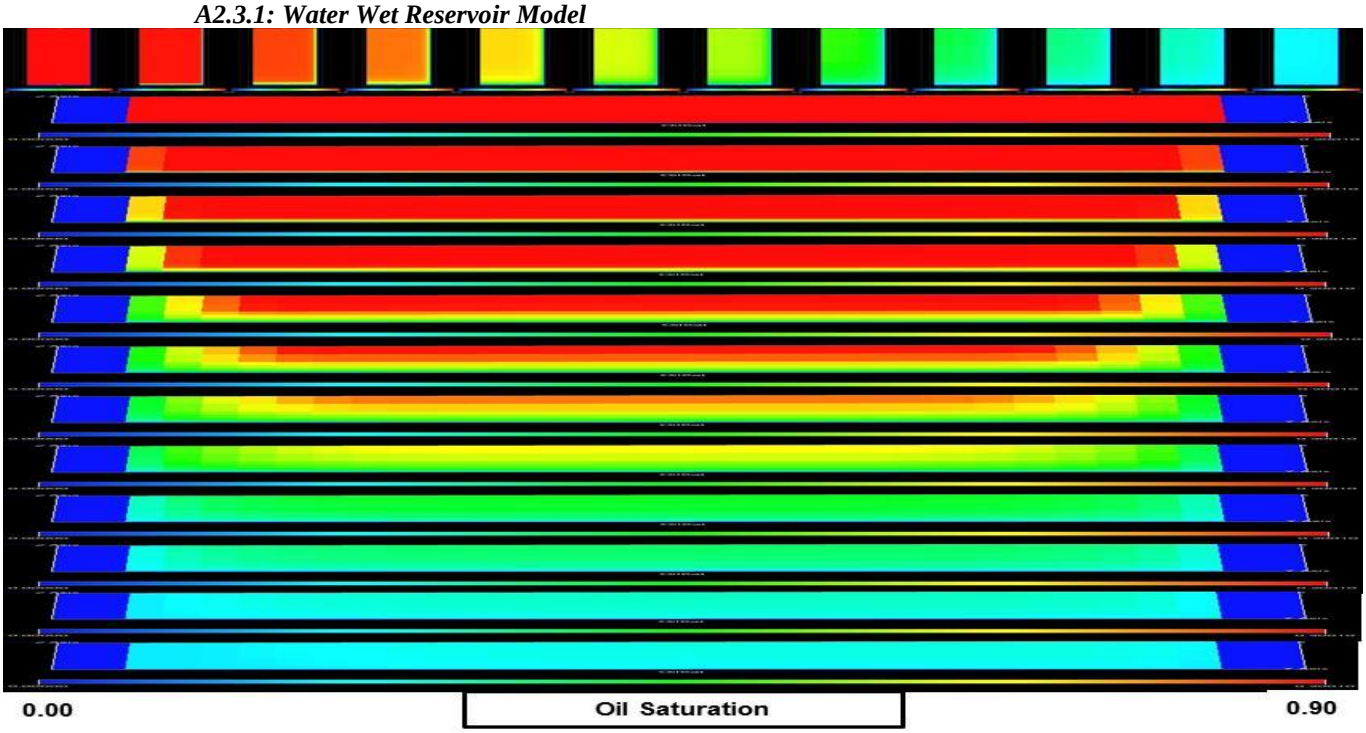

Figure A2.3.1.1: 3D visual of the flow behaviour in Water Wet Reservoir model with Capillarity Effect and Gravity drainage

Matrix – Exchange Flow Exchange

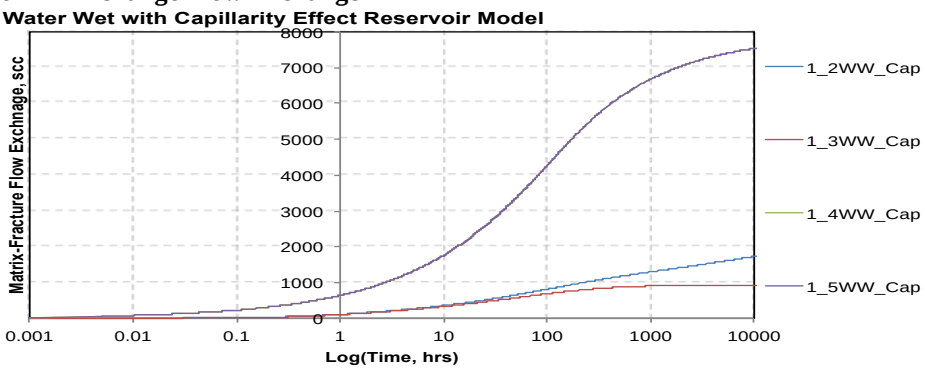

Figure A2.3.1.2: Matrix-Fracture Exchange behaviour in each layer of the reservoir

A2.3.2: Water Wet Reservoir Model without Capillarity Effect

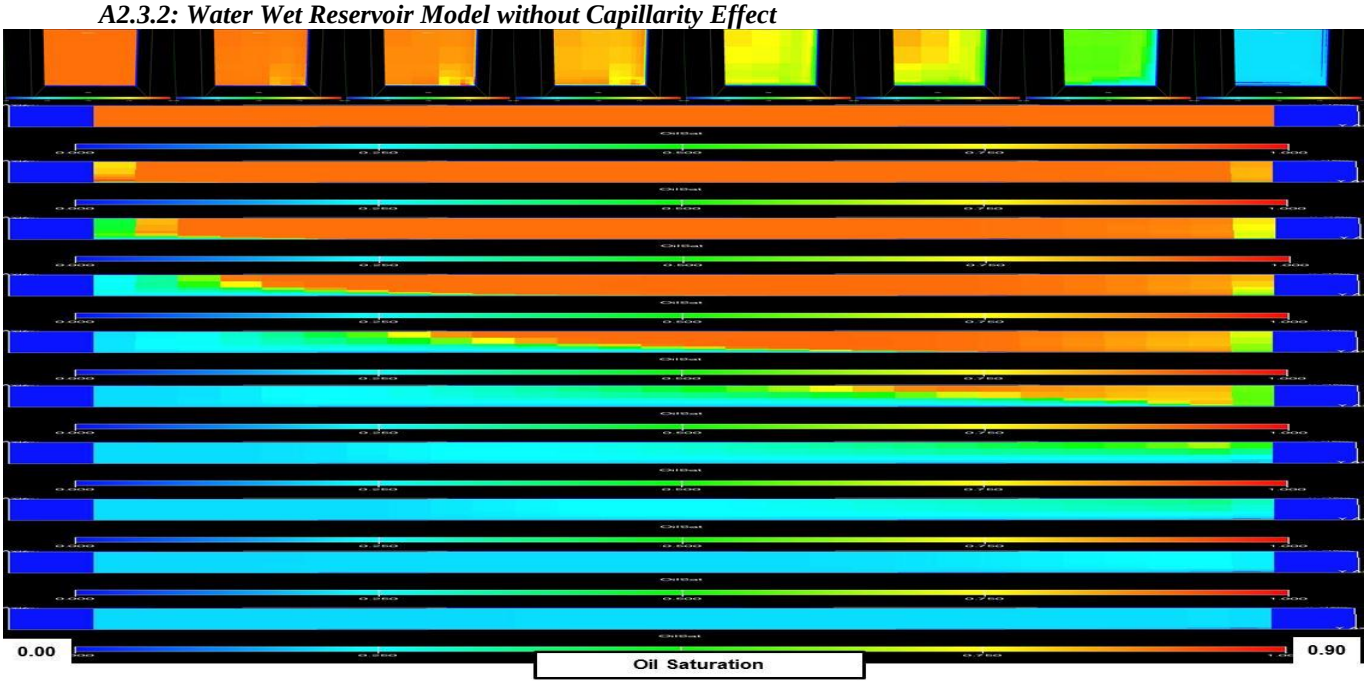

Figure A2.3.2.1: 3D visual of the flow behaviour in Water Wet Reservoir model with Gravity drainage only

Matrix – Exchange Flow Exchange

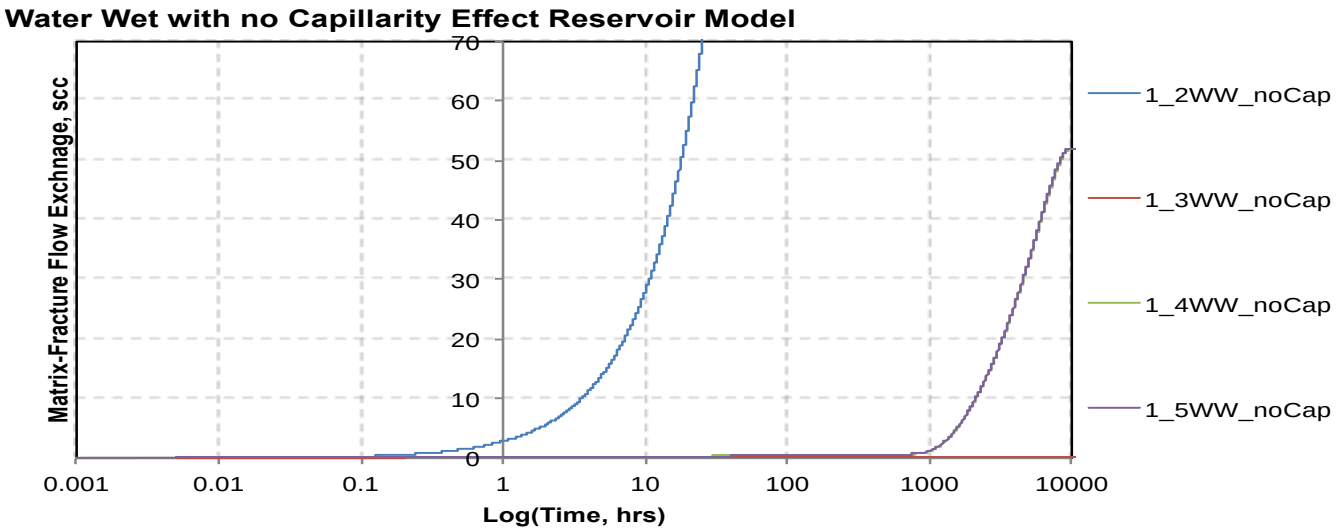

Figure A2.3.2.2: Matrix-Fracture Exchange behaviour in each layer of the reservoir

A2.3.3: Mixed Wet Reservoir Model

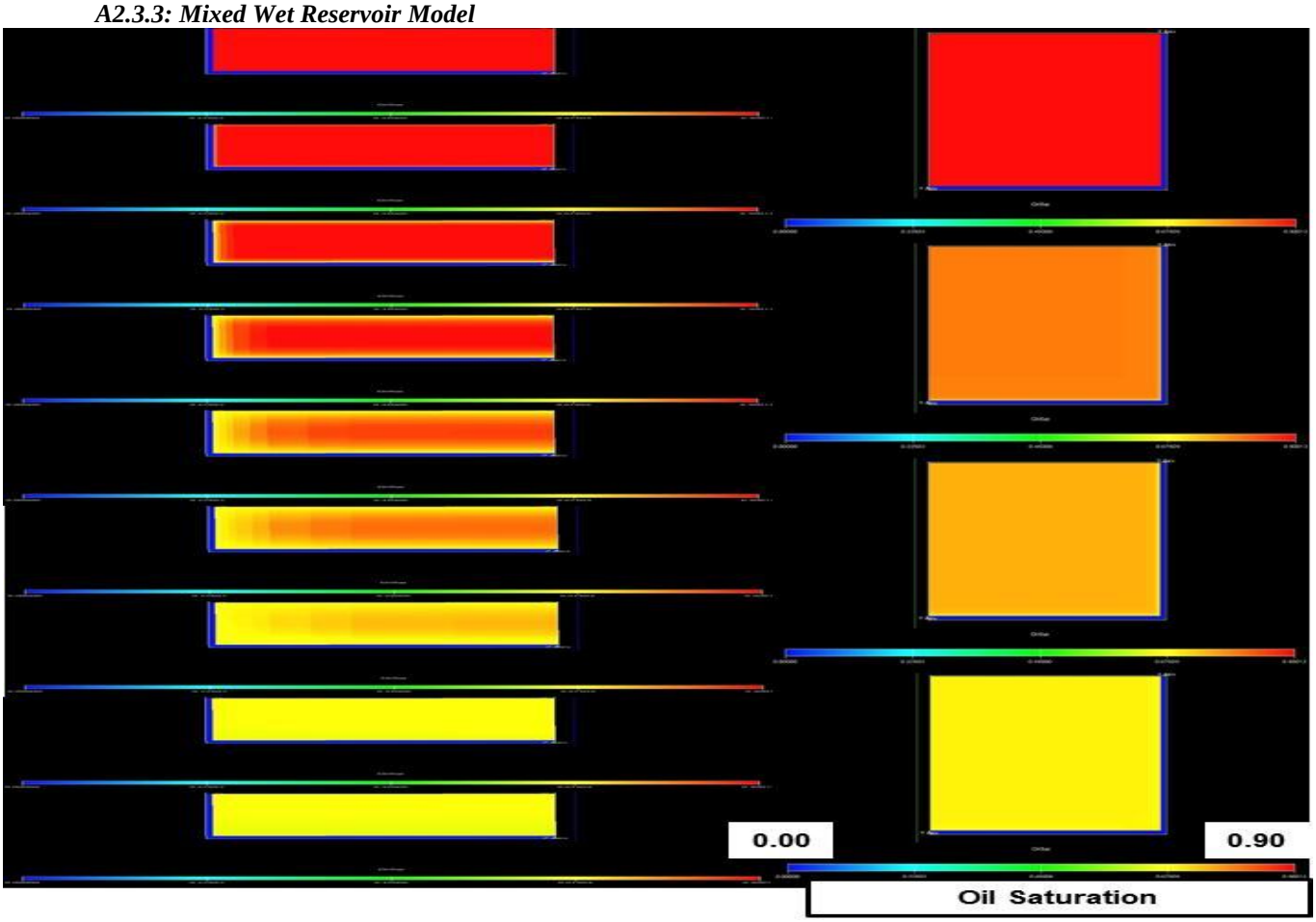

Figure A2.3.3.1: 3D visual of the flow behaviour in Water Wet Reservoir model with Gravity drainage only

Matrix – Exchange Flow Exchange

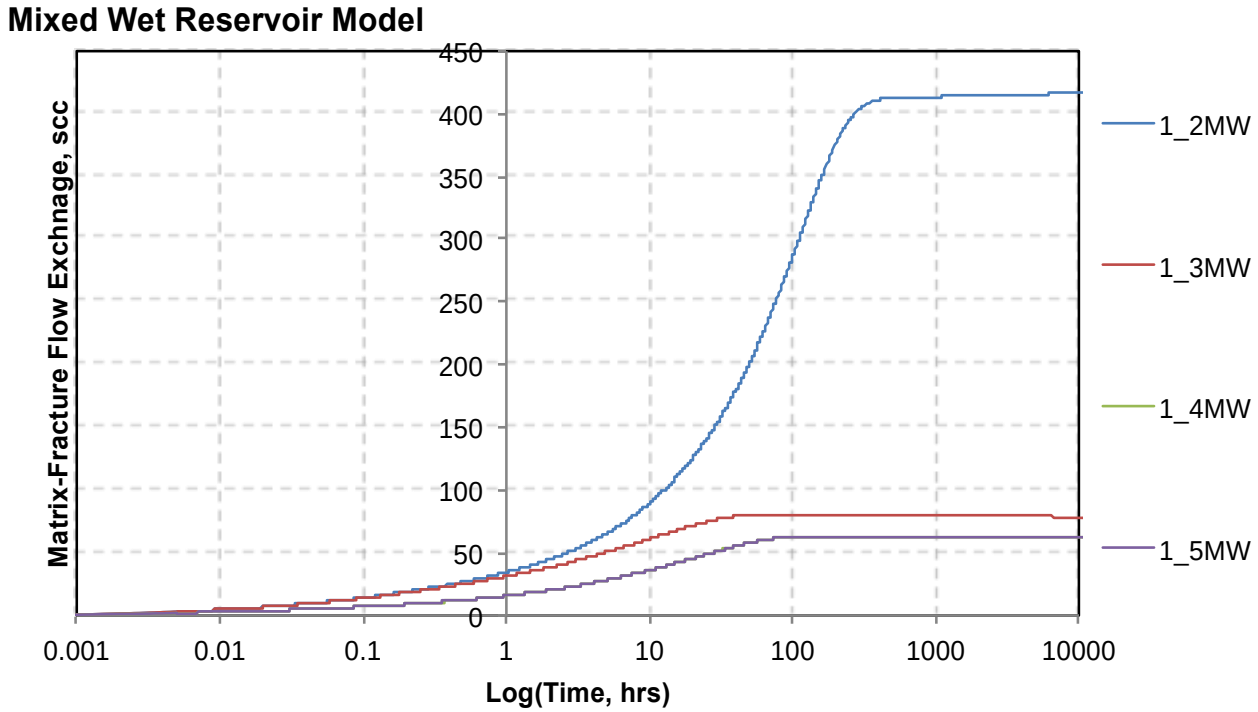

Figure A2.3.3.2: Matrix-Fracture Exchange behaviour in each layer of the reservoir

A2.3.6: Sensitivity Study in Gravity Drainage Effect: Case 1 (Increase reservoir thickness x10)
Matrix – Exchange Flow Exchange

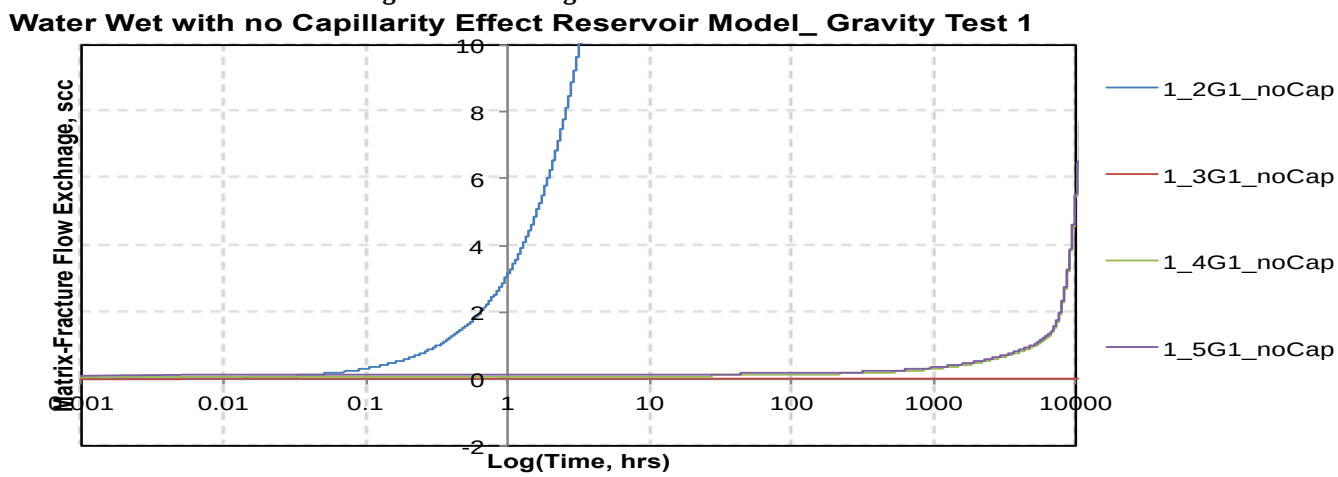

Figure A2.3.6.1: Matrix-Fracture Exchange behaviour in each layer of the reservoir

A2.3.7: Water Wet Reservoir Model without Capillarity Effect: Sensitivity Study for Gravity Effect (Decrease x10)
Matrix – Exchange Flow Exchange

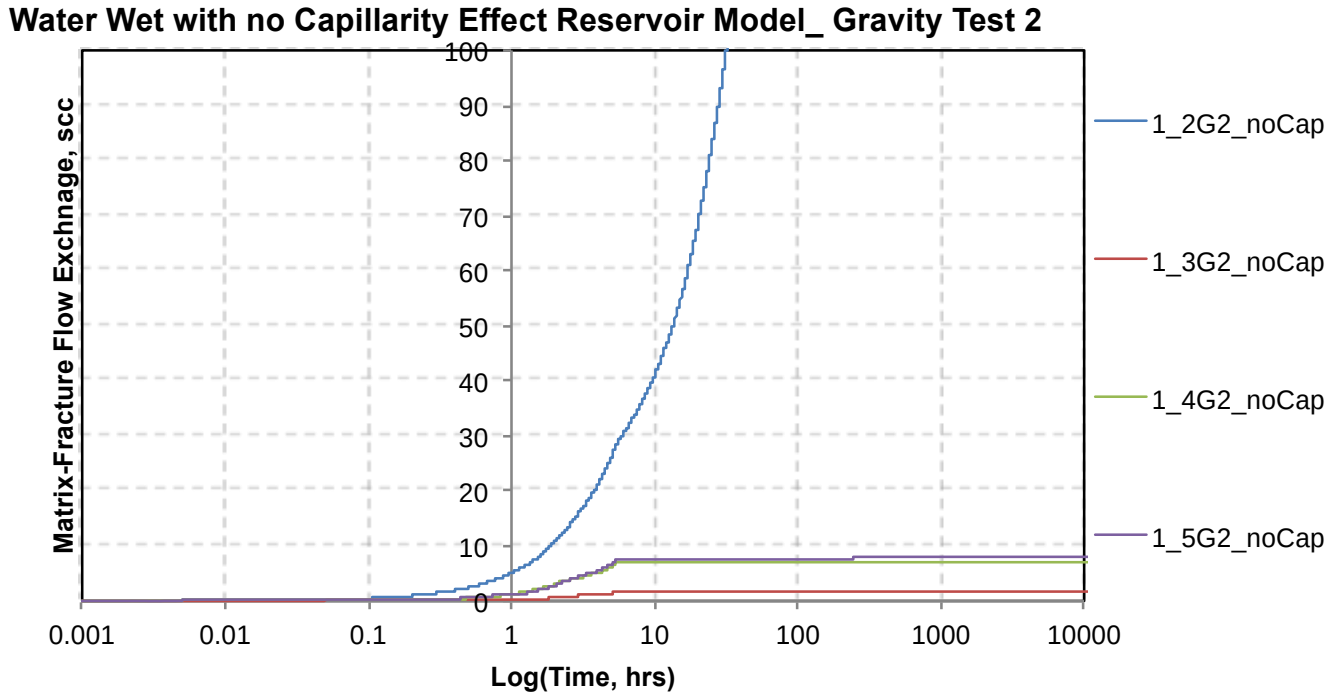

Figure A2.3.7.1: Matrix-Fracture Exchange behaviour in each layer of the reservoir

A2.4: Non-Orthogonal Flow Simulation

Model Specification:

TableA2.1 5: Eclipse Reservoir Parameter	
Model Parameters	
Model Grid Size (Cell Count)	50x50x1
Model Grid Size (cm)	10x10x1
Model gridding methodology	Centre-Point Gridding
Reservoir Datum Depth (cm)	15100
Reservoir Pressure (BARS)	400
Number of Matrix Blocks	19
Fracture Aperture Size (mm)	6
Matrix Porosity (%)	25
Matrix Permeability (mD)	20
Oil Water Contact for Matrix (cm)	30000
Fracture Porosity (%)	100
Fracture Permeability (mD)	1000
Oil Water Contact for Fracture (cm)	12000
Gas Oil Contact for matrix (cm)	13000
Gas Oil Contact for Fracture (cm)	10000

PVT Table

TableA2.1 6: Base Case Fluid Properties	
Fluid Properties	
Datum Pressure (BARS)	400
Water Formation Volume Factor	1
Water Compressibilty (BAR-1)	4x10-5
Water Viscosity (cP)	1.4
Viscositivity	0
Water Density (kg/m3)	1000
Oil Formation Volume Factor	1
Oil Compresibility (BAR-1)	4x10-5
Oil Viscosity (cP)	0.5
Oil Density (kg/m3)	897
Gas Density (kg/m3)	1.5

A2.4.1: Water Wet Reservoir Model

Matrix – Exchange Flow Exchange

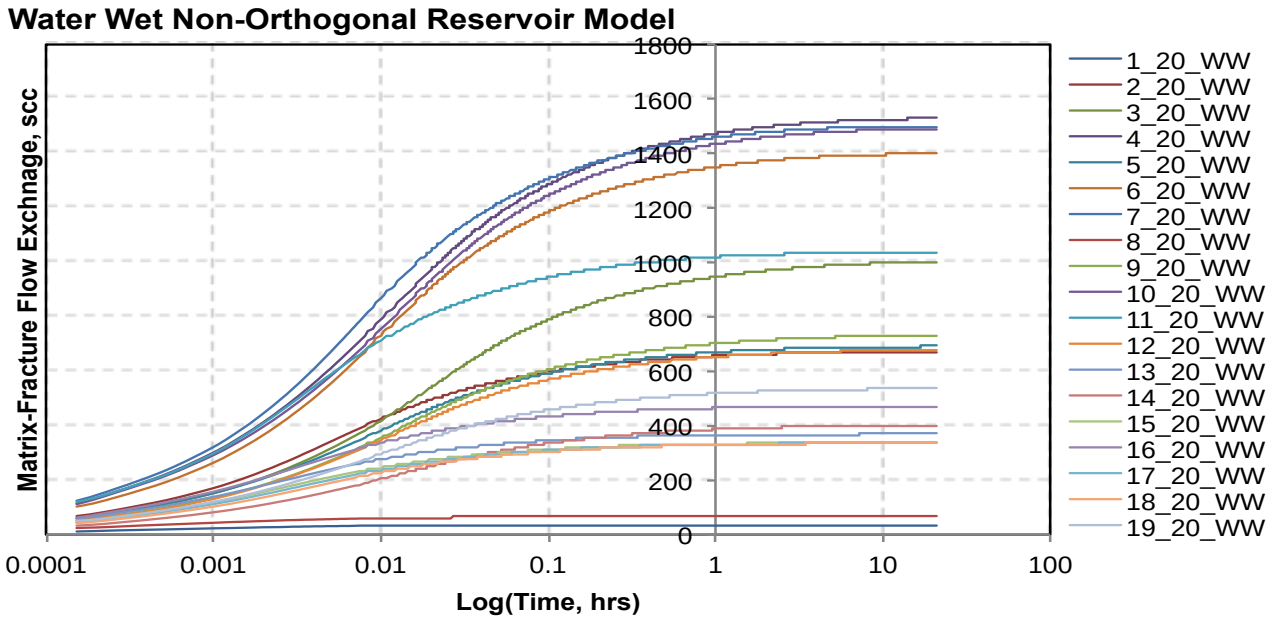

Figure A2.4.1.1: Matrix-Fracture Exchange behaviour in each layer of the reservoir

A2.4.2: Mixed Wet Reservoir Model

Matrix – Exchange Flow Exchange

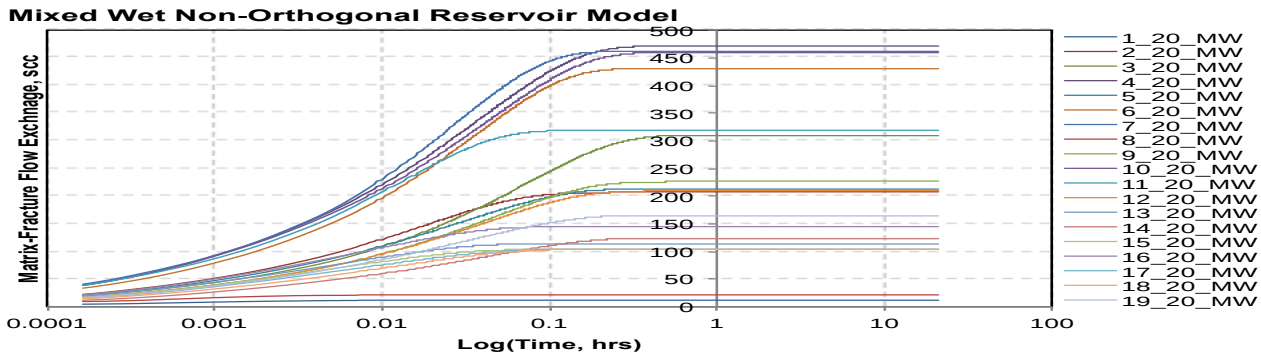

Figure A2.4.2.1: Matrix-Fracture Exchange behaviour in each layer of the reservoir

A2.4.3: Water Wet Reservoir Model: Apperture Size Decrease x0.01 to Original case

Matrix – Exchange Flow Exchange

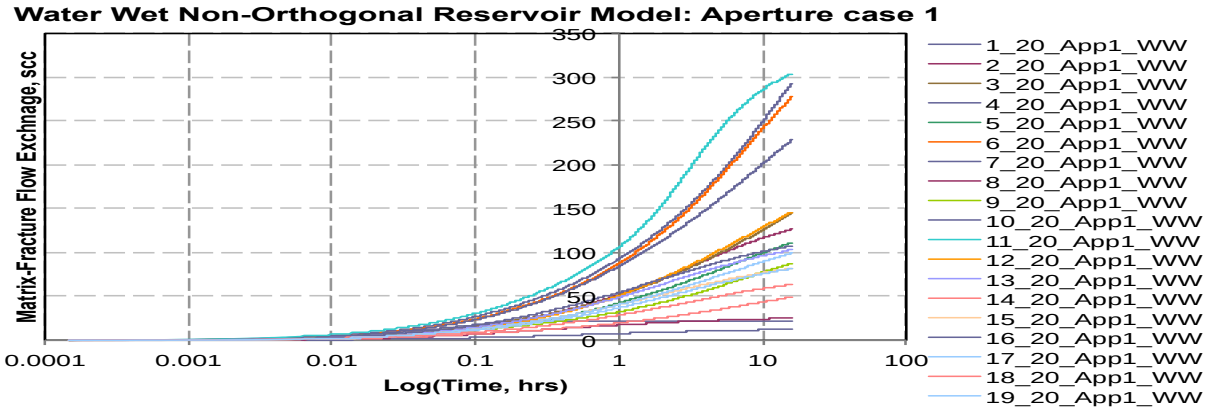

Figure A2.4.3.1: Matrix-Fracture Exchange behaviour in each layer of the reservoir

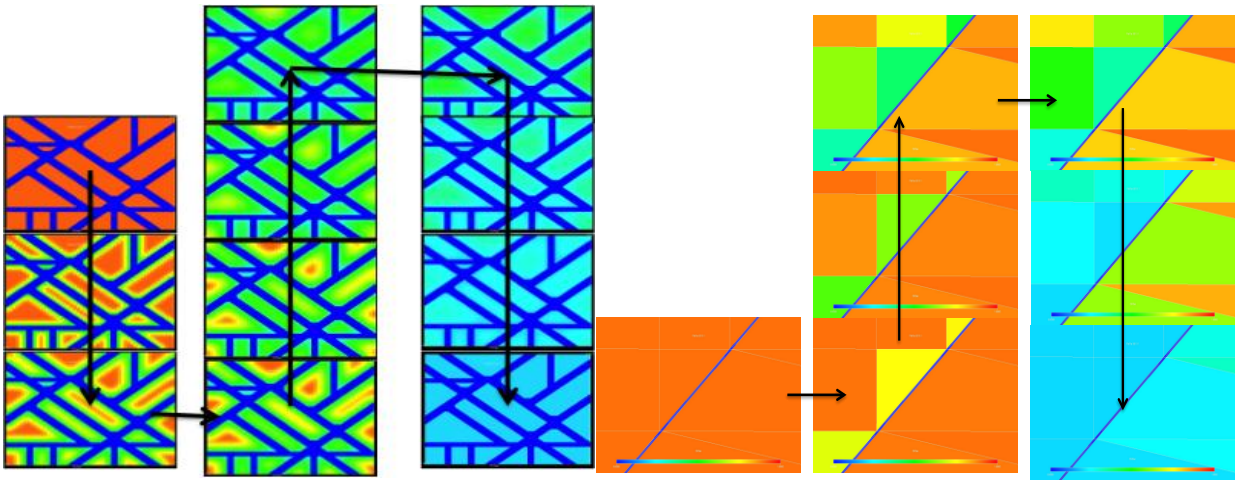

Figure A2.4.3.2: flow simulation of non-orthonal, model and behaviour of simulation by reducing size of fracture aperture

A2.4.4: Sensitivity Study In Water Wet Model: Different fracture length

Matrix – Exchange Flow Exchange

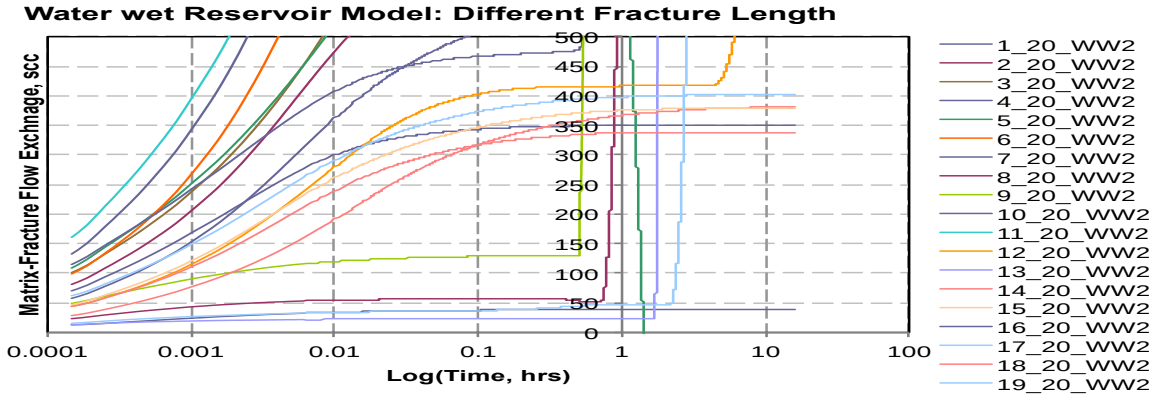

Figure A2.4.4.1: Matrix-Fracture Exchange behaviour in each layer of the reservoir

A2.4.5: Sensitivity Study in Water Wet Model: Aperture Size decrease x0.01 with different fracture length

Matrix – Exchange Flow Exchange

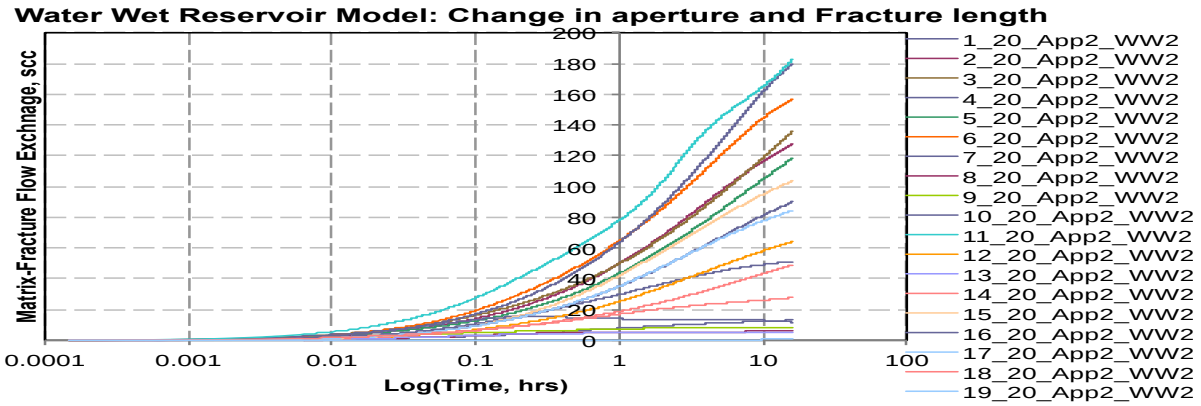

Figure A2.4.5.1: Matrix-Fracture Exchange behaviour in each layer of the reservoir