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Original Article

The Dependence of Water and Gas Breakthrough on the Choice of Model Parameters in Naturally Fractured Reservoirs Using Sector and Full Reservoir Models

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Abstract: Assessing fractures in carbonate reservoirs is crucial due to their substantial impact on reservoir permeability. Understanding the characteristics of these fractures is vital for optimizing oil production. Additionally, extremely heterogeneous and anisotropic permeability distribution within the natural fractured reservoir is often caused by the complexity of a fracture network. Therefore, accurate reservoir modelling and simulation must be conducted in order to achieve ultimate recovery. In this paper a sector model has been developed based on the studied example field, its results are compared with the full reservoir model to find out the degree of resemblance between their outputs. The study area has four natural fracture compartments, with an average reservoir height of 95m and water/oil contact (WOC) and gas/oil contact (GOC) depths of 685 m and 590 m, respectively. A dual-porosity with single-permeability modelling system was used to simulate the properties of the reservoir rock. This model was derived from the Petrel layercake model. A sensitivity analysis was also carried out to look into the relationships between field performance and the well. The outcomes of both models demonstrated that matrix permeability and fracture dimension had a significant impact on the early breakthrough of water and gas to comparable huge extents. While other factors, such as aquifer size and WOC, show a moderate impact on water and gas breakthrough as well as final recovery.

1. Introduction

Fracture systems are complex. Their geometrical characterization can be defined by a relatively simple set of parameters, such as length and height (also defining hierarchy), morphology, density and or spacing. However, these parameters are normally related to bed thickness, lithology, texture, structural position, fault proximity, and environmental condition at the time of fracturing [1]. Although these same natural fractures frequently extend above the gas/oil interface or below the oil/water contact, some reservoirs have vertical natural fractures that help lessen the problem of permeability anisotropy for horizontal wellbores. The production of gas or water might swiftly take precedence over all other production when these reservoirs are created at high withdrawal pressures [2].

Three primary factors determine breakthrough: the distribution of fracture apertures throughout the wellbore, their location within the geological environment, and their size. Wells displaying fractures with a diverse distribution of differing apertures typically experience an abrupt water breakthrough followed by an exponential increase in water-to-oil ratios. Conversely, wells with homogeneous distribution along the wellbore and consistently or uniformly tiny apertures exhibit post-breakthrough behavior similar to that reported by Buckley and Leverett [3]. This requires data acquisition in areas that are distributed across the whole area of interest. One of the critical parameters that characterizes fractured reservoirs is the opening of the fractures, which is directly related to fracture permeability. The transmissibility of the system depends on the interplay of the various open fracture sets. The understanding and prediction of which fracture set opens is probably the most important and most difficult task, and it entails a thorough understanding of the evolution of the stress state over time [4]. The assessment of this key parameter necessitates the integration of all static and dynamic data in the Kurdistan Region's X field.

The purpose of these sensitivities was to investigate the dependence of the well and field-performance in terms of water and gas production on the properties of the fracture network.

2. Related Works

In order to better understand the effects of fractures on reservoir performance and storage capacity, several classifications have been proposed [5]. The recognition of fractured reservoirs as such is of great importance for selecting the most appropriate field development strategy. This has been demonstrated to have a major impact on the final hydrocarbon recovery, e.g. avoiding early water breakthrough due to fracture-conveyed water from the aquifer.

According to Warren and Root [6], a naturally fractured reservoir may be regarded as a two-domain system (Figure 1a). The primary rock matrix containing large quantities of fluids has a rather low permeability, and the fracture is a small volume, yet has the ability to transmit a large portion of the flow through the porous medium. Researchers tend to describe the fractured reservoir as a double porosity medium. To describe the behavior of naturally fractured reservoirs, few models have emerged over the past twenty years. Most notable are the models proposed by Warren, Root and Kazemi [6, 7]. Each of these models also describes the fractured reservoir as a double-porosity medium.

In the model proposed by Warren and Root (Figure 1b), fluid flow takes place through the anisotropic, and fluid flow will happen between matrix blocks and fracture systems. The fractured model proposed by Kazemi consist of various horizontal layers of fractures and matrix (Figure 1c), where fluid flows through the layers with different permeabilities [8-13]. These models include laboratory studies on the extraction of oil and gas from individual matrix blocks, modeling of single-phase and multiphase flow in fractured reservoirs.

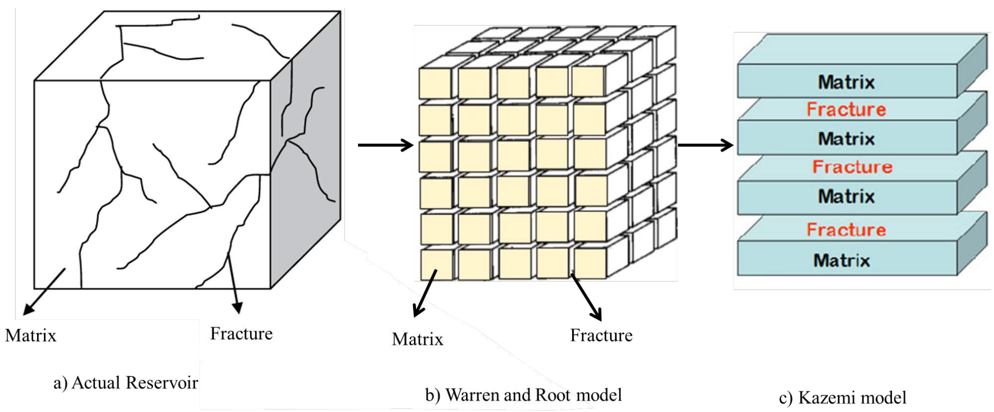

Figure 1: Naturally fractured porous medium a) Actual reservoir b) Warren and Root model c) Kazemi model.

By carefully preparing reservoir management methods, which are the result of accurate reservoir modeling and simulation efforts, fractured reservoirs can be produced with an improved recovery. However, the lack of knowledge about how fluid flow occurs between the rock matrix and surrounding fractures is the greatest hindrance to achieving these goals [15-18]. Sonier *et al.* [19] examined alternative methods for solving this problem proposed by several authors [8-13]. In addition, further technical developments have been used to simulate the matrix/fracture flow with a special emphasis on gravitational forces. Zhang and Feng [20] developed a 3D numerical simulation model for water drive gas reservoir to study the fracture water breakthrough. In their research, four different models of water invasion were accounted for: slow water coning, horizontal and vertical water breakthroughs, and horizontal and vertical water breakthroughs. Results showed that the gravitational effects, which vary depending on the saturation and height of the matrix and the critical pressure drop, were considered the main factors controlling the fluid flow between the rock matrix and fractures.

In this paper, a 1-well SM has been developed based on the studied example field to conduct a set of sensitivities.

3. Materials and Methods

A system with dual porosity and single permeability is used, since matrix blocks are connected only through the fracture system i.e. fluid flow through the formation occurs only in the fracture network, and the matrix block acts as the source. Before performing sensitivities with the full field model (FFM), a sector model (SM) was constructed. As the SM is much smaller than the FFM, simulation times are reduced, thus accelerating the study. A set of sensitivities was performed with a 1-well SM and a FFM. These models were based on the layercake Petrel model constructed. The purpose of these sensitivities was to investigate the dependence of the well and field-performance in terms of water and gas production on properties of the fracture network. Parameters to investigate were matrix permeability, fracture spacing, matrix block size, aquifer size and aquifer strength (Figure 2).

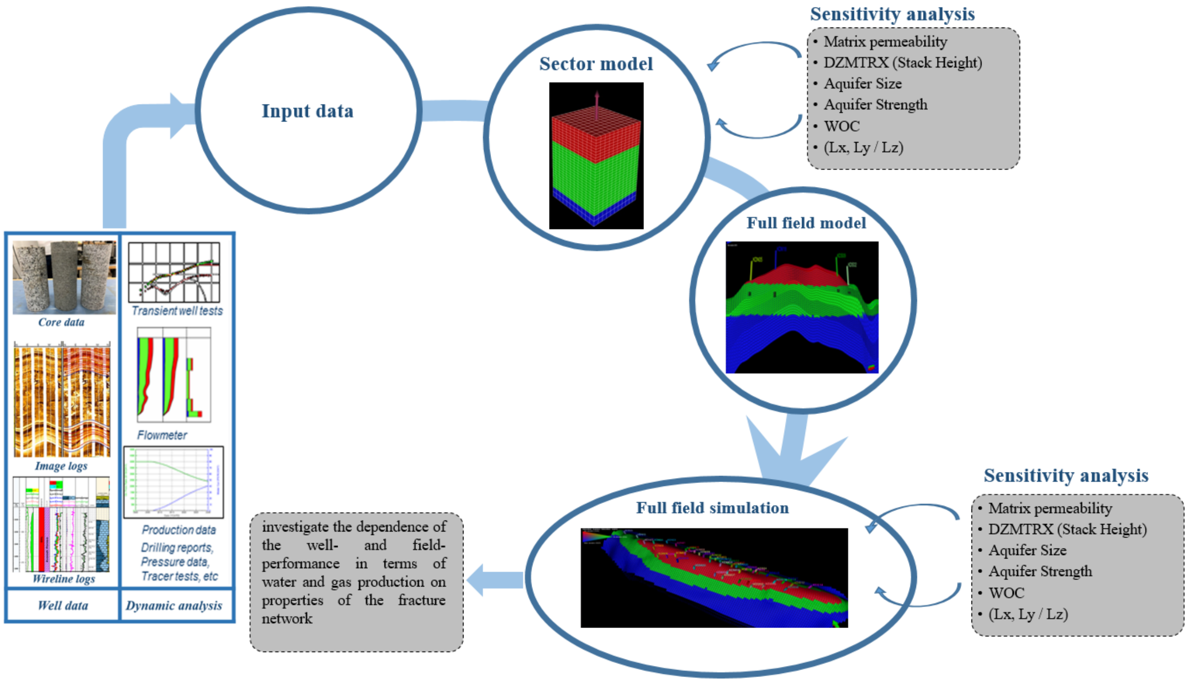

Figure 2: Methodology workflow.

3.1. Model Construction

A 1-well sector model with dual-porosity was built based on a typical average oil, water and gas column thickness. The number of grid blocks was: Nx x Ny x Nz = 11 x 11 x 30, and the grid block dimensions are: Δx x Δy x Δz = 50 x 50 x 50 m3. Matrix porosity and water saturation in the oil zone are 0.25 and 0.25 respectively. The fracture porosity was set at 0.5%. Table 1 summarizes the characteristics of the base case model. The model's characteristics roughly match those of a typical producing formation in the Kurdistan Region's X field. The distribution of fluids in the sector model is shown in figure 3. Figure 4 depicts a cross section of the sector model through the well with oil saturation indicated during production (gray; So = 0, orange: unswept zone, blue-green: swept zone).

Table 1: Simulation base case properties.

Parameters	Value	Unit
Max Qo	318 (approximate gravity drainage rate)	m^3/d
GOR	35.62	sm^3/sm^3
Min FBHP	7×10^6	Pa
Production Period	10	Year
GOC	590	m ss
WOC	685	m ss
(Lx, Ly / Lz)	(5, 5 / 5)	m
Matrix permeability	5	mD
Fracture permeability	Horizontal (Kh) =1000, Vertical (Kv) = 400	mD
DZMTRX	5	m

GOR: gas/oil ratio, GOC: gas/oil contact, WOC: water/oil contact, DZMTRX: function of stack height.

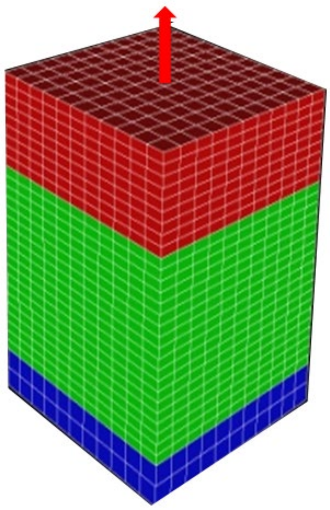

Figure 3: Conceptual model used for subsurface parameters global sensitivity analysis.

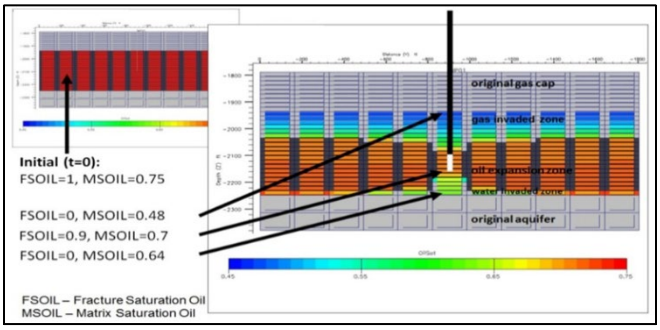

Figure 4: Left: initial fluid distribution in the system (Pc=0); Right: typical fluid distribution and contact movements when draining from fractures in a well-connected dual-porosity system.

3.2. Sensitivity Analysis

Several simulation runs have been performed to investigate the effectiveness of parameters causing gas and water coning in a naturally fractured reservoir. The model's parameters were adjusted in a way that was thought to be reflective of the range that may be anticipated in the Kurdistan Region's X field. Thereafter, seven different parameters were investigated for the sensitivity analysis to compare them with the base case. In addition, the FFM was also carried out with few sensitivities with regards to water breakthrough time (WBT) and gas breakthrough time (GBT). Wells were placed at the right areal locations in the model in line with the latest well surveys, while the producing intervals were placed at the proper depth within the oil column. Table 2 shows the parameters range studied by this research work.

Table 2: Illustrate sensitive model parameters with their ranges.

Sensitive Parameters	Sector Model	Full Field Model
	Range	
Production period	10 years	5 years
GOC	---------	590 m ss
WOC	685, 740, 780 m ss	685, 740 m ss
K matrix	5, 25, 50 mD	As per model property map
(Lx, Ly / Lz)	(5, 5 / 5), (50 / 25), (100 / 50) m	(5 / 10), (50 / 10) m
DZMTRX	5, 25, 50 m	25, 50 m
Aquifer Size	S (small), L (large)	M (medium)
Aquifer Strength	SK (small permeability), LK (large permeability)	MK (medium permeability)

4. Results

Figures 5a and 5b show the WBT and GBT in years as a function of the matrix permeability.

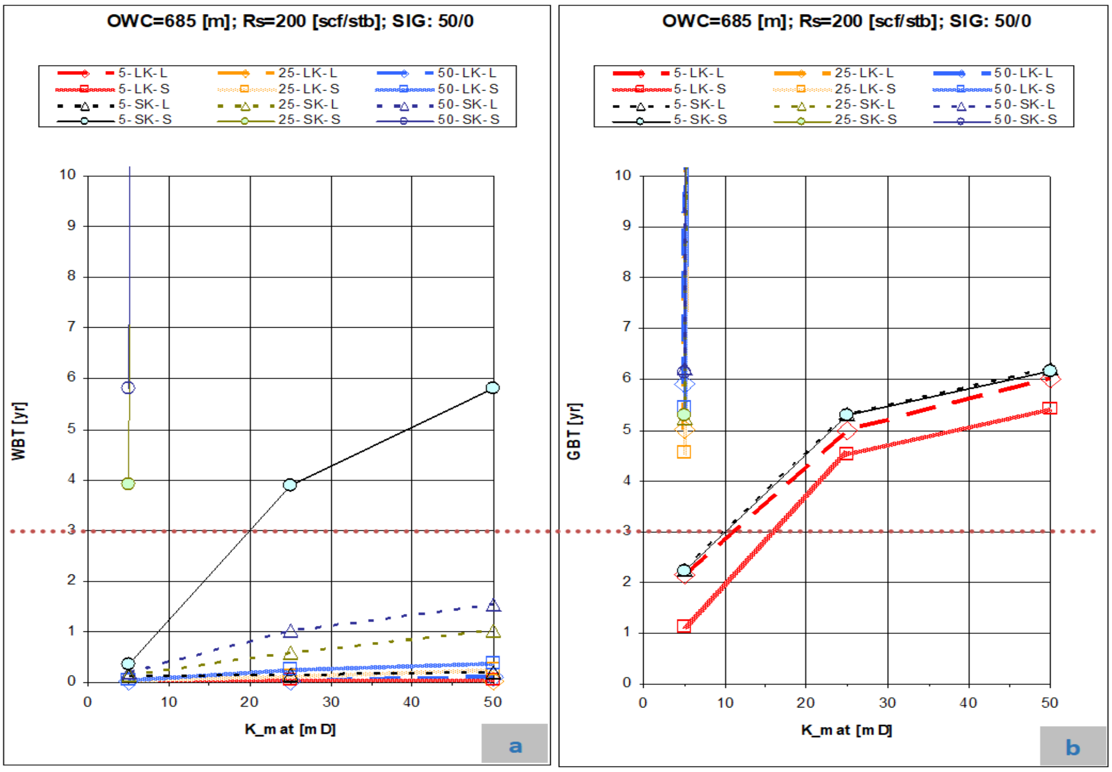

Figure 5: WBT (a) and GBT (b) as a function of matrix permeability.

Figures 6a and 6b show the WBT and GBT in years as a function of stack Height (DZMTRX).

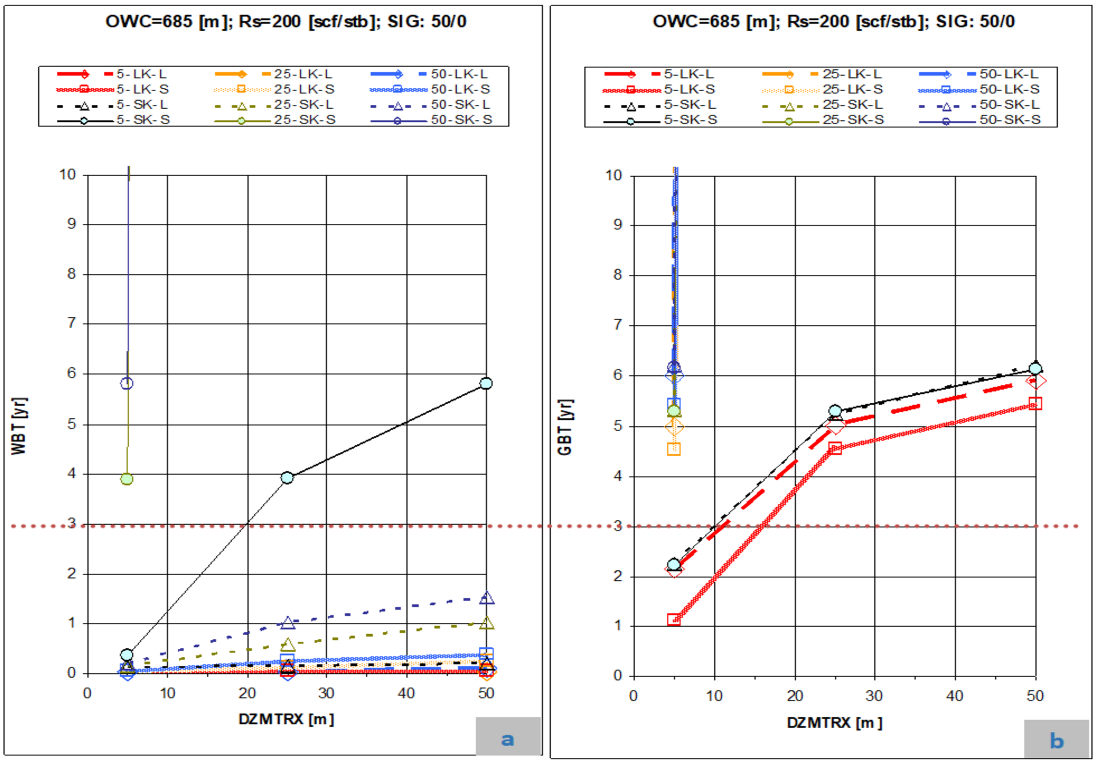

Figure 6: WBT (a) and GBT (b) as a function of Stack Height (DZMTRX).

Figures 7a and 7b show the WBT as a function of matrix permeability for a large aquifer and small aquifer.

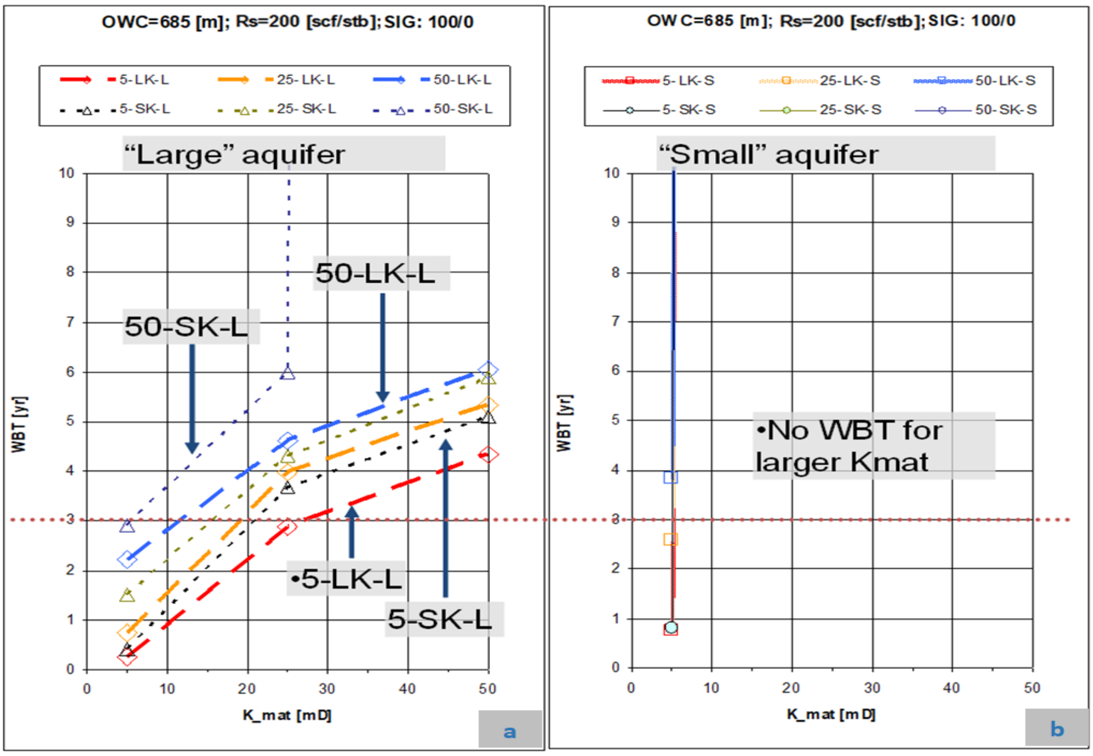

Figure 7: WBT as a function of matrix permeability for a large aquifer (a) and small aquifer (b).

Figures 8a and 8b show WBT and GBT for various values of Lx, Ly, and Lz (matrix block size).

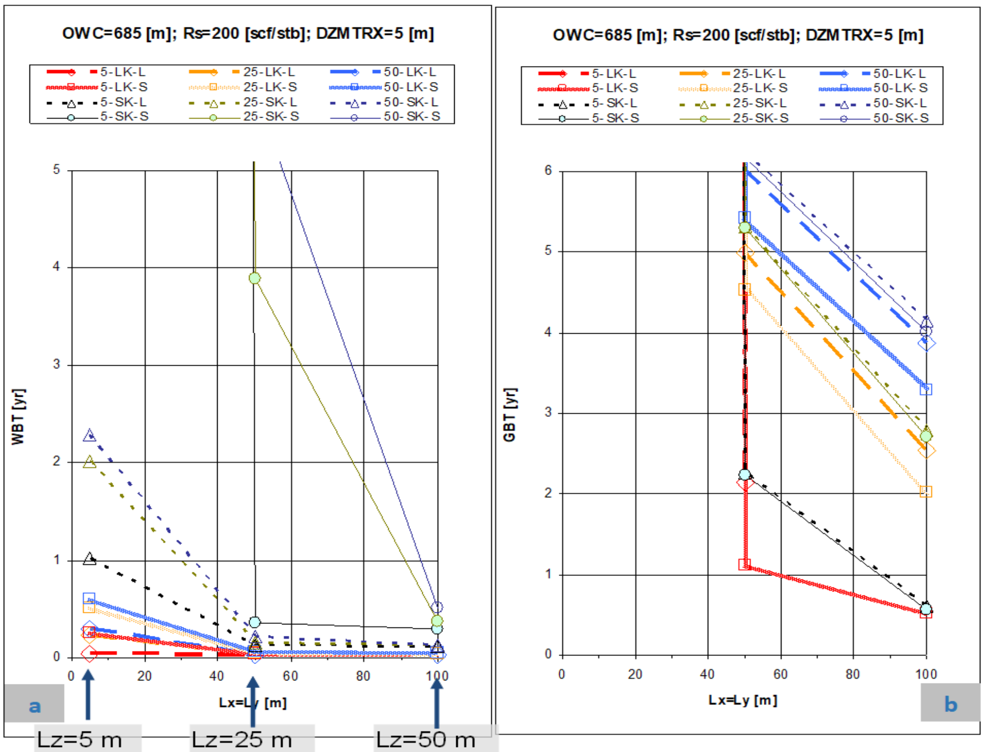

Figure 8: WBT (a) and GBT (b) for various values of Lx, Ly, and Lz (matrix block size).

Figures 9a and 9b show GBT for two values of SIGMAGD.

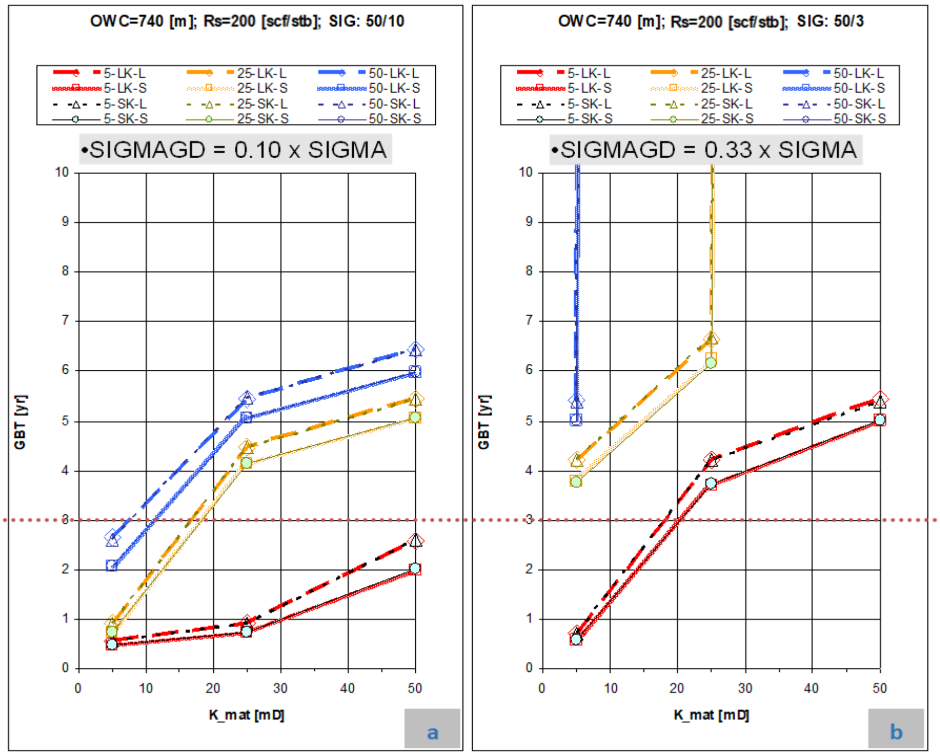

Figure 9: GBT for two values of SIGMAGD.

Figures 10, 11, 12 and 13 show the first set of sensitivities was performed with an oil/water contact (OWC) at 685 m ss and figure 14, 15, 16 and 17 show the second set of sensitivities was performed with an OWC at 740 m ss.

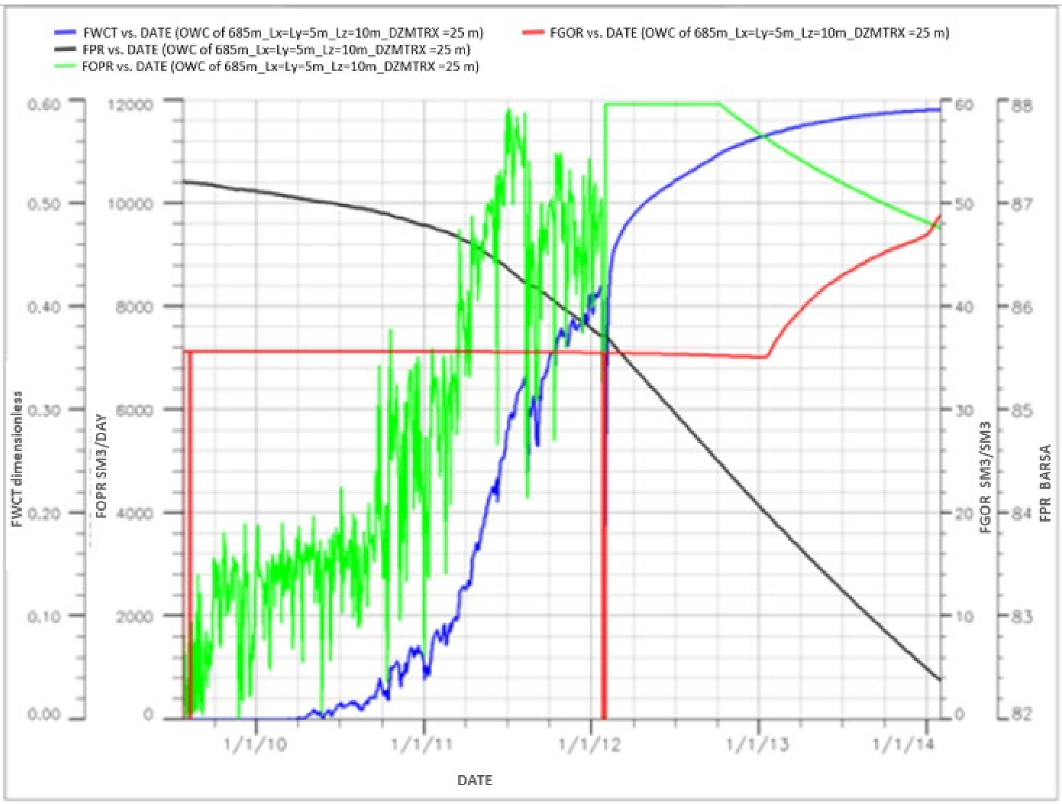

Figure 10: FFM sensitivities at an OWC of 685 m ss and Lx = Ly =5 m (DZMTRX =25 m).

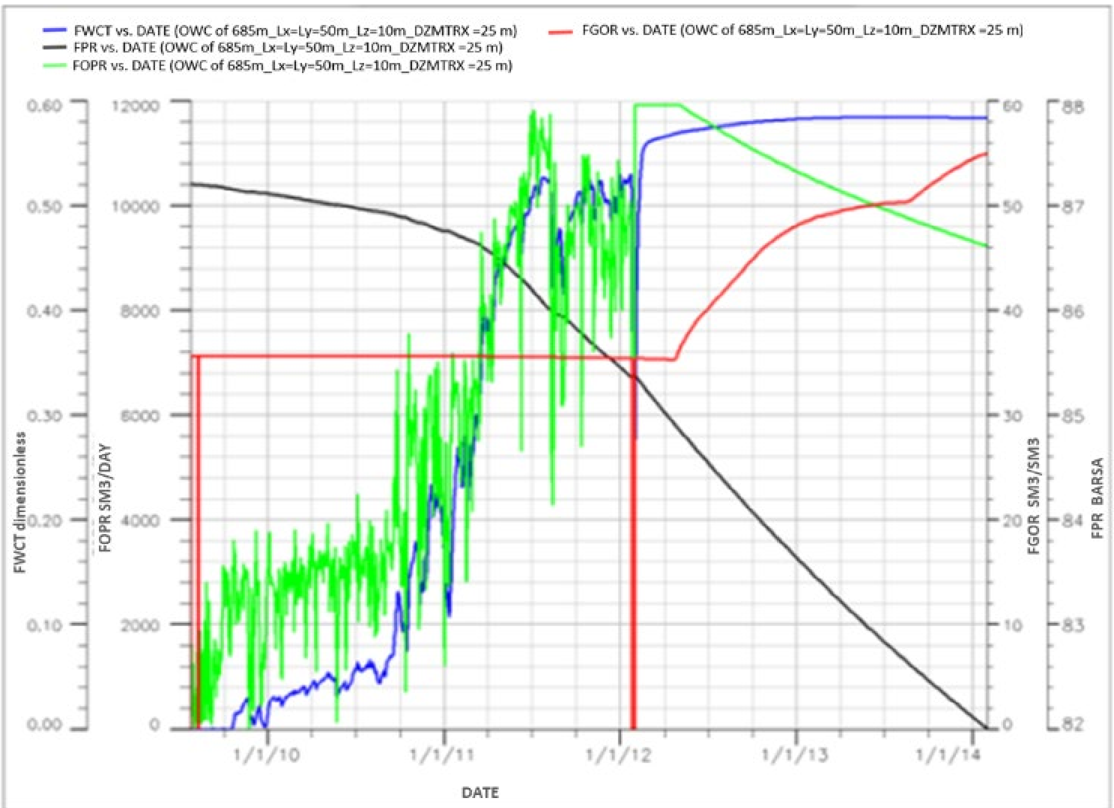

Figure 11: FFM sensitivities at an OWC of 685 m ss and Lx= Ly =50 m (DZMTRX= 25 m).

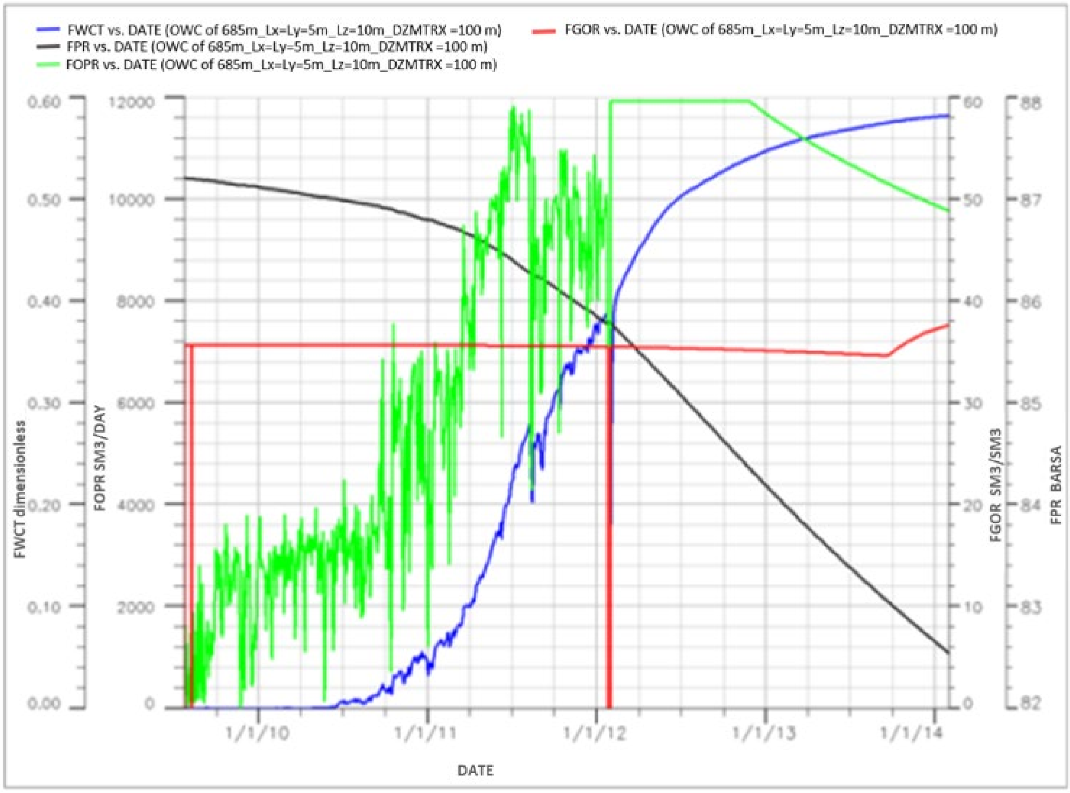

Figure 12: FFM sensitivities at an OWC of 685 m ss and Lx = Ly =5 m (DZMTRX =100 m).

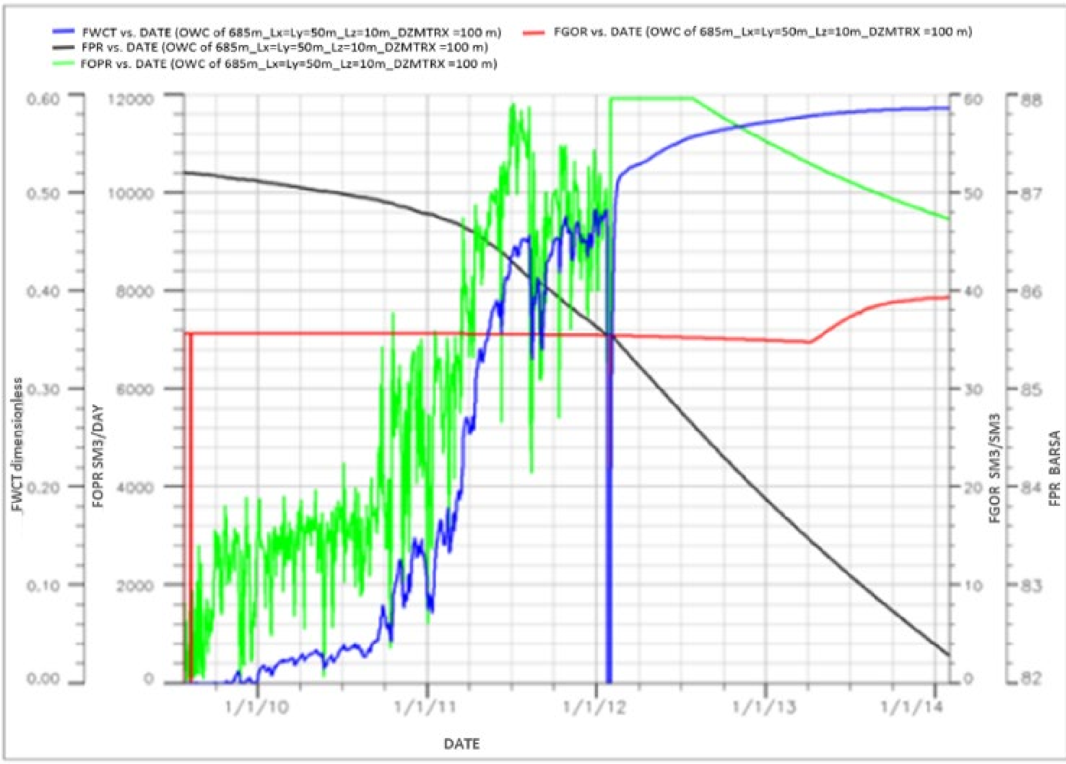

Figure 13: FFM sensitivities at an OWC of 685 m ss and Lx=Ly=50 m (DZMTRX =100 m).

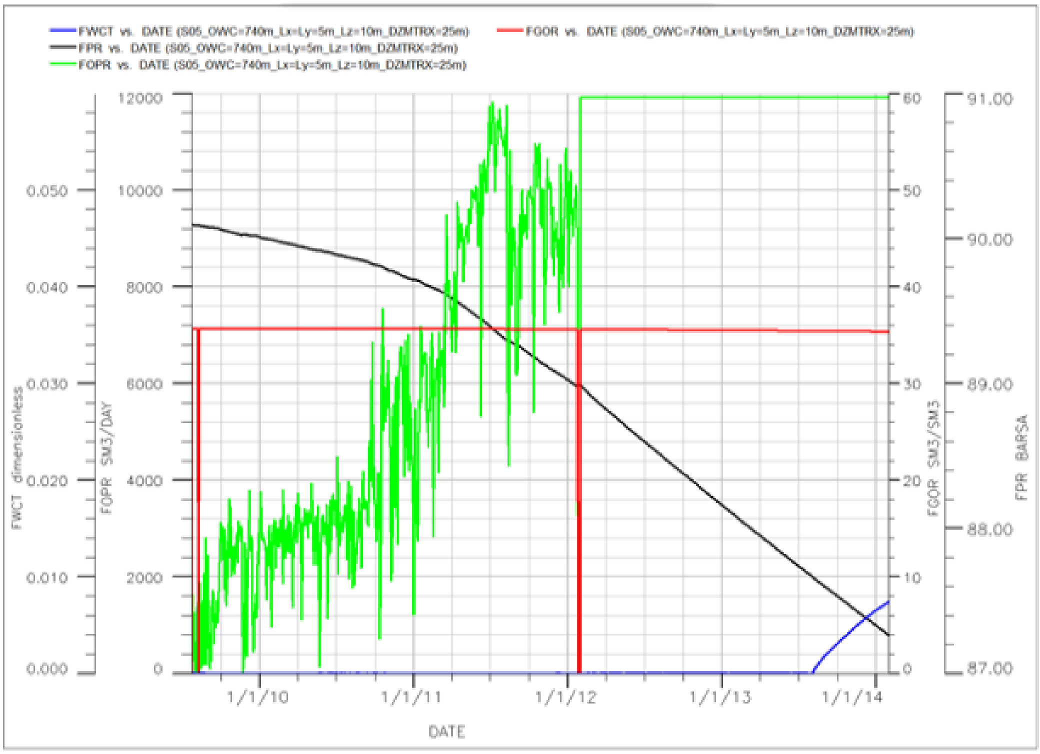

Figure 14: FFM sensitivities at an OWC of 740 m ss and Lx = Ly =5 m (DZMTRX =25 m).

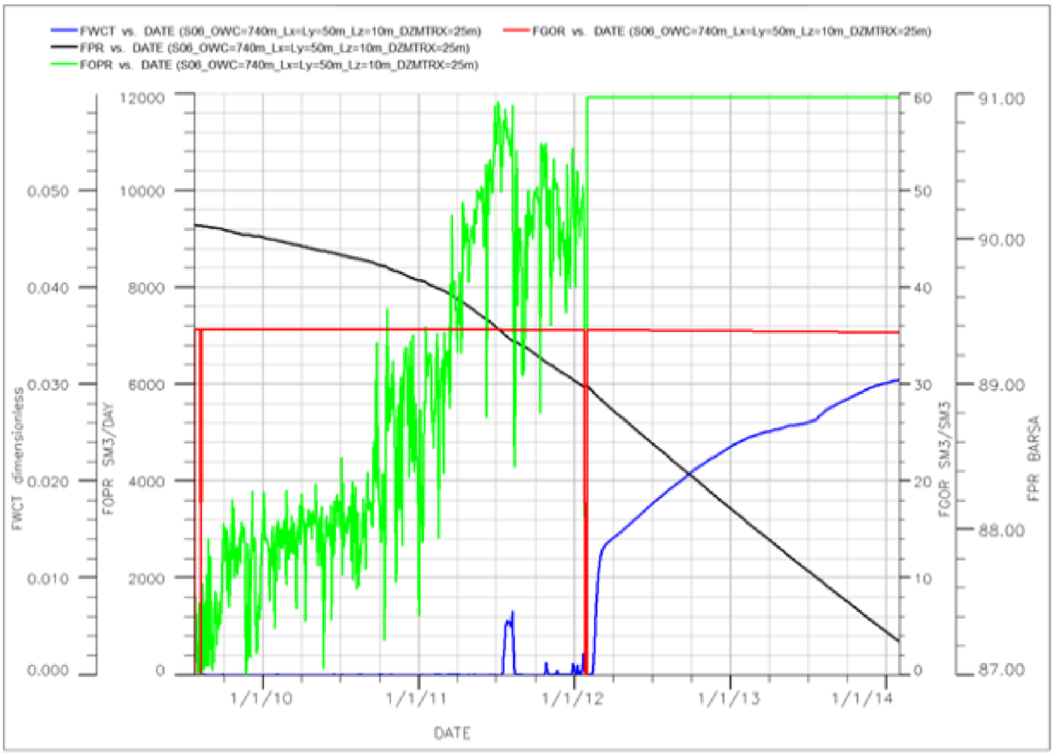

Figure 15: FFM sensitivities at an OWC of 740 m ss and Lx= Ly =50 m (DZMTRX= 25 m).

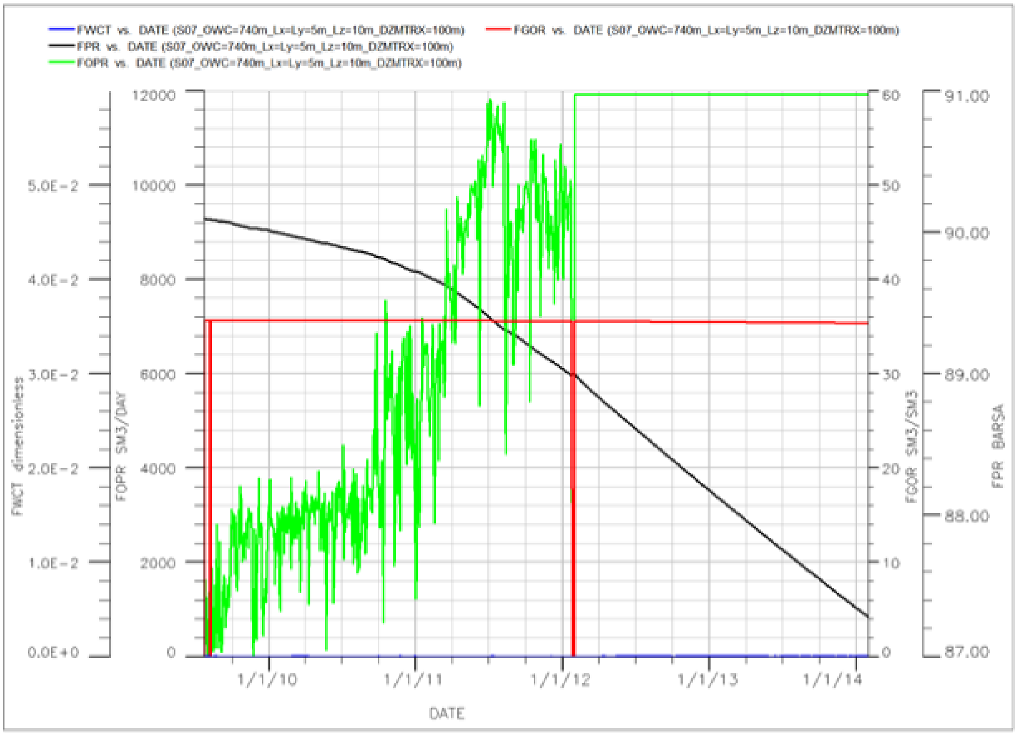

Figure 16: FFM sensitivities at an OWC of 740 m ss and Lx = Ly =5 m (DZMTRX =100 m).

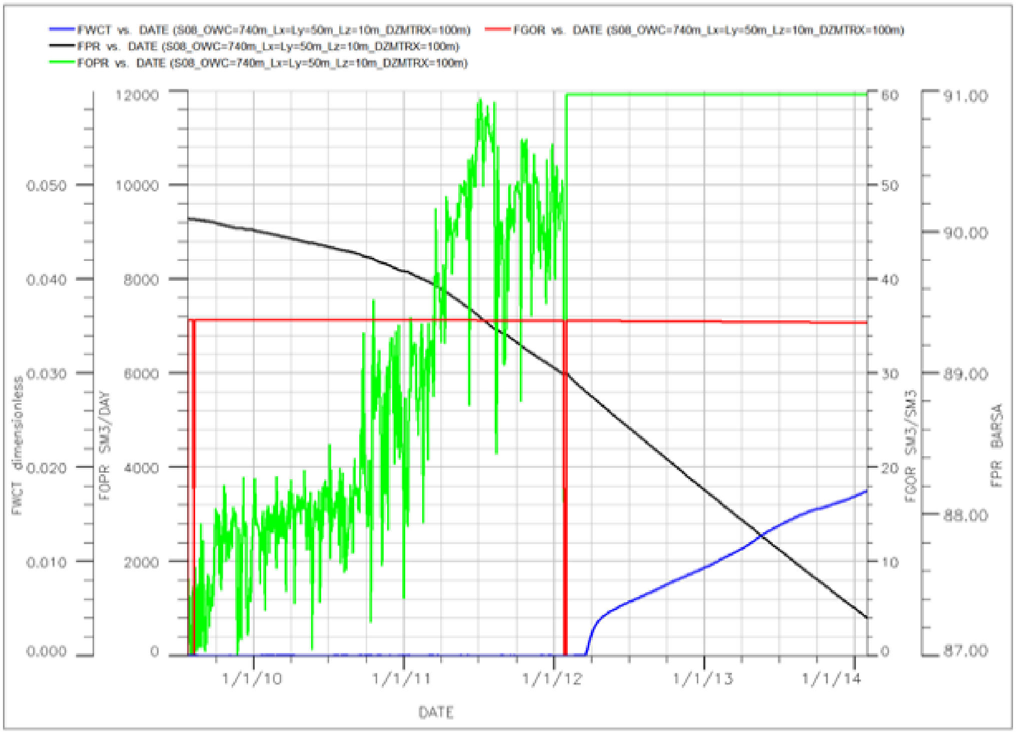

Figure 17: FFM sensitivities at an OWC of 740 m ss and Lx=Ly=50 m (DZMTRX =100 m).

5. Discussion

5.1. Matrix Permeability

The graphs of figure 5a and 5b contain several curves for various values of DZMTRX and aquifer size and strength, and should be understood as follows:

The studied well produces oil from fractures. If the matrix diffuses oil into the fractures at the same speed, the matrix replenishes the oil that is withdrawn from the fractures. Under this condition, the

OWC and gas/oil contact (GOC) do not move very much, because the well produces at the inherent gravity drainage rate of the system. The gravity drainage rate is controlled by the gravity force, which is proportional to the density difference of the fluids and to the vertical dimension of a block of matrix (Stack Height or DZMTRX) over which the gravity force acts. If DZMTRX is small (e.g. 5 m), the gravity force is relatively small which implies that the gravity drainage rate is low. In other words, for a small DZMTRX, the gravity force does not drive the oil from the matrix into the fractures quickly enough, so the fluid contacts (OWC and GOC) are move towards the producing interval in the well. That is, the well starts coning water and / or gas. The same is true for matrix permeability. The gravity force is also directly proportional to the matrix permeability. Therefore, if the matrix permeability is too low, the gravity drainage rate of the system will be low so that the well starts water and/ or gas coning quickly and WBT and GBT is early.

The mechanism above is visible in both graphs and figures 5a and 5b. Figure 5a shows that for most values of DZMTRX, matrix permeability (Kmat) and aquifer strength, WBT occur within 3 years. Only when the aquifer strength is low, WBT times occurred after 3 years. A trend is visible a larger matrix permeability and a larger DZMTRX (stack height) increase the WBT time. This is entirely consistent with the mechanism described above. The graph also shows that certain stack height and matrix permeability combinations allow WBT times that exceed 3 years.

The same trends can be observed in figure 5b, which shows gas break through (GBT) time sand exceeds 3 years. When the matrix permeability is as low as 5 – 10 mD does GBT occurs. Some southern wells in X field have experienced GBT recently. The graph also shows that GBT is not strongly dependent on the aquifer size and strength.

5.2. Stack Height (DZMTRX)

The graphs in figure 6a and 6b show the WBT and GBT times as a function of DZMTRX (the stack height of matrix blocks). As numerically the DZMTRX values (5, 25, 50 m) and matrix permeability values (5, 25, 50 mD) are the same, and because the gravity force is directly proportional to both DZMTRX and Kmat, the dependency of WBT and GBT on DZMTRX is the same as on Kmat. This explains why the graphs in figure 6a and 6b are identical to the ones in figure 5a and 5b.

5.3. Aquifer Size and Strength

The sensitivities in figure 7a show the WBT time for several cases for a large aquifer. Figure 7b shows similar cases for a small aquifer. The first conclusion that can be drawn is that with a small aquifer WBT hardly ever occurs, except when the matrix permeability is very low (5 mD or less). Figure 7a shows that with a large aquifer WBT can occur within 3 years if the matrix permeability is low (20 mD or lower). These sensitivities were performed with an OWC at 685 mss.

Additional sensitivities were performed with an OWC at 740 m ss and 780 m ss. The results showed that no WBT occurred in a period of 10 years. The actual depth of the OWC has little impact on the GBT time.

5.4. Matrix Block Size

The matrix block size (or equivalently the fracture spacing) is given by Lx, Ly and Lz in the horizontal and vertical plane. The left- and right-hand graphs in figure 8 show sensitivities of WBT and GBT, respectively, for various values of Lx, Ly and Lz as specified in Section II. The fracture spacing increases from left to right in these graphs.

Figure 8a and 8b show that if the fracture density decreases the WBT and GBT times come down. This is explained by the fact that if fractures are far apart, the oil in the matrix needs to travel long distances before it flows into the fractures. Under these conditions, gas and water coning in the fractures are occur quickly because the matrix production cannot keep up with the oil production from the fracture system.

Figure 8a and 8b display trends in a qualitative sense. To quantify the effects (and heterogeneity) of the fracture network, much more data gathering, and interpretation is required. This involves core data, log data (particularly Bore Hole Image logs), seismic data and mapping of features of the surface terrain.

5.5. Sigmagd

The exchange of fluids between matrix and fractures is governed by several forces. The most important force is the gravity force. However, capillary forces and to lesser extent viscous forces also play a role. The gravity force acts between gas and oil and between water and oil in the vertical direction. The flux of oil from matrix to fracture depends on Lx, Ly and Lz. In the simulator (Petrel), this information is entered via a keyword called SIGMA. This quantity is defined in terms of Lx, Ly and Lz according to the Kazemi relation.
Petrel provides an additional keyword, SIGMAGD, which purely describes the gas-oil gravity drainage process (whereas SIGMA describes all other matrix-fracture processes). In dual-porosity simulations, the initial values of SIGMA and SIGMAGD can be determined by fracture network information obtained from core and log data and possibly other sources. Ultimately, though SIGMA and SIGMAGD are determined by means of a history match of the reservoir simulation model to production and pressure data.

Figure 9a and figure 9b show the effect of SIGMAGD on the GBT time as a function of the matrix permeability and for various aquifer sizes and strengths. Comparing figure 8a and figure 8b shows that the larger SIGMAGD results in delayed GBT times. That is, the flux of oil from matrix to fracture is larger if SIGMAGD is bigger. This is explained by the fact that the larger SIGMAGD corresponds to a denser fracture network. In that case, fracture spacings are smaller and oil must travel only short distances through the matrix before it reaches a fracture. The trends are qualitative and SIGMAGD are ultimately a history match parameter.

5.6. Full Field Model Sensitivities Result and discussions

5.6.1. Sensitivities at an OWC of 685 m ss

The first set of sensitivities was performed with an OWC at 685 m ss. This is the shallowest level at which OWC values have been reported and have been observed. Figure 10, 11, 12 and 13 display 4 graphs for the following parameter combinations:

1) Lx = Ly = 5 m, DZMTRX = 25 m
2) Lx = Ly = 50 m, DZMTRX = 25 m
3) Lx = Ly = 5 m, DZMTRX = 100 m
4) Lx = Ly = 50 m, DZMTRX = 100 m

All cases show that the field starts to produce water after around 1 year of production. In case 2, the GOR starts to increase in the first half of 2012. In all other cases, this increase occurs only in 2013 or later. The case 2 values for Lx, Ly and DZMTRX could be representative to some extent for the south of X field, where gas coning in some of the wells has indeed been observed. The other conclusion that can be drawn is that it is highly likely that the OWC near the wells is deeper than the 685 m ss that was modelled in these sensitivities.

5.6.2. Sensitivities at an OWC of 740 m ss

The second set of sensitivities was performed with an OWC at 740 m ss. Figure 14, 15, 16 and 17 display 4 graphs for the following parameter combinations:

1) Lx = Ly = 5 m, DZMTRX = 25 m
2) Lx = Ly = 50 m, DZMTRX = 25 m
3) Lx = Ly = 5 m, DZMTRX = 100 m
4) Lx = Ly = 50 m, DZMTRX = 100 m

In these sensitivities, WBT occurs much later. Case 2 and 4 have WBT in early 2012, the other two cases in 2013 or later. In none of these, cases are GBT observed. Contrary to the SM results described in Section 3.3 (result and discussion), the FFM seems to indicate that the depth of the OWC does have an impact on the GBT time.

6. Conclusions

A series of sensitivity analyses on both the full field model and 1-well sector model has been done in the study. These models were built using the layercake petrel model. The purpose of these sensitivities was to investigate how the fracture network's characteristics affected the well's and field's performance to produce water and gas. The results of both models demonstrated that:

- Matrix permeability and fracture dimension had a significant impact on the early breakthrough of water and gas to comparable huge extents.
- While other parameters, such as aquifer size and WOC demonstrate moderate effect on water and gas breakthrough as well as overall recovery.

Authors contributions: Barham Sabir Mahmood: Methodology. **Mohammed Jamal Awl:** Writing – original draft, Writing – review & editing. **Farhad Abdulrahman Khoshnaw:** Writing – original draft, Writing – review & editing.

Data availability: Data will be available upon reasonable request.

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