

NUMERICAL SIMULATION OF A NATURALLY FRACTURED RESERVOIR.

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ARTICLE INFO

Received: 2 / 1 /2010
Accepted: 22 / 7 /2010
Available online: 14/6/2012
DOI: [10.37652/juaps.2010.15372](https://doi.org/10.37652/juaps.2010.15372)

Keywords:

NUMERICAL SIMULATION ,
NATURALLY FRACTURED
RESERVOIR.

ABSTRACT

This research is concerned with the development of a numerical model for stratified normally fractured reservoirs. Three dimensional three phase flow black oil simulation model is adopted. The dual porosity-dual permeability model is used. The IMPES (Implicit Pressure Explicit Saturation) method is used to solve the difference equations. The Tertiary trap in K oil field (an Iraqi oil field) was simulated by the numerical model. The trap consists of six layers having different properties. Equally spaced Cartesian grids were used to divide each layer into 1600 cells in the x-y plane with the thickness as the dimension of each grid block in z direction. Applying the two IMPES pressure equations to each grid of the simulated domain resulting in a block seven diagonal coefficient matrix.

Gauss-Seidel iterative method was used to solve the system of equations. The time steps are controlled through a maximum saturation difference and a material balance error limits. The actual production histories of the 15 wells in K oil field are used to get the past performance of the field for the production period. The calculated and measured average reservoir pressures, produced gas/oil ratio through the production periods had acceptable match.

Introduction

The development of a simulator for naturally fractured reservoirs (NFR) is a real challenge from both the reservoir description and numerical solution point of view. Fluid flow behavior in fractured reservoir through high-permeability low effective porosity fracture surrounding low-permeability high porosity matrix block has been described extensively in the oil literature during the last thirty- five years. The fluid exchange between the fracture network and the individual matrix blocks is the most physical aspect of the fluid flow problem to characterize.

4 developed 3D, multiple well numerical simulator for simulating single or two-phase flow of water and oil in a fractured reservoir. The simulator equations are a two- phase flow extension of single – phase flow equation derived by 6.

The simulator account for relative fluid mobility, gravity forces, imbibition, and variation in reservoir properties. It handles uniformly and non-uniformly distributed fractures and for no fractures at all. A semi-implicit finite difference expansion had been used to solve the original dual porosity equations. Different methods of solving the system of equations were proposed depending on the number of nodes. The results showed the significance of imbibition on recovery of oil from the rock in reservoirs with inter-connected fracture network.

3 modeled the flow in the fracture system by representing fluid transfer from the matrix into the fracture by a “source” term and fluid transfer from the fracture to the matrix by a “sink”(or negative source) term.

8 presented a stable, flexible, fully implicit, finite difference simulator in heterogeneous, dual-porosity reservoir. They used the flow equation proposed by 7.

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Cartesian and radial coordinates are included in the model. The conventional five point finite difference in the x-y plane was extended to a special nine-point formulation to account for the directional flow other than the x-y directions. Each node in the model has two properties one for the matrix and the other for the fracture. Good agreement was noticed between the analytical and numerical solution for pressure build up prediction.

Thomas, 5 used the dual porosity model to develop 3D, three phase simulator for NFRs. The same flow equations of 7 were used. The formulation was implicit in pressure, water saturation and gas saturation for both matrix-fracture flow and fracture flow. The gravity and capillary effect were incorporated. After expanding the matrix-fracture flow equation in totally implicit form the matrix unknown were eliminated in terms of fracture unknowns to reduce the total number of unknowns. The time steps were controlled automatically using a maximum saturation change of 0.1.

3 described a 3D three phase compositional simulator. A dual permeability and/or a dual porosity system were used to describe complex porous media including highly fractured, micro fractured or non-fractured regions. In addition to the viscous and capillary pressure forces, the matrix-fracture exchange term can handle gravity effects. The conservation equations were expressed in compositional form and equilibrium K-values were used. The fully implicit equations are linearized by Newton-Raphson iteration scheme. Because of the multi-purpose nature of the model, several different choices of discretized time-solution techniques are available.

9 presented an empirical formulation for the transfer function representing the matrix-fracture interaction in the dual-porosity model. Depending on the assumption that when water imbibition is the dominant force for displacing oil from the matrix. The aim of the study is to develop a numerical simulation model for a naturally fractured stratified Iraqi reservoir (the ministry of oil does not give permission to state the name

or publish the map of the reservoir) and check the match between the actual reservoir history with that predicted using the simulator.

Field Description

K oil field is an Iraqi oil field located in the north of Iraq. The field is a simple asymmetrical doubly plunging anticline. Its main axes strike NW-SE. The slope of the NE flank is between 9o to 13o while the slope of SW flank reaches 20o in some locations (geological study 1992). The structure is about 17 Km long and 6 Km wide. This work is concentrated on the Tertiary trap which consists of six carbonate units having different thickness and different petrophysical properties. The structural map of the trap is shown in Fig.1. Core sample studies showed that the fractures are homogeneously distributed in the field and can be divided into open, closed, completely filled and partially filled fractures. The degree of fracturing in the units ranges from rare in the top and bottom units to open fractures and vugs in the middle units.

The reservoir has a large gas dome, medium oil column and water at the flanks. Fifteen producing wells were drilled in the trap during the 1980ths having different production history (field measurements 2007).

Grid Construction

Each layer in the reservoir was subdivided using a grid system having equal spacing in the x and y directions (200 meter) spacing. Layer thickness was considered as the spacing in the z direction.

Block centered grid and row ordering methods were used. The grid network with the location of the producing wells is shown in Fig.2.

Transmissibility Evaluation

Single point upstream weighing is used to evaluate transmissibility at the block boundaries. The fluid potential is used to recognize the upstream cell from which fluids are flow to the adjacent one. Each grid block, not in the boundary of the simulated area, is communicated with six blocks. So for each flowing phase the transmissibility at the six

blocks boundaries are calculated after assigning the upstream one in each direction.

Flow Equations

The dual porosity dual permeability model is used in which the flow in the reservoir occurs in both fracture and matrix system in addition to fluid exchange between those systems. The equations describing three phase

three dimensions flow in the fracture system written in finite difference form are:-

$$\Delta \left[T_w (\Delta p_w - \gamma_w \Delta D) \right]_f - \tau_{wmf} - Q_{wf} = \frac{V_b}{\Delta t} \Delta_r (\phi b_w S_w)_f \quad (1)$$

$$\Delta \left[T_o (\Delta p_o - \gamma_o \Delta D) \right]_f - \tau_{omf} - Q_{of} = \frac{V_b}{\Delta t} \Delta_r (\phi b_o S_o)_f \quad (2)$$

$$\Delta \left[T_g (\Delta p_g - \gamma_g \Delta D) \right]_f + \Delta \left[T_o R_s (\Delta p_o - \gamma_o \Delta D) \right]_f - \tau_{gmf} - R_s \tau_{omf} - Q_g - R_s Q_{of} = \frac{V_b}{\Delta t} \Delta_r (\phi b_g S_g + \phi b_o S_o)_f \quad (3)$$

The matrix equations are same as eqs.(1, 2 and 3) but using the parameters of the matrix system. The transfer function, τ , governing fluids transfer between the fracture and matrix system is defined as:

$$\tau_{\alpha m f} = \sigma V_b \lambda_{\alpha} \left(p_f - p_m \right) \alpha \quad (4)$$

Where σ is the shape factor, λ is the mobility of phase α (water, oil or gas). The shape factor σ in eq. (4) is calculated from the relation (Kazemi 1976) but a factor of 2 is used instead of 4 in the original equation.

$$\sigma = 2 \left(\frac{1}{Lx^2} + \frac{1}{Ly^2} + \frac{1}{Lz^2} \right) \quad (5)$$

The difference equations 1, 2 and 3 are solved using the IMPES method resulting in two main pressure equations in terms of fracture and matrix pressure (Ahmed 2007).

$$Gf1_{k-1/2} P_{f_{k-1}}^{n+1} + Gf2_{j-1/2} P_{f_{j-1}}^{n+1} + Gf3_{i-1/2} P_{f_{i-1}}^{n+1} - Gf4_{ijk} P_{f_{ijk}}^{n+1} + Gf5_{i+1/2} P_{f_{i+1}}^{n+1} + Gf6_{j+1/2} P_{f_{j+1}}^{n+1} + Gf7_{k+1/2} P_{f_{k+1}}^{n+1} + Gf8_{ijk} P_{m_{ijk}}^{n+1} = RHS_f \quad (6)$$

$$Gm1_{k-1/2} P_{m_{k-1}}^{n+1} + Gm2_{j-1/2} P_{m_{j-1}}^{n+1} + Gm3_{i-1/2} P_{m_{i-1}}^{n+1} - Gm4_{ijk} P_{m_{ijk}}^{n+1} + Gm5_{i+1/2} P_{m_{i+1}}^{n+1} + Gm6_{j+1/2} P_{m_{j+1}}^{n+1} + Gm7_{k+1/2} P_{m_{k+1}}^{n+1} + Gm8_{ijk} P_{f_{ijk}}^{n+1} = RHS_m \quad (7)$$

Equations 6 and 7 are applied to the grids in the simulated domain, therefore 2N equations resulted from

N grid blocks. The 2N equations are overlapped together to get a final equation having a matrix form of:

$$AP = D \quad (8)$$

where A is the coefficient matrix, P is the pressure vector and D is the right hand side vector.

Matrix A is a seven diagonal matrix consisting of six individual matrices (blocks), each individual matrix represents one of the six layers forming the field. Each non-zero entry in matrix A is a 2x2 matrix. The components of matrix A and D are initially calculated using the pressure and saturation values for water, oil and gas resulted from the initialization process.

To solve this equation Gauss-Seidel iteration method is used in the following manner:

- 1-Take a certain time step and use the pressure distribution values results from initialization process as initial pressure values.
- 2-Calculate the new pressure values in the 1st layer for the fracture and the matrix using the Gauss-Seidel iterative method.
- 3-Check the maximum difference between the initial and the calculated values, if the difference $\leq .01$ psi then proceed to step 4 other wise use the newly calculated pressure values in step 2 as an initial values and repeat calculations starting from step 2.
- 4-Repeat steps 2 and 3 for the layers 2 to 6.
- 5-Use the final pressure distribution resulted from the above calculations as initial pressure values and repeat calculations from step 2 to step 5 checking for maximum pressure difference of .01 psi between all initial and calculated values to stop the calculations.

After calculating the pressure distribution in the field at the new time level, calculation of oil and water saturations at the new time level in the fracture are calculated from eq. (1) and (2) also these saturations in the matrix are calculated using the same equations but using the matrix properties.

Check is made for maximum saturation difference in all the cells, if the difference is higher than the allowable saturation difference limit of .01, then the time step is reduced and calculations are restarted from step 1, otherwise, the new calculated pressure and saturation values are used to calculate the components of matrix A and D. A new time step is taken and calculations restarted from step 1.

Model Evaluation Process

Starting from July 1990 to December 1993 the reservoir undergoes alternating periods of production and complete closing. Oil production started from ten wells for two months (July and Aug. 1990) then the production stopped. After a closing interval of five months, individual wells were put into production for small periods and also closed. The production rates during these producing periods are small compared with rates after 1993. In January 1994 continuous production from eight wells started with rates ranging from 500 to 1100 STB/day lasting to June 1999 with small closing periods in some wells.

In July 1999 the fifteen wells were put into production at rates ranging from 600 to 2500 STB/day with some closing intervals part of them. The field was completely shut down from December 2004 to May 2005, and then production started from seven wells at rates ranging from 400 to 1500 STB/day.

The production history of the wells are used by the simulator to get the past reservoir performance.

Due to the fact that the IMPES solution is sensitive to the time step size and the monthly changes in wells production rates thirty days time step is used as an upper limit. If the saturations changes and the material balance errors are within the allowable limits the calculations proceeds, if not, half the time step is used and so on.

During the field history many down-hole pressure measurements for the closed wells and pressure build up tests for the producing wells were performed (field measurement 2007). The measured pressure values in those wells are compared with the pressure values which are calculated by the simulator at the same depths and plotted in Fig. (3) (Jan.1990 considered as zero time for this field) the plots are for four wells only because there is enough reading to make a comparison. The plots show good agreement between the measured and the calculated pressure values.

Average measured reservoir pressure is calculated from the different well measurements. The measured pressures are corrected to a datum depth of 1990 meter below sea level. This depth was chosen since it is almost at the middle of the oil column. The measured reservoir pressures are mean averaged if there is more than one measurement at different wells at the same time, if not,

single well measurements are considered. The average reservoir pressure at any time step is calculated at the same prementioned datum. Reservoir pressure at any time is calculated as a weighted average depending on the block size.

The pre-mentioned calculations are conducted in the matrix and the fracture system then a mean average is taken. The calculated and the measured average reservoir pressure with the monthly production of the reservoir are plotted against time in Fig. (4).

The difference between some measured and calculated values resulting from considering readings of one well as an average reservoir pressure due to the lack of measurements in certain time while the simulator calculates the average reservoir pressure from all the grid blocks located at the datum.

The initial reservoir pressure is above the oil bubble point pressure and all the wells are completed at the oil zone, so the produced gas is in solution only. At the end of 1998 the pressure in some producing wells dropped to the oil bubble point pressure so a reduction in the produced gas oil ratio was seen. After that time the average reservoir pressure dropped below the bubble point pressure resulting in an increase in the produced gas oil ratio. The produced gas oil ratio and the monthly oil produced were plotted with time in Fig. (5). In addition some measured values of the produced gas oil ratio were plotted.

The drop of the gas oil ratio (GOR) values in some periods resulted from closing some wells which have high produced GOR. One of the causes of the difference between the measured and calculated GOR can be attributed to the difference between the used and the actual relation between the solution gas and pressure and still there is a good match between the calculated and the measured values.

The simulator constructed in this study has good accuracy when the calculated values are compared with the field measured values.

The program can provide a numerical simulator for naturally fractured reservoirs using the dual porosity dual permeability model.

The accuracy of the IMPES solution can be ensured by controlling the time step size through both the

saturation change and the material balance error at each time step.

Nomenclature

b : Shrinkage factor, cuft/SCF.
Co : Oil compressibility, psi-1.
Cw : Water compressibility, psi-1.
D : Depth from certain datum, ft.
Gf : Coefficient of pressure terms. SCF/day/psi
h : Thickness, ft.
hnet : Net thickness, ft.
I: The number of grid blocks in the x direction.
J : The number of grids in the y direction.
K The number of grids in the z direction.
Kf : Fracture absolute permeability, md.
Km : Matrix absolute permeability, md.
Kro : Oil relative permeability, fraction.
Krw : Water relative permeability, fraction.
Kx : Permeability in x direction, md.
Ky : Permeability in y direction, md.
Kz : Permeability in z direction, md.
P : Pressure, psi.
Pcog : Gas-oil capillary pressure, psi.
Pcow : Water-oil capillary pressure, psi.
Pwoc : Pressure at the water oil contact,
Pgoc : Pressure at the gas oil contact,
Q : Flow rate, SCF/D.
Rs : Solution gas oil ratio, SCF/SCF.
r1 : Radius of the boundary, ft.
rw : Well radius, ft.
S : Phase saturation, fraction.
Sg : Gas saturation, fraction.
So : Oil saturation, fraction.
Sw : Water saturation, fraction.
Tmf : Transmissibility of the fracture- matrix transfer function, scf/day/psi.
Tg : Gas transmissibility, scf/day/psi.
To : Oil transmissibility, scf/day/psi.
Tw: Water transmissibility, scf/day/psi.
Vb: Bulk volume of a grid block, ft3.
Greek
λ : Phase mobility, md/cp.
α : Phase.
γ : Specific gravity.
ρ : Phase density, psi/ft.
σ : Shape factor, ft-2.

μ : Phase viscosity, cp.
∅ : Porosity, fraction.
ω : Weighting factor.
Δ : Difference.
Δt : Difference with respect to time.
τ : Matrix-fracture transfer function.

Subscript

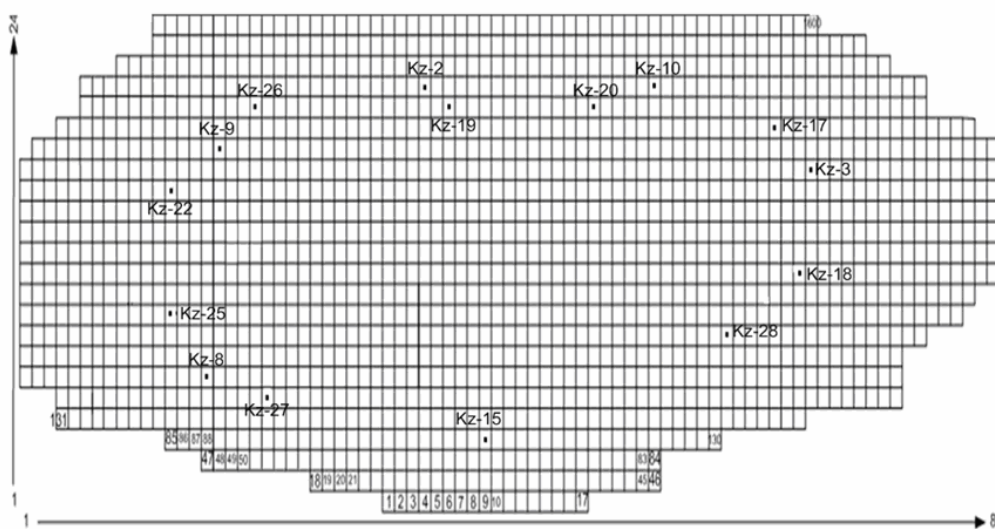
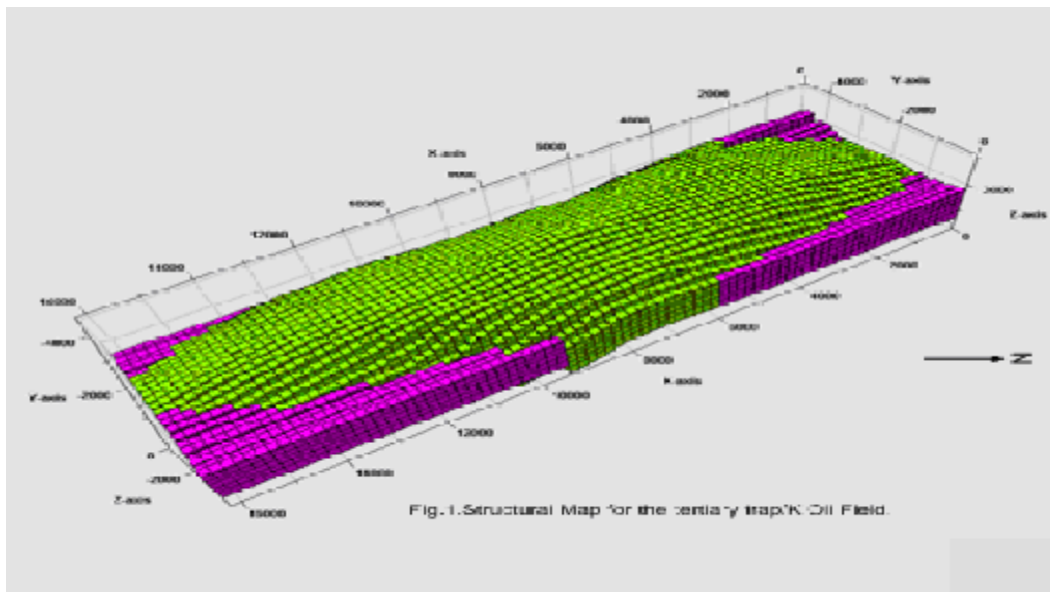
f : Fracture system.
g : Gas.
i : Index of the grid block in the x direction.
i ± ½ : Outer and inner boundary index of a grid block in the x direction.
j : Index of the grid block in the y direction.
j ± ½ : Outer and inner boundary index of a grid block in the y direction.
k : Index of the grid block in the z direction.
k ± ½ : Upper and lower boundary index of a grid block in the z direction.
m : Matrix system.
o : Oil.
w : Water.

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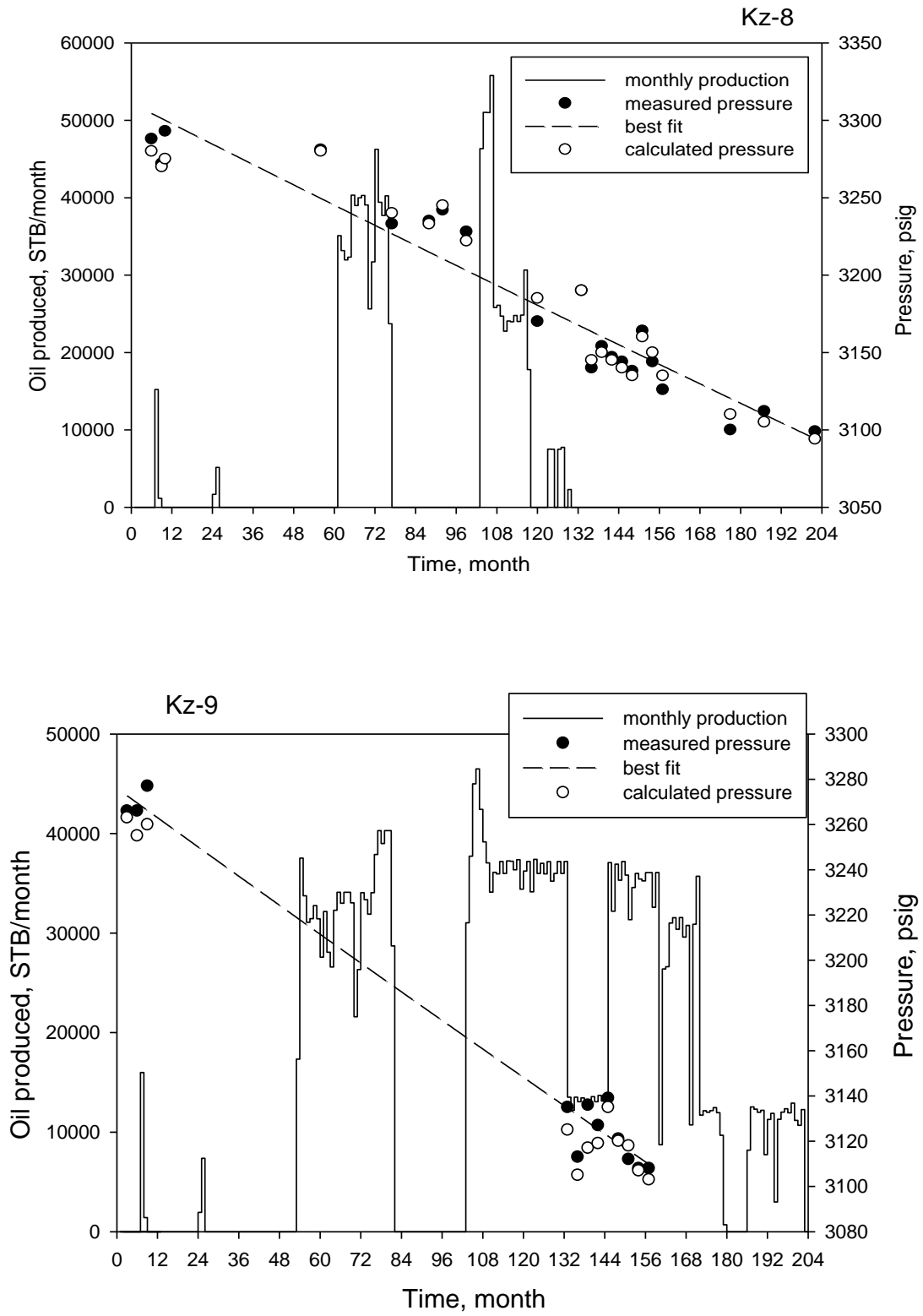


Fig.3. Comparison between the measured and calculated pressure.

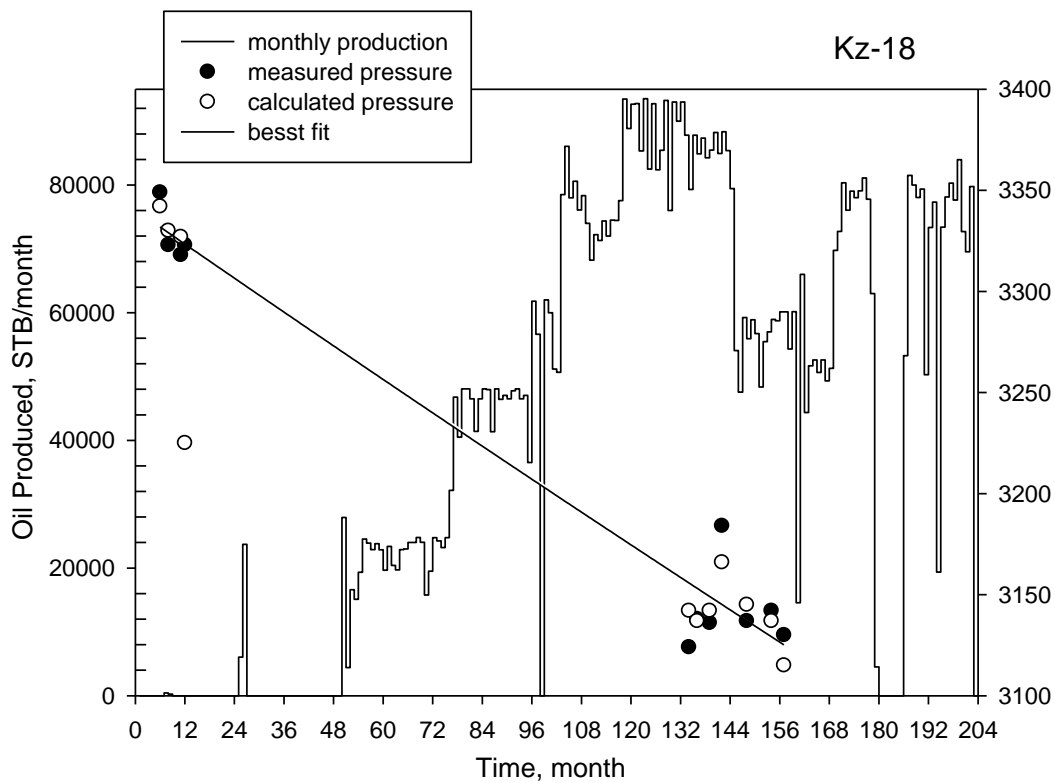
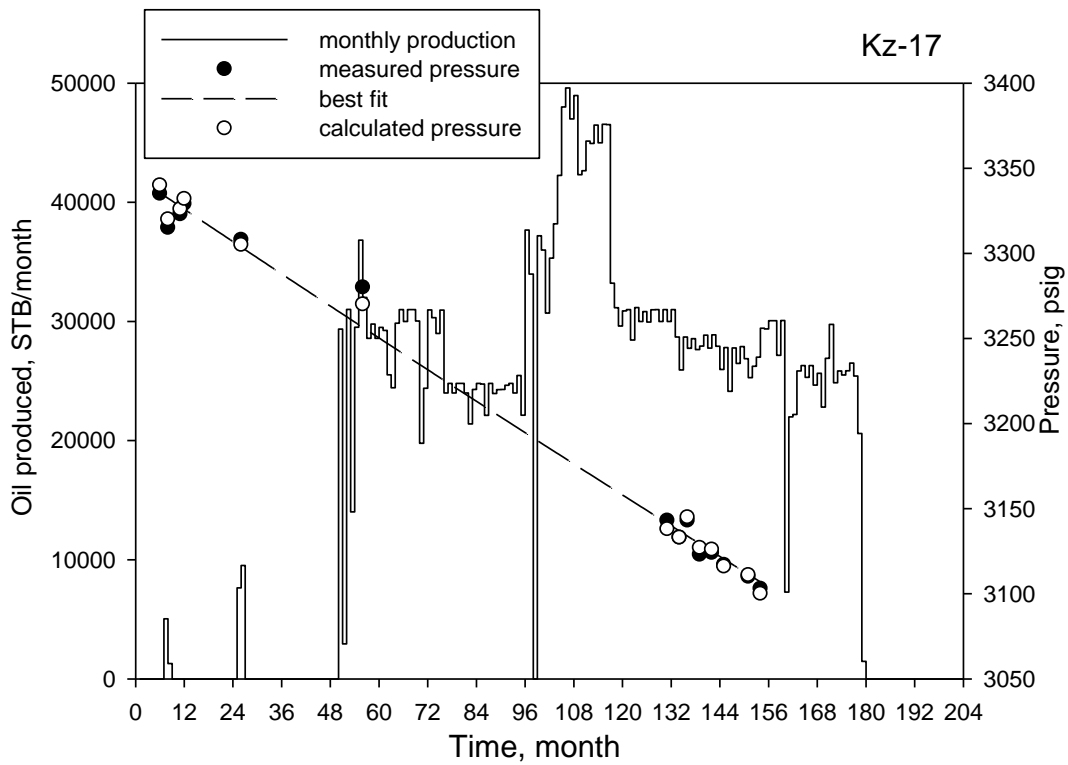


Fig.3.(continued).

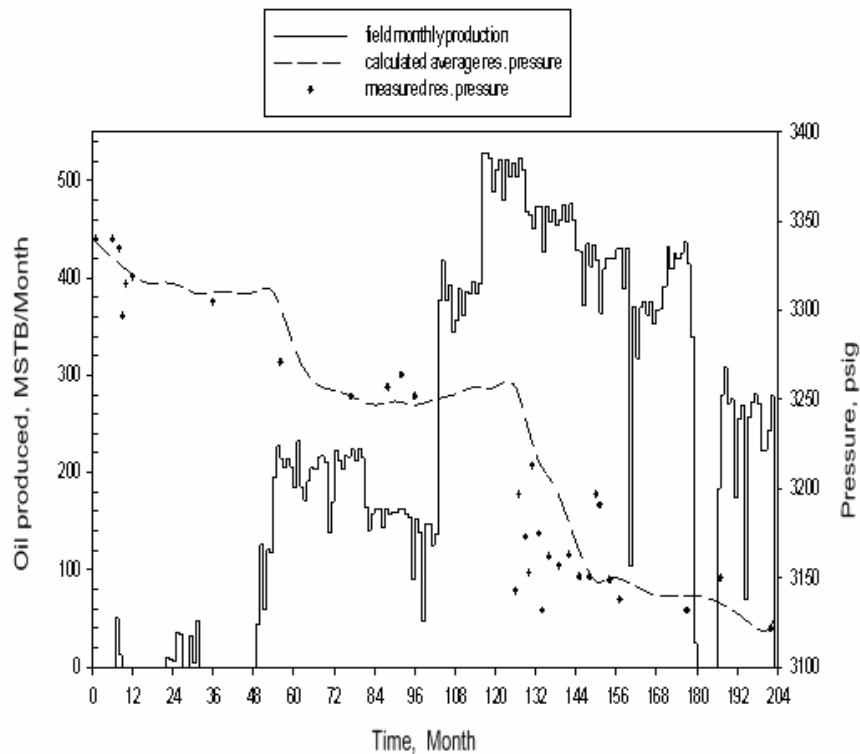


Fig.4. Measured and calculated average reservoir pressure with time.

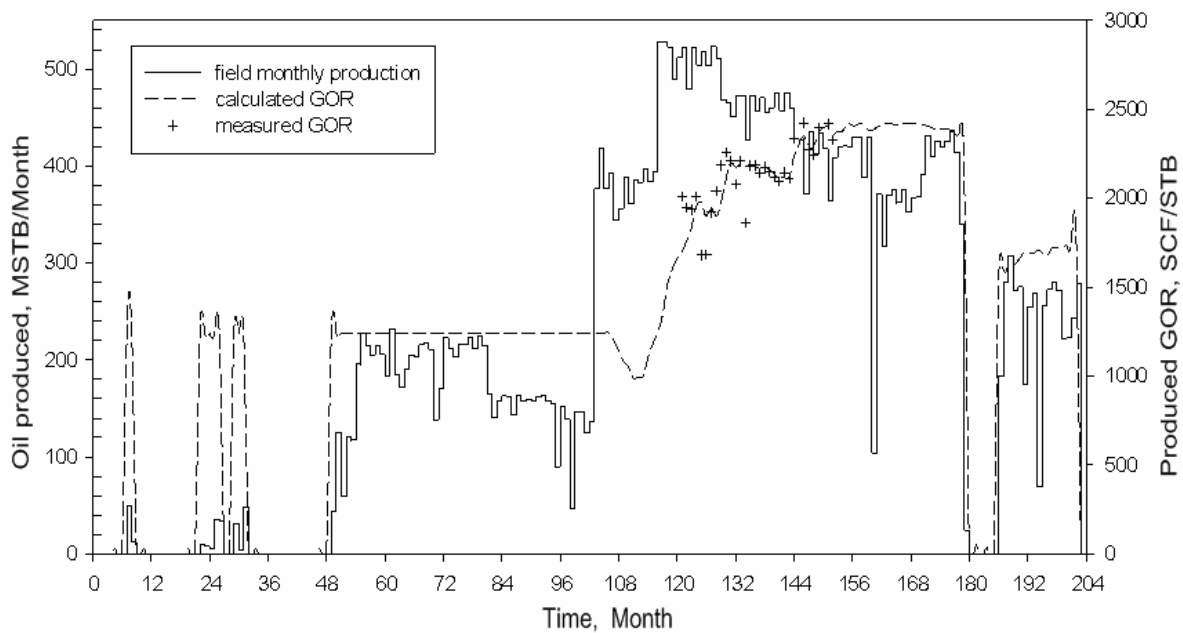


Fig.5. Measured and calculated produced gas oil ratio with time.

المحاكاة العددية للمكامن النفطية المتشقة

احمد جبير محمود محمد صالح الجواد

الخلاصة:

في هذه الدراسة تم بناء نموذج محاكاة عددي يتناول حالات الجريان الثلاثي الأبعاد والثلاثي الطور في الأوساط المسامية المتشقة. استُخدم نموذج ثنائي المسامية-ثنائي النفاذية لوصف الوسط المسامي المتشقق، واستخدمت طريقة IMPES لحل معادلات الفروق الجزئية. تم تطبيق النموذج على المكامن الثلاثي في حقل K (أحد الحقول النفطية العراقية) والذي يتألف من ستة طبقات حاوية على النفط بكميات متباينة إضافة إلى الغاز والماء. تختلف هذه الطبقات بالصفات الفيزيائية وشدة التشققات فيها. المكامن له قبة غازية كبيرة نسبياً وعمود نفطي متوسط إضافة إلى الماء في جوانب التكوين. بلغ عدد الآبار المحفورة في المكامن خمسة عشر بئراً ولكل بئر تاريخ إنتاج مختلف. تم إدخال المعلومات الخاصة بالحقل للموديل الرياضي وقُسمت كل طبقة من طبقات المكامن الست إلى 1600 خلية في المستوي الأفقي باستخدام شبكه ذات شكل غير منتظم ومتساوية الأبعاد في الاتجاهين السيني والصادي مع اعتماد سمك ألطبقة كبعد بالاتجاه العمودي.

إن تطبيق معادلاتي (IMPES) على كل خلية في الشبكة نتجت عنه مصفوفة تم حلها باستخدام طريقة التكرار Gauss-Seidel. كانت وسيلة التحكم في الخطوة الزمنية المستخدمة في الحسابات هما مقدار التغير في نسب التشبع ومقدار الخطأ في الميزان المادي. تم استخدام تاريخ الإنتاج لخمسة عشر بئراً المحفورة في الحقل في الموديل الرياضي للحصول على تصرف المكامن لفترة الإنتاج الممتدة من عام 1990 إلى عام 2005 أظهرت مقارننه معدل الضغط المكامني خلال مدة الإنتاج المحسوب بواسطة الموديل الرياضي والمقاس حقلها في عدد من الآبار تطابقاً جيداً. كما إن هناك تطابقاً جيداً بين نسبة الغاز إلى النفط المنتج المحسوب رياضياً والمقاس حقلها.