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Research Article

Decreasing CPU Time in Simulation of Thermal Recoveries in Hydrocarbon Reservoirs

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Abstract

The work flow of reservoir studies is an integration of interdisciplinary works by the geophysicists, reservoir geologists, petro physicists and reservoir engineers. Reservoir simulation helps to determine initiation of operating controls at the proper time, and to consider all important economic factors. Future improvement in oil recovery with pressure maintenance by re-injection of produced gas or by water injection into an aquifer can also be evaluated. The original fine grids are generated by primary geological blocks which are output of geological software. The upscaling is necessary since geological software by means of statistical methods create models with millions and even billion of grid blocks and dynamic simulation on these models is practically not possible. In this paper we are going to introduce a fast simulation method in high heterogeneous multiphase reservoir which steam injection simulated as a thermal enhanced oil recovery. The principle of multi scale grid generation of this method is base on the trend of streamline which could be as a great map to find effective segments of a reservoir. The simulation results on the geological structure well compared with the results of upscaled models. The results confirm that this method consumes less run time with nearly accuracy of fine model.

Keywords: *Steam Injection, Geological Model, Run Time, CPU Time, Elapsed Time*

1. Introduction

The work flow of reservoir studies is an integration of interdisciplinary works by the geophysicists, reservoir geologists, petrophysicists and reservoir engineers. The reservoir studies can be outlined as follows; The objectives of reservoir simulation are to estimate oil and gas reserves, predict reservoir performance, make decision regarding reservoir management for process design and strategic planning. Reservoir simulation can be used to estimate recovery factor alongside analogy or analytical methods. Recovery factor, in its turn, is used in the estimation of reserves (see e.g. Demirmen, 2007; Rietz & Usmani, 2009; Masoud Babaei 2013). To obtain maximum net present value from a field the engineer or the engineering team must identify and define all individual reservoirs and their physical properties and deduce each reservoir's performance. Such reservoir performance studies lead to estimation of expected production rates of oil, water and gas or prediction of recovery, estimation of water/gas breakthrough time for water/gas injection, design of facilities, plan for the safe drilling of additional wells, prevention of drilling of unnecessary wells, identification of the number of wells required, plan for the optimal placement, spacing and completion of wells, representation of highly deviated or horizontal wells and determination of the present and future needs for artificial lift. Moreover reservoir simulation helps to determine initiation of operating controls at the proper time, and to consider all important economic factors. Future improvement in oil recovery with pressure maintenance by re-injection of produced gas or by water injection into an aquifer can also be evaluated.

Early and accurate identification and definition of the reservoir system is essential to effective engineering (Essley, 1965; M.Babaei 2013). The various predictions using different production, well and injection scenarios are interpreted and ranked according to acceptability. Additionally, the application of enhanced oil recovery (EOR) processes requires that the field possesses the necessary characteristics to make application successful. Model studies can assist in this evaluation. Reservoir simulations can take into account detailed areal variations in reservoir properties to design a sound enhanced recovery process (Carlson, 2003; M.Babaei 2013). Uncertainty is an important factor in reservoir engineering that is conjoined with reservoir simulations. There is a need to run multiple realisations to assess uncertainty of the

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models in oil recovery and future production. Uncertainty in reservoir data can be classified into uncertainty in geophysical, geological, dynamic and reservoir fluids data (Schulze-Riegert & Ghedan, 2007; M.Babaei 2013) and is usually investigated by constructing several different realisations of the sets of attribute values. The behaviour of the resulting simulation models can indicate the associated level of economic uncertainty. For example consider the situation that we wish to build a reservoir simulation model to investigate what parameters our model is sensitive to and also to obtain an estimated range of values of some objective function (e.g. total oil production or gas in place). Rather than running just one instance of the simulation model with just one set of parameter values, we would really like to run as many simulation model instances as possible (given time and budget constraints), each simulation run having its own set of parameter values and resulting in a new estimated objective function value (e.g. total oil production). Hence, the multiple number of models are produced. Some models will be optimistic, some pessimistic, but all are designed to characterise the reservoir and the uncertainty about the reservoir (Farmer, 2005; M.Babaei 2013).

There is a definite trend toward ensemble reservoir forecasting, where a wide range of models are developed that sample probability distributions of reservoir parameters. Running all of these simulation models helps us to quantify the range of uncertainty in our objective function and we should be able to pull out forecast values. There are various methods for quantifying uncertainties in reservoir simulations (see e.g. Floris *et al*., 2001; Barker *et al*., 2000; M.Babaei 2013). One obvious observation is that, quantification of geological uncertainty relies on having high-quality upscaled reservoir model that honours the geological model details, because while we are quantifying uncertainties based on such details we are not able to do so on the geological model itself. In this case the workflow to generate such an upscaled model is as follows: Firstly, a high resolution geological model for the reservoir is provided through the application of an integrated workflow that includes robust seismic and petrophysical analysis.

The objective is to design a static model that includes reservoir heterogeneities and internal baffles and barriers to flow and account for inherent degree of uncertainty that is related to the partial knowledge of the reservoir and the limitations of the techniques that are commonly utilised. The static description of the reservoir, both in terms of geometry and petrophysical properties, is one of the main controlling factors in determining the field production performance (Cosentino, 2001; M.Babaei 2013). Once a detailed reservoir model has been constructed, the next step is to build a reservoir simulation model by upscaling of the geological model and run reservoir simulations. The results of actual production analysis obtained from field are used for comparison to reservoir simulations, in a process called history-matching, using parameters representative of the field. The idea is to match gas oil ratios, water cuts, and pressures predicted by the model to actual real-time performance data. In general, some previously unknown aspects of the reservoir (uncertainties) will become apparent by the analysis of production performance. The objective is to determine why the reservoir performance is not matching our production. This knowledge is used to correct our conceptual model of reservoir and devise plans to improve reservoir performance (Carlson, 2003; M.Babaei 2013). At this stage the application of Bayes' rule can be used to update our prior probability assessment performed previously and to produce the posterior probability distribution (see e.g. Busby *et al*., 2007; M.Babaei 2013). Reservoir monitoring to study the changes that occur in a reservoir during production is performed. The monitoring can include renewed seismic surveys or log and core data designed to detect changes that occur during production. These dynamic data are integrated into the geological model and subsequently into the reservoir simulation model in order to assess changes and to edit input data for the simulator. The data is used to manage the reservoir, and to make or revise decisions that will drive production plans for the future. The above-mentioned stages of reservoir engineering studies should be tightly integrated in order to foster more effective, less expensive reservoir engineering projects (Cosentino, 2001; M.Babaei 2013).

2. Aims and Objectives

We are going to define a method which is independent of wavelet transformation in upscaling which able to preserve effective segments of reservoir in fine mesh scale and generates non-uniform coarsening gridding. Simulation is done in three different ways (Fully implicit, IMPES and Adaptive Implicit method (AIM)) and base on minimum elapsed time one of those three methods is chosen. The EOR scenario is steam injection.

3. Geological Fine Scale Model (GM)

Flow processes occur in a 3D heterogeneous reservoir with a fine mesh composed of $[40 \times 40 \times 3]$ (total cell number: 4,800).The permeability field is a distribution of low and high values, 5 and 100 milidarcy respectively. The porosity is constant and equal to 0.3 and initial reservoir pressure is 2,900 psia. Initial reservoir temperature is 125°F. PVT properties of water are; the water formation volume factor at the reference pressure is 1.0 (rb/STB), water compressibility is 3.0E-6 (1/psi), water viscosity at the reference pressure is 0.30 cP and the reference pressure for PVT properties of water is 75.0 psia. The rock compressibility is 5.0E-6 (1/psi). Oil component compressibility for C_1 , C_2 and heavy is 0.00005 (1/psi), respectively. Oil component reference density for C_1, C_2 and heavy is 52.3, 57.64 and 61.2 (lb/ft^3) respectively.

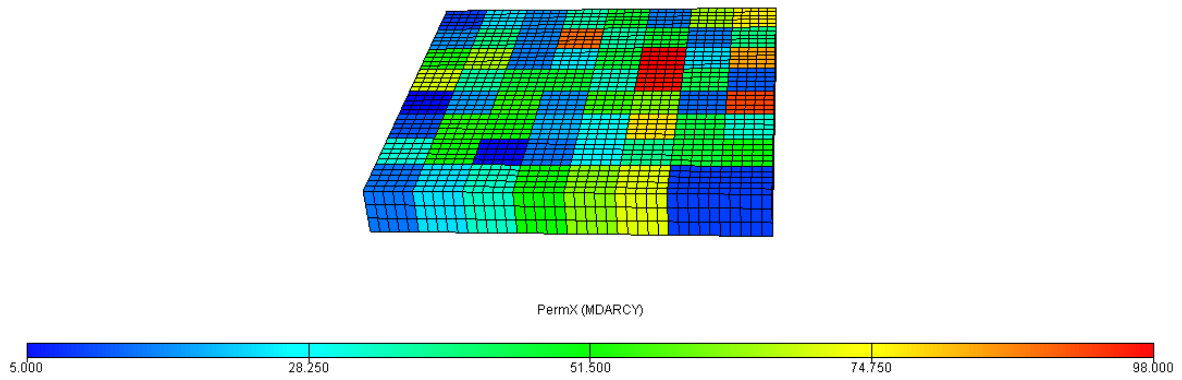

Figure 1 Permeability Map, Reservoir Dimension [40 × 40 × 3]

Thermal expansion coefficient for C_1, C_2 and heavy is 0.00036, 0.00037 and 0.00038 $\left(\frac{1}{^\circ_R}\right)$, respectively. Oil component specific heat for C_1, C_2 and heavy is 0.53, 0.55 and 0.6 $(Btu/lb/^\circ_R)$, respectively. Oil component critical temperature for C_1, C_2 and heavy is 1259.67, 1409.67 and 10,000 $(^\circ_R)$, respectively. Oil component critical pressure for C_1, C_2 and heavy is 225, 140 and 100 Psia, respectively. Oil component molecular weight for C_1, C_2 and heavy is 250, 450 and 600 respectively.

4. Steam Injection Simulation

Thermal recovery methods are typically used in heavy oil reservoirs, where the oil viscosity is high at reservoir temperatures, but reduces as the temperature increases. A number of thermal recovery processes:

- Steam injection or steam assisted gravity drainage (SAGD)
- Hot fluid or gas injection
- Well bore heaters
- Combustion

Information required for the simulation of steam injection is as Follows:

The thermal conduction of heat in the rock is often a small effect compared with the convection of heat with the injected water. Property data for the rock are as follows:

- Initial temperature
- Rock conductivity
- Volumetric heat capacity of the rock
- Calculation method for heat loss(Vinsome and Westerveld or Numerical)

Oil Component K-value correlation specifies up to five constants for each oil component. These constants are used to calculate an oil component K-value versus temperature and pressure.

$$K(P,T) = \left(A + \frac{B}{P} + C.P\right).e^{-D(T-E)} \quad (1)$$

Where
P: Pressure
T: Temperature
A,B,C,D,E: Constant depends on component

Oil component compressibility specifies the liquid compressibility for each of the hydrocarbon components. The expression used to calculate oil component liquid densities is the following:

$$\rho_c = \frac{\rho_{ref,c}}{[1-C_{P_c}(P-P_{ref,c})][1+C_{T1_c}(T-T_{ref,c})]} \quad (2)$$

Where
$\rho_{ref,c}$: Reference density
C_{P_c} : Oil component liquid compressibility
$P_{ref,c}$: Reference pressure
C_{T1_c} : Thermal expansion coefficient
$T_{ref,c}$: Reference temperature
Z-factors are used to determine molar volumes using the relationship PV=ZRT.

Trangenstein's modification of Kell's 1975 correlations is used for the water density.

$$\rho_w = \frac{A_0+A_1T_c+A_2T_c^2+A_3T_c^3+A_4T_c^4+A_5T_c^5}{1+A_6T_c} e^{C_{PW}(P-A_7)} \quad (3)$$

$A_0 = 999.83952$
A_1= 16.955176
A_2 = -7.987E-3
A_3=-46.170461E-6
A_4=105.56302E-9
A_5= -280.54353E-12
A_6= 16.87985E-3
A_7= -10.2

The oil phase molar enthalpy is:

$$h_o = \sum_{c=1}^{N_c} x_c \,.\, h_c \,.\, mw_c \quad (4)$$

Where
x_c : Mole fraction of component c
mw_c : Component molecular weight

$$h_c = C_{P1,c}.(T - T_{st}) + \frac{1}{2}.C_{P2,c}.(T - T_{st})^2 \quad (5)$$

$C_{P1,c}$: The first coefficient of the component liquid specific heat
$C_{P2,c}$: The second coefficient of the component liquid specific heat
T_{st} : Standard temperature

5. Non-Uniform Grid Generation

Recent amelioration in reservoir imaging techniques and geostatistical procedures allow very detailed reservoir explanations containing millions of grid blocks to be produced. However, time limitations in reservoir simulation generally limit the flow model to a coarser grid. Each coarse grid block property value is received from the original fine scale grid using different upscaling techniques.

After all averaging, interpolation and data populating, from a simulation point of view, geological models are ironically too complex and too large, i.e., they contain more information than we can handle in simulation studies. Therefore, we usually use a coarsened grid model, or a simulation flow model. The model contains of grid blocks with their petrophysical properties replaced by averaged or upscaled quantities based on variations of underlying geomodel quantities that occur at length scales below the simulation grid block. The main reason for using the upscaled models is computational limitations since it is usually impossible to perform flow simulations on the geomodel.

Significant progress was made when Durlofsky *et al*. (1997) introduced a method whereby finer resolution is used in the regions of high-fluid velocities, and upscaled, homogenized description is utilized for the rest of the domain. In their approach no upscaling scheme is used for the relative permeabilities, as the original rock curves are used for the upscaled grid blocks, hence making the technique process-independent. Non-uniform grid coarsening offers significant computational speed-up and general applicability, but at the cost of increasing numerical dispersion and decreasing accuracy for the nonseparable scales. Such upscaling techniques are suitable for the sectors that are far from the wells. Since the pressure field in the near-well regions usually changes rapidly in the radial direction, the above upscaling approaches are not suitable. For such situations, well pseudo-functions to account for the pressure changes were suggested by Chappelear and Hirasaki (1976) and King *et al*. (1991). Durlofsky *et al*. (2000) developed a method for calculating the transmissibility and well index for single-phase flow based on the solution to the local well-driven flow. Grid selection methods that rely on dynamic responses, such as streamline simulation, in order to identify the locations of the grid blocks in the geological model through which most of the fluids pass, were also proposed by Verma and Aziz (1996) and Castellini *et al*. (2000). Static methods, suggested by Garcia *et al*. (1992), Li and Beckner (2000), and Younis and Caers (2001, 2002), that rely on the spatial distribution of the permeability for developing upscaled grids, are also robust (Mohammad Reza Rasaei, Muhammad Sahimi,2007).

To implement the procedure we need a tree algorithm which consider the streamline behavior as follow:

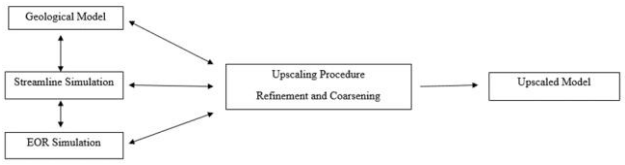

Figure 2 Tree Algorithm

The computations are required are as follow:

- Solve the pressure equation for the time step.
- Compute the total Darcy velocities based on the pressure potentials.
- Compute a set of streamlines to represent the computational domain for the saturation solver.
- Map saturations or concentrations onto the streamlines.
- Solve the saturation equation individually on each of the streamlines.
- Solve for the gravity segregation.
- Accumulate all the solution variables on each individual streamline or gravity line to form the solution on the global grid at the end of the time step.

Up-scaling studies show that past achievements require simplifying assumptions such as reservoir dimensions (1D or 2D) or limitation in the number of phases in the reservoir due to flash calculation, which limit the effectiveness of those methods for real models. This method is independent of type of EOR method which is capable of performing on three-dimensional, heterogeneous and multiphase reservoirs and for the first time it defines a regular pattern for multi-scale grid generation.

Within each coarse block the properties are simply upscaled from fine (f) to coarse (c) in a single coarse cell amalgamation $(I1, I2) \times (J1, J2) \times (K1, K2)$ as follows:

$$DX_c = \frac{\sum_f DX_f}{(J_2 - J_1 + 1)(K_2 - K_1 + 1)} \quad (6)$$

$$DY_c = \frac{\sum_f DY_f}{(I_2 - I_1 + 1)(K_2 - K_1 + 1)} \quad (7)$$

$$DZ_c = \frac{\sum_f DZ_f}{(I_2 - I_1 + 1)(J_2 - J_1 + 1)} \quad (8)$$

Where
c: Coarse
f: Fine

A way to calculate **k** is the renormalization method. Renormalization is a recursive algorithm. The effective properties of small regions of the reservoirs are first calculated and then placed on a coarse grid. The grid is further coarsened and the process repeated until a single effective property has been calculated (King *et al.*, 1993). The renormalization transformation is by no means unique and many different renormalization schemes have been proposed, some inspired by an analogy between flow in porous media, percolation processes and the flow of currents through resistors (King, 1989) (M.Babaei, 2013).

$$\mathbf{K}= \mathrm{f}(K_1, K_2, K_3, K_4) \tag{9}$$

$$\mathrm{f} = \frac{(2(K_1+K_2)(K_3+K_4)(K_{12}+K_{34}))}{3(K_1+K_3)(K_2+K_4)+\frac{1}{2}(K_1+K_2+K_3+K_4)(K_{12}+K_{34})} \tag{10}$$

Where
K_1, K_2, K_3, K_4: Absolute permeabilities of four constituent fine cells
K_{12}, K_{34}: Harmonic means of permeabilities of the cells with the given subscripts

We should avoid defining too large coarse cells in order to encompass wide relative permeability variations between different rock types.

For single phase flow, permeability is assumed to be a rock property and independent of the fluids present. This is only true in the case where the rock is completely saturated with a specific fluid. In the case where two fluids are present, it is necessary to define phase specific permeabilities which are defined as the product of the absolute permeability of the rock and a function of saturation of the phase considered (M.Babaei, 2013):

$$K_l = \mathbf{K}K_{rl}(S_l) \tag{11}$$

Where
l: Phase
K_{rl}: Permeability of phase l
K: Rock permeability

Relative permeabilities are functions of saturation, implying that in the presence of more than one phase in the rock, an equation for saturation will also be needed. Assuming that a generalization of Darcy's law to multiphase flow is valid (Bear, 1972), we need to formulate equations for the flow of each phase l using relative permeabilities (M.Babaei, 2013):

$$V_l = -\frac{\mathbf{K}K_{rl}(S_l)}{\mu_l}(\nabla p_l + \rho_l g \nabla z) \tag{12}$$

Where
V: Volumetric flow
p: Pressure
g: Gravitational Force
z: Spatial coordinate

A common approach is to use an averaging technique to generate relative permeability curves similar to global-local upscaling. For instance, for calculating an upscaled mobility of phase l, denoted by λ_l^* , a fine scale global solution, provides the flow rate between the grid blocks. To match the phase flow rates between coarse grid blocks E_i and E_j in x direction the following must hold:

$$\sum_{K=1}^{N}(f_l)_k = \overline{f}_l \tag{13}$$

Substituting in Darcy's law for multiphase flow:

$$-\sum_{K=1}^{N}(t\lambda_l(S)\nabla p)_K = -(T^*\lambda_l^*(\overline{S})\nabla\overline{p})_{ij} \tag{14}$$

Where
t: Fine transmissibility
T^*: Coarse transmissibility

In the case of different rock type need to define averaging method for rock heat capacity.

The enthalpy per unit volume of rock in each cell is calculated as:

$$H_{rock} = C_{R0}(T - T_{ref}) + \frac{C_{R1}(T-T_{ref})^2}{2} \tag{15}$$

Where
C_{R0}: Specifies the rock volumetric heat capacity value for each cell
C_{R1}: Temperature dependence of the rock heat capacity

$$H_{rock}(Upscaled) = C_{R0_{ave}}(T - T_{ref}) + \frac{C_{R1_{ave}}(T-T_{ref})^2}{2} \tag{16}$$

For C_{R0} and C_{R1} Arithmetic Averaging is recommended.

The pore volume of a refined global cell may differ from the sum of the pore volumes of the local cells which it contains, either because the local porosities and net-to-gross ratios differ from the values for the host cell or because of discrepancies in geometry. After computing the local pore volumes, replaced the pore volume of the host cell with the sum of the refined pore volumes.

$$PV_c = \sum_f PV_f \tag{17}$$

c: Coarse
f: Fine
PV: Pore Volume

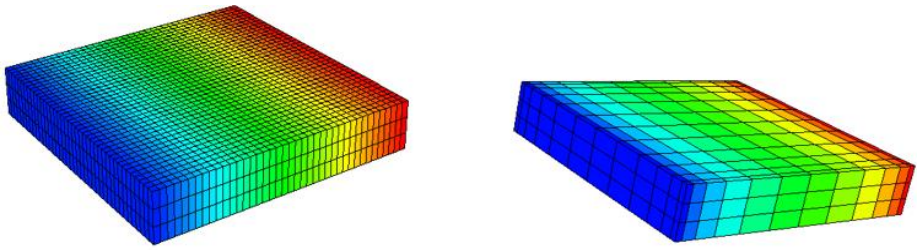

Figure 3 Non-Uniform Grid Generation through Tree Algorithm

The dynamic model which designed in this study has one production and injection well which perforated in 3 layers, the production well controlled by oil rate target (ORAT, 400 STB/Day) and injection well controlled by surface flow rate target (RATE, 300 STB/Day), the steam quality of the injected fluid and the temperature of the injected fluid are 0.7 and 450 °F, respectively.

6. Numerical Results

First, we need to choose solving method of the saturation and pressure equations based on the minimum elapsed time for the fine mesh model which the results are as follow:

Simulation time is 2,920 days, elapsed time in fully implicit is 105.23 sec and IMPES is 102.52 sec and for adaptive implicit method (AIM) is 68.28 sec therefore, base on minimum elapsed time AIM selected.

CPU Time in fine mesh and non-uniform model is 59.59 sec and 9.06 sec respectively. Now we are going to show the results of algorithm in some aspects of simulation such as: heat loss rate (HLR), energy percentage in oil, energy percentage in water and energy percentage in rock.

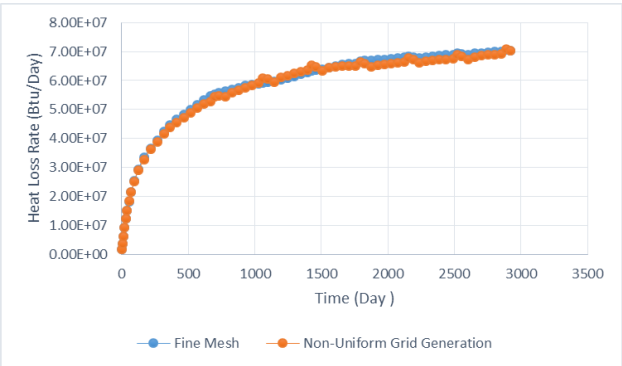

Figure 4 Heat Loss Rate vs. Time

Figure 4 presents the computed heat loss rate (HLR) and compares it with the non-uniform grid generation which provides the accurate result with the fine mesh model.

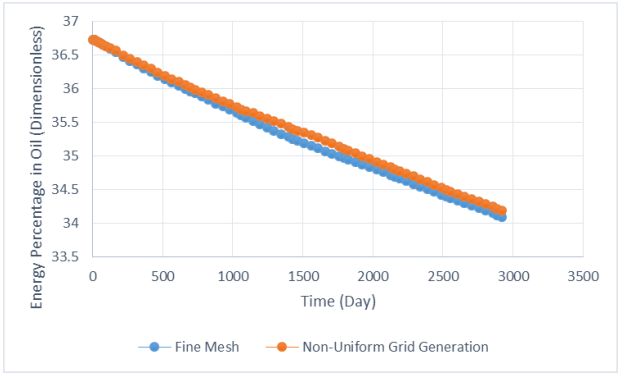

Figure 5 Energy Percentage in Oil vs. Time

Figure 5 makes the same comparison as in fig.4 but in aspect of energy percentage in oil.

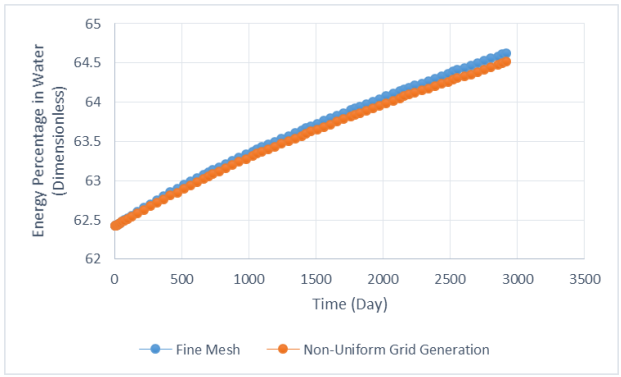

Figure 6 Energy Percentage in Water vs. Time

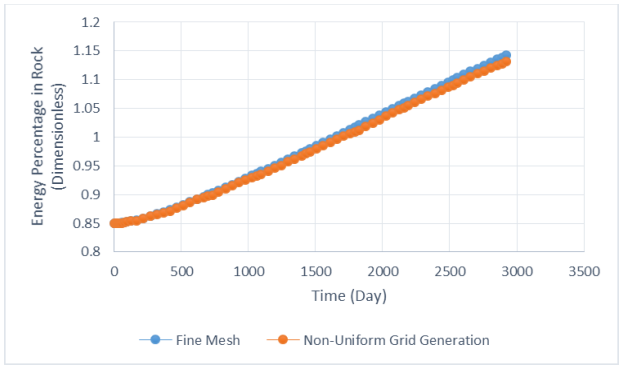

Figure 7 Energy Percentage in Rock vs. Time

Figure 6 and 7 show energy percentage in water and rock respectively, computed with the result reported by fine mesh model. The agreement is excellent.

7. Summery of Results

The upscaling method that we presented in this article yielded predictions with an accuracy that, when compared with the fine-grid simulations. The computation times of non-uniform grid generation is faster enough in compare with computation of fine mesh grids and figure 4 to 7 present the excellent accuracy with the fine scale grid. The method can be improved for other well pattern for instance 5-Spot well pattern and fractured reservoir.

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