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Single-phase Near-well Permeability Upscaling and Productivity Index Calculation Methods

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Abstract

Reservoir models with many grid blocks suffer from long run time; it is hence important to deliberate a method to remedy this drawback. Usual upscaling methods are proved to fail to reproduce fine grid model behaviors in coarse grid models in well proximity. This is attributed to rapid pressure changes in the near-well region. Standard permeability upscaling methods are limited to systems with linear pressure changes; therefore, special near-well upscaling approaches based on the well index concept are proposed for these regions with non-linear pressure profile. No general rule is available to calculate the proper well index in different heterogeneity patterns and coarsening levels. In this paper, the available near-well upscaling methods are investigated for homogeneous and heterogeneous permeability models at different coarsening levels. It is observed that the existing well index methods have limited success in reproducing the well flow and pressure behavior of the reference fine grid models as the heterogeneity or coarsening level increases. Coarse-scale well indexes are determined such that fine and coarse scale results for pressure are in agreement. Both vertical and horizontal wells are investigated and, for the case of vertical homogeneous wells, a linear relationship between the default (Peaceman) well index and the true (matched) well index is obtained, which considerably reduces the error of the Peaceman well index. For the case of heterogeneous vertical wells, a multiplier remedies the error. Similar results are obtained for horizontal wells (both heterogeneous and homogeneous models).

Keywords: Near-well Permeability Upscaling, Heterogeneity, Peaceman Well Index, Single Phase Upscaling

1. Introduction

Reservoir simulation suffers from an extensive number of grid blocks and long run times. Methods such as parallel computation can reduce this long run time, but it is common to reduce the number of equations. Coarsening and upscaling are common practices in reservoir simulation for reducing the model size to improve computational efficiency. As part of the standard simulation workflow, engineers upscale geological models to simulation models to reduce the CPU time and the requirement of computational resources (Li et al., 2013 and Yang et al., 2013). Also, Yang et al. (2013) and Mallison et al. (2013) noted that the scale of geological models was often too large for

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effective and efficient simulations. Upscaling is therefore a necessary and practical option to reduce the model size.

There are many definitions in the literature for upscaling. Based on Ligero et al. (2003) and Maschio (2003) upscaling is a set of techniques allowing to obtain the same response from fine-scale flow simulations using coarse-scale models. Christie et al. (2001) also mentioned that all upscaling methods assume that fine scale models are exact, and based on this, a coarser scale which is close to this fine scale model is constructed. Due to the radial flow near the wells, and high-pressure gradients, the usual upscaling techniques could not be used for well vicinity. For the near-well regions, Ligero et al. (2003) also proposed to treat the well index or productivity parameters to approximate the coarse grid simulation results to those obtained for the fine grid model. This would result in agreement between coarse and fine grid simulations. Ding (2004) suggested that, owing to the fact that the well-driven flow dominates in the well proximity, the results of near well upscaling were almost independent of boundary conditions.

Upscaling techniques can be divided into single phase and multiphase categories. While single-phase upscaling is concerned with the upscaling of absolute permeability, multiphase upscaling deals with the upscaling of absolute and relative permeabilities. Over the years, several different techniques have been proposed for upscaling absolute permeability, including local upscaling, extended local upscaling, local-global upscaling, and global upscaling among others (Yang et al., 2013; Chandra et al., 2013 and Li et al., 2013).

Some researchers believe that compared to the upscaling of absolute permeability, the upscaling of relative permeabilities, or multiphase upscaling, is not still as well-understood because of the complexity of the problem. The upscaled relative permeability is the average of fine-cell relative permeability weighted by transmissibility. Based on the work of some researchers on local upscaling, a combination of Dirichlet and Neumann boundary condition is usually used (Gerritsen et al., 2008; Yang et al., 2013, and King et al., 2013). Local-global upscaling attempts to eliminate the need for the assumption of local boundary conditions by iterating over local and global pressure solutions. Global upscaling, on the other hand, solves global fine-scale pressure problems.

Studies have found that the global method provides better accuracy for flow simulation on upscaled coarse models. Wolfsteiner et al. (2003) suggested that owing to the difference between block size and well diameter, the well bore pressure differs from that of block pressure. Thus a relationship between block pressure and wellbore pressure is necessary. This is accomplished by the well index:

$$q_i^w = \frac{WI_i}{\mu}(p_i - p_i^w) \tag{1}$$

where, μ is the fluid viscosity and *WI* is the well index; p_i is the wellbore pressure and p_i^w stands for the well block pressure in block *i*. For the case of multiphase flow, relative permeability, as one extra parameter, must be included:

$$q_{pi}^w = WI_i \frac{k_{rp}}{\mu_p}(p_{pi} - p_i^w) \tag{2}$$

where, the subscript *p* denotes the phase and k_{rp} is the relative permeability of the phase *p*.

The important parameter in well modeling, which connects the reservoir body to the production well, is the well index. Therefore, it is necessary to introduce a proper well index to the simulator. The well index equation, which is used in all commercial simulators, was first proposed by Peaceman (1983):

$$WI = \frac{2\pi\Delta z(k_x k_y)^{0.5}}{ln\,({}^{r_o}/_{r_w})} \tag{3}$$

where, r_w is the wellbore radius and r_o represents the equivalent well block radius given by:

$$r_o = 0.28\frac{(\left(\frac{k_y}{k_x}\right)^{0.5}(\Delta z)^2 + (\frac{k_x}{k_y})^{0.5}(\Delta y)^2)^{0.5}}{(\frac{k_y}{k_x})^{0.25} + (\frac{k_x}{k_y})^{0.25}} \tag{4}$$

where, k_x, k_y, and k_z are permeabilities in i, j, and k directions respectively. Δz and Δy are block sizes in Z and Y directions correspondingly. This accounts for the geometry of the grid block, anisotropy and heterogeneity, block size and thickness, and well direction. Any change in these parameters would result in a different well index. In this paper, the changes in block size are considered to investigate the scale up. Moreover, the anisotropy, heterogeneity, and the well direction have been investigated by introducing both horizontal and vertical wells to determine the best well index and to improve the Peaceman equation. In order to execute the simulation runs, a Black-oil commercial simulator has been used. An injector well, which injects water at a constant rate of 1600 bbl/day, and a production well, which produces oil at a constant rate of 1000 bbl/day, have been used.

2. Methodology

Both homogeneous and heterogeneous permeability distributions were investigated for both horizontal and vertical wells. For the vertical well, 50, 100, and 1000 mD permeabilities were perused in both homogeneous and heterogeneous models. Reservoir porosity has a normal distribution and permeability has a log-normal distribution (John et al., 2007). Hence it is tried to establish a model with normal porosity and log-normal permeability distributions for heterogeneous models (in this paper, Dikstra-Parsons method is used to determine the level of heterogeneity). To compare the results of homogeneous and heterogeneous models, the heterogeneous models are established in a way that they have the same mean permeability and porosity as homogeneous models. Two rock types have been distributed around the reservoir model using the flow zone indicator (FZI) method (Aguilar et al., 2014; Prasad 1999). The number of blocks in the vertical model is 10×3×48 in X, Y, and Z directions respectively. The minimum block size of 0.5 ft has been considered as the reference fine block size, which gives us the exact response for the well index. The other coarsening levels are 5, 10, 20, 40, and 200 ft.

A similar investigation has been carried out for horizontal wells, but only two types of permeabilities have been selected; in other words, for the homogeneous model the permeabilities are 50 and 100 mD, and in the case of the heterogeneous well model, the average reservoir permeabilities are 50 and 100 mD.

The number of blocks in the horizontal model is 20×3×21 in X, Y, and Z directions respectively. Block sizes in X, Y, and Z directions are 200, 200, and 20 ft respectively. Then, the 40 ft around the horizontal well is tuned through the base fine level, i.e. 0.5 ft.

The horizontal section in the horizontal direction was divided into layers with different thicknesses. Coarse grid block levels are 2, 4, 10, and 20 ft in thickness.

3. Results and discussion

3.1. Vertical well results

Figure 1 shows the well bottom-hole pressure of all coarsening levels with respect to the fine grid block (0.5 ft) for the 50 mD model. As it can be seen, the profile of well block pressures of the producer is such that it first decreases and then changes direction toward increasing. This trend is due to water injection in the injection well; in other words, water is injected at a rate of 1600 bbl/day, but oil is only produced at a rate of 1000 bbl/day. It is obvious that production well has such an increasing trend in pressure. However, after the water breaks through the production well, the pressure starts to fall off. There is a significantly high range of difference from 40 psia to 100 psia in the bottom-hole pressure for 5 ft and 200 ft respectively. These are calculated by Peaceman *WI* (the default *WI* of all commercial simulators is calculated by Peaceman well model). An increase in the block size increases the gap between the pressures of the fine grid block and higher coarsening levels. In order to eliminate this error in the bottom hole and well block pressures, a scenario is established to find the correct *WI*'s at all coarsening levels. They are manually entered into the simulator. Figure 2 illustrates the resulting pressure readings before and after entering the matching well indexes for the 200 ft model (the highest level of coarsening); this is considered as the coarse level. After careful considerations, it is observed that in all cases the true (matching) well index is higher than the Peaceman well index by a constant i.e.:

$$\text{True well index} = \text{Peaceman well index} + k$$

where, k is the matching constant.

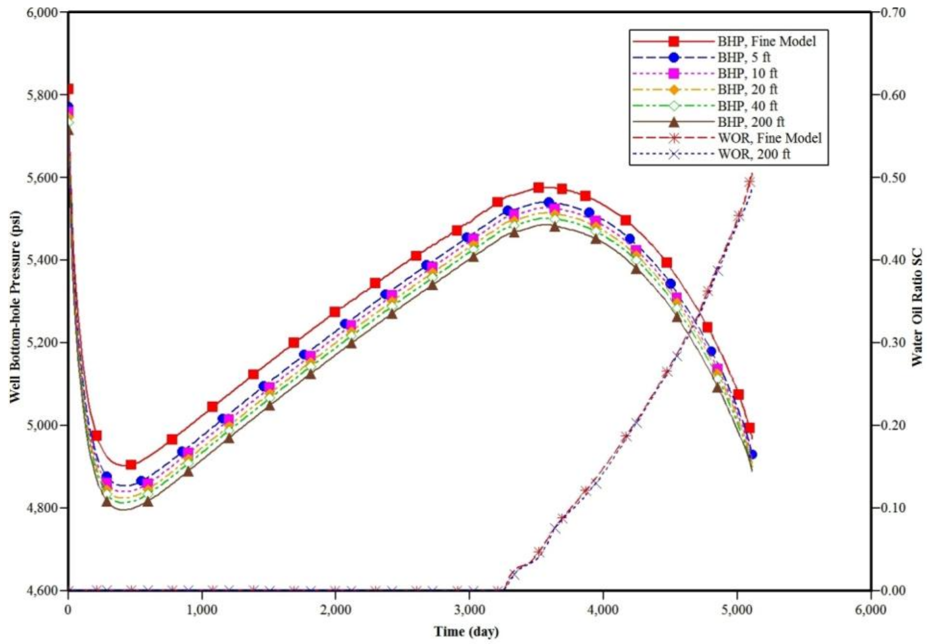

Figure 1
The result of well bottom-hole pressure at all coarsening levels with respect to fine scale model (the 0.5 ft model which is denoted by red squares), 50 mD homogeneous producer well.

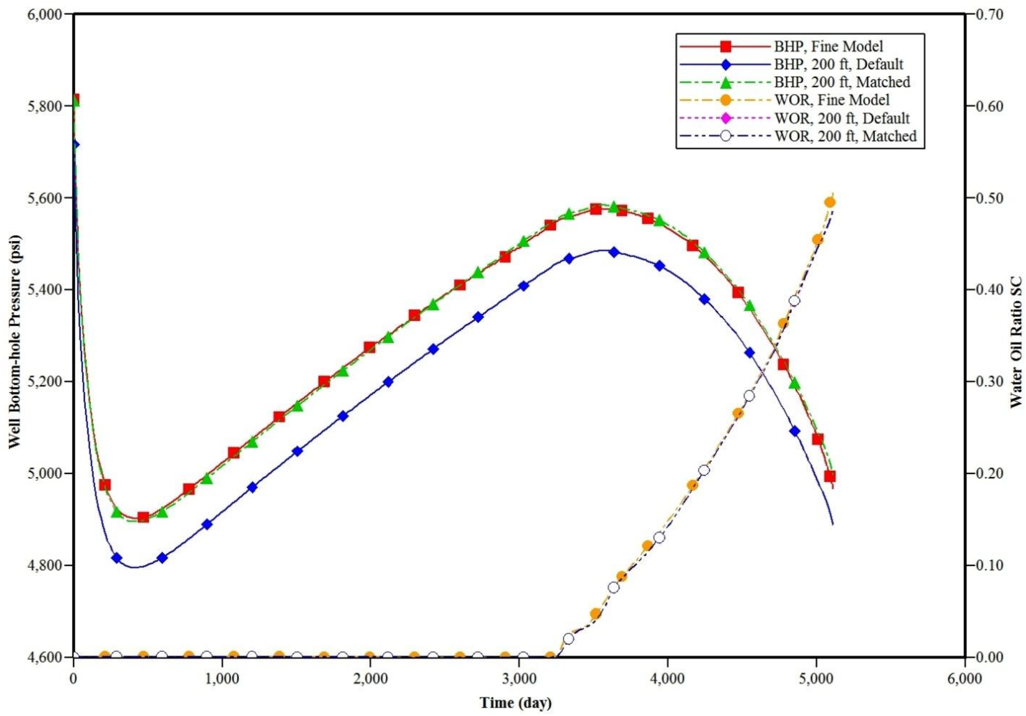

Figure 2
Comparison between default pressure (using Peaceman *WI*) and matching pressure results from matching well index for 50 mD permeability and water oil ratio at all permeability levels, 50 mD homogeneous producer well.

Table 1 presents the results for the matching well index for 50, 100, and 1000 mD. The matching constant for 50 mD is 700 mD×ft. The constants for the 100 and 1000 mD are 1400 mD×ft and 120000 mD×ft respectively. It is observed that a rising permeability level increases the level of matching constant. Figure 3 shows the matching pattern for 50 mD permeability level. It is observed that the abovementioned constants are only those that reduce the error for all the coarsening levels, i.e. the well index can precisely be matched for any single coarsening level.

Table 1
The well index results for 50, 100, and 1000 mD homogeneous vertical well.

Permeability	50 mD		100 mD		1000 mD	
Grid size	**Peaceman *WI***	**Matched *WI***	**Peaceman *WI***	**Matched *WI***	**Peaceman *WI***	**Matched *WI***
5 ft	1392	2000	2784	4000	27841	150000
10 ft	1263	1995	2526	3950	25256	148000
20 ft	1155	1995	2311	3900	23110	145000
40 ft	1065	1920	2130	3800	21300	140000
200 ft	901	1800	1802	3500	18022	130000

Figure 2 shows that for homogeneous and near homogeneous reservoir models in both single-phase and multiphase regions only permeability upscaling gives the appropriate matching and there is no need for relative permeability upscaling. Moreover, an exact matching between the coarse model (200 ft) and the fine model (0.5 ft) is obtained before (single-phase) and after (multiphase) water breakthrough. This figure also presents the water-oil ratio for the 200 ft model before and after matching. They are labeled as default and matched water-oil ratios respectively.

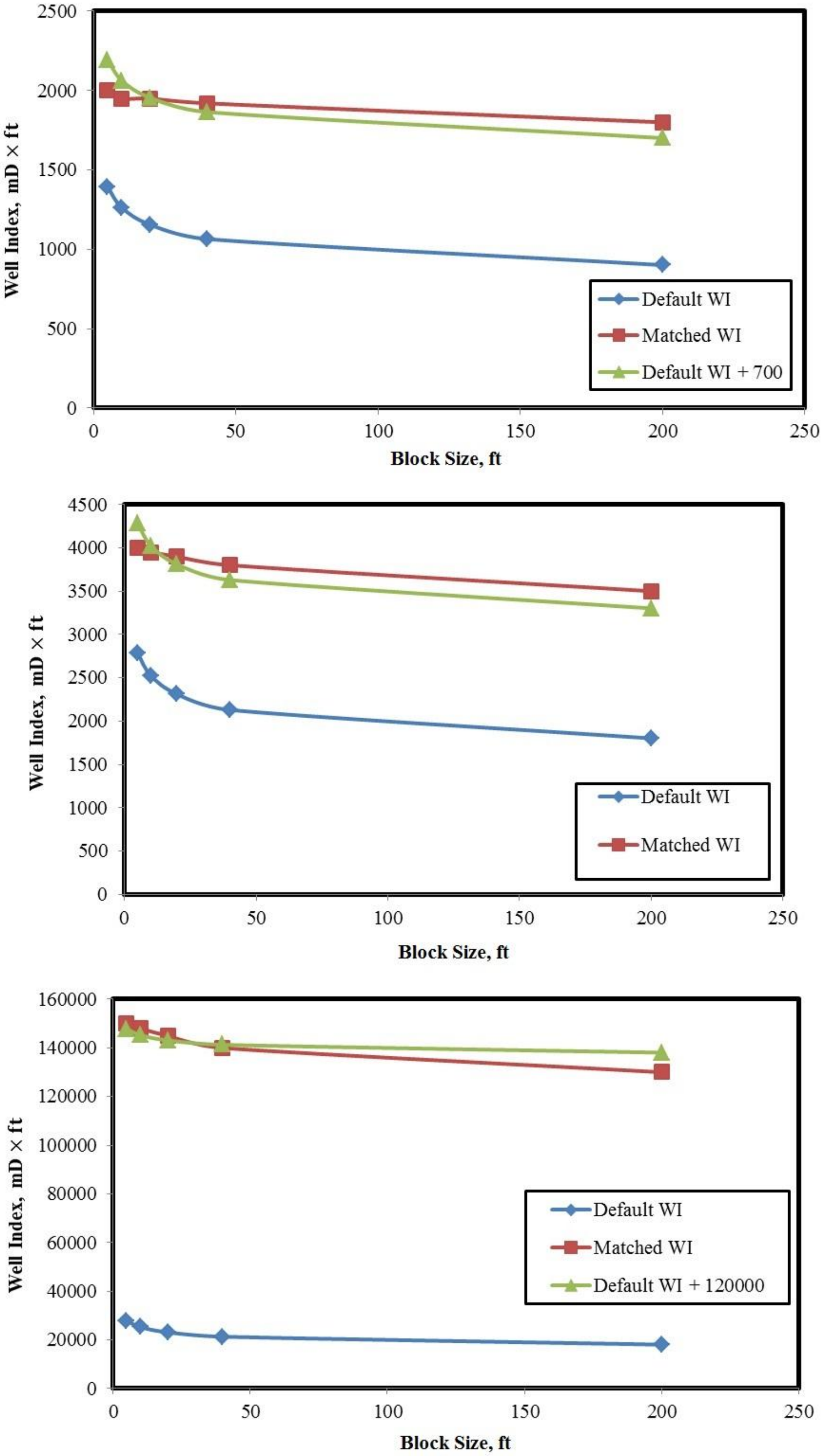

Figure 3
Matching scenario of three different permeability levels (from Top to Bottom 50 mD, 100 mD, and 1000 mD, homogeneous models) and how matching constants for all grid sizes are acquired.

After the investigation of the homogeneous model, it is attempted to establish a similar scenario for the heterogeneous model. Figure 4 shows the permeability and porosity distributions, which have been distributed all around the heterogeneous reservoir model. It is clear in this figure that permeability has a log normal distribution, while porosity has a normal distribution. As it was denoted in the preceding paragraphs, the level of heterogeneity is evaluated by Dykstra-Parsons. In this study, the Dykstra-Parsons constant is about 0.506. Figure 5 presents the matching scenario before and after entering the correct *WI*'s. A very precise matching is observed in the single-phase region, but there still exists a pressure gap in the two-phase region (which is observed after water breakthrough). This indicates that, in order to fill the pressure gap, it is necessary to upscale another parameter that is the relative permeability. Referring to Equations 1 and 2, it is observed that in Equation 1, which is for the single-phase well model, there is no term as relative permeability. However, in the case of multiphase model (Equation 2), there exists a $\frac{k_{rp}}{\mu_p}$ term, which introduces the phase permeability (relative permeability) and the phase viscosity. As a result, there is no need to use this term as an upscaling parameter in order to obtain a proper matching.

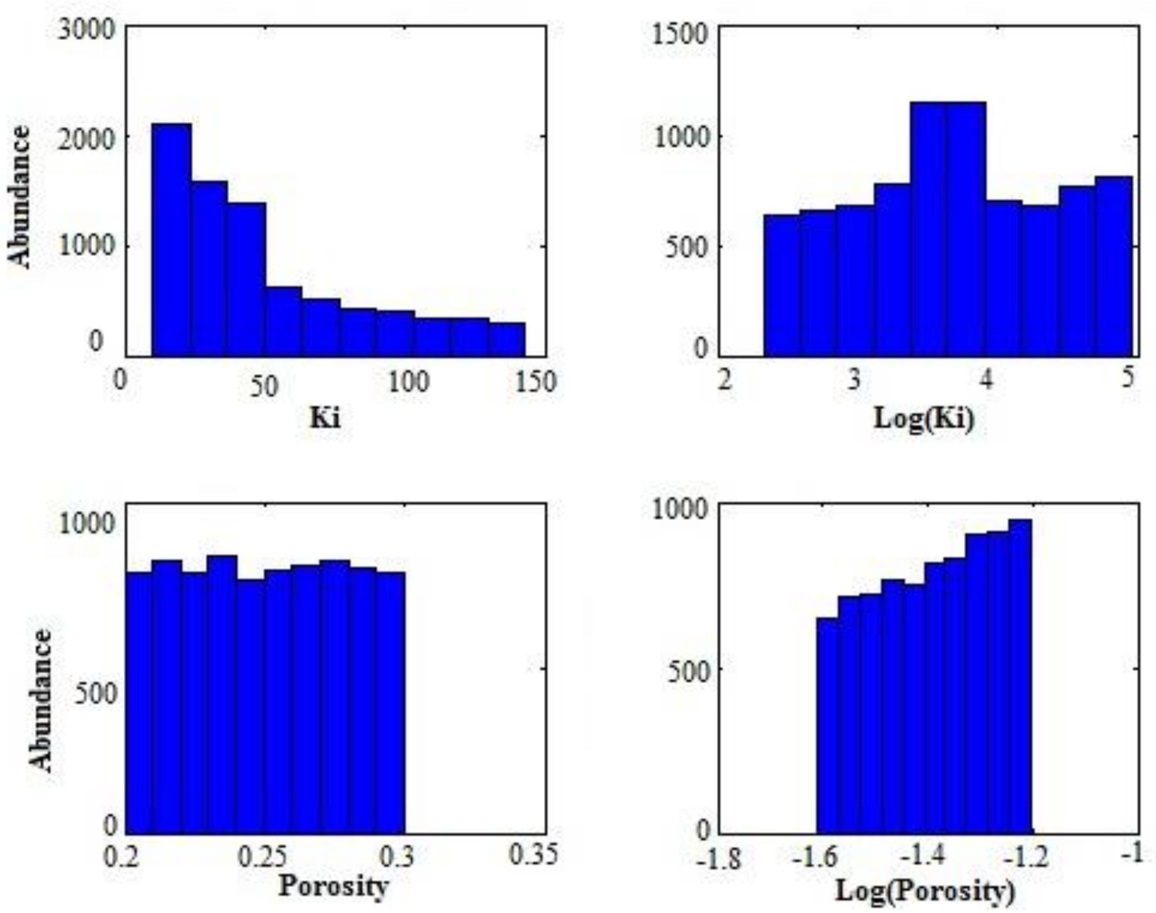

Figure 4
The histogram plot for permeability distribution for the heterogeneous model (lognormal distribution).

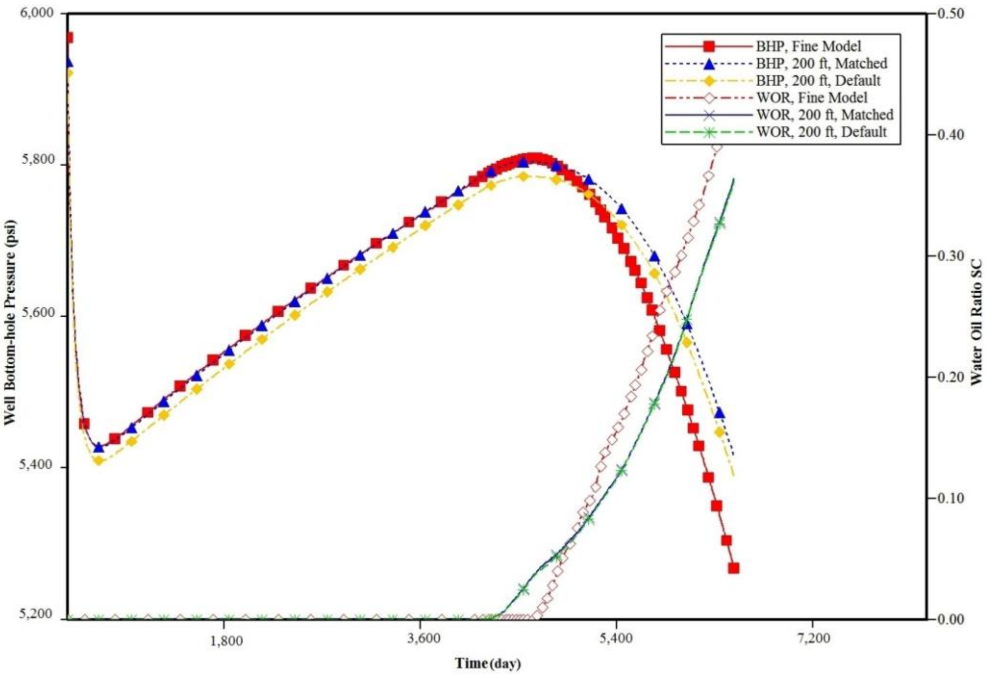

Figure 5
Matching scenario before and after entering the correct *WI*'s for heterogeneous reservoir model, 100 mD producer well.

Table 2 illustrates the results of the heterogeneous reservoir. Due to the variation in the well index in every grid block, the matching *WI* has been demonstrated by a multiplier to the *WI*'s of all the grid blocks, i.e. for the heterogeneous reservoir, one may obtain:

$$WI_{\text{Matching}} = L \times WI_{\text{Peaceman}}$$

where, the multiplier *L* is a constant with an approximate uptrend for lower permeabilities (50-100 mD) and an approximate downtrend for higher permeabilities (1000 mD) as listed in Table 2.

Table 2
The well index results for 50, 100, and 1000 mD heterogeneous vertical well.

Average Permeability	**50 mD**	**100 mD**	**1000 mD**
Grid size	**Matching Multiplier**	**Matching Multiplier**	**Matching Multiplier**
5	0.8	1.1	6.5
10	1.5	1.2	0.2
20	0.65	0.8	0.18
40	0.8	1.3	0.1
200	2.3	1.6	0.09

3.2. Horizontal well results

In this section, the matching results for the 50 mD model are illustrated. Since the results are the same for the 100 mD model, they have not been discussed to avoid rehashing.

Figure 6 shows the results of matching for the 50 mD model. They illustrate a very precise matching between fine grid and coarse grid models compared to the Peaceman results (those calculated by commercial simulators). Considering water-oil ratio curves in Figure 6, a very good matching both in the single and multiphase regions is observed. A similar conclusion could be drawn from this figure, i.e. absolute permeability upscaling gives appropriate results in the two regions and there is no need for relative permeability upscaling. Due to the various grid sizes of the horizontal well models, different pressure profiles are expected for these models.

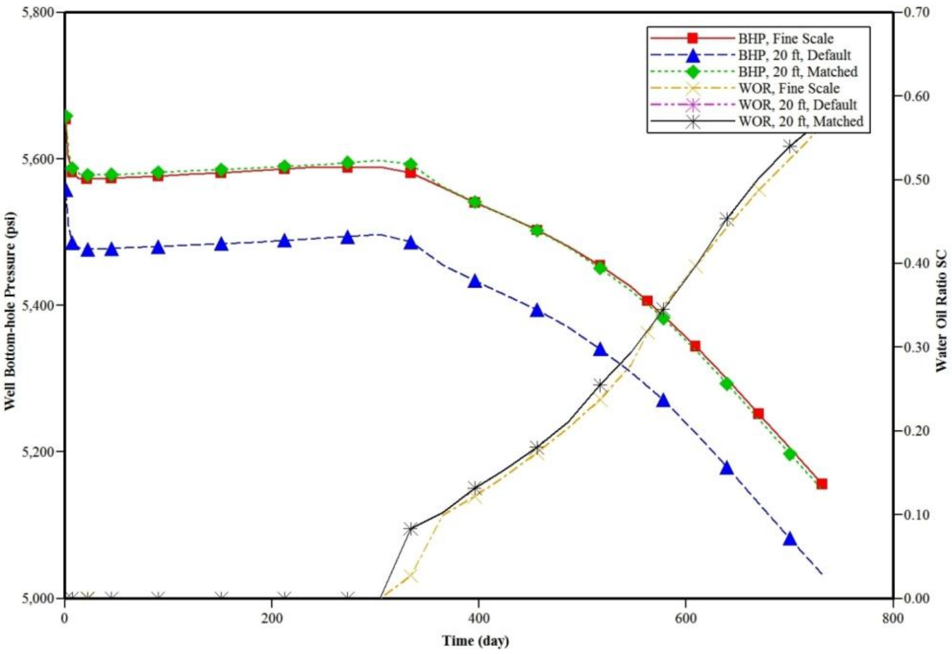

Figure 6
The results of matching for horizontal homogeneous well model, 50 mD producer well.

For the other coarsening levels, a similar scenario has been carried out to find the matching *WI*'s. Figure 7 displays the results of *WI* matching multiplier for each coarsening level in both 50 and 100 mD models. It illustrates that the difference between the two graphs is approximately constant.

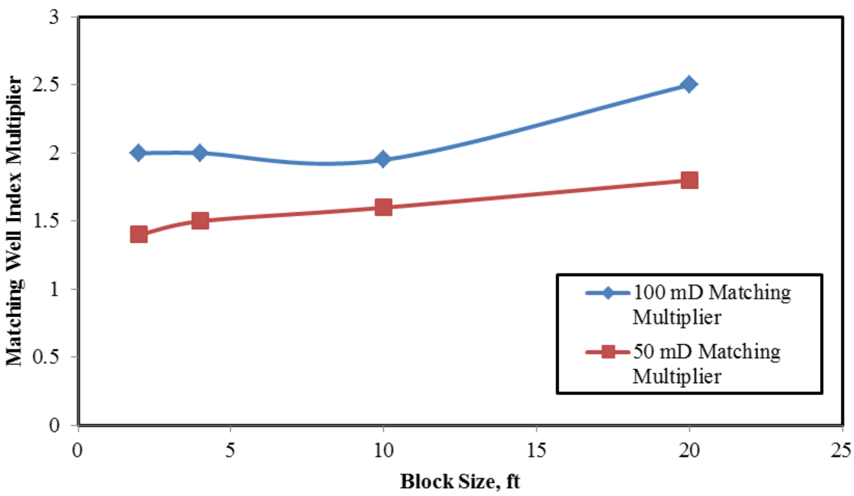

Figure 7
The results of *WI* matching multiplier for each coarsening level in both 50 and 100 mD horizontal homogeneous model.

For the heterogeneous case, just like the homogeneous case, a lognormal permeability distribution was generated for all the coarsening levels starting from 0.5 ft (which is the fine grid model) block size to the coarsest level (the 20 ft model, 100 mD). Figure 8 represents a sample of the permeability distribution of the fine grid model. It is clear that this permeability distribution is a log-normal distribution. Then, an attempt has been made to find the best matching *WI*'s for this set of grid blocks. Figure 9 shows the established matched model compared to the default model. Best matches between pressures in the single-phase region are observed; but, in the two-phase region there still exists a pressure gap, which should be compensated by relative permeability upscaling as it was mentioned in the preceding paragraphs. It should be noted that a single-phase region is the region of no water breakthrough; however, if water breaks through the investigated block, it is considered a two-phase region. Therefore, when an increase in water-oil ratio is observed, it means that there is a two-phase region.

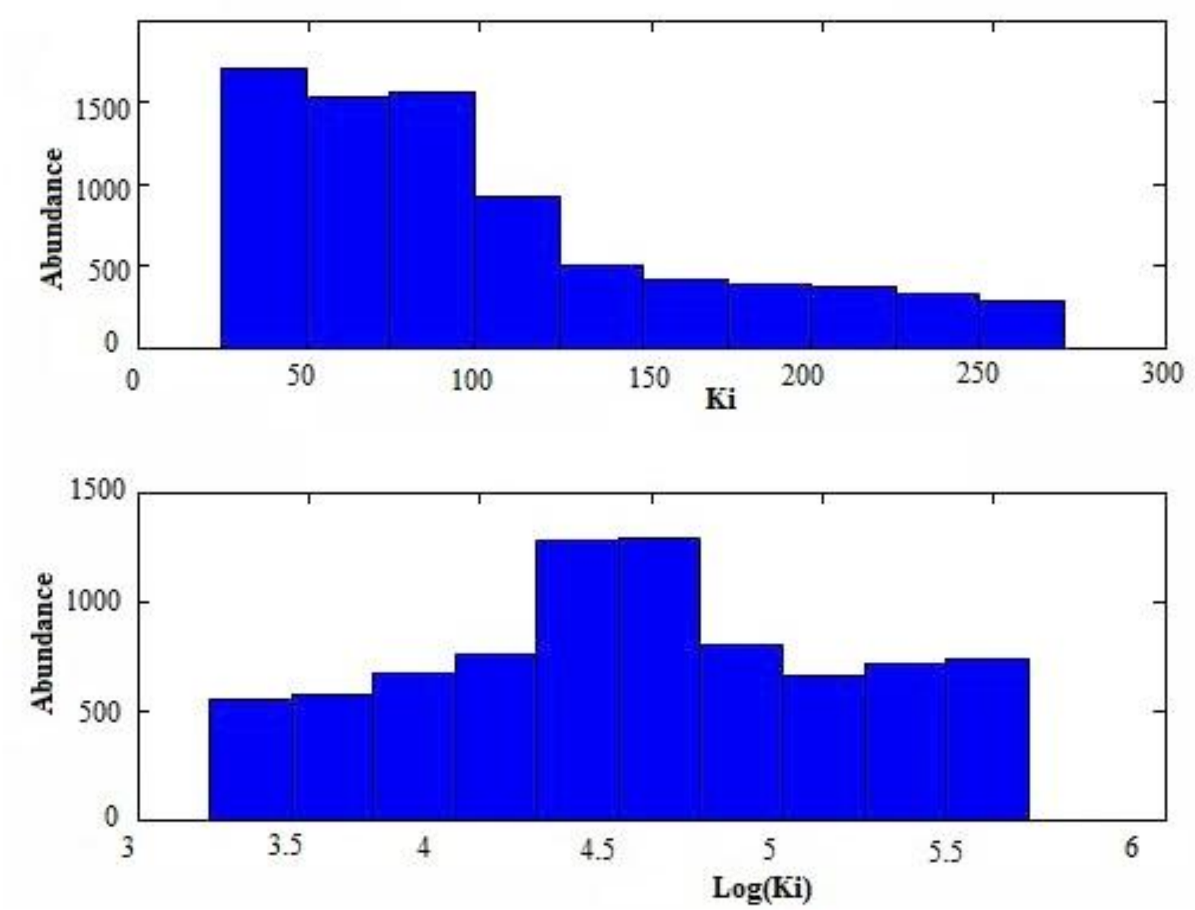

Figure 8
A schematic of a sample of permeability distribution for the fine grid for horizontal heterogeneous model.

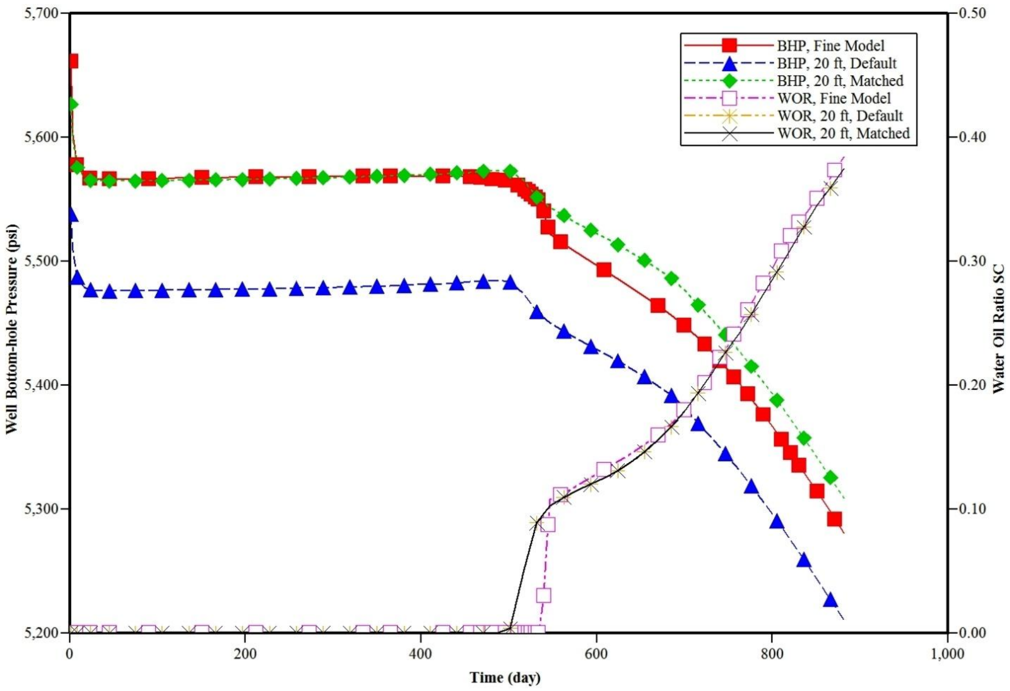

Figure 9
Established matched model compared to default model in horizontal heterogeneous model, 50 mD producer well.

4. Conclusions

In this paper, the near well upscaling and calculation of the well index were investigated. A good understanding of the exact well index is crucial for well modeling and reservoir simulation. Both horizontal and vertical wells were investigated to calculate the almost exact well index. According to the results, the following conclusions can be drawn:

1. In both homogenous horizontal and vertical well models, the exact well index could be obtained by the addition of a constant to the Peaceman well index;
2. In heterogeneous models, the exact well index could be obtained by multiplying the Peaceman well index by a constant;
3. For homogeneous reservoir models, absolute permeability upscaling gives the satisfactory results and there is no need for relative permeability upscaling;
4. In order to establish a good pressure matching and compensate the drawbacks of the Peaceman well index model some scenarios for permeability upscaling are recommended. However, these scenarios perform well only in single-phase regions. In order to improve the Peaceman well index drawbacks, it is recommended devising a relative permeability upscaling scenario for the two-phase regions. The single-phase region is considered as the region where there is no breakthrough of water, whereas a two-phase region is where water breaks through.

Nomenclature

bbl/day	: Barrel per Day
cP	: centipoise

ft	: Foot
k_r	: Relative Permeability
mD	: mili-Darcy
WI	: Well Index
μ	: Viscosity

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