PRODUCTIVITY AND INJECTIVITY OF HORIZONTAL WELLS

Quarterly Technical Progress Report
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Summary of Technical Progress

A number of activities have been carried out in the last three months. A list outlining these efforts is presented below.

- The work on modeling hydraulically fractured horizontal wells has moved forward. A literature review on the subject was done and some of the existing models have been coded and applied to example problems for evaluation purposes.

- Previous work on the effects of heterogeneities on the performance of horizontal wells was continued by conducting a sensitivity study on various parameters thet were kept constant in the earlier study. For example, we have studied the effect of gas cap and aquifer size, well location, fluid viscosity, etc.

- The experimental work on using horizontal wells as injectors and producers in a gas injection gravity drainage process continued. New and repeat experiments were conducted.

- Work on streamline grids was advanced by considering example problems with highly distorted grids which cannot be directly used for flow simulation. Grid smoothing and domain mapping techniques were investigated to handle such situations.

- A technique was developed for the computation of well index with consideration to wellbore pressure drop. A recently developed reservoir/wellbore coupling model was used for this purpose.

The last activity listed above is the subject of this quarterly report. Only a brief discussion and some sample results will be shown here. A comprehensive account of the work will be included in the Annual Report.

Impact of Wellbore Pressure Drop on the Well Index for Horizontal Wells (Task 1)

Introduction

It is now recognized that pressure drop in a horizontal well can have a significant impact on its productivity. Frictional and accelerational pressure drops are the two main contributing factors to this wellbore pressure drop. This work investigates the productivity losses due to frictional and accelerational pressure drops in a horizontal well. Comparison between a commercial numerical simulator and a semi-analytical solution is made on the basis of well indices. The results are used to determine correct well indices. We present several cases which show how the results of numerical simulators can be improved via this approach.

Conventional Well Model

The standard well model used in most numerical simulators was introduced by Peaceman (1978, 1983) with the assumptions of 2D single phase flow for an isolated well under steady state or pseudo-steady state flow conditions.

The basic equations (well model) relating the well pressure p^w to the well block pressure p_0 at a given well flow rate q^w are

$$WI = \frac{2\pi k h}{\ln \frac{r_0}{r_w} + s} \tag{1}$$

$$p^w = p_0 + \frac{q^w}{WI \cdot \lambda} \tag{2}$$

In above equations, WI is the well index, λ is the mobility defined as $\frac{k_r}{\mu B}$. Nomenclature contains the definition of other symbols. r_0 is the equivalent wellblock radius. Several formulae are available to compute r_0 for different geometries. For the examples discussed here, we used rectangular grids with block spacing Δx, Δy in an isotropic reservoir for which r_0 is given by

$$r_0 = 0.140365\sqrt{\Delta x^2 + \Delta y^2} \tag{3}$$

Correct Well Model

Recently, a semi-analytical coupling model for flow in the reservoir and in the wellbore was developed by Penmatcha (1997). This is a transient, three-dimensional model and considers pressure drop in the well. In this approach, a horizontal well is divided into many segments. The analytical solution of Babu and Odeh (1989) is used for each segment. Solution for the entire well is obtained by superposition in time and space. For finite conductive wells (with wellbore pressure drop), a momentum equation which accounts for frictional and accelerational pressure drop is written for each segment. The effect of inflow is accounted for by using the model proposed in Ouyang et al. (1996).

This coupling model is used to compute the analytical values of well pressure p^w and flow distribution q^w for each well segment. Using the same inflow distribution in a simulator, the wellblock pressures are obtained for the same problem. The correct well index for each block can then be obtained from Equation 2.

Comparative Simulation Study

In this section the results of the semi-analytical model with those obtained from a commercial reservoir simulator (Eclipse, 1996A) are compared.

A single horizontal well was aligned parallel to the y-axis in a block shaped reservoir (see Table 1 and Figure 1). Effects of pressure drop in the well and other parameters were studied. A 51 x 100 x 5 grid was used.

reservoir length a	6,000	ft
reservoir width b	12,000	ft
reservoir height h	50	ft
permeability $k_x = k_y = k_z$	3,000	mD
porosity ϕ	0.3	
initial reservoir pressure p_{ini}	4000	psi
total compressibility c_t	$3 \cdot 10^{-5}$	psi^{-1}
form. volume factor B_o	1.05	$\frac{RB}{STB}$
viscosity μ	1	cp
density at res. cond. ρ	60	$\frac{lb_m}{ft^3}$
max. well rate q_{max}	10,000	$\frac{STB}{day}$
min. bottom hole pressure p_{min}^w	1,200	psi
well location	variable	
well radius r_w	0.1667	ft
skin s	0	

Table 1: Data of basic reservoir-well model.

Four cases were considered. In the first case, a 6000 ft well was placed at the center of the reservoir. The only difference in the second case was that the well was much shorter (1200 ft). In the third and fourth cases, we moved the long well to another location in the reservoir. For instance in the third case, well was positioned offcentered midway between the center of the reservoir and its boundary. In the last case, well was located near the edge of the reservoir, referred to as an edge well. A relative roughness value of 0.0005 was used in all calculations when considering pressure drop in the wellbore. These cases are summerized in Table 2.

The top plot in Figure 2 shows variation of wellbore pressure along the well length from analytical and numerical solutions at 1, 2, and 4 days. The light horizontal lines correspond to the situation when pressure drop in the wellbore is ignored. When pressure drop is present, pressure at the heel is lower than the toe. At 1 day where flow is in the transient regime, there is some difference between the analytical and numerical (with peaceman WI) results. This difference becomes less at day 2 and almost completely vanishes at day 4, where pseudo-steady state (PSS) has been reached. This indicates that for this well configuration, the default Peaceman well model is appropriate when PSS is reached. Figure 2 also shows that the numerical solution with the correct well index, obtained as described above, closely reproduces the analytical solution. The bottom plot in Figure 2 depicts the inflow distribution along the well for the same conditions as in the top plot at day 4. It shows that with no pressure drop, a symmetric flow distribution is obtained which has higher inflow at the tips signifying spherical flow. With pressure drop included, the distribution is asymmetric with much larger inflow at the heel than at the toe. There are no significant differences between the analytical and numerical results for the case with pressure drop.

Figure 3 shows similar results for case 2 where the only difference is a shorter well.
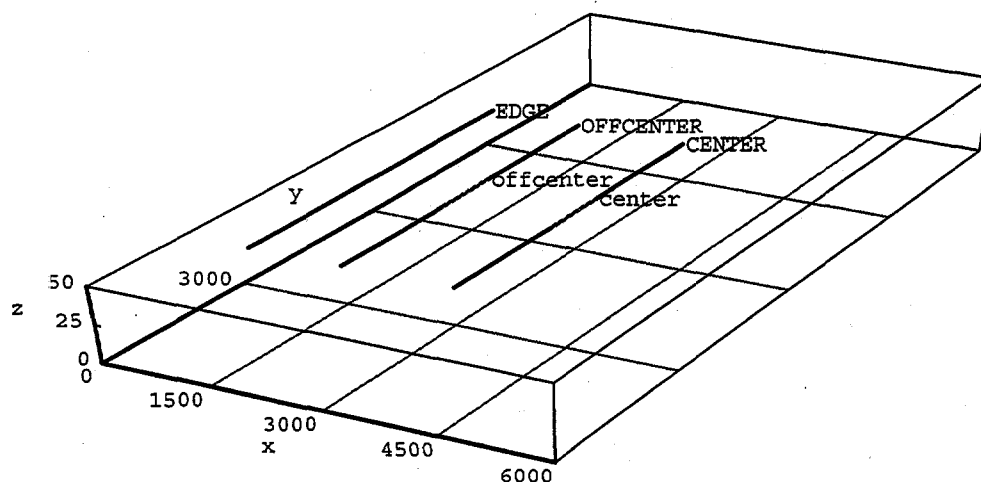
Figure 1: Geometry of wells in a block shaped reservoir

The top plot shows a larger difference between the analytical and simulation results at all three times. The differences are especially large for the first day. It also shows that the corrected WI's improve the numerical results. The bottom plot illustrates that inflow distribution along a shorter well is different by comparison with the previous case. The effect of spherical flow at the end is more pronounced and some differences in inflow distribution between numerical and analytical results are observed for this case.

Results for an offcentered well (case 3) and an edge well (case 4) are presented in Figures 4 and 5. While they show similar trends, the difference between numerical and analytical results in the case of an edge well are larger.

case	1(Long Centered)	2 (Short Centered)	3 (Long Offcenter)	4 (Long Edge)
x_0	3000	3000	1440	120
y_0	3000	5400	3000	3000
length	6000	1200	6000	6000
z_0	25	25	25	25
D_{ref}	4025	4025	4025	4025
segs	50	10	50	50
ϵ	0.0005	0.0005	0.0005	0.0005
reservoir dimensions: 6000 x 12000 x 50 ft				

Table 2: Well location for cases under study (length unit: feet).

4

Conclusions

An analysis of well indices for a finite conductivity horizontal well is presented. Correct values were obtained from a semi-analytical solution. The use of a numerical simulator with a conventional well model showed the following results:

- Consideration of frictional pressure drop in the well can be very important for horizontal wells.

- Considerable errors are made by the numerical solution during the early time transient behavior. This is mostly due to violations of the basic assumptions of the conventional well model.

A method for correcting the well index was presented. The cases investigated show improved results with corrected well index, especially in the transient flow regime.

Nomenclature

$B, B_o = $ *formation volume factor*, $\frac{RB}{STB}$
$D = $ *pipe diameter*, *ft*
$\varepsilon = $ *relative pipe roughness*
$\phi = $ *porosity*
$p^w = $ *well perforation pressure*, *psi*
$p_0 = $ *well block pressure*, *psi*
$k = $ *permeability*, *mD*
$k_r = $ *relative permeability*
$k_x, k_y, k_z = $ *anisotropic k in directions* x, y, z
$\lambda = $ *mobility*
$\mu = $ *viscosity*, *cp*
$r_0 = $ *equivalent wellblock radius*, *ft*
$r_w = $ *well radius*, *ft*
$s = $ *skin factor*
$WI = $ *well index*
$\Delta x, \Delta y, \Delta z = $ *block length in* x, y, z *direction*, *ft*

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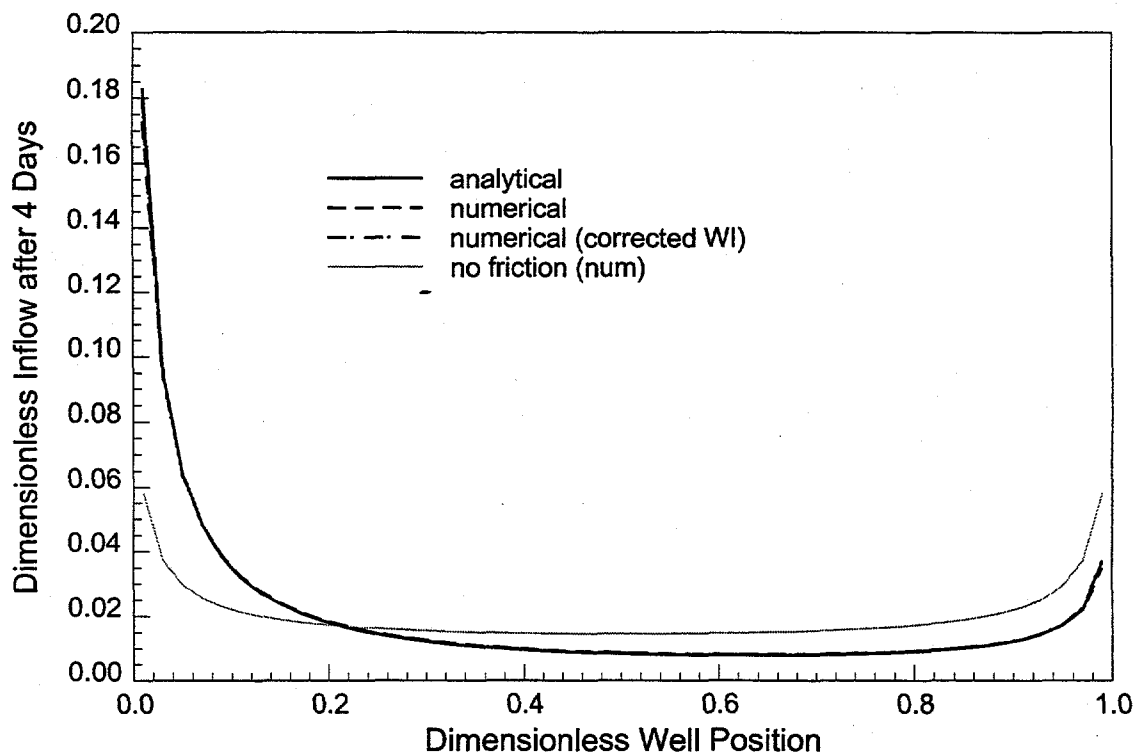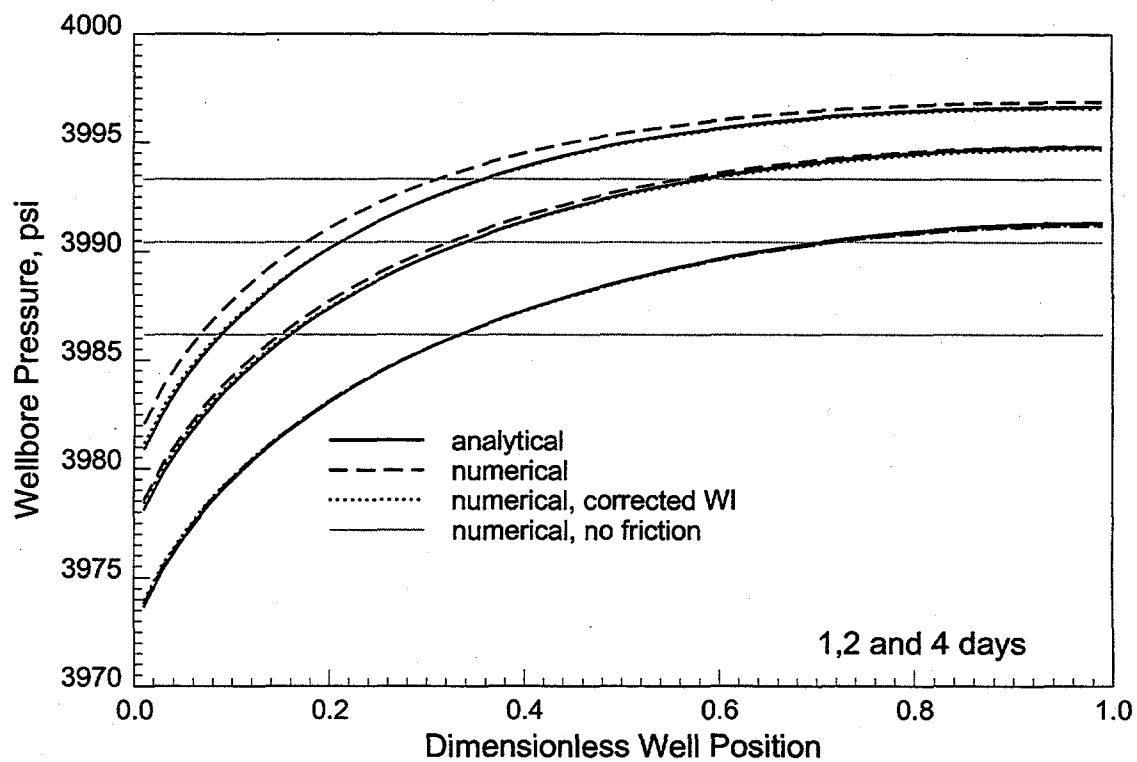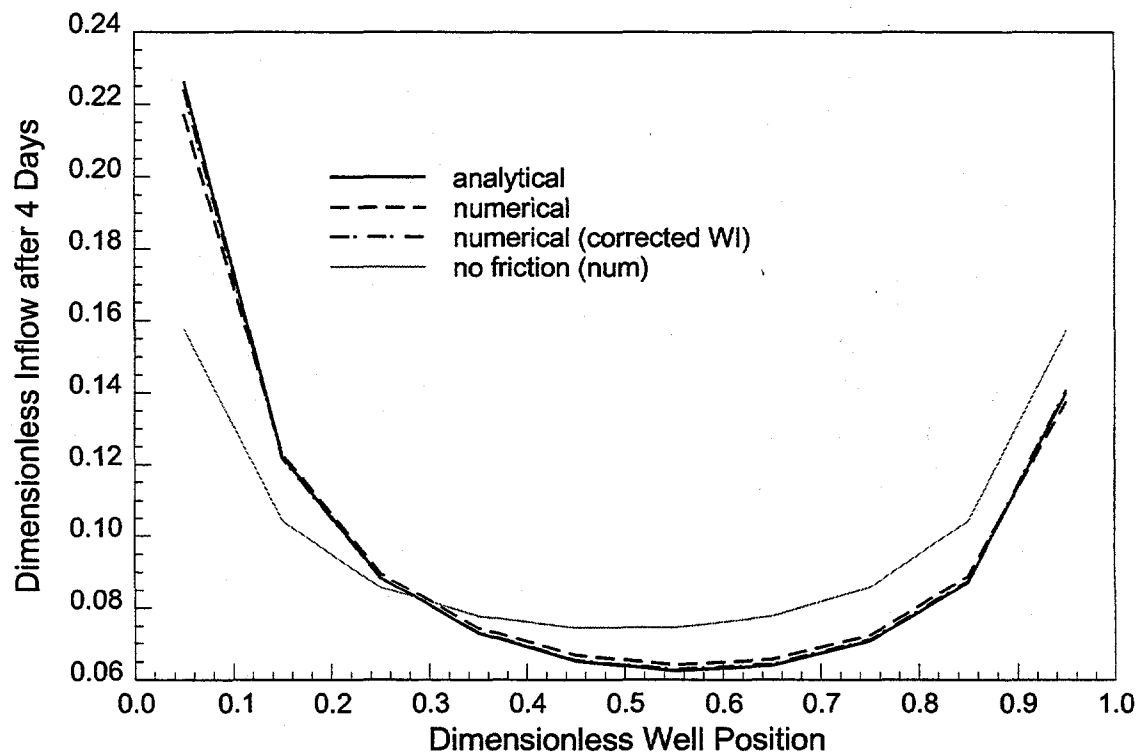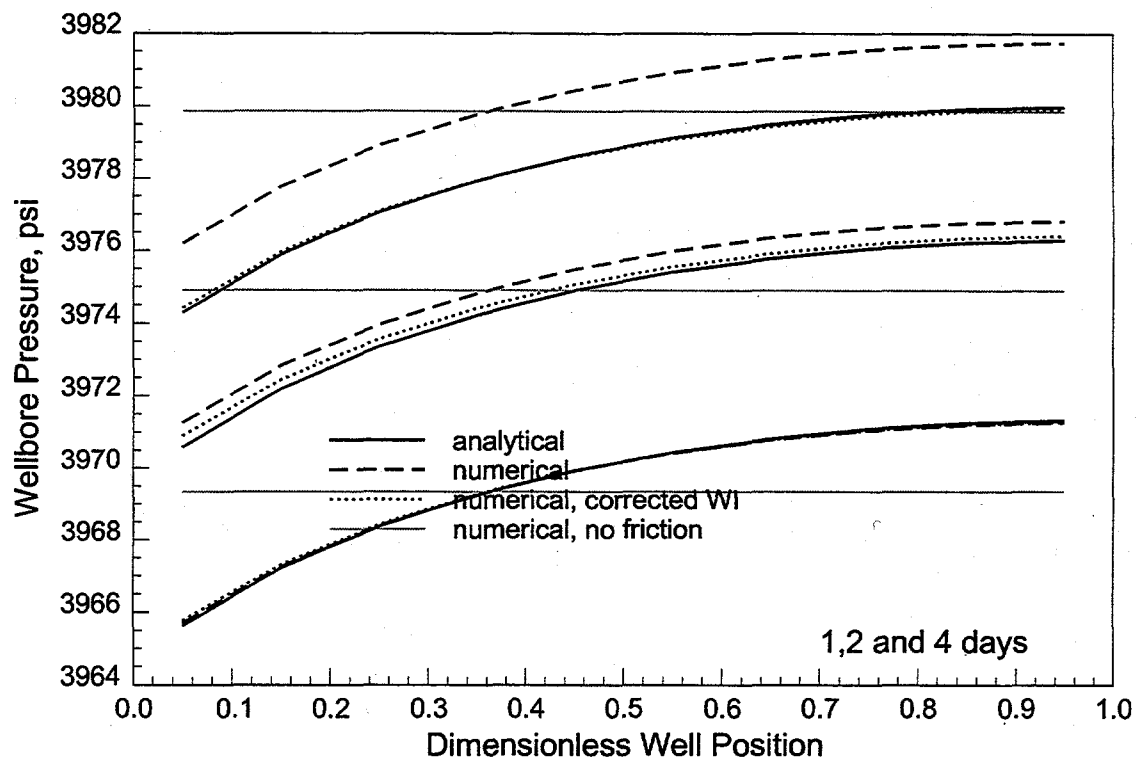
Figure 2: Case 1, Long Centered Well - (Top) Comparison between numerical and analytical results for wellbore pressure at different times - (Bottom) Variation of inflow distribution along the well length from numerical and analytical solutions at 4 days
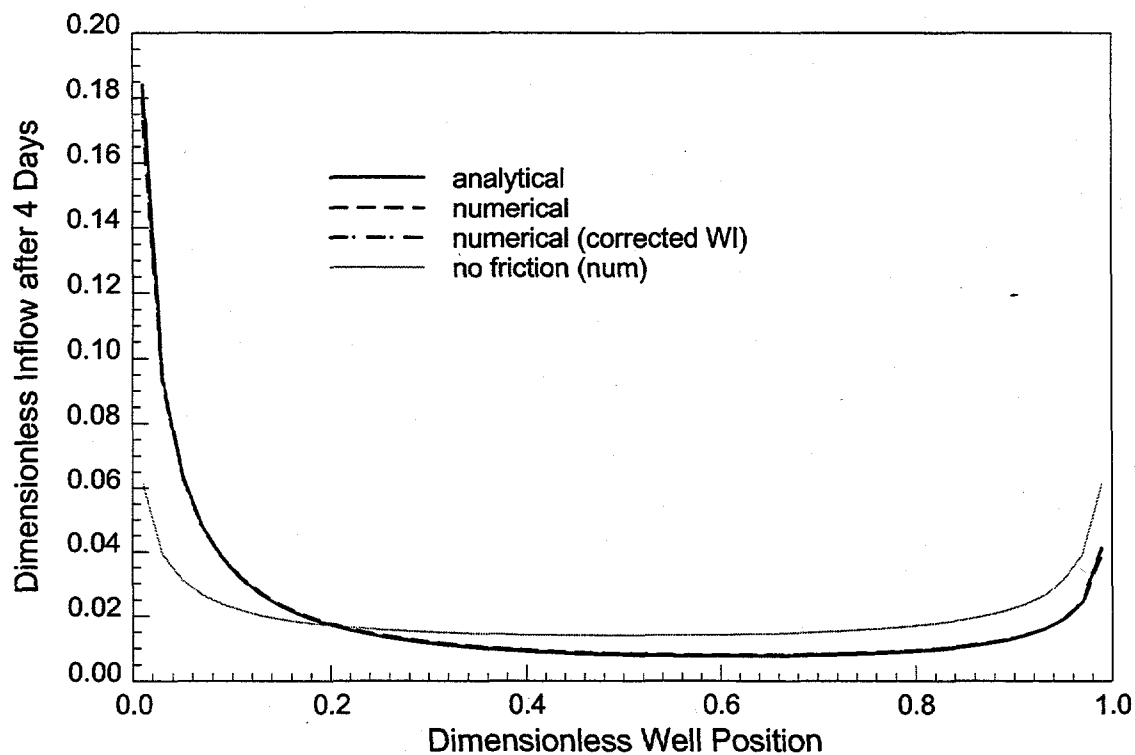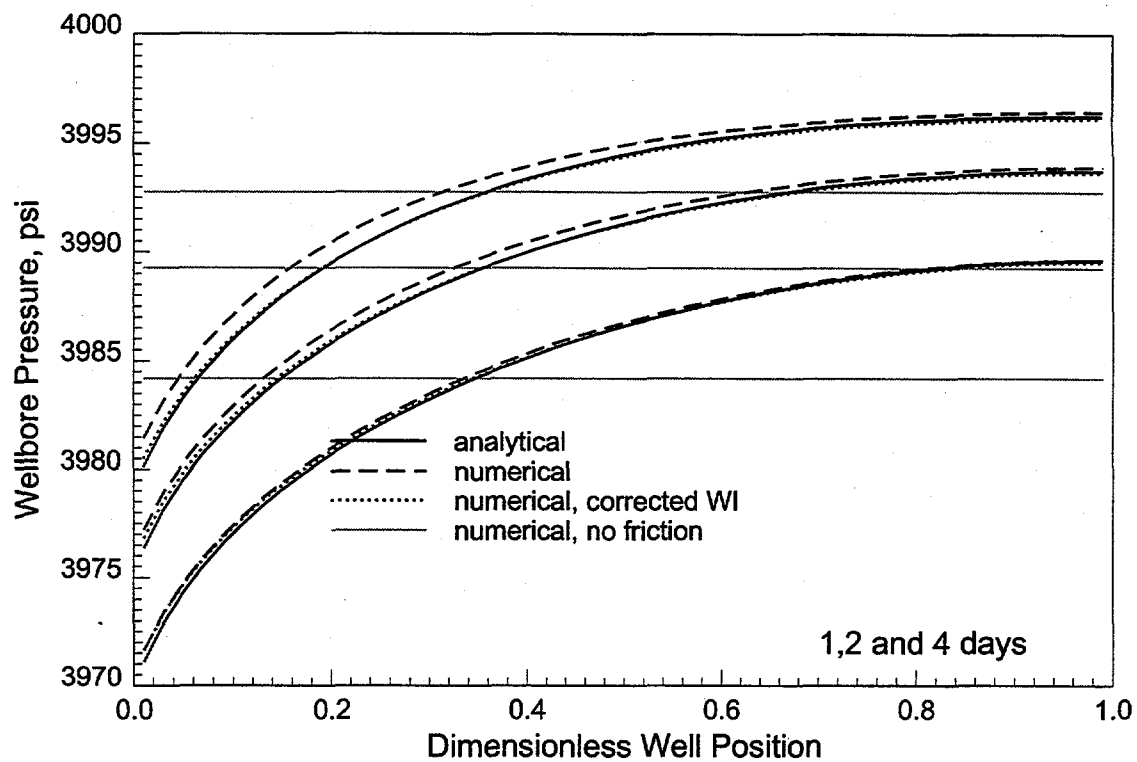
7

Figure 3: Case 2, Short Centered Well - (Top) Comparison between numerical and analytical results for wellbore pressure at different times - (Bottom) Variation of inflow distribution along the well length from numerical and analytical solutions at 4 days

Figure 4: Case 3, Offcentered Well - (Top) Comparison between numerical and analytical results for wellbore pressure at different times - (Bottom) Variation of inflow distribution along the well length from numerical and analytical solutions at 4 days
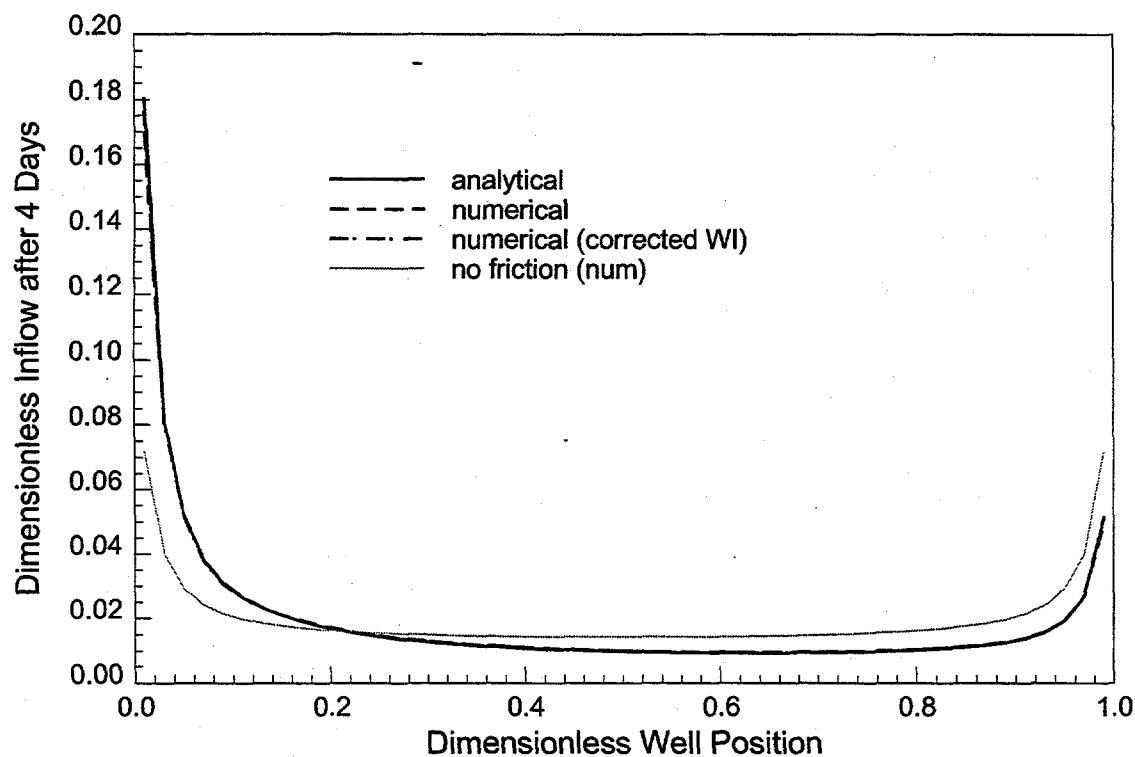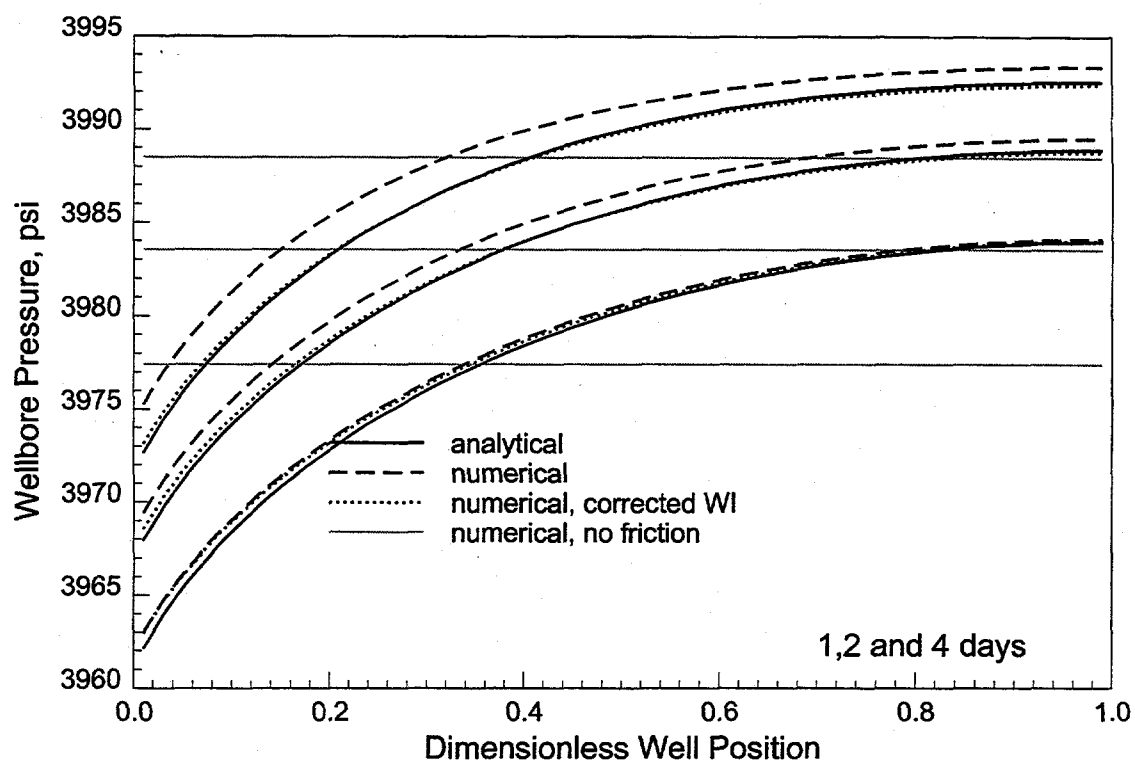
9

Figure 5: Case 4, Edge Well - (Top) Comparison between numerical and analytical results for wellbore pressure at different times - (Bottom) Variation of inflow distribution along the well length from numerical and analytical solutions at 4 days