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Research paper

New Technique for Calculation of Well Flowing Performance in Hydraulically Fractured Wells

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A b s t r a c t

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One of the main concerns for reservoir engineers is prediction of future well performance. In hydraulically fractured wells flowing parameters completely change the governing equations of fluid flow through the reservoir and wellbore. Since the purpose of hydraulic fracturing is reduction of skin effect, this parameter plays the most important role in the future well performance. This paper introduces a new method for prediction of hydraulically fractured wells performance. This technique is based on using a new approach for skin effect parameter in hydraulically fractured wells. This method uses the concept of Part's fracture relative capacity, without requiring knowing fracture and reservoir permeability or fracturing width. In this approach to convergence the fracture skin effect have derived a relation between fracture relative capacity and dimensionless fracture conductivity by using Cinco-Ley and Samaniego method. A program had been prepared to calculation of numerical equations governing on well flowing performance in the case of hydraulically fractured well through this study. At the end, this approach and developed code have been applied to the several fractured well fine grid black-oil simulation of a real oil reservoir. Finally, the simulation study confirmed the results of the proposed model and there was a reasonable agreement between the obtained results of proposed model and numerical simulator.

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1. Introduction

One of the first attempts to quantify the benefits of hydraulic fracturing was that of McGuire and Sikora in 1960. They employed an electrical model of a fractured reservoir. With a ratio of fracture length to reservoir drainage radius from 0.1 to 1.0, they showed that the expected stimulation PIR falls between about 1.5 and 14 [1].

Previous studies have addressed both vertical and horizontal wells considering both oil and gas production. For gas production there is a need to adjust the fracture design to account for non-Darcy flow, especially for transverse hydraulic fracture created in horizontal wells. Economides and Martin (2012), indicated that vertical wells with vertical fractures outperform multiple transverse fractures in horizontal wells for permeability above 0.5 md [2].

Jiajing Lin and Ding Zhu (2012) presented a semi-analytical model by a source method to estimate well performance in a complex fracture network system. Their method simulated complex fracture system in a more reasonable approach. They also showed that non-Darcy flow can be treated as the reduction of permeability in the fracture to a considerably smaller effective permeability. The reduction was about 2% to 20%, due to non-Darcy flow that could result in a low rate [3].

Shen Ruiand Geo Shusheng (2010) considered numerical simulation of production performance of fractured horizontal wells with respect to the conductivity variation. The black oil model was improved in their study and the relation of the hydraulic fracture conductivity changing with time was considered in their model. The mathematical model was discretized by the finite-difference approximation, and the control equations of percolation were solved by the implicit pressure explicit saturation method. They showed that the fracture conductivity has great influences on pressure distributions. In the initial stage of simulation, pressure contours near fractured wells was oval. When the fracture conductivity disappeared, pressure near wells was circular shape [4].

Meyer and Bazan (2010) presented a comprehensive methodology using the trilinear solution to predict the behavior of multiple transverse finite conductivity vertical fractures in horizontal wellbores [5].

Amimi and Valko (2007) developed a method with distributed volume sources to estimate fractured horizontal wells in a box-shaped reservoir. A source term was added to the diffusivity equation to calculate the pressure distribution. Then the production rate from a fracture is computed [6].

Different from the other point source methods, the volume source approach is able to describe the pressure behavior inside sources and its influence to the flow field. Magalhaes and Zhu (2007) showed applications of the volumetric source model and field cases are presented in their work [7].

Miskimins and Baree (2005) demonstrated that non-Darcy flow effects can influence well productivity across the entire spectrum of flow rates. They showed that even in low velocity situations, non-Darcy effects can influence the productivity. Non-Darcy flow have a major impaction reduction of a propped half-length to a considerably shorter effective half length, thus lowering the well's productivity capability and overall recovery [8].

Bobby and Poe (2000) presented a detailed analysis procedure for obtaining estimates of the reservoir effective permeability, fracture effective half-length, and average fracture conductivity using the bilinear to formation linear transition regime duration production performance data. A combination of fractured well diagnostic analyses and history-matching with analytic solutions were used to obtain reliable estimates of the average fracture properties and reservoir effective permeability. The transient performance models reported in their study included the practical reservoir effects of dual porosity, reservoir permeability anisotropy, and fracture face skin effect [9].

Hrachovy (1993) investigated the equations governing well performance for hydraulically fractured wells producing from solution gas drive oil reservoirs. He presented a method which permitted prediction of the folds of increase and the corresponding oil production rate obtained by fracturing until the economic limit was reached. His paper presented a method which accounted for multiphase flow effects in the prediction of productivity index ratios and production performance for hydraulically fractured oil wells in solution gas drive reservoirs. Also he presented a new reference curve for Productivity Index Ratio for Multiphase flow (PIRm) for hydraulically fractured wells. An algorithm for the new method was also presented to enable calculation of rate versus time. The predictions were compared with those obtained from a reservoir simulator and with the predictions calculated using a single phase commercial fracture design program. Additionally, an example problem using actual field production data was shown to validate the method's predictions [10].

In 1961, Parts provided pressure profiles in a fractured reservoir as function of the fracture half-length and the relative capacity, a, which he defined as

$$a = \frac{\pi k x_f}{2 k_f w} \qquad (1)$$

Where k is the reservoir permeability, k_f is the fracture permeability, and w is the propped fracture width. In subsequent work, Argawal et al. (1979) and Cinco-Ley and Samaniego (1981) introduced the fracture conductivity [11], C_{FD}, which is exactly

$$C_{FD} = \frac{k_f w}{k x_f} \qquad (2)$$

And is related to Parts a by

$$C_{FD} = \frac{\pi}{2a} \qquad (3)$$

Parts (1961) also introduced the concept of dimensionless effective wellbore radius in a hydraulically fractured well,

$$r_{wa_D} = \frac{r_{wa}}{x_f} \tag{4}$$

Where r_{wa} is

$$r_{wa} = r_w e^{-s_f} \tag{5}$$

The radial flow fracture skin factor, S_f , can be estimated (by correlation) for the case a well with a finite conductivity vertical fracture in a homogeneous, infinite-acting reservoir. In the case of a fractured well the radial flow skin factor represents the deviation from radial flow that the fracture causes (i.e., the flow improvement). This result is [12]:

$$\frac{r_w e^{-s_f}}{x_f} \cong exp\left[-\frac{1.648546-3.002711\times10^{-1}u+1.506532\times10^{-1}u^2}{1+2.136604\times10^{-1}+9.513761\times10^{-2}u^2+8.276998\times10^{-3}u^3}\right]\text{(Valko Correlation)} \tag{6}$$

Where $u = \ln(C_{FD})$. Solving for the skin factor, s, we have

$$s = ln\left[\frac{r_w}{x_f}\right] + \frac{1.648546-3.002711\times10^{-1}u+1.506532\times10^{-1}u^2}{1+2.136604\times10^{-1}+9.513761\times10^{-2}u^2+8.276998\times10^{-3}u^3} \tag{7}$$

$$\frac{r_w e^{-s}}{x_f} \approx \frac{1}{2}\begin{bmatrix} 1 - 4.622848\times10^{-2}\exp\left(-4.354799\times10^{-3}C_{fD}\right) \\ -3.536031\times10^{-1}\exp\left(-8.119795\times10^{-1}C_{fD}\right) \\ -5.874493\times10^{-1}\exp(-8.119795\times10^{-1}C_{fD} \end{bmatrix} \quad \text{(Alternative Correlation)} \tag{8}$$

2. Methodology

This paper introduces a new method for prediction of fractured wells performance. This technique is based on using a new approach for skin effect parameter in hydraulically fractured wells. This method uses the concept of fracture relative capacity (Parts, 1961), without requiring to know fracture and reservoir permeability or fracture width. In this approach to convergence the fracture skin effect have derived a relation between fracture relative capacity and dimensionless fracture conductivity [13].

A program had been prepared to calculation of numerical equations governing on well flowing performance in the case of hydraulically fractured well through this study.

At the end, this approach and developed code have been applied to the several fractured well fine grid black-oil simulation of a real oil reservoir. Finally, the simulation study confirmed the results of the proposed model and there was a reasonable agreement between the obtained results of proposed model and numerical simulator.

3. Computational algorithm

Suppose that the available data are the well radius, fracture half-length, wellbore pressure, PVT data (assuming a black oil model). Then the computational algorithm for the proposed approach can be summarized as follow:

1) In current time step input an initial reasonable guess for fracture radial flow skin factor.

2) In next time step calculate apparent wellbore radius and fracture relative capacity by using Parts method.

3) Determine dimensionless fracture conductivity by using Cinco-Ley and Samaniego method.

4) Calculate a new value of fracture radial flow by using Valko correlation.

5) Check the calculated "S_f" in step 4 with the guessed value in step 1.

6) If the value of absolute difference between the two value of "S_f" is less than ε go to next step, if not replace the calculated "S_f" in step 4 with the guessed value in step1, then continue again.

7) Determine the average reservoir pressure with the respect to the obtained "S_f" by using material balance methods.

8) Compare the calculated average pressure in step 7 with the observed data. If there is a reasonable agreement, continue; otherwise select an average value between observed pressure and calculated average pressure in step 7.

9) Record the converged values for the flow rates and the average reservoir pressure. Then go to the next well pressure and time.

Then the computational algorithm for the proposed approach can be summarized as it is shown in Figure 1.

To validate the proposed approach we have taken a field study on three hydraulically fractured wells with characteristics that are given in Table 1. Figure 2shows the locations of the three wells in the reservoir. We have simulated pressure drop profile and cumulative oil production in this reservoir for 25 years by using new designed technique and Eclipse software in order to see the applicability of the proposed approach.

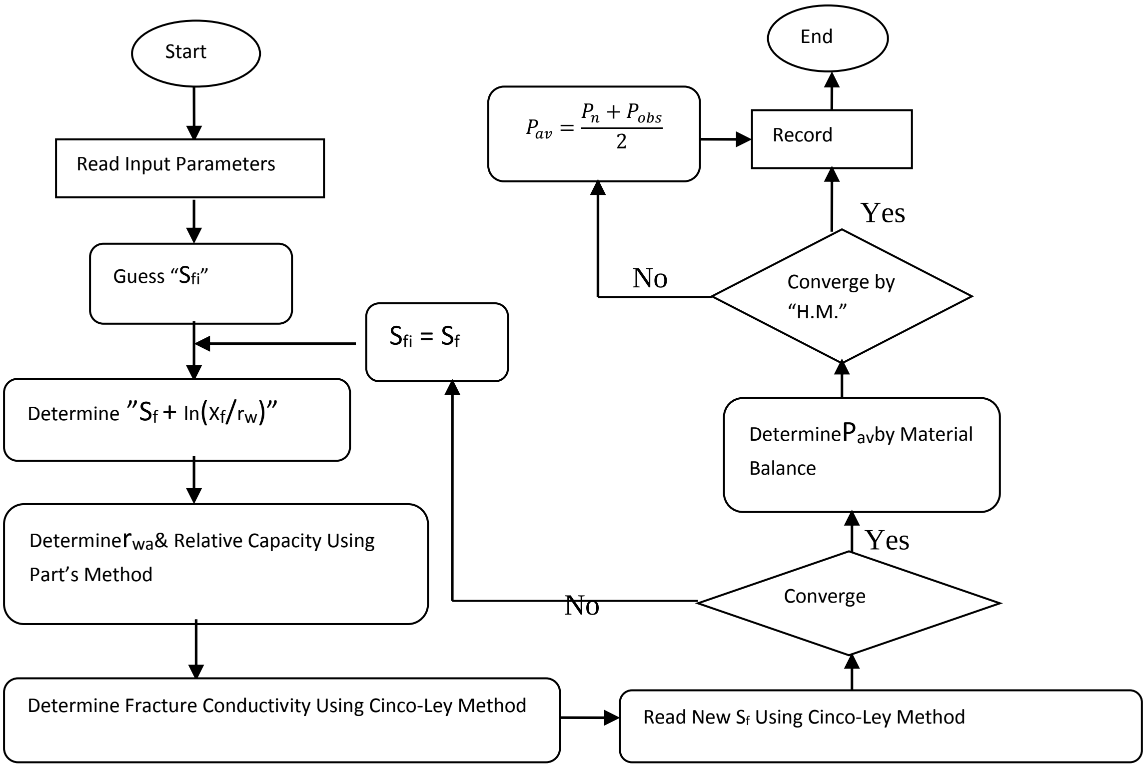

Fig.1: Computational algorithm for the proposed approach

Production from this reservoir has started from 500 bbl/day and has increased up to 6000 bbl/day. After history matching field flowing performance has predicted for next 25 years. Results relating to history matching process are presented in Figure 3.

Figure 4 and Figure 5 present result of pressure behaviour and cumulative oil production predicted by the simulator. Also output results of the new technique and simulator have presented in Figure 6 and Figure 7.

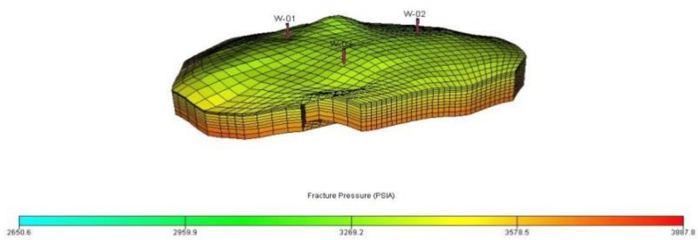

Fig.2: A three-dimensional view of the reservoir and well arrangement

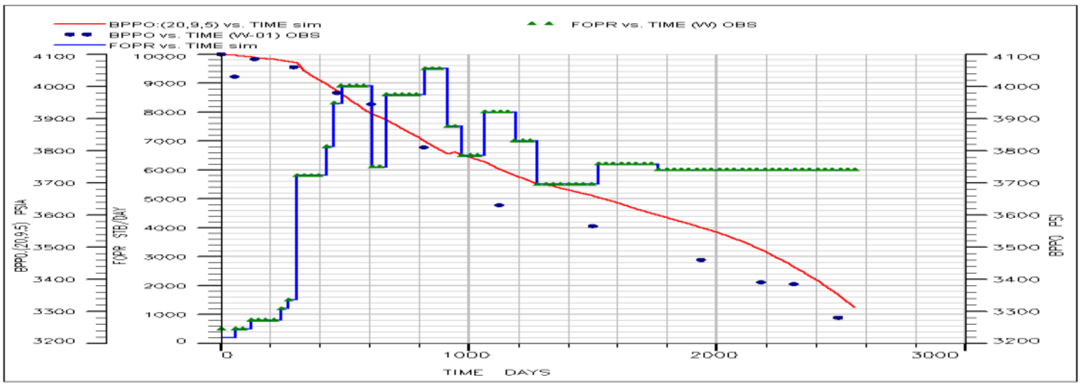

Fig.3: Results relating to history matching process

Table 1: Reservoir, well and fracture parameters used in this paper

Parameters	Values
Reservoir permeability, md	8.4
Fracture permeability, md	372
Reservoir porosity	18%
Fracture porosity	0.76%
Reservoir pressure, p_i (psi)	4120
Wellbore pressure, p_{wf} (psi)	3280
Fracture half-length, ft	900
Well radius, ft	0.32
Well drainage radius, ft	2465

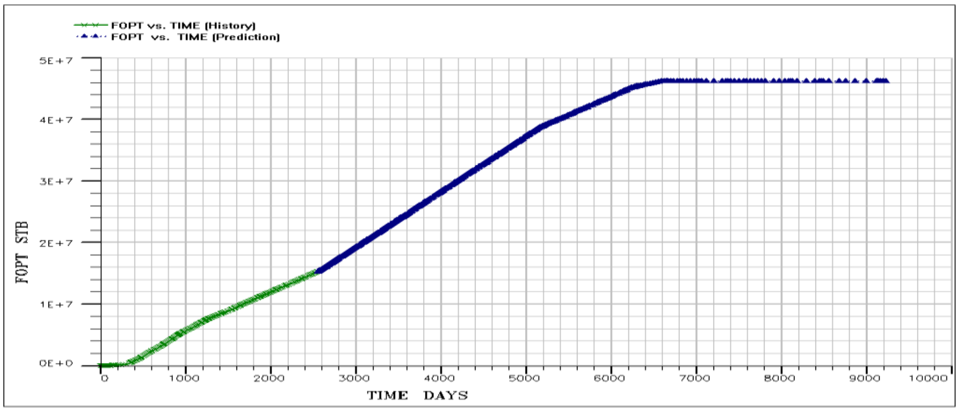

Fig. 4: Prediction of field cumulative oil production for a natural depletion case by simulator

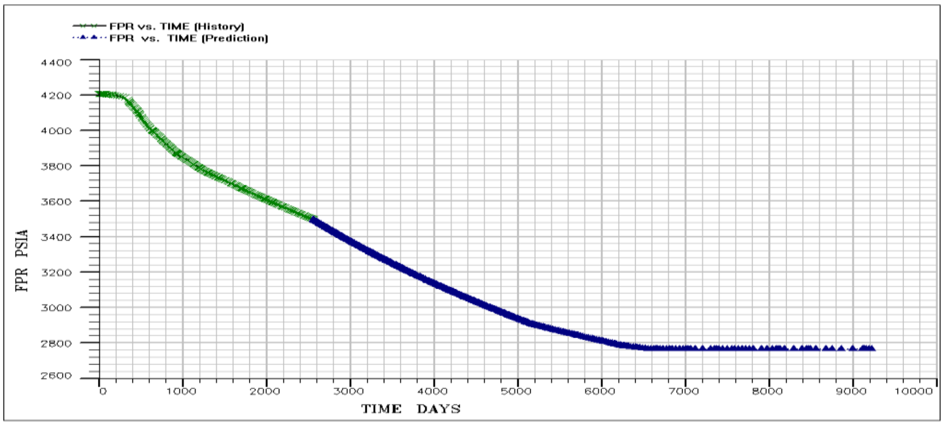

Fig. 5: Prediction of field pressure profile for natural depletion case by simulator

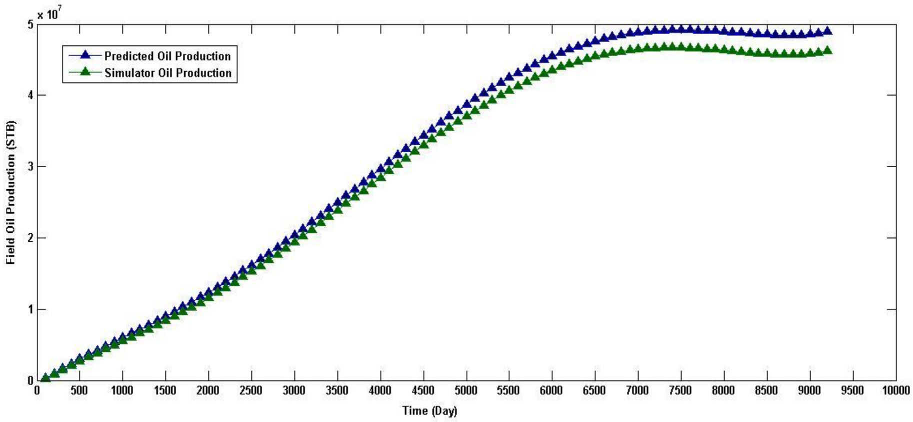

Fig. 6: Prediction of field cumulative oil production for a natural depletion case by simulator and the proposed approach

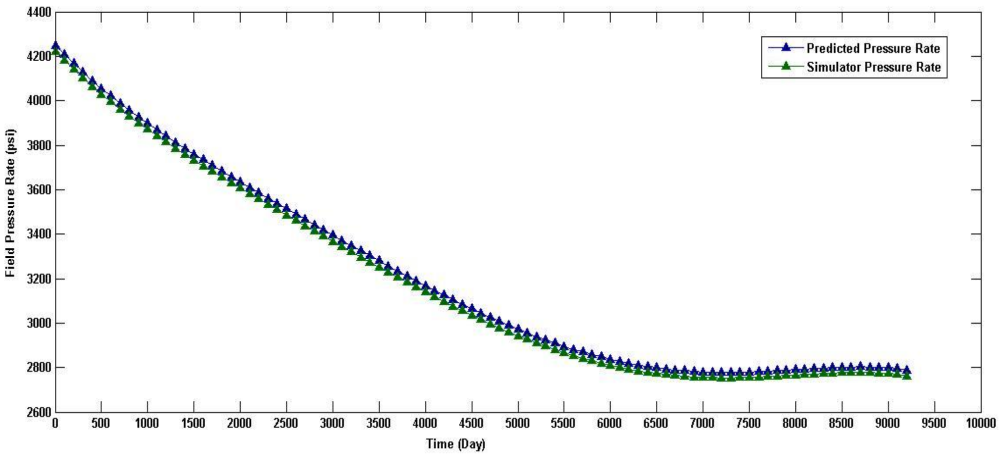

Fig. 7: Prediction of field pressure profile for natural depletion case by simulator and the proposed approach

Finally the concepts of relative error in the various times have been used to measurement the accuracy of predicted results. The average relative error for the predicted cumulative oil production is estimated to be about 4.92% and for pressure drop is about 0.81%. Figure 8 and 9 show relative error rate between prediction results of new technique and simulator versus time.

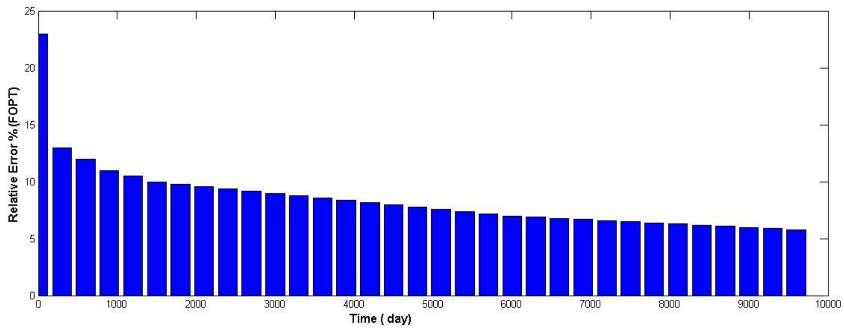

Fig.8: Relative error rate of cumulative oil production between prediction results of the proposed approach and simulator versus time

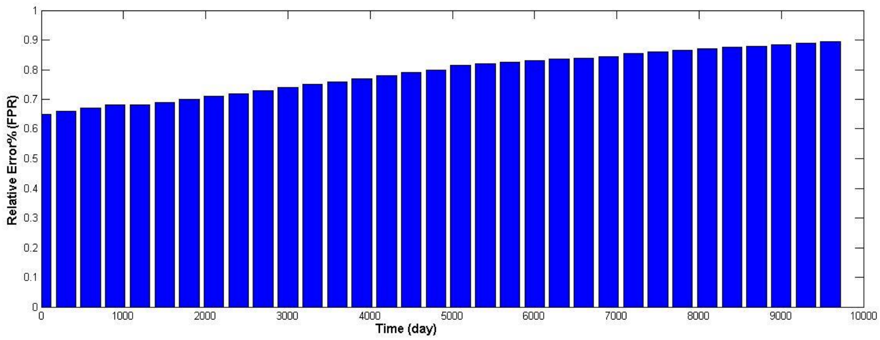

Fig.9: Relative error rate of pressure profile between prediction results of the proposed approach and simulator versus time

The main source of these errors in the proposed technique is related to the heterogeneity properties that is the major indexes of Iranian oil and gas reservoirs. Usually in reservoirs with high heterogeneity PDE equations, governing the fluid flow through porous media of the reservoir rock, cannot perfectly converge. So some errors are inevitable in most cases. Another source of error may from computer processing. Different computers may not have the same capability to perform complex mathematical operations and may produce significantly different results for the same problem. Computer processing errors occur in rounding off operations and are subject to the inherent limits of number manipulation by the processor.

Nomenclature

C_{FD} : Dimensionless fracture conductivity

K : Formation permeability

K_f : Fracture permeability

S_f : Fracture radial flow skin factor

X_f : Fracture half-length

r_w : Well radius

r_{wa}: apparent wellbore radius

a : Fracture relative capacity

w_f : Fracture width

4. Conclusions

i. To develop the previous efforts a technique has designed in this paper that with less required data presents a relatively accurate approach of the hydraulically fractured well performance.

ii. The advantage of this model over the previous studies is that, no need to know fracture permeability and width parameters.

iii. A program had been prepared to calculation of numerical equations governing on well flowing performance in the case of hydraulically fractured well through this study.

iv. The proposed approach and developed code have been applied to the several fractured well fine grid black-oil simulation of a real oil reservoir.

v. The simulation study confirmed the results of the proposed model and there was a reasonable agreement between the obtained results of proposed model and numerical simulator.

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