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CRM WELL INTERFERENCE MODELS FOR EVALUATING RESERVOIR FILTRATION AND VOLUMETRIC PROPERTIES FROM PRODUCTION DATA

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Abstract: the study proposes two CRM models that simulate well interference. The models combine the material balance equation and the inflow equation. The first model considers the reservoir pore volume common to all wells. The second model uses individual pore volumes to each well with interconnecting flows. The simulated examples show that the first model applies to infinite reservoirs while the second model gives the best results for limited reservoirs.

Keywords: CRM model, well interference.

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ИСПОЛЬЗОВАНИЕ CRM-МОДЕЛЕЙ ИНТЕРФЕРЕНЦИИ СКВАЖИН ДЛЯ ОЦЕНКИ ФИЛЬТРАЦИОННО-ЕМКОСТНЫХ СВОЙСТВ ПЛАСТА ПО ДАННЫМ РАЗРАБОТКИ

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Аннотация: в работе предложены две CRM-модели, описывающие интерференцию скважин. Модели получены путем комбинации уравнения материального баланса и уравнения притока. В первой модели рассматривается общий для всех скважин поровый объем пласта. Во второй модели все скважины имеют индивидуальные поровые объемы, между которыми происходят перетоки. На синтетических примерах показано, что для бесконечного пласта можно применять первую модель, а для ограниченного пласта лучшие результаты дает вторая модель.

Ключевые слова: CRM-модель, интерференция скважин.

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Introduction

A capacitance resistive model (CRM) [1] describes the operation of several wells draining the same formation. The model is a combination of the material balance equation (the formation fluid flow continuity equation) and the well inflow equation [1]. There are many modifications of CRM models taking into account the various effects.

Most publications consider analytical (or semi-analytical) solutions of the ordinary differential equation for downhole pressure or fluid flow rate obtained through a CRM model development [1–3]. This paper deals with a numerical solution.

The advantage of CRM models is that the reservoir pressure value is not required as it changes during the extraction, and its field measurements are rare and often irregular.

As a rule, such models are used to estimate the drained volumes of production wells and optimize the reservoir pressure maintenance system [1–3]. They are also used for short-term forecasting of production metrics.

The purpose of this work is developing CRM models that evaluate reservoir filtration and capacitative properties (including permeability) around the wells and in the inter-well space from the production logging data. The production data, in this case, are fluid flow rate, injected water flow rate, and bottom hole pressure. The fluid flow rate and the injected water flow rate are logged at all production and injection wells. Most production wells are equipped with submersible electric submersible pumps (ESPs) with telemetry units (TMUs) comprising of a pressure sensor at the pump suction line. Such units can measure downhole pressure in production wells. The downhole pressure in injection wells is measured with dedicated downhole pressure gauges (either stand-alone or plugged to a cable), or estimate from the wellhead pressure with Bernoulli's equation.

We will consider two CRM models of well interference as applied to the interference of a production well and an injection well.

A Single Volume Model

Consider a single volume CRM model for the production-injection wells interference. The model is a single volume since only the common pore volume served by both wells is considered. The system of equations describing the production well operation under such conditions is as follows:

$$c_t V_p \frac{dP}{dt} = q_{iw}(t) - q_l(t), \tag{1}$$

$$q_l(t) = PI\,[P(t) - P_w(t)] + \frac{PI}{K} q_{iw}(t), \tag{2}$$

where (1) is the material balance equation (fluid flow continuity equation) in a drained volume; (2) is the production well inflow equation (obtained by applying the potential theory to solving the planar steady-state filtration problem [4]), c_t is the total compressibility of the formation and the fluids saturating it; V_p is the pore volume; *P(t)* is the reservoir pressure, $q_{iw}(t)$ is the injected water flow rate, $q_l(t)$ is the production fluid flow rate, *t* is time, *PI* is the productivity factor of the producing well; *K* is the injection-to-production well interference factor, $P_w(t)$ is the production well bottom-hole pressure. The equations are expressed through the reservoir variables.

Let us express the reservoir pressure from the inflow equation (2):

$$P(t) = P_w(t) + q_l(t)/PI - q_{iw}(t)/K. \tag{3}$$

By substituting (3) into (1), we obtain:

$$c_t V_p \left(\frac{dP_w}{dt} + \frac{1}{PI}\frac{dq_l}{dt} - \frac{1}{K}\frac{dq_{iw}}{dt} \right) = q_{iw}(t) - q_l(t). \tag{4}$$

Expressing the downhole pressure derivative from (4), we obtain a first-order ordinary differential equation with respect to P_w:

$$\frac{dP_w}{dt} = \frac{1}{c_t V_p}[q_{iw}(t) - q_l(t)] - \frac{1}{PI}\frac{dq_l}{dt} + \frac{1}{K}\frac{dq_{iw}}{dt}. \tag{5}$$

Let us apply the first-order Runge-Kutta method to equation (5):

$$P_w(t+\Delta t) = P_w(t) + \frac{\Delta t}{c_t V_p}[q_{iw}(t) - q_l(t)] - \frac{1}{PI}[q_l(t+\Delta t) - q_l(t)] + \frac{1}{K}[q_{iw}(t+\Delta t) - q_{iw}(t)] \tag{6}$$

where Δt is the time increment.

As indicated in[4], the productivity and interference factors can be expressed as:,

$$PI = \frac{2\pi k_1 h_1}{\mu} \cdot \frac{1}{\ln\left(\frac{R_c}{r_w} + S\right)}, \tag{7}$$

$$K = \frac{2\pi k_{12} h_{12}}{\mu} \cdot \frac{1}{\ln\left(\frac{R_c}{r_{12}}\right)}, \tag{8}$$

where k_1 is the reservoir permeability at the production well location; h_1 is the reservoir thickness at the production well location; μ is the fluid dynamic viscosity; R_c is the external reservoir boundary radius; r_w is the production wellbore radius; S is the production well skin factor; k_{12} is the reservoir permeability in the inter-well area; h_{12} is the reservoir thickness in the inter-well area; r_{12} is the production to injection well distance.

Provided that other variables are known, equations (7) and (8) give the k_1 reservoir permeability at the production well and the k_{12} reservoir permeability in the inter-well area. If the skin factor for a particular well is unknown (it is a typical situation in real life), we can use an empirical skin factor vs. permeability relation obtained from the results of hydrodynamic studies in other wells in the same reservoir [5]. The fluid viscosity should generally be estimated taking into account the relative phase permeabilities.

To account for the stationary inflow as the well operation mode changes, the following correction factors are applied to the productivity and interference factors [3]:

$$PI\left(t\right) = \frac{PI}{1 + b_1 \ln\left(t/t_1\right)}, \tag{9}$$

$$K\left(t\right) = \frac{K}{1 + b_{12} \ln\left(t/t_{12}\right)}, \tag{10}$$

where b_1 and b_{12} are constant factors; t_1 and t_{12} are the periods of relaxation.

For an infinite reservoir (in real life, a very large value of the V_p pore volume when no reservoir pressure drop occurs), the external reservoir boundary radius is estimated by the Pisman equation [6]. In this particular case it can be reduced to:

$$R_c = 0{,}12\sqrt{2F}, \tag{11}$$

$$F = \frac{V_p}{mh_{12}}, \tag{12}$$

where F is the drainage area, m is the reservoir porosity.

For a limited reservoir (relatively small V_p pore volume), the drainage zone shape can be represented as an ellipse with the well at its focal points. Then we can use Borisov's equation [7] to approximate the external reservoir boundary radius:

$$R_c = 2a + \sqrt{4a^2 - r_{12}^2}, \tag{13}$$

$$a = \sqrt{\frac{\pi^2 r_{12}^2/4 + \sqrt{\pi^4 r_{12}^4/16 + 4\pi^2 F^2}}{2\pi^2}}, \tag{14}$$

where a is the major semi-axis of the ellipse.

If the production well downhole pressure, fluid flow rate and water injection volume values are available, we can estimate the reservoir parameters by adapting the downhole pressure model (6). For this, the following optimization problem is to be solved:

$$F\left(X\right) = \sum_t \left[P_w^c\left(t\right) - P_w^f\left(t\right)\right]^2 \rightarrow 0, \tag{15}$$

where F is the function to be minimized; X is a vector of variables; the c and f superscripts indicate the estimated and actual values, respectively. We add the values for each moment t when the actual downhole pressure value is available.

The optimization problem variables are:

1) V_p: porous volume
2) PI: production well productivity factor
3) K: production-to-injection well interference factor
4) b_1 and b_{12} factors
5) t_1 and t_{12} relaxation periods.

If PI and K are known, we can estimate k_1 and k_{12} provided that other variables are also available. The above model can be easily generalized for a larger number of wells.

A Multivolume Model

Let us consider a multivolume CRM model of well interference. The model is multivolume since the number of pore volumes considered is equal to the number of wells. Each well operates in its dedicated pore volume. There are inter-flows between the porous volumes of the wells. The system of equations describing the production and injection wells operation under such conditions is as follows:

$$c_{t,1}V_{p,1}\frac{dP_1}{dt} = q_{21}(t) - q_l(t), \tag{16}$$

$$c_{t,2}V_{p,2}\frac{dP_2}{dt} = q_{iw}(t) - q_{21}(t), \tag{17}$$

$$q_l(t) = PI_1\left[P_1(t) - P_{w,1}(t)\right], \tag{18}$$

$$q_{iw}(t) = PI_2\left[P_{w,2}(t) - P_2(t)\right], \tag{19}$$

$$q_{21}(t) = PI_{21}\left[P_2(t) - P_1(t)\right], \tag{20}$$

where (16) and (17) are material balance equations (fluid continuity equations) for the porous volumes of the production and injection wells, respectively; (18) and (19) are the production well inflow and injection well outflow equations, respectively; (20) is the porous volume-to-porous volume inter-flow equation; subscript "1" indicate the production well porous volume; superscript "2" indicate the injection well porous volume; $c_{t,1}$ and $c_{t,2}$ are the total compressibility of the reservoir and the fluids saturating it; $V_{p,1}$ and $V_{p,2}$ are the porous volumes; $P_1(t)$ and $P_2(t)$ are the reservoir pressures; $q_{iw}(t)$ is the injection water rate; $q_l(t)$ is the production well flow rate; q_{21} is the second-to-first porous volume inter-flow; t is time; PI_1 is the production well productivity factor; PI_2 is the injectivity factor of the injection well; PI_{21} is the porous volume-to-porous volume inter-flow factor; $P_{w,1}(t)$ and $P_{w,2}(t)$ are the downhole pressures of the production and injection wells, respectively. The equations are expressed through the reservoir variables.

Let us express reservoir pressures from (18) and (19):

$$P_1(t) = P_{w,1}(t) + q_l(t)/PI_1, \tag{21}$$

$$P_2(t) = P_{w,2}(t) - q_{iw}(t)/PI_2, \tag{22}$$

By substituting (21) and (22) into (16) and (17), respectively, we obtain:

$$c_{t,1}V_{p,1}\left(\frac{dP_{w,1}}{dt} + \frac{1}{PI_1}\frac{dq_l}{dt}\right) = q_{21}(t) - q_l(t), \tag{23}$$

$$c_{t,2}V_{p,2}\left(\frac{dP_{w,2}}{dt} - \frac{1}{PI_2}\frac{dq_{iw}}{dt}\right) = q_{iw}(t) - q_{21}(t). \tag{24}$$

Expressing the downhole pressure derivatives from (23) and (24), we obtain a first-order ordinary differential equation with respect to $P_{w,1}$ and $P_{w,2}$:

$$\frac{dP_{w,1}}{dt} = \frac{1}{c_{t,1}V_{p,1}}\left[q_{21}(t) - q_l(t)\right] - \frac{1}{PI_1}\frac{dq_l}{dt}. \tag{25}$$

$$\frac{dP_{w,2}}{dt} = \frac{1}{c_{t,2}V_{p,2}}\left[q_{iw}(t) - q_{21}(t)\right] + \frac{1}{PI_2}\frac{dq_{iw}}{dt}. \tag{26}$$

Let us apply the first-order Runge-Kutta method to equations (25) and (26):

$$P_{w,1}(t+\Delta t) = P_{w,1}(t) + \frac{\Delta t}{c_{t,1}V_{p,1}}\left[q_{21}(t) - q_l(t)\right] - \frac{1}{PI_1}\left[q_l(t+\Delta t) - q_l(t)\right] \tag{27}$$

$$P_{w,2}(t+\Delta t) = P_{w,2}(t) + \frac{\Delta t}{c_{t,2}V_{p,2}}\left[q_{iw}(t) - q_{21}(t)\right] + \frac{1}{PI_2}\left[q_{iw}(t+\Delta t) - q_{iw}(t)\right], \tag{28}$$

where

$$q_{21}(t) = PI_{21}\left[P_{w,2}(t) - P_{w,1}(t) - q_l(t)/PI_1 - q_{iw}(t)/PI_2\right], \tag{29}$$

Δt is the time increment.

Productivity (injectivity) and inter-flow factors can be defined as follows:

$$PI_i = \frac{2\pi k_i h_i}{\mu} \cdot \frac{1}{\ln\left(\frac{R_{c,i}}{r_{w,i}} + S_i\right)}, i = 1{,}2 \tag{30}$$

$$PI_{21} = \frac{k_{21}}{\mu} \cdot \frac{A_{21} h_{21}}{r_{21}}, \tag{31}$$

where k_1 and k_2 are the reservoir permeability at the production and injection wells, respectively; h_1 and h_2 are the reservoir thicknesses at the production and injection wells, respectively; μ is the fluid dynamic viscosity; $R_{c,1}$ and $R_{c,2}$ are the external reservoir boundary radii; $r_{w,1}$ and $r_{w,2}$ are the bore well diameters; S_1 and S_2 are the well skin factors; k_{21} is the reservoir permeability in the inter-well area; h_{21} is the reservoir thickness in the inter-well area; r_{21} is the production-to-injection well distance; A_{21} is the length of the wells porous volume interface where the fluid inter-flows occur.

Provided that other variables are known, equations (30) and (31) give the k_1, k_2 reservoir permeability at the well location and the k_{21} reservoir permeability in the inter-well area.

To account for the stationary inflow as the well operation mode changes, we can introduce correction factors to the productivity and interference factors similar to (9).

The external reservoir boundary radius can be determined with Pisman equation [6]. In this particular case it can be reduced to:

$$R_{c,i} = 0{,}12\sqrt{2F_i}, i = 1{,}2, \tag{32}$$

$$F_i = \frac{V_{p,i}}{m_i h_i}, i = 1{,}2, \tag{33}$$

where F_1 and F_2 are draining (injection) areas; m_1 and m_2 are the porosities.

The shape of the total drainage (injection) area of the two wells can be represented as an ellipse with the wells located at its focal points. Then, the ellipse geometry equations can be used to estimate the length of the interface between the well pore volumes through which the fluid flows:

$$A = 2b, \tag{34}$$

$$b = \sqrt{a^2 - r_{21}^2/4}, \tag{35}$$

$$a = \sqrt{\frac{\pi^2 r_{12}^2/4 + \sqrt{\pi^4 r_{12}^4/16 + 4\pi^2 F^2}}{2\pi^2}}, \tag{36}$$

where a and b are the major and minor ellipse semi-axes.

If the production well downhole pressure, fluid flow rate and water injection volume values are available, we can estimate the reservoir parameters by adapting the downhole pressure model (27) and (28). For this, the following optimization problem is to be solved:

$$F(X) = \sum_t \left\{\left[P_{w,1}^c(t) - P_{w,1}^f(t)\right]^2 + \left[P_{w,2}^c(t) - P_{w,2}^f(t)\right]^2\right\} \to 0, \tag{37}$$

where F is the function to be minimized; X is a vector of variables; the c and f superscripts indicate the estimated and actual values, respectively. We add the values for each moment t when the actual downhole pressure value is available. The injection well downhole pressure can easily be estimated from the wellhead pressure using Bernoulli's equation.

The optimization problem variables are:

1) $V_{p,1}$ and $V_{p,2}$ porous volumes
2) PI_1 and PI_2 productivity and injectivity factors
3) PI_{21}: fluid inter-flow factor

4) b_1 and b_2 factors account for the stationary inflow as the well operation modes change
5) t_1 and t_2: relaxation periods

If PI_1, PI_2 and PI_{21} are known, we can estimate k_1, $k_2$and k_{21}provided that other variables are also available.

The above model can be easily generalized for a larger number of wells.

Optimization Problem Solution

In this paper, we use Newton's method to solve optimization problems. Let us consider its principles.

Suppose we need to find the minimum of the $f(X)$ multi-argument function, where $X=(x_1, x_2, x_3,..., x_n)$. This problem is equivalent to the problem of finding the X values at which the gradient of the function f(X) is zero:

$$grad\,(f\,(X)) = 0. \tag{38}$$

Let us apply Newton's method to (38):

$$grad\,\left(f\,\left(X^j\right)\right) + H\,\left(X^j\right)\left(X^{j+1} - X^j\right) = 0, \tag{39}$$

where j=1,2,3,..., m is the iteration number, $H(X)$ is a hessian of the function $f(X)$.

Note that the Hessian of a function is a symmetrical quadratic form that describes the behavior of the function in the second order:

$$H\,(X) = \sum_{i=1}^{n}\sum_{j=1}^{n} a_{ij}x_ix_j, \tag{40}$$

where $a_{ij}=\partial^2 f/\partial x_i \partial x_j$, $f(X)$ is defined over an n-dimensional space of real numbers.

For convenience, equation (40) can be represented as:

$$X^{j+1} = X^j - H^{-1}\left(X^j\right) grad\,\left(f\,\left(X^j\right)\right). \tag{41}$$

Models Testing with Simulated Examples

Problem No. 1

Consider a two-well (production and injection) interference problem in a homogeneous infinite reservoir as the well operation is variable. In general, Laplace images are used to obtain the exact solution to such a problem. We used the Saphir software from Kappa Engineering to plot the production well downhole pressure vs. time curve. The flow is single-phase. The initial data are as follows:

1) well radius: 0.1 m
2) reservoir thickness:9.1 m
3) reservoir porosity factor: 0.1 dec.qty
4) well-to-well distance: 300 m
5) volume factor: 1 m^3/m^3
6) dynamic fluid viscosity: 1 cps
7) total compressibility of the reservoir-fluid system: $4.267 \cdot 10^{-5}$ 1/bar
8) dimensionless well skin factor: 0
9) initial reservoir pressure: 350 bar
10) reservoir permeability: 50 mD.

Refer to Fig. 1 for the variable fluid flow rate and injected water flow rate.

We interpreted the flow rate and downhole pressure measurements using the single-volume CRM model presented in Section 1. The downhole pressure curves are shown in Fig. 1. A satisfactory matching of the downhole pressure curves was obtained. The results are as follows:

1) reservoir porous volume: $6.0 \cdot 10^{10}$ m^3
2) production well productivity factor: 2.0 m^3/day/bar
3) production-to-injection well interference factor: 6.2 m^3/day/bar
4) reservoir permeability at the production well: 78.6 mD
5) reservoir permeability in the inter-well area: 59.6 mD.

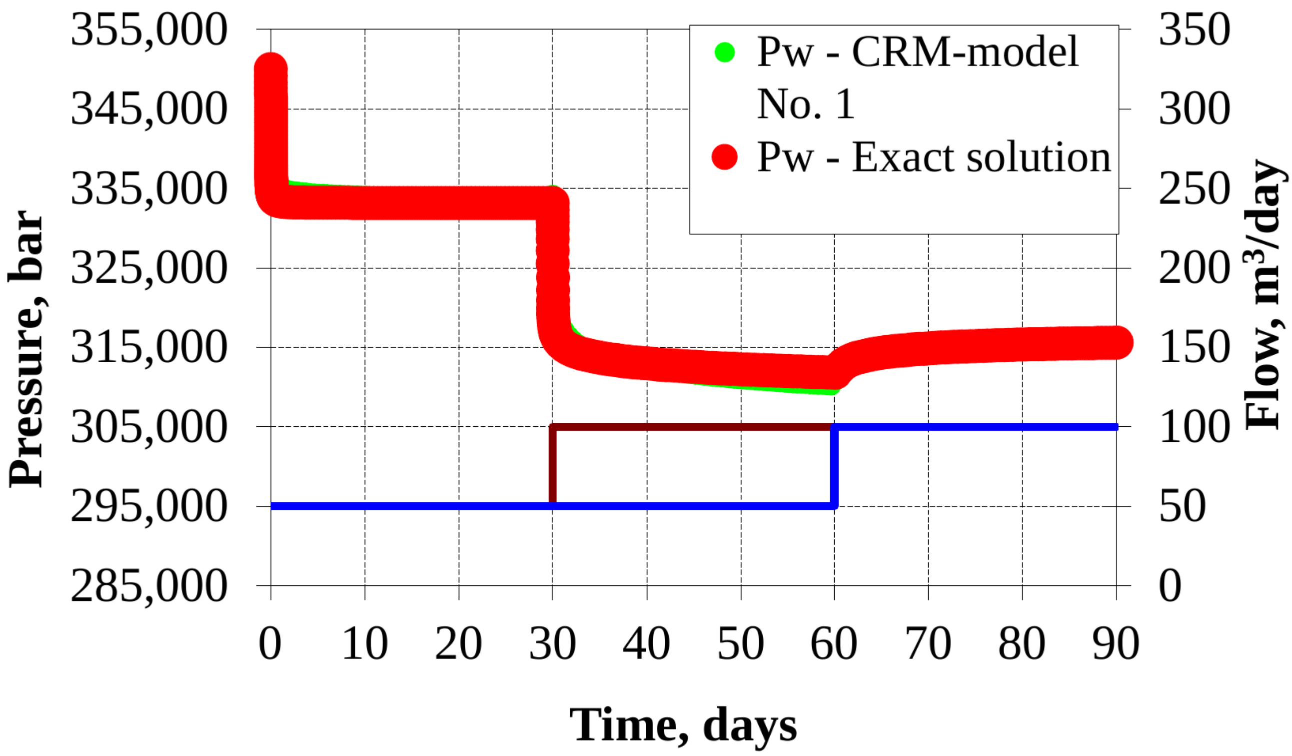

Figure 1. *Well performance for a homogeneous infinite reservoir. CRM model No. 1*

The resulted permeability values are in satisfactory agreement with the initial data.

Problem No. 2

Consider a two-well (production and injection) interference problem in a heterogeneous (in terms of permeability) limited square-shaped reservoir. The wells operate in a variable mode. There is no exact solution to such a problem. We used a simulation model developed with the Saphir software from Kappa Engineering to plot the production well downhole pressure vs. time curve (refer to Fig. 2.) The flow is single-phase. The piezoconductivity problem is solved. The Voronoi grid is used. The initial data are as follows:

1) XY plane area size: 848x848 m
2) permeability at the production well: 50 mD
3) permeability at the injection well: 100 mD.

We used linear interpolation of the inter-well area permeability. The rest of the data are similar to those used in Problem No. 1.

The fluid flow rate and the injected water flow rate are variable, refer to Fig. 3.

We used two approaches to interpret the flow rate and downhole pressure measurements.

The first one is using the single-volume CRM model described in section 1. The downhole pressure curves are shown in Fig. 3. Good matching of the downhole pressure curves was obtained. The results are as follows:

1) reservoir porous volume: $6.3 \cdot 10^5$ m^3
2) production well productivity factor: 3.6 m^3/day/bar
3) production-to-injection well interference factor: 40.2 m^3/day/bar
4) reservoir permeability at the production well: 50.4 mD
5) formation permeability in the inter-well area - 105.7 mD.

The resulted permeability values are in satisfactory agreement with the initial data. The reservoir permeability at the production agrees well with the target value. The reservoir permeability in the inter-well area poorly agrees with the "actual" value that can be estimated from the initial permeability at the wells using the average harmonic equation as 66.7 mD. This is probably due to imprecise external reservoir boundary radius estimation as the drained volume is elliptical.

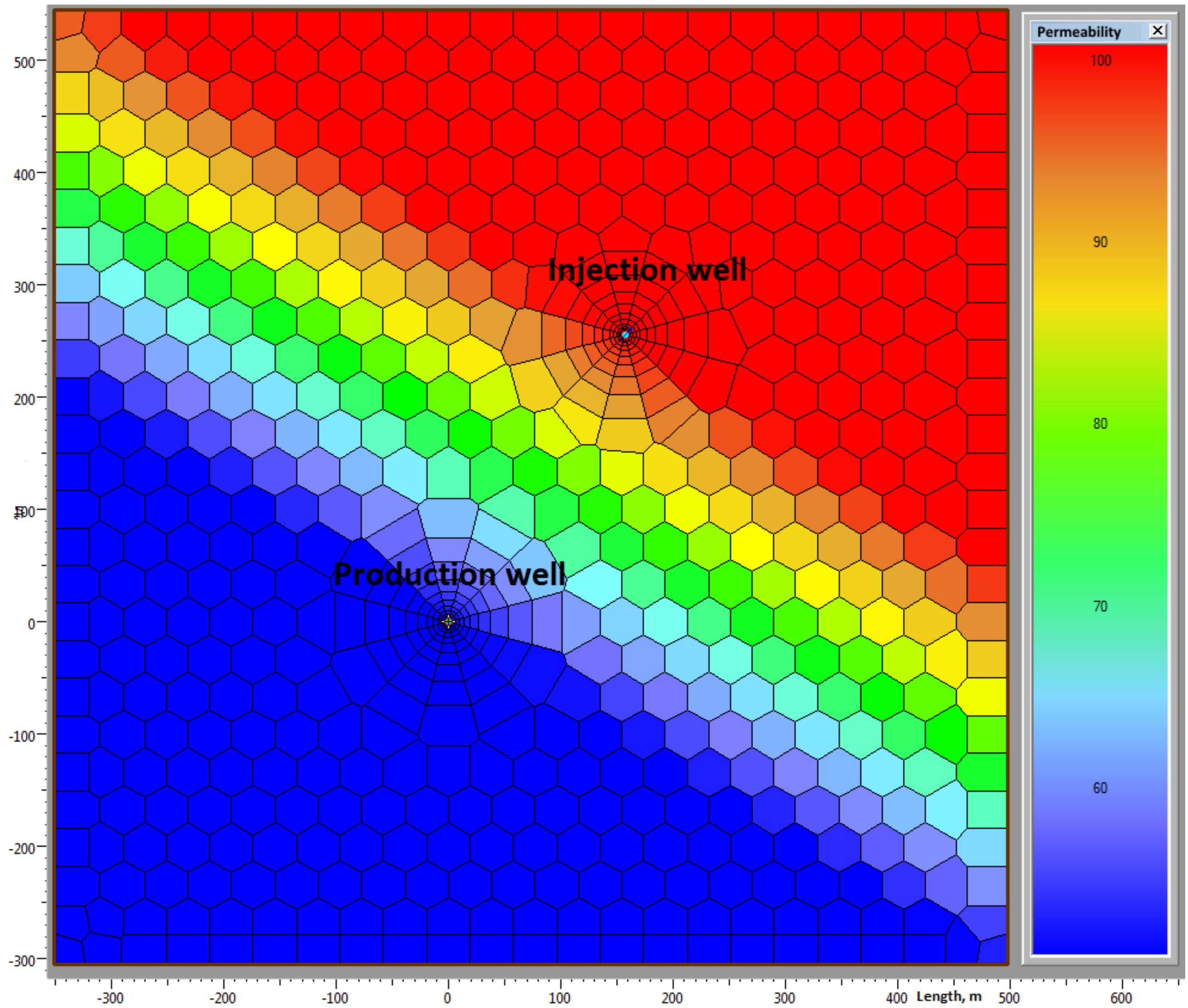

Figure 2. *Permeability distribution over the grid (Saphir software)*

The second approach is using the multivolume CRM model described in Section 2. The downhole pressure curves are shown in Fig. 4. Good matching of the downhole pressure curves was obtained.

The results are as follows:

1) reservoir porous volume at the production well: $3.19 \cdot 10^5$ m^3
2) reservoir porous volume at the injection well: $3.21 \cdot 10^5$ m^3
3) production well productivity factor: 3.7 m^3/day/bar
4) injection well injectivity factor: 7.15 m^3/day/bar
5) inter-flow factor: 12.5 m^3/day/bar
6) reservoir permeability at the production well: 50.1 mD
7) reservoir permeability at the injection well: 96.2 mD
8) reservoir permeability in the inter-well area: 52.9 mD.

In general, the resulted permeability values are in good agreement with the initial data. The reservoir permeability at the production and injection wells agrees well with the target values. The reservoir permeability in the inter-well area satisfactory agrees with the “actual” value that can be estimated from the initial permeability at the wells using the average harmonic equation as 66.7 mD.

Conclusion

This paper proposes two CRM models of production-injection well interference used to estimate the reservoir filtration and volumetric properties based on the production data. The production data, in this case, are fluid flow rate, injected water flow rate, and bottom hole pressure. CRM models are a combination of

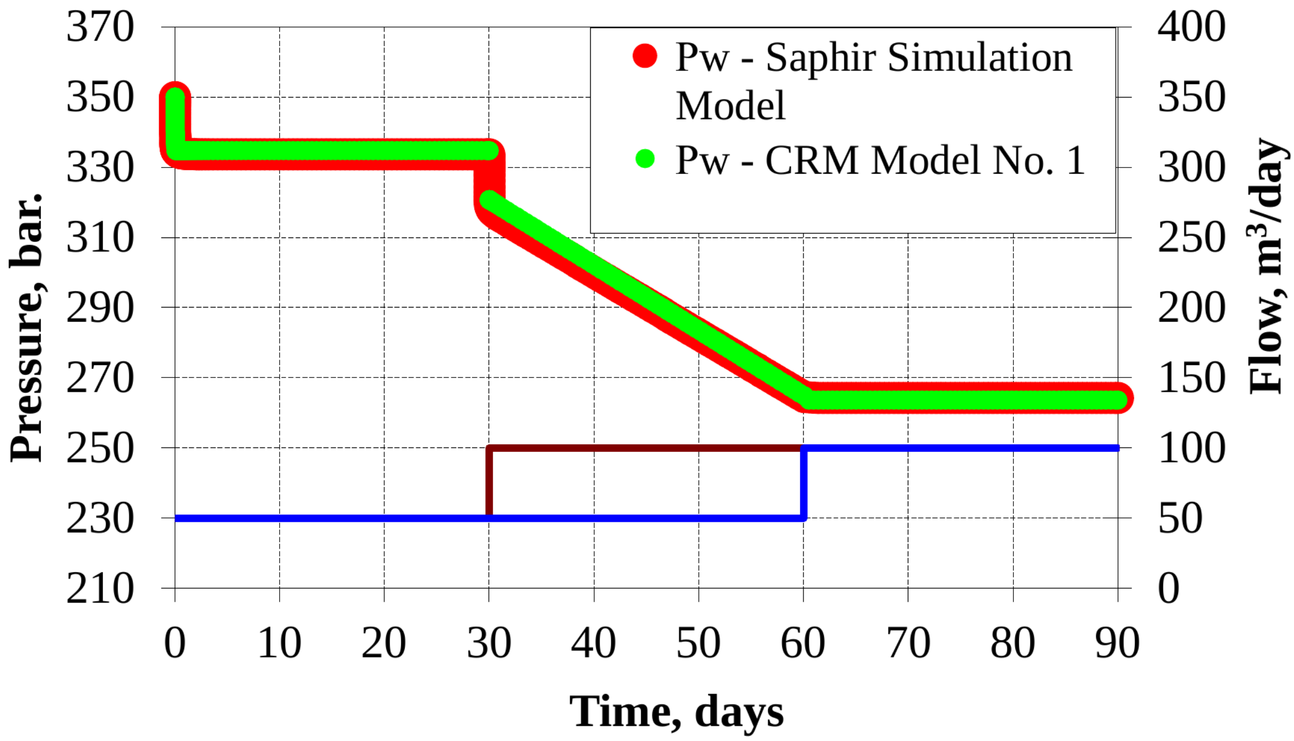

Figure 3. *Well performance in a heterogeneous (in terms of permeability) square-shaped limited reservoir. CRM model No. 1*

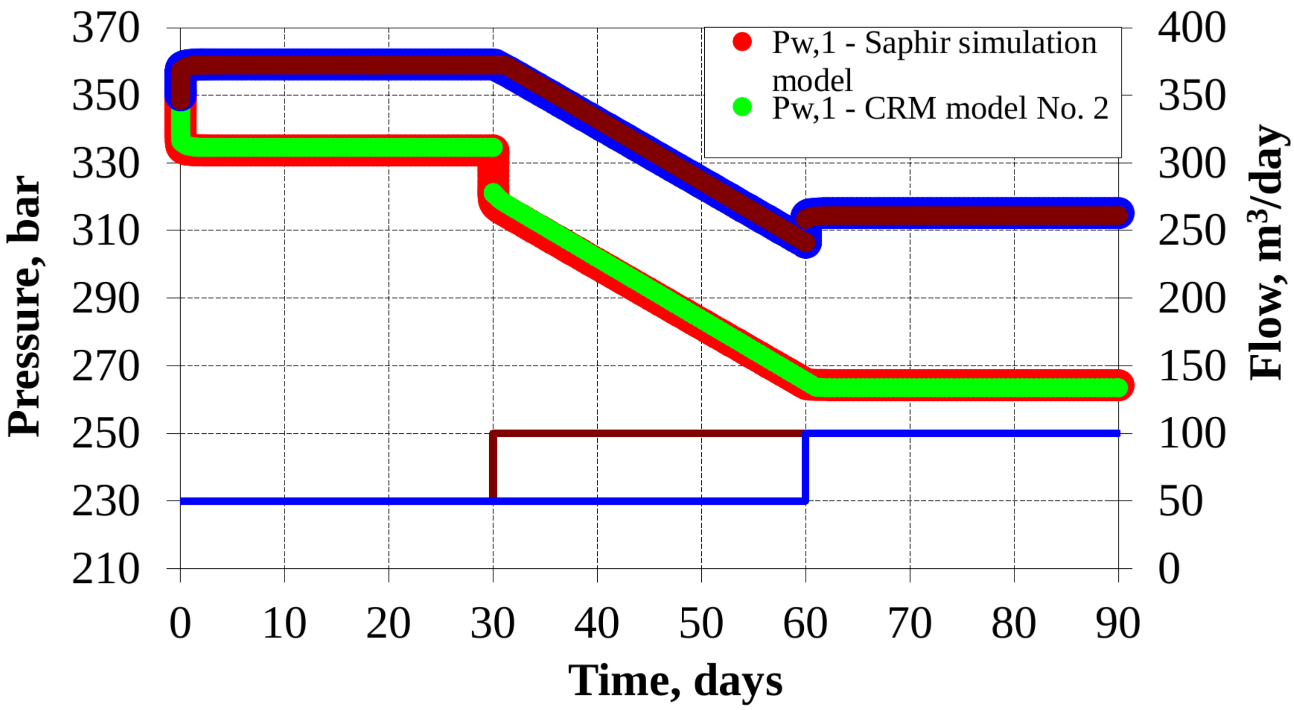

Figure 4. *Well performance in a heterogeneous (in terms of permeability) square-shaped limited reservoir. CRM model No. 2*

the material balance equation (the formation fluid flow continuity equation) and the well inflow equation. The advantage of all CRM models is that the reservoir pressure value is not required as it changes during the extraction, and its field measurements are rare and often irregular.

The first proposed model is single-volume because only one, common pore volume served by both wells is considered.

The second proposed model is multivolume since the number of pore volumes considered is equal to the number of wells. Each well operates in its dedicated pore volume. There are inter-flows between the porous volumes of the wells.

The models were applied to a two-well case: a production well and an injection well. However, the models can be easily generalized for a larger number of wells.

This paper proposes to solve inverse subsoil hydrodynamics problems with CRM models by combining estimated and actual downhole pressure values. The filtration and capacitative reservoir properties, including its permeability in various regions, are evaluated in this way. The inverse problem is solved by Newton's method.

The models were tested with simulated examples generated by Kappa Engineering's Saphir software. It is shown that for an infinite reservoir (in real life, a very large porous volume value at which no reservoir pressure drop occurs), the simpler first CRM model can be applied, while for a limited reservoir, the second CRM model provides better results. In general, with the right choice of the proposed CRM models, it is possible to determine the filtration and capacitative parameters with accuracy sufficient for practical purposes.

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