Fluid Flow Prediction with Development System Interwell Connectivity Influence

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Abstract. In this paper interwell connectivity has been studied. First of all, literature review of existing methods was made which is divided into three groups: Statistically-Based Methods, Material (fluid) Propagation-Based Methods and Potential (pressure) Change Propagation-Based Method. The disadvantages of the first and second groups are as follows: methods do not involve fluid flow through porous media, ignore any changes of well conditions (BHP, skin factor, etc.). The last group considers changes of well conditions and fluid flow through porous media. In this work Capacitance method (CM) has been chosen for research. This method is based on material balance and uses weight coefficients lambdas to assess well influence. In the next step synthetic model was created for examining CM. This model consists of an injection well and a production well. CM gave good results, it means that flow rates which were calculated by analytical method (CM) show matching with flow rate in model. Further new synthetic model was created which includes six production and one injection wells. This model represents seven-spot pattern. To obtain lambdas weight coefficients, the delta function was entered using by minimization algorithm. Also synthetic model which has three injectors and thirteen producer wells was created. This model simulates seven-spot pattern production system. Finally Capacitance method (CM) has been adjusted on real data of oil Field Ω. In this case CM does not give enough satisfying results in terms of field data liquid rate. In conclusion, recommendations to simplify CM calculations were given. Field Ω is assumed to have one injection and one production wells. In this case, satisfying results for production rates and cumulative production were obtained.

1. Introduction

The aim of the project will be a selection of methods for production rates forecasting with the influence of interwell connectivity in the development scheme and theirs application on Field Ω.

The objectives of the study will include the following items:
• Investigate all methods which are used for production rates prediction.
• Select the most suitable method for the field Ω.
• Apply the chosen method on the different synthetic models.

All methods can be divided into three groups: statistically-based method, material propagation-based method and potential change propagation-based method. The last method is based on the material balance and superposition principle. Unlike simulation-based methods, capacitance method (CM) doesn't require geophysical and geological data to generate the proxy model. Moreover, CM is less time-consuming than simulation modelling.

Field Ω is a sandstone reservoir. The average permeability and porosity are 7.7 mD and 15%, respectively. Average initial oil saturation equals 53%. The field is developed by inverted 7-spot pattern.

2. Capacitance method

Capacitance method was checked on synthetic model, which has size 70x70x10 cells, the size of one cell is 10x10x2 m, porosity φ=15%, permeability κ=10 mD, anisotropy k_v/k_h=0.1.

The proposed formula for the calculation of average production is expressed as:

$$\overline{q}_j(t_n) = \frac{\tau_{pj}q_j(t_0)}{t_n - t_{n-1}}\left[e^{-\frac{t_{n-1}-t_0}{\tau_{pj}}} - e^{-\frac{t_n-t_0}{\tau_{pj}}}\right] + \sum_{i=1}^{I}\lambda_{ij}\left[\tau_{ij}\left(\frac{w'_{ij}(t_{n-1}) - w'_{ij}(t_n)}{t_n - t_{n-1}}\right) + w_i(t_n)\right], where \quad (1)$$

$$w'_{ij}(t) = \sum_{m=1}^{n}\left[e^{\frac{t_m-t}{\tau_{ij}}} - e^{\frac{t_{m-1}-t}{\tau_{ij}}}\right]w_j(t_m) \quad (2)$$

$$p'_{ij}(t) = \sum_{m=1}^{n}\left[e^{\frac{t_m-t}{\tau_{ij}}} - e^{\frac{t_{m-1}-t}{\tau_{ij}}}\right]p_{wf,kj}(t_m) \quad (3)$$

where $\overline{q}_j(t_n)$ - average production rate of well j, τ_{pj}- time constant, w'_{ij} – convolved injection rate equation, λ_{ij} – weight coefficient which depends on well location and boundary.

$$[\lambda]_{N_p \times N_i} = \overline{A}_{prod}^{-1}\left(\frac{\overline{1}_{N_p \times N_p} \overline{A}_{prod}^{-1} \overline{A}_{con}^{T} - \overline{1}_{N_p \times N_i}}{\overline{1}_{1 \times N_p} \overline{A}_{prod}^{-1} \overline{1}_{N_p \times 1}} - \overline{A}_{con}^{T}\right) \quad (4)$$

where $\overline{A}_{prod}$ -influence matrix of producer wells

$$\overline{A}_{prod} = \begin{bmatrix} a_{11} & \cdots & a_{1N} \\ \vdots & \ddots & \vdots \\ a_{N1} & \cdots & a_{NN} \end{bmatrix} + \begin{bmatrix} S_1 & \cdots & 0 \\ \vdots & \ddots & \vdots \\ 0 & \cdots & S_N \end{bmatrix} \quad (5)$$

$a_{11}\ldots a_{NN}$ – influence functions which depends on well location and reservoir boundary, S_{NN} – skin factor of producer.

$[A_{con}]$- matrix accounting for influence of injection wells on producer.

$$\overline{A}_{con} = \begin{bmatrix} a_{11} & \cdots & a_{1N} \\ \vdots & \ddots & \vdots \\ a_{N1} & \cdots & a_{NN} \end{bmatrix} \quad (6)$$

In the case of one producer and one injector λ_{ij} equals 0.904. So equation (1) has the form:

$$\overline{q}_j(t_n) = \frac{\tau_{pj}q_j(t_0)}{t_n - t_{n-1}}\left[e^{-\frac{t_{n-1}-t_0}{\tau_{pj}}} - e^{-\frac{t_n-t_0}{\tau_{pj}}}\right] + \lambda_{ij}\tau_{ij}\left(\frac{w'_{ij}(t_{n-1}) - w'_{ij}(t_n)}{t_n - t_{n-1}}\right) + w_i(t_n) \quad (7)$$

Flow rates calculated from the synthetic model and CM application are presented in Figure 1 and 2. As we can see, capacitance method works well with relative error less than 1%.
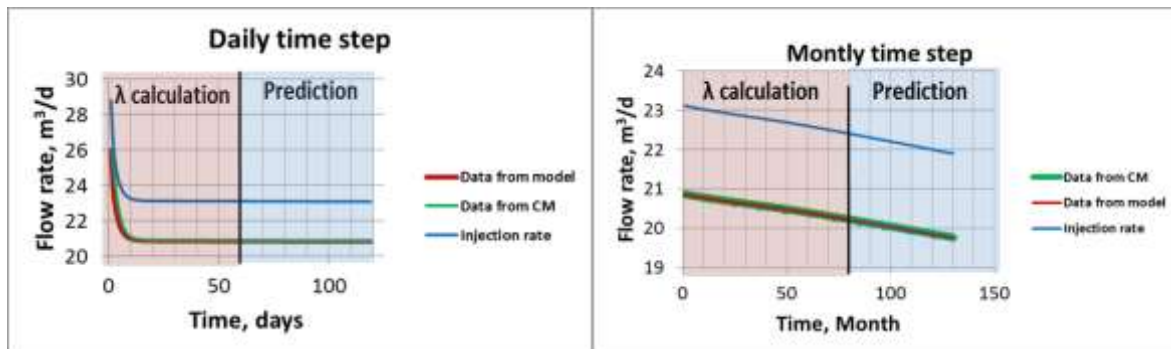
Figure 1. Sensitivity analysis of method at daily time step – left figure. Sensitivity analysis of method monthly time step – right figure; blue curve shows injection rate, green curve shows production rate calculated by CM, red curve shows production rate from synthetic model.
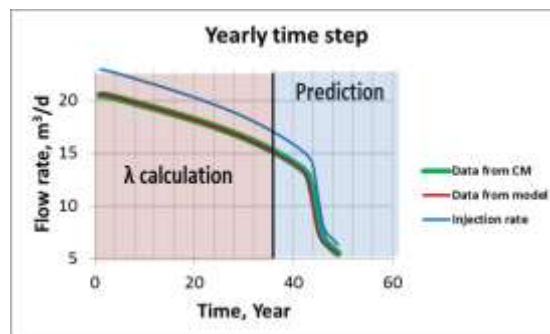

Figure 2. Sensitivity analysis of method at yearly time step; blue curve shows injection rate, green curve shows production rate calculated by CM, red curve shows production rate from synthetic model.

Difference of rates of synthetic model and CM has been revealed in initial period of time. It is evidence of transient flow regime which cannot be evaluated by capacitance method.

Sensitivity analysis of different time steps has been considered and results were represented in Figure 1. It was concluded that duration of time steps didn't influence on final results.

Another synthetic model with 7-spot pattern and semi permeable barrier was created. The location of wells and barrier are shown in Figure 3. Permeability of the barrier is fifty times less than cell permeability. The main idea of this model is resulted in the determination of barrier influence on weight coefficients λ_{ij} and time constants τ_{ij}.
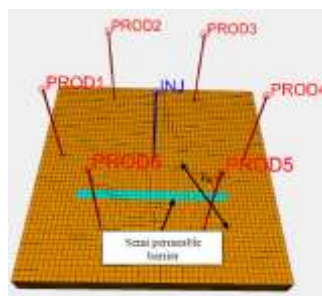

Figure 3. Location of wells and semi-permeable barrier.

Liquid rate's prediction of well PROD3 is quite similar for synthetic and capacitance models, but liquid rate of well PROD6 has the high difference between CM and synthetic model because of barrier's influence on rates and reservoir pressure.

South-western sector of field Ω has been chosen for CM's application. It consists of 10 production wells and 3 injection wells.

Equation 1 was used for calculation of average production rates. Figure 4 shows graph of liquid rates, which were obtained from monthly operational report (red curve) and data which was obtained from CM for typical production well 161. As can be seen, flow rate, calculated using the formula (1), has the trend that coincides with the field data of the well 161. It's obvious that cumulative production from field data and cumulative production from CM are the same in spite of difference of production flow rates. Data from CM converge with the field data with determination coefficient R^2 equals to 0.998.
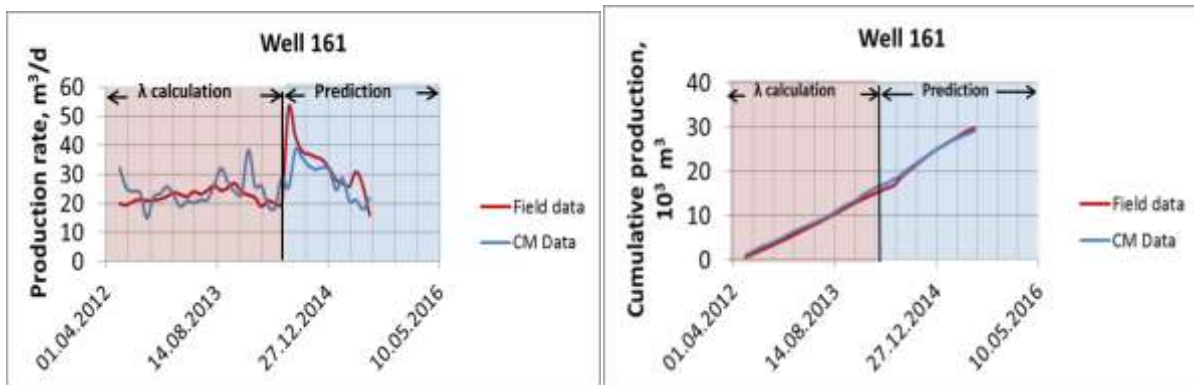

Figure 4. Liquid production rates from field (red curve) and from CM (blue curve) - left figure. Cumulative production from field data (red curve) and from CM (blue curve) – right figure.

It should be mentioned that wells which are located near the margins have lower determination coefficient R^2 for cumulative production and practically zero determination coefficient for liquid production rate. It can be explained by presence of production and injection wells outside the considered sector. Correlation for the wells located in the middle of the sector is much better.

Algorithm of fitting of λ_{ij} and τ_{ij} for large number of wells and time intervals requires a lot of time. All production wells can be assumed like one well and all injectors can be assumed like one well for the simplicity of task.

Average values of λ_{ij} and τ_{ij} were used in this case. Figure 5 shows data which was calculated by capacitance method. As can be seen on Figure 5, liquid production rate which was calculated by using analytical method has similar trend with field data.
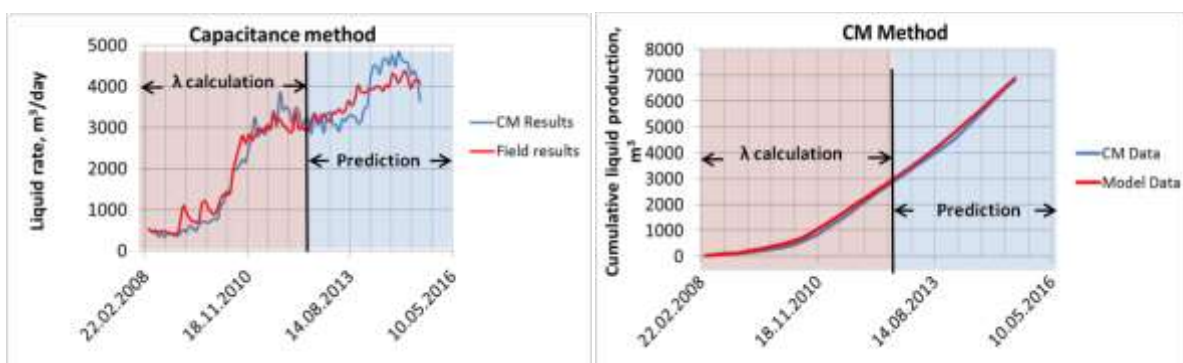

Figure 5. Liquid production rates from field (red curve) and from CM (blue curve) - left figure. Cumulative production from field data (red curve) and from CM (blue curve) – right figure.

Figure 6 shows correlation of liquid production rates from field data and CM .Coefficient R^2 has high value and it means that coefficients λ_{ij} and τ_{ij} were estimated right.
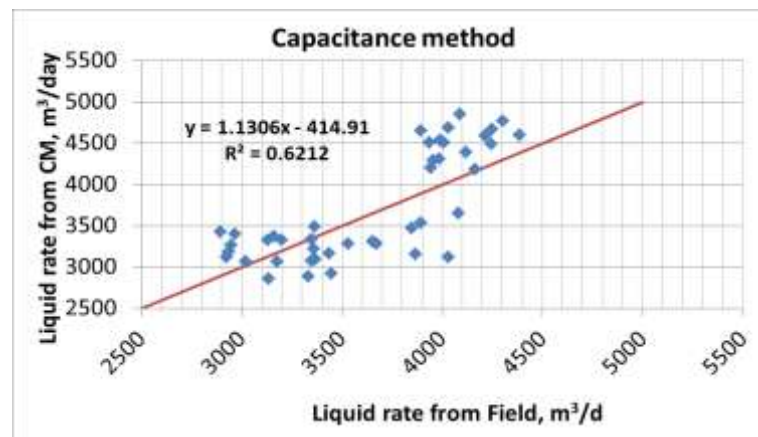
Figure 6. Correlation of liquid production rates from field data and CM.

Cumulative liquid production which was calculated by using CM and field data has similar trend. Both curves (red and blue) have good convergence which means that variance of data is small. Weight factors λ_{ij} for CM is 0.15 and time constant τ_{ij} equals 20 days.

So in case of one development object and small field, oilfield can be considered like a simple model (tank) which has one injector and one producer.

Fractional flow model (equation 8) is used to estimate oil production at capacitance method.

$$q_{oil} = q_{fluid} \times WC = \frac{q_{fluid}}{1 + \alpha \cdot w(t)^{\beta}}, where \tag{8}$$

q_{oil}, q_{fluid} – oil rate and liquid rate, respectively, w(t) – injection rate, α and β– coefficients, which were determined from field data.

3. Conclusion
- Parameters λ and τ depend on many parameters: fluid and reservoir properties, square of field, number of samples and noises of input data.
- Methods CM works better for field which has high diffusivity constant $>10^6$ bar*mD/cp
- Sensitivity analysis has shown that optimized time step will be 1 month for calculation by using analytical methods.
- The equations which have been used in this paper do not take into account transient flow.
- Large error is occurred when methods CM uses real production field data.
- Capacitance method works like "tank" (material balance) model and operates with liquid flow rates and cumulative liquid production. Fractional flow model should be used for oil production rates estimation.

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