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A CORRECTION METHODOLOGY FOR EXPLICIT COUPLING BETWEEN RESERVOIR AND PRODUCTION SYSTEM SIMULATORS

João Carlos von Hohendorff Filho

Denis José Schiozer

hohendorff@cepetro.unicamp.br

denis@cepetro.unicamp.br

Department of Energy, FEM, UNICAMP/CEPETRO

Caixa Postal 6052, CEP 13083-970, São Paulo, Brazil

Abstract. *Various methodologies to model the coupling of reservoirs and production systems have been applied in the oil industry in recent years due to the need to model properly the integrated solution of models that represent the flow of fluids through the reservoir to the surface. Explicit methodology can be an efficient choice to integrate simulations because allows coupling adequate simulators to model the whole system and also to grant flexibility in study of well management alternatives. Several authors have shown the limitations of explicit methodology coupling reservoirs and production systems, such as errors due to the inadequate choices of time step and boundary conditions.*

The objective of this work were formulated a theoretical foundation to support the adopted IPRc correction methodology, comparing with observed well bottom hole pressure data from reservoir simulation, and validate explicit coupling methodology for producer wells, applying in cases of known response in common situations of well operation in production and injection of fluids. The explicit coupling between reservoir simulator and production systems was implemented obtaining satisfactory results when compared with uncoupled and decoupled methodologies.

Keywords: Coupling, simulation, reservoir, production system

1 INTRODUCTION

Several methodologies have been applied to model the coupling of petroleum reservoirs and production systems in recent years due to the need to model properly the integrated solution of models that represent the flow of fluids through the reservoir to the surface.

These methodologies are used to forecast production of multiple reservoirs, sharing production platforms with limited production e injection capacities collecting fluids from complex production systems. They can be grouped into two basic forms of coupling: implicit and explicit.

Explicit coupling can be an efficient choice to integrate simulations because allows using adequate simulators to model the whole system and also to grant flexibility in study of well management alternatives.

Many recent publications use explicit form of coupling (Hayder et al, 2001, Vera et al, 2007, Rotondi et al, 2008) because formulation in implicit methodology is complex and involves modeling systems with different characteristics, it is sometimes hard to obtain a unique solution for the whole system. Also, a solution for two or more joint fields in one model can be complex and require adjustments to obtain equivalent results.

Several authors (Schiozer, 1994, Zapata et al, 2001, Ghorayeb et al, 2003, Cao et al, 2015) showed limitations of explicit coupling, causing mainly oscillations in the injection and production. Such as errors can be minimized by decreasing the time step but this causes a significant increase in the computational time.

These oscillations reported in the literature are caused by numerical instability of the solution and inability to guarantee a unique response between reservoir and production system models, caused by time advancing, especially in scenarios with high productive producer wells (Rotondi et al, 2008).

Some authors proposed solutions (Middya and Dogru, 2008, Güyagüler et al, 2011, Liang and Rubin, 2014) to minimize these numerical instabilities and guarantee the unique response, but each solution is software dependent.

The Inflow Performance Relationship Corrector (IPRc) methodology proposed by Hohendorff Filho and Schiozer (2014) to correct Inflow Performance Relationship curves obtained from reservoir simulator search a good solution for explicit coupling for some validation cases presented.

A great advantage of this methodology is its application for any reservoir simulator that contains an appropriated interface for data exchanging, without internal code changes inside the reservoir simulator. The disadvantages of this correction methodology, on the other hand, arise in the lack of the theoretical foundation and intrinsic parameters obtainment, being based only on experimental results.

The first objective of this work was to formulate a theoretical background to support the adopted IPRc correction methodology, comparing with observed well bottom hole pressure data from reservoir simulation.

A secondary objective is to validate explicit coupling methodology for scenarios including high productivity producer wells, applying in cases of known response in common situations of well operation in production and injection of fluids. The results are compared with the response of the uncoupled and decoupled methodologies to check the quality of numerical solution.

The authors proposed also a methodology for adaptive control of time step advance (ACET), which verifies changes in pressure and flow rate of the previous time step and modifies the length of the next time step by a pre-established criterion. This methodology did not improve the numerical response to proposed scenarios, but in this study is evaluated again.

2 METHODOLOGY

The work follows the respective steps:

1) Formulated a theoretical background to support the adopted methodology, comparing with observed data from reservoir simulation.

2) Investigate intrinsic parameters for the correction method, verifying simulation results.

3) Validation study of explicit coupling methodology where the production system would be tested on common operating conditions during production and injection of fluids.

Our explicit methodology that incorporates production system model within reservoir and production system simulators is based on our own explicit coupler (Hohendorff Filho and Schiozer, 2014) that applies an explicit integration approach between commercial simulators, with important topics incorporated, as the IPRc methodology.

3 RESULTS

We formulated a theoretical background to support the adopted methodology, comparing with observed data from reservoir simulation, using concepts of semi-steady state flow behavior as hypothesis for bottom-hole pressure behavior for wells producing for short periods of time like days or weeks.

3.1 Theoretical Foundation

According Ertekin et al (2001), the equation for single-phase, slight compressible flow through porous media for one-dimensional flow has the form of Eq. (1):

$$\frac{\partial}{\partial x}\left(\beta_c \frac{A_x k_x}{\mu_l B_l}\frac{\partial p}{\partial x}\right)\Delta x + q_{lsc} = \frac{V_b \phi c_l}{\alpha_c B_l^o}\frac{\partial p}{\partial t} \tag{1}$$

where x is length, A is area, k is permeability, μ is phase viscosity, B is FVF, p is pressure, q_{sc} is flow rate, V_b is grid block bulk volume, c is compressibility, ϕ is porosity, t is time, α_c is volume conversion factor, and β_c is transmissibility conversion factor. Subscript l refers to Phase l (oil or water). Subscript x refers to direction x.

The central-difference approximation to the first derivative for a grid point i can be defined as Eq. (2):

$$\frac{\partial}{\partial x}\left(\beta_c \frac{A_x k_x}{\mu_l B_l}\frac{\partial p}{\partial x}\right)_i \approx \frac{1}{\Delta x}\left[\left(\beta_c \frac{A_x k_x}{\mu_l B_l}\frac{\partial p}{\partial x}\right)_{i+\frac{1}{2}} - \left(\beta_c \frac{A_x k_x}{\mu_l B_l}\frac{\partial p}{\partial x}\right)_{i-\frac{1}{2}}\right] \tag{2}$$

Using central differences to approximate $(dp/dx)_{i+½}$ and $(dp/dx)_{i-½}$ yields to Eq. (3) and Eq. (4):

$$\left(\frac{\partial p}{\partial x}\right)_{i+\frac{1}{2}} = \frac{p_{i+1}-p_i}{x_{i+1}-x_i} = \frac{p_{i+1}-p_i}{\Delta x_{i+\frac{1}{2}}} \tag{3}$$

$$\left(\frac{\partial p}{\partial x}\right)_{i-\frac{1}{2}} = \frac{p_i-p_{i-1}}{x_i-x_{i-1}} = \frac{p_i-p_{i-1}}{\Delta x_{i-\frac{1}{2}}} \tag{4}$$

Substituting Eq.s (2), (3) and (4) into (1) results in Eq. (5):

$$T_{lx_{i+\frac{1}{2}}}\left(p_{i+1}-p_i\right) - T_{lx_{i-\frac{1}{2}}}\left(p_i-p_{i-1}\right) + q_{lsc} = \left(\frac{V_b \phi c_l}{\alpha_c B_l^o}\right)_i \frac{\partial p}{\partial t} \tag{5}$$

The coefficients $Tix_{i+½}$ and $Tix_{i-½}$ are referred as the transmissibilities of the porous medium and defined by Eq. (6) and (7).

$$T_{lx_{i+\frac{1}{2}}} = \left(\beta_c \frac{A_x k_x}{\mu_l B_l}\frac{\partial p}{\partial x}\right)_{i+\frac{1}{2}} \tag{6}$$

$$T_{lx_{i-\frac{1}{2}}} = \left(\beta_c \frac{A_x k_x}{\mu_l B_l}\frac{\partial p}{\partial x}\right)_{i-\frac{1}{2}} \tag{7}$$

The transmissibility of a porous medium is considered to be a property of the porous medium, the fluid flowing through the medium (subscript *l*), the direction of flow (subscript *x*), and the position in space (subscripts *i+½* and *i-½*).

The backward-difference approximation to the first derivative at the base time level t^n is defined in Eq. (8):

$$\frac{\partial p_i}{\partial t} = \frac{p_i^{n+1}-p_i^n}{\Delta t} \tag{8}$$

Substituting Eq. (8) into (5) at level t^{n+1} in terms of transmissibilities evaluated at p^n results in Eq. (9):

$$T_{lx_{i+\frac{1}{2}}}^n\left(p_{i+1}^{n+1}-p_i^{n+1}\right) - T_{lx_{i-\frac{1}{2}}}^n\left(p_i^{n+1}-p_{i-1}^{n+1}\right) + q_{lsc_i}^n = \left(\frac{V_b \phi c_l}{\alpha_c B_l^o \Delta t}\right)_i \left(p_i^{n+1}-p_i^n\right) \tag{9}$$

Rearranging Eq. (9) yields to Eq. (10):

$$T_{lx_{i+1/2}}^{n}\, p_{i+1}^{n+1} - \left[\left(\frac{V_b \phi c_l}{\alpha_c B_l^o \Delta t}\right)_i + T_{lx_{i+1/2}}^{n} + T_{lx_{i-1/2}}^{n}\right] p_i^{n+1} + T_{lx_{i-1/2}}^{n}\, p_{i-1}^{n+1} = -\left[q_{lsc_i}^{n} + \left(\frac{V_b \phi c_l}{\alpha_c B_l^o \Delta t}\right)_i p_i^{n}\right] \tag{10}$$

Evaluating Eq. (10) at level t^{n+2} in terms of transmissibilities evaluated at p^{n+1} and results in Eq. (11):

$$T_{lx_{i+1/2}}^{n+1}\, p_{i+1}^{n+2} - \left[\left(\frac{V_b \phi c_l}{\alpha_c B_l^o \Delta t}\right)_i + T_{lx_{i+1/2}}^{n+1} + T_{lx_{i-1/2}}^{n+1}\right] p_i^{n+2} + T_{lx_{i-1/2}}^{n+1}\, p_{i-1}^{n+2} = -\left[q_{lsc_i}^{n+1} + \left(\frac{V_b \phi c_l}{\alpha_c B_l^o \Delta t}\right)_i p_i^{n+1}\right] \tag{11}$$

Adopting coefficient Qi defined by Eq. (12):

$$Q_i = -\left(\frac{V_b \phi c_l}{\alpha_c B_l^o \Delta t}\right)_i p_i - q_{lsc_i} \tag{12}$$

Subtracting Eq. (10) from (11) and substituting Eq. (12) yields in Eq. (13):

$$\begin{aligned} &T_{lx_{i+1/2}}^{n+1}\, p_{i+1}^{n+2} - T_{lx_{i+1/2}}^{n}\, p_{i+1}^{n+1} + T_{lx_{i-1/2}}^{n+1}\, p_{i-1}^{n+2} - T_{lx_{i-1/2}}^{n}\, p_{i-1}^{n+1} - \left[\left(\frac{V_b \phi c_l}{\alpha_c B_l^o \Delta t}\right)_i + T_{lx_{i+1/2}}^{n+1} + T_{lx_{i-1/2}}^{n+1}\right] p_i^{n+2} \\ &+ \left[\left(\frac{V_b \phi c_l}{\alpha_c B_l^o \Delta t}\right)_i + T_{lx_{i+1/2}}^{n} + T_{lx_{i-1/2}}^{n}\right] p_i^{n+1} = -Q_i^{n+1} + Q_i^{n} \end{aligned} \tag{13}$$

Assuming coefficients $Tix_{i+1/2}$ and $Tix_{i-1/2}$ similar at levels t^n and t^{n+1} and rearranging Eq. (13) yields to Eq. (14):

$$\begin{aligned} &T_{lx_{i+1/2}}^{n}\left(p_{i+1}^{n+2} - p_{i+1}^{n+1}\right) + T_{lx_{i-1/2}}^{n}\left(p_{i-1}^{n+2} - p_{i-1}^{n+1}\right) - \left[\left(\frac{V_b \phi c_l}{\alpha_c B_l^o \Delta t}\right)_i + T_{lx_{i+1/2}}^{n} + T_{lx_{i-1/2}}^{n}\right] \\ &\times \left(p_i^{n+2} - p_i^{n+1}\right) = -Q_i^{n+1} + Q_i^{n} \end{aligned} \tag{14}$$

Rearranging Eq. (14) yields to Eq. (15):

$$p_i^{n+2} - p_i^{n+1} = \frac{\left[Q_i^{n+1} - Q_i^{n} + T_{lx_{i+1/2}}^{n}\left(p_{i+1}^{n+2} - p_{i+1}^{n+1}\right) + T_{lx_{i-1/2}}^{n}\left(p_{i-1}^{n+2} - p_{i-1}^{n+1}\right)\right]}{\left[\left(\frac{V_b \phi c_l}{\alpha_c B_l^o \Delta t}\right)_i + T_{lx_{i+1/2}}^{n} + T_{lx_{i-1/2}}^{n}\right]} \tag{15}$$

Generally the difference of terms q_{lsci} in coefficient Qi is bigger that differences of p^n, p_{i+1} and p_{i-1} at levels t^n and t^{n+1}, simplifying Eq. (15) to Eq. (16):

$$p_i^{n+2} - p_i^{n+1} = \left(Q_i^{n+1} - Q_i^{n}\right) \Big/ \left[\left(\frac{V_b \phi c_l}{\alpha_c B_l^o \Delta t}\right)_i + T_{lx_{i+1/2}}^{n} + T_{lx_{i-1/2}}^{n}\right] \tag{16}$$

For small time steps the term of volume compressibility is bigger than the sum of coefficients $Tix_{i+½}$ and $Tix_{i-½}$, yields to Eq. (17).

$$p_i^{n+2} - p_i^{n+1} = \left(q_{lsc_i}^{n+1} - q_{lsc_i}^{n}\right)\left(\frac{\alpha_c B_l^o \Delta t}{V_b \phi c_l}\right)_i \tag{17}$$

Eq. (17) is similar to Eq. (18) that compounded the IPRc equation shown in the previous work.

$$\left.\frac{\partial P}{\partial t}\right|^n = K\left(q_w^{n+1} - q_w^{n-1}\right) \tag{18}$$

where P is pressure, q_w is water rate, and K is a constant obtained in function of P and q_w.

For oil and water biphasic flow, all formulation could be applied considering the sum of equations for single-phase, slight compressible flow through porous media for one-dimensional flow for each phase. A new hypothesis is necessary, considering the total liquid effective permeability varies few during the time step.

The next step was investigate how to obtain intrinsic parameters for the correction method, for the same consider aspects as drainage radius, reservoir porosity and thickness, rock compressibility, fluid viscosities and saturations, and others that could vary during time. A discussion about this topic based on coupled simulation results was need.

3.2 Intrinsic Parameters

To validate Eqs. (17) and (18), some results present in previous work are present next. Figure 1 show results from an evaluation test for the five-spot without IPR correction for Case 1, indicating numerical instability. Figure 2 show the relation observed between delta of pressure and delta of water rate, indicating a linear correlation of the values, what would be represented by a time dependent term T.

One concern about the IPRc methodology is how obtain term K because it is time dependent and could include some influences simplified in previous hypotheses. A first verification is based on hypothesis for the Eq. (1), where rate values for q_{lsci} consider respective signals for production and injection, determining the signal of K. Some cut values could be necessary.

The second concern is how computed term K among integrated time step advancing. Direct application of Eq. (18) shown some instabilities when the delta of pressure or water rate is zero, or in cases of great influence of one simplified hypothesis. The solution adopted is considering a linear regression of deltas without the intercept term.

Finally, there was the validation study of explicit coupling methodology where the production system would be tested on common operating conditions during production and injection of fluids, verifying benefits and limitations of explicit methodology, as numerical stability, computational demand and global solution. The results were compared with the response of the implicit coupling methodology to check the quality of numerical solution.

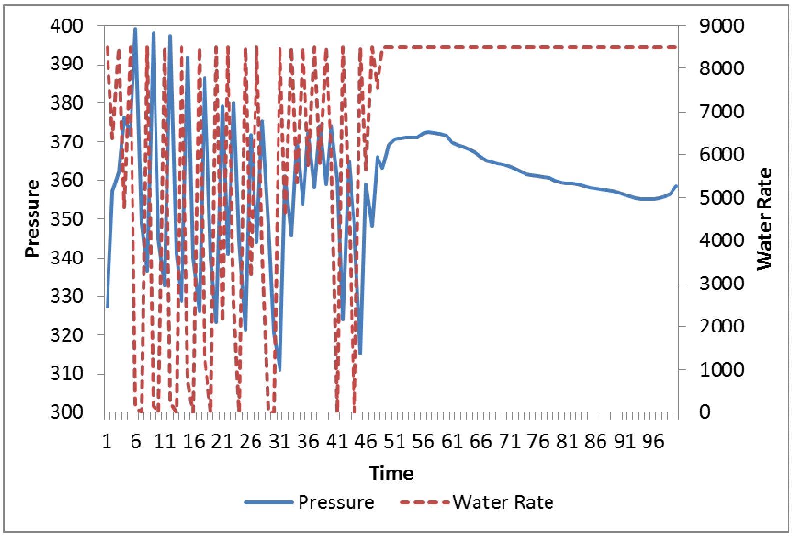

Figure 1 - Behavior of pressure and water rate in explicit coupling

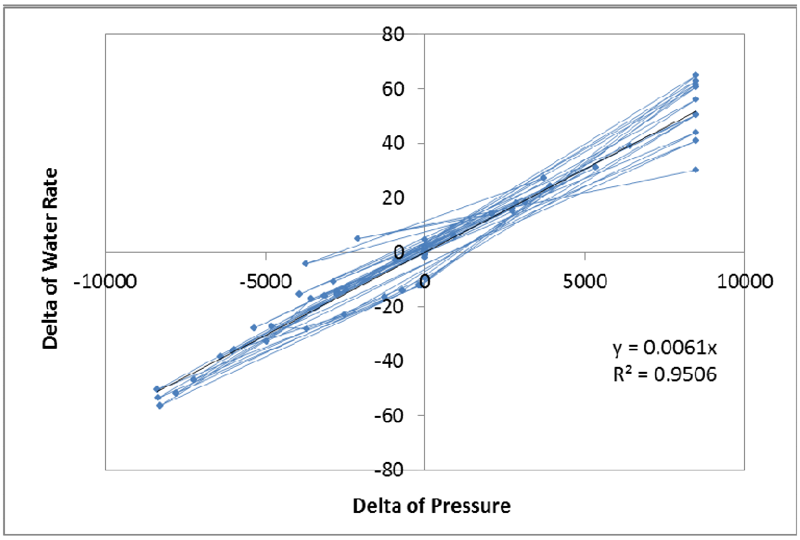

Figure 2 - Correlation between deltas of pressure and water rate

3.3 Validation Study

To validate the explicit coupling methodology, we have chosen the benchmark case UNISIM-I-D in the MR9 representative model (Schiozer et al, 2015) for scenarios including high productivity producer and injector wells, applying in cases of known response in common situations of well operation in production and injection of fluids.

Case 1 compares the response of the base uncoupled run (Uncoupled) with coupled runs with different IPRc configurations: all wells (Integrated); for injectors only (Without IPRc for Producer; for producers only (Without IPRc for Injectors); none well (Without IPRc). The coupling for producer and injector wells occurs at bottom-hole level imposing bottom-hole pressure and rates of production, and injection operational limits, with group restriction.

ACET methodology for minimize numerical oscillation is applied in all IPRc configurations, except in one run (Without ACET) to reevaluate the effectiveness of this methodology.

When compared with uncoupled results, the field production and injection (Figure 3, Figure 4, Figure 5 and Figure 6) are greatly affected by the IPRc configuration. IPRc for all wells is the configuration that obtains the better correlation with uncoupled run. ACET did not improve the numerical response to proposed case.

Figure 7, Figure 8, Figure 9, Figure 10 and Figure 11 shows typical behaviors for producers and injectors during a coupled run at bottom-hole level, showing injector well is most affected by the explicit coupling. The IPRc methodology for producer and injector wells is crucial to minimize oscillation and obtain reliable results.

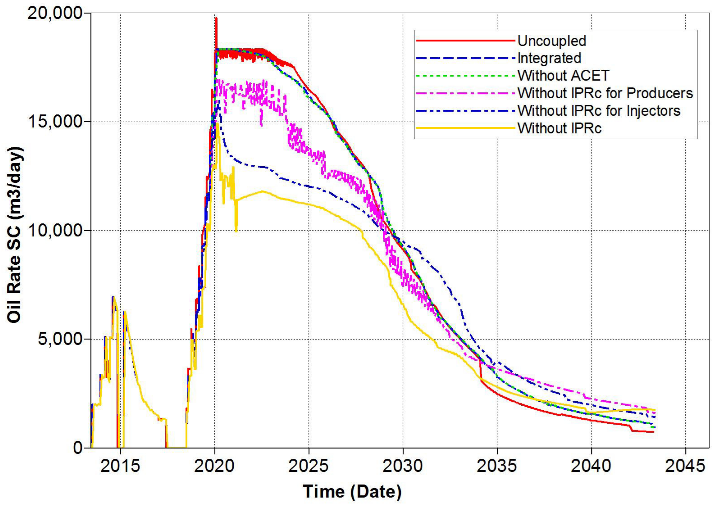

Figure 3 - Oil Production for field (Case 1)

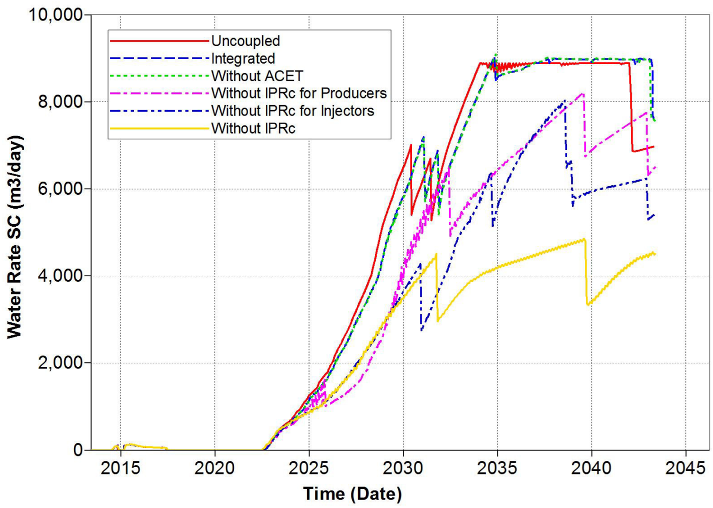

Figure 4 - Water production for field (Case 1)

Case 2 compares the response of the base decoupled run (Decoupled) with coupled runs with different IPRc configurations: all wells (Integrated); for injectors only (Without IPRc for Producer; for producers only (Without IPRc for Injectors); none well (Without IPRc). The coupling for producer and injector wells occurs at surface level imposing wellhead pressure and rates of production, and injection operational limits, with group restriction.

ACET methodology for minimize numerical oscillation is applied in all IPRc configurations, except in one run (Without ACET) to reevaluate the effectiveness of this methodology.

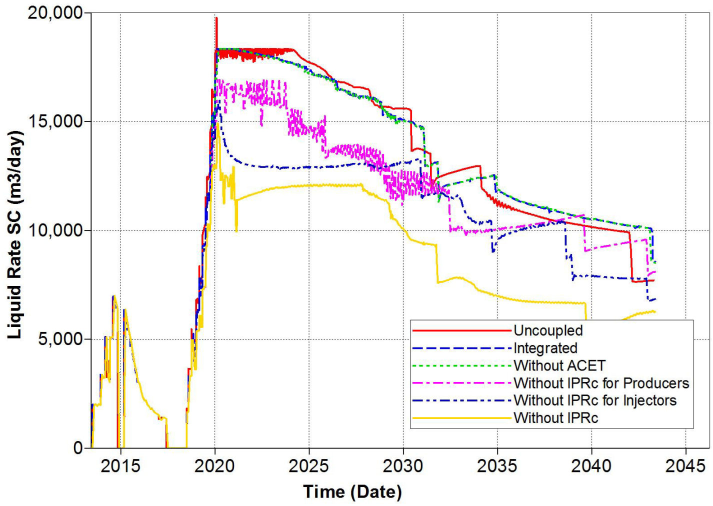

Figure 5 - Liquid production for field (Case 1)

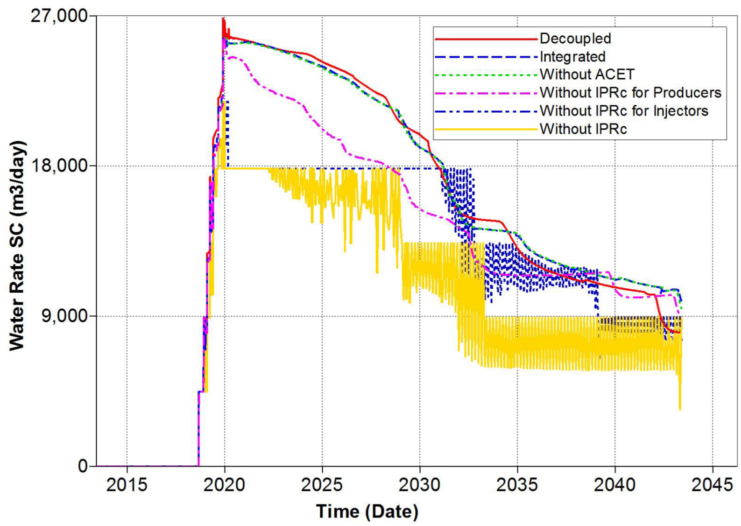

Figure 6 - Water injection for field (Case 1)

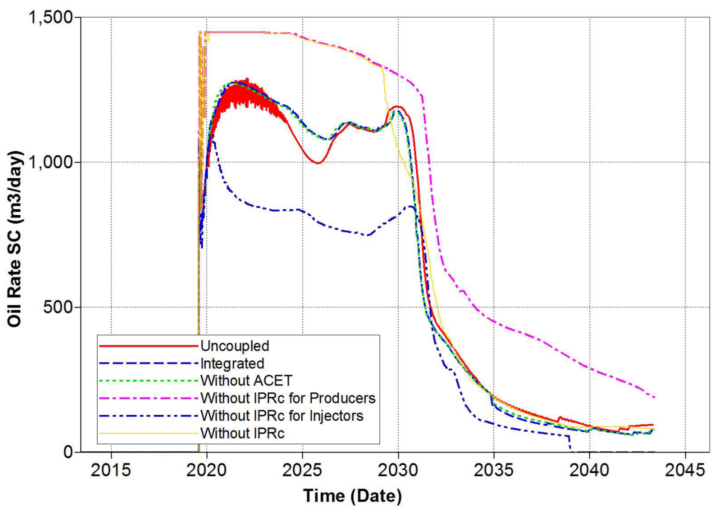

Figure 7 - Oil production for PROD-012 (Case 1)

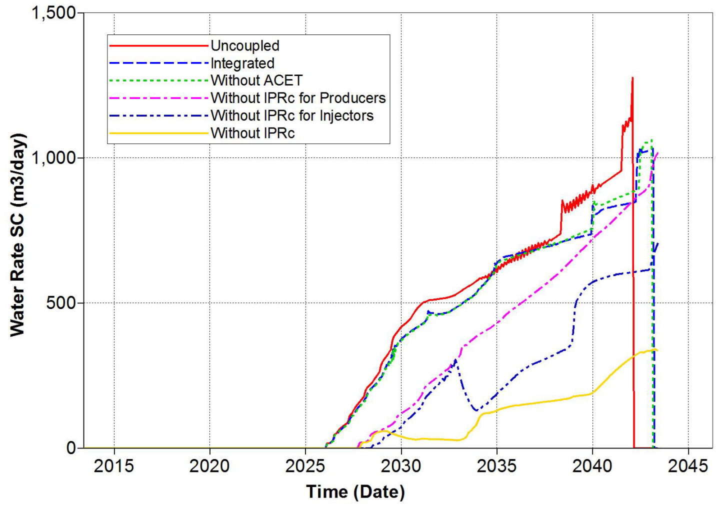

Figure 8 - Water production for PROD-012 (Case 1)

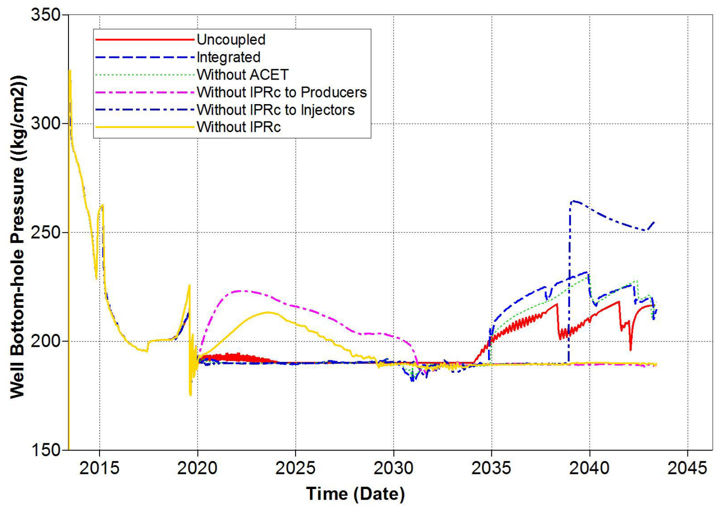

Figure 9 – Well bottom-hole pressure for PROD-012 (Case 1)

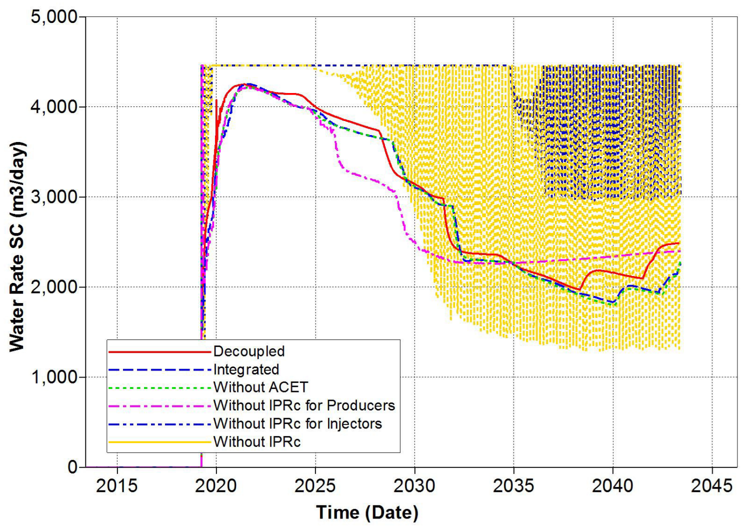

Figure 10 - Water injection for INJ-022 (Case 1)

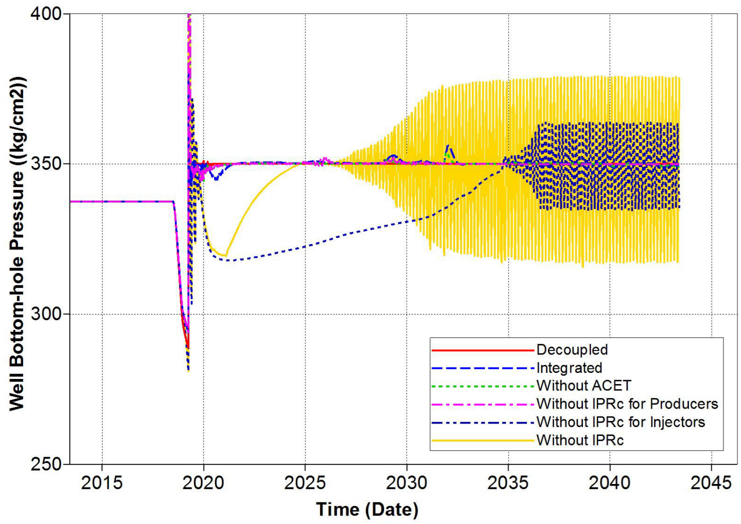

Figure 11 – Well bottom-hole pressure for INJ-022 (Case 1)

The wells are defined as production systems describing satellite wells configured by production column, flowline and riser, with diameters of 4', 6' and 6' respective. There are assumed a gas lift injection rate of 200.000 m³/day.

When compared with decoupled results, the field production and injection (Figure 12, Figure 13, Figure 14 and Figure 15) are greatly affected by the IPRc configuration. IPRc for all wells is the configuration that obtains the better correlation with decoupled run, but IPRc for producers shown to be unnecessary. ACET did not improve the numerical response to proposed case.

Figure 16, Figure 17, Figure 18, Figure 19 and Figure 20 shows typical behaviors for producers and injectors during a coupled run at surface level, showing injector well is most affected by the explicit coupling. The IPRc methodology for injector wells is crucial to minimize oscillation and obtain reliable results.

The computational time in Case 1 (BHP control) for decoupled run spent 424s, compared to integrated run that spent 549s with similar results. In Case 2 (WHP control), decoupled run spent 441s more previous VLP tables generation spent 417s, totaling 858s, compared to integrated run that spent 574s more 250s for pressure drop determination, totaling 827s with similar results. These results indicate a suitable time for explicit coupling applications.

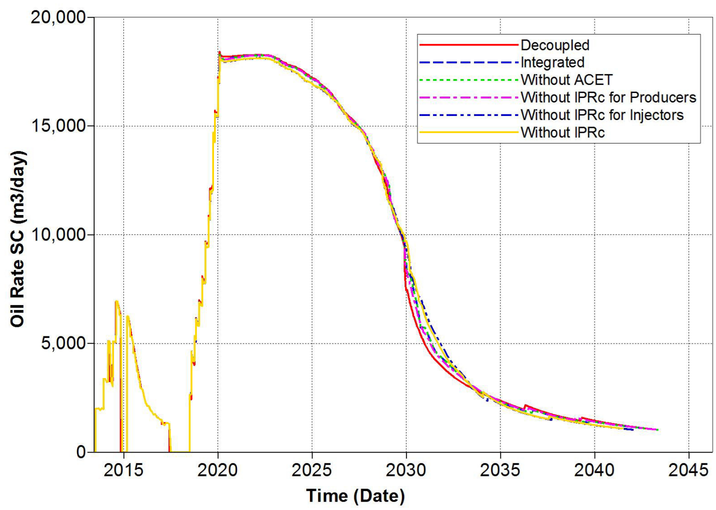

Figure 12 - Oil production for field (Case 2)

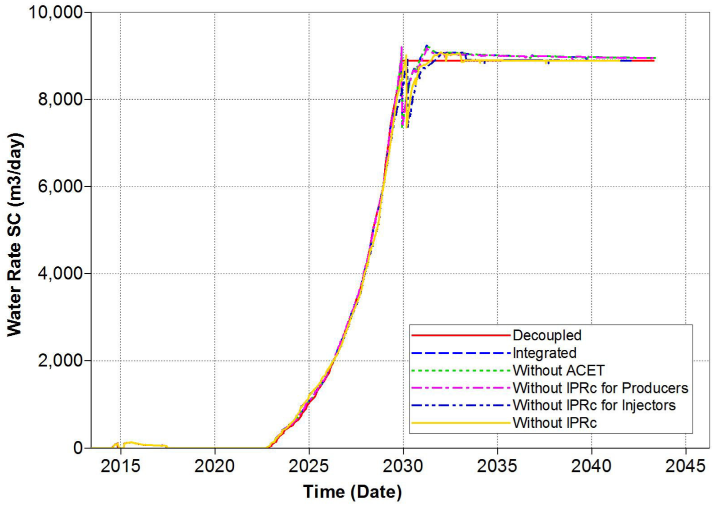

Figure 13 - Water production for field (Case 2)

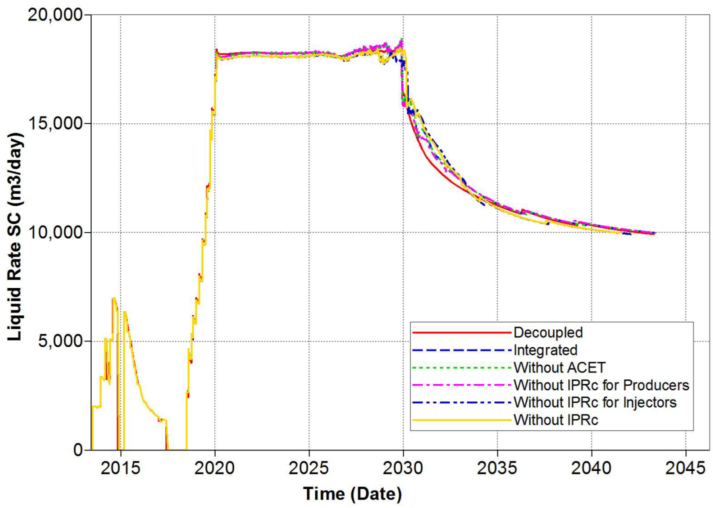

Figure 14 - Liquid production for field (Case 2)

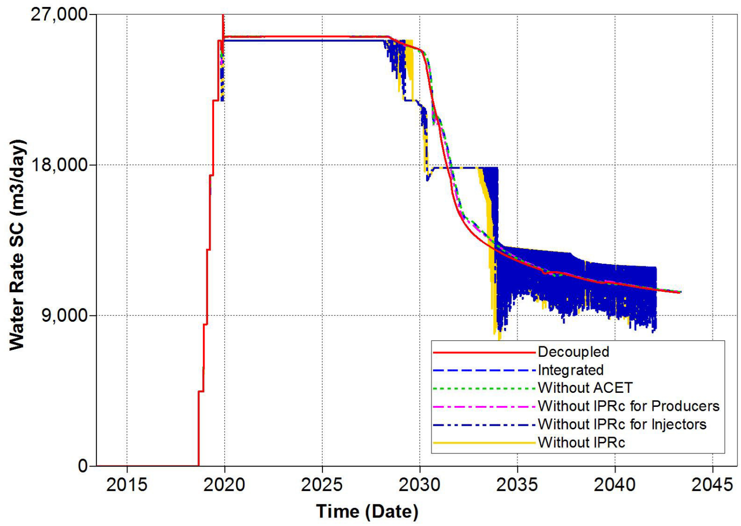

Figure 15 - Water injection for field (Case 2)

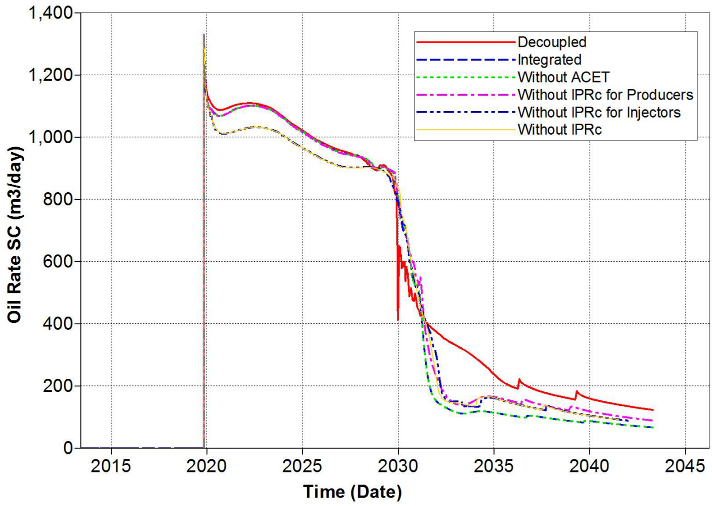

Figure 16 - Oil production for PROD-026 (Case 2)

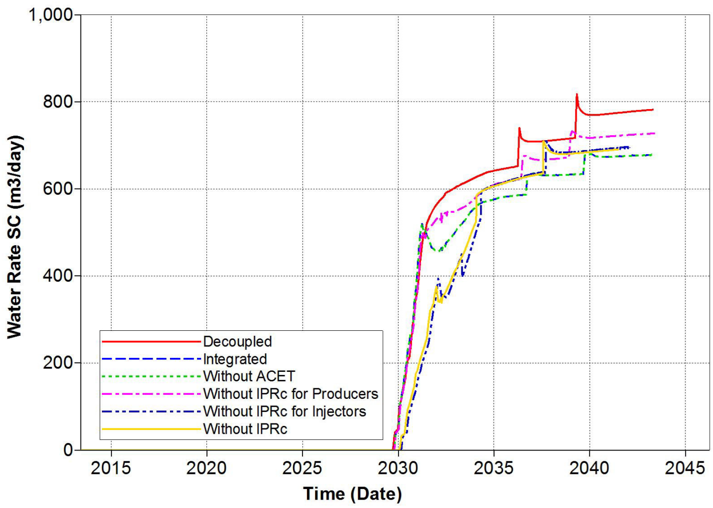

Figure 17 - Water production for PROD-026 (Case 2)

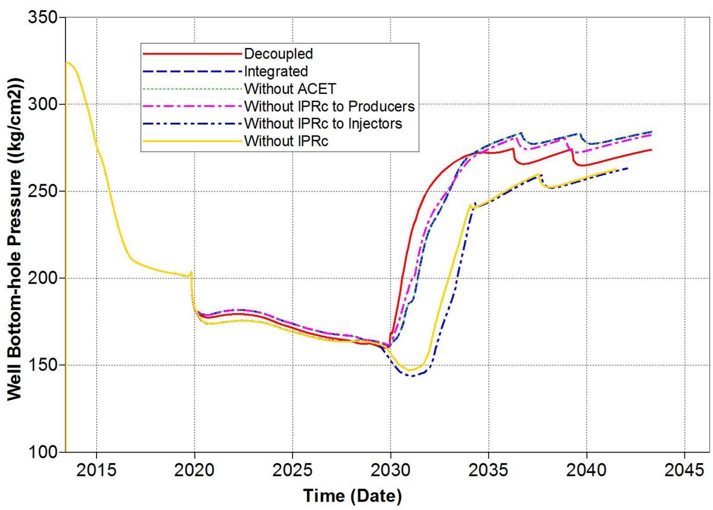

Figure 18 – Well bottom-hole pressure for PROD-026 (Case 2)

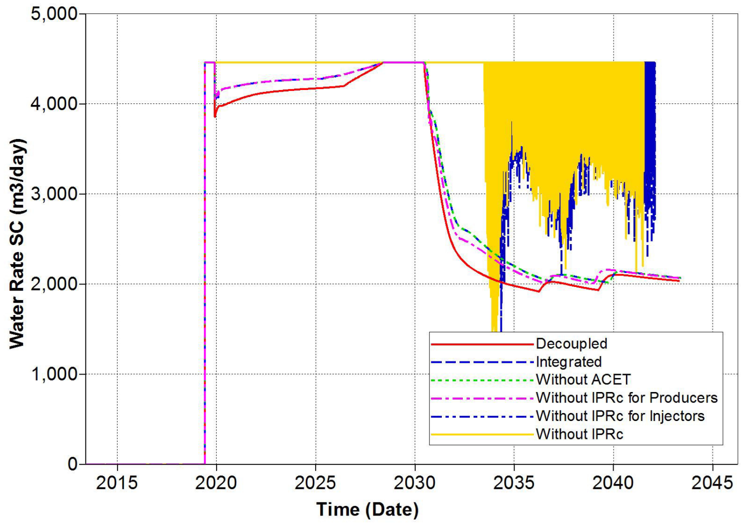

Figure 19 - Water injection for INJ-006 (Case 2)

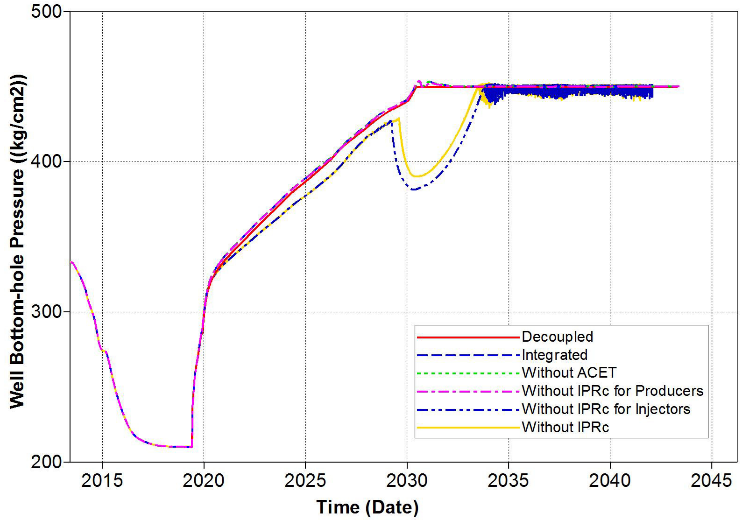

Figure 20 – Well bottom-hole pressure for INJ-006 (Case 2)

4 CONCLUSIONS

The theoretical formulation was able to represent flow behavior from reservoir simulator data, validating IPRc methodology formulation for explicit coupling correction.

Both producer and injector wells presented numerical instability problems, indicating the necessity of correction methodologies for explicit methodology. The IPRc methodology applied minimized numerical instabilities consistently, but ACET correction methodology, based on an adaptive time step advancing and initially discarded by the authors, again didn´t improve the numerical response to proposed scenarios.

The explicit coupling between reservoir simulator and production systems was implemented obtaining satisfactory results when compared with uncoupled and decoupled methodologies. All well and group operating constraints defined were honored.

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