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Pressure and temperature response of stratified reservoirs during well tests

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Abstract. *Most of the Brazilian pre-salt oil reserves are located across the layers of stratified carbonate reservoirs with different petrophysical properties. Since most production optimization strategies rely on accurate reservoir characterization, the multiple layers represent an extra challenge. In order to determine the reservoir parameters, the inverse problem must be solved by fitting a model to transient measurements of pressure and temperature. This work presents a coupled well-reservoir dynamic model able to describe the flow and heat transfer in a stratified reservoir linked to a vertical wellbore. The results show how well pressure and temperature measurements change with reservoir conditions far from the wellbore. Ultimately, fitting this model to transient data results in accurate characterization of the individual layers.*

Keywords: *Reservoir Engineering, Well Testing, Stratified Reservoir*

1. INTRODUCTION

Campos Basin is one of the twelve coastal sedimentary basins in Brazil. It has played a significant role in the country's oil and gas production, since its early days in 1979, with the Enchova field (Bruhn *et al.* (2017)). Figure 1, sourced from Bruhn *et al.* (2017), presents Petrobras' production history in Brazil, from its establishment in 1953 until 2017.

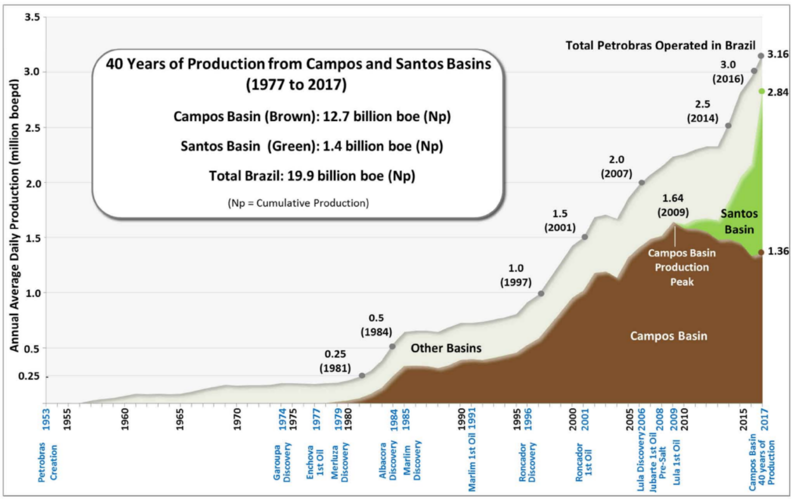

Figure 1. Average annual production by Petrobras in Brazil since 1953, extrated from Bruhn *et al.* (2017). The graph illustrates the transition in production trends, with the Campos Basin experiencing a peak production by 2009, followed by an increasing dominance of the pre-salt basins, specifically Campos and Santos, in Petrobras' production.

Due to its strategic importance, pre-salt fields management demands particular attention. More accurate reservoir characterization methodologies may represent a huge impact on oil recovery rates, providing the tools to manage different zones in order to postpone water production. However, when it comes to characterization, the pre-salt reservoir poses several complex geological challenges. One example is the presence of stratified configuration, where each layer within the reservoir may exhibit unique petrophysical properties.

Conducting a iterature review focused on reservoir modeling, Galvao *et al.* (2020) presented a study involving analytical modeling of a radial reservoir coupled with a vertical well, considering non-isothermal flow hypotheses. Galvão demonstrated that the isothermal assumption could lead to misinterpretation, especially highly transmissible reservoir like the pre-salt, using the Bourdet pressure derivative graph (Bourdet *et al.* (1989)). This plot is an important diagnostic tool used in the reservoir characterization process, which can be observed in Figure 2, taken from Galvao *et al.* (2020). The graph illustrates a scenario where, under the isothermal assumption, the field data could be modeled as a double-porosity system. On the other hand, considering the non-isothermal hypothesis, this could be interpreted as a homogeneous reservoir.

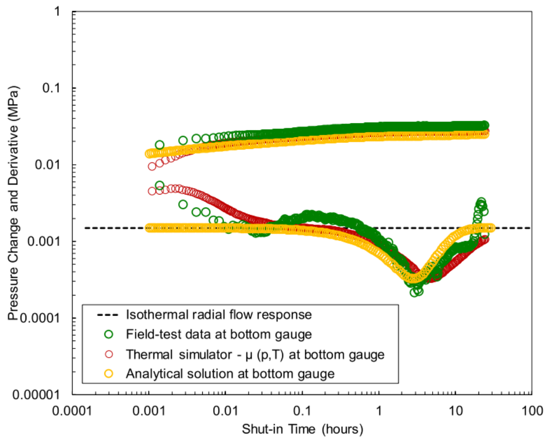

Figure 2. Comparison chart from Galvao *et al.* (2020), with field data (green) along with responses from different simulation models

The isothermal hypothesis (black dashed line) leads to misinterpretations, while the non-isothermal simulator (red line) and proposed analytical model (yellow line) provide more accurate results. Non-isothermal simulations mitigate errors, highlighting the importance of considering non-isothermal flow in reservoir analysis.

Considering the availability of temperature data obtained due to the smart completions, numerous studies have focused on investigating the use of temperature data (Sui *et al.* (2008); Onur and Palabiyik (2015); Mao and Zeidouni (2017); de Souza Cardoso (2020)). These studies, which include both numerical and analytical analyses, demonstrate the advantages of incorporating temperature data in multi-layer or single-layer reservoirs characterization.

Acknowledging the importance of temperature data, da Silva *et al.* (2021) conducted a recent study where they employed the Ensemble Smoother with Multiple Data Assimilation (ES-MDA) techniques developed by Emerick and Reynolds (2013). The objective of their research was to evaluate the benefits of using only pressure data versus utilizing coupled pressure and temperature data in reservoir characterization. The results from da Silva *et al.* (2021) support the importance of incorporating temperature data in the reservoir characterization process.

Another challenge associated with pre-salt reservoir models, as highlighted by Dias *et al.* (2019), is their predominantly stratified nature. This necessitates the use of a multi-layer simulator that requires careful consideration in selecting appropriate boundary conditions for the model. Focused on this aspect Shi *et al.* (2021) investigate the pressure response in a two-layer reservoir with different boundary conditions. The results of their work show that different combinations of reservoir layers boundary conditions can lead to inaccurate reservoir characterization, subsequently resulting in ineffective reservoir management.

Figure 3, extracted from Shi *et al.* (2021), illustrates the response of two different combinations of reservoir boundary conditions. In blue is the pressure feedback from a reservoir with one layer with a closed boundary and the other layer with infinite acting, and this response is similar to a radial composite reservoir with a higher permeability near the well followed by a poor permeability zone. In red is the combination of a constant pressure layer with the other with infinite acting, this pressure response can be confused with a dual-porosity reservoir.

These possible misinterpretation highlights the critical influence of boundary conditions on a stratified reservoir behavior and emphasize the necessity of accurate boundary characterization for reliable reservoir management. The present study proposes a numerical model of a two-layer reservoir coupled in a wellbore. The simulator incorporates factors such as Joule-Thomson heating and cooling, adiabatic fluid expansion/compression, conduction, and convection effects in the thermal energy balance equation. The objective is to achieve temperature and pressure data to evaluate if the temperature data can improve the decision of the model boundary condition.

The structure of this work is as follows. It begins with a literature review and the motivation behind this study. The subsequent section presents the mathematical formulation, which includes the equations, boundary conditions, coupling, and initial conditions used in the simulator. Moving forward, the results section and finally the conclusion and discussion of this work.

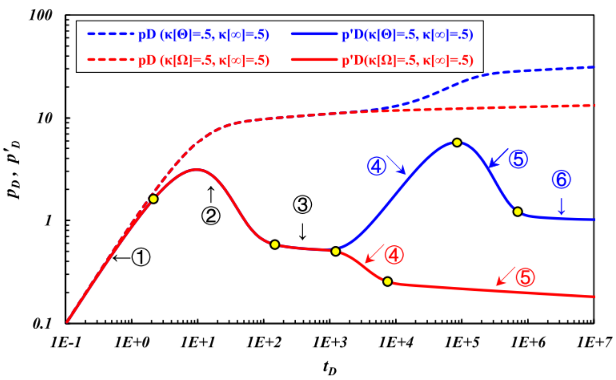

Figure 3. Comparison of pressure delta (dashed lines) and pressure derivative responses (continuous lines) from Shi *et al.* (2021), in a case with a combination of no-flow and infinite-acting boundary conditions are applied (blue lines) and in case with constant pressure and infinite-acting boundary conditions are used (red lines).

2. MATHEMATICAL FORMULATION

The model utilized in this study represents a two-layer reservoir coupled to a vertical well. Each layer of the reservoir is treated as a single-phase radial flow system. The simulator solves the mass balance equation, which is expressed by Eq.1. For a more comprehensive understanding of the mass balance equation and its hypothesis adopted, detailed explanations can be found in the works of Onur and Çinar (2016); Onur and Cinar (2017).

$$\phi\left(C_t\frac{\partial p}{\partial t}-\beta_t\frac{\partial T}{\partial t}\right)=\frac{1}{r}\left[\frac{\partial}{\partial r}(rv_{ro})+rv_{ro}\left(C_o\frac{\partial p}{\partial r}\right)-rv_{ro}\left(\beta_o\frac{\partial T}{\partial t}\right)\right]. \tag{1}$$

In the previously presented equation, the total compressibility (C_t) and the total thermal expansion (β_t) can be defined in terms of the saturation (s), compressibility (C), and thermal expansion (β) of each phase, namely the oil (o) and connate water (w).

$$C_t = C_r + s_wC_w + s_oC_o\,, \quad (2) \qquad \beta_t = \beta_r + s_w\beta_w + s_o\beta_o. \quad (3)$$

Moreover, since the model considers only radial flow in the reservoir, the Darcy velocity (v_{ro}) can be defined concerning the radial pressure gradient ($\frac{\partial p}{\partial r}$) as:

$$v_{ro} = -\frac{K}{\mu_o}\frac{\partial p}{\partial r}, \tag{4}$$

where K represents the permeability of the reservoir, μ_o represents the viscosity of the oil phase.

After describing the mass balance equations of the flow simulator, the reservoir energy conservation equation is expressed by the Eq.5. This equation, based on Barenblatt *et al.* (1990), takes into account the local thermal equilibrium between the fluid phase and the rock formation, as well as the inclusion of the Joule-Thomson effect(ε_{JTo}). The equation is given by:

$$\frac{\partial T}{\partial t}+u_{co}(r,t)\frac{\partial T}{\partial r}-\frac{1}{r}\frac{\partial}{\partial r}\left(r\alpha_t\frac{\partial T}{\partial r}\right)-\varphi_t^*\frac{\partial p}{\partial t}-u_{co}(r,t)\varepsilon_{JTo}\frac{\partial p}{\partial r}=0. \tag{5}$$

The energy equation above also takes into account the thermal diffusivity (α_t), the velocity function of heat transfer ($u_{co}(r,t)$), and the effective adiabatic expansion coefficient of the fluid-saturated porous medium (φ_t^*). For a deep understanding of the wellbore governing equations and the finite difference approach employed in the simulator implementation, detailed information can be found in the previous works of Gonçalves *et al.* (2022) and Mattoso (2022). These works provide comprehensive explanations and insights into the methodology and numerical techniques utilized in the simulation process.

2.1 INITIAL AND BOUNDARY CONDITIONS

The initial condition considered in this study shall be uniform pressure and temperature in each reservoir layer domain according to their respective level of static hydraulic profile and surrounding rock thermal profile. Along the well domain, the static hydraulic profile and the rock thermal profile need to be considered. The initial flow rate is zero in well domain. Pressure and temperature references for well profiles are created considering the initial pressure and temperature from layer 1, as follows:

$$p_{r1}(r,t=0) = p_w(z=0,t=0) = p^0, \tag{6}$$

$$T_{r1}(r,t=0) = T_w(z=0,t=0) = T^0. \tag{7}$$

An infinite mixed boundary condition is considered at the outer region of the reservoir. For the bottom layer, consider that no perturbation reaches the reservoir (infinity acting reservoir). For the top layer, two different boundary conditions will be set: Non-flow and constant pressure conditions.

The inner well boundary condition is related to the flow rate $q_w(z=L,t) = Q$.

The coupling between well and the reservoir is imposed by setting the following equations:

$$p_{r1}(r=r_c,t) = p_w(z=0,t), \tag{8}$$

$$T_{r1}(r=r_c,t) = T_w(z=0,t), \tag{9}$$

$$\frac{\partial p_{r1}}{\partial r} = \frac{\rho_{ow}}{\rho_{o_{r1}}} \frac{\mu_{r1} q_w(z=0,t)}{2\pi r_c K_{r1} H1}, \tag{10}$$

$$p_{r2}(r=r_c,t) = p_w(z=100,t), \tag{11}$$

$$T_{r2}(r=r_c,t) = T_w(z=100,t), \tag{12}$$

$$\frac{\partial p_w}{\partial t} + \frac{q_w}{AC_o}\frac{\partial p_w}{\partial z} - \frac{\beta_o}{C_o}\frac{\partial T_w}{\partial t} - \frac{q_w \beta_o}{AC_o}\frac{\partial T_w}{\partial z} + \frac{1}{AC_o}\frac{\partial q_w}{\partial z} = \frac{\rho_{ow}}{\rho_{o_{r2}}}\frac{H_2}{C_o r_c dz}\frac{K_{r2}}{\mu_{r2}}\frac{\partial p_{r2}}{\partial r} \tag{13}$$

Where r_c represents the radius of the wellbore's chase, and $H1$ and $H2$ denote the height of each reservoir layer as shown in Fig.4.

3. RESULTS

This section presents the results obtained from the analysis of the pressure and temperature transient response of the non-isothermal simulator developed. The findings highlight the relevance of temperature data in the process of selecting appropriate boundary conditions for each reservoir layer. By incorporating temperature data, a more accurate characterization of the reservoir's behavior can be achieved.

The results in this work were generated using the model illustrated in the scheme of Fig.4. The model consists of two layers of a reservoir with equal properties coupled in a vertical wellbore, where the length of the upper layer ($L2$) is 50 m and the length of the bottom layer ($L1$) is 25 km. The chosen lengths of the layers allow for the investigation of the reservoir behavior and the influence of different boundary conditions within each layer. The permeability of the layers is equal to $100mD$ and the porosity is equal to 12%. The other properties used can be found in detail in the tables from Galvao *et al.* (2020). In this work, the equations shown in the previous section were solved using the finite difference method and the right side of Fig.4 shows the scheme of the nodes used.

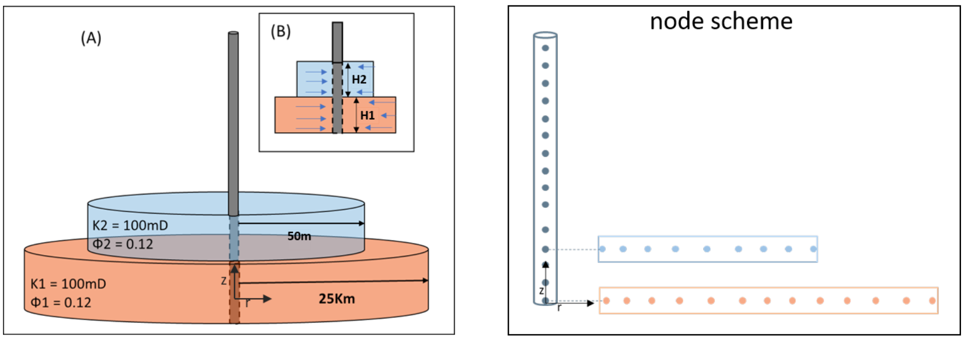

Figure 4. Scheme of the well-reservoir stratified model that the numerical simulator is solving: (A) volumetric representation of the system indicating some properties of each layer, (B) view of a vertical section indicating the heights and the flow direction.

Figure 5 is a qualitative comparison of the pressure delta (Dp) and pressure derivative (Dp') responses from the presented simulator with the responses shown in Fig.3. The numbers were also placed in the graph to facilitate the comparison. The blue number is referent to the response of the case that the $L2$ is considering no flow and the bottom is infinite acting as boundary conditions. The red ones are the case that the upper layer is considering constant pressure (maintenance pressure) as the boundary condition.

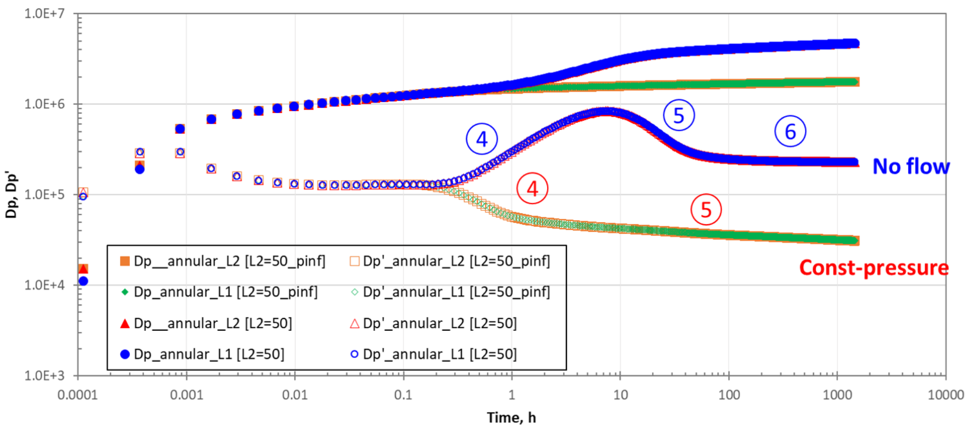

Figure 5. Log-log graph showing pressure deltas and their derivatives generated with data from the developed simulator. The blue and red curves represent the case where the upper layer has the no-flow reservoir boundary condition and the lower layer is considered infinite. The green and orange curves are the case where the upper layer is under pressure maintenance and the lower layer continues to be considered as infinite.

As illustrated in Fig.5, the pressure delta and pressure derivative curves alone do not provide clear information regarding the specific layers to which the boundary conditions apply. This observation aligns with the results of Shi *et al.* (2021), which emphasized the potential for misinterpretation when relying solely on these curves. Since the simulator was developed considering the non-isothermal hypotheses, Fig. 6 shows the absolute temperature derivative curves for the same configurations. The temperature derivative was calculated using Onur and Çinar (2016) methodology, the thermal data provide complementary information that can aid in the interpretation of the reservoir behavior and the identification of the effects of different boundary conditions on each layer.

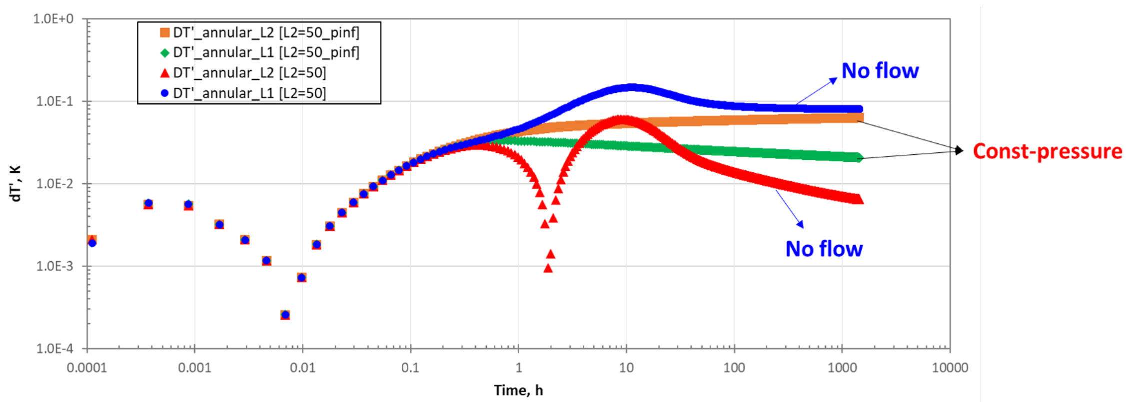

Figure 6. Log-log graph with the modules of temperature derivatives generated with data from the simulator under development. In blue and red are the curves produced for the case in which the upper layer has the bounded reservoir boundary condition and the lower layer is considered infinite. The curves in green and orange are for the case where the upper layer is under pressure maintenance and the lower layer continues to be considered as infinite.

In Fig.6, the case with no-flow boundary condition for the upper layer is represented by red and blue markers for $L2$ and $L1$, respectively, while the case of maintaining pressure and temperature is depicted by orange and green markers for $L2$ and $L1$, respectively. Starting the analysis of the result for the case with no-flow boundary, it is possible to observe that the temperature derivative of layer $L2$ has an inflection point, while the derivative of $L1$ has a small increment and then follows similar to the initial behavior. For the other case, a deviation between the orange and green curves can be observed after approximately one hour, with the orange curve showing a slight thermal increase while the green curve demonstrates a loss of heat over time. These observations highlight the significance of the non-isothermal model in distinguishing between the types of boundary conditions for each layer.

In addition to the benefits of considering the non-isothermal simulation showed the previous results, the developed simulator also offers the capability to inform the ratio of flow between the reservoir layers. The ability to apportion the flow between layers is valuable to oil producer companies, as the measurement of flow is typically obtained in the wellhead by adding the contributions from all perforated layers. Figure 7 depicts the influence of various combinations of conditions analyzed in this study on the flow rate ratio between the reservoir layers. By understanding the flow rate ratio between layers, producers can make informed decisions regarding reservoir management and optimize production strategies.

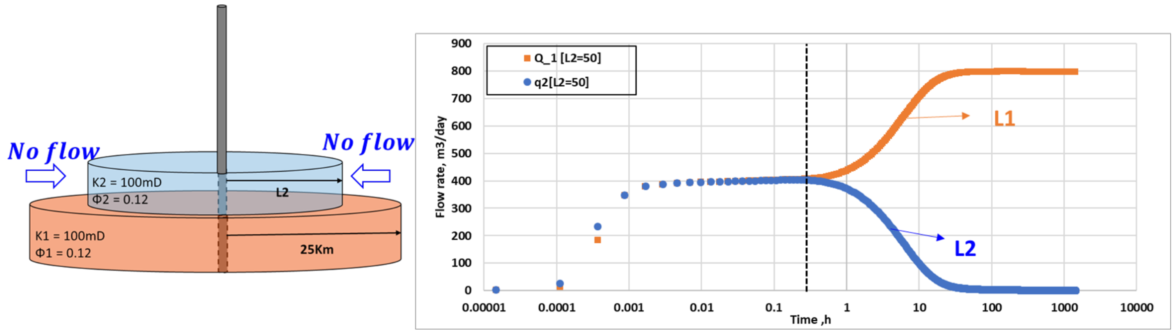

Figure 7. Schematic and flow rate plot for a well-reservoir with the no-flow boundary condition analyzed. The figure illustrates the well-reservoir model with a limited reservoir boundary condition, depicted on the left side of the figure. On the right side, a semi-log graph displays the flow rates of the two reservoir layers over time.

In this respect, the initial stages of the flow rate graph shown in Fig.7, both reservoir layers exhibit similar flow rates since they have equal properties. However, after the vertical dashed line, there is a noticeable decrease in the contribution of the smaller layer, while the larger layer increases its production to meet the total demand at the wellhead. This behavior can be attributed to the specific boundary condition of the limited reservoir. Similarly, in Fig.8, the flow rates in the initial moments are equivalent, but after the dashed line, there is an increase in the contribution of the smaller layer. This can be explained by the boundary condition of maintaining pressure, which creates a higher pressure differential in the upper layer, leading to an enhanced flow contribution from that layer.

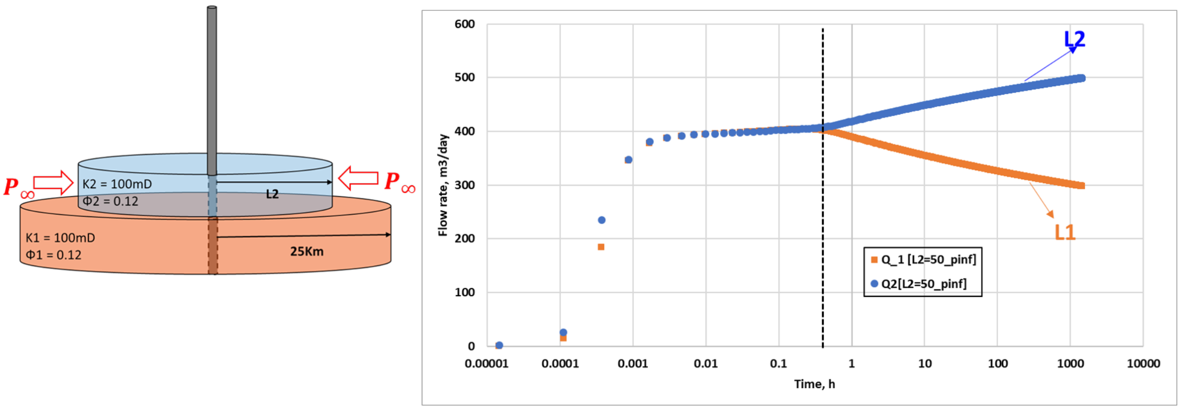

Figure 8. Schematic and flow rate plot for a well-reservoir with the pressure maintenance boundary condition. The figure illustrates the well-reservoir model with the pressure maintenance reservoir boundary condition, depicted on the left side of the figure. On the right side, a semi-log graph displays the flow rates of the two reservoir layers over time.

4. CONCLUSIONS

Summing up, this study has successfully developed a simulator based on a stratified reservoir model that incorporates the non-isothermal flow hypothesis. By analyzing different boundary conditions, the simulator provides valuable insights into reservoir behavior and enhances reservoir characterization.

The results obtained in the simulator align with existing models in the literature, as indicated by the comparison made between the pressure data. Furthermore, the analysis of temperature data corroborates the literature regarding the use of the non-isothermal hypothesis. The addition of temperature data has proven to be effective in avoiding misinterpretations. In this regard, the analysis of temperature data allows for the identification of specific boundary conditions applied to each layer of the reservoir, providing a more accurate understanding of reservoir behavior.

Additionally, the developed simulator offers the capability to determine the flow rate ratio between the reservoir layers. This information is highly valuable to oil production companies as it helps assess and optimize production operations.

As conclusion, the developed simulator, with its integration of temperature data and analysis of flow rate distribution, contributes significantly to reservoir engineering practices. It enables more accurate reservoir characterization, aids in effective reservoir management decision-making, and has the potential to optimize oil production and reservoir management strategies.

5. ACKNOWLEDGEMENTS

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