Evaluation of Laminar Heterogeneities on Flow Simulations Applied to 3D SCAL Models

Douglas Silva de Almeida[1,2], Caroline Henrique Dias[2], Filipe Oliveira da Silva[2,3], Gianfranco de Mello Stieven[2,3], André Compan[4], Paulo Couto[1,2]

[1]*Escola Politécica, Universidade Federal do Rio de Janeiro*
Av. Athos da Silveira Ramos, 149, 21941-909, Rio de Janeiro - RJ, Brasil
douglastec2@poli.ufrj.br
[2]*Laboratório de Recuperação Avançado de Petróleo (LRAP⁺)*
R. Moniz de Aragão, 360, 21941-594, Rio de Janeiro - RJ, Brasil
caroldias@petroleo.ufrj.br, pcouto@petroleo.ufrj.br, filipe@petroleo.ufrj.br
[3]*Programa de Engenharia Mecânica, Universidade Federal do Rio de Janeiro*
Av. Athos da Silveira Ramos, 149, 21941-909, Rio de Janeiro - RJ, Brasil
stieven@petroleo.ufrj.br
[4]*Centro de Pesquisas, Desenvolvimento e Inovação Leopoldo Américo Miguez de Mello - CENPES/PETROBRAS*
Av. Horácio Macedo, 950 - Cidade Universitária,21941-915, Rio de Janeiro - RJ, Brasil
andrecompan@petrobras.com.br

Abstract.
Heterogeneities within reservoir cores significantly influence fluid flow behavior, which can lead to early breakthrough and biased results of experiments. Neglecting to account for these heterogeneities when incorporating relative permeabilities into reservoir simulation models can render such models non-representative of real field conditions, thus impacting field performance predictions. Therefore, it is crucial to mitigate these effects by studying local heterogeneities to better understand their influence at larger scales. This study uses CMG® IMEX to solve numerically the Black-Oil equations. Synthetic heterogeneous plugs were simulated under various scenarios to assess their impact on flow parameters during SCAL experiments in multiple flow rate experiments. The analysis concentrated on laminar heterogeneity variability, investigating net production output and pressure differentials. Flow simulation findings show that the most significant differences between heterogeneous and homogeneous differential pressure curves were obtained when the central layer was thinner and the permeability ratio was lower. Low absolute permeability, on the other hand, diminishes net production in diverse settings by increasing flow resistance. The lowest central layer thickness and permeability ratio created the most significant variations, particularly at higher flow rates. To gain a deeper understanding of the influence of parameters on simulation runs, this work employed a 2^n factorial design experiment and applied a matrix correlation of measurement outcomes, parameter change, and correlation between them. The findings indicate that central layer permeability is more significant in influencing pressure drop and that the factors that have the greatest impact on net production outcomes are the permeability ratio and central layer permeability.

Keywords: Numerical simulation; Special Core Analysis; Heterogeneous porous media; Enhanced Oil Recovery.

1 Introduction

Relative permeability estimation plays a critical role in estimating oil reserves. It offers a solid basis for the characterization of the reservoir, production planning, carrying out simulations with accuracy, and the implementation of effective recovery strategies, directly influencing the efficiency and economic viability of petroleum operations. Numerous studies show that variables such as rock wettability [1], flow directions [2], and heterogeneities [3, 4] affect relative permeability. These variables can differ significantly between the laboratory and the field due to differences in the properties of rock samples, experimental conditions, and representations of the heterogeneities of laboratory samples relative to the real reservoir [5, 6].

Petrophysical properties, such as porosity and permeability, are influenced by factors such as mineralogy, pore size, sedimentary fabric, as well as the chemical and physical properties of both the solids and fluids. As a result, these properties may exhibit large variations across regions, indicating a heterogeneous reservoir, or they may stay constant, implying a homogeneous reservoir [7].

The investigation of relative permeability and heterogeneities' impact on the estimation of oil reserves has been thoroughly explored. In a prior investigation, Huppler [8] documented that distributed heterogeneities, with varying permeability of the surrounding matrix or small vugs, have negligible effects on fluid flow in rocks that display a water-wet behavior. However, the influence becomes significant when the rock is partially oil-wet or when heterogeneities manifest as channels. The study conducted by Honarpour et al. [3] revealed that water-wet rocks with laminar heterogeneity, ranging in scale from millimeters to centimeters, can exhibit a scale-dependent behavior in relative permeability. Furthermore, this scale dependence may also exhibit directional characteristics. This finding indicates that the relationship between relative permeability and length scale, along with anisotropy data, indicates that when scaling up, the effective relative permeability must accurately consider heterogeneity.

Hamon and Roy [4] conducted an experimental analysis to examine how small-scale heterogeneity influences the relative permeability curve. It was noted that when the flow is in an unsteady state, it is susceptible to heterogeneity along the axis and should be ignored in "horizontal" heterogeneous plugs. These samples demonstrate that steady-state flow is more stable, but it does not accurately replicate the actual flow curves of relative permeability. In addition, when capillary forces are negligible, flows in an unstable or stationary state are almost unaffected by heterogeneity along the axis.

More recently, the authors of the study conducted by AlMansour et al. [9] employed a numerical investigation to assess the influence of the heterogeneity of synthetic rock plugs on the interpretation of relative permeability. The arrangement of various sections within the central section of the plug was demonstrated to have a significant impact on the relative permeability curves. Plugs that possess characteristics such as high permeability striations or composite composition have a significant influence, particularly on the oil relative permeability curve.

Therefore, to better understand the events that cause the relative permeability curves to change with heterogeneity, it is essential to understand the impact of heterogeneity in the fluid distribution of rock samples. Furthermore, this understanding is essential for developing appropriate methodologies to upscale data from the laboratory in order to accurately model the behavior of multiphase flow on a larger scale in the field.

This study examines the impact of laminar heterogeneities on the pressure differential and oil net production in core-flooding numerical simulations conducted on a synthetic plug. It evaluates how the related parameters influence these outcomes. The 2^n factorial experiment was used to analyze and extract important information about the variation of the results. This experimental design enables the exploration of the relationships between the factors that control heterogeneity and their corresponding responses in the simulations.

2 Methodology

2.1 Numerical Simulation

The flow simulations were performed using CMG™ IMEX [10], a fully implicit, isothermal black oil simulator. This simulator utilizes the finite difference method to solve the governing equations for multiphase fluid flow through porous media. The principle of mass conservation is represented for each phase in the following manner:

$$\phi \frac{\partial S_\alpha}{\partial t} + \nabla \cdot u_\alpha = 0 \tag{1}$$

$$u_a = -\frac{k k_{r\alpha}(S_\alpha)}{\mu_\alpha} \nabla p_\alpha \tag{2}$$

where α denotes the average fluid phase, ϕ the rock porosity, S_α the phase saturation, u_α the fluid phase velocity, k the rock absolute permeability, $k_{r\alpha}(S_\alpha)$ the fluid phase relative permeability, μ_α the fluid viscosity, and ∇p_α the fluid phase pressure gradient.

In this study, the focus lies on the multiphase flow of water and oil. Therefore, we denote water as $\alpha = w$ and oil as $\alpha = o$. The correlations between phase saturation and pressure, as represented by capillary pressure P_c, can be described by the following equations:

$$S_w + S_o = 1 \tag{3}$$

$$P_c(S_w) = P_o - P_w \tag{4}$$

The relative permeability, as defined by Eq. 2, and the capillary pressure, as defined by Eq. 4, are both dependent on the water saturation. These parameters are often determined through a history-matching process using data collected from core-flooding experiments. In this study, the LET correlation [11], a commonly utilized equation that offers more flexibility in accurately matching production data points over time, was employed. The expression is as follows:

$$k_{rw}(S_{wn}) = \frac{k^o_{rw}(S_{wn})^{I_w}}{S_{wn}^{L_w} + E_w(1 - S_{wn})^{T_w}} \quad (5)$$

$$k_{ro}(S_{wn}) = \frac{(1 - S_{wn})^{I_o}}{S_{wn}^{L_o} + E_o(1 - S_{wn})^{T_o}} \quad (6)$$

$$S_{wn} = \frac{S_w - S_{wi}}{1 - S_{or} - S_{wi}}, \quad (7)$$

These equations describe the relative permeability of water (k_{rw}) and oil (k_{ro}) as a function of the normalized water saturation (S_{wn}). The parameters L^n_w, L^w_n, E^n_w, E^w_n, T^n_w and T^w_n are phenomenological parameters of the correlation. S_{wi} represents the water initial saturation and S_{or} the residual oil saturation.

The capilary pressure is parameterized using an analytical function, called Log(beta) [12]. In this function, the capillary pressure is defined as follows.

$$P_c = -\frac{A}{\beta} P_0 \left[\ln\left(\frac{S^{*\beta}}{1 - S^{*\beta}}\right) - \ln\left(\frac{1 - S^{*\beta}}{1 - (1 - S*)^{\beta}}\right)\right] + b \quad (8)$$

$$b = \frac{A}{\beta} P_0 \left[\ln\left(\frac{{S_0}^{*\beta}}{1 - {S_0}^{*\beta}}\right) - \ln\left(\frac{1 - {S_0}^{*\beta}}{1 - (1 - S_0*)^{\beta}}\right)\right] \quad (9)$$

In Eq. 8 and Eq. 9, $S = S_{wn}$ and stands for a rescaled saturation, β is the curve skewness, P_0 and S_0 are the pressure and saturation corresponding to $P_c = 0$. The parameter A is calculated for continuity at the limit cases, with the thresholds set at $S^* = 0$ and $S^* = 1$, for either drainage or imbibition:

$$P_c \leq P_t \rightarrow S^* = 1 \quad ; \quad P_c > P_t \rightarrow P_c = P_0 \frac{1}{S^*} \quad (10)$$

$$P_c \geq P_t \rightarrow S^* = 0 \quad ; \quad P_c < P_t \rightarrow P_c = -P_0 \frac{1}{(1 - S^*)} \quad (11)$$

where P_t is the pressure at the threshold.

2.2 Mesh Convergence

A mesh convergence study was conducted on a homogeneous base case, consisting of a cylindrical plug with $k = 256mD$ and $\phi = 0.24$. An analysis was performed to examine the relative error by increasing the number of blocks in all three dimensions. The cases are represented as M1 (7x7x252), followed by M2 (9x9x252), M3 (13x13x302), M4 (15x15x352), and M5 (17x17x352). The relative error was evaluated for differential pressure and oil production at six distinct timesteps: the initial five, identified by the increase of flow rate in the multistep experiment, and the last one corresponding to the conclusion of the experiment (600 s, 1200 s, 2160 s, 3600 s, 5040 s, 7920 s). Tables 1 and 2 display the relative error for each data point and its respective simulation runtime. The M5 mesh, consisting of 79,200 blocks, was chosen for its low error.

Table 1. Relative error accounting for differential pressure results.

Case	$\Delta P1$	$\Delta P2$	$\Delta P3$	$\Delta P4$	$\Delta P5$	$\Delta P6$	**Time (s)**
M1	-	-	-	-	-	-	57.21
M2	22.66%	24.84%	26.51%	27.84%	31.25%	34.50%	154.85
M3	6.56%	7.87%	8.89%	9.72%	12.03%	14.52%	454.95
M4	1.85%	3.03%	3.87%	4.53%	6.31%	8.19%	641.37
M5	0.54%	0.47%	0.44%	0.43%	0.43%	0.48%	1378.12

Table 2. Relative error accounting for net production results.

Case	NP1	NP2	NP3	NP4	NP5	NP6	Time (s)
M1	-	-	-	-	-	-	57.21
M2	10.16%	29.61	9.37%	9.23%	9.01%	8.94%	154.85
M3	0.95%	0.90%	0.88%	0.87%	0.84%	0.84%	454.95
M4	2.48%	2.36%	2.31%	2.26%	2.21%	2.20%	641.37
M5	0.75%	0.71%	0.70%	0.68%	0.66%	0.66%	1378.12

2.3 Model Construction — Heterogeneity

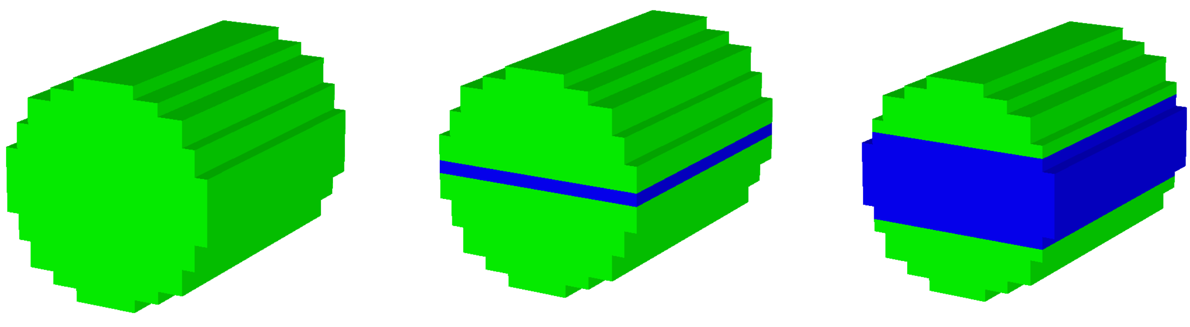
Multiple heterogeneity cases were created using the model of laminar heterogeneity along the core presented by Maas et al. [13]. The generation of these scenarios involved the creation of permeability and porosity maps, which were derived using the following correlation [14]:

$$k = 0.1038e^{0.3255\phi} \tag{12}$$

The examined plugs exhibit a core layer with three distinct values of layer thickness ratio $\epsilon = r/R$, as depicted in Figures 1 and 2. In Case A, the correlation is 0, indicating a plug that is completely homogeneous. Cases B and C exhibit ratios of 0.0294 and 0.2064, respectively, indicating thinner and thicker layers. The Permeability Ratio (k_r) was also investigated and is defined as the ratio between the permeability of the rock matrix (k_1) and the permeability of the central layer (k_0), expressed as $k_r = k_1/k_0$. Two values of k_0 were examined: 50 and 450 mD. Using these variables, two scenarios were generated:

Scenario A: The permeability of the central layer was fixed at 50 mD, while k_r varied between 1, 0.75, and 0.25, which leads to matrix permeability values of $12.5mD$ and $37.5mD$. This analysis was conducted for three different values of ϵ.

Scenario B: The permeability of the central layer was fixed at 450 mD. The same range of k_r and ϵ values from Scenario A was used.



(a) (b) (c)

Figure 1. Representation of laminar heterogeneity from different ϵ values: (a) $\epsilon = 0$; (b) $\epsilon = 0.0294$; (c) $\epsilon = 0.2064$.

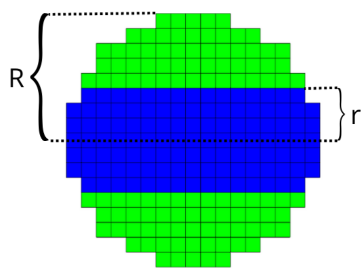


Figure 2. Radius difference presented on epsilon calculations.

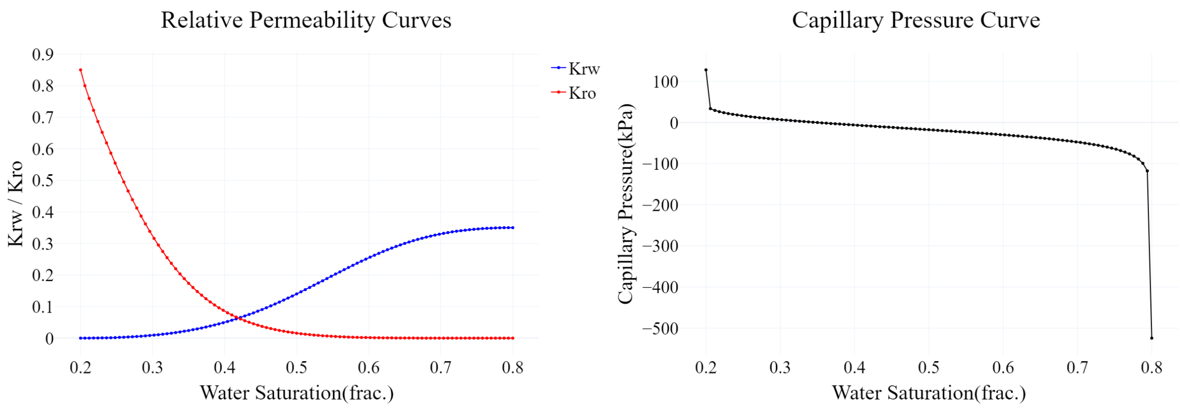
The specific values of the parameters k_r, k_0, k_1, and ϵ for each scenario can be found in Table 3. Table 4 displays the rock and fluid properties utilized in the numerical simulation for unsteady state (USS) experiments involving the homogeneous plug.

Table 3. Parameter values for scenarios A and B.

Scenario	ϵ	k_r	$k_0(mD)$	$k_1(mD)$
AH	0	1	50	50
A1	0.0294	0.25	50	12,5
A2	0.2064	0.25	50	12,5
A3	0.0294	0.75	50	37,5
A4	0.2064	0.75	50	37,5
BH	0	1	450	450
B1	0.0294	0.25	450	112.5
B2	0.2064	0.25	450	112.5
B3	0.0294	0.75	450	337.5
B4	0.2064	0.75	450	337.5

Table 4. Fluid and rock simulations properties.

Fluid and Rock Properties	Value
Diameter(cm)	3.8
Length (cm)	5
Water Viscosity (cp)	0.5
Oil Viscosity (cp)	2
Water Density (g/cm3)	1
Oil Density (g/cc)	0.8



(a) (b)

Figure 3. Relative permeability (a) and capillary pressure (b) curves used in the simulations.

2.4 2^n parameters analyses

The study adopted a 2^n factorial design as the experimental methodology to assess the impact of parameters, such as ϵ, k_r, and k_0 on the behavior of differential pressure and oil production output. In this approach, 'n' represents the number of factors examined, with each factor being tested at two levels: a high level (450 mD base permeability) and a low level (50 mD base permeability).

This approach allows for a comprehensive examination of both primary effects and their interactions with one another. By systematically modifying these variables and analyzing the corresponding output changes, a value of-1 is assigned for the lower cases and 1 for the higher cases, and then a matrix of correlations for all experiments is generated. The design matrix of the 2^n experiment included lower and higher levels, which were selected as values equivalent to 25% and 75% of the base value, respectively. Eight simulation runs are undertaken for every heterogeneity scenario. The impacts of each parameter and their interactions on the differential pressure and the net production are computed and arranged in Pareto charts, as depicted in Figures 5a and 5b.

3 Results and Discussion

3.1 Effect of laminar heterogeneity on production and pressure differential curves

The most significant differences between the heterogeneous and homogeneous pressure drop (ΔP) curves were found in situations where the layers were thinner (with smaller ϵ values) and the k_r were lower. This implies that even a slight heterogeneity can have a substantial effect on fluid flow in these conditions. Furthermore, the k_r was a crucial factor in changing the pressure drop curve compared to the uniform sample. Variations in k_r had a more substantial effect on ΔP than changes in ϵ, highlighting the importance of accounting for this permeability ratio in laminar heterogeneous systems. Additionally, by maintaining a fixed k_r, it was observed that thinner layers had a more significant effect on the pressure drop curve compared to bigger layers. This shows that thin, low-permeability layers make it harder for fluids to move, which causes pressure to rise and fall even though the total k_r stays the same.

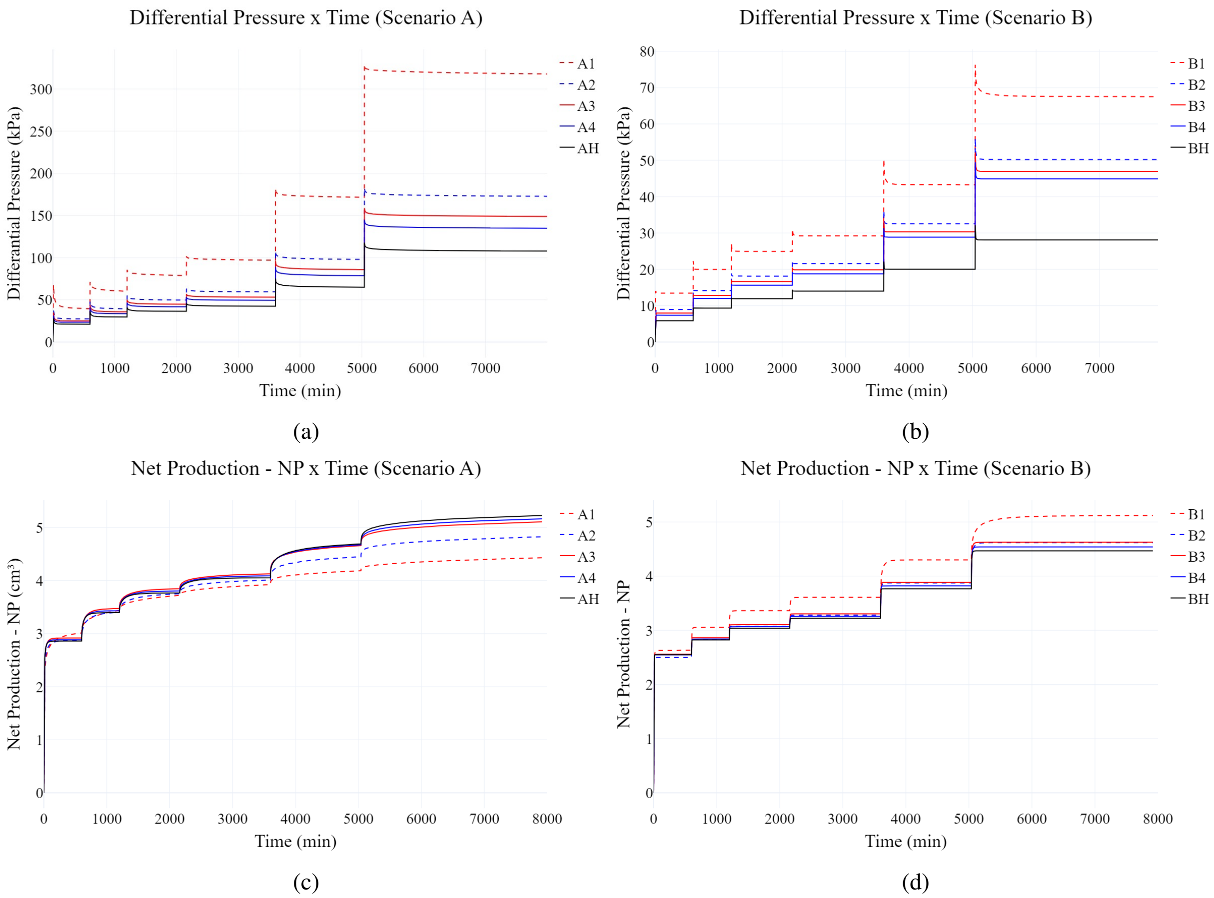


Figure 4. Differential pressure for scenarios A (a) and B (b) and net production for scenarios A (c) and B (d).

Taking a closer look at the differential pressure output of Case A in Figure 4a, it is evident that as the injection flow rate increased, the ΔP increased due to changes in k_r and ϵ. This suggests that both parameters are critical in influencing the pressure dynamics during fluid injection, with their impact becoming more evident under higher flow conditions. The results for Case B, in Figure 4b, were notably similar to those observed in Case A. While both the permeability ratio and layer thickness had a substantial impact on the ΔP curve, the k_r exhibited higher levels of responsiveness compared to the layer thickness, highlighting the importance of thoroughly analyzing these factors in order to more accurately forecast and manage fluid flow in reservoirs with laminar heterogeneity.

In scenario A (Figure 4c), which is defined by low absolute permeability, the net production curves consistently exhibited lower values in heterogeneous situations compared to homogeneous ones due to increased flow resistance under low-permeability conditions. This lower production is expected in heterogeneous scenarios, given the increased resistance to flow under these conditions. The cases with lower ϵ and k_r showed the most significant deviations from the homogeneous scenario, similar to what was observed in the differential pressure curves. This was notable in both subscenarios A1 and B1 , which also presented a more pronounced deviation from the homogeneous case as the test flow rate was increased suggesting that the influence of heterogeneity on net production becomes more noticeable during periods with higher flow. In contrast to scenario A, where case A1 shows lesser production for the identical circumstance, case B1, which represents a high absolute permeability scenario, likewise displayed a behavior of higher production when compared with homogenous case.

On the other hand, the A2 sample, which had a thick layer with a low ratio of permeability, only exhibited notable deviations from the homogeneous scenario under situations with low permeability and high flow rates. Under conditions of high permeability, the B2 sample did not demonstrate the same trend, suggesting that the influence of thick layers on net output decreases as total permeability increases. In general, however, the remaining samples exhibited small deviations from the homogeneous case, indicating that their heterogeneity had a limited impact on net production. This implies that the influence of heterogeneity on fluid flow and production might be substantial, but its magnitude depends on the particular attributes of the heterogeneity and the overall permeability of the system.

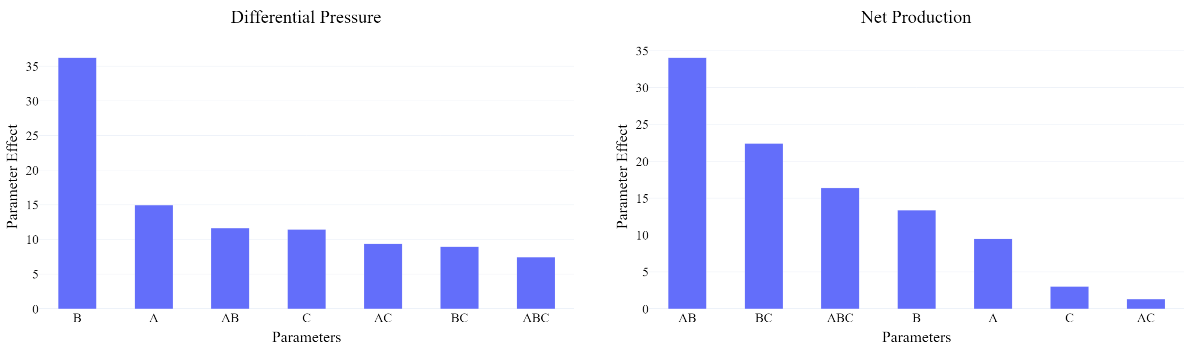
The results obtained in this study reaffirm the observations made by AlMansour et al. [9] in scenarios with low permeability levels for experiments with a single flow. The authors observed significant impacts on fluid flow and pressure dynamics under these conditions, which is consistent with our findings. Due to the use of a multi-flow experiment, our results also demonstrated that high permeability rates between the plug layers have a pronounced effect on the differential pressure curve and, to a lesser extent, on the net production curve. This indicates that while low permeability rates are critical for influencing resistance to fluid flow, high permeability contrasts can also significantly affect pressure dynamics, albeit with a more modest impact on overall production.

3.2 Parameter Importance Analysis

Figure 5 present the Pareto charts derived from the 2^n factorial design experiment that provide a clear visualization of the relative significance of each factor and their interactions on the observed outcomes.

The charts highlight the factors considered, such as k_r, ϵ, and k_1 as well as their interactions. The analysis purpose is to determine how each parameter affects differential pressure and oil output. The Pareto principle is clear, with a few significant factors accounting for the majority of the observed variation. Figure 5a reveals that the product permeability ratio (k_r) and central layer permeability (k_1) appear to have the greatest impact on the measurements of net production, suggesting that optimizing this parameter could lead to significant improvements in oil production efficiency. Conversely, factors like ϵ had a comparatively lower influence, indicating that adjustments in this area may yield less substantial changes. Figure 5b shows that central layer permeability is the most significant parameter that affects differential pressure measurements. In contrast, the product of k_r, ϵ, and k_1 appear to have the lowest impact on differential pressure results.

These insights are extremely valuable for determining which parameters to prioritize in future optimization efforts. The visual representation provided by the Pareto chart facilitates a deeper understanding of the experimental results, guiding strategic decisions in process enhancement and resource allocation.



(a) (b)

Figure 5. Pareto charts: (a) Differential pressure; (b) Net production.

Table 5. Pareto properties label.

Pareto label	A	B	C
Parameter	k_r	k_1	ϵ

4 Conclusions

This study evaluated the impact of heterogeneity parameters in synthetic plugs on fluid flow through numerical simulations using CMG™ software. Our findings highlight the significant role that local heterogeneities play in influencing flow behavior, particularly in scenarios with varying flow rates. Specifically, the results demonstrated that plugs with lower permeability exhibited greater resistance to flow, which aligns with expected outcomes. Additionally, scenarios with thin layers and low permeability ratios showed the most pronounced deviations from homogeneous behavior.

Importantly, our work reaffirms AlMansour et al. [9] observations regarding the influence of low permeability ratios on fluid dynamics. However, in contrast to the authors, we discovered that high permeability ratios also significantly affect the pressure differential curves, albeit to a lesser extent in net production curves. These insights underscore the necessity of considering heterogeneity in reservoir simulations to enhance the accuracy of field performance predictions, ultimately contributing to more effective reservoir management and recovery strategies.

Pareto charts derived from the 2^n factorial design experiment guide to align with the main paper goal, emphasize the significance of the effects of parameters such as permeability ratio, permeability thickness, and central layer permeability on heterogeneity, as well as the importance of continuity studies to achieve optimal measurements.

Acknowledgements. This research was carried out in association with the ongoing R&D project registered as ANP nº 24.551, "Avaliação de Metodologias para Interpretação de Curvas de Permeabilidade Relativa em meios porosos heterogêneos " (UFRJ/Petrobras Brasil/ANP), sponsored by Petróleo Brasileiro S/A under the ANP R&D levy as "Compromisso de Investimentos com Pesquisa e Desenvolvimento".

References

[1] A. Caruana and R. A. Dawe. Flow behaviour in the presence of wettability heterogeneities. *Transport in Porous Media*, vol. 25, pp. 217–233, 1996.
[2] G. Goodlett, M. Honarpour, F. Chung, and P. Sarathi. The role of screening and laboratory flow studies in eor process evaluation. In *SPE Rocky Mountain Petroleum Technology Conference/Low-Permeability Reservoirs Symposium*, pp. SPE–15172. Spe, 1986.
[3] M. Honarpour, A. Cullick, N. Saad, and N. Humphreys. Effect of rock heterogeneity on relative permeability: implications for scale-up. *Journal of Petroleum Technology*, vol. 47, n. 11, pp. 980–986, 1995.
[4] G. Hamon and C. Roy. Influence of heterogeneity, wettability and coreflood design on relative permeability curves. *SCA paper*, vol. 25, 2000.
[5] J. R. Fanchi. *Principles of applied reservoir simulation*. Elsevier, 2005.
[6] M. M. Honarpour. *Relative permeability of petroleum reservoirs*. CRC press, 2018.
[7] P. J. Fitch, M. A. Lovell, S. J. Davies, T. Pritchard, and P. K. Harvey. An integrated and quantitative approach to petrophysical heterogeneity. *Marine and Petroleum Geology*, vol. 63, pp. 82–96, 2015.
[8] J. D. Huppler. Numerical investigation of the effects of core heterogeneities on waterflood relative permeabilities. *Society of Petroleum Engineers Journal*, vol. 10, n. 04, pp. 381–392, 1970.
[9] O. AlMansour, M. A. AlSaud, S. Ayirala, and Y. Cinar. An investigation of core plug heterogeneity effect on estimated relative permeability. In *SPE Gas & Oil Technology Showcase and Conference*, pp. D012S006R002. SPE, 2024.
[10] C. M. G. Ltd. *IMEX User Guide*. Computer Modelling Group Ltd., 2024.
[11] F. Lomeland, E. Ebeltoft, and W. H. Thomas. A new versatile relative permeability correlation. In *International symposium of the society of core analysts, Toronto, Canada*, volume 112, 2005.
[12] Cydarex. *CYDAR User Guide*. Cydarex, 2024.
[13] J. G. Maas, N. Springer, and A. Hebing. Defining a sample heterogeneity cut-off value to obtain representative special core analysis (scal) measurements. In *International Symposium of the Society of Core Analysts held in Pau, France*, pp. 26–30, 2019.

[14] E. J. Peters. *Advanced Petrophysics: Geology, porosity, absolute permeability, heterogeneity, and geostatistics*, volume 1. Greenleaf Book Group, 2012.