Pore compressibility modeling using four different approaches for Brazilian carbonate rocks

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Abstract

Reservoir compaction is an important parameter to be analyzed by petroleum engineers. The hydrocarbon production operation directly depletes the reservoir dimensions because of the reduction in the pore fluid pressure and subsequent changes in effective external stress. Therefore, it impacts the calculation of oil in place by pressure decline data in undersaturated volumetric reservoirs when the field limits are unknown or indefinite and studies of natural water drive performance. According to Hall (1952), the omission of rock compressibility is undoubtedly justified in calculations for a saturated reservoir. However, expansion of the rock accompanying decline in the reservoir pressure may be of such magnitude as to affect materially the reservoir performance prediction. Therefore, it is important to estimate de pore volume compressibility once it impacts the reservoir's mechanical behavior, which may displace the reservoir fluids, changing its production and budgetary management. Unfortunately, there is still no public result concerning the pore compressibility of the Barra Velha Formation from Santos basin pré-salt. For this reason, this work aims to estimate the pore compressibility of carbonates from the Barra Velha Formation, simulating natural reservoir conditions. The laboratory sample data were measured by Coreval 700 equipment that measures the porosity and permeability to helium/nitrogen of plug-sized core samples at different hydrostatic confining pressure. Previous data regarding the samples under normal conditions were obtained from the Ultrapore 300 for porosity. The results endorse optimistic conclusions, showing that the Barra Velha Formation samples' pore compressibility is similar to the sandstone trend. Furthermore, four models of pore compressibility estimation were applied to estimate and rate the best prediction for the pore compressibility calculation method.

Introduction

The energy that drives hydrocarbon production is a consequence of external pressure. According to Tiab and Donaldson (2004), it is due to the overburden pressure and the pore pressure exerted on the grain by the confined fluid. However, this internal and overburden pressure becomes uneven when hydrocarbon production occurs. As a result, the fluid inside the reservoir becomes less effective in opposing the weight of the overburden, and pores are compressed by additional formation compaction. Therefore, pore volume compressibility must be considered since it commonly affects rock porosity. If neglected, it can result in an erroneous analysis of reservoir behavior, recoverable volume, and driving mechanism (Tiab and Donaldson, 2004). Also, according to Mohsin et al. (2022), the effects and influence on porosity and permeability are often neglected in the formation evaluation, while it has important consequences on reservoir storage and flow capacities. Therefore, they concluded that porosity and permeability are considerably affected by overburden pressure. In addition, Oliveira et al. (2014) said that pore compressibility could also be used to calculate produced oil volume, gas and/or water during each production stage. For that reason, many researchers have tried to find new methods to estimate pore compressibility over time. The current study It complements the previous work made by Bueno et al (2022) presented on SimBGf, where the object of study was coquinas carbonate pore compressibility and its influence on flow zone indicator (FZI) and reservoir quality index (RQI). Along with this reseach line, Ceia et al. 2022, also published previous results regarding pore compressibility estimations by using different methods on a different set of Brazilian carbonates. This study performed pore compressibility tests in the laboratory and compared the results with four different pore compressibility methods.

Method

The pore compressibility was obtained from the gradual loading application of the confining pressure in the sample, causing the variation of the pore volume. Therefore, constant grain volume was estimated without variation within the selected pressure range. With this, the contraction of the pores causes changes in the rock volume. Therefore, Zimmermann (1984) defined compressibility as related to confining pressure variation (while pore pressure is constant), as defined by Equation 1.

$$C_{pc} = -\frac{1}{Vp}(\frac{\partial Vp}{\partial Pc})_{Pp}$$

Where; C_{pc}= pore compressibility after confining pressure variation, V_p= pore volume, P_c= confining pressure, and P_p= pore pressure.

The method used to estimate pore compressibility was based on Unalmiser-Swalwell's (1993) theory. They developed a power-law relationship to relate the pore volume measurements and the applied confining pressures. It consists in fitting a power-law curve relating the pore volume variation to external pressure and estimating pore compressibility using the derivative of that power-law function. This relationship is expressed in the following Equation:

$$V_p = b \ x \ Pc^{-m}$$

Where; b = proportionality constant (derived from power-law fitting), m = exponent constant (derived from power-law fitting).
By doing its derivation, the Equation as a function of pressure is expressed as:

$$\frac{dV_p}{dP} = -m \ x \ b \ x \ p^{-(m+1)}$$

If substituting Eq. 3 and 2 into Eq. 1, we have the following:

$$C_{pc} = -\frac{m}{P_p}$$

Pore compressibility estimations were studied over time, and some models are described and applied in this study, which are Hall (Hall, 1953), Horne (Horne, 1990), Modified Horne (Jalalh, 2006) and Oliveira et al. (2014). Oliveira's Equation is an empirical model for pore compressibility data of North American outcrop rocks (carbonates).

Model 1 - Hall Equation

$$C_p = \frac{1.78 \ x \ 10^{-5}}{\phi^{0.4358}} x \frac{1}{6.89476x10^{-6}}(\frac{1}{GPa})$$

Hall's equation model was based on limestone and sandstone tested cores by laboratory measurements. At the end of his study, he assumed that in all cases, the reservoir fluid had a compressibility of 10×10^{-6} change in volume per unit volume per psi. It can be seen that the magnitude of rock compressibility is such that if neglected, calculated values for oil in place in reservoirs covering the practical range of porosities will be from 30 to 100 percent higher than the actual oil in place.

Model 2 - Horne Equation

$$C_p = exp \ (4.026 - 23.07\phi + 44.28\phi^2) \ x \ \frac{10^{-6}}{6.89476x10^{-6}}(\frac{1}{GPa}) \quad (1)$$

Horne studied three reservoir types: consolidated limestones, sandstones and unconsolidated sandstones. In this study equation for consolidated limestone was chosen to be tested. He developed those equations by summarizing published data from different rock types from Newman's study (consolidated, friable and unconsolidated reservoir rocks under hydrostatic loading).

Model 3 - Modified Horne Equation

$$C_p = exp \ (3.4895 - 15.249\phi + 31.599\phi^2) \ x \ \frac{10^{-6}}{6.89476x10^{-6}}\left(\frac{1}{GPa}\right)$$

Jalalh (2006) applied Horne's equations to available data from the literature. He concluded that the fitting was not satisfying, so he proposed the modified Horne equation (2) by using twelve different fitting formulas and other comprehensive nonlinear fitting regression programs, elaborating new rock compressibility correlations for limestone and sandstone rocks.

Model 4 - Oliveira Equation

$$C_p = F \ exp \ (G\phi) \ x \ \frac{10^{-6}}{6.89476x10^{-6}}(\frac{1}{GPa}) \quad (3)$$

Where $F = 0.102XP_c{}^{-1.032}$; (4)

$$G = -1 \ X \ 10^{-9}xP_c^2 + 3x10^{-6}P_c - 0.0921)$$

Oliveira et al. (2014) tested sandstone and carbonate cores in a uniaxial apparatus associated with a helium porosimeter and then developed an empirical equation for each rock type. The tests went from 400 psi (2.75 MPa) to 2.000 psi (22.1 MPa). The samples were split into groups G1 and G2. Both groups are Aptian lacustrine carbonates from the Barra Velha Formation, located in the Santos Basin's central portion. They are composed essentially of carbonates interpreted as microbial, with complex and heterogeneous texture and pore system and are considered the main reserve for hydrocarbons on the pré-sal play (Souza and Sgarbi, 2019). (5)

Results

Figures 1 A and B show a crossplot using data obtained from coreval equipment and pore compressibility calculated from Unalmiser-Swalwell's Equation. Carbonates are heterogeneous rocks and might show unexpected results regarding pore behavior under compressibility, depending on their properties. However, according to Figures 1 A and B, all samples tend to decrease porosity and pore compressibility as the confining pressure increases. These findings corroborated the Unalmiser-Swalwell study.

Equations from Models 1, 2, 3 and 4 of the four models were applied for four confining pressure intervals; 5.52 MPa, 8.27 MPa, 13.79 MPa and 22.1 MPa (highest pressure) shown in Figure 2. It is possible to see that the highest estimation values are from method 4 – Oliveira, and the lower estimation values come from method 1 – Hall, model 2 – Horne and model 3 – Modified Horne represented intermediate estimation. However, after 22.1 MPa, model 3 showed higher estimation, surpassing model 4.

Furthermore, the relative percentage error was calculated to evaluate which model provides the most accurate prediction, according to Figure 2. The median relative errors for each pressure interval are shown in Table 1. Where Model 4 – Oliveira Equation presented the smallest error compared to the laboratory data at 5.52 MPa. The other three models did not provide good results at low pressures. Model 3 - Horne Modified Method showed the smallest error At 8.27 MPa, which indicates that this model also exhibited the best performance in low/medium pressure intervals. At 15.17 MPa, model 3 - Modified Horne model also showed the lowest error. Model 1 – Hall Equation showed the smallest error at the highest pressure, 22.1 MPa. Therefore, it is possible to suggest that when at higher pressures, models like Hall Equation can be more suitable for medium-pressure intervals and when at lower pressures, Model 4 - Oliveira Equation is more suitable, providing better estimations. It is essential to state that Oliveira et al. (2014) have reported that the model was designed for work between 2.76-13.79 MPa.

Conclusions

Using a static approach, this work successfully addressed the pore compressibility behavior of the Barra Velha Formation. Those estimates enhance the understanding of pre-salt carbonate's mechanical behavior.

The Modified Horne Method presented better results for medium pressure intervals, the Hall Method presented better results for higher pressures, and the Oliveira Method presented better results for lower pressures. Despite it, none of those models deals with pore geometry, which can impact the pore compressibility of some samples and may explain the deviation from the model's predictions.

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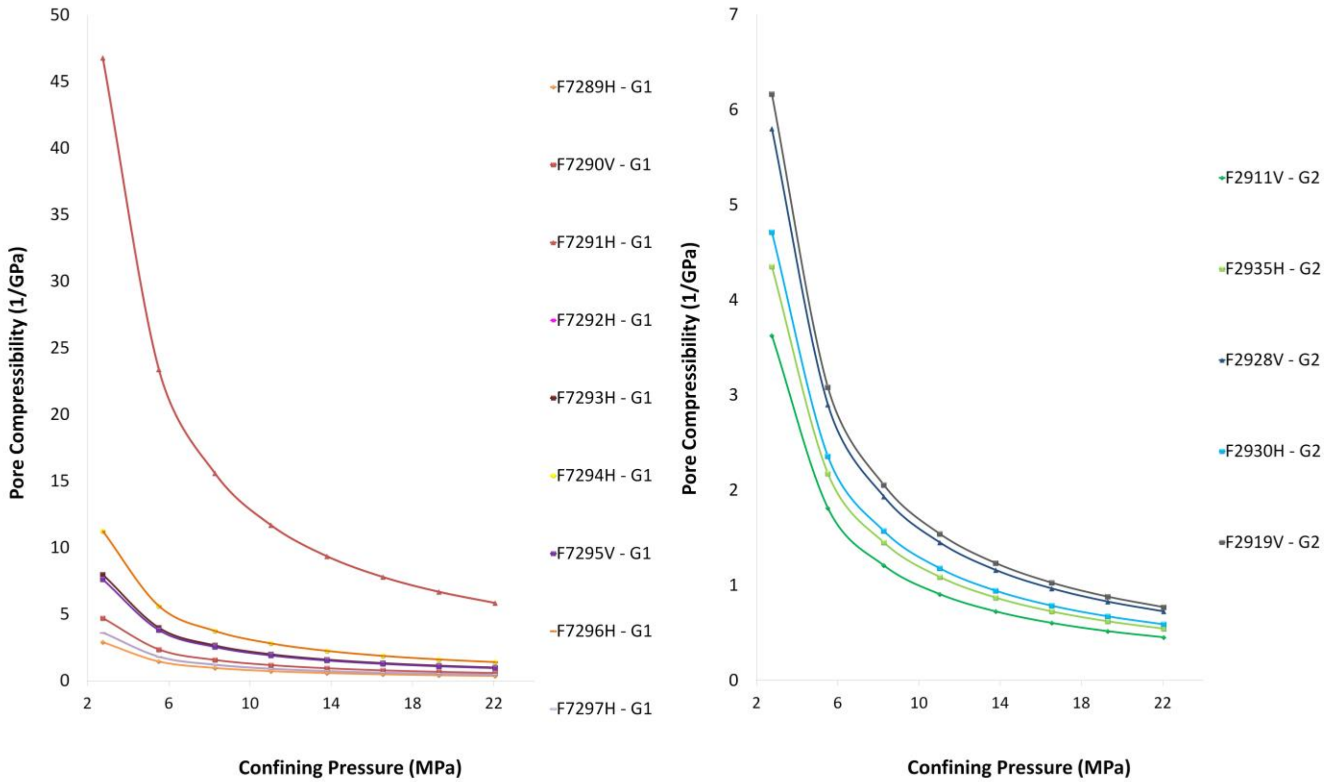

Figure 1 - Crossplot between confining pressure versus pore compressibility variation plot from samples from group G1 (a) and (b) Group 2 of Barra Velha Formation.

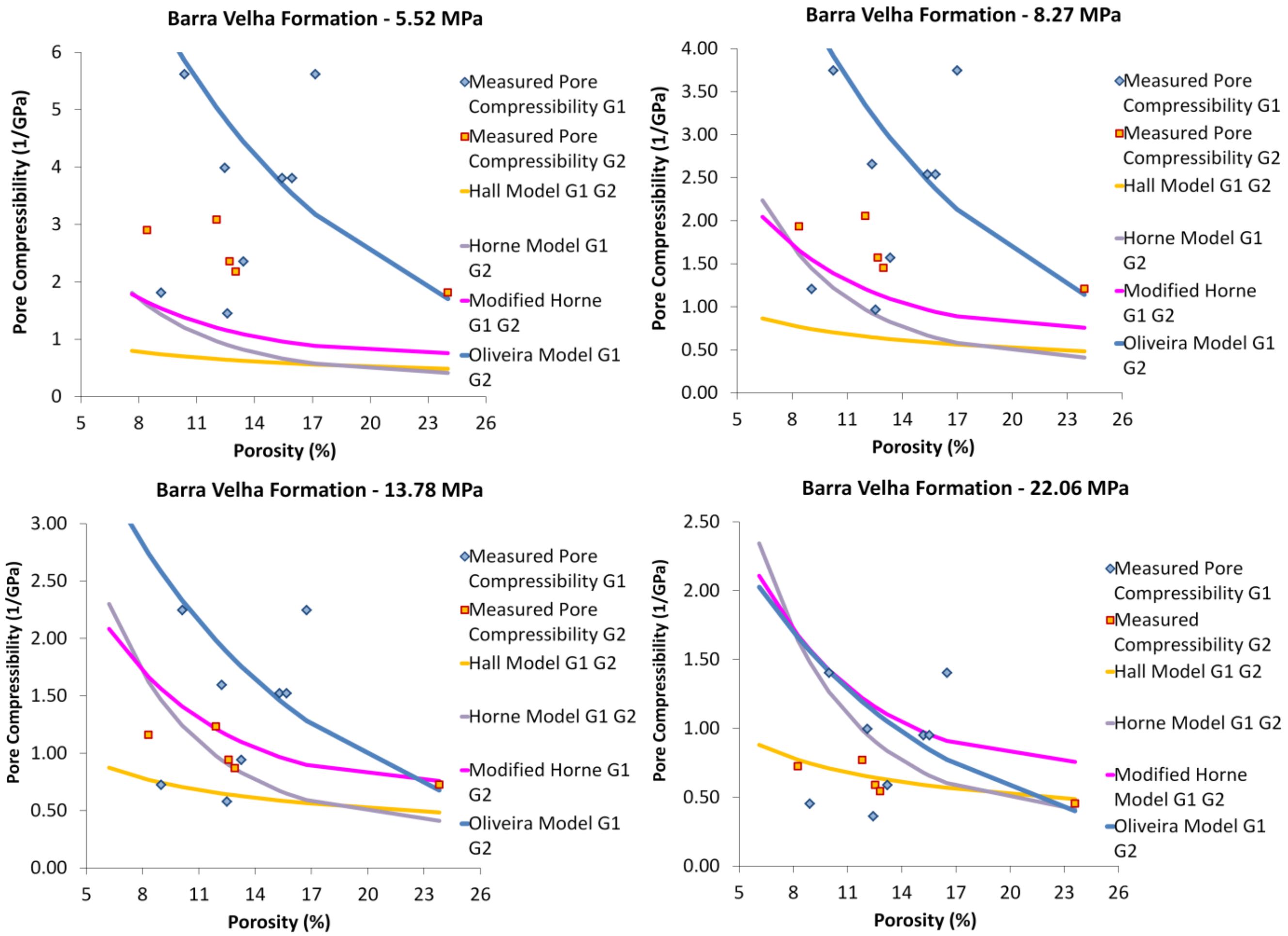

Figure 2 Figure 2 A, B, C and D – Crossplot between pore compressibility and porosity of all twenty-five Coquinas samples for six different pressure stages. Each different colour line corresponds to a model of pore compressibility prediction. Light blue dots correspond to the measured pore compressibility in the lab.

Table 1 - Relative error statistical average from proposed models when compared to pore compressibility measured in laboratory:

Confining Pressure	*Measured P. C x Model 1 - Hall*	*Measured P. C x Model 2 – Horne*	*Measured P. C x Model 3 – Horne Modif.*	*Measured P. C x Model 4 – Oliveira*
	Groups 1 and 2	Groups 1 and 2	Groups 1 and 2	Groups 1 and 2
5.52 MPa	79.75	74.15	64.01	**46.37**
8.27 MPa	64.27	59.07	**39.37**	63.65
13.78 MPa	40.27	44.02	**36.94**	62.75
22.06 MPa	**36.31**	47.69	65.52	60.16