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Total Organic Carbon, Porosity and Permeability Correlation: A Tool for Carbon Dioxide Storage Potential Evaluation in Irati Formation of the Parana Basin, Brazil

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***Abstract*—**The correlation between Total Organic Carbon (TOC) and flow units have been carried out to predict and compare the carbon dioxide (CO_2) storage potential of the shale and carbonate rocks in Irati Formation of the Parana Basin. The equations for permeability (K), reservoir quality index (RQI) and flow zone indicator (FZI) are redefined and engaged to evaluate the flow units in both potential reservoir rocks. Shales show higher values of TOC compared to carbonates, as such, porosity (Φ) is most likely to be higher in shales compared to carbonates. The increase in Φ corresponds to the increase in K (in both rocks). Nonetheless, at lower values of Φ, K is higher in carbonates compared to shales. This shows that at lower values of TOC in carbonates, Φ is low, yet, K is likely to be high compared to shale. In the same vein, at higher values of TOC in shales, Φ is high, yet, K is expected to be low compared to carbonates. Overall, the flow unit factors (RQI and FZI) are better in the carbonates compared to the shales. Moreso, within the study location, there are some portions where the thicknesses of the carbonate units are higher compared to the shale units. Most parts of the carbonate strata in the study location are fractured in situ, hence, this could provide easy access for the storage of CO_2. Therefore, based on these points and the disparities between the flow units in the evaluated rock types, the carbonate units are expected to show better potentials for the storage of CO_2. The shale units may be considered as potential cap rocks or seals.

***Keywords*—**Total organic carbon, flow units, carbon dioxide storage.

I. Introduction

TOC relationship with porosity (Φ) and permeability (K) is a reliable tool for the prediction of the storage potential of carbon dioxide (CO_2) in the Irati Formation of the Paraná Basin. Different types of shale exist based on different depositional environment. They include calcareous shale, carbonaceous shale and black shale (examples are in the Irati Formation). Others could include siliceous shale, ferruginous shale and sandy/silty shales. The black shales exhibit highly laminated bedding and their TOCs can be up to 16%. Carbonaceous shales are likely to show TOC up to 20% [1]. TOC in rocks is dependent on the percentage of organic carbon. It ranges from less than 0.5% to above 12% in potential reservoir rocks. The target of an evaluation may be focused on TOC quality in potential reservoir rocks. TOC quality of reservoirs may be considered to be very poor to poor when its percentage values range from 0.5% to less than 2%. Above 2% to 5% may be considered as good, but up to 12% and above are considered very good/excellent.

Generally, shales may have TOC of ≥ 2% [2]. Higher values of TOC likely correspond to higher values of porosity [3]-[6]. Similarly, high values of Φ are synonymous to high values of K [7], [8]. RQI and FZI expressions are dependent on permeability. RQI may be used to describe the distribution of pores, grains and pore-throats, FZI describes the grain sizes, grain sorting, textures and structures of grains/pores [9]. Core samples with a suite of wireline logs consisting of gamma-ray, neutron density, bulk density and/or sonic, from boreholes of interest are expected to be analyzed in the second phase of this project. Herein, the relatedness of TOC to Φ and K will be used to examine the flow units of the formation under study in order to predict the CO_2 storage potentials of the shale and the carbonate rock reservoirs in the Irati Formation.

II. Methods

The Irati Formation consists of stratified rocks, such as carbonates (limestone/dolomite) and shale in alternation. These rocks are bituminous. Herein, both rocks are evaluated with a view of predicting the CO_2 storage potential of the reservoirs. This work is tended towards evaluating and comparing the potentials CO_2 storage in the shale and carbonates reservoirs in the Parana Basin. The primary interest was in the shale reservoirs. Herein, the interdependency among TOC, porosity and permeability will be used to predict CO_2 storage potentials in both rocks (carbonates and shales). A review of the use of cementation exponent (m) and the factor of tortuosity (a) in these rocks shows that "a" ranges from 0.6 to 1.0, "m" could be up to 2 in carbonates [10], [11]. Similarly, in rocks that are consisting of clay minerals/shale, "a" can be up to 1.65, while "m" can be above 2.5 depending on the type of clay minerals [12]-[14]. Porosity and RQI/FZI relationship is a good tool for checking the flow units of reservoirs [15]. Hence, the expressions for RQI and FZI by Tiab and Donaldson are redefined herein, based on the expression for permeability (K) [16], to enable the generation of permeability/flow units plots. The correlation between TOC and RQI/FZI considering the shale and the carbonates rocks was done. Thereafter, the comparison and prediction of the

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CO_2 storage capacity of the shale and carbonate rocks in the study location were carried out.

Consequently, if a = 1 and m = 2 in carbonate rocks, the expression for irreducible water saturation (S_{wiir}), (1) becomes (2);

$$(S_{wirr})^2 = \frac{a}{2000\Phi^m} \quad (1)$$

$$S_{wirr} = \frac{1}{44.72\Phi} \quad (2)$$

Similarly, if a = 1.65 and m = 2.2 in shales, (1) becomes (3); where, 2000 = formation constant and Φ = porosity.

$$S_{wirr} = \frac{1.65^{0.5}}{(2000\Phi^{2.2})^{0.5}} \quad (3)$$

Hence, the expression for permeability [15] (4) becomes (5) in carbonates.

$$K^{0.5} = 100\,\frac{\Phi^{2.25}}{s_{wirr}} \quad (4)$$

$$K^{0.5} = (4472\Phi^{3.25}) \quad (5)$$

such that;

$$K = (4472\Phi^{3.25})^2 \quad (6)$$

Similarly, in shales;

$$K = \frac{(20000000\Phi^{6.7})}{1.65} \quad (7)$$

Such that;

$$K = \frac{(2\times10^7\Phi^{6.7})}{1.65} \quad (8)$$

In the same vein, RQI and FZI expressions [9] (9) and (10) are redefined herein:

$$RQI = 0.0314\left(\frac{K}{\Phi}\right)^{0.5} \quad (9)$$

$$FZI = \frac{RQI}{\Phi_r} \quad (10)$$

Hence, for carbonates, RQI is redefined as (11);

$$RQI = \frac{140.4\Phi^{3.25}}{\Phi^{0.5}} \quad (11)$$

and in shales, it is redefined as (12):

$$RQI = \frac{0.0314*(2\times10^7\Phi^{6.7})^{0.5}}{1.65\Phi^{0.5}} \quad (12)$$

Similarly, FZI is modified as (13) in carbonates and as (14) in shales in this evaluation.

$$FZI = \frac{140.4\Phi^{3.25}}{\Phi^{0.5}*\Phi_r} \quad (13)$$

$$FZI = \frac{0.0314*(2\times10^7\Phi^{6.7})^{0.5}}{1.65\Phi^{0.5}*\Phi_r} \quad (14)$$

where, Φ_r is the ratio of the derived porosity and the difference between the maximum derivable value (100%) of porosity and the derived porosity, it is expressed by Equation (15) [9].

$$\Phi_r = \frac{\Phi}{1-\Phi} \quad (15)$$

III. Results and Discussion

Previous studies [3], [5] have shown values of TOC with corresponding porosity (Φ) and indicated that in most cases increase in the values of TOC corresponds to the increase in the porosity values. The results of this evaluation clearly show that for the same value of Φ (with the equations), permeability (K) is higher in carbonates than in shales. In shales, porosity maybe high (even higher than sandstones and carbonates), but they often consist of very tiny grain sizes that diminish the path of fluid flow. High Φ values in shales may not totally correspond to high K. In sandstones and fractured carbonates, high Φ with good rates of interconnected pores and fluid paths connotes high K. K can be as low 0.01mD in carbonates (limestone/dolomite) and 0.0001mD in clay/clayey rocks [8] and the results (Figs. 1 and 2) of this evaluation (aided by the redefined equations) are in tune with these values. Hence, these equations are quite supportive of the general characteristics of the kind of rocks they represent individually and they are recommendable.

In a related evaluation [5], a range of values of 0.1% to 8.01% of TOC with the corresponding Φ values of a range of 0.7% to 5.7% for shale was showcased. Within the Irati Formation, a related study [17] presented 0.8% to 14.4% for TOC in shales and 1.1% for limestone. Similarly, a range of values of 0.20% to 5.31% for TOC was also presented in a formation [18] consisting of carbonate rock units. Consequently, it is observed that shales could show high TOC compared with carbonates. Hence, shale Φ may be higher than carbonates Φ. With the K expressions herein, an increase in Φ brings about an increase in K, Nonetheless, with the same value of Φ, K is higher in carbonates than in shales. This implies that at lower values of TOC in carbonates, Φ will be low; yet, K will be significantly high when compared with shale. In the same vein, at higher values of TOC in shales, Φ will be high; yet, K will be low when compared with carbonates. Therefore, the RQI and FZI will be significant in carbonates compared to shales. Significant values of RQI and FZI suggest that flow (hydraulic) units are good and the reservoirs will support significant rates of fluid flow within the reservoir rock. Furthermore, even at the same Φ values in both rocks, the hydraulic unit factors (K, RQI and FZI) in carbonate reservoirs (Figs. 3 and 4) are also better and are likely to support fluids' movement and storage more than the shale reservoirs.

IV. Conclusion

High TOC in shales and carbonates contributes to the increase in porosity (Φ) and permeability (K) in both rocks. The fact that the carbonates in the Irati Formation consist of portions with fractures is not negligible in this evaluation. Considering this fact with the deductions made based on the relationship between TOC and the hydraulic units, the carbonate rocks portray better potentials as reservoirs for the storage of CO_2. In addition, artificial fracturing may not be necessary if the carbonates rocks are considered. Meanwhile, the shales in some parts of the location are exfoliating (or exfoliated) and this may be another good reason they are not recommendable for the purpose of CO_2 storage.

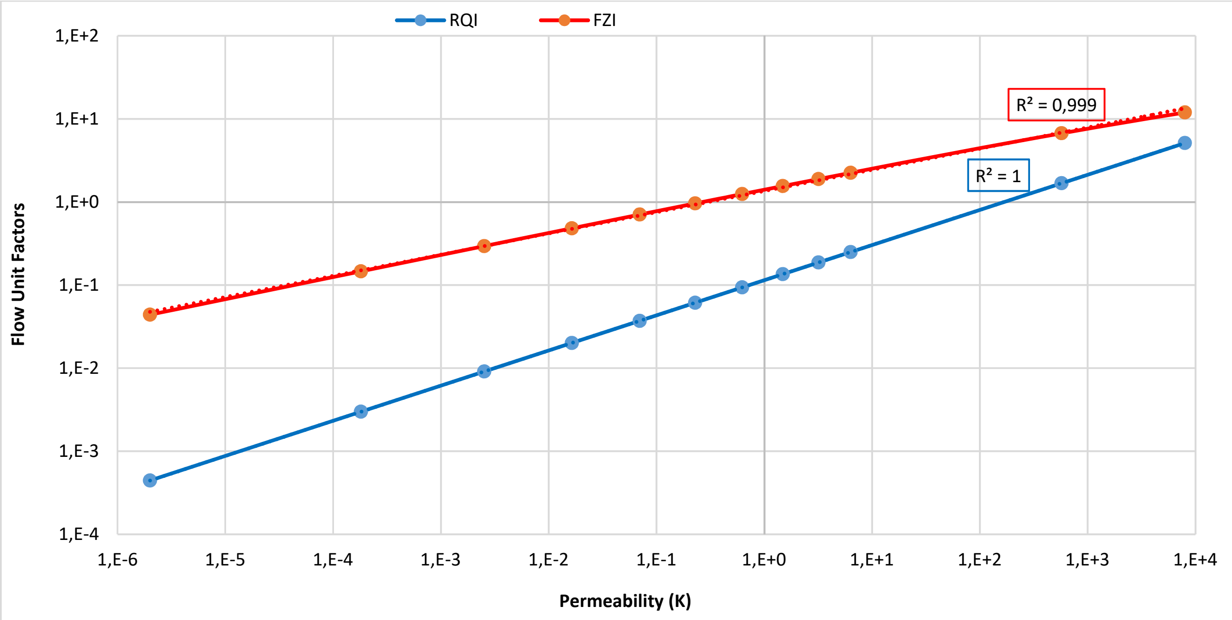

Fig. 1 Flow Unit and Permeability Correlation Plots in Carbonate Rocks

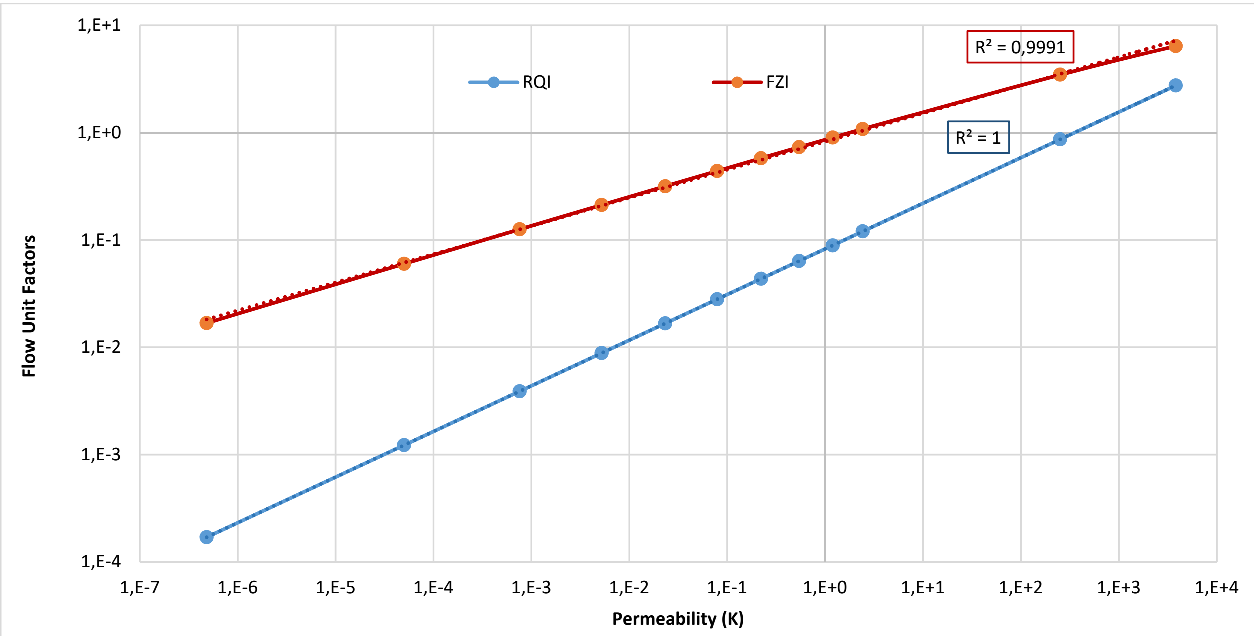

Fig. 2 Flow Unit and Permeability Correlation Plots in Shales

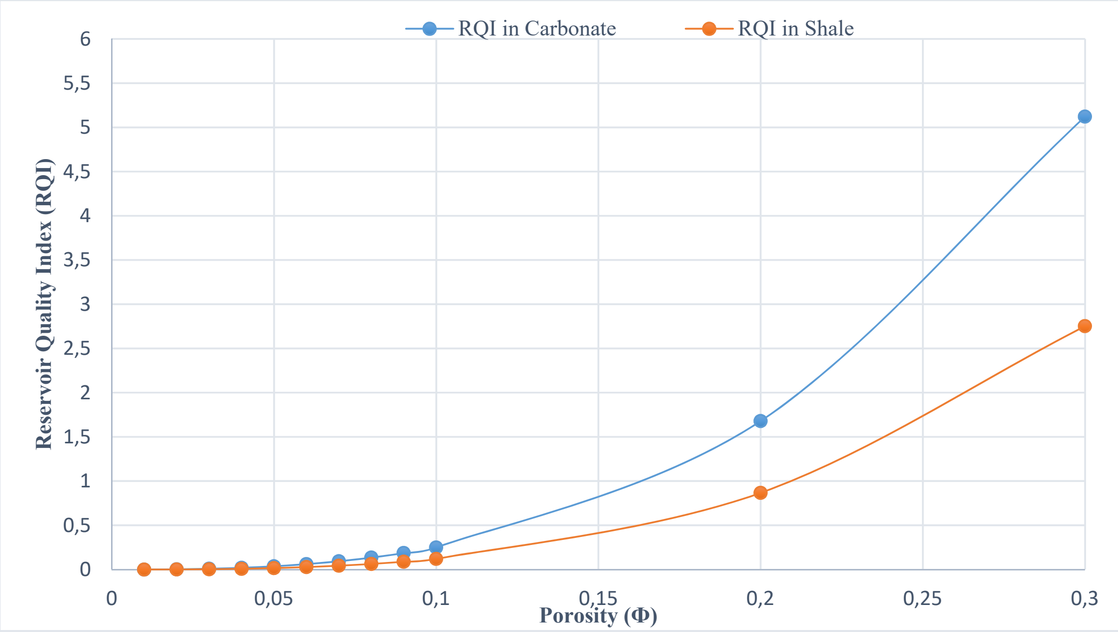

Fig. 3 Comparison between carbonate and shale RQI

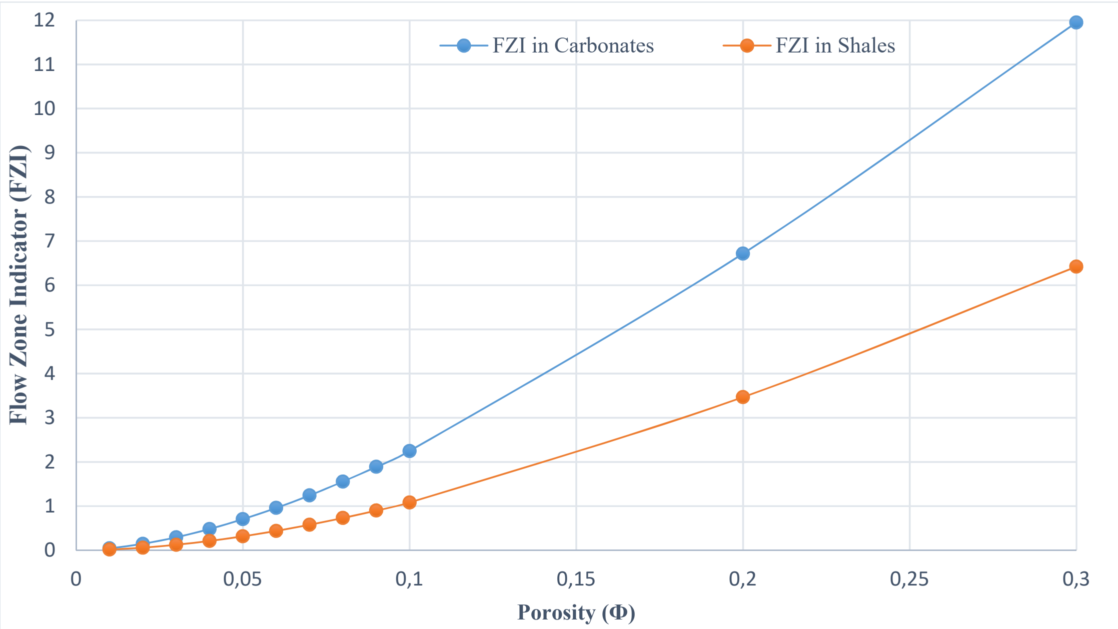

Fig 4 Comparison between carbonate and shale FZI

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