Pore Throat Radius and Fracability interpretation for sweet spot selection in carbonate formations

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Abstract

Currently, shallow and light-oil reservoirs can be difficult to find out and for this reason, oil and gas operators are exploring and developing complex, risky, and therefore costly reservoirs. This is the case of the Tamabra carbonate formation in México, which have gained relevance as potential reservoir for hydrocarbon production.

This study presents a strategy to assess the petrophysical and geomechanical rock properties to guarantee the optimal productivity from the Tamabra carbonate formation, located in the Tampico-Misantla basin in Mexico. This is based on the integration of petrophysical and rock physics models. The petrophysical model includes the determination of the pore throat radius, which defines the flow capacity through the pore space because it is an indicator of the connectivity between them. This pore throat radius is calculated using an equivalent Pittman equation corresponding to a mercury saturation of 50% (r50) that is considered the best predictor for carbonate formations in general. The rock physics model includes the determination of Young's modulus and Poisson's ratio from acoustic and density log for brittleness estimation. This brittleness is integrated with fracture toughness and fracture gradient to generate the geomechanical model. Fracture toughness and fracture gradient are estimated from acoustic and density log as well as different petrophysical properties such as shale volume and porosity.

Introduction

Petrophysics is one of the most fundamental tools for the industry of oil and gas exploration and production because its main objective is to estimate different petrophysical properties of the rocks to describe the potential of production of a hydrocarbon reservoir. Another important science behind is Geomechanic, which provides useful information for the best well location, drilling trajectory, optimum mud density, hydraulic stimulation design and to optimize well completion based on the stress field analysis, rock mechanical properties and formation pressure.

This study proposes an integration between the pore throat radius as pretrophysical property and the fracability as geomechanical property in order to define the best intervals for hydraulic stimulation. The proposed methodology was applied in a well, named Well-A, which is part of the oil production system of the Chicontepec channel located in the Tampico-Misantla Basin as shown in Figure 1. This basin covers the region from the south of the Tamaulipas State up to the central portion of the Veracruz State in Mexico. The formation of interest is the carbonate Tamabra formation from Cretaceous.

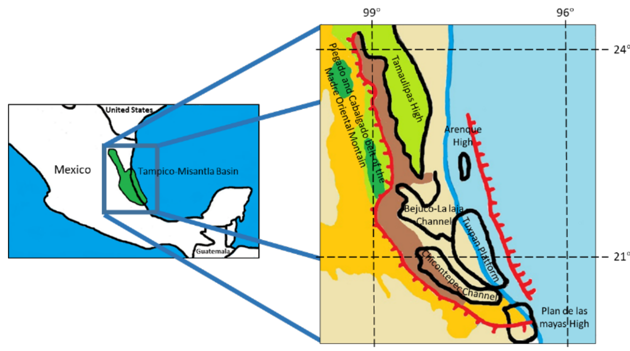

Figure 1. Tectonic-structural elements of the Tampico-Misantla Basin.

The results of integrating the interpretation of the pore throat radius as petrophysical property to define the best zone for fluid flow is integrated with the geomechanical properties, improves the selection of the best zones for hydraulic stimulation and optimization of the strategy for sweet spot determination in the Tamabra Carbonate formation. This approach is validated with the results of the fracturing operation performed in different intervals in the Tamabra formation.

Methodology

Pore throat radius is defined as the radius of the circle drawn perpendicular to the fluid direction in the narrowest point in the connection between the pores. Windland (1975) developed a mathematical equation that associates porosity, permeability and pore throat radius corresponding to a mercury saturation of 35%.

$$log r_{35} = 0.732 + 0.588 \log(k_{air}) - 0.864 \log(\phi) \qquad (1)$$

where r_{35} corresponds to the pore throat radius at 35% mercury saturation from a capillary pressure test, K_{air} is the air permeability and ϕ is the porosity.

Based on Windland's work, Pittman (1992) introduced a group of equations generated from multi-linear regressions analyses corresponding to mercury saturation from 10% to 75% at 5% increments. Different techniques are used to determine which of these equations better fit the study field, such as performing a comparison between the actual pore throat radius and the estimation of each equation or the apex method, which consists in determining the mercury saturation at the maximum of the SHg/Pc vs. SHg curve where SHg corresponds to mercury saturation and Pc to capillary pressure (Romero et al., 2004). These equations are described as:

$$logr_{10} = 0.459 + 0.500\log(k_{air}) - 0.385\log(\phi)$$
$$logr_{15} = 0.330 + 0.509\log(k_{air}) - 0.344\log(\phi)$$
$$logr_{20} = 0.218 + 0.519\log(k_{air}) - 0.303\log(\phi)$$
$$logr_{25} = 0.204 + 0.531\log(k_{air}) - 0.350\log(\phi)$$
$$logr_{30} = 0.215 + 0.547\log(k_{air}) - 0.420\log(\phi)$$
$$logr_{35} = 0.255 + 0.565\log(k_{air}) - 0.523\log(\phi)$$
$$logr_{40} = 0.360 + 0.528\log(k_{air}) - 0.680\log(\phi)$$
$$logr_{45} = 0.609 + 0.608\log(k_{air}) - 0.974\log(\phi)$$
$$logr_{50} = 0.778 + 0.626\log(k_{air}) - 1.205\log(\phi)$$
$$logr_{55} = 0.948 + 0.632\log(k_{air}) - 1.426\log(\phi)$$
$$logr_{60} = 1.096 + 0.648\log(k_{air}) - 1.666\log(\phi)$$
$$logr_{65} = 1.372 + 0.643\log(k_{air}) - 1.979\log(\phi)$$
$$logr_{70} = 1.664 + 0.627\log(k_{air}) - 2.314\log(\phi)$$
$$logr_{75} = 1.880 + 0.609\log(k_{air}) - 2.626\log(\phi)$$

The optimal Pittman equation for the studied formation is determined using different methods. One of the most common is the apex plot method that is obtained from the results of mercury injection in rock samples.

Based on Pittman's work, Rezaee et al. (2006) established a relationship between permeability, porosity and pore throat radius in carbonate rocks. Regression analysis and artificial neural networks were used to correlate permeability with porosity values for different pore throat size corresponding to mercury saturations from 5 to 65%. The result of this approach was that the best correlation was found for 50% of mercury saturation. Their empirical correlation for r50 is described as:

$$Logr_{50} = 1.247 + 1.075\,\mathrm{Log}\,K_{air} - 1.913\mathrm{Log}\phi \qquad (2)$$

Fracability is a property that indicates how easily the reservoir rock can be fractured in hydraulic fracturing operations. It mainly reflects two aspects: the degree of difficulty for fracture initiation, reflected by brittleness, and the degree of difficulty for the induced fracture propagation, which is usually represented by the fracture toughness. Rocks with high brittleness index and low fracture toughness allow the formation of complex fracture networks. Additionally, the lower the in-situ stresses, the smaller is the fracture closure stress, resulting in easier fracture propagation and higher fracture conductivity.

Fracability index (FI) and its profile with formation depth can be calculated by incorporating fracture gradient $\sigma_{h,min}$, together with brittleness index BI and fracture toughness K_{IC} and K_{IIC} as:

$$\boldsymbol{FI = BI\frac{2}{K_{IC}+K_{IIC}}\frac{1}{\sigma_{h,min}}} \qquad (3)$$

where FI is the fracability in MPa-2m0.5, and $\sigma_{h,min}$ is the gradient of fracture or the gradient of the minimum horizontal in-situ stresses.

Brittleness index is obtained from Young's modulus and Poisson's ratio assuming that rocks that are more brittle have relatively high Young´s modulus and low Poisson´s ratio, whereas rocks that are more ductile exhibit a low Young´s modulus and high Poisson´s ratio. Based on this, brittleness can be defined as:

$$\boldsymbol{BI = 0.5\left[\frac{E_v - E_{min}}{E_{max} - E_{min}} + \frac{\nu_v - \nu_{max}}{\nu_{min} - \nu_{max}}\right]} \qquad (4)$$

where Ev is the average static Young's modulus, Emin and Emax are minimum and maximum static Young's modulus respectively, $\boldsymbol{\nu}$v is the average static Poisson's ratio and $\boldsymbol{\nu}$min and $\boldsymbol{\nu}$max are the minimum and maximum static Poisson's ratios respectively.

Fracture toughness is estimated from a correlations between fracture toughness, logging data and clay content using a multi-regression method. The logging data includes bulk density and acoustic logs. The shale content is estimated using the gamma ray log response. These correlations can be written as:

$$K_{IC} = 0.45\boldsymbol{\rho} - 0.151e^{V_{sh}} + 0.201\ln(\boldsymbol{DT}) - 0.877 \qquad (5)$$

$$K_{IC} = 0.45\boldsymbol{\rho} - 0.151e^{V_{sh}} + 0.201\ln(\boldsymbol{DT}) - 0.877 \qquad (6)$$

where KIC indicates the resistance of the material to tensile failure, KIIC indicates the resistance of the material to shear failure, ρ represents the bulk density, Vsh is the shale content and DT is the compressional acoustic transit time.

The fracture gradient or minimum horizontal stress, is calculated by poroelastic equation and then calibrated with field measurements. Given the assumption that the formation is poroelastic and homogenous, the following equation is used to calculate the fracture gradient:

$$\boldsymbol{\sigma_{h.min} = \frac{\nu}{1-\nu}(\sigma_v - \alpha P_p) + \alpha P_p + P_{Tectonic}} \qquad (7)$$

where σh,min is the fracture gradient, $\boldsymbol{\nu}$ is the Poisson's ratio, $\sigma\nu$ is the vertical stress, α is the Biot's coefficient, Pp is the pore pressure and PTectonic is the tectonic pressure. All this information can be obtained from well logs.

Pore pressure (Pp) is the pressure of fluid within the pores of the rock (Rabe et al., 2021). The Pp may be above or below the hydrostatic pressure, which is equivalent to the pressure exerted by a water column from the depth of interest up to sea level. When sedimentary rocks are compacted, the pore fluids may be trapped inside and exert pressure well above hydrostatic. The Pp at a specific depth represents the average scalar value acting within an interconnected pore space. The value of Pp is equivalent to a hydraulic potential measured with respect to the free water existing on the Earth's surface.

Results

The pore throat radius of the Tamabra formation was determined from Eq. 2. The average pore throat radius was approximately 0.31 μm, with a minimum radius of 0.007 μm and a maximum of 0.88 μm. The continue pore throat radius curve is presented in the last track of the Figure 2.

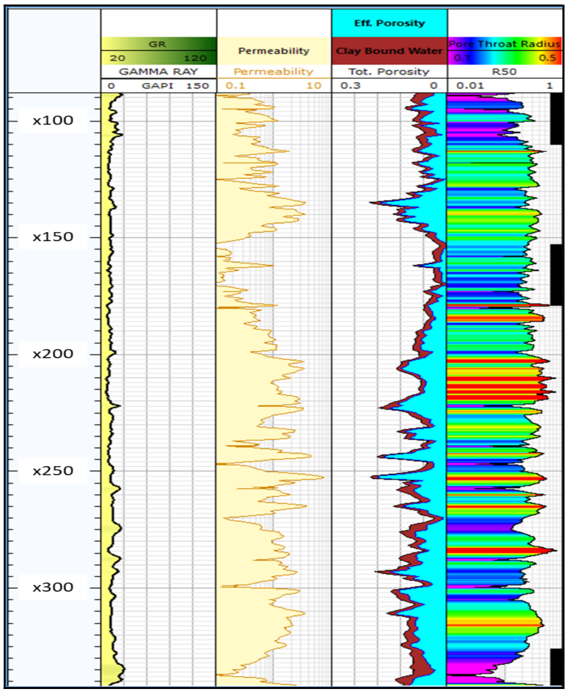

Figure 2. Pore throat radius results in well-A in track five.

The pore throat radius curve indicates that the better rock quality intervals, in terms of petrophysical interpretation, are between x111 and x128m, x138 and x153m, 2200 and x220m and between x310 and x320m. The best interval is the one between x200 and x220m. There are other isolated intervals with thickness between 1 to 5 meters. On the other hand, the worse rock quality, indicated by dark blue and cyan, are in the interval x090 – x108m, x153 – x179m and x326 – x340m. The rest of the intervals could be considered as relatively as medium rock quality. The worse intervals are denoted by the black flag in the fifth track.

Before calculating the brittleness index from Eq. 4, the Young's modulus and Poisson's ratio were calculated from acoustic compressional and shear slowness and bulk density well log data. The minimum used value of the Young's modulus values used were 15 GPa and the maximum in 60 GPa. For the Poisson's ratio, the minimum used value was 0.1 and the maximum in 0.3. A crossplot between Young's modulus and Poisson's ratio is shown in Figure 3, as a graphical representation of the brittleness index in z-axe.

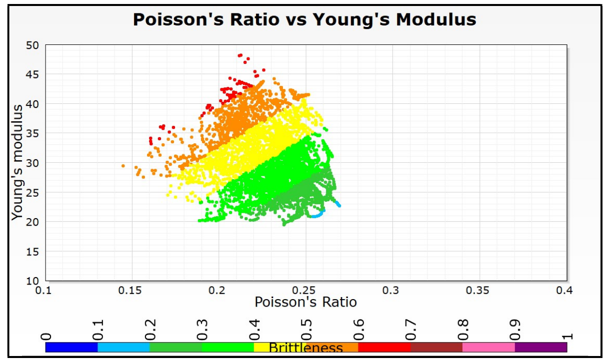

Figure 3. Crossplot between Young's modulus and Poisson"s ratio colored by Brittleness Index (BI)

Based on the concept of brittleness that defines that the most brittle material is that with high Young's modulus and low Poisson's ratio, the brittle material is in the northwest quadrant in the crossplot. In this way, the most ductile material corresponds to the southeast quadrant in the crossplot.

In terms of fracture toughness, Eq. 5 and 6 were used to calculate the resistance of the material to tensile fracture and to shear failure, KIC and KIIC respectively from well logs. Carbonate shale volume used in these equations was calculated from gamma ray log. Additionally, fracture gradient was calculated from equation 2.25.

The determination of brittleness, fracture toughness and fracture gradient allow to predict a profile of Fracability Index (FI) from equation 7, which is shown in Figure 4.

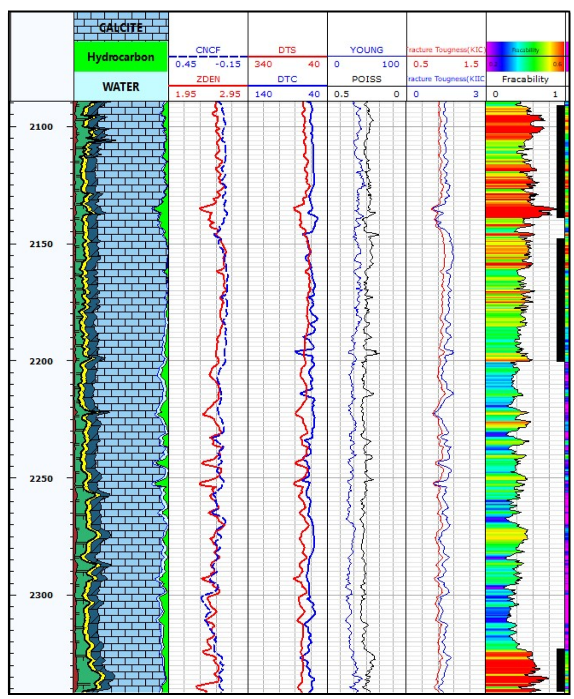

Figure 4. Petrophysical and geomechanical interpretation for Well-A. Depth (Track 1), petrophysical model (Track 2), geo shown in track 7

Based on the concept of fracability, the best interval for hydraulic fracturing operations is between x148 and x191m. Other intervals with high fracability are between x095 and x130m and between x319 and x338m. These intervals are indicated with a black flag in the seventh track.

The results can be combined with the petrophysical interpretation to select the best intervals for geomechanical stimulation. In terms just of pore throat size, the recommended interval for fracturing is those with not pore connectivity, i.e, with small pore throat radius.

In terms of geomechanical interpretation, the best intervals for hydraulic stimulation are those with the higher fracability. Figure 5 shows the combination of the pore throat radius and fracability. The black flag in track 6 corresponds to the lower connectivity, i.e., the lower pore throat radius. The black flag in track 7 corresponds to the higher fracability, which should be considered as good candidates for hydraulic stimulation.

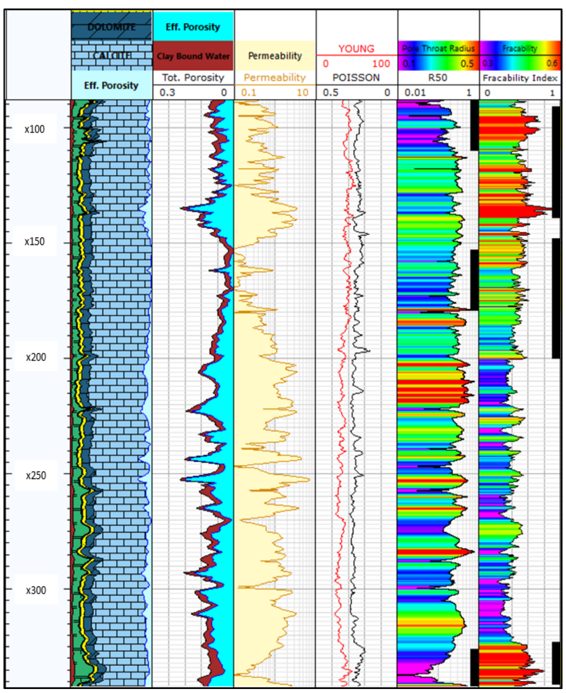

Figure 5. Combination between pore throat radius (Track 6) and fracability (Track 7).

Comparing all the intervals suggested by the petrophysical and by the geomechanical interpretation, it can be noticed that there is an overlapping between them. So, it seems that the intervals with lower connectivity have, in general, high fracability, so, based on both approach, these intervals could be selected for hydraulic stimulation.

An important petrophysical property to be considered is the porosity, because the main objective of hydraulic fracturing is to produce the fluid contained in the pore space. So, among of low pore throat radius and high fracability, the interval should have fluid to be produced, which is determined by the formation porosity.

Based on this, the interval between x148 and x191 could be not a good candidate for hydraulic stimulation because the porosity is low, indicating low presence of fluid on it.

Conclusions

This results of this study indicate that the determination of the different petrophysical properties, such as pore throat radius and porosity, are important properties to describe the potential of production of a hydrocarbon of the studied reservoir. It is also shown that the integration between petrophysical and geomechanical analysis provides a tool to define the optimal interval for stimulation, called sweet spot and for hydraulic stimulation, in terms of fluid flow, rock capacity to initiate and propagate an induced fracture and fluid storage.

The best intervals for reservoir stimulation in the Tamabra formation are located in the top and in the bottom of the formation, where the high pore pressure, median Young's modulus, low Poisson's ratio and High porosity, indicate good reservoir quality and an excellent interval for reservoir stimulation in order to improve the connectivity between the pores allowing the hydrocarbon production. This is confirmed when the results of the hydraulic fracturing are analyzed and compared with the results of hydraulic fracturing in the other intervals performed in correlate wells.

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