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Research paper

Estimation of clay minerals from an empirical model for Cation Exchange Capacity: An example in Namorado oilfield, Campos Basin, Brazil

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ABSTRACT

Clay minerals are important components of shales and occur predominantly in clastic sedimentary basins. Although the classification of such minerals arouses the interest of oil exploration practitioners, this is a hard task to accomplish. In order to typify the main clay minerals of turbidite sandstones in Campos Basin, this study comprises an empirical model to estimate Cation Exchange Capacity. The basic parameter for applying the empirical model is shale volume, whose values are calculated from natural gamma ray, neutron and bulk density measurements. Two-dimensional maps of Cation Exchange Capacity in specific depths are also provided in order to extend the analysis to the whole Namorado oilfield, Campos Basin, in southeast Brazil. The application of this methodology in two wells drilled in Namorado oilfield reveals, despite significant differences in shale content estimation, the predominance of kaolinite in the selected sedimentary interval, while layers of illite and chlorite are noticed at the top of the sediments. There is a total absence of smectite in all studied area. Two-dimensional maps for specific depths of Namorado reservoir enhance discrepancies associated with limitations of both methods to obtain shale content.

1. Introduction

Clay minerals consist of fine-grained material which are classified according to their crystal structure into four major groups: kaolinite, chlorite, illite and smectite. Although these minerals are the main constituents of shale rocks, they are often present in sandstones (Ruhovets et al., 1982). Regarding the exploration of oil and gas, clay presence in reservoir rocks such as sandstones affects not only most geophysical well log responses but also the technical features of reservoirs. Characterization of pores is the main aspect to be taken into account in reservoir rocks. This is mainly related to porosity and permeability (Schön, 2011). Both properties commonly depend on clay content within pore space. Without the knowledge of such type of clays and its distribution in rock pores, one struggles to describe the quality of reservoirs and some valuable log data becomes biased (Keelan and Mcginley, 1979; Fertl, 1986; Asquith, 1990; Jiang, 2012). Each group of clays may alter the rock properties in reservoirs in different ways. According to Ruhovets et al. (1982), severe reduction in permeability and porosity readings occurs in the presence of smectites. The same phenomenon is significantly reduced when the clay mineral is kaolinite. Clays also provide an increase in conductivity due to the free charge within the layers of silica. For this reason, rocks with clay constituents have higher conductivity measurements when compared to those obtained from clean rocks (Ramirez, 1990; Doveton, 2014).

Specific chemical parameters exhibit particular characteristics of a clay mineral in a rock sample, like photoelectric cross section, hydrogen index, matrix density, potassium, uranium and thorium content and Cation Exchange Capacity(Fertl and Chilingarian, 1990; Clerke and Martin, 1994). The latter is really important in measuring the capability of clays to adsorb ions. This behavior occurs due to clays negatively charged surface, which enable the adsorption of cations in the surrounding water solution, leading to an excess of negative charge in clay surfaces (Johnston, 1952; Carroll, 1959; Johnson and Linke, 1978; Ramirez, 1990; Causey, 1991; Dohrmann, 2006). Cation Exchange Capacity, referred here as *CEC*, is mostly obtained in laboratory by different methods, like methylene blue adsorption (Kahr and Madsen, 1995), ethylenediamine complex of copper (Bergaya and Vayer, 1997), divalent cation electrodes (Chiu et al., 1990) and triethanolamine -buffered barium chloride (Dohrmann, 2006). Nevertheless, these are all very financially demanding methods with very dispersive results (Ramirez, 1990; Dohrmann, 2006). To work around this issue, a few researches proposed alternative empirical methods to identify clay minerals from log data. Quirein et al. (1981) presented an interesting interrelation between subsets of logging and laboratory measurements to develop a more sophisticated method of estimating clay types. Such laboratory data involves Q_v (that is, *CEC* per unit pore volume) and

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total porosity ϕ_T that enables the application of dual water saturation equation and also the Waxman-Smits equation (Waxman and Smits, 1968). Such data is combined with shale volume log data and other logs using regression techniques to provide first-order estimates of how each logging tool responds to expected clay or mineral types. Juhasz (1981) used the *CEC* and hydrogen index ratio as clay mineral indicators. Both quantities worked as ambiguity-handling, once *CEC* values for chlorite and illite are really close, which is not the case for hydrogen index values. Afterwards, Ruhovets et al. (1982) used the same set of parameters together with natural gamma ray spectral data, neutron porosity and bulk density logs to compare log-derived *CEC* values with those determined in laboratory. Fertl (1986) based his calculations on density, neutron and natural gamma ray spectral data to obtain specific clay parameters (i.e., clay density, neutron response to 100% clay and clay volume). This set of parameters is empirically related to *CEC* and hydrogen index logs. Ramirez (1990) computed *CEC* values from well logs, using the normalized Q_v, also known as Q_{nv} from Juhasz equation (Juhasz, 1981). *CEC* obtained from laboratory and also from geochemical model showed good agreement with the continuous *CEC* log-derived values. Demircan et al. (2000) introduced a *CEC* model for perfect shale log data that is based on the petrophysical model of Waxman and Smits (1968). The perfect shale concept assumes that all electric conductivity is due to bound water, which transforms Waxman-Smits equation into shale formations.

To obtain more precise values of *CEC* by the empirical methods cited in the previous paragraph, it is essential to determine the volume of shale (Ruhovets et al., 1982; Kamel and Mohamed, 2006). To perform such estimates in an accurate manner, Hamada (1996) developed an integrated algorithm to compute shale volume from different shale indicator quantities. The method uses a structure independent of logging suite of models to determine shale characteristics and hydrocarbon potential of a shaly sand formation. Two wells in Gulf of Suez were taken into account to apply the proposed method. Kamel and Mabrouk (2003) developed an equation for evaluating the volume of shale using standard porosity logs such as neutron-density and acoustic logs. The equation considers the effect of matrix, fluid and shale parameters and works well in hydrocarbon-bearing formations and where radioactive material other than shale is present. Adeoti et al. (2009) presented a similar application of the work of Hamada (1996) to the Old Niger Delta Field, located in the Gulf of Guinea. In the method proposed by Hamada (1996), three different volume of shale methods involving gamma ray, neutron-density combination and resistivity were combined with a view to finding the minimum of the three. In this paper, we focus in two standard approaches to estimate volume of shale (V_{sh}): one involving gamma ray logs from Larionov (1969) and the other from Schlumberger (1975), which based its calculus in neutron and density logs. More details are found in Section 2.1.

1.1. Study area: Namorado oilfield, Campos Basin, Brazil

Campos Basin is a passive continental margin-type basin associated with the breakup of Gondwana supercontinent, which is the reason for the separation of South America and Africa (Guardado et al., 1989). Regarding the tectonic evolution of the basin, the sedimentary fill of Campos Basin has been divided into four major lithostratigraphic units (the Lagoa Feia, Macaé, Campos, and Emboró Formations) (Winter et al., 2007). Inside Macaé group, the one in which we are interested in, there is also a subdivision into five formations: Goitacás, Quissamã, Outeiro, Namorado and Imbetiba (Okubo et al., 2015). Fig. 2 presents the stratigraphic column of Macaé group in Campos Basin.

Goitacás Formation is composed of polymictic conglomerates, sandstones, marls and calcilutites, both last in minor quantities (Rangel et al., 1994). The Quissamã Formation comprises layers of calcarenite and calcilutite, with small amounts of dolomites. In Outeiro Formation, one finds calcilutites, some layers of turbidite sandstones from Namorado Formation, also shales and marls. The latter are presented in the hemipelagic sequence and work as reservoir seals. The Imbetiba Formation is composed of marls, and rare turbidite sandstones (Winter et al., 2007). Finally, in Namorado Formation, there are several interbedded deposits of turbiditic sandstones and pelitic sediments from Outeiro and Imbetiba Formations. Sandy reservoirs embedded in depositional valleys are then raised and controlled by albian salt tectonics (Rangel et al., 1994; Winter et al., 2007).

A particular portion of Campos Basin called Namorado oilfield is located in the central portion of this basin (see Fig. 1). Namorado is a mature field with an area of 23 km^2 located 80 km from the Brazilian coast. The Namorado reservoir is mainly composed of turbidite sandstones, ranging from 2900 to 3400 m depth (Meneses and Adams, 1990; Bueno et al., 2011). The reservoir rocks are also characterized by K-feldspar occurrence, which yields to rocks that are known as arkose sandstones (Cruz, 2003). As stated in Blaquez et al. (2007), Namorado oilfield is prominent for exploration purposes due to low argillosity and lithification. The calcite cementation signficantly contributes with the values of porosity and permeability obtained in Namorado reservoir, that is, average of 26% and around 1 Darcy, respectively. Additionally, these values are also dependent on the presence of clay minerals, which reinforces the importance of analyzing clay contents in reservoir rocks.

Based on exploration purposes, Brazilian Petroleum Agency (ANP) has funded projects to increase the data-coverage of Namorado oilfield. A total of 55 wells were drilled and logged between 1975 and 1986, as stated in Flexa et al. (2004) and Bueno et al. (2011). Well logs presented in the dataset are: density, gamma ray, resistivity, neutron porosity and sonic.

The study involving clay typification is not a common task in Campos Basin. The only work to date, of which we are aware, that investigated the clay minerals in one non-identified well in the Southeast Brazilian basin was Anjos (1986). In her work, the transformation of smectites into illites in samples from Campos Basin was analyzed by using the X-ray powder diffraction technique. An extensive comparison in one well in the Gulf Coast region was also performed. Results indicated that major clay minerals in this well are kaolinite and mica. The frustrating aspect of this work is not providing the location of the studied well, which encouraged us to investigate more closely the clay mineral content in Namorado oilfield, one of the most important exploration field of Campos Basin. Despite several investigations done so far to better understand general aspects of Namorado oilfield, the knowledge of clay distribution is still lacking. Based on this and also on the fact that there is available log data, we showcase some insights about the distribution of clay minerals in the Namorado oilfield.

1.2. Paper overview

The aim of this work is to provide a complete description of the clay types in Namorado reservoir by means of empirical *CEC* estimates. To achieve this purpose, we firstly start from Q_v and total porosity (ϕ_T) laboratory measures compiled by Waxman and Smits (1968). We then follow the work of Tenchov (1998) that found out an empirical expression to compute *CEC* values from V_{sh}. Thereupon, regression techniques are used to provide an exponential estimate of how *CEC* responds to expected V_{sh} values. Complementary V_{sh} estimates from gamma ray (GR) and neutron-density (ϕ_N and ρ_B, respectively) logs are taken into consideration. Specific analysis on pros and cons of using such methods are discussed. To verify the capability of both techniques in computing reasonable shale contents and consequently *CEC* values for Namorado reservoir, we discussed both methods, focusing on two specific wells in Namorado oilfield. To provide a broader analysis on spacial distribution of *CEC* values, we also present 2-D maps of such property for the whole Namorado oilfield. Through these examples and Section 4 that concludes our paper, we demonstrate the potentialities and drawbacks of the empirical method to proving good clay typing.