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Prediction of shale prospectivity from seismically-derived reservoir and completion qualities: Application to a shale-gas field, Horn River Basin, Canada

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ABSTRACT

Prospective shale plays require a combination of good reservoir and completion qualities. Total organic carbon (TOC) is an important reservoir quality and brittleness is the most critical condition for completion quality. We analyzed seismically-derived brittleness and TOC to investigate the prospectivity of the Horn River Group shale (the Muskwa, Otter Park, Evie shales) of a shale-gas field in the western Horn River Basin, British Columbia, Canada. We used the $\lambda\rho$-$\mu\rho$ brittleness template, constructed from the mineralogy-based brittleness index (MBI) and elastic logs from two wells, to convert the $\lambda\rho$ and $\mu\rho$ volumes from prestack seismic inversion to the volume for the brittleness petrotypes (most brittle, intermediate, and least brittle). The probability maps of the most brittle petrotype for the three shales were generated from Bayesian classification, based on the $\lambda\rho$-$\mu\rho$ template. The relationship between TOC and P-wave and S-wave velocity ratio (V_P/V_S) at the wells allowed the conversion of the V_P/V_S volume from prestack inversion to the TOC volume, which in turn was used to construct the TOC maps for the three shales. Increased TOC is correlated with high brittleness, contrasting with the commonly-held understanding. Therefore, the prospectivity of the shales in the study area can be represented by high brittleness and increased TOC. We propose a shale prospectivity index (SPI), computed by the arithmetic average of the normalized probability of the most brittle petrotype and the normalized TOC. The higher SPI corresponds to higher production rates in the Muskwa and Evie shales. The areas of the highest SPI have not been fully tested. The future drilling should be focused on these areas to increase the economic viability of the field.

1. Introduction

The two factors that determine the prospectivity of a shale play are reservoir quality and completion quality (Glaser et al., 2014). Reservoir quality for a shale play, i.e., the ability to produce hydrocarbons economically after hydraulic fracture stimulation, is governed by porosity, hydrocarbon saturation, total organic carbon (TOC), and thermal maturity (Glaser et al., 2014). Completion quality is the geomechanical conditions that depend on elastic properties of a rock such as Young's modulus, Poisson's ratio, and bulk modulus as well as mineralogy. Completion quality is also affected by fracture density, orientation and anisotropy of *in-situ* stresses, and strength properties (Glaser et al., 2014; Herwanger et al., 2015). High completion-quality shales must be brittle enough to readily fail upon hydraulic fracturing and maintain fractures for proppant placement for higher production rates. As such, rock brittleness is an important measure for the completion quality of shale reservoirs.

Jarvie et al. (2007), Wang and Gale (2009), and Jin (2014) proposed brittleness index (BI) definitions based on the mineral composition of the rock, dividing the fractional content of the most brittle minerals – quartz (Jarvie et al., 2007), quartz and dolomite (Wang and Gale, 2009), or quartz-feldspar-mica and carbonate minerals (Jin, 2014) – by the sum of the all constituent minerals. These mineralogy-based BIs (MBIs) require core measurements or a lithology log such as the Elemental Capture Spectroscopy (ECS) data.

Grieser and Bray (2007) and Rickman et al. (2008) proposed a brittleness measure for shale reservoirs by combining Young's modulus and Poisson's ratio derived from well-log data. Poisson's ratio represents the

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rock's ability to fail while Young's modulus represents the rock's ability to maintain a fracture once the rock fractures. Thus, the lower the value of Poisson's ratio and the greater the value of Young's modulus, the more brittle the rock. This elastic log-based brittleness measure can be referred to as the elastic brittleness index (EBI) (Soltanzadeh, 2014). Young's modulus and Poisson's ratio of a shale reservoir away from well control can be estimated from P-impedance (I_P), S-impedance (I_S) and density (ρ) computed from prestack seismic inversion.

The minimum horizontal closure stress, i.e., the minimum pressure required to open a pre-existing fracture or plane of weakness, can also be a measure of rock brittleness. Goodway et al. (2010) reformulated the closure stress equation by Sayers (2010) in terms of the Lamé parameters, λ (incompressibility parameter) and μ (rigidity parameter). In the isotropic case, where the tectonic strain energy vectors are equal, the Goodway et al.'s closure stress can be simplified such that the minimum amount of pressure that must be applied to open a fracture and the overburden-pore pressure differential are related by the closure stress scalar (CSS) or bound Poisson's ratio (Goodway et al., 2010; Close et al., 2012). For a given overburden and pore pressure, an increase in the CSS results in an increase in the amount of pressure required to initiate and sustain a fracture (Close et al., 2012). A coupled decrease in λ and increase in μ leads to lower CSS (i.e., an increase in rock brittleness). However, lower CSS values can result from an independent increase in μ or decrease in λ (Close et al., 2012).

Goodway et al. (2012) predicted completions performance and well production for the Horn River Group shale of the Horn River Basin, British Columbia, Canada using $\lambda\rho$ and $\mu\rho$ computed from prestack inversion. They showed that lower $\lambda\rho$ and CSS are suitable for mapping potential production performance in the Horn River Group shale. Close et al. (2012) also showed that the sweet spots within the Horn River Group shale are characterized by low $\lambda\rho$ and high $\mu\rho$ or, alternatively, low CSS.

Perez and Marfurt (2014) designed an empirical $\lambda\rho$-$\mu\rho$ brittleness template for the Barnett Shale based on mineralogy from ECS data and elastic parameters from elastic log data. They computed $\lambda\rho$ and $\mu\rho$ volumes through prestack inversion, calibrated the results with the $\lambda\rho$-$\mu\rho$ template, and determined the brittle and ductile regions of the shale and the ductile limestone fractures. Most microseismic events fell into the zone predicted as brittle in the $\lambda\rho$-$\mu\rho$ template.

Good reservoir-quality shales are typically characterized by mid to high TOC (at least 4–5%) (Quenes, 2012). The primary component of organic matter is kerogen and its physical properties differ significantly from those of the mineral constituents in shale. Very high kerogen content induces an excess of ductility (Pendrel and Marini, 2014). Contrary to this commonly held understanding, increased TOC in the Barnett Shale does not make the rock more ductile, but rather corresponds to high brittleness (Perez and Marfurt, 2013). This is probably because kerogen in the Barnett Shale is encapsulated in the pores of the rock, not affecting the mechanical properties of the rock (Perez and Marfurt, 2014), and also because the quartz-rich, more brittle lithofacies of the Barnett Shale were deposited in more poorly oxygenated environment than the quartz-poor lithofacies (Singh, 2008).

Løseth et al. (2011) showed that I_P from well log data decreases nonlinearly with increasing TOC measured from corresponding core samples. They used this relationship to transform I_P volumes from seismic inversion into TOC volumes. Zagorski et al. (2012) showed that the TOC of the Marcellus Shale can be inferred from gamma-ray and density logs. TOC of shale reservoirs can also be derived from seismic data because it influences P-wave (V_P) and S-wave velocities (V_S) as well as the density of shale (Chopra et al., 2012). Gupta et al. (2013) analyzed elastic parameters and TOC from core measurements of the Woodford Shale and showed that the high-, intermediate-, and low-TOC petrotypes can be delineated from the Young's modulus-Poisson's ratio crossplot. Liu et al. (2014) showed a well-defined negative relationship between TOC and V_P/V_S for a North American shale play. Yu et al. (2014) demonstrated that TOC-rich patches of the shale-gas reservoirs in southern China are correlated with low values of the product of Young's modulus and density.

In this study, we integrated well-log data and TOC from core measurements with results from prestack inversion to identify prospective areas or sweet spots for the Horn River Group shale in a shale-gas field located in the western central part of the Horn River Basin (Fig. 1). We combined the brittleness from ECS log and elastic parameters computed from elastic logs to create a brittleness template that was used to calibrate the elastic parameter volumes from prestack inversion to the brittleness probability volume. For reservoir quality, we transformed an elastic parameter volume to TOC volume based on the relationship between TOC and the elastic parameter at the wells. The combined interpretation of brittleness and TOC volumes helped predict the most prospective areas for future drilling in the field.

2. The Horn River Group shale

The Horn River Basin represents one of the largest unconventional gas accumulations in North America (Close et al., 2012). The basin was initiated during the Early Devonian by the extension caused by the subduction along the western margin of ancient North America (Blakey, 2011). During the Middle to Late Devonian, reef-fringed carbonate platforms of the Upper Keg River, Sulphur Point, and Slave Point formations (Fig. 2) formed the eastern border of the basin. Basinal shales laterally-equivalent to these carbonate units, deposited in the poorly oxygenated waters of the basin, consist of the Evie, Otter Park, and Muskwa members of the Horn River Formation from oldest to youngest (McPhail et al., 2008). These shales comprise the Horn River Group shale unit and have been the main shale-gas target in the Horn River Basin.

The Evie Shale consists of dark gray to black, radioactive, organic-rich, pyritic, variably calcareous and siliceous shale (British Columbia Ministry of Energy and Mines, 2011), characterized on well logs by relatively high gamma ray and resistivity (Ness et al., 2010). The Evie Shale is over 75 m thick immediately seaward of the barrier reef complex in the east and generally thins westward to <40 m (British Columbia Ministry of Energy and Mines, 2011). The average TOC of the Evie Shale is about 4.5% (Advanced Resources International, Inc., 2013).

The Otter Park and Muskwa shales are often considered as one flow unit, from a geomechanical perspective, after hydraulic fracturing with few barriers to fracture propagation (British Columbia Oil and Gas Commission, 2014). The Otter Park Shale consists of dark gray calcareous shale with lower radioactivity and resistivity on well logs than the Evie and Muskwa shales (British Columbia Ministry of Energy and Mines, 2011). The Otter Park Shale is the thickest of the three and reaches a maximum thickness of over 270 m in the southeastern corner of the basin (British Columbia Oil and Gas Commission, 2014).

The Muskwa Shale consists of gray to black, pyritic, radioactive, organic-rich siliceous shales, and is characterized by high radioactivity and resistivity (British Columbia Ministry of Energy and Mines, 2011). The Muskwa Shale is about 30 m thick adjacent to the barrier reef complex in the east and thickens to over 60 m in the western part of the basin (British Columbia Ministry of Energy and Mines, 2011). The Muskwa Shale continues over the top of the barrier reef and extends further eastward. The TOC of the Otter Park-Muskwa interval in prospective areas averages 3.5% for the net shale thickness (Advanced Resources International, Inc., 2013). Drilling depths to the top of the Otter Park-Muskwa interval range from about 1900 m to about 3100 m, averaging about 2400 m for prospective areas (Advanced Resources International, Inc., 2013).

3. Data

The data used in this study consist of: (1) 3D prestack time-migrated seismic data, (2) various logs (P-sonic, S-sonic, density, gamma-ray, and ECS) and stratigraphic tops (tops of Muskwa, and Otter Park shales and