AP18

3D Seismic Characterization of a Heterogeneous Cenomanian Carbonate Reservoir Containing "Channels"

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SUMMARY

This work discusses an integrated characterization of a shallow-marine carbonate oil reservoir of the Cenomanian age, taking advantage of high-quality 3D seismic data. 3D seismic attribute and AVO inversion analysis were applied and revealed field-wide reservoir heterogeneity. The most noticeably, 3D slices of seismic attribute visualized gigantic channel-shaped signatures that traverse across the field, with their widths and thicknesses reaching upto 3km and over 100m, respectively. In the 3D sdata, the "channels" appeared to be erosional and the channel-fill sediments are less porous and more argillaceous than the surroundings, often accompanied by underlying porous property. A well suggested the channel-fill sediments to be low-porosity karst-related breccia and the underlying interval is productive in the well test. Integration of these seismic and well observations led to a unified interpretation that the channels are formed by Turonian erosional incision and the channel-fills are likely to be muddy/tight sediments. Due to the tight property, the channels were considered as possible cause of reservoir compartmentalization identified from well data. Throughout this work, 3D seismic was utilized as the key driver of the integrated evaluation and was confirmed to successfully reveal critical carbonate reservoir characteristics.

This work discusses an integrated characterization of a shallow-marine carbonate oil reservoir of Cenomanian age, taking advantage of high-quality and high-resolution 3-D seismic data. The reservoir resides in the uppermost part of the thick limestone sequence, having the net thicknesses of 200–350 m and the average porosity of 5–15% with large vertical/lateral variations.

3-D seismic attribute and AVO inversion analysis were applied and revealed field-wide reservoir heterogeneity. The rock physics analysis using elastic logs and ultrasonic core velocity data enabled correlating seismic attributes, i.e. acoustic impedance (AI) and V_p/V_s , with petrophysical properties, i.e. porosity and shaliness. The seismic AI predicted generally more porous properties to the northwest, consistently with paleo-bathymetry estimated from structural restoration.

Most noticeably, 3-D slices of seismic attributes visualized gigantic channel-shaped signatures that traverse across the field, with their widths and thicknesses reaching upto 3 km and over 100 m, respectively. In the 3-D data, the "channels" appeared to be sharply bounded and erosional in nature with relatively straight patterns. Seismic inversion predicted the channel-fill sediments are commonly less porous and more argillaceous than the surroundings. Moreover, porous properties were often observed below the channel bottoms. A well intersected a small-sized channel having the above seismic characteristics and its log interpretation suggested the channel-fill sediments to be low-porosity karst-related breccia and the underlying interval is productive in the well test.

Integration of these seismic and well observations led to a unified interpretation that the channels are formed by erosional incision during Turonian regional exposure and that the channel-fills are likely to be muddy/tight sediments often accompanied by diagenetic enhancement below them. Due to the tight property, the channels were considered as possible cause of reservoir compartmentalization identified from well data. Throughout this work, 3-D seismic was utilized as the key driver of the integrated evaluation and was confirmed to successfully reveal critical carbonate reservoir characteristics.