RESERVOIR FLUIDS VARIABILITY THROUGH INTEGRATED ENGINEERING AND GEOCHEMICAL STUDY – GULF OF MEXICO

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Introduction

Reservoir grading and connectivity is one of the most important questions facing any field development team in planning production of oil/gas fields. The subject had been addressed already in the 1980s (e.g., Schulte, 1980; Hirschberg, 1988), and the first integrated look at reservoir fluids and reservoir architecture in the Gulf of Mexico (GOM) was published by Westrich et al. (1999). Since then, there has been an increased focus on understanding the properties of reservoir fluids, mechanisms leading to gradients, and assessment of continuity through the integration of downhole tools and laboratory analyses (e.g., McKinney et al., 2007; Betancourt et al., 2016).

We present an integrated study, including downhole fluids analysis (DFA), physical fluids properties measurements, PVT, and geochemical analyses, to shed light on vertical and lateral gradients in a field in the northern GOM. The field is characterized by a series of structural-stratigraphic traps controlled by faults in a series of stacked turbidite-amalgamated channels and sheet sandstones of Late Pliocene age. Two wells, 800 m apart, penetrated three sandstone units (A, B, and C). We demonstrate how an integrated fluids evaluation approach can support field development and provide insight to this dynamic petroleum system.

Results

Exploration well Y penetrated two sands (A and B). Five DFA stations with corresponding samples were taken in the main B unit over an interval of 100 m. The appraisal well X penetrated three sands (A, B, and C), with one DFA and sample station in each of the units A and C and seven DFA stations plus five downhole samples in unit B. Sand B is divided into upper and lower zones by a shale break. The drilling mud contamination of the bottomhole samples ranged from 0.5 to 3 wt% on a stock-tank liquid (STL) basis, thus confirming excellent sample quality.

DFA data showed clear compositional gradients in the main B sand, with the gas/oil ratio (GOR) varying from ~1500 ft^3/bbl in the upper part down to ~1000 ft^3/bbl in the lower section, with corresponding decrease in methane content and increase of *in situ* density (~0 to 0.73 g/cm^3) and viscosity (0.6 to 1.2 cP). Both samples from A and C had GOR and methane values outside of the B trend, indicating clear separation and different fluid properties.

PVT analyses confirmed observed gradients. Although the absolute numbers varied slightly from the DFA data, both DFA and PVT data suggest a subtle shift in GOR and density trends between wells X and Y in unit B. In addition, DFA and PVT data are consistent; both demonstrate a slight shift in GOR slope between the upper and lower B zones. Simple equation-of-state modelling indicates the fluids are close to thermodynamic equilibrium, with possible subtle disequilibrium between the upper and lower B zones.

A comprehensive set of physical fluids properties were measured on STL derived from the bottomhole samples. These data reveal strong gradients in the heavier portion of the B sand liquid – API gravity (30 to 24), Sulfur (1.7 to 2.5%), Ni + V (20 to 140 ppm), asphaltenes content (0.1 to 6 wt%). There is a clear relation between GOR and API gravity (lighter fluid = higher GOR). Fluids in the more crestal X well are lighter than those from the flank Y well. The properties for the A-sand STL are similar to the lightest B sand STL, while the C sand STL is much lighter (API=36°, S=1.5%, Ni+V ~0 ppm). Gasoline-range components (C7) indicate a mature oil window; fluids from A and C are slightly more mature.

Geochemical fingerprinting of the STLs in the B sand showed 'annoying' similarities, yet reveal correlation between the chemical distance and depth, supporting the gradient observed in the B sand. Since we have not observed any severe in-reservoir processes affecting the geochemical fingerprints, the observed variations support the conclusion of a gradient in the overall large column that is close to thermodynamic equilibrium.

Biomarker analysis of the STLs characterizes the fluids as typical of a mixed marine, marly source facies. The maturity level from biomarkers indicates an early to mid-mature oil window, with fluids from A and C being slightly more mature. The latter is consistent with the C7 parameters discussed above.

Analysis of the flashed gas derived from the bottomhole samples indicates that the gases are of mixed, thermal-dominated origin, with isotope values for the B sand typical of GOM Tertiary reservoirs (–58‰ $\delta^{13}C$–C_1). Sand A clearly shows input of biogenic source (–63‰ $\delta^{13}C$–C_1), whereas gas from unit C shows more thermogenic input (–55‰ $\delta^{13}C$–C_1).

Conclusions

The combination of early stage DFA fluid analysis with subsequent laboratory data was used to describe the fluids system of a GOM field. Results of physical fluids properties and PVT clearly showed compositional gradients in the B sand whereas geochemical parameters did not reveal noticeable vertical and lateral variations, yet clearly pointed to different fluids in the A and C sands. All fluids came from a marly, mixed source. Comprehensive analysis indicated that at least three main events affected the charge into the system: 1) fluids of early- to mid-mature oil window, 2) later filling with more mature fluids (C7's), 3) biogenic gas input into an A sand. While gas and light components indicated well mixed B sand, a gradient is driven by heavier portion of liquid. The observed gradient is similar to the neighbouring Bullwinkle field J-sand and possibly sheds a light for the fluid dynamics of this basin.

References

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