INTRA-FORMATIONAL GEOCHEMICAL VARIATIONS OF A MIDLAND BASIN BLACK SHALE DEPOSIT AND IMPACT ON ITS PETROLEUM SYSTEMS

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Introduction and Methodology

Sediments of early- to mid-Permian age in Midland Basin are composed of a great variety of facies from organic-rich mudstones, siliciclastic mudstones, carbonate rich mudstones, skeletal wackestone-packstone to grainstones (Baumgardner and Hamlin, 2014). Organic-rich facies within these formations have been interpreted as a result of deposition in the basins during suboxic to anoxic events. The understanding of intra-formational facies variations and the associated petroleum fluid properties is essential to the development of these shale resources.

A high frequency sampling of core samples from ~1000 ft of a thick sequence of black and carbonaceous shale formations were characterized by rock geochemistry and by high resolution gas chromatography of extracts. Instead of conventional Soxhlet extraction method where extracts are devoid of hydrocarbon compounds less than C_{12}, a closed vial CS_2 extraction method allows the analysis of light hydrocarbons that are preserved in tight shales.

Results and Discussion

The maturity differences from the top to the bottom of this 1000 ft section is relatively small, 0.05 VRo% unit. In addition, the low permeability of the mostly shale units has allowed minimal migration of hydrocarbons into the rock pore space due to their high capillary entry pressure. Thus the extract geochemistry fingerprints can be related to compositions of the source rock kerogen and its in-situ generated bitumen. Some higher permeability samples may have received hydrocarbon charge from a short distance, likely from interbedded high TOC shale layers.

This unique dataset allows us to identify the impact of source rock facies and kerogen composition on geochemical fingerprinting and hydrocarbon ratio parameters. Traditional determination of facies/maturity parameters is derived from oil samples in reservoirs that have been charged from source rocks that are most likely a mixture of many different kerogen facies. This study can shed light on the degree of variability of these parameters from analyses of discrete source rock samples of varying kerogen compositions.

There are some front end losses in the core extract GCs and the losses are closely related to the permeability of the samples, with more loss for high permeability carbonate and minimal loss for low permeability tight black shale samples.

The classic source rock biomarker parameter Pr/Ph ratios vary notably with depth (Fig. 1), suggesting significant shift in bottom water oxygen conditions during organic matter diagenetic process. This degree of variability is not shown with TOC data, indicating that different mechanisms of production/preservation played a role during deposition of these organic rich layers. Within part of the cored section, a relative uniform Pr/Ph ratio may suggest limited cross stratal migration of hydrocarbon.

Light hydrocarbon ratios, when they are not affected by evaporation during sample retrieval and preparation, also show distinct depth trends in correspondence to Pr/Ph ratios, suggesting the important role of kerogen composition on their distribution/presence in extracts. Some of the proposed maturity parameters from light hydrocarbon ratios don't follow the presumed trend with depth. For example, heptane values decrease with depth, a reverse function to maturity.

The work will also examine the utility of many other geochemical parameters for source rock facies and maturity interpretations, and their impact on petroleum systems interpretation.

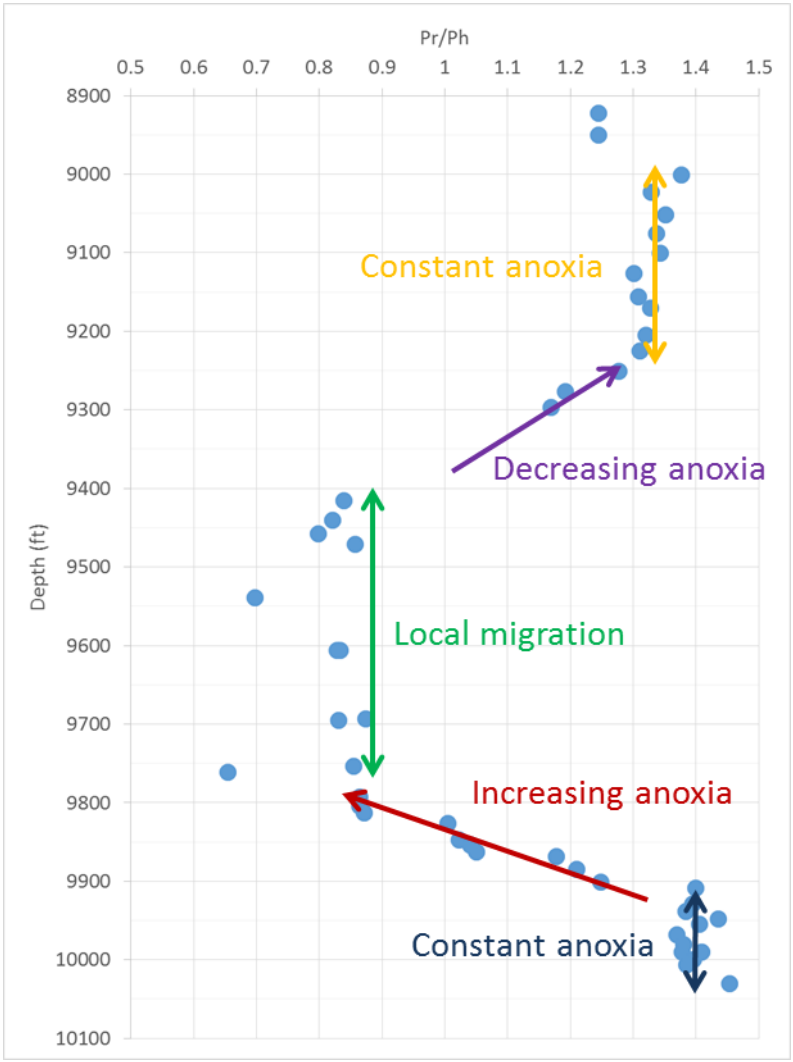

Figure 1 *Variation of Pristane/Phytane ratios in core extract GCs suggesting intra-formational changes in source rock preservation conditions and hydrocarbon migration*

References

Baumgardner, R.W., and H.S., Hamlin, 2014, Core-based Geochemical study of Mudrocks in Basinal Lithofacies in the Wolfberry Play, Midland Basin, Texas, Part II: Search and Discovery Article no. 10572.