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An Applied Geochemical Look at Delaware Basin Petroleum Systems

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ABSTRACT

Over 600 Permian Basin crude oils were geochemically assessed and grouped into 21 oil families that share common sources using genetic-specific biomarkers (geochemical fossils) and stable carbon isotope compositions by means of multivariate statistics (hierarchical cluster & principal component analyses).

Interpretation of the geochemical data allowed prediction of:
• source rock kerogen type
• source rock lithology and depositional environment
• geologic age
• organic matter thermal maturity

Delaware Basin Lower Permian Wolfcamp-sourced oils (Family 8) are different from Wolfcamp-sourced oils which occur in the Midland Basin (Family 11). The Delaware Basin Wolfcamp oils are from more of a marl source lithofacies, while the Midland Basin oils were generated from a distal shale lithofacies. A small number of Wolfcamp oils with a Family 11 affinity have been noted in the Delaware basin, although Family 8 dominates.

Wolfcamp-sourced oils are relatively isotopically positive with high C27 and low C29 steranes, the reverse of Upper Devonian Woodford-sourced oils. Upwelling terpane biomarkers are dominant. Oils sourced from Wolfcamp- Bone Spring (WC/BS) transitional facies (Families 9 & 10) appear to have been derived from organic-rich horizons stratigraphically between the Lower Wolfcamp shales and the Leonardian Upper Bone Spring (1st)/Avalon marls/ carbonates. These oils occur in the Delaware Basin and Northwest Shelf in New Mexico. Family 16 oils were generated from the most carbonate-rich facies of the Bone Spring Formation. Younger Guadalupian carbonate-sourced oils (Family 17) also occur on the Northwest Shelf. A number of biomarker maturity-sensitive ratios, not used in the statistical determination of oil families, track the level of thermal maturity of oils and reflect the source rock maturity at the time of initial expulsion/primary migration. These maturity ratios were subjected to principal component analysis with the resulting 1st or primary factor converted to estimated vitrinite reflectance equivalent (VRE) values. One significance of this interpretive approach is that more mature oils may provide relatively more reservoir energy (due to increased associated gas content) than less mature oils. Additionally, an understanding of source rock, gas and oil thermal maturities provides insight into primary and secondary migration and timing within the petroleum system.