Barnett Shale Oil and Gas as a Analog for Other Black Shales

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Source-reservoir systems such as black shales have shown excellent commercial results over the years including oil in Monterey and Antelope shales in California and Bakken wells in the Williston Basin, whereas Barnett Shale gas production in the Newark East Field in the Ft. Worth Basin is currently the largest gas field in Texas. These systems are more difficult to log, although logging techniques have improved significantly over the past few years. Using techniques of organic geochemistry prospect generation by mapping of oil versus gas prone areas, and evaluation of oil and gas yields at various maturity levels aid high-grading of perspective drill sites. The success of these techniques in the Barnett Shale is applicable to exploration for oil and gas in other black shale petroleum systems.

Immature Mississippian-age Barnett Shale is readily identified as a Type II oil prone, marine shale based on its high petroleum potential (*ca.* 350-1400 BO/AF at low maturity). Barnett Shale-derived oil is found in the western portion of the Ft. Worth Basin and is high quality (35-45°API), low sulfur oil. Higher maturity oils and condensates are associated with gas found in Wise County, but are generally of similar quality (40-50°API)

These black shales are similar to pressure cookers in that as significant burial occurs oil and gas is generated and is episodically expelled

The retention of hydrocarbons in the Barnett is due to its high carbon content and lithofacies. Until it reaches fracture thresholds, oil is retained and portions of the oil can be cracked to lighter hydrocarbons. This is in part why such high quality oils are associated with Barnett and Bakken source rocks. Further, this explains why in some areas a high oil content is found where higher gas content is expected.

Mapping the maturity of Barnett sources and fingerprinting the retained oil in those reservoirs helps delineate the best prospective wells for high quality, oil and high B.T.U. gas. This is further enhanced by using a kerogen decomposition model that accurately describes dry gas, wet gas, light oil, and heavy oil generation and yields at various maturity levels. Data are shown demonstrating the yield of oil and gas at various maturity levels by laboratory maturation and decomposition experiments on an immature Barnett Shale from Brown County, Texas.

A prospect ranking and well evaluation system is proposed based on specific geochemical parameters such as total organic carbon (TOC), the transformation ratio (TR) or extent of organic matter conversion into hydrocarbons, thermal maturity (vitrinite reflectance), and gas data such as gas wetness, freely desorbed headspace gas, and macerated cuttings headspace gas, when available. Mac. gas provides an indication of gas yields upon fracturing a shale. Thermal maturity and kerogen transformation are used to resolve any maturity questions, but require larger databases. These data must be combined with gross thickness of the source to rank a shale gas prospect. This approach may be used in regional assessments and in well completion activities. Prediction of calorific value from shale hydrocarbon composition at various maturities is also possible. Ash and carbonate content may also be important variables as lithofacies of thick shales can be quite variable.

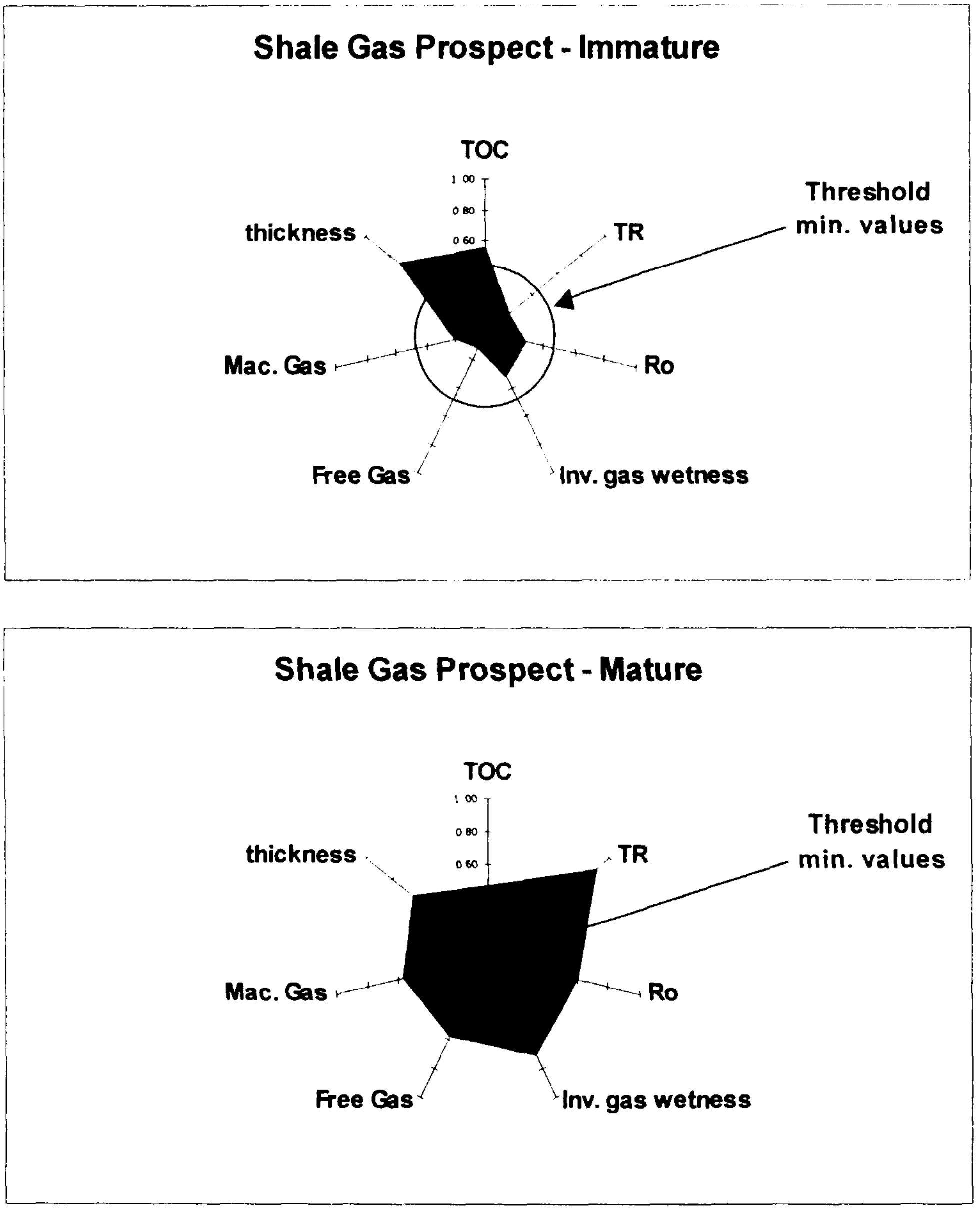

Figure 1 a-b. Prospect and well evaluation criteria based on geochemistry and source/reservoir thickness: (a) prospective low maturity areas will have sufficient organic carbon content and source thickness, but will not sufficiently mature to generate and expel hydrocarbons; (b) prospective areas in the wet and dry gas windows will meet all requirements, and may be gauged for the calorific value (BTU) and macerated gas (mac. gas) will provide an indication of yields upon fracturing.