Evaluation of unconventional natural gas prospects in the Barnett Shale: Fractured shale gas model.

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As global demand for natural gas intensifies, identifying and producing reserves from unconventional (continuous) resources close to markets have gained considerable exploration interest and activity. Unconventional natural gas systems include fractured shale gas (FSG), tight gas sands (TGS), basin center gas (BCG), shallow basin methane (SBM), and coalbed methane (CBM). The origin of natural gas in these types of accumulations may be thermogenic sources, either from primary cracking of organic matter or secondary cracking of bitumen and oil, or mixed thermogenic-biogenic sources. Gas may be further categorized as in-situ generated-reservoired or as migrated gas. Fundamental geochemical characteristics of the petroleum system and type of gas must be determined to map favorable production fairways (sweet spots).

One such unconventional shale gas system is the Mississippian Barnett Shale, which is both source rock and reservoir rock for the largest gas field in Texas (Newark East field, Fort Worth Basin). Commercial gas accumulations are derived from secondary cracking of bitumen and oil. Gas production is from hydraulically-fractured black shales that yield gas with calorific values ranging from about 1050 to 1300 BTU. The economics of this gas play are enhanced by production of wet gas with higher BTU contents so areas with higher wet gas contents are preferred. Without stimulation, gas flow rates are non-commercial. Successful completion requires frac jobs (proppant-induced fracturing) and results in average commercial flow rates of about 150 to 555 MCF/day with a per well EUR of 1.0 BCF. While production decline curves show classical profiles over 10-20 years, re-fracturing of a well stimulates production to levels equivalent to initial flow rates.

The Barnett Shale is a very tight, over-pressured black shale with porosities averaging 6% and permeabilities in the 0.1 to 0.02 millidarcy range. It is organic-rich (4.5% average TOC at >1.1% Ro) and is very thick (450 ft. in Newark East field). Thermal maturity is greater than 1.1%Ro in Newark East field, but maturation varies across the basin and oil production occurs in the northern and western portions of the basin. Expulsion of hydrocarbons has been episodic as Barnett-sourced oil is found in both younger and older horizons as demonstrated by oil fingerprinting and biomarker analysis. Even at low maturity (ca. 0.6%Ro), it expels a high quality (low sulfur, high API gravity) oil, which appears to be a function of the organic matter type and mineralogy. Barnett lithofacies are primarily siliceous and calcareous shales with clay-rich intervals, but cherty and dolomitic units are also common. Regional uplift facilitated an erosional event that is at least partially responsible for a two-phase system when both oil and gas are present. Thus, the elements and processes governing the Barnett petroleum system provide an excellent model for predictive evaluation of other unconventional gas resources.

Hydrocarbon generation produces overpressuring and induces microfractures in the source-reservoir system. However, highly mature Barnett shale shows little evidence of fracturing because microfractures are subsequently annealed by residual oil and pyrobitumen through time. Tectonic fracturing appears to be a negative function as some of the poorest flow rates are obtained in wells with the highest amount of such fractures (Bowker, 2002). Decreasing well spacing from 55 to 27 acres has had no apparent impact on production decline curves demonstrating the temporal integrity of this system.

Integrating extensive and diverse Barnett Shale data sets, from production data to geochemical measurements, predictive maps can be constructed to high-grade the best prospects for oil versus gas and the highest BTU gas prospects. In addition, because of the difficulties inherent in logging fractured shales, the use of basic geochemical measurements (TOC, Rock-Eval, Ro, TEGC) and gas analysis including gas flow line samples (free gas), desorbed gas from cuttings headspace analysis (desorb. gas), and gas released from maceration of cuttings (mac. gas), it is possible to predict sweet-spots within the well bore prior to completion.

A risking model showing minimum geochemical values applicable to discovery of gas in the Barnett fractured shale gas play is shown in Figure 1. This does not include all risking components such as the timing of events and processes, the presence of seal(s), and other geological parameters. Modifications to this risking plot are shown for use with other FSG systems as well as with TGS, BCG, SBM, and CBM prospects.

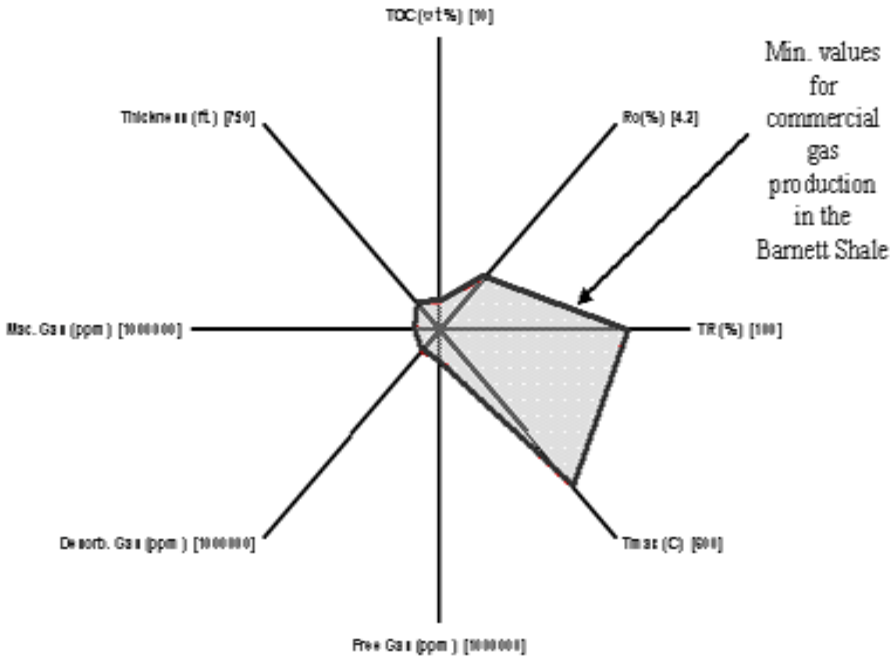

Figure 1. Threshold geochemical risking values for thermogenic gas production from black shales (scale 0-[value] for each variable). These parameters may be used to resolve conflicts, e.g., thermal maturity must translate into an equivalent level of transformation. These can be further restricted to identify wetter gas prospects by restricting the maturity and transformation variables and adding a wet gas ratio. These variables may be used with CBM, BCG, TGS, and SBM prospects with changes in the envelope of minimum values.

Reference:

Bowker, K. A., 2002, Recent Development of the Barnett Shale Play, Fort Worth Basin, Innovative Gas Exploration Concepts, Denver, CO, October 1, 2002, oral presentation.