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Gas Shales Committee Report

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In general, gas shales are organic-rich, fine-grained sedimentary rocks. Rocks included in this definition of gas shales are true shales, mudrocks (non-fissile rocks comprised mainly of clays), siltstones, and very fine-grained sandstones. In many basins, gas shales are gradational with tight sands or may contain conventional reservoir lenses.

In some ways, the situation for gas shales is similar to where coalbed methane was several decades ago. Exploration and development companies are scurrying to decide where to drill and lock up leases in secret as not to attract competition. Some companies, alone or in consortia, are spending millions of dollars on research to understand many aspects of gas shales, from how gas is stored in shales to how to create fractures to produce the gas. Service companies also are investigating how their tools and methods can benefit gas shales. Those that have some of the answers are hesitant to share the information, and at the same time realize that the more they understand the less they truly know.

We need to keep an open mind while establishing end members of gas shales. Thick, low gas-content subbituminous coals in the Powder River Basin of Wyoming were avoided for a long time because emphasis was placed only on high gas content. Similarly, we need to keep from thinking that all gas shales should follow a particular formula. Hill and Nelson (2000, p. 10) aptly stated that "experience over the past 20 years has demonstrated that every gas shale play is unique and must be examined, explored and exploited differently."

According to Curtis (2002), the first commercial gas well in the U.S. was completed in the organic-rich Dunkirk Shale (Devonian) in New York in 1821. Hill and Nelson (2000) estimated more than 28,000 shale-gas wells have been drilled in the U.S. since the early 1800s.

Curtis (2002) summarized the main gas-shale plays to that time: Antrim Shale (Devonian) in the Michigan Basin; Barnett Shale (Mississippian) in the Fort Worth Basin, Texas; Lewis Shale (Cretaceous) in the San Juan Basin; New Albany Shale (Devonian) in the Illinois Basin; and Ohio Shale (Devonian) in the Appalachian Basin. Recent additions are included in the map below. The first gas production from the Barnett Shale in the Fort Worth Basin was in 1981 by Mitchell Energy and Development Corporation (Curtis, 2002). Until the success of the Barnett Shale, it was thought that natural fractures needed to be present in gas shales. Low-permeability gas-shale plays are currently viewed as technological plays where advances in horizontal drilling, fracture stimulation, micro-seismic fracture mapping and the application of 3-D seismic data have contributed to their success.

It can not be emphasized enough that gas shales are complex petroleum systems and generalizations have limited application. Having said that, some of the generalized lessons learned about gas shales from recent presentations and articles are as follows.

(1) Gas shales require fractures as permeability pathways for gas. Fractures can be either natural or induced. Orientation, extent, type, and frequency of fractures need to be studied and understood.

(2) Mineralogy of shales is important for fracture generation. Fractures are more prevalent and created more easily in silica-rich shales than in clay-rich shales. Mineralogy alone may make or break a gas-shale play lacking innovative completion technology.

(3) Gas shales drainage area depends on the extent of fracture development (permeability) and whether the well is vertical or horizontal. In general, drainage area is considered to be on the order of tens of acres with well spacing of 10-27 acres. Drainage area is an ongoing concern and area of research.

(4) Type II kerogen (oil-generative organic matter) is the predominant type of organic matter in current gas-shale plays. Based on hydrous pyrolysis, Lewan (2002) indicated that 75% of the gas produced from Type II kerogen is generated by 1.1%

vitrinite reflectance (Ro) and 93% of the gas is generated by 1.5% Ro; Type II kerogen generates nearly twice as much gas as Type III kerogen (gas-generative organic matter predominant in humic coals). Thermogenic methane generation is complete by 3% Ro (Taylor and others, 1998, p. 504).

(5) Liquid hydrocarbons and water are detrimental to a gas-shale play. (a) If present in abundance in the oil window, large oil molecules may plug permeability and slow the rate of gas production. The transition from the oil window to the gas window is currently estimated to occur at 1.15-1.4% Ro (Jarvie and others, 2005). Higher gas rates are possible at >1.4% Ro. (b) Antrim and New Albany shales produce significant amounts of water (average of 30 bbl/day) with predominantly biogenic methane (Curtis, 2002). Connection to an aquifer (especially along faults) will ruin an otherwise good gas-shale well. Unlike coalbed methane wells where water is essential for gas desorption, water is generally a detriment to gas shales.

(6) Even though gas sorbed (adsorbed and absorbed) on organic matter and clays is important during the life of the well, free gas is important in the first months of a gas-shale well. How free gas occurs in shales and conditions necessary for production are currently not well understood.

Concerning minimum requirements, some parameters may be interchangeable or are too variable to specify.

(1) Thickness (although 50 ft has been suggested as a minimum thickness, it depends on many variables, including economics)
(2) Depth (what are the minimum and maximum economic depth limits?)
(3) Pressure (what is the importance of pressure, from hydrostatic to overpressured, to drive gas production?)
(4) Organic matter type (kerogen type) and quantity (total organic carbon)
(5) Thermal maturity (minimum and maximum limits; optimum range?)
(6) Gas type (biogenic, thermogenic, or mixed)
(7) Gas content (measurement; range?)

Annual shale-gas production has increased from about 60 Bcf from the Ohio Shale in 1979 to about 640 Bcf from the Ohio, Antrim, and Barnett shales in 2003 (Montgomery, 2004). Curtis (2002) and Montgomery and others (2005) estimated the following ultimate technically recoverable reserves: Ohio Shale, 14.5-27.5 tcf; Antrim Shale, 11-18.9 tcf; New Albany Shale, 1.9-19.2 tcf; and Barnett Shale, 3-40 tcf. Refer to the map below for recent estimates. The Barnett Shale is cited as the example of a technological thermogenic gas-shale play. According to Montgomery and others (2005), more than 2,340 wells had been drilled in the Barnett Shale as of January 2004. Initial rates of gas production were 500 mcf/day to 2.0 mmcf/day for vertical wells with estimated ultimate reserves of 1.0-2.5 bcf/well. Initial rates of gas production were 1.5 to 8.1 mmcf/day for horizontal wells with average estimated ultimate reserves of 2.5 bcf/well. Production curves show rapid initial decline (related to production of free gas) followed by gradual flattening over time.

The future looks bright for gas shales as technological advancements (such as horizontal drilling, water-based, low-proppant stimulation, and restimulation) are applied to additional black shales.

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U.S. Shale Gas Basins Active in 2005 (from Schlumberger Shale Gas White Paper; http://www.slb.com/media/services/solutions/reservoir/shale_gas.pdf?)