OKLAHOMA COALBED METHANE, 2001

TECHNOLOGY CONNECTIONS
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BOTTOM LINE

Experience indicates that coalbed methane productivity in Oklahoma is at least as dependent on production practices as it is on drilling and completion practices. Cased-hole completions in larger hole sizes have been shown to provide significant advantages for completion and production. Coal fines are often created during improper fraccing and too high a production rate of either gas or water leads to high decline rates and low gas productivity. In eastern Oklahoma and surrounding regions, fresh water with a biocide and a minimal amount of friction reducer has proven to be the least damaging fracturing fluid. Fracturing gels and most conventional stimulation additives are generally detrimental to production. Average well costs in eastern Oklahoma are in the range of $30-40K, plus an equal amount if pumping or a frac job is required.

PROBLEM ADDRESSED

Economic coalbed methane (CBM) production is a combination of the reservoir being there, drilling and completion practices, and production practices. One must know the coal geology and understand the factors controlling productivity. Permeability reduction by improper stimulation is the major cause of impaired coalbed methane production in eastern Oklahoma. Permeability-reducing coal fines are often created during turbulent flow and during frac treatment. Such fines can be significantly reduced and well productivity increased by careful selection of drilling, stimulation and completion practices.

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SPEAKERS:

Oklahoma Coalbed Methane Activity
Brian J. Cardott, Oklahoma Geological Survey

A Coalbed Methane Exploration Model: Application to the Cherokee, Forest City, and Arkoma
Andrew Scott, Altuda Geological Consulting

Arkansas Coal Geology and Potential for Coalbed Methane
William Prior and Bekki White, Arkansas Geological Commission

Coal Stratigraphy of the Northeast Oklahoma Shelf Area
LeRoy Hemish, Oklahoma Geological Survey

Arkoma Basin Coalbed Methane Potential and Practices
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Midcontinent Evolving Coalbed Methane Completion Techniques and Practices
Roger Marshall, Cudd Pumping Services

Arkansas Coalbed Methane: Successes and Failures
Doug O'Connor, Muirfield Resources Company

Hartshorne Coalbed Methane Economics in Oklahoma
S. Neil Sissen, Wildhorse Operating Company

TECHNOLOGY OVERVIEW

CBM Production Concepts. Cleat is a term for natural fractures in coal. Coals break along cleat planes. Cleats form as the result of dehydration, devolatilization, tectonic, and unloading of overburden. In coal seams, most gas is absorbed on the coal. As hydrostatic pressure is decreased, gas desorbs and moves into the cleat system where it begins to flow. The cleats control the directional permeability of coal and so are highly important for planning well placement and spacing.

Two orthogonal sets of cleats develop in coals and are perpendicular to bedding (barring local fault and fold complications). The face cleat set is the dominant set. It is well developed in that this set cuts across the coal's bedding planes. Face cleats form parallel to maximum compressive stress. The butt cleat set is secondary in that it is discontinuous. Butt cleats terminate against face cleats and thus are strain-release fractures that form parallel to fold axes.

Cleat spacing is related to rank, bed thickness, and composition. Coal with well-developed cleat sets is brittle. In general, cleats are more frequent with increasing coal rank. Average cleat spacing values for three coal grades include: subbituminous (2-15 cm), high-volatile bituminous (0.3-2 cm), and medium- to low-volatile bituminous (<1 cm). Cleat spacing is more frequent in thin coals. Cleats are also more frequent in banded coals, vitrinite-rich lithotypes, and in low-ash coals. Secondary mineralization of cleats will lower bulk coal porosity and permeability.

CBM Exploration Model. Geologic and hydrologic comparisons of coal basins worldwide indicate that depositional systems and coal distribution, coal rank, gas content, permeability, hydrodynamics, and tectonic/structural setting are critical controls on CBM producibility. High productivity is governed by: (1) thick, laterally continuous coals of high thermal maturity; (2) moderate to high permeability; (3) basinward flow of ground water through coals of high rank orthogonally toward no-flow boundaries; (4) generation of secondary biogenic gases; and (5) conventional trapping of migrated thermogenic and secondary biogenic gases at permeability barriers to provide additional gas beyond that generated during coalification.

Pennsylvanian-age coals in the Cherokee, Forest City and Arkoma basins have generally reached the thermal maturity level required to generate significant quantities of thermogenic methane. Secondary biogenic methane generation may have occurred near the outcrop, but the apparent presence of predominantly saline waters in the Cherokee and Arkoma Basin coupled with relatively low water production suggests that secondary biogenic methane generation may be limited. The presence of wells with exceptionally high production is encouraging and suggests that adequate permeability exists at depth. The biggest limiting factor appears to be net coal thickness. However, gas production from carbonaceous shales and/or adjacent sandstones may enhance the economic viability of CBM wells.

Coal Stratigraphy in the NE Oklahoma Shelf Area. 34 named coal beds and several unnamed coal beds are present in the NE Oklahoma shelf area. Nine coal beds that have the requisite thickness for surface mining are present in the same area. From oldest to youngest they are: Rowe coal, Drywood coal, Bluejacket coal, Weir-Pittsburg coal, Mineral coal, Fleming coal, Croweburg coal, Iron Post coal, and Dawson coal. Seven of these beds (the Rowe, Drywood, Bluejacket, Weir-Pittsburg, Croweburg, Iron Post, and Dawson coals) produce coalbed methane. Additionally, gas is produced from three coal beds (Riverton, Bevier and Mulky) that are too thin to be of interest for surface mining. Methane is also produced from one unidentified coal bed for a total of 742 completions in the shelf area.

Although a greater number of coal beds have methane-producing potential in the northeast Oklahoma shelf area, they are generally thinner and less widespread than those in the Arkoma Basin. The main differences between coals in the two regions are:

- Coal-bearing rocks present above the Croweburg coal of the Senora Formation in the shelf area are absent in the Arkoma Basin.
- Stratigraphic units are generally much thicker in the Arkoma basin.
- Commercial coal beds in the NE shelf area pinch out to the south and are absent in the basin; conversely certain well-developed commercial coals in the Arkoma Basin, such as the Hartshorne coal, pinch out to the north, or have no commercial value in the shelf area.
- Quality of the same coal in the two regions often varies because of different depositional environments.
- Arkoma basin coals are much more deformed than they are in the shelf area.

CBM Activity in Oklahoma, 2001. Nearly 1,300 wells in the Oklahoma coalfield have been drilled exclusively for coalbed methane since 1988, in part for the Section 29 tax credit. 742 completions were on the northeast Oklahoma shelf and 552 completions have occurred in the Arkoma Basin. Operators presently target ten coal objectives on the shelf and five in the basin. The primary objectives, all Desmoinesian (Middle Pennsylvanian) in age, are the Mulky (315 wells) and Rowe (299 wells) coals on the shelf and the Hartshorne coals (519 wells) in the basin.

In general, coals in the Arkoma Basin are deeper and thicker than those on the NE Oklahoma shelf and have higher initial gas rates and lower initial produced water rates. Since 1998 the more successful horizontal CBM wells in the Arkoma Basin have followed improvements in completion techniques. The present emphasis in this area is on finding permeable sweet spots and matching coal characteristics to optimum completion techniques.

Arkoma Basin CBM Potential and Practices. Critical factors to Arkoma Basin CBM producibility include:

- Deposition and Distribution of coal- Coals split toward the southern part of the basin where they are generally thicker.
- Structure & Stress-A number of faults, synclines and anticlines within the basin control varying stress fields. Cleat directions will vary according to local stress field variances.
- Coal Rank and Trend-The western part of the region comprise high-volatile bituminous coals that grade eastward to medium-volatile bituminous and low-volatile bituminous coals adjacent to the Arkansas border.
- Permeability-this can be calculated by three methods: pump injection-falloff tests, tank injection with BHP gauge or fluid level meter, and regression of frac-falloff data. The key to CBM production is largely protecting the permeability developed in the cleats from such detrimental substances as acids, xylene-toluene, gasoline-benzene-diesel, condensate-strong solvents, bleach, gels, foams, strong surfactants-formers, and 100-mesh sand. Fines plugging must be minimized. It can be caused by well stimulation, can be released by chemical action, or can migrate into a well's zone of influence by poor production practices elsewhere.
- Gas Content-Recoverable gas can be determined using the equation:
  $Gc = 32.0375 (6.252*\ln(Depth)-27.882)$, then apply a recovery factor of approximately 65% for permeability of 25 md. Finally, experience in the area indicates that gas recovery can be expected to be 30-100% above calculated levels.

Midcontinent Drilling and Completion Considerations for CBM

Cased-hole completions with larger hole sizes are preferred due to improved zonal isolation, fewer production problems, reduced damage, and added flexibility in completions. Generation of coal fines is a major cause of stimulation failures, high decline rates and resulting low gas productivity. Using proper stimulation techniques and production practices can minimize the generation of coal fines. By eliminating fines, many production problems can be significantly reduced. Fracturing gels and most other conventional stimulation additives have generally proven to be detrimental to CBM production.

In eastern Kansas, western Arkansas and all of eastern Oklahoma, fresh water with a biocide and a minimal amount of friction reducer has proven to be the least damaging fracturing fluid. Although hydrochloric acid can be damaging to most coals, small volumes of acid can provide benefits. Fracturing procedures are continually being modified and improved as more experience is gained in the Midcontinent area. Current treatment trends are toward lower pumping rates, less 100 mesh and 20/40 sand, and more 12/20 sand. Experience has shown that proper production practices are at least as important as drilling and completion practices.

Economics of CBM Wells in Oklahoma

Economics of CBM wells in Oklahoma can be estimated based on recent data from the Hartshorne coal. Well costs based on four wells drilled to an average 856 ft depth in January through October, 2000 were $30,030. This included $25,240 intangible drilling and completions costs and an additional $7,790 in equipment costs. Costs in the range of $30-40,000 are typical. Additional costs that might be encountered include $10,000 for a pumping well and $30,000 for a frac job. Yearly lease operating expenses are estimated between $650-$1,005 depending on whether the well is flowing or pumping.

Major pipeline markets at this time include ONEOK (300-400 psi line pressure), ENOGEX (50-80 psi), and RELIANT (50-150 psi). Deals generally require the producer to lay lines to the market lines and compress. Deal terms vary from 10-36 cents/mcf and 3-8% fuel. Lower pressure pipeline markets include Enerfin, Duke, and Ozark. Deal terms with lower pressure markets are generally based on a percentage of the proceeds. Low-side deals are in the range of 65-70%, while high-side deals are between 80-85%, depending on proximity to their lines, volume and quality of the gas.

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