Chikeluba Akah

Marietta College

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Best Practices Analysis for Coal bed Methane Production in Appalachian Basin

The Issue

The technology of coal bed methane has evolved tremendously over the past two decades, but in spite of what has been learned about exploration, reservoir characterization and reservoir management in the context of this resource, considerable potential remains essentially untested in the Appalachian Basin; Coal bed methane has moved well past the novelty stage to a legitimate and established source of energy, and in the Appalachian Basin its promising potential exists and remains to be developed in proximity to major markets.

Introduction

The Appalachian basin is the world's second largest coal bed-methane (CBM) producing basin. It has nearly 4000 wells with annual production around 147.8 billion cubic feet (Bcf). Cumulative CBM production is close to 0.9 trillion cubic feet (Tcf). The Black Warrior Basin of Alabama in the southern Appalachian basin accounts for about 75% of this annual production and about 75% of the wells, and the remainder comes from the central and northern Appalachian basin. The Southwest Virginia coal field accounts for about 95% of the production from the central and northern parts of the Appalachian basin.

Production data and trends imply that several of the Appalachian basin states are in their infancy with respect to CBM development. Total in-place CBM resources in the central and northern Appalachian basin have been variously estimated at 66 to 76 trillion cubic feet (Tcf), of which an estimated 14.55 Tcf (~ 20%) is technically recoverable according to a 1995 U.S Geological Survey assessment.

For comparison in the Black Warrior basin of the 20 Tcf in-place CBM resources, 2.30 Tcf (~ 12%) is technically recoverable. Because close to 0.9 Tcf of CBM has already been produced from the Black Warrior basin and the proved reserves are about 0.8 Tcf for 1996 [Energy Information Administration (EIA), 1997] these data imply that the central and northern Appalachian basin will become increasingly important in the Appalachian basin CBM picture as CBM resources are depleted in the southern Appalachian basin (Black Warrior Basin and Cahaba Coal Field).

CBM development in the Appalachian states could decrease the eastern U.S.A.'s dependence on coal for electricity. CBM is expected to provide over the next few decades a virtually untapped source of unconventional fossil fuel, in the Appalachian states, where the CBM resources are large and the demand for cleaner fossil-fuel energy is high.

Suggested Practices

In any coal bed methane prospect, the key parameters are the thickness of the coal, the gas content and permeability of the coal. Additionally, a fairly large number of pilot wells are needed before you the productivity of the reservoir in terms of recoverable reserves for the average well and for the field as a whole can be predicted.

Bearing these parameters in mind, coal bed methane field development should be executed according to a well-designed plan in order to maximize total gas production, field life, and profitability. First, the geology of the reservoir (and the interbedded formations) should be studied in considerable detail so that the lateral extent, coal thickness, and degree of fracturing are known. With this information, the approximate volume of the reservoir can be calculated.

The gas content and temperature in the reservoir should be determined as the field is developed through an extensive coring and core analysis program, including pressure cores. Consistent and accurate well testing must be conducted, and the results stored in a database. This database can be used to map the reservoir, with the maps updated as each new well is drilled. Carbonaceous shales interbedded with the coals should also be cored and analyzed for their gas content.

Cavitation tests are then run to determine how production rates can be enhanced by hydraulic fracturing. The orientation of stress fields in the reservoir should be determined to aid in predicting fracture directions, and if faulting is suspected, down hole imaging tools can be run to find their location, orientation, and permeability characteristics.

Some coal bed methane fields are divided into separate reservoir compartments by faults, coal bed pinch-outs, or permeability variations. Detailed structural and lithofacies mapping are needed to get a better understanding of these reservoirs. Different reservoir compartments exhibit different reservoir pressures, water levels, and permeabilities.

Regional stratigraphic studies are used for understanding sedimentary sequences, sequence boundaries and unconformities in the section, important information for predicting coal cutouts and oxidized zones. Thermal modeling of the field is needed for understanding the burial history, coal maturity, gas content, and formation pressure.

Mud logs and wireline logs should be run in all the pilot holes as well as the production wells. The hydrogeology of these fields is also important, because the water strongly influences reservoir pressure, the gas saturation, and the ability to de-water the coals. Fluctuations in groundwater levels and the piezometric surface can also indicate the connectivity of coal seams.

Solutions

Current estimates of CBM reserves in the U.S. are in the neighborhood of 740 Tcf, but these investigations reveal that the reserve growth potential for CBM is considerable because of inaccurate estimates of gas-in-place. Cumulative production in many reservoirs has already exceeded the initial gas-in-place estimates.

Four pieces of information are necessary to estimate gas-in-place:

(1) Well drainage area,

(2) Reservoir rock thickness,

(3) Average reservoir rock density,

(4) In-situ gas content.

Other technical solutions address completion and well spacing optimization. Use of limited entry completions in coal seams has been found to be more effective than the traditional "staged ball and baffle" technique for treating thin, multiple coal seams. In applying this technique, the bottom hole pressure is raised above the fracture initiation pressure for each zone in succession. A structured reservoir management approach with judicious gathering of geological and engineering data is recommended to maximize the net present value of a CBM project through selection of optimum well spacing and completion techniques.

Conclusion

Less than two decades ago, CBM was viewed as a marginally interesting endeavor from an economic perspective. Production of CBM has proven to be a more positive economic venture as more was learned about the behavior of existing reservoirs. As is not often the case with conventional reservoirs, CBM reservoirs have almost routinely produced well above expectations. Better techniques for estimation of reserves coupled with increased experience in designing optimum completions and reservoir management strategies make the future of CBM promising.