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Modeling of Devonian Shale Gas-Reservoir Performance

A recent trend in developing new natural gas reserves has been the intensified efforts to exploit Devonian shale gas reservoirs in the Appalachian basin. Thus, the Department of Energy is now engaged in the support of the Eastern Gas Shale Project, which is aimed at accelerating the development of this resource.

To make an engineering and economic evaluation of Devonian shale gas-reservoir development, it is necessary to be able to predict future reservoir performance. A review of the Devonian shale modeling experience to date reveals that such a demonstration of predictive capability has not been achieved.

Most Devonian shale reservoirs are expected to consist of very tight porous shale formations which may be rather highly fractured in certain tectonic terranes. Under these conditions, the fractures may provide most of the permeability to gas flow, but contribute very little to the overall storage capacity. By comparison, the matrix of the shale may provide most of the storage capacity, but contribute very little to flow because of the low permeability. The gas-release and sorption-isotherm data from Devonian shale samples indicate that gas is present in the matrix of the shale both as a free-gas phase and as a sorbed-gas phase.

Gas transport in Devonian shale reservoirs, according to the assumption adopted here, occurs only in the permeable fractured medium, into which matrix blocks of contracting physical properties deliver their gas contents, that is, the matrix acts as a uniformly distributed gas source in a fractured medium. Furthermore, desorption from pore walls is treated in the modeling as a uniformly distributed source within the matrix blocks.

A mathematical model to simulate well and field-wide performance of Devonian shale gas reservoirs has practical applications for gas reservoir studies such as well-test and history-matching problems.

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Submarine Slumping in Reef-Flank Deposits (Middle Silurian) of Indiana

Flank beds adjacent to the Rich Valley bioherm, Wabash County, Indiana, display unusual structures suggesting catastrophic slumping during and shortly after deposition. Lithotopes representative of reef core, reef flank, and interreef environments are mixed randomly within the deformed sedimentary rocks. Deformation appears to have involved processes of both brittle and semiplastic materials.

Displaced boulders, 1 to 2 m in diameter, are imbedded in laminated calcilutite. Uniformly inclined stratification typical of reef flanks is here locally reversed in dip, faulted, and contorted into minor folds within the sequence. A dike of fine-grained limestone, about 0.5 m thick, perpendicularly transects an inclined sequence of flank beds. Masses of mature quartz sandstone also are present, apparently as isolated blocks, displaced from some formerly higher location.

Observed features tentatively are attributed to multiple failures resulting from unstable oversteepening of normal flank sediments, storm ripping of semilithified core materials, and plastic flowage of poorly lithified flank-margin materials. Individual events could have been triggered by storms, earth shocks, or other catastrophic events.

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Bishop–Bradshaw Creek Fault

The Bishop–Bradshaw Creek fault extends 22 mi (35.2 km) across McDowell County, West Virginia. Initially identified on side-looking airborne radar (SLAR) in 1974, the fault trace has since been confirmed as a distinct linear feature trending N60°W on Landsat, black and white and color infrared photography, and topographic maps. Located astride the northwestern end of the fault trace is a semi-circular "donut," 5 mi (8 km) in diameter and truncated by a N25°E-trending linear fault. Displacement along the Bishop-Bradshaw Creek fault has been reported as .75 mi (1.2 km) right-lateral strike slip.

Considerable geologic information exists that contradicts the reported strike-slip displacement along this linear feature. Structural contours of the top of the Berea and the base of the Big Lime show a 150 ft/mi (28 m/km) westward dip, but neither map indicates any displacement. Further, a Berea isopach map does not show any indication of movement. After fracturing parallel and across the fault trace, a Berea gas field extending across the fault at Berwind shows elongations of contours of both natural open flow and flow without apparent displacement. Structural contour maps of the top of the Pocahontas 3, Sewell, and Douglas coal seams also show no measurable displacement. The same conclusion can be reached from examinations of geologic maps, the state aeromagnetic map, and elevations of salt water.

However, the use of the word "fault" has been retained. Coal mining at the southeastern end is presently taking place on both sides of the fault. At this location, the Pocahontas 3 seam is displaced 40 ft (12 m) vertically with the southern side downthrown. That is the only known place where fault displacement can be observed. The fault can be observed at Canebrake as a razor-sharp vertical fracture with slickensides oriented horizontally; however, displacement cannot be detected.

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Meteoritic Impact—Reservoir-Forming Process

Known impact sites caused by meteoritic bodies falling to earth's surface, together with frequency distributions for observed rates of material infall and those inferred from lunar, martian, and mercurian data for the Phanerozoic, indicate that meteoritic-impact features have been sufficiently common and large to justify their recognition by petroleum geologists. The rock-shattering and dome-forming process of impact cratering can and does result in unconventional petroleum reservoirs.

Two oil fields in the Williston basin and one potential gas field in Algeria are interpreted to be reservoirs in fractured strata beneath buried impact structures.

In addition to fractured domal structures, impact events in water-bearing, poorly consolidated materials can produce large bodies comparable to sand-flow volcanoes and clastic dikes. Such permeable features, after burial and lithification, may or may not be found in sedimentary environments, such as starved basins, deltas, or lagoonal areas, in which petroleum reservoirs normally occur.

Impact features with petroleum accumulations are most likely to be formed in relatively young, shallow-marine depositional environments (water depths less than 200 m) merely because these structures are most favorably located relative to the time and place of petroleum origin and its later migration. Terrestrial impact sites in well-lithified ancient strata, even crystalline rocks, however, may become reservoirs if a subsequent transgression results in deposition of a basal marine sequence of petroleum-generating sediments.

The best means of recognizing subsurface-impact features are detailed stratigraphic analyses, local structural-anomaly recognition, and high-recognition seismic data. Potential reservoirs of impact origin will be randomly distributed geographically and temporally throughout stratigraphic sequences; prediction of their location will therefore be difficult. Lack of trends, preferential location, or predictable distribution of impact sites precludes systematic search strategies during petroleum exploration. Commonly, magnetic and gravimetric signatures of buried impact features tend to be so subtle as to be ignored by geologists and geophysicists, although known large surface impact sites typically display gravity deficiencies. Only those isolated anomalies which show an obvious circularity can be readily distinguished as possible subsurface impact features. Constant alertness for subtle clues to the presence of subsurface impact structures during routine stratigraphic, structural, and seismic data analyses will be most effective in achieving their discovery.

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Oil- and Gas-Producing Configurations in Trenton Limestone, Northwestern Ohio

Five types of petroleum-producing configurations are present in the Middle Ordovician Trenton Limestone around the Lima-Indiana field in northwestern Ohio. The first, an anticlinal trap, is present along the Findlay arch. Closure is provided on top of the Trenton by regional carbonate bank buildup, folded with and capped by the Utica Shale. The second, a faulted anticline, is present along the Bowling Green fault in Wood, Hancock, and Lucas Counties. A high-angle reverse fault along the crest of the Findlay arch juxtaposes dolomitized Trenton rock with the overlying Utica Shale. This configuration has accounted for significant oil and gas production. The third trap type consists of an updip facies change from Trenton Limestone to Utica Shale, with draping of the thickened shale over the Trenton Limestone. The fourth type, in the Michigan basin, is the fracture systems and dolomitization in the Albion-Scipio trend. The fifth, and less well documented, is a porosity trap in dolomitized upper parts of the Trenton. Dolomitization may function in two ways, both as a prerequisite to formation of sufficiently porous reservoir rock with other trapping mechanisms. Other Trenton fields are not accounted for by these five configurations.

Stratigraphic and structural cross sections from the top of the Trenton to the Knox unconformity, as well as structural and isopach maps of the area, show a major carbonate buildup of the Trenton in a northeast-southwest trending arc in northwestern Ohio. A broad carbonate platform with wedge-top dolomitization in an island environment is postulated as an alternative to a regional erosional unconformity between the Trenton Limestone and Utica Shale.

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Interaction of Proppants with Crack Formation and Propagation in Hydraulic Fracturing

In many wells, productivity can be increased by repeated hydraulic fracturing. Repeated flow cycling has also been shown to increase productivity, sometimes significantly above what can be obtained with a single cycle. The increased productivity from repeated flow cycling suggests that a predictive capability for treating specific wells could be developed if the controlling parameters and their interactions in the flow/cycle treatment process were better understood. Although the primary role of the proppant in hydraulic fracturing is to maintain fracture opening, the proppants may have other effects such as altering the pressure distribution along the fracture (e.g., by blocking the tip) and hence significantly affecting the fracture mechanics.

Although proppant transport by fluids has been studied intensively, the coupled interaction problem of fracture propagation, fluid flow, and proppant transport has not been previously investigated. In SRI International's program to analyze the coupled interactions of proppants and fracture mechanics, proppant distributions are being determined for the coupled problem of fluid-proppant-fracture interaction, and the effects of the proppant distributions on fracture production are being evaluated for the flow/cycle treatment.

Scaled experiments in several media (PMMA and rock simulant) will check the correlation of fluid penetration and fracture propagation rate with a calculational model for the fluid-fracture interactions. The scaled experiments will also constrain the relation between the proppant distributions and the fluid-fracture interactions. The computational model will be verified by comparing calculations of the proppant distributions in the scaled experiments, for which viscous or gravitational effects are dominant, with the scaled experiments.

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