Origin of Reservoir Fractures in Little Knife Field, North Dakota

Thin, vertical, planar fractures in the Mission Canyon Formation of the Little Knife field, in west-central North Dakota, appear to be naturally occurring extension fractures. The fractures are restricted to carbonate units, but are not lithology dependent within the carbonate rocks. Fracture density averages 1 ft (0.3 m) of fracture per 2.3 ft (0.7 m) of core. The predominant east-west trend of the fractures, measured in oriented core from six wells, parallels the estimated maximum horizontal compressive stress in the Williston basin.



Formation and mineralization of these fractures were the most recent diagenetic events in the Little Knife carbonates. Heatingand cooling-stage observations of fluid inclusions in crystals bridging the fractures yield homogenization temperature ranges of 90 to 106°C and 102 to 126°C for hydrocarbon and aqueous inclusions, respectively. Correlation of these observations with the PVT properties of Little Knife reservoir fluids leads to the following conclusions: (1) the fractures formed after the strata were buried to at least their present depth of 9,800 ft (3,000 m), which indicates their age is post-Mesozoic; (2) the pore-fluid pressure gradient was normal hydrostatic immediately after, if not during, fracture system development; (3) formation-water salinity has remained fairly constant since fracture initiation; (4) migration of hydrocarbons into the reservoir probably preceded or accompanied fracture genesis; and (5) methane concentration may have decreased since fracture initiation.

The geologic mechanism specifically responsible for creating the fractures remains unknown. The potential for using fluid inclusions to document changing methane concentration within a reservoir could be significant to studies of hydrocarbon migration.

NASCIMENTO, O. S., E. BORNEMANN, L. D. C. JOBIM,* M. D. CARVALHO, A. M. PIMENTEL, E. J. BONET, E. B. RODRIGUES, J. R. L. SANDOVAL, V. LASSANDRO, T. C. RODRIGUES, and C. R. HOCOTT, PETROBRAS, Rio de Janeiro, Brazil

Aracas Field—Reservoir Heterogeneities and Secondary Recovery Performance

In the Aracas field (Reconcavo basin, Brazil), the Sergi Formation held about 30% of the $60 \times 10^6 \text{m}^3$ of the field's original oil in place. Its contribution for the field cumulative production is, however, less than 11%.

The Sergi Formation (Upper Jurassic) is a braided-stream sequence of conglomeratic and coarse to very fine-grained sandstones and minor siltstone and shale layers (<5%) with an average thickness of 215 m. The pool has an area of 7.5 km² and the reservoir average depth is 2,750 m. Primary recovery started in 1967 and 37 wells were drilled for exploitation of the pool (29 for production and 8 for peripheral water injection). The water injection was initiated in 1973 and neither improved the production nor repressured the reservoir to the expected levels. Today an average production of 23 $m^3/day/well$ is obtained from 12 wells, far below the initial rates of 100 $m^3/day/well$. To date, only 8% of the estimated original oil in place has been recovered from this pool.

The Sergi Formation was cored in two new wells and the measured petrophysical parameters (such as porosity, permeability and water saturation) served to establish a model for the log analysis of the remaining wells. A good correlation of log-derived permeabilities and core permeabilities was obtained by the method known as multidimensional histogram. Standard computerized log analysis in conjunction with estimation of permeability made possible a description of each of the 12 reservoir zones in the form of contour maps depicting mean porosity, water saturation, and permeability and development of a suite of structural and isopach maps.

Pressure data from new wells and geologic analysis derived from log and core interpretation strongly suggest that the present peripheral injection-well pattern is insufficient and that an infill drilling program could contribute to a more effective pressure maintenance.

NASCIMENTO, O.S., S. X. MENEZES, A BANDEIRA, JR., A. M. PIMENTEL, C. M. P. OLIVEIRA, C. A. M. SILVA, E. M. RAMOS, and H. P. GOMES, PETROBRAS, Rio de Janeiro, Brazil

Camorim Field, Brazil—Facies and Oil Qualities Controlling Reservoir Behavior and Well Performances

Camorim field is located offshore Sergipe State, Brazil. The producing section includes 150 m of Cretaceous conglomerates and coarse to very fine-grained sandstones, interbedded with siltstones and shales. Within this interval, six pools are recognized based on log correlation and facies analysis. The field has an area of 25 km² and the reservoir average depth is 1,900 m.

Twenty-eight development wells were drilled to exploit the pools and the productivity ranges from 100 to 1 $m^3/day/well$. Reservoir geology and performance were analyzed by a multidisciplinary group composed of development geologists, sedimentologists, production engineers, and log analysts.

The reservoirs were fully cored in five wells and the correlation between rock and log responses allowed facies mapping throughout the field. The depositional model is interpreted as an alluvial-fan complex prograding toward a lacustrine environment. Log analysis and correlation between lithofacies and permeability allow the estimation of reservoir quality at any point of the pools.

Together with reservoir quality, the oil properties are recognized as controlling the productivity of the wells. At reservoir conditions, oil viscosity ranges from 1 to 5 cp (centipoises). Data at tank conditions show that density (18 to 37° API) and viscosity (10 to 200 cp) increase eastward throughout the field and from the upper to the lower part of the blocks.

To support reservoir simulation, permeability is calculated for each well as a weighted geometric mean based on the thickness of each of the three reservoir facies: conglomerates (200 md), coarse to medium-grained sandstones (23 md) and fine to very finegrained sandstones (1 md). This model explains the initial and long-term well performances and the pressure behavior of the reservoirs.

NEWTON, ELISABETH G., U.S. Geol. Survey, Reston, VA

Development of Publicly Owned Oil Shale Lands of United