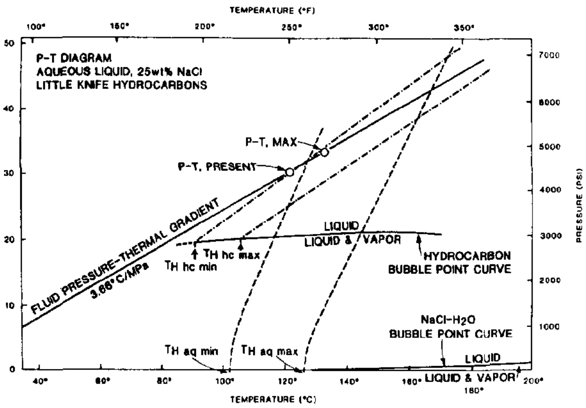
Origin of Reservoir Fractures in Little Knife Field, North Dakota

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. Heating- and 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.

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Aracas Field—Reservoir Heterogeneities and Secondary Recovery Performance

In the Aracas field (Reconcavo basin, Brazil), the Sergi Formation held about 30% of the 60 × $10^6 m^3$ 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 km^2 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.

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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 km^2 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 fine-grained sandstones (1 md). This model explains the initial and long-term well performances and the pressure behavior of the reservoirs.

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Development of Publicly Owned Oil Shale Lands of United

States—Prospect for 1980s

The potential for commercial development of shale oil in the United States exists principally within the vast acreages of publicly owned oil shale lands in Colorado, Utah, and Wyoming. The resource that formed as varves in four lake beds during the Tertiary occur today as oil shale deposits in the Piceance basin, Colorado, the Uinta basin, Utah, and the Green River–Washakie basin, Wyoming. It is estimated to be a resource that could yield approximately 1.2 trillion bbl of shale oil from the Piceance basin alone. The authority to lease these public lands for development is defined by the Mineral Leasing Act (MLA) of 1920.

In addition to technologic breakthroughs to support more effective and less environmentally stressful development, the future development of commercial quantities of oil from this publicly owned resource is dependent on (1) administrative decisions to lease oil shale lands for development and (2) amendment of the MLA that would modify existing development practices.

Appropriate legislative and policy decisions can provide strong incentives for the commercial development of publicly owned oil shale deposits in the 1980s.

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Depositional Environments and Petroleum Potential of Miocene Lacustrine Deposit, West-Central Nevada

The lacustrine Esmeralda Formation (Miocene) of Nevada was studied with the purpose of determining the depositional environment of petroliferous laminated rocks that are interbedded with volcaniclastic sands and localized carbonate units.

Fine-grained petroliferous shales make up a 40-m section at the inferred depositional center of the basin and interfinger laterally with volcaniclastic mudstones, sandstones, and breccias. The areal extent and geometric shape of this unit were determined by detailed geologic mapping and measurement of stratigraphic sections. This unit and other units of the Esmeralda Formation have undergone extensive folding and faulting which produced possible reservoir structures.

The depositional environment is interpreted as beginning as a freshwater lake that evolved through time into a saline lake environment. This basin received volcaniclastic sediments from surrounding volcanic highs. Influx of these sediments slowed during periods of carbonate deposition. Unusual stromatolites and large tufa mounds with pseudomorphs of evaporite minerals are associated with dolostone and limestone layers.

This study provides a depositional and structural context for evaluating the petroleum potential of the Esmeralda Formation in Stewart Valley, as well as an aid in understanding similar Tertiary deposits in the Basin and Range province of Nevada.

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Permian Evaporites, Western Colorado Plateau, Southwestern Utah and Northwestern Arizona

Permian rocks of the western Colorado Plateau contain five evaporite units that are separated by one marine sandstone and four limestones in a cyclic relationship. These evaporites were deposited during regressions in the Permian seas that allowed sabkhas to develop between the shallow-marine shelf of the Cordilleran geocline and the nonmarine sediments that were being deposited along the transcontinental arch during Early Permian time. The lowest Permian unit containing gypsum is the Pakoon Formation which represents the first regressive cycle in the Lower Permian. Above the Pakoon Formation is the Quantoweap Sandstone deposited in a shallow-marine environment. Overlying the Quantoweap Sandstone is gypsum and gypsiferous siltstone of the Seligman Member of the Toroweap Formation, representing the second regression. During this regression a sabkha developed along what is now the western margin of the Colorado Plateau. A marine transgression followed depositing the limestone of the Brady Canyon Member in shallow-marine conditions. The third and largest marine regression produced the gypsum of the Woods Ranch Member of the Toroweap Formation while an eolian environment was depositing the Coconino Sandstone on the east. The last major transgression partly dissolved the gypsum of the Woods Ranch Member, locally generating the erosional unconformity between the Toroweap and Kaibab Formations. Along the present margin of the Colorado Plateau the regression of the Permian sea, which deposited the limestone of the Fossil Mountain Member, marked the development of the final sabkha represented by the gypsum of the Harrisburg Member in the area north of Grand Canyon. The deposition of gypsum in the Harrisburg Member was interrupted by a minor transgression that destroyed some of the underlying gypsum by dissolution and deposited a marine limestone. Alternating gypsum and limestone units are present between the limestone deposited by the minor marine transgressions and the Permo-Triassic boundary, suggesting that fluctuations between sabkha and tidal flat environments occurred before the final regression of the Permian sea.

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Localization of Tabular, Sediment-Hosted Uranium-Vanadium Deposits of Henry Structural Basin, Utah

Tabular uranium-vanadium mineralization characteristic of the Colorado Plateau occurs in fluvial sandstones of the Salt Wash Member of the Morrison Formation (Jurassic) within the Henry structural basin, south-central Utah. The ore consists of a mineralized interval (MI) of two closely spaced uranium and vanadium-rich zones separated by one barren of uranium but enriched in vanadium. No known stratigraphic feature controls the position of this MI which occurs at successively higher stratigraphic levels toward the interior of the basin. The dominant clay mineral throughout the MI is an unusual vanadium-rich di,trioctahedral chlorite. Laterally continuous with and below the MI, mixed-layer chlorite/smectite and illite/smectite (greater than 75% expandable layers) predominate. Above the MI, kaolinite in sandstone beds and illite/smectite plus kaolinite in bentonitic beds are the dominant authigenic clay minerals. The MI and its unmineralized lateral extensions are bounded, both above and below, by zones rich in authigenic dolomite cement. Petrographic evidence places the dolomite as pre-ore to contemporaneous with ore, and the chlorite contemporaneous with ore. Geochemical and mineralogical data, $\delta^{18}O$ to δD values of clay minerals and $\delta^{18}O$ to $\delta^{13}C$ values of dolomite indicate the presence of an interface between two isotopically and chemically distinct fluids. The lower fluid was typical of closed-basin evaporated brines with a high Mg/Ca ratio and high SO_4^{2-} content. The upper fluid was meteoric water. Elemental zoning patterns and isotopic data suggest that the upper (meteoric) fluid carried the uranium and vanadium to the solution interface, but that ore grade mineralization occurred only where the brine-meteoric water interface intersected horizons with anomalous concentrations of organic matter (dominantly detrital plant debris).