Microscopic Distribution of Uranium in Oakville Sandstone, South Texas

When uranium ore is mined and processed in the conventional crushing plant there is little urgency to know what mineral contains the uranium and how that mineral is distributed within the ore. However, solution mining techniques depend for their success on bringing the dissolving solutions into contact with the uranium-bearing mineral and dissolving it. With that requirement in mind, a study was undertaken to help understand the character and location of the uranium-bearing mineral in the Oakville Sandstone of south Texas where solution mining is being carried out.

Thin-section and electron-microprobe analyses were conducted on a sample of high concentration ore to confirm that uranium was located in the space between framework sand grains. Moreover, uranium was not uniformly distributed throughout the silt and clay intergranular matrix material. The disaggregated and fractionated sandstone showed the highest concentration of uranium to be in the silt-size fraction. Further separation of the ore was carried out by heavy liquids and magnetic fractionations. The uranium-bearing mineral was concentrated along with dense and magnetic minerals. Openwork intergrowths of pyrite crystals made up most of this fraction. In spite of having concentrated uranium in excess of 43,000 ppm U_3O_8, it was still not possible to identify any uranium-bearing mineral by X-ray diffraction. This suggests that uranium may be held in the sandstone as an amorphous oxide.

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Integration of Microscopic Organic Analysis and Geochemical Measurements in Evaluation of Source Rocks

A major problem facing all scientists working in the field of source rock evaluation is choice of an analytic mix which yields necessary and sufficient data that are dependable, economical, and not unnecessarily redundant. Chevron handles this problem by combining microscopic observations with measurements of the total organic carbon (TOC) and the hydrogen-carbon (H/C) ratio of the organic matter (OM). This combination of analyses yields two independent estimates of organic quantity, quality (type), and maturation, the three organic parameters which are necessary for a proper source-rock evaluation.

Despite the strong subjective element, we consider microscopic organic analysis (MOA) indispensable to an accurate evaluation of organic quality and maturation. In addition, MOA is useful in detecting analytic errors in geochemical measurements, uphole cave, contamination from organic well additives, and the presence of reworked OM. MOA is, however, quite subjective and requires continuous calibration against geochemical numbers to minimize errors in judgment.

Geochemical analyses of kerogens are objective, precise, accurate, lend themselves readily to comparison between different laboratories, and are appealing both to geologists using source-rock data and to management. However, most of them are bulk measurements and cannot resolve the kerogen into its components as can microscopic analysis. In addition, many geochemical measurements do not discriminate between effects due to maturation and effects due to different organic types.

Used together, MOA and geochemistry strongly complement each other and minimize the possibilities of incorrect interpretation of the generative potential and generative history of the OM.

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Predictions of Oil or Gas Potential by Near-Surface Geochemistry

No abstract available.

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Interactive Modeling and Interpretation of Two-Dimensional Gravity and Magnetics Data

The number of possible interpretations of a gravity or magnetic profile is reduced by the presence of other geophysical or geologic data. Experience, common sense, and a newly developed interactive modeling program make it possible to examine and choose among those that remain. The interactive modeling program is based on Talwani's algorithm and includes features which make it possible to change the geometry and properties of the causative bodies and quickly observe the results.

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Bathymetric Distribution of Trace Fossils in Upper Pennsylvanian and Lower Permian, Western Oquirrh Basin, Utah

Detailed study of the Oquirrh Group in Tooele and Box Elder Counties, Utah, has revealed a history of basin development during the Late Pennsylvanian and Early Permian. Trace fossils are of paramount significance in recognizing depositional environments in this sequence (a) because of uniform composition and uniform grain size and (b) because most megafossils were redeposited several miles or more from their initial growth sites.

Middle Pennsylvanian littoral and inner-shelf limestones and quartz arenites form the base of the sequence studied. During Late Pennsylvanian time, the western Oquirrh basin area was primarily an outer-shelf environment. Trace fossils in shelf units are diverse, recording a variety of behavior patterns, and include *Zoophycos*, *Teichichnus*, and *Helminthoida* in the Hogup/Terrace Mountains and *Zoophycos*, *Phycodes*, *Helminthoida*, and *Spirophycus*(?) in the Grassy Mountains.

Rapid subsidence in latest Pennsylvanian–earliest Permian time is marked by conglomerates and arenites that carried shallow-water fossils into the bathyal environments. Trace preservation is poor, but is typified by low diversity and high abundance. Uppermost Pennsylvanian turbidite deposits on Bovine Mountain contain *Helminthoida* and *Chondrites;* basal Wolfcampian rocks of the Grassy Mountains bear *Helminthoida, Protopaleodictyon,* and *Lophoctenium.*

Upper Wolfcampian fetid, soft-sediment-folded, arenaceous siltstones locally yield indigenous fauna that suggests an off-shelf origin. In the Hogup and Grassy Mountains, *Helminthoida* is preserved, but in general the trace-fossil record is scanty in this interval.

In Leonardian time, the Oquirrh basin filled to shelf depth, and a mixture of vertical and horizontal bioturbation again prevailed.

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Regional Tectonics and Petroleum Geology of Tunisia—Introduction and Overview

Tunisia can be divided into five tectonic provinces: (1) La Galite–Numidian zone, (2) zone of diapirs–Zaghouan fault, (3) Kasserine Island, (4) Gabes basin–Cretaceous platform–Offshore, and (5) Djefarra-Paleozoic complex. Thin-skin tectonics dominate the La Galite–Numidian zone. Perhaps as much as 20 km of shortening indicates that the best petroleum prospects may lie beneath the thrusts. Oil and gas seeps in Algeria suggest that lower Numidian clastics induce favorable hydrocarbon generating environments. In the Kasserine Island area, as much as 5 km of late Miocene shortening complicates earlier extensional structures. Basement involvement in early extension and its possible influence on later compressive events could generate significant hydrocarbon accumulations. The section beneath the decollement also may have significant petroleum potential.

The zone of diapirs–Zaghouan fault, intermediate between the allochthonous Numidian–La Galite complex and the Kasserine Island may have potential beneath a possible decollement. Of particular interest are favorable autochthonous Jurassic facies. These prospects must have been generated during Early Cretaceous time with the subsequent trap improved during the Miocene orogeny. The Gabes basin–Cretaceous platform–Offshore province has well-developed extensional structures. Hydrocarbon source and maturation appear to be sufficient, as seen in the Isis and Ashtart fields. Reservoir quality is the major problem. The Paleozoic tectonic province has favorable extensional structures in the Djefarra complex, but source problems and tilting may have a negative effect. Paleozoic truncation plays south of the Djefarra are possible. However, large structures and thick reservoirs have not been found. The petroleum potential of Tunisia must be rated high, but only sophisticated and imaginative exploration programs will realize this potential.

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Tunisia—Plate Tectonics and Hydrocarbon Accumulation of Contiguous Areas

The position of Tunisia on the African plate is of importance to explorationists. Present work suggests that the African plate margin roughly coincides with the present northern African-Sicilian coastline. The eastern margin of this Algerian-Tunisian-Sicilian salient of the African plate is marked by the east coast of Sicily and the Malta Scarp. This sharply defined feature continues into the Gulf of Sirte where it joins with the post-Jurassic extensional Sirte basin. This represents a zone where eastern North Africa (Egypt and Cyrenaica) moved northeastward and western North Africa (Morocco, Algeria, Tunisia, and western Tripolitania) have a more northwesterly vector of movement. There may be a shear component in addition to the extensional faulting on the west side of the Sirte basin, which continues into the Malta Scarp.

Active rifting in Tunisia extends from Late Triassic through early Miocene with no appreciable compression. Miocene to Holocene compression is associated with collision along the northern continental margin. The Pantelleria trough and horst zone in central Tunisia developed in response to these stresses, as did the final tectonic framework of the zone of diapirs–Zaghouan fault and the Kasserine Island. These features buffered the Gabes basin and Cretaceous platform on the south from this compression.

This model defines as prospective all of northern Tunisia (except the northern Numidian zone), Sicily and the offshore Malta Bank, Gabes basin, and the Cretaceous shelf area.

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Oil Generation and Migration in Lusitanian Basin, Portugal

The Lusitanian basin covers coastal Portugal and the adjacent offshore and received sediments from Triassic to Tertiary time. Presence of source beds, reservoirs, diapirs, and surface indications has attracted exploration since the late 1940s. Three principal potential source-rock zones have been identified from surface and subsurface work: Permian coals and Lower and Upper Jurassic kerogenous beds. The Permian coals occur only in localized basins and are of limited significance only as a potential gas source. The Lower and Upper Jurassic potential oil source rocks are confined to two subbasins in the center of the Lusitanian basin. Net source-rock thickness decreases from the subbasin centers toward the rims. Source maturity, established by various and independent techniques, appears to be rather low, suggesting a low resulting generation, expulsion, and migration efficiency. Surface indications and crude oil derived from tests support the hypothesis of a not very mature system. Although the subsurface data confirm the early interpretation that the Lusitanian basin contains the necessary basic ingredients for a successful exploration play (i.e., structures, reservoirs, source rocks), the absence of sufficient source maturation