are favorable sites for generation and accumulation of organic biomass.

The prolonged exposure to the freshwater diagenesis in regressive phases of depositional megacycles results in destruction of organic matter in tidal-flat and lagoonal environments. The transgressive phase of depositional megacycles provides for short-lived exposures to the freshwater diagenesis. Consequently, tidal-flat and astricted lagoonal deposits of transgressive phase can be considered as petroleum source rocks.

Bitumens and hydrocarbons, which evolve from the thermal degradation of kerogens, migrate to the nearest available microporosities such as recrystallized patches of limestones, calcite cements, and dolomitic mosaics. Thus, early and late diagenesis helps to bring about a continuous segregation of bitumens and hydrocarbons from kerogens in carbonate source rocks. Tectonic fracturing can provide avenues for secondary migration from source to reservoir facies.

MARCHANT, L. C., J. J. STOSUR, and C. Q. CUPPS
U.S. Dept. Energy, Laramie, WY

Recent Activities in United States Tar Sand

The known tar sand resources of the United States consist of about 550 occurrences located in 22 states. Total oil-in-place in 39 of these occurrences, which have been submitted to some reservoir evaluation, is estimated between 23.7 billion and 32.7 billion bbl. At least 90% of this resource is located in Utah, where six deposits each contain from 1 to 16 billion bbl of oil. Other significant deposits occur in Texas, New Mexico, California, and Kentucky.

Current efforts to develop the United States tar sand resource include: reservoir characterization and evaluation work by industry, states, and the U.S. Department of Energy (D.O.E.); oil recovery and related research by industry, academia, and D.O.E.; and a few field mini-tests and pilots by industry and D.O.E.

The future supply role of the United States tar sand resource is necessarily vague because of the relatively small magnitude of the known resource, when compared to other potential synthetic fuels such as coal or oil shale, the lack of demonstrated applicable oil recovery technologies, and a resultant lack of recoverable reserve estimates.

MARLOW, M. S., A. K. COOPER, and D. W. SCHOLL, U.S. Geol. Survey, Menlo Park, CA

Hydrocarbon Prospects of Bering Sea Shelf South of St. Lawrence Island, Alaska

Hydrocarbon prospects of the Bering Sea shelf are encouraging because of the presence of numerous, large sediment-filled basins, a variety of structural and stratigraphic traps, and potential reservoir beds. The large shelf area south of St. Lawrence Island is underlain by at least 13 sediment-filled basins. One of these basins, Bristol Bay basin, extends offshore from the Alaska Peninsula and contains more than 3 km of section. Nearby on the northwest is St. George basin, a graben approximately 300 km long and 50 km wide that includes a section about 10 km thick. The northwestern region of the shelf near Siberia is underlain by the large Navarin basin province (40,000 sq km), which comprises three subshelf basins that contain sections as much as 15 km thick.

Structural traps for hydrocarbons occur as folds associated with growth faults flanking the basins, strata draped over basement blocks, regional dip divergence in the upper sedimentary basin sequence, and thinning of beds against the basement flanks of the basins. Diapirlike folds as well as large anticlinal structures occur in the Navarin basin province.

Rocks dredged from the Beringian continental slope include volcanic sandstone of Late Jurassic age, mudstone of Late Cretaceous age, and less consolidated deposits of early Tertiary age. Pyrolytic analyses of these rocks indicate that none are good source beds for petroleum; however, the samples are generally sandy units that may not be representative of finer grained possible source beds that may be present along the margin or within the subshelf basins. Tertiary samples are generally porous—probably because of abundant diatom frustules. The permeability of these rocks is variable. Tertiary outcrops can be traced as seismic reflectors to the subshelf basins, where, if the beds remain diatomaceous, potential reservoir beds may be present.

SOURCE ROCK & RESERVOIR CHARACTERISTICS
BERING SHELF DREDGE SAMPLES

Sample number	Lith.	Age	Org. Carb. (Wt.%)	Pyrol. HC (Wt.%)	Vitr Refl. (%)	Por. (%) perm.(md)
96-77-BS						
DRI-20	Vol. Ss.	Late Jur.	—	—	0.38	— —
DRI-26	Vol. Ss.	Late Jur.	—	—	1.14	— —
TT-1-021						
001	Mudst.	Late Cret.	0.62	0.11	0.40	— —
L5-78-BS						
5-5	Ss.	Late Jur.	0.27	0.02	0.63	— —
2-3	Mudst.	E. Tert.	0.33	0.02	0.41	— —
16-9	Mudst.	M. Eo.	0.83	0.04	0.31	— —
2-4	Mudst.	L. Olig.	—	—	—	68.3/5.46
2-11	Sltst.	L. Olig.	—	—	—	45.1/1.25
5-10	Tuff	L. Olig.	—	—	—	50.7/19.0
7-3	Mudst.	M. Mio.	—	—	—	57.4/1.67

MATHEW, DAVID, M. A. BAUER, and S. J. TEWALT, Bur. Econ. Geology, Univ. Texas at Austin, Austin, TX

Development of Conceptual Model to Characterize Uncertainty in Coal Resource Estimates

Published coal reserve estimates for the United States have traditionally differed by wide margins, e.g., Electric Power Research Institute estimating 135 billion tons and U.S. Geological Survey estimating 212 billion tons. These differences in reserve estimates possibly result from mechanically following the USGS/USBM resource classification system, without appreciation of lateral variability in seam thickness and seam discontinuity. Variability and discontinuity are dependent in part upon depositional history. For example, coals accumulated on an ancient alluvial plain or in a back barrier setting are more variable and, thus, more difficult to characterize as to resources than are those that accumulated on a delta plain.

A statistical model for characterizing uncertainty in coal resource estimates is proposed. This model is based upon defining the area of influence of bore holes in different depositional settings with respect to consistency of coal thickness and coal quality. The model is being developed through evaluation of lignite occurrences in the Texas Gulf Coast Tertiary basin. In this basin, lignites occur in three Eocene stratigraphic units, the Wilcox Group, Yegua Formation, and Jackson Group, as component facies of three depositional systems—fluvial, deltaic, and strand plain/lagoonal. Within a particular depositional setting, densely-drilled deposits are being compared with areas of sparse drilling to characterize variability and, thus, determine the optimum spacing necessary to define seam geometry. Geostatistical analyses such as variograms, which estimate the range of influence of a bore hole as a measure of spacing, should aid in determining optimum spacing for a specific degree of certainty, within a given depositional setting. In this way, certainty ranges could be established for different depositional systems within a given coal basin. It is anticipated that this evaluation could lead to more reliable coal resource estimates.

MATTICK, ROBERT E., U.S. Geol. Survey, Reston, VA

Geologic Setting and Oil and Gas Potential of Eastern United States Continental Margin North of Cape Hatteras

Two sedimentary basins, the Georges Bank basin off New England and the Baltimore Canyon Trough off the Middle Atlantic states, have been examined for geologic setting and hydrocarbon potential. Georges Bank basin, a complex-shaped trough, is on a block-faulted basement of igneous, metamorphic, and sedimentary rocks. The deepest part of the basin (deeper than 8 km) and the oldest sediments are restricted to south-central Georges Bank. Toward the northeast and southwest, the sedimentary section thins to less than 2 km over the Yarmouth Arch-LeHave platform and the Long Island platform. The only deep wells in the area are the COST G-1 and G-2; data from these wells will not be released until 60 days after the first oil and gas lease sale. Seismic correlation with the Shell Mohawk B-93 well on the Scotian Shelf indicates that most of the sedimentary rocks in the Georges Bank basin are Jurassic and older. Jurassic sandstone and limestone units serve as potential reservoir rocks. Potential hydrocarbon traps may occur on structural highs associated with draping of Jurassic and basal Lower Cretaceous strata over basement blocks.

The Baltimore Canyon Trough is an elongated northeast-trending basin that contains at least 14 km of Jurassic and younger marine and nonmarine sedimentary rocks. Lithologic and stratigraphic data from the COST B-2 and B-3 wells indicate that Lower Cretaceous and Jurassic rocks are predominantly nonmarine to shallow-marine sandstone and shale. Analyses of organic carbon and identification of low thermal maturity suggest that gas rather than oil will be produced. Nineteen wildcat wells have been completed; three are significant natural-gas discoveries. The largest discovery is probably associated with a large rollover trap on the downthrown block of a Cretaceous and Jurassic growth fault. Potential hydrocarbon traps in carbonate rocks beneath the present continental slope have not yet been explored.

MAUGHAN, DAVID M., Esso Australia Ltd., Sydney, Aust.

Definition and Development of Mackerel Field, Gippsland Basin, Australia

The Mackerel oil field, located offshore in the Gippsland basin, Australia, was discovered in April 1969. The field, which is a topographic-erosional feature, contains oil in high-quality Eocene-Paleocene reservoir sands which lie beneath an unconformity at the top of Latrobe Group, and is sealed by calcareous shales and mudstone of the Oligocene Lake's Entrance Formation. The initial definition of the field was based on 235 km of seismic data which had been shot in an irregular grid involving seven different surveys and on a total of four exploration wells. At the end of 1974, 145 km of high-resolution seismic data were shot over Mackerel to better define the top of Latrobe unconformity and the internal reservoir configuration. In 1976 a detailed pre-development structural interpretation was undertaken and a stratigraphic model of the field was constructed from detailed analysis of the seismic data.

The pre-development seismic structural and stratigraphic mapping was used to determine the final platform location and to choose the initial development well locations. These well locations were picked to gain early structural control on the top of Latrobe, to test the interpretation in the problem areas, and to investigate the internal geometry of the reservoir units.

Development drilling started in July 1977, and these well results have provided feedback to both the structural and stratigraphic models, which are being continuously updated. The pre-development mapping of the Mackerel field was successful in delineating the basic size and shape of the field and its internal stratigraphic configuration and in identifying all the geophysical and geologic problems which were subsequently encountered in the development drilling. Thus a rigorous seismic interpretation provided the geologists and engineers with a sound basis for field development planning.

MAUGHAN, EDWIN K., U.S. Geol. Survey, Denver, CO

Phosphorite, Organic Carbon, and Hydrocarbons in Permian Phosphoria Formation, Western United States

The Permian Phosphoria Formation in the northwestern interior United States contains two phosphatic and organic carbon-rich shale members that include both phosphorite and petroleum source beds. The association suggests an intimate relation between factors which generate phosphorite deposits and hydrocarbon source beds. The two members, the Meade Peak Phosphatic Shale Member and the Retort Phosphatic Shale Member, were deposited at the periphery of a foreland basin between the Cordilleran geosyncline and the North American craton. The concentration, distribution, and coincidence of phosphorite, organic carbon,