shape of the coal body is modified by coexisting and postdepositional environments such as channels.

Iron disulfides are present in coals either as marcasite or pyrite and are the major cause of sulfur variation within the seam. High sulfur contents in the form of disseminated framboidal pyrite are present in coals that were transgressed by marine to brackish-water environments. The only exception is where a sufficient thickness of sediment is introduced early enough to shield the peat from marine to brackish waters. Thus, the environments of deposition that overlie the coal are more important to the distribution of the type and amount of sulfur in the coal than the environments of deposition of the sediment on which the coal developed.

Roof quality in underground mines is dependent on the interrelations of rock types, syndepositional structures, early postdepositional compactional traits, and later tectonic features. Most of the features of roof conditions can be related to depositional or early-stage compactional processes of the environments overlying the coal. Later tectonic events may accentuate these early traits, but the basic characteristics seem to have been established during or shortly after the sediments were deposited.

Superposed on changes in seam character attributed to variations in environments of depositions are contemporaneous tectonic influences. Rapid subsidence during sedimentation generally results in rapid variation in coal seams but favors lower sulfur and trace-element content, whereas slower subsidence favors greater lateral continuity by higher content of chemically precipitated material.

Knowledge of depositional environments and of their tectonic setting is a valid and viable tool in the search for and development of coal resources.

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Oil Expulsion—A Consequence of Oil Generation

In source beds, much of the oil-generating organic matter is concentrated along bedding surfaces. During the principal phase of oil generation, when adequate thermal energy is available, 25 to 30 wt. % of the organic matter commonly is converted to liquids, mainly bitumen with some water. Part of the bitumen is then thermally cracked to crude oil. Hydrocarbon gases with some CO_2 and N_2 are generated also; much of the water and CO_2 is generated before oil is formed.

The release of fluids from organic matter causes a reduction in volume of the residual solid organic matter; however, this volume decrease is offset by the considerably greater volume of generated fluids. As a result, pressures increase greatly along sealed bedding surfaces. Internal (intrasource) migration of oil and gas occurs when local, transitory fluid pressures become sufficient to part the bedding laminae and to form or reopen near-vertical microfractures connecting the partings. Permeable migration pathways also may develop along laminae as a result of the reduced volume of the organic matter. Fluids are driven along permeable laminae and partings, into connecting, less pressurized laminae where two or more laminae converge, and along microfractures and faults within the source sequence. Eventually, high fluid pressures will develop in most parts of an actively generating source-rock section if the section is sealed and confined.

Two properties of argillaceous rocks that permit overpressuring are anisotropy and heterogeneity. Additionally, enough oil must be generated to increase fluid pressure sufficiently for local dilations to occur in oil-source rocks. This requires at least 0.5 wt. % of hydrogen-rich organic matter. In argillaceous source rocks, clay-sized quartz and clay provide brittle pressure and fluid seals, susceptible to microfracturing, on individual laminae. In carbonate-evaporite sequences, evaporites sealing laminae are less likely to fracture.

At a given generation site, dilation and fluid release are followed by a sharp reduction in pressure and closing of partings and fractures to further fluid movement. Pressure will again increase and dilation will recur at a given generation site until the fluid generation rate has diminished enough for the fluid pressure to remain below the dilation point, that is, the fluid pressure required to open or reopen any part of the system sufficiently for local internal fluid migration or expulsion.

A source-rock system functions much like a pressure cooker. It is self-opening and self-sealing. As liquids are expressed from a parting into a fracture, the pressure drops quickly and the fracture will close on the retained liquids, immobilizing them. Silica and/or calcite cement commonly are precipitated along such fractures, both before and after oil migration. Immobilized oil devolatilizes, leaving a solid or semisolid residue. These materials enable resealed parts of the system to repressurize and refracture through the peak gas-generation phase. Thus, the generation of fluids can provide the means by which oil and gas are expelled from source rocks.

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Resource Potential and Plate-Margin Geology of Frontier Basins of North Pacific and Bering Sea

Few of Alaska's offshore frontier basins have been explored by drilling. However, regional geologic data and tectonic considerations can be used to assess the likelihood that commercial volumes of oil and gas are present in the basins.

Basins of the northern margin of the Gulf of Alaska, and the contiguous Aleutian Ridge on the west, have formed along the Aleutian subduction zone, a tectonic terrane 3,600 km long that separates the Pacific and North American plates. The eastern gulf shelf is underlain by Cenozoic deposits that are as much as 10 km thick, but adequate reservoir beds are thought to be absent in Neogene and younger beds. However, the discovery that potential reservoir and source beds of early Tertiary age underlie the continental slope enhances the oil and gas prospects of the eastern gulf margin. Basins of the central gulf shelf (Kodiak Island area) contain upper Cenozoic beds that are as much as 5 to 6 km thick. These beds are broadly deformed and unconformably overlie more deformed rocks of Paleogene and Cretaceous age. Grabens (unusual for the gulf margin) filled with 6 to 8 km of Neogene and younger beds are present beneath the western gulf shelf (Sanak Island). Publicly available data imply that reservoir and source beds adequate to form large hydrocarbon deposits are probably absent from the central and western gulf. Farther west the lower Tertiary igneous core of the Aleutian Ridge is overlain by broadly deformed Neogene and younger deposits. These beds are 2 to 4 km thick in summit basins, and probably much thicker below the Aleutian terrace along the ridge's southern flank. Although these basins include diatomaceous and turbidite sequences, the probable abundance of readily altered volcanic detritus cautions against optimistic expectations of large quantities of oil and gas along the Aleutian Ridge.

Five extensive (25,000 sq km) basins filled with as much as 15 km of mostly Cenozoic beds are present beneath the Beringian shelf, and, therefore, north of the Aleutian subduction zone. Except near Siberia, the deposits in these basins are little deformed. Elongate St. George and Navarin basins, along the southern or outer edge of the shelf, have formed on a collapsed foldbelt of miogeoclinal rocks that include beds of Jurassic and Cretaceous age. Subsidence of the foldbelt occurred after subduction of oceanic crust ceased beneath the Beringian margin (60 to 70 m.y. ago) and shifted south to the Aleutian Ridge. In contrast, Norton basin, which underlies the inner or northern edge of the shelf, is floored by Paleozoic and older rocks of Brooks Range affinity that subsided in response to Cenozoic strike-slip faulting in western Alaska. A speculative reading of the geologic history of the Beringian basins implies that some of them could harbor commercial volumes of oil and gas. South of the Beringian margin, the abyssal floor (3 to 4 km) of the Bering Sea basin is underlain by 4 to 10 km of undeformed deposits chiefly of Cenozoic age. Drilling results, and the detection of deep-water bright spots (VAMPs), suggest that hydrocarbon deposits (of unknown volume) occur in the basin. Its basement of Lower (?) Cretaceous oceanic crust was presumably separated from the north Pacific by the formation of the Aleutian Ridge in latest Cretaceous or earliest Tertiary time.

Since early Mesozoic time, the evolution of the structural framework of the north Pacific margin has been controlled by the subduction of more than 10,000 km of oceanic lithosphere. However, recognition that segments of the margin are underlain by deeply submerged miogeoclinal rocks of Mesozoic and early Tertiary age, and the results of DSDP drilling at Pacific margins, attest that the evolution of Alaskan and Bering Sea margins is not adequately described by models of accretionary tectonics or back-arc spreading. Little understood aspects of subduction and post-subduction tectonics that cause and control marginal uplift and subduction are thought to hold important clues to the economic potential of the frontier basins of the north Pacific and Bering Sea regions.

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Deep-Water Reservoirs: Submarine Fans and Fantasies

Many large oil and gas fields are producing from turbidites and associated deep-water rocks; examples include the Los Angeles and Ventura basins, many fields in the Great Valley of California, and some less obvious turbidite areas such as the Bradford field, Pennsylvania. For future exploration, and for the development of existing fields, it is important to understand the different types of turbidites, how they are related, and how they fit into an overall submarine-fan model that can be used predictively.

The basic deep-water (below storm wave base) facies consists of classic turbidite monotonous alternations of parallel-bedded sandstones and shales. As the sandstones thicken and the shales become thinner or absent, the classic turbidite facies grades into massive sandstones and pebbly sandstones. These are characterized by vertical amalgamation of sandstones, channeling, and scouring. The distribution of these facies on modern submarine fans is understood only sketchily, and hence the predictive fan models have been constructed largely on facies relations and observed channels in ancient rocks, and on subsurface data. Classic turbidites, with excellent bedding continuity, suggest a smooth seafloor, whereas the massive and pebbly sandstones suggest a channelized inner fan. Different types of thin-bedded classic turbidites indicate levee, interchannel, and distal-fan fringe environments.

Sequences of turbidites in which beds become thicker upward may indicate progradation, and thinning-upward sequences may indicate channel filling. Both can be recognized on electric logs.

Fan models can lead to fantasies when applied uncritically as examples from the Ventura basin and Great Valley illustrate.

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Abstracts

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Geology of Wheaton Consolidated Oil Field, Gibson County, Indiana

The Wheaton Consolidated oil field is in Union and Barton townships of Gibson County, Indiana. The field has produced oil since the 1920s from a sandstone reservoir referred to as the "Jackson Sand," which is equivalent to the Big Clifty Formation of surface terminology. The Big Clifty Formation is part of the Stephensport Group, and is Chesterian or Late Mississippian in age.

Within the field area the Big Clifty Formation can be mapped between the underlying Barlow Limestone and overlying Golconda Limestone. The lower contact appears to be sharp over the field area. The upper contact of the Big Clifty intergrades with at least one tongue of Golconda which pinches out into the Big Clifty.

The Big Clifty Formation includes sandstone, shale, and mudstone with minor amounts of sandy limestone. A typical sequence from top to bottom includes: black shale; thin red mudstone; gray shale; silty limestone; interbedded gray shale and very fine-grained, white, sandstone; well sorted, fine-grained, white, sandstone; and thin gray shale. The percentage of sandstone within the Big Clifty Formation varies significantly.

The thickness of the Big Clifty Formation ranges from 64 to 89 ft (19.5 to 27 m). The unit dips to the