with depth more so than identical normal faults active after deposition. The observed dip of a fault decreases as the velocity of the adjacent rock increases. For example, normal faults in rocks whose velocities increase with depth (e.g., most clastic sedimentary rocks) appear to flatten with depth more so than identical normal faults in rocks with more uniform velocities.

The appearance of secondary structures associated with normal faulting on our unmigrated seismic models depends on the position and size of the secondary structures. The increased thickness of low-velocity rock on the downthrown side of normal faults disrupts and bends the reflections on the upthrown side. Depth, fault displacement rock velocity distribution, and the angle between the fault surface and adjacent beds affect the severity of the distortion. This distortion obscures any secondary structures present on the upthrown side of faults (i.e., minor faults, anticlines produced by drag) and can erroneously be interpreted as secondary faulting and folding. Synclines produced by drag on the downthrown side of normal faults have small radii of curvature relative to their burial depths. This relationship makes these synclines difficult to identify on unmigrated seismic sections. Many forced folds in rifts are gentle shallow structures overlying normal faults. These folds are the most easily identifiable because they are unaffected by the distortion beneath faults and the synclines have large radii of curvature compared to their burial depths.

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Petroleum Geology of Bangladesh

The easternmost part of the Bengal foredeep or Surma basin is the most prospective area for finding additional gas because the degree of folding diminishes markedly in a westward direction. The foothills of the Tripura-Chittagong area and the Bengal basin (sometimes called Bengal foredeep or Surma basin) are locations of the gas fields in Bangladesh. These areas have sometimes been called the Outer Molasse basin. Folding occurred in four phases. Gas discoveries are in the Chittagong foothills. Similar structural features to those of the Chittagong foothills appear to be present in the extreme eastern part of the Bay of Bengal. Compressional folding did not affect the central and western part of the Bay of Bengal. However, by comparison with other areas of deltaic deposition, rollover structures associated with growth faults may be significant. The Oligocene to Holocene rock sequences were deposited in environments that range from abyssal marine prodelta to subaerial delta plain. In productive areas onshore and offshore, hydrocarbon traps include asymmetric, elongate, faulted anticlines. Strategic traps and sedimentary growth structures are found in the Bengal basin. Miocene sandstones constitute the gas reservoirs; Eocene, Paleocene, and Oligocene carbonaceous shales and Miocene shales are the source rocks. In the central and western part of the Bay of Bengal area, the major uncertainties are the development and thickness of sandstones and the possible size of structures.

Thirteen gas fields have been discovered: (1) Kutubdia, (2) Chhatak (8 mmcf/day), (3) Kailashtilla, (4) Habiganj (14 mmcf/day), (5) Bakhrabad, (6) Murdi, (7) Begumgoni, (8) Beanibazar, (9) Sylhet, (10) Rashidpur, (11) Titas, (12) Semutang, and (13) Jaldi. Chhatak, Habiganj, Sylhet, and Titas fields were on production during 1979.

The gas in these fields occurs in multi-sandstone reservoirs in anticlines that probably developed in late Miocene to Pliocene time. The gas reservoirs are the lower Miocene Bhuban Formation and lower to lower-middle Miocene Boka Bil Formation. Both formations are included in the Surma Group.

Total recoverable gas reserves are 7 to 7.8 tcf. Total estimated gas reserves in place are 9.33 to 10.39 tcf and possibly 10 to 20 tcf of gas resources yet to be discovered.

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Raton Basin, New Mexico—Exploration Frontier for Fracture Reservoirs in Cretaceous Shales

The Raton basin contains up to 3,000 ft (900 m) of marine shale and subordinate carbonate rocks of Cretaceous age, including (in ascending order) the Graneros Shale, Greenhorn Limestone, Carlile Shale, Niobrara Formation, and Pierre Shale. Clastic reservoir rocks are sparse in this part of the section and drilling for them in the Raton basin has led to disappointing results. However, brittle siltstone and carbonate-rich interbeds within the Cretaceous shale intervals are capable of providing fracture reservoirs under the right conditions.

Fracture reservoirs in other Rocky Mountain basins occur where there is maximum curvature of brittle interbeds within shale sequences at fairly shallow depths. Relatively low confining pressures found at shallow depth facilitate development of open fractures in the brittle interbeds. Anticlines, synclines, and monoclines can have favorable fracture systems. It should be kept in mind that if the axial surface of a fold is inclined, the hinge will migrate laterally with depth, and the hinge is generally the part of the fold having the maximum curvature. There are numerous folds in the Raton basin that could have excellent fracture systems. It is necessary to determine the areas of maximum curvature of the shale interval having brittle interbeds capable of fracturing.

Carbonate-rich beds of the Greenhorn Limestone and Niobrara Formation appear to be the most widespread and thickest intervals that might develop fracture reservoirs. Siltstone or orthoquartzitic interbeds in the Graneros, Carlile, and Pierre Shales may provide other zones with fracture systems. Hydrocarbon shows have been reported from the Graneros, Greenhorn, Niobrara, and Pierre Formations in the New Mexico parts of the Raton basin. Also, minor gas was produced from the Garcia field near Trinidad, Colorado. Fracturing appears to have enhanced the reservoir characteristics of the Wagon Mound Dakota gas field in the southern part of the basin.

Structure contour maps and lithofacies maps showing brittle interbeds in dominantly shaly sequences are the basic tools used in exploration for fracture reservoirs. These maps for the Raton basin indicate numerous exploration targets.

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Burial Cements in Lower Cretaceous Pearsall Formation and Lower Glen Rose Formation, South Texas

Lower Cretaceous platform carbonates and shales were buried to depths in excess of 2,000 ft (610 m) by the end of Eocene time, and were locally affected by late-stage cementation. Burial diagenetic cements include ferroan baroque dolomite, ferroan and nonferroan calcite, anhydrite, kaolinite, barytocelestite, galena, and sphalerite. The lack of these minerals in outcrop and their occurrence in fractures are evidence for a subsurface origin.

Carbonate cements are chemically and isotopically zoned; the $FeCO_3$ content in baroque dolomite cement varies by as much as 10 wt. % across a single crystal. Stratigraphic and regional distribution of iron in baroque dolomite indicates that the iron is derived from local sources. Good negative correlation between $\delta^{13}C$ values and iron contents of baroque dolomite suggests the