tary cover; and if the basin is asymmetrical, in monoclines developed on the slope. Basin size is typically 20-60 km (12-37 mi) in width and 70-300 km (43-186 mi) in length.

An intracratonic rift of this type is part of the Central African rift system. This system trends east-west, from the Benue trough in Nigeria to the Lamu embayment in Kenya. It is the result of the propagation of rifting from the triple junction that separated South America from the western margin of Africa, and also from the triple junction on the eastern margin where Madagascar separated from Africa. The rift system was tectonically active during the Cretaceous and Tertiary (Paleogene), and ceased after the initial faulting and coincident igneous activity but before any new crust was formed. The rifting along this trend was superseded in the Miocene by the East African rift system, which is still active.

Several companies have made significant oil discoveries in different components of the Central African rift system. Average daily production for 1982 from the basins associated with the Benue trough was 107,928 BOPD. Conoco has drilled at least eight discovery wells in the Chari basin and Ngaoundere rift components, and zones tested flowed up to 1,900 BOPD. In the Abu Gabra rift component, where Marathon is currently exploring, Chevron has drilled approximately 60 wells. Nineteen of these were discoveries and tested an average rate per well of 3,500 BOPD. The oil in the Chari basin and Abu Gabra rift is found in multiple zones in the Upper Cretaceous and Tertiary continental sands, and is a typical derivative of lacustrine sediments. The Abu Gabra rift may contain up to 10 billion bbl of oil.

Research indicates that this type of rift system is present in other areas of the world. Ongoing worldwide exploration has shown that intracratonic rift basins have the potential to make a significant contribution to world oil reserves.

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## Deep Mediterranean Basins and Their Oil Potential

Mediterranean deep basins are surrounded by oil and gas producing areas, either onshore or beneath the continental shelf. The main zones are the Ebro delta and the Valencia Gulf (Spain); the Pelagian Sea off Tunisia, western Libya; Sicily; the Adriatic Sea; the Prinou basin in the Greek Aegean Sea; and the Nile delta. In other areas, as in the Adana basin (Turkey), offshore Cyprus (DSDP Leg 42A), and west of Sardinia (DSDP Leg 13), oil and gas shows were present in boreholes.

In general, the Mediterranean basins have relatively flat and uniform bottoms with water depths of the order of 2,800-3,000 m (9,200-9,850 ft). Several major exceptions are the Tyrrhenian Sea and the Aegean Sea, which are internal parts of the Alpine orogenies with a stretched structure of a back-arc type. The Ionian Sea has gradual northward slopes. The Eastern basin occupies a typical external position with the front of the Hellenic and Tauric nappes and the external overthrust zone known as the "Mediterranean ridge."

In terms of the crust, the problem can be approached with the aid of geophysical studies (gravimetry, magnetism, and seismic) and variations in heat flow. The superposition of these varied data thus enables us to schematize the nature of crust of the Mediterranean basins.

The western Mediterranean has a high heat flow that is surpassed only at certain points in the Tyrrhenian Sea. In contrast, the eastern Mediterranean in general has a very low heat flow, even in the Ionian Sea where a very considerable positive gravimetric anomaly is known to exist. Without reaching the high Tyrrhenian levels, the Aegean Sea has relatively high heat values. This is normal because of the area's volcanic activity.

The main potential oil and gas objectives are the Oligocene and Miocene Series, deposited after and during the main orogenic phases, and covered by thick Messinian evaporites and Pliocene-Pleistocene marine sediments. Underlying the Ionian Sea, the Mediterranean ridge, and the eastern basins, Mesozoic and Paleogene rocks may be possible targets. The zone at the shelf limit of the African platform and the alpine chains resembles many of the productive areas around the globe.

In conclusion, the deep Mediterranean basins could hide large targets. The exploration effort will require various improvements (excluding that of the price of crude oil): a better comprehension of the deep structure, seismic techniques capable of obtaining reflection beneath the evaporites and in the overthrust sectors, and technology that allows drilling in 3,000-4,000 m (10,000-13,000 ft) of water with the requisite security safeguards.

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## Giant Fields: Present and Future Petroleum Resources

By the end of 1982, 319 giant oil fields plus at least 159 giant gas fields had been discovered. Total ultimate recovery of these fields amounts to 847 billion bbl of oil and over 2,362 tcf of natural gas.

The numbers and reserve potentials of giant oil fields are considered reasonably accurate. It is most likely that many giant fields remain to be discovered worldwide.

Giant gas fields and reserves are certainly understated when costs of transportation to market are not considered. But, using an economic definition that requires demonstrated development activity, the giant gas data may be significantly overstated.

The rate of giant field discoveries has been declining, and has been low for the past decade; political restrictions and economic constraints have contributed more to this decline than have technical criteria. Less expensive energy sources may arrive before the remaining geologically favorable areas are thoroughly explored for oil and natural gas.

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## African Oil—Past, Present, and Future

Nearly 50% of Africa's total area is comprised of sedimentary basins. These basins number more than 80 and contain an estimated proven hydrocarbon reserve of 89 billion bbl (oil equivalent), about 8% of the world's resources. Of these reserves, 68% occur in North Africa, 22% in Nigeria, and 7% in the Aptian Salt basin, which encompasses the coastal parts of Cameroon, Gabon, Congo, Zaire, and Angola. The first discovery of hydrocarbons in Africa was in Egypt in 1886, and the most recent discoveries are in the Gulf of Guinea and the interior rift basins of central Africa.

Africa's basins can be classified into six types. However, each type has modifiers and most basins have evolved through a polycyclic history from one type to another.

Giant hydrocarbon accumulations are related to marine source strata and large, non-giant pools to nonmarine source strata. All sizes of fields occur in areas with marine source rocks, but giant fields very rarely occur in areas where nonmarine source rocks are thought to predominate.

Estimates of future potential reserves for each basin have been established by conventional basin assessment, play assessment, and volumetric yield methods, where data were sufficient. The most intensely explored basins are those containing giant fields. However, basins such as the Taoudenni, Zaire, Okawango, and Kalahari are each as large as Texas or the North Sea, yet the number of wildcats in each can be counted on one hand. Furthermore, about 80% of Africa's sedimentary area is virtually unexplored.

Giant accumulations will be found in the future in Tunisia and Egypt, in east Africa (if a deeper Karroo-play is pursued), and in the interior sag basins of central Africa, which are remote and unexplored. Some chance of finding one or two giant fields exists in Algeria and Libya, the Aptian Salt basin, the Gulf of Guinea, and the interior rift basins of central Africa, but generally only large accumulations will be found. Also, northwest Africa may yield oil in commercial quantities.

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## Southern Mozambique Basin: Most Promising Hydrocarbon Province Offshore East Africa

Recent offshore acquisition of 12,800 km (8,000 mi) of seismic reflection data, with gravity and magnetic profiles encompassing the southern half of the Mozambique basin, reveals new facets of the subsurface geology. Integrated interpretation of these new geophysical data with old well information results in the development of depositional and tectonic models that positively establish the hydrocarbon potential of the basin. Previous drilling was sparse and predated modern seismic technology and exploration philosophy, leaving the area classified as a frontier province.