Geology and Total Petroleum Systems of the West-Central Coastal Province (7203), West Africa

U.S. Geological Survey Bulletin 2207-B

U.S. Department of the Interior
U.S. Geological Survey

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By Michael E. Brownfield and Ronald R. Charpentier

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Foreword

This report was prepared as part of the World Energy Project of the U.S. Geological Survey. The purpose of the World Energy Project is to assess the quantities of oil, gas, and natural gas liquids that have the potential to be added to reserves within the next 30 years. These volumes either reside in undiscovered fields whose sizes exceed the stated minimum field-size cutoff value for the assessment unit (variable, but must be at least 1 million barrels of oil equivalent) or reside in fields already discovered and will subsequently be identified as reserve growth.

For this project, the world was divided into eight regions and 937 geologic provinces, which were then ranked according to the discovered oil and gas volumes within each (Klett and others, 1997). Of these, 76 "priority" provinces (exclusive of the United States and chosen for their high ranking) and 26 "boutique" provinces (exclusive of the United States and chosen for their anticipated petroleum richness or special regional economic importance) were selected for appraisal of oil and gas resources.

A geologic province characteristically has dimensions of hundreds of kilometers and encompasses a natural geologic entity (for example, sedimentary basin, thrust belt, accreted terrane) or some combination of contiguous geologic entities. Province boundaries were generally drawn along natural geologic boundaries, although in some provinces the boundary location was based on other factors such as a specific bathymetric depth in open oceans.

The total petroleum system constitutes the basic geologic unit of the oil and gas assessment. The total petroleum system includes all genetically related petroleum that occurs in shows and accumulations (discovered and undiscovered) that (1) has been generated by a pod or by closely related pods of mature source rock and (2) exists within a limited mappable geologic space, along with the other essential mappable geologic elements (reservoir, seal, and overburden rocks) that control the fundamental processes of generation, expulsion, migration, entrapment, and preservation of petroleum.

An assessment unit is a mappable part of a total petroleum system in which discovered and undiscovered fields constitute a single, relatively homogeneous population such that the chosen resource-assessment methodology, based on estimation of the number and sizes of undiscovered fields, is applicable.

A total petroleum system may equate to a single assessment unit, or, if necessary, may be subdivided into two or more assessment units such that each unit is sufficiently homogeneous in terms of geology, exploration considerations, and risk to assess individually.

A graphical depiction of the elements of a total petroleum system is provided in the form of an events chart that shows the times of (1) deposition of essential rock units; (2) trap formation; (3) generation, migration, and accumulation of hydrocarbons; and (4) preservation of hydrocarbons.

A numeric code identifies each region, province, total petroleum system, and assessment unit; these codes are uniform throughout the project and throughout all publications of the project. The codes used in this study were generated according to the following scheme:

Unit	Name (example)	Code (example)
Region	Sub-Saharan Africa	**7**
Province	West-Central Coastal	7**203**
Total petroleum system	Melania-Gamba	7203**01**
Assessment unit	Gabon Subsalt	720301**01**

The codes for all the world's regions and oil and gas provinces are listed in Klett and others (1997).

Oil and gas production and reserve volumes stated in this report are derived from the Petroconsultants, Inc., 1996 Petroleum Exploration and Production database (Petroconsultants, 1996) and other area reports from Petroconsultants, Inc., unless otherwise noted. Hydrocarbon field centerpoints are used by permission (Petroconsultants, 1996; IHS Energy Group, 2003).

Illustrations in this report that show boundaries of the total petroleum systems and assessment units were compiled by using geographic information system (GIS) software. Political boundaries and cartographic representations were taken, with permission, from Environmental Systems Research Institute's ArcWorld 1:3 million digital coverage (1992), have no political significance, and are displayed for general reference only. Oil and gas field centerpoints, shown in the included figures, are reproduced, with permission, from Petroconsultants (1996).

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Conversion Factors

Multiply	By	To obtain
	Length	
meter (m)	3.281	foot (ft)
kilometer (km)	0.6214	mile (mi)
	Area	
square kilometer (km^2)	0.3861	square mile (mi^2)
	Volume	
barrel (bbl) (1 barrel = 42 gallons)	0.1590	cubic meter (m^3)
	Mass	
milligram (mg)	0.001	gram (g)
gram (g)	0.03527	ounce, avoirdupois (oz)

Temperature in degrees Celsius (°C) may be converted to degrees Fahrenheit (°F) as follows:
°F = (1.8 × °C) + 32.

Altitude, as used in this report, refers to distance above or below sea level.

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By Michael E. Brownfield and Ronald R. Charpentier

Abstract

The West-Central Coastal Province of the Sub-Saharan Africa Region consists of the coastal and offshore areas of Cameroon, Equatorial Guinea, Gabon, Democratic Republic of the Congo, Republic of the Congo, Angola (including the disputed Cabinda Province), and Namibia. The area stretches from the east edge of the Niger Delta south to the Walvis Ridge. The West-Central Coastal Province includes the Douala, Kribi-Campo, Rio Muni, Gabon, Congo, Kwanza, Benguela, and Namibe Basins, which together form the Aptian salt basin of equatorial west Africa. The area has had significant exploration for petroleum; more than 295 oil fields have been discovered since 1954. Since 1995, several giant oil fields have been discovered, especially in the deep-water area of the Congo Basin.

Although many total petroleum systems may exist in the West-Central Coastal Province, only four major total petroleum systems have been defined. The area of the province north of the Congo Basin contains two total petroleum systems: the Melania-Gamba Total Petroleum System, consisting of Lower Cretaceous source and reservoir rocks, and the Azile-Senonian Total Petroleum System, consisting of Albian to Turonian source rocks and Cretaceous reservoir rocks. Two assessment units are defined in the West-Central Coastal Province north of the Congo Basin: the Gabon Subsalt and the Gabon Suprasalt Assessment Units. The Congo Basin contains the Congo Delta Composite Total Petroleum System, consisting of Lower Cretaceous to Tertiary source and reservoir rocks. The Central Congo Delta and Carbonate Platform and the Central Congo Turbidites Assessment Units are defined in the Congo Delta Composite Total Petroleum System. The area south of the Congo Basin contains the Cuanza Composite Total Petroleum System, consisting of Lower Cretaceous to Tertiary source and reservoir rocks. The Cuanza-Namibe Assessment Unit is defined in the Cuanza Composite Total Petroleum System.

The U.S. Geological Survey (USGS) assessed the potential for undiscovered conventional oil and gas resources in this province as part of its World Petroleum Assessment 2000. The USGS estimated a mean of 29.7 billion barrels of undiscovered conventional oil, 88.0 trillion cubic feet of gas, and 4.2 billion barrels of natural gas liquids. Most of the hydrocarbon potential remains in the offshore waters of the province in the Central Congo Turbidites Assessment Unit.

Large areas of the offshore parts of the Kwanza, Douala, Kribi-Campo, and Rio Muni Basins are underexplored, considering their size, and current exploration activity suggests that the basins have hydrocarbon potential. Since about 1995, the offshore part of the Congo Basin has become a major area for new field discoveries and for hydrocarbon exploration, and many deeper water areas in the basin have excellent hydrocarbon potential. Gas resources may be significant and accessible in areas where the zone of oil generation is relatively shallow.

Introduction

The U.S. Geological Survey (USGS) assessed the potential for undiscovered conventional oil and gas resources in the West-Central Coastal Province (fig. 1) as part of its World Petroleum Assessment 2000 (U.S. Geological Survey World Energy Assessment Team, 2000). The West-Central Coastal Province consists of the coastal and offshore areas of Cameroon, Equatorial Guinea, Gabon, Republic of the Congo, Democratic Republic of the Congo, Angola (including the disputed Cabinda Province), and Namibia. The area stretches from the east edge of the Niger Delta south to the Walvis Ridge along the Atlantic margin of equatorial west Africa (fig. 1). The West-Central Coastal Province includes the Douala, Kribi-Campo, Rio Muni, Gabon, Congo, Kwanza (also spelled Cuanza after two Angola provinces and the Cuanza River), Benguela, and Namibe Basins, which together form the Aptian salt basin of equatorial west Africa.

Four total petroleum systems are defined in the West-Central Coastal Province: (1) the Melania-Gamba Total Petroleum System, (2) the Azile-Senonian Total Petroleum System, (3) the Congo Delta Composite Total Petroleum System, and (4) the Cuanza Composite Total Petroleum System. Five assessment units are defined within these total petroleum systems: (1) the Gabon Subsalt Assessment Unit of the Melania-Gamba Total Petroleum System, (2) the Gabon Suprasalt Assessment Unit of the Azile-Senonian Total Petroleum System, (3) the Central Congo Delta and Carbonate Platform Assessment Unit of the Congo Delta Composite Total

Figure 1. Location map for the West-Central Coastal Province (7203), showing the approximate locations of the Douala, Kribi-Campo, Rio Muni, Gabon, Congo, Kwanza (Cuanza), Benguela, and Namibe Basins with their associated fracture zones, structural arches and highs, and volcanic axes in the Aptian salt basin of equatorial west Africa. The N'Komi Fracture Zone separates the Gabon Basin into the North Gabon and South Gabon subbasins. The western limit of the province was set at 4,000-m water depth. In the index map, the West-Central Coastal Province is outlined in red. Abbreviation: Eq. Guinea, Equatorial Guinea.

Petroleum System, (4) the Central Congo Turbidites Assessment Unit of the Congo Delta Composite Total Petroleum System, and (5) the Cuanza-Namibe Assessment Unit of the Cuanza Composite Total Petroleum System (figs. 2 and 3). This report documents the assessment of the West-Central Coastal Province and supplements the World Petroleum Assessment 2000 by providing additional geologic detail concerning the total petroleum systems and assessment units as well as a more detailed rationale for the quantitative assessment input.

The USGS estimated a mean of 29.7 billion barrels of undiscovered conventional oil, 88.0 trillion cubic feet of gas, and 4.2 billion barrels of natural gas liquids (table 1). The estimated undiscovered oil and gas were partitioned into offshore and onshore hydrocarbon resource potential. Most of the hydrocarbon potential is in the offshore parts of the West-Central Coastal Province.

Since the assessment, three major volumes (Cameron and others, 1999; Mello and Katz, 2000; Arthur and others, 2003) and several significant papers (especially Burwood, 1999; Schiefelbein and others, 1999; Harris, 2000; Da Costa and others, 2001; Hudec and Jackson, 2002) discussing the petroleum geology of the West-Central Coastal Province have been published. These new studies are the result of the increased interest and exploration activity in the province.

West-Central Coastal Province Geology

The Aptian salt basin of equatorial west Africa extends from Cameroon in the north to Namibia in the south (fig. 1). The West-Central Coastal Province includes the Douala, Kribi-Campo, Rio Muni, Gabon, Congo, Kwanza, Benguela, and Namibe Basins, which together form the Aptian salt basin (Edwards and Bignell, 1988a). These basins share common structural and stratigraphic characteristics and therefore were grouped together as the West-Central Coastal Province. The northern boundary is the south edge of the Niger Delta Province (Klett and others, 1997), and the southern boundary is the Walvis Ridge volcanic high of Early Cretaceous to Holocene age (figs. 1 and 4), which formed as a result of the migrating hot spot now sited below the island of Tristan da Cunha. The eastern province boundary is the east edge of the sedimentary basins, and the western boundary was set at 4,000-m water depth. These basins are classified as Atlantic-type marginal sag basins (Clifford, 1986) and contain rocks ranging from Paleozoic to Holocene in age (fig. 4).

The Aptian salt basin formed during the breakup of North America, Africa, and South America at the culmination of the Late Jurassic to Early Cretaceous rifting of an extensive Paleozoic basin. The Aptian salt basin has undergone a complex

Table 1. Summary of estimated undiscovered volumes of conventional oil, gas, and natural gas liquids for undiscovered oil and gas fields in the West-Central Coastal Province, west Africa, showing allocations to the offshore and onshore for total province.

[MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. MFS, minimum field size assessed (MMBO or BCFG). Prob., probability (including both geologic and accessibility probabilities) of at least one field equal to or greater than the MFS. Results shown are fully risked estimates. For gas fields, all liquids are included under the NGL (natural gas liquids) category. F95 represents a 95 percent chance of at least the amount tabulated. Other fractiles are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. Shading indicates not applicable. Totals do not reflect rounding]

Code and Field Type	MFS	Prob. (0-1)	Undiscovered Resources											
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
7203	**Total: Assessed onshore portions of West-Central Coastal Province**													
Oil Fields		1.00	511	1,592	3,298	1,710	950	3,005	6,656	3,301	44	146	350	165
Gas Fields							389	1,746	4,489	2,001	16	75	207	88
Total		1.00	511	1,592	3,298	1,710	1,338	4,750	11,145	5,302	60	220	557	253
7203	**Total: Assessed offshore portions of West-Central Coastal Province**													
Oil Fields		1.00	8,522	26,325	53,166	28,036	16,743	53,364	117,142	58,307	783	2,593	6,132	2,915
Gas Fields							4,879	21,406	54,305	24,435	201	914	2,508	1,076
Total		1.00	8,522	26,325	53,166	28,036	21,623	74,770	171,447	82,742	984	3,507	8,640	3,991
7203	**Grand Total: Assessed portions of West-Central Coastal Province**													
Oil Fields		1.00	9,033	27,917	56,465	29,747	17,693	56,368	123,798	61,608	827	2,739	6,483	3,080
Gas Fields							5,268	23,152	58,794	26,436	217	989	2,715	1,164
Total		1.00	9,033	27,917	56,465	29,747	22,961	79,520	182,592	88,044	1,044	3,727	9,198	4,244

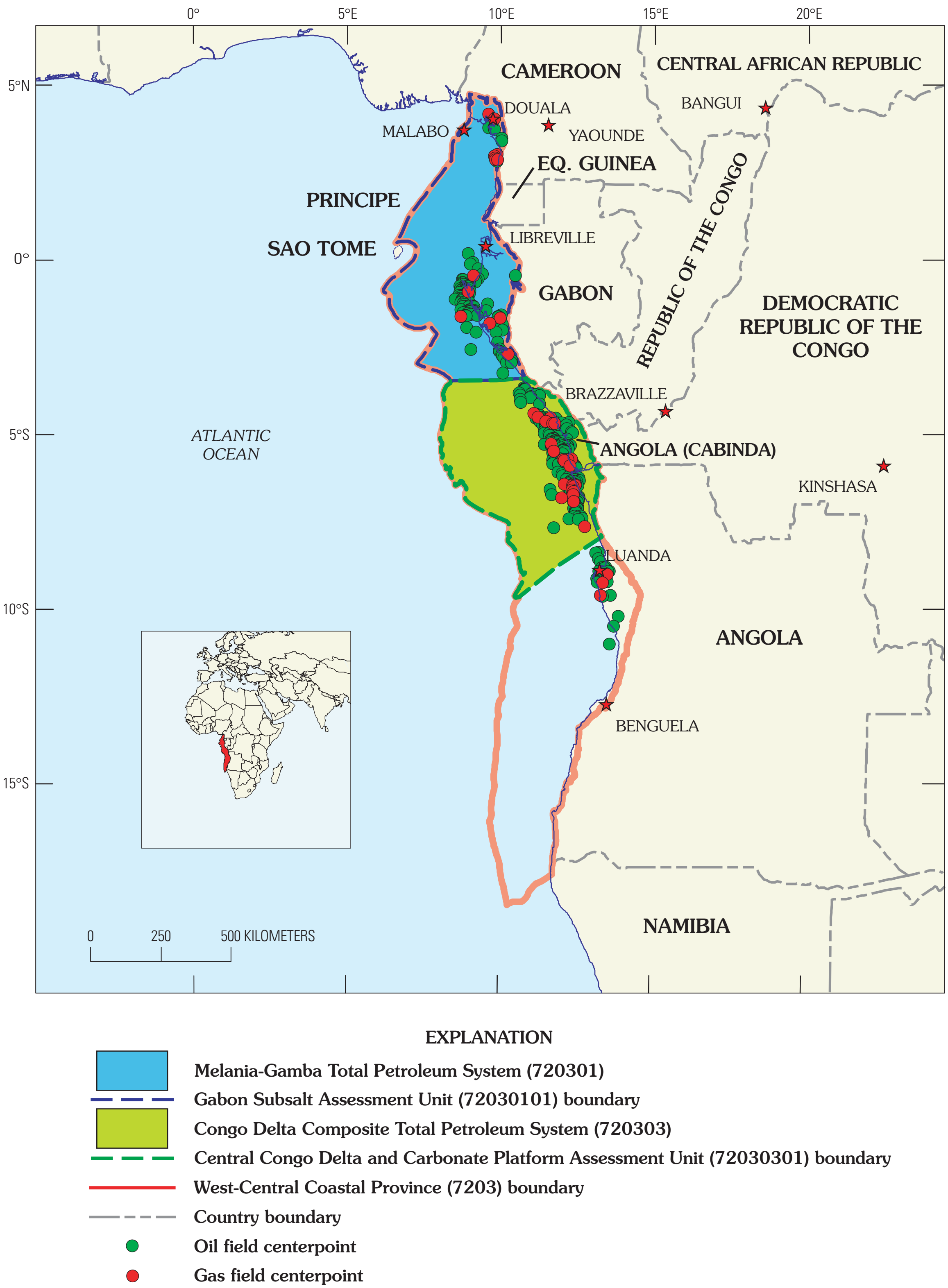


Figure 2. Location map of the Gabon Subsalt Assessment Unit within the Melania-Gamba Total Petroleum System and the Central Congo Delta and Carbonate Platform Assessment Unit within the Congo Delta Composite Total Petroleum System in the West-Central Coastal Province, equatorial west Africa. The western limit of the assessment units and the petroleum system was set at 4,000-m water depth. In the index map, the West-Central Coastal Province is shown in red. Abbreviation: Eq. Guinea, Equatorial Guinea.

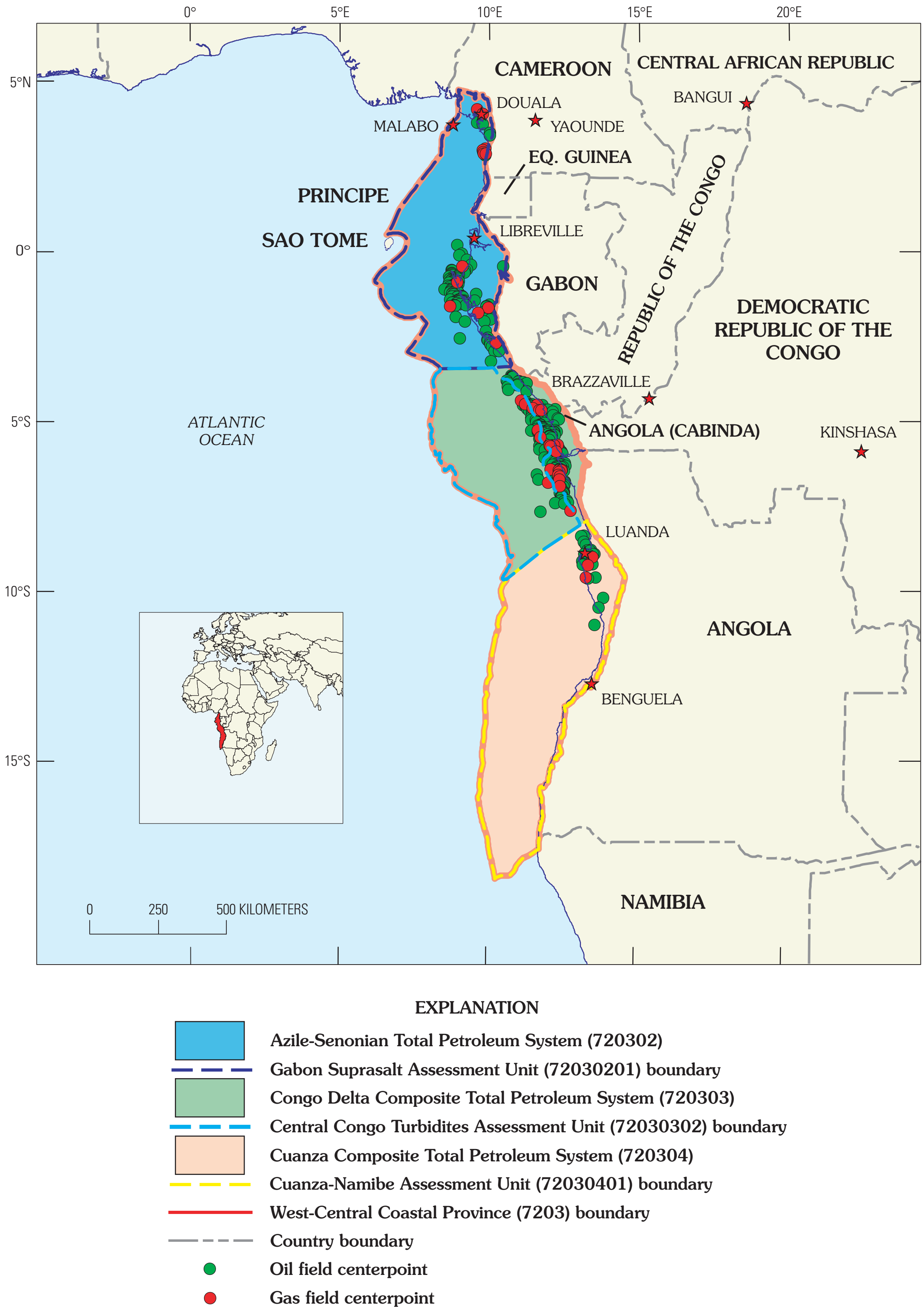


Figure 3. Location map of the Gabon Suprasalt, the Central Congo Turbidites, and the Cuanza-Namibe Assessment Units of the Azile-Senonian, the Congo Delta Composite, and the Cuanza Composite Total Petroleum Systems, respectively, in the West-Central Coastal Province, equatorial west Africa. The western limit of the assessment units and the petroleum systems was set at 4,000-m water depth. In the index map, the West-Central Coastal Province is shown in red. Abbreviation: Eq. Guinea, Equatorial Guinea.

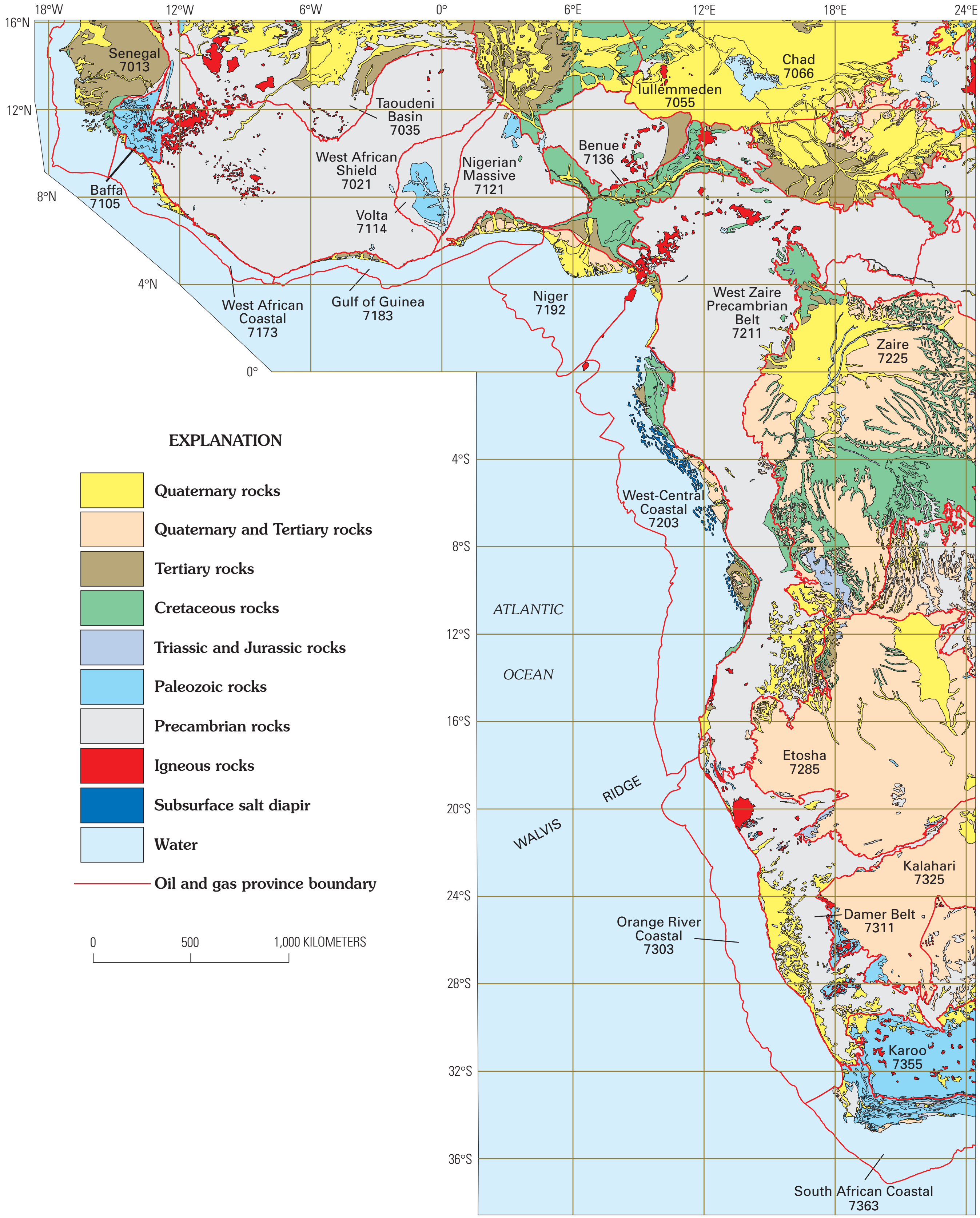


Figure 4. Generalized geologic map of west Africa (Persits and others, 2002), showing province boundaries, selected province names, and codes as defined in Klett and others (1997).

history that can be divided into stages of basin development: pre-rift stage (late Proterozoic to Late Jurassic), syn-rift stage (Late Jurassic to Early Cretaceous), and post-rift stage (Late Cretaceous to Holocene). The Aptian salt basin can be divided into a number of basins aligned in a north-south direction and delimited by an east-west-trending fault system and other structural arches and highs related to syn-rift tectonics (fig. 1).

The initial phase of the post-Hercynian (Carboniferous to Permian) opening of the north Atlantic and the splitting of the North American plate from the Eurasian and African plates began during Late Permian to Early Triassic time (Uchupi and others, 1976; Lehner and De Ritter, 1977; Ziegler, 1988; Lambiase, 1989). The final breakup of Africa and South America began in the Early Jurassic in the southernmost part of the south Atlantic and gradually proceeded northward during Neocomian time (Uchupi, 1989; Binks and Fairhead, 1992; Guiraud and Maurin, 1992). The area now occupied by the Gulf of Guinea opened last, forming a continuous anoxic seaway from the Walvis Ridge to North Africa (fig. 5) in the late Albian to Turonian (Tissot and others, 1980). A continuous oxic Atlantic Ocean existed by the end of the Turonian (fig. 5) between Africa and South America. The presence of Aptian evaporites and clastic rocks in the West-Central Coastal Province provides evidence that rift-related sedimentation occurred during this time, associated with the breakup of Africa and South America.

Understanding of the geology of both the African and South American margins of the Atlantic, and appreciation of their resource potential, have increased greatly since about 1985. Some references for general geology of the African Atlantic margin are those by Uchupi (1989), Doust and Omatsola (1990), Teisserenc and Villemin (1990), Brown and others (1995), Cameron and others (1999), and Mello and Katz (2000).

Pre-Rift Stage

The pre-rift section consists of rocks of Precambrian to Jurassic age that crop out in the Interior subbasin of the Gabon Basin (fig. 6) and exist in the subsurface in the eastern part of the Congo Basin. The pre-rift stage lasted through the Late Jurassic and incorporated several phases of intracratonic faulting and downwarping during which as much as 600 m of continental clastic rocks of Carboniferous to Jurassic age (fig. 6) were deposited in the Interior subbasin (Teisserenc and Villemin, 1990). The Interior subbasin is separated from the North Gabon subbasin by the Lambarene Horst (fig. 6). These intracratonic basins were depocenters for continental sediments that are now important hydrocarbon-producing reservoirs. Upper Carboniferous rocks contain interbedded tillites and black shales of the Nkhom Formation, whereas the overlying Permian (Agoula Formation) continental rocks, from bottom to top, contain conglomerates, bituminous shale, phosphatic rocks, lacustrine dolomite, anhydrite and anhydrite-bearing limestone, shale, and sandstone (Teisserenc and Villemin, 1990). The Triassic to Jurassic fluvial rocks (Movone Formation) consist of sandstone and shale.

Pre-rift rocks have not been penetrated by drilling in the offshore parts of the Benguela and Kwanza Basins (fig. 1), whereas in the Douala, Kribi-Campo, and Rio Muni Basins, the pre-rift section has been penetrated and consists of Precambrian arkosic sandstones and conglomerates (Nguene and others, 1992). The onshore part of the Kwanza Basin (fig. 1) contains possible pre-rift rocks of Jurassic age consisting of the continental Basal Red Beds and Red Basal Series (Burwood, 1999).

Pre-rift rocks in the Congo Basin are limited to the Jurassic(?) Lucula Sandstone, which directly overlies Precambrian basement (Brice and others, 1982; Schoellkopf and Patterson, 2000). This unit consists of well-sorted, quartzose, micaceous sandstone and was most likely deposited as alluvial or eolian sands. The total thickness of pre-rift rocks in the Congo Basin is unknown, but more than 1,000 m of clastic rocks have been penetrated in some wells (Brice and others, 1982). The upper boundary of the Lucula Sandstone is usually defined by the lowest occurrence of lacustrine shale, marl, or siltstone of the Bucomazi Formation (McHargue, 1990).

Syn-Rift Stage

Initial rifting in the “Aptian salt basin” formed a series of asymmetrical horst-and-graben basins trending parallel to the present-day coastline. Thick sequences of fluvial and lacustrine rocks were deposited in the rift basins. Organic-rich, lacustrine rocks of the rift stage are some of the most important hydrocarbon source rocks in these basins of equatorial west Africa.

Syn-rift rocks are known to exist in the Rio Muni, Douala, and Kribi-Campo Basins of Equatorial Guinea and Cameroon (fig. 1). The syn-rift rocks in the Rio Muni Basin (figs. 7 and 8), as much as 4,000 m thick (Ross, 1993; Turner, 1995), consist of Neocomian to Barremian fluvial and lacustrine sandstones and shales deposited in a broad, low-relief basin. Later basinwide normal faulting resulted in increased syntectonic, lacustrine sedimentation. The oldest syn-rift rocks penetrated in this basin unconformably overlie the Precambrian basement in the Douala and Kribi-Campo Basins (fig. 9) and are Barremian(?) to Aptian in age (Nguene and others, 1992). They include continental conglomerates and sandstones with lacustrine shales, limestones, and marls. Evaluation of higher resolution seismic data has shown several undrilled syn-rift tilted blocks in the offshore Rio Muni Basin (Ross, 1993).

Syn-rift rocks in Gabon’s Interior subbasin (fig. 10) are generally similar to those of the South Gabon subbasin (figs. 6 and 11), but some differences exist because the Interior subbasin was much quieter tectonically than the South Gabon subbasin. Syn-rift rocks in these subbasins can be divided into two groups separated by a major unconformity. The lower group includes the N’Dombo and Welle Formations (fig. 10) of latest Jurassic to Neocomian age. The 150- to 400-m-thick N’Dombo consists of conglomeratic sandstone, sandstone, and minor shale (Brink, 1974) and is equivalent to the Basal Sandstone in the South Gabon subbasin (fig. 11), whereas the

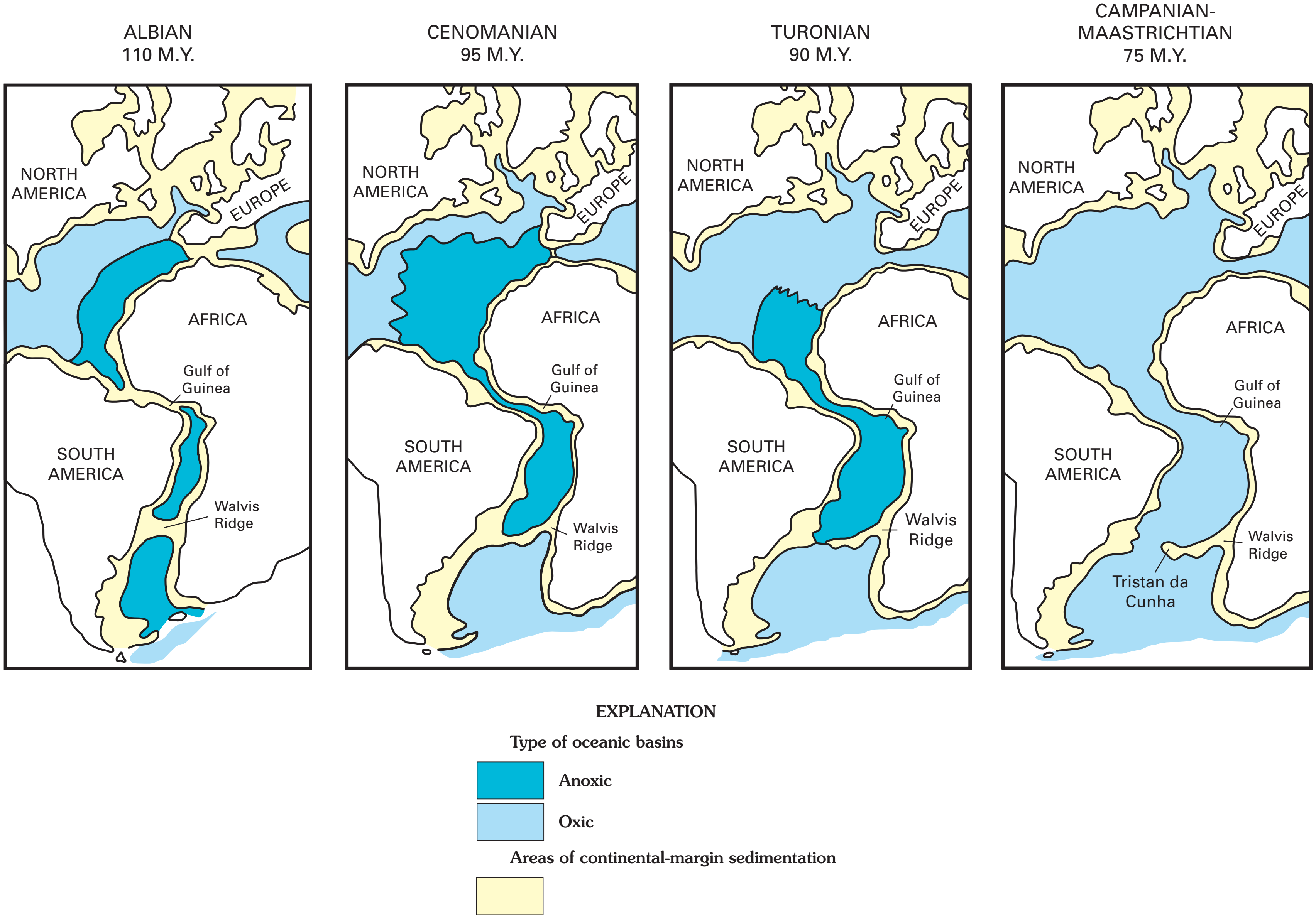
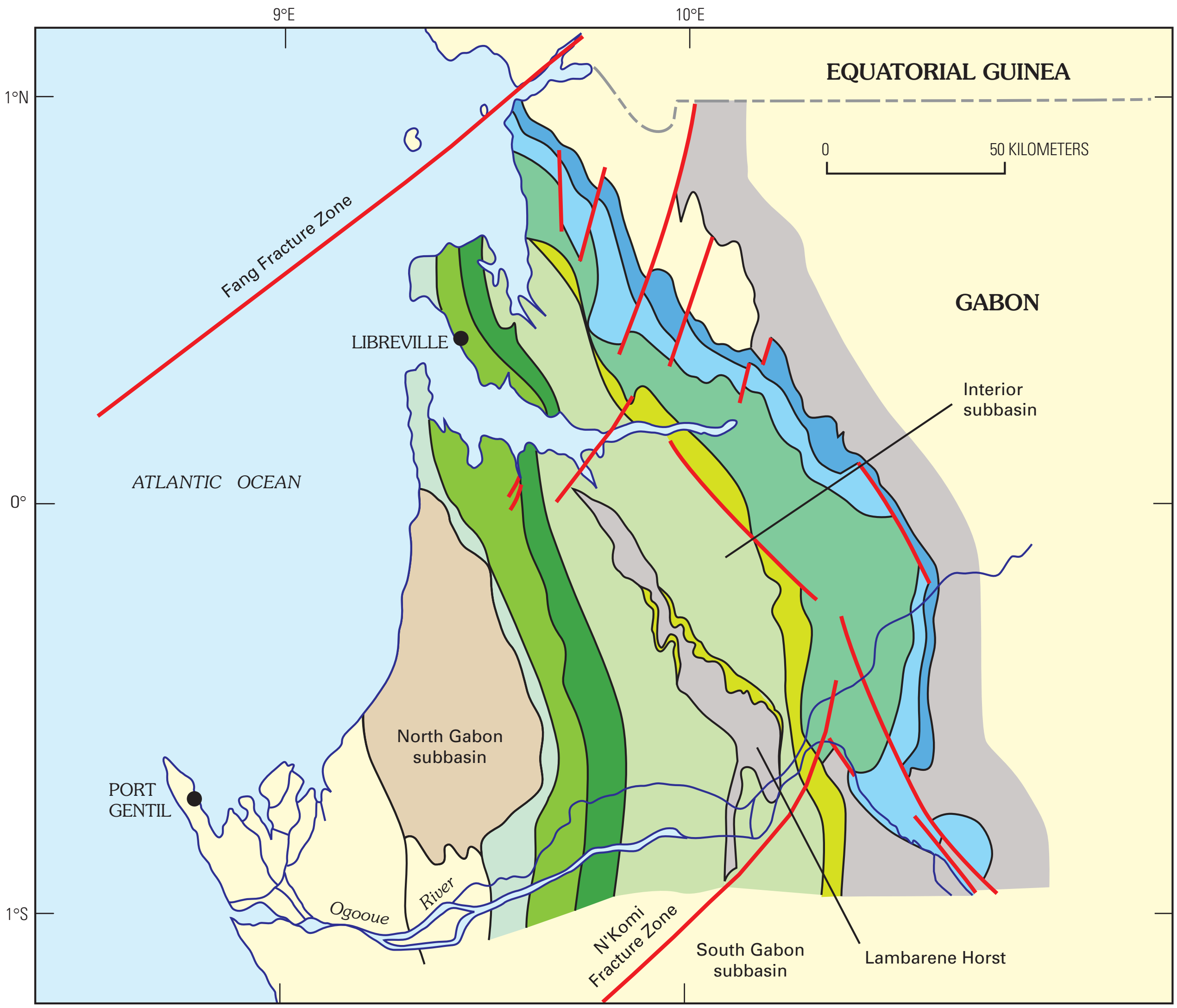


Figure 5. Paleogeographic maps of the Cretaceous breakup of Africa and South America, showing the approximate location of the Gulf of Guinea and the Walvis Ridge. Modified from Tissot and others (1980).



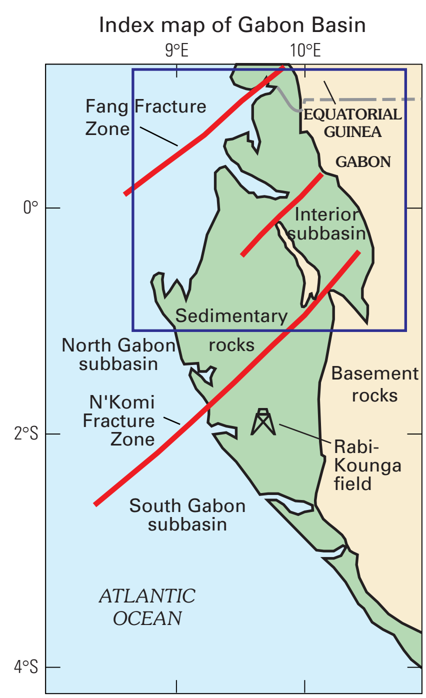


Figure 6. Schematic geologic map of the Interior and North Gabon subbasins in the Aptian salt basin, equatorial west Africa. The Lambarene Horst separates the Interior and North Gabon subbasins. Modified from Teisserenc and Villemin (1990).

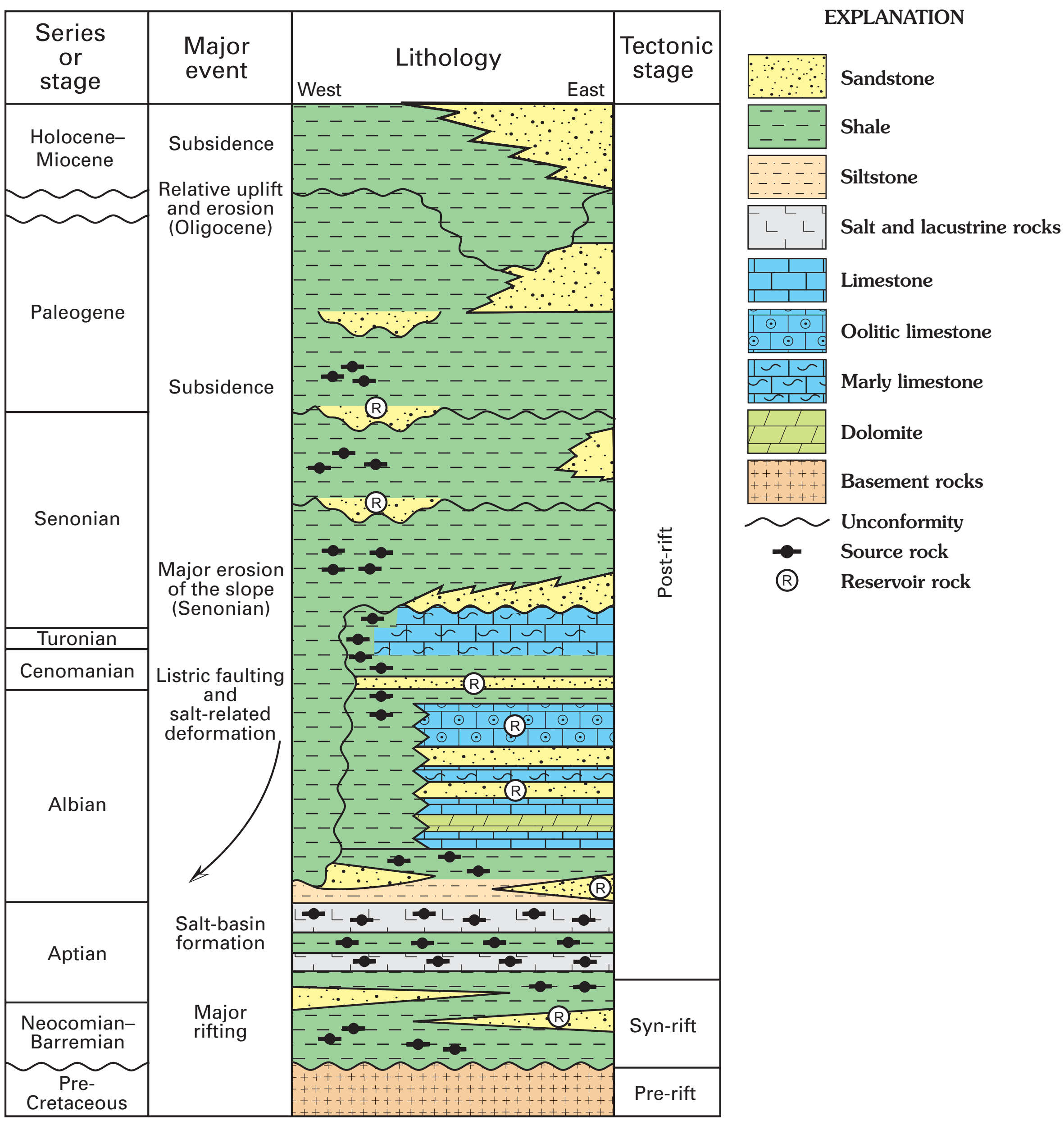


Figure 7. Generalized stratigraphic column, showing ages of units, major geologic events, lithology and probable source rocks, and tectonic stages of the Rio Muni Basin, Equatorial Guinea, west Africa. Modified from Ross (1993),Turner (1995), and the Equatorial Guinea Ministry of Mines and Energy (2003).

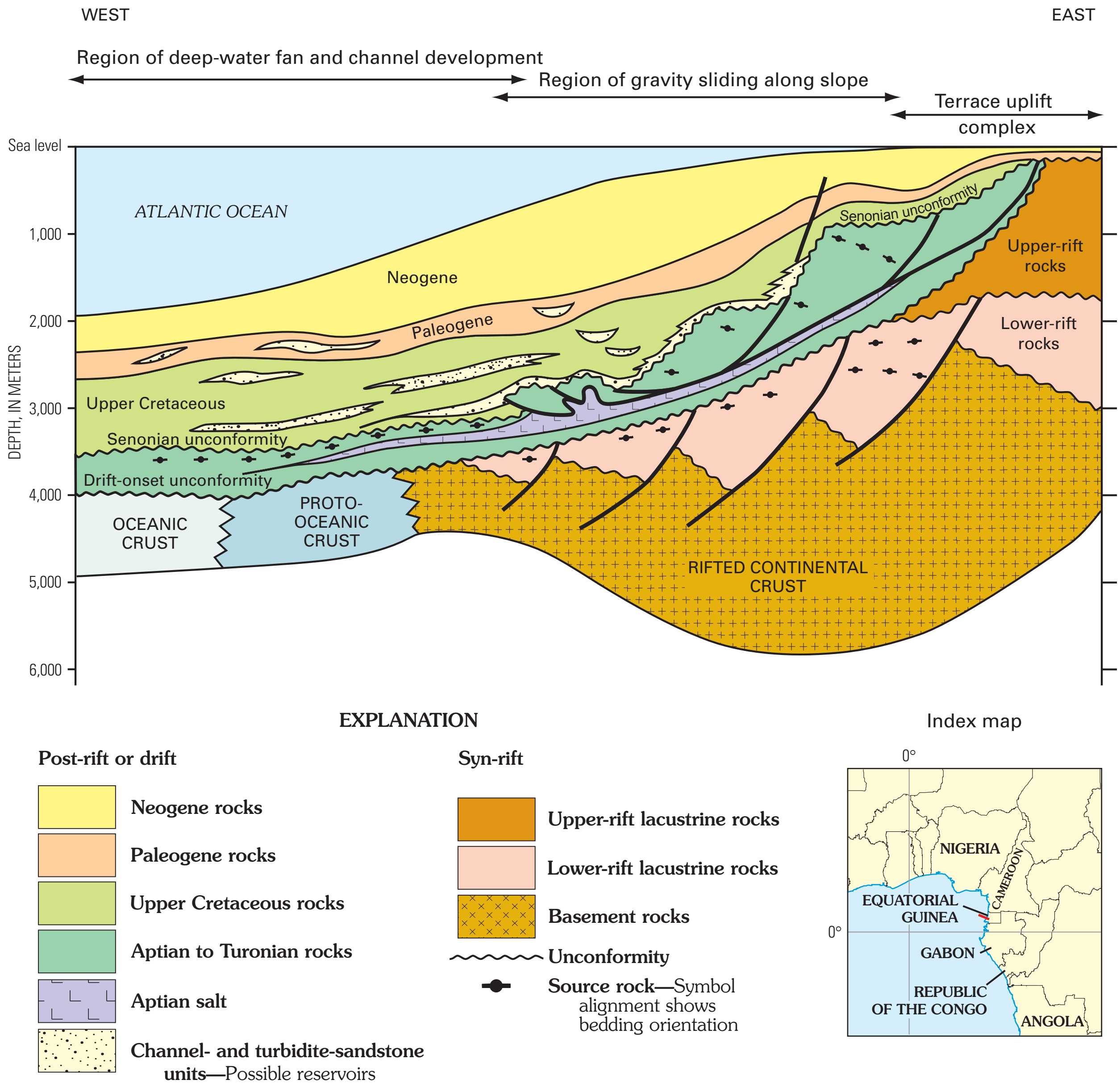


Figure 8. Generalized cross section, showing position of probable source rocks of the Rio Muni Basin, Equatorial Guinea, west Africa. Formation names and lithology are shown in figure 10 for the syn-rift and post-rift units. Modified from Equatorial Guinea Ministry of Mines and Energy (2003). Location of the cross section shown by short red line in index map. Horizontal scale generalized; not given.

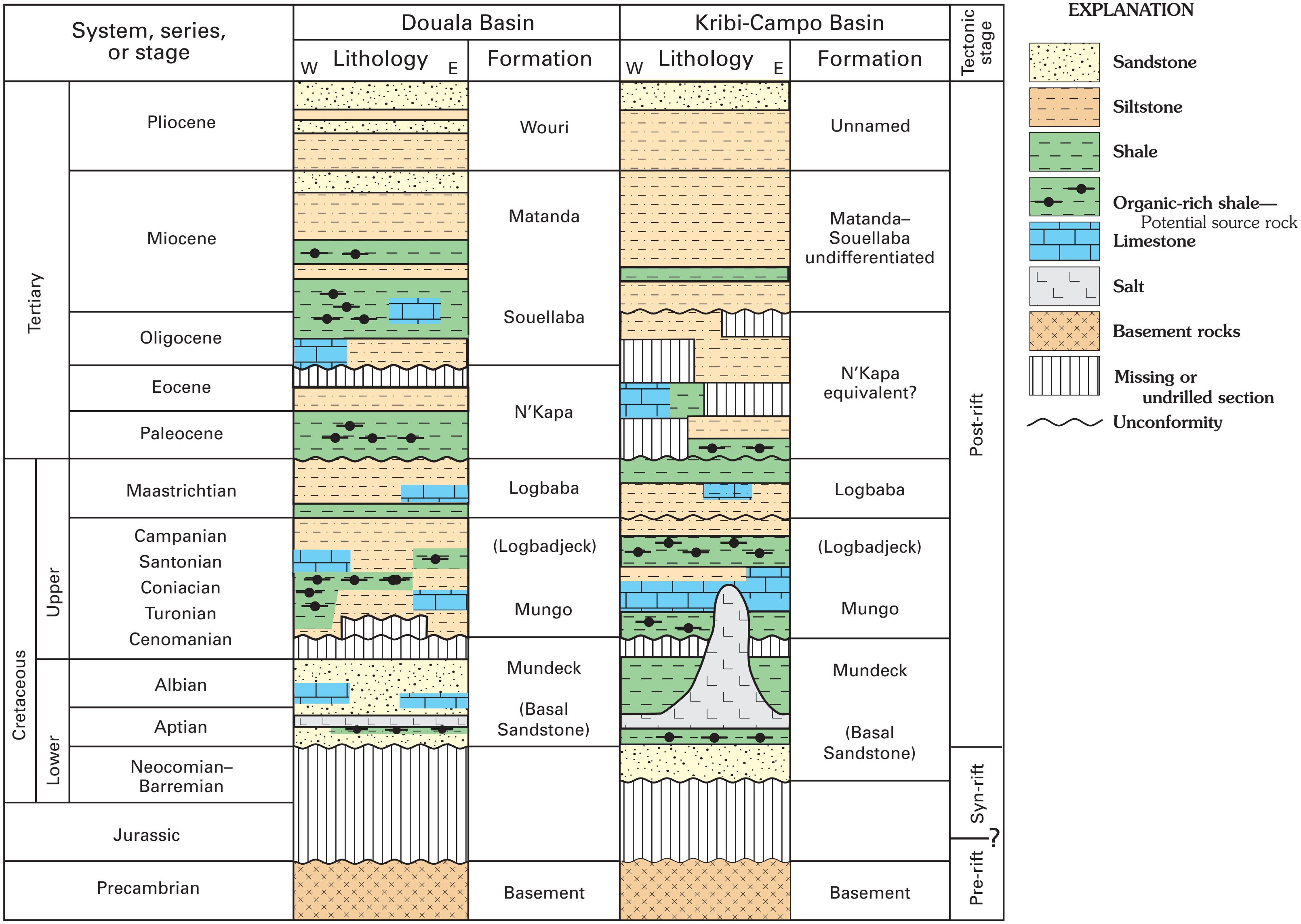


Figure 9. Generalized stratigraphic columns, showing ages, lithology and probable source rocks, formation names, and tectonic stages of the Douala and Kribi-Campo Basins, Aptian salt basin, Cameroon, equatorial west Africa. Modified from Nguene and others (1992), Tamfu and others (1995), and Oba (2001).

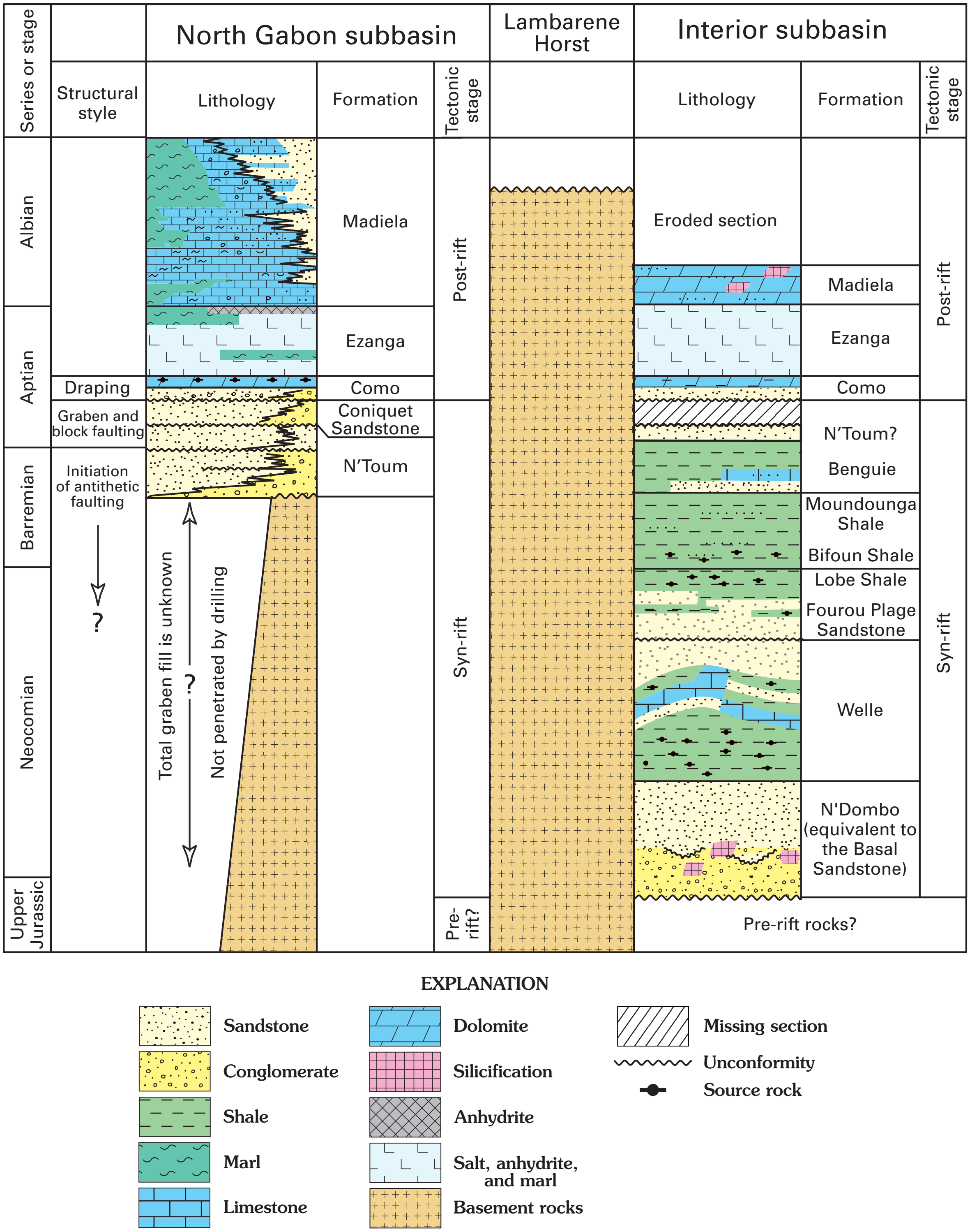


Figure 10. Generalized stratigraphic columns, showing ages, structural styles, lithology and probable source rocks, formation names, and tectonic stages of the Interior subbasin and onshore part of the North Gabon subbasin, equatorial west Africa. Seismic data indicate that the N'Toum Formation in the North Gabon subbasin is thicker than in the Interior subbasin and underlain by other sedimentary units. Modified from Brink (1974) and Teisserenc and Villemin (1990).

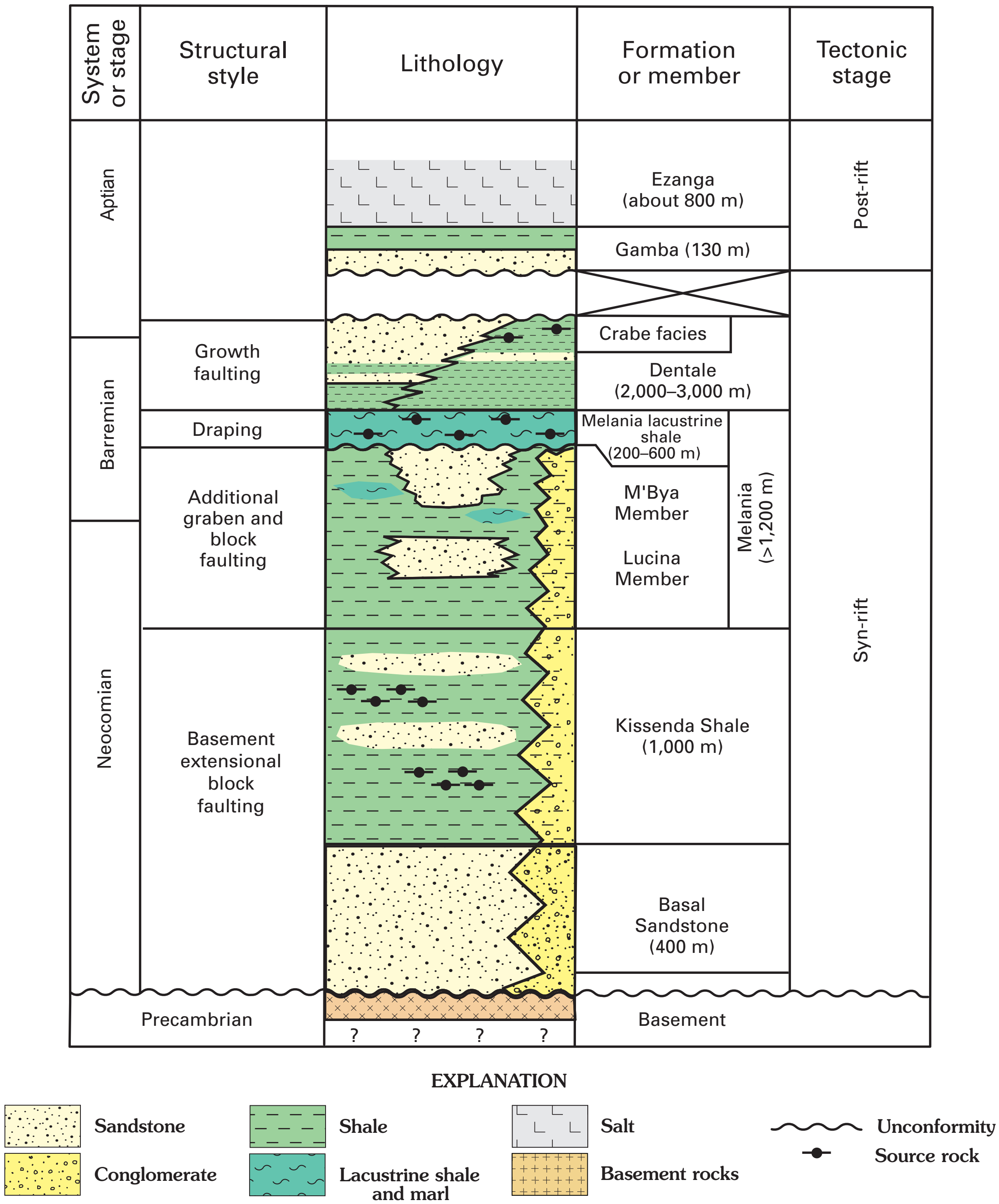


Figure 11. Generalized stratigraphic column, showing ages, structural styles, lithology and potential source rocks, formation or member names, and tectonic stages of the South Gabon subbasin, Gabon, equatorial west Africa. The Melania Formation lacustrine shale contains as much as 20 percent organic matter consisting predominantly of Type I kerogen. Modified from Teisserenc and Villemin (1990).

800- to 900-m-thick Neocomian Welle Formation consists of organic-rich lacustrine shale with pyrobituminous laminae and correlates with the Kissenda Shale in the South Gabon subbasin (Teisserenc and Villemin, 1990). Unconformably overlying the Welle Formation is a second group of rift rocks, including the Fourou Plage Sandstone, the Lobe Shale, and the Bifoun Shale (fig. 10). The Lobe and Bifoun Shales are organic rich and lacustrine in origin. Above the organic-rich Bifoun Shale is the 600-m-thick Moundounga Shale, which correlates to the Melania Formation lacustrine shale in the South Gabon subbasin (fig. 11). The Moundounga Shale consists of interbedded sandy shale and bituminous shale of lacustrine origin. The youngest rift rocks deposited in the Interior subbasin are represented by two units of late Barremian to early Aptian age: (1) the 300- to 400-m-thick continental Benguie Formation (fig. 10) and (2) the N'Toum Formation, which consists of at least 400 m of fluvial sandstone and shale. The N'Toum Formation may include rocks that are equivalent to the Coniquet Sandstone of the North Gabon subbasin (fig. 10).

The syn-rift rocks of the North Gabon subbasin (figs. 6 and 10) are not as well known as those in the Interior and South Gabon subbasins (fig. 11) because no wells have been drilled into rocks older than Barremian (fig. 10). The oldest unit penetrated is the N'Toum Formation of late Barremian to Aptian age, which was deposited in a lacustrine environment as fan-delta turbidites. The maximum thickness drilled is 1,500 m, but the total thickness as shown by seismic data is much greater (Teisserenc and Villemin, 1990). The Neocomian Basal Sandstone and other syn-rift units found in the Interior and South Gabon subbasins are most likely present in the North Gabon subbasin. The syn-rift rocks were continuously deposited in the North Gabon subbasin through the early Aptian, whereas the South Gabon subbasin had a break in deposition during that time. Overlying the N'Toum Formation in the North Gabon subbasin is the lower Aptian Coniquet Formation of continental and lacustrine origin.

The rocks of the syn-rift stage are present in the South Gabon subbasin (fig. 11), are generally fluvial and lacustrine in origin, and range in age from Neocomian to early Aptian. Three main structural phases are known (fig. 11): (1) initial basement extensional block faulting and basin formation in the Neocomian, (2) additional graben and block faulting in the late Neocomian to early Barremian, and (3) draping and growth faulting during the late Barremian and early Aptian (Teisserenc and Villemin, 1990). Overlying the basement rocks is the Basal Sandstone (figs. 11 and 12), consisting of medium- to fine-grained sandstone and conglomerate, which has a maximum thickness of 400 m. The Basal Sandstone is considered fluvial in origin and was deposited in a braided-stream environment. Overlying the Basal Sandstone is the Kissenda Shale, which was deposited in a deep lacustrine environment. The Kissenda Shale consists of lacustrine shale, thin carbonates, and minor amounts of siltstone, sandstone, and conglomerate. After the deposition of the Kissenda Shale, the South Gabon subbasin area was again subjected to strong tectonic activity that created a second phase of grabens and block faults. The Melania Formation, as much as 1,200 m thick, is conformable with the Kissenda Shale (figs. 11 and 12) and contains many facies that reflect these tectonic events. Abrupt thickness changes are commonly found within the different fault blocks, and the facies can be different from one tectonic block to the next. The lower part of the Melania Formation consists of shale and locally well developed, fine-grained, argillaceous sandstone units such as the Lucina Member; these units contain abundant plant material (fig. 11). The Lucina Member was deposited as turbidite channels and fans, whereas the middle part of the Melania Formation includes thick detrital fans such as the M'Bya Member. Tectonic activity ceased by mid-Barremian time, and the upper part of the Melania Formation (the Melania Formation lacustrine shale, fig. 11) is unconformably draped over the underlying units (fig. 11). The Melania Formation lacustrine shale consists of organic-rich shale, siltstone, and calcareous shale and ranges in thickness from 200 to 600 m. The South Gabon subbasin depocenter shifted westward and expanded during the late Barremian because of extensional thinning of the crust. This episode allowed the deposition of the 2,000 to 3,000 m of interbedded lacustrine deltaic sandstone and shale rocks of the Dentale Formation and its organic-rich Crabe facies (figs. 11 and 12). The Crabe facies was deposited on a lacustrine deltaic platform (Teisserenc and Villemin, 1990).

Syn-rift offshore rocks of the northern part of the Congo Basin (Republic of the Congo) range in age from Neocomian to Barremian and consist of lacustrine and fluvial rocks (Baudouy and Legorjus, 1991; Harris, 2000). The Neocomian Vandji Sandstone (figs. 13 and 14) overlies the Precambrian basement and consists of coarse sandstone equivalent to the Basal Sandstone of the South Gabon subbasin (fig. 11). The Sialivakou Shale and Djeno Sandstone (fig. 13) are Neocomian to Barremian lacustrine shales and turbidite sandstones equivalent to the lower part of the Bucomazi, whereas the Barremian organic-rich lacustrine shales and marls and dolomitic black shales of the Pointe Noire Marl, as much as 500 m thick, are equivalent to the Melania Formation lacustrine shale in the South Gabon subbasin and the middle part of the Bucomazi Formation of the central and southern (also known as the lower Congo Basin) parts of the Congo Basin (figs. 13 and 15). The Barremian Pointe Indienne Shale and Toca Formation consist of lacustrine siliciclastic shales and carbonate rocks equivalent to the Melania and Dentale Formations in the South Gabon subbasin (fig. 11).

When active rifting began in the Early Cretaceous, the pre-rift rocks in the central and southern parts of the Congo Basin (fig. 1) underwent extensive block faulting and erosion forming a graben-lacustrine depositional setting. The succeeding syn-rift rocks in the Congo Basin (fig. 1) range from Neocomian to early Aptian in age (fig. 15) and consist of lacustrine, alluvial, and fluvial rocks (Brice and others, 1982; McHargue, 1990; Schoellkopf and Patterson, 2000; Da Costa and others, 2001). These include the Lucula Sandstone and Bucomazi Formation in the offshore part of the basin.

The syn-rift Neocomian Lucula Sandstone (fig. 15) consists of well-sorted, quartzose, micaceous sandstone

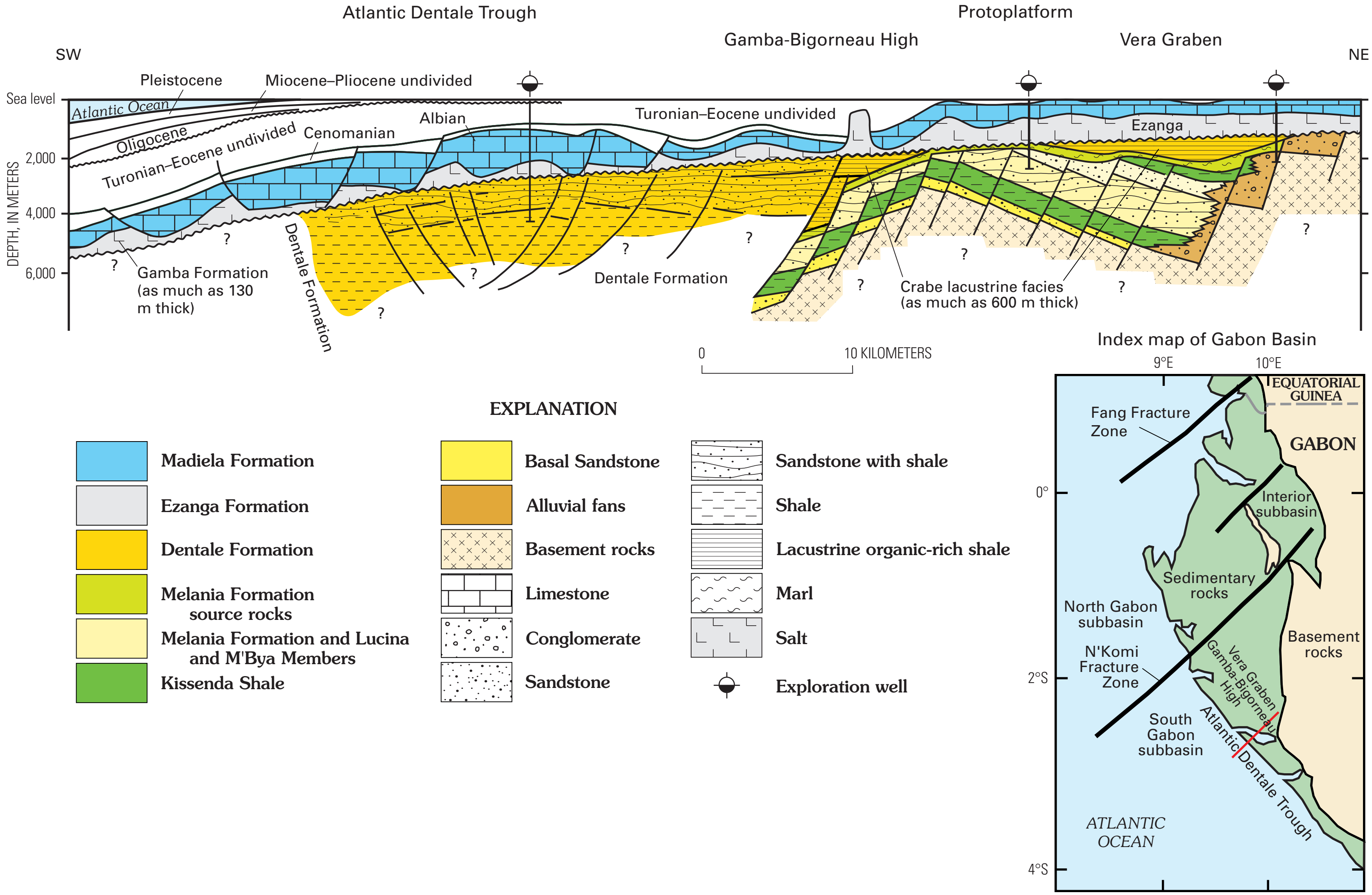


Figure 12. Schematic cross section, showing relationships between the Atlantic Dentale Trough, Gamba-Bigorneau High, and the protoplatform, South Gabon subbasin, Gabon, equatorial west Africa. Modified from Teisserenc and Villemin (1990). Location of the cross section shown by red line in index map.

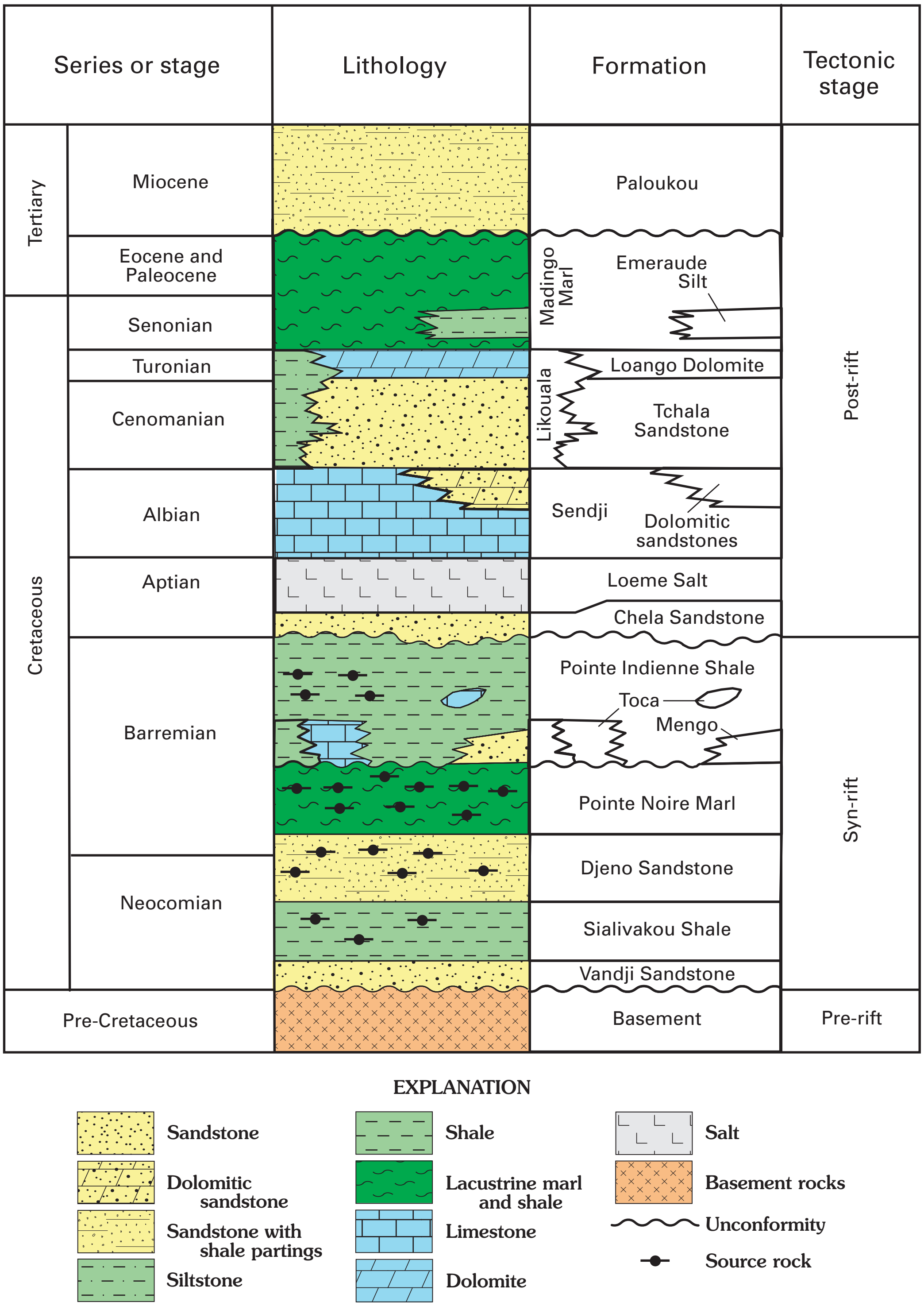


Figure 13. Generalized stratigraphic column, showing ages, lithology and potential source rocks, formation names, and tectonic stages of the Congo Basin, Democratic Republic of the Congo, equatorial west Africa. Pointe Noire Marl consists of lacustrine marls and shales containing total organic carbon contents from 1 to 5 percent, although some units locally reach 20 to 30 percent. Modified from Baudouy and Legorjus (1991).

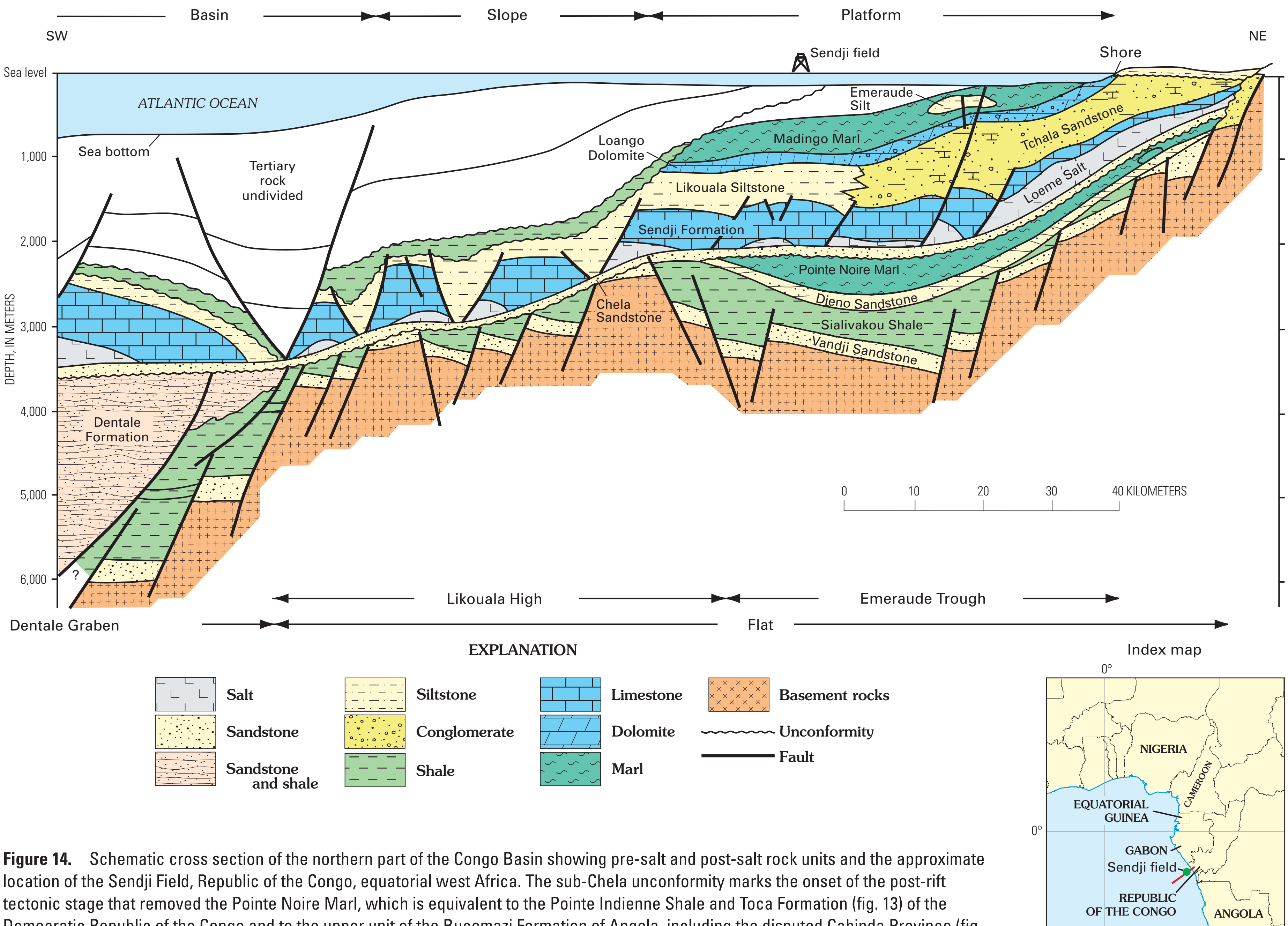
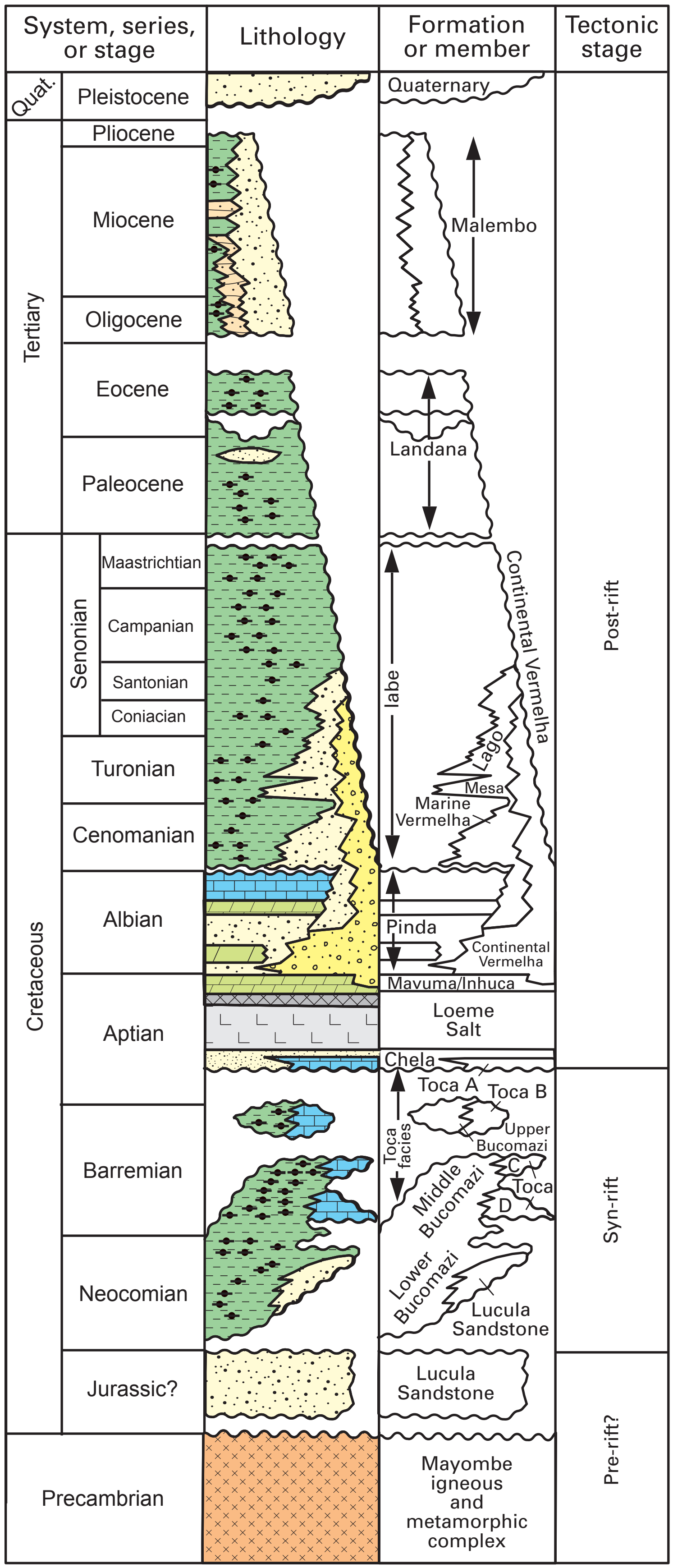


Figure 14. Schematic cross section of the northern part of the Congo Basin showing pre-salt and post-salt rock units and the approximate location of the Sendji Field, Republic of the Congo, equatorial west Africa. The sub-Chela unconformity marks the onset of the post-rift tectonic stage that removed the Pointe Noire Marl, which is equivalent to the Pointe Indienne Shale and Toca Formation (fig. 13) of the Democratic Republic of the Congo and to the upper unit of the Bucomazi Formation of Angola, including the disputed Cabinda Province (fig. 15). Structural features are approximately located in figure 15 index map. Modified from Baudouy and Legorjus (1991). Location of the cross section shown by red line in index map.



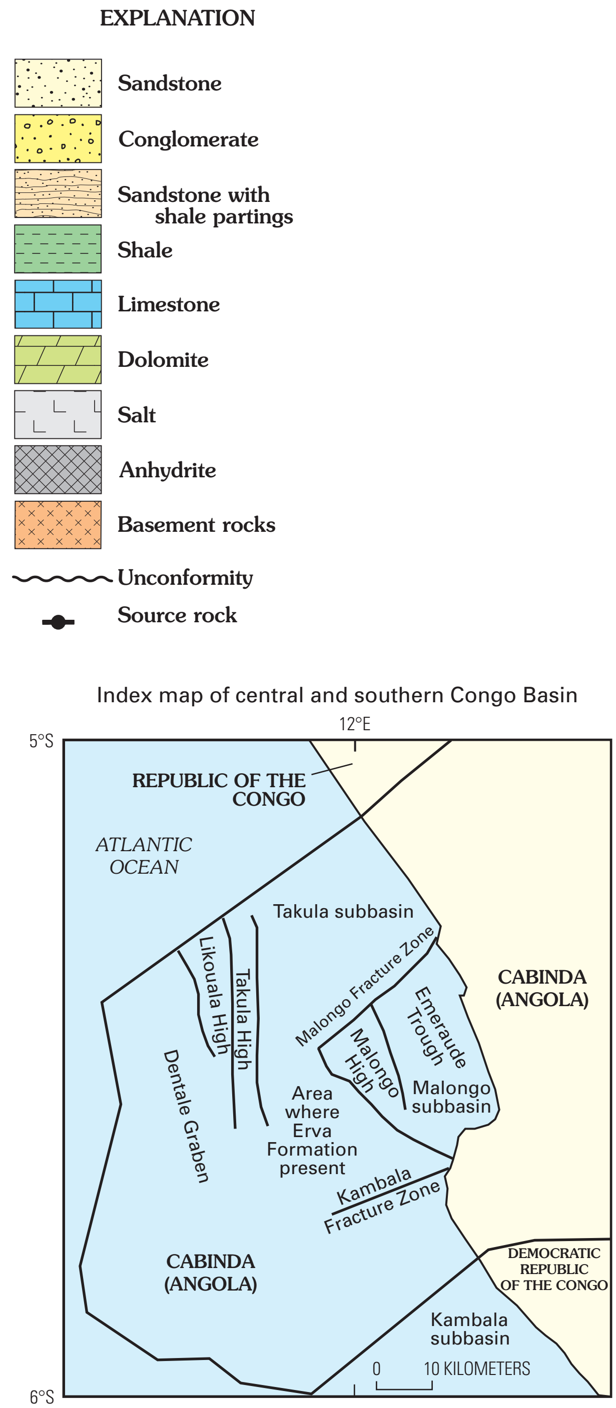


Figure 15. Generalized stratigraphic column of the central and southern (also known as lower) parts of the Congo Basin, showing ages, lithology and potential source rocks, formation names, and tectonic stages of the Republic of the Congo and Angola including the disputed Cabinda Province (fig. 1), equatorial west Africa. Modified from McHargue (1990), Schoellkopf and Patterson (2000), and Da Costa and others (2001).

and unconformably overlies the pre-rift Jurassic(?) part of the Lucula Sandstone (McHargue, 1990; Schoellkopf and Patterson, 2000). The Lucula Sandstone is thickest along the eastern margin of the Congo Basin (McHargue, 1990) in the Democratic Republic of the Congo, interfingers with the lower part of the Bucomazi (fig. 15), and is thought to shale-out westward. McHargue (1990) defined two environments of deposition for the Lucula: (1) the so-called S-Lucula (straight Lucula), which was derived from nearby Neocomian basement highs and deposited as alluvial-fan deposits, and (2) the L-Lucula (lobate Lucula) that intertongues with the green shale facies of the lower part of the Bucomazi, which is a shoreline facies of the Bucomazi Formation derived from both nearby highlands and the S-Lucula.

The Neocomian to Barremian Bucomazi Formation (fig. 15) is divided into three informal units (McHargue, 1990; Schoellkopf and Patterson, 2000). The lower part of the Bucomazi exceeds 1,000 m and consists of laminated shale, mudstone, calcareous shale, marl, and sandstone. The middle part of the Bucomazi consists of organic-rich shale, carbonate mudstone, and marl and may be as thick as the lower Bucomazi, whereas the upper part of the Bucomazi consists of green to brown mudstone and gray shale and is at least 400 m thick (Schoellkopf and Patterson, 2000). The depositional thickness of the upper Bucomazi is unknown because of erosion prior to the deposition of the post-rift Toca A part of the Toca Formation and Chela Sandstone (fig. 15). The Bucomazi Formation was deposited in an anoxic lacustrine environment that became less anoxic with the deposition of the upper part of the Bucomazi. The middle and upper parts of the Bucomazi Formation are equivalent to the Point Noire Marl and Pointe Indienne Shale of the northern part of the Congo Basin (fig. 13). Stratigraphically the Bucomazi Formation unconformably overlies or interfingers with the Lucula Sandstone and is separated by an unconformity from the overlying Chela Sandstone. Toca Formation carbonate rocks overlie the Bucomazi conformably in some places and unconformably in others. The thickness of the Bucomazi Formation ranges to more than 2,100 m but varies considerably across the offshore part of the disputed Cabinda Province and the Congo Basin region (McHargue, 1990).

In the western offshore part of the Congo Basin, at least 1,200 m of the Erva Formation (McHargue, 1990), a unit temporally equivalent to the Lucula Sandstone and Bucomazi Formation, consists of argillaceous sandstone and interbedded organic-rich shale and well-sorted sandstone. West of the Malongo High, the Erva Formation comprises a series of fan-delta and interbedded organic-rich lacustrine deposits (index map, fig. 15); the fact that the unit has not been found in the central and eastern parts of the Congo Basin suggests a western source from an intrarift highland or possibly from the western rift margin, now in Brazil.

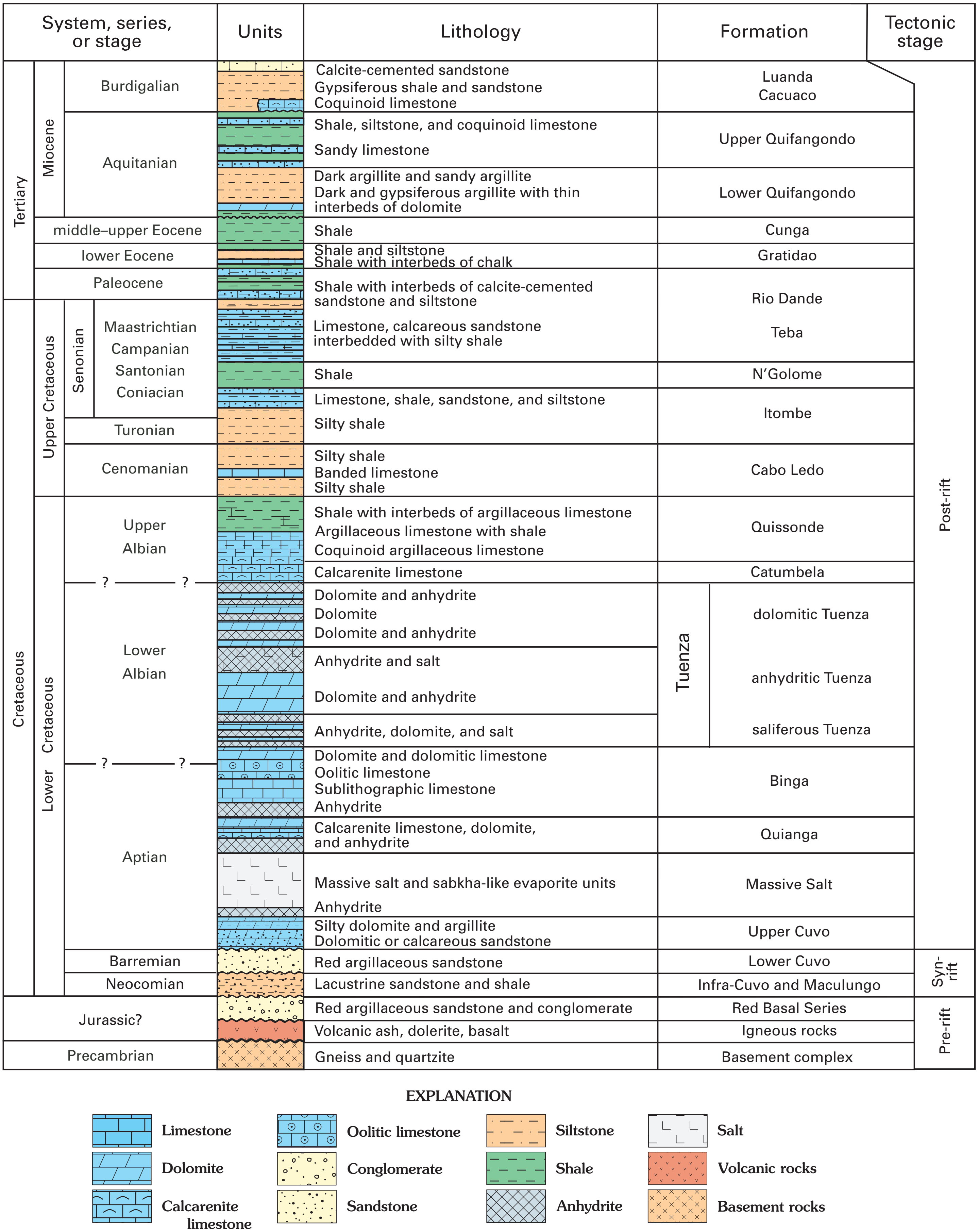
The Toca Formation represents the uppermost syn-rift rocks in the Congo Basin. The Toca, as much as 300 m thick, consists of limestone, dolomite, minor shale, and sandy carbonate rocks. The Toca Formation was informally divided into four units (McHargue, 1990); the lower three units (Toca B, C, and D) interfinger with the Bucomazi Formation (fig. 15), and the uppermost unit (Toca A) interfingers with the post-rift Chela Sandstone.

The Kwanza Basin (figs. 1, 16, 17, and 18) is separated into inner (onshore) and outer (offshore) basins, and these in turn are dissected by three major basement structural highs (the “transfer zones” in fig. 18) where Aptian salt is thin or absent (Hudec and Jackson, 2002). The structural highs (horsts?) are the Flamingo, Ametista, and Benguela Platforms (fig. 18) and most likely are equivalent to the Cabo Ledo Uplift, Longa Ridge, and Morro Liso Ridge (not shown in fig. 18), respectively, of Brognon and Verrier (1966). The inner Kwanza Basin, which includes the present-day onshore region and some nearshore areas, is an interior salt basin confined by basement highs to the west and Precambrian highlands to the east, whereas the outer Kwanza Basin, which includes the western offshore part of the basin, developed as a continental-margin basin. The independent development of the two basins resulted in the deposition of stratigraphically different but time-equivalent units.

The syn-rift rocks of the inner Kwanza Basin of southern Angola are represented by the Infra Cuvo, Maculungo, and Lower (Red) Cuvo Formations (Brognon and Verrier, 1966; Burwood, 1999) and range from latest Jurassic(?) to Barremian in age (fig. 16). The Neocomian Infra Cuvo and Maculungo Formations are lacustrine in origin and consist of tuffaceous rocks, shales, organic-rich shales, and evaporites (Burwood, 1999; Coward and others, 1999). The Barremian Lower Cuvo Formation consists of conglomerate, red sandstone and claystone, and interbedded volcanic ash of continental origin (Brognon and Verrier, 1966).

Syn-rift rocks of the outer Kwanza Basin (fig. 17) are similar to the syn-rift rocks of the southern Congo Basin (fig. 18). The oldest syn-rift rocks in the offshore southern outer Kwanza Basin are Neocomian to early Barremian in age, similar to the Bucomazi Formation of the central and southern Congo Basin (fig. 17), and consist of sandstone, siltstone, shale, organic-rich shale, and minor limestone (Uncini and others, 1998; Pasley and others, 1998a). Carbonate rocks similar to the Barremian Toca Formation (fig. 17) have also been penetrated by offshore drilling and are interpreted to interfinger with the Bucomazi Formation. The outer Kwanza Basin seems to have developed in much the same way as the central and northern parts of the Aptian salt basin and the southern Brazil basins (fig. 17), where the syn-rift rocks are similar in age and lithology (Pasley and others, 1998b).

Figure 16 (following page). Generalized stratigraphic column, showing ages, lithology and formation names, and tectonic stages of the onshore Kwanza Basin (also known as the interior salt basin), Angola, equatorial west Africa. Modified from Brognon and Verrier (1966) and Burwood (1999).


System, series, or stage
Units
Lithology
Formation
Tectonic stage
Tertiary
Miocene
Burdigalian
Calcite-cemented sandstone
Gypsiferous shale and sandstone
Coquinoid limestone
Luanda
Cacuaco
Aquitanian
Shale, siltstone, and coquinoid limestone
Sandy limestone
Upper Quifangondo
Dark argillite and sandy argillite
Dark and gypsiferous argillite with thin interbeds of dolomite
Lower Quifangondo
middle–upper Eocene
Shale
Cunga
lower Eocene
Shale and siltstone
Shale with interbeds of chalk
Gratidao
Paleocene
Shale with interbeds of calcite-cemented sandstone and siltstone
Rio Dande
Cretaceous
Upper Cretaceous
Senonian
Maastrichtian
Campanian
Santonian
Coniacian
Limestone, calcareous sandstone interbedded with silty shale
Teba
Shale
N'Golome
Limestone, shale, sandstone, and siltstone
Silty shale
Itombe
Turonian
Cenomanian
Silty shale
Banded limestone
Silty shale
Cabo Ledo
Lower Cretaceous
Upper Albian
Shale with interbeds of argillaceous limestone
Argillaceous limestone with shale
Coquinoid argillaceous limestone
Quissonde
Calcarenite limestone
Catumbela
? ?
Lower Albian
Dolomite and anhydrite
Dolomite
Dolomite and anhydrite
Tuenza
dolomitic Tuenza
Anhydrite and salt
Dolomite and anhydrite
anhydritic Tuenza
Anhydrite, dolomite, and salt
saliferous Tuenza
? ?
Dolomite and dolomitic limestone
Oolitic limestone
Sublithographic limestone
Anhydrite
Binga
Aptian
Calcarenite limestone, dolomite, and anhydrite
Quianga
Massive salt and sabkha-like evaporite units
Anhydrite
Massive Salt
Silty dolomite and argillite
Dolomitic or calcareous sandstone
Upper Cuvo
Post-rift
Barremian
Red argillaceous sandstone
Lower Cuvo
Neocomian
Lacustrine sandstone and shale
Infra-Cuvo and Maculungo
Syn-rift
Jurassic?
Red argillaceous sandstone and conglomerate
Red Basal Series
Volcanic ash, dolerite, basalt
Igneous rocks
Precambrian
Gneiss and quartzite
Basement complex
Pre-rift
EXPLANATION
Limestone
Oolitic limestone
Siltstone
Salt
Dolomite
Conglomerate
Shale
Volcanic rocks
Calcarenite limestone
Sandstone
Anhydrite
Basement rocks

Post-Rift Stage

Post-rift rocks in the West-Central Coastal Province range from Aptian to Holocene in age and represent the initial opening of the Atlantic Ocean in equatorial west Africa. The initial post-rift rocks are of early to mid-Aptian age and consist of continental, fluvial, and lagoonal rocks that were deposited as rifting ceased in the province. A period of extensive deposition of evaporite units, mainly salt, followed. Younger post-rift rocks were generally deposited in two distinct regimes: (1) as transgressive units consisting of shelf clastic and carbonate rocks followed by progradational units along the continental margin and (2) as open-ocean deep-water units.

In the Douala, Kribi-Campo, and Rio Muni Basins (fig. 1), the oldest post-rift rocks are represented by mid-Aptian organic-rich shales, marls, and sandstones (Ross, 1993) of probable lacustrine origin (figs. 7, 8, and 9).

In the Interior and North Gabon subbasins (fig. 6) the initial post-rift rocks (fig. 10) are represented by the mid-Aptian Como Formation (Teisserenc and Villemin, 1990), as much as 500 m thick, consisting of sandstone, dolomite, shale, and organic-rich shale. The Como Formation is equivalent to the Gamba Formation of the South Gabon subbasin (figs. 11, 12, and 19). The Gamba Formation, as much as 130 m thick, is a transgressive unit consisting of fluvial sandstones with lagoonal rocks at the top. Where a complete section of the Gamba is present, it consists of (1) basal conglomerate, (2) poorly sorted sandstone, (3) sandy shale, (4) clean sandstone, and (5) at the top, shale interbedded with sandstone, dolomite, and (or) anhydrite at the top.

In the offshore section of the Republic of the Congo (that is, the northern part of the Congo Basin), the oldest post-rift rocks (figs. 13 and 14) are the lower Aptian Chela Sandstone, consisting of sandstone and shales deposited in a variety of environments including marine, lacustrine, and fluvial (Harris, 2000). The oldest post-rift rocks in the Congo Basin are represented by the coarse-grained clastic rocks of the lower Aptian Chela Sandstone (figs. 13, 14, and 15) and the carbonate rocks, sandstone, and shale of probable lacustrine origin that make up the Toca A unit of the Toca Formation (Brice and others, 1982; McHargue, 1990).

The basal post-rift rocks in the onshore part of the inner Kwanza Basin include the lower Aptian Upper Cuvo Formation (fig. 16) and consist of sandstone, dolomite, and limestone with minor thin coals (Brognon and Verrier, 1966; Burwood, 1999). The Upper Cuvo, as much as 300 m thick, is equivalent to the Chela Sandstone of the Congo Basin (figs. 13 and 15). In the outer Kwanza Basin the youngest post-rift rocks (equivalent to the Chela Sandstone) are represented by the thick Upper Cuvo Formation (Uncini and others, 1998; Pasley and others, 1998a, 1998b), consisting of sandstone, siltstone, shale, and minor limestone of fluvial and lacustrine origin (fig. 17). The Upper Cuvo Formation here is equivalent to the Chela Sandstone of the Congo Basin and intertongues with dolomite and anhydrite of the Upper Cuvo Formation to the east.

Pervasive Salt Deposition in the West-Central Coastal Province

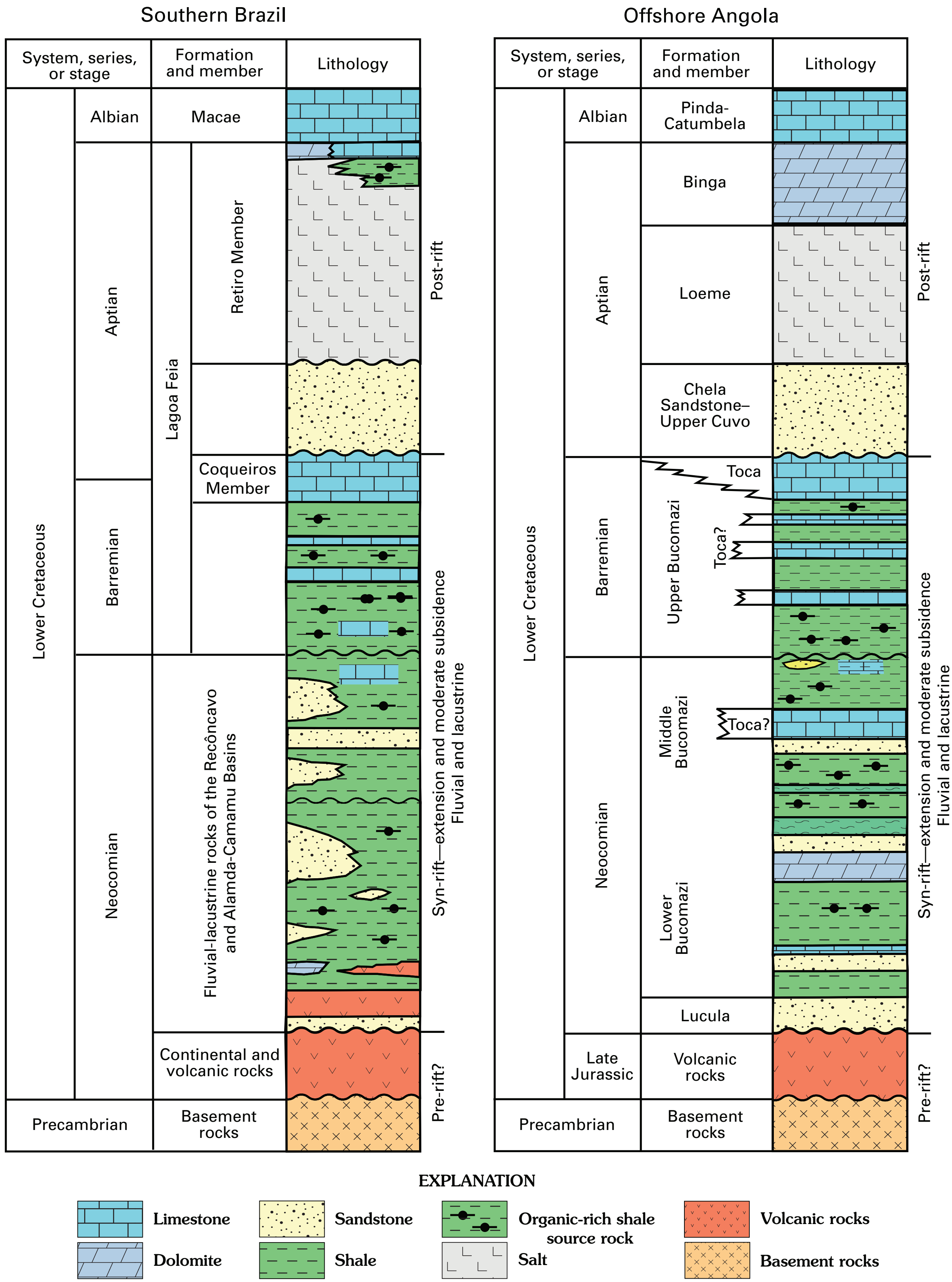
Salt was deposited during the late Aptian throughout the equatorial west Africa basins within the West-Central Coastal Province. The south end of the province had a barrier formed by the migrating Tristan da Cunha hot spot, also known as the Walvis Ridge (fig. 4), that restricted circulation from the open marine ocean to the south. The Annobon-Cameroon volcanic axis (fig. 1), which is also called the Cameroon Fracture Zone, formed during the Early Cretaceous and limited the northern extent of the Aptian salt basin.

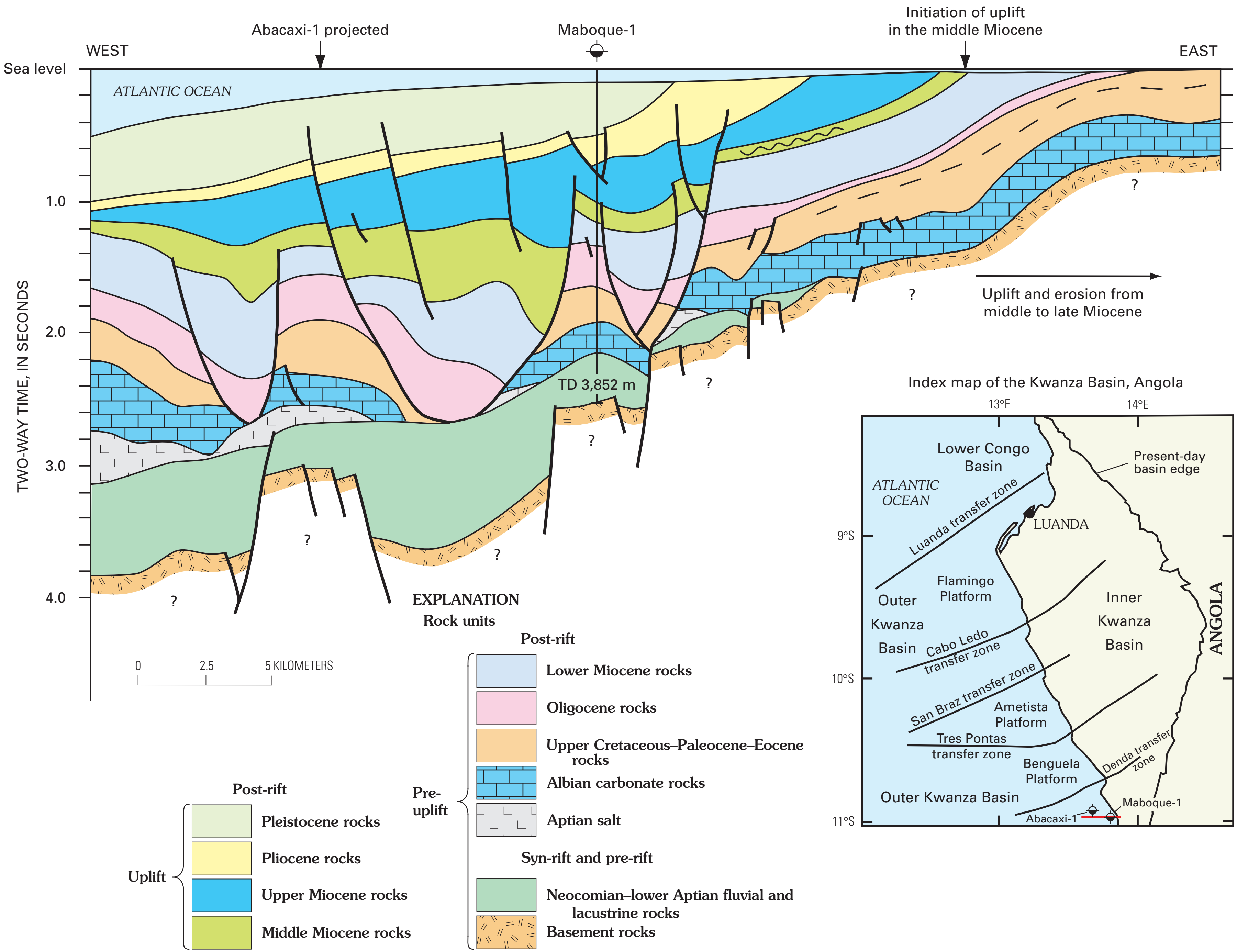
Evaporite units, as thick as 800 m, are present in the Rio Muni Basin (figs. 7 and 8) and consist of interbedded evaporites (as much as 10 m thick) and organic-rich shales (Turner, 1995) deposited in a deep lacustrine basin starved of coarser siliciclastic sediments. Overlying the evaporites is a turbidite unit at least 200 m thick that consists of sand-shale cycles and minor organic-rich shales. The evaporites and interbedded lacustrine shales thin northward and have not been penetrated by drilling in the northernmost part of the Douala Basin. However, diapiric evaporites were penetrated in the Kribi Marine-1 well in offshore Cameroon (Pauken, 1992) in the Kribi-Campo Basin (fig. 9).

The region-wide salt unit is represented in the onshore parts of the Interior, North, and South Gabon subbasins by the Ezanga Formation (figs. 10, 11, and 19), as much as 800 m thick, whereas in the offshore part of the Gabon Basin, the Ezanga may be as much as 1,000 m thick. The true thickness is difficult to estimate because of the extensive salt deformation. The Ezanga Formation is characterized by a high volume of salts; these comprise mainly carnallite ($KMgCl_3{\cdot}6H_2O$) and minor amounts of bischofite ($MgCl_2{\cdot}6H_2O$) and halite (NaCl); little anhydrite is observed in the basin, but, where present, anhydrite is restricted to thin intertongued beds and to caps on some diapirs (Teisserenc and Villemin, 1990).

Offshore Angola and the Congo Basin, massive salt deposits are represented by the Aptian Loeme Salt (figs. 13, 14, and 15), which is at least 1,000 m thick and composed of halite, potash salts (such as carnallite), and minor anhydrite. As many as four evaporite cycles (Dale and others, 1992; Brice and others, 1982) have been recognized within the unit. Near the top of the main evaporite section, thin beds of clastics are commonly found, and the salt grades upward into a regionally extensive, 50-m-thick dolomite unit representing a basin-wide freshening of the Congo Basin and the end of the Loeme

Figure 17 (following page). Generalized stratigraphic columns, showing ages, formation and member names, lithology and potential source rocks, and tectonic stages for the Lower Cretaceous rocks of the offshore marginal Kwanza Basin, west Africa, and the Alamda-Camamu and Recôncavo Basins, southern Brazil (see fig. 22). Modified from Pasley and others (1998b).


Southern Brazil
System, series, or stage
Formation and member
Lithology
Albian
Macae
Aptian
Barremian
Neocomian
Lower Cretaceous
Precambrian
Lagoa Feia
Retiro Member
Coqueiros Member
Fluvial-lacustrine rocks of the Recôncavo and Alamda-Camamu Basins
Continental and volcanic rocks
Basement rocks
Post-rift
Syn-rift—extension and moderate subsidence
Fluvial and lacustrine
Pre-rift?
Offshore Angola
System, series, or stage
Formation and member
Lithology
Albian
Pinda-Catumbela
Binga
Aptian
Loeme
Chela Sandstone–Upper Cuvo
Barremian
Toca
Upper Bucomazi
Toca?
Neocomian
Middle Bucomazi
Toca?
Lower Bucomazi
Lucula
Late Jurassic
Volcanic rocks
Precambrian
Basement rocks
Lower Cretaceous
Post-rift
Syn-rift—extension and moderate subsidence
Fluvial and lacustrine
Pre-rift?
EXPLANATION
Limestone
Dolomite
Sandstone
Shale
Organic-rich shale source rock
Salt
Volcanic rocks
Basement rocks



WEST
EAST
Abacaxi-1 projected
Maboque-1
Initiation of uplift in the middle Miocene
Sea level
ATLANTIC OCEAN
TWO-WAY TIME, IN SECONDS
1.0
2.0
3.0
4.0
TD 3,852 m
?
Uplift and erosion from middle to late Miocene
0
2.5
5 KILOMETERS
EXPLANATION
Rock units
Post-rift
Uplift
Pleistocene rocks
Pliocene rocks
Upper Miocene rocks
Middle Miocene rocks
Pre-uplift
Lower Miocene rocks
Oligocene rocks
Upper Cretaceous–Paleocene–Eocene rocks
Albian carbonate rocks
Aptian salt
Syn-rift and pre-rift
Neocomian–lower Aptian fluvial and lacustrine rocks
Basement rocks
Index map of the Kwanza Basin, Angola
13°E
14°E
9°S
10°S
11°S
Lower Congo Basin
ATLANTIC OCEAN
Present-day basin edge
Luanda transfer zone
LUANDA
Flamingo Platform
Outer Kwanza Basin
Inner Kwanza Basin
ANGOLA
Cabo Ledo transfer zone
San Braz transfer zone
Ametista Platform
Tres Pontas transfer zone
Benguela Platform
Denda transfer zone
Outer Kwanza Basin
Maboque-1
Abacaxi-1

Figure 18 (preceding page). Schematic cross section based on geologic interpretation of seismic data, showing age of rock units, preuplift and uplift units, and syn-rift and post-rift units in the southern part of the Kwanza Basin, Angola. Neocomian to lower Aptian lacustrine and Albian carbonate source rocks were penetrated in the Maboque-1 well. Modified from Lunde and others (1992). Location of cross section shown by red line in index map. Abbreviation: TD, total depth.

evaporite cycle. The thick salt in the basin acts as a décollement zone for many of the post-salt growth-fault structures in the Congo Basin.

The Aptian to Albian evaporite units in the inner Kwanza Basin (fig. 16) were deposited as a succession of evaporite cycles beginning with the Massive Salt (Brognon and Verrier, 1966). The Massive Salt, as much as 600 m thick, is overlain by eight sabkha-like evaporite cycles with a total thickness of as much as 1,400 m. The sabkha evaporite units become less saline upward. Overlying the Massive Salt and sabkha units are two carbonate-evaporite cycles, the Quianga and Binga Formations (fig. 16), which are followed by six depositional cycles whose salt, anhydrite, and dolomite units are grouped into the Tuenza Formation. The unit was divided into three members on account of the upward transition from penesaline to nearly normal marine conditions. The complete evaporite section intertongues with continental facies in the easternmost part of the Kwanza Basin (Brognon and Verrier, 1966; Burwood, 1999). The evaporite unit in the outer Kwanza Basin (fig. 17) consists of massive halite and interbedded anhydrite, similar to the Loeme Salt of the Congo Basin and the Retiro Member of the Lagoa Feia Formation of Brazil (Pasley and others, 1998a, 1998b; Uncini and others, 1998).

Salt-Related Deformation and Progradational Sedimentation

Thick ramp- or shelf-carbonate units were deposited from south to north in the Aptian salt basin of west Africa during Albian to Turonian time, and beneath those units the salt began to flow by both differential loading and gravity sliding. High-energy shoal areas developed over the salt diapirs and swells, and clastic sediments with reservoir potential were deposited along the continental margin. The upper Albian Catumbela Formation found in the southern offshore and marginal part of the Kwanza Basin (fig. 17) is the oldest shelf carbonate unit in the basins of west Africa. The Catumbela consists of oolitic limestone and is the lateral equivalent of (1) the dolomitic Tuenza Formation (Danforth and others, 1997) and the Catumbela Formation (calcarenite) of the inner Kwanza Basin (figs. 16 and 17) and (2) the upper Albian Pinda Formation in the southern Congo Basin (fig. 15). The Pinda Formation, as much as 1,200 m thick, consists of cyclic carbonate and siliciclastic units deposited in a sabkha to shallow-marine environment. The lower units of the Pinda Formation consist of interbedded dolomite, sandstone, conglomerate, and evaporites deposited during the initial flooding of the basin by normal-marine waters. The upper units of the Pinda Formation consist of shelf-carbonate rocks. The lowermost shelf carbonate in the outer Kwanza Basin is the Binga Formation, a transitional unit between the massive Aptian salt and the shelf carbonates. In the inner Kwanza Basin, the Binga is the second of eight evaporative cycles above the Massive Salt (Brognon and Verrier, 1966).

In the northern part of the Congo Basin, the shelf-carbonate rocks are represented by the Albian Sendji Carbonate, consisting of high-energy dolomitic, oolitic limestones and interbedded sandstone units deposited in tidal channels in the lower part and as offshore bars and shoreface units in the upper part (fig. 13).

In the North Gabon (fig. 10) and the offshore part of the South Gabon (fig. 19) subbasins, the shelf-carbonate rocks are represented by the Albian to lower Cenomanian Madiela Formation, ranging from 90 to 1,500 m in thickness, and the Turonian Sibang Limestone Member (Teisserenc and Villemin, 1990). Deformation of the underlying Ezanga Formation evaporites during the deposition of the shelf-carbonate Madiela Formation resulted in its wide range in thickness.

The shelf-carbonate rocks in the Rio Muni Basin consist of middle Albian to Cenomanian cyclic, shallowing-upward units of oolitic limestone and calcarenite from 5 to 15 m thick (Turner, 1995). Shelf carbonates in the Cameroon Kribi-Campo Basin are similar to the Rio Muni carbonate rocks and are represented by carbonate rocks in the Mengo Formation (fig. 9), whereas in the Douala Basin of northernmost Cameroon, the Mungo Formation lacks massive shelf-carbonate rocks.

Widespread organic-rich marine mudstones and marls developed lateral to and above the shelf carbonates in the Aptian salt basin during the early post-rift phase in Albian to Maastrichtian time (figs. 7, 9, 13, 15, and 19). These marine rocks include the Madingo Marl and the Logbadjeck, Mengo, Cap Lopez, Azile, and Iabe Formations. The regional extent and organic richness of these marine rocks suggest that marine circulation between the North and South Atlantic was still partially restricted in the Gulf of Guinea during their deposition (figs. 1 and 5). A regional erosional event that began during the early Senonian and continued into the Paleogene formed a widespread unconformity.

Cenozoic sedimentation was dominated by progradational marine sedimentation that included the development of several Tertiary deltas, especially those of the Niger and Congo Rivers in the Niger Delta Province and West-Central Coastal Province, respectively. This progradational phase resulted in the deposition of regressive sandstones and siltstones, turbidites, and deep-marine shale units during the Paleocene and Eocene. Calcareous mudstones and marls were deposited in the Paleocene and Eocene in the Douala Basin (Coward and others, 1999). A worldwide Oligocene lowering of sea level resulted in nondeposition and erosion in the Aptian salt basin (Edwards and Bignell, 1988a). Continued drifting during the

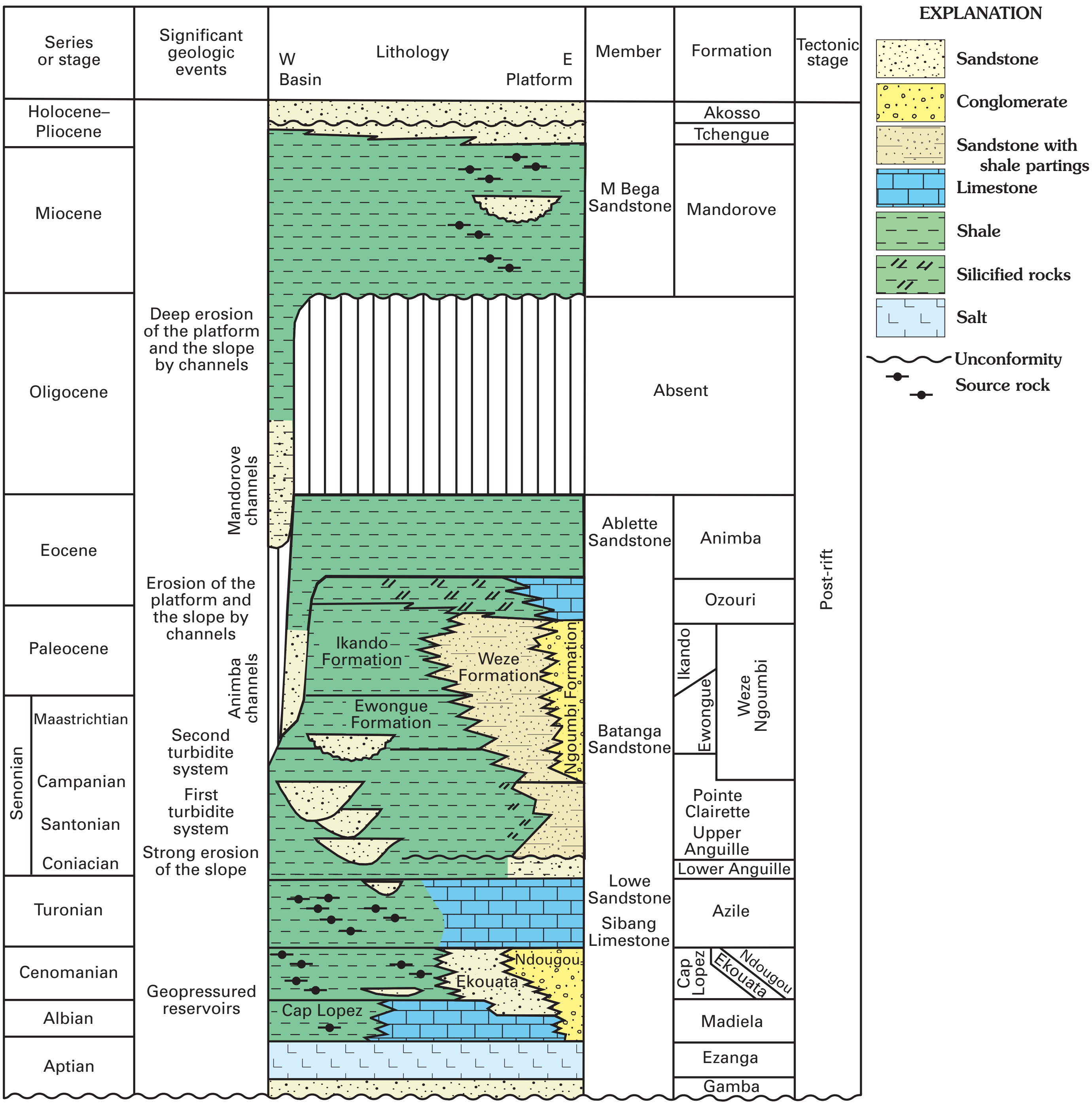


Figure 19. Generalized stratigraphic column, showing ages, significant geologic events, lithology and potential source rocks, member and formation names, and tectonic stage of the offshore part of the North Gabon and South Gabon subbasins, equatorial west Africa. Modified from Teisserenc and Villemin (1990).

Neogene caused westward tilting and subsidence of the west African marginal basins, which accentuated the erosion of the continental slope and formed a regional Miocene unconformity (Da Costa and others, 2001). The Miocene unconformity represents an important event for the occurrence of hydrocarbons because in some basins the erosion cut part way into the prolific Albian to Cenomanian reservoir rocks. The unconformity may form hydrocarbon traps and seals (Edwards and Bignell, 1988a). The post-Miocene rocks in the Aptian salt basin consist of poorly sorted marine rocks with localized channel-fill sandstones and turbidites.

Petroleum Occurrence in the West-Central Coastal Province

Hydrocarbons have been found both onshore and offshore in several formations in the West-Central Coastal Province. The best-understood hydrocarbon occurrences in the province are in Cretaceous and Tertiary reservoirs in the Douala, Kribi-Campo, Rio Muni, Gabon, Congo, and Kwanza Basins (fig. 1).

Hydrocarbon Source Rocks in the West-Central Coastal Province

Cretaceous Source Rocks

The Cretaceous source rocks most closely related to hydrocarbon discoveries and production in the West-Central Coastal Province are the syn-rift Neocomian to Aptian organic-rich shales and marls. A series of graben and half-graben basins along the Early Cretaceous rifted margins of western Africa and Brazil formed depocenters for organic-rich lacustrine shales and marls. In the offshore Lower Congo and outer Kwanza Basins of Angola, this syn-rift event produced the lacustrine source rocks of the Bucomazi Formation (figs. 15 and 17), which is as much as 1,500 m thick (McHargue, 1990). Time-equivalent organic-rich lacustrine rocks include the Pointe Noire Marl of the northern part of the Congo Basin (figs. 13 and 14) and the Kissenda and Melania Formations of the offshore South Gabon subbasin (fig. 11), respectively, as well as the Lagoa Feia (Campos Basin), Guaratiba (Santos Basin), Mariricu (Espirito Santos Basin), and Itaípe (Alamda-Camamu Basin) Formations of Brazil (Coward and others, 1999; Schiefelbein and others, 1999).

The source rocks in the middle units of the Bucomazi Formation contain Type I kerogens and have a wide range of total organic carbon (TOC) percentages. These generally average more than 5 weight percent, although some analyses show TOC contents as high as 20 weight percent. The source rocks of the lower and upper units of the Bucomazi contain Type I and Type II kerogens and average 2–3 weight percent TOC, although some organic-rich claystones locally contain more than 10 percent TOC (Brice and others, 1982; Schoellkopf and Patterson, 2000).

Hydrocarbon source rocks within the early syn-rift section of the outer Kwanza Basin contain thick, organic-rich, lacustrine shales, which have abundant Type I kerogen (Pasley and others, 1998b). These source rocks are limited in regional extent because they were deposited within grabens. The upper part of the syn-rift section contains source rocks that are more widespread. These syn-rift source rocks were deposited during a regional sag phase and contain shales rich in Type I and Type II kerogens. Analyses from Bucomazi time-equivalent source rocks in the southern outer Kwanza Basin contain Type I kerogens (Pasley and others, 1998b) and have an average TOC content of 3.1 weight percent; some analyzed samples had TOC contents greater than 20 weight percent (Geochemical and Environmental Research Group, 2003).

In the northern part of the Congo Basin, potential source rocks are numerous in the Neocomian to Barremian syn-rift rocks. The lacustrine Pointe Noire Marl (fig. 13) contains Type I and Type II saprolitic organic matter averaging from 1 to 5 weight percent TOC; some source rocks contain more than 20 weight percent TOC (Baudouy and Legorjus, 1991). The Sialivakou Shale and lower part of the Djeno Sandstone contain Type II and Type III organic matter and have TOC contents averaging 1 weight percent. The upper part of the Djeno Sandstone contains Type I and Type II saprolitic organic matter and generally has a TOC content of 1 to 5 weight percent, but some source rocks contain as much as 20 weight percent TOC (Baudouy and Legorjus, 1991).

In the South Gabon subbasin, the most important source rock is the uppermost part of the Barremian Melania Formation (figs. 11 and 20). The Melania Formation organic-rich source rock was deposited in a low-energy lacustrine environment. The source rock consists of varved, pyritic shale and has an average TOC content of 6.1 weight percent (Teisserenc and Villemin, 1990); some analyzed samples contained as much as 20 weight percent TOC. Although the Melania Formation has not been penetrated by drilling in the North Gabon subbasin, either onshore or offshore, it should be considered a potential hydrocarbon source. Less is known about the Neocomian Kissenda Shale source rocks because they are encountered in only a few onshore wells. The Kissenda Shale consists of organic shale with interbeds of siltstone and carbonaceous shale deposited in a lacustrine environment. The facts that Kissenda source rocks contain mostly Type III or Type II/III kerogens and have an average TOC content of 1.5 to 2 weight percent suggest a partially terrestrial source. Type II/III kerogens have compositions between Type II and Type III kerogens and intermediate hydrogen indexes (HI; 200–300 mg HC/g TOC). The Kissenda Shale in the South Gabon subbasin is similar to the lower unit of the Congo Basin's Bucomazi Formation (fig. 15), which is considered to be landward of the organic-rich middle unit of the Bucomazi and closer to the sources of fresh water in the stratified lake (McHargue, 1990). These stratigraphic relationships suggest that the Kissenda Shale in the center of the offshore Gabon Basin may be similar to the middle unit of the Bucomazi.

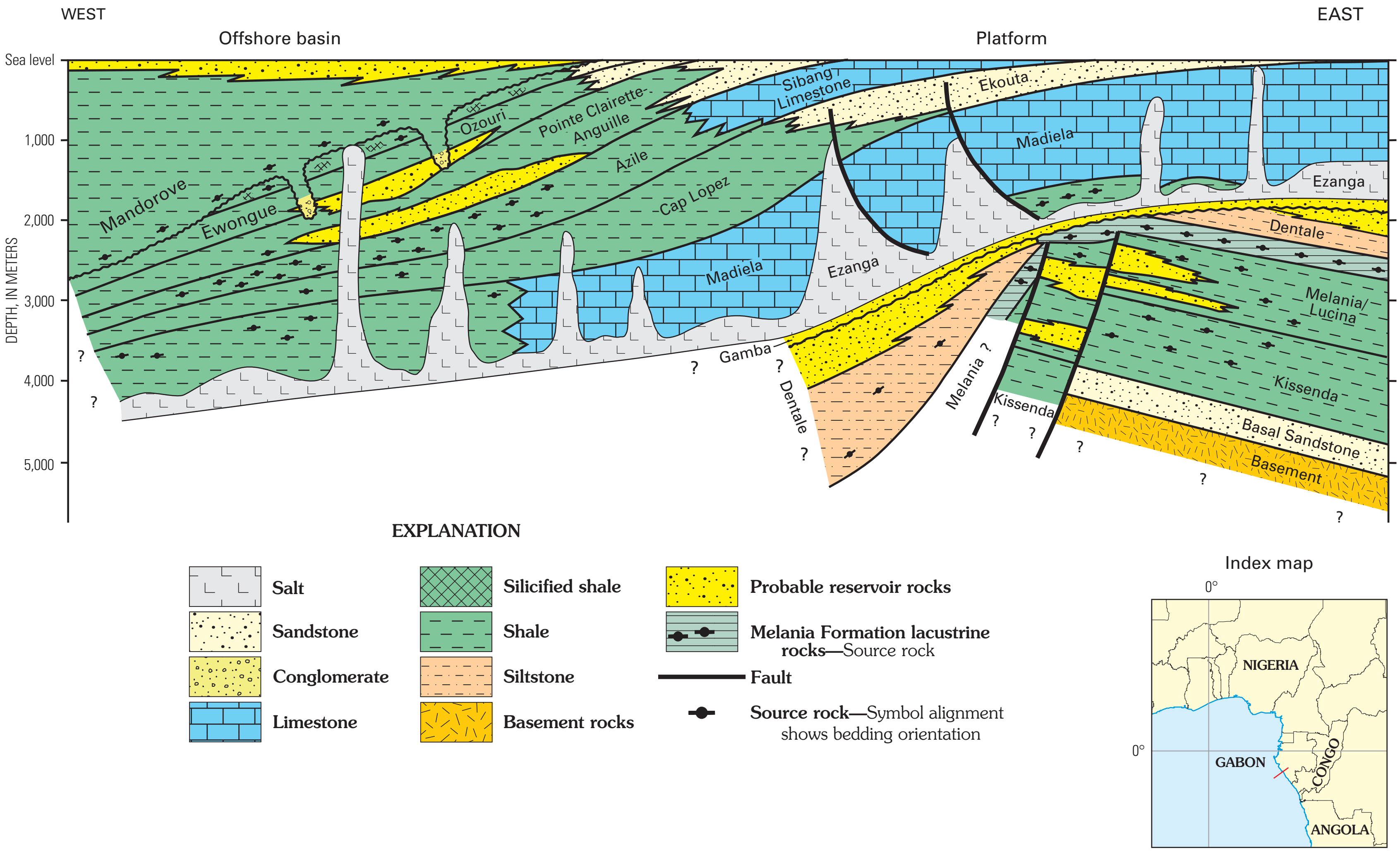


Figure 20. Schematic cross section, showing lithology, formation name, known source rocks, and probable reservoir rocks in the southern part of the Gabon Basin, Gabon, equatorial west Africa. Modified from Teisserenc and Villemin (1990). Location of cross section shown by red line in index map.

In the Rio Muni Basin (fig. 8), the Kissenda Shale–equivalent lacustrine source rocks of Barremian to Aptian age are found underlying and interbedded with the Aptian evaporites (Turner, 1995). These lacustrine rocks constitute the Rio Muni Basin's primary source rock, consisting chiefly of algal kerogen with TOC contents of as much as 6 weight percent. In the Kribi-Campo Basin of Cameroon (fig. 9), similar evaporites were penetrated in the Kribi Marine-1 offshore well (Pauken, 1992). Aptian evaporites have also been identified in the Douala Basin (Coward and others, 1999; Oba, 2001), and analyses of oil seeps in the Douala Basin suggest that there may be lacustrine source rocks (fig. 9) interbedded with these thin evaporite beds toward the center of the basin (Tamfu and others, 1995).

Upper Albian to Maastrichtian source rocks, consisting of marine marls, were deposited during the early post-rift phase in the Aptian salt basin, from the Douala Basin in the north to the Kwanza Basin in the south. The outer Kwanza Basin (fig. 18) may contain Cenomanian to Maastrichtian marine shales and marls that resulted from deep-water sedimentation in graben basins that developed over a detachment surface in the salt (Duval and others, 1992; Lundin, 1992) along the regionally subsiding Late Cretaceous shelf edge. These rocks are equivalent to the Iabe Formation in the Congo Basin (fig. 15).

Analyses of marine source rocks (marls and shales) from the Cenomanian to Maastrichtian Iabe Formation in the central and southern Congo Basin generally contain TOC contents greater than 2 weight percent; some intervals have contents as high as 3 to 5 weight percent. The organic matter in these samples consists mostly of Type II kerogens, but some Type I kerogens are found in organic-rich intervals (Schoellkopf and Patterson, 2000). The Madingo Marl (Senonian to Eocene) of the Democratic Republic of the Congo part of the Congo Basin (fig. 13) consists of marine marls (Baudouy and Legorjus, 1991) and may be equivalent, in part, to the Iabe Formation (fig. 15).

Analyses of the upper Albian to Cenomanian Madiela and Cap Lopez Formations in the North and South Gabon subbasins (figs. 19 and 20) have shown excellent source rock potential, but data from these units are scarce. Deep Sea Drilling Project data (Leg 40, Site 364; Tissot and others, 1980) indicate that these units contain TOC contents as high as 10 weight percent. The Turonian Azile Formation, though, is probably the most important source unit in offshore fields south of Port Gentil (fig. 6). The source rocks of the Azile Formation contain mostly marine-algae-derived, Type II/III kerogens and have an average TOC content of 3 to 5 weight percent (Teisserenc and Villemin, 1990). Potential source rocks showing characteristics similar to those of the Azile Formation have been found in the Anguille and Pointe Clairette Formations (fig. 19) but lack regional distribution.

The Rio Muni Basin (fig. 7) contains Cenomanian to Turonian source rocks (Equatorial Guinea Ministry of Mines and Energy, 2003) for which chemical data suggest deposition in similar paralic to hypersaline marine settings. These source rock-bearing units may be equivalent to the Cap Lopez and Azile Formations in the Gabon Basin (fig. 19). Geochemical analyses on hydrocarbon samples suggest that oil-prone source rocks probably exist in the Upper Cretaceous Logbadjeck and Mengo Formations in the Douala and Kribi-Campo Basins (fig. 9), and paleoenvironmental data suggest that these source rocks were deposited in paralic-deltaic to hypersaline marine settings (Ackerman and others, 1993). In corroboration with the source rock studies, chemical studies of oil-seep samples suggest that the oils could have been derived from rocks deposited in a hypersaline marine environment.

Tertiary Source Rocks

Paleocene to Miocene marine source rocks exist in the West-Central Coastal Province. Oil-prone, deep-water source rocks contain Type II, Type II/III, and Type III kerogens, whereas the gas-prone source rocks are associated with Tertiary deltas and contain mostly Type III kerogens. However, the source rocks are generally immature.

The Paleocene N'Kapa and the Oligocene Souellaba Formations in the Douala and Kribi-Campo Basins of Cameroon contain marine source rocks (fig. 9). Miocene deep-marine, oil-prone source rocks with mixed Type II and Type III kerogens are found in the northern part of the Douala Basin of Cameroon (Equatorial Guinea Ministry of Mines and Energy, 2003). These rocks have a TOC content of 1 to 2 weight percent and may be locally mature owing to elevated heat flow from the Annobon-Cameroon volcanic axis (fig. 1). Gas-prone Miocene source rocks that contain Type III kerogens and have TOC contents of 1 to 2 weight percent are found associated with the Sanaga Sud gas field in the southern part of the Douala Basin, whereas oil-prone source rocks are rare (Pauken, 1992). Somewhat farther south, Paleocene source rocks (fig. 7) have been reported in the Rio Muni Basin (Ross, 1993).

The Miocene Mandorove Formation (figs. 19 and 20), of the South Gabon subbasin, contains coaly source rocks with an average TOC content of 4 to 5 weight percent. Some higher values have also been measured, but the formation is thermally immature throughout the basin.

In the central and southern Congo Basin, the Paleocene to Eocene source rocks of the Landana Formation consist primarily of deep-water shales. They generally have TOC contents as high as 3 to 5 percent, similar to those of the Iabe Formation (fig. 15). The mid-Oligocene to Miocene Malembo Formation (fig. 15) generally has TOC contents of 1 to 2 weight percent; the lower and upper parts of the formation contain from 2 to 5 weight percent TOC in the form of Type II and Type II/III kerogens.

The fact that the subsidence was regional indicates that the outer Kwanza Basin should contain similar Paleocene to Oligocene source rocks. Miocene uplift of the inner Kwanza Basin resulted in the deposition of 3,000 m of sediments in the outer Kwanza Basin. The offshore section now contains deep-marine source rocks in fault-controlled troughs (Lunde and others, 1992). Analyses show that marine source rocks with Type II and Type II/III kerogens contain 2 to 10 weight percent TOC (Raposo and Inkollu, 1998), and the oil compositions in discoveries in the outer Kwanza Basin also suggest a marine source.

Correlation of West African Oils and Source Rocks to Those of South America

The Brazil and west Africa continental margins share similar stratigraphic units (fig. 17) and tectonic history because of their proximity before and during the breakup of Africa and South America in Late Jurassic to Late Cretaceous time. As a result of the paleogeographic ties between the South American and African plates, the oil habitats of the rift and marginal basins (fig. 21) of both continents can be correlated (Schiefelbein and others, 2000). The lacustrine oils of the southern part of the Congo Basin and of the Kwanza Basin of west Africa were generated from brackish lacustrine source rocks and can be correlated to the Recôncavo and Alamda-Camamu Basins of Brazil. Lacustrine oils from the South Gabon subbasin also seem to correlate to oils in the Recôncavo Basin of Brazil. Lacustrine oils of the central and northern parts of the Congo Basin (fig. 21) were generated from deep-water (freshwater) lacustrine source rocks and could not be correlated to Brazilian oils (Schiefelbein and others, 1999). Some marine oils from the Sergipe Basin in Brazil and the northern part of the Gabon Basin may be genetically related (Schiefelbein and others, 2000).

Hydrocarbon Generation and Migration in the West-Central Coastal Province

Oil generation has been active in the Aptian salt basin from the Late Cretaceous to the present (Schoellkopf and Patterson, 2000), while the sedimentary depocenters, sites of hydrocarbon generation, and charging systems have shifted westward through time as the western African continental margin prograded westward.

Timing of oil generation from syn-rift source rocks in the Douala, Kribi-Campo, and Rio Muni Basins is not well understood, but most of the hydrocarbons were likely generated from the Late Cretaceous to the present (Pauken, 1992). Upper Cretaceous and Tertiary source rocks in the post-rift (post-salt) section may be locally mature and may have been generating hydrocarbons from mid-Tertiary time (figs. 7, 8, and 9). Mature Cretaceous and Tertiary source rocks have not been penetrated in the Douala and Rio Muni Basins, but chemical analyses of oil samples from seeps and wells indicate that generation and migration have occurred from lacustrine as well as from shallow-marine to lagoonal source rocks located in the deeper parts of the basins (Tamfu and others, 1995).

In the North and South Gabon subbasins, oil generation has been active from the Late Cretaceous to the present (Edwards and Bignell, 1988a). The Melania Formation lacustrine shale (fig. 11) is widespread in the South Gabon subbasin, both offshore and onshore, and is the major source of hydrocarbons in the basin (Teisserenc and Villemin, 1990). Thermal maturity gradients observed in the onshore and offshore syn-rift section in the South Gabon subbasin are higher than gradients calculated from models (Teisserenc and Villemin, 1990). This thermal maturity anomaly is due to (1) higher heat flow associated with the earliest phase of rifting and (2) erosion of overburden rocks from uplifted blocks during rifting. Burial history graphs of post-rift source rocks in the Madiela, Cap Lopez, and Azile Formations in the North and South Gabon subbasins indicate that the rocks did not mature until the Miocene (Teisserenc and Villemin, 1990). The zone of oil generation in the South Gabon subbasin that corresponds to vitrinite reflectance values of 0.5 to 1.0 (fig. 22) occurs at depths of 1,000 to about 2,000 m.

The timing of oil generation from hydrocarbon sources in the Congo Basin's Bucomazi Formation (fig. 15)—and in stratigraphically equivalent source rocks such as the Melania Formation lacustrine shale and Pointe Noire Marl (figs. 11 and 13)—varies slightly from the south to north in the basins. Most of the oil was generated during the Cenomanian to Paleocene interval, but generation of small amounts continues to the present (Schoellkopf and Patterson, 2000). Geochemical modeling also suggests that oil generation and migration started in the Late Cretaceous (Orsolini and others, 1998), has been enhanced by Tertiary sediment downloading, and is still active today. The Iabe and Landana Formations (fig. 15) and their stratigraphically equivalent source rocks began generating oil in the middle Miocene and continue into the present. In the eastern parts of the basin, the rate of oil generation slowed after the Cretaceous owing to the lack of further deposition of Tertiary overburden rocks (Schoellkopf and Patterson, 2000). This slowing is quite evident in the Democratic Republic of the Congo part of the Congo Basin (figs. 13 and 14), where the post-salt source rock (Madingo Marl) is immature, and in the Congo Basin and South Gabon subbasin, where the Miocene Malembo and Mandorove Formations (figs. 15 and 19), respectively, are mostly immature. Exceptions are seen where deep troughs are filled with Tertiary rocks because of rafting of the underlying marine section on the Aptian salt (Schoellkopf and Patterson, 2000).

In the inner Kwanza Basin, Miocene erosion of overburden had a direct effect on the regional maturation of post-salt units in the outer Kwanza Basin. As much as 2,000 m of sedimentary rocks was eroded, and the detritus was redeposited in the outer Kwanza Basin, where offshore troughs contain as much as 3,000 m of Miocene rocks (Lunde and others, 1992). Maturation levels sufficient to generate oil are much shallower in the inner Kwanza Basin compared to the outer Kwanza Basin. Offshore well data show the onset of oil generation (Ro = 0.5 percent) at the depth of 4,000 m, whereas onshore well data show this maturity level at depths ranging from 2,000 to 3,000 m. Most of the oil in the inner Kwanza Basin was probably generated in the Miocene, but the outer Kwanza Basin post-rift source rocks were still immature at that time. The offshore syn-rift source rocks most likely

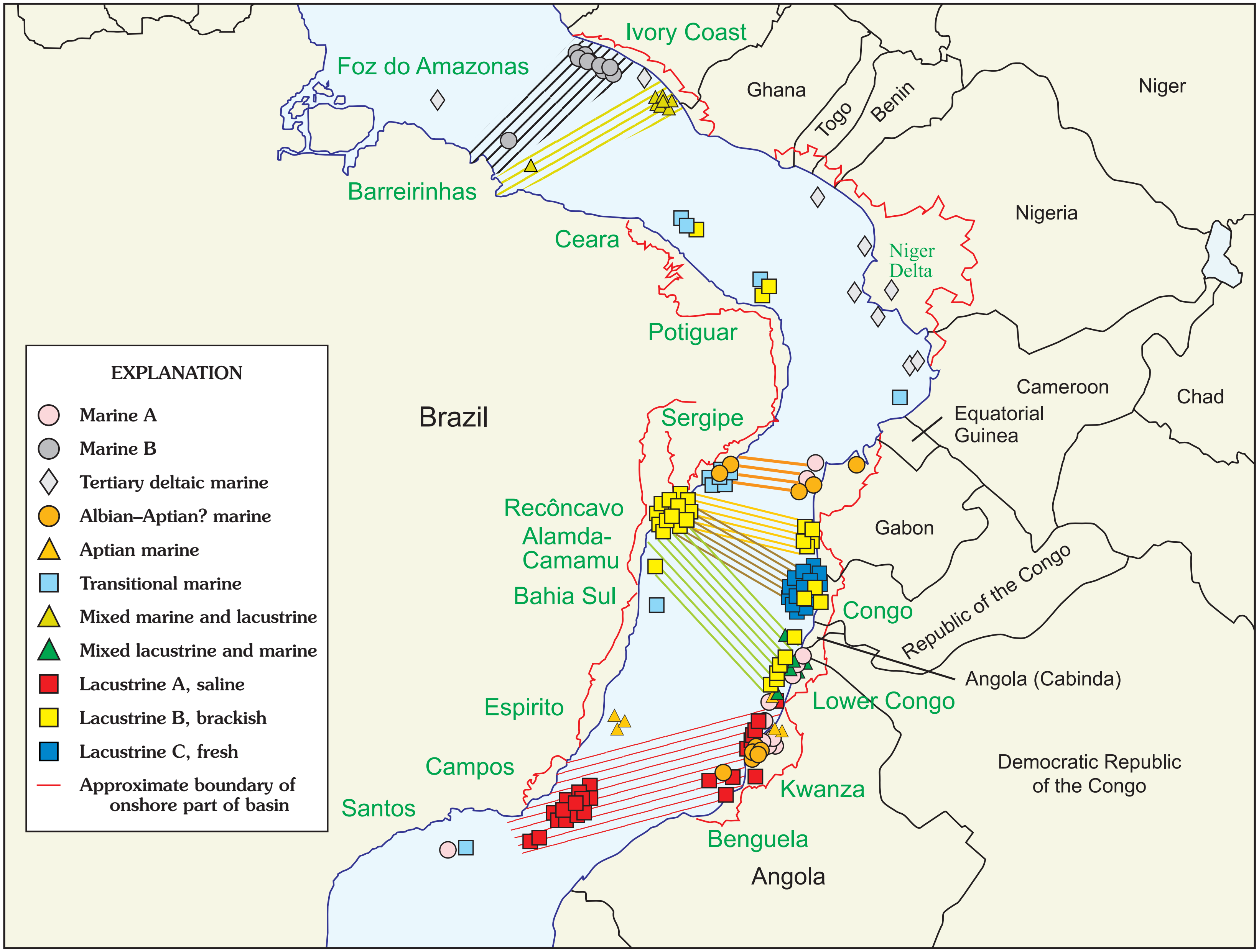


Figure 21. Schematic map of the South Atlantic margin (intervening ocean is collapsed to increase scale), showing families of oils and their distribution, depositional environments of source rocks, and major basins. Major basin names are shown in green, and oil families are shown by colored symbols. Modified from Schiefelbein and others (1999, 2000).

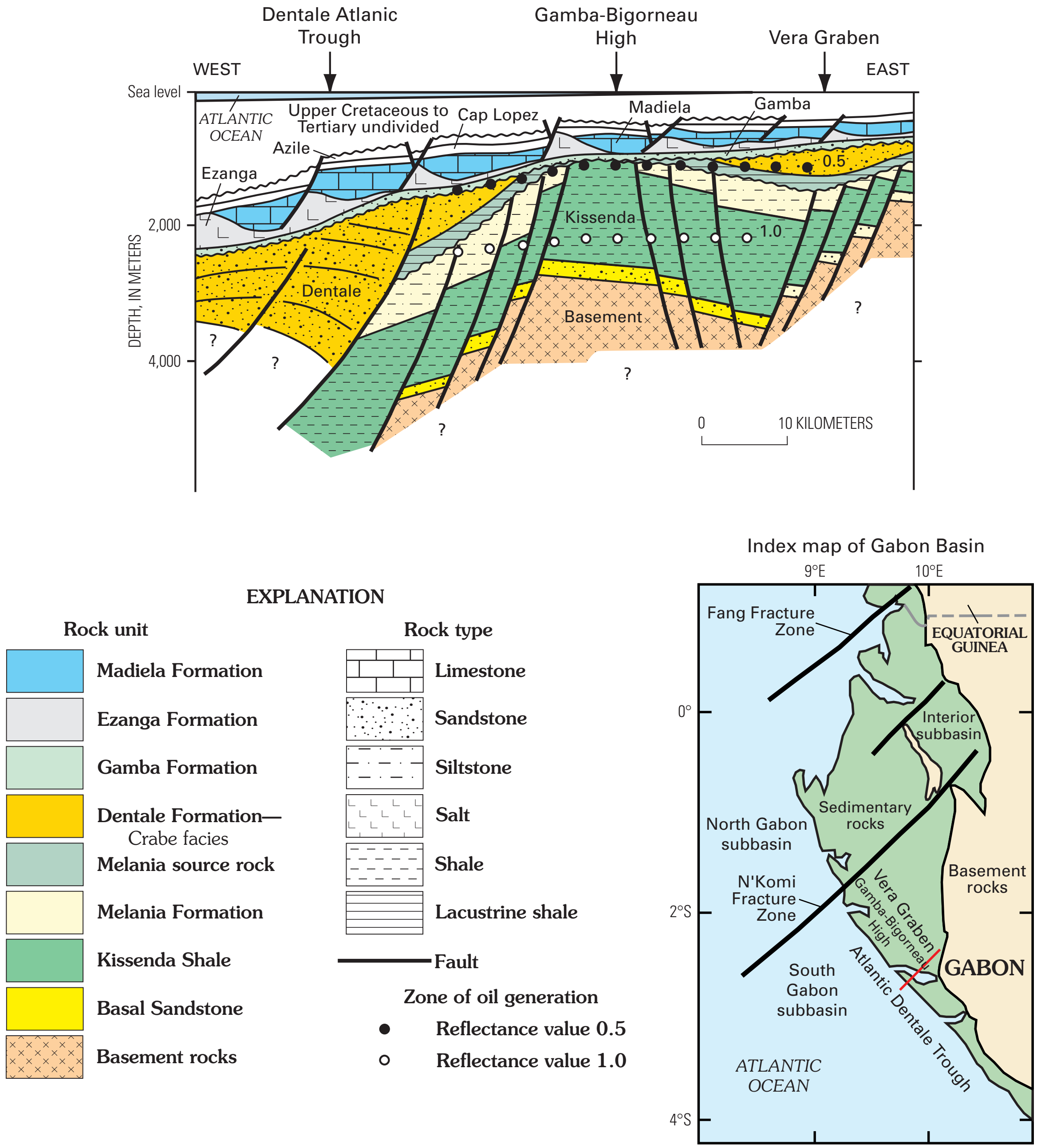


Figure 22. Schematic cross section, showing formations, lithology, and the zone of oil generation through the Gamba-Bigorneau High, South Gabon subbasin, equatorial west Africa. Modified from Teisserenc and Villemin (1990). Location of cross section shown by red line in index map.

reached maturity during early Tertiary time (Danforth and others, 1997) but, as in the Congo Basin, may have reached maturity as early as the Late Cretaceous (Schoellkopf and Patterson, 2000).

Migration pathways are predominantly fault related and generally nearly vertical in the West-Central Coastal Province. Salt windows provide the major migration pathways for syn-rift oils into the post-salt reservoirs. Significant lateral migration of syn-rift oil has taken place along clastic units directly underlying the regional salt in the Aptian salt basin, such as the Chela Sandstone in the Congo Basin (figs. 13, 14, and 15). Stratigraphically equivalent sub-salt units—the Como, Gamba, and Upper Cuvo Formations in the North Gabon subbasin, South Gabon subbasin, and offshore part of the outer Kwanza Basin, respectively—also act as lateral oil-migration pathways (figs. 10, 11, 12, 17, 19, and 20).

Hydrocarbon Reservoir Rocks, Traps, and Seals

A limited number of core studies in the offshore Douala Basin (fig. 1) have shown that the Lower Cretaceous submarine fan and fan-delta sandstone reservoir rocks are as thick as 100 m and have porosities ranging from 20 to 25 percent and an average permeability of 142 millidarcies (mD) (Pauken, 1992). Upper-fan or turbidite-channel deposits are less well sorted and therefore have lower porosities. Interpretations of higher resolution seismic data indicate a variety of potential syn-rift reservoir rocks, including Aptian to Albian deep-water sandstone units deposited as submarine fans, fan-deltas, and turbidites with their associated channel sediments (Pauken and others, 1991).

Syn-rift reservoir rocks in the Rio Muni Basin consist of lacustrine and fluvial sandstones, whereas post-rift reservoir rocks consist of both sandstone and carbonate rocks. Potential traps include fault blocks, rollovers, and salt structures with Cenomanian to Senonian shales acting as seals. Interpretations of higher resolution seismic data indicate that Turonian to Paleocene deep-water turbidite rocks may be potential hydrocarbon reservoirs with hydrocarbon traps consisting of stratigraphic pinchouts, shale-channel truncations, or thickened sandstone units related to growth faults. Miocene submarine-fan units are also potential reservoir rocks in the Rio Muni Basin.

The Lower Cretaceous section of the Interior, North, and South Gabon subbasins (figs. 10 and 11) contains many potential reservoir units in the N'Dombo Formation and Basal Sandstone, the Lucina and M'Bya Members of the Melania Formation, and the Dentale and Gamba Formations. The N'Dombo and the Basal Sandstone are present throughout most of the Interior and South Gabon subbasins, but only a few wells have penetrated them. The N'Dombo and Basal Sandstone have the best reservoir properties (Brink, 1974): porosity is as high as 25 percent, and the permeabilities are as great as 100 mD (Teisserenc and Villemin, 1990). Near the eastern margin of the Interior and South subbasins, other wells have tested the Basal Sandstone closer to the source, where it consists of clay-rich conglomerate with poor reservoir properties. The Basal Sandstone has not been penetrated by drilling in the North Gabon subbasin, but seismic data suggest it should be present. The Lucina Member sandstones have porosities ranging from 15 to 25 percent and permeabilities from 10 to 100 mD; the M'Bya Member most likely has similar reservoir characteristics. In the upper part of the Dentale Formation, reservoir sandstones have porosities as high as 29 percent and permeabilities as great as 1 D (Teisserenc and Villemin, 1990), whereas in the Rabi-Kounga field the Dentale Formation sandstones are the main hydrocarbon reservoirs and have porosities of nearly 30 percent and permeabilities of several darcies (Boeuf and others, 1992). The Gamba Formation sandstone reservoirs have porosities ranging from 20 to 30 percent and permeabilities ranging from 100 to 5,000 mD (Teisserenc and Villemin, 1990; Boeuf and others, 1992).

The offshore sedimentary section of the Congo Basin includes many potential reservoirs and traps. The syn-rift reservoir rocks include the pre-rift Jurassic(?) Lucula Sandstone and syn-rift Neocomian Lucula Sandstone and Toca Formation carbonate rocks (fig. 15) that were deposited in eolian, alluvial, and lacustrine environments. The Toca Formation carbonate rocks have porosities ranging from 16 to 20 percent (Dale and others, 1992) and locally have permeabilities as high as 600 mD. Hydrocarbon traps in the Lucula Sandstone and Toca Formation consist of faulted basement blocks in which the Bucomazi Formation shales and the Loeme Salt form the seals. Cretaceous post-salt reservoirs in the Congo Basin include the Mavuma, Pinda, Vermelha, and Iabe Formations (fig. 15) that were deposited as lagoonal, strand-plain, and nearshore sands and carbonates. The Aptian Mavuma Formation produces oil in the Kungulo field where the reservoir properties range from poor to fair. The Vermelha Formation reservoir rocks consist of strand-plain and nearshore sandstones with porosities of 25 percent and permeabilities as great as 1,000 mD, whereas the Pinda Formation sandstone reservoirs have average porosities of 22 percent (porosities of some units are as high as 35 percent) and permeabilities of 150 mD (Dale and others, 1992). Traps associated with the Vermelha and Pinda Formations are rollover anticlines in which marine shales act as seals. The Turonian to Coniacian Mesa and Lago Members of the Iabe Formation (fig. 15) contain sandstone reservoir rocks with interbedded limestone and dolomite; these reservoir units display variable porosity and permeability (Schoellkopf and Patterson, 2000). Traps associated with the Iabe Formation are primarily rollover structures and thickened turbidite sandstone units related to growth faults; marine-flooding shales form the seals. Tertiary reservoir rocks were deposited as turbidite channel and stacked turbidite sands and delta, pro-delta, and basin-floor-fan sands. Reservoir rocks in the Oligocene to Miocene Malembo Formation are exceptional and consist of stacked turbidite channel deposits; claystone units form the seals. The reservoir sandstone units have porosities of 20 to 40 percent and permeabilities of 1 to 5 D (Raposo and Inkollu, 1998). Eocene to Miocene turbidite channel deposits are the reservoirs in many of the most important post-1994 offshore discoveries; cumulative drill-stem tests range from 10,000 to 15,000 barrels of oil per day (Raposo and Inkollu, 1998).

Potential fluvial and lacustrine sandstone and carbonate reservoir rocks in the outer Kwanza Basin are equivalent to the Neocomian to Barremian Toca Formation (Uncini and others, 1998) of the southern Congo Basin (fig. 17). Fluvial and lacustrine sandstone reservoir rocks may also be present in equivalent rocks of the Bucomazi Formation. The Aptian Upper Cuvo Formation, of fluvial and lacustrine origin, is a potential reservoir unit and is equivalent to the Chela Sandstone of the Congo Basin. Oil accumulations are present in the Albian Catumbela Formation (fig. 17). Other potential reservoir rocks are associated with a Late Cretaceous divergent-margin phase related to regional subsidence that allowed the deposition of progradational clastic units, equivalent to the Iabe Formation of the Congo Basin.

The outer Kwanza Basin was influenced by a major Neogene uplift that removed as much as 2 km of Cretaceous and Paleogene rocks from the inner Kwanza Basin. As a result, Miocene sediments (fig. 18) were deposited to form a section currently at least 3,000 m thick (Lunde and others, 1992; Raposo and Inkollu, 1998) in Tertiary troughs that were probably formed along growth faults resulting from extension along a detachment surface within the salt (Duval and others, 1992; Lundin, 1992). These troughs or grabens developed primarily during the middle Tertiary, but some deformation appears to have started in the late Cenomanian to early Turonian (Duval and others, 1992; Lundin, 1992). Filled grabens as long as 70 km and as wide as 15 km contain both structural and stratigraphic traps.

Tertiary sandstone reservoir rocks in the outer Kwanza Basin are similar to units found in the southern Congo Basin. The outer Kwanza Basin Tertiary sandstones have porosities of 20 to 40 percent and permeabilities of 1 to 5 D. These rocks represent deposition in amalgamated or stacked turbidite channels and sand bodies in delta, pro-delta, and basin-floor-fan settings and have interbedded marine shales that act as seals (Raposo and Inkollu, 1998).

Total Petroleum Systems of the West-Central Coastal Province

Four major total petroleum systems are defined in the West-Central Coastal Province. Three regional areas in the province are delineated according to subbasin geology to separate the total petroleum systems: (1) the offshore and onshore area north of the Congo Basin includes the Gabon, Rio Muni, and Douala and Kribi-Campo Basins; (2) the Congo Basin includes the large Tertiary Congo Delta; and (3) the offshore and onshore area south of the Congo Basin includes the Kwanza and Benguela Basins (fig. 1). The West-Central Coastal Province north of the Congo Basin contains two major total petroleum systems: (1) the Melania-Gamba Total Petroleum System (fig. 2), consisting of Lower Cretaceous source and reservoir rocks, and (2) the Azile-Senonian Total Petroleum System, consisting of Albian to Turonian source rocks and Cretaceous reservoir rocks (fig. 3). The Congo Basin contains the Congo Delta Composite Total Petroleum System (figs. 2 and 3), consisting of Lower Cretaceous to Tertiary source and reservoir rocks, whereas the area south of the Congo Basin contains the Cuanza Composite Total Petroleum System, consisting of Lower Cretaceous to Tertiary source and reservoir rocks.

Five assessment units are defined in the West-Central Coastal Province:

Total Petroleum System	Assessment Unit
Melania-Gamba	Gabon Subsalt
Azile-Senonian	Gabon Suprasalt
Congo Delta Composite	Central Congo Delta and Carbonate Platform
Congo Delta Composite	Central Congo Turbidites
Cuanza Composite	Cuanza-Namibe

Input-data forms describing each assessment unit are given in the U.S. Geological Survey World Petroleum Assessment 2000—Description and Results, Disk 3 (U.S. Geological Survey World Energy Assessment Team, 2000).

Melania-Gamba Total Petroleum System (720301)

The Melania-Gamba Total Petroleum System was defined north of the Congo Basin (fig. 2). An events chart (fig. 23) for this total petroleum system summarizes the ages of the source, seal, and reservoir rocks as well as the timing of trap development, generation, and migration of hydrocarbons.

The primary source rocks of the Melania-Gamba Total Petroleum System are found in the syn-rift section north of the Congo Delta and are composed of Neocomian and Aptian continental and lacustrine rocks (figs. 7–11). The lacustrine shales are highly organic, especially the upper part of the Melania Formation (fig. 11) in the Gabon Basin where the total organic carbon (TOC) content averages 6.1 weight percent and reaches as high as 20 percent (Teisserenc and Villemin, 1990). The organic-rich black shale section is 200 to 600 m thick and contains both Type I and Type II kerogens. Source rocks of secondary importance are the lacustrine shales found in the Neocomian Kissenda Formation (fig. 11). The Kissenda contains source rocks averaging 1.5 to 2 weight percent TOC in Type II/III kerogens. Lacustrine syn-rift generated oils are paraffinic. Maturation and migration probably began in the Late Cretaceous (fig. 23) and have continued to the present. In the Rio Muni Basin, similar lacustrine source rocks of Barremian to Aptian age (figs. 7 and 8) contain as much as 6 weight percent TOC (Turner, 1995), and geochemical evidence suggests that lacustrine source rocks may exist in the Douala Basin.

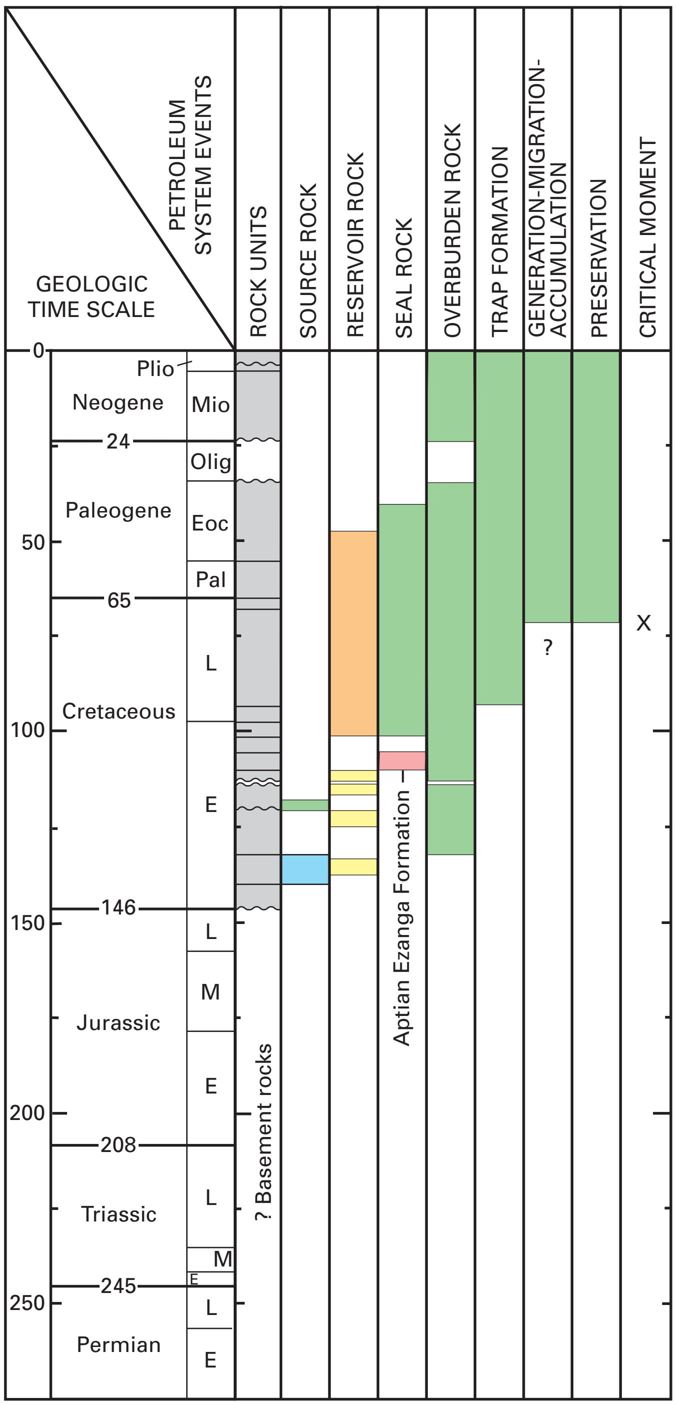


Figure 23. Events chart for the Melania-Gamba Total Petroleum System (720301) and the Gabon Subsalt Assessment Unit (72030101). Light-gray shading indicates rock units present (figs. 7, 11, and 19). Light blue indicates secondary or possible occurrence of source rocks depending on quality and maturity of the unit. Age ranges of primary source, seal, reservoir, and overburden rocks and the timing of trap formation and generation, migration, and preservation of hydrocarbons are shown in green and yellow. Aptian Ezanga Formation (regional evaporite unit) is shown in pink. Orange indicates probable reservoir rocks containing lacustrine oil in the Douala and Rio Muni Basins (figs. 8 and 9).

Reservoir rocks in the syn-rift section are primarily fluvial and shoreface sandstones of the Gamba Formation. In the Rabi-Kounga field (fig. 6, index map), the Gamba Formation sandstone reservoirs have porosities ranging from 25 to 30 percent and permeabilities ranging from 100 to as high as 5,000 mD (Teisserenc and Villemin, 1990; Boeuf and others, 1992). Some lacustrine deltaic sandstones of the Dentale Formation have porosities as high as 29 percent and permeabilities as high as several darcies (Teisserenc and Villemin, 1990; Boeuf and others, 1992). Lacustrine turbiditic sandstones of the Melania Formation and particularly its Lucina Member also produce hydrocarbons; these reservoir rocks have porosities as high as 25 percent and permeabilities as high as 100 mD (Teisserenc and Villemin, 1990). Reservoir rocks in the Douala Basin consist of Lower Cretaceous submarine fans and fan-delta sandstones with porosities ranging from 20 to 25 percent and permeabilities as high as 142 mD. Trap formation began in the Late Cretaceous; traps are mostly broad anticlines in the Gamba Formation, but some traps are formed by rift structures (Teisserenc and Villemin, 1990; Boeuf and others, 1992). The Ezanga Formation salt forms a regional seal, although some hydrocarbons may have migrated through faults that have penetrated the Ezanga and equivalent rocks. This possibility is especially likely in the Douala and Rio Muni Basins where Upper Cretaceous reservoir rocks have been charged with lacustrine oils. Other hydrocarbon traps are stratigraphic and include fluvial and lacustrine sandstone units in the Dentale and Melania Formations, including the Lucina and M'Bya Members (fig. 11); shales are the seals.

Gabon Subsalt Assessment Unit (72030101)

The Gabon Subsalt Assessment Unit of the Melania-Gamba Total Petroleum System includes syn-rift source rocks and reservoir rocks north of the Congo Basin (fig. 1). The eastern boundary of the assessment unit was defined as the eastern limit of the Cretaceous rocks, whereas the western boundary was set at 4,000-m water depth (fig. 2). Most of the discoveries have been made since 1970, and most of the discovered fields have been small or moderate in size. One giant field, Rabi-Kounga (fig. 6, index map; 1,400 million barrels), was discovered in 1985 (Boeuf and others, 1992).

Most of the exploration has taken place onshore or in shallow water. Dense jungle has hampered onshore exploration. Exploration for syn-rift reservoirs has also been hampered by the difficulty of resolving seismic reflections below the Ezanga Formation salt. These statements suggest that exploration is still immature in the syn-rift section and that there may be more undiscovered fields than have already been discovered (17 oil and 2 gas fields). We concluded, however, that Rabi-Kounga is the largest field in the assessment unit and that no larger undiscovered field remains to be found.

The USGS assessed mean undiscovered volumes of 727 million barrels of oil (MMBO), 3,674 billion cubic feet of gas (BCFG), and 172 million barrels of natural gas liquids (MMBNGL) (tables 2 and 3). The expected sizes of the

Table 2. Summary of estimated undiscovered volumes of conventional oil, gas, and natural gas liquids for undiscovered oil and gas fields in the West-Central Coastal Province, west Africa, showing allocations to the offshore and onshore for each petroleum system and assessment unit.

[MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. MFS, minimum field size assessed (MMBO or BCFG). Prob., probability (including both geologic and accessibility probabilities) of at least one field equal to or greater than the MFS. Results shown are fully risked estimates. For gas fields, all liquids are included under the NGL (natural gas liquids) category. F95 represents a 95 percent chance of at least the amount tabulated. Other fractiles are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. Shading indicates not applicable. Totals do not reflect rounding]

Code and Field Type	MFS	Prob. (0-1)	Undiscovered Resources											
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
720301 Melania-Gamba Total Petroleum System														
72030101 Gabon Subsalt Assessment Unit Onshore (59.8% of undiscovered oil fields and 32.2% of undiscovered gas fields allocated to onshore)														
Oil Fields	1	1.00	127	408	833	435	265	891	1,990	979	12	43	105	49
Gas Fields	6						86	562	1,544	656	4	24	71	29
Total		1.00	127	408	833	435	350	1,453	3,533	1,635	16	67	176	78
72030101 Gabon Subsalt Assessment Unit Offshore (40.2% of undiscovered oil fields and 67.8% of undiscovered gas fields allocated to offshore)														
Oil Fields	1	1.00	85	274	560	292	178	599	1,338	658	8	29	71	33
Gas Fields	6						181	1,183	3,250	1,382	8	51	150	61
Total		1.00	85	274	560	292	359	1,782	4,588	2,040	16	80	220	94
720302 Azile-Senonian Total Petroleum System														
72030201 Gabon Suprasalt Assessment Unit Onshore (10.55% of undiscovered oil fields and 11.8% of undiscovered gas fields allocated to onshore)														
Oil Fields	1	1.00	131	479	1,100	531	170	651	1,634	744	8	32	85	37
Gas Fields	6						146	638	1,629	729	6	27	75	32
Total		1.00	131	479	1,100	531	316	1,288	3,263	1,473	14	59	160	69
72030201 Gabon Suprasalt Assessment Unit Offshore (89.45% of undiscovered oil fields and 88.2% of undiscovered gas fields allocated to offshore)														
Oil Fields	1	1.00	1,110	4,065	9,329	4,500	1,444	5,518	13,857	6,305	67	269	721	316
Gas Fields	6						1,088	4,765	12,174	5,452	45	204	559	240
Total		1.00	1,110	4,065	9,329	4,500	2,532	10,283	26,032	11,757	113	473	1,281	556

Table 2. Summary of estimated undiscovered volumes of conventional oil, gas, and natural gas liquids for undiscovered oil and gas fields in the West-Central Coastal Province, west Africa, showing allocations to offshore and onshore for each petroleum system and assessment unit.—Continued

[MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. MFS, minimum field size assessed (MMBO or BCFG). Prob., probability (including both geologic and accessibility probabilities) of at least one field equal to or greater than the MFS. Results shown are fully risked estimates. For gas fields, all liquids are included under the NGL (natural gas liquids) category. F95 represents a 95 percent chance of at least the amount tabulated. Other fractiles are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. Shading indicates not applicable. Totals do not reflect rounding]

Code and Field Type	MFS	Prob. (0-1)	Undiscovered Resources											
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
720303			**Congo Delta Composite Total Petroleum System**											
72030301			Central Congo Delta and Carbonate Platform Assessment Unit Onshore (14.25% of undiscovered oil fields and 14.25% of undiscovered gas fields allocated to onshore)											
Oil Fields	1	1.00	245	644	1,154	666	507	1,404	2,814	1,500	23	68	149	75
Gas Fields	6						151	500	1,068	540	6	21	50	24
Total		1.00	245	644	1,154	666	657	1,904	3,882	2,040	30	89	199	99
72030301			Central Congo Delta and Carbonate Platform Assessment Unit Offshore (85.75% of undiscovered oil fields and 85.75% of undiscovered gas fields allocated to offshore)											
Oil Fields	1	1.00	1,473	3,878	6,943	4,010	3,050	8,450	16,934	9,027	141	410	898	451
Gas Fields	6						907	3,007	6,427	3,247	37	128	300	143
Total		1.00	1,473	3,878	6,943	4,010	3,956	11,457	23,361	12,274	178	538	1,198	593
72030302			Central Congo Turbidites Assessment Unit Offshore (100% of undiscovered oil fields and 100% of undiscovered gas fields allocated to offshore)											
Oil Fields	10	1.00	5,778	17,561	34,409	18,522	11,999	38,265	83,026	41,605	564	1,859	4,341	2,080
Gas Fields	60						2,644	12,026	30,195	13,663	109	513	1,398	602
Total		1.00	5,778	17,561	34,409	18,522	14,643	50,290	113,220	55,268	673	2,372	5,739	2,682
720304			**Cuanza Composite Total Petroleum System**											
72030401			Cuanza-Namibe Assessment Unit Onshore (9.9% of undiscovered oil fields and 9.9% of undiscovered gas fields allocated to onshore)											
Oil Fields	1	1.00	8	60	212	78	8	58	218	78	0	3	11	4
Gas Fields	6						7	47	248	76	0	2	11	3
Total		1.00	8	60	212	78	15	105	467	154	1	5	22	7
72030401			Cuanza-Namibe Assessment Unit Offshore (90.1% of undiscovered oil fields and 90.1% of undiscovered gas fields allocated to offshore)											
Oil Fields	1	1.00	76	548	1,926	712	72	532	1,987	712	3	26	102	36
Gas Fields	6						60	426	2,259	692	3	18	101	30
Total		1.00	76	548	1,926	712	133	957	4,246	1,404	6	44	203	66

Table 3. Summary of estimated undiscovered volumes of conventional oil, gas, and natural gas liquids for undiscovered oil and gas fields in the Gabon Subsalt Assessment Unit of the Melania-Gamba Total Petroleum System, West-Central Coastal Province, west Africa.

[MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. MFS, minimum field size assessed (MMBO or BCFG). Prob., probability (including both geologic and accessibility probabilities) of at least one field equal to or greater than the MFS. Results shown are fully risked estimates. For gas fields, all liquids are included under the NGL (natural gas liquids) category. F95 represents a 95 percent chance of at least the amount tabulated. Other fractiles are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. Shading indicates not applicable. Totals do not reflect rounding]

Field Type	MFS	Prob. (0-1)	Undiscovered Resources												Largest Undiscovered Field (MMBO or BCFG)			
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)							
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Oil Fields	1	1.00	212	682	1,392	727	443	1,490	3,327	1,637	20	72	176	82	45	138	434	173
Gas Fields	6						267	1,745	4,794	2,038	11	75	221	90	96	420	1,489	550
Total		1.00	212	682	1,392	727	709	3,235	8,121	3,674	32	147	397	172				

largest undiscovered oil and gas fields are 173 MMBO and 550 BCFG, respectively. The Gabon Subsalt Assessment Unit ranks as the smallest one in the West-Central Coastal Province (table 2) in terms of mean undiscovered oil. It has less potential for undiscovered resources than the overlying Gabon Suprasalt Assessment Unit.

Azile-Senonian Total Petroleum System (720302)

The Azile-Senonian Total Petroleum System was also defined (fig. 3) north of the Congo Delta (it is collocated geographically with the Melania-Gamba Total Petroleum System, 720301). An events chart (fig. 24) summarizes the ages of the source, seal, and reservoir rocks and the timing of trap development and generation and migration of hydrocarbons.

The primary source rocks for the Azile-Senonian Total Petroleum System in the Gabon Basin are marine shales and marls of the Turonian Azile Formation (fig. 19) above the Ezanga Formation salt. These shales average 3 to 5 weight percent TOC; some samples contain as much as 10 weight percent TOC (Tissot and others, 1980). The kerogens are mainly Type II/III. Other possible sources include shales in the Cap Lopez and Madiela Formations. Oils generated in this total petroleum system are paraffinic. Maturation and migration began later, during the Miocene, than for the post-rift source rocks (Teisserenc and Villemin, 1990) and have continued to the present (fig. 24).

Upper Albian to Maastrichtian source rocks in the Douala and Rio Muni Basins (figs. 7 and 9) consist of marine marls that may be equivalent to the Cap Lopez and Azile Formations. Secondary Paleocene, Oligocene, and Miocene source rocks have also been identified in these basins.

In the North Gabon subbasin, known reservoir rocks are mainly turbidite sandstones of the Senonian Anguille and Pointe Clairette Formations and Batanga Sandstone Member of the Ewongue Formation (fig. 19). Porosities average 23 percent and permeabilities average 1,500 mD. Trap formation began in the Late Cretaceous. Most traps are salt-related, primarily nonpiercement domes, sealed by shales. Some stratigraphic traps may exist that are related to turbidites.

In the deep-water parts of the Douala and Rio Muni Basins, higher resolution seismic data indicate that Upper Cretaceous and Tertiary reservoir rocks are turbidite channel and sandstone units. Possible Miocene turbidite reservoirs may also occur in the deeper water offshore. Most Miocene traps are stratigraphic and include turbidite channels and sandstones sealed by shales.

Gabon Suprasalt Assessment Unit (72030201)

The Gabon Suprasalt Assessment Unit of the Azile-Senonian Total Petroleum System includes suprasalt source rocks and reservoirs north of the Congo Basin (fig. 3). The eastern boundary of the assessment unit was defined as the eastern limit of the Cretaceous rocks, whereas the western boundary was set at 4,000-m water depth. Since the 1950s, about 75 fields have been discovered, mostly small or moderate-sized oil fields. Most of the discovered fields have been in the Ogooue River Delta area of Gabon (fig. 6). The Douala and Rio Muni Basins of Cameroon and Equatorial Guinea (fig. 1), to the north of Gabon, are also included with this assessment unit.

Most of the exploration has taken place onshore or in shallow water. Significant potential exists for the deeper water

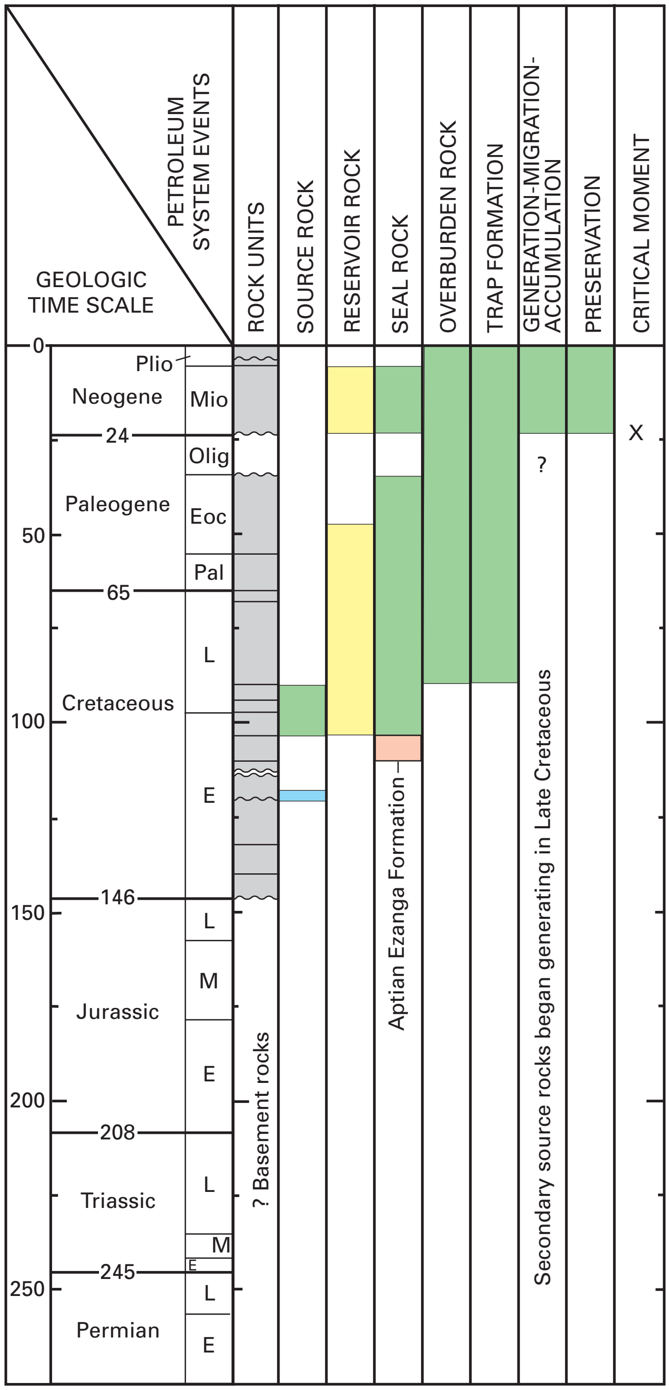


Figure 24. Events chart for the Azile-Senonian Total Petroleum System (720302) and the Gabon Suprasalt Assessment Unit (72030201). Light-gray shading indicates rock units present (figs. 7, 11, and 19). Light blue indicates secondary or possible occurrences of source rocks depending on quality and maturity of the unit. Age ranges of primary source, seal, reservoir, and overburden rocks and the timing of trap formation and generation, migration, and preservation of hydrocarbons are shown in green and yellow. Aptian Ezanga Formation (regional evaporite unit) is shown in pink. Reservoir rocks containing lacustrine oil are found in the Douala and Rio Muni Basins (figs. 8 and 9).

part of the Ogooue River Delta and the Douala and Rio Muni Basins, including potential for large undiscovered oil and gas fields. Oil exploration is considered moderately mature, whereas gas exploration is immature.

The USGS assessed mean undiscovered volumes of 5,031 MMBO, 13,230 BCFG, and 625 MMBNGL (tables 2 and 4). The expected sizes of the largest undiscovered oil and gas fields are 1,112 MMBO and 2,022 BCFG, respectively. The Gabon Suprasalt Assessment Unit ranks as the second assessment unit in the West-Central Coastal Province (table 2) in terms of mean undiscovered oil. This assessment unit has more potential for undiscovered resources than the underlying Gabon Subsalt Assessment Unit.

Congo Delta Composite Total Petroleum System (720303)

The Congo Delta Composite Total Petroleum System was defined in the West-Central Coastal Province of equatorial west Africa (fig. 2). An events chart for this total petroleum system summarizes the age of the source, seal, and reservoir rocks and the timing of trap development and generation and migration of hydrocarbons (fig. 25).

The primary source rock for the Congo Delta Composite Total Petroleum System is the syn-rift Lower Cretaceous lacustrine shales of the Bucomazi Formation (figs. 15 and 25). Source rocks in the middle unit of the Bucomazi Formation contain Type I kerogen and average 5 weight percent total organic carbon (TOC), though some of those source beds contain 20 weight percent TOC. The lower and upper units of the Bucomazi Formation average only 2 to 3 weight percent TOC. Additional marine source rocks from the post-rift section are marine shales and marls of the Upper Cretaceous Iabe Formation, the Paleocene to Eocene Landana Formation, and the Oligocene to Miocene Malembo Formation (figs. 15 and 25). Lacustrine oils generated from the Bucomazi are paraffinic. Oil generation began in the Late Cretaceous (Schoellkopf and Patterson, 2000) and has continued to the present (fig. 25). The migration pathways are mostly fault related, but some lateral migration has occurred below the Loeme Salt within the Chela Sandstone. Lacustrine oils charged many of the Upper Cretaceous and Tertiary turbidite channels and sandstones in the Congo Basin (Schoellkopf and Patterson, 2000).

In the shallow-water areas of the Congo Basin, the majority of reservoir rocks are sandstones of both syn-rift and post-rift age (fig. 15). A large number of reservoirs consist of carbonate rocks (about 50 percent limestone reservoirs, 50 percent dolomite reservoirs), mainly those found in the Albian Pinda Formation (fig. 15). Overall, porosities average about 21 percent, and permeabilities average 450 mD. In the deeper water prospects, reservoir rocks are expected to represent primarily Oligocene and Miocene turbidite channels and basin-floor fans and mounds.

Trap formation most likely began in the late Neocomian to Barremian (Edwards and Bignell, 1988b; Teisserenc and

Table 4. Summary of estimated undiscovered volumes of conventional oil, gas, and natural gas liquids for undiscovered oil and gas fields in the Gabon Suprasalt Assessment Unit of the Azile-Senonian Total Petroleum System, West-Central Coastal Province, west Africa.

[MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. MFS, minimum field size assessed (MMBO or BCFG). Prob., probability (including both geologic and accessibility probabilities) of at least one field equal to or greater than the MFS. Results shown are fully risked estimates. For gas fields, all liquids are included under the NGL (natural gas liquids) category. F95 represents a 95 percent chance of at least the amount tabulated. Other fractiles are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. Shading indicates not applicable. Totals do not reflect rounding]

Field Type	MFS	Prob. (0-1)	Undiscovered Resources												Largest Undiscovered Field (MMBO or BCFG)			
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)							
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Oil Fields	1	1.00	1,241	4,545	10,429	5,031	1,615	6,169	15,492	7,049	75	300	806	353	234	898	2,758	1,112
Gas Fields	6						1,233	5,403	13,803	6,181	51	232	634	272	322	1,423	6,025	2,022
Total		1.00	1,241	4,545	10,429	5,031	2,848	11,572	29,295	13,230	127	532	1,441	625				

Villemin, 1990) when a second phase of rifting and subsidence developed in the central part of the Aptian salt basin. The thick regional evaporite sequence deposited in Aptian time and the subsequent salt deformation had a major influence on both structure and facies distribution related to trap development (Edwards and Bignell, 1988b). In the shallow-water areas, traps are mostly anticlinal. Some are related to rollovers. Other traps are related to fault blocks or paleotopography. Seals are Cretaceous to Tertiary lacustrine and marine shales. In deeper water, traps are both stratigraphic and structural and include turbidite channels and sandstones and ponded or thickened, growth-fault-related sandstones sealed by shales.

Central Congo Delta and Carbonate Platform Assessment Unit (72030301)

The Central Congo Delta and Carbonate Platform Assessment Unit of the Congo Delta Composite Total Petroleum System (fig. 2) contains both syn-rift and post-rift source rocks and reservoirs of Mesozoic through Miocene age in the area of the Congo Basin (fig. 1). The eastern boundary of the assessment unit was defined as the eastern limit of the Cretaceous rocks, whereas the western boundary was set at 4,000-m water depth. Although the nonturbidite reservoirs included in this assessment unit theoretically could extend into its westernmost area, most of the prospectivity is expected to be in the eastern, shallow-water part.

Most of the exploration in this assessment unit has taken place since the middle 1960s. Since that time, 174 oil fields larger than 1 MMBO have been discovered. Sizes of discovered oil fields have not shown much decrease with time, suggesting that the exploration is not mature. Therefore, some possibility of oil fields larger than 500 MMBO was accommodated in the assessment. At the median, about the same number of oil fields were considered undiscovered as discovered, but the median size of 6 MMBO shows that they would be much smaller on the average.

The USGS assessed mean undiscovered volumes of 4,677 MMBO, a mean of 14,314 BCFG, and a mean of 692 MMBNG (tables 2 and 5). The expected sizes of the largest undiscovered oil and gas fields are 557 MMBO and 983 BCFG, respectively. This assessment unit ranks as the third largest in the West-Central Coastal Province (table 2) in terms of mean undiscovered resources, but still has much less potential than the deeper water equivalent, the Central Congo Turbidites Assessment Unit.

Central Congo Turbidites Assessment Unit (72030302)

The Central Congo Turbidites Assessment Unit of the Congo Delta Composite Total Petroleum System (fig. 3) includes both subsalt and suprasalt source rocks and Oligocene to Miocene turbidite reservoirs in the area of the Congo Basin (fig. 1). The eastern boundary of the assessment unit is defined at 200-m water depth, and the western boundary was set at 4,000-m water depth. The assessment unit lies primarily in deep water.

This assessment unit was treated differently from most of the other assessment units in the World Petroleum Assessment 2000, in that the 1996 version of the Petroconsultants database was used (Petroconsultants, 1996). Most assessment units have few post-1995 discoveries of significant size. Thus most assessments treated the post-1995 discoveries as part of the undiscovered resource. For the Central Congo Turbidites Assessment Unit (fig. 3), almost all the discoveries were post-1995, but little specific information on individual field sizes was available. Thus the assessment-unit map based on the Petroconsultants (1995) data had only three field locations, and plots of exploration history could not be constructed. Because of the large volumes (several billion barrels) of oil discovered between 1995 and 1999 (the time of the actual assessment), it was decided to treat these fields as discovered and thus move the effective date of the assessment to 1999.

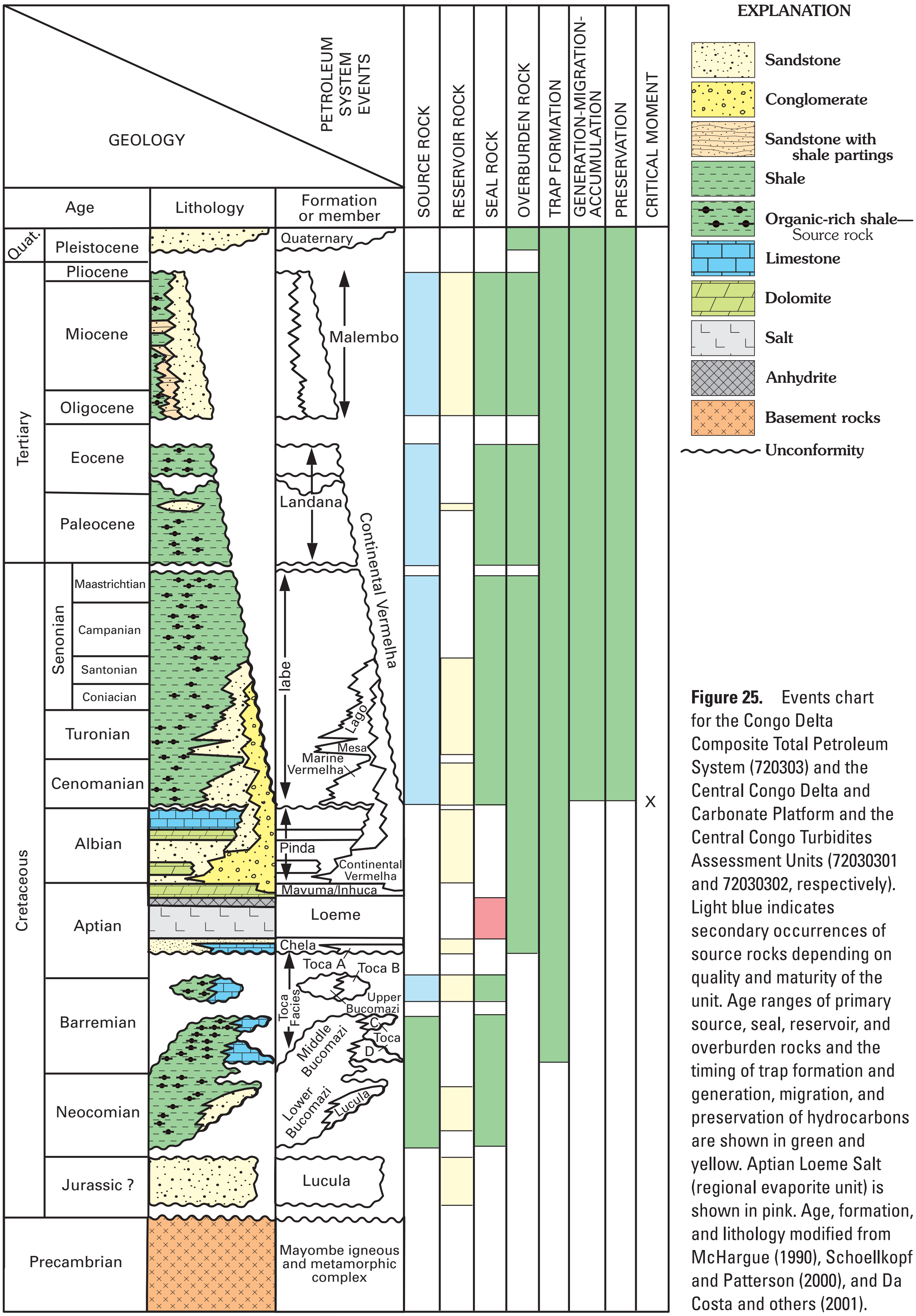


Figure 25. Events chart for the Congo Delta Composite Total Petroleum System (720303) and the Central Congo Delta and Carbonate Platform and the Central Congo Turbidites Assessment Units (72030301 and 72030302, respectively). Light blue indicates secondary occurrences of source rocks depending on quality and maturity of the unit. Age ranges of primary source, seal, reservoir, and overburden rocks and the timing of trap formation and generation, migration, and preservation of hydrocarbons are shown in green and yellow. Aptian Loeme Salt (regional evaporite unit) is shown in pink. Age, formation, and lithology modified from McHargue (1990), Schoellkopf and Patterson (2000), and Da Costa and others (2001).

Table 5. Summary of estimated undiscovered volumes of conventional oil, gas, and natural gas liquids for undiscovered oil and gas fields in the Central Congo Delta and Carbonate Platform Assessment Unit of the Congo Delta Composite Total Petroleum System, West-Central Coastal Province, west Africa.

[MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. MFS, minimum field size assessed (MMBO or BCFG). Prob., probability (including both geologic and accessibility probabilities) of at least one field equal to or greater than the MFS. Results shown are fully risked estimates. For gas fields, all liquids are included under the NGL (natural gas liquids) category. F95 represents a 95 percent chance of at least the amount tabulated. Other fractiles are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. Shading indicates not applicable. Totals do not reflect rounding]

Field Type	MFS	Prob.	Undiscovered Resources												Largest Undiscovered Field			
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)				(MMBO or BCFG)			
		(0-1)	F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Oil Fields	1	1.00	1,717	4,522	8,097	4,677	3,556	9,855	19,748	10,527	164	478	1,047	525	195	509	1,065	557
Gas Fields	6						1,057	3,507	7,495	3,787	43	149	350	166	218	752	2,612	983
Total		1.00	1,717	4,522	8,097	4,677	4,614	13,361	27,243	14,314	207	627	1,397	692				

The large size of discovered fields (some over 500 MMBO) suggested significant potential for large remaining fields. The deeper water turbidite areas are underexplored (fig. 26), and geologic considerations suggest that they may be the locations of basin-floor fans equivalent in prospective resources to the recent discoveries of slope-channel turbidites (fig. 26). The geologic setting presents the possibility of very large fields in these underexplored deep-water turbidite areas, given appropriate fluid generation and migration paths. The maximum sizes of 7,000 MMBO and 15,000 BCFG were chosen so that the expected sizes of the largest undiscovered fields would be in the 2,000–3,000 MMBO range for oil and somewhat smaller in equivalent value for gas.

The minimum field size assessed was 10 MMBO. In deep water, fields of this size may not merit development of infrastructure on their own. Within the 30-year time frame of the assessment, however, some of these fields could be developed if they are located near infrastructure that will be set up for larger fields. Most of the fields smaller than the median sizes of 60 MMBO and 300 BCFG are unlikely ever to be developed, but they were assessed to give economic modelers the data they needed.

The USGS assessed mean undiscovered volumes of 18,522 MMBO, 55,268 BCFG, and 2,682 MMBNGL (table 6). The expected sizes of the largest undiscovered oil and gas fields are 2,698 MMBO and 3,483 BCFG, respectively. This assessment unit is estimated to have the largest amount of undiscovered resource potential in the West-Central Coastal Province (table 2) in terms of mean undiscovered oil.

Cuanza Composite Total Petroleum System (720304)

The Cuanza Composite Total Petroleum System was defined south of the Congo Basin (figs. 1 and 3). An events chart (fig. 27) summarizes the age of the source, seal, and reservoir rocks and the timing of trap development and generation and migration of hydrocarbons.

Primary source rocks in the Cuanza Composite Total Petroleum System are syn-rift lacustrine shales (figs. 16 and 17) and post-rift marine shales and marls (fig. 27). Syn-rift source rocks in the southern offshore part of the outer Kwanza Basin consist of thick, organic-rich, lacustrine shales and marine shales that contain Type I and Type II kerogens (Pasley and others, 1998b). The source rocks have an average total organic carbon (TOC) content of 3.1 weight percent; some analyzed samples have TOC contents greater than 20 weight percent (Geochemical and Environmental Research Group, 2003). The oils generated in this total petroleum system are paraffinic. The syn-rift sources may have become mature in the Late Cretaceous. The post-rift marine source rocks probably became mature in the early to mid-Tertiary (Danforth and others, 1997). Migration pathways are mostly fault related, but lateral migration in the Cuvo or equivalent Chela Sandstone is possible (fig. 17).

Cretaceous onshore and nearshore reservoirs include both carbonate and clastic types. Porosities average 14 percent and permeabilities average 162 mD. Traps in the onshore and nearshore discovered fields are primarily anticlinal. Analogous to the deep-water discoveries in the Congo Basin, Oligocene to Miocene turbidite reservoirs are present in deeper water of the outer Kwanza Basin. These reservoir rocks are located in grabens related to Tertiary extension along the detachment surface in the salt (Duval and others, 1992; Lundin, 1992). Tertiary reservoir rocks are similar to reservoirs found in the southern Congo Basin. Porosities and permeabilities range from 20 to 40 percent and from 1 to 5 D, respectively (Raposo and Inkollu, 1998). The Tertiary turbidite sandstone units could have both stratigraphic and structural traps with shale seals.

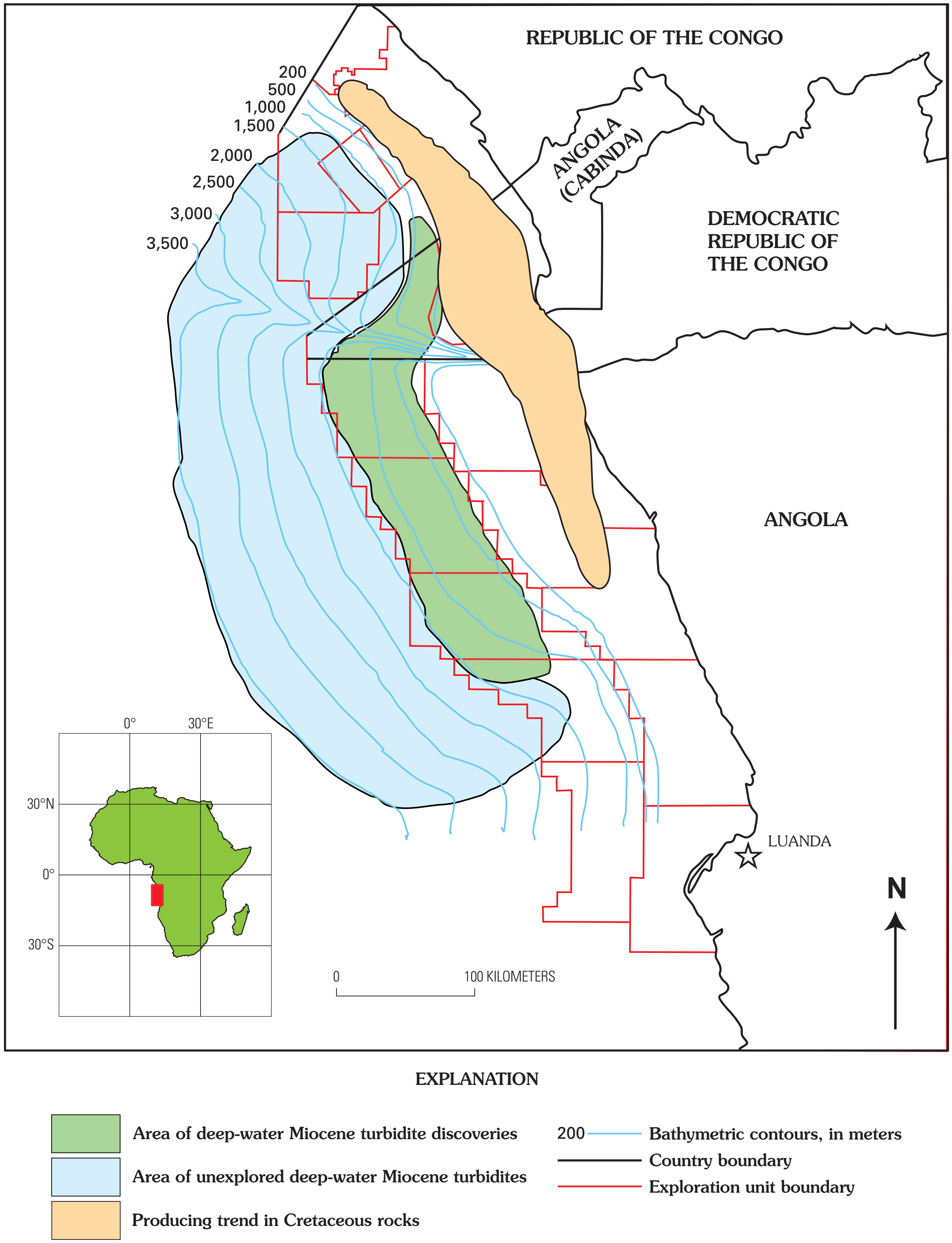


Figure 26. Generalized map of the Congo Basin within the West-Central Coastal Province (7203), showing the position of the producing trend in Cretaceous (post-rift and pre-rift) rocks, present area of Tertiary turbidite discoveries, and the unexplored deep-water Tertiary turbidite area. Within the area of present deep-water discoveries, the well density is only one well per 484 km^2, which indicates that the area is underexplored. Modified from Da Costa and others (2001). The West-Central Coastal Province is shown in red in index map.

Table 6. Summary of estimated undiscovered volumes of conventional oil, gas, and natural gas liquids for undiscovered oil and gas fields in the Central Congo Turbidites Assessment Unit of the Congo Delta Composite Total Petroleum System, West-Central Coastal Province, west Africa.

[MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. MFS, minimum field size assessed (MMBO or BCFG). Prob., probability (including both geologic and accessibility probabilities) of at least one field equal to or greater than the MFS. Results shown are fully risked estimates. For gas fields, all liquids are included under the NGL (natural gas liquids) category. F95 represents a 95 percent chance of at least the amount tabulated. Other fractiles are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. Shading indicates not applicable. Totals do not reflect rounding]

Field Type	MFS	Prob. (0-1)	Undiscovered Resources												Largest Undiscovered Field (MMBO or BCFG)			
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)							
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Oil Fields	10	1.00	5,778	17,561	34,409	18,522	11,999	38,265	83,026	41,605	564	1,859	4,341	2,080	829	2,353	5,773	2,698
Gas Fields	60						2,644	12,026	30,195	13,663	109	513	1,398	602	773	2,724	9,018	3,483
Total		1.00	5,778	17,561	34,409	18,522	14,643	50,290	113,220	55,268	673	2,372	5,739	2,682				

Cuanza-Namibe Assessment Unit (72030401)

The Cuanza-Namibe Assessment Unit of the Cuanza Composite Total Petroleum System includes source rocks and reservoirs in the Mesozoic and Cenozoic rocks of the Kwanza Basin of Angola, south to the Walvis Ridge (figs. 1 and 3). The eastern boundary of the assessment unit was defined as the eastern limit of the Cretaceous rocks, whereas the western boundary was set at 4,000-m water depth (fig. 3). Exploration since the 1950s has focused on the onshore and nearshore parts of the Kwanza Basin. Only a few small to moderate-sized oil fields have been discovered in that time.

The immaturity of exploration, especially in deeper waters, could allow for some large undiscovered fields. Prospectivity would be greatest in the northern part of the assessment unit, where the stratigraphic section is thickest. To the south, the section is thinner, and there are no large deltas like the Congo Delta. These factors suggest that there may be fewer good sandstone reservoirs and that the source rocks may not be buried sufficiently for peak generation of hydrocarbons. Therefore, only small numbers of undiscovered fields were estimated.

The USGS assessed mean undiscovered volumes of 790 MMBO, 1,558 BCFG, and 73 MMBNGL (table 7). The expected sizes of the largest undiscovered oil and gas fields are 315 MMBO and 450 BCFG, respectively. This assessment unit is estimated to have the second smallest amount of undiscovered resource potential in the West-Central Coastal Province (table 2) in terms of mean undiscovered oil.

Discussion

In all the subbasins in the West-Central Coastal Province, new field discoveries and higher-resolution seismic studies have led to an increase in exploration since the USGS assessment in 2000 (fig. 1). Between 1995 and 2004, there have been 130 new oil and gas field discoveries (IHS Energy Group, 2004) in the province (fig. 28). Also since the 2000 assessment, the offshore part of the Congo Basin has become a major area for new field discoveries; 96 new fields have been discovered since 1995. The offshore parts of the Gabon, Kwanza, Rio Muni, Kribi-Campo, and Douala Basins have had 34 new field discoveries since the 2000 assessment. The rate of deep-water field discoveries has accelerated throughout the province (fig. 29). The Congo Basin was developing into a deep-water exploration region in 1995. Since 1995, seventy-four new fields have been discovered in the deep-water part of the Central Congo Turbidites Assessment Unit. Many of these new fields contain Miocene turbidite channel reservoirs.

Prospective new areas have been identified within the province since the 2000 assessment: (1) the outer Kwanza Basin, (2) the offshore Rio Muni Basin where the Ceiba Field (discovered in October 1999; 1,000 MMBO) is producing, and (3) the offshore Douala and Kribi-Campo Basins. Interpretation of higher resolution seismic and geochemical data and post-1995 drilling indicate the presence of Lower Cretaceous lacustrine source rocks and potential Cretaceous to Tertiary reservoir rocks in the offshore Kwanza, Douala, and Rio Muni Basins. Probable Tertiary turbidite reservoirs have been identified in deeper parts of the basins. Many of the offshore parts of the Kwanza, Douala, and Rio Muni Basins are underexplored—considering the size of the basins—and must contain many potential prospects.

The cumulative known oil volume has more than doubled in the province (fig. 30) since 1995 (Petroconsultants, 1996; IHS Energy Group, 2004, includes data current through December 2004). The cumulative known oil volume for the 1995 data is 13.72 billion barrels of oil (BBO), and the cumulative oil volume for the 2004 data is 28.25 BBO (fig. 30). The sharp increase in the cumulative known oil volume since 1995 supports the fact that the West-Central Coastal Province is immature, considering its size, number of exploration wells, and the number of field discoveries in the province.

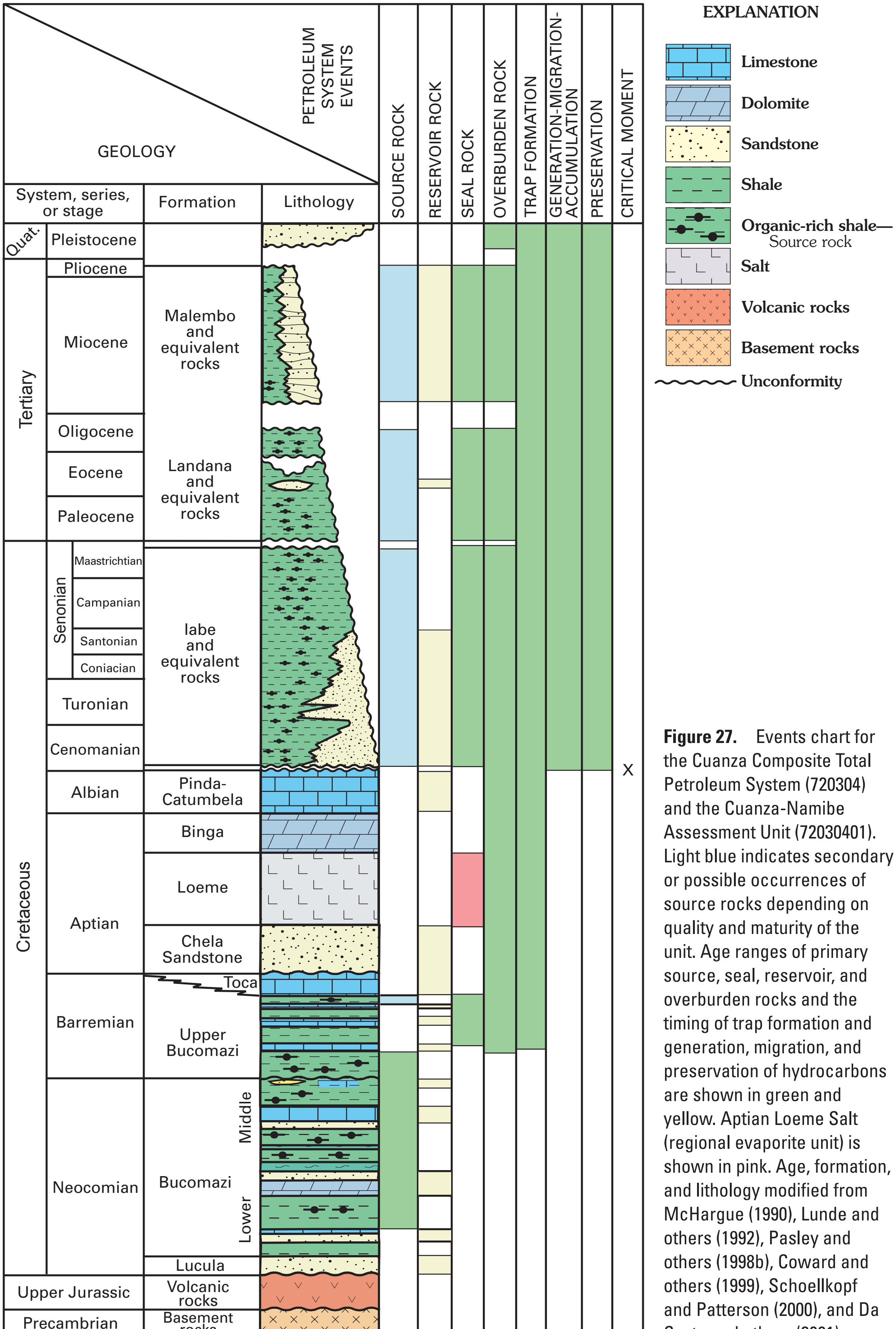


Figure 27. Events chart for the Cuanza Composite Total Petroleum System (720304) and the Cuanza-Namibe Assessment Unit (72030401). Light blue indicates secondary or possible occurrences of source rocks depending on quality and maturity of the unit. Age ranges of primary source, seal, reservoir, and overburden rocks and the timing of trap formation and generation, migration, and preservation of hydrocarbons are shown in green and yellow. Aptian Loeme Salt (regional evaporite unit) is shown in pink. Age, formation, and lithology modified from McHargue (1990), Lunde and others (1992), Pasley and others (1998b), Coward and others (1999), Schoellkopf and Patterson (2000), and Da Costa and others (2001).

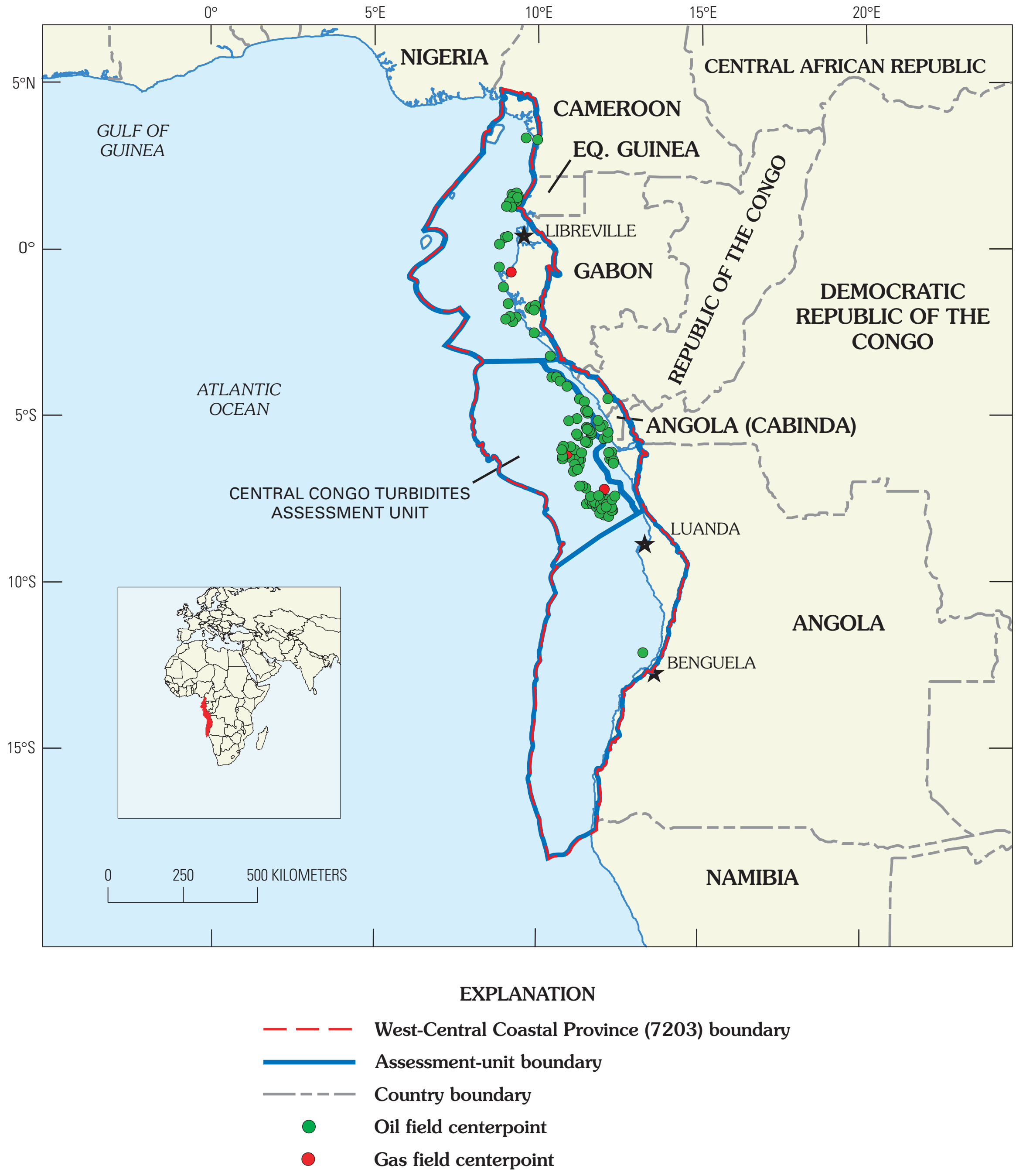


Figure 28. Location map of equatorial west Africa showing the West-Central Coastal Province (7203) and the assessment unit boundaries (figs. 2 and 3) with the approximate locations (centerpoints) of 130 oil and gas fields discovered since 1995. The majority of the new field discoveries (74) are located in deep water within the Central Congo Turbidites Assessment Unit (72030302). The eastern boundary of the Central Congo Turbidites Assessment Unit is set at 200-m water depth, and the western boundary is set at 4,000-m water depth. Locations of field centerpoints are used by permission (IHS Energy Group, 2004). In the index map, the West-Central Coastal Province is shown in red.

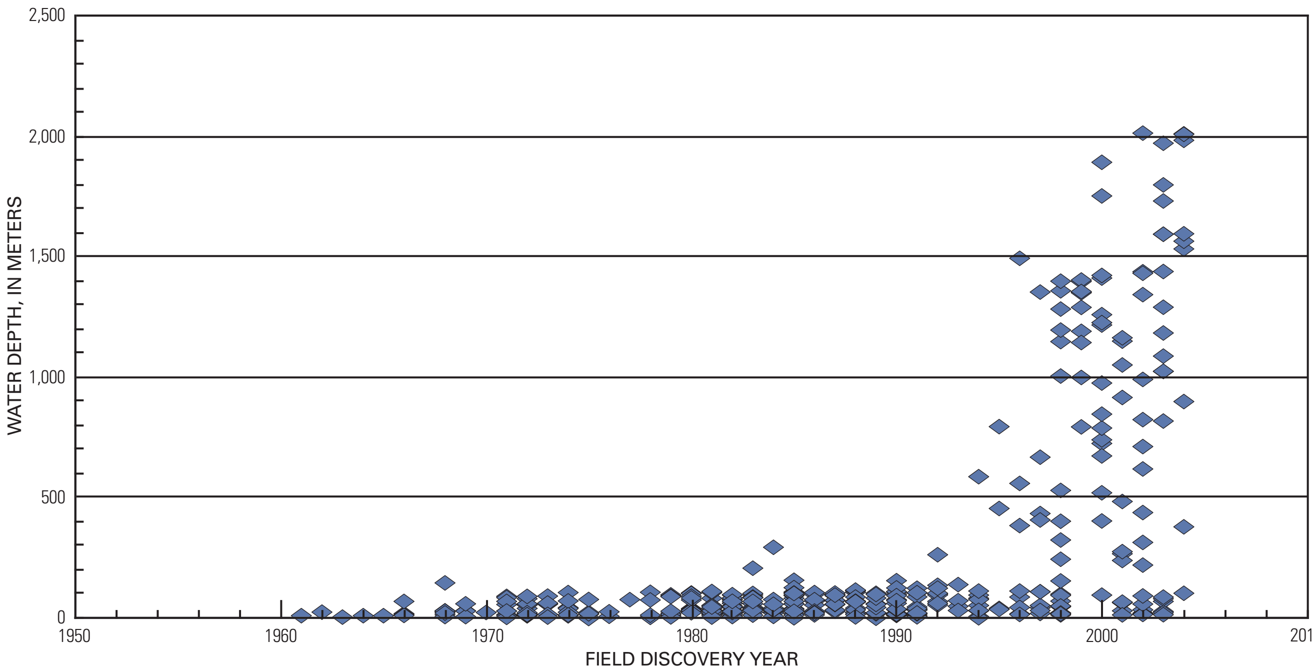


Figure 29. A scatter plot showing oil and gas field water depth and field discovery year for the West-Central Coastal Province (7203) of west Africa. Since 1995, 130 new fields have been discovered in the province; 81 fields are classified as deep water. Oil and gas field water-depth data are used by permission (Petroconsultants, 1996; IHS Energy Group, 2004).

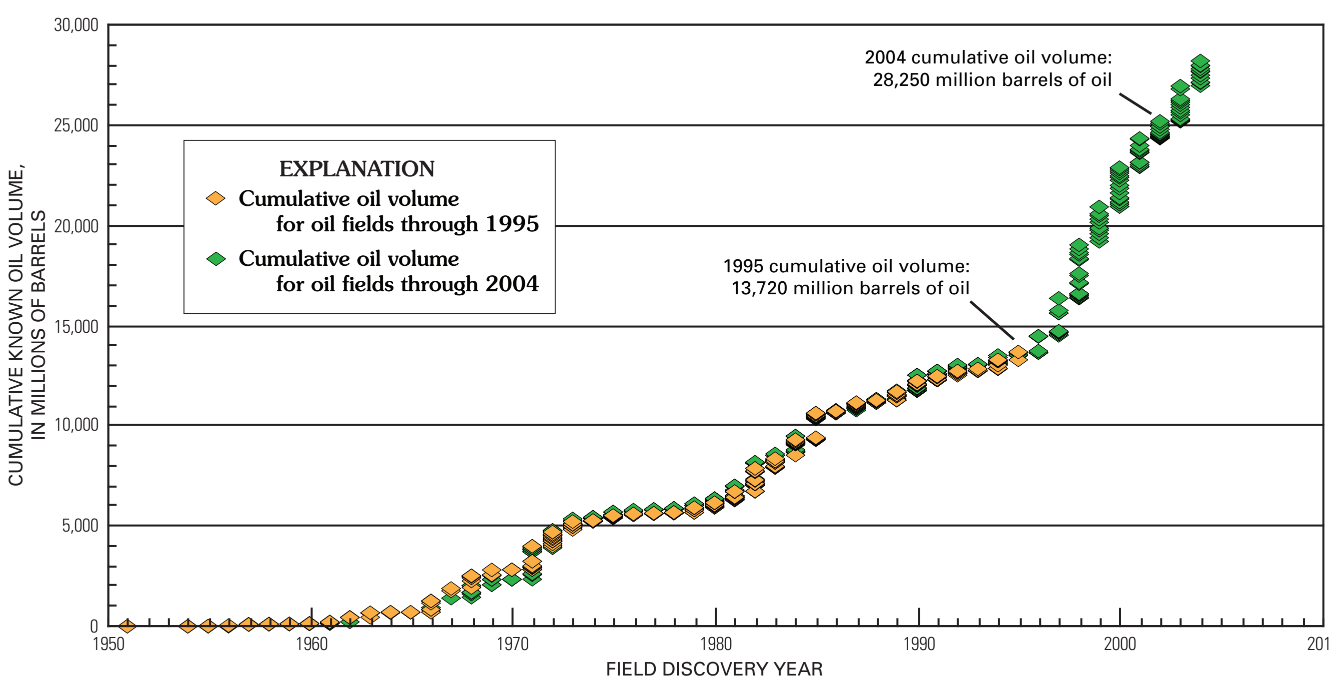


Figure 30. A scatter plot showing cumulative discovered oil volume and field discovery year for oil fields in the West-Central Coastal Province (7203) of west Africa. Since 1995, 130 new fields have been discovered in the province. Oil volume and field discovery year data for the 1995 and 2003 databases are used by permission (Petroconsultants, 1996; IHS Energy Group, 2004).

Table 7. Summary of estimated undiscovered volumes of conventional oil, gas, and natural gas liquids for undiscovered oil and gas fields in the Cuanza-Namibe Assessment Unit of the Cuanza Composite Total Petroleum System, West-Central Coastal Province, west Africa.

[MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. MFS, minimum field size assessed (MMBO or BCFG). Prob., probability (including both geologic and accessibility probabilities) of at least one field equal to or greater than the MFS. Results shown are fully risked estimates. For gas fields, all liquids are included under the NGL (natural gas liquids) category. F95 represents a 95 percent chance of at least the amount tabulated. Other fractiles are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. Shading indicates not applicable. Totals do not reflect rounding]

Field Type	MFS	Prob. (0-1)	Undiscovered Resources												Largest Undiscovered Field (MMBO or BCFG)			
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)							
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Oil Fields	1	1.00	84	608	2,138	790	80	590	2,205	790	4	29	113	39	28	190	1,088	315
Gas Fields	6						67	472	2,507	768	3	20	112	34	28	212	1,730	450
Total		1.00	84	608	2,138	790	147	1,062	4,712	1,558	7	49	225	73				

Summary

The West-Central Coastal Province is estimated to have mean undiscovered resources of 29,746 MMBO, 88,044 BCFG, and 4,244 MMBNGL (table 1). These values are less than the undiscovered resources of the Niger Delta Province (table 8), but the West-Central Coastal Province is still one of the largest in the World Petroleum Assessment 2000 (U.S. Geological Survey World Energy Assessment Team, 2000) and the second largest in the Sub-Saharan Africa Region. Most of this undiscovered resource is offshore (figs. 28 and 29; tables 1 and 2; 28.0 BBO), and much of it is in the deeper water part of the Central Congo Turbidites Assessment Unit (table 2; 18,522 MMBO).

The cumulative known oil volume has more than doubled in the province (fig. 30) since 1995 (Petroconsultants, 1996; IHS Energy Group, 2004), when the western part of equatorial Africa became a deep-water hydrocarbon province. New field discoveries and higher resolution and three-dimensional seismic studies since the USGS assessment of the province have led to an increase in exploration in all the subbasins in the West-Central Coastal Province. Large offshore parts of the Kwanza, Douala, and Rio Muni Basins are underexplored and contain many potential prospects. The province has hydrocarbon potential in both onshore and offshore parts, but the greatest potential is in the deep-water parts of the province. Gas resources may be significant and accessible in areas where the zone of oil generation is relatively shallow.

Acknowledgments

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Table 8. Summary of estimated undiscovered volumes of conventional oil, gas, and natural gas liquids for undiscovered oil and gas fields for the Sub-Saharan Africa Region, showing allocations by the oil and gas province.

[MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. MFS, minimum field size assessed (MMBO or BCFG). Prob., probability (including both geologic and accessibility probabilities) of at least one field equal to or greater than the MFS. Results shown are fully risked estimates. For gas fields, all liquids are included under the NGL (natural gas liquids) category. F95 represents a 95 percent chance of at least the amount tabulated. Other fractiles are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. Shading indicates not applicable. Totals do not reflect rounding]

Code and Field Type	Prob. (0-1)	Undiscovered Resources											
		Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
		F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
7013	Senegal Province												
Oil Fields	1.00	15	120	430	157	33	255	968	345	2	15	59	21
Gas Fields						83	414	1,276	510	3	18	58	22
Total	1.00	15	120	430	157	116	669	2,244	856	5	33	118	43
7183	Gulf of Guinea Province												
Oil Fields	1.00	225	901	2,117	1,004	918	3,846	9,845	4,420	29	124	339	146
Gas Fields						1,256	5,064	12,000	5,650	28	118	303	136
Total	1.00	225	901	2,117	1,004	2,174	8,910	21,846	10,071	57	242	642	282
7192	Niger Delta Province												
Oil Fields	1.00	17,487	39,975	65,123	40,487	28,703	70,120	133,579	74,056	903	2,292	4,608	2,459
Gas Fields						28,845	57,910	90,585	58,660	1,741	3,517	5,594	3,574
Total	1.00	17,487	39,975	65,123	40,487	57,548	128,030	224,165	132,716	2,643	5,808	10,202	6,034
7203	West-Central Coastal Province												
Oil Fields	1.00	9,033	27,917	56,465	29,746	17,693	56,368	123,798	61,608	827	2,739	6,483	3,080
Gas Fields						5,268	23,152	58,794	26,436	217	989	2,715	1,164
Total	1.00	9,033	27,917	56,465	29,746	22,961	79,520	182,592	88,044	1,044	3,727	9,198	4,244
7303	Orange River Coastal Province												
Oil Fields	1.00	23	87	312	116	46	186	701	256	3	11	43	15
Gas Fields						629	2,829	7,889	3,348	26	121	361	147
Total	1.00	23	87	312	116	675	3,015	8,590	3,603	28	132	404	163
7	**Total: Sub-Saharan Africa**												
Oil Fields	1.00	26,783	68,999	124,447	71,512	47,393	130,775	268,891	140,685	1,763	5,180	11,533	5,722
Gas Fields						36,081	89,369	170,545	94,604	2,015	4,762	9,031	5,044
Total	1.00	26,783	68,999	124,447	71,512	83,474	220,144	439,436	235,290	3,778	9,942	20,564	10,766

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