Bombay Geologic Province Eocene to Miocene Composite Total Petroleum System, India

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Foreword

This report describing the petroleum resources within a total petroleum system in Pakistan and India, was prepared as part of the World Energy Assessment Project of the U.S. Geological Survey. For this project, the world was divided into 8 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 U.S. and chosen for their high ranking) and 52 "boutique" provinces (exclusive of the U.S. and chosen for their anticipated petroleum richness or special regional economic importance) were selected for assessment of undiscovered oil and gas resources. The petroleum geology of these priority and boutique provinces is described in this series of reports.

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 occur as reserve growth of fields already discovered.

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. The minimum petroleum system is that part of a total petroleum system encompassing discovered shows and accumulations along with the geologic space in which the various essential elements have been proved by these discoveries.

An assessment unit is a mappable part of a total petroleum system in which discovered and undiscovered fields constitute a single, relatively homogenous population such that the chosen methodology of resource assessment 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 it may be subdivided into two or more assessment units if 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 will identify the same type of entity in any of the publications. The code is as follows:

The codes for the regions and provinces are listed in Klett and others (1997). Oil and gas reserves quoted in this report are derived from Petroconsultant's Petroleum Exploration and Production database (Petroconsultants, 1996) and other area reports from Petroconsultants, Inc., unless otherwise noted. Figure(s) in this report that show boundaries of the total petroleum system(s), assessment units, and pods of active source rocks were compiled 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 center points, shown on these figures, are reproduced, with permission, from Petroconsultants, 1996.

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Introduction

Among the 76 priority geologic provinces identified for the World Energy Assessment Project of the U.S. Geological Survey is the Bombay geologic province (province 8043), which is an oil-prone area, both onshore and offshore (fig. 1). The Bombay geologic province is bounded on the north by the Nagar-Parkar Ridge, on the east by the Precambrian Vindhyan Plateau and Deccan Syncline, on the south by the Vengurla Arch and on the west by the 2,000-m bathymetric contour (fig. 2). The area includes the outer shelf of western India, much of which is referred to as the Bombay Shelf; Bombay High; Dahanu, Panna, and Surat Depressions; Cambay and Narmada Deltas; Cambay and Kutch Grabens; and Saurashtra or Kathiaw Peninsula.

Figure 1. Location of the Bombay geologic province (8043) shown in green; other assessed provinces within region 8 shown in yellow.

Figure 2. Generalized geology of the study area in western India and southeastern Pakistan (modified from Wandrey and Law, 1999).

Structurally, the province consists of a deformed and rifted portion of the western Indian plate passive margin. Significant features include the uplifted structures of the Bombay High and Saurashtra Peninsula, failed rifts forming the Kutch and Cambay Grabens, and the Narmada-Domodar Graben or lineament (fig. 2).

Within the Bombay geologic province, a composite total petroleum system (TPS), the Eocene-Miocene Composite TPS (804301), was identified. For the purposes of oil and gas assessment, the TPS was further subdivided into two assessment units (AU), the Eocene-Miocene Bombay Shelf AU (80430101) and the Eocene-Miocene Cambay Deltaic AU (80430102) (fig. 3). The Eocene-Miocene Bombay Shelf AU is an oil-prone assessment unit located offshore along the west coast of India. A pericratonic basin, it is characterized by extensive carbonate-platform shelf development during middle Eocene to middle Miocene time. The carbonates reached their maximum areal extent in the late Oligocene, covering much of the shelf from the Indus River Delta, south to the Vengurla Arch . The Eocene-Miocene Cambay Deltaic AU is also an oil-prone composite assessment unit, located both onshore and offshore along the west coast of India. The prospective area consists of the Cambay Graben created during Late Cretaceous failed rifting and a delta extending southwest from the graben toward the Bombay Shelf.

Figure 3. Map showing Bombay geologic province and assessment unit boundaries for the Bombay geologic province. The extent of the total petroleum system is coincident with the extent of the two assessment units combined.

Acknowledgments

Geologic expertise and insight provided by the scientists of the Oil and Natural Gas Corporation (ONGC), Keshav Deva Malviya Institute of Petroleum Exploration (Kdmipe), DehraDun, India, contributed greatly to development of this report.

Regional Geologic History

The total petroleum systems (TPS) and assessment units (AU) discussed herein (fig. 3) acquired their primary structural and stratigraphic features from events associated with plate movements that occurred from latest Paleozoic time to the present. From Permian through Middle Jurassic time, the Indian plate was located in the Southern Hemisphere between the African, Antarctic, and Australian plates and comprised part of southern Gondwana. Basal Permian glacial deposits on the southern Indian plate and Lower Permian tillites in the Kohat-Potwar area indicate a much cooler Permian climate (Shah and others, 1977). The area that is today the Indus Basin (fig. 2) was a shallow continental shelf accumulating shales, sands, and carbonates. This carbonate-dominated shelf environment persisted at least intermittently on the western part of the shelf through the Late Jurassic and is evidenced in part by the interbedded shales and thick limestones of the Patcham, Chari, and Katrol Formations in the Kutch area (Biswas and Deshpande, 1983) and the Springwar and Sulaiman Limestone Groups in the area that is now the Indus Basin. Formed near the intersection of three orogenic trends during the separation of the Indian and African plates, the Kutch Graben is filled with Jurassic to Recent sediments (fig. 4).

Figure 4. Generalized stratigraphy of the Bombay-Cambay-Kutch area (modified from Mishra and others, 1997; ONGC, 1983; Biswas and others, 1982)

During Early Cretaceous time, the Indian plate drifted northward entering warmer latitudes (fig. 5). In the Kutch area, shallow-marine shales and sandstones were being deposited, and, by Late Cretaceous time, regressive sandstones such as the Bhuj, Lumshiwal, and Pab Formations on the western Indian Shelf and Tura Formation on the eastern part of the shelf were being deposited. During latest Cretaceous time, the Indian plate continued drifting northward toward the Asian plate, the seafloor of the Bengal Basin began to form, and flysch accumulated on all sides of the Indian plate (fig. 6).

Figure 5. Middle Jurassic (approximately 166 Ma). Perspective lat 20°S., long 68°E. (modified from Scotese and others, 1988; Scotese, 1997).

Figure 6. Early Cretaceous (approximately 130 Ma). Perspective lat 20°S., long 68°E. (modified from Scotese and others, 1988; Scotese, 1997).

Northward plate movement continued during the Late Cretaceous and a transform fault became active along the Ninety-East Ridge (see figs. 8–10). In the Assam area, a southeasterly dipping shelf developed. Rifting between Madagascar and the Seychelles initiated formation of the Mascarene Basin. Extensional faulting occurred as the western Indian plate sheared southward relative to the main plate (Kemal and others, 1992) (figs. 7 and 8). Counterclockwise rotation of the Indian plate was initiated, and the Seychelles plate began to break away from the Indian plate, forming the Somali Basin (Waples and Hegarty, 1999).

Figure 7. Late Cretaceous (approximately 94 Ma). Perspective lat 20°S., long 68°E. (modified from Scotese and others, 1988; Scotese, 1997).

Figure 8. Latest Cretaceous (approximately 69 Ma). Perspective lat 20°S., long 68°E. (modified from Scotese and others, 1988; Scotese, 1997).

Latest Cretaceous time also brought to western India intense volcanism, expulsion of the Deccan Trap basalts and further rifting, which began, and then failed, leaving the Cambay and Kutch Grabens floored with the Deccan Trap basalts (Biswas and Deshpande, 1983). The rifting event in the Cambay and Kutch areas may be related to the extensional faulting and shear zone that was developing in the Indus Basin area.

From the Late Cretaceous through middle Paleocene, trap deposits and basal sands continued to accumulate on the Assam-Arakan, Indus, Bombay, and Bengal shelves. Oblique convergence of the Indo-Pakistan plate with the Afghan and other microplates resulted in wrench faulting and development of regional arches such as the Jacobad and Sargodha Highs in the Indus Basin (Kemal and others, 1992).

The Indian plate continued to move northward at an accelerated rate of 15–20 cm/yr. When the eastern edge of the plate passed over the Kerguelen hot spot, a chain of islands began to form near long 90°E. (fig. 8). Continued northward movement and counterclockwise rotation of the Indian plate slowly closed the Tethyan Sea along the northern and northwestern plate boundaries. The Sulaiman-Kirthar fold belt began to develop as a result of the oblique collision and rotation. Regional uplift and rising mountain ranges on the Eurasian plates to the north and west created a new sediment source, and the prevailing sediment transport direction of south to north was reversed. From Eocene through middle Miocene time, carbonate-platform buildup occurred intermittently on the shelves around much of the Indian plate. A trench formed along the subduction zone as the Indian plate began to slip beneath the Eurasian plate (fig. 9).

Figure 9. Middle Eocene (approximately 50 Ma). Perspective lat 20°S., long 68°E. (modified from Scotese and others, 1988; Scotese, 1997).

The Eurasian plate shed large volumes of sediments into the trench as subduction continued. This terrestrial sediment influx from the rapidly rising Himalayan, Sulaiman-Kirthar, Sino-Burman, and Indo-Burman Ranges, exceeded carbonate-buildup rates on late Miocene platforms (Roychoudhury and

Deshpande, 1982) and smothered carbonate reef development along the shelf areas. The former shelf areas along the collision zones were either subducted or became emergent fluvial-deltaic environments (fig. 10).

Figure 10. Late Oligocene (approximately 27 Ma). Perspective lat 20°S., long 68°E. (modified from Scotese and others, 1988; ;Scotese, 1997).

The proto Indus, Narmada, Ganges, Brahmaputra, Megna, Chindwin, and Irrawaddy Rivers developed extensive deltas as the Himalayas and other ranges continued to shed sediments at a high rate. Today, uplift of the Himalayas and subduction of the Indian plate continues, and the growth rate of the Indus, Ganges-Brahmaputra (Megna), and Irrawaddy Deltas remains high. To the northwest of the study area, crustal shortening continues along the Indian-Eurasian plate boundary.

Stratigraphy

Within the Bombay geologic province, the stratigraphic record is incomplete. Mesozoic rocks are exposed primarily in the northwest part of the study area (fig. 11). In the subsurface, Mesozoic rocks, other than Upper Cretaceous trap deposits, are known from drilling only in the Kutch area. In the Cambay Graben and southward to the Bombay High, trap deposits lie on basement (fig. 4).

Figure 11. Generalized conceptual model of the Mesozoic stratigraphic section in the Kutch area (top) (modified from Biswas and Deshpande, 1982) and generalized north-south section of the Cambay Graben, (modified from Banerjee and others, 2002).

The Mesozoic depositional history is preserved only in the Kutch area, where a structural feature, the Median High hinge line, influenced sediment deposition from the Late Jurassic until at least late Miocene time (Biswas, 1982). Middle Jurassic shallow-marine shales and limestones of the Jhurio and Kaladonger Formations were deposited on Archean and Proterozoic basement rocks. During the Jurassic, areas west of the Median High received a much greater sediment load than the area east of the Median High. Deposition of nearshore sandstones and shales of the Jumara and Jhuran Formations continued through the Late Jurassic and into the Early Cretaceous. West of the Median High, the basin was filled with as much as 3,050 m of these Jurassic and Lower Cretaceous sediments (fig. 11). In the Late Cretaceous, there was a change to fluvial-deltaic environments. Deposition of the Bhuj and Wagad Formations contributed further to the tilting and westward subsidence of the entire Saurashtra block, including the Kutch and Cambay Grabens (Biswas and Deshpande, 1983). This was followed by increased tectonic activity in the Late Cretaceous and extensive Deccan Trap volcanism, which continued through the early Paleocene, depositing as much as 2,000 m of volcanics over most of western India. In the Kutch area, erosion of the volcanics was followed in late Paleocene time by continental deposition of Paleocene and lower Eocene nonmarine sediments in the south Cambay Graben (Olpad Formation) (fig. 11). The Surat and Panna Depressions (Panna Formation) were filled with trap wash overlain by carbonates, shales, and interbedded siltstones from fluvial to transitional environments. In the Kutch area, marine sedimentation occurred only in the western part until the end of the Paleogene. Lower to middle Eocene rocks are absent from most of the offshore area, and an erosional unconformity that extends over most of the offshore area truncates the Panna. In the Cambay Graben, the

Olpad is truncated, but there is little missing section. The overlying lower to middle Eocene Cambay Formation marine shale is considered the primary source rock in the southern Cambay Graben (Banerjee and Rau, 1993; Biswas and others, 1994; Banerjee and others, 2002). Eocene marine carbonates and shales of the Belapur, Bassien, and Dui Formations extend over much of the present-day offshore (fig. 12), and Eocene-Oligocene sandstones, siltstones and shales reflect shallow-marine to alluvial environments in the south Cambay Graben.

Figure 12. Generalized cross sections of Bombay-High area (modified from Basu and others, 1980).

Middle to late Eocene time in the shelf margin or outer shelf, Bombay High, and Panna-Bassein areas is represented by shallow-marine shales and shelf carbonates of the Belapur and Bassein Formations. Shoreward, and to the northeast, shallow-marine to lagoonal Dui Formation shales dominate. Still farther to the north, in the south Cambay Graben, deltaic and alluvial sediments of the Ankleswar Formation dominate late Eocene-Oligocene environments. These depositional environments fluctuated (fig. 13) but prevailed until late Miocene when large volumes of terrestrial sediments inundated the grabens and shelf area (fig. 14).

Figure 13. Generalized Paleocene (left) and Oligocene (right) paleogeographic maps of Bombay-High and western shelf area (modified from Rao and Talukdar, 1980).

Figure 14. Generalized early Miocene (left) and Pliocene (right) paleogeographic maps of Bombay-High and western shelf area (modified from Rao and Talukdar, 1980).

Today, the shelf area continues to receive terrestrial sediments, and the Cambay and Narmada Deltas continue to expand. To the north, the mainland and islands of Kutch have been folded into east-west-trending, parallel, faulted anticlines that have been eroded to Jurassic cores, and Tertiary rocks remain only in synclinal troughs (K.A. Yenne, unpub. data).

Production History

In 1958, the Cambay field was discovered in the south Cambay Graben (fig. 15). This was the first commercial oil discovery for India outside of Assam. The field has produced from the shallow-marine Eocene Cambay Shale and Oligocene Dadhar Formation, delta-plain basal sandstones. Since the discovery, more than 2,000 wells have been drilled. Ninety-nine offshore, 95 onshore, and 2 onshore and offshore fields have been discovered in the province (IHS Energy Group, 2001). Of the 196 discovered fields, 70 are presently producing. Only 11 have been temporarily shut in after producing, and more than 100 await appraisal or development. Of the 70 producers, 13 are enhanced or improved-recovery fields (IHS Energy Group, 2001). The majority of the fields are classified as oil and gas fields. The largest field is the Bombay High field, which was discovered in 1974 using seismic data. It is located approximately 170 km west of Mumbai on a persistent structural high that is 65 km long and 23 km wide (Rao and Talukdar, 1980). Production is from structural and stratigraphic traps in rocks ranging in age from basement and basal sands to Miocene carbonates. Cumulative production from the Bombay High field has exceeded 2 billion barrels of oil (BBO) and 3 trillion cubic feet of gas (TCFG).

Figure 15. Regional structure and selected oil and gas fields (modified from Rao and Talukdar, 1980; Biswas and Deshpande, 1983; Mitra and others 1983; Wandrey and Law, 1999).

Exploration efforts in the offshore area of Kutch and Saurashtra through 1996 included more than 35,000 km of 2-D and 3-D seismic surveys and the drilling of 21 exploratory wells. These efforts resulted in 56 prospects or structures confirmed with seismic data (Bhat and others, 1997). Twenty-one wells have been drilled onshore and offshore to test 15 of these prospects. Of these 15 prospects, there were 1 oil, 2 gas, and 12 dry prospects (Bhat and others, 1997). The KD-1 well in the western offshore of Kutch (fig. 15) tested oil from Eocene limestones; the GK-29A-1 well tested semicommercial gas from Eocene-Paleocene sandstones; and the GK-22C-1 well tested semicommercial gas from Cretaceous sandstones. Through 1996 there were no commercial discoveries, but there are 41 identified prospects remaining to be tested (Bhat and others, 1997).

Exploration and development in the province has been relatively uninterrupted and successful, and significant discoveries continue to be made. The cumulative new-field wildcat wells versus well-completion-year plots (fig. 16) show that the field-discovery rate has remained relatively constant since the initial discoveries in both assessment units. The plots in figure 16 also show that the exploration effort (the indicator used in figure 16 is the number of new-field wildcat wells drilled to find each new field) has remained relatively constant. The plots showing grown oil and gas fields are ranked by size and grouped by date of discovery in thirds (figs. 17 and 18). For comparative purposes, the fields were ranked and grouped to standardize and increment time in the context of exploration maturity. These plots provide indications of the assessment units' development history and maturity as well as possible new plays or trends within the assessment unit. The Eocene-Miocene Bombay Shelf AU plot (fig. 17) for oil shows a progressive decrease in field size, in each third, for the largest fields. The plot displays trends that indicate a relatively mature assessment unit for the developed part of the province and largest fields. There is crossover in the second and third thirds that may indicate discovery of a new play or an improved understanding of existing plays. The gas plot for the same AU shows an early crossover of the trends. Most third third discoveries are larger than those of the first and second thirds, which may also indicate a better understanding of an existing play or the discovery of a new play. Intentional exploration for gas rather than oil may have also affected the discovery trends. In both cases, the field sizes show a range of several orders of magnitude through each third. The Eocene-Miocene Deltaic AU discovery thirds plots (fig. 18) for oil and gas display trends similar to those of the Eocene-Miocene Bombay Shelf AU plots and are subject to the same influences. The oil plot displays little crossover and exhibits the trends expected in a mature, relatively homogenous, and well-understood assessment unit. The number of gas discoveries was insufficient to create a meaningful plot.

Figure 16. Plots showing the cumulative number of new-field wildcat wells versus well-completion year. These plots are an indication of exploration effort. Based on Petroconsultants well and field data (Petroconsultants, 1996).

Figure 17. Maturity of exploration indicator plot showing a comparison of grown oil and gas field size grouped by age of discovery in thirds for the Eocene-Miocene Bombay Shelf Assessment Unit. Based on Petroconsultants well and field data (Petroconsultants, 1996).

Figure 18. Maturity of exploration indicator plot showing a comparison of grown oil and gas field size grouped by age of discovery in thirds for the Eocene-Miocene Cambay Deltaic Assessment Unit. Based on Petroconsultants well and field data (Petroconsultants, 1996).

Exploration-maturity and success plots showing the cumulative grown volumes of oil and gas fields versus the cumulative number of new-field wildcat wells drilled for the Eocene-Miocene Bombay Shelf AU (fig. 19) indicates that the size of both oil and gas fields found has diminished rapidly after the first and generally largest discoveries, and the size remains relatively constant. The rate of effort required to discover individual fields is indicated in part by the number of new-field wildcat wells drilled to find each field. After the initial discoveries, the number of new-field wildcat wells drilled to find each field has remained relatively constant. Exploration-maturity and success plots showing the cumulative grown volumes of oil and gas versus the cumulative number of new-field wildcat wells drilled for the Eocene-Miocene Deltaic AU (fig. 20) suggest a similar history—the size of both oil and gas fields found has diminished significantly after the first and generally largest discoveries. The rate of effort required to find smaller fields has increased for all cases.

Figure 19. Bombay geologic province exploration maturity and success indicator plot showing the grown size of individual fields versus the cumulative number of new-field wildcat wells drilled for the Eocene-Miocene Bombay Shelf Assessment Unit. Based on Petroconsultants field and well data (Petroconsultants, 1996).

Figure 20. Bombay geologic province exploration maturity and success indicator plot showing the grown size of individual fields versus the cumulative number of new-field wildcat wells drilled for the Eocene-Miocene Cambay Deltaic Assessment Unit. Based on Petroconsultants field and well data (Petroconsultants, 1996).

Production

Ranked 38th worldwide (Klett and others, 1997), known petroleum resources of the Bombay geologic province are 8.4 BBO, 24.2 TCFG, and 0.3 billion barrels of natural gas liquids (BBNGL) (Petroconsultants, 1996). The total, 12.7 billion barrels of oil equivalent (BBOE) including natural gas liquids, is from 165 fields of which 126 are 1 million of barrels of oil equivalent (MMBOE) or greater in size.

Composite Total Petroleum System

Source Rock

Thick deltaic clay and shale facies deposited in the Surat and Dahanu Depressions and the Shelf Margin Basin during Paleocene, Eocene, Oligocene, and early Miocene time (Rao and Talukdar, 1980; Sankaran and others, 1995) are the most likely sources for the Eocene-Miocene Composite TPS in those depressions as well as on the Bombay High and on the shelf margin (see fig. 25). Paleocene and lower Eocene rocks probably contributed the largest volumes of oil and gas to the TPS. The primarily terrestrially sourced material, consisting of types-II and -III kerogen (Das and others, 1987), is similar to, but not as rich in total organic carbon (TOC) as, the correlative Eocene Cambay Shale of the Cambay-Hazad and Cambay-

Kalol petroleum systems to the north (Banerjee and Rao, 1993; Biswas and others, 1994; Samanta, 2000). Eocene through lower Miocene shales in and surrounding the Bombay offshore area have TOC values ranging from 0.5 to 2.0 percent, with higher values measured for Eocene shales in the Dahanu Depression. Thermal-alteration-index (TAI) values of 3 or higher reported for lower Miocene and older rocks indicate that temperatures were sufficiently high to generate oil and gas (Basu and others, 1980). Where these shales alternate in thin layers with limestones on the adjoining carbonate banks of the Bombay High and Ratnagiri Shelf, they are generally immature. Therefore, it is most likely that oil and gas generation occurred in early Miocene time and earlier in shales of the Surat and Dahanu Depressions and, to a lesser extent, in the Shelf Margin Basin.

In the Cambay Graben, source rocks include the lower Paleocene Olpad, upper Paleocene to middle Eocene Cambay Shale, and middle Eocene Kalol Formations (Banerjee and others, 2002; Biswas and others, 1994; Banerjee and Rao, 1993) (fig. 11). Organic material in rocks of the Cambay Graben consist primarily of terrestrially derived types-II and -III kerogens. TOC values range from less than 2 percent to as high as 48 percent, averaging 2 to 3 percent.

Kutch Basin source rocks include shales of the Middle Jurassic Jhurio and Kaladonger, Upper Jurassic Jhuran, and Cretaceous Bhuj Formations (Biswas and Deshpande, 1983). Although these shales have sufficient organic content, they are not mature in outcrop. However, these source rocks are likely to be mature and generating at greater burial depths and thickness to the southwest in the offshore. Biswas, (1982) suggested that maturity may have been enhanced near the end of the Cretaceous when this portion of the Indian plate passed over a hot spot near the Equator. The present-day thermal gradient for the Bombay-High area is 3°F/100 ft, and 2°F/100 ft in the Indus Basin. It is likely that the thermal gradient for the Kutch area falls within that range. The source rocks contain mixed type-II and -III kerogens.

The Tertiary part of the TPS in the Kutch area is most prospective in the western offshore, where sedimentary rock thickness is as much as 2,000 m. The source rocks are probably thinner and not as rich as in the Bombay-High area, which received organic source material from both the ancestral Narmada and Cambay Rivers of the Cambay Basin. Potential source rocks include black shales of the Eocene lower Kakdi stage, and the Miocene Vinjhan stage (Biswas and Deshpande, 1983). Burial depths are not great, and source rocks may only be mature in the deepest parts of the western offshore area.

Reservoir Rocks

In the Bombay-High area, oil and gas is produced from fractured basement through middle Miocene reservoirs, with the most prolific being the platform carbonates such as the lower Miocene L-III limestone. Other significant reservoirs are the middle Miocene L-II limestone, L-I limestone, S-sandstone, middle Eocene Bassein limestone, and lower Eocene Panna sandstone. Approximately 70 percent of the reservoirs in the Bombay-High area (fig. 21) are carbonates. The primarily intergranular porosities range from less than 10 percent to greater than 30 percent, with an average between 15 and 20 percent. Permeabilities range from 0.01 milidarcies (mD) to 1,000 mD with averages in the range of 100 to 250 mD.

Figure 21. Lithologic and temporal distribution of reservoir rocks in the area of the Bombay-High and Surat-Depression areas (IHS Energy Group, 2001).

The Surat Depression reservoirs are primarily Eocene, Oligocene, and Miocene sandstones and siltstones. Porosities range from less than 10 percent to more than 30 percent and permeabilities range from 10 mD to 8,000 mD.

The Cambay Graben reservoirs include fractured Cretaceous basement rocks; Paleocene basalts, conglomerates, and sandstones; Eocene sandstones, siltstones, shales, and coals; Oligocene siltstone and sandstone; and Miocene sandstones and siltstones. In the Cambay Graben, approximately 70 percent of the reservoirs are Eocene sandstones and siltstones (fig. 22). Porosities are generally good, ranging from less than 10 percent to greater than 40 percent, with an average between 20 and 30 percent. Permeabilities range from 0.1 mD to 20,000 mD, with averages of 100 to 200 mD.

Figure 22. Temporal and lithologic distribution of reservoir rocks in the Cambay Graben (IHS Energy Group, 2001).

The Kutch Basin potential reservoir rocks include the massive sandstones of the Upper Jurassic Jhuran Formation. The Upper Cretaceous Bhuj and Kori limestones may also have good reservoir qualities. Middle Eocene and Oligocene platform limestones analogous to those of the Bombay High and Pliocene Kanakawati sandstones are the most prospective reservoirs. Porosity and permeability averages are as high as 25 percent and 30 mD, respectively, where reported.

Traps

The most prolific traps are those located on persistent paleo-highs of the Bombay-High area and horst blocks within the Cambay Graben (fig. 23). These structures developed in Late Cretaceous or early Paleocene time in association with rifting events (Sankaran and others, 1995) and were reactivated numerous times. Anticlinal structures are also productive in the area of the Bombay High, Surat Depression, and Cambay Graben (fig. 24). Anticlines in the Kutch Basin are breached except offshore to the west where they may still hold potential. There are also untested anticlinal features on the outer shelf.

Figure 23. Trap type distribution in the Bombay-High area and Cambay Graben (IHS Energy Group, 2001).

Figure 24. Trap type distribution in the Surat-Depression (top) and Kutch areas (IHS Energy Group, 2001).

Stratigraphic traps and pinch-outs are productive in the Cambay Graben and have recently received more attention. These traps may also have potential in the Kutch area west of the Median High.

Seals

In the Bombay offshore and Kutch areas, the most likely seals are an extensive series of thick middle to upper Miocene shales. In the Cambay Graben, interbedded Paleocene through middle Miocene shales provide seals for the various reservoirs.

Generation and Migration

Generation and expulsion adjacent to the Bombay-High area may have occurred as early as middle Miocene and continued, or began again, in the Pliocene (Basu, and others, 1980). Burial-history data indicate peak generation most likely occurred during the late Miocene and early Pliocene (fig. 25) (Samanta, 2000; Biswas and others, 1994; Banerjee and others, 2002).

Figure 25. Events chart summarizing stratigraphy, source rocks, reservoirs, seals, traps, and petroleum information for the Bombay geologic province Eocene-Miocene Composite Total Petroleum System.

Eocene to middle Miocene sedimentary sequences in the shelf-margin area west of the Bombay-High area show thermal-alteration-index (TAI) values > 2.5 (Rawat and others, 1987), and the onset of hydrocarbon generation occurred at approximately 2.5 Ma. Generation in the Kutch area may have begun as early as Paleocene for Jurassic source rocks, and in the late Miocene and Pliocene for Tertiary source rocks.

Assessment Units

Two assessment units were defined and assessed with in the Eocene to Miocene Composite TPS (804301): the Eocene-Miocene Bombay Shelf AU (80430101) and the Eocene-Miocene Cambay Deltaic AU (80430102). The Eocene-Miocene Bombay Shelf AU (80430101) (fig. 3) which is an oil-prone assessment unit located offshore along the west coast of India. A pericratonic basin, it is characterized by extensive carbonate-platform shelf development during middle Eocene to middle Miocene time. The carbonates reached their maximum extent in late Oligocene time, covering much of the shelf south of the Indus River Delta.

Thick deltaic clay and shale facies deposited in the Surat and Dahanu Depressions, and the Shelf Margin Basin, during the Eocene through early Miocene are the most likely source rocks. The Shelf Margin Basin and Saurashtra and Kutch offshore areas, with thinner source-rock intervals, have less potential. Kerogens are primarily terrestrial types II and III. Eocene through lower Miocene shales in the Bombay offshore area have TOC values from 0.5 to 2.0 percent; TOC values are higher for Eocene shales in the Dahanu Depression

Thermal-alteration-index (TAI) values of 3 or higher and vitrinite reflectance values (R_o) of 0.4 to 1.1 percent, reported for early Miocene and older rocks, indicate that temperatures were sufficiently high to generate both oil and gas. Burial-history data indicate that generation occurred during the Pliocene. Migration is primarily updip. Because shales on the carbonate platforms of the Bombay High and Ratnagiri Shelf are generally immature, it is likely that oil and gas migrated from early Miocene and older shales of the Surat and Dahanu Depressions.

Oil and gas is produced from fractured basement through middle Miocene reservoirs, with the most prolific being platform carbonates such as the lower Miocene L-III Limestone. Other significant reservoirs are the Miocene L-II Limestone, L-I Limestone, S-Sandstone, Eocene Bassein Limestone, and Eocene Panna Sandstone.

Discovered traps are primarily anticlines and faulted anticlines revealed by seismic surveys. The most prolific traps are carbonate reefs located on paleo-highs that developed in the Late Cretaceous or early Paleocene as a result of rifting. The most likely seal is a series of thick middle to upper Miocene shales extending over the area.

The Eocene-Miocene Cambay Deltaic AU (80430102) is also an oil-prone composite assessment unit, located both onshore and offshore along the west coast of India. The prospective area consists of a graben that developed during Late Cretaceous failed rifting and a delta extending southwest from the graben toward the Bombay-Shelf area.

The Eocene Cambay and other shales deposited during the Eocene, Oligocene, and early Miocene are the primary source rocks. The terrestrially sourced shales discussed here have TOC values from 1 to 3 percent where sampled.

Vitrinite reflectance values are low (0.4 to 0.6 percent) in rocks younger than the Cambay Shale onshore, but are as high as 1.1 percent for Oligocene rocks offshore. Burial-history data indicate that generation occurred during the Miocene and early Pliocene. Migration is primarily vertical, along faults and fractures into overlying sandstone reservoirs.

Oil and gas is produced from Eocene to lower Oligocene deltaic sandstone reservoirs, siltstones of the Cambay shale, and lower Miocene sandstones such as the Babaguru. Traps include faulted anticlines, fault blocks, and combination and stratigraphic traps. Stratigraphic traps associated with deltaic and alluvial sequences may hold much of the future potential for this assessment unit. The most likely seals are lower Oligocene marine and lower and middle Miocene marine to fluvial-deltaic shales.

Assessment Comparisons

Kingston (1986) estimated the mode of remaining undiscovered hydrocarbon resources in the Bombay province at 1.9 BBO and 8.5 TCFG. The 1998 assessment by Masters and others (1998) for Kutch, Cambay, and Bombay Basins combined estimated mean undiscovered hydrocarbon resources at 1.76 BBO and 13.9 TCFG. The volumes of oil and gas in the areas previously assessed are difficult to compare with this assessment because the locations and sizes of these areas, including the Bombay Shelf, are not clear. In this study, mean undiscovered petroleum resources were estimated to be 2.1 BBO and 12.9 TCFG.

Assessment Results

The U.S. Geological Survey has estimated undiscovered oil and gas resources that may be found within the assessed portions of the Bombay geologic province (Wandrey, 2000) based on TPS extent and quality, oil and gas production, oil and gas reserves, discovery rate, and field-growth data (table 1).

Summary

Parts of the Bombay geologic province are relatively mature in terms of exploration, but many good prospects remain to be tested. The largest field has probably already been found, but there remains an opportunity to find a significant number of smaller fields. The Gulf of Cambay, north Cambay Graben, Kutch offshore, and Shelf Margin Basin all hold potential for future discoveries. Early exploration concentrated on anticlinal and fault-block structures located with 2-D seismic data. The development of 3-D seismic and improvement of 2-D processing has helped identify a number of combination and stratigraphic traps.

Source rocks in outcrop are not mature, and even offshore burial depths may not have been sufficient to generate significant quantities of hydrocarbons in some areas. In the Kutch area, Mesozoic anticlinal traps have been breached onshore and may also be breached offshore.

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