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Hot deep origin of petroleum: Deep basin evidence and application

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Contents

HOT DEEP ORIGIN OF PETROLEUM:

DEEP BASIN EVIDENCE AND APPLICATION[1]

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ABSTRACT

Use of the model of a hot deep origin of oil places rigid constraints on the migration and entrapment of crude oil. Specifically, oil originating from depth migrates vertically up faults and is emplaced in traps at shallower depths. Review of petroleum-producing basins worldwide shows oil occurrence in these basins conforms to the restraints of and therefore supports the hypothesis. Most of the world's oil is found in the very deepest sedimentary basins, and production over or adjacent to the deep basin is cut by or directly updip from faults dipping into the basin deep. Generally the greater the fault throw the greater the reserves.

Fault-block highs next to deep sedimentary troughs are the best target areas by the present concept. Traps along major basin-forming faults are quite prospective.

The structural style of a basin governs the distribution, types, and amounts of hydrocarbons expected and hence the exploration strategy. Production in delta depocenters (Niger) is in structures cut by or updip from major growth faults, and structures not associated with such faults are barren. Production in block fault basins is on horsts next to deep sedimentary troughs (Sirte, North Sea). In basins whose sediment thickness, structure and geologic history are known to a moderate degree, the main oil occurrences can be specifically predicted by analysis of fault systems and possible hydrocarbon migration routes.

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Use of the concept permits the identification of significant targets which have either been downgraded or ignored in the past, such as production in or just updip from thrust belts, stratigraphic traps over the deep basin associated with major faulting, production over the basin deep, and regional stratigraphic trapping updip from established production along major fault zones.

INTRODUCTION

One of the strongest checks on the model of a deep, hot origin of petroleum (Price, 1973, 1976) is the geology of oil occurrence in basins worldwide. Use of the model puts rigid restraints on which basins and specific areas in basins should have oil and which should not. Structural and geologic controls on the occurrence of these oil deposits are also defined by consideration of the model. The geology of oil occurrences in all the different petroleum producing areas of the world that I examined fits the requirements of the hypothesis. Although much of this evidence does not prove that the oil deposits originated in the deep parts of basins and migrated upward from them, all the evidence shows the model is geologically compatible with the natural system. Moreover, part of the evidence is more than merely compatible and thus goes much further toward substantiating the model. This paper reviews a portion of this evidence and attempts to demonstrate the use of the model as a tool in petroleum exploration.

REVIEW OF MODEL

Organic analysis of sediments at depths of 18,000 ft (5.49 km) and deeper shows 100-3,000 ppm of C_{15+} heavy hydrocarbons are present in these sediments in a number of basins (Price, 1977, unpublished data). The high temperatures at these depths greatly increase the solubility of oil in water (Price, 1976). Thus at depths of 15,000-30,000 ft, 4.57-9.15 km (depending on the geothermal gradient), the temperatures become high enough to dissolve these newly created hydrocarbons into the pore water of the deep basin. Although the bulk of sediment pore water has been previously lost to compaction by these depths, Price (1976) argued that enough water remains in deep basinal sediments to allow primary migration by molecular solution.

Fluid pressure gradients build up to abnormally high values approaching or exceeding lithostatic pressure gradients. These high fluid pressure gradients force shale waters into sands and silts which transfer this water, with dissolved hydrocarbons, to fault zones, the only possible avenues of vertical fluid transport. Lateral flow of water through shales may also occur. The deep basin pressures also open faults and keep them open until the abnormal pressures are relieved by vertical fluid transport. As the waters move up the fault plane, temperature decreases cause hydrocarbon exsolution. Eventually a long continuous hydrocarbon phase is built up and the fluid pressure gradient created by the migrating waters overcomes the surface tension of the hydrocarbons. This allows the hydrocarbon phase to move up the fault plane with the water. The buoyancy of oil in water also aids in this upward movement.

As the fluids rise into the normally pressured section, the pressure necessary for continued movement up the fault may be greater than the pressure needed for movement of the fluids off the fault and laterally into a permeable unit. If this is not the case, the migrating fluids will continue to move up the fault and eventually may be lost as seepage at the outcrop.

Let us consider movement laterally off the fault into a sandstone (Fig. 1). If the migrating oil (and water) enters the downthrown side of the fault plane, it is caught in the first structure off the fault (A), which is an anticline. If more petroleum enters, eventually the spill point may be exceeded and oil migrates to a second trap (B). On the other hand, if oil enters the upthrown side of the fault where no traps are present, the hydrocarbons migrate updip long distances to be caught in subtle traps such as small unfaulted anticlines (C) or stratigraphic traps on the shallow shelf area of the basin. If a regional high(D) cuts off a part of the shallow shelf from the deep basin this prevents lateral migration of hydrocarbons updip into this area and it is barren of oil.

Abnormal fluid pressures not only aid in the origin and migration of petroleum, they also may control petroleum emplacement if the pressures are higher on one side of a fault plane than on the other (Fig. 2). The Ship Shoal Block 28 field (Myers, 1968) of offshore Louisiana has produced 17 million bbls of condensate and 627 Bcf as of 1/1/73. The structure is a faulted anticline with the hydrocarbons in the downthrown block. The fault has 2,000-3,000 ft (609-914 m) of throw and reserves are in Pliocene and Miocene sands at depths of 7,500-17,000 ft (2.29-5.18 km). Because the pressure on the upthrown side of the fault is much higher at any given depth than on the downthrown side, the migrating hydrocarbons were forced into the latter, as high pressures impeded entrance into the up block. Also, as Myers (1968) pointed out, abnormal fluid pressures on the upthrown side of a fault can also serve as a trap by not permitting updip migration of hydrocarbons across the fault.

During migration and emplacement of oil, fluids cannot enter sands in the abnormal pressure zone; however, this does not mean that hydrocarbon deposits cannot exist in abnormal pressure zones. Normally pressured sands could receive hydrocarbons from faults and then the entire area could receive additional sedimentation, burying the deposits into the abnormal pressure zone. Thus by this model significant oil and gas deposits could be present in the abnormal pressure zones of some basins.

By the present model multipay fields should normally result from a series of thin reservoirs each of which may build up temporary abnormal fluid pressures, thus forcing fluids into other reservoirs above or below. The Block 28 field is an example. However, if the reservoirs are thick and laterally continuous, they could receive large amounts of fluids without building up abnormal pressures. Thus all of the fluids that rise along a fault could be focused into a single reservoir.

RESTRAINTS OF MODEL

The model puts rigid restraints on petroleum occurrence in the natural system:

1. Most of the world's oil should be found in sedimentary basins with sediment thicknesses of at least 25,000-30,000 ft (7.62-9.14 km).

2. Oil over or immediately adjacent to the basin deeps should be associated with or immediately updip from major faults.

3. Deep basins should be more productive than shallow basins in terms of recoverable oil per unit area or volume.

4. Strongly faulted and folded (if structure is not too complex) hotter basins (at some geologic time), shoud be more productive than basins without these features.

5. Fault-block highs adjacent to deep sediment troughs are primary exploration targets.

6. Traps immediately adjacent to basin deeps should be productive, whereas structures at basin margins should be barren or have small reserves (unless extensive lateral migration has taken place such as in western Canada or northern Algeria).

7. Structures associated with major faults (throws of 1,000 ft; 340 m or more) tapping the deep basin should be productive, with greater throws generally resulting in greater reserves.

8. Basin-forming faults should be especially productive.

9. Aborted rift (block fault) basins and strike-slip (wrench) basins should be especially productive in terms of reserves per unit area or volume because of high heat flows.

10. With knowledge of the structure and sediment thickness distribution in a basin, one should be able to use the present model to predict very precisely where the main occurrences of oil should be, and what areas should be barren.

Table 1 supports the first point and a number of basins for which sediment thickness data is available. The correlation of petroleum productivity with sediment thickness is not new. For example, Weeks (1955, p. 9) noted "Practically all of the world's oil is accumulated in pools within or flanking deposition sinks, basins of broad stable regions produce little of the world's oil and some are largely barren of commercial oil." Weeks (1958) further noted that a major part of the world's oil is accumulated adjacent to the more prominent depocenters in the basins, and gives the following examples: the Southern San Joaquin Valley, Los Angeles basin, Illinois basin, Vienna basin, North German basin, Persian Gulf, Middle Magdalena Valley, Lake Maracaibo, Suez graben, all the Argentinian basins, the Big Horn Basin, and North Coastal Peru.

The second point (the association of oil over the basin deep with major faulting) is documented extensively throughout the text for the Los Angeles, Ventura, Ploiesti, Gippsland, North Sea, Cook Inlet, Big Horn, Niger Delta, Sirte, Vienna, and Po Valley basins. I have also examined a large number of other basins mentioned briefly or not at all in the present text. In all of these basins the association of faulting with oil production is typical.

Table 2 lists discovered reserves per unit area for a number of shallow basins as well as the deep basins discussed in this article. The deeper basins are much more productive per unit area than the shallower basins, documenting the third point. Weeks (1955) had also earlier noticed this fact.

Although points 4 and 5 are covered below in the text, brief examples are given here. The correlation of complex structure with prolific production is present in the Los Angeles and Southern San Joaquin Valley basins of California, the fold belt (Asamari region) of the Persian Gulf basin, southern Oklahoma over the Andarko basin deep, the Ploeisti district of Rumania, the Big Horn Basin, and Eastern Venezuela, to name a few. Examples of prolific production associated with fault block highs are the Sirte and North Sea basins, the Central Basin Platform of the West Texas Permian basin, the Amarillo uplift of the Anadarko basin, and the Casper Arch of the Powder River Basin.

Examples of the sixth point, the productivity of traps adjacent to the deepest part of the basin while traps on the basin margins are barren, are discussed below for the Los Angeles, Ventura, and Big Horn Basins although this point is common for almost all petroleum basins.

Examples of the seventh point, the positive correlation of increasing fault throw with increasing reserves, are present in the Gulf Coast, North Sea, Ploeisti, Niger Delta and Los Angeles basins to name a few.

The association of prolific production with basin forming faults, the eight point, is seen along the basin-forming faults (Newport-Inglewood, Norwalk, Whittier) of the Los Angeles basin; the Los Bajos wrench fault of Trinidad, the Mexia-Talco-Luling system of the interior Gulf Coast, U.S.A.; the McClain County and Mountain View faults of the Anadarko basin; the Midland fault of the Sacramento Valley basin, California; the Steinberg fault of the Vienna basin, Austria; and the Vicksburg fault system of the south Texas Gulf Coast area.

Examples of the ninth point, the prolific nature of aborted rift or block fault basins, are the North Sea basin; Sirte basin; the West Siberian Lowland basin, U.S.S.R.; Tsaidam basin, China; and the Suez graben. Wrench basins give some of the most prolific production per unit sediment area in the world--the Los Angeles basin, the Southern San Joaquin Valley basin, Central Sumatra, Lake Maracaibo, Eastern Venezuela, Trinidad, and Northwest Peru.

Two examples of the tenth point, the use of the model for specific prediction of oil and gas occurrence in a basin, are given below. These are the Los Angeles and Ventura basins.

PREDICTED TARGETS

Use of the present model permits prediction of a number of targets which have high potential but generally have not been considered in the past

Thrust Belts

This target centers on major low angle thrust faults that originate in what was once a deep sedimentary basin. Plate collision, resulting in subduction, thrusting, and uplift and erosion all have since destroyed the basin. Such structural evolution is commonly accompanied by upward movement of a large amount of overpressured water with dissolved gas and oil along thrust faults. Rubey and Hubbert (1959) and Hubbert and Rubey (1959) have shown that the presence of such fluids is necessary for low angle thrust faulting to take place.

Western Canada.--The Turner Valley field (Fox, 1959) in the folded foothill belt of Western Canada serves as an example (Fig. 3) of the thrust belt play. Nine major overthrusts and many lesser ones, all dipping toward the basin deep, lie in the region of the field. Most of the major thrusts have known lengths of 50-125 mi (80-201 km), stratigraphic throws of 5,000-8,000 ft (1.52-2.44 km), and displacements of 1.5-8 mi (2.4-13 km). The Lewis overthrust, the largest in the area, is 175 mi (282 km) long with a maximum throw of 20,000-25,000 ft (6.10-7.62 km) and a stratigraphic displacement of 25 mi (40 km).

The producing structure at Turner Valley is a drag fold above the Turner Valley overthrust; the stratigraphic throw on this fault is 5,000 ft (1.52 km) with 17,500 ft (5.33 km) of displacement. Both the throw and displacement decrease noticeably away from the producing structure. Fox (1959) believed that the structure at Turner Valley (as well as those at Savanna Creek, Jumping Pound, Pincher Creek, Castle Creek, and Waterton fields), was formed during the Laramide orogeny, as a result of drag folding due to the thrusting. Because there were no traps prior to thrusting, the oil must have accumulated during or after thrusting, and either moved updip in the sediments from the west or up the fault from the deep basin. It is unlikely that the former is the case because the complex structure of the area gives little continuity in the sediments.

Wells (1968) noted to the end of 1965, 20 fields had been discovered in the Alberta foothills province (Fig. 4) representing 11.5 Tcf of gas in place with at least 145 million bbls of recoverable gas liquids and over 120 million bbls of recoverable oil. All these fields are geologically similar to Turner Valley. Thus Mississippian sediments (mainly the Turner Valley formation) are the reservoir rocks in 18 of the 20 fields, Triassic sediments in 2 and Devonian sediments in 2. The average reservoir depth is about 10,000 ft (3.05 km). All the fields are overthrust fault structures, thrust from the west with structural closure provided by the thrusts on the east sides of the fields. The steep dips of the west flanks and north and south plunges of fault blocks provide closure in the other directions.

Although such faulted structures have trapped significant amounts of oil and gas in western Canada, the present model requires the bulk of the hydrocarbons to have migrated up the thrust faults and to have entered permeable sediments of the overthrust (easternmost) blocks. As there are no traps in these blocks, the hydrocarbons migrated updip to the east for hundreds of miles and were trapped in various subtle traps on the shallow shelf region. Hydrocarbons that migrated up the Turner Valley fault (Fig. 3) for example, encountered any given bed in the overthrust (easternmost) block before the same bed was encountered in the overriding block. Thus the permeable beds of the overthrust block drained off the bulk of the abnormally pressured fluids from the fault plane allowing only a small percentage to reach the drag folds in the overriding block.

Big Piney LaBarge.--The overthrust belt of western Wyoming, a continuation of the disturbed belt that extends southward from the Canadian Rockies, consists of Paleozoic and Mesozoic sediments thrust east in Laramide and Post Laramide time over Tertiary rocks. A number of major thrusts with lateral displacements of 15-45 miles (24-72 km) have been mapped in the area. Estimates of the maximum thickness of the sediments in the basin to the west of the field before thrusting range up to 60,000 ft (18.3 km).

The Big Piney-La Barge field (Krueger, 1968) lies on the La Barge platform, a southeast-trending nose or arch just east of the disturbed belt. The Darby overthrust, one of the major thrusts in the area, has thrust Paleozoic rocks over Cretaceous and lies in the western part of the field. Several other large thrusts also cut the field. The Frontier and Mesaverde (both Upper Cretaceous), and Almy (Paleocene) formations produce gas and oil in the field. The traps are structures updip from thrusts, west-dipping sands that abut against thrusts or sands that pinch out east and updip from major thrusts. This complex in 1966 had an EUR of 1.5 Tcf with substantial oil and condensate reserves.

Other such occurrences of hydrocarbons in structural or stratigraphic traps updip from or cut by major thrusts that rise out of what once were deep sedimentary basins can be expected. In fact, the entire disturbed belt from Utah to the Canadian border should be productive according to the present concept. The structural complexity of thrust belts, the exploration difficulties in the generally rugged terrain, and the prejudice that oil and gas do not occur in these areas have previously downgraded this exploration target.

Stratigraphic Traps

Stratigraphic traps can contain rich deposits and yet are the hardest to find. The present model may aid in the exploration for stratigraphic traps over the deep basin. The key to exploration for such traps is to first identify a major fault over the deep basin (which will transport hydrocarbons upward whether a trap is present or not) and then locate stratigraphic changes which could trap hydrocarbons and are either updip or cut by the fault. A number of large fields serve as examples.

The East Texas field is a classic example of a stratigraphic trap, with the reservoir rock (the Cretaceous Woodbine sand) pinching out on the west side of the Sabine uplift. The sand is truncated by the Austin Chalk (Cretaceous) which forms the cap rock. The oil is generally thought to be from Cretaceous sediments westward and deeper in the east Texas basin with migration east and updip to the trap. Just south of the field is the large Mount Enterprise fault system with a throw of 1,000 ft (305 km) at the level of the Lower Cretaceous Massive Anhydrite (Nichols et al, 1968). This fault strikes east-west across the east Texas basin and extends into a thick Paleozoic section which underlies the Mesozoics. If the East Texas oil did come from the fault to the south and not from the west and if there were a gas cap in the field it would be expected at the southern end of the field, the place where the hydrocarbons would first enter the trap. Gussow (1955) notes that there is a small gas cap in the southeast part of the field in a separate closure isolated from the main reservoir.

Jay (Ottmann et al, 1973) is a recently discovered major stratigraphic trap with recoverable reserves of over 300 million bbls and 300 Bcf. The field (Fig. 5) lies across the Florida-Alabama state borders and occurs in Smackover limestone (Jurassic). The oil water contact is at 15,480 ft (4.72 km). The trap is a south plunging large, low relief anticline with the critical northern closure provided by an updip facies change from a porous dolomite to a dense micritic limestone. Just downdip and to the east of the field is part of the Gilbertown-Pickens-Pollard fault which extends into the underlying thick Paleozoics and could have been responsible for the Jay crude.

Prudhoe Bay (Morgridge and Smith, 1972) with an EUR of 9.6 billion bbls and 26 Tcf is a stratigraphic trap located on the Barrow Arch on the north slope of Alaska. The trap (Fig. 6) is a west plunging anticlinal nose faulted on the north, with the critical eastern closure being provided by unconformity truncation. Reservoir rocks range from Pennsylvanian to Jurassic; however, the bulk of the field's reserves are in the Lower Triassic and Permian Sadlerochit sands. Faults with large throws lie on the north side of the field and dip into a thick body of sediments. These faults by the present model could have transported the hydrocarbons from these sediments.

The South Glenrock oil field (Curry and Curry, 1972) is located on the southern flank of the Powder River Basin of northeast Wyoming, just southwest of one of the deeper parts of the basin (Fig. 7). The field, on the southeast flank of the Big Muddy anticline, is a stratigraphic trap caused by an updip permeability barrier in Dakota (Cretaceous) sandstones. These sands hold the major reserves of the field but stratigraphic traps also occur in Cretaceous Muddy channel and marine bar sands. Updip from and to the west of Glenrock is the (Dakota) Big Muddy field on the Big Muddy anticline.

The CP of these two fields to 1/1/73 was 124 million bbls and 44 Bcf. The Laramie mountains reverse fault, which has placed Paleozoic and Precambrian in contact with Cretaceous, cuts the southern part of the Glenrock field along the Laramie Mountain front. The presence of oil at Glenrock on the southern flank of the Muddy anticline suggests that the oil must have come from the south. Yet a downdip southern source for the Glenrock-Muddy fields is lacking because of the presence of the crystalline rocks of the up thrust Laramie Mountain front a few miles to the south. Maps (Petromotion, 1974; and others) show that numerous tests of Dakota traps to the east of the Muddy-Glenrock complex have been dry, ruling out an eastern source for the hydrocarbons. This leaves the Laramie frontal reverse fault (which taps the Powder River basin deep) as an apparent source.

Other fields, which also serve as examples of stratigraphic traps associated with faulting are the Cottonwood Creek field, Bighorn Basin, Wyoming; the Candeias field (Vieira, 1972), Reconcavo basin, Brazil; the Sergano gas field (Rocco and D'Agostino, 1972), Po Valley, Italy; Grimes gas field (Weagant, 1972), Sacramento Valley basin, California; the Chateaurenard fields (Heuillon, 1972), Paris basin, France; and the Tchengue field (Societe des Petroles, 1963), Gabon basin, Africa.

Basin Deeps

Early exploration in most basins is aimed at large obvious (seismic or surface) anticlines which are either directly adjacent to the basin deep or are found at the basin edges. When such structures have been tested the basin exploration is then usually considered mature, and efforts are greatly reduced. Examples are the Los Angeles, Big Horn, Southern San Joaquin Valley, and Anadarko basins. Yet the central deeps of these "mature" basins remain poorly explored. For example, Gardett (1971) notes that the deeper part of the Los Angeles basin is hardly explored, and Adler (1971, p. 1062) summarizing the extent of exploration in the areas over the Anadarko basin trough stated "in contrast the deep basin is virtually untested." Similar conditions exist for the area over the deepest parts of almost all petroleum basins. For example, dry hole maps (Petromotion, 1974) show as of 1973, only 13 wells had been drilled over the deepest part of the Big Horn basin in an area of 1,400 mi^2 (3,730 km^2); no fields had been discovered. The deepest part of the Powder River basin, covering 2,196 mi^2 (5,688 km^2), had only 41 tests, resulting in five small fields and the prolific Spearhead Ranch field. The deepest part of the North Park basin of north-central Colorado covers 216 mi^2 (559 km^2) and has had six tests with one field discovered. The deepest part of the Williston basin, covering 1,728 mi^2 (4,475 km^2), has received but 21 tests with only two small fields discovered. These examples could go on, but to further compound the matter many of the tests probably have not exceeded 5,000 ft (1.52 km).

Updip from the Vicksburg fault for a distance of 200 mi (518 km) stretches the Jackson trend (Fisher et al, 1970), the only stratigraphic trend in the entire Gulf Coast. These fields are in strike-oriented, strand plain and barrier-bar sands of the Upper Eocene Jackson group. Over 300 fields are present and 50 individual sands all produce. Traps are mainly due to permeability loss with some fault closure. Producing sands can be correlated downdip for 10-20 mi (16-32 km). The larger fields in the trend are Government Wells (75 million bbls), Hoffman (46 million bbls), Lopez (28 million bbls), and O'Hern (22 million bbls); all figures are CP's to 1/1/73.

By the present concept most of the hydrocarbons would have moved up the Vicksburg fault from deeper sediments (Fig. 9) and off the fault downdip into Vicksburg and Frio sediments where they were trapped in rollover anticlines. However, some of the hydrocarbons would have moved off the fault and updip into Jackson sediments to be caught by the subtle stratigraphic traps of the trend.

Vertical Versus Horizontal Exploration

Another exploration aid that can be derived from the present model is the concept of vertical as opposed to horizontal exploration. If production from a sediment of a certain age has been established in a basin, then future exploration generally is geared toward that formation, disregarding other deeper possible reservoirs. However, by the present model of vertical migration, what may be a reservoir in one part of the basin may be too deep or too shallow in another part of the basin for the correct fluid entry pressure to allow hydrocarbons to move off a fault. Many producing fields have not been adequately tested for deeper possible production because of the prejudice in favor of lateral exploration. Such an exploration philosophy is justified where long lateral secondary migration in one unit has obviously supplied the hydrocarbons in an area (the Arbuckle (Cambro-Ordovician) production in Kansas for example). However, over the deep basin, restriction to lateral exploration will necessarily exclude many possible discoveries.

Viable exploration targets may be deeper tests in established faulted fields over the deep basin.

Buried Fault Zones

Traps associated with fault zones buried by shallower unfaulted sediments are very viable targets by this concept. Not only do examples of single fields exist, such as the Gela field (Rocco, 1959) Sicily; as well as entire trends of production (Vicksburg fault zone of south Texas), but also much or all of the production of some basins is restricted to sediments cut by faults overlain by barren unfaulted sediments. Examples of such production are: the Gippsland basin, the North Sea, the Po Valley, and much of the Sacramento Valley basin. These exploration targets can only be delineated by detailed seismic studies. The key to these targets is the identification of deeper faulted possible reservoirs while completely ignoring the overlying unfaulted sediments.

Altamont-Bluebell Field

The Altamont-Bluebell field (Lucas and Drexler, 1975) is an example of a number of the exploration targets of this model. The field is over the deepest part of the Uinta basin, in a stratigraphic trap updip from a buried fault. Production is multipay from a number of thin Tertiary reservoirs between 8,000-17,000 ft (2.44-5.18 km). The trap is wholly stratigraphic as the regional dip down to the north provides the setting for updip pinchout to the south. The updip seal is provided by nonporous clastic red beds, lacustrine shale and dense carbonates. The field covers 350 mi^2 (906 km^2). Its northern limit is a buried reverse fault with over 6,000 ft (1.83 km) of displacement at the base of the Tertiary and no recognizable displacement in beds above the level of the oil occurrence. The production is associated with abnormal pressures which begin at 8,000-10,000 ft (2.44-3.05 km) and increase with depth, reaching gradients of 0.8 psi/ft. The abnormal pressure gradient decrease to hydrostatic levels upward, where the fault dies out, and also decrease below the productive zone (B. M. Miller, personal commun., 1977). By the present hypothesis these abnormally pressured fluids, including the hydrocarbons, would have moved up the fault from the deep basin to form this overpressured stratigraphic trap.

SPECIFIC PREDICTION OF OIL AND GAS OCCURRENCE

The Los Angeles and Ventura basins are examples of the tenth point of "Restraints of the model,"--the potentially powerful use of the present concept for specific prediction in a given basin as to where oil should and should not occur. These basins are examined in some detail both to demonstrate the use of the model in exploration, and the association of the production in these basins with faults the extend back to the deep basin.

Los Angeles Basin

The Los Angeles Basin (Yerkes et al, 1965) of onshore southern California is noted for great structural relief and complexity as well as for prolific oil production relative to its small size (1,300 mi^2; 3,108 km^2) and young age. The basin to 1/1/73 had a CP of 6.46 billion bbls and 6.69 Tcf. The Lower Pliocene and Upper Miocene account for 97 percent of the total production. Gardett (1971) notes that 12 of the basin's 52 fields have each produced over 100 million bbls, with Upper Miocene sediments having 15.7 billion bbls of oil-in-place and Lower Pliocene sediments having 15.3 billion bbls of oil-in-place.

The main structural feature of the basin is a northwest trending synclinal central basin deep which may contain as much as 35,000 ft (10.67 km) of sediment. Pre-Cretaceous metamorphosed sediments are overlain by as much as 16,000 ft (4.88 km) of Upper Cretaceous, Paleocene, and Early Miocene clastics. A basin-wide unconformity exists at the base of the Mid-Miocene and a succession of marine clastics and interbedded basic to intermediate volcanics makes up the Mid-Miocene section. Brown (1968) notes that the Mid-Miocene culmination of igneous activity resulted in basaltic extrusives, andesites, tuffs and breccias, and ended with intrusives being injected along some of the faults of the basin. Intense structural activity and sedimentation began in the Late Miocene and continued into the Early Pleistocene resulting in more than 18,000 ft (5.49 km) of Late Miocene to Late Pliocene sediments in the Central Basin deep. Subsidence continued, resulting in the accumulation of 2,500 ft (762 m) of Recent and Pleistocene sediment from the uplift areas surrounding the basin.

Figure 10 shows contours on crystalline basement as well as major fault systems and Figure 11 shows the major structural features of the basin. The major basin-forming Newport-Inglewood fault separates the Southwestern and Central Blocks, and is a right lateral wrench with 3,000-5,000 ft (0.91-1.52 km) of horizontal displacement and 4,000 ft (1.22 km) of vertical displacement at basement. The major basin-forming Whittier strike-slip fault has a vertical throw of 14,000 ft (4.27 km) in the Upper Miocene, with 15,000 ft (4.57 km) of post-Miocene strike slip displacement. The Santa Monica fault has 7,500 ft (2.29 km) of throw at basement.

The present concept can be used to predict very specifically where the main oil occurrence should be in this basin. As in any new venture area, the most prospective areas are over and adjacent to the basin deep, especially along basin forming faults and fault-block highs. Thus the Newport-Inglewood fault, the Whittier fault, and the Norwalk fault all are very good targets and all structures along these faults should produce. The entire southwestern block is a viable target as it lies just updip from the basin-forming Newport-Inglewood fault. On the other hand the entire Palos Verdes block should be barren as it is cut off from updip lateral migration of oil from the Central Basin Deep by the Palos Verdes fault which dips to the southwest and therefore cannot tap the deep basin. The entire northwestern block should also be barren, except for a narrow area parallel to the Santa Monica fault on the northwest, as this block does not have a sediment thickness adequate to cause the temperatures necessary for hydrocarbon generation and migration by the present model. For the same reason both the San Gabriel Valley Basin and northeastern blocks should be barren except for a narrow strip parallel to and just north of the Whittier fault. The Chino basin should also be barren as it is too shallow to generate its own oil by the present model, and the Chino and Whittier-Elsinore faults stop northeast migration of oil out of the deep basin area into this block. On the other hand, the entire Central Basin Deep block as well as the Central block should be prospective. These areas are either deep enough to allow generation and migration of hydrocarbons to take place, or have continuous migration paths back to the basin deep, which would allow updip migration of hydrocarbons from the deep basin.

To review, the Southwestern, Central Basin Deep, and Central blocks should all be productive by the model with all other basin areas expected to be barren (Fig. 11). Within the target area, the four basin-forming faults (Newport-Inglewood, Whittier, Santa Monica and Norwalk) are all especially prospective.

Figure 12 shows the hydrocarbon occurrence of the Los Angeles basin superimposed on Figure 10, and Table 3 aids in the following discussion. As expected, the main hydrocarbon occurrence of the basin is along the four fault zones (table 3). The Southwestern block, the Central Basin Deep block and the Central block contain virtually all the production (99.03 percent of the oil and 99.94 percent of the gas).

Further, almost all the production has been from fields which are faulted or are directly updip from faults extending into the basin deep (Table 3). Only seven fields of this basin are not known to be fault-associated and they have accounted for less than 0.01 percent of the total oil and gas this basin has yielded.

On the other hand, the Palos Verdes block is essentially dry--one small field (Gaffey) along the Palos Verdes fault has produced 18,112 bbls of oil and was abandoned in 1967. The Northwestern block is completely barren. The San Gabriel Valley Basin block has five small fields which have produced .97 million bbls and .58 Bcf. The Northeastern and Chino Basin blocks have three fields which have produced 3.22 million bbls and 3.68 Bcf and two of the fields (which have produced 92 percent of the oil and 91 percent of the gas of this area) are cut by the major Chino fault (2,400 ft; 0.73 km of throw) which dips back toward the basin deep. Thus these fields are not exceptions to the model, due to their association with the Chino fault. However, an exploration effort based on the present model would have missed them.

Factors favorable for oil generation and migration, all of which fit the present hypothesis, have combined to make the Los Angeles basin the prolific basin it is. The basin has a high geothermal gradient which well could have been even higher in the past; Mayuga (1970) gives the present geothermal gradient in the Wilmington field (the largest in the basin) as 3.06^{o} F/100 ft. The intense faulting in the basin with throws of thousands of feet, has allowed a thorough draining of the deep source area of the basin.

The geology and oil occurrence in this basin as well as studies in organic geochemistry support the model. Brown (1968) noted that the origin of oil and gas and the identity of the present major source rocks of the basin have not been fully determined. The larger producing reservoirs of the basin are in proximity to light, coarse-grained shales with low organic contents, and are not found associated with the dark, organic shales (commonly identified as typical source rocks) which are elsewhere in the basin. Phillipi (1965) concluded after a detailed organic geochemical study in the basin that the bulk of the oil in the Los Angeles basin was generated at depths equivalent to temperatures of 120^{o}C (248^{o}F) or greater and traveled up faults to the present reservoirs.

The Los Angeles basin supports the present model. The producing structures are faulted or directly updip from faults that extend into the basin deep, volcanic activity was present, the basin is still very hot, and all the production rings the sedimentary deep of the basin. Also, knowledge of the sediment isopach and the main faulting allows very specific prediction of the barren and oil bearing areas of the basin. Organic geochemical work in the basin also supports a deep origin of the oil in this basin.

Ventura Basin

The Ventura Basin (Nagle and Parker, 1971) of Southern California has a sediment thickness of over 55,000 ft (16.8 km) that ranges from Cretaceous to Pleistocene; all ages are oil-productive. The structural features result from the Pasadenian orogeny which continues into the present, as well as from Early Mid-Miocene structural activity.

Figures 13 and 14 show contours on crystalline basement, and the major structural features of the basin.

The Eastern Ventura Basin (the eastern extent of the basin trough) is bounded by the Oakridge and San Gabriel faults and passes into the Santa Clara trough to the west. The Eastern Ventura Basin is an area of extreme compression, with many thrust faults, and all the anticlines in this area are faulted. The Santa Clara trough, like the Eastern Ventura Basin, is a U-shaped syncline with steep to overturned north and south limbs and with the Oakridge and and San Cayetano reverse faults bounding the trough on the south and north respectively. Both faults have very large displacements. The Santa Clara trough has a Pliocene-Pleistocene section exceeding 20,000 ft (6.10 km) in thickness. The total thickness of all age sediments is possibly as much as 60,000 ft (18.3 km).

The Santa Ynez-Topatopa uplift, north of the basin deep, has had extensive erosion and virtually no Upper Tertiary rocks are preserved. East-west trending folds, which may persist for miles, are numerous and their flanks are cut by south-dipping thrusts. The San Rafael-Upper Piru uplift block lies north of the Santa Ynez-Topatopa uplift. The Santa Ynez fault separates the two blocks. Only Cretaceous to Eocene sediments remain in the San Rafael-Upper Piru block due to uplift and erosion.

South of the Santa Clara trough is the Oxnard uplift with the Oakridge fault bounding the two areas. Early Mid-Miocene volcanism led to intrusive as well as extrusive igneous activity in the Oxnard uplift. Some of the volcanics serve as seals of oil pools. All ages of sediment are present as are many faults. The Simi uplift (to the south of the Oxnard uplift) has been deeply eroded with only Mid-Miocene and older sediments remaining. The northern and southern boundaries of this block are the Los Posas and Sulphur Springs faults, respectively. The Santa Monica uplift, to the south of the Simi uplift, has a thick section of Lower and Mid-Miocene sediments and volcanics. The block is a north-dipping homocline broken by several east-west faults. Sands are tight, very few folds are present in this block, and sediments younger than Mid-Miocene have been completely eroded.

The San Fernando Embayment, cut off from the eastern Ventura Basin to the north by the Oakridge fault, has a maximum sediment thickness of about 15,000 ft (4.57 km) from Cretaceous through Pliocene. The Ridge-Soledad basin, resulting from the San Gabriel fault, contains 15,000 ft (4.57 km) of mainly nonmarine sediment.

Again, knowledge of the structure and total sedimentary isopach of a basin allows one to use the present model to predict very specifically where the main oil occurrence should be expected in a basin. Of immediate interest are the areas of greatest sediment thickness, especially large faults over and bounding these areas. Thus faulted structures over the Santa Clara trough and the Eastern Ventura basin blocks as well as structures along the faults (Oakridge, San Gabriel, and San Cayetano) bounding these blocks should all be productive. Further, the uplift blocks due north and due south of the basin trough should be productive, as oil that moved up the bounding faults could have migrated off these faults and updip into the uplift blocks until it was trapped.

Both the San Rafael and Upper Piru uplifts, on the other hand, should be barren as these blocks do not have a sufficient sediment thickness to have generated their own oil. Also, the Santa Ynez fault cuts off any northward migration of oil from the trough areas from ever reaching the San Rafael and Upper Piru uplifts. Further, both uplifts have had extensive erosion. Although they may once have had a sufficient thickness of sediment to have generated their own oil, the upper part of the section where the oil would have been emplaced has long since been removed by erosion. The Ridge-Soledad basin block with only 15,000 ft(4.57 km) of sediment is likewise too shallow to have generated its own crude and is not at all prospective except for a narrow area paralleling the San Gabriel fault which could receive fluids moving off that fault from the deep Eastern Ventura basin. The San Fernando Embayment with only 15,000 ft (4.57 km) of sediment is likewise too shallow to have generated its own oil by the present model. Also, the southernmost splinter of the Oakridge fault would prohibit updip migration of oil into this area from the Oakridge fault which taps the eastern Ventura Basin deep.

Most of the Simi uplift would not be a viable target as the Las Posas fault would prohibit southward lateral migration of oil from the trough area and across the Oxnard uplift from ever reaching this uplift. Except for the westernmost side of this uplift the entire block is too shallow to have generated its own oil. Another negative feature of this block is the extensive erosion in this area which has left no rocks younger than Lower Miocene. Thus any oil which was generated and migrated into the shallower sediments of this block before this erosion, would have been lost.

The Santa Monica uplift is amarginally prospective target. Although the Las Posas and Sulphur Springs faults would cut off any lateral migration of oil southward out of the deep trough area, this block has a sufficient thickness of sediments to have generated its own oil. On the negative side, the sands are tight and no rocks younger than Mid-Miocene remain in this area, due to uplift and erosion. Thus if this block did generate its own oil, which would have been emplaced in the shallower rocks, it was probably lost by erosion. Although the most prospective area of this block would be along the Sulphur Springs fault, which would tap the deep basinal area of this block, exploration here should be carried out only after the more promising areas of the basin have been looked at in detail.

In summary, the deepest areas of the basin as well as the uplift blocks immediately adjacent to the synclinal areas are viable targets. These are the Eastern Ventura basin, the Santa Clara Trough, the Santa Ynez-Topatopa uplift, and the Oxnard uplift. All other blocks of the basin are not of interest because of erosion, or because they are too shallow to have generated their own oil, or both, and because they are cut off by faults from the lateral migration of oil out of the deep basin. The Santa Monica uplift is only of marginal interest. The Ridge Soledad basin should not produce except along the San Gabriel fault.

Figure 15 shows the oil occurrence of the basin superimposed on Figure 13. The areas one expects to be barren by the model are, and the areas expected to be oil bearing contain oil. The San Rafael and Upper Piru uplifts have no proven reserves. The Ridge Soledad basin has two small fields, Tapia Canyon and part of the Honor Rancho field. Both these fields lie along the prospective area bordering the San Gabriel Fault and have an EUR of 5 million bbls. The rest of the Ridge Soledad basin is totally barren. The Simi uplift has a total EUR of less than 1 million bbls. The San Fernando embayment, also considered non-prospective, has an EUR of less than 5 million bbls with the Cascade oil field at the boundary of the Eastern Ventura Basin and the San Fernando Embayment having over 60 percent of the reserves of this block.

The prospective areas by the model, on the other hand, have rich deposits. The Santa Clara trough has 1.1 billion bbls of discovered recoverable oil with the eastern extension of the trough area (the Eastern Ventura Basin) having an EUR of 296 million bbls. The Oxnard uplift to the south of the trough area has an EUR of 330 million bbls and the Santa Ynez-Topatopa uplift to the north of the trough has an EUR of 19 million bbls.

Of the 2,300 mi^2 (5,954 km^2) the Ventura Basin covers, the Eastern Ventura Basin, the Santa Clara Trough, the Oxnard Uplift, and the Santa Ynez-Topatopa Uplift blocks cover 44.1 percent and contain 99.7 percent of the 1.76 billion bbls of recoverable oil developed in the basin. By using the present model to outline the most prospective areas of the basin, we are able to disregard the oil barren areas of the basin and concentrate exploration efforts on the other 44 percent of the area which has almost all the recoverable reserves. This concept obviously can be a tremendous advantage in the exploration of a basin.

Not only are the fields in areas where they are expected to be, but essentially all fields are cut by faults or are directly updip from faults which extend into the basin deep (Table 4). Of the 1.45 billion bbls and 2.00 Tcf thus far produced in the basin, only 50,000 bbls of oil and no gas have been produced from two fields (Moorpark and Canton Creek) not known to be associated with faults. The long thin Rincon-Ventura field at the western end of the Santa Clara trough is the giant of the basin. Over the basin deep, this field has produced 943 million bbls and 1.2 Tcf to 1/1/73. The trap is an elongate anticline cut by at least two major faults (Taylor and Barnard) each with a throw of over 1,000 ft (305 km). The multipay field produces from Pliocene sediments 3,700 to 12,000 ft (1.13 to 3.66 km) in depth.

The Oakridge, Holser, and San Gabriel faults all have major production along them (Table 4).

The Ventura Basin supports the present model as the occurrence of oil in the basin falls within its restraints. All the fields are faulted and the largest field in the basin is over the basin deep and cut by at least two major faults. Volcanic activity was present in the basin, and most of the major basin-forming faults are productive. Lastly, knowledge of the structure and sediment isopach of this basin allows very precise predictions of the basin's oil-bearing and oil barren areas.

GEOLOGY OF OIL OCCURRENCE

One of the best checks of the proposed model of a hot deep origin and migration of petroleum is found in the geology of oil occurrence in basins worldwide. If the model is valid, the oil and gas occurrence in petroleum basins should fall within the restraints of the model, such as demonstrated for the Los Angeles and Ventura Basins. With this in mind an extensive search of the published and unpublished literature was carried out. In all the basins examined, the oil and gas occurrence and associated geology fell within the restraints of the model. Brief reviews of some of these basins, which are characterized by a variety of different ages, sediment types, and structural style, are given to offer evidence to explorationists of the possible validity of the model and of how it may be used in exploration.

Ploiesti District

The Ploiesti district of Rumania (Paraschiv and Olteanu, 1970) is bordered on the north by the folded flysch units of the Carpathian Mountains, and by the Moesic Platform on the south. In going from the Moesic Platform north to the Carpathian Mountains, the structural intensity of the basin increases greatly. The southern structures, slightly uplifted domes, change northward into anticlines cut by axial reverse faults with large throws. Further north the producing structures bordering the Carpathian Mountains are even sharper, more markedly faulted anticlines, overturned to the south from the Carpathian thrusting. The structural intensity of the basin is also a function of the depth and age of sediments. The Moreni-Gura-Ocnitei anticline is cut by a reverse fault with a throw of 10,500 ft (3.20 km) in Lower Helvetian sediments (Early Miocene) which decreases to 4,500 ft (1.37 km) at the Miocene-Pliocene boundary, which further decreases to 3,600 ft (1.10 km) at the base of the Dacian (Mid-Pliocene). The Quaternary, which may be up to 6,000 ft (1.83 km) thick, is almost homoclinal.

All producing structures in this basin are cut by numerous faults.

The Neogene section in the eastern part of the district is approximately 90,000 ft (27.4 km) thick with 30,000 ft (9.14 km) of Pliocene alone. This sequence is made up of marls, limestones, shales, sandstone, and evaporites. Oil and gas occur in Early Oligocene to Late Pliocene sediments with the Meotian (Lower Pliocene) and the Dacian and Levantine (Upper Pliocene), in that order contributing the bulk of the production.

Parachiv and Olteanu (1970) note that there are two schools of thought on the origin of oil in the basin: 1) the oil originated in older, deeper sediments and migrated up faults to shallower reservoirs; and 2) that the oil originated downdip in sediments of the same age as those in which it is found and migrated updip to the structural trap. Evidence that the first alternative is the case is given by Walters (1960), who notes that the producing structures of this district have no staining downdip from the production as all traces of oil in the producing units stop at the limit of production of the field. Walters (1960, p. 1704) further notes "Although oil must have migrated through porous beds to reach the traps in which it is found, no record of such movement having taken place is visible in these beds. Traces of oil stop practically at the limit of the pool with the porous bed being oil free from that point downdip. The situation is not what one would expect; field observations show that once oil has been in a bed, a permanent record is left. That relatively long periods of geologic time are not sufficient to eradicate such a record is shown by numerous field examples."

A reasonable explanation of this anomaly is that the oil in these producing structures migrated up faults.

The thirty-five producing fields of the basin (all faulted) have produced 1.72 billion bbls with the Moreni-Guri-Ocnitei giant having yielded 724 million bbls, and if the Baicoi-Tintea field is included (since it is on the same structural trend) this structure has produced 967 million bbls or 53 percent of the region's oil.

Walters (1946) notes that the Carpathian geosyncline trends east-northeast through the Ploesti district, makes the Carpathian bend in southeast Rumania, and then trends northwest through east-central Rumania and on into Poland. The same structural and a similar sedimentological setting as found in Rumania accounts for the prolific production in the foothill belt of the Polish Carpathians. Here Cretaceous to Oligocene flysch sediments are closely folded and extensively overthrust. These faulted structures make up a major province, for example, the Boryslaw field in 1946 had an EUR of 205 million bbls of oil. Other large fields of this area are Dolina, Bitkow, and Moinesti.

Thus the accumulation of oil in the Carpathian geosyncline conforms to and supports the concept of a hot deep origin and migration of petroleum. The basin is very deep (over 90,000 ft; 27.4 km of sediment), and all the producing structures are faulted. The major production in the basin (53%) is associated with a fault with a minimum throw of 10,500 ft (3.20 km). Also lack of staining downdip in producing units suggests vertical migration of hydrocarbons up faults.

Gippsland Basin

The Gippsland basin (Vale and Jones, 1967; Franklin and Clifton, 1971) offshore southeast Australia is an aborted rift (block fault) basin which contains over 15,000 ft (4.57 km) of Tertiary sediments, 8,000 ft (2.44 km) of Lower Cretaceous sediments plus other Mesozoics and unmetamorphosed Paleozoics. Basalt flows occur at the base of the Tertiary. Published and unpublished data show that all the production in the basin is associated with faulting which taps the deeper older sediments (Fig. 16). The stratigraphic occurrence of production in the basin strongly correlates with the faulting which rarely extends beyond Eocene sediments (Fig. 16). All of the production in the basin is found in the Late Cretaceous to Eocene Latrobe group and the younger unfaulted sediments are barren. One expects this by the present model as there are no avenues available for oil migrating from depth to reach the barren post-Eocene sediments.

Table 5 lists the fields of the basin for which published data are available. As is obvious there is a close association of faulting with production in this basin.

The Gippsland basin falls within the restraints of the present model, being of a small size (18,000 mi^2; 46,620 km^2) with large reserves (4.36 billion bbls of recoverable oil, condensate or oil-equivalent gas--combined estimates of Halbouty et al (1970) and Beddoes (1973)). All the production is associated with faulting, and this aborted rift basin has a high geothermal gradient. Beddoes (1973) discusses five fields with an average gradient of 1.98° F/100 ft assuming an average surface temperature of 72°F. Lastly, faulting correlates with the stratigraphic occurrence of hydrocarbon production, the unfaulted younger sediments being barren, whereas the underlying faulted sediments produce.

The North Sea Basin

The North Sea basin (Kent and Walmsley, 1970; Watson and Swanson, 1975; Ziegler, 1975) has developed into one of the major petroleum basins of the world. The basin has accumulated a great thickness of sediments ranging in age from Cambrian to Holocene, consisting of shales, sands, marls, red beds, evaporites, chalks and Jurassic volcanics. Triassic to Cretaceous rifting was followed by a thick Tertiary sedimentation over the rift. The basin is classed as an aborted rift or block fault basin.

The discovered recoverable reserves found thus far are 16 billion bbls and 145 Tcf. The production is found in Paleocene sediments (22 Tcf; 6 billion bbls); in the Jurassic Dogger (17.5 Tcf; 9 billion bbls); in the Triassic Middle Bunter sandstone with 6.2 Tcf and in the Permian Rotliegendes Formation with 99.2 Tcf and 0.9 billion bbls.

Available data show that all discovered production in the North Sea is associated with faulting of large magnitude which taps the great sedimentary thicknesses of the North Sea basin (Table 6). Not only is all the production associated with faulting but the stratigraphic occurrence of hydrocarbons is controlled by the vertical extent of the faulting (Table 6). In spite of the fact that there is a wide range between geologic ages of the reservoirs (Paleocene to Permian--a time span of 170 million years) in no case does production occur in any field in a horizon which is above the uppermost vertical limit of faulting.

An association exists between the large oil fields of the North Sea and the large throws of the faults cutting these fields. The fault on the northeast side of the Argyll field has between 4,000-5,000 ft (1.22-1.52 km) of displacement at the Jurassic (Pennington, 1975). A fault on the northeast side of the Viking gas field has 1,000 ft (305 m) of throw (Gray, 1975), and single faults near the Brent field have 6,000 ft (1.83 km). Two faults immediately east of the Statfjord field have a combined 6,500 ft (1.09 km) of displacement (Whiteman in Brennand, 1975). Faults in the Piper field have up to 1,000 ft (305 m) of throw.

The Gronigen field (Stauble and Milius, 1970) lies in northeast Netherlands in the onshore portion of the North Sea basin (Fig. 17) and is one of the world's largest gas fields. The structure is a gently folded high with a gently dipping north flank and strongly faulted southwest and east flanks. Numerous faults run through the structure; they trend northwest to southeast with throws ranging from 200 to over 1,000 ft (61 to over 305 km). The Slochteren member of the Rotliegendes formation (Lower Permian) is the reservoir in the field which has an EUR of 58 Tcf.

The Brent platform (Watson and Swanson, 1975), a structure surrounded on all sides by faults, is a rotated block of a detached graben flank and has 9 billion bbls of recoverable oil in a number of fields all of which are associated with the major faults of the Brent platform (Bowen, 1975). These fields include Magnus, Thistle, Cormorant, Dunlin, Heather, Hutton, Ninian, Alwyn, Statfjord and Brent. Brent (Bowen, 1975) with recoverable reserves of 2 billion bbls and 3.5 Tcf produces from Middle and Lower Jurassic sands at depths ranging from 8,500-10,000 ft (2.59-3.05 km). The trap is a stratigraphic-structural combination with unconformable shales forming the seal for sands on a tilted fault block. A thick section (7,000-10,000 ft; 2.13-3.05 km) of unfaulted younger sediments overlies the buried structure.

Watson and Swanson (1975) also show the Hutton (1 billion bbls EUR), Ninian (1.9 billion bbls EUR), Ekofisk (5.8 Tcf EUR), Alwyn, and Argyle fields all to be faulted as are the Beryl, Frigg, and Dan fields (Ziegler, 1975). In fact, unpublished reports show all the production in the North Sea to be associated with large-magnitude faulting, the typical oil occurrence in the basin being on fault block highs next to deep sedimentary troughs. The highs usually are covered by unfaulted younger sediments.

The North Sea basin fits the present model. The basin has a very thick sedimentary column, all the fields are cut by faults of large displacement, and all the production in the basin is found only in faulted horizons. The overall structure of the basin--"block fault" or "aborted rift," high geothermal gradients, and the extensive block faulting all combine to explain the large reserves discovered at such early stages of exploration. All these geologic elements are positive factors for major production by the present model.

Cook Inlet

Cook Inlet (Crick, 1971), offshore Alaska, is a narrow deep trough bordered by major crustal faults, Bruin Bay and Castle Mountain on the northwest and Chugach on the southeast. The basin contains 60,000 ft (18.30 km) of nonmarine Cenozoic clastics and Mesozoic marine sediments with the reserves found in nonmarine Pliocene through Late Oligocene sediments. The proven in-place reserves of the basin are 2.6 billion bbls with an EUR of a little more than 1 billion bbls and 5 Tcf. The basin trends northeasterly as do all the producing structures, which are asymmetric anticlines with steep western limbs. Many of the structures are accompanied by long, parallel, high-angle reverse faults and in other structures smaller faults displace the axial crests of the domes. All the oil and gas discovered thus far in the province has been in such anticlines. Kelly (1968) also notes that all the oil and gas production in the Cook Inlet Basin is characterized by complexly faulted anticlines (Table 7).

Cook Inlet is yet another case of the hydrocarbon production in a basin that conforms to the model of the hot deep origin and migration of petroleum. The basin is very deep and all the established production is in structures cut by major faults. Further, a large source rock problem exists in the basin with none of the Tertiary continental clastics being likely sources for the oil in the basin. Some industry people working in this basin (discussions held with members of the Anchorage Geological Society) believe the deep marine Mesozoics to be the source for the hydrocarbons. The only paths of travel for these hydrocarbons from the deep Mesozoics would be up fault zones.

Big Horn Basin

The Big Horn Basin (Stone, 1967; Landes, 1970) of north-central Wyoming is the most prolific petroleum basin in the Rocky Mountain region (Fig. 18), with 6.96 billion bbls of discovered in-place oil and a CP to September 1969 of 1.4 billion bbls of oil and 900 Bcf of gas (Weldon, 1972). The basin was part of the Cordilleran geosyncline during Cambrian-Paleozoic time and into Mesozoic time. Continental Tertiary beds overlie a thick marine Mesozoic sequence and a thinner marine Paleozoic section. The basin's structure is due to the Laramide orogeny (Upper Cretaceous to Eocene) which resulted in major folding and faulting as well as late Tertiary volcanism on the western edge of the basin (Weldon, 1972). All the oil-bearing anticlines in the basin are faulted or just updip from faults. Deep basement-left lateral wrenching has been very important in determining the structural style of the basin, and is largely responsible for the basin anticlines (Stone, 1967; Sales, 1968). Production ranges from Cambrian to Cretaceous with the most prolific reservoirs being the Phosphoria formation (Permian) and the Pennsylvanian Tensleep. Stone (1967) notes that all the basin's anticlines are asymmetrical and faulted on their basin flank edge.

Table 8 lists the major fields of the basin with their CP's and associated structure.

Partridge (1958) notes that the anticlines closest to the basin deep have trapped the largest amounts of oil, and anticlines on the basin edges (not shown in Fig. 18) are either barren or have small amounts of oil. Gussow (1954) also noted that the belt of domes closest to the mountains in the Big Horn Basin are barren whereas the more basinward domes, which in all aspects are structurally the same as the mountain-belt domes, contain large reserves. One expects this by the present model as the basinward faults would be the main carriers of oil from the deep basin and not the basin edge faults which do not extend back to the deep basin. In order for the basin edge anticlines to contain oil, lateral migration would have to have taken place from the basinward domes. This is not possible, because as Stone (1967) notes, most of these basinward domes are only half filled with oil.

The Big Horn Basin thus conforms to the restrictions of the present model and therefore, supports it. This is a deep basin; all the producing structures are cut by or updip from faults which dip back into the basin deep; volcanism was present in the basin. Structures (basin edge anticlines) expected to be barren of oil are barren, whereas basinward anticlines cut by faults extending out of the basin deep are productive.

Niger Delta

The Niger delta (Frankl and Cordry, 1967; Short and Stauble, 1967; and Weber and Daukor, 1976), currently one of the major petroleum producing areas of the world, is characterized by a thick sequence of delta deposited clastics of Cretaceous to Recent age. The Agbada formation, which produces most of the oil and gas in the basin, is underlain by the Ataka formation, a thick sequence of abnormally pressured shales. The structural style of the basin is characterized by growth faults with associated rollover anticlines. The strike of these faults parallels the ancient shorelines of the delta and the fault throws are usually seaward. The throws of the major faults are usually several thousand feet at the top of the Akata formation. The rollover anticlines, which are always in the downthrown blocks, generally are severely faulted internally. Besides these rollover anticlines, the only other traps in the basin are fault traps and minor stratigraphic traps. The crests of the rollover anticlines shift with depth and multipay fields are the rule.

All of the fields are directly associated with major growth faults and the hydrocarbons are thought to have originated in the deep Akata shale and migrated vertically up faults to shallower reservoirs. A number of lines of evidence support this concept. Organic geochemistry has shown the Akata shale is to be the likely source rock for the basin, because the shallower sediments are immature. Weber and Daukorn (1976) studied the association of the spill points of the fields with the faults and concluded that the oils migrated up the faults. Production is found only in traps associated with faults of at least 150 m (429 ft) of throw, even though the traps associated with faults of lesser throws are identical in all other respects with productive traps. The association of production with major faults is one of the restraints of the present model.

The major fields of the basin with their EUR's (Halbouty et al, 1970) are Jones Creek 1 billion bbls, Imo River 600 million bbls, Bomu 550 million bbls and Meren and Okan each with 500 million bbls. Bomu was the first commercial field discovered in the basin. Four sands total 235 ft (72 m) of gas pay and 5 sands total 165 ft (50 m) of oil pay. The structure is a faulted anticline bounded by major growth faults to the north and south of the field, and the crestal structure of the field shifts to the south with depth. Okan was the first field found offshore. The structure is a rollover anticline on the downthrown side of a major growth fault. The dome is also cut by a number of other secondary faults. The field is multipay with oil columns in the larger reservoirs exceeding 200 ft (61 m) and gas caps present in most reservoirs.

The occurrence of oil and gas in the Niger Delta falls within the restraints of and strongly supports the present model.

Sirte Basin

The Sirte basin (Roberts, 1970), one of the world's most prolific petroleum basins, is a block fault or aborted rift basin. Reservoirs range in depth from 500-13,000 ft (0.15-3.96 km) and are mainly carbonates and sands of Early Cretaceous to Oligocene age. Basement block faulting has resulted in the formation of an extensive horst and graben structure throughout the basin. The trends are northeast or else parallel older northwest Paleozoic trends. Igneous activity accompanied this faulting. A transgression caused the deposition of a sequence of Cretaceous through Miocene sediments on top of Paleozoics with differential movements on horsts and grabens accounting for very thick deposits in the troughs and much thinner sections on the fault block highs. The younger sediments were often deposited directly on Cambrian crystalline rock due to erosion of the Paleozoics from the highs.

Table 9 lists the reserves of the largest fields in the basin up to 1970. The total EUR of these 16 oil fields is 25.6 billion bbls plus a 12 Tcf dry gas field. As Gillespie and Sanford and Sanford (1970) note, all the fields of the Sirte basin are on horst ridges (fault block highs) and all are associated with normal faults. The strong association of the production (Fig. 19) with the main faults of the basin is obvious. Many other less important faults with large throws which are present in the basin are not shown in this figure.

The Sarir, Amal, Augila, and Idris "A" oil fields are typical of the production in the basin. Sarir (Sanford, 1970) is perhaps the largest field in the basin with 11-13 billion bbls of in-place oil with an EUR of 5-6 billion bbls. The oil is at 9,000 ft (2.74 km) in a broad anticline and fault-trap accumulation. The reservoir sand (Upper Cretaceous) has extensive block faulting through it with some of the faults having up to 1,000 ft (305 m) of throw. The oil accumulation rings a deep sedimentary section and the faults that bound the field dip back into this sedimentary section.

Amal (Roberts, 1970) is on the Rakb fault-block high which is bordered by a deep sedimentary trough and which trends northwest and is bounded on both flanks by large faults.

Augila (Williams, 1972) lies on the same fault block high as Amal, 12 mi (19 km) to the northwest, and has the same structural picture. The reservoirs are Upper Cretaceous sediments, as well as underlying fractured and weathered granitic rocks of the structural high. Immediately to the east of the field is a large (1,200 ft; 366 m displacement) vertical fault dipping into a trough of thick sediments.

Table 9.--Largest fields of Sirte basin, northeastern Libya (EUR equal to or greater than 500 million bbls). After Halbouty et al (1970).

		Billions of barrels of oil
Sarir		8.0
Amal-Nafoora-Augila		5.2
Zelten		2.2
Gialo		2.0
Nefa		2.0
Samah		1.3
Intisar (Idris D)		1.2
Waha		1.0
Raguba		1.0
A-100		1.0
Dahra-Hofra		0.7
	Total	25.6
Hateiba		12 Tcf of gas

The Idris "A" oil field (Terry and Williams, 1969) has two billion bbls of in-place oil at 9,400-10,400 ft (2.86-3.17 km) of which 40-75 percent will be recoverable. The field lies on a fault block high. A large fault about one mile (1.6 km) west of the field dips into a deep sedimentary trough.

The Sirte basin also fits the model of a hot deep origin and migration of petroleum. All the production of the basin is found on fault block highs bordering very deep sedimentary troughs--the prime exploration target by this model. The faults, closely associated with the production in this basin, have very large throws. Igneous activity was also present in the basin.

Vienna Basin

The Vienna basin (Friedl, 1959; Buchta et al, 1963; Janoschek and Gotzinger, 1969), mainly in Austria and partly in Czechoslovakia (Fig. 20), is in the Alpine Carpathian Mountain Range. Through June 30, 1968, the CP of the basin was 440 million bbls and 540 Bcf. Younger Tertiary sediments 5 km (16,400 ft) thick overlie a sequence of flysch, limestone, and graywacke sediments of Tertiary-Mesozoic age which in turn overlie Paleozoics.

The flysch (Lower Cretaceous to Upper Oligocene) and older rocks, deformed by an early period of structuring, were further deformed by Mid-Miocene block faulting.

Marine Tortonian (Upper Mid-Miocene), and brackish Sarmation (Upper Miocene) and Helvetian (Lower-Mid Miocene) sediments have almost all the oil reserves of the basin. Pannonian (Lower Pliocene) sediments contain important gas reserves.

Two types of normal faulting are present in the basin: growth faults, and post-depositional faults. Both generally strike northeast and dip 50-70°. The largest fault in the basin, Steinberg, is a growth fault with a throw of over 1,000 m (3,048 ft). Almost all the oil production of the basin is found on or just updip from the Steinberg fault in a series of oil fields stretching 22 mi (35 km) from Pirawarth in the south to Bernhardsthal in the north. The producing structures along the fault in the younger Tertiary sediments are drag or rollover anticlines, which grade into monoclines at depth. Auxiliary faults along the Steinberg fault section these fields into a series of step-down fault blocks toward the basin deep. Thus Pirawarth, cut by seven faults including Steinberg, is broken into six separate blocks.

All the fields surround the deepest part of the basin, and are usually multipay. For example, Pirawarth has 3 gas and 31 oil pays (Sarmatian and Tortonian) and Matzen, the largest field of the basin, has 27 oil pays and 9 gas pays.

Matzen is a highly faulted flat anticline east of the Steinberg fault with Sarmatian and Lower Pannonian gas production and Tortonian and Helvetian oil production. The Matzen sand at the base of the Tortonian contains the major deposits of the field (and of the basin). The field has produced 264 million bbls and 76 Bcf to June 30, 1968. Another major field, also on the Steinberg fault, is Muhlberg which has produced 35 million bbls and 42 Bcf to June 30, 1968. Zwendorf, the largest gas field in the basin, is a flat anticline on the upthrown block of the major Zwendorf fault. The field has produced 316 Bcf to June 30, 1968.

Freidl (1959) notes that two theories are popular regarding the origin of the basin's oil: the first holds that the oil originated in the Tertiary shales and in some cases migrated across fault blocks into the older juxtaposed flysch sediments; the other holds that the oil originated from deeper sediments and migrated up faults to shallower reservoirs. The second theory finds support in the fact that no Tertiary rock which even resembles a source rock for the basin's oils has been found (Friedl, 1959). Buchta et al (1963) examined the rock extracts of the Neogene and older sediments of the basin, and found that the extracts of the older, deeper limestone and flysch sediments chemically resembled the crudes much more than the younger Neogene extracts. They concluded that in all likelihood the crudes in the basin had originated from the deeper strata.

The Vienna basin thus conforms to the restraints placed on oil occurrence by the present model. The deep basin is rich for its small size (2,703 mi^2; 7,000 km^2). All production is associated with faulting with most of the production along the major fault of the basin--Steinberg. Multipay fields are the rule and all the hydrocarbons surround the basin deep. Lastly, geochemical work suggests that the oil originated in the deeper sediments of the basin and moved up faults.

Po Valley

The Po Valley (Rocco and Jaboli, 1958; and Rocco and D'Agostino, 1972) of northern Italy has an EUR, as of 1968, of 7.07 Tcf (Pieri, 1969). The Appennines Mountains form the southern boundary of the basin, the Alps limit the basin on the north and west, and the east boundary extends into the Adriatic Sea. The basin can be subdivided into two provinces: the Peri-Appenninic trough and the Pede-Alpine region. The northwest-trending Peri-Appenninic trough on the south side of the basin has an average width of 50 km (31 mi), and has very thick sediments. For example, in its deepest part the Cretaceous is overlain by over 10 km (32,800 ft) of Tertiary sediments. A belt of elongate southeast-trending anticlines resulting from two folding events (Late Miocene and Mid-Pliocene) lies in the trough and parallels the Appennine Mountains. Folds near the mountains are asymmetric and overthrust to the northeast. Subsidence was always active in the trough area but intensified from Mid-Pliocene on. For example, Quaternary strata are over 3 km (9,842 ft) thick in the southeast and are subhorizontal with local gentle undulation.

The Pede-Alpine region is made up of intensely deformed pre-Pliocene sediments which were uplifted and partially eroded before the Pliocene transgression occurred which produced a subhorizontal surface only interrupted by drape over buried structures. Folds in the Pede-Alpine region are asymmetric and overthrust to the south due to the influence of the Alps.

The basin has produced mainly gas with minor oil, although a major new oil discovery could change the proportions. Pliocene units are the main producers although Oligocene, and Miocene production is also present with Quaternary beds yielding only small production. All the producing anticlines are cut by faults, some of which may have displacements of 3 km (9,842 ft) and can be up to 100 km (62 mi) long. These longer gravity faults, with Early Pliocene to Recent movement, generally cut the north flanks of anticlines, and are downthrown to the north.

Published data show that all the production in the basin is associated with faults. Thus Rocco and D'Agostino (1972) show the Correggio, Santerno, Bordolano, Sergnano, S. Giorgio, Ripalta, Caviaga, Romanengo, Cremona South, Spilamberto, Pietro C., Tresigallos, Sabbioncello, Cotignola, as well as the offshore field P. Corsini Mare, all are faulted structures. Rocco and Jaboli (1958) show the Corneliano, Soresina, Cortemaggiore, Podenzano, Ravenna, Afonsine and Catignola fields all faulted. Rocco (1955) shows the Piadena East, Pontenure, Selva, Minerbio and Malabergo fields all faulted or just updip from faults.

Figure 21 is a north-south cross section across the western Po Valley basin showing the faulting associated with the Caviaga, Ripalta, Romanego, and Sergnano fields; the thrusting in the south; the disturbed nature of the Pliocene and older sediments; and the undisturbed relatively flat lying younger sediments.

Malossa (Gardner, 1975) in the Po Valley is now Italy's largest oil field. The new discovery produces at 19,680 ft (6.00 km) from a highly fractured Mesozoic limestone ("Hauptdolomit") with 1970 ft (600 m) of pay. Reserves on the basis of three wells are at least 292 million bbls of recoverable oil and 1.8 Tcf of recoverable gas. Observers predict the reserves will increase as field development continues. The bottom hole temperature is 320° F (160° C) with a bottom hole pressure of 21,600 psi and a flowing wellhead pressure of 11,750 psi. The field is on a fault block high with the limestone reservoir cut by two normal faults. The deep structure is overlain by over 15,000 ft (4.57 km) of unfaulted flat-lying Tertiary clastics. Rocco and Jaboli (1958) had previously noted that the small (pre-Malossa) oil fields of the basin, which were reservoired in Tertiary rocks, all had the same chemical characteristics; This pointed to a common source, which they believed to be deep Mesozoic with extensive vertical migration of oil taking place to the shallower Tertiary reservoirs.

The Po Valley basin supports the present model. All the production is associated with faults, and this very deep basin now has some of the deepest, hottest oil production in the world (Malossa). Only those horizons in the basin which are faulted or have faults subcropping directly under them produce oil or gas, and overlying unfaulted beds are barren. Yet these overlying beds often have traps due to drape or differential compaction over the deeper producing beds. This basin offers another example of how faulting controls the vertical distribution of hydrocarbons.

Other Basins

Extensive documentation for a number of other petroleum basins also supports the present model. Thus the production in all these basins is associated with major faulting over or dipping back to the basin deep. The basins all have thick sedimentary sequences or extensive igneous/volcanic activity or both. Geochemical work in some of the basins suggests that the hydrocarbons originated from sediments deeper than where they are now found.

In a journal article such extensive documentation can only be given for a small number of basins. However, the data from 22 other basins strongly support the model. These basins include: the Northwest, Cuyo, Nequen, Golfo San Jorge and Magallanes basins of Argentina; the West Texas Permian basin; Northwest Peru; the Cambay basin, India; the Eastern Venezuelan basin; Trinidad; the Reconcavo basin, Brazil; the Mid Magdalena basin, Colombia; the Sicily basin, the Asamari area of the Persian Gulf basin; the Arkoma basin, Oklahoma and Arkansas; the Gulf Coastal basin, U.S.A.; the Anadarko basin, U.S.A.; the Aquitaine basin, France; and the Southern San Joaquin Valley, Sacramento, Santa Maria, and Santa Barbara basins, California. In addition to the detailed work carried out for these basins, the literature available strongly suggests that the occurrence of oil in many other basins also conforms to the restraints of the present model.

APPARENT EXCEPTIONS

Although the geology of oil occurrence of all the deep basins I have examined falls within the restraints of the present model, there are apparent exceptions. However, when the entire geologic history of these basins is examined, it is apparent that they also fit the model. These "exceptions" are of two types: 1) basins which presently are too shallow and cold to meet the requirements of the present model (Denver, Williston, Paris, North Park, Michigan, and Illinois); and 2) oil production far out on the stable shelf areas of deep basins away from their depocenters (Anadarko-Arkoma, Persian Gulf, Powder River, Paradox, Algeria, Appalachian, and Western Canada). However, the oil deposits found over the depocenters of these deep basins conform to the restraints of the present model. Thus, only the oil fields on the shelf areas of these basins appear to be exceptions. Both these cases are discussed in detail elsewhere (Price, 1977).

The first class of exceptions is explained by the fact that these individual basins were either hotter in the past from higher geothermal gradients or have lost large amounts of sediment through uplift and erosion. Geologic and geochemical evidence exists in a number of basins which support these explanations. The production over what is now the deepest part of these basins is all associated with faulting. The second class of exceptions is explained by the oil originating from the deep basin up faults (Fig. 1) and migration off the fault into continuous conduits, with long lateral secondary mgiration onto the shelf area. Evidence is also available that this was the case in a number of basins.

Other apparent contradictions to the model are based on published and unpublished geochemical analyses from some basins (for example the North Sea, North Slope, Big Horn, and Sirte basins). These analyses have provided good source rock-crude oil correlations and thus provide a case for shallow lateral primary migration. However, in most of these cases the fields are on fault block highs and the same source beds are buried under tens of thousands of feet of younger sediment in the adjacent troughs. This model would have the equivalent deeper source rocks as providing the oil.

CONCLUSION

The fact that oil production in basins worldwide fulfills the restraints of the model of a hot deep origin and migration of petroleum does not prove that the hydrocarbons originated by this model. However, the evidence in basin after basin suggests at the very least that the model may be a useful tool in exploration, and that much more attention should be paid to major faults than has been paid in the past.

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List of Illustrations

Figure 8.--Jackson sand and Vicksburg fault oil production of South Texas. Arrows show proposed migration of oil from Vicksburg fault into Jackson sands and updip to the stratigraphic traps of the Jackson trend. Jackson outcrop and oil fields of Jackson trend after Fisher et al (1970); Vicksburg oil fields after Landes (1970); Vicksburg fault after Landes (1970) and Stanley (1970).

Figure 9.--Northwest-southeast cross section of Vicksburg fault zone about 30 mi (48 km) north of Corpus Christi, Texas. Arrows show proposed migration of hydrocarbons up Vicksburg fault and into Frio sands in rollover anticlines on the down side of fault zone and also into monoclinal Jackson sediments on the upside of the fault. After Stanley (1970).

Figure 10.--Contours on crystalline basement with total sediment fill in thousands of feet and major faults of the Los Angeles basin. From Yerkes et al (1965) with the Norwalk fault zone superimposed from Harding (1974). Throws on the Norwalk fault are not shown in Figure 10.

Figure 11.--Main structural features of Los Angeles basin with prospective areas for oil and gas production (discussed in text) shown by stippled pattern. Partially after Yerkes et al (1965).

Figure 12.--Known oil and gas production of Los Angeles basin. After Yerkes et al (1965) with additions from California Division of Oil and Gas (1974). Abbreviations for the major fields are: B.H., Beverly Hills; I., Inglewood; P.D.R., Playa Del Rey; R., Rosecrans; T., Torrance; D., Dominguez; L.B., Long Beach; S.B., Seal Beach; Wil., Wilmington; H.B., Huntington Beach; RI., Richfield; B.O., Brea-olinga; E.C., East Coyote; W.C., West Coyote; S.F., Santa Fe Springs; M., Montebello.

Figure 13.--Contours on crystalline basement (with total sediment fill in thousands of feet) and major faults of the Ventura basin. After Nagle and Parker (1971).

Figure 14.--Main structural features of the Ventura basin with prospective areas for oil and gas production (discussed in text) shown by stippled pattern. Partially after Nagle and Parker (1971).

Figure 15.--Known oil and gas production of Ventura basin. After Nagle and Parker (1971).

Figure 16.--Northeast-southwest cross section of Gippsland basin showing major unconformities and faults. After Franklin and Clifton (1971).

Figure 17.--East-west cross section of Gronigen field, onshore North Sea basin. After Stauble and Milius (1970).

Figure 18.--Map of Big Horn basin with major faults, oil fields and crystalline uplifts at basin edges. After Stone (1967).

Figure 19.--Map of productive portion Sirte basin showing major regional faults and most of the major fields. After Sanford (1967).

Figure 20.--Map of Vienna basin showing close association of production in the basin with faulting. Partially after Friedl (1959).

Figure 21.--Cross section of western Po Valley. After Rocco and D'Agostino (1972).

FIGURE 1

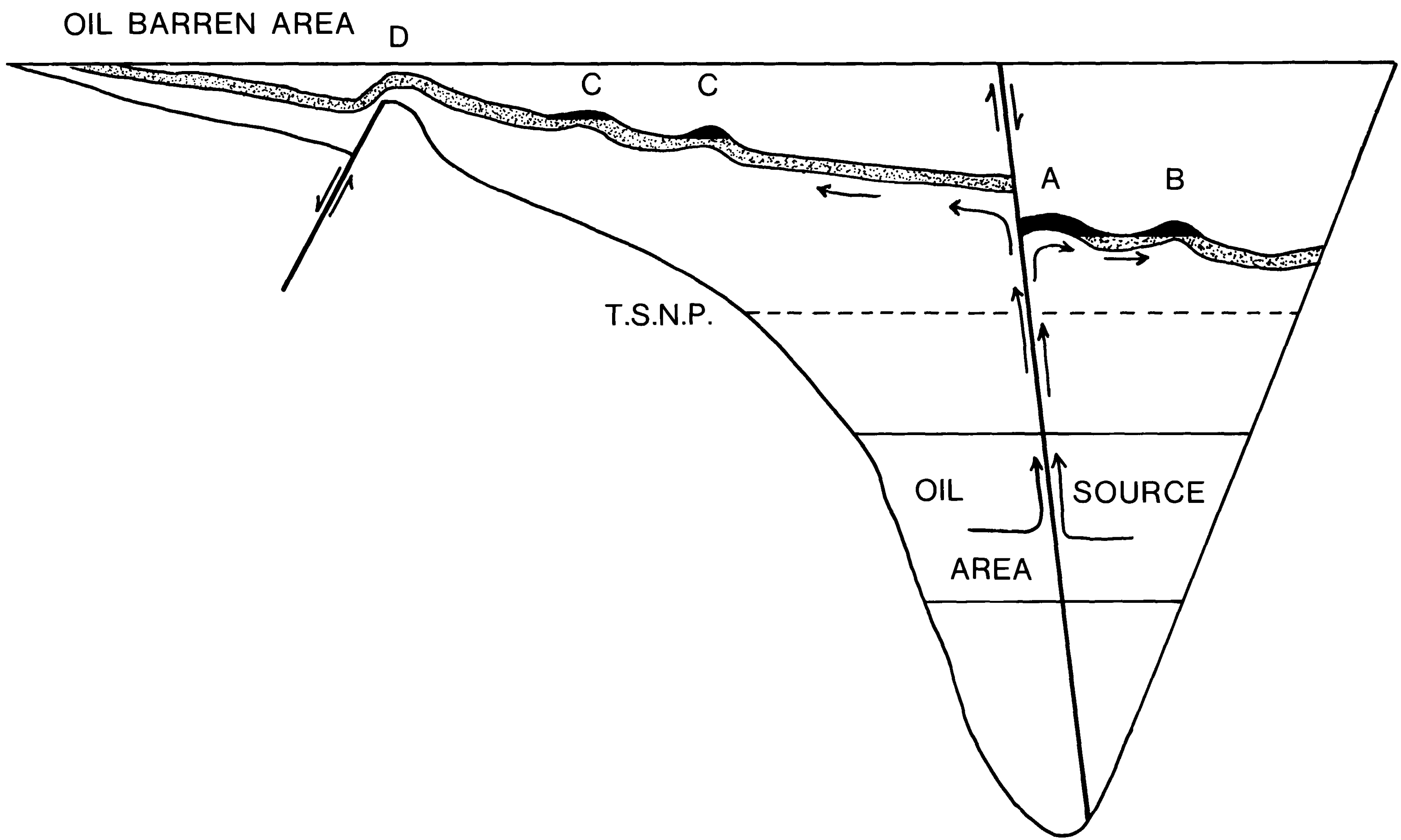


FIGURE 2

BLOCK 28 FIELD

OFFSHORE LOUISIANA

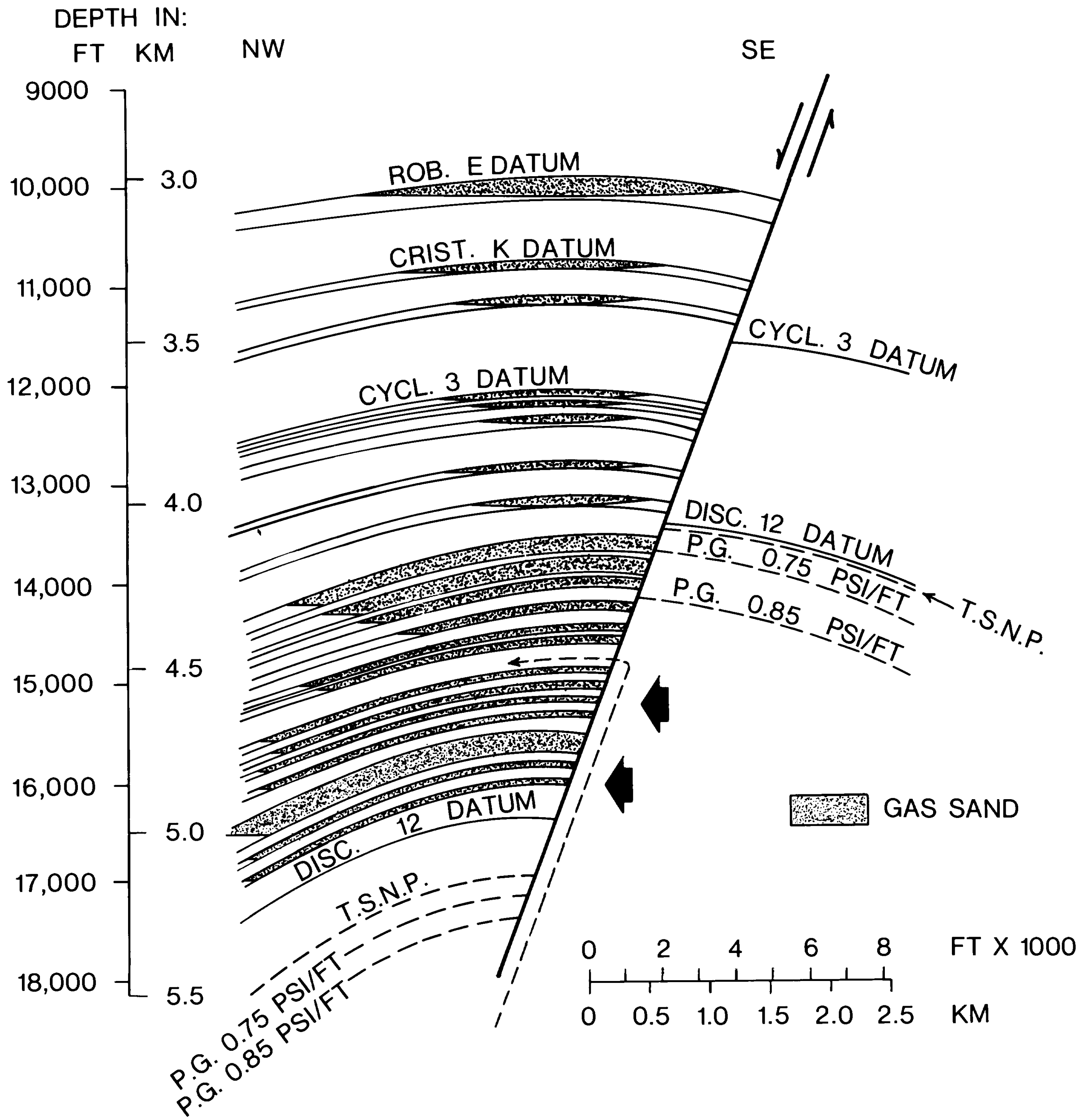
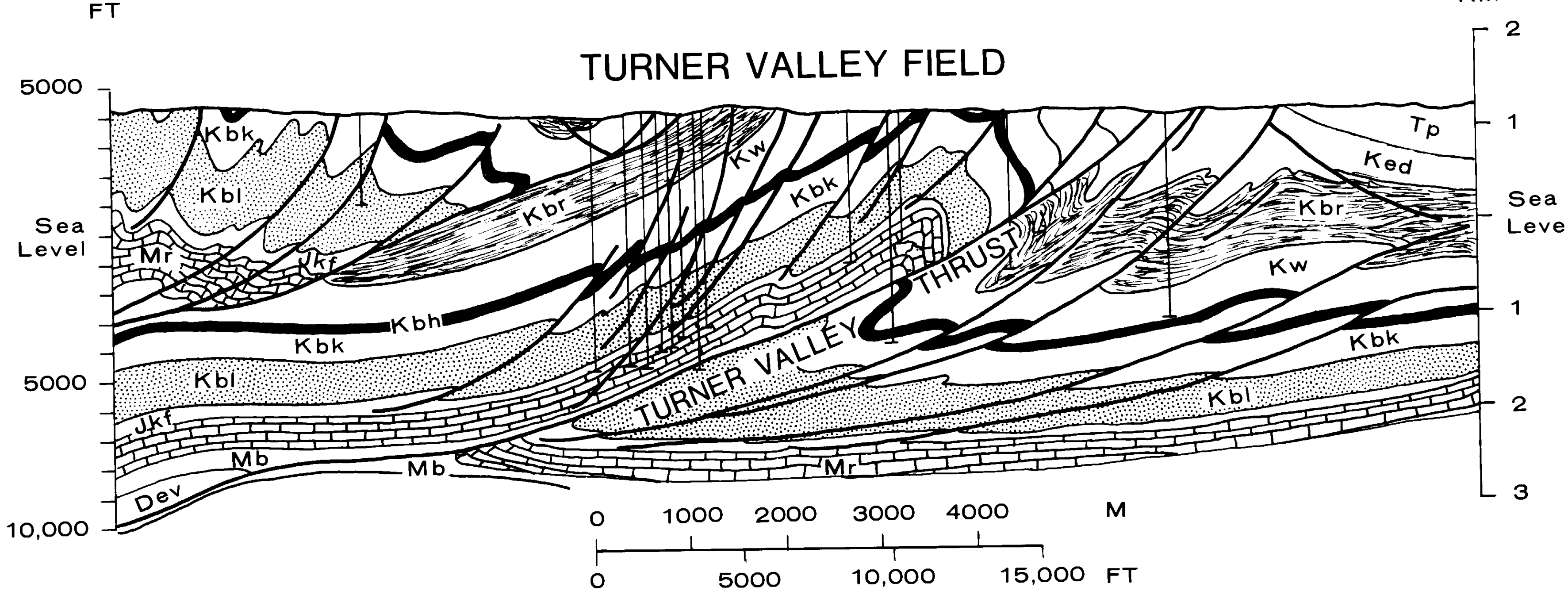


FIGURE 3

TURNER VALLEY FIELD



Tp -Paskapoo	Tertiary	Kbl-Blairmore	Lower Cretaceous
Ked-Edmonton-Bearpaw	Upper Cretaceous	Jkf-Kootenay Fernie	Jurassic
Kbr-Belly River		Mb -Banff	Mississippian
Kw -Wapiabi		Mr -Rundle	
Kbh-Bighorn		Dev- Devonian	
Kbk-Blackstone			

FIGURE 4

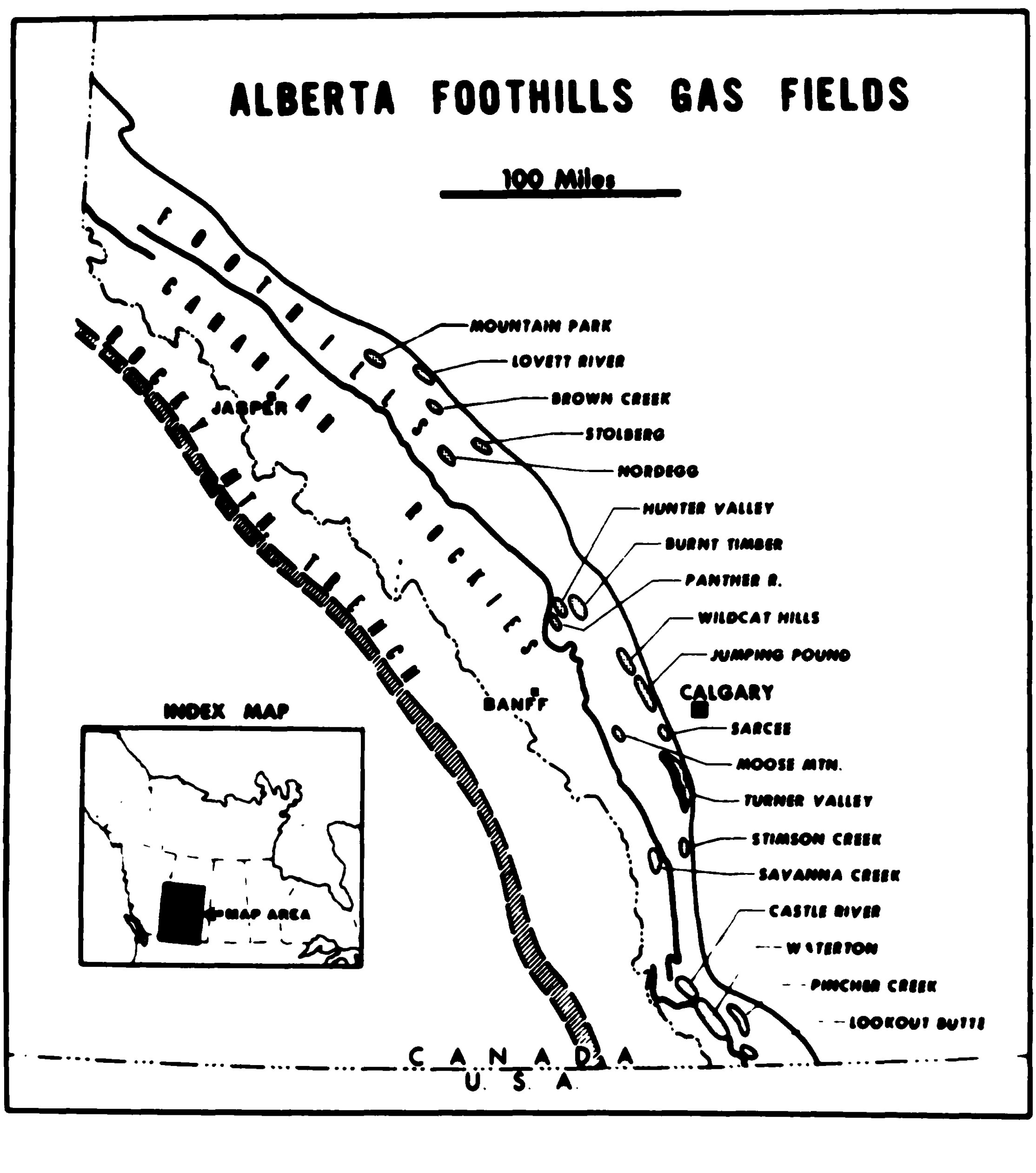

ALBERTA FOOTHILLS GAS FIELDS
100 Miles
JASPER
BANFF
CALGARY
INDEX MAP
MAP AREA
MOUNTAIN PARK
LOVETT RIVER
BROWN CREEK
STOLBERG
NORDEGG
HUNTER VALLEY
BURNT TIMBER
PANTHER R.
WILDCAT HILLS
JUMPING POUND
SARCEE
MOOSE MTN.
TURNER VALLEY
STIMSON CREEK
SAVANNA CREEK
CASTLE RIVER
PINCHER CREEK
LOOKOUT BUTTE
CANADA
U.S.A.

FIGURE 5

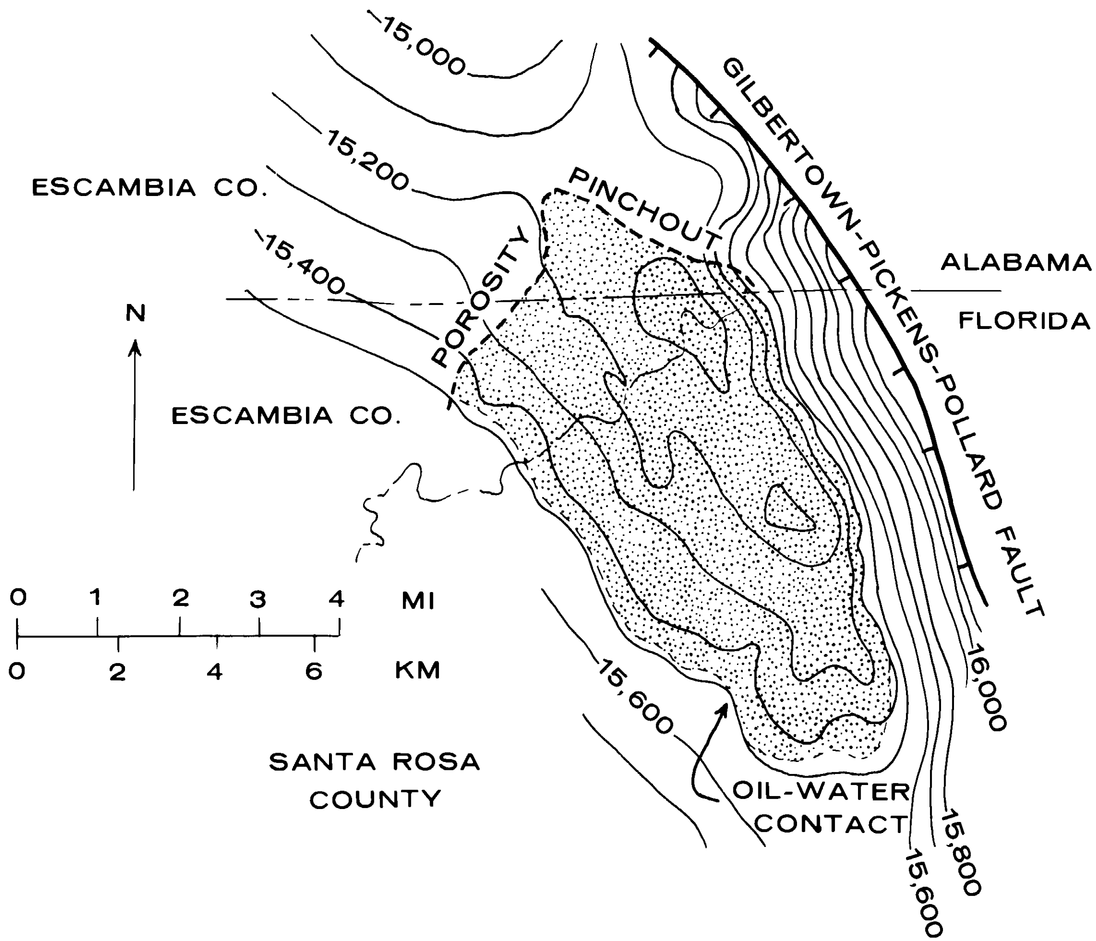

-15,000
15,200
-15,400
15,600
15,600
15,800
16,000
GILBERTOWN-PICKENS-POLLARD FAULT
ALABAMA
FLORIDA
ESCAMBIA CO.
ESCAMBIA CO.
PINCHOUT
POROSITY
OIL-WATER CONTACT
N
0 1 2 3 4 MI
0 2 4 6 KM
SANTA ROSA COUNTY

FIGURE 6

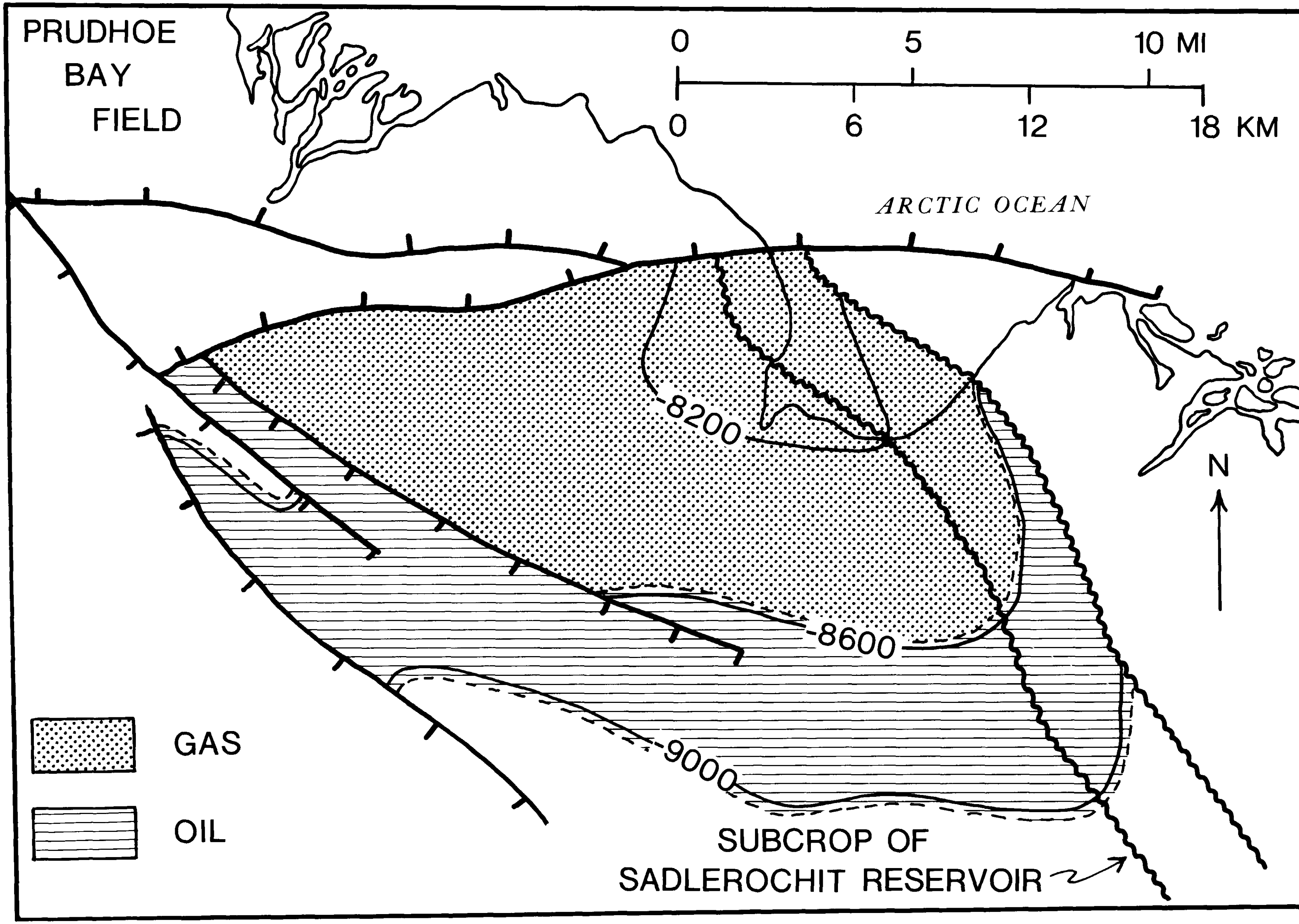
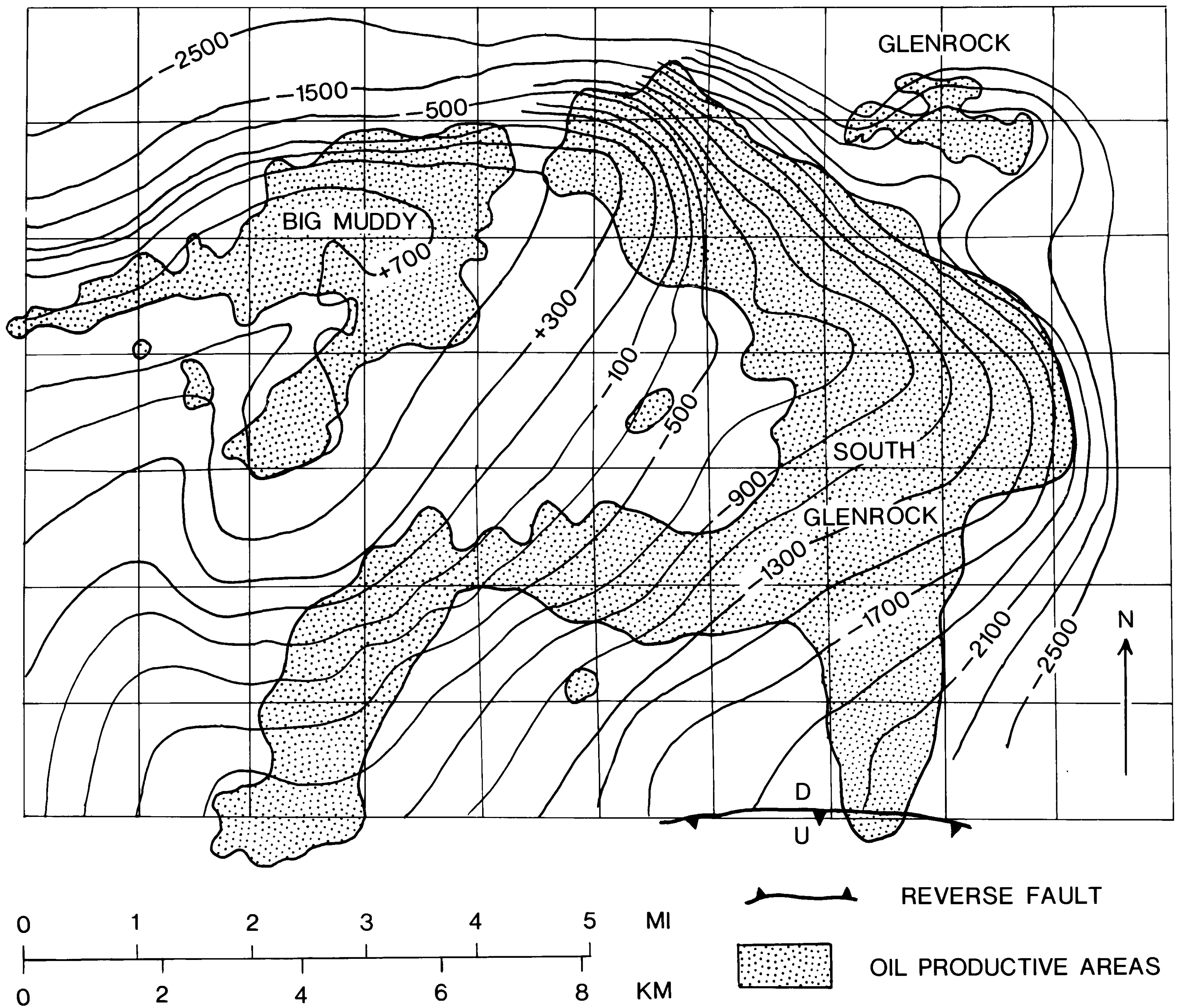
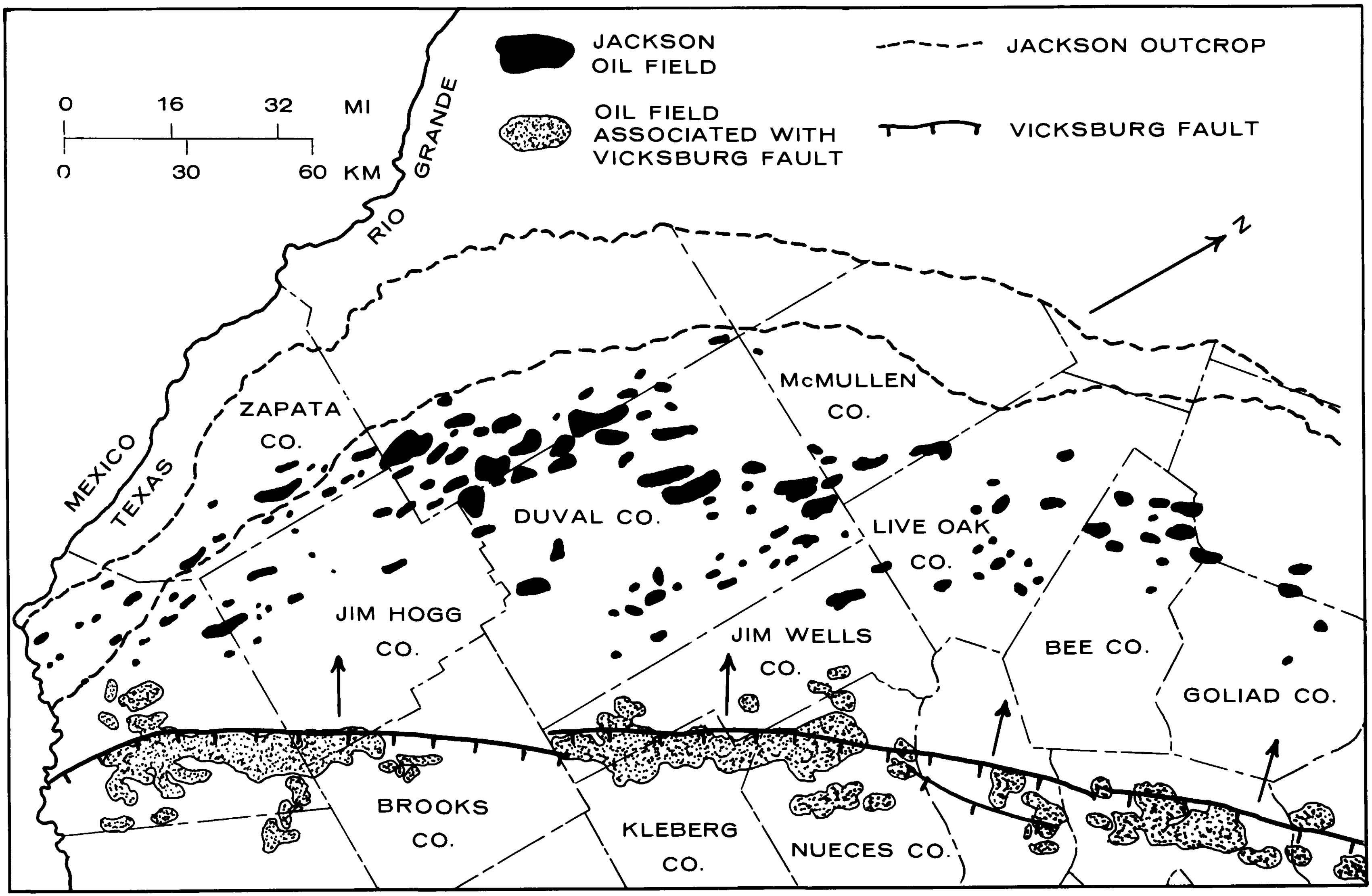

PRUDHOE
BAY
FIELD
0
5
10 MI
0
6
12
18 KM
ARCTIC OCEAN
8200
8600
9000
N
GAS
OIL
SUBCROP OF
SADLEROCHIT RESERVOIR

FIGURE 7



GLENROCK
-2500
-1500
-500
BIG MUDDY
+700
+300
-100
-500
SOUTH
GLENROCK
-900
-1300
-1700
-2100
-2500
N
D
U
REVERSE FAULT
OIL PRODUCTIVE AREAS
0 1 2 3 4 5 MI
0 2 4 6 8 KM

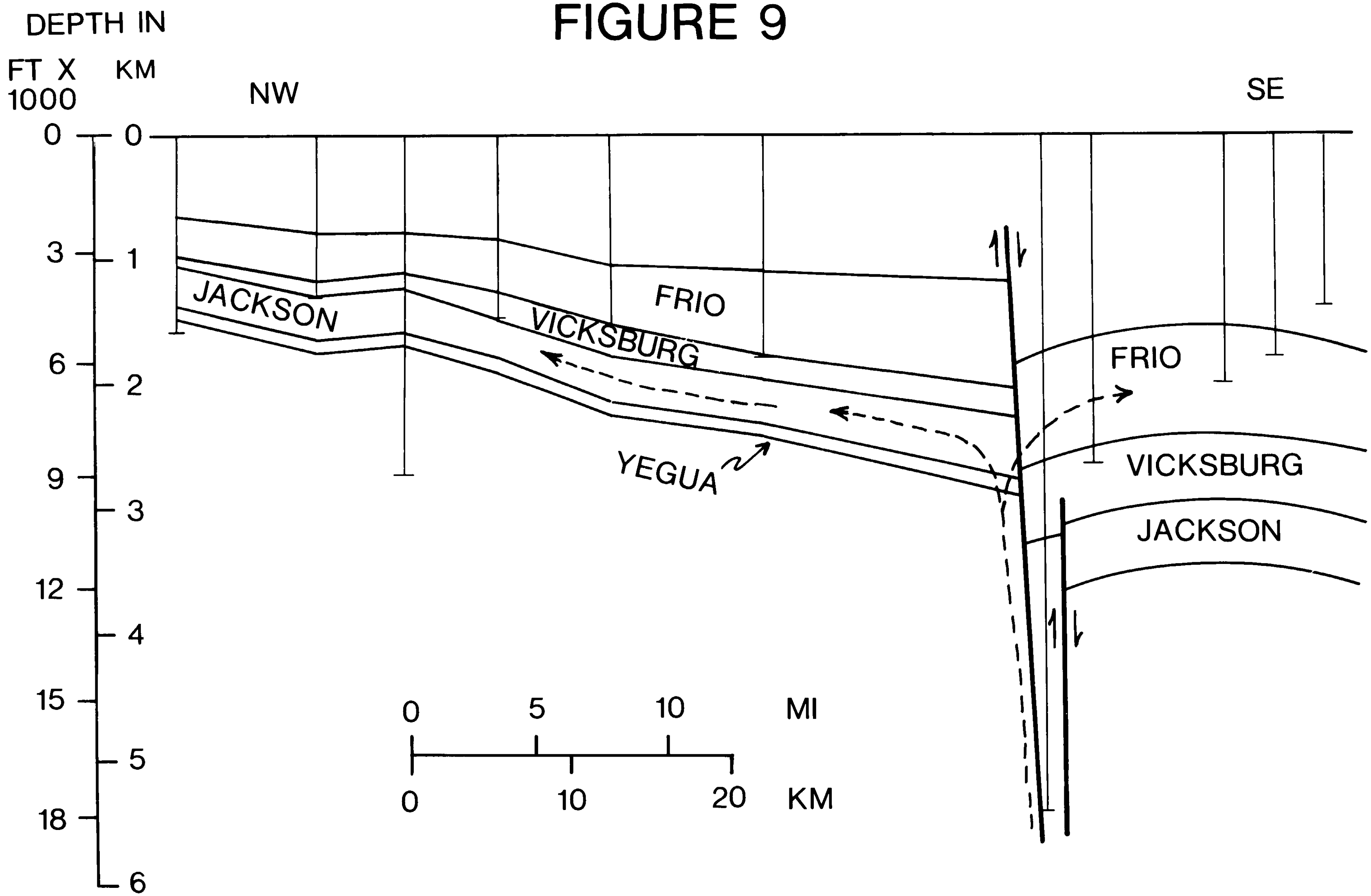
FIGURE 8



JACKSON OIL FIELD
OIL FIELD ASSOCIATED WITH VICKSBURG FAULT
JACKSON OUTCROP
VICKSBURG FAULT
0 16 32 MI
0 30 60 KM
RIO GRANDE
MEXICO
TEXAS
N
ZAPATA CO.
McMULLEN CO.
DUVAL CO.
LIVE OAK CO.
JIM HOGG CO.
JIM WELLS CO.
BEE CO.
GOLIAD CO.
BROOKS CO.
KLEBERG CO.
NUECES CO.

80

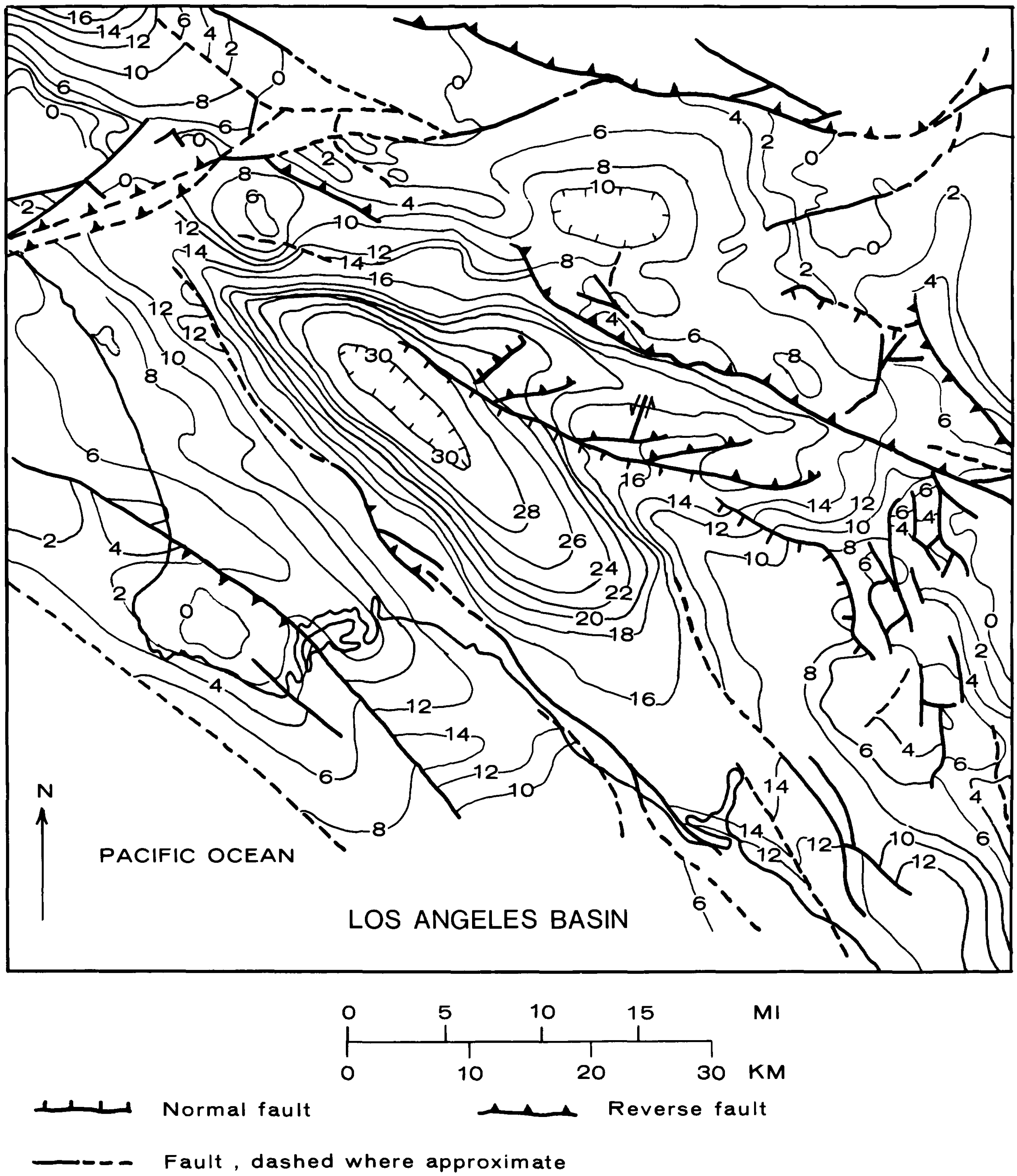
FIGURE 9



DEPTH IN
FT X 1000
KM
0
3
6
9
12
15
18
0
1
2
3
4
5
6
NW
SE
FRIO
JACKSON
VICKSBURG
YEGUA
FRIO
VICKSBURG
JACKSON
0
5
10
MI
0
10
20
KM

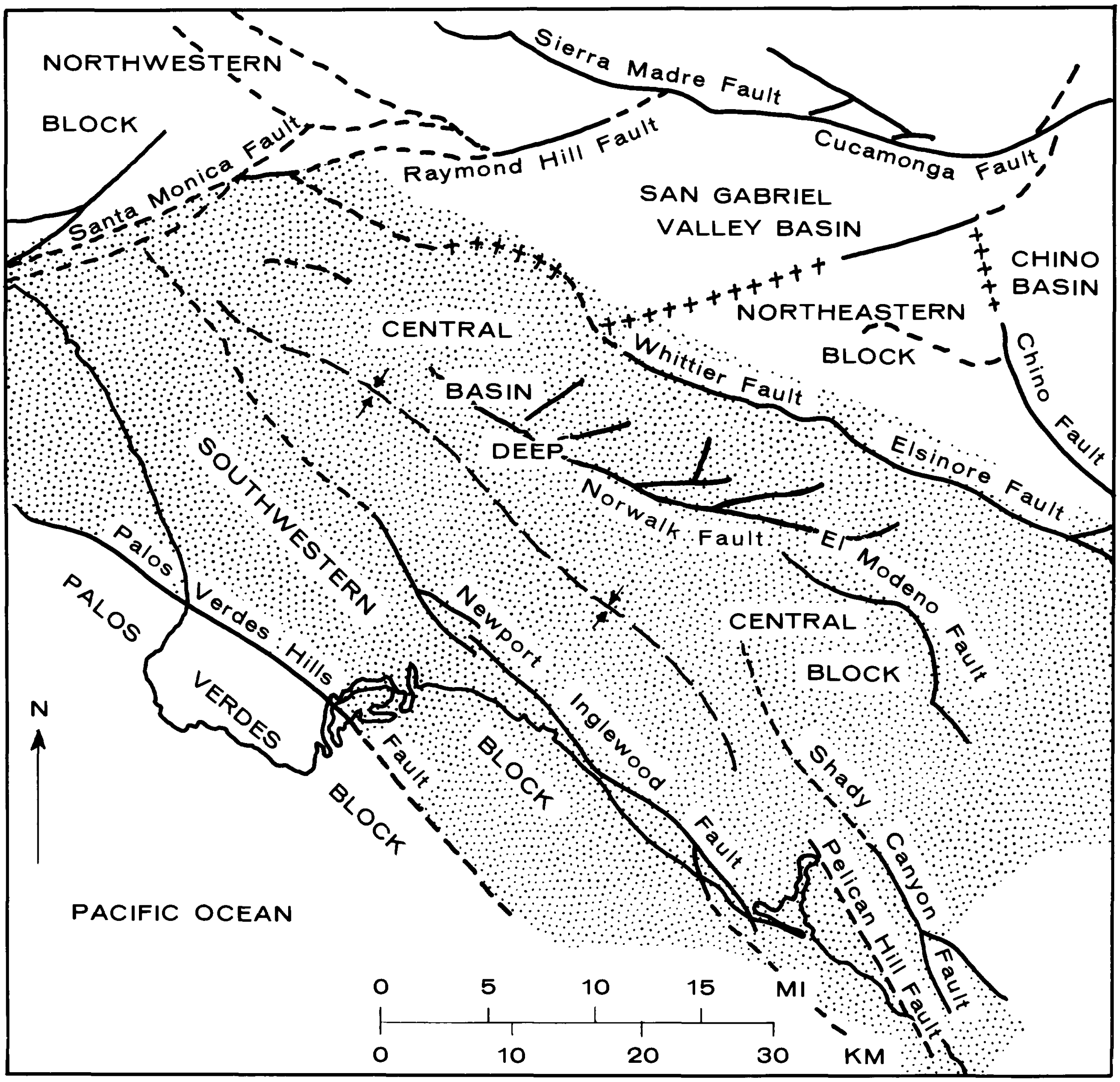
81

FIGURE 10



PACIFIC OCEAN
LOS ANGELES BASIN
N
0 5 10 15 MI
0 10 20 30 KM
Normal fault
Reverse fault
Fault , dashed where approximate

FIGURE 11



FAULT, DASHED WHERE APPROXIMATE

+++++ GEOLOGIC BOUNDARY

PROSPECTIVE AREAS

FIGURE 12

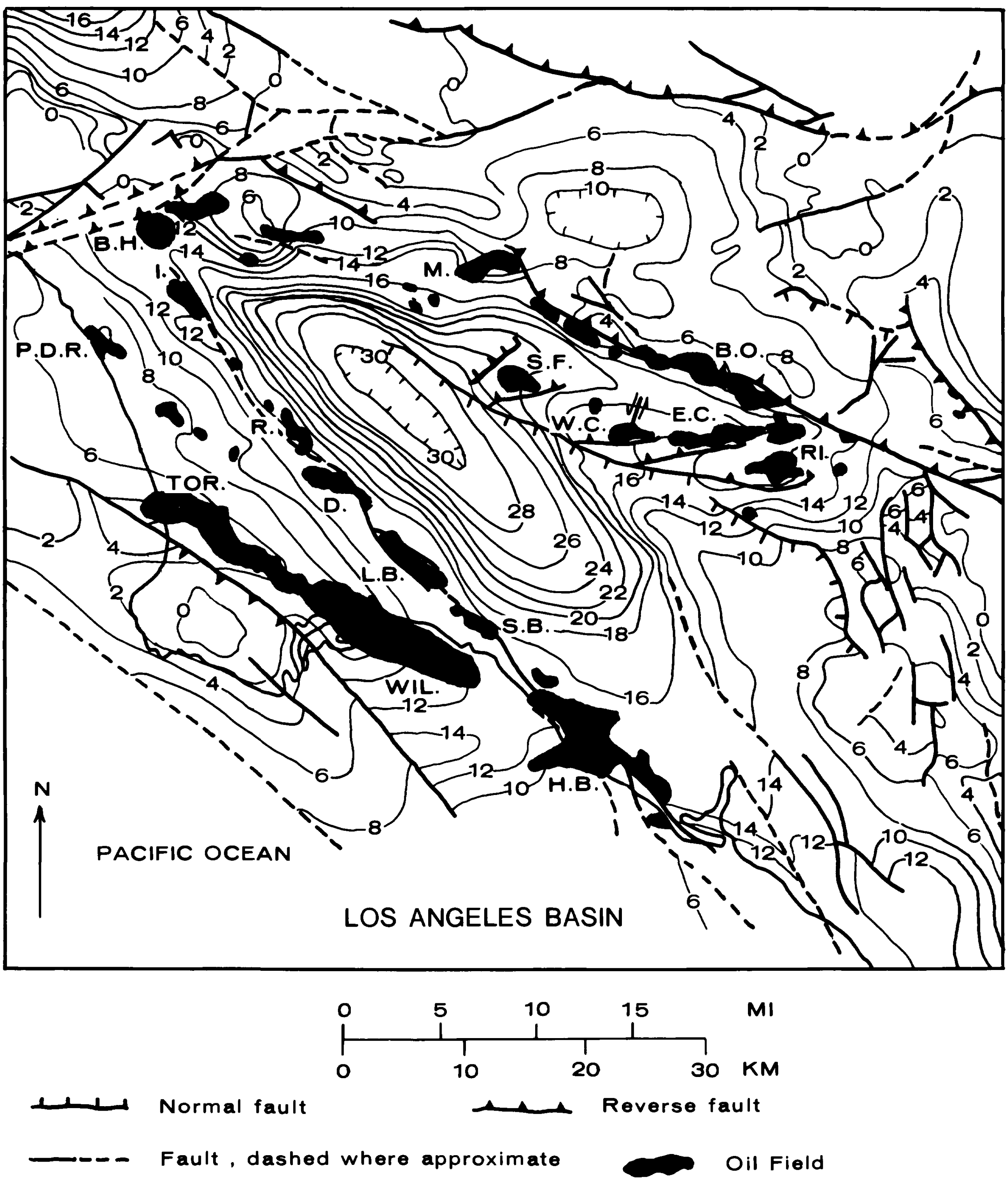

PACIFIC OCEAN
LOS ANGELES BASIN
N
B.H.
I.
P.D.R.
TOR.
R.
D.
L.B.
S.B.
WIL.
H.B.
M.
S.F.
W.C.
E.C.
B.O.
RI.
0 5 10 15 MI
0 10 20 30 KM
Normal fault
Reverse fault
Fault , dashed where approximate
Oil Field

FIGURE 13

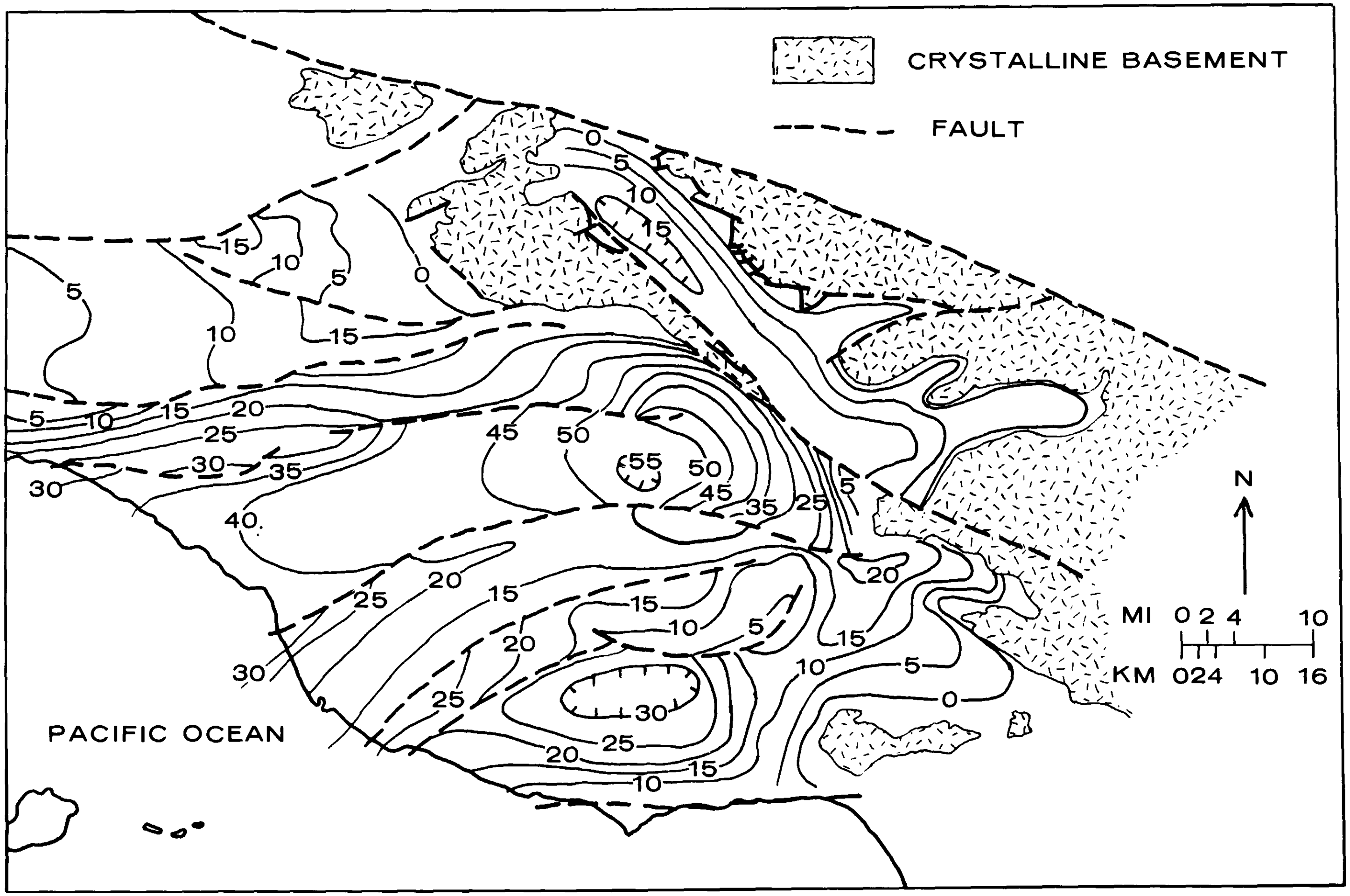
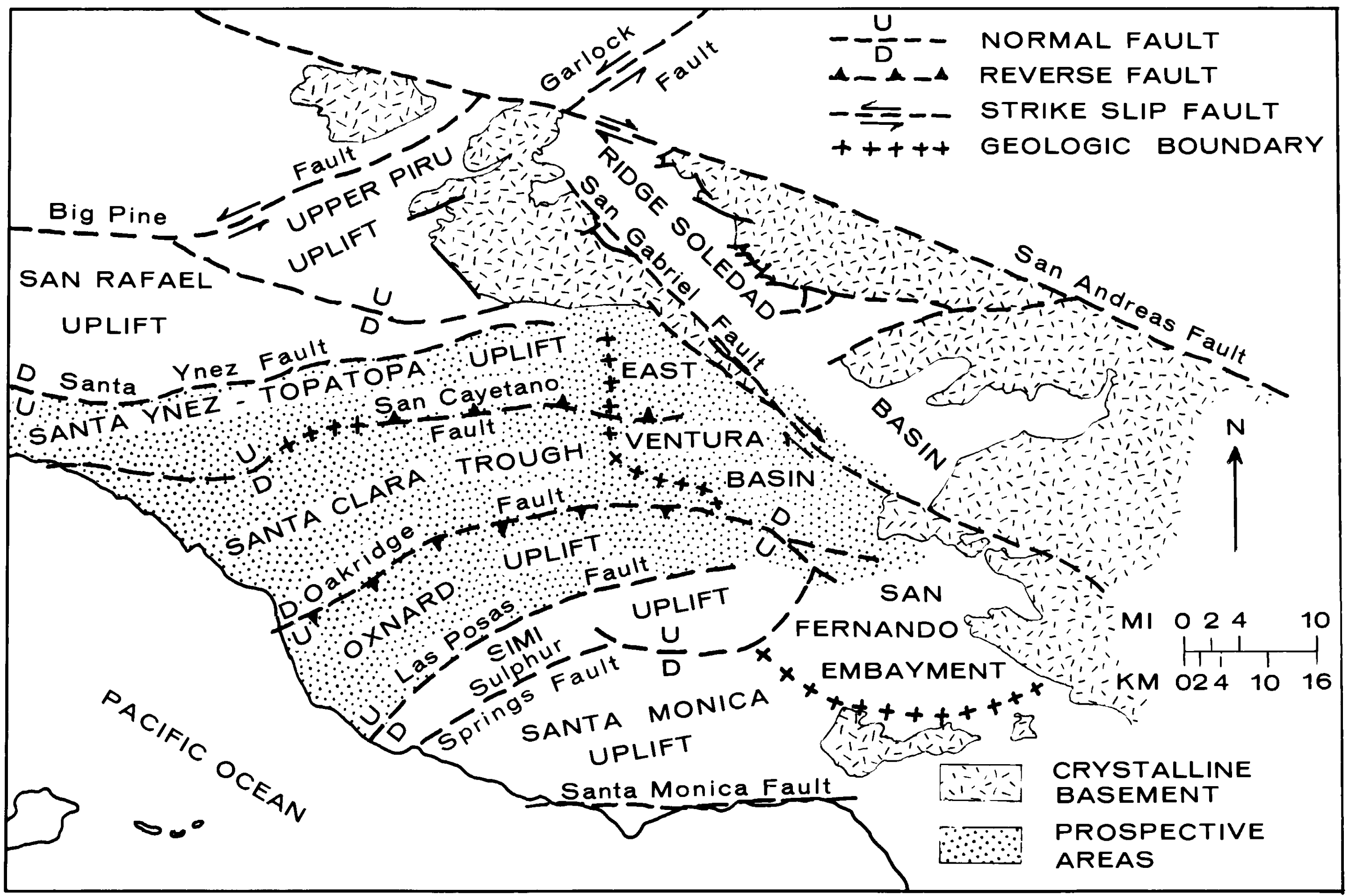

CRYSTALLINE BASEMENT
FAULT
N
MI 0 2 4 10
KM 0 2 4 10 16
PACIFIC OCEAN

FIGURE 14



NORMAL FAULT
REVERSE FAULT
STRIKE SLIP FAULT
GEOLOGIC BOUNDARY
U
D
Garlock Fault
Big Pine Fault
UPPER PIRU UPLIFT
SAN RAFAEL UPLIFT
RIDGE
San Gabriel Fault
SOLEDAD
San Andreas Fault
BASIN
Santa Ynez Fault
SANTA YNEZ - TOPATOPA UPLIFT
San Cayetano Fault
EAST VENTURA BASIN
SANTA CLARA TROUGH
Oakridge Fault
OXNARD UPLIFT
Las Posas Fault
SIMI UPLIFT
Sulphur Springs Fault
SAN FERNANDO EMBAYMENT
SANTA MONICA UPLIFT
Santa Monica Fault
PACIFIC OCEAN
N
MI 0 2 4 10
KM 0 2 4 10 16
CRYSTALLINE BASEMENT
PROSPECTIVE AREAS

FIGURE 15

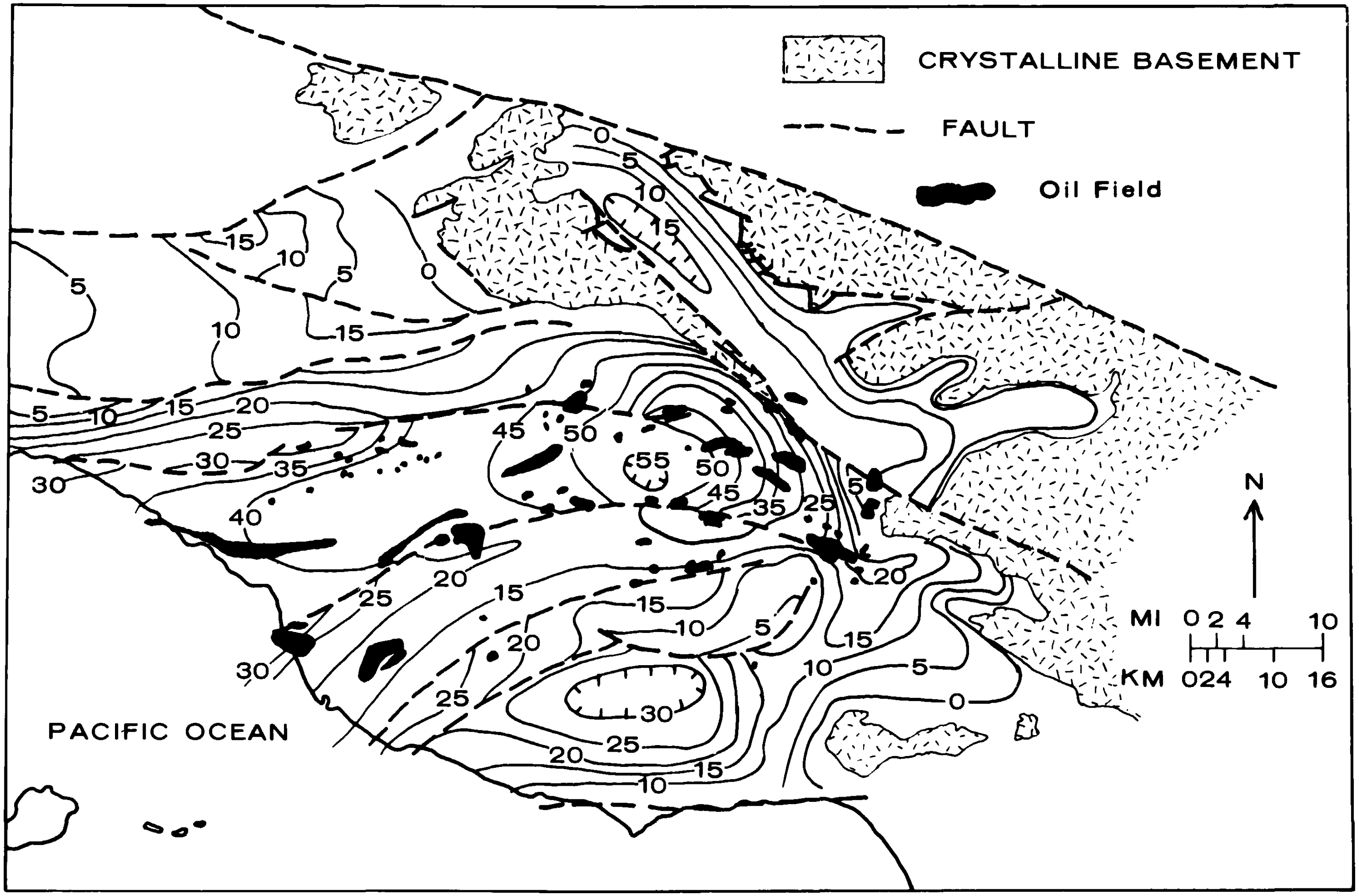

CRYSTALLINE BASEMENT
FAULT
Oil Field
PACIFIC OCEAN
N
MI 0 2 4 10
KM 024 10 16
0
5
10
15
20
25
30
35
40
45
50
55

FIGURE 16

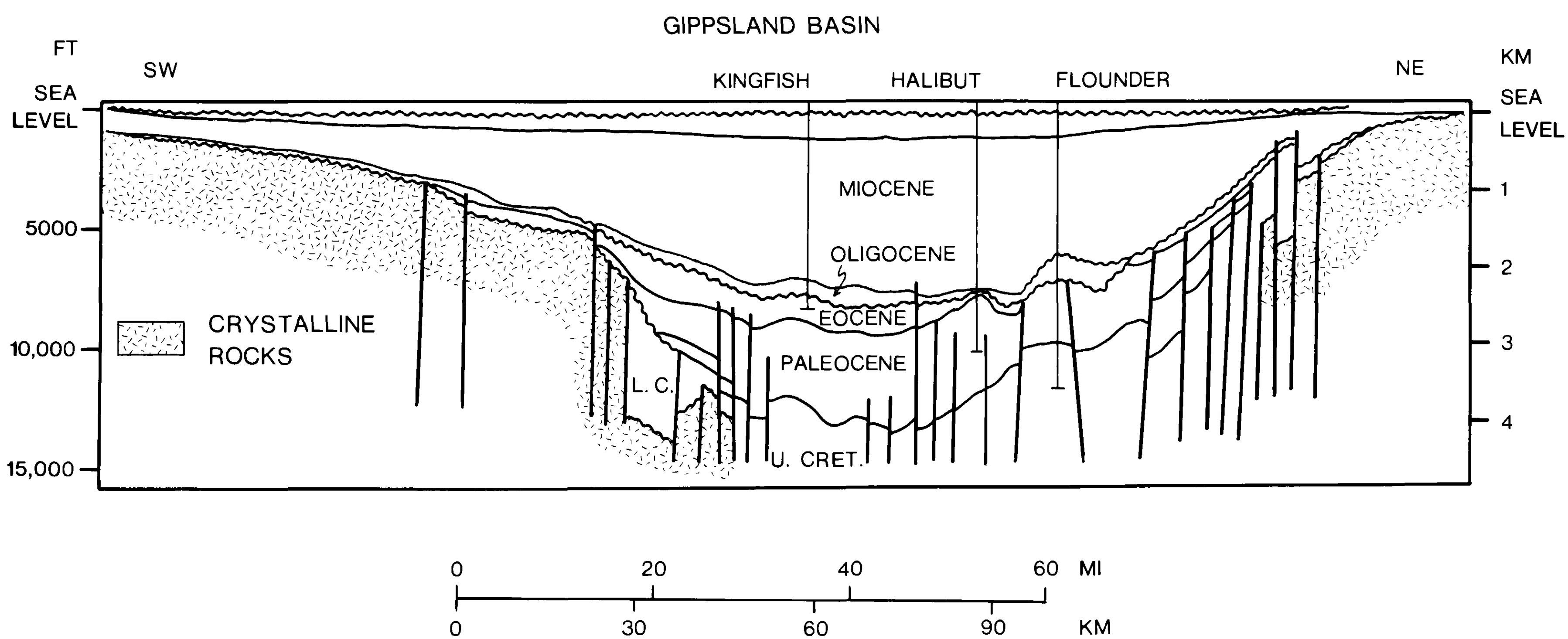
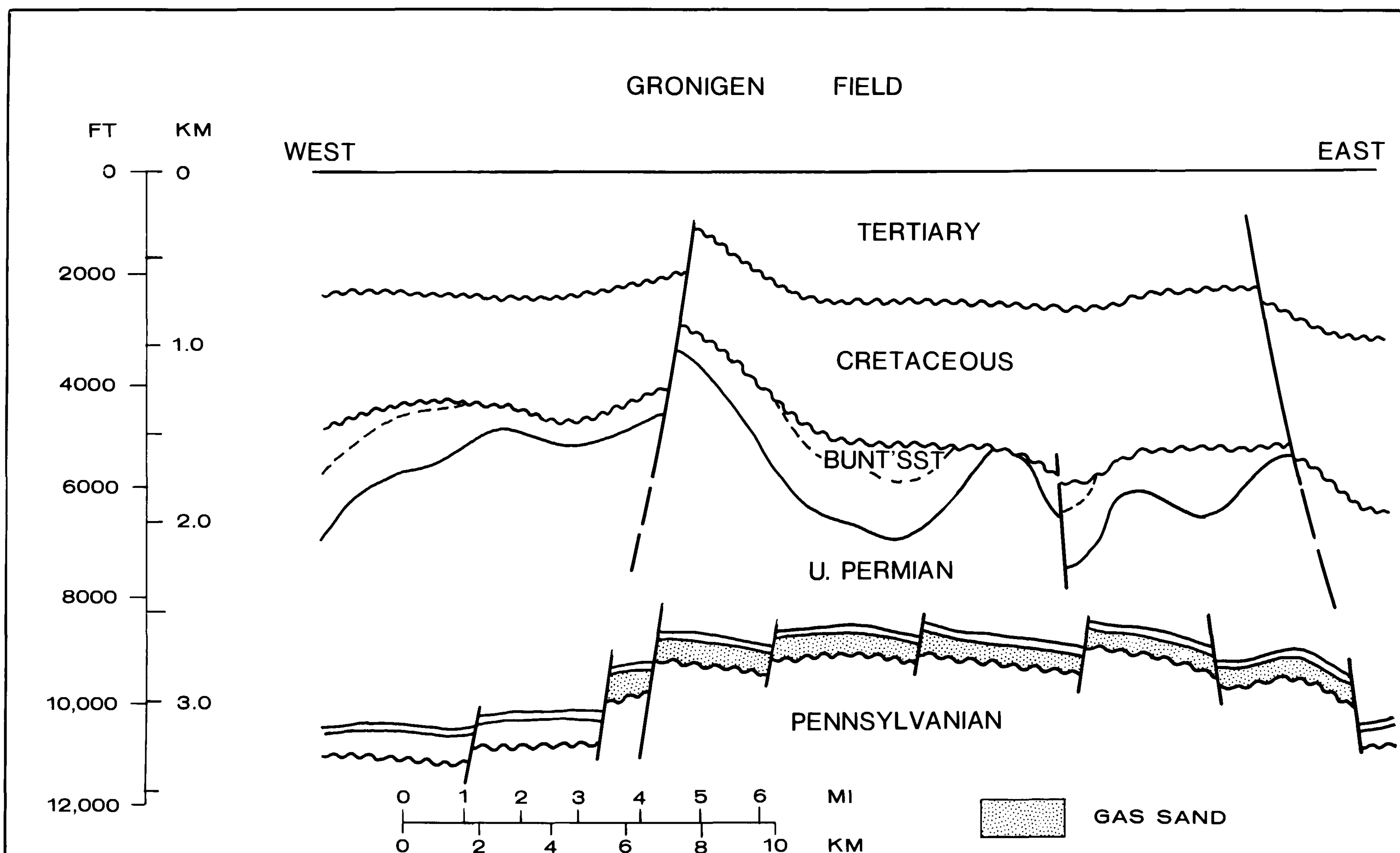
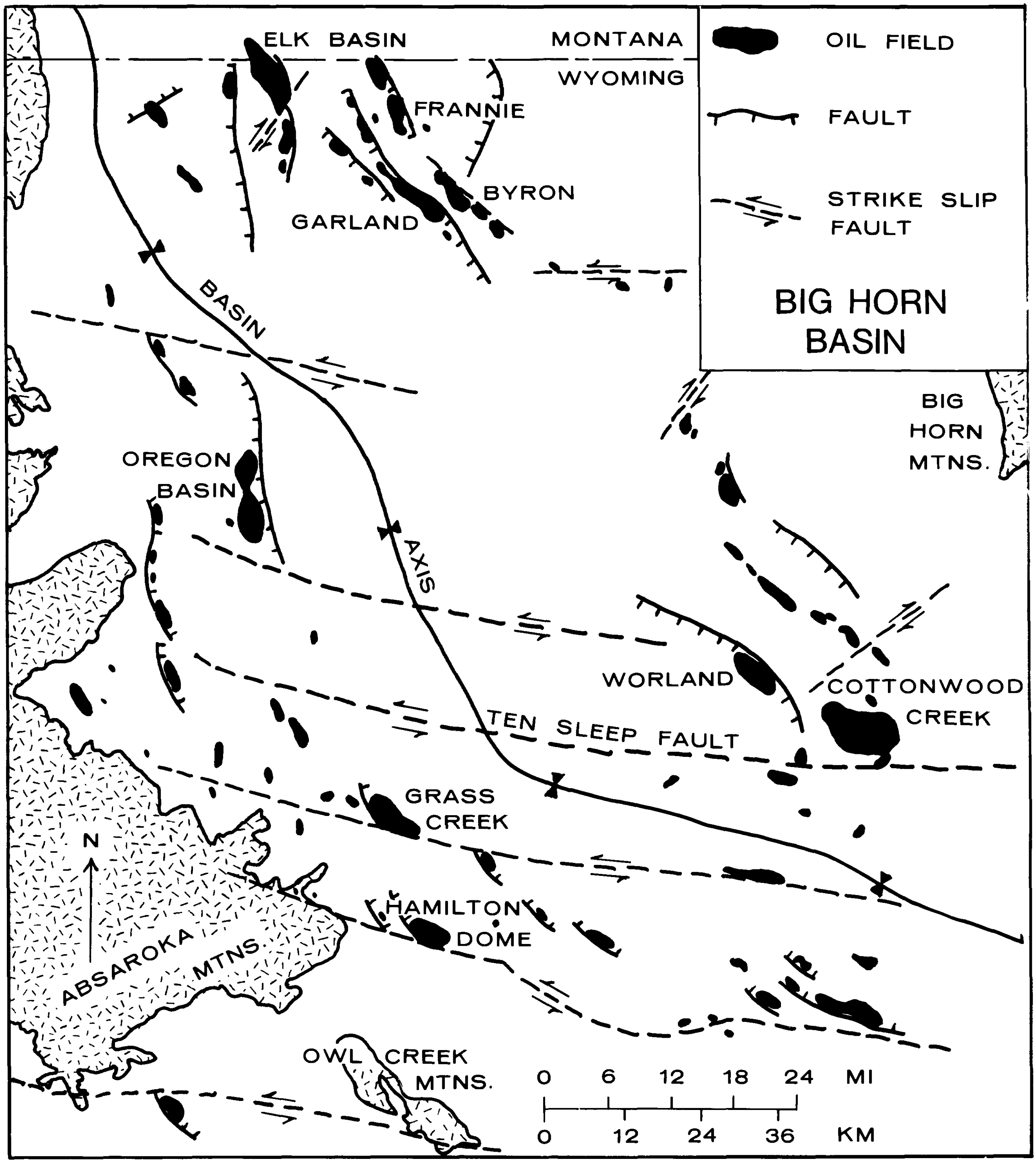

GIPPSLAND BASIN
FT
SEA LEVEL
5000
10,000
15,000
SW
KINGFISH
HALIBUT
FLOUNDER
NE
KM
SEA LEVEL
1
2
3
4
MIOCENE
OLIGOCENE
EOCENE
PALEOCENE
L. C.
U. CRET.
CRYSTALLINE ROCKS
0
20
40
60
MI
0
30
60
90
KM

FIGURE 17



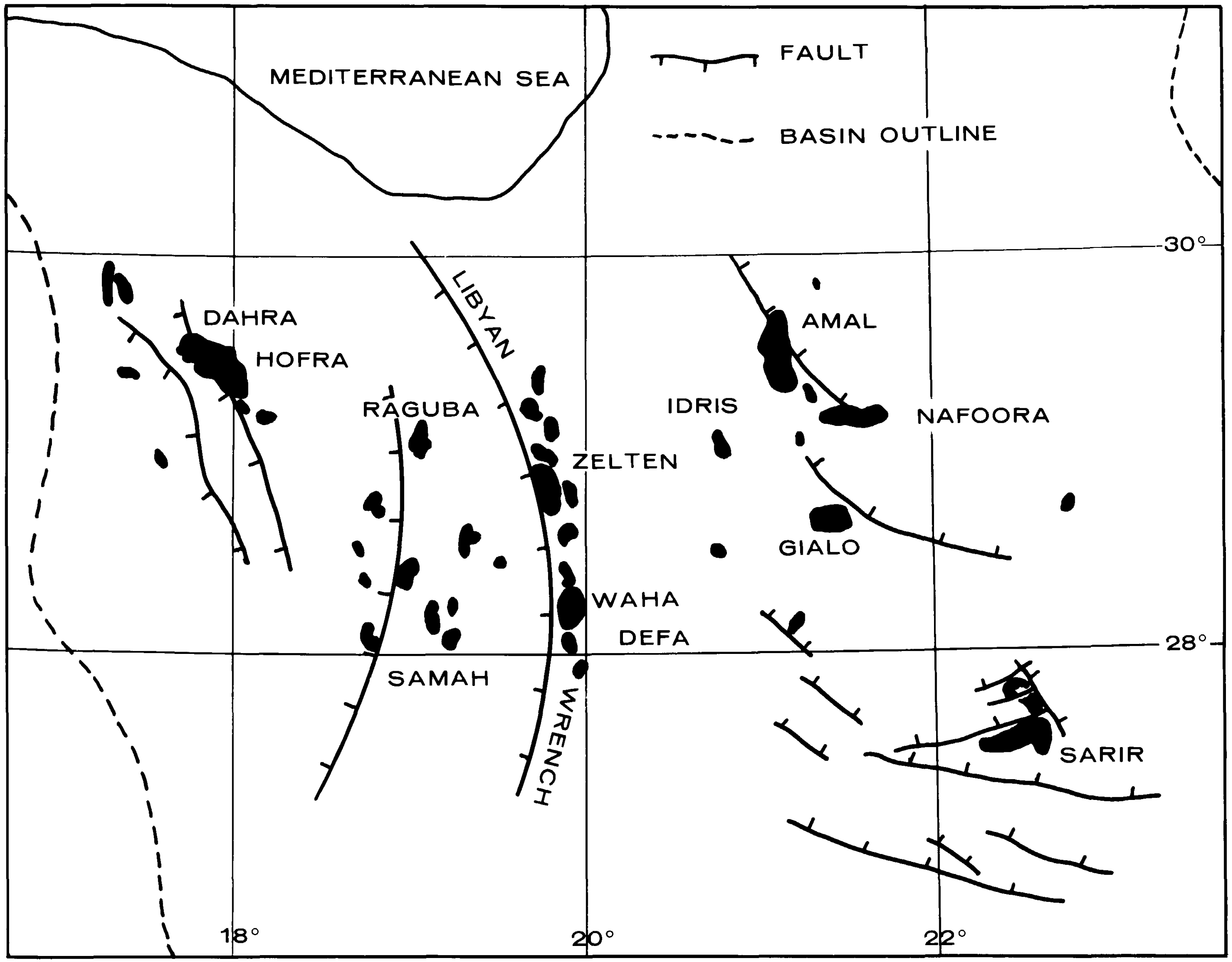
GRONIGEN FIELD
FT
KM
WEST
EAST
0
2000
4000
6000
8000
10,000
12,000
0
1.0
2.0
3.0
TERTIARY
CRETACEOUS
BUNT'SST
U. PERMIAN
PENNSYLVANIAN
0 1 2 3 4 5 6 MI
0 2 4 6 8 10 KM
GAS SAND

FIGURE 18



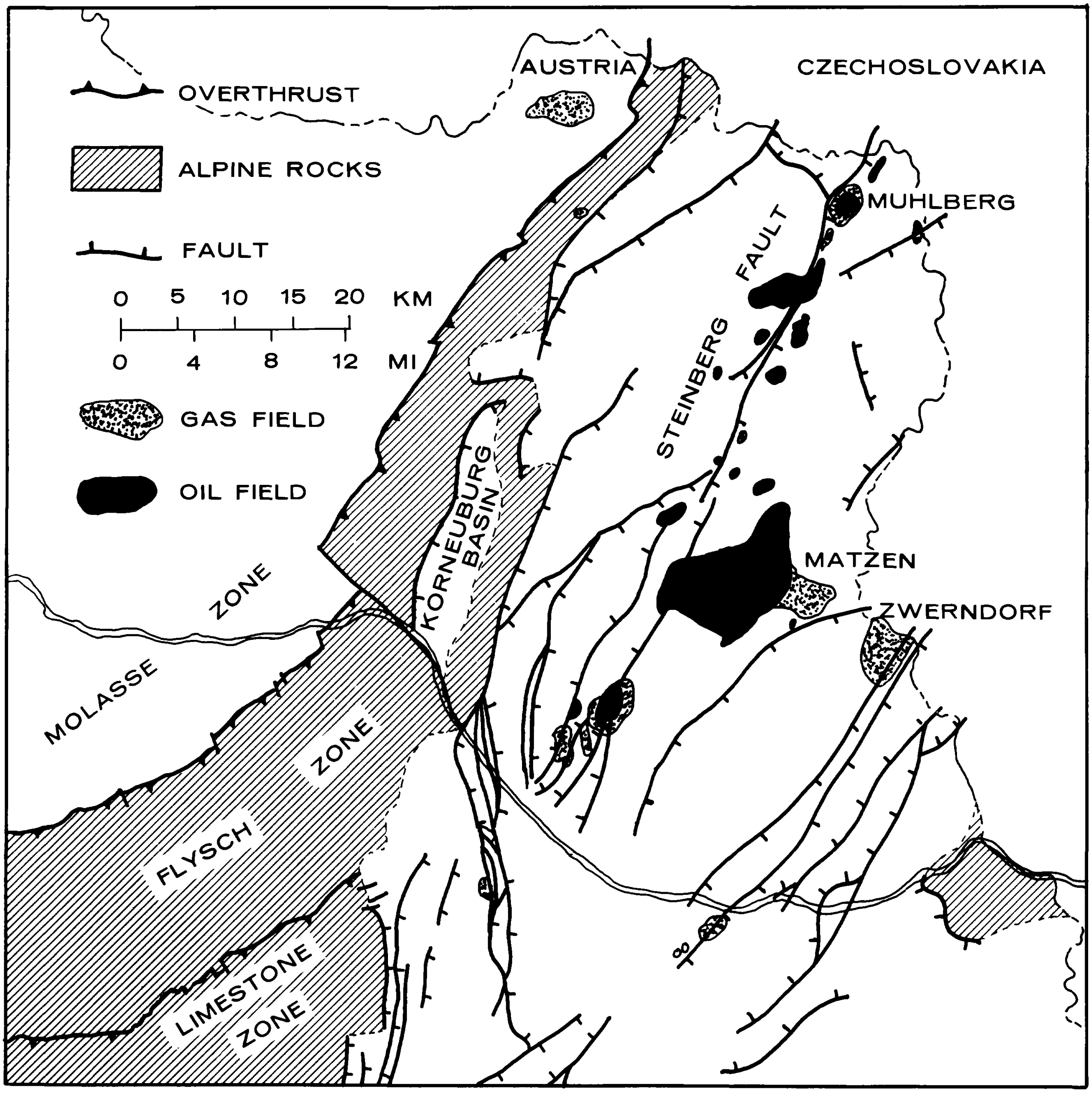
ELK BASIN
MONTANA
WYOMING
FRANNIE
BYRON
GARLAND
BASIN
AXIS
OREGON
BASIN
WORLAND
COTTONWOOD
CREEK
TEN SLEEP FAULT
GRASS
CREEK
HAMILTON
DOME
ABSAROKA MTNS.
N
OWL CREEK
MTNS.
BIG
HORN
MTNS.
OIL FIELD
FAULT
STRIKE SLIP
FAULT
BIG HORN
BASIN
0 6 12 18 24 MI
0 12 24 36 KM

FIGURE 19



FAULT
BASIN OUTLINE
MEDITERRANEAN SEA
30°
28°
18°
20°
22°
DAHRA
HOFRA
RAGUBA
LIBYAN
WRENCH
ZELTEN
SAMAH
WAHA
DEFA
IDRIS
AMAL
NAFOORA
GIALO
SARIR

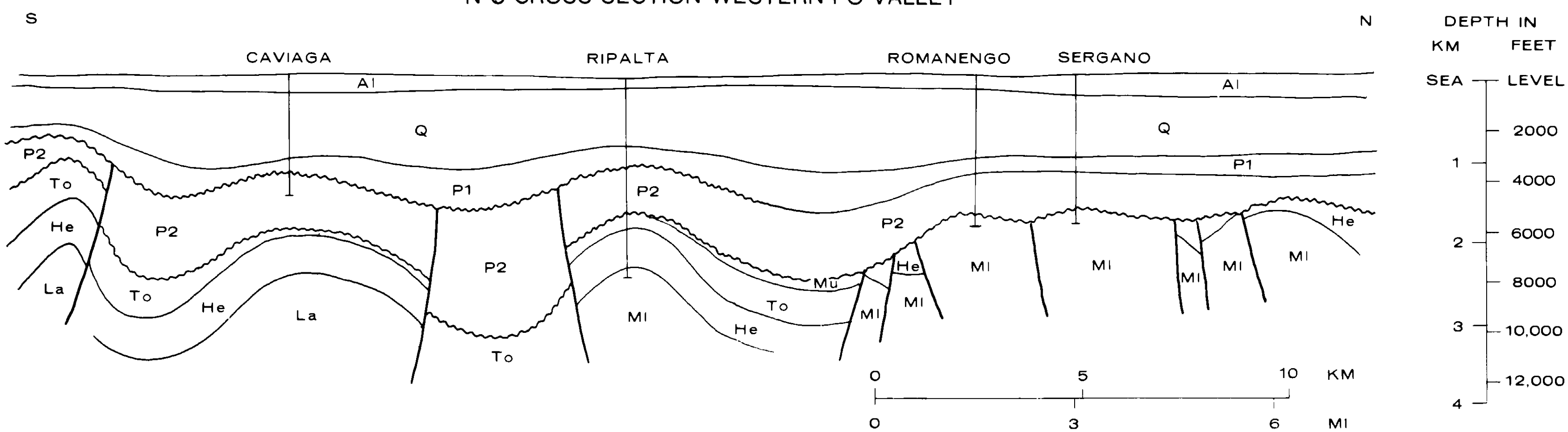
FIGURE 20



AUSTRIA
CZECHOSLOVAKIA
OVERTHRUST
ALPINE ROCKS
FAULT
0 5 10 15 20 KM
0 4 8 12 MI
GAS FIELD
OIL FIELD
MUHLBERG
STEINBERG FAULT
KORNEUBURG BASIN
MATZEN
ZWERNDORF
MOLASSE ZONE
FLYSCH ZONE
LIMESTONE ZONE

FIGURE 21

N-S CROSS SECTION WESTERN PO VALLEY



Al ALLUVIUM
Q QUATERNARY (MARINE)
P1 U.-M. PLIOCENE
P2 L. PLIOCENE
Mu U. MIOCENE
To TORTONIAN
He HELVETIAN
La LANGHIAN
Ml L. MIOCENE

List of Tables

Table 7.--Structure and reserves for fields of Cook Inlet. Data on structure from State of Alaska (1972); EURs from Crick (1971) who notes they are conservative.

Table 8.--Structure and reserves for fields of the Big Horn basin. All CP's are to 1/1/73 and are from International Oil Scouts Association (1974).

Table 9.--Largest fields of Sirte basin, northeastern Libya, (EUR equal to or greater than 500 million bbls.).

Table 1.--Sediment Thicknesses for Petroleum Producing Basins of the World

Basin	Sediment Thickness ft (km)	Notes	Reference
Aquitaine	over 32,808 ft (10 km)	To bottom of Triassic, Paleozoics also present	Costay et al (1969)
Anadarko	40,000 ft (12.19 km)		this study
Appalachian	35,000 ft (10.67 km)		this study
Ardmore	35,000 ft (10.67 km)		this study
Arkoma	30,000 ft (9.14 km)		Branan (1968)
Assam	50,000 ft (15.24 km)	Tertiary only, older sediments also present	Ghosh (1959)
Australia, Northwest Shelf	30,000 ft (9.14 km)		Martison et al (1972)
Barinas	44,000 ft (13.41 km)		this study
Beaufort	over 35,000 ft (10.67 km)		this study
Bengal	38,000 ft (11.58 km)	Pliocene to Cretaceous only	this study
	50,000 ft (15.24 km)		Rahmam (1963)
Big Horn	30,000 ft (9.14 km)		Fanshawe (1971)
Burma	50,000 ft (15.24 km)	To top of Eocene only	Tanish (1950)
Canning Fitzroy Trough	over 30,000 ft (9.14 km)		Cameron (1967)
Caspian	65,617 ft (20 km)		Ermenko et al (1973)
Chaco	40,000 ft (12.19 km)	To crystalline basement	Lamb and Truitt (1963)
Cook Inlet	70,000 ft (21.34 km)		Kirschner (1971)
Dnieper-Donetz	over 26,248 ft (8 km)		this study
Dzungaria	36,089 ft (11 km)	Tertiary and Mesozoic only	Roe (1963) and Meyerhoff (1970)
Eastern Venezuela	43,000 ft (13.11 km)		this study
Gabon	59,055 ft (18 km)		Brink (1974)
Ganges-Brahmapurtra Trough	40,000 ft (12.19 km)		this study
Gippsland	38,000 ft (11.58 km)	Tertiary and Mesozoic only	this study
Green River	over 30,000 ft (9.14 km)		Krueger (1960)
Gulf Coast (Texas and Louisiana on and off shore)	40,000 - 50,000 ft (12.19 - 15.24 km)		this study
Gulf of Suez	over 32,808 ft (10 km)		Said (1963)
Hanna	over 30,000 ft (9.14 km)		Sales (1971)
Honshu	26,246 - 29,528 ft (8 - 9 km)	Extensive igneous activity	Kaufman (1959)
Indus	over 50,000 ft (15.24 km)		Rahman (1963)
Kerch-Taman	over 32,808 ft (10 km)		this study

TABLE 1 CON'T

Lake Maracaibo	over 40,000 ft (12.19 km)		this study
Llanos	over 32,808 ft (10 km)		this study
Lower-Magdalena	50,000 ft (15.24 km)		this study
Mahakram	40,000 ft (12.19 km)		this study
Mexican Bay (Poza Rica)	over 32,808 ft (10 km)		Sokolov et al (1969)
Middle Magdalena	over 39,000 ft (11.89 km)		this study
Niger Delta	39,370 ft (12 km)		Weber (1971)
North German	over 32,808 ft (10 km)	To crystalline basement	Roll (1969)
North Sakhalin	40,000 ft (12.19 km)	Tertiary and Mesozoic only	Kaufman (1959)
North Sea	over 35,000 ft (10.67 km)		this study
Northwest Borneo	49,212 ft (15 km)		Roe (1963)
Northwest Peru	over 30,000 ft (9.14 km)		Youngquist (1958)
Pechora	over 32,808 ft (10 km)		this study
Persian Gulf	60,000 ft (18.29 km)		Anonymous (1969)
Perth	over 30,000 ft (9.14 km)		Cameron (1967)
Ploiesti	90,000 ft (27.43 km)		Paraschiv and Olteanu (1970)
Polish	26,247 ft (8 km)	To base of Mesozoic, thick Paleozoic section also present	Depowski (1963)
Pre-NanShan	32,808 ft (10 km)		Meyerhoff (1970)
San Joaquin Valley	60,000 ft (18.29 km)		Berry (1973)
Santa Barbara Channel	67,000 ft (20.42 km)		Curran et al (197)
Sinu	33,000 ft (10.06 km)		this study
Sirte	over 35,000 ft (10.67 km)		this study
Southern Sakhalin	36,500 ft (11.12 km)	Tertiary and Upper Cretaceous only	Kaufman (1959)
Southern Sumatra	over 30,000 ft (9.14 km)		this study
Tarija	37,500 ft (11.43 km)		this study
Tsaidam	31,168 ft (9.5 km)	Tertiary and Mesozoic only	Roe (1963)
Unita	48,000 ft (14.63 km)		Wells (1958)
Upper Magdalena	42,000 ft (12.80 km)		this study
West Wyoming-Southeastern Idaho (Overthrust belt)	60,000 ft (18.29 km)		Rocky Mt. Assoc. Geol. (1951), and Christensen and Marshall (1950)
Ventura	55,000 ft (16.76 km)		this study
Vienna	39,370 ft (12 km)	To crystalline basement	Kapounek et al (1963)
Volga-Urals	29,526 - 52,493 ft (9 - 16 km)		this study
West Texas Permian	over 30,000 ft (9.14 km)		Oil and Gas Journal (1972)
Wind River	35,000 ft (10.67 km)		this study

Table 2.--Productivity of Shallow and Deep Petroleum Productive Basins
(CP, cumulative production; EUR, estimated ultimate recovery)

Shallow basins				Deep basins			
Basin	Surface area	Reserves in millions of barrels	Productivity[a]	Basin	Surface area	Reserves in millions of barrels	Productivity[a]
Paris	[1] 50,193 mi^2 130,000 km^2	[2] 42.01 (CP) 1/1/73	837 (44)	Vienna	[1] 2,703 mi^2 7,000 km^2	[3] 536 (CP) 7/1/68	198,298 (10,431)
Denver	[4] 60,000 mi^2 155,400 km^2	[3] 734 (CP) 1/1/70	12,233 (643)	Big Horn	[15] 8,500 mi^2 22,015 km^2	[14] 1,560 (CP) 9/1/69	183,529 (9,653)
Williston	[5] 240,000 mi^2 621,600 km^2	[25] 2,152 (EUR)	8,985 (471)	Los Angeles	[16] 1,200 mi^2 3,108 km^2	[7] 7,650 (CP) 1/1/73	6,375,000 (333,294)
North Park	[6] 1,200 mi^2 3,108 km^2	[7] 18 (EUR)	15,000 (789)	Ventura	[17] 2,300 mi^2 5,957 km^2	[7] 1,840 (CP) 1/1/73	800,000 (42,076)
Michigan	[8] 122,000 mi^2 315,980 km^2	[8] 655 (CP) 1/1/68	5,369 (282)	North Sea	[20] 280,000 mi^2 725,200 km^2	[20] 41,800 (EUR)	149,286 (7,852)
Illinois	[9] 79,246 mi^2 205,247 km^2	[9] 3,400 (CP) 1/1/69	42,904 (2,256)	Cook Inlet	[18] 15,000 mi^2 38,850 km^2	[18] 1,890 (EUR)	126,000 (6,627)
Paradox	[7] 22,500 mi^2 58,275 km^2	[10] 450 (EUR)	20,000 (1,052)	Sirte	[7] 265,000 mi^2 683,760 km^2	[19] 30,700[d]	115,849 (6,116)
San Juan	[11] 20,000 mi^2 51,800 km^2	[12] 628[b] (CP) 1/1/64	31,400 (1,651)	Gippsland	[21] 18,000 mi^2 46,620 km^2	[22] 4,360 (EUR)	242,222 (12,740)
Black Warrior	[13] 35,000 mi^2 90,650 km^2	[13] .343[c] (CP) 1/1/64	9.8 (0.52)	Po Valley	[23] 16,000 mi^2 41,440 km^2	[24] 1,870[e] (EUR)	116,875 (6,147)
Average of all			15,190 (809)	Average of all			923,006 (48,551)
Average excluding Illinois			11,726 (623)	Average excluding Los Angeles			241,507 (12,703)

[a] Bbls/mi^2, (M.T./km^2); [b] 82% oil equivalent gas; [c] gas condensate; [d] EUR for only fields of 500 mm bbls EUR or greater

[e] 84% oil equivalent gas.

[1] Perrodon (1963); [2] Internat. Oil Scouts Assoc. (1974); [3] Janoschek and Gotzinger (1969); [4] Volk (1972); [5] Landes (1970); [6] Oburn (1968); [7] this study; [8] Ells (1971); [9] Bond et al (1971); [10] Ohlen and McIntyre (1965); [11] Wengerd (1958); [12] Peterson et al (1965); [13] Pike (1968); [14] Weldon (1972); [15] Stauffer (1971); [16] Yerkes et al (1965); [17] Nagle and Parker (1971); [18] Crick (1971); [19] Halbouty et al (1970); [20] Watson and Swanson (1975); [21] Beddoes (1973); [22] Combined estimates of Beddoes (1973) and Halbouty et al (1970); [23] Rocco and Jaboli (1958); [24] Combined estimates of Pieri (1969) and Gardner (1975); [25] Hansen (1974).

Table 3.--Los Angeles Basin Fields

Field	Cumulative production to 1/1/73 in millions of barrels of oil (MM) and billions of cubic feet of gas (BCF)	Faulted or updip from fault
Fields cut by Newport-Inglewood fault		
Dominguez	255.48 MM/ 375.93 BCF	yes
Howard Townsite	--	yes
Huntington Beach	884.20 MM/ 769.84 BCF	yes
Inglewood	289.50 MM/ 233.30 BCF	yes
Long Beach and Long Beach Airport		yes
Newport	.19 MM/--	yes
Newport, W.	41.26 MM/ 7.48 BCF	yes
Potero	13.66 MM/ 58.18 BCF	yes
Rosecrans	81.76 MM/ 196.70 BCF	yes
Rosecrans, E.	.14 MM/--	yes
Rosecrans, S.	6.90 MM/--	yes
Seal Beach	185.40 MM/ 200.26 BCF	yes
Sunset Beach	6.56 MM/ 9.64 BCF	yes
Talbert	.13 MM/--	yes
Fields directly updip from Newport-Inglewood fault		
Alondra	2.10 MM/ 1.39 BCF	yes
El Segundo	13.53 MM/ 24.81 BCF	yes
Hyperion	.49 MM/ .18 BCF	yes
Lawndale	3.13 MM/ 4.61 BCF	yes
Playa del Rey	63.26 MM/ 67.95 BCF	yes
Torrance	173.99 MM/ 123.12 BCF	yes
Wilmington	1,549.50 MM/ 942.70 BCF	yes
Sub-total	4,446.44 MM/4,106.46 BCF	
Fields along and cut by Whittier fault		
Brea-Olinda	336.53 MM/ 411.30 BCF	yes
Montebello	183.32 MM/ 210.98 BCF	yes
Sansinena	44.98 MM/ 53.60 BCF	yes
Whittier	40.24 MM/ 44.30 BCF	yes
Sub-total	605.07 MM 720.18 BCF	
Fields along Norwalk fault		
Coyote, E.	96.77 MM/ 88.08 BCF	yes
Coyote, W.	227.86 MM/ 193.27 BCF	yes
Richfield	161.82 MM/ 171.90 BCF	yes
Santa Fe Springs	599.14 MM/ 839.75 BCF	yes
Yorba Linda	42.32 MM/ 1.87 BCF	yes
Sub-total	1,127.91 MM/1.294.87 BCF	

Fields along Santa Monica fault

Beverly Hills	68.22 MM/	139.39 BCF	yes
Salt Lake	47.81 MM/	190.33 BCF	yes
Salt Lake, S.	3.48 MM/	1.43 BCF	yes
San Vicente	5.94 MM/	5.15 BCF	yes
Sawtelle	8.00 MM/	6.56 BCF	yes
Sherman	.09 MM/	.05 BCF	no
Sub-total	133.94 MM/	342.81 BCF	

Fields in predicted productive area of basin but
not along basin forming faults

Anahiem	--		yes
Bandini	5.14 MM/	14.94 BCF	yes
Boyle Heights	.27 MM/	.11 BCF	no
Buena Park, E.	.20 MM/	.02 BCF	no
Buena Park, W.	.05 MM/	.02 BCF	no
Esperanza	.82 MM/	.66 BCF	yes
Kraemer	3.06 MM/	.99 BCF	yes
Kraemer, N.E.	--		no
Kraemer, W.	--		yes
La Mirada	.02 MM/	.01 BCF	no
Leffingwell	.77 MM/	2.26 BCF	yes
Los Angeles City	7.56 MM/	9.41 BCF	yes
Newgate	.05 MM/	--	yes
Olive	1.57 MM/	.51 BCF	yes

Fields outside of the predicted productive area of the basin

San Gabriel Valley block			
Lapworth	.05 MM/	--	no
North Whittier Heights	.08 MM/	--	yes
Rowland	--		yes
Turnbull	.76 MM/	.58 BCF	yes
Walnut	.07 MM/	--	yes
Chino basin block - Northeast block			
Chino-Soquel	.27 MM/	.33 BCF	yes
Mahala	2.57 MM/	1.13 BCF	yes
Prado-Corona	.38 MM/	2.22 BCF	yes
Palos Verdes block			
Gaffey	--		no

Total production of fields outside the predicted productive area
of the basin, with percentage of basin total production

10 fields 4.20 MM (.07%)/4.26 BCF (.06%)

Total production of fields not cut by or updip from a fault
dipping back into the basin deep

7 fields .61 MM/.16 BCF

Total production of all fields of the Los Angeles basin

6,480.77 MM/6,701.83 BCF

Table 4.--Ventura Basin Fields

Field name	Cumulative production to 1/1/73 in millions of barrels of oil (MM) and billions of cubic feet of gas (BCF)	Faulting present (and name)
Bardsdale	12.26 MM/ 74.56 BCF	yes (Oakridge)
Chaffe Canyon	--	yes (Oakridge)
Saticoy	19.07 MM/ 39.25 BCF	yes (Oakridge)
Shiells Canyon	22.29 MM/ 43.50 BCF	yes (Oakridge)
South Mountain	91.28 MM/ 186.66 BCF	yes (Oakridge)
Torrey Canyon	18.02 MM/ 18.51 BCF	yes (Oakridge)
Sub-total for fields on the Oakridge fault	162.92 MM/ 362.48 BCF	
Cascade	1.02 MM/ .06 BCF	yes (Santa Susana)
Oakridge	11.24 MM/ 7.63 BCF	yes (Santa Susana)
South Tapo Canyon	4.30 MM/ 1.94 BCF	yes (Santa Susana)
Sub-total for fields on the Santa Susana fault	16.56 MM/ 9.63 BCF	
Castaic Hills	8.19 MM/ 17.31 BCF	yes (San Gabriel)
Placerita	40.47 MM/ 6.79 BCF	yes (San Gabriel)
Sub-total for fields on the San Gabriel fault	48.66 MM/ 24.10 BCF	
Castaic Junction	26.19 MM/ 37.95 BCF	yes (Holser)
Del Valle	24.69 MM/ 94.64 BCF	yes (Holser)
Ramona	19.17 MM/ 36.08 BCF	yes (Holser)
Subtotal for fields on the Holser fault	70.05 MM/ 168.67 BCF	
Bouquet Canyon	--	yes
Canton Creek	.02 MM/ --	no
Charlie Canyon	--	yes
Conejo	.12 MM/ --	yes
El Rio	.34 MM/ .17 BCF	yes
Elizabeth Canyon	--	yes
Fillmore	12.58 MM/ 17.91 BCF	yes, updip from Oakridge fault (Nagl[e] and Parker, 1971)
Honor Rancho	25.10 MM/ 37.49 BCF	yes
Horse Meadows	.14 MM/ .09 BCF	yes
Las Llajs	.05 MM/ .02 BCF	yes
Long Canyon	--	yes (Barnard)
Mission	.52 MM/ .28 BCF	yes
Moorpark	.03 MM/ --	no
Newhall	7.72 MM/ 5.42 BCF	yes
Newhall-Potrero	68.90 MM/ 78.16 BCF	yes
North Ramona	--	yes
Oak Canyon	11.53 MM/ 17.52 BCF	yes
Oakview	--	yes
Ojai	8.65 MM/ 5.92 BCF	yes (Pirie, Big Canyon, Sisar)
Oxnard	33.39 MM/ 20.35 BCF	yes (Livingstone, Vac
Piru	4.90 MM/ 3.23 BCF	yes
Piru Creek	--	yes
Rincon-Ventura	943.08 MM/1,212.36 BCF	yes (Taylor, Barnard, Rincon)
Santa Paula	2.47 MM/ 1.96 BCF	yes
Saugus	.49 MM/ .78 BCF	yes
Sespe	16.82 MM/ 13.62 BCF	yes (Sulphur Peak)
Simi	3.16 MM/ 1.42 BCF	yes (Simi, CDLB)
Somis	--	yes (Simi)
Tapia	.34 MM/ --	yes
Tapo Ridge	--	yes
Temescal	6.61 MM/ 5.38 BCF	yes (Nagle and Parker, 1971)
Timber Canyon	5.08 MM/ 7.86 BCF	yes (Sisar)
Total production of all fields of the Ventura Basin	1,450.13 MM/ 1,994.82 BCF	

Table 5.--Structuring and reserves for fields of the Gippsland basin

Field	Reserves	Age and depth of producing sediments	Structuring	Reference
Halibut	600 million bbls EUR	Top of Latrobe group (Eocene) at 7400-7500 ft (2.25-2.29 km)	Fault block high with down-to-the-north normal fault cutting the field on the east. Faulting does not extend beyond top of Latrobe group.	Franklin and Clifton (1971); Halbouty et al (1970)
Kingfish	1.06 billion bbls oil and 250 Bcf of gas. Largest field in the basin	Lower Eocene sandstones at 7500-8000 ft (2.28-2.44 km)	Trap is a faulted anticline on a fault block high. Faulting does not extend past Upper Eocene.	Beddoes (1973); Halbouty et al (1970)
Marlin	3.6 Tcf of gas, 266 million bbls condensate, 20-50 million bbls of oil EUR	Eocene and Paleocene sands. Oil-water contact at 5170 ft (1.58 km), gas-oil contact at 5114 ft (1.56 km)	Trap is combination plunging nose and closed erosional high. Field is faulted and also updip from major faulting. Neither set of faults extends past Eocene sediments	Beddoes (1973); Halbouty et al (1970)
Tuna	500 Bcf of gas, 84 million bbls oil EUR	Eocene sands; top of gas at 4300 ft (1.31 km), top of oil at 7760 ft (2.37 km)	Anticline directly updip from Marlin faulting.	Beddoes (1973)
Barracouta	1.8 Tcf of gas, 137 million bbls condensate, 500 million bbls of oil EUR	Late to Early Eocene sands; gas-oil contact at 3775 ft (1.15 km), oil-water contact at 4565 ft (1.39 km)	Northeasterly trending anticline directly updip from a major north-westerly trending fault.	Beddoes (1973); Halbouty et al (1970)
Golden Beach	200 Bcf of gas EUR	Upper Cretaceous sands gas-water contact at 2165 ft (0.66 km)	Anticline on east-trending horst with east-trending faulting downdip from both flanks of the structure.	Beddoes (1973)

Table 6.--Associated structure and vertical control of production by faulting for fields of the North Sea basin

Field (reserves EUR) (when available)	Production and age of reservoir	Upper vertical limit of faulting	Structure (when available)	Reference
Cormorant (650 million bbls)	Oil-Jurassic sandstones	Jurassic--does not extend past pre-Kimmerian unconformity.	Brent Platform	Watson and Swanson (1975)
Ekofisk (5.8 Tcf)	Oil-Paleocene	Faulting stops in Paleocene sediments	--	Watson and Swanson (1975)
Auk	Oil-Permian	Faulting stops at top of Permian	--	Watson and Swanson (1975)
Josephine	Triassic and Jurassic	Faulting stops at top of Jurassic	--	Watson and Swanson (1975)
Forties (1.8 billion bbls)	Oil-Paleocene	Faulting stops in Lower Eocene sediment	Broad dome faulted on northeast side	Thomas et al (1974)
Piper (650-900 million bbls)	Oil-Upper Jurassic sandstones	Faulting terminates in Cretaceous sediments	Faulted anticlines and fault blocks	Williams et al (1975)
Indefatigable (8 Tcf)	Gas-Lower Permian	Faulting dies out in Upper Permian salts	Fault block traps	Watson and Swanson (1975), Kent and Walmsley (1970)
West Sole (1.0 Tcf)	Gas-Lower Permian	Faulting dies out in Upper Permian salts	Elongate faulted dome	Kent and Walmsley (1970)
Hewett (4.2 Tcf)	Gas-Permian and Triassic	Faulting stops in Cretaceous sediments	Anticline between two large down-to-the-northeast faults	Kent and Walmsley (1970)

Viking	Gas-Permian Rotliegendes formation	Faulting dies out in overlying Permian Zechstien formation		Gray (1975)
Leman (12 Tcf) (Shipa line)	Gas-Lower Permian	Faulting dies out in Upper Permian salts	Broad gentle faulted dome	Kent and Walmsley (1970)
Thistle	Oil-Jurassic sands	Jurassic--does not extend past pre-Kimmerian unconformity	Brent Platform	Watson and Swanson (1975)
Dunlin	Oil-Jurassic sands	Jurassic--does not extend past pre-Kimmerian unconformity	Brent Platform	Watson and Swanson (1975)
Brent (2 billion bbls, 3.5 Tcf)	Oil-Jurassic sands	Jurassic-does not extend pas pre-Kimmerian unconformity	Brent Platform	Watson and Swanson (1975)

Table 7.--Structural association and reserves for fields of Cook Inlet. Data on Structure from State of Alaska (1972); EUR's from Crick (1971) who notes they are conservative

Field (EUR)	Structure	Reservoirs
Granite Point (155 million bbls)	Asymmetric anticline faulted on northwest flank	Kenai Group (Lower to Middle Miocene); 7570-10,200 ft (2.36-3.11 km), 11,130-11,540 ft (3.39-3.52 km)
McArthur River (170 million bbls)	Anticline faulted on northwest and southwest flanks	Kenai Group (Lower to Middle Miocene) 9100-9800 ft (2.77-2.99 km); West Foreland Formation (Late Oligocene), 10,200-11,000 ft (3.11-3.41 km)
Middle Ground Shoal (173 million bbls)	Long thin anticline cut by three major faults, one fault with over 2000 ft (610 m) of throw	Kenai Group (Lower to Middle Miocene)
Swanson River (225 million bbls, 30 Bcf	Anticline cut by numerous faults, throws up to 500 ft (152 m)	Sterling Formation (Pliocene) Gas, 3000-58000 ft (0.91-1.77 km); Hemlock Formation (Miocene) Oil, 10,150-11,700 ft (3.09-3.57 km)
Trading Bay (36 million bbls)	Complexly faulted anticline	
Kenai (2.2 Tcf)	Anticline cut by normal faults Down to the north with 150-200 ft (46-61 m) of throw	

Structural association

Table 8.-- and reserves for fields of the Big Horn basin. All CP's are to 1/1/73 and are from International Oil Scouts Association (1974)

Field	Reserves	Structuring
Elk Basin	500 million bbls EUR	Anticline cut on south flank by left lateral wrench, and on northeast flank by a reverse fault with over 700 ft (213 m) of throw
Garland	111 million bbls CP	Dome cut on northeast flank by reverse fault with over 1000 ft (305 m) of throw
Byron	84 million bbls CP	Anticline cut by reverse fault on northeast flank
Worland	17 million bbls, 408 Bcf CP	Anticline cut by reverse fault with over 1300 ft (396 m) of throw
Hamilton Dome	153 million bbls CP	Anticline cut by reverse fault with over 4000 ft (1.22 km) of throw, southwest flank of dome cut by left lateral wrench
Grass Creek	134 million bbls CP	Anticline cut by reverse fault on west and southwest flanks, also cut by large left lateral wrench with 3000-4000 ft (0.91-1.22 km) of throw
Skip line → Frannie	74 million bbls CP	Anticline cut by reverse fault
Byron	84 million bbls CP	Anticline cut by same reverse fault as Frannie
Murphy Dome	32 million bbls CP	Anticline cut on southwest flank by large reverse fault
Bonanza	40 million bbls CP	Anticline cut by left lateral wrench
Little Buffalo Basin	50 million bbls CP	Anticline cut by left lateral wrench
Cottonwood Creek	39 million bbls,	Stratigraphic trap flanked on south by Tensleep left lateral wrench, and updip from large reverse fault on northeast flank of Worland field