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HYDROCARBON RESOURCE POTENTIAL OF THE BALTIMORE CANYON TROUGH

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CONTENTS

Page

APPENDICES

ILLUSTRATIONS

TABLES

HYDROCARBON RESOURCE POTENTIAL OF THE

BALTIMORE CANYON TROUGH

ABSTRACT

It is now possible to evaluate some of the earlier assessments and offer tentative conclusions about the hydrocarbon resource potential of the Baltimore Canyon trough, a major northeast-southwest trending sedimentary basin off the Mid-Atlantic coast of the United States. For this purpose the Delaware Geological Survey has examined more than 2,500 miles (4,022 km) of seismic reflection profiles, the results of some offshore magnetic and gravity surveys, the results of the COST B-2 well, and the nonproprietary results through 1978 of exploratory drilling by the petroleum industry on federal leases.

The data establish the presence of reservoir beds, sealing beds, and potential traps for hydrocarbons in the basin. Potential source beds are present, i.e., sufficient kerogen is preserved in the rocks, but it has not yet yielded oil or gas (thermally immature). The kerogen in the nonmarine to marginal and shallow marine Upper Jurassic-Lower Cretaceous section of clastic sedimentary rocks targeted for exploration is predominantly of terrestrial origin. Therefore, if thermal maturity has been attained in areas other than where the COST B-2 well was drilled, natural gas rather than oil would be the likely resource. Seven of eight complete exploratory wells drilled over promising geologic structures encountered no significant shows of hydrocarbons. This may indicate a general lack of thermal maturity in the basin. A significant, although not yet declared commercial, discovery of natural gas by Texaco supports source rock studies indicating gas as the major resource, if any. The gas trapped in the structure may have been generated locally (heat anomaly associated with a salt dome?) or it might have migrated vertically from a thermally mature zone at depths approaching 20,000 feet (6,095 m) or greater.

If oil-prone source beds or potential source beds (containing kerogen predominantly of marine origin) are present in the basin they are most likely to be associated with carbonate rocks (limestone, dolomite) which may be present at depths greater than 20,000 feet (6,095 m) beneath the continental shelf. At such depths the peak oil-generating zone would have been exceeded, and only gas would have formed. Beneath the upper continental slope the carbonate (?) rocks are not buried as deeply and appear as reef-like masses on several seismic reflection profiles. If reefs are present they would probably be excellent reservoirs, but they may not have been buried deeply enough for oil or gas to have been generated from associated source beds.

INTRODUCTION

Purpose and Scope

The exploration for oil and gas in the Baltimore Canyon trough has progressed to a point where we can now evaluate some of the earlier assessments (Mattick *et al*., 1974; Miller *et al*., 1975; Bureau of Land Management, 1976, 1978; Schlee *et al*., 1977) and offer tentative conclusions about the hydrocarbon resource potential of the major sedimentary basin of the Mid-Atlantic Outer Continental Shelf (OCS). In addition to the geologic information from land a small proportion of all the data from the Atlantic OCS is available to the Delaware Geological Survey (DGS) for this purpose. We have examined more than 2,500 miles (4,022 km) of multi-channel common depth point (CDP) seismic reflection profiles, the results of the COST B-2 stratigraphic test well, and the publicly available results of exploratory drilling on OCS Sale No. 40 leases. Because the Baltimore Canyon trough is a frontier area of oil and gas exploration, I must emphasize that conclusions based on analyses of the available information could be changed dramatically as drilling progresses and new areas of exploration are leased.

This report derives from a presentation to the Delaware Academy of Science "Symposium on Energy and the Delaware Valley," November 9, 1978, at the University of Delaware. It is intended to convey to both the technical and nontechnical reader the basic geologic criteria for the generation and accumulation of oil and natural gas in sedimentary basins. The criteria are applied to the Baltimore Canyon trough, first in an evaluation of quantitative estimates of oil and gas made prior to exploratory drilling, then in an analysis of the resource potential based on results of exploration through 1978.

Definition of Terms

In this paper the term hydrocarbon is used in a general sense to include both crude oil and natural gas. Levorsen (1967) refers to hydrocarbon as a general term often used interchangeably with petroleum. According to his definition petroleum is a complex mixture of hydrocarbon (hydrogen and carbon) compounds which occurs widespread in the earth as gas, liquid, semi-solid, or solid, or in more than one of these states in a single place. Liquid petroleum is called crude oil, and petroleum gas is referred to as natural gas.

Usage of the term kerogen, or oil former, to describe the insoluble organic matter present in nonreservoir sedimentary rocks is much broader than its original definition as the organic matter present in oil shales and other rocks rich in organic carbon. Robinson (1969) restricted the broad definition by using the term to describe the insoluble organic material present in kerogen rocks, those rocks defined as sedimentary deposits in which the contained kerogen yields on distillation an oil equivalent to more than 50 percent of the organic content of the rock. He used the term bitumen to describe the organic material present in the kerogen rock that is soluble in a hydrocarbon solvent. Dow (1978) apparently has returned to the broader definition because he refers to all disseminated organic matter in sedimentary rocks as kerogen. I will apply Dow's usage in this report. Kerogen, organic matter, and buried organic carbon are used interchangeably.

Acknowledgments

Dr. Kent S. Price, President of the Delaware Academy of Science, graciously approved my request to publish this Report of Investigations as a modified version of the manuscript submitted to the Academy for publication in its Proceedings volume "Energy and the Delaware Valley."

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GEOGRAPHICAL, GEOLOGICAL, AND HISTORICAL PERSPECTIVE

The Atlantic continental margin is one of the last frontiers of exploration in the search for additional reserves of oil and gas in North America. This major geologic province extends from the Grand Banks off Newfoundland to peninsular Florida. It includes four physiographic provinces: the emerged coastal plain and the submerged continental shelf, slope, and rise (Figure 1). The margin consists of a major accumulation of sedimentary rocks deposited over a basement of crystalline rocks. The sediment mass thins both landward and seaward from its thickest part located beneath the outer shelf and upper slope.

Current exploratory activity is confined to the submerged portion and is concentrated in several sedimentary basins underlying the continental shelf and upper slope. The basins, results of the subsidence of fault-bounded basement blocks, are filled with a much thicker accumulation of sedimentary rocks than that present over the intervening basement arches or uplifts separating the basins. Over 100 wells drilled between 1966-1977 in offshore Canada's Scotian and Grand Banks basins have failed to find any large commercial reserves of hydrocarbons (Bujak et al., 1977). In the offshore basins of the United States, current exploratory drilling is just beginning and is concentrated off the coasts of Delaware and New Jersey in the thickest part of a major northeast-southwest trending sedimentary basin designated the Baltimore Canyon trough by Maher (1965) (Figure 2). Schlee et al. (1977) report that the basin contains at least 46,000 feet (14 km) of Jurassic and younger marine and nonmarine sedimentary rocks. Other basins being explored off the United States' East Coast include the Georges Bank basin off New England and the southeast Georgia embayment and the Blake Plateau trough off Florida, Georgia, and South Carolina.

Exploratory drilling for oil and gas in the Atlantic continental margin of the United States occurred previously, primarily during the first half of this century. Because this took place before technology became available for

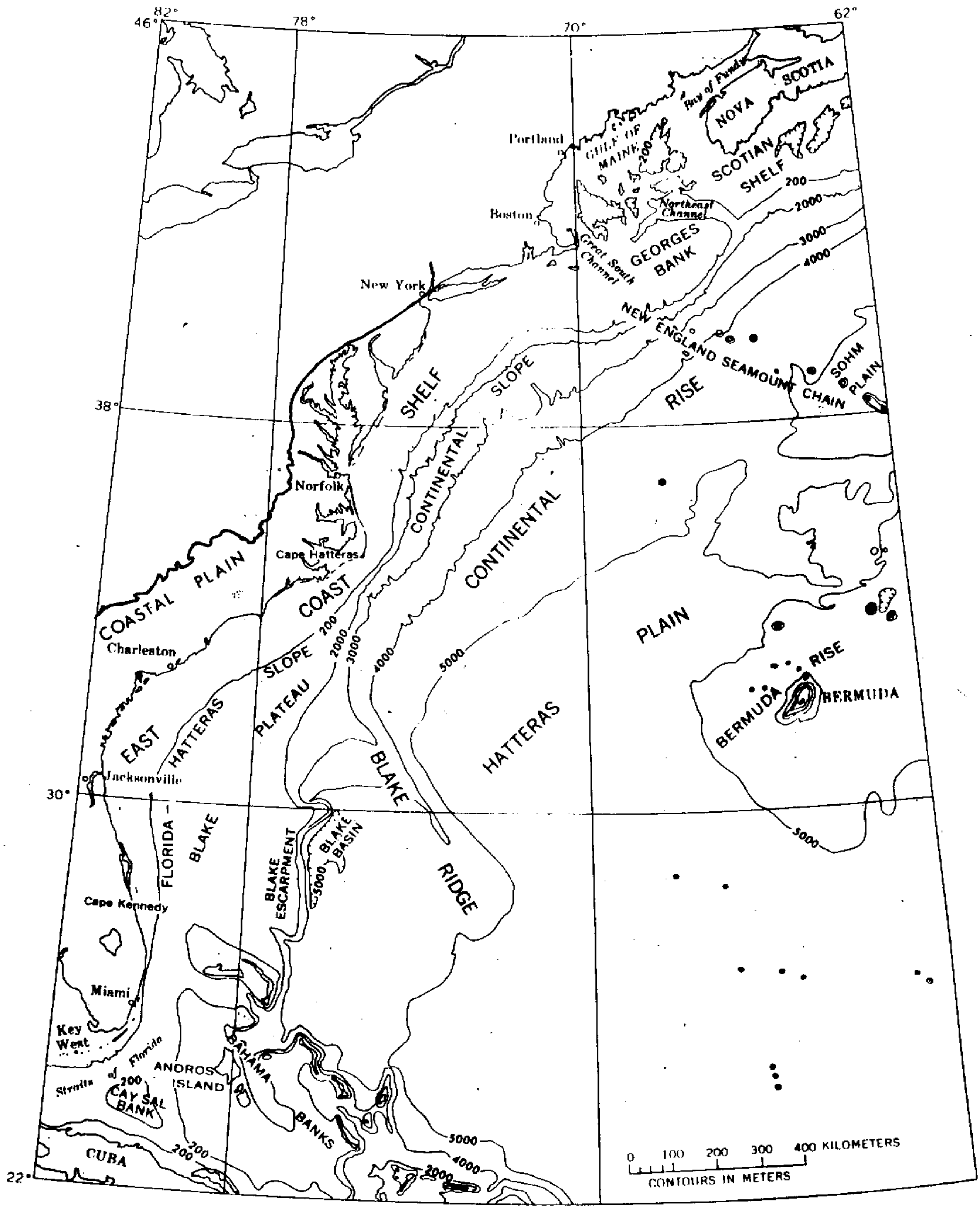


Figure 1. Physiographic provinces of the Atlantic continental margin of the United States. (After Uchupi, 1970).

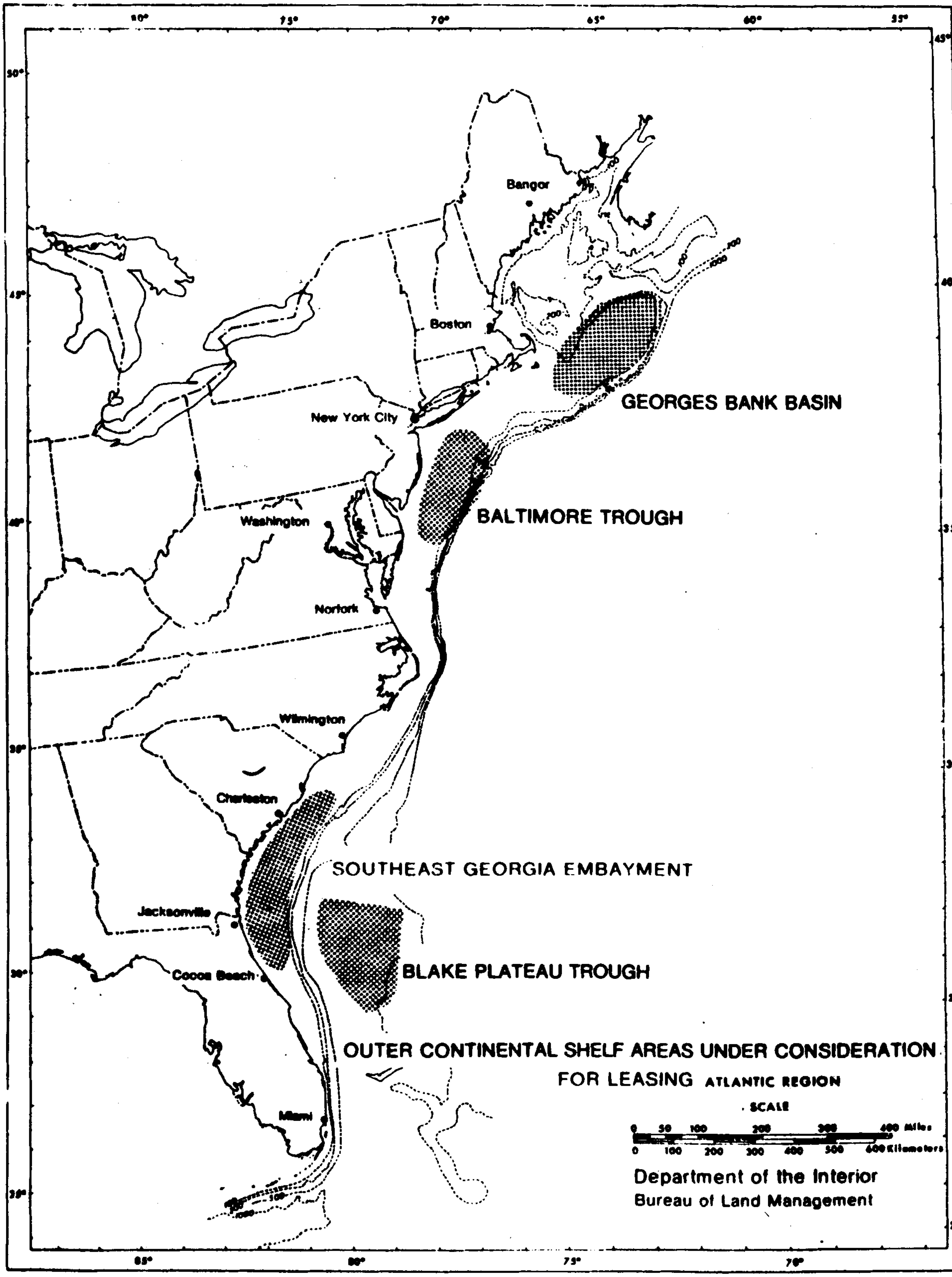


Figure 2. Sedimentary basins off the east coast of the United States. (After Bureau of Land Management, 1975).

offshore exploration, drilling was confined to the emerged portion of the continental margin, the Coastal Plain. In contrast with the approximately 800,000 wells that have been drilled in the Gulf Coastal Plain, only a few hundred were drilled from New Jersey to Florida, most of them in Florida. The only oil fields discovered, however, were in the southwestern part of the Florida Peninsula, a part of the Gulf Coastal Plain (Maher, 1971). Drilling activity in the Delmarva region was summarized by Anderson (1948). During the 1930's, several shallow oil test wells were drilled in the vicinity of Bridgeville, Delaware, with no substantiated reports of oil or gas. During the 1940's three deeper test holes were drilled in Maryland just south of the Delaware-Maryland border. No shows of oil or gas were reported. A deep test drilled in Accomack County, Virginia, in 1971 likewise had no reported shows (Onuschak, 1972).

The early attempts to find oil and gas in the Atlantic Coastal Plain represented a natural outgrowth of the successful exploration in the Gulf Coast region. The geology of the two regions, although similar, is not identical; so far as is now known only that of the Gulf Coastal Plain favored the accumulation of commercial deposits of hydrocarbons. Because many onshore oil fields extended offshore, exploration and development moved offshore. Development of offshore drilling and production technology kept pace with the gradual move into deeper waters of the Gulf of Mexico continental shelf and upper slope. Today, this highly sophisticated technology is suddenly in our midst in the Mid-Atlantic region, concentrated 80 to 100 miles (129 to 161 km) offshore where the geology is more favorable for the accumulation of hydrocarbons.

Although recognized as a certainty at some future time, offshore exploration of the Atlantic continental margin was hastened by the international events of the 1970's. The OPEC oil embargo prompted President Nixon, in his address to the Nation on January 23, 1974, to outline a program for U. S. energy independence (Bureau of Land Management, 1975). Accelerated leasing of the Outer Continental Shelf (OCS) was a part of the plan which was begun in 1975. Although less ambitious under the Carter Administration, the expanded leasing program continues.

After the 1975 Supreme Court decision in U. S. v. Maine et al. upheld federal jurisdiction of the Outer Continental Shelf beyond the 3-mile (4.8 km) limit on the Atlantic Coast, the Department of Interior began the formal process of leasing Atlantic OCS lands, the first priority being the Baltimore Canyon trough. This culminated in August, 1976, with OCS Lease Sale No. 40. Over one billion dollars were bid by the oil industry for the right to lease 93 tracts of submerged lands, each tract measuring 2.98 miles (4.8 km) on a side (Figure 3). A list of successful bidders is given in Appendix A. After a delay of a year and a half due to litigation unsuccessfully challenging the adequacy of the Environmental Impact Statement for Sale 40, drilling began on the leases.

The Sale 40 leases and those being considered for Sale 49 are in that part of the Baltimore Canyon trough that both industry and the federal government consider most likely to have commercial deposits of hydrocarbons according to the presently available information. This reasoning is examined and evaluated below.

THE HABITAT OF OIL AND GAS

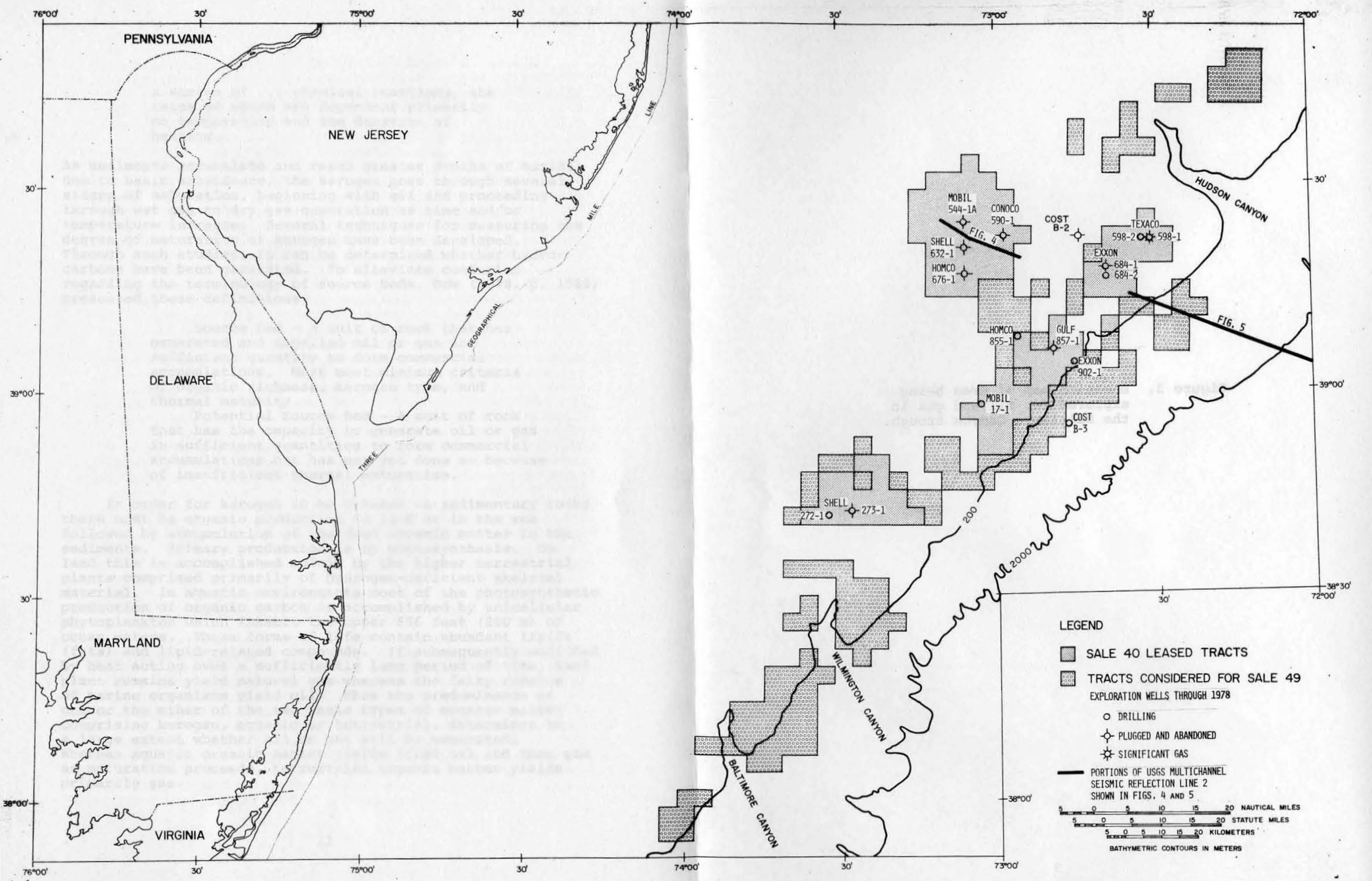
The theme of the 40th Annual Meeting of the American Association of Petroleum Geologists in 1957 was "The Habitat of Oil." Weeks (1958) edited a volume of that title dealing with the generation and accumulation of oil and natural gas in many of the world's petroleum producing areas. In evaluating the hydrocarbon potential of sedimentary basins being explored today, Tucker (1978) re-emphasized the importance of the theme of the Weeks volume that the occurrence of oil and gas can be explained by analysis of three factors: 1) the presence of organic-rich source beds, 2) the generation of fluid hydrocarbons from these beds through attainment of sufficiently high temperatures, and 3) migration and retention of the fluids in porous and permeable reservoir rocks and traps.

Source Beds

Most theories on the formation of petroleum subscribe to an organic origin - the transformation of dead organic matter buried in sediments. Dow (1978) has reviewed source beds and petroleum generation in various geologic settings. His analysis is summarized in this and the next section. Dow (1978, p. 1584) agrees with

> ...the modern geochemical concept that petroleum and gas are formed from disseminated organic matter (kerogen) by

Figure 3. Location map of area being explored for oil and gas in the Baltimore Canyon trough.


PENNSYLVANIA
NEW JERSEY
DELAWARE
MARYLAND
VIRGINIA
THREE GEOGRAPHICAL MILE LINE
76°00'
30'
75°00'
74°00'
73°00'
72°00'
39°00'
38°30'
38°00'
HUDSON CANYON
WILMINGTON CANYON
BALTIMORE CANYON
MOBIL 544-1A
CONOCO 590-1
COST B-2
TEXACO 598-2 598-1
SHELL 632-1
HOMCO 676-1
EXXON 684-1 684-2
FIG. 4
FIG. 5
HOMCO 855-1
GULF 857-1
EXXON 902-1
MOBIL 17-1
COST B-3
SHELL 272-1 273-1
200
2000
LEGEND
SALE 40 LEASED TRACTS
TRACTS CONSIDERED FOR SALE 49
EXPLORATION WELLS THROUGH 1978
DRILLING
PLUGGED AND ABANDONED
SIGNIFICANT GAS
PORTIONS OF USGS MULTICHANNEL SEISMIC REFLECTION LINE 2 SHOWN IN FIGS. 4 AND 5
NAUTICAL MILES
STATUTE MILES
KILOMETERS
BATHYMETRIC CONTOURS IN METERS

> a series of ... chemical reactions, the rates of which are dependent primarily on temperature and the duration of heating.

As sediments accumulate and reach greater depths of burial due to basin subsidence, the kerogen goes through several stages of maturation, beginning with oil and proceeding through wet gas to dry gas generation as time and/or temperature increase. Several techniques for measuring the degree of maturation of kerogen have been developed. Through such studies, it can be determined whether hydrocarbons have been generated. To alleviate confusion regarding the terminology of source beds, Dow (1978, p. 1586) presented these definitions:

> Source Bed - A unit of rock that has generated and expelled oil or gas in sufficient quantity to form commercial accumulations. Must meet minimum criteria of organic richness, kerogen type, and thermal maturity.
>
> Potential Source Bed - A unit of rock that has the capacity to generate oil or gas in sufficient quantities to form commercial accumulations but has not yet done so because of insufficient thermal maturation.

In order for kerogen to be present in sedimentary rocks there must be organic production on land or in the sea followed by accumulation of the dead organic matter in the sediments. Primary production is by photosynthesis. On land this is accomplished mainly by the higher terrestrial plants comprised primarily of hydrogen-deficient skeletal material. In aquatic environments most of the photosynthetic production of organic carbon is accomplished by unicellular phytoplankton which inhabit the upper 656 feet (200 m) of ocean waters. These forms of life contain abundant lipids (fats) and lipid-related compounds. If subsequently modified by heat acting over a sufficiently long period of time, land plant remains yield natural gas whereas the fatty remains of marine organisms yield oil. Thus the predominance of one or the other of the two basic types of organic matter comprising kerogen, aquatic or terrestrial, determines to a large extent whether oil or gas will be generated. Whereas aquatic organic matter yields first oil and then gas as maturation proceeds, terrestrial organic matter yields primarily gas.

The major accumulations of kerogen in sediments are associated with the continental margins. Sediments and transported terrestrial organic matter are concentrated here because deposition (aggradation) predominates over erosion (degradation). Kerogen is particularly abundant in areas of major river runoff. In situ accumulation of organic carbon as coal beds is usually associated with ancient coastal environments. In the marine environment, the phenomenon of upwelling results in high primary productivity by phytoplankton. Upwelling is most common along continental margins, especially along west coasts of continents (Dow, 1978, Fig. 3, 4). Detrital terrestrial organic matter dominates east coasts of continents because primary marine productivity is lower there.

In order that there be a net accumulation of organic carbon in sediments the processes that conserve and concentrate it must dominate over those that destroy and dilute it. Less than 1% of the organic matter produced ultimately is preserved in sediments (Dow, 1978). The main processes that destroy organic matter are chemical oxidation and consumption by organisms. Organic matter, therefore, is preserved in areas where oxygen content is low, such as in closed anoxic basins or where the oxygen minimum zone of the ocean impinges on the upper continental slope. Organic matter is concentrated in areas of high organic productivity and where sedimentation rates are intermediate, i.e., rapid enough to dominate over consumption by organisms but slow enough to avoid excessive dilution by mineral sediment particles. Organic matter is further concentrated in clay-rich shales. Because fine-grained clay mineral particles adsorb certain polar organic compounds, dissolved organic matter in the sea is attracted to the particles and deposited with the clay in relatively quiet water.

Generation of Fluid Hydrocarbons

The generation of hydrocarbons from kerogen is a complex chemical process similar to cooking. Reaction rates depend primarily on temperature and duration of heating. They are very slow at first but generally double with a doubling of the exposure time or with each temperature increase of 10°C (18°F) (Philippi, 1965). This exponential increase produces a peak generation period when commercial quantities of hydrocarbons are produced. The oil peak is attained first and is followed by wet gas and dry gas peaks as temperature and time increase.

Other than the above relationship no quantitative information regarding actual temperature-depth vs. kerogen maturation level can be applied generally to all sedimentary basins. For specific basins quantitative information can only be obtained after extensive drilling. Therefore, the ability to predict the hydrocarbon potential in a frontier area based on studies of kerogen from only one or just a few wells is low.

As an illustration of quantitative information available in a well known petroleum area, Dow (1978) lists data based on studies of kerogen maturation levels in wells from the Louisiana Gulf Coast where the geothermal gradient is 1.4°F per 100 feet of depth (2.6°C/100 m), a normal figure.

Table 1. Depth and temperature at which peak oil generation and oil destruction occurs for rocks of two contrasting ages, Louisiana Gulf Coast. (After Dow, 1978).

AGE	Oil Generation				Oil Destruction			
	Depth		Temp.		Depth		Temp.	
	Feet	Km	°F	°C	Feet	Km	°F	°C
Cretaceous (100 million years old)	8,100	2,470	183	84	12,400	3,780	244	118
Pliocene (5 million years old)	18,300	5,580	327	164	30,100	9,175	495	257

Data in Table 1 illustrate that at least for the Gulf Coast region the younger the rocks the thicker the sedimentary section required to generate hydrocarbons at the same geothermal gradient.

Migration and Retention of Fluid Hydrocarbons

Hydrocarbon fluids cannot be extracted by conventional methods from source beds because, although generally very porous, these fine-grained rocks are not sufficiently permeable due to the small size of pores and/or lack of interconnected pore spaces. In order to form accumulations of commercial value, once hydrocarbon fluids are generated they must be able to move from the source beds through a "plumbing system" of permeable pathways to porous and permeable reservoir rocks that are sealed to form a trap.

Lateral migration of fluids parallel to sedimentary bedding is more easily accomplished than vertical migration across bedding. Laterally permeable pathways result from inherent rock properties, the most important of which is primary porosity (Levorsen, 1967). As grain size and degree of sorting increase so do pore size, degree of interconnection of pores, and permeability. Therefore, coarse clastic sedimentary rocks consisting of sand- and gravel-size grains are the best inherent "plumbing systems." Levorsen (1967) concluded that although petroleum may have moved vertically along openings provided by fault planes and fractures in some fields, most of the evidence indicates that most petroleum migrated laterally to traps. On the other hand, Dow (1978) cites studies in the Louisiana Gulf Coast by Frey and Grimes (1970) who concluded that deep-seated faults and salt piercements (diapirs) with their associated fracture systems serve as vertical pathways for oil and gas migration. Dow (1978) also cites Young et al. (1977) who calculated that an average of 11,000 feet (3,353 m) of vertical oil migration must have taken place in the Gulf Coast region because the ages of the oils average 8.7 million years older than their reservoir rocks.

As source rocks become compressed through burial and/or tectonic forces, large quantities of the entrained water containing dissolved or colloidally suspended oil and gas are squeezed out. The waters move through permeable pathways in response to the hydraulic head. The dispersed oil particles eventually flocculate to form a phase separate from the water. With movement of water or oil toward regions of lower pressure in response to head differences, a gas phase also forms as gas comes out of solution at reduced pressures. When the gas or oil phases form a large enough mass that their buoyancy forces overcome the hydrodynamic forces, oil and gas move upward (Levorsen, 1967). In order that oil and gas may form accumulations occupying the pore spaces of rocks, traps must be available, otherwise the hydrocarbons would be lost at the earth's surface through seepage. Oil and gas will accumulate in the highest parts of the traps because they are less dense than the water generally present in rocks and will remain there unless they escape due to tilting or fracturing of the traps by later earth movements.

The effect of a trap is to bar further movement of oil and gas and hold it in permeable reservoir rock. There must be an impermeable barrier, the roof rock, overlying the reservoir rock (Levorsen, 1967). As viewed from below the configuration of the roof rock is concave, which prevents oil and gas from escaping either vertically or laterally. This type of trap is termed a structural trap. Because they can be "seen" on seismic reflection profiles, and therefore offer the best chance for success, such traps are the prime targets of exploration on the Outer Continental Shelf.

Another type of trap is related to internal rock properties such as a lateral decrease in permeability due to finer textures in the direction of migration and is termed a stratigraphic trap. A lateral facies change from a sandstone (reservoir rock) to a shale (impermeable seal) is an example of a stratigraphic trap. Most stratigraphic traps occur in varying degrees of combination with structural traps.

The timing of hydrocarbon generation, migration, and entrapment is critical to the accumulation of oil and gas. A trap must have been formed prior to hydrocarbon generation and migration otherwise the migrating fluids would escape at the earth's surface. Traps formed during sedimentation are ideal because their presence prior to generation and migration, which occur long after the time of sedimentation, is assured.

In attempting to understand the timing of the events leading to the accumulation of oil or gas in frontier sedimentary basins, if not known from regional geologic history, the most useful data available prior to drilling are seismic reflection profiles. By studying these, traps can be identified and mapped, and geologic events of sedimentation and growth of structures can be deduced. Whether or not the traps contain commercial quantities of oil or gas, however, can only be determined by drilling.

Hindsight is very important in explaining the occurrence or nonoccurrence of oil and gas, but there is no way at present to predict with certainty that accumulations actually exist. Prediction is limited to locating the best sites for drilling, nearly always over structural traps. Subtle traps, usually stratigraphic traps, are generally overlooked because of difficulties in determining precisely where to drill. Quantitative estimates of resource potential in frontier areas, therefore, are always based on incomplete knowledge.

OIL AND GAS POTENTIAL OF THE BALTIMORE CANYON TROUGH

Quantitative Estimates

Quantitative estimates of undiscovered oil and gas resources in unexplored sedimentary basins must rely on several assumptions. The evaluation of the assumptions themselves is beyond the scope of this paper. Controversies over resource estimates in general, whether for a single basin or a whole country, usually are the result of using different methods, each having its own set of assumptions. Comparison of the two major approaches - geological and mathematical - that were used in estimating U. S. oil and gas reserves and resources prior to 1975 are given by the U. S. Geological Survey (USGS, 1972) and the Council on Environmental Quality (CEQ, 1974).

It is, nonetheless, important to develop quantitative estimates in advance of exploration. Much can be learned about the resource potential from such an exercise. The results may, however, be misleading if they are applied for evaluation or planning purposes without understanding the qualifying assumptions of each method.

In 1975, the U. S. Geological Survey (USGS) published Circular 725 (Miller *et al.*, 1975) entitled "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States." No proprietary data were used in the estimating methods employed; therefore, it is likely that figures derived by industry, utilizing proprietary data, may differ greatly from those of the USGS and may be more reliable. It may also be noted that estimates may vary widely between individual oil and gas companies. Industry estimates are not generally available to the public.

For OCS areas, the USGS did not evaluate the offshore petroleum potential beyond 656 feet (200 m) of water depth so deep water areas that may be leased in proposed OCS Sale No. 49 (Figure 3) were not considered in the study. Also, factors of economics and technology prevailing in 1974 were used, and 1978 price-cost relationships would alter resource estimates.

Because the entire Atlantic offshore region is a frontier area, no drill hole data existed. Miller *et al.* had to rely primarily on the volumetric-yield method of analysis in determining reserve estimates. In this method prospective areas are measured, and the volume of contained sedimentary rock is calculated. A yield factor in barrels of oil or cubic feet of gas per cubic mile of sedimentary rock or per square mile of surface area is applied. The critical part of this method is choosing the appropriate yield factor. The 1975 study based yield factors on geologic analogs, i.e., it determined this factor from data available in a well-explored geologic basin that is closely analagous to the frontier basin. In Circular 725 there is no discussion of methods specifically used for each region evaluated, so it cannot be determined from the publication which basin was considered to be analagous to the Atlantic offshore region.

It is my opinion that the Scotian basin offshore Nova Scotia represents the best analog that has a significant amount of drill hole data available. In light of the lack of success to date, yield factors derived from this basin and applied to the Atlantic OCS would give low estimates of reserves. Gulf Coast basin yield factors, on the other hand, would give high estimates. However, I agree with Dow (1978) who criticizes the volumetric method because it is applied too generally. Only the volume of sediments thermally mature enough to generate oil and gas should be considered in the calculations.

In USGS' determination of total U. S. reserves the results of calculations for each U. S. region at the 95% and 5% probability levels were added together except that for the Atlantic OCS the 75% and 25% probability levels were used. The undiscovered recoverable resources of the Atlantic OCS out to a depth of 656 feet (200 m) are given in Table 2.

Table 2. USGS reserve estimates for the Atlantic OCS (Miller et al., 1975).

	Probability level - the chance that there is at least this amount.			
	95%	75%	25%	5%
Oil (bbl x 10^9)	0	2	4	6
Gas (cu. ft x 10^{12})	0	5	14	22

For the Baltimore Canyon trough a completely different approach was used by the Conservation Division of the USGS in evaluating tracts offered for competitive bidding in OCS Lease Sales 40 and 49. Reserve estimates were based primarily on analysis of industry-generated, therefore proprietary, CDP multichannel seismic reflection profiles. The results were published in the Environmental Impact Statements (EIS) issued for each sale (Bureau of Land Management, 1976, 1978). Only those tracts chosen for consideration in the EIS were evaluated. In the Proposed Notice of Sale, the Secretary of Interior did not delete from OCS Sale 40 any of the 154 tracts evaluated in the EIS. Final tracts to be offered in Sale 49 scheduled for early 1979 have not yet been chosen.

For the tracts that were considered in each EIS the following procedures, as described by the USGS (1975) were applied. The USGS prepared maps of geologic structures based on interpretations of proprietary geophysical data. Geologists and engineers calculated the thickness and extent of presumed reservoirs in the structural traps and made several assumptions regarding reservoir characteristics, production rates, and exploration and development costs. A computer technique known as the "Monte Carlo Analysis Method" was applied to each tract in order to determine a range of values. In this technique the "emphasis is shifted from one overall judgment of risk to a series of risks that are made at the beginning of the analysis."

The above procedures provide a more realistic resource appraisal than the volumetric-yield method because actual geologic structures are evaluated. Given reasonable assumptions of reservoir rock thickness, extent, porosity, and permeability, a range of calculations can be made based on zero to full occupation of the pore spaces in a trap by oil or gas. As drill hole data accumulate the assumptions are re-evaluated and estimates are refined. In making assumptions about reservoir rock characteristics in frontier areas data from Continental Offshore Stratigraphic Test (COST) wells are very useful.

Because the Conservation Division's method is applied only to tracts that might be offered in a lease sale, only a small portion of the sedimentary basin is evaluated. Reserve estimates of tracts over promising geologic structures that were deleted from lease sales because of environmental considerations or conflicts with other users of the OCS (Department of Defense, for example) are not included in figures published in the EIS's. The published reserve estimates are given in Table 3.

Table 3. Undiscovered recoverable resources for OCS Sales 40 and 49 in the Baltimore Canyon trough.

	No. of tracts evaluated	Range of Estimates	
		Oil (bbl x 10^9)	Gas (cu.ft. x 10^{12})
Sale 40 (Bureau of Land Management, 1976)	154	0.4 - 1.4	2.6 - 9.4
Sale 49 (Bureau of Land Management, 1978)	136*	0.028-0.32	0.46-5.33

*30 of these tracts were evaluated as part of the 154 tracts of Sale 40 and are being considered again for Sale 49.

Analysis of Potential Based on Results of Exploration through 1978

Data available to the DGS allow for a preliminary qualitative evaluation of the oil and gas potential of the sedimentary rock section currently being explored in the Baltimore Canyon trough. Seismic reflection profiles, data available from the COST B-2 well, and the results of exploratory drilling to date (Figure 3) provide the basis for evaluating the "triad of source bed, generation, and migration/retention." For illustration, portions of USGS CDP multichannel seismic reflection line 2 are reproduced here as Figures 4 and 5, and their locations are shown in Figure 3. I have added to line 2 interpretive overlays based on correlation of reflectors from the COST B-2 well.

Prospective Sedimentary Section

The prospective sedimentary section is the clastic Upper Jurassic (J) - Lower Cretaceous (LK) interval. In the COST B-2 well this extends from a depth of about 8,100 feet (2,470 m) below sea level to the total depth of the well at nearly 16,000 feet (4,877 m) and probably deeper than this to the top of the interval interpreted as a carbonate-evaporite (?) facies (Figure 5; also Horizon Z of Schlee et al. 1976) at a depth in excess of 20,000 feet (6,095 m).

Figure 4. Portion of USGS CDP multichannel seismic reflection line 2 over the Great Stone Dome, a potential structural (anticlinal) trap. See Figure 3 for location.

J = Jurassic; LK - Lower Cretaceous; UK = Upper Cretaceous; P = Paleogene (Paleocene, Eocene, and Oligocene); N = Neogene (Miocene, Pliocene, Pleistocene); unc. = unconformity.

Interpretation based on correlation from the COST B-2 well in which the top of the Jurassic is placed at 13,000 feet (3,960 m) as recognized by Geological Survey of Canada criteria used for offshore East Canada (G. Williams, personal communication).

Approximate depth equivalents of two-way travel time: 1 sec - 3,000 feet (0.9 km); 2 sec. - 7,500 feet (2.3 km); 3 sec. - 14,000 feet (4.3 km); 4 sec. - 22,000 feet (6.7 km). After Schlee et al. (1975).

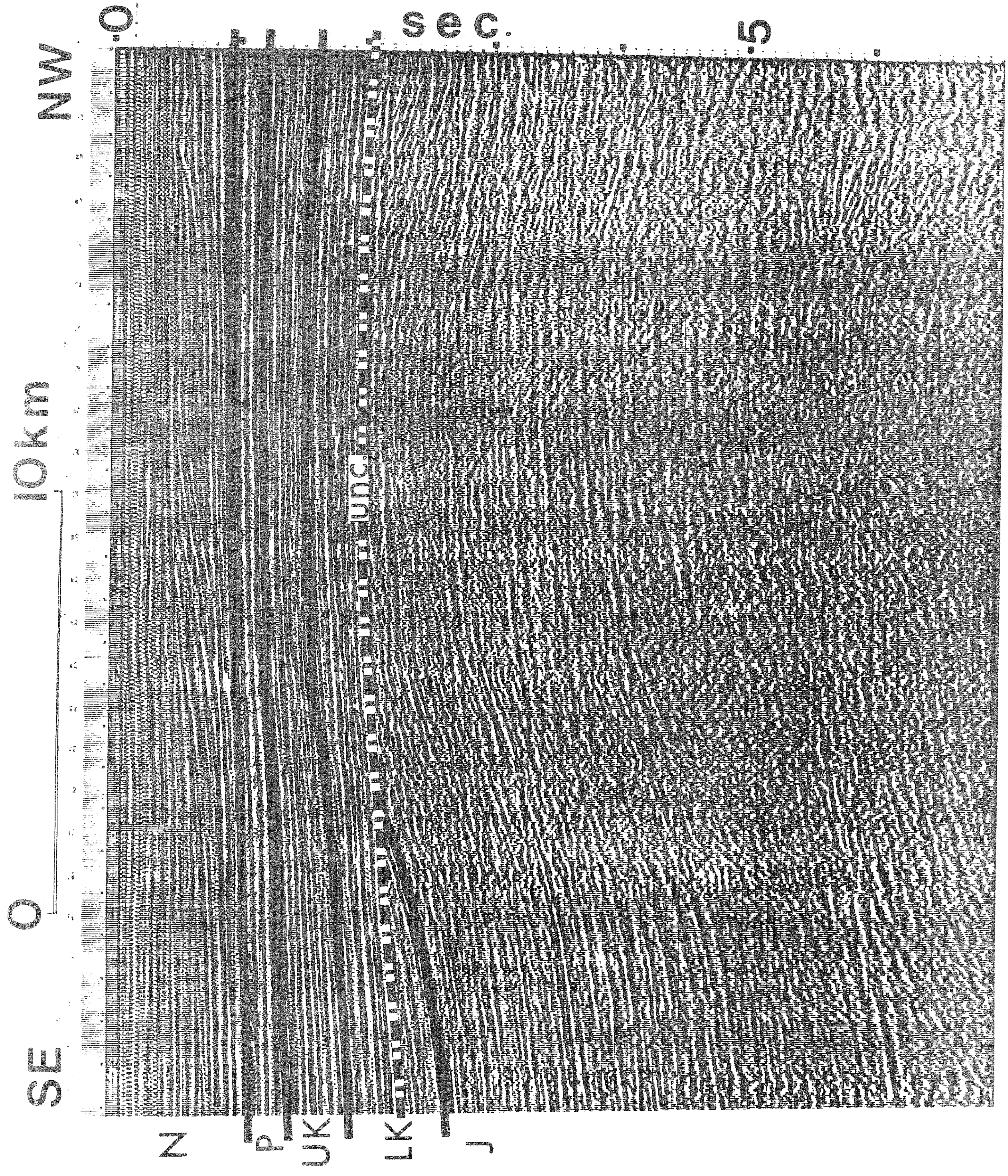
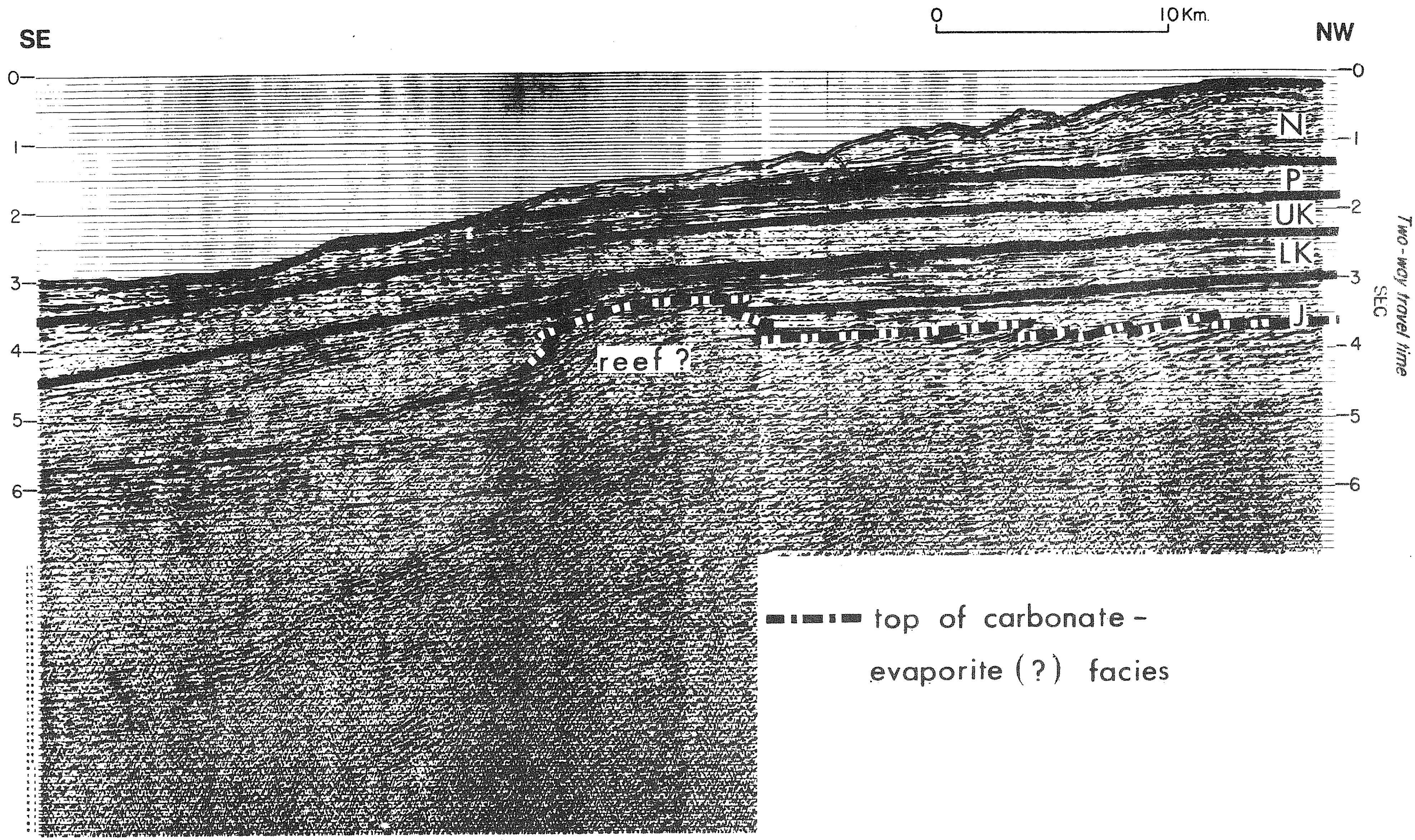

NW
SE
0
sec.
.5
10km
0
unc
N
P
UK
LK
J

Figure 5. Portion of USGS CDP multichannel seismic reflection line 2 over the edge of the continental shelf and the upper continental slope. Interpreted reef (organic carbonate build-up) is a possible stratigraphic trap. See Figure 3 for location.

Abbreviations as for Figure 4.

Approximate depth equivalents of two-way travel time as given for Figure 4 apply only to the NW end of Figure 5. After Schlee *et al.* (1975).


SE
NW
0
10 Km.
N
P
UK
LK
J
reef ?
Two-way travel time
SEC
0
1
2
3
4
5
6
top of carbonate -
evaporite (?) facies

In the COST B-2 well there is a favorable ratio of reservoir beds (sandstone) to source and sealing beds (shale) in the 8,100 - 16,000 foot (2,469 - 4,877 m) interval. Sandstone ranges from 26 - 60% of the total of sandstone plus shale and averages 42% (Scholle, 1977). The porosity and permeability of the sandstones, however, decrease rapidly with depth. Below 12,000 feet (3,658 m) in the well most porosities are less than 15%, and permeabilities are less than 1 millidarcy (Scholle, 1977). Thus, there are reservoir-quality beds present that would have allowed for the migration of oil and gas along lateral permeable pathways. The interbedded shales would have sealed the hydrocarbons in the sandstones if traps had been formed before migration occurred. If enough organic matter were present in the shales, they would also represent source beds or potential source beds.

Examples of Potential Traps

Potential structural, and some stratigraphic, traps are known from seismic reflection profiles. The locations of the largest and most readily identifiable traps governed the choice of tracts for OCS Sale No. 40 and proposed OCS Sale No. 49. The types of traps identified in the Baltimore Canyon trough include: (1) anticlinal traps with associated crestal faulting, (2) growth faults (active during sedimentation and thus controlling locus of sedimentation), (3) anticlinal structural traps and angular unconformity stratigraphic traps associated with igneous intrusives and vertical salt and/or shale movement (salt domes and piercements or diapirs), and, (4) stratigraphic traps including sedimentary onlap over crystalline basement and those formed by organic carbonate buildups (reef (?) in Figure 5).

Figure 4 is the portion of USGS seismic reflection line 2 that extends over part of a broad anticlinal structure nearly 30 miles (48 km) across. Tracts receiving the highest bids in OCS Sale No. 40 are centered over this feature where the structural relief is greatest (1,000 or more feet; 305 or more m). The vertical intrusion of an igneous rock body of cylindrical shape, not unlike a volcanic neck, is thought to have caused the arching of the sedimentary layers. This interpretation is based on the high magnetic intensity measured over the structure. A positive gravity anomaly of circular shape matching the shape of the magnetic high also is located over the structure. This suggests that at depth an igneous body of greater density than the surrounding sedimentary rocks is present. If a salt body, which would be of a lower density than the surrounding sedimentary strata, were present, a negative gravity anomaly would be expected.

Although vertical salt movement apparently did not form the structure, small salt domes are associated with it. Houston Oil and Minerals Corporation (HOMCO) reported that "a thickness of salt" was encountered in their dry well number 676-1 (Figure 3) which was drilled to a total depth of 12,500 feet (3,810 m) (Oil and Gas Journal, September 18, 1978, p. 72). Because the large anticlinal structure illustrated in Figure 4 was probably the result of an igneous intrusion, it has been nicknamed the "Great Stone Dome." Several oil companies, however, refer to it as the Baltimore Dome.

The arching of the sedimentary rocks took place during the Early Cretaceous as evidenced by an angular unconformity developed over the structure during this time as a result of truncation of the tilted strata by erosion. Following the interval of erosion, younger beds of Early Cretaceous age were deposited over the unconformity. These beds and most of the still younger strata overlying the structure are also arched. This may be due to the draping effect over the pre-existing high rather than subsequent vertical movement of the structure. The most likely place to find oil or gas is over the crest of the structure. Apparently the oil industry assumed the accuracy of this statement because the tract occupying this crestal position was sold to the group headed by Mobil for over $107 million.

Figure 5 illustrates a possible stratigraphic trap in the form of a carbonate reef formed by marine animals, plants, and algae. Reefs are highly porous and are important reservoirs in many of the world's petroleum producing areas. If sealing beds cover a reef above and laterally, an excellent trap is formed. On the seismic profile (Figure 5) this appears to be the case, but potential source beds may have not been buried deeply enough to have reached the necessary hydrocarbon generation temperatures. Also, the reef underlies tracts that have not been sold and will not be offered for sale in proposed OCS Sale No. 49.

Source Rocks

The above discussion establishes that reservoirs and traps do exist in the Baltimore Canyon trough. The remaining critical question as raised by Dow (1978) is whether source rocks are present in the thermally mature part of the section. The only nonproprietary data available for attempting to answer this question are from the COST B-2 well. Data from the COST B-3 well (Figure 3) now being drilled will not be available until at least 60 days after OCS Sale No. 49 which is scheduled for early 1979. Data from exploratory wells drilled on Sale 40 leases remain confidential for two years and, therefore, will not be available until 1980 at the earliest.

As reported by Smith et al. (1976), source rock analyses of the COST B-2 well provided by Geochem Laboratories, Inc. indicate that between 7,000 and 14,700 feet (2,134 and 4,481 m) the percentage of organic carbon consistently exceeds 0.5 percent, the minimum required for significant petroleum generation in shales. Abundant organic material and high concentrations of hydrocarbons were found between 9,400 and 13,900 feet (2,865 and 4,237 m). There is an overall down-hole increase of organic carbon to about 14,000 feet (4,267 m). These results are confirmed by Scholle (1977). Sufficient organic matter, therefore, is present at least to establish that potential source beds exist.

The remaining questions are: what is the predominant type of kerogen, aquatic or terrestrial?, and has thermal maturity been attained for the type of kerogen present? In answer to the first question Smith et al. (1976) report that both aquatic and terrestrially derived organic matter is present throughout the stratigraphic section. However, they point out that studies by Amoco Production Company indicate that rocks with oil generating potential (predominantly marine type of organic matter) are found only above 4,890 feet (1,490 m) where sufficient temperatures for hydrocarbon generation have not been reached. Rocks to a depth of about 9,000 feet (2,743 m) are primarily of marine origin, and from 9,000 to 16,000 (2,743 to 4,879 m) they are non-marine to marginal marine. In fact, there are several coal bed intervals in this lower section. Therefore, in the Upper Jurassic-Lower Cretaceous section targeted for exploration, and presumably the remainder of the clastic section down to the top of the evaporite-carbonate (?) facies at a depth in excess of 20,000 feet (6,095 m), the kerogen is dominated by terrestrially derived organic matter and is capable of yielding only gas with little or no oil.

Finally, studies of kerogen maturation in these rocks indicate that the peak value for oil generation is reached at 11,300 feet (3,444 m) and for wet gas generation at about 19,000 feet (5,791 m). Given that the geothermal gradient of 1.4°F/100 feet (2.6°C/100 m) in the COST B-2 well is about the same as that for the Gulf Coast region, Dow (1978) reasoned that the peak oil generation zone for the Cretaceous rocks is deeper in the Atlantic shelf than in the Gulf Coast because of a much thicker cover of Cenozoic age rocks. The thicker the Cenozoic cover, the shorter the exposure time of

Mesozoic age rocks to temperatures capable of generating hydrocarbons. Thus, the results of studies conducted so far suggest that only potential source beds were encountered in COST B-2 well.

Significance of Texaco's Gas Discovery

Given the above, how does one explain the discovery of significant amounts of natural gas by Texaco in well no. 598-1 (Figure 3) in the depth interval 13,000 - 15,000 feet (3,962 - 4,572 m), well above the peak zone of gas generation at 19,000 feet (5,791 m) in the COST B-2 well? The *Wall Street Journal* of August 28, 1978 quotes one independent oil analyst as saying that "the odds are nine to one that Texaco has got more than one trillion cubic feet" and that there may be as many as three trillion cubic feet of reserves on Block 598, with the admission that any speculation is highly risky at this time. One explanation may be that the information from the COST B-2 well cannot be applied generally throughout the Baltimore Canyon trough. The COST B-2 well was drilled off structure in an area not expected to encounter hydrocarbons. This area perhaps is representative of the sedimentary basin as a whole. Exploration for oil and gas, however, takes place over anomalies which may not be generally characteristic of the basin. The discovery of natural gas in Block 598 does support the prediction from study of the potential source beds of the COST B-2 well that gas, not oil, is to be expected.

In order for gas to have accumulated, either significant vertical migration from the gas-generating zone at depth (below 19,000 feet? (5,791 m)) must have occurred or the geothermal gradient over Block 598 is higher than 1.4°F/100 feet (2.6°C/100 m). From study of a seismic reflection profile across Block 598 it appears that the structure containing the gas may have been the result of vertical salt movement (salt dome). In discussing the hydrocarbon potential of the Nova Scotian shelf, Bujak *et al.* (1977) refer to Rashid and McAlary's suggestion that the presence of hydrocarbons in the Primrose wells drilled over a salt dome could be explained by local generation in the thermally immature sedimentary rocks. Salt is more conductive of heat than are other sedimentary rocks; therefore, a salt dome may be hotter than the surrounding rocks. Perhaps local gas generation over such a heat anomaly due to the presence of a salt dome explains the occurrence of gas in Block 598. Certainly, gas-generating source beds, including coal beds, are present nearby in the COST B-2 well. On the other hand, Dow (1978) points out that most of the Louisiana Gulf Coast production is from thermally immature rocks, and oil must have migrated vertically from more mature source beds at depth. He cites Frey and Grimes (1970) who concluded that vertical pathways for oil and gas migration are provided by deep-seated faults and piercements (salt domes) with their associated fracture systems. Dow also cites Young et al. (1977) who determined that an average of 11,000 feet (3,353 m) of vertical migration of oil has taken place in the Gulf Coast. Further studies will be required to determine whether the gas discovered by Texaco was generated locally or migrated from a deeper, more thermally mature portion of the basin.

The Deeper, Undrilled Part of the Basin

If significant vertical or lateral migration of hydrocarbons has occurred in the Baltimore Canyon trough, what is the nature of the source rocks at depth? What is the nature of the rocks interpreted as carbonate-evaporite (?) facies (Figure 5) underlying the clastic nonmarine to marginal marine facies of the Upper Jurassic-Lower Cretaceous? Does the latter facies become more marine farther downdip or along strike thus favoring oil production in the oil-generating zone beginning at depths of about 11,000 feet (3,353 m)? What is the extent of the reef-like structures shown in Figure 5? Have source beds with permeable pathways to the "reefs" been buried deeply enough for hydrocarbons to have been generated?

Drill hole data in the Baltimore Canyon trough are not available to answer most of the above questions. Dow (1978) concluded that rocks beneath the present continental slope and rise are thermally immature and cannot be oil or gas source beds. This would rule out the possibility of commercial accumulations of hydrocarbons in the "reef" type of stratigraphic trap shown in Figure 5, unless significant vertical migration from deeper oil- or gas-generating zones occurred. Based on analyses of at least three seismic lines (USGS lines 2, 5, and 6) Schlee et al. (1976) infer the presence of reef-like buildups under the northern Baltimore Canyon trough. Because they are beneath deep slope waters these "reefs" may not be explored for some time unless deep water production technology is further developed.

The deeper carbonate-evaporite (?) facies under the shelf region of the Baltimore Canyon trough could, if of marine origin, contain oil-generating source beds. These rocks are buried deeply enough for oil or gas to have been generated. In the Scotian basin of offshore Nova Scotia, rocks of this age and with similar lithologies are not as deeply buried and have been drilled extensively.

Purcell *et al.* (1978) report that these rocks are in the marginally mature zone and that they are dominated by gas-prone source rocks. They point out, however, that good oil source rocks are present in the Sable Island 4-H-58 well where prevailing marine conditions occurred in the Verrill Canyon Formation of Jurassic age. They suggest from this that undrilled, deeper prospects in the Scotian basin could have good potential for oil. However, unlike the situation for the OCS of the United States, no off structure Continental Offshore Stratigraphic Test (COST) wells have been drilled on the Canadian shelf, and this potential has not been tested (L. Jansa, personal communications).

CONCLUSIONS

The available data through 1978 from the area of the Baltimore Canyon trough currently being explored are sufficient to establish that most of the geologic criteria necessary to the accumulation of hydrocarbons have been met. If oil and/or gas were generated within the basin there are both structural and stratigraphic traps as well as reservoir and sealing beds to fulfill the requirements for the migration and retention of these fulid hydrocarbons. The most promising areas where potential traps exist are now leased (Figure 3; Appendix A) and are being drilled. Texaco's discovery of natural gas on one of these leases indicates that, at least for the structure being drilled, the generation of gaseous hydrocarbons from source beds did occur contemporaneously with or after the development of the trapping mechanism. Elsewhere, seven dry wells have been drilled (Figure 3), but many more will be required to test the timing of fluid hydrocarbon generation with entrapment for the structures being explored.

The most critical unknown factor is whether source rocks exist in the thermally mature part of the sedimentary rock section. Data from the COST B-2 well indicate that only potential source beds are present, i.e., sufficient kerogen is present but the temperature was not high enough for a long enough period of time for the generation of hydrocarbons. If this condition of thermal immaturity is typical of the whole basin, generation of fluid hydrocarbons would only have occurred at depths greater than those presently being drilled (20,000 feet (6,095 m) or so) or in areas of locally higher geothermal gradients (Texaco discovery?), assuming, of course, that source beds are present in these regions of thermal maturity.

It appears that if commercial discoveries are made they will likely be of natural gas rather than oil. At the depths of expected thermal maturity, the rocks that might contain sufficient quantities of preserved organic matter for the generation of hydrocarbons most likely would have produced gas rather than oil for two reasons. First, the organic matter present in the rocks at these depths is primarily of terrestrial origin, thus capable of yielding only gas. Secondly, if oil-prone source rocks are present at these depths, the oil generation phase would have been succeeded by the peak zone of gas generation; therefore, gas, not oil, would have been generated as the stable phase at these depths.

Even though the results of drilling a few wells so far have not been entirely encouraging, the oil and gas potential of the vast volume of sedimentary rock in the Baltimore Canyon trough is still unknown. The area leased so far, in size approximately 42 percent of the land area of the State of Delaware, has not yet been adequately tested. Because of the high cost of drilling wells ($10-15 million per well) in this region there must be a limit on their number if discoveries are not made. If the basin has no commercial deposits of oil or gas, the petroleum industry may be able to determine this before 100 wells have been drilled. Over one hundred wells have been drilled in the last ten years of exploration on Canada's Scotian Shelf and Grand Banks without any reported commercial discoveries (Bujak et al., 1977). Because the Canadian shelf appears to be geologically similar to the North and Middle Atlantic OCS of the United States, the petroleum industry may interpret the disappointing results of exploration in the Canadian area as indicative of conditions in the U. S. Atlantic offshore. On the other hand, if commercial discoveries are made in the Baltimore Canyon trough, a long period of exploration and development lasting perhaps thirty or more years will follow. In the Louisiana Gulf Coast offshore area over 16,500 exploratory and development wells have been drilled since the 1940's (API, 1978) and about 16 percent success is recorded for exploratory wells and 75 percent for the development wells. For that area Henton (1978) reports 26 fields each with recoverable reserves in excess of 100 million barrels of oil.

In offshore areas, the petroleum industry must find giant oil fields of 100 million or more barrels of oil or gas equivalent in order to offset the high costs of leasing and drilling. Drilling statistics indicate that between 1949 and 1968, it took more than 1,000 new-field wildcat wells to find a field of 50 million or more barrels of oil or the equivalent in gas (AAPG, 1975). To lessen these odds, only the largest and most favorable geologic structures capable of containing giant oil fields are being drilled in the Baltimore Canyon trough. If giant fields are not discovered shortly, interest in further exploration of the basin will probably decline, unless additional structures are found. In light of this it will be some time before the full potential of the Baltimore Canyon trough is known.

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APPENDIX A

OWNERS OF MID-ATLANTIC

OCS SALE NO. 40 LEASES

August 17, 1976

Lease No.	OCS Protraction Diagram	Block No.	Lease Owner (lead company)	Bidding Group No. if more than one Company (p. 41-43)	Bid Amount $	No. of bids on block
OCS-A-1	NJ18-3	412	Atlantic Richfield	1	612,000	1
OCS-A-2	NJ18-3	454	Chevron Oil Co.	2	813,000	2
OCS-A-3	NJ18-3	455	Atlantic Richfield	3	2,533,000	7
OCS-A-4	NJ18-3	456	Exxon Corp.		3,212,000	7
OCS-A-5	NJ18-3	457	Chevron Oil Co.	2	5,102,000	4
OCS-A-6	NJ18-3	497	Chevron Oil Co.	2	320,000	1
OCS-A-7	NJ18-3	498	Shell Oil Co.	4	2,199,000	6
OCS-A-8	NJ18-3	499	Exxon Corp.		22,358,000	8
OCS-A-9	NJ18-3	500	Exxon Corp.		51,308,000	9
OCS-A-10	NJ18-3	501	Exxon Corp.		11,108,000	8
OCS-A-11	NJ18-3	502	Continental Oil		3,709,440	4
OCS-A-12	NJ18-3	541	Chevron Oil Co.	2	320,000	1
OCS-A-13	NJ18-3	542	Shell Oil Co.	4	6,399,000	7
OCS-A-14	NJ18-3	543	Chevron Oil Co.	20	65,222,000	8
OCS-A-15	NJ18-3	544	Mobil Oil Corp.	24	75,707,400	6
OCS-A-16	NJ18-3	545	Atlantic Richfield	27	51,111,000	8
OCS-A-17	NJ18-3	546	Continental Oil		4,619,520	5
OCS-A-18	NJ18-3	554	Murphy Oil Corp.	17	209,000	2

APPENDIX A (continued)

Lease No.	OCS Protraction Diagram	Block No.	Lease Owner (lead company)	Bidding Group No. if more than one Company (p. 41-43)	Bid Amount $	No. of bids on block
OCS-A-19	NJ18-3	585	Chevron Oil Co.	2	320,000	1
OCS-A-20	NJ18-3	586	Shell Oil Co.	9	4,799,000	8
OCS-A-21	NJ18-3	587	Mobil Oil Corp.	30	59,688,800	8
OCS-A-22	NJ18-3	588	Mobil Oil Corp.	32	107,788,600	8
OCS-A-23	NJ18-3	589	Shell Oil Co.	9	42,868,000	8
OCS-A-24	NJ18-3	590	Continental Oil	37	17,745,408	6
OCS-A-25	NJ18-3	591	Continental Oil	37	317,952	1
OCS-A-26	NJ18-3	596	Exxon Corp.		518,000	1
OCS-A-27	NJ18-3	597	Exxon Corp.		208,000	1
OCS-A-28	NJ18-3	598	Texaco, Inc.	22	16,830,000	9
OCS-A-29	NJ18-3	599	Exxon Corp.		1,018,000	3
OCS-A-30	NJ18-3	630	Atlantic Richfield	11	612,000	7
OCS-A-31	NJ18-3	631	Exxon Corp.		17,078,000	10
OCS-A-32	NJ18-3	632	Shell Oil Co.	9	44,695,000	8
OCS-A-33	NJ18-3	633	Continental Oil		23,109,120	8
OCS-A-34	NJ18-3	634	Continental Oil		5,610,240	3
OCS-A-36	NJ18-3	640	Exxon Corp.		86,388,000	9
OCS-A-37	NJ18-3	641	Exxon Corp.		10,058,000	2

APPENDIX A (continued)

Lease No.	OCS Protraction Diagram	Block No.	Lease Owner (lead company)	Bidding Group No. if more than one Company (p. 41-43)	Bid Amount $	No. of bids on block
OCS-A-38	NJ18-3	642	Tenneco Oil Co.	38	8,190,000	8
OCS-A-39	NJ18-3	643	Exxon Corp.		1,508,000	3
OCS-A-40	NJ18-3	674	Murphy Oil Corp.		212,000	1
OCS-A-41	NJ18-3	675	Exxon Corp.		1,318,000	8
OCS-A-42	NJ18-3	676	Houston Oil & Minerals Corp.		5,734,655	7
OCS-A-43	NJ18-3	677	Shell Oil Co.	4	1,210,000	4
OCS-A-44	NJ18-3	678	Continental Oil	37	518,400	2
OCS-A-45	NJ18-3	683	Exxon Corp.		8,068,000	8
OCS-A-46	NJ18-3	684	Exxon Corp.		72,088,000	9
OCS-A-47	NJ18-3	685	Exxon Corp.		2,508,000	5
OCS-A-48	NJ18-3	718	Gulf and Continental		5,310,720	1
OCS-A-49	NJ18-3	719	Continental Oil		4,400,640	1
OCS-A-50	NJ18-3	720	Houston Oil & Minerals Corp.		152,824	1
OCS-A-51	NJ18-3	727	Exxon Corp.		212,000	1
OCS-A-52	NJ18-3	728	Exxon Corp.		1,018,000	2
OCS-A-53	NJ18-3	729	Exxon Corp.		518,000	1
OCS-A-54	NJ18-3	813	Murphy Oil Corp.		212,000	1

APPENDIX A (continued)

Lease No.	OCS Protraction Diagram	Block No.	Lease Owner (lead company)	Bidding Group No. if more than one Company (p. 41-43)	Bid Amount $	No. of bids on block
OCS-A-55	NJ18-3	816	Exxon Corp.		8,688,000	3
OCS-A-57	NJ18-3	855	Houston Oil & Minerals Corp.		1,799,424	1
OCS-A-59	NJ18-3	857	Gulf Oil Corp.	28	10,646,784	6
OCS-A-60	NJ18-3	858	Exxon Corp.		4,212,000	2
OCS-A-62	NJ18-3	899	Murphy Oil Corp.		212,000	2
OCS-A-63	NJ18-3	900	Atlantic Richfield	3	414,000	2
OCS-A-64	NJ18-3	901	Exxon Corp.		618,000	3
OCS-A-65	NJ18-3	902	Exxon Corp.		5,212,000	2
OCS-A-66	NJ18-3	942	Freeport Minerals	19	1,127,000	2
OCS-A-68	NJ18-3	944	Exxon Corp.		7,212,000	2
OCS-A-69	NJ18-3	945	Exxon Corp.		6,312,000	1
OCS-A-70	NJ18-3	985	Mobil Oil Corp.	10	1,102,880	3
OCS-A-71	NJ18-3	986	Mobil Oil Corp.	10	1,311,760	2
OCS-A-72	NJ18-3	987	Chevron Oil Co.	2	319,000	2
OCS-A-73	NJ18-3	988	Exxon Corp.		12,312,000	1
OCS-A-74	NJ18-6	16	Mobil Oil Corp.	10	5,706,950	2
OCS-A-75	NJ18-6	17	Mobil Oil Corp.	10	3,103,260	2

APPENDIX A (continued)

Lease No.	OCS Protraction Diagram	Block No.	Lease Owner (lead company)	Bidding Group No. if more than one Company (p. 41-43)	Bid Amount $	No. of bids on block
OCS-A-76	NJ18-6	18	Murphy Oil Corp.	17	609,000	1
OCS-A-77	NJ18-6	19	Exxon Corp.		418,000	1
OCS-A-78	NJ18-6	61	Murphy Oil Corp.		212,000	1
OCS-A-79	NJ18-6	62	Murphy Oil Corp.		212,000	1
OCS-A-80	NJ18-6	105	Chevron Oil Co.	2	301,000	1
OCS-A-81	NJ18-6	106	Murphy Oil Corp.		212,000	1
OCS-A-83	NJ18-6	142	Exxon Corp.		1,018,000	2
OCS-A-84	NJ18-6	143	Exxon Corp.		508,000	1
OCS-A-85	NJ18-6	184	Shell Oil Co.	48	314,000	2
OCS-A-86	NJ18-6	185	Tenneco Oil Co.		7,264,000	5
OCS-A-88	NJ18-6	187	Tenneco Oil Co.	16	6,167,808	7
OCS-A-90	NJ18-6	228	Shell Oil Co.	48	5,260,000	7
OCS-A-91	NJ18-6	229	Shell Oil Co.	21	31,790,000	9
OCS-A-92	NJ18-6	230	Tenneco Oil Co.	33	23,747,328	9
OCS-A-93	NJ18-6	231	Union Oil Co. of California		16,355,000	8
OCS-A-94	NJ18-6	232	Shell Oil Co.	21	710,000	4
OCS-A-95	NJ18-6	271	Exxon Corp.		2,028,000	1

APPENDIX A

Lease No.	OCS Protraction Diagram	Block No.	Lease Owner (lead company)	Bidding Group No. if more than one Company (p. 41-43)	Bid Amount $	No. of bids on block
OCS-A-96	NJ18-6	272	Shell Oil Co.	48	7,370,000	6
OCS-A-97	NJ18-6	273	Shell Oil Co.	21	35,790,000	9
OCS-A-98	NJ18-6	274	Sun Oil Co. Delaware	15	19,677,800	8
OCS-A-99	NJ18-6	275	Texaco, Inc.	22	33,780,000	7
OCS-A-100	NJ18-6	276	Exxon Corp.		3,722,000	4
OCS-A-101	NJ18-6	277	Houston Oil & Minerals Corp.		467,712	3

Totals: Accepted Bids - 93 Accepted Bonus - $1,127,936,425 No. of Bids - 410

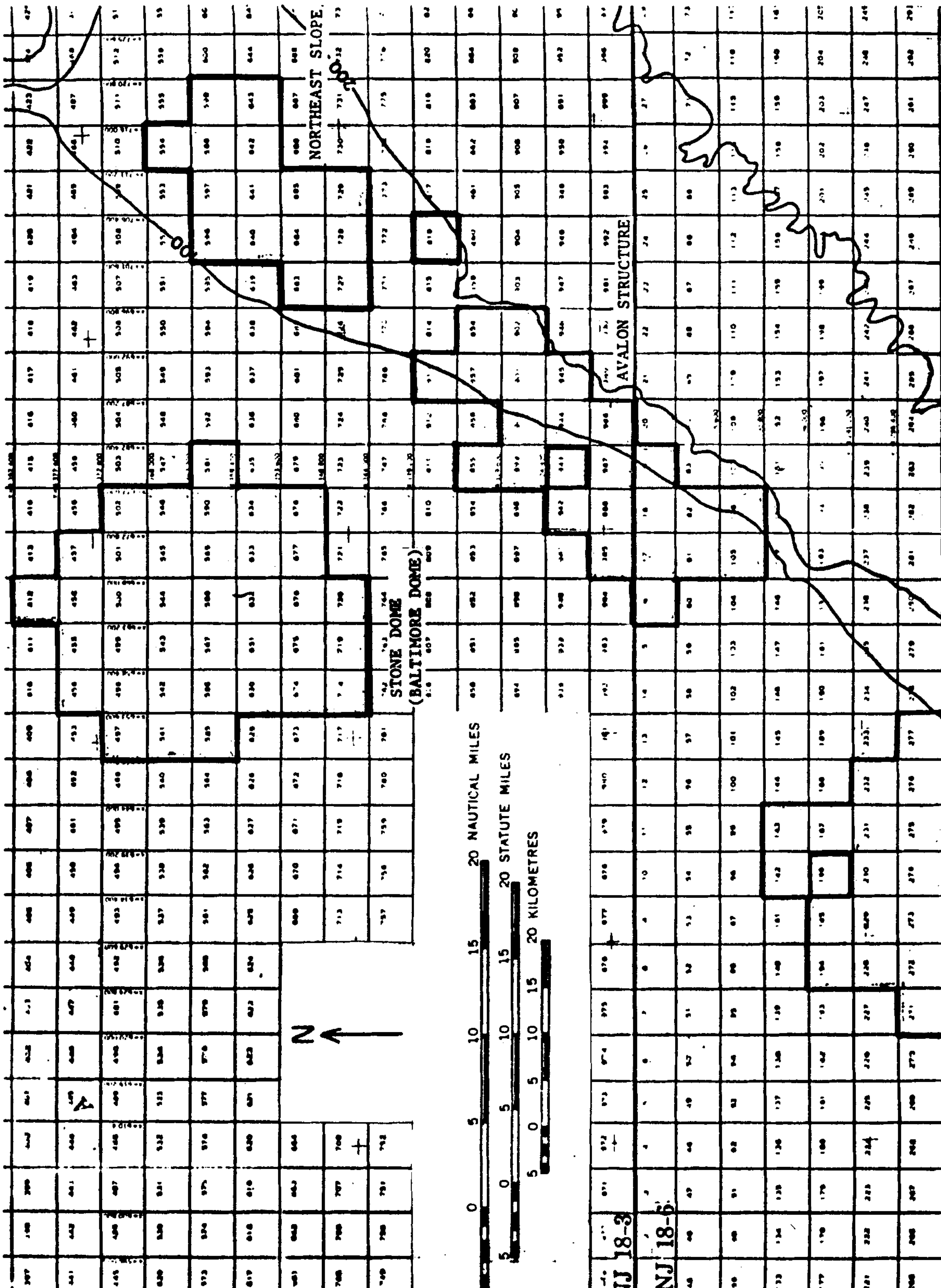
Total Amount Exposed $3,513,411,802

Companies in Bidding Groups

Bidding Group No.	Companies	Percentage of Interest
1	Atlantic Richfield Company	36%
	Chevron Oil Company	36%
	Hamilton Brothers Oil Company	5%
	Ocean Production Company	23%
2	Atlantic Richfield Company	35%
	Chevron Oil Company	35%
	Murphy Oil Corporation	13%
	Hamilton Brothers Oil Company	5%
	Ocean Production Company	12%
3	Atlantic Richfield Company	35%
	Chevron Oil Company	35%
	Murphy Oil Corporation	5%
	Hamilton Brothers Oil Company	5%
	Ocean Production Company	5%
	ICI Delaware, Inc.	15%
4	Continental Oil Company	30%
	General American Oil Co. of Texas	10%
	Shell Oil Company	36%
	Weeks Natural Resources, Inc.	1%
	Cities Service Company	18%
	Santa Fe Minerals Co. - U.S.	1%
	United States Steel Corporation	3%
	Energy Development Corporation	1%
9	Shell Oil Company	30%
	Continental Oil Co.	25%
	General American Oil Co. of Texas	10%
	Louisiana Land & Exploration Co.	15%
	Weeks Natural Resources, Inc.	1%
	Cities Service Company	15%
	Santa Fe Minerals Co. - U.S.	1%
	United States Steel Corporation	2%
	Energy Development Corporation	1%
10	Mobil Oil Corporation	25%
	Getty Oil Company	23%
	Amerada Hess Corporation	15%
	Diamond Shamrock Corporation	14%
	Sun Oil Company, Delaware	23%

Bidding Group No.	Companies	Percentage of Interest
11	Atlantic Richfield Company Kerr-McGee Corporation Chevron Oil Company ICI Delaware, Inc.	35% 15% 35% 15%
15	Sun Oil Company, Delaware Getty Oil Company Mobil Oil Corporation Amerada Hess Corporation Diamond Shamrock Corporation Anadarko Production Co.	23% 20% 20% 15% 14% 8%
16	Tenneco Oil Company Gulf Oil Corporation	50% 50%
17	Murphy Oil Corporation Ocean Production Company	50% 50%
19	Freeport Minerals Co. Transco Exploration Co.	50% 50%
20	Atlantic Richfield Co. Kerr-McGee Corporation Chevron Oil Company Hamilton Brothers Oil Company ICI Delaware, Inc.	35% 10% 35% 5% 15%
21	Shell Oil Company General American Oil Co. of Texas Weeks Natural Resources, Inc. Cities Service Company Santa Fe Minerals Co. - U.S. United States Steel Corporation Energy Development Corporation	62% 10% 1% 18% 1% 5% 3%
22	Texaco, Inc. Freeport Minerals Co. Skelly Oil Company Allied Chemical Corporation Transco Exploration Company	48% 10% 20% 12% 10%

Bidding Group No.	Companies	Percentage of Interest
24	Mobil Oil Corporation Getty Oil Company Amerada Hess Corporation Sun Oil Company, Delaware Anadarko Production Co. PanCanadian Petroleum Co.	25% 23% 15% 23% 10% 4%
27	Atlantic Richfield Co. Chevron Oil Company Hamilton Brothers Oil Company ICI Delaware, Inc.	39% 39% 7% 15%
28	Gulf Oil Corporation Aminoil Resources, Inc. Tenneco Oil Company	60% 25% 15%
30	Mobil Oil Corporation Getty Oil Company Amerada Hess Corporation Anadarko Production Co. Sun Oil Company, Delaware	25% 23% 15% 14% 23%
32	Mobil Oil Corporation Amerada Hess Corporation Anadarko Production Co. Sun Oil Company, Delaware PanCanadian Petroleum Co.	46% 20% 16% 15% 3%
33	Tenneco Oil Company Gulf Oil Corporation The Superior Oil Company Canadian Superior Oil U.S.Ltd. American Petrofina Exploration Co.	38% 38% 10% 5% 9%
37	Continental Oil Company Cities Service Company	63% 37%
38	Tenneco Oil Company Aminoil Resources, Inc.	65% 35%
48	Shell Oil Company General American Oil Co. of Texas Weeks Natural Resources, Inc. Santa Fe Minerals Co. - U.S. United States Steel Corporation Energy Development Corporation	77% 10% 1% 2% 7% 3%



Map of OCS Sale No. 40 Leases

APPENDIX B

Conversion Factors

The following factors may be used to convert data from the English Units published herein to the International System of Units (SI).

Multiply English units	By	To obtain SI units
	Length	
inches (in)	25.4	millimeters (mm)
inches (in)	0.0254	meters (m)
feet (ft)	0.3048	meters (m)
miles (mi)	1.609	kilometers (km)
	Temperature	
degrees Fahrenheit (°F)	(°F x 5/9) -32	degrees Centigrade (or Celsius) (°C)