DEPARTMENT OF THE INTERIOR

U.S. GEOLOGICAL SURVEY

Estimation of Condensate in the Assessment of Undiscovered Petroleum Resources

by

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ABSTRACT

Assessment of undiscovered condensate in a play seems best made by first considering the amount of undiscovered nonassociated gas volume, and then estimating the yield of condensate per unit gas, usually in barrels of condensate per million cu ft of gas (BC/MMCFG).

Gas-condensate and nonassociated gas may be generated at mature levels (in the oil window), largely from type III kerogen. Accumulations in the West Siberia basin and in many deltas are examples of such accumulations.

Gas-condensate and nonassociated gas may migrate from thermally mature(oil-window) source shales and become separated from the larger oil molecules, which are inhibited from primary migration by lesser solubility in gas or pore-water and/or by pore size, which allow only the passage of gas and condensate-size molecules; by gas solution and entrainment, or by diffusion where source shales are geopressured. The Arun Field of North Sumatra basin, Indonesia, and the Mahakam delta, Kutei basin, Indonesia, appear to have gas-condensate accumulations of this origin.

The greatest volume of gas-condensates probably forms when the light ends of reservoired oil are dissolved or partially dissolved at depth by gas. This (so-called) secondary condensate is the preferentially dissolved light ends of the oil, the amount and the molecular weight of the oil molecules dissolved depending largely on the pressure (i.e. depth). Large condensate fields of this origin extend over many areas of Russia, of which the North Caspian basin is the best example. Another secondary condensate forming process is the exsolution of the lighter ends of reservoired oil to the associated gas when gas is released from the reservoir. Some Gulf Coast gas-condensates are formed in this way.

Substantial gas-condensate accumulations result from the thermal cracking of reservoired and dispersed oil in the over-mature or wet-gas zone. Examples of this are the gas-condensate fields of the Interior Salt basin in southwestern Alabama.

The generation of most condensate is by any of these four general processes which are described. Analog basins accompanied by condensate yield figures are given for each process. It is emphasized that these analog basins have near optimum conditions, and basins being compared should be appropriately discounted depending on the relevant geologic conditions. Particular regard should be paid to biodegradation and to dilution of the nonassociated gas volume by dry gas.

INTRODUCTION

Purpose of Study

In the assessment of undiscovered petroleum resources, condensate is often neglected since it is deemed a small percentage of the total petroleum resource, or because there is little information upon which to base an estimate.

Condensate accumulations can be quite large, amounting to billions of barrels in gas-condensate fields of Russia and the Middle East. The purpose of this paper is, after briefly reviewing the processes leading to condensate concentration, to describe basins which are deemed representative analogs of the principal geologic settings and processes that have produced most of the world's condensate accumulations.

Problems and Methods of Study

An element which is often difficult to deal with in assessing the undiscovered oil and gas of a basin is the amount of natural gas liquids (NGL) of which condensates are usually the major part. This difficulty is due partly to the lack of uniform definitions and reporting in production statistics, and to the frequent failure to distinguish or report natural gas liquids when they occur along with oil.

NGL is a mixture of hydrocarbons present as vapors in a natural gas reservoir, which condense to liquids at or near surface conditions. The term, natural gas liquids, as presently used, includes such liquids as condensates, natural gasolines, and liquified petroleum gas (LPG) (which is not a liquid at surface conditions).

Condensate may include all or part of the other liquids; its composition depends on how much of the petroleum mix was gaseous in the reservoir. The reservoir pressure and temperature govern the molecular weight of the hydrocarbon molecules in a gaseous state, as well as the amount and molecular weight of the light oil molecules which may be in gaseous solution. For instance, in deep accumulations, such as the Maloosa condensate field in Italy, hydrocarbons as heavy as C_{18} appear to be in a gas phase at 20,000 ft (Hunt, 1979). In general, however, condensate composition includes some butane and all or part of the gasoline fraction. Natural gasoline is approximately iso-pentane and heavier, coinciding approximately with the normal gasoline range (mainly C_5 to C_{10}). LPG is propane, N- and iso-butane. Figure 1 indicates the approximate distribution of N-alkanes, iso-alkanes, cyclo-alkanes, and aromatics in these liquids.

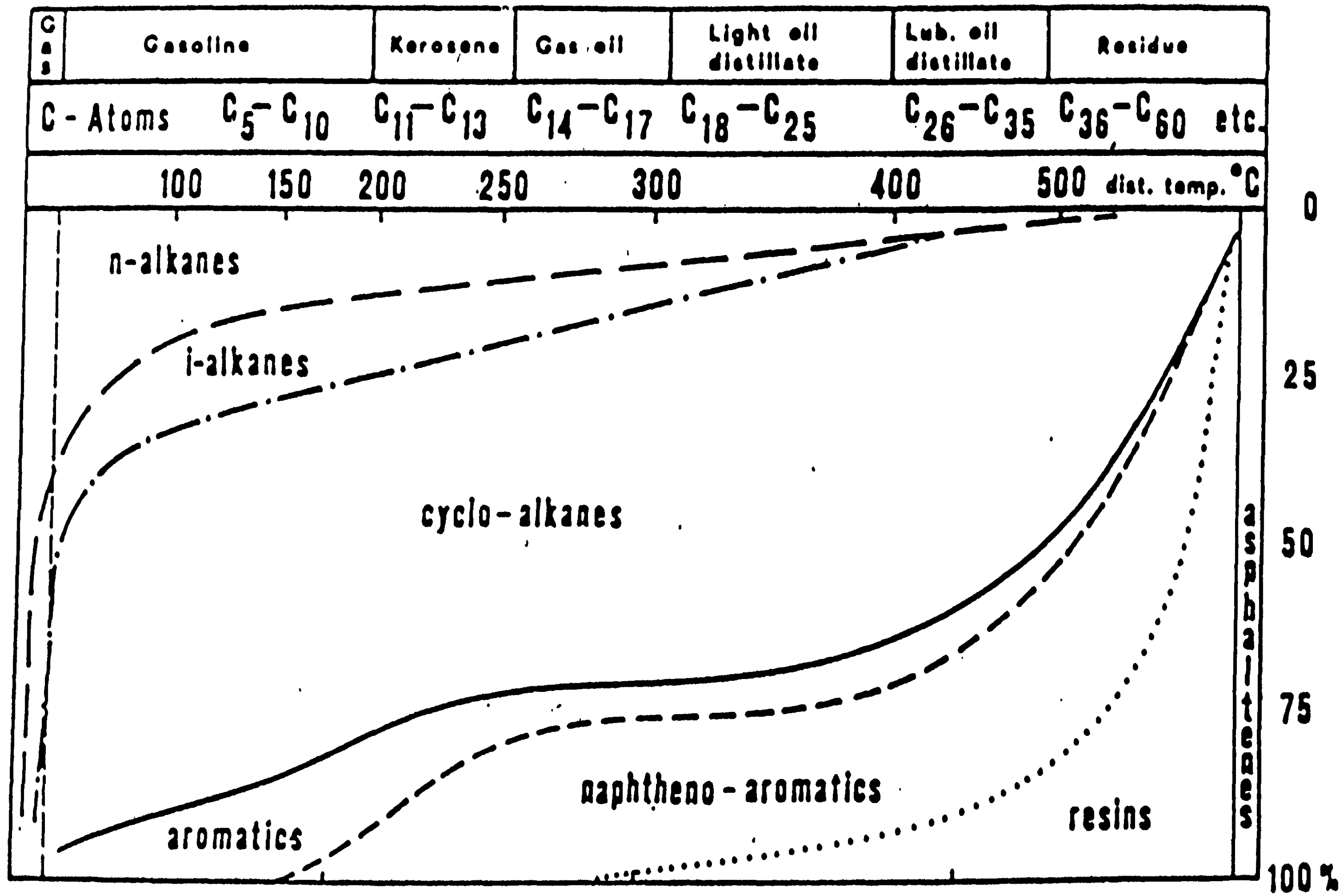

Figure 1.--Diagram showing distribution of various petroleum compound classes in a typical medium crude oil (after Bestougeff, 1967; from Tissot and Welte, 1978).

NGL is removed from the gas flow first by separators, usually at the field or "lease," and then by gas processing plants. Most of the condensate is removed by the separators and the rest of the condensate plus the LPG is recovered at the processing plant. In most U.S. oil fields, the liquid collected at the lease separators, mostly condensate, is commingled with oil and therefore unreported in most U.S. statistics. The liquid collected at the plant, largely LPG and some condensate, is usually reported as the NGL. The resulting NGL to associated gas ratios vary widely. NGL to gas ratios of new oil fields in the U.S., according to R. Nehring (NRG Associates, Inc.,1986), range from 15 to 95 barrels NGL to a million cu ft of gas (apparently averaging around 30 BBLS/MMCFG).

These reporting problems are concentrated in areas where oil and condensate are produced from the same fields. Although condensates are frequently found in gas caps of oil fields, non-associated gas fields contain 75 percent of the world's gas (Blackstock and others, 1968) and consequently most of the gas condensate; I estimate that 80 to 90 percent of the world's separately reported condensate production is from non-associated gas and gas-condensate fields. Consequently the study is limited to non-associated gas and gas-condensate fields. By so doing, most of the condensate is accounted for without dealing with ambiguous reporting problems. This limitation would not diminish an overall petroleum resource assessment which included an oil-associated play since condensates are usually included with the oil in the petroleum statistics of the play or in the most relevant analogs to the play.

In assessing the quantity of condensate in a basin, the first step would be to estimate the volume of nonassociated gas and the second step would be to determine the condensate richness or yield of the gas. The condensate yield, expressed in barrels per million cu ft of gas (BC/MMCFG) or cu cm of condensate per cu ft of gas (cm^3/m^3), is usually determined by local production data or by comparison with geologically analogous basins. This condensate yield is the key factor in making assessments of a new basin since it varies widely depending on the geologic setting, thermal maturation, and migration patterns This report describes analog basins whose condensate yield may then be compared to geologically similar basins under assessment.

Definition of Condensate

Usually condensate only exists as such at the surface. It is a transparent to light-colored liquid with the viscosity and appearance of gasoline. Since it was once a gas, the heavy residues, the dark asphaltenes, and resins are missing. Because it is composed of light, more volatile molecules, it is less dense, usually with a specific gravity of less than .78 or API gravity of more than 50^{o}. Recognized condensate is found with abundant gas; as a rule of thumb, when the gas-oil ratio (GOR) of a produced petroleum mixture exceeds 3,000 cu ft of gas per barrel (CFG/BO), it is usually assumed that the liquid is a condensate rather than oil. The molecular composition of the condensate varies as discussed under "Problems and Methods of Study". Condensates may also be formed by retrograde condensation in the reservoirs when gas-condensate migrates to lower pressured reservoirs or gas-condensate reservoirs lose pressure. These condensates are usually not distinguished from light oil, and are produced as oil and therefore not relevant to our assessment process. An example of this is the oil fields of North Sumatra which appear to be largely reservoir condensates.

The Organization of Petroleum Exporting Countries (OPEC) adopted a stringent definition of condensates and NGL effective January 1, 1989. Liquids with API gravity of 50^{o} or higher, a gas:liquids ratio of 5,000:1 or more, or a C_7+ fraction of 3.5 percent mole weight or less are automatically classified as condensates. There is a lower limit of 45^{o} gravity, less than 5,000:1 gas liquids ratio, or a C_7+ fraction of not more than 8 percent mole weight. There are various specific requirements for liquids between the two limits (Oil and Gas Journal, 1989).

PRINCIPAL TYPES OF GAS-CONDENSATE ACCUMULATION

Gas-condensate accumulations may be grouped according to what is believed to be their formation processes. There appear to be four principal processes:

1. Humic generation. Gas and gas-condensate are generated in the thermal zone of oil generation, but with little or no accompanying oil since the humic organic matter (largely type III kerogen) generates mainly gas and gas-condensate.

2. Primary migration fractionation. Gas and gas-condensate are generated along with oil in the thermal zone of oil generation but separated from the oil by primary migration fractionation through shales.

3. Secondary condensate. Secondary gas-condensate is formed when (1) dry allochthonous gas migrates into an oil-filled trap, dissolves out the lighter ends of the oil, forming gas-condensate, and often buoyantly displacing the oil from the trap, and (2) the lighter ends of reservoired, saturated oil are separated from the oil by exsolution, forming a gas-condensate vapor when saturated gas is released from the reservoir, i.e. evaporative fractionation.

4. Cracked oil and kerogen. Gas and gas-condensate is formed by the cracking of reservoired oil, disbursed oil and kerogen molecules in the thermally over-mature, or wet gas zone.

Examples of gas-condensate accumulations will be discussed under the above grouping. It should be noted, however, that all accumulations do not neatly fit these categories since in many cases, more than one process may be operating, e.g. delta accumulations may be affected by the first two and possibly the third process.

PROCESSES OF GAS-CONDENSATE GENERATION AND ANALOG PROVINCES

Humic Source

General

Type III kerogen may generate condensate along with gas from the main oil generation zone of termal maturity. Under certain conditions, however, especially abundant type III kerogen will generate considerable oil (i.e. South Sumatra, Northwest Java, Mahakam delta, Indonesia), but usually it generates mainly nonassociated gas and gas-condensate. The condensate yield from type III kerogen increases at the thermal maturity level corresponding to the main oil generating zone. Examples of gas and gas-condensate generated from Type III kerogen are those in the Neocomian reservoirs of western Siberia and in the deltaic sands of the Mahakam, Niger, and Gulf Coast Tertiary deltas.

West Siberia: USSR.--The western Siberian gas-condensates in Neocomian reservoirs are associated with gases, the methane carbon of which has a $\delta^{13}C$ average of -43 $^{o}/oo$ and the composition, C_1/C_1-C_4, of approximately .88 (Grace and Hart, 1986). These condensates, according to Goncharov (1985), have relatively high pristane-phytane ratios and some predominance of odd-numbered carbon molecules. These parameters indicate terrigenous (type III kerogen) and early mature to mature source suggesting the Middle and Early Jurassic Tyumen Suite (J_1+J_2), which is partly in and below the main oil generating zone in the area of Urengoy and southward (fig. 2), and is of terrestrial origin. (It should be noted that the Prasolov and others (1981) indicate $\delta^{13}C$ of -39.7 $^{o}/oo$ for the Neocomian gases and -47 $^{o}/oo$ for the overlying dry, biogenic gas of the Cenomanian. Both these values appear heavy and inconsistent with the other geochemical parameters cited, and with the biogenic nature (universally lighter than the -55) of the shallow Cenomanian gas). The average condensate yield from nonassociated gases in the Neocomian reservoir is around 35 BC/MMCFG (Goncharov, 1985).

Deltas: Appreciable gas-condensate concentrations occur in the Tertiary deltas of the Mahakam River, Kalimantan, Indonesia, the Niger delta of West Africa, and the Gulf Coast of the U.S.A. All these deltas appear to have source rocks containing mainly type III kerogen.

Although considerable gas and gas-condensate, formed in the main oil generating zone of deltas, appear to be largely derived from type III kerogen, a complicating factor in this apparent relationship is that in the usual absence of sufficient organic richness to cause oil-phase migration gas and gas-condensate accumulations may also result from fractionation from oil during primary migration. Primary migration in these deltas is discussed in more detail under "Primary migration fractionation".

Gas from the Badak Field of the Mahakam delta has an average δ13C value of -45 $^{o}/oo$, placing its source in the oil window. Condensate production from the Badak complex of fields ranges from 10 to 150 barrels condensate per million cubic ft of gas (BC/MMCFG) (Hadisamita, 1985) and averages 27 BC/MMCFG at the gas plant although one of the deeper fields, Tunu, averages 47.7 BC/MMCFG. Migrating gas from the deeper, dry-gas zone may have decreased the condensate yield.

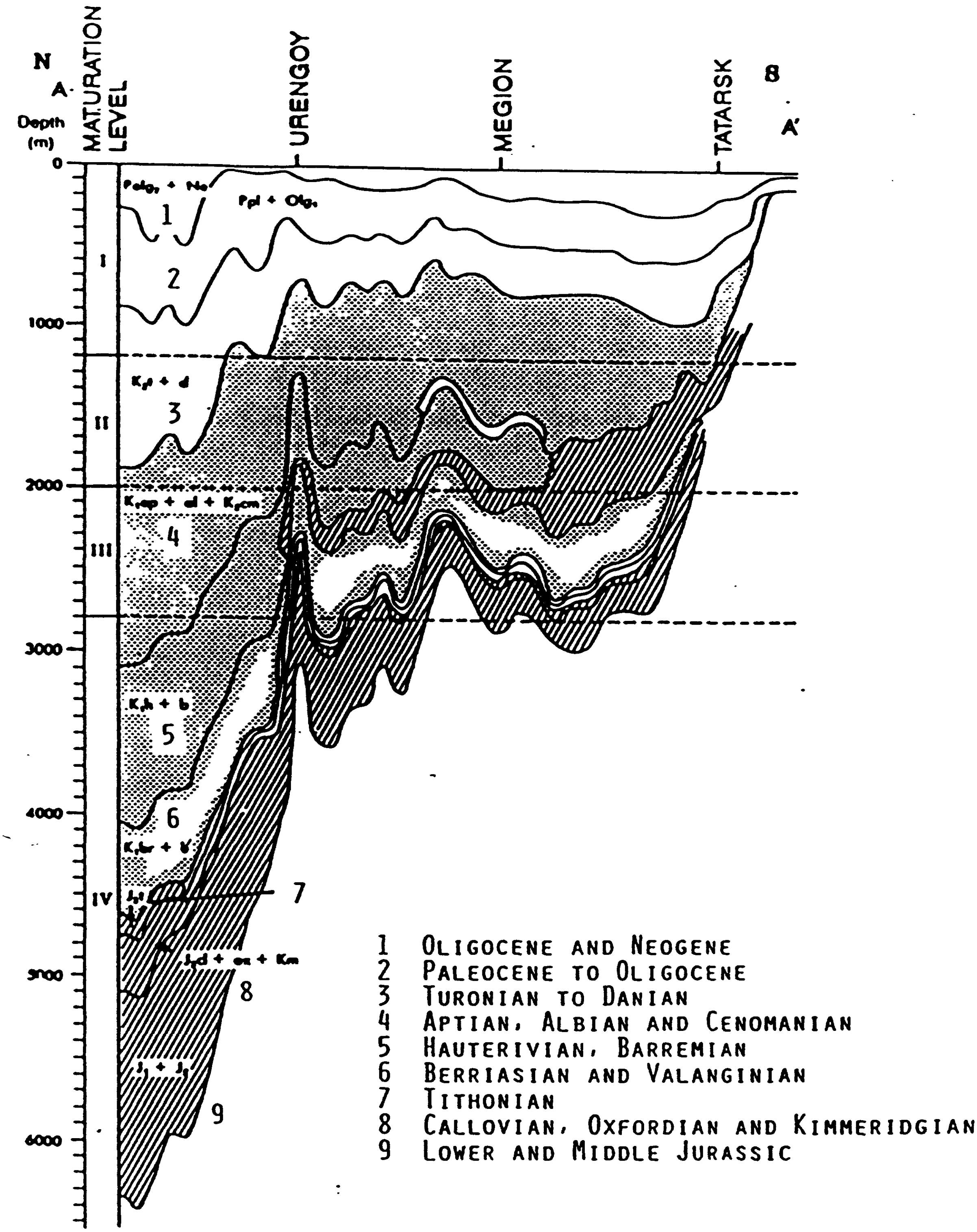

Figure 2.--North-south section across the West Siberian basin showing rate of subsidence and thermal maturity of source beds. Abbreviations refer to periods, epochs, and ages. Maturation Level I is diagenetic zone of biogenic gas generation (R_o<0.25); Level II shallow gas generation (R_o<0.6); Level III main oil generation zone (R_o<1.2); Level IV deep (thermogenic gas generation (R_o>1.2) (modified from Kontorovich, 1984; Kontorovich et al., 1975; by Grace and Hart, 1986).

Gas and condensate from some fields of the Gulf Coast U.S.A., which appear to have been generated in the oil window, have condensate yields of 27 to 48 BC/MMCFG, although other fields are much less and the average condensate yield of the Gulf Coast as a whole is estimated to be 16.7 BC/MMCFG (Attanasi and Haynes, 1983). This lower yield is considerably less than the Mahakam delta, and is ascribed to partial biodegradation in these sediments which are much more accessible to surface water (see "Destruction of Condensate").

It should be noted that although it is believed that a humic source may be a dominant factor in gas-condensation formation in these deltas, (1) migration fractionation and, perhaps to a lesser extent, evaporative fractionation are important factors and will also be discussed, and (2) there is a growing consensus that much of the hydrocarbon, particularly oil, in the Gulf Coast, for example, may have been generated in the prodelta sediments.

Primary Migration Fractionation

General

Migration of petroleum is not fully understood, but it does take place vertically through thousands of feet of shales and sandstones. This is demonstrated in many instances by the position of reservoired petroleum in respect to much deeper source rock. Also pertinent to condensate concentration is the migration pattern; condensate molecules, largely as a gas, are differentiated from the heavier and larger oil molecules under four migration processes: 1) emanation, rather than expulsion, from lean source shale, 2) diffusion through geopressured shale, 3) gas entrainment, and 4) solution in formation water.

1) Emanation from lean source shale. Present consensus is that a considerable portion of oil and gas is expelled from mature or overmature source rocks in a single phase. Although gas and oil may apparently be generated in almost any shale, it appears that the expulsion requires sufficient total mass of organic matter so that enough oil or gas is generated relative to the available pore space. This would permit a single hydrocarbon phase saturation of a path through hydrocarbon-wet pores, or expulsion-created mini-fractures. Where the apparent source rocks are organically lean (0.3 to 1.0 percent TOC) such as in the U.S.A. Gulf Coast deltas, generated gas-condensate may not be in sufficient quantity to be expelled in a gas-condensate phase, i.e. gas bubble, but may diffuse or dissolve in the relatively high-pressure nonsaturated pore water and thus leave the source shale for the porous conduit or reservoir.

Oil, on the other hand, would be of insufficient quantity to migrate from the source shale in a continuous oil phase, and the heavier, less soluble oil would remain there until continued subsidence cracked the oil to gas and condensate-size molecules which could migrate from the source shale by diffusion or solution in pore water. Therefore, source rocks generating largely gas (and gas-condensate) tend to be lean. This direct causal relationship, however, is complicated by the fact that the humic source rocks, which are largely gas-prone, are also generally lean (J. Clayton, pers. commun.). Lean source rock in very great volumes is a particular feature of deltas, which are generally gas (and gas condensate) prone.

2) Geopressure and diffusion. Geopressuring or overpressuring exists only in relatively enclosed, impervious systems, most commonly massive shale bodies. The causes of geopressuring are not wholly understood; however, four principal causes may be 1) unexpelled pore water under rapid depositional conditions, 2) thermal heating of the confined water, 3) decrease of pore-space by loss of load-bearing strength of shale minerals caused by loosening of bounded water (an amount equal to about half the volume of the mineral (Burst, 1969)), and 4) organic matter transformation to oil and gas, causing expansion (Spencer, 1987).

Diffusion appreciably affects only hydrocarbon molecules of less than oil-range size (Leythaeuser and others, 1982); i.e. gas and the lighter condensates. Diffusion requires no pressure differential or fluid flow, but only a concentration gradient; the molecules diffuse through water saturated shale which would entirely hold or entrap oil molecules. Diffusion perhaps represents the only means of transportation of gas (and lighter condensates) through geopressured shale sections (Leythaeuser and others, 1982), leaving the larger molecules imprisoned. Vandenbroucke, and others (1981) found that in the geopressured source shale of the Mahakam delta apparently only one tenth of the C_6-C_9 hydrocarbons, and one third of the C_{10}-C_{14} hydrocarbons remained while all the C_{25}-C_{35} hydrocarbons remained almost unaffected by migration.

Although geopressured lean shale is apparently a complete barrier (seal) to migration other than by diffusion, large petroleum accumulations occur in conjunction with geopressured, lean source shale. It appears that growth faults (largely developed in deltas and accompanying fractures and microfractures) open when pore pressures, increased by equathermal expansion, clay dehydration, and/or by hydrocarbon expulsion, approaches or exceeds the lithostatic pressure. This allows gas and oil to escape the confined system. The openings close again when the pore-pressure is bled down to less than the lithostatic pressure.

3) Gas entrainment. Another method of migration affecting gas-condensate distribution is gas entrainment, i.e., dissolution and carrying along of light-oil and condensate-weight molecules. The gas migrates upward, from the mature and overmature zones, through pores and fractures, dissolving and entraining the lighter ends of generated, but perhaps unexpelled, oil. (Gas may also dissolve the light ends of already reservoired oil, see discussion of secondary condensate). It is well known that the deeper, and therefore more compressed a gas is, the more and heavier oil molecules it can dissolve. Gas entrainment would be the main light oil and condensate carrier within deltas, perhaps in episodic growth-fault and fracture openings, if the source were in the deep pro-delta shales.

4) Gas (including condensates) migration as a solute in formation water. Gas is more soluble than oil in water; in general the smaller the hydrocarbon molecule size, the greater the solubility. The solubility of normal alkanes, for instance, sharply increases for C_{10} and smaller molecules. Therefore, almost all dissolved hydrocarbons in formation waters are of the gas (and gas-condensate) fraction. Subsurface waters in petroliferous basins are estimated to contain 100 to 200 times as much dissolved gas as exists in the reservoirs (Hunt, 1979). Solubility of gas in water increases or decreases sharply with change in pressure. Accordingly, gas accumulation can be very much delayed, or even completely hindered, by the gas being held largely dissolved in deep, high-pressure formation water and only released if and when pressure is reduced by regional uplift, faulting, or other tectonics.

Examples of Primary Migration Fractionation

Examples of migration fractionation accumulation are found in the Arun gas field of North Sumatra and in Tertiary deltas of the world.

Arun Gas-Condensate Field, Indonesia.--An example of this condition is the Arun gas-condensate field of North Sumatra. This field is essentially one carbonate reefal reservoir at a depth of 10,000 ft (fig. 3). It is completely enveloped in an organic-lean (TOC of about 1.0 percent) marine shale of mixed oil and gas-prone kerogen, probably too lean for oil- or gas-phase expulsion. The reservoir is within the lower part of the Main Oil Generating Zone as indicated by a hydrocarbon wetness of .84 and a $\delta^{13}C$ of -42 $^{o}/oo$ (Kingston, 1978). In spite of this, the reservoir contains no oil; only gas and condensate. The surrounding shale is geopressured, and it appears that only the smaller molecules (C_6 and smaller) could have passed through the massive shale to the reservoir by diffusion while the larger oil molecules remain in the shale until continued subsidence cracks them to a size suitable for primary migration, or until the pressure is removed from the shale. The condensate yield of the Arun Field is 53 BC/MMCFG.

Mahakam Delta Fields, Indonesia.--At Badak, and adjoining gas fields, Nilam and Tunu, in the Mahakam delta of eastern Kalimantan, Indonesia, the mature ($\delta^{13}C$ = -45 $^{o}/oo$) source shale is partially within the geopressured zone, the amount of gas and condensate versus oil production being directly proportional to how much of the mature source shale is affected by geopressure. Figure 4 shows two fields, Handil and Badak. Handil is primarily an oil field with gas while the Badak complex is essentially a gas-condensate field with some oil. The top of the geopressured zone is indicated by the "transition zone" and the top of the mature zone by the 0.6 isoreflectance line. It will be noted that the Handel oil field has about 1,500 ft (500 m) of normally pressured mature shale under it while the Badak gas field has relatively little normally pressured mature shale, most of it being geopressured, hindering the migration of the large oil molecules.

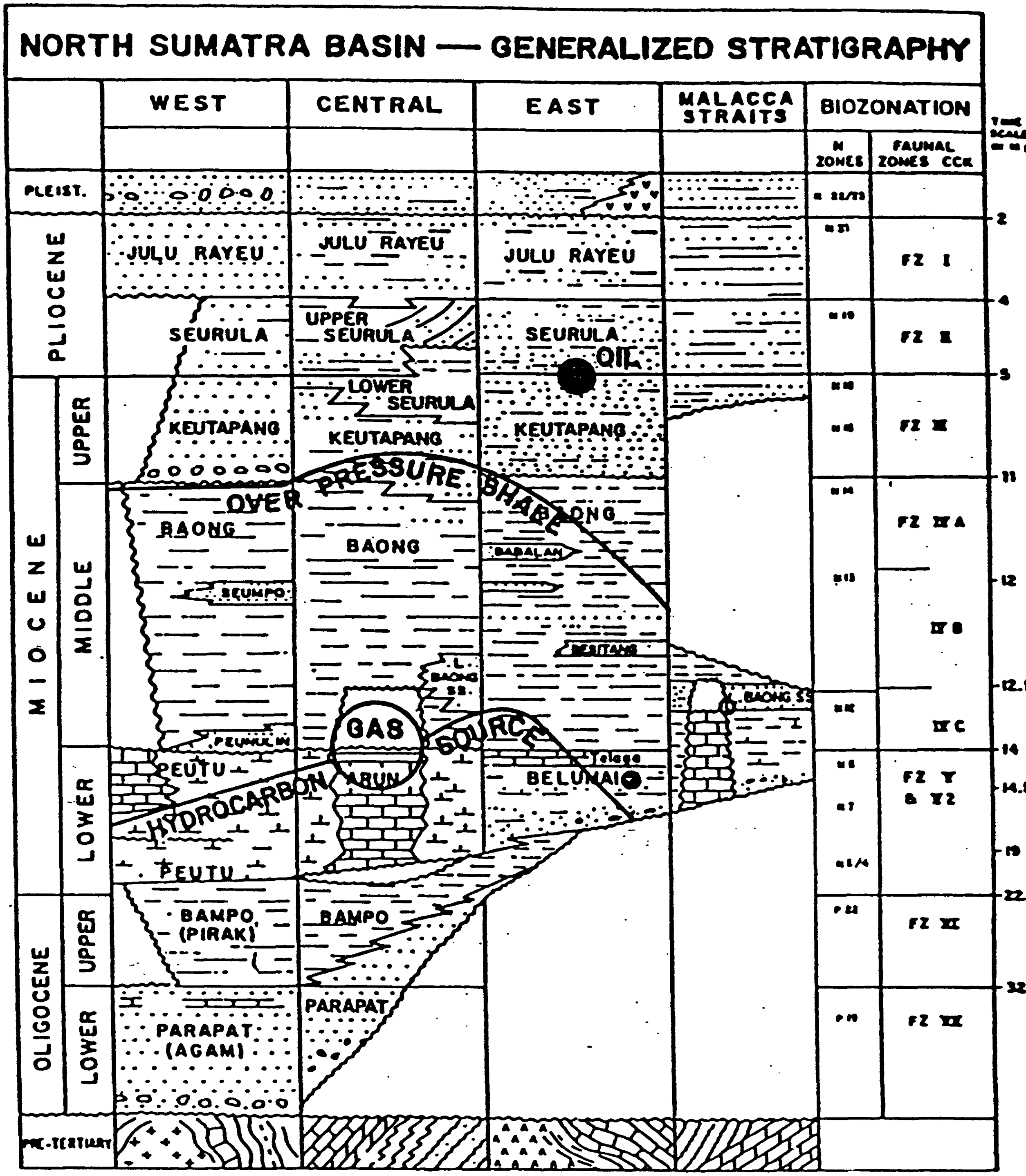

Figure 3.--Diagrammatic stratigraphic cross-section through North Sumatra showing the Arun gas reservoir and its relation to the top of the mature source rock and the overpressured section (from Kingston, 1978).

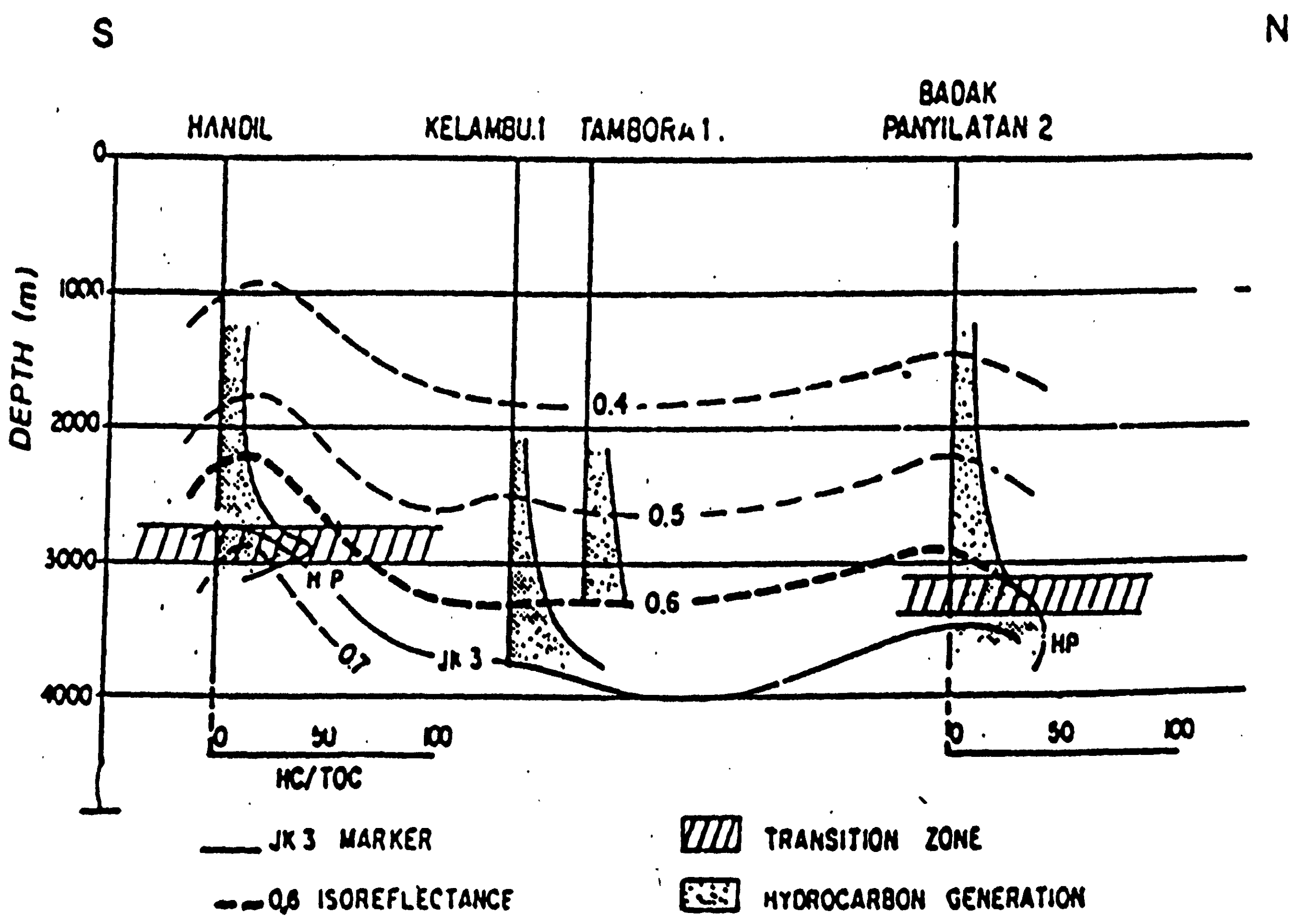

Figure 4.--South to north section through the Handil and Badak fields of the Mahakam delta showing the relation of the mature source rock and the geopressured zone (from Oudin and Picard, 1982).

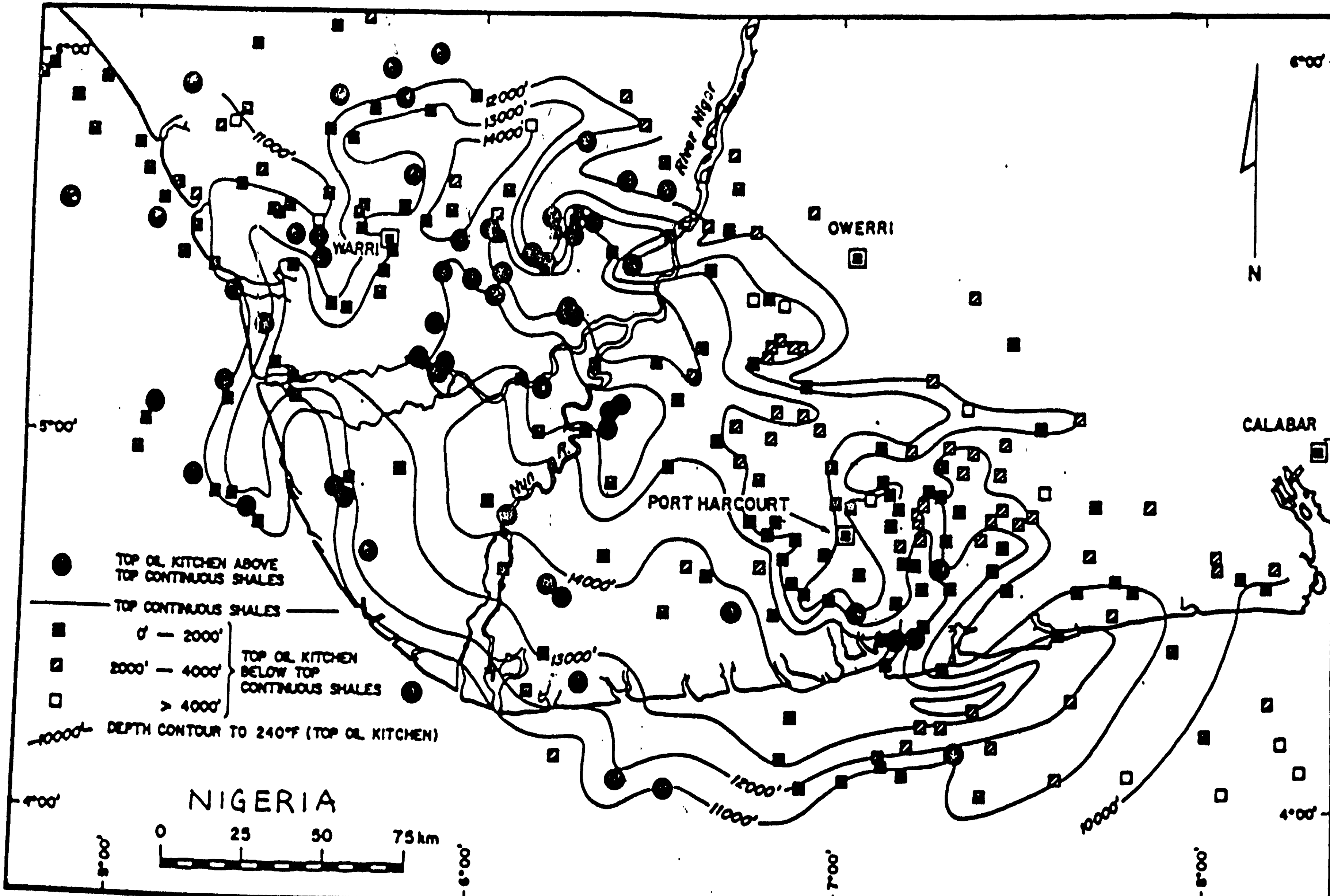

Figure 5. --Map of Niger delta showing the relation of the "oil kitchen" or oil generating zone, to that of the top of the "continuous shales", which is taken to be the top of the geopressured section (after Evamy, et al., 1978).

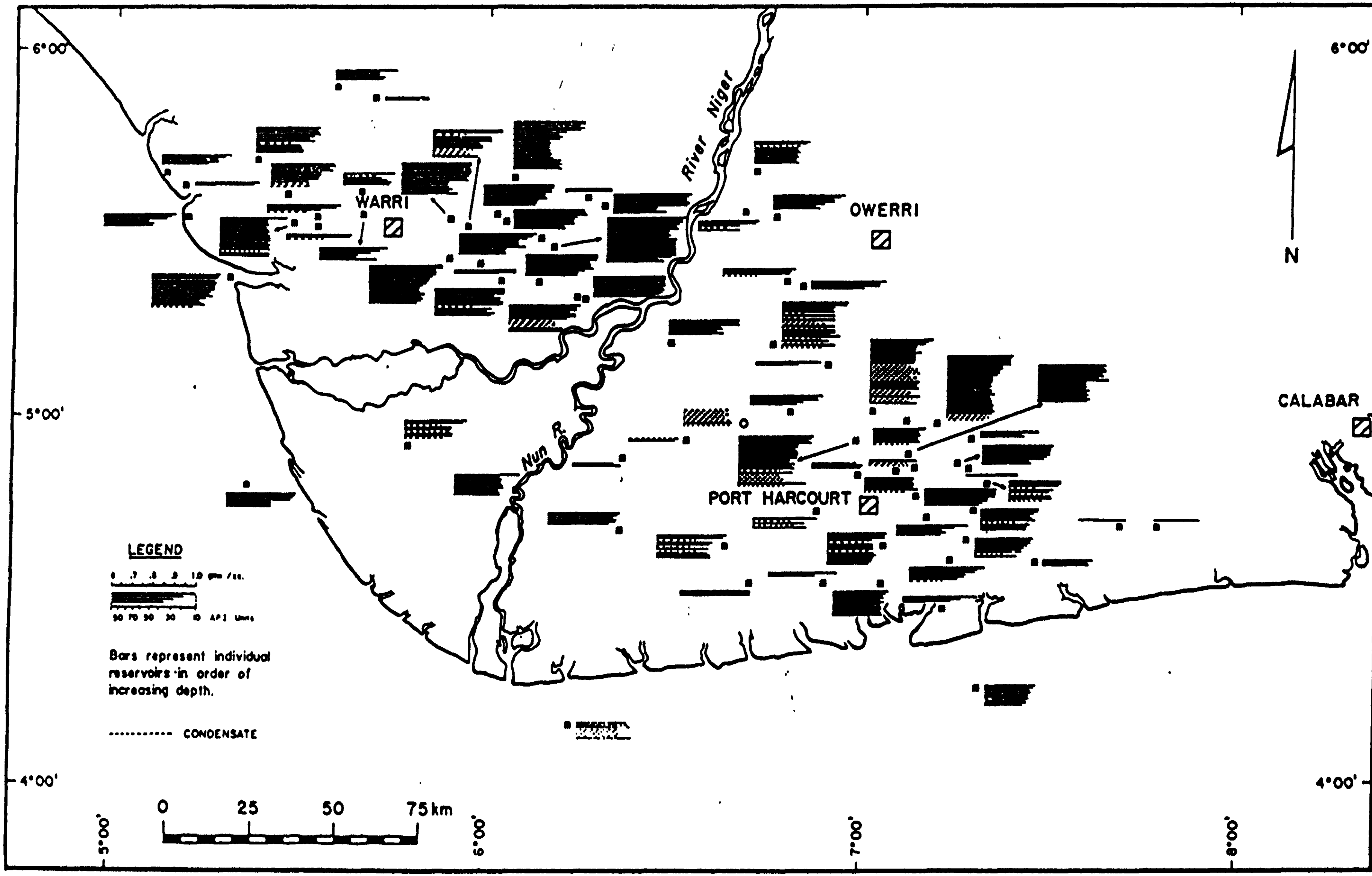

Figure 6.--Map of Niger delta showing the horizontal and vertical distribution of condensate versus oil and generally indicating less condensate where "oil kitchen" is above geopressured "continuous shales" west of the Niger-Nun River (after Evamy et al., 1978).

Above the geopressure zone, the Mahakam delta accumulated oils are lighter and lighter approaching the surface reflecting the higher mobility of the lighter hydrocarbon molecules.

Niger Delta, Nigeria.--The Niger delta has a mixture of oil, gas, and condensate fields. It has the classic delta sedimentation of a largely sandy section prograding over a largely, or "continuous", shale section (Evamy and others, 1978). The "continuous shales", or Akata Formation, appears to be generally geopressured. Figure 5 shows the depth relationship of the "continuous", presumably geopressured, shale and the oil "kitchen" or oil-generating zone. As may be seen, the top of the zone of oil generation (oil kitchen) is generally above the top of the geopressured shale, or "continuous shale", in the northwest, roughly northwest of the Niger-Nun River, and below the top of the geopressured shale to the southeast of the river. Figure 6 indicates the distribution of condensate (and presumably accompanying gas) versus oil. Similar to the Handil field, the condensate (and presumably non-associated gas) production is generally less abundant in favor of oil where the oil generation zone is largely above the geopressured zone (i.e. northwest of the Niger-Nun River), while more condensate production, similar to the Badak field, is where the source rock is largely within the geopressured shale (i.e. southeast of the river).

By analogy with the U.S. Gulf Coast, the average condensate yield for the Niger delta is assumed to be low, about 16.7 BC/MMCFG. The low yield in the Gulf Coast has been ascribed to biodegradation and the mixing of the condensate-yielding thermal gas with dry microbial gas; this also appears to be the case in the Niger delta (see Destruction of Condensate).

Gulf Coast Fields, U.S.A.--The variance of specific gravity of oil and gas with depth in the deltaic sediments of the Gulf Coast is shown by Galloway and others (1982) (fig. 7). It indicates a similar relationship between geopressure, maturation, and condensate formation as in the Mahakam and Niger deltas. The density of the condensate decreases upward through the geopressured zone indicating fractionation during upward migration from a source which is deep within the geopressured zone (and within or below the oil window). The density of the oil, on the other hand, is shown to decrease downward within the geopressured zone, indicating progressive cracking of the heavier oil molecules with increasing maturation, and more significantly, contrary to the gas-condensate trend, the heavy oil molecules are relatively immobile, not migrating from that portion of the oil window which is geopressured. The zone of maximum oil generation, as indicated by the peaking liquid specific gravity, is limited approximately to that relatively narrow interval where the oil generation zone, i.e., the "oil window," is unaffected by geopressure.

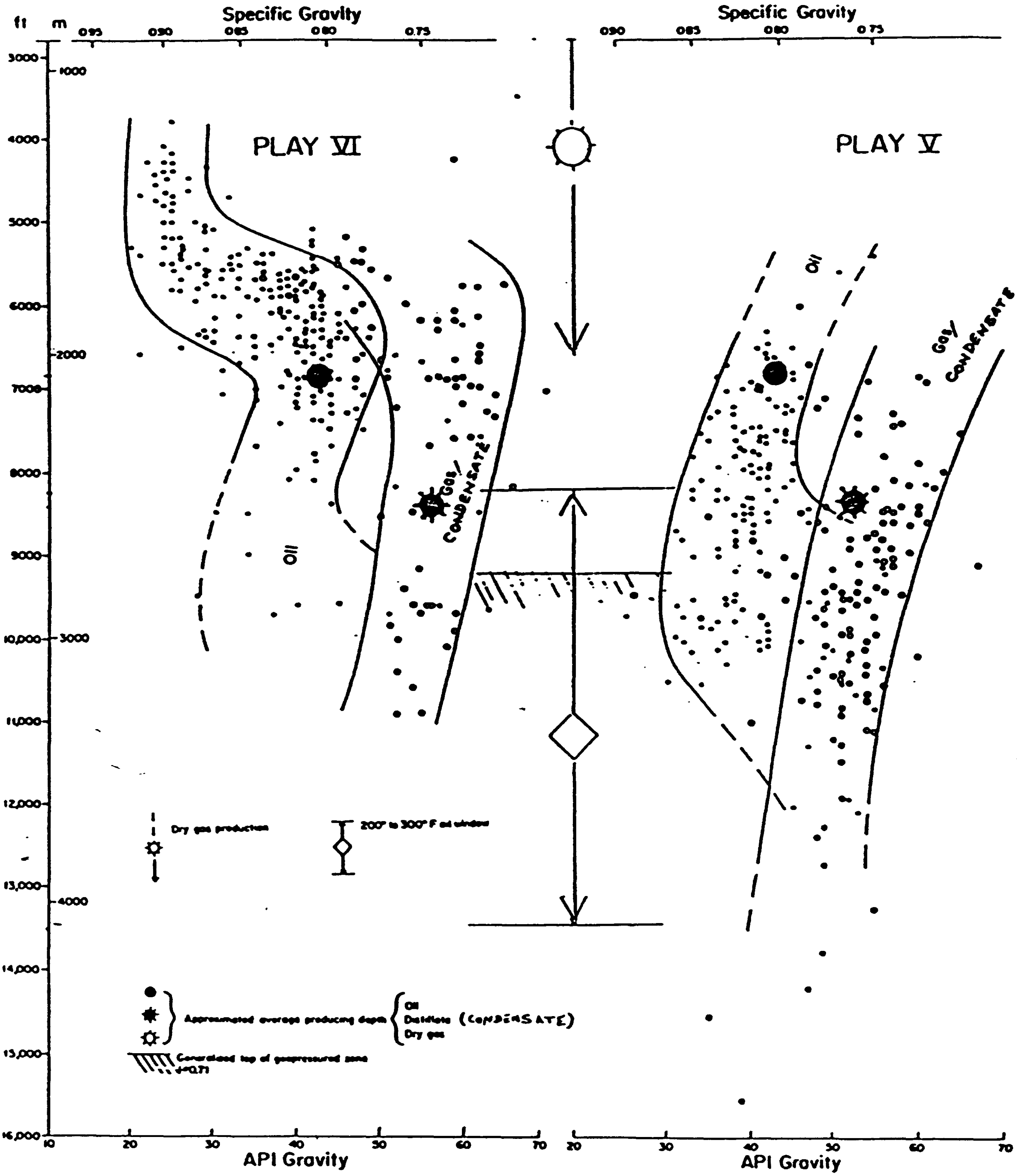

Figure 7.--Representative plots of hydrocarbon liquids density versus depth from Frio Formation accumulations of the northern central Texas coast. Play VI is of the inner coastal plain zone. Play V is of the coast and immediate offshore zone (after Galloway et al., 1982).

There is an alternate interpretation of Galloway and others' data, which should be mentioned. As may be seen, the trend lines drawn in figure 7 indicating decreasing oil specific gravity below 9,000-10,000 ft is based on sparse data. Given the low TOC of the oil window sediments (0.2 to 0.4 percent wt), and of the delta as a whole, a second interpretation might be that both the oil and gas-condensate density changes are on a parallel path of only upward decreasing specific gravity values, implying a common, deep, perhaps pro-delta, source well below the assumed base of the oil window of Galloway and others. This would indicate that migration through the geopressured section must have taken place, perhaps largely by episodic growth-fault channel openings along which upward migration with the indicated fractionation took place. This second interpretation does not necessarily exclude the supposition that oil-window gas-condensate molecules are isolated from the oil molecules by migration fractionation through geopressured source shale. The picture is probably blurred by the effects of indicated episodic growth-fault migration.

The condensate yield from nonassociated gas for the Gulf coast is estimated to be 35 BC/MMCFG, after discounting the shallow dry (biogenic) and biodegraded gas; the overall yield, however, is only 16.7 BC/MMCFG (Attanasi and Haynes, 1983). The sharp increase in density of oil and condensate at a depth of 6,500 ft (fig. 7) is believed to be caused by the destruction of the lighter fractures by biodegradation and dilution by dry biogenic gas (see Destruction of Condensate).

Secondary Gas-condensate

General

Secondary condensates are formed by the solution of light ends of reservoired oil by gas. This takes place principally under two conditions: 1) when allochthonous gas enters oil-occupied traps, and 2) when lighter ends of reservoired oil is separated into a vapor stage with the release of associated gas from the reservoir, i.e., evaporative fractionation.

Allochthonous Gas Reaction with Reservoired Oil

The solution of the light ends of reservoired oil by late-migrating high-pressure gases resulted in the gas-condensate fields of Russia, Canada and elsewhere. Under normal conditions in a subsiding basin, gas is generated later and at greater depth than oil. In its upward migration, the gas, either in a gas phase or aqueous solution, must frequently encounter, and indeed sometimes bypass, previously migrated and accumulated oil. Gas can dissolve increasing amounts and molecular weights of oil as pressure and temperature increase. Sokolov and others (1963), found from laboratory studies, that at a pressure of 5,880 psi (400 atmospheres) and temperature of 212° F, (100° C), corresponding to a depth of 6,000 or 7,000 ft (2 km), oil would be 9 to 11 percent dissolved. At these depths, one would also expect appreciable quantities of gas would be absorbed by the oil.

In the reservoirs where this interaction takes place, lighter oils and condensates result and asphaltenes are precipitated (deasphaltation). These conditions have been observed in the Alberta basin and in many Russian basins.

Alberta Basin.--In the Alberta Basin, the migration of gas from the deeper, over-mature, gas-producing part of the basin into an updip area of oil accumulations is demonstrated in figure 8. The source rock west of the "hot line" is over mature, generating only gas with a high content of H_2S and aromatics (Hitchon and Horn, 1974); east of the line is generally only mature source rock. As may be seen, gas containing H_2S has migrated updip into the area of less mature source sediments and presumably interacted with oil accumulations forming gas fields, and gas condensate fields. An additional indication of the interaction is deasphaltation; solid bitumens were deposited east of the "hot line" with high hydrogen/carbon ratios and high solubility in CS_2, demonstrating that they are products of deasphaltation rather than thermogenic cracking (Bailey and others, 1974).

North Caspian and Russian Basins.--Condensate concentrations, evolved from the dissolving of reservoired oil by late migrating gas, reach giant size only in basins where there are evaporite seals, generally impervious to gas as well as oil, trapping the oil and gas together in the same closures. Because of its greater buoyancy, the gas displaces all, or part of, the oil from the trap and in so doing, mixes intimately with, and dissolves the lighter ends of the oil. Under these conditions, large condensate fields, many with an oil leg, develop. This type of field is particularly prevalent in the platform areas of the U.S.S.R. where extensive evaporite formations occur (e.g., North Caspian, East Siberia, Amu Darya, Timan-Pechora basins). This condensate is so prevalent that the Russians have a designation for it - secondary condensate; the usual, thermally generated, condensate is termed primary condensate (Chakhmakhchev and others, 1986). Secondary gas-condensates, according to Chakhmakhchev and others (1986) are the most widespread type of gas condensates in nature. Examples of this type of accumulation are in the huge gas-condensate fields of the North Caspian basin (fig. 9). According to Russian geologists, petroleum accumulated in about Triassic time under a thick regional seal, the Kangurian evaporites of Permian age. Later deeper subsidence generated more gas, most of which went into solution in deep, high-pressure formation waters. When the northern and western parts of the basin were later uplifted in Mesozoic and Tertiary time, much of the gas was released from solution. The released gas migrated, partially dissolved, and in part, buoyantly displaced the previous oil accumulations trapped beneath the evaporite seal in favor of gas and gas-condensate fields.

Approximately the same scenario applies to other Russian secondary condensate basins except that migrating gas need not necessarily pass through a long period where the gas is held dissolved in high pressure formation water. In the Timan-Pechora basin, for instance, the secondary condensate fields occupy a zone between the shallower oil fields and the deeper primary gas-condensate fields, indicating that the secondary condensate is the result of more direct contemporaneous intermingling of gas and oil.

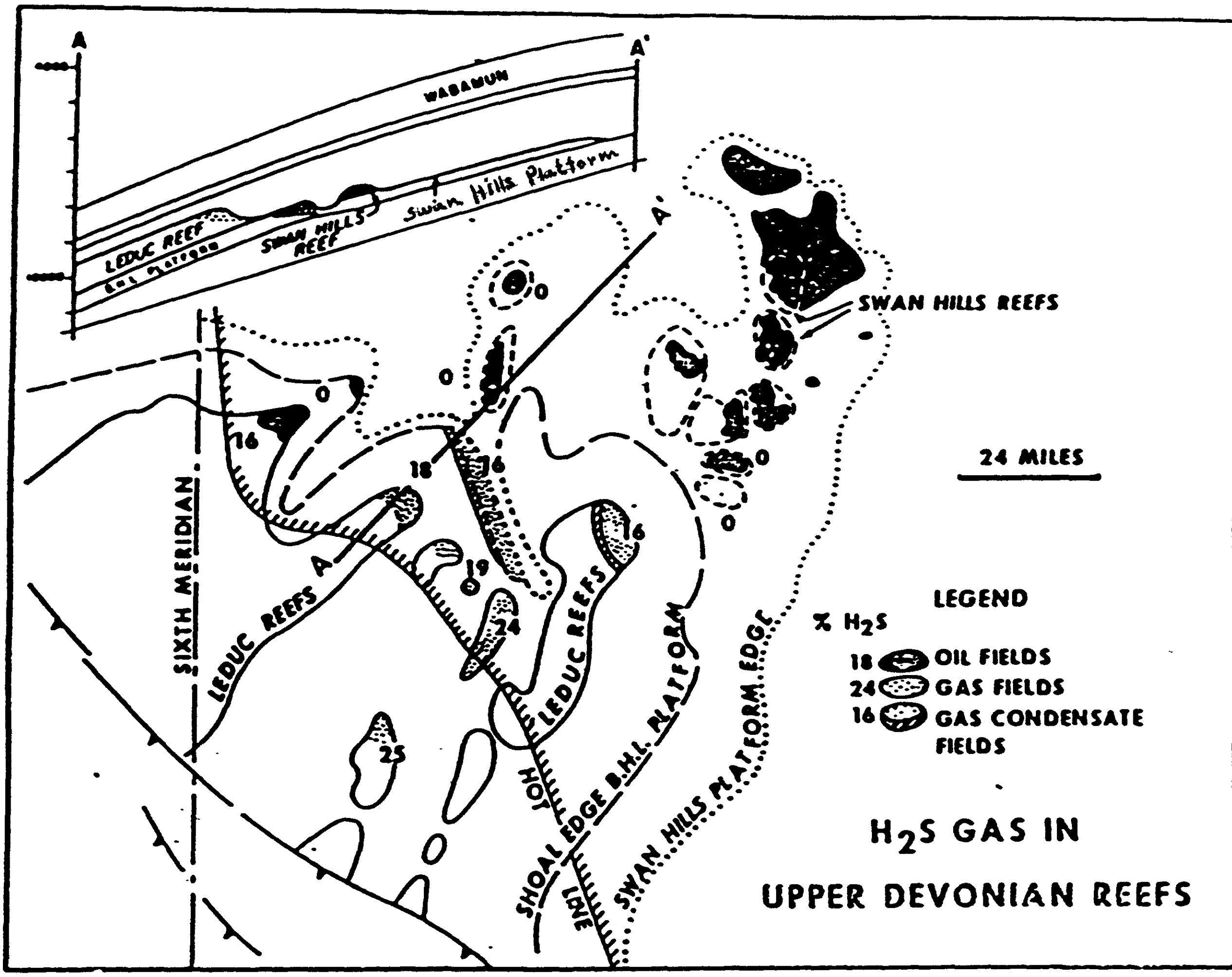

Figure 8.--Map of Late Devonian Swan Hills and Leduc reef fields in west-central Alberta showing progression from oil to gas-condensate to gas and also increasing abundance of hydrocarbon sulfide gas in southwesterly direction toward and beyond the "hot line" (from Bailey et al., 1974).

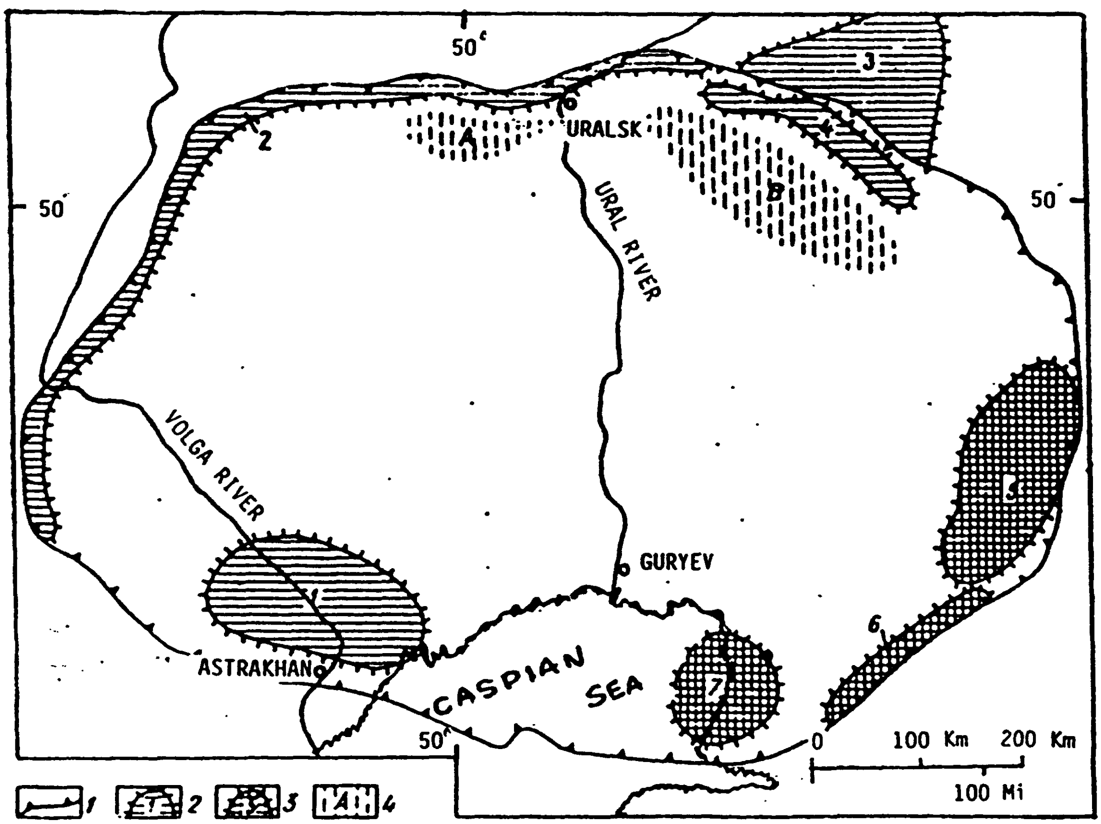

Figure 9.--Map of the North Caspian (Peri-Caspian) basin showing the distribution of oil- and gas-prone districts of the sub-salt complex: 1-Boundary of the basin; 2-Gas-prone districts (1-Astrakhan, 2-Volgograd-Ural, 3-Orenburg, 4-Karachaganak); 3-Oil-prone districts (5-Vostochno-Prikaspiy, 6-Yuzhno-Emba, 7-Primor); 4-Probable gas districts: A-Altatinsko-Ozinkov, B-Utvion-Ilik (from Solv'yev, 1982).

The secondary gas-condensates evolving from these generation and migration patterns have certain recognizable geochemical characteristics and condensate yields distinguishing them from primary gas-condensates. The geochemical characteristics, such as low percentage of aromatics, are discussed in detail under "Criteria for recognizing factors controlling gas-condensate accumulation."

The condensate yield in gas is usually greater for secondary than primary condensates. Figure 10 shows that in the case of the Karachaganak Field of North Caspian basin and similar fields, the condensate yield of primary condensates of the region is less than 27 BC/MMCFG (150 cm^3/m^3), while gases containing secondary condensates have a yield of at least up to 90-125 BC/MMCFG (500-700 cm^3/m^3) as at Karachaganak. It should be noted, however, that primary condensates in other instances such as cracked oil pools of the Interior Salt basin, U.S.A., have yields much exceeding 27 BC/MMCFG and the high (25) percentage of aromatics may be the primary factor in distinguishing primary from secondary condensates.

It is assumed that figure 10 applies to other secondary condensate concentrations, especially concerning the condensate yield (factor). The condensate yield of the Karachaganak field is shown to be about 90-125 BC/MMCFG (500-700 cm^3/m^3). The Astrakhan field (fig. 9) with a reported yield of 42 to 102 BBLS/MMCFG (240-570 cm^3/m^3) (Kondratyev and others, 1982) would fit well on the diagram for secondary condensate. The Orenburg field (fig. 9) however, has a yield of only about 16 BBLS/MMCFG (76.3 gms/m^3) which places it in the mixed primary and secondary condensate category of the diagram. This may be the case, since the Orenburg field is outside the area of principal basin subsidence. The interaction at Orenburg would be at shallower depths with attendant lower pressure and temperature causing less solubility of the heavier hydrocarbons and, therefore, less heavy hydrocarbons (condensate) in the gas, or it may be subject to the diluting effects of dry (biogenic or biodegraded) gas.

In the absence of other data, it is assumed that the condensate yields of the Astrakhan and Karachazanak secondary condensates which range from 43 to 125 BC/MMCFG (240-799 cm^3/m^3) averaging some 90 BC/MMCFG (500 cm^3/m^3), are reasonably representative of condensate yields for secondary condensates in general.

Evaporative Fractionation

The term, evaporative fractionation, was proposed by Thompson (1987), to describe a mode of origin for a class of petroleum encountered in Gulf coast Tertiary reservoirs. It is the exsolution of gas from reservoired, saturated oil, involving the transfer of material of low or intermediate molecular weight (including the gas condensate range, C_2-C_9) into the vapor stage. The release of saturated gas from an oil and gas accumulation apparently drives the process of evaporative fractionation. Condensates originating in this fashion are initially enriched in paraffin and depleted in aromatics compared to the parent oil. This process is essentially the same as described for some occurrences of secondary condensates in Russia and the resulting condensates, therefore, may be grouped with secondary condensates.

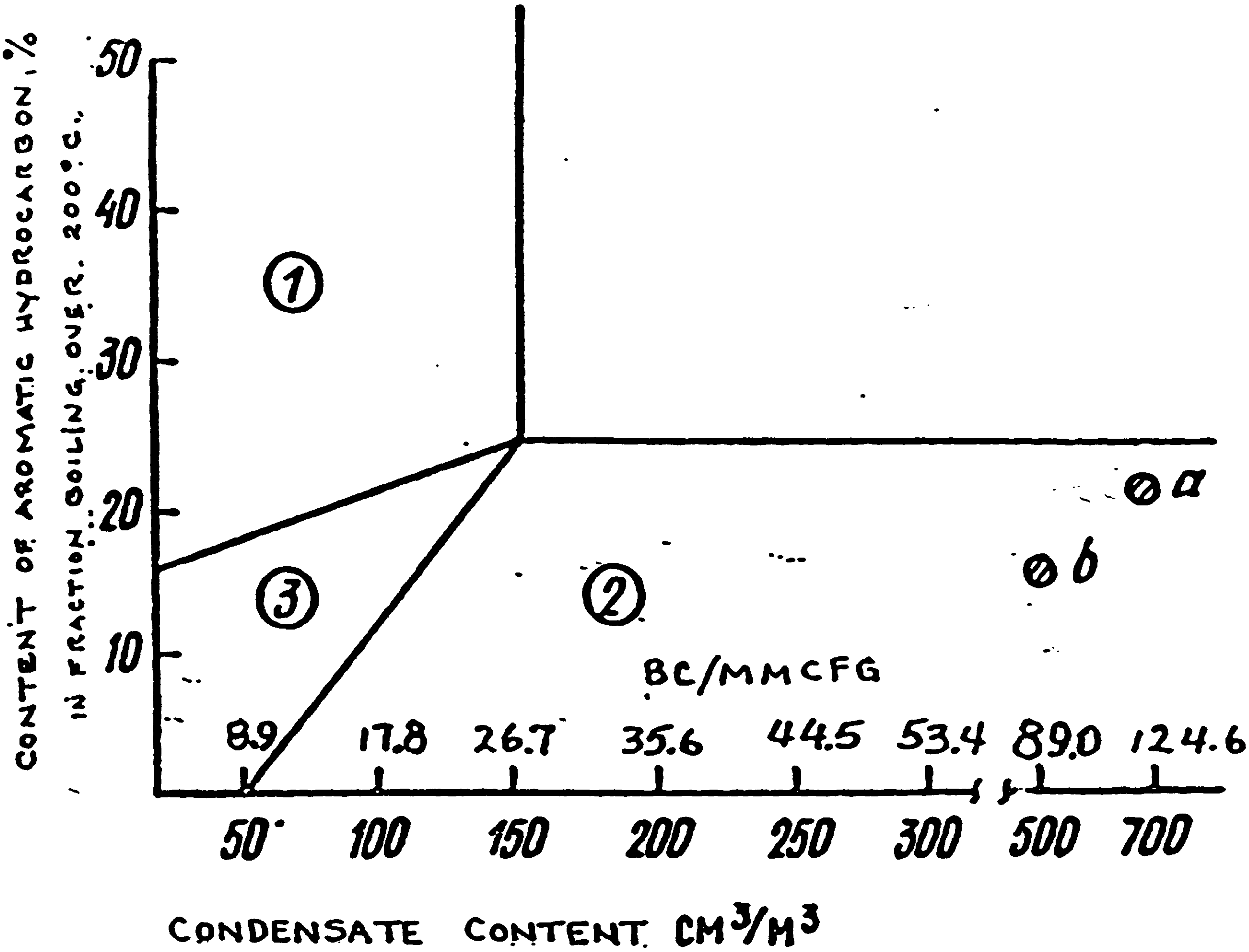

Figure 10.—Diagram showing relationship of primary condensates and secondary or oil-condensates to content of aromatic hydrocarbons and to condensate content (or yield) for gas-condensate fields of the North Caspian basin. Areas: 1-Primary condensates, 2-Secondary or oil condensates (oil-gas-condensates), and 3-mixed. The composition of Karachaganak Field is indicated by "a" and "b" (after Chakhmakhchev et al., 1985).

Gulf Coast, U.S.A.--An interpretation of U.S. Bureau of Mines Routine Oil Analysis Data by Thompson (1987) indicates that over 75 percent of the oils in Gulf Coast Tertiary reservoirs are depleted in light ends, and are enriched in light aromatic hydrocarbons, that is, they are evidently affected by evaporative fractionation. A majority of the Gulf Coast gas-condensates appear to be the product of evaporative fractionation. There are no identifiable secondary gas-condensate accumulations in the Gulf Coast where condensate yields are available. It is, therefore, assumed, pending more information, that the condensate yields would be approximately of the same magnitude of those of the Russian secondary condensates. In any case, the condensate yield is not significant to this study as the condensate liquid in this situation would be assessed with the associated oil.

Primary Gas Condensate (Cracked Oil and Kerogen)

General

As burial and heat increase, breaking of carbon-carbon bonds occurs more frequently affecting both the oil already formed and the kerogen remaining in the source rock. Light hydrocarbons, gas-condensate and gas, are generated through this cracking and their proportion increases rapidly in the source rock hydrocarbons and in the petroleum. The depths where this occurs are usually termed the Wet Gas or Late Mature Zone. As subsidence continues, the condensates in turn crack and the hydrocarbons become largely methane. An example of the Wet Gas stage of thermal maturation is found in the Interior Salt basin.

Interior Salt Basin, Southwestern Alabama.--The Wet Gas Zone is where the cracking of oil, as well as kerogen, is the dominant process, although the initial cracking starts early in the main oil generation zone. The top of this zone is gradational. Figure 11A shows the percent of gas formation (gas/gas + oil), Figure 11B the API gravity, and Figure 11C the petroleum liquid yield, all plotted against depth. The data is from oil and gas fields producing from the Smackover and adjacent formations in the southwestern Alabama portion of the Interior Salt basin (Table 1). The main oil generation zone is indicated to be between 9,000 and 16,000 ft in Figures 11A, 11B, and 11C, as defined by vitrinite reflectance of 0.65 and 1.2 percent (Shell Schneider No. 1 well, Escambia County, Florida).

As may be seen in Figure 11A, the Percent Gas curve deviates sharply at 11,000 ft. Above this depth, the oil of the province has less than two percent gas; at 11,000 ft, it starts cracking and gas and gas-condensate begin to form. Another sharp deviation occurs at about 15,000 ft where the percentage of gas again abruptly increases as shown by the wide scatter of the gas percentages in the indicated condensate fields.

Figure 11B shows that the API gravity of the petroleum fluids increases uniformly with depth with no discernible break as in the other parameters.

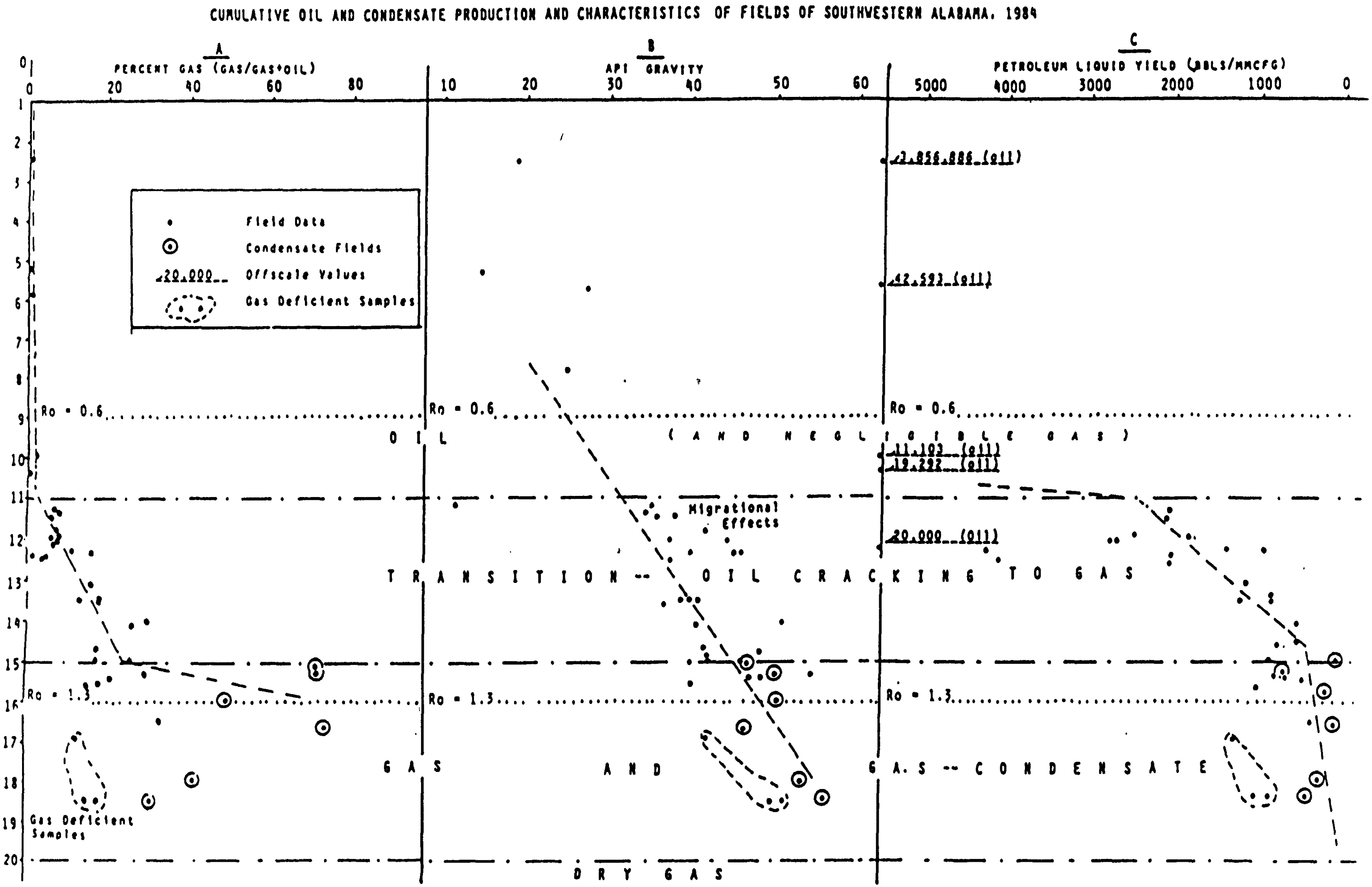

Figure 11.--Chart of 1984 cumulative oil and condensate production and characteristics of fields in southwestern Alabama, showing: A - percent gas (gas/gas + oil) versus depth; B - API gravity versus depth, and C - petroleum liquid yield versus depth. Depth zones indicate vertical distribution between oil, condensate, and gas (data from G.E. Claypool, written commun., 1987).

Table 1

CRUDE OILS AND CONDENSATE FIELDS, SOUTHWESTERN ALABAMA: 1984 CUMULATIVE PRODUCTION AND DERIVED RATIOS

FIELD	DEPTH, FT	API G	1984 CUM. PRODUCTION OIL (BBL)	GAS (MCF)	GOR CF/BBL	% CONVERTED TO GAS a/	LIQUID/GAS BBL/MMCF
CRETACEOUS OIL FIELDS							
1. GILBERTOWN	2575-2585	18.7	12704584	3294	.3	.005	3856886
2. SOUTH CARLTON	5260-5280	14.4	5544876	0	0	0.0	
3. POLLARD	5775	27.2	12055137	282366	23	.4	42693
4. LATHAM	7936-7944	24.9					
5. HUBBARDS LANDING		20.7					
6. CITRONELLE	10014-10827	43.7	139881358	12598810	90	1.6	11103
JURASSIC OIL FIELDS--SMACKOVER							
7. TOXEY	10460-10480	17.1	1583714	82194	52	.9	19268
8. MELVIN	11176-11189	11.3	42109	0	0	0.0	
9. BUCATUNNA CREEK	12070-12100	34.3	731558	268654	367	6.2	2723
10. SUGAR RIDGE	11560-11620	33.4	2835054	1421136	501	8.2	1995
11. NORTH CHOCTAW RIDGE	11950-11980	34.3	4725704	2634779	558	9.1	1794
12. CHOCTAW RIDGE	11940-11950	37.5	3180020	1831730	576	9.3	1736
13. CHAPPELL HILL	11410-11420	34.0	1129874	553797	490	8.0	2040
14. WIMBERLY	11250-11270	35.1	1057175	456418	432	7.2	2316
15. MILL CREEK	12330-12340	39.9	770966	564676	732	11.6	1365
16. LITTLE MILL CREEK	12358-12370	45.5	359207	380850	1060	15.9	943
17. WEST BARRYTOWN	12052-12064	43.2	504177	188187	373	6.2	2679
18. BARRYTOWN	11830-11860	41.9	2687181	1103101.0	411	6.8	2436
19. WOMACK HILL	11430-11440	36.0	19434640	9406017	484	8.0	2066
20. SOUTH WOMACK HILL (OIL C)	11332-11352	37.9					
21. TURKEY CREEK	12380-12390	40.5	2483932	124198	50	.9	20000
22. WEST BEND	12424-12430	37.2	140937	32636	232	4.0	4318
23. PUSS CUSS CREEK	13532-13542	38.6	64388	54626	848	13.2	1179
24. SILAS	13564-13578	39.5	1100399	1321728	1201	17.7	833
25. ZION CHAPEL	14059-14078	40.3	359716	711325	1977	26.1	506
26. COPELAND *	16614-16758	46.8	654248	10547236	16121	74.2	62
27. CHATOM *	16000-16115	50.2	9924018	53333738	5374	49.0	186
28. STAVE CREEK	12450-12470	37.7	1211557	296368	245	4.2	4088
29. LOVETTS CREEK	13080-13104	31.5	96394	86392	896	13.8	1116
30. WALLERS CREEK	13000-14000	37.1					
31. VOCATION	13990-14000	51.8	1401132	3196096	2281	28.9	438
32. BARNETT	13430-13476	40.6	274801	328695	1196	17.6	836
33. LITTLE RIVER	14976-14981	40.0	110113	129565	1177	17.4	850
34. BLACKSHER	15590-15600	40.1	712702	730334	1025	15.5	976
35. HUXFORD	14670-14700	49.3	180000	346000	1922	25.5	520
36. APPLETON		51.3					
37. BIG ESCAMBIA *	15090-15180	46.7	25613952	349327823	13638	70.9	73
38. FANNY CHURCH	15380-15460	47.1	3480469	5168138	1485	21.0	673
39. LITTLE ESCAMBIA	15380-15470	48.4	27597667	35373977	1282	18.6	780
40. PERDIDO	16510-16540	47.2	25940	70411	2714	32.6	368
41. MOVICO	16906-16952	42.4	649911	521682	803	12.5	1246
42. CHUNCHULA *	18420-18470	56.0	27586257	70384604	2551	31.3	392
43. COLD CREEK	18432-18440	49.8	495413	494871	999	15.1	1001
44. SOUTH COLD CREEK	18438-18470	51.4	31687	38679	1221	17.9	819
45. HATTERS POND *	18040-18060	53.3	20213236	78626028	3890	41.0	257
JURASSIC OIL FIELDS--NORPHLET							
46. CATAWBA SPRINGS	14868	42.0					
47. CHAVERS CREEK (OIL A)	14626-14656	41.4	837000	973000	1162	17.2	860
48. HALL CREEK	15017-15034	41.9					
49. SIZEMORE CREEK (OIL B)	15287-15340	54.3	130000	303000	2331	29.4	429
50. FLOMATON	15300-15360	49.8	9357587	135041968	14431	72.0	69

* CONDENSATE FIELD

a/ GAS/(GAS+OIL), ON BTU EQUIV., WHERE GAS = 1100 BTU/MCF, OIL = 6162000 BTU/BBL

Thermal gradient = 1.3° F/100'

(from G. E. Claypool, unpub. data, 1987)

The petroleum liquid yield (in barrels per million cu ft of gas) is plotted against depth (fig. 11C). It shows the petroleum liquid yield to abruptly decline in the vicinity of 11,000 ft and then to decline more gradually with depth along a curve which breaks sharply at about 15,000 ft where the decline of the liquid yields almost ceases. This lower break in the curve coincides with the top of the gas and gas-condensate zone as indicated by the abrupt increase in the percentage of gas (11A).

Considering all factors, the top of the wet-gas or the Late Mature Zone, as indicated by the depth of gas and gas-condensate, is around 15,000 ft. The base of this zone, or top of the dry gas zone, is observed to be from 19,000 to 20,000 ft. Within the wet-gas zone, there are at least six producing condensate fields. Their condensate yields vary from 62 to 392 and average 173 BC/MMCFG. These numbers provide an analog for yields from cracked oil. Any comparable yields, however, would depend on the composition of the oil being cracked. Since the southwest Alabama oil is almost gas-free, its cracking would produce a high-condensate-yield gas which would be on the upper end of the range of condensate yields one could expect.

Khuff Formation of the Persian Gulf Region.--There may be considerable condensate resources even in the lower part of the zone of decreasing condensate yields if the accumulations of nonassociated gas are large. A case in point is that of the extensive gas-bearing Khuff Formation of the Persian Gulf region. The North Field of Qatar reportedly has gas reserves of 380 TCF and 5 to 8 billion barrels of condensate (a yield of 12 to 20 BC/MMCFG). Khuff Formation gas is also reported in other parts of the region, such as at Bahrein where the condensate yield is 6 BC/MMCFG.

Dry Gas Stage (vitrinite reflection more than 2.0 and $\delta^{13}C$ more than 30 $^o/oo$).--Within this stage there is very little condensate as cracking of both hydrocarbon and kerogen has proceeded to the stage where almost all the larger molecules have broken down to methane and solid bitumen. The condensate yield for dry gas is less than 7.14 barrels per million cu ft of gas (0.3 gal/MCFG). Actually it is usually considerably less and the amount of dry-gas condensate would be negligible in an overall petroleum assessment. Examples of basins in the dry gas stage are the Sacramento, the Indus, and the southern North Sea.

ENRICHMENT OF GAS-CONDENSATE YIELDS

Migration does not cease once oil, gas, gas-condensate, and water are together in the average trap. While the oil may be relatively immobilized in most instances, the gas, gas-condensate, and water continue to move. The seal to most traps are shales or other related relatively impermeable sediments. With the exception of thick evaporites, however, gas and water can pass through them. Depending on the permeability of the cover (pore size of cap rock), a gas-condensate play of essentially the same source rock may have fields ranging from large gas-condensate fields under thick evaporite cover, to smaller oil-fringed gas-condensate fields with intermediate pore size in the cap rock, to progressively smaller oil fields with relatively large pore size in the cap rock. Figure 12 shows an example of this situation in the Dneper-Donets basin of Russia. Most significant for gas-condensate assessment is that the condensate yield becomes progressively greater as gas leakage continues.

DESTRUCTION OF GAS-CONDENSATE

General

Condensate is much more vulnerable to destruction and dissipation than oil. Gas and gas-condensate, in comparison to oil, are only temporarily held in most traps and with time, unless covered by a truly impermeable seal, will escape. Major gas and condensate accumulations cannot be expected in basins where the accumulations are older than Mesozoic, unless they are especially well-sealed.

Condensates are even more ephemeral than gas, as its C_2-C_4 components are vulnerable to biodegradation (James and Burns, 1984). This vulnerability, combined with its upward migratory mobility which brings it into the shallow zone of biodegradation, leads to a short-lived existence for condensates.

Gulf Coast, U.S.A.--In figure 7, showing the density distribution of oil and gas-condensates of the central Texas Gulf coast, there is sharp increase in the density of both oil and gas liquids at depths shallower than 6,500 ft (2 km). This, along with an interpreted increase of naphthene and aromatic factions of the oil at the expense of normal paraffins, lead Galloway and others (1982) to believe that the hydrocarbons are being altered by bacterial action. The 6,500 ft depth coincides with that of the deepest known aquifers of the region and coincidentally corresponds to the base of the dry gas (fig. 7). The base of the dry gas appears to be at the greatest depth and temperature tolerated by microbes (160° F). Later subsidence can, however, lower dry gas accumulations to as much as 10,000 ft in the Gulf Coast (Rice and Claypool, 1981). In general, it would appear that gases at shallow depths (those above about 6,000 ft) in any case have little prospect for economical yields of condensate. The gross condensate yield for the Gulf coast (taking condensate versus total nonassociated gas into account) is low, about 16.7 BL/MMCFG (Attanasi and Haynes, 1983). This low yield is believed to be caused by the fact that a great portion of the gas reservoirs within present drilling depth, especially offshore, is either biodegraded or biogenic dry gas. The average yield of the published fields where dry gas can be excluded is estimated to be about 35 BC/MMCFG.

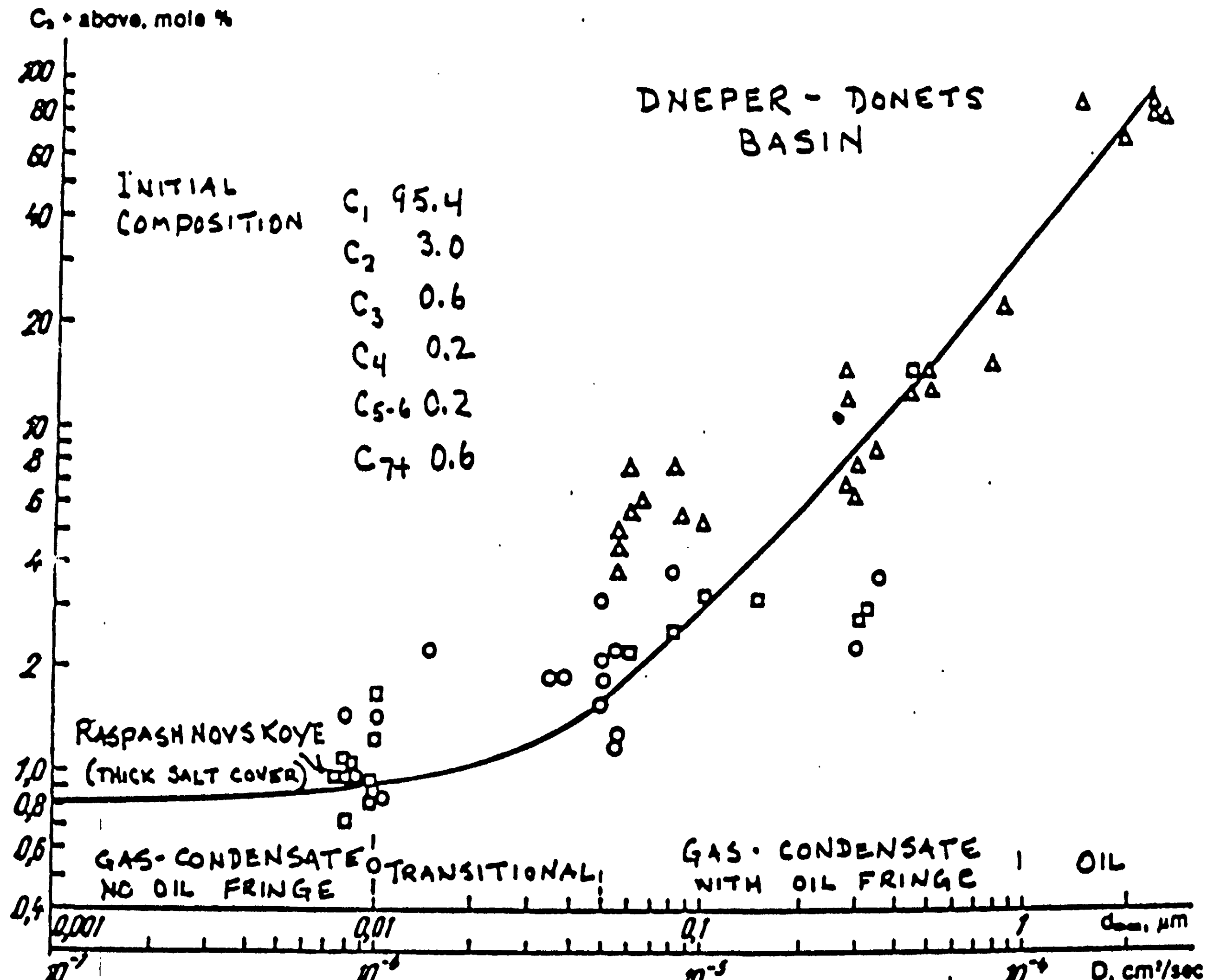

Figure 12.--Plot showing the proportion of C5 and higher fraction in formation gas as a function of maximum pore space in caprock and its diffusion permeability. The relation of pore size to the range of gas-condensate to oil fields in the Dneper-Donets basin is indicated. Symbols denote actual pools, circles-southern marginal zone, squares-central graben zone, and triangles-northern margin zone. Indicated initial composition near that of Raspashnovskoye field and assumed norm of the basin (after Stepanova et al., 1982).

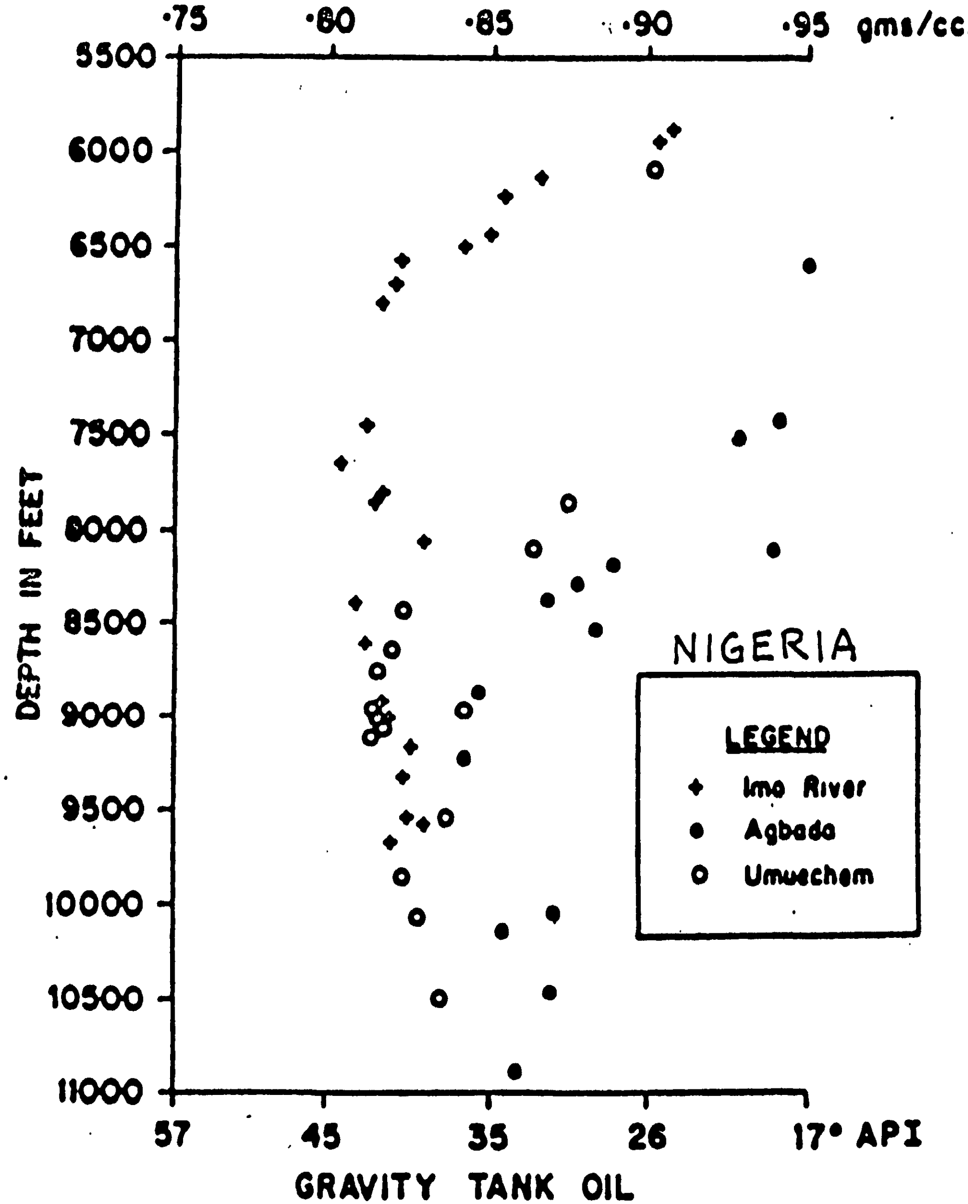

Figure 13.--Plot of oil gravity against depth for selected fields of the Niger delta (after Evamy et al., 1978).

Niger Delta, Nigeria.--The Niger delta has been similarly affected by biodegradation. Figure 13, which shows oil gravity plotted against depth, indicates a sharp increase of density at depths above 7,500 to 9,000 ft depending upon the location within the basin. These transition depths correspond to temperatures of approximately 150° F and 180° F. This same transition zone is observed to separate the two principal types of oil of the Niger delta (Evamy and others, 1978). Below is a light, paraffinic crude, and above is a heavy, naphthenic crude which is interpreted to be the biodegraded equivalent of the deeper light oil. The depth of the transition reflects the approximate maximum temperature of biodegradation (i.e. 160° F) plus a small amount of additional depth due to later subsidence. This indicated transition zone is believed to mark the top of any condensate occurrence. The average overall yield of the Niger delta condensate is probably analogous to the Gulf Coast, i.e., 16 BC/MMCFG; a low figure caused by the inclusion of biogenic gas, and of biodegraded gas from which condensate components have been removed.

Mahakam Delta, Indonesia.--The Mahakam delta of eastern Kalimantan, Indonesia is different from the Niger and Gulf Coast deltas in several respects. It has fold structure; the folds trending northeastward, parallel to the delta front and fold-associated faulting is prevalent. However, the deep growth faults typical of the Gulf Coast and Niger deltas apparently do not prevail and surface water has not deeply penetrated the subsurface. The section contains thick layers of shale which are geopressured at depth and some shale diapirs are seen onshore. Unlike the situation in the Gulf Coast and Nigeria, the oils become progressively lighter upwards and the percentage of distillate (gasoline range) increases upwards indicating upward migrating fractionation of more deeply sourced petroleum with no evidence of biodegradation. The average condensate yield, as that obtained at the Badak gas plant is 27 BC/MMCFG and at a more recently discovered field, Tunu, it averages 47 BC/MMCFG; the condensate yield of the nonassociated gas having been apparently decreased by addition of dry gas which is continually migrating upwards from the dry gas zones below (Schoell and others, 1985).

CRITERIA FOR RECOGNIZING FACTORS CONTROLLING GAS-CONDENSATE ACCUMULATION

General Characteristics

Basins having appreciable amounts of condensate of whatever origin have the following general characteristics:

1. Late subsidence. Gas and gas-condensates, with notable exception, are usually confined to basins where subsidence (and therefore generation) is late i.e. largely Tertiary, or less often Mesozoic, since gas, given time, will escape through the shale cover rock, while oil remains trapped.

2. Well-sealed traps. Basins which generated gas in the Mesozoic and Paleozoic may also retain gas and gas-condensate if the seals are efficient, e.g. evaporites, and to a lesser extent, carbonates and tight shales.

3. Deep source rock. The source rock must be sufficiently deep and hot to be at least partially within the oil window as gas generated at shallow depths has negligible condensate yield. The richer condensate yields are from deeper source rock within the wet-gas zone, usually 12,000 to 15,000 ft.

4. Moderately deep reservoirs. Condensate is vulnerable to bacterial action. The intolerance of most bacteria to high temperature usually precludes bacterial action on hydrocarbon in rocks warmer than 160° F. Therefore, depending on the thermal gradients and hydrodynamics, condensates will not be found shallower than approximately 6,000 to 7,000 ft.

5. The established presence of oil and nonassociated gas.

Distinctive Characteristics

The four principal gas-condensate accumulating processes take place under discrete often recognizable sets of conditions which are summarized below:

1. Humic Generation

   a. Considerable amounts of gas and waxy crude is in the basin production.

   b Source rock contains coal and carbonaceous matter from oxidizing environments such as coal measures and deltas.

   c. Source rock is in the zone of oil generation.

   d. Analogs: Tyumen Suite (Western Siberia), Talang Akar delta (Indonesia), Niger delta (Nigeria), Mahaham delta (Indonesia), and (with some reservation) the Gulf Coast deltas (U.S.A.).

2. Primary Migration Fractionation

   a. Lean source rock, i.e. less than 2.5 percent wt TOC for oil and 1.0 percent for gas.

   b. Linear decrease in hydrocarbon specific gravity. Decrease reflecting decreasing molecular weight of hydrocarbon molecules by fractionation in direction of migration.

   c. Higher level of maturity in the reservoired hydrocarbon than the bitumen or oil in the adjacent shales.

   d. Absence of oil-size molecules in gas and gas condensate-filled reservoirs surrounded by mature but lean source shales.

e. A preponderance of shale. Massive shales, unbroken by interfingering sands or faults.

f. Geopressured source. At least part of the identified source is geopressured.

g. Source rock in the mature zone.

h. Analogs: Arun, North Sumatra (Indonesia), Mahakam delta (Indonesia).

3. Secondary Condensate

a. Usually evaporite seals for giant size deposits.

b. Indicated source in oil window.

c. Abundant fractionated oils with depleted light ends in the province.

d. Density of liquids increase downward (presumably away from the gas interaction) while that of oil or primary condensates would decreas downward (reflecting increasing cracking with depth) (Karachaganak Field, Chakhmakhchev and others, 1985).

e. Tars and asphaltenes in the secondary gas-condensates reservoirs (either as a result of deasphaltization or as oil pool relics).

f. Condensate contains N-alkanes of the C_{14}-C_{30} range, more characteristic of oil, in contrast to primary (cracked) gas-condensates which do not have N-alkanes over C_{15}-C_{20} (Chakhmakhchev and others, 1985).

g. Secondary condensates, in contrast to primary condensates, are generally deficient in aromatic hydrocarons.

h. The gasoline fraction of secondary condensates has the same hydrocarbon distribution as that of the oils underlying gas caps of Timan-Pechora basin (Chakhmakhchev, 1986).

i. Analogs: Alberta basin (Canada), North Caspian basin (USSR), Timan-Pechora basin (USSR), and Gulf Coast (U.S.A.)

4. Primary Condensate (Cracked Oil and Kerogen)

a. Both oil and gas fields in basin. The gas fields are generally deeper or down dip from the oil fields.

b. Deep reservoirs. Reservoir depths are usually from 10,000 to 20,000 ft depending on the thermal gradient.

c. Deep source, below the oil window.

d. Source usually predominantly of type II and type I kerogen.

e. Analog: Interior Salt basin (S.W. Alabama).

BASIN ANALOGS FOR THE FOUR PRINCIPAL PROCESSES OF GAS-CONDENSATE FORMATION

The condensate yields of analog basins for each of the four principal processes described above are summarized.

Condensate Yields

Analog Province	Process	(BC/MMCFG) Range	Average
1. West Siberia, U.S.S.R.	Humic generated	40-100	56
2. North Samatra (Arun), Indoneisa	Primary migration fractionation	20?-150?	53
3. North Caspian, U.S.S.R.	Secondary condensate	43-125	84
4. Interior Salt basin, U.S.A.	Primary condensate (cracked oil)	10-400	173

Published condensate yield values for provinces, where identifiable processes are dominant, are so far, meagerly available and with ranges that overlap considerably. Furthermore, the relationship of yield value to process is obscured when more than one process is acting concurrently, e.g. humic source and primary migration fractionation in deltas, or when the yields are enriched by gas leakage. Nevertheless, it is believed that as more values become available, a clearer relationship between a particular process (which may be deduced from the geologic setting and geochemical parameters) and definitive condensate yield values shall emerge. At the very least, the above values give a general but quantified idea of condensate yields from gas-condensates of whatever origin.

Although the condensate yields given in above province descriptions are the best available values, it is emphasized that the values may vary widely depending on sampling conditions. Examples of some of the many variations are: 1) generally the deeper the sampled reservoir, the richer the gas-condensate concentration in the gas, regardless of maturity or source richness, 2) contamination by reservoir hydrocarbon liquids (i.e. the oil leg) is likely when they are near the tested interval, causing a high yield value, and 3) the later the test is made in the production history, the lower the yield of the sample, especially if the field is recycled.

The condensate yield in nonassociated gas as described above is under ideal conditions. Gas-condensate accumulations are not only relatively uncommon, but perishable. Most nonassociated gas is dry, which by definition, is less than about 7.14 BC/MMCFG with most of the liquid having been cracked to methane, or biodegraded to methane. At shallower depths, nonassociated gas is likely to be largely microbial gas which contains no liquids. Accordingly, once a nonassociated gas volume estimate is made, condensate yield analogies may be applied, but with a considerable discount, taking into account, among a number of other factors, the likelihood of its biodegradation, dilution by dry gas, or preferential leakage of smaller molecules.

CONCLUSIONS

A. Assessment of gas-condensate, in most cases, would be best made by first considering the volume of nonassociated gas in the play and then estimating the condensate yield of the gas.

B. Most nonassociated gas is dry, being either immature, microbial, biodegraded, or thermally overmature. Dry gas by definition has less than 7.14 BC/MMCFG and is, in most instances, of negligible account in the resource assessment.

C. Most appreciable gas-condensate concentrations in nonassociated gas result from what are essentially four general processes:

1. Humic generation. Gas and gas condensate generated in the oil generating zone from humic organic material.

2. Primary migration fractionation. Gas condensate generated in the oil generating zone but separated from oil by primary migration fractionation.

3. Secondary condensate. Probably the greatest volume of gas-condensate is formed by the dissolving of the light ends of reservoired oil in late migrating gas or contemporary gas.

4. Primary condensate. Gas condensate and gas formed by the cracking of reservoired or dispersed oil and kerogen at over-mature thermal levels.

D. Analog provinces for each of these processes along with estimated condensate yields, as listed below in order of richness, provide a guide for the condensate assessment. Included with the list are delta-generated condensates as exemplified by the Mahakam delta since the dominant concentration process, primary migration fractionation or humic generation, in delta provinces is not always clear. These analogs probably represent near optimum conditions for gas-condensate formation and a province being compared should probably be discounted depending on the relative geologic factors, and especially depending on the probability of biodegradation and of dilution by dry gas.

Condensate Yields

Analog	Process	(BC/MMCFG) Range	Average
1. Interior Salt basin	Primary condensate (cracked oil and kerogen).	10-400	173
2. N. Caspian basin	Secondary condensate	43-125	84
3. West Siberia	Humic generated	40-100	56
4. North Sumatra (Arun) Indonesia	Primary migration fractionated.	20?-150?	53
5. Mahakam delta	Delta-generated (primarily migration fractionation and humic generation).	10-150	27

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