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Giant oil accumulations and their areal concentration efficiency

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Abstract: The ratio of the areal concentration (barrels of oil equivalent/km^2) of accumulated oil in the richest sedimentary basin to that in the poorest basin, among those basins having "giants" and "supergiants", is more than 500 to 1. On the contrary, the ratio of the richest to the poorest petroliferous basin in terms of the total organic concentration may be less than 20 to 1. Such a large discrepancy between these two ratios suggests that the organic concentration alone cannot account for oil concentration in commercial reservoirs, because significant quantities of oil may have been lost to the surface and also disseminated throughout the sedimentary sequence in the geological past. Most of the disseminated oil cannot be produced economically by the present-day technology.

For a better petroleum assessment, the author stresses the importance of the petroleum accumulation/preservation efficiency in commercial reservoirs; this may be evaluated as combining, 1) the organic concentration of the source rock, 2) the duration of oil generation, 3) the thickness of the oil-generating "window", 4) the total geologic age involved, and 5) the fluid expulsion efficiency and the presence or absence of undercompacted intervals. Other parameters such as the trap, reservoir and cap rock, and also the types of organic matter in the source rock, would have a great influence on the efficiency of oil concentrations in commercial reservoirs as well. However, most of them are related to the geologic conditions of each specific area or basin, and thus are more difficult to generalize than those mentioned above in the context of the global distribution and concentration of oil reservoirs.

INTRODUCTION

An oil accumulation is believed to have been formed as a result of geological and geochemical processes of generating, maturing, migrating and trapping petroleum. Petroleum geologist, therefore, exerts his effort in evaluating such essential factors as source, hydrocarbon generation/maturation, primary secondary migration, reservoir, seal and trap, in areas where he expects to find commercial hydrocarbon accumulations. The geologist also believes that all the oil and gas fields must have been associated with these essential factors in their geologic history.

Presence of all of these factors at the present time, however, does not necessarily mean the existence of an oil or gas field in the area of study. This may be due to timing problems (or lack of good timing, geologically speaking) of the factors involved. For example, when oil was actively generated and migrated toward a trap which was not properly sealed, most of the migrated oil would have been lost. At a later geologic stage, the rocks above the trap may have gained their sufficient sealing capacity due to compaction and/or diagenesis. In this case, all the essential factors are present at this moment, but it would have been too late for causing a significant hydrocarbon accumulation there.

Petroleum reserves of two sedimentary basins from different parts of the world, whose geologic settings and reservoirs and source rock potentials resemble to each other, can be greatly different from each other. In such a case, a simple volumetric method based on thickness and areal distribution of matured source rocks will not provide a reasonable oil/gas reserve figure, because for one thing the expulsion efficiency of generated petroleum differ from area to area. Difficulties are not only on the expulsion efficiency of hydrocarbons, but also on the assessments of hydrocarbons dispersed in source and low-grade reservoir rocks, as well as hydrocarbons lost to the surface. Even if the geologist is lucky enough to be able to establish a volumetric relationship among them in a basin or area, he would definitely face a serious difficulty in applying the same relationship to another basin in a different part of the world with a similar or different geologic setting. In summary, petroleum is extremely unevenly distributed in the world.

According to McDowell's (1975) study of four major sedimentary basins of the world, the percentage of reservoired oil compared to the total volume generated in source rocks varies so widely: only about 2% in the West Siberian Basin, about 3% in the Permian Basin, west Texas, about 9% in the Arabian Gulf Basin and about 30% in the Los Angeles Basin, U.S.A. This study suggests that a true reserve assessment needs to include not only the volume of oil/gas generated but also those unexpelled from source rocks, dispersed in non-reservoir rocks and lost to the surface. These latter factors are commonly much less understood than the volume of oil generated from source rocks.

For the sake of argument, taking the petroleum concentration efficiency to be either 2% (e.g. West Siberian Basin) or 30% (e.g. Los Angeles Basin) would have a more significant impact on assessment than would the knowledge that the organic concentration was 0.5% by weight or 2 to 3%.

ORGANIC CARBON PERCENT

Basin assessment for hydrocarbon potentials is usually based on the organic-geochemical methods. Organic carbon concentration, type and maturity are three principal factors to be evaluated.

In discussing the importance of organic carbon concentration, Barker (1977) showed a graph of the distributions of the average organic carbon percentage, the number of giant fields, and the amount of expandable clay throughout geologic time (Fig. 1). Barker stated that the curve for the total petroleum reserves from the giant fields is essentially the same as that for their number, except for lower values in the Tertiary section. He then summarized that the "organic-carbon-concentration" curve follows the trend of the "giant-field-petroleum abundance" curve much better than the "expandable clay-mineral" curve. This data shows that the average organic carbon content ranges from about 0.2 to 1.2%.

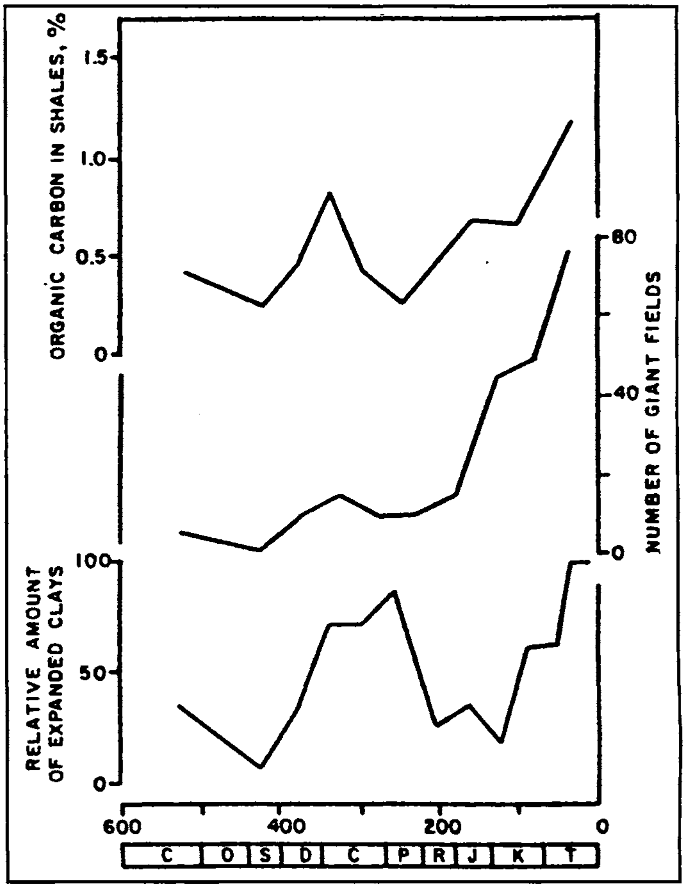

Figure 1. Variations through geologic time of average organic carbon content of shales, number of giant fields, and relative amount of expandable clays (after Barker, 1977).

Ronov's (1958) classical study based on over 25,700 samples from the Russian Platform shows that the concentration ranges from about 0.1 to 1.4% (Fig. 2). The relatively low values refer to non-petroliferous basins. On the other hand, Bordovskiy's study (1965) from the recent sediments from the Bearing Sea shows a range between about 0.4 (medium grained sand) to about 1.5% (silty clay). In the Arabian Basin, one of the most petroliferous basins in the world, Ayres *et al.* (1982) reported that the total organic carbon content of the Callovian and Oxfordian (Jurassic) source rocks averages 3 to 5 wt %. There are much more data of the organic contents of different source rocks from different parts of the world, but it is not the prime purpose of this paper to compile all of them. It would be sufficient to show a possible range of organic carbon content in petroliferous basins, from about 0.3 to 5% (or 1 to less than 20 by ratio) in most cases.

Dow (1979) stated that marine organic-matter production is controlled by light, temperature, and the nutrient content of the water. Upwelling of deep ocean water, that is most common along the western coasts of continents, can introduce large quantities of nutrients such as phosphate and nitrate into the euphotic zone, and results in localized high rates of organic production. Dow concluded that "most organic-rich sediments are deposited in areas of high organic productivity where the supply of bottom oxygen is minimal, the water is reasonably quiet and the sedimentation rate of mineral particles is intermediate".

Based on the Deep Sea Drilling Project (DSDP) data, Ibach (1982) reported the relationship between the sedimentation rate and organic carbon percentage (Fig. 3). He indicated optimum sedimentation rates for the accumulation of the maximum concentration of organic carbon: 14.10 m/Ma for calcareous shales: 21.13 for siliceous shales: and 40.80 for black shales. Sedimentation rates either greater or smaller than these optima tend to result in accumulation of lower concentrations of organic carbon. In addition to the conditions discussed by Dow, important factors include organic destruction by oxygen and bacteria for relatively slow sedimentation rates, and the

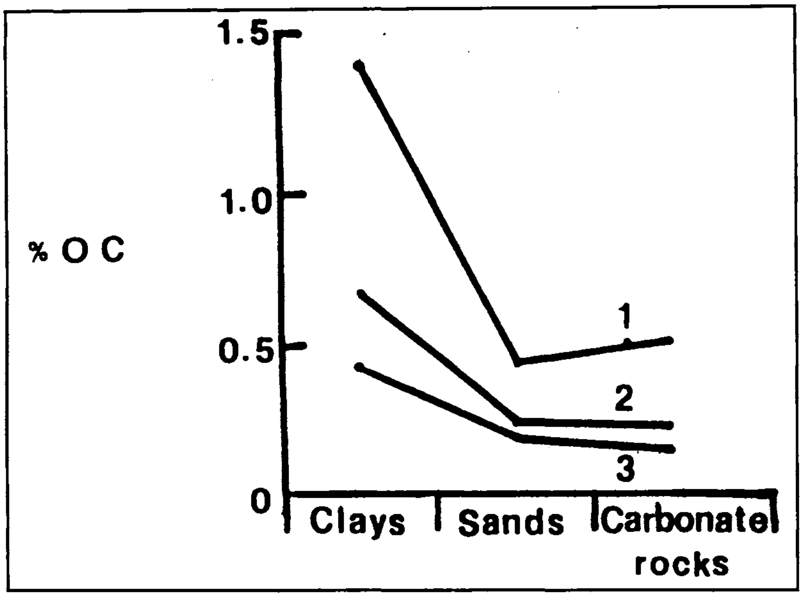

Figure 2. Average weight % organic carbon (OC) in the Russian Platform: 1. petroliferous area, 2. entire platform, and 3. non-petroliferous area (based on the 25,700 samples cited in Ronov, 1958).

dilution of organic carbon in sediments for relatively fast sedimentation.

More data from other basins, such as the Canadian Arctic, the Palo Duro and Midland basins in west Texas, the Japanese Tertiary, and the Peregrina Canyon, Mexico, were reported by Magara (1986a), who concluded that there is an optimum sedimentation or burial rate for the accumulation of organic carbon in each basin. The optimum rate, however, changes between basins and within each basin, depending upon the changing environment as described by Dow (1979), the mid-value being about 70-85 ft/Ma (Magara, 1986b).

AREAL CONCENTRATION EFFICIENCY OF ACCUMULATED PETROLEUM

St. John (1980) reported the estimated ultimately recoverable (EUR) oil and gas, and the barrel oil-equivalent (BOE: gas is converted to oil equivalent) for "giant" and "super-giant" fields. He also showed the areas of the sedimentary basins containing these fields (volumes of these basins were unfortunately not estimated). Using St. John's data, the ratio BOE/km^2 of basin, as a measure of the efficiency of petroleum concentration in reservoirs, was calculated: it ranges from about 0.9 MM bbl/km^2 (million barrels per sq km) in the Williston (North America) to about 540 MM bbl/km^2 in the Los Angeles Basin (North America — Table 1). The values for other well-known basins are about 35 MM bbl/km^2 in the South Brunei, about 87 in the Central Sumatra, about 25 in the Mahakam and about 80 in the Gippsland basins (all in Asia/Oceania), about 510 in the Maracaibo Basin (South America), about 470 in the Gulf of Suez (Africa), about 270 in the Arabian Gulf (Middle East) and only about 52 in the West Siberian Basin (former U.S.S.R.) (see Table 1).

Figure 4 shows the frequency distribution graph of these calculated values from all the basins containing "giant" and "super-giant" fields. This figure depicts that the ratio of the smallest value to the largest is 1:500 or more (based on the data derived from only the world's richest basins). If, therefore, smaller fields and/or less petroliferous basins were included in the study, the ratio would have been even greater than 1 to 500. What, then, makes such large differences in the areal efficiency of petroleum concentration in the reservoirs? A probable answer would be that such factors as organic concentration, type and maturity, migration efficiency, reservoir, seal and trapping conditions, etc., that change between basins, have resulted in petroleum accumulations with wide variations of efficiency.

To compare the distributions of the areal petroleum concentrations of Asia, North America with world, both Figures 5 (frequency plots) and 6 (cumulative frequency plots) were constructed; Asia's distribution is narrower than that of the world, and North America's plot shows a bimodal distribution.

TIME-TEMPERATURE RELATION IN OIL GENERATION

The concept of the geologic time-temperature relationship for hydrocarbon generation has been known in the industry for the last several decades. This concept suggests that there are optimum ranges of the age and temperature suite, called "oil

Table 1. Area and estimated ultimately recoverable (EUR) barrels oil-equivalent (BOE) of major oil-producing basins. Ratio of BOE over area (MM bbl/ km^2) is also shown. Data from St. John (1980).

Basin	Area, km^2	BOE (MM bbl)	BOE/area (MM bbl/ km^2)
SOUTH AMERICA			
Maturin	200,000	2.51	12.6
Maracaibo	80,000	40.6	507.5
Middle Magdalena	30,000	0.7	23.3
Oriente	480,000	1.9	4.0
Peru Coastal	60,000	1.0	16.7
San Jorge	150,000	2.0	13.3
NORTH AMERICA			
North Slope	300,000	20.25	67.5
Mackenzie Delta	170,000	0.58	3.4
Sverdrup	920,000	1.67	1.8
Alberta	810,000	9.33	11.5
Cook Inlet	30,000	0.83	27.7
Williston	540,000	0.5	0.9
Powder River	45,000	0.76	16.9
Sacramento/San Joaquin	50,000	8.34	166.8
Uinta	50,000	0.8	16.0
San Juan	55,000	1.83	33.3
Anadarko	230,000	16.84	73.2
Ardmore	20,000	1.43	71.5
Permian	150,000	12.33	82.2
Tampico	80,000	23.1	288.8
Gulf Coast	600,000	21.16	35.3
Salinas	65,000	11.92	183.4
Campeche	275,000	3.0	10.9
Appalachian	310,000	0.66	2.1
Cincinatti Arch	140,000	0.51	3.6
Illinois	210,000	0.68	3.2
Grand Banks	200,000	1.0	5.0
Ventura	10,000	1.2	120.0
Los Angeles	10,000	5.44	544.0
AFRICA			
Algerian Sahara	310,000	5.83	18.8
Polignac	45,000	1.3	28.9
Ghadames	240,000	9.08	37.8
Sirte	300,000	34.69	115.6
Niger Delta	280,000	5.45	19.5
Gulf of Suez	10,000	4.7	470.0
Gabon	130,000	0.5	3.8
Congo	70,000	2.5	35.7
EUROPE			
Vienna	5,000	0.49	98.0
Aquitanie	60,000	1.74	29.0
Po	30,000	0.5	16.7
German	205,000	11.47	56.0
S. North Sea	320,000	4.81	15.0
N. North Sea	160,000	15.86	99.1
Pre-Carpathian Depression	110,000	0.8	7.3

Table 1 (Continue). Area and estimated ultimately recoverable (EUR) barrels oil-equivalent (BOE) of major oil-producing basins. Ratio of BOE over area (MM bbl/ km^2) is also shown. Data from St. John (1980).

Basin	Area, km^2	BOE (MM bbl)	BOE/area (MM bbl/km^2)
MIDDLE EAST			
Arabian	1,540,000	414.05	268.9
Iranian Foldbelt	350,000	175.82	502.3
Red Sea	260,000	0.58	2.2
ASIA/OCEANIA			
Tadzhik	45,000	0.6	13.3
Cooper	185,000	1.67	9.0
Gippsland	40,000	3.2	80.0
Dampier	260,000	1.88	7.2
S. Brunei	60,000	2.08	34.7
Dzungaria	160,000	0.73	4.6
North China	240,000	0.5	2.1
Pre-nan-shan	40,000	0.53	13.3
Songliao	185,000	6.0	32.4
Szechwan (Sichuan)	230,000	3.0	13.0
Tsaidam (Chaidam)	90,000	1.1	12.2
Bombay	80,000	2.05	25.6
C. Sumatra	65,000	5.67	87.2
Mahakam	95,000	2.4	25.3
N. Sumatra	50,000	2.5	50.0
N. Malay	115,000	1.0	8.7
Taranaki	75,000	1.67	22.3
Indus	250,000	2.33	9.3
Thai	80,000	1.5	18.8
Former USSR			
C. Caspian	550,000	14.63	26.6
Dniepr/Donets	80,000	4.07	50.9
Kyzyl-Kum	650,000	6.35	9.8
Pechora	360,000	7.87	21.9
Vilyuy	550.000	4.86	8.8
Volga-Urals	350,000	29.15	83.3
West Siberia	2,940,000	153.63	52.3
Tadznik	45,000	1.88	41.8

windows", for generating and maturing oil/gas.

Magara (1978) plotted Connan (1974) and Hunt's (1974) time-temperature data on a graph where the giant oil/gas field data by Halbouty (1970) is also shown (see Fig. 7).

The oil reserves drop sharply below the "oil phase-out" line, suggesting the reasonableness of the Connan-Hunt's oil window. Significant amounts of oil/gas reserves for the Tertiary and Cretaceous are plotted above the oil window (Fig. 7). This may be due to the effects of structural uplift and also of upward oil migration. It is also noted that oil/gas reserves decrease significantly in the Triassic and older formations, even though the oil window extends to older geologic ages (or formations) as well (Fig. 7). There must be some fundamental reasons to cause such a drastic change.

To test the effect of organic concentration as a result of changing burial rate, a series of diagonal lines were drawn in Figure 7. The high concentration of the Tertiary-to-Jurassic oil/gas reserves fall within the burial rates between about 40 and 150 ft/Ma. Note that there seem to be optimum rates of sedimentation or burial to accumulate highest concentrations of organic matter, as discussed earlier. Therefore, the

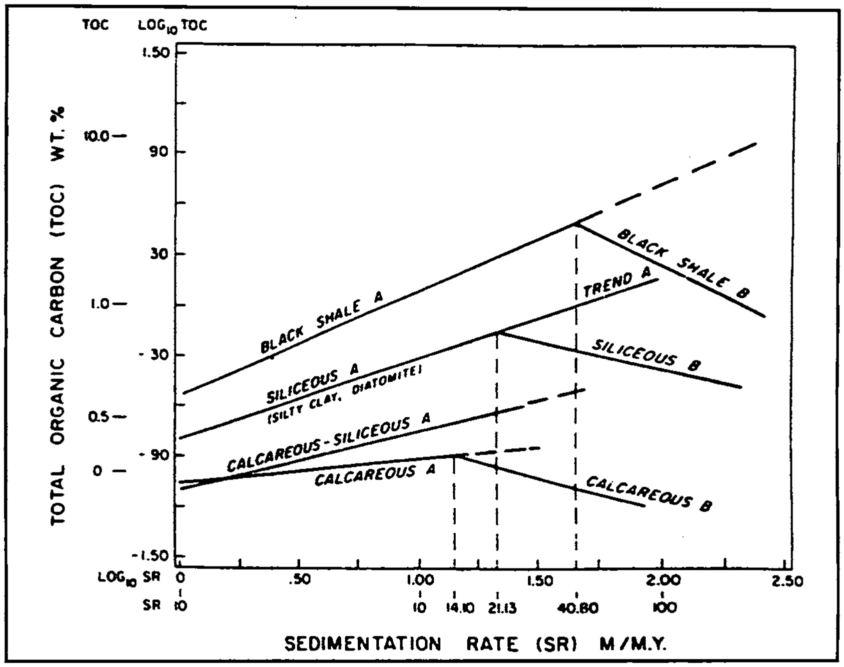

Figure 3. Relationship between total organic carbon percentage and sedimentation rate (m/million years) from Deep Sea Drilling Project data (Ibach, 1982).

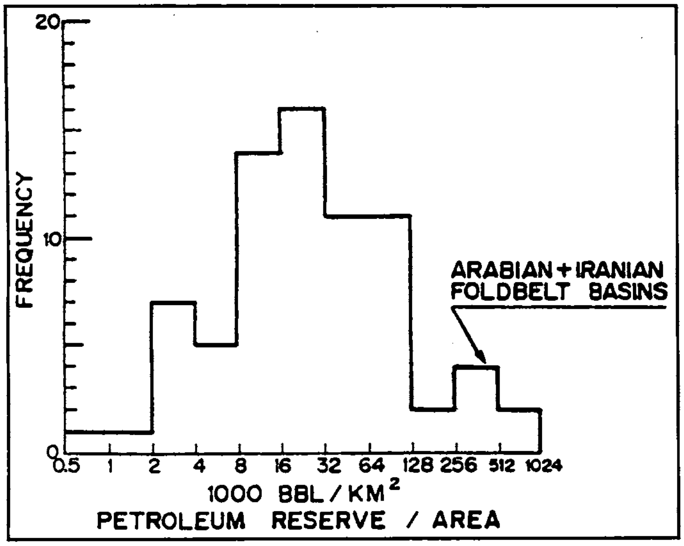

Figure 4. Frequency distribution of petroleum reserves per unit area (BOE/km^2) for the world's major sedimentary basins (data from St. John, 1980).

comparison made in Figure 7 is quite interesting and may at least partly explain the oil reserve distribution in the world. At the same time, however, one must not forget that the range of organic concentration (ratios of 1 to less than 20) would not correspond to such a wide range of the areal efficiency of the petroleum reserves (ratios of 1 to more than 500). Therefore, the changing burial rates and related organic contents may offer only a partial solution to this complicated problem, and other factors must also be taken into consideration.

PROBABILITY MODEL

To demonstrate various factors involved in petroleum concentration in commercial reservoirs, Figure 8 was constructed. Figure 8A shows the relationship between organic carbon percentage and sedimentation rate, suggesting the intermediate sedimentation rates for high organic concentration.

As described earlier, diagonal lines in Figure 7 depict burial rates. If, for example, the burial rate was 20 ft/Ma, about 290 Ma would elapse between the onset of oil generation and oil "phase-out". On the other hand, if the average burial rate was 200 ft/Ma, only 40 Ma would be required to pass through the oil window. If the length of time involved in oil generation and maturation was long (the first case), the chances of either disseminating or losing petroleum would be larger than in the second case. Therefore, there would be a higher probability of more effective concentration of petroleum in the second case than in the first. This situation is depicted in Figure 8B.

Thickness of the oil window increases with increasing burial rate, from about 5,500 ft for the rate of 20 ft/Ma to about 8,000 ft for the rate of 200 ft/Ma. If the oil window is thinner, the generated oil would be more easily concentrated than in the case of a thicker window, other conditions being constant. Relatively fast burial may cause undercompaction and abnormally high fluid pressure. Average geothermal gradient in such an undercompacted region tend to be lower because of the insulating effect by these shales than those in

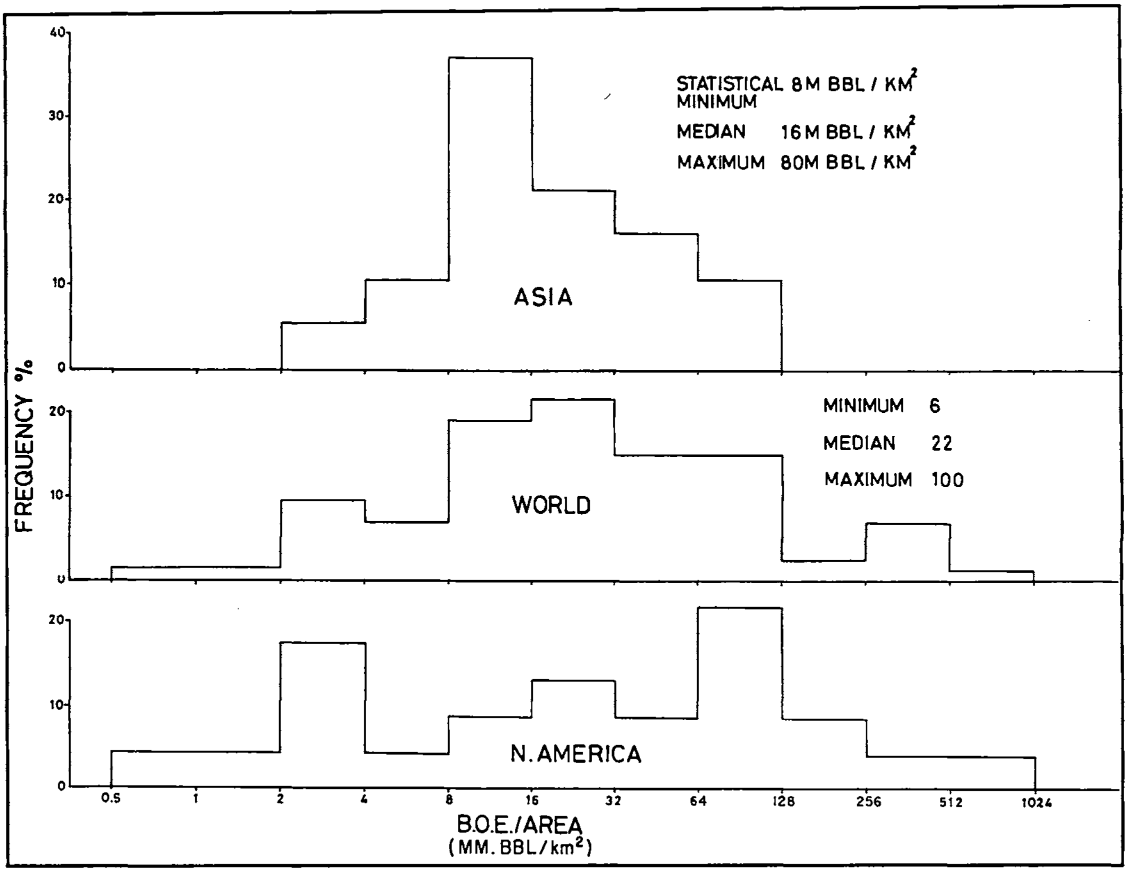

Figure 5. Comparison of areal concentration efficiency of petroleum (BOE/km²) of Asia, North America and World (data from St. John, 1980). Values of median and statistical minimum (median minus one standard deviation) and maximum (median plus one standard deviation) were estimated for the first two regions from the interpretation of the cumulative frequency plot (Fig. 6).

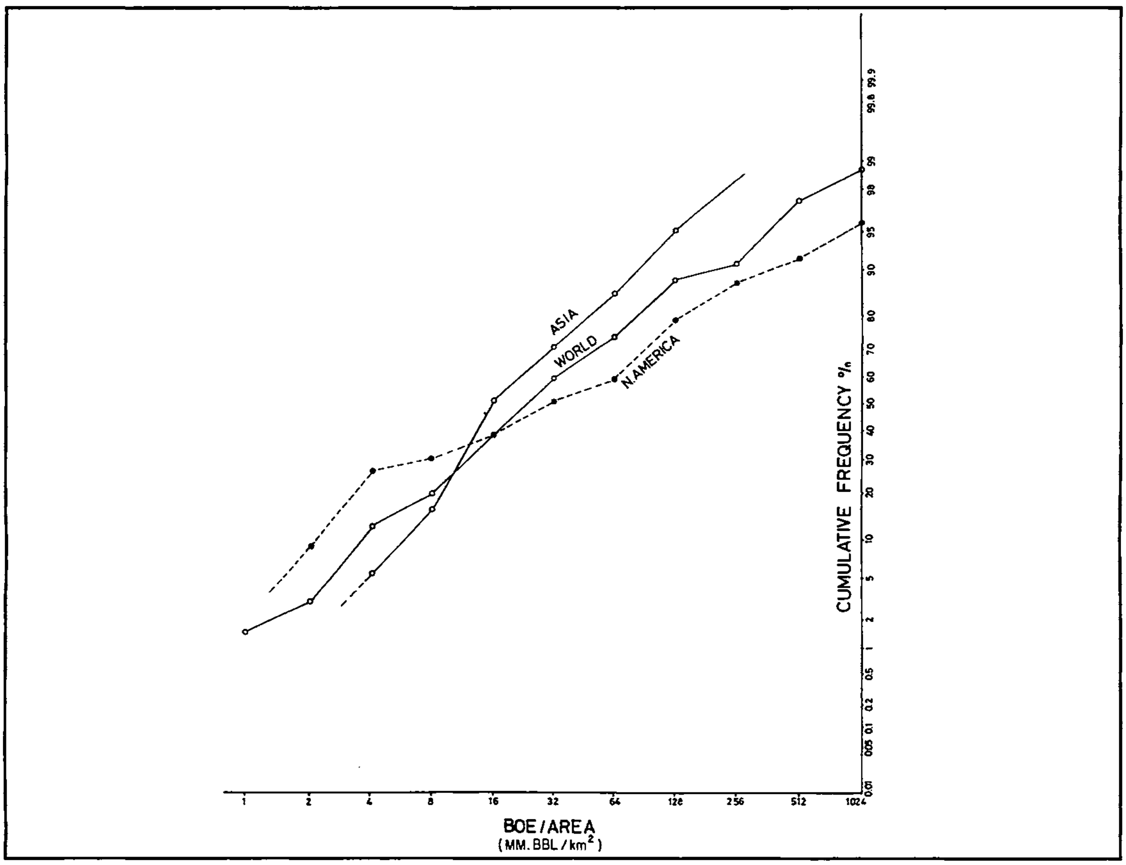

Figure 6. Cumulative frequency plots of areal concentration efficiency of petroleum (BOE/km²) of Asia, North America and World (data from St. John, 1980).

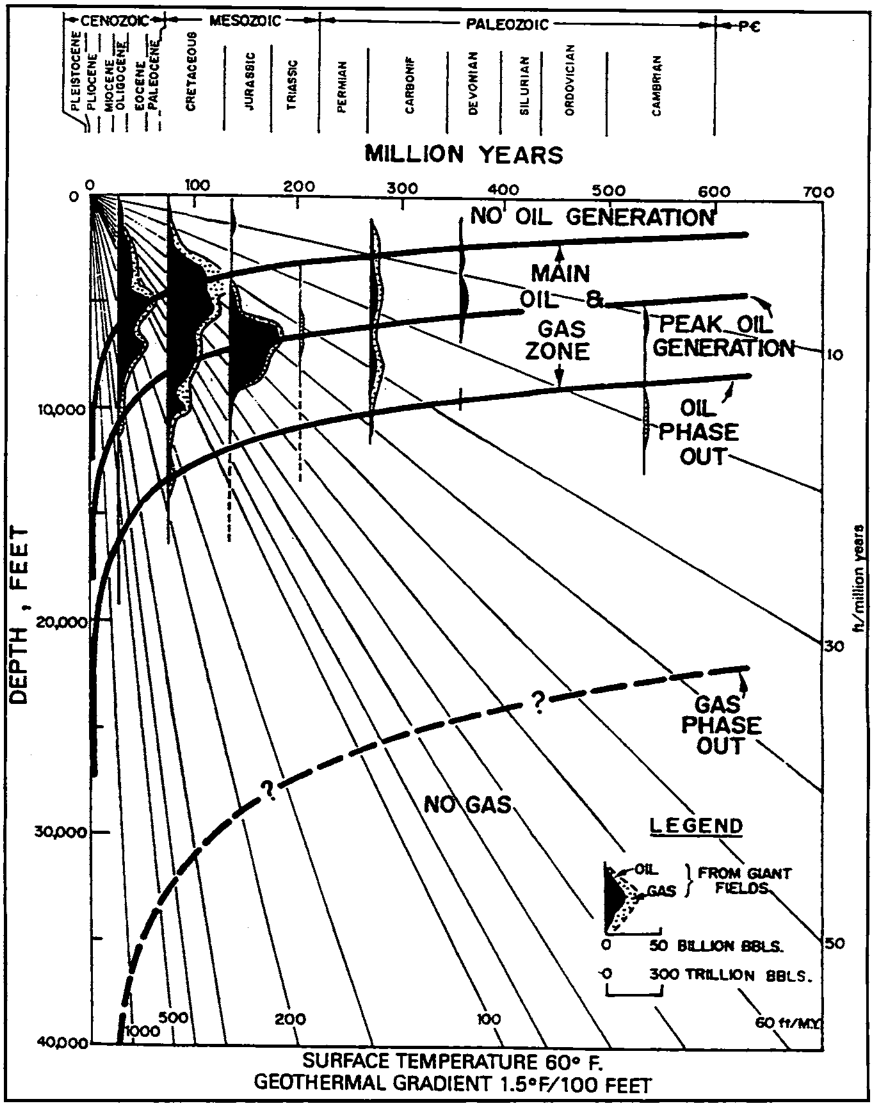

Figure 7. Comparison of Connan-Hunt's oil-genesis stages with world's giant oil/gas fields (from Magara, 1978). Diagonal lines show various rates of burial or sedimentation.

a normally-compacted region (Magara, 1986a). Therefore, the oil generation window would be thicker in the former than in the latter. Figure 8C shows the probability of oil concentration in terms of the thickness of the oil window. The solid curved line in this figure represents this probability when compaction is normal; the dashed line shows the probability when undercompaction and abnormal fluid pressure prevail.

If the geologic age of a reservoir or source rock is great, the chances of its having lost petroleum are generally greater than if it were small, and thus the rocks were younger, other conditions being constant. This age-factor must not be confused with average rate of burial; the former represents the total geologic age of a reservoir or source rock, while the latter refers to the geologic period involved in generation and maturation of petroleum. The effect of the absolute geologic age is depicted in Figure 8D.

The rate of fluid expulsion would increase as the rate of burial or sedimentation increases. However, if the sedimentation rate exceeds a certain critical level beyond which normal fluid expulsion does not occur, undercompaction may result. The efficiency of fluid expulsion from source rocks and the concentration of hydrocarbons into reservoirs would be relatively low in such undercompacted zones. As a summary, Figure 8E shows schematically the efficiency of fluid expulsion when sediment compaction is either normal (solid curve) or subnormal (dashed curve-undercompaction).

Hunt (1990) recently suggested that oil and gas have migrated upwards from deep, hot overpressured source rocks in such basins as the U.S. Gulf Coast, Niger and Mahakam, where sedimentation rates have been fast. Although Hunt's hypothesis may be valuable in these basins, its application for more general cases has not yet proven, because undercompaction/overpressure is believed to be caused by the restricted fluid (hydrocarbons and water) movement.

SUMMARY

In addition to the elements of a local but important nature, such as trap, reservoir and seal, all the factors listed above seem to have influenced the concentration or dispersion of petroleum. A combined effects of these factors may have controlled the richness of a basin in terms of commercially producible oil/gas volume. The idea presented in this paper is tentative, and needs to be verified by evidences in the future. However, the suggestions themselves may be worthwhile because they should encourage further thinking, and may guide petroleum geologists toward more efficient exploration practices.

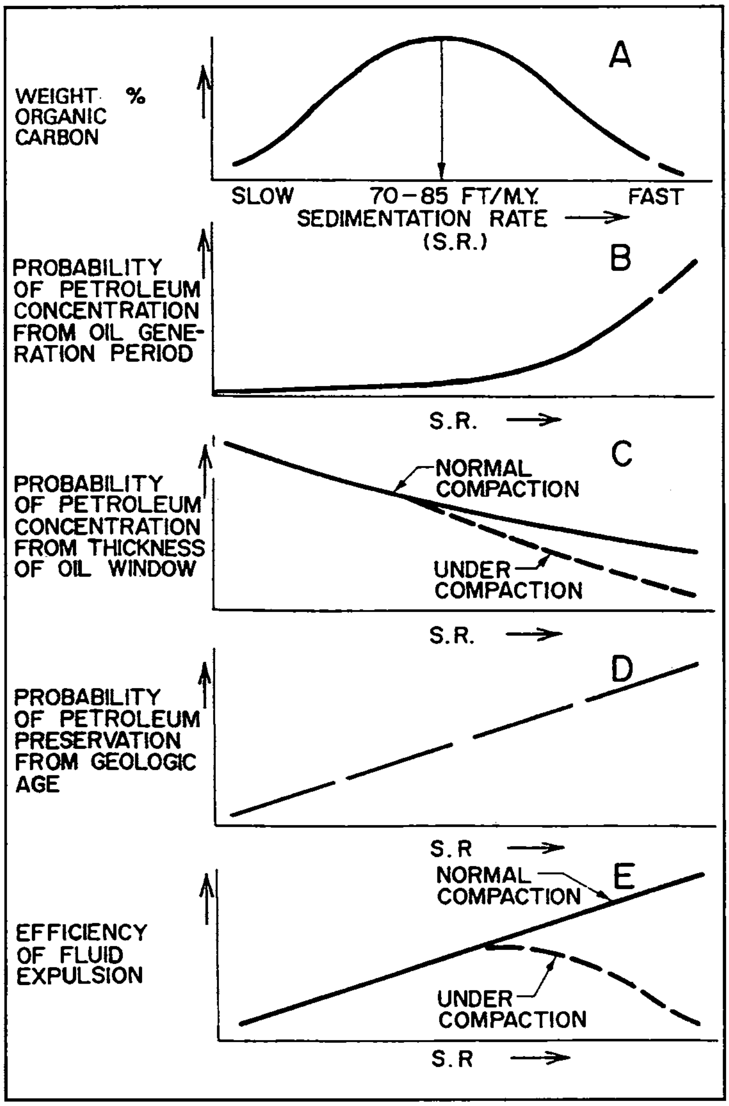

Figure 8. Schematic diagram showing relationships between sedimentation rate (ft/million years) and: (A) weight % organic carbon, (B) probability of petroleum concentration based on duration of time for oil genesis, (C) probability based on thickness of oil window, (D) probability based on total geologic age, and (E) efficiency of fluid expulsion.

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