Mass Properties of Sedimentary Rocks and Gravimetric Effects of Petroleum and Natural-Gas Reservoirs

GEOLOGICAL SURVEY PROFESSIONAL PAPER 528-A

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By THANE H. McCULLOH

MASS PROPERTIES OF SEDIMENTARY ROCKS AS RELATED TO PETROLEUM EXPLORATION

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An investigation of the basic natural factors that control the volumetric and mass properties of sedimentary rocks in situ, and an examination of expected surface and subsurface gravimetric effects of low-density reservoir rocks saturated with petroleum fluids

UNITED STATES GOVERNMENT PRINTING OFFICE, WASHINGTON : 1967

UNITED STATES DEPARTMENT OF THE INTERIOR

STEWART L. UDALL, *Secretary*

GEOLOGICAL SURVEY

William T. Pecora, *Director*

For sale by the Superintendent of Documents, U.S. Government Printing Office
Washington, D.C. 20402 - Price $1 (paper cover)

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MASS PROPERTIES OF SEDIMENTARY ROCKS AND GRAVIMETRIC EFFECTS OF PETROLEUM AND NATURAL-GAS RESERVOIRS

By Thane H. McCulloh

ABSTRACT

Relatively negative gravity anomalies of very local extent and with amplitudes of 1.2 milligals or less have been observed over some known petroleum and natural-gas fields in southern California and in South Dagestan, Azerbaijan, U.S.S.R. These anomalies indicate that such productive hydrocarbon reservoirs are lower in density than surrounding strata. The hypothesis that the low densities result importantly from hydrocarbon pore fluids that have densities significantly lower than the density of water suggests that most petroleum and natural-gas reservoirs should produce negative gravimetric effects, although such effects may be small enough in many instances to be obscured or hidden by other anomalies. This hypothesis and its practical prospecting consequences and limitations are examined and analyzed in detail.

First-order factors that determine the densities of underground sedimentary rocks in situ are mineralogical composition (grain density), total porosity, composition of pore-filling fluid, temperature, and fluid pressure.

Grain densities of most clastic sediments and sedimentary rocks (mixtures mainly of clay minerals, quartz, and feldspars) are about 2.67 g per cm^3 (grams per cubic centimeter) when measured under standard conditions. Addition of carbonate minerals to a clastic mixture raises the average grain density and addition of carbonaceous matter lowers it, the extremes being approximately 2.87 g per cm^3 and 1.46 g per cm^3 for pure dolomite and coal, respectively. The combined effect of increased temperature and confining pressure in subsurface environments usually found in petroleum exploration is a small increase in grain density (by perhaps as much as 0.01 g per cm^3) over the laboratory values.

Total porosity of a rock is simply related to its grain and dry-bulk densities, properties which can be determined accurately from laboratory measurements of weight, grain volume, and bulk volume of samples from conventional drill cores. Analysis of published determinations of compressibility of porous rocks and of meaningful comparisons between densities determined in the laboratory and those calculated from gravimeter observations in a mine shaft suggests that accurate laboratory determinations of total porosity are reliable measures of total porosity of rocks in situ underground. Laboratory measurements of thousands of samples from hundreds of wells, mainly in the deep Tertiary basins of California and Italy, are the basis for several empirical curves of decreasing porosity as a function of increasing depth. Second-order factors that affect the densities of sedimentary rocks in situ are in large part factors that affect only the total porosities of the rocks. These factors—grain size, sorting, depositional environment, depth of burial, postdepositional cementation and recrystallization, deformational history, pore-fluid pressure history, and age—are therefore only summarily reviewed.

Coefficients of isothermal compressibility and of isobaric thermal expansion of natural pore fluids of rocks are very large in comparison with those of the mineral constituents of the rocks. For the range of temperature and pressure gradients usually found in petroleum exploration, water, the normal pore fluid in sedimentary rocks, contains variable quantities of dissolved material and ranges in density from 1.00–1.08 g per cm^3 at the surface to 0.95–1.03 g per cm^3 at a depth of 13,000 feet. Under the same conditions, many hydrocarbons have densities much lower than do water and brine, although the wide range of compositions of petroleum fluids makes simple generalizations impractical. As an illustration, petroleum of 30° API gravity containing 500 cu ft of gas per barrel of oil increases curvilinearly in density under normal temperature and pressure conditions from 0.3 g per cm^3 at a 1,000-foot depth to 0.7 g per cm^3 at a 5,000-foot depth, whereas pure methane, the extreme low-density member of the hydrocarbon series, increases from virtually 0 g per cm^3 at the surface to 0.2 g per cm^3 at a 20,000-foot depth.

Density of a rock of a particular grain density at a certain temperature and pressure is a function of total porosity and composition of pore fluid. In a reservoir sandstone of a certain average total porosity, density at a particular depth is thus a function of only the pore-fluid composition. An illustration of the kind of relationships analyzed in detail is that in many basins a reservoir sandstone of 25-percent porosity has a density of 2.24 g per cm^3 where saturated with water, 2.17 g per cm^3 where saturated with petroleum of 30° API gravity and a gas-oil ratio of 500 cu ft per bbl, and 2.02 g per cm^3 where saturated with methane. Moreover, interbedded with such a sandstone are impermeable water-saturated argillaceous or calcareous rocks having densities of 2.44 g per cm^3 or greater.

The very large negative density contrasts of 0.1–0.3 g per cm^3 between porous reservoir rocks saturated with petroleum fluids and the same rocks saturated with water under reservoir conditions and the even larger contrasts of 0.2–0.6 g per cm^3 between such rocks and interbedded impermeable strata are sufficient to account for those relatively negative gravity anomalies associated with some petroleum and natural-gas fields. In others, excessive porosity within the hydrocarbon-bearing part of the reservoir or other density deficiencies may be required to account for the gravimetric effects.

Hypothetical gravimetric effects computed from density models based on selected well-drilled California oil fields of small to moderate size illustrate the kinds and magnitudes of effects expectable. The conclusion drawn from these analyses is that the negative gravimetric effects produced by petroleum and natural gas in reservoirs of moderate to large volume should be detectable in many places by conventional precise surface gravity surveys. Those factors which tend to make a reservoir commercially attractive, such as large volume, large volume-to-area ratio, shallow depth, high porosity, high petroleum gravity, and high gas-oil ratio, are those which tend to produce the most conspicuous gravity anomaly. Consideration is also given to the fact that this gravimetric method of prospecting for hydrocarbon reservoirs does not depend on indirect detection of structures favorable for entrapment, and thus should be particularly valuable in searching for stratigraphic traps and traps resulting from isolated (and unpredictable) regions of fracture, residual, or solution porosity.

The hypothetical gravimetric effects computed from the density models were utilized also for an examination of the subsurface gravimetric effects that would be obtainable through use of a borehole gravimeter having a sensitivity equal to modern surface gravimeters. Underground (borehole) gravity measurements should be of particular value in exploration for deep and small hydrocarbon accumulations in extensively explored basins, where much is already known about the rocks and structures and their densities, by extending to depth the technique of detection of the relatively negative gravimetric effects of petroleum and natural-gas reservoirs. Borehole gravimeter measurements should also prove of great value in exploration for deeper pools and lateral extensions of known pools in partly developed oil fields, thereby lowering development risks and costs. Because of the pronounced gravimetric effects of variations in porosity and pore fluid composition, borehole gravity measurements could be utilized also with advantage in evaluating reservoir properties and monitoring reservoir performance in a developing and producing field.

INTRODUCTION

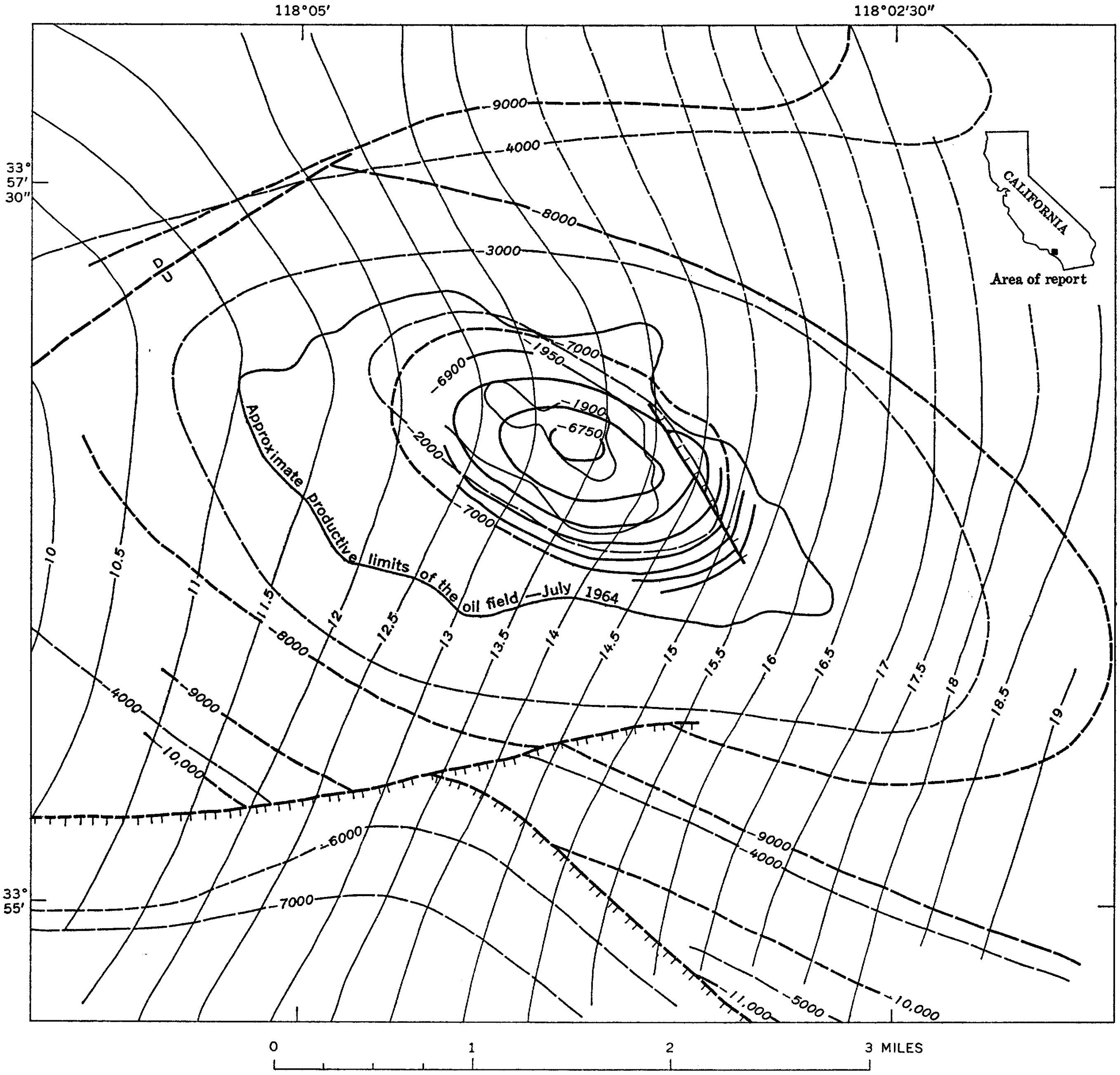
SUBJECT OF THE INVESTIGATION AND HISTORY OF PREVIOUS WORK

The thinking and interpretation by most users of gravimetric methods of prospecting have been dominated by an assumption that positive geologic structures in general produce positive gravity anomalies except where a mineralogically controlled rock density deficiency (such as arises from mineralogically unusual rocks like salt, gypsum, coal, or diatomite) reverses the general and normal tendency for sedimentary rocks of all types to decrease in porosity and increase in density with greater depth. This assumption is correct in some places and incorrect in others. Most structural highs that contain volumetrically important reservoirs of petroleum fluids produce gravity anomalies of smaller positive amplitudes than do barren analogous structures. This is due partly or wholly to the relatively low densities of most petroleum and natural-gas reservoirs, and holds even where no mineralogically controlled rock density deficiency is present.

Small but recognizable gravity minimums that seem to be attributable to the density deficiency resulting from petroleum or natural-gas saturation are fairly common but have not been widely publicized, and many other minimums are probably unrecognized because they are superimposed on larger gravity maximums attributable to pronounced positive structures. Minimums are most noticeable in multiple-zone oil fields of the type prevalent in the deep Tertiary basins of California; such fields are characterized by large thicknesses of highly porous petroleum-saturated sandstone. In some exceptional fields where the total reservoir thickness is thousands of feet, where the sandstones are young and highly porous, where petroleum gravity and gas-oil ratios are high, or where the reservoir is at a depth of only hundreds or a few thousand feet, conspicuous gravity minimums completely unrelated to positive gravity anomalies are present over pronounced anticlinal culminations. A few examples of such anomalies in California are those of the Santa Fe Springs oil field (fig. 1), the Buena Vista Hills field, and the main producing anticlines of the Midway-Sunset field.

R. H. Miller (1931) was apparently the first to notice and publicly record gravity minimums associated with oil-producing anticlines (in California), and he attributed the required deficiency of density to "the compaction and rarefaction of the beds caused by folding." Somewhat later, Poletaev,[1] as reported by Tsimel'zon (1959a), independently recognized local gravity minimums comparable to those of southern California, associated with gas-producing anticlines in South Dagestan, U.S.S.R., and suggested an interpretation "that the rocks saturated with gas have a low density." Barton (1938, p. 377–78; 1944) and Boyd (1946), apparently independently, interpreted the prominent gravity minimum over the Lost Hills anticline of the Central Valley of California as a product of excessively low density diatomaceous shales of Miocene age a few hundred to several thousands of feet beneath the surface, even though, in Barton's (1944, p. 13) words, "Simple anticlinal arching of the beds

[1] S. P. Poletaev in review of gravity work done by NGRI in South Dagestan from 1927 to 1931. Presented in 1934 at a conference on oil fields of Dagestan (North Caucasus Conference of Oil Geologists Trust). In Russian and not available to the writer.



EXPLANATION

Normal Reverse
Fault, approximately located
Short dashed where inferred. U, upthrown side; D, downthrown side; hachures on downthrown side

—3000—
Approximate base of upper Pliocene strata and top of highest productive sandstone reservoir unit

—8000—
Approximate base of lower Pliocene strata (top of the upper Miocene Clark zone)

Structure contours
Dashed where control is poor; short dashed where questionable. Contour interval 50 and 1,000 feet. Datum is mean sea level

—10—
Contour of equal relative Bouguer gravity anomaly values
Dashed where station density less than 8 per square mile. Values are positive relative to a local datum. Interval is 0.5 milligal

FIGURE 1.—Generalized structure contours and contours of equal Bouguer gravity values for the Santa Fe Springs anticline, Los Angeles County, Calif.

would not seem competent to produce so simple and so sharp an anomaly as the Lost Hills minimum." Tsimel'zon (1956a, b; 1959a) reexamined the anticlinal gravity minimums of South Dagestan first noted by Poletaev and concluded that they result from "zones of fracturing (high porosity) * * * " of carbonate rocks of Cretaceous age in the crests and steep flank parts of the anticlines, a conclusion not greatly unlike that reached by Miller in southern California 25 years earlier. Most recently, Medovskiy and Komarova (1959) examined several Russian anticlinal minimums, including those of South Dagestan, in terms of the possible local gravitational effects of the low densities of the petroleum and natural gas filling the pores of the reservoir rocks of these folds. They (1959, p. 676) concluded "Thus, these experimental operations allow us to assume that local gravity minima above the crests of structures are caused by gas-oil deposits," a reiteration of the long-buried view attributed to Poletaev, and a view that deserves the critical examination presented in this paper.

Three, and possibly four, characteristics of sedimentary rocks saturated with petroleum or natural gas tend to cause such rocks to be less dense than the surrounding water-saturated rocks and therefore to produce relatively negative gravimetric effects. The principal purpose of this paper is to describe and examine the consequences of what may be the most important characteristics—the low densities under reservoir conditions of many of the petroleum fluids that fill or partly fill the pores of reservoir rocks—and to consider all other factors that affect this characteristic. It is worth noting and emphasizing that this and the other characteristics which tend to cause petroleum and natural gas reservoirs to possess low densities exist in some degree irrespective of the reservoir's relationship to structure. Reservoirs not associated with prominently positive geologic structures (for example, stratigraphic traps, fracture porosity traps, reservoirs formed by lateral permeability barriers, fault traps of negligible structural relief, and anticlinal traps of small closure) produce negative gravity anomalies that may be large enough to be easily identified if they are not too small or too deep. Reservoirs associated with salt domes or with other structures in which density-deficient rocks are present also produce negative gravimetric effects, but these may be indiscernible or discernible only with difficulty against the background of effects of the other strong density contrasts.

An examination of the gravimetric effects of petroleum and natural gas reservoirs must include, as a minimum, consideration of the variations within sedimentary rocks of porosity, grain density, fluid density, and bulk density. These physical properties of sedimentary rocks and their pore fluids vary widely as a function of present (or prior) depth of burial, lithology, age, environment of deposition, deformational history, pore-fluid pressure history, pore-fluid pressure, temperature, and pore-fluid composition. Enough is known about most of these factors to establish practical limits on the range of effects of each.

ACKNOWLEDGMENTS

The author is indebted to an unusually large number of persons and organizations for assistance, advice, and many of the data that went into the preparation of this report.

For extensive discussions, helpful criticism, much encouragement, and very substantial assistance in the preparation of the manuscript, thanks are due J. E. Schoellhamer. For discussions over a period of many years of numerous questions relating to the topics of this paper, G. P. Eaton, R. F. Yerkes, C. E. Corbato', T. J. Donovan, D. E. Duggan, L. A. Beyer, P. D. Snavely, Jr., R. E. von Huene, C. H. Dix, A. O. Woodford, and James Gilluly are specially thanked.

For invaluable assistance in obtaining conventional core samples for bulk-volume measurements, the author thanks J. F. Taylor and D. C. Pontius of the Shell Oil Co.; R. C. Clawson of the Standard Oil Co. of California; D. D. Barman, Joseph Ernest, F. R. Goodban, L. J. Simon, and A. A. Cohn, Jr., of Texaco, Inc.; B. K. Johnson of the Marathon Oil Co.; H. E. Stark of the Richfield Oil Corp.; J. A. Forman of the Mobil Oil Co.; R. L. Johnston of the Gulf Oil Corp.; Tiziano Rocco of A.G.I.P. Mineraria, Ente Nazionale Idrocarburi, Italy; K. V. Hoover of the Ohio Geological Survey; F. G. Blake, Jr., California Research Corp.; and W. R. Muehlberger and P. S. Morey of the University of Texas.

For data about gravity minimums in South Dagestan, U.S.S.R., the author is indebted to I. O. Tsimel'zon.

For assistance in obtaining and compiling porosity and bulk-density data, special thanks go to J. P. Lockwood, F. K. Miller, and R. W. Tracy.

Although the report is based in largest part on data gathered in the course of investigations sponsored by the U.S. Geological Survey, gathering of many of the data that led to it and have been used in it was financed by the Institute of Geophysics and the Intramural Research Committee of the University of California. Grateful acknowledgment is also made to the Research Corporation for funds granted through the University of California, and to the Guggenheim

Foundation for financial assistance to permit contributory studies in the Po basin of Italy.

ROCK DENSITY IN SITU

A widespread practical technique has not yet been devised for determining the density of rock in situ underground without direct or indirect dependence upon laboratory volume measurements of core samples. Core-sample analysis provides the calibration and control data needed for interpretation of gamma-gamma and velocity logs in terms of density (Pickell and Heacock, 1960). Until a practical borehole gravimeter, or some other sensitive device capable of producing detailed and precise density logs, has become a reality, we will remain dependent on core analysis.

Expressed in terms of parameters partly measurable in a core sample of rock, the density in situ (σ_{is}) is:

$$\sigma_{is}=\sigma_b+\sigma_f\phi \qquad (1)$$

where

σ_{is}= the density of the rock saturated with fluid in its natural condition underground,

σ_b= the dry-bulk density of the rock, including its pores,

σ_f= the average density of the fluid (or fluids) filling the pores under natural conditions,

ϕ= the total porosity expressed as a fraction, and is equal to $1-\frac{\sigma_b}{\sigma_g}$,

where

σ_g= the average density of the solid mineral grains composing the rock.

Other equivalent expressions for density in situ obtained by substitution of various of the foregoing terms in equation 1 are:

$$\sigma_{is}=\sigma_g+(\sigma_f-\sigma_g)\phi \qquad (2)$$

and

$$\sigma_{is}=\sigma_b+\sigma_f-\frac{\sigma_f\sigma_b}{\sigma_g} \qquad (3)$$

Consideration of the terms in equations 2 and 3 reveals that knowledge of the densities of underground rocks in situ from core analysis depends on evaluation of the volume compressibilities—under low to moderate pressures and a range of temperatures like those found in nature—of the crystalline solid and the interstitial fluid constituents of such rocks, and also depends on the porosity or dry-bulk volume. The question of whether core samples provide a satisfactory basis for evaluating these factors has never been fully and satisfactorily answered and is therefore examined here. The first step in such an examination is consideration of subsurface temperature and pressure gradients.

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SUBSURFACE TEMPERATURE AND PRESSURE GRADIENTS

Subsurface temperature and pressure variation with depth produces negligible effects on the densities of the crystalline mineral constituents of most rocks, apparently produces negligible short-term effects on their dry-bulk densities or porosities, but produces pronounced effects on the densities of the interstitial fluids.

The extreme range of geothermal gradients observed from region to region over the continental areas (Van Orstrand, 1935, p. 114; French, 1940; Birch, 1954; Maxwell, 1960, p. 107–108; Moses, 1961) makes selection of a "normal" value impractical. Although the gradient range is 30–200 feet per degree Fahrenheit, a gradient of 60–70 feet per degree Fahrenheit occurs in many deep basins having thick sections of marine sedimentary rocks of late Cenozoic age. On this basis, 67 feet per degree Fahrenheit has been adopted, somewhat arbitrarily, as a standard gradient for many of the computations described here. Different gradients should be used if areas unlike the late Tertiary basins of California are to be similarly examined.

Variations of pressure with depth are only partly understood. Fluid pressures (static pressures of interstitial or pore fluids) in many wells are very nearly equal to the hydrostatic pressure of a column of moderately saline water extending from the point of measurement to the water table (Dickinson, 1953, p. 413). Sheldon (1961, p. 3) cited a range of gradients from 0.435 to 0.465 psi (pounds per square inch) per foot of depth; the gradient of 0.465 psi per foot from the water table is commonly accepted as the "normal gradient along the Gulf Coast and elsewhere (Dickinson, 1953, p. 413; Hubbert and Rubey, 1959, p. 129). In some locations, however, "abnormal" fluid pressures that are decidedly in excess of "normal" hydrostatic pressure have been noted at depths ranging from a few thousand to many thousands of feet (Dickinson, 1953; Tkhostov, 1960, p. 77–95). Hubbert and Rubey (1959, p. 149–153) reviewed the mechanisms that could produce such anomalously high fluid pressures and noted (1959, p. 153) that only in exceptional situations of rapid imposition of extreme tectonic stress would fluid pressures be produced or sustained which would equal or exceed the confining pressure of the overburden—that is, the pressure exerted at its base by a column of rock plus its contained pore fluid, sometimes called the lithostatic or geostatic pressure. Thus, the minimum pressure to be expected at depths below the surface of the zone of saturation is greater than the hydrostatic pressure exerted by a column of distilled water of appropriate height and varying temperature; the maximum expectable pressure does not exceed the pressure exerted by a column of nonporous rock having the density of the mineral constituents of sedimentary rocks, except perhaps locally in rocks of very low porosity (Judd, 1964, p. 9–13).

Static pressure at a given point in the subsurface is determined by the height of the column of fluid or rock and the density gradient in that column, in accordance with the hydrostatic equation,

$$P=\sigma g Z \tag{4}$$

where

P=pressure,
σ=average density,
g=the value of gravity,
Z=the height of the column.

Substitution of the local value of gravity in equation 4 enables one to calculate directly the pressure in pounds per square inch:

$$P=0.433\sigma Z \tag{5}$$

where

σ=average density in grams per cubic centimeter,
Z=height of the column in feet.

From equation 5 and the fluid and rock density data presented in following pages, the ranges of hydrostatic and lithostatic pressures expectable in basinal sedimentary-rock columns have been calculated and plotted in figure 2.

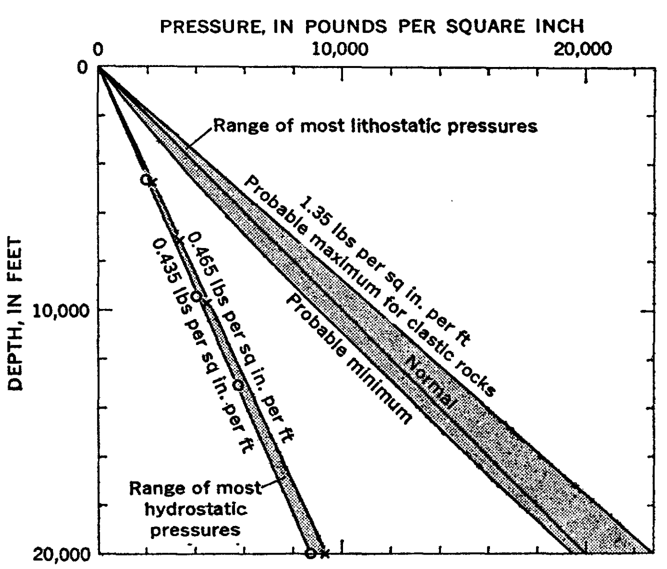

FIGURE 2.—Hydrostatic and lithostatic pressure ranges versus depth below surface. Calculated values for distilled water, o, and for brine containing 100,000 ppm dissolved solids, x, fall very near the frequently cited straight-line boundaries.

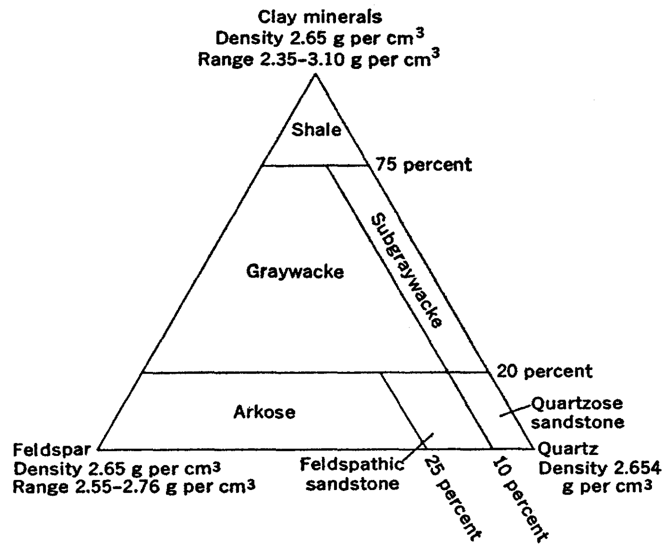

FIGURE 3.—Ranges of composition and grain densities of clastic sediments and sedimentary rocks that contain no carbonate, no carbonaceous matter, and no heavy minerals. Modified from Krumbein and Sloss (1963, fig. 5–5). Clay minerals include illite, montmorillonite, chlorite, kaolinite, and others; density at clay-mineral corner is for 70 percent illite (2.67 g per cm^3), 20 percent montmorillonite (2.40 g per cm^3), and 10 percent chlorite (3.00 g per cm^3). Feldspar includes microcline, plagioclase, orthoclase, sanidine, and others; density at feldspar corner is for calcic oligoclase ($Ab_{70}An_{30}$).

The presence of "heavy" minerals or carbonate minerals in a clastic rock such as can be portrayed in figure 3 causes the grain density to range upward from 2.65 to 2.75 g per cm^3, or higher, and explains why most grain densities reported from marine sedimentary rocks and sediments are about 2.68 g per cm^3 (Hedberg, 1936; Trask and Rolston, 1951; Hamilton and Menard, 1956, p. 756; Nafe and Drake, 1957, p. 541 and fig. 15).

Sedimentary rocks containing large percentages of "heavy" minerals are rare. On the other hand, clastic rocks rich in carbonate minerals are abundant; the mineral composition of clastic rocks ranges continuously from that which can be portrayed completely in terms of the constituents of figure 3 to pure calcite, aragonite, or dolomite rocks. In such a series, increasing carbonate content increases the grain density, which reaches a maximum of about 2.87 g per cm^3 for nearly pure dolomite. Thus, because of their admixed carbonate minerals, calcareous sandstones and marls have higher grain densities than noncalcareous sandstones and shales.

In contrast to the "heavy" and carbonate minerals that raise the grain densities, carbonaceous material, a fairly common constituent of near-shore clastic facies (even those deposited in deep water), causes grain density to be as low as 2.54 g per cm³ for some carbonaceous sandstones and silt stones. Certain less common rocks, such as diatomite and salt, also have low grain densities by virtue of their content of opaline silica or of evaporite minerals, particularly halite and gypsum.

Although little is known about the combined effects of moderately elevated temperatures and pressures on the volumes and densities of the abundant constituents of sedimentary rocks, the available data indicate that the effects are negligible for the range of temperatures and pressures found to depths of about 20,000 feet in most sedimentary basins.

The coefficient of isothermal compressibility, C, of a homogeneous substance at a temperature, t, is defined as:

$$C=-\frac{1}{V_o}\left(\frac{\Delta V}{\Delta P_e}\right)_t \tag{6}$$

where

V_o=an initial volume,
ΔV=a finite small change in volume,
ΔP_e=a corresponding finite change in external confining pressure.

The isothermal compressibility of a pure mineral substance can be expressed in terms of equation 6.

For a porous substance, the bulk volume isothermal compressibility, C_b, at a certain temperature, t, is defined as:

$$C_b=-\frac{1}{V_{b,o}}\left(\frac{\Delta V_b}{\Delta P_e}\right)_{P_i,\,t} \tag{7}$$

where

$V_{b,o}$=bulk volume (initial),
ΔV_b=a finite small change in volume,
P_e=the external confining pressure,
P_i=the pressure of the fluid in the pore spaces.

The isobaric coefficient of thermal expansion, α, of a substance at a given confining pressure, P, is defined as:

$$\alpha=\frac{1}{V_o}\left(\frac{\Delta V}{\Delta T}\right)_P \tag{8}$$

where

V_o and ΔV are defined as for equation 6 and
ΔT is a finite small change of temperature corresponding to a particular quantity for ΔV.

The volume compressibility of quartz is such that, under 20,000 psi confining pressure, it has a density of 2.665 g per cm³, an increase of 0.011 g per cm³ over the density at surface conditions (Fatt, 1958, p. 1930), if the effect of increased temperature is neglected. The effect of the expectable temperature increase on compressibility of quartz (Birch, 1942, p. 55) is a density decrease of 0.0001–0.0002 g per cm³ that is totally negligible in our considerations. Other minerals in sedimentary rocks have comparable compressibilities. Fatt (1958, p. 1937) estimated that a mixture of quartz, feldspar, and rock fragments has a grain volume compressibility of about 0.16×10^{-6} psi $^{-1}$, only slightly less than that of quartz. This compressibility would lead to an increase in grain density of less than 0.01 g per cm³ at a pressure of 20,000 psi, if the presumably small effect of the temperature change is ignored, an effect which is opposite in sign to that due to pressure.

Although more complete experimental data are highly desirable, it appears that most mineral constituents of sedimentary rocks have coefficients of isothermal compressibility and of isobaric thermal expansion such that the small changes in their densities which occur as a result of changes in temperature and pressure in the subsurface down to 20,000 feet are virtually negligible in relation to the variations in subsurface rock density which occur for other reasons.

If sedimentary rocks were not porous, their densities would be determined solely by the densities of their mineral constituents, as outlined above, and would mostly range from 2.65 to 2.87 g cm³. However, the density range of mineralogically normal sedimentary rocks is vastly greater than the restricted range of their mineral constituents because of their highly variable porosities (eq 2 and 3), and thus the effect of pressure and temperature variations on dry-bulk density and porosity, is examined next.

DRY-BULK DENSITY AND POROSITY

The question of whether core samples provide a satisfactory basis for evaluating rock density in situ is in large measure a question of whether laboratory measurements of dry-bulk volumes and grain densities of core samples are reliable measures of bulk volumes and pore volumes underground.

The author (McCulloh, 1965) has demonstrated that conventional diamond drill cores of compact shales, sandstones, and limestones of Paleozoic age can be used to determine dry-bulk density, total porosity, and density profiles in situ for depths of a few thousand feet. This conclusion is based on comparison of accurate laboratory measurements of core sample densities calculated from gravimeter measurements of the gravity gradient in a mine shaft by the method of Hammer (1950), and thus takes into account virtually all variations that might result from subsurface temperature variations.

Data of Fatt (1958) suggest that sandstones and silty sandstones with low to intermediate total porosities of 10–20 percent have bulk volume compressibilities so small at low to moderate pressures that core samples of such rocks probably provide a satisfactory basis for estimating density in situ, even though the effects of temperature variations are unknown. Only for rocks with extremely high porosities (30 percent and more) and for rocks possessing fracture porosity is there a question about the reliability of accurate core-sample dry-bulk-density determinations. The low confining pressures characteristic of the environments of the highly porous rocks minimize the possible errors arising from elastic expansion of the cores during and following the coring and removal process, providing that the internal fluid pressures are known. Therefore, one may conclude that, for these rocks also, accurate laboratory measurements of a sufficiently large number of representative core samples probably provide a satisfactory knowledge of their porosities and densities in situ, although a thorough evaluation by means of a sensitive borehole gravimeter would be highly desirable. Only cores of dense rock with secondary fracture porosity (or the relatively rare case of cavernous solution cavities or geodes) fail to provide a basis for a reasonable approximation of density in situ.

The intimate relation between the dry-bulk density and total porosity of a rock is shown by equation 2 and has been emphasized by many authors (Hedberg, 1936; Davis, 1954). Given a particular grain density, porosity is a straight-line function of dry-bulk density, the latter ranging from the density of the grains at 0 percent porosity to a density approaching 0 at 100 percent porosity.

Many authors have been concerned with variations of porosity and density of sedimentary rocks as a function of depth. Papers by Athy (1930), Hedberg (1936), Hammer (1950), Dallmus (1958), Engelhardt (1960), and Woollard (1962) are noteworthy. Data of these and many other authors, supplemented by the author's measurements on more than 4,000 conventional core samples from hundreds of wells in the Los Angeles and Ventura basins of California and the Po basin of Italy, show that gravitational consolidation reduces porosity and concomitantly increases density of sediments of all kinds. These changes are mainly functions of maximum net overburden pressure and of time, although they are secondarily affected by lithology (composition, grain size, and sorting), diagenesis, depositional environment, and tectonic stress (McCulloh, 1963). The interplay of these relationships is sufficiently complex that pronounced variations in porosity depth curves occur from place to place (Nafe and Drake, 1957, fig. 14; Dallmus, 1958; McCulloh, 1960, fig. 150.3; Meade, 1961, 1963a, b; Maxwell, 1964, fig. 12).

If accurate total porosities versus depths are plotted for a large number of sedimentary rock samples from a wide variety of geologic environments, from a broad range of lithologies, from an extreme range of depths, and from rocks of all geologic ages, a curve of maximum porosity versus depth can be drawn. In view of the great number of published porosity values for sedimentary rocks, particularly reservoir sandstones (see for example Rall and Taliaferro, 1949; Manger, 1963), there would seem to be ample data. Such curves have been made by Woollard (1962, fig. 13) and Maxwell (1964, fig. 12). However because of the possibility of systematic positive errors in many of the published porosity values, the present author has chosen to rely heavily upon his own data in drawing the curve of maximum probable porosity versus depth shown in figure 4. Only for the uppermost 1,000 feet of the curve has heavy reliance been placed on data from other sources. For that part of the curve, data of Hamilton and Menard (1956), Nafe and Drake (1957), Sutton, Berckhemer, and Nafe (1957), and Richards (1962) form a substantial basis.

The maximum probable porosity curve of figure 4 lies well toward the zero porosity line from the highest porosity "boundary curves" of Maxwell (1964, fig. 12), even though most of the samples on which the curve is based are from rocks younger than those used by Maxwell. Over much of the depth range 8,000–20,000 feet, the curve of maximum probable porosity of figure 4 is about half the porosity value of the limiting curve for all the natural rock data presented by Maxwell and is nearly the same as his most dense boundary curve for Pennsylvanian rocks. These comparisons are made and the discrepancies pointed out to emphasize the need for better quality control in core analysis data to be used in geological applications, and to stress the present state of uncertainty about such a fundamental property of fluid-bearing rocks as their pore volumes.

As better and more determinations of total porosity of sedimentary rocks accumulate, our understanding of subsurface porosity distribution and the factors that control porosity will improve, and the curves of figure 4 will probably be revised. However, because of the unanswered questions concerning the reliability of available alternative curves, these conservatively drawn curves are preferred for the purposes of this paper.

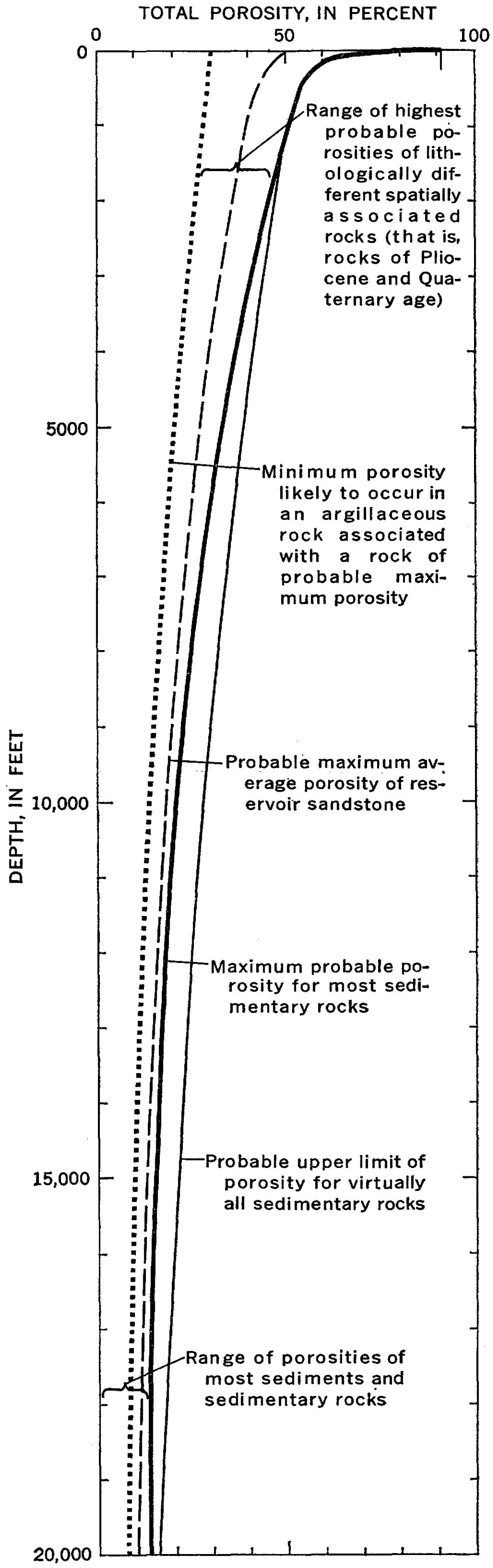

FIGURE 4.—Total porosities of sedimentary rocks versus depth derived empirically from laboratory measurements of more than 4,000 samples of conventional cores from the Los Angeles and Ventura basins of California, other scattered localities in the United States, and the Po basin of Italy.

Porosity of sediment deposited on the sea floor varies widely; the finest grained and best sorted material tends to be most porous and least dense. Subsurface sedimentary rocks beneath more than a few hundred feet of overburden also vary in porosity through a fairly wide range, but the coarser grained and best sorted materials, the sandstones, tend to be most porous and least dense. At depths greater than a few hundred feet, spatially associated samples of different lithologies have notably different porosities and densities. The maximum ranges of these porosity differences vary from about 10 percent porosity at 20,000 feet to about 30 percent porosity (possibly more) at 5,000 feet. These greatest ranges are found in the youngest rocks (Pliocene and Quaternary). The ranges found in older strata at all depths tend to be less. Figure 4 shows the limits of the range of average porosities observed by the author in spatially associated clastic marine sedimentary rocks of maximum porosity. Similar ranges probably could be established for older and less porous rocks, but these ranges probably would be found to overlap considerably at depths greater than 15,000 feet and in pre-Cretaceous rocks.

The intimate relation between dry-bulk density and total porosity has already been pointed out. Because of compositional variations, sedimentary rocks of 0 percent porosity range in dry-bulk density from less than 2.65 g per cm^3 to 2.87 g per cm^3. As porosity increases, the effect of this rather wide range of grain densities on the dry bulk density decreases (eq 2). Rocks of 40 percent porosity that differ in grain density by 0.1 g per cm^3 differ in dry-bulk density by only 0.06 g per cm^3. If the pores of such rocks are saturated with salt water—the densest of the abundant interstitial fluids—their water-saturated or "natural" (Hedberg, 1936) densities also differ by only 0.06 g per cm^3. The underground densities of most other natural interstitial fluids vary through such a wide range that saturation of a rock of 40 percent porosity with petroleum fluids instead of water produces a decrease of 0.2–0.4 g per cm^3 in the bulk density of the rock in situ, and this finding focuses our attention on the densities of natural interstitial fluids in situ underground.

SUBSURFACE DENSITIES OF NATURAL INTERSTITIAL FLUIDS

Temperature and pressure have important effects on the volumes, and therefore on the densities, of natural interstitial fluids in rocks. The importance of the thermal coefficient of expansion of petroleum fluids in production, transportation, and refining was recognized early. Isothermal compressibility similarly was recognized as an important characteristic of crude oils at an early stage, but its full importance was not evident until the economic value of the expansion of gas dissolved in reservoir crudes began to be appreciated (Miller, H. C., 1929). By 1925 the physical principles of the volumetric response of petroleum systems to variations of temperature and pressure were understood by many American petroleum engineers and chemists (Shaw, 1926), and by 1936 considerable experimental, analytical, and observational data about natural petroleum systems were published. These principles and data was admirably summarized by Sage and Lacey in a book (1939) which is still a model of clarity and thoroughness. Important subsequent developments have mainly concerned increased quantity and improved quality of observational data and analytical techniques and are summarized for the most part in numerous textbooks and reference works, such as those by Muskat (1949), Standing (1952), Burcik (1957), Amyx, Bass, and Whiting (1960), and Frick and Taylor (1962). This wealth of data enables evaluation, for present purposes, of the ranges of densities expectable under prevailing subsurface temperature and pressure conditions for each major group of natural interstitial fluids, namely waters and brines, natural gases, and crude oils. Each fluid may differ notably in density from one subsurface location to another because of the great variability of subsurface temperature and pressure gradients and coefficients of thermal expansion and compressibility.

WATERS AND BRINES

The density of interstitial water at a particular confining pressure is a function of its composition, temperature, and compressibility (the last is itself a function of the first two). To set some limits on the range of interstitial water density underground, density gradients, for hydrostatic conditions and a temperature gradient of 67 feet per degree Fahrenheit, from 0 to 10,000 feet, have been calculated approximately for distilled water, as one extreme, and for brine containing 100,000 ppm (parts per million) NaCl. The compressibility data of Long and Chierici (1961) have been used in this calculation, and the resulting density gradients (based on assumed hydrostatic pressure continuity to the water table) are shown in figure 5. At 60°F (surface temperature) and 14.7 psi (sea level atmospheric pressure), the density of distilled water is 0.999 g per cm^3. From the surface to a depth of 9,400 feet, this density decreases smoothly but nonlinearly to approximately 0.968 g per cm^3 at the temperature gradient assumed. Addition of 100,000 ppm of NaCl to distilled water at surface conditions raises the density to 1.071 g per cm^3 (Reistle and Lane, 1928, table 2) but also raises slightly the compressibility so that the density of this saline water decreases nonlinearly to approximately 1.037 g per cm^3 at 9,700 feet.

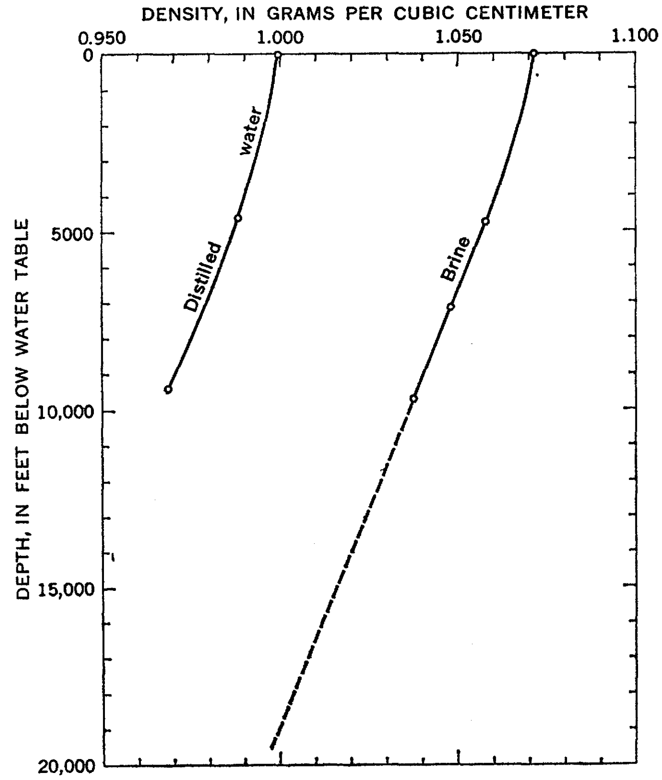

FIGURE 5.—Density gradients of pure water and brine containing 100,000 ppm NaCl, at an assumed temperature gradient of 6.7 feet per degree Fahrenheit and hydrostatic pressure continuity.

Although the solubility of natural gas in interstitial water is small relative to its solubility in crude oil, Dodson and Standing (1945) have shown that the presence of even small quantities of dissolved gas at pressures below the saturation pressure substantially lowers the density of interstitial waters. Increasing brine salinity appears to lower the natural-gas solubility and therefore to increase the density, as does increasing the gas gravity.

The density gradients of figure 5 have been used in equation 4 to calculate hydrostatic pressure versus depths shown in figure 2 for comparison with those cited in the literature. Figure 2 shows that pressures due to nearly pure water at the assumed geothermal gradient fall almost on the limiting pressure gradient of 0.435 psi per ft, and those due to the assumed brine fall near the upper limiting gradient of 0.465 psi per ft. From figure 5, one can also see the rationale in assuming a density of 1.00 g per cm^3 for the interstitial water in the calculation of "natural" density from dry bulk density and total porosity when actual measurements of density (or composition) and temperature of subsurface waters are not available.

NATURAL GASES

Even though interstitial waters are variable in composition, and therefore in their volumetric behavior, they are almost ideally simple in comparison with petroleum fluids. Most natural hydrocarbon systems are much more varied chemically than aqueous systems, and the range of characteristics of different hydrocarbon systems, from almost pure methane to dense asphaltic tars, is far greater. Natural petroleum systems are complex and multicomponent, commonly consist of two or more phases, and are much more responsive volumetrically than water or brine to variations in temperature and pressure. Rarely are hydrocarbon reservoirs as easily assayable or as thoroughly assayed as water reservoirs can be. For these reasons, generalizations about the underground densities of petroleum fluids in situ cannot be made without scrupulous attention to qualifications.

The least dense of the abundant natural interstitial fluids are methane, ethane, and other so-called gaseous hydrocarbons.[2] Methane, having the lowest molecular weight, is the least dense of these, and is very responsive volumetrically to variations of temperature and confining pressure. Although pure methane and the other gaseous hydrocarbons do not behave as ideal gases, except at high temperatures and very low pressures, the "perfect gas laws" (Boyle's law, Charles' law, and Avogadro's law) are nevertheless a convenient starting point for consideration of their volumetric behavior under varying subsurface conditions.

The relations between temperature, T, specific volume, $\overline{V}$, and pressure, P, of an ideal gas at equilibrium may be expressed by the basic equation,

$$P\overline{V}=\frac{RT}{M} \tag{9}$$

where

R= the gas constant for one mole of the gas,
M= the molecular weight of the gas.

One sees from this relation that the $P\overline{V}$ product of an ideal gas is a linear function of the temperature, and that specific volume is directly proportional to temperature and inversely proportional to pressure.

Actual hydrocarbon so-called gases at most temperatures and pressures depart from the behavior described by the perfect gas laws. For them, exact relations of pressure, volume, and temperature are described (Opfell and others, 1959, p. 7–13, and equation I.3) by the expression,

$$P\overline{V}=Z\frac{RT}{M} \tag{10}$$

where Z, the "compressibility factor" for any actual so-called gas, is a function of temperature and pressure, and is an empirical and experimentally determined quantity. Z for a perfect gas would be equal to 1, and for a real and imperfect gas may vary from greater to ess than 1, as a function of temperature and pressure.

Standing and Katz (1942a) and Elfrink, Sandberg, and Pollard (1949) provided compressibility data and correlations for many saturated natural gases, and Kvalnes and Gaddy (1931), followed by Olds, Reamer, Sage, and Lacey (1943), Brown, Katz, Oberfell, and Alden (1948), Brokaw (1949), Sage and Lacey (1955), and Opfell, Pings, and Sage (1959), presented masses of compressibility data for pure hydrocarbon gases and undersaturated natural gases. From these and other published data, the densities characteristic of pure and natural hydrocarbon gases of different compositions or gravities at various temperatures and pressures may be calculated exactly, or closely approximated.

Methane provides a means of establishing minimal limiting gradients of fluid density versus depth for the entire family of petroleum fluids. To accomplish this, a minimum likely confining pressure gradient of 0.435 psi per ft and a maximum likely temperature gradient of 30 feet per degree Fahrenheit are assumed, and the density of methane is approximated for a series of depths down to 20,000 feet by using data of Brown, Katz, Oberfell, and Alden (1948, fig. 12, p. 18). Similarly, a curve of maximum methane density versus depth is based on a maximum possible overburden pressure of 1.135 psi per ft and a minimum likely temperature gradient of 200 feet per degree Fahrenheit. Lastly, a curve of methane density versus depth more reasonably expectable in young marine sedimentary basins is based on an assumed pressure gradient of 0.445 psi per ft and a temperature gradient of 67 feet per degree Fahrenheit. These three curves—the probable minimum, the probable maximum, and a "normal" profile of methane density versus depth—are reproduced in figure 6, in comparison with the profiles of water and brine densities of figure 5. Whereas the density of interstitial waters

[2] For convenience, some authors (Sage and Reamer, 1941, p. 180) arbitrarily define "gas" as the fraction consisting predominantly of pentanes and less dense hydrocarbons, and "oil" as the fraction consisting mainly of hexanes and more dense compounds. This device is practically convenient but is not realistically related to the phase behavior of these compounds, all of which may exist as components in various solutions which may be gaseous, liquid, or above the critical point, depending upon the composition of the particular solution, and the temperature and pressure of the system.

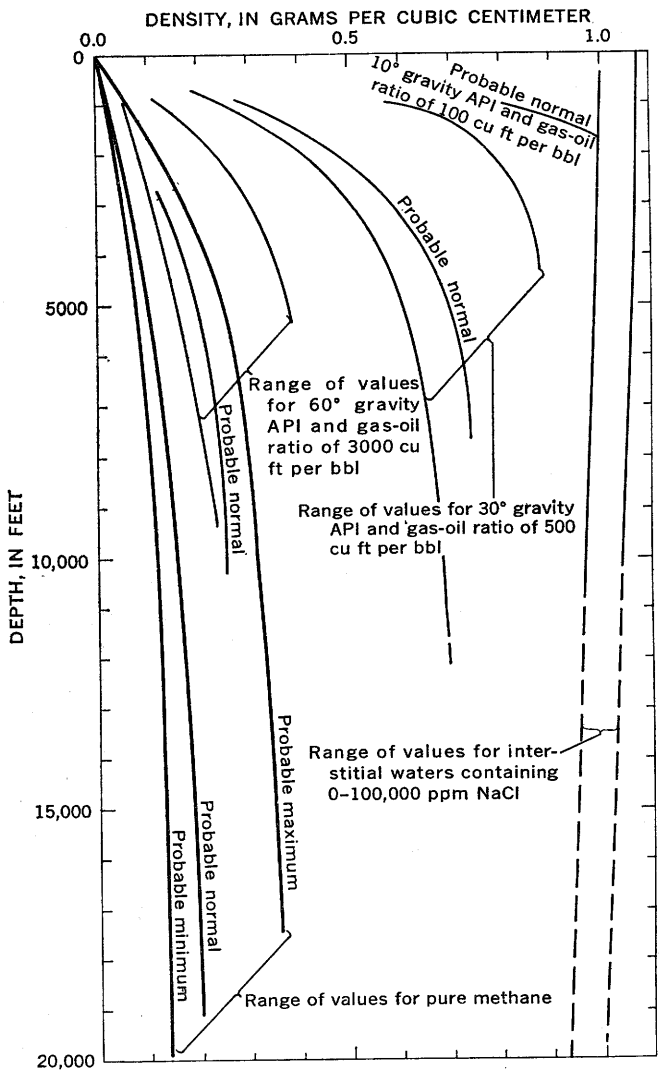

FIGURE 6.—Variations in density of interstitial fluids as functions of depth, three sets of assumed temperature and pressure gradients, and fluid composition. Curves for interstitial waters from figure 5.

gradually decreases with depth, the density of methane increases with depth under any set of subsurface temperature and pressure gradients. The rate of increase of density is greatest at low pressures and temperatures (shallow depths), and becomes almost negligible at moderate to high pressures and temperatures. Even at the relatively great depth of 20,000 feet, the density difference between "normally" dense methane and water is roughly 0.75 g per cm³.

The compressibility factors of pure hydrocarbon so-called gases of higher molecular weight than methane and their solutions are smaller at low to moderate pressures than those of methane (Sage and Lacey, 1939, fig. 124, p. 188–191), resulting in a greater rate of increase of density with depth for gases of higher molecular weight than for those of lower molecular weight. For example, the difference in density between methane and ethane at 62°F and 40 psia (pounds per square inch absolute) is 0.002 g per cm³, but at 100°F and 577 psia is 0.035 g per cm³. Density versus depth curves analogous to those for pure methane shown in figure 6 can be constructed for other pure gaseous hydrocarbons of higher molecular weight from the data of Brown, Katz, Oberfell, and Alden (1948), or for gas "mixtures" (solutions), from the data of Elfrink, Sandberg, and Pollard (1949) or Brokaw (1949). Such curves constitute a series of families for different combinations of temperature and pressure gradients, the higher molecular weight gases being the higher density members of the families, and the families of lower temperature and higher pressure characteristics having overall greater densities. The three methane density curves of figure 6 represent the extreme low density members for three such families.

Although the maximum possible number of hydrocarbon compounds is enormous, probably only a few of them actually occur in considerable amounts in natural petroleum systems, and most of these are known to be homologous members of the three major series: the paraffins, the naphthenes, and the aromatic hydrocarbons. Illustrative of the close physical relationships of the members of the most abundant of these groups, the paraffins, is the variation in their critical properties as a function of their molecular weights (Sage and Lacey, 1939, fig. 27). Critical temperatures and densities of these compounds increase regularly and surprisingly smoothly with increasing molecular weight, and the critical pressures first rise moderately and then fall gradually. The regularity of these relationships allows order to be perceived in what otherwise might appear to be a chaos of pressure-volume-temperature variations. The particular meaning of the word "critical," as used in the preceding sentences, deserves emphasis and amplification.

Sufficient isothermal compression of a specified amount of a pure hydrocarbon gas causes condensation and the separation of a denser liquid phase of the compound. Isobaric heating of the resultant volume of the two phases causes evaporation to form a single relatively dense gas phase. If, instead, temperature and pressure are both raised, but volume is decreased in a particular way, both the liquid and gas phases persist in equilibrium with one another, the gas growing more dense and the liquid growing slightly less dense as the temperature-pressure product increases and the combined volume decreases. Further increase in temperature and pressure along the

the "dew point curve" causes the properties of the two coexisting phases to approach one another so that they become indistinguishable at and above the critical temperature and pressure of the compound. The state at which liquid and gas phases are continuous with one another is called the critical state.

Natural hydrocarbon fluids near their critical states exhibit very large coefficients of thermal expansion and compressibility. At low pressures and high temperatures, the linear relation for pure hydrocarbon gases between $\overline{V}$ and T that is described by the perfect gas laws is approached. Similarly, at very high pressures and low temperatures in the liquid region there is again a nearly straight-line relationship between $\overline{V}$ and T (the volume here being almost invariant at constant P with large change of T), behavior which approximates that attributed to ideal liquids. At temperatures above those of the critical region, these two seemingly very different sets of properties and modes of volumetric behavior grade transitionally into each other. In those regions of temperature and pressure where idealized behavior of gases and liquids cannot be used as satisfactory bases for prediction of volumes and densities, accurate experimental data are essential. The empirically determined compressibility factors, Z, previously mentioned, constitute an example, one of particular importance to us, of such experimental data obtained expressly to permit introduction of corrections for departures of real fluids from ideal behavior.

Pure methane is above its critical temperature and pressure at surface conditions and persists as a single, supercritical phase at all subsurface temperatures and pressures expected in petroleum exploration. Other pure members of the paraffin group can exist as gas-plus-liquid phases only at pressures lower than a maximum of about 750 psia (for ethane), pressures expectable only in extremely shallow reservoirs. However, the critical point for a solution of two hydrocarbon compounds is generally higher than the critical points of the two pure components. The greater the difference in the molecular weights of the two components, the greater the enlargement of the critical pressure of the intermediate solutions. For example, an intermediate solution of methane (critical pressure of about 650 psia at about —120°F) and n-decane (critical pressure of about 350 psia at 625°F) has a critical pressure of approximately 5,300 psia at 100°F (Brown and others, 1948, p. 4). This phenomenon explains the familiar and frequent occurrence in natural reservoirs of free gas caps above oversaturated petroleums, the pure components of which have critical points appreciably below the reservoir temperature and pressure.

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CRUDE OILS

Just as the volumetric behavior of hydrocarbon "gases" is determined by composition, temperature, and pressure, so also is the volumetric behavior of the denser hydrocarbons that constitute the greater bulk of crude oils. However, the task of obtaining a complete compositional analysis representative of the fluid or fluids in a particular productive petroleum reservoir is vastly more difficult for most crude oils than it is even for gases or condensate fluids. Data that are generally readily available are the gas-oil ratio (GOR) of the produced fluids (which may or may not closely resemble the original reservoir solution gas-oil ratio for a single-phase reservoir or the combined gas-oil ratios in situ of the petroleum and gas cap materials for a two-phase reservoir), the tank-oil gravity, the produced gas gravity, and partial analyses of gas composition. Because field conditions generally restrict us to the use of these simple parameters, several workers have investigated empirical correlations that would permit prediction of "shrinkage of crude oils" attendant upon their production from the reservoir from measurements of gas-oil ratio, tank-oil gravity, gas gravity, and reservoir temperature and pressure. Such correlations evolved from the work of many investigators: Sage and Reamer (1941), Standing and Katz (1942b), Katz (1943), Sage and Olds (1947), and Standing (1947, 1948).

Of particular interest to us are the formation volume correlation equations established by Standing (1947, eq 5 and 6, p. 101) for saturated single-phase and two-phase petroleum systems:

$$V_{F,BP}=f\left[GOR\left(\frac{\sigma_g}{\sigma_o}\right)^{0.5}+1.25T\right] \tag{11}$$

and

$$V_{F,t}=fP\left[GOR\,\frac{T^{0.5}}{\sigma_g{}^{0.3}}\,\sigma_o \qquad 2\times10^{-0.00027GOR}\right] \tag{12}$$

where

f=an experimental constant given by Standing,

$V_{F,\,BP}$=formation volume of bubble-point liquid in volume units per volume unit of tank oil,

$V_{F,\,t}$=formation volume of gas plus liquid phases in volume units per volume unit of tank oil,

GOR=gas-oil ratio in cubic feet per barrel,

σ_g=gravity of dissolved gas taking the gravity of air as 1 at 60°F and 14.7 psi pressure,

σ_o=specific gravity of the tank oil at 60°F and 14.7 psi pressure,
T=temperature in degrees Fahrenheit,
P=absolute pressure in psi.

These equations yield predicted values that are valid to within about 5 percent over the following ranges: 400–5,000 psia, 75–37,000 cu ft of gas per bbl, 100–258°F, 16.5–63.8° API (as defined by the American Petroleum Inst.) tank-oil gravity, and 0.59–0.95 gas gravity (air=1); they indicate that the formation volume is greater (and therefore the underground fluid density is less) as the gas-oil ratio increases, the temperature increases, the pressure decreases, or the gas gravity decreases.

To circumvent the necessity of the involved and laborious computations required in the use of equations 11 and 12, Standing (1947, figs. 8, 9) prepared convenient calculation charts that have been reproduced in several text and reference books (Standing, 1952, charts 1, 3; Amyx and others, 1960, figs. 5–31, 5–32; Standing, 1962, figs. 19–29, 19–37), and one of these charts is reproduced here as figure 7 by courtesy of Dr. Standing and with permission of the Chevron Research Corp. These charts permit the rapid approximation of formation volume factors for different sets of assumptions or facts. The in situ densities of the assumed fluids may be simply calculated using these formation volume factors from the relationship:

$$\sigma_f=\frac{\sigma_{o,atm}}{FVF} \tag{13}$$

where

σ_f= the density in grams per cubic centimeter of the combined gas and oil under reservoir conditions of temperature and pressure,
$\sigma_{o,atm}$= the specific gravity of the tank oil at 60°F and 14.7 psi,
FVF=formation volume factor, which is numerically equal to Standing's values of V_F, BP or $V_{F,t}$.

The correlations and charts of Standing have been utilized in the construction of curves of hydrocarbon fluid-density versus depth for two contrasting petroleum systems under the same three sets of temperature and pressure gradients that were assumed for computation of the minimal, maximal, and "normal" density-versus-depth curves for pure methane. In the first instance, a petroleum is assumed which has a gas-oil ratio of 3,000 cu ft per bbl, a tank-oil gravity of 60° API (sp gr 0.74), and a gas gravity of 0.80. In the second instance, a petroleum is assumed which has a gas-oil ratio of 500 cu ft per bbl, tank-oil gravity of 30° API (sp gr 0.88), and a gas gravity of 0.60. The resultant groups of curves of fluid density versus depth are shown in figure 6. The fluid density of each system increases rapidly with depth for the first few thousands of feet and then at a gradually decreasing rate of increase, illustrating the importance of the rate of change of fluid compressibility with change of pressure at all temperatures and pressures. Also, the density of a given fluid may vary for any depth through a range of more than 0.2 g per cm^3 as a function of variations from place to place of temperature and pressure gradients. However, inasmuch as highly abnormal subsurface pressures are the exception, especially at moderate depths (Tkhostov, 1960), the densities of most natural occurrences of hydrocarbon fluids are in the low-density region of the ranges shown in figure 6 and tend to lie close to the "normal" curves pictured. Finally, the strong contrasts between the densities of the petroleum fluids here assumed and interstitial waters are obvious in figure 6. Even at conditions prevalent at 12,000-foot depths, the "normal" density of a crude oil of moderate gravity and relatively low gas-oil ratio is 0.2 g per cm^3 less than that of the least dense interstitial water.

Compressibility data for hydrocarbon systems of very low API gravity and very low gas content are unavailable. Standing's data are valid only for saturated or two-phase systems in which tank-oil gravity exceeds 16.5° API and gas-oil ratios exceed 75 cu ft per bbl. Relationships publicized by Trube (1957) for undersaturated reservoir fluids are not applicable at the low pressures characteristic of most known low-API-gravity petroleum reservoirs. By a slight extrapolation of Standing's graphs, the writer has calculated the questionable density-versus-depth curve for 10° API gravity stock tank oil and 100 cu ft per bbl gas of 0.60 gravity that is shown in figure 6 at assumed "normal" temperature and pressure conditions. This curve establishes a kind of upper limit to the family of "normal" curves shown. At a depth of slightly more than 2,000 feet in young deep sedimentary basins, relatively low-gravity petroleum of low gas content has a density equal to or greater than that of interstitial water, and a positive density contrast between the two fluids occurs and increases at greater depths. It is worth noting that removal of the solution gas by depressurization from this particular crude oil also results in an increase in density to 1.0 g per cm^3 at 60°F and atmospheric pressure.

Petroleum fluids of greater specific gravity than 1.0 (at 60°F and atmospheric pressure) are known, and some are of commercial importance. Such hydro-

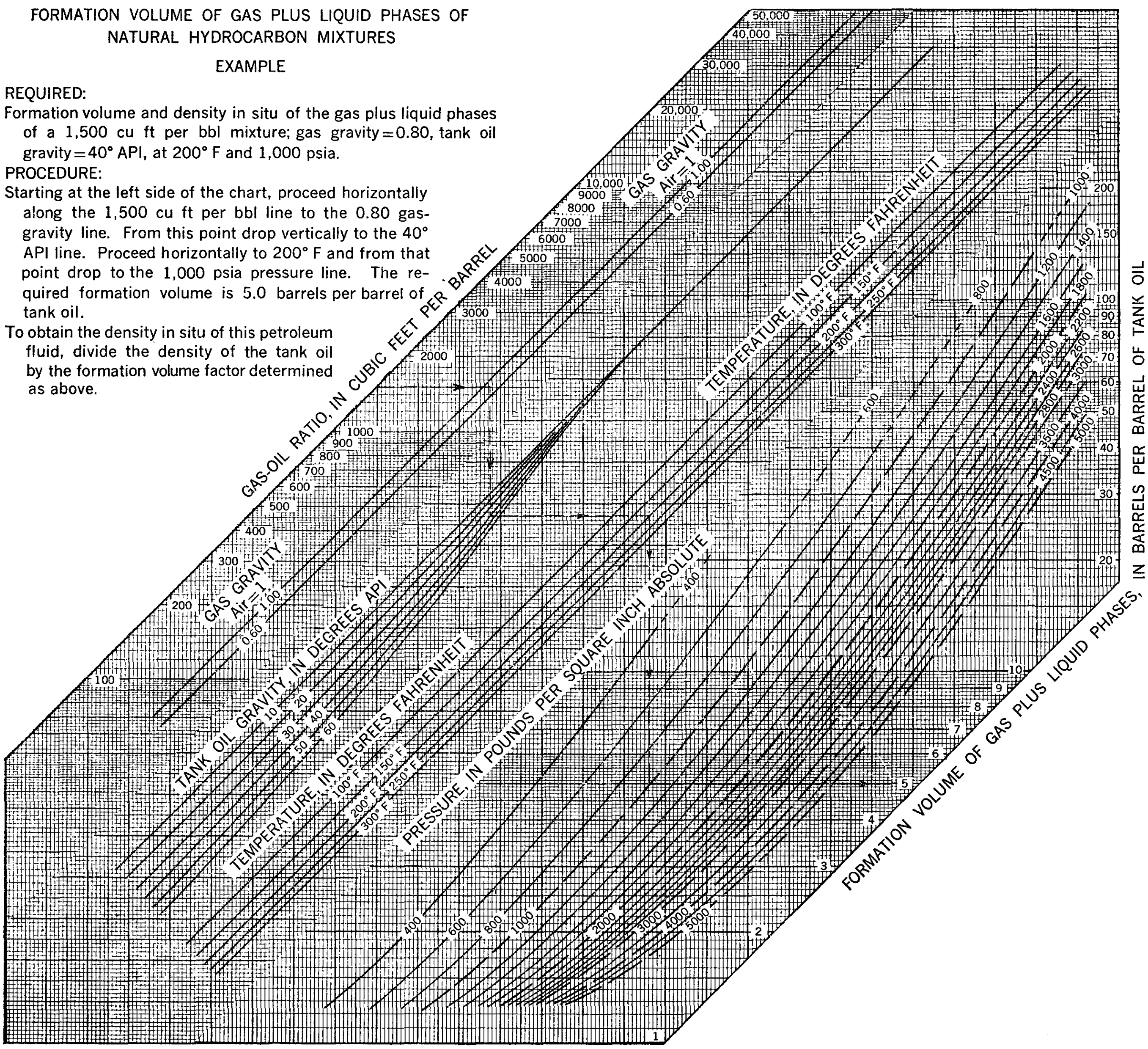

Figure 7.—Relationships among formation volume, gas-oil ratio, tank-oil gravity, gas gravity, temperature, and pressure for natural hydrocarbon mixtures. Modified from chart 1 of Standing (1947), copyright 1947 and reproduced by permission of Chevron Research Corp.

carbons are eliminated from further consideration here because the closeness of their subsurface densities to those of natural waters makes their distinction from water by gravimetric means alone impossible.

The pore space in "oil sands" may contain, in addition to the hydrocarbon fluid, a considerable volume of water. Lewis and Horner (1936, p. 354) were apparently the first to point out that 10–50 percent of the pore volume of many producing reservoirs is water instead of petroleum, and that " * * * a definite oil-water contact does not exist in most reservoirs * * *." An oil-water mixture in the pores of a reservoir rock produces an average fluid density between that of the denser water and the less dense petroleum fluid.

Figure 6 may be considered a summary of the principal facts and conclusions regarding the subsurface densities of natural interstitial fluids. Variations in temperature, pressure, and composition cause densities of interstitial fluids to vary broadly, but most commercially attractive petroleum fluids are from a few one-hundredths to several tenths of a gram per cubic centimeter less dense than the least dense interstitial waters.

SUBSURFACE DENSITIES OF FLUID-SATURATED POROUS ROCKS

The density in situ of rock of a certain porosity (and fixed dry-bulk and grain densities) is a function only of the density of the fluid filling the pores (eq 1, 2; Pickell and Heacock, 1960, fig. 6). The facts that grain density varies as a function of lithology and that fluid density varies as a function of composition, temperature, and pressure prevent establishment of a simple and universal straight-line relationship between porosity and rock density in situ. However, if the variable factor of lithology is minimized by considering at this time only porous sandstones of comparatively fixed grain density (see p. A6), and if the problem of variations in fluid density is sidestepped momentarily by arbitrarily fixing the temperature, pressure and composition of the fluid that is assumed to fill the pores of the standstone, then appropriate values of σ_g, σ_f, and $\emptyset$ can be combined in equation 3 to yield a straight-line graph of rock density in situ versus porosity.

Figure 8*A* is such a graph of densities in situ for a sandstone (grain density of 2.67 g per cm^3) assumed to be saturated in turn with each of the four principal interstitial fluids (pure water for water-saturated sandstone) whose densities are plotted versus depth in figure 6, under temperature and pressure conditions prevalent at 1,000-foot depths in young deep marine sedimentary basins ("normal" conditions of fig. 6). Saturation with methane leads to a minimum density of 1.61 g per cm^3 for rock of 40-percent porosity, whereas saturation with nearly pure water leads to a density of about 2.01 g per cm^3 for the same rock. Even the density contrast between water-saturated rock and rock saturated with moderately dense petroleum (30° API gravity) is nearly 0.3 g per cm^3 for 40-percent-porosity rock. Lower porosity leads to diminution of the density contrast between water-saturated and petroleum-saturated rock, the various lines converging on the grain density at 0 percent porosity. Figure 4 shows that at a depth of 1,000 feet in young sedimentary basins, the maximum probable sandstone porosity is 50 percent, and that the average porosity of a series of sandstone beds composing such a shallow reservoir is likely to be 40 percent, or less. Thus, one may conclude that an in situ rock density lower than 1.6 g per cm^3 at a depth of 1,000 feet is likely to arise from coal, some diatomites, or rock of unusual composition.

Figure 8*B* is analogous to figure 8*A*, except that the assumed temperature and pressure conditions (and therefore the various fluid densities) are those shown by figure 6 to be prevalent at depths of 4,000 feet. The increased density of pure methane over the values at 1,000-foot depths increases the in situ density for a rock of 40-percent porosity to 1.63 g per cm^3, whereas the very slight density decrease of interstitial water leaves the in situ density of the same water-saturated rock virtually unchanged. The in situ density of the same water-saturated rock. The decrease in the density contrast between water-saturated rock and that saturated with 30° API gravity petroleum is relatively much greater; the contrast of nearly 0.3 g per cm^3 at 1,000 feet is decreased at 4,000 feet to only slightly more than 0.15 g per cm^3. Figure 4 shows that the probable maximum sandstone porosity at 4,000 feet is slightly less than 40 percent and that the average sandstone porosity likely to characterize the most porous reservoir is about 30 percent. Therefore, an in situ density less than about 1.90 g per cm^3 at this depth is probably indicative of coal, some other mineralogically unusual rock, or possibly, sedimentary rock dilated by abnormal fluid pressure.

Temperature and pressure conditions prevalent at depths near 6,000 feet lead to the in situ rock densities shown in figure 8*C*, for fluid compositions identical with those previously assumed. As the rate of increase of hydrocarbon fluid density slackens between 4,000- and 6,000-foot depths (see fig. 6), the rate of density increase of porous rock of a given porosity also decreases. However, the probable maximum average porosity of a reservoir sandstone at 6,000 feet is about 25 percent, a decrease of 5 percent from that at 4,000 feet, so that the probable maximum density contrast is decreased to approximately 0.22 g per cm^3 (between water-saturated and methane-saturated rock of 25 percent porosity). The density contrast, at the temperature and pressure assumed, between sandstone saturated with water versus the same rock saturated with petroleum of 30° API gravity is 0.08 g per cm^3, or less.

If a temperature of 209°F and a pressure of 4,465 psia are characteristic of a reservoir at 10,000 feet, the in situ densities of the reservoir rocks vary as shown by figure 8*D*. Even for the relatively low probable maximum porosity of 21 percent at such a depth, the density contrast between methane-saturated and water-saturated rock is 0.18 g per cm^3, and the density in situ of a rock saturated with petroleum of high gravity and large gas-oil ratio is much closer to the minimum values of methane-saturated rock than

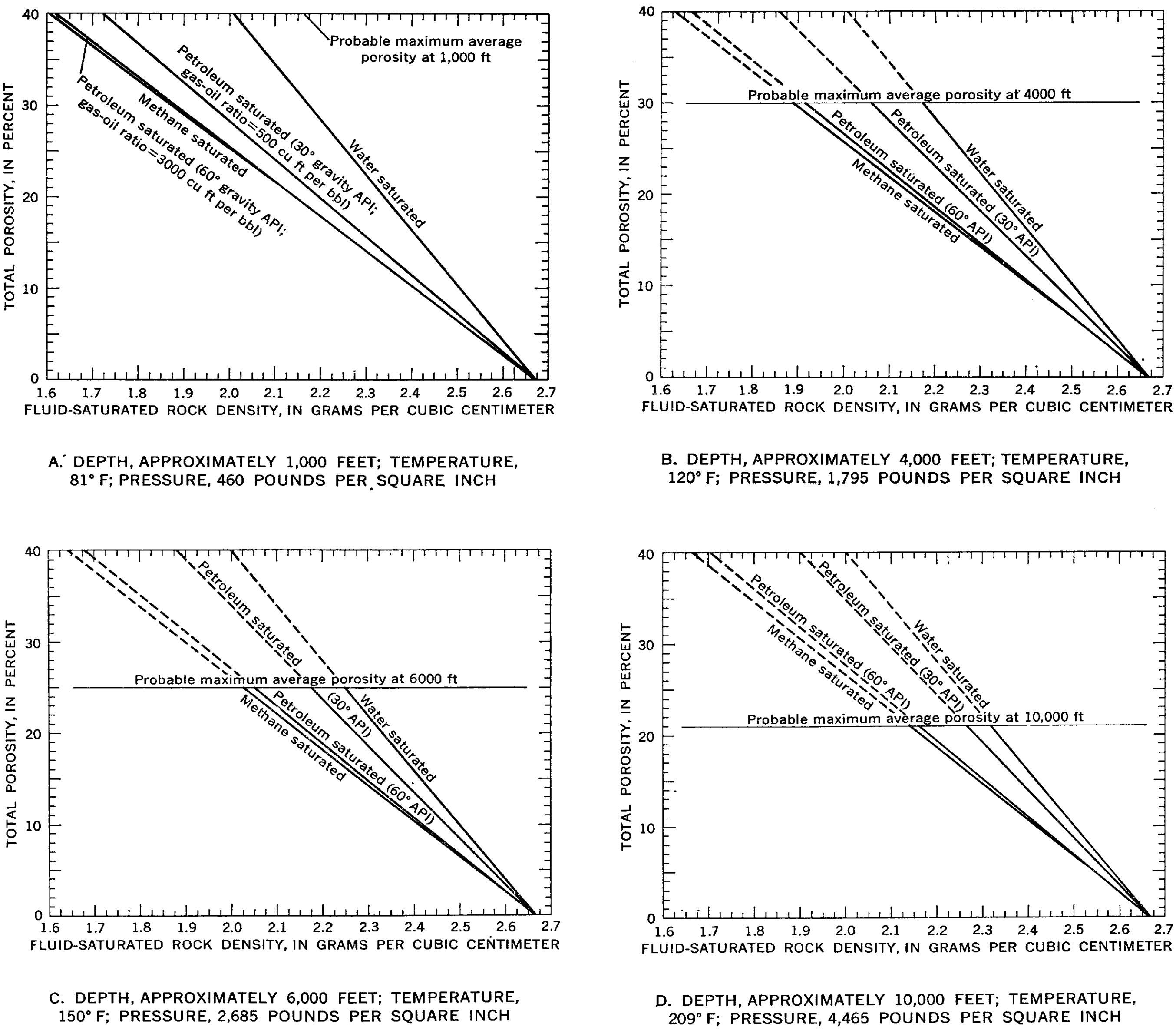

FIGURE 8.—Rock density in situ as a function of total porosity and fluid composition at various temperatures and pressures assumed to be prevalent in young deep marine sedimentary basins. Grain density assumed is 2.67 g per cm^3.

to values for rock saturated with petroleum of intermediate or low gravity and gas-oil ratio.

For any set of depth-dependent temperature and pressure gradients, a matching set of density-versus-depth curves can be calculated for interstitial fluids of different compositions. If measurements of subsurface temperature gradients are available for a particular region, and if a hydrostatic pressure gradient can be assumed as a basis for a first-approximation prediction of subsurface pressures, curves of fluid density versus depth for that region can be drawn for any number of possible interstitial fluids. If, in addition, the distribution of porosity is known as a function of depth for a potential reservoir unit or units, the curves of fluid density can be meshed with the curves of porosity to establish curves of in situ reservoir density versus depth for each of the fluids and reservoir rocks of interest.

As an illustration of this procedure, let us consider a part of a hypothetical deep marine basin filled with clastic sedimentary rocks of late Cenozoic age, having a temperature gradient of 67 feet per degree Fahrenheit and a pressure gradient of 0.445 psi per ft, as assumed in the development of the data presented in figure 8. Assume further that sandstone units holding promise as oil or gas reservoirs are known to vary

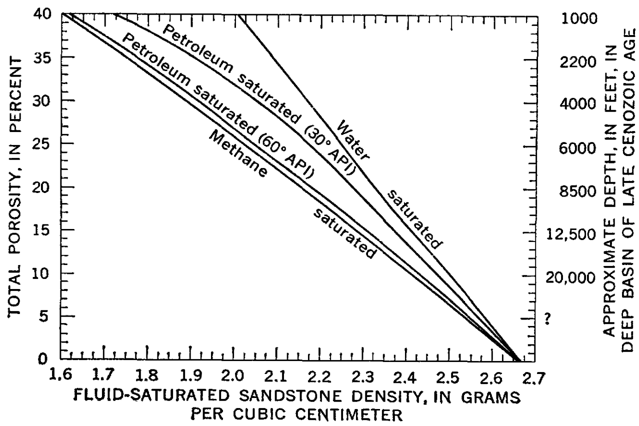

FIGURE 9.—Average density in situ of reservoir sandstone, as a function, of fluid composition and total porosity. Assumptions: Probable maximum average porosity for depth, temperature, and pressure gradients prevalent in young marine sedimentary basins, and gas-oil ratios as given in figures 6 and 8.

in total porosity with depth in approximately the same way as the dashed line (assumed probable maximum average porosity of reservoir sandstones) in figure 4. Combining these two sets of factors by use of equations 1 or 3, 11 or 12, and 13 for the same fluids considered in figure 8, the curves of average sandstone density versus depth shown in figure 9 can be constructed. Temperature, pressure, and porosity gradients used in the construction of figure 9 are nearly limiting values (at least in the light of the author's knowledge); temperature and pressure at any depth are near the minimum values found in petroleum exploration, and porosity at any depth is near the maximum. The approximate depths on the right side of the diagram correlated with the average reservoir sandstone porosities on the left side can be thought of as nearly maximum depths of the in situ densities shown. An increased temperature in such rocks would result in less dense fluid, but would probably be accompanied by a decreased porosity, changes which would tend to compensate for each other in respect to their effects on in situ density. Similarly, an increased fluid pressure would result in more dense fluid but would probably be accompanied by an enlarged pore volume, changes which again tend to compensate for one another in respect to their effects on the in situ density.

The in situ densities are higher (fig. 8), and the range of densities for different fluids is less, in proportion to the lessened porosity, of reservoir rocks of lower porosities than these probable maximum average values at such temperatures and pressures. Similarly, different pressure or temperature gradients can accompany this or other porosity gradients, but, as mentioned previously, the curves shown probably represent values near the low density end of the range of in situ density. As such, they provide, together with the data of figure 8, a limiting basis for consideration of the gravitational effects of petroleum and natural-gas reservoirs.

All the data on the densities and porosities of sedimentary rocks and their constituents that are presented separately in figures 4–9 are combined in figure 10. In addition, figure 10 summarizes graphically the effect on in situ rock density of variations in mineralogical composition. It also shows the probable maximum densities that clastic and carbonate sedimentary rocks attain without hydrothermal alteration or metamorphic recrystallization and the positions of densities of some coals (Heiland, 1940, table 14, p. 79) and some water-saturated diatomites (the author's data). Two features of the graph deserve particular attention. One is the large area of overlap of density in situ among rocks saturated with water and those saturated with petroleum fluids; the in situ density of most rocks at most depths is nondiagnostic of the fluid content when viewed alone. The other is the area of densities of rocks saturated with petroleum fluids, ranging in composition from methane to 30° API petroleum, which does not overlap the area of densities of water-saturated rocks. At all depths down to 15,000 feet, rocks in the range of "maximum probable porosity" of figures 4 and 10 that are saturated with petroleum fluids less dense than 30° API gravity and 500 cu ft per bbl gas-oil ratio are less dense than the same, or more porous, rocks saturated with water under the same conditions of temperature and pressure. For these rocks of maximum probable porosity (and even more so for rocks, if they occur, which exceed the upper limit of this range), the in situ density alone is diagnostic of the hydrocarbon pore fluid content.

QUANTITATIVE GRAVIMETRIC EFFECTS OF FLUID-SATURATED POROUS ROCKS

The basic principles underlying the methods of measuring, reducing, and analyzing gravity variations are well established (Hubbert and Melton, 1928; Lambert, 1930; Heiland, 1940, p. 88–167; Nettleton, 1940, p. 11–62; 1962, p. 1825–1838), and need not be reviewed in detail here. A difference between two gravity measurements at two horizontally separated points (after adequate corrections are made for differences of latitude, elevation, terrain, and near-surface rock density) is attributable entirely, or almost entirely, to lateral variations in subsurface rock density. If the earth were homogeneous in density, or

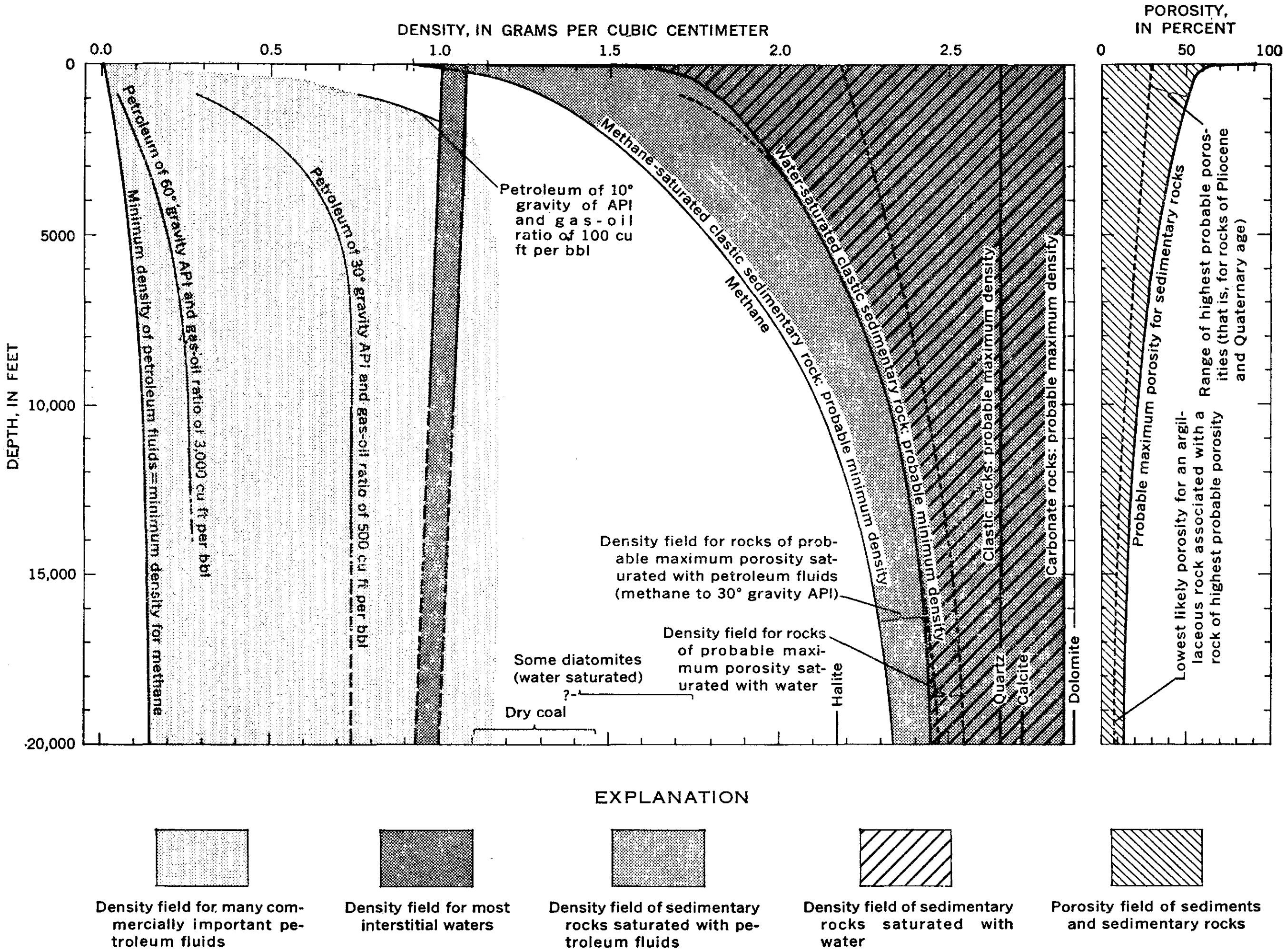

FIGURE 10.—Densities and porosities of sedimentary rocks and their constituents as functions of depth and of temperature and pressure gradients prevalent in young deep marine sedimentary basins.

if it were composed of perfectly concentric shells of laterally unvarying densities, properly reduced gravity measurements would be the same everywhere. A local mass or density deficiency gives rise to a local deficiency of gravity on the earth's surface or at any point in the subsurface above the local deficiency. The converse is true for a local excess of mass or density. The amplitude of the local deficiency or excess of gravity, the Bouguer gravity anomaly, is directly proportional to the contrast in density between the disturbing mass and its surroundings and to the size of the mass. The sharpness of the deficiency or excess of gravity—the degree to which it contrasts with the regional gravity field—is an inverse function of the depth of the disturbing mass below the point of observation. A shallow density deficit or excess gives rise to a gravity anomaly having a small width-to-height ratio compared with an anomaly produced by the same deficit or excess located at greater depth.

The proposition that petroleum reservoirs may produce gravity minimums detectible by precise gravity measurements has been stated before. The possibility was first implied apparently by Poletaev (as reported by Tsimel'zon, 1959a), suggested again by Medovskiy and Komarova (1959), and discussed by Nemtsov (1962). That the suggestion has not met with unqualified acceptance, however, is amply demonstrated by the disagreements mentioned on pages A2 and A4 (this report) over interpretation of the causes of gravity minimums associated with known petroleum-producing reservoirs, especially those disagreements between Tsimel'zon (1956a, b; 1959a, b) and Medovskiy and Komarova (1959). Moreover, the conclusions of Nemtsov (1962, p. 5 and 6 of the English translation) that "Amplitudes of model gravitational effects of oil pools in the oil field under consideration * * * range from 0.005 to 0.025 mgal, the average being 0.007–0.010 mgal" discouraged his hopes regarding gravimetric identification of such reservoirs, except possibly in the case of natural-gas reservoirs. No doubt his discouragement is conditioned in part by the relatively low accuracy of "* * * up to 0.3 milligals, * * *" admittedly characteristic of Russian gravimetric surveys (Brod and Vasilev, 1958, p. 109 of English translation). However, the present author's investigation of the problem leads him to more positive and optimistic conclusions, particularly in regard to oil fields of large closure and thick petroleum columns, multiple-zone fields with thick aggregate petroleum columns, natural-gas and condensate reservoirs, and small unexploited pools in extensively developed oil fields providing access for underground (borehole) gravimetric surveys. These conclusions also hold for the special case of detailed precise gravity surveys in support of expensive underwater exploration by seismic surveys.

Knowledge of density contrasts of rocks in an area is critical to the analysis of an observed gravity anomaly, or to the prediction of an anomaly from structural and lithologic data. Understanding the gravimetric effects of petroleum and natural-gas reservoirs requires knowledge of the density contrasts between the target of our search, rocks saturated with petroleum fluids, and rocks that characteristically surround or adjoin the target, the same reservoir rocks saturated with water and the interbedded nonreservoir rocks of low permeability and low porosity (and consequently generally of higher density). We know (fig. 10) that the rock densities vary through a wide range as a function of lithology, age, depth of burial, and pore-fluid content, but we also have seen (fig. 9) that some limits can be set on the ranges of variation.

In figure 11, the density data presented in figure 9 are replotted, for convenience, in the form of density contrasts. Water-saturated porous reservoir rocks of varying porosity provides the standard against which the densities of such rocks saturated with various fluid hydrocarbons are contrasted. The "total porosity" is average reservoir porosity, and (as in fig. 9) values of average total reservoir porosity have been related to probable maximum depths by reference to the porosity data of figure 4. Thus, a certain density contrast, which is a function of total porosity if fluid composition, temperature, and pressure are fixed, can be related to a range of depths between the surface and the probable maximum depth shown. It should be emphasized again that the porosity curves of figure 4 are conservatively drawn and have been conservatively used, so that, for the fluids shown, at the temperatures and pressures assumed, the correlations between density contrasts and probable maximum depths are almost certainly not set too deep, and any error

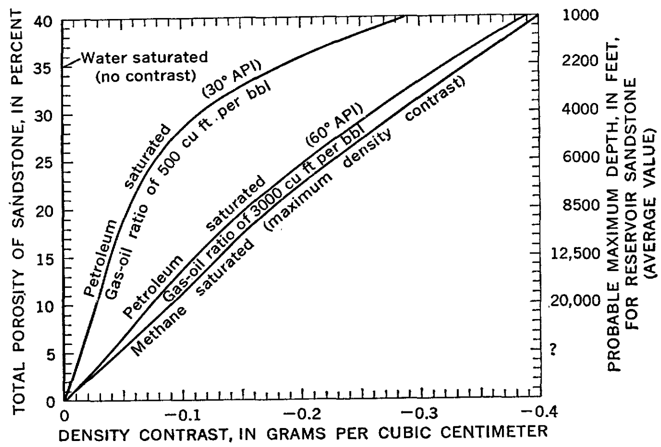

FIGURE 11.—Density contrasts between reservoir rocks saturated with water and those saturated with petroleum fluids, as functions of hydrocarbon composition and average total porosity, assuming temperature and pressure gradients prevalent in deep young marine sedimentary basins.

is likely to be on the side of being set too shallow. Similarly, the temperature gradient of 67 feet per degree Fahrenheit, assumed in calculating the fluid densities, is conservative so as to minimize the magnitudes of the density contrasts. Most departures of actual reservoirs from the assumed reservoir temperatures will tend to enlarge the density contrasts shown.

The density contrasts plotted in figure 11 represent only part of the gravimetrically important facts. On page A9 it was pointed out that porous sandstones in situ at any depth greater than a few hundred feet have densities that tend to be notably lower than interbedded shale, siltstone, mudstone, marl, carbonate rock, or almost any other nonevaporite sedimentary rock except coal or diatomite. Assuming that somewhat impure argillaceous rocks are the most abundant interbeds of porous reservoir rocks, it is desirable to know the variation in density contrast as a function of depth between water-saturated sandstones and such argillaceous rock types. Unfortunately, published data of reliable quality to fill this need are sparse. The author's own studies suggest that the average density of siltstone and shale in situ ranges from 0.25 g per cm^3 more dense than interbedded water-saturated sandstones of variable porosity in young rocks at very shallow depths to 0.06 g per cm^3 more dense in older rocks or at great depths. Figure 12 is a plot of the best and most conservative estimate of density contrasts that the author is presently able to provide.

Figure 12 shows that the greatest density contrasts between water-saturated reservoir sandstones and water-saturated argillaceous rocks occur where sandstone porosity is maximum, and thus in the youngest

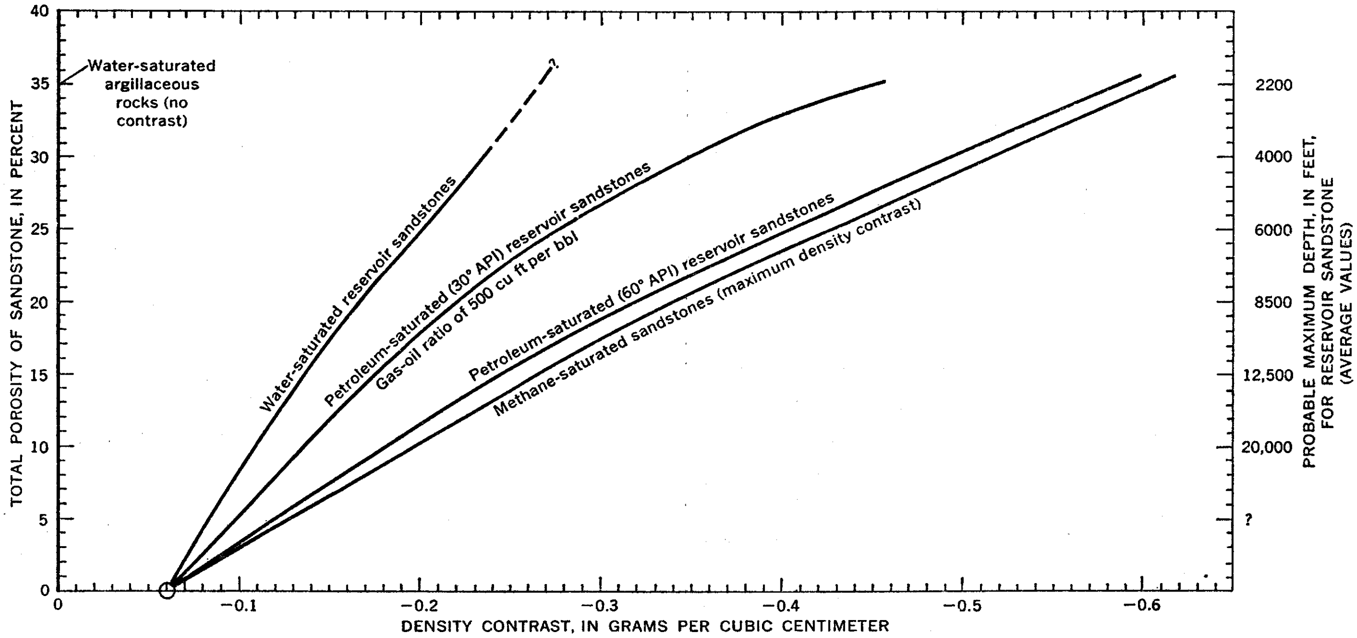

FIGURE 12.—Density contrasts between water-saturated argillaceous rocks of various maximum porosities and reservoir sandstones saturated with water or petroleum fluids, as functions of average total sandstone porosity and fluid composition.

and shallowest rocks. The same is true for the greatest negative contrasts caused by saturation with petroleum fluids. The density convergence between water-saturated sandstone and argillaceous rocks is based entirely on the author's core analysis data and is completely empirical, and the 0.06 g per cm³ separation between the two at 0 percent porosity appears to be a measure of the difference in grain density between two nonporous rocks.

One may readily discern from figure 12 that the density contrast produced by a localized mass (tongue or wedge) of water-saturated porous sandstone in a relatively homogeneous section of denser siltstones or shales should tend to produce a negative surface gravity anomaly. Saturation of that sandstone mass by petroleum fluids less dense than water merely tends to increase the negativity of the anomaly. As is usual in gravity interpretation, there is thus nothing unique about such a surface negative gravity anomaly that would permit its identification as definitely a product of petroleum saturation instead of water saturation of a hidden porous reservoir unit. However, certain factors that operate in some geologic situations should produce distinctive characteristics in the surface gravimetric effects of petroleum and natural-gas reservoirs. These factors are illustrated on pages A25–A42 by consideration of calculated hypothetical gravimetric effects of several well-drilled California oil fields used as density models but can be more fully appreciated by first considering the hypothetical subsurface gravimetric effects of reservoir and nonreservoir rocks.

SUBSURFACE GRAVIMETRIC EFFECTS OF PETROLEUM AND NATURAL-GAS RESERVOIRS AND OF SEDIMENTARY ROCKS IN SITU

The importance of reservoir depth (together with reservoir volume, porosity, and fluid density) in limiting the geologist's ability to measure or recognize the relatively negative gravity anomalies produced at the surface by hydrocarbon reservoirs must be emphasized. Reservoirs of small volume, even if they occur at shallow depths, may produce negative anomalies too small in amplitude to be recognizable, in a surface gravity survey, against the background of other gravimetric effects. Similarly, some reservoirs of very large volume may occur at depths so great that the broad anomalies produced by them at the surface may be masked. In both situations, precise subsurface gravimetric observations would provide an illuminating extension and magnification, with powerful resolving characteristics, of the surface data, and might be expected to provide a means of predicting more reliably whether a particular surface negative gravity anomaly is a product of water saturation or petroleum saturation of a porous rock.

The art of subsurface (borehole) gravitmetry is still in an infant stage of development, even though it might be said to have been conceived in 1826. In that year, Airy (1856) first attempted to determine the mean density of the earth by measuring with a pendulum the vertical gradient of gravity between the top and bottom of a vertical shaft sunk through sedimentary rocks, the average density of which was estimated from laboratory measurements of bulk density of hand samples. Although there have been subsequent attempts to repeat Airy's experiment (Miller and Innes, 1953; Domzalski, 1955) most mine shaft and borehole gravimeter measurements have had an opposiite aim: to determine, from measurements of the vertical gradient of gravity underground, the densities of the rocks surrounding the shaft or borehole. The author (McCulloh, 1965) has recently reviewed most of the papers reporting the results of gravimetric determinations of rock density in situ in mine shafts, tunnels, quarries, and boreholes in North America, western Europe, and European Russia, as well as the literature describing experimental borehole gravimeters that actually have been constructed and tested. The questionable, or limited, sucesses of the three instruments (Gilbert, 1952; Lukavchenko, 1962; Van Melle and others, 1963, p. 475; Goodell and Fay, 1964) publicized to date emphasize the need for further research efforts in developing an instrument having 10–100 times greater sensitivity and accuracy.

The principles forming the basis for reduction, interpretation, and uses of underground gravity data have been succinctly and thoroughly summarized by Smith (1950) and amplified somewhat by Domzalski (1954) and Dolbear (1959). If the earth were homogeneous in density, or if it were composed of concentric shells of laterally unvarying density, gravity in a vertical borehole would increase downward, and the increase would everywhere be the same function of depth and latitude, the differential effect of latitude variations being nearly imperceptible. In the actual earth, gravity in a vertical borehole increases as a function of depth because of the above-mentioned "free-air" effect, but small algebraically additional variations from a constant underground vertical gradient of gravity, $\Delta g/\Delta Z$, occur from place to place, vertically as well as horizontally. These variations are produced by differences in the average density of the rock layers separating two vertical observation points (and extending laterally, a distance away from the borehole that is a function of the layer thickness, ΔZ), and by isopycnic configurations that depart from level below, above, and around the borehole. If we neglect the possible gravimetric influences of the borehole cavity itself, and assume a constant free-air vertical gravity gradient, the relations among these variables may be expressed as:

$$\Delta g=(F-4\pi K\sigma)\Delta Z+\Delta T+\Delta Cg \tag{14}$$

where

Δg = the variation in gravity, expressed in milligals, measured over a certain vertical depth interval, ΔZ,

F = the assumed "normal" free-air gradient of gravity in milligals,

K = the usually accepted value for the gravitational constant,

σ = the average density, in grams per cubic centimeter, of the rocks in the interval ΔZ,

ΔT = the variation in surface terrain correction, expressed in milligals, over the depth interval, ΔZ,

ΔCg = the variation in gravity, expressed in milligals, over the depth interval, ΔZ, that results from departures from the idealized level configuration of the isopycnic surfaces around and beneath the measurement interval.

One can see that if Δg and ΔZ are measured in a vertical borehole, if F is assumed to be a valid approximation, and if ΔT and ΔCg are either negligible (no local surface terrain effects and effectively level isopycnic surfaces to great horizontal distances from the borehole) or can be evaluated from geologic and geophysical measurements, equation 14 can be solved for the average density, σ (Jung, 1939; Hammer, 1950), of the rocks between the two points of measurement with an accuracy limited only by the accuracies of the numerical values substituted for each of the foregoing terms. Conversely, if σ is known from accurate laboratory analyses of statistically valid core samples (McCulloh, 1965) or from carefully evaluated and adjusted gamma-gamma logs, and ΔCg is the critical quantity sought for exploration purposes, the equation again can be solved, this time for ΔCg, if F is known or can be assumed, and ΔT can be evaluated with sufficient accuracy.

It is apparent from equation 14 that both the average interval density, σ, and the subsurface gravity anomaly, ΔCg, are related to the subsurface vertical gravity gradient, $\Delta g/\Delta Z$, rather than to the value of gravity at a point. These facts have been clearly recognized and stated (Smith, 1950, p. 612-614; Hammer, 1950, p. 642–643, and eq 3; Hammer, 1963b) and led Smith (1950, p. 626–630) and Egyed (1960), apparently independently, to discuss the possibility of constructing a gravity-gradient meter (or gradiometer) for borehole (and other) uses. These facts also led Gran (1962) and Hammer (1963b) to examine the possibility of utilizing a vertical torsion balance for such purposes.

The importance in subsurface gravimetry of the vertical gravity gradient also focuses attention on the validity of assuming the accepted constant value of F in the interpretation of borehole gravity data, particularly in the light of empirical observations by Hammer (1938), Thyssen-Bornemisza and Stackler (1956), and Kumagai, Abe, and Yoshimura (1960) that the free-air vertical gradient of gravity varies from place to place through a range that may exceed ±10 percent of the normally accepted value after topographic corrections, but before corrections for local subsurface geology.

If it is assumed that F at a particular locality can be measured and is constant vertically beneath that point, then σ in situ underground is a straight-line function of $\Delta g/\Delta Z$ if ΔT and ΔCg are negligible or can be evaluated. Figure 13 shows graphically the correlation between rock density in situ in grams per cubic centimeter and subsurface vertical gravity gradient in milligals per foot,[3] assuming the normally accepted free-air gradient of 0.09406 mgal per ft. It is readily apparent from comparison of figure 13 with figures 5–10 that vertical gravity gradient values could be substituted for fluid-saturated rock density values in each diagram, and that precise measurements of Δg over small depth intervals if plotted against depth are logs of rock density in situ.

The potential value of detailed gravimetrically determined in situ density logs is manifold. If the pore-fluid composition of strata penetrated by a borehole is

[3] Vertical gravity gradients may be expressed in several possible sets of units, but established practice among geophysicists is to express gravity gradients in general in Eötvös units. One Eötvös unit equals $10^{-9}\frac{\text{cm per sec}^2}{\text{cm}}$ in units of the cgs system and is equal to 0.0001 mgal per m.

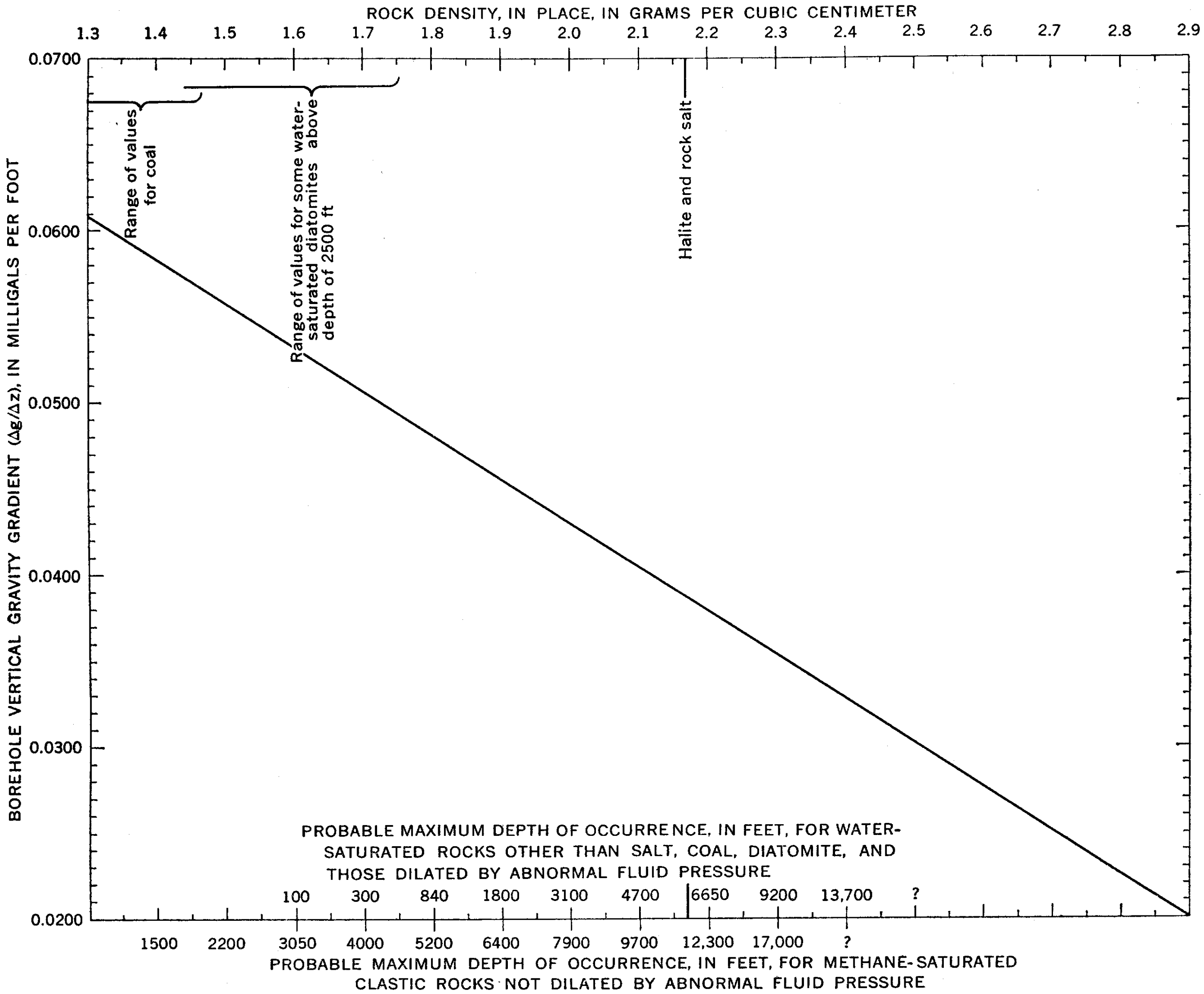

FIGURE 13.—Relation between rock density in situ and borehole vertical gravity gradient, assuming no effects from surface terrain or from subsurface departures from level isopycnic surfaces, and assuming the normal free-air vertical gravity gradient of 0.09406 mgal per ft.

known (for example, if all the rocks in a particular hole are known to be water saturated), the gravimetric density log is, in effect, usable as an average interval porosity log, particularly if drill cuttings can be used in conjunction with electric-log lithology estimates to determine grain density. It should be emphasized that such a log is one of average total porosity of the rock within a distance of the hole roughly equal to the depth interval ΔZ. (About 67 percent of the total gravimetric effect arises from rocks within $1\Delta Z$ of the well, and about 95 percent arises from rocks within $10\Delta Z$ of the well.) It is thus well suited for detecting fracture porosity, or otherwise concealed porosity, where other methods cannot. Conversely, if the average porosity in an interval is known accurately from core analysis or log interpretations, or if a reservoir porosity-depth function can be assumed, the gravimetric density in that interval can be used to measure fluid density in situ. This not only suggests a novel method of estimating reservoir fluid composition from pressure, temperature, and production gas-oil ratio measurements, but it invites consideration of borehole gravimetry as a method of monitoring the all-important changes in fluid phase or phases during production of a reservoir, of evaluating the variation of reservoir-fluid composition with depth, of studying the distribution of interstitial water within a reservoir and across the oil-water interface, and of observing edge-water fingering during water floods.

The potential importance of such applications for better understanding of reservoir properties and performance and for better production practices and reserve and recovery estimates is impossible to predict now, but surely is great. However, the applications are possible in many locations only if an instrument of very high accuracy is used. Table 1 shows the precision required in measurements of Δg to determine σ with different precisions and for different intervals of ΔZ (different bed thicknesses). Many modern surface gravimeters may be read with precisions of ± 0.01 mgal, and these high precisions presumably indicate equivalently high accuracies, if sufficient care is taken in instrument calibration and in correction for instrumental drift and tidal variations in gravity. Some surface gravitometers in use for observations of earth tides are reportedly (Lucien LaCoste, oral commun., August 20, 1964) readable with precisions of ± 0.001 mgal. The borehole gravimeter described by Goodell and Fay (1964, p. 774) apparently is capable of measuring gravity with a precision of ± 0.5 mgal, since the authors claim that, "The instrument * * * is capable of determining differences in gravity between stations to one milligal or better." If we assume that a gravimeter can be constructed to operate in a borehole with a precision and accuracy of ± 0.01 mgal, equal to that of conventional commercial surface and remote-reading ocean-bottom meters, table 1 shows that differences in density of 0.01 g per cm³ in intervals or units 100 feet thick or more could be detected, or that larger differences could be detected with greater precision or for thinner units. Reference to figure 12 will show that the ability to detect a density difference of 0.01 g per cm³ or more would enable one to discriminate between saturation by 30° API petroleum or by water in a thick sandstone unit of only 4 percent porosity, and of course would be a very sensitive indicator of all density contrasts larger than that. Thus, if a modern surface gravimeter can be adapted to the borehole environment without loss of accuracy owing to the need for remote leveling and reading and to the high temperatures and large temperature and pressure variations underground, an instrument of great practical importance in petroleum production and exploitation would result, altogether aside from its potential use as an exploration and research tool.

TABLE 1.—*Precision of determination of in situ rock density, σ, as a function of different precisions of measurement of Δg for different values of ΔZ, assuming 0.09406 mgal per ft as a free-air gradient*

Precision of σ (g per cm³)	Precision of Δg (mgal)		
	ΔZ=1 ft	ΔZ=10 ft	ΔZ=100 ft
±0.01	±0.00025	±0.0025	±0.025
±.05	±.00128	±.0128	±.128
±.10	±.00255	±.0255	±.255
±.20	±.00510	±.0510	±.510

Apart from the potential utility of borehole gravimetric measurements in studies of rock density and porosity in situ and in studies of pore-fluid content and changes of reservoir-fluid content and composition, a vast and fascinating field of use in the areas of petroleum exploration, and of underground exploration and research in general, await the development of a sensitive instrument of small size and high temperature tolerance. As we have seen, if the terms F, σ, and ΔT in equation 14 can be satisfactorily evaluated, measurements of $\Delta g/\Delta Z$ can be interpreted in terms of ΔCg, the underground gravity anomaly. One can view such interpretations in several different ways, but relating them to consideration of surface gravity anomalies, with reference to specific hypothetical examples, is desirable. Therefore, further consideration of subsurface gravimetric effects is incorporated in the discussion of hypothetical gravimetric effects calculated for selected well-drilled California oil fields.

The subsurface gravimetric effects produced in the regions below a low-density mass are rather like inverse, or mirror, images across a level surface through the middle of the mass of those in the regions above it. At a point immediately beneath the base of the low-density mass, the absence of that component of the upwardly directed gravitational attraction of an equal volume of denser rock (for example, water-saturated rather than petroleum-bearing sandstones) is sensed by the borehole gravimeter, and the measured value of gravity is excessive in proportion to the thickness, volume, and negative density contrast of the mass above. In other words, if a gravity anomaly can be perceived by surface and (or) borehole gravity surveys above an anomalous density mass, that mass will produce an anomaly of opposite sign in the regions beneath it unless its effect is compensated by a geologic correction. The practical significance of this fact for exploration can be visualized by considering qualitatively the effect of an undiscovered deeper or flanking pool on borehole gravity surveys in and beneath a known and exploited reservoir. If a positive anomaly does not occur beneath the known reservoir, or if its amplitude is less and its shape different from that expected, a deeper, or flanking, undiscovered reservoir can be suspected. Such techniques of exploration for deeper pools and undetected small extensions of known pools in oil fields where numerous production wells provide the access for fairly extensive underground surveys at several levels are probably the most commercially significant type of inquiry for the borehole gravimeter in the immediate future.

With such problems in mind, let us examine again the possible prospecting utility of departures from normal of the underground vertical gravity gradient corrected for ΔT and σ. We have seen that in a vertical borehole drilled above a reservoir, this quantity is relatively negative and is more and more negative as the low-density mass is approached vertically from above. As the reservoir is penetrated, the steep gravity gradient associated with its lower density compensates for the accumulative departure from normal and, in fact, overcompensates for it so that beneath the reservoir the gradient is again abnormally low, becoming more and more normal as measurements are made at still deeper and deeper levels. If these departures of the underground gravity gradients along a vertical line, or a vertical or horizontal profile, could be measured with a borehole gravimeter or gravity gradiometer, a very powerful and depth-sensitive technique would be available for prospecting in general, but particularly for prospecting for deeper pools and extensions of partly exploited oil fields. Therefore, the factors that limit ability to apply this technique should be examined.

Figure 13 illustrates graphically that smaller real values of $\Delta g/\Delta Z$ signify denser rocks than larger values do. A variation in $\Delta g/\Delta Z$ of 0.01 mgal per 1,000 feet is equivalent to an apparent variation in density of 0.0004 g per cm^3 over that interval. If a departure from normal of the underground gradient of 0.01 mgal per 1,000 feet is to be detected, therefore, the density term of equation 14 must be known with an accuracy greater than 0.0004 g per cm^3; such accurate measurements of density in situ are probably not possible (except by borehole gravimeter measurements where ΔCg, the quantity being sought in effect, can be evaluated with an equally high accuracy). The author (McCulloh, 1965) has shown that core-sample density profiles of compact rocks can be constructed that appear to be accurate on the average over large depth ranges to about 0.001 g per cm^3. This suggests that departures from normal of the underground gravity gradient begin to enter the range of detectability, by comparison of accurate core-sample density profiles with profiles calculated from the abnormal gravity gradient, when the departure equals or exceeds 0.03 mgal per 1,000 feet. As will be seen in following pages, a departure from normal calculated for a fairly large reservoir in the interval from sea level to minus 2,600 feet is only half the value that is the present practical limiting value, so one can see that this technique has only limited applications in regions close to small disturbing masses or more distant from masses of large volume or very large density contrast. Probably the greatest utility of the method again is to be found in searching for deeper pool extensions or lateral extensions of known traps in already drilled oil fields, and in checking the significance in shallow core holes of small local surface gravity, minimums that might be related to shallow reservoirs or to other shallow masses of low density.

HYPOTHETICAL GRAVITY PROFILES CALCULATED FOR SELECTED WELL-DRILLED OIL FIELDS IN VENTURA COUNTY, CALIF.

The recognition, almost by chance, that some productive petroleum and natural-gas reservoirs in California and South Dagestan, Azerbaijan, U.S.S.R., are marked by local small negative gravity anomalies should probably lead to suitable statistical studies of gravity maps of those and other petroliferous regions to establish empirical correlations between known reservoirs and observed gravity anomalies. Such studies would provide guides to further exploration. Of greater importance to scientific understanding, however, would be detailed gravimeteric model examinations of thoroughly explored oil fields, the geometry and physical characteristics of which are known. Such examinations would provide a basis for understanding the causes, the kinds, and the magnitudes of gravimeteric effects associated with different kinds of traps and could be conducted for any number of fields and in various degrees of refinement. The use of density models based on actual oil fields, or reservoirs, rather than on theoretical geometrically simple models seems to the author to be more logical, realistic, and instructive, but abstract models would serve the present purpose of illustration of principles equally well.

The results of analyses of three thoroughly explored California oil fields are presented here for illustration. The selection of fields has been determined to considerable extent by availability of the required basic data, tempered by the desire to illustrate the effects of several different geologic and geometric factors for reservoirs of small to moderate size. published data pertaining to the geology, reservoir properties, and fluid properties of each field have been relied upon insofar as possible. Also, the simplest kind of gravimetric analytical technique has been used, a technique that assumes an infinitely extended two-dimensional body (Gamburzeff, 1929; Hubbert, 1948; Talwani and others, 1959). The use of such a method has further limited the choice of examples to reservoirs that are greatly extended in one direction relative to their cross-sectional dimensions. Although only approximate when a mass is not infinitely extended along the strike, this method is simple and graphic, and the results are probably consistent in quality with the basic data upon which these analyses otherwise depend.

HYPOTHETICAL GRAVIMETRIC EFFECTS OF THE FAULTED ANTICLINAL FIRST GRUBB POOL, SAN MIGUELITO OIL FIELD

The San Miguelito oil field is one of four separate large fields astride a major faulted anticlinal trend in the central Ventura basin of coastal southern California. An overall view of the geology of the region was given by Bailey and Jahns (1954, p. 95), and the local surface stratigraphy and structure was described by Putnam (1942). Excellent descriptions of the subsurface geology and of factors influencing the petroleum accumulations were provided by McClellan and Haines (1951), and Haines and Minshall (1954), and were supplemented and brought up to date in a brief sketch by the California Division of Oil and Gas (1961, p. 746–747).

Discovered in 1931 after surface geological mapping, the San Miguelito field had, by January 1, 1961, produced 52,617,636 bbl of oil and 151,778,617 $\times 10^3$ cu ft of gas (California Division of Oil and Gas, 1961, p. 747) from three major and two minor sandstone zones of Pliocene age between depths of 4,700 and approximately 12,000 feet. The shallowest of these zones, "the First Grubb Pool" of Glenn (1950), had produced 19,330,250 bbl of oil by February 1, 1953, and at that time was still producing in excess of a million barrels per year by solution gas expansion and gravity drainage (Haines and Minshall, 1954). The First Grubb pool is thus an oil reservoir of respectable, but not remarkable, productivity.

According to Glenn (1950, p. 243), "* * * the First Grubb Pool, ranging in thickness from 1,105 to 1,680 ft, with an average of 1,220 ft, includes approximately 685 ft of oil-bearing sands * * * in eight sand intervals separated by shales." The "shale" interbeds separating the productive sandstone units are stated by Glenn to be continuous and effective barriers to petroleum migration throughout the major part of the field, so that the First Grubb pool is actually a multiple-zone pool with at least six, and probably eight, stratigraphically distinct producing units. These units are folded about a west-northwest trending and doubly plunging axis of a faulted anticline of fairly high structural relief. The 685 feet of petroleum-saturated strata being interbedded with nonproductive "shales," in a fold of such large relief causes an aggregate maximum vertical relief of approximately 2,300 feet of petroleum-saturated rocks within the First Grubb pool in the central part of the field (Glenn, 1950, fig. 2, section P–I). Some wells (for example, Continental Oil Co. Grubb 42) were originally opened through slotted liner to about 1,500 feet of productive sandstones in the pool. The deeper productive zones of pools of the field would, of course, add very substantially to this large vertical column of petroleum-saturated rock, but here we shall consider only those factors that influence the gravimetric effect of the shallowest pool.

The geologic structure of the shallower portions of the San Miguelito oil field is illustrated on plate 1 by means of structure contour maps of horizons approximately 100 feet stratigraphically below the top and approximately 200 feet stratigraphically above the base of the First Grubb pool. The anticlinal structure which has entrapped the petroleum is elongate and gently plunging. Its limbs are steep and relatively straight; faults that disrupt the structure are mainly parallel to, or oblique to (rather than transverse to) the fold axis, and are of small throw in relation to the structural height of the fold. These characteristics make the oil field suitable for methods of gravimetric analysis in which an infinitely extended two-dimensional mass is assumed. Further justification was given by Glenn (1950, p. 245, fig. 2), who showed that the stratigraphy as well as the structure is continuous and relatively constant along the length of the fold.

The average thickness of the beds of the First Grubb pool is 1,186 feet, rather than 1,220, according to Haines and Minshall (1954). As already indicated, approximately 685 feet (56 percent) of the average thickness is productive sandstone. The maximum estimated area of the pool is 302 acres, and "The total bulk sand volume * * * was calculated to be 136,600 acre-ft." (Glenn, 1950, p. 244). Glenn (1950, p. 244) gave 18 percent as the "weighted average porosity" for the pool based on "* * * only some 800 samples from 20 wells * * *." McClellan and Haines (1951, p. 2555) revised this figure to 20.6 percent, but their log (1951, fig. 8) is more nearly consistent with 18 percent. For this reason, and because 18 percent is the more conservative estimate, Glenn's figures are used in the following calculations.

The fluid pressure in the virgin reservoir was estimated by Glenn (1950, fig. 4, p. 248) to have been 3,000 psi at the minus 5,500-foot pool datum. The original temperature at the same datum was 158°F. Tank-oil gravity was originally 32° API at 60°F, and the initial solution gas-oil ratio was calculated by Glenn (1950, table 2) to range from 830 cu ft per bbl in the highest subzone of the pool to 915 cu ft per bbl in the lowest subzone, the value at the pool datum being 890 cu ft per bbl. According to estimates cited by Glenn (1950, p. 244), water occupied approximately 27 percent of the average pore space, and the California Division of Oil and Gas (1961, p. 747) cited a salinity for the water of 1,400 grains per gal.

The density of water of the low salinity indicated is approximately 0.998 g per cm³ at 158°F and 3,000 psi. The range of water density over the range of temperature and pressure cited by Glenn is so small that the value at the pool datum may be applied throughout the entire pool. The formation volume factors calculated by Glenn (1950, table 2) from the charts of Standing (1947) for the combined oil and gas in place in each subzone of the pool are accepted as a basis for correcting the density of tank stock oil (sp gr 0.86) to the density of the combined fluids in the reservoirs. Density of the sandstone in situ is then calculated by use of equation 1, assuming that 27 percent of the total pore volume is saturated with water, 73 percent is saturated with petroleum fluids, grain density is 2.67 g per cm³, and bulk density can be calculated from the porosity data of Glenn (1950, table 1). In the absence of density for the interbedded shales, or nonpetroliferous argillaceous rocks, that constitute nearly half the stratigraphic thickness of the pool, values for these are assumed—in the present report—from the relationships of figure 12 and from unpublished data of the author. All the pertinent values used in and resulting from the calculations just described are summarized in table 2.

The last two columns of table 2 show that the density contrast between the weighted average formation density (including the nonpetroliferous "shale" interbeds) within the reservoir and that outside the reservoir ranges between minus 0.03 g per cm³ and minus 0.04 g per cm³. Weighing these values in turn, by using the subzone acreage figures provided by Glenn (1950, table 1), to take into account the relative volumes of the various subzones of the pool, an overall weighted average density for the pool as a whole has been calcu-

TABLE 2.—*Principal facts and conclusions regarding densities of rocks in situ in the First Grubb pool, San Miguelito oil field, Ventura County, Calif.*

[Data in first seven columns are from Glenn (1950, tables 1 and 2)]

Producing interval	Sandstone thickness (ft)	"Shale" thickness (ft)	Mean temperature (°F)	Mean pressure (psi)	Petroleum formation volume factor	Sandstone total porosity (percent)	Sandstone σ_b (g per cm³)[1]	σ_w (g per cm³)[2]	σ_o (g per cm³)[3]	Petroliferous sandstone σ_{is} (g per cm³)[4]	Water-saturated sandstone σ_{is} (g per cm³)[5]	"Shale" σ_{is} (g per cm³)[6]	Weighted average formation density within reservoir (g per cm³)[7]	Weighted average formation density outside reservoir (g per cm³)[8]
"G–H"	71	29	149	2,770	1.406	17.2	2.21	0.998	0.616	2.34	2.38	2.48	2.38	2.41
"H–Ha"	78	47	151	2,817	1.410	18.1	2.19	.998	.614	2.32	2.37	2.48	2.38	2.41
"Ha–I"	75	55	154	2.875	1.416	17.2	2.21	.998	.611	2.33	2.38	2.48	2.40	2.42
"I–Ia"	65	50	157	2,930	1.422	19.5	2.15	.998	.609	2.29	2.34	2.48	2.37	2.40
"Ia–J"	70	70	159	2,985	1.427	17.9	2.19	.998	.606	2.32	2.37	2.48	2.40	2.43
"J–Ja"	83	42	162	3.042	1.433	18.5	2.18	.998	.604	2.31	2.36	2.49	2.37	2.40
"Ja–Jc"	111	104	165	3,105	1.438	19.2	2.16	.998	.602	2.29	2.35	2.49	2.39	2.42
"Jc–K–L"	131	109	169	3,195	1.448	17.2	2.21	.998	.598	2.33	2.38	2.49	2.40	2.43

1 Assumed equal to −0.00267 (percent porosity—100).
2 Assumed constant at 0.9980 g per cm³.
3 Equals 0.8654 g per FVF cm³.
4 Equals $\sigma_b+[0.27\ (\sigma_w)+0.73\ (\sigma_o)]\phi$.
5 Equals $\sigma_b+\sigma_w\phi$.
6 Estimated from fig. 12 and from unpublished data.
7 Calculated by averaging the density of petroliferous sandstone and of "shale" in situ in proportion to their stratigraphic thicknesses.
8 Calculated by averaging the density of water-saturated sandstone and of "shale" in situ in proportion to their stratigraphic thicknesses.

lated to be 2.39 g per cm³. Density contrasts between the various subzones outside the pool and this weighted average value for the pool as a whole range from minus 0.01 to minus 0.04 g per cm³. The weighted average density contrast between the pool as a whole and the contiguous rocks outside the pool is estimated to be minus 0.03 g per cm³. It should be emphasized here that these values are based almost entirely upon the published data of Glenn (with the exception of the "shale" density estimates).

The density data combined with the structural and stratigraphic data of Glenn can be used to construct a density model of the First Grubb pool. From such a model, hypothetical gravimetric effects can be calculated. Plate 1*C* is a transverse structure section through the First Grubb pool near its culmination (modified from section P–I of Glenn, 1950, fig. 2; and from McClellan and Haines, 1951, fig. 9). The height of the fold and steepness of its limbs are shown at true scale, together with the vertical and horizontal extent of petroleum-bearing sandstones and the locations of the nonlevel oil-water interfaces. The deeper pools of the San Miguelito field and the locally complex structural details outside the First Grubb pool are not showing. Superimposed on the structure section are the weighted average densities calculated for each subzone of the pool. In most of the computations that led to the results presented in the following paragraphs, the simple overall weighted density of 2.39 g per cm³ for the whole pool has been used instead of the separate subzone densities. Trial calculations show that the effects computed using the single average value are nearly identical with the effects obtained using separate averages.

If one assumes that the minus 0.03 g per cm³ weighted average density contrast between the First Grubb pool and its surroundings is a valid approximation, and that no other density contrasts are present near the San Miguelito oil field to otherwise complicate the subsurface density distribution, the approximate gravimetric effects of the pool may be calculated directly. Although they are almost certainly invalid, these assumptions have been made for the sake of illustration and comparison, and the computations carried out with the results shown graphically in profile *A* of plate 1*D*. A relatively negative gravity anomaly of 0.055 mgal is centered over the crest of the anticlinal accumulation. The anomaly is nearly symmetrical in profile, and half the total amplitude occurs within a horizontal distance of 5,000 feet on either side of the trace of the anticlinal axis. Such an anomaly, though small, would be detectable by modern methods of detailed gravimetric surveying and analysis, provided that a high signal-to-noise ratio could be maintained by the avoidance of rugged surface terrain, of heterogeneous near-surface geology, and of large-amplitude anomalies resulting from other subsurface density complications. These special requirements are inadequately satisfied at San Miguelito, and the author would be somewhat surprised if the small relatively negative gravity anomaly produced at sea level by the First Grubb pool could be discerned in an observed surface gravity anomaly map or profile over the San Miguelito oil field. However, there are many other oil fields like the first Grubb pool in California, and elsewhere, where these special requirements are met, and where an anomaly such as that pictured on plate 1*D* could be readily detected. In a favorable geologic and topographic setting, the First Grubb pool negative anomaly would be obvious.

The subsurface density configuration in and near the San Miguelito oil field is probably far more complex than was assumed in the foreging computation. We have seen (table 2) that rather pronounced variations in density occur within the First Grubb pool because of variations in lithology, grain size, sorting, and sand-shale ratios. These variations, which were averaged for the sake of simplified computation, are doubtless matched by density differences in these same rocks on the limbs of the fold outside the reservoir. Moreover, Putnam (1942) showed that growth of the Ventura Avenue anticline (including the San Miguelito culmination) occurred after the rocks that constitute the First Grubb pool had been buried beneath a consolidating load of many thousands of feet of sediment of late Pliocene and Pleistocene age. Even if the rocks of the pool are as old as middle Pliocene and have relaxed and expanded somewhat as erosion stripped away part of the superincumbent load after the mid-Pleistocene folding, the average porosities of the reservoir rocks are those appropriate to depths roughly 4,000 feet greater (see fig. 4) than the present depths of these rocks. Unpublished investigations at the University of California, by D. E. Duggan and the author, of rocks 2½–3 miles east of the San Miguelito culmination of the anticline, and in the Ventura syncline 6 miles farther to the east, indicate that folding and localized uplift of these partly consolidated strata have distorted the surfaces of equal average rock density (isopycnic surfaces) to an unusually large degree. It seems desirable therefore to take into account as many as possible of these various complications in the computation of the gravimetric effects of the First Grubb pool for comparison with the grossly simplified calculations already described.

Superimposed on the transverse structure section of the First Grubb pool (pl. 1 *C*, *E*) are hypothetical isopycnic lines (section views of the three-dimensional isopycnic surfaces). Lines outside the pool have been extrapolated on the basis of the aforementional unpublished investigations by D. E. Duggan and the author, conducted near the central culmination of the Ventura Avenue anticline a few miles east of San Miguelito. It should be emphasized that the real isopycnic surfaces at San Miguelito are almost certainly greatly distorted by known structural complexities that are here completely disregarded. Large faults are present about 1 mile north of the San Miguelito oil field (Putnam, 1942, section A–A′, pl. 1), and beneath the Pacific Ocean only 1 mile southwest of the axis of the anticline possible structural trends are unknown. Thus, one might say that the first Grubb pool and the San Miguelito part of the Ventura Avenue anticline are out of context here and are treated as isolated masses for the sake of illustration. One could probably evaluate the gravimetric effects of some, or possibly all, contiguous complexities of structure and stratigraphy, but the labor of doing so is prohibitive and unnecessary for the present purposes.

Assuming an overall weighted average density of 2.39 g per cm^3 for the entire first Grubb pool and assuming that the isopycnic lines of plate 1*C* are greatly extended as level surfaces beyond the limits of the section, the gravimetric effects of the entire density model are computed by means of the Hubbert (1948) method and shown in profile *B* of plate 1*D*. A broad, nearly symmetrical gravity maximum with an amplitude of nearly 0.7 mgal is centered over the anticline. This relatively positive gravity anomaly reflects the large volume of upfolded rocks of relatively high density in the axial portion of the fold and has more than 10 times the amplitude of the relatively negative anomaly resulting from the deficit of density within the rocks of the first Grubb pool because of the low density of the hydrocarbon pore fluids. If water were substituted for oil and gas in the pool, the gravity maximum over the density model shown would have the greater amplitude and slightly different shape shown by profile *C*.

The differences between profiles *B* and *C* (pl. 1*D*) are neither great enough nor distinctive enough to permit one to discern from them alone that the anticline at San Miguelito contains a commercial petroleum accumulation. The large gravity maximum masks the small gravity minimum in profile view. Whether complete masking also occurs in a map of the contours of equal Bouguer gravity anomalies over the model depends upon the relative longitudinal changes of amplitude of the negative and positive elements of the total anomaly. The three-dimensional analysis required to answer this question has not been attempted, but analyses of other models suggest that complete masking in map view is unlikely.

If the anticline had grown by differential subsidence only, instead of by differential uplift accompanied by erosion after subsidence and consolidation, the isopycnic surfaces would be more nearly level and might even dip down toward the axial plane of the fold. For this situation, the gravity maximum would not be present and the gravity minimum of profile *A* might be detectable. Similarly, if the rocks of the San Miguelito anticline had been folded during Paleozoic or even Mesozoic time, postfolding consolidation would have erased much of the distortion of the isopycnic surfaces, again leaving them more nearly level. Under these conditions also, the gravity minimum produced by the low-density fluid of the reservoir might be obvious. Lastly, if the First Grubb pool were larger and thicker (or if we were able to take into account the effects of the deeper pools of the San Miguelito field), the associated gravity minimum would be correspondingly larger. Effects of the deeper pools at San Miguelito would probably double the amplitude of the gravity minimum to approximately 0.1 mgal, and correspondingly decrease the amplitude of the relatively positive anomaly to perhaps 0.6 mgal. If the San Miguelito field were extremely large and, like the Long Beach, Dominguez, or Santa Fe Springs fields of Los Angeles County, Calif., had unusually large reserves per acre, the gravity minimum over the field due to hydrocarbon fluids (like that at Santa Fe Springs Oil field, fig. 1) have an amplitude of roughly 1 mgal and overshadow, at least locally, the positive anomaly calculated from the density model.

Had the geologic history or evolution of the first Grubb pool been different in one of several ways, the gravimetric profiles would also be different. If the reservoir were saturated with methane instead of crude oil and remained otherwise unchanged, the gravity minimum produced by the pool alone would be that shown by profile *D* of plate 1*D*, and the gravity maximum associated with the anticline would be sharply reduced in amplitude to that shown by profile *E*. Assuming nearly level isopycnic surfaces outside the pool instead of strongly distorted ones, the 0.18-mgal negative anomaly produced at sea level by a gas-filled First Grubb reservoir should be conspicuous on a detailed gravity anomaly map. On the other hand, if one assumes, for an otherwise unchanged reservoir, 100-percent saturation by petroleum of the composition produced at San Miguelito, instead of saturation by a mixture of water and petroleum, the weighted average pool density contrast increases negatively to minus 0.05 g per cm^3, but the amplitude of the gravity minimum is only enlarged to minus 0.07 mgal (profile *F*), an increase of only about one-third. Similarly, if one envisions the First Grubb reservoir as having the maximum likely porosity of 26 percent (see fig. 4) for its present depth, but as being otherwise unchanged (density contrast of minus 0.04 g per 3), the amplitude of the gravity minimum due to the low-density pool would be enlarged to about minus 0.09 mgal (profile G).

If uplift and erosion has caused the First Grubb pool to be shallower, though unchanged with respect to porosity and fluid density, the negative gravity anomaly would be more localized, more sharply defined, and increased somewhat in amplitude. As an illustration, the differential gravimetric effect of the pool alone (assuming a density contrast of minus 0.03 g per cm^3) has been calculated at the minus 2,600-foot datum (approximately 2,100 feet above the top of the pool) and shown as profile *H* (pl. 1*D*). The amplitude of the resultant negative anomaly is 0.09 mgal, as contrasted with the 0.06-mgal effect at sea level. Moreover, half the amplitude occurs within 3,000 feet of the anticlinal axis as compared with 5,000 feet for the effect at sea level. An anomaly of these dimensions would be clearly discernible in many locations. Presumably, the density of the reservoir fluid, if the top of the pool were only 2,100 feet below the ground surface as hypothesized, would be considerably lower than that assumed here (see fig. 6), and the amplitude of the negative anomaly would be proportionately larger. If the pool were filled with methane at the temperature and pressure reported by Glenn (1950), the amplitude of the negative anomaly due to the pool at the minus 2,600-foot datum would be minus 0.32 mgal (profile *I*). Inasmuch as methane density changes little with large changes of temperature and pressure (fig. 6), the density of the pool and its gravimetric effects at the minus 2,600-foot datum would undergo only slight changes if temperature and pressures more appropriate to the hypothesized shallower depth were assumed.

If the gravimetric effects of the strongly arched isopycnic surfaces hypothesized for the San Miguelito anticline density model outside the First Grubb pool are calculated for the minus 2,600-foot datum, assuming that all rocks above that level have been removed by erosion, the amplitude of the positive anomaly is greatly deminished. In a comparison of the positive and negative anomalies computed at the same datum for a methane-saturated First Grubb pool, the amplitudes of the positive and negative components nearly cancel each other over the crest of the fold. However, the different width-to-height ratios of the two anomalies result in a composite anomaly consisting of a small minimum on the crest of a broader maximum, the minimum here being a direct reflection of the hypothesized gas saturation. Rocks having lower density than that of the overlying and underlying strata, when brought near the surface in the crestal parts of an anticline, tend to produce such a small minimum, with or without the broader maximum (depending on the distribution of density outside the low-density unit). Porous gas- or petroleum-filled reservoirs are the rocks most likely to have low density in such a structural situation in a marine sequence.

We have seen that the amplitude of the negative gravity anomaly produced by the density deficiency of the model of the First Grubb pool increases negatively from minus 0.06 mgal at sea level to minus 0.10 mgal at minus 2,600 feet, approximately 2,100 feet above the top of the highest point of the pool. The latter amplitude value would be the same if erosion removed the rocks between the present surface and the minus 2,600-foot level, enabling us to measure gravity at the latter surface; it also would be the same if we could measure gravity in a borehole over the pool at the minus 2,600-foot level and subtract from the gravity measurement the gravimetric effects of the free-air gravity gradient and of the rocks between the present surface and the selected level. Similarly, from sea level to minus 2,600 feet, half the negative anomaly decreases in width from about 8,000 feet to about 6,000 feet. This change in depth-dependent ratio of anomaly width to height could also be measured by measuring gravity at minus 2,600 feet in several boreholes spaced widely above the pool, again provided that an instrument were capable of measurements accurate to ± 0.01 mgal, and that adequate free-air, Bouger, and terrain corrections could be applied to all measurements. This technique of subsurface gravity mapping is superficially similar to, but basically different from, the process referred to by Hammer (1963a) as "stripping." "Stripping" is not fundamentally different from the methods, long in use, of applying corrections for known geology to reduced gravity data (White, 1924; Woolard, 1938; 1962; Evans and Crompton, 1946; McCulloh, 1959, 1960), as T. C. Richards (1964) pointed out. The subsurface gravimetric mapping technique suggested here would have the very substantial (and, in some geological situations, essential) advantage of overcoming the attenuation that great depth produces on gravimetric effects of small amplitude, as well as the desirable filtering accomplished by correcting for known density distributions (or "stripping," as that word has been applied by Hammer).

In view of the gravity changes that occur between sea level and minus 2,600 feet at different locations above the First Grubb pool, it is obvious that the vertical gradient of gravity, corrected for terrain and Bouguer effects, varies both vertically and horizontally because of the density deficiency of the petroleum reservoir. Ignoring those gravimetric effects at San Miguelito oil field not due to the First Grubb pool, at a level intermediate between sea level and minus 2,600 feet, the differences between these varying underground gradients and the normal free-air gradient (as it could be measured only far above the ground surface where the local effects of the First Grubb pool are attenuated effectively to extinction) range from immeasurably small positive values, at horizontal distances greater than 4,000 feet from a point directly above the pool, to negative values of 0.015 mgal per 1,000 feet directly over the pool. At depths closer to the pool, both the positive and negative departures from the normal value are greater, and the most negative departures from normal occur exactly at the top of the pool above its greatest thickness. From table 2 and figure 13, we see that the negative density contrast of minus 0.03 g per cm^3 of the First Grubb pool corresponds to a relatively positive vertical gravity gradient of about 0.0007 mgal per ft compared with water-saturated rocks outside the pool. Thus, the negative gravity anomaly and the negative departures of the vertical gravity gradient from normal that are present immediately above the pool because of its low density become compensated below those points by the excessively steep vertical gravity gradient existing downward and through the reservoir.

In summary, the relatively negative gravimetric effect calculated from the model of the density-deficient First Grubb pool of the San Miguelito anticline is large enough (minus 0.06 mgal) at the sea level datum and 4,700 feet above the crest of the pool to be detectable by modern gravimetric surveys if an optimum signal-to-noise ratio could be achieved. Because the San Miguelito anticline was formed recently by localized uplift of strata that have been much more deeply buried and consolidated, the isopycnic surfaces of the rocks of the fold are strongly distorted and arched. The hypothesized density model of the anticline produces a broad, relatively positive, gravimetric anomaly of plus 0.7 mgal, which seemingly prohibits direct detection by surface gravity surveys alone of the small and broad gravity minimum produced by the pool. If the pore volume of the reservoir were maximal, or if the pores were completely saturated by petroleum fluids, the amplitude of the relatively negative anomaly would be magnified by a factor of 1.3–1.6. Saturation of the pores by a less dense fluid than that actually present in the First Grubb pool would also amplify the anomaly, the maximum amplitude of minus 0.18 mgal occurring for saturation with methane. Reducing the volume of rock (and the distance) between the gravimeter and the First Grubb pool strongly increases the amplitude of the relatively negative gravity anomaly and the ratio of anomaly amplitude to its wavelength, illustrating the masking effect of depth on the detectability of a negative gravity anomaly produced by a petroleum or natural-gas reservoir. This suggests not only that reservoirs of the dimensions of the First Grubb pool should be detectable by surface gravimetric surveys of high precision where surface terrain and subsurface density configurations are simple and where the reservoir is beneath a thin cover, but that subsurface (borehole) gravity might be definitive even for deep reservoirs.

HYPOTHETICAL GRAVIMETRIC EFFECTS OF THE STRATIGRAPHIC TRAP-FAULT TRAP SATICOY OIL FIELD

A type of oil field that has produced large volumes of petroleum in California for many years and which continues to be of interest to California petroleum exploration geologists is the combination fault entrapment-stratigraphic entrapment field in which steeply dipping reservoir sandstones are closed updip by a basin-margin reverse fault and by pinchout of the sand units beneath or in front of the fault toward the basal margin. The Saticoy oil field, in the south-central Ventura basin approximately 15 miles east of the San Miguelito oil field, is such a combination trap and provides the basis of a second density-model and gravimetric analysis.

The Saticoy oil field was discovered in 1955 as a result of reflection seismic and regional subsurface work. From the multiple sandstone reservoirs of the field, 9,928,661 bbl of oil and 20,310,320×10^3 cu ft of gas had been produced by January 1, 1961 (California Div. Oil and Gas, 1961, p. 755). Schultz (1960, p. 67) cited estimates that the Saticoy reservoirs contain reserves sufficient to permit recovery by primary methods of 15,000,000 bbl of oil and 35,000,000×10^3 cu ft of gas, and Taylor (1959), who considered the Saticoy oil field and the "Bridge area" of the South Mountain oil field, which was also discovered in 1955 (Ware and Stewart, 1958, p. 181), to be parts of one large multizone accumulation, cited a cumulative aggregate production of 16,200,000 bbl of oil as of June 30, 1959. These figures provide some idea of the relatively small size of the Saticoy oil field in terms of productivity.

The Saticoy oil field, together with its apparent extension into the "Bridge area" to the northeast, is productive from strata beneath a narrow strip of the nearly level Santa Clara River valley 7¼ miles long by only 800–1,500 feet wide. Beneath this strip over 17 productive sand groups are present in a 3,000 foot stratigraphic interval (Taylor, 1959), varying in depth from 5,900 to 11,700 feet or more, and yielding crude petroleum ranging in gravity from 31° to 35° API. These sandstones are of oldest Pleistocene and late Pliocene age and are thought by Taylor (1959) and Schultz (1960, p. 64) to have been deposited in a deep-water marine environment by west-flowing turbidity currents. They are interbedded with and grade into impermeable siltstones and mudstones, are overlain by thousands of feet of Pleistocene and Recent siltstone, sandstone, and gravel, and rest conformably upon a great thickness of older Cenozoic marine and nonmarine strata. Northward (basinward) thickening of the reservoir sandstones and steepening of their dips with age suggest deformation, and differential subsidence, and tilting during deposition.

The regional structural setting of the Saticoy oil field is shown by Kew (1924, pl. 1, 2, section A–A′) and by Bailey and Jahns (1954, fig. 8). The southern boundary of the extremely depressed central synclinal trough of the late Cenozoic Ventura basin is a south-dipping high-angle reverse fault, known for many years as the Oak Ridge fault zone, on which as much as tens of thousands of feet of throw accumulated in late Pliocene and Pleistocene time. Eocene, Oligocene, and Miocene strata on the upthrown south side of the fault dip gently to steeply against and over Pleistocene and Pliocene strata on the downthrown north side. The reservoir units north of the fault, which dips 70°–80° to the south or southeast, dip steeply (70° and more) to the north or are locally overturned beneath the fault. A slice of crushed cherty Miocene shale is everywhere present at or near the base of what is termed the fault zone, but shearing and low sandstone permeability mark a zone extending into the Pliocene beds 700–900 feet vertically below this base. Although the rocks below the fault are nearly homoclinal, their strikes being subparallel to the fault, a slight tendency toward anticlinal bowing of the steeply dipping strata has undoubtedly influenced petroleum migration and entrapment, as have updip pinchout of some sandstone units and fault closure of others.

The areal extent and major structural features of the Saticoy part of the oil field are shown on plate 2*A* by structure contours drawn on the base of the fault zone and others drawn on the top of one of the prominent oil sands in the middle part of the productive section. The greatly extended length of the field relative to its width and to the vertical extent of the productive sandstones makes it particularly well suited to the method of gravimetric analysis used for this study. For an additional impression of the structural relief of the reservoir units and of the great throw on the Oak Ridge fault zone, see the profile of the Saticoy oil field, plate 2*B*.

Published reservoir engineering data for the Saticoy oil field are minimal but sufficient for our needs. Jeffreys (1958, p. 183) stated that the discovery well had a representative settled initial production of 268 bbl of 32.5° API oil and 173×10^3 cu ft of gas per day, cutting 0.7 percent water. This production gas-oil ratio of 645 cu ft per bbl is doubtless larger than the solution gas-oil ratio in the reservoirs and is much lower than the 2,045 cu ft per bbl ratio derived from the 5-year cumulative production totals cited by the California Division of Oil and Gas (1961, p. 755). On the basis of these figures, an original solution gas-oil ratio in the virgin reservoirs of 550 cu ft per bbl is assumed for the following calculations. Gravity of oil produced from the Saticoy reservoirs averages 34° API according to the California Division of Oil and Gas (1961, p. 755), 34.7° API according to Schultz (1960, p. 64), but 31° API for the deeper reservoirs of the "Bridge area" according to Ware and Stewart (1958, p. 181). From these slightly divergent values, it is here assumed that the average gravity throughout all the reservoirs is 33° API. As nothing is said in the published literature about original free gas caps in any of the reservoirs, it is here assumed that the reservoir fluid was at or below saturation with respect to gas, and that the gas gravity is 0.80 relative to 1.0 for air. Initial pressures in the reservoirs are not known to the author, except for the stratigraphically youngest zone at the southwest end of the field which Schultz (1960, p. 64) stated had an original reservoir pressure of 3,000 psi, presumably at a depth of about 6,700 feet. From this single statement it is here assumed that the original pressures at the oil-water interfaces of all the reservoir units were virtually normal hydrostatic pressures at a fluid pressure gradient of approximately 0.45 psi per foot of depth. The temperature gradient at the Saticoy oil field is nearly linear and very close to 77 feet per degree Fahrenheit, according to J. C. Taylor (oral commun., August 23, 1964); the temperature increases from 115°F at minus 4,000 feet to 250°F at minus 14,200 feet. The interstitial water content was published only for the shallowest and youngest oil reservoir. For that Pleistocene sandstone, Schultz (1960, p. 64) cited an interstitial water content of approximately 40 percent. It is here assumed that this figure is conservative and applies also to all the deeper reservoirs. Schultz gave an analysis of the above-mentioned water which showed that it contained 16,200 ppm total dissolved solids, principally Na^+ and Cl^-. California Division of Oil and Gas (1961, p. 755) stated the average salinity of zone waters for the entire field to be 1,000 grains per gal (or 17,000 ppm), equivalent to a density under surface conditions of about 1.01 g per cm^3.

Published porosity data for rocks of the Saticoy oil field are restricted to a single average value of 22 percent for the shallowest and youngest reservoir sandstone in the field (Schultz, 1960, p. 64). This is an exceptionally low value for such a young marine sandstone (earliest Pleistocene age) at such a depth, and suggests either (1) that the porosity has been decreased by consolidation resulting from a considerably greater depth of burial and subsequent uplift to the present depth, or by consolidation and alteration resulting from proximity to the Oak Ridge fault zone, or (2) that the porosity is low near the pinchout of the sandstone unit because of poor sorting and an exceptionally large content of silt and clay. Unpublished average reservoir porosity values released by the Shell Oil Co. to the American Petroleum Institute Pacific Coast Study Committee on core analysis and well logging range from 23.9 percent at about minus 6,800 feet to 20.5 percent at about minus 9,000 feet. Measurements by the author of the much greater porosities of samples of conventional cores of these same rocks from wells approximately 5 and 7.5 miles southwest of the Saticoy oil field, but many thousands of feet basinward from the Oak Ridge fault zone, confirm the abnormality of the available porosity values. Therefore, it is here assumed that average porosities of the reservoir rocks within the steeply dipping zone near the Oak Ridge fault are substantially less than porosities of the same, or comparable, rocks 1,000 feet or more from the fault. Thus, it is assumed that the average porosity of sandstone units 500 feet from the fault base decreases from 23 percent at minus 6,500 feet to 19 percent at minus 10,500 feet, whereas similar rocks more than 1,000 feet north of the fault have porosities ranging from 33 to 19 percent at those respective depths. Similarly, it is here assumed that the interbedded impermeable silty argillaceous rocks have average porosities that range from 17 to 12 percent, respectively, near the fault, and from 19 to 12 percent at some distance from the fault. The sandstone units at Saticoy appear to be distinct and clearly separable from the intercalated impermeable units, whether petroleum plus brine or only brine forms the pore fluid (Schultz, 1960, pls. 3, 4).

From the foregoing data and assumptions regarding temperatures, pressures, porosities, and fluid compositions at the Saticoy oil field, curves of density versus depth have been calculated for each of the pertinent fluids and for the two major rock types (sandstone and impermeable silty argillaceous rocks) in the two extreme structural locations (adjacent and 1,000 feet or more from the fault zone). The resultant curves are shown in plate 2*D*. The smooth density curves for crude petroleum and for brine and crude petroleum are approximations based on the assumed linear pressure gradient hypothesized for the pressures at the oil-water interfaces of the various productive zones. Departures from hydrostatic pressures, especially within the higher parts of the petroleum-bearing sandstones of great vertical extent, if they were known, would permit drawing the pressure curve—and hence the fluid-density curves—as a discontinuous series of related, but unconnected, curve segments. The curves of rock density in situ converge for sandstones near, and at a distance from, the fault. Available data suggest that at about minus 12,000 to minus 13,000 feet at Saticoy oil field the porosities of sandstones near the fault and those 1,000 feet or more from the fault are identical. Wherever this condition exists, the profiles of in situ rock density converge and become identical.

The structural geology, lithology, and distribution of different pore fluids in the northeastern (deeper) part of the Saticoy oil field are shown in the transverse geologic profile on plate 2*B*. This profile, modified and adapted from Schultz (1960, pl. 4) and Jeffreys (1958), shows the great structural relief of the youthful sedimentary rocks beneath and in front of the Oak Ridge fault, the post-middle Miocene throw of more than 13,000 feet at this location on the fault zone itself, the steepness characteristic of the reservoir units in traps of this type, and the high oil columns in some reservoirs in such traps.

For comparison with the structure and lithology, the idealized hypothetical isopycnic surfaces for each of the three major rock types (impermeable silty argillaceous rocks saturated with brine, reservoir sandstone saturated with brine, and reservoir sandstone saturated with fluid consisting of 60 percent petroleum and 40 percent brine) have been computed from the porosity and fluid-density data summarized on plate 2*D*, and are shown in section view on plate 2*C*. Isopycnic lines for impermeable rocks (or undifferentiated impermeable rocks and sandstones in the trough of the Santa Clara syncline) slope gradually and smoothly up toward the base of the Oak Ridge fault zone as porosities diminish gradually and slightly in that direction. Isopycnic lines for sandstones curve abruptly upward to nearly vertical, or even slightly inverted, positions as porosities diminish abrupty and strongly toward the fault and pore-fluid density scarcely changes or decreases. Thus, at any selected subsurface level, rock density is a function of horizontal location (relative to the fault), lithology (whether sandstone or impermeable rock), and composition of pore fluid (whether brine or reservoir fluid), the least dense rock at any position is that saturated with reservoir fluid (if present), and the most dense rock is brine-saturated impermeable rock (or undifferentiated siltstone and sandstone where geologic information does not permit differentiation). It should be emphasized that the relations shown on plate 2*C* are derived, hypothetical, and idealized, and that they are therefore the product of judgment and interpretation as well as fact. Perhaps the curvatures for the sandstone isopycnic lines are unrealistically sharp and the nearly vertical parts too long, but the scanty evidence available does suggest that the upper part of each curve in the depth range shown is very steep and that a fairly sharp inflection occurs in each curve as it passes from the zone near the fault into the regions of normal porosity and density in the syncline.

Combining the lithologic data of plate 2*B* with the idealized density data portrayed on plate 2*C* results in a transverse section of a density model of the Saticoy oil field and its environs. Such a model is shown on plate 2*E*. Here again, the author wishes to emphasize that construction of an isopycnic model necessarily involves partly arbitrary compartmentalization of natural units in which real variations are partly gradual and transitional rather than the abrupt discontinuities of the compartments of the model. Wherever natural boundaries exist and are known at Saticoy, they have been used in the construction of the model. The boundaries between sandstone and impermeable rocks, or the interface between sandstone saturated with brine and that saturated with reservoir fluid, are such natural boundaries. But other compartments are required for convenience in the gravimetric computation, and these have no geologic meaning in many instances.

Plate 2*E* is a somewhat simplified version of the actual density model constructed from the data of plate 2*B*. It differs somewhat from that used to represent the San Miguelito anticline, wherein density contrasts, rather than the densities themselves, have been plotted. Each density contrast on plate 2*E* has been obtained by subtracting from the hypothesized density of a given rock mass the density hypothesized for impermeable silty argillaceous rock or undifferentiated impermeable rock and sandstone in the trough of the Santa Clara syncline (location *A* on illustration). Inspection of *E* and *F* permits qualitative anticipation of some of the gravimetric effects obtainable quantitatively only through laborious computation. The strongly positive density contrasts that are hypothesized as characteristic of the older rocks of the upthrown block southeast of the Oak Ridge fault can be expected to produce a very large positive gravity anomaly over the upthrown block and a steep gravity declivity across the fault. Adding positively to these should be the effects of the moderately positive contrasts beneath and in front of the fault that are produced by the increase in density of silty argillaceous rocks (and undifferentiated rocks) from the trough of the syncline toward the fault. Conversely, the relatively negative contrasts produced by fluids in the more porous reservoir sandstone should produce relatively negative gravimetric effects tending to offset or oppose some portion of the relatively oppositive anomaly.

From the density model of the northeastern part of the Saticoy oil field (pl. 2*E*), the gravimetric effects have been computed and plotted as profiles for four subsurface levels: sea level, minus 2,000 feet, minus 3,000 feet, and minus 4,000 feet. These computations were made with the assumption that all rocks above each level were absent. For example, the effects computed for minus 3,000 feet were those which hypothetically could be measured at that datum if erosion removed all overlying rocks of the model without changing the subsurface temperatures and pressures, thereby not changing the densities of the interstitial fluids and the porosities of the fluid-saturated rocks. Furthermore, the computations were carried out separately for each of the three major classes of rocks making up the model: (1) the petroleum-bearing sandstones, (2) the water-saturated differentiated sandstones, and (3) the water-saturated rocks constituting the upthrown block south of the Oak Ridge fault zone and the siltstones and undifferentiated siltstones and sandstones of the downthrown block.

The gravimetric data computed from the density model are shown as four sets of profiles plotted at two scales. The effects of the petroleum-bearing rocks—the "oil sands" of the Saticoy reservoirs—are plotted as one group of curves. A second group of curves represents the combined gravimetric effect of the oil sands and the differentiated water-saturated sandstones of the downthrown block. A third set of curves shows the differential effects that would result if the oil and gas in the reservoirs were replaced by water. The fourth set shows the integrated effects of the entire density model.

At sea level, the "oil sands," as modeled, give rise to a nearly symmetrical gravity minimum of 0.063 mgal, half of which occurs within horizontal distance of 7,500 feet of a point almost directly above the middle of the group of reservoir units and a few hundred feet basinward from the pinchout of the "I sand" (pl. 2*A*–*B*). By itself, without the masking effects of the other large density contrasts presumed present at Saticoy, this anomaly has an amplitude and width that could be detected by high-precision gravity surveying under good field conditions (Ferris, 1964, p. 150; 1965, p. 156–157). That part of the anomaly (maximum amplitude of minus 0.015 mgal) produced because petroleum fluids instead of water are in the porous reservoir units is shown in *E* as the shaded area between the pairs of curves computed at the sea-level datum.

At the 2,000-foot datum, approximately 3,400 feet above the highest part of the shallowest reservoir in the northeast part of the field, the gravity minimum caused by the "oil sands" has an amplitude of 0.084 mgal, half of which occurs within a horizontal distance of 6,000 feet of a point above the middle of the group of reservoirs shown in *A*, *B*, and *E* of plate 2. At the minus 3,000-foot datum, the amplitude of the minimum is 0.120 mgal and the half width is less than 10,000 feet. At the minus 4,000-foot datum, approximately 1,450 feet above the highest reservoir rock and about 3,500 feet above the middle of the group of reservoirs, the amplitude of the negative anomaly is 0.130 mgal, of which 0.03 mgal is due to the presence of oil instead of water, and its half width is less than 8,000 feet. The gravimetric effects of steeply dipping petroleum and natural-gas reservoirs, and of petroleum-fluid saturation in them at shallow to intermediate depths, are measurable by modern methods even where such reservoirs are of small total volume, relatively low porosity, and large interstitial water content, as at Saticoy. Whether these measurable effects are also recognizable depends on the absence or presence of other masking density contrasts as well as on the interpretive procedures used, as can be seen in the following paragraphs.

Because their thicknesses (and, therefore, volumes) and porosities increase basinward from the Oak Ridge fault zone, the reservoir sandstones of the Saticoy oil field are sources of relatively negative gravimetric effects even when they are saturated with brine instead of petroleum fluid plus brine. The combined effects of the "oil sands" and the differentiated water-saturated sandstones are plotted on plate 2*E* as a second set of curves at the same scale used for plotting the effects of the "oil sands". An apparent gravity minimum of 0.188 mgal amplitude and half width of 17,000 feet at the sea-level datum deepens to an amplitude of 0.364 mgal and narrows to half width of 9,000 feet at the minus 4,000-foot datum. These composite anomalies are misleading in that their simple, nearly symmetrical, shapes result partly from the arbitrary downdip limits placed on the water-saturated sandstone units in construction of the density model. If geologic data permitted their downdip extensions to be modeled separately from the enclosing siltstones, the computed composite gravimetric effects would plot, not as a family of nearly symmetrical minimums, but instead as a family of sloping curves on which the small-amplitude minimums arising from the petroleum content of the updip ends of the reservoir units are superimposed as slight concavities. Stated briefly, the only real gravity minimums associated with the Saticoy oil field are those arising from petroleum in the reservoirs.

The gravimetric effects of the undifferentiated rocks in both the upthrown and the downthrown blocks of the density model of the Saticoy oil field are positive and of much larger magnitudes than the negative effects of the sandstones saturated with petroleum fluids and brine. At any level and position, the composite effect obtained by algebraic addition of all effects of the entire model is positive. The total composite gravimetric effects are plotted as a third family of curves in the upper part of *E* (pl. 2) at a gravity scale that is two-hundredths the scale used for plotting only the much smaller negative effects. These curves are of the type generally associated with high-angle faults and consist at each level of a steep gravity declivity nearly centered over the midpoint of the fault step. The amplitude of the total composite anomaly ranges, within the horizontal distance considered, from approximately 28 mgal at the sea-level datum to approximately 17 mgal at minus 4,000 feet—from nearly 500–130 times the amplitude of the negative anomalies produced by the petroleum reservoirs. The masking effect of these relatively very large positive anomalies, due mainly to the hypothesized change in density across the fault step, appears at first glance to be overwhelming.

Two methods are suggested to screen out the very large positive effects for recognition of the small negative effects indicative of petroleum reservoirs beneath and in front of a fault such as the Oak Ridge fault. Where well control shows the location and dip of the fault, a partial density model can be constructed, the large positive gravimetric effects simulated by computation, and a simple subtractive procedure applied to field gravity measurements to remove the positive regional effects of the fault step in order to show more clearly on a map the small-amplitude anomalies produced by the small volume masses. That is, a partial geologic correction would be applied to the already distributed observed gravity data. A second, purely mechanical, method that might be applied consists of procesing the observed reduced gravity data through a trend surface analysis designed to search for elongate gravity minimums of small amplitude and large width-to-height ratio. Whether such an analysis would reveal the minimum caused by petroleum reservoirs at Saticoy requires an actual test using surface gravity data, which are currently unavailable.

The enlargement of the amplitude of the negative anomaly caused by the petroleum reservoirs, as the vertical distance is decreased between the reservoirs and the level of gravity measurement, suggests again that subsurface gravity surveying would aid in disclosing the distinctive but small negative anomaly.

Study of plate 2*E*, *F* suggests one final general comment. In areas of intensely deformed strata beneath unconformities covered by flat-lying or gently dipping rocks, reservoirs of large volume and considerable vertical extent beneath an unconformity might produce detectable gravity minimums that would be attenuated because of depth but not masked or otherwise distorted by the gravimetric effects of the blanket of overlying strata. The search for such reservoirs might be appreciably facilitated by the gravimetric techniques examined in this paper. The older and more thoroughly consolidated the strata and the more homogeneous the lithology of the surrounding nonreservoir rocks, the more likely are such applications to yield worthwhile results. Steeply dipping sandstone reservoirs of large volume in thick siltstone or shale sections of Cretaceous or older age beneath an unconformity of low structural relief at a depth of 7,000 feet or less constitute the most suitable environment.

HYPOTHETICAL GRAVIMETRIC EFFECTS OF THE SPALDING ZONE OF THE STRATIGRAPHIC ENTRAPMENT FILLMORE OIL FIELD

Unlike the faulted anticline of the First Grubb pool in the San Miguelito oil field or the steeply dipping Saticoy reservoirs, the third example is a thin extensive sandstone reservoir having very low structural relief and small total pore volume. The Spalding zone of the Fillmore oil field is the deeper, thicker, and more extensive of two productive sandstones in a very deep and purely stratigraphic trap in the central Ventura basin. The geology of the surrounding region was described in general terms by Kew (1924, pls. 1, 2, section B–B′) and by Bailey and Jahns (1954, p. 91 and fig. 8). The geology of the oil field itself was briefly described by Henriksen (1958) and by the California Division of Oil and Gas (1961, p. 704–705). Discovered in 1954, after an arduous exploration campaign involving deep reflection seismic work, regional subsurface studies, and numerous deep exploratory wells, the field had produced by January 1, 1961, a total of 9,073,211 bbl oil and 15,582,610$\times10^3$ cu ft of gas from two pools more than 14,000 feet beneath the surface of 960 proven acres. Both pools are in the relatively thin updip ends of sand units of late Pliocene age on the extremely depressed but gently dipping (5°) northwest flank of the Santa Clara syncline. Closure in both zones results from abrupt updip pinchout and (presumably) by lateral diminishment of permeability in the sandstone units, and appears altogether unrelated to structural factors.

The areal limits of the Spalding zone and structural contours drawn on the top of the sandstone body are shown on plate 3*A* to illustrate that the reservoir is greatly elongated relative to its width and thickness, and therefore can be satisfactorily analyzed by a two-dimensional analytic method. The geometry of the reservoir is shown by cross section on plate 3*B*. Plate 3 is a modification of illustrations of the Fillmore oil field published by the California Division of Oil and Gas (1961, p. 704). The shape and downdip limits of the sand unit as shown on plate 3*B* are largely conjectural.

Henriksen (1958, p. 179) gave 6,170 psi as the original reservoir fluid pressure and an assumed unusually low temperature gradient of 95 feet per degree Fahrenheit yields a temperature of 217° F for a depth of 14,550 feet, a figure that closely matches the temperature of 213°F in the reservoir recorded on electric logs shortly after the drilling of a well. Gravity of the oil produced ranges from 27° to 37° API, averaging about 30° (Henriksen, 1958, p. 178), and the average solution gas-oil ratio is stated to be "* * * 1,000 or slightly higher." A very small original free gas cap indicates that the reservoir fluid initially was just at saturation. Despite a level oil-water interface, low initial water cuts in most wells, and rapid pressure depletion in the reservoir, water drive has little effect or is absent. Salinity of the zone water is 250 grains per gal (California Div. Oil and Gas, 1961, p. 705), indicating nearly pure water. Porosities of the reservoir rocks range from 5.8 to 34.4 percent and average 18 percent (Henriksen, 1958, p. 178). Maximum thickness of the sandstone in the field is 300 feet, and, although the total vertical extent of petroleum-saturated rock is 203 feet, no more than 160 feet of oil sand occurs in any well.

An average porosity of 18 percent for a sandstone composed of grains having a density of 2.67 g per cm^3 corresponds to a dry-bulk density of 2.19 g per cm^3. Filling the pores of such a rock with fluid of 1.00 g per cm^3 density results in an in situ density of 2.37 g per cm^3. Filling the pores instead with fluid having a density of 0.63 g per cm^3 (the density under original reservoir conditions of the petroleum and natural gas in the Spalding zone) results in an in situ density of 2.30 g per cm^3. The density contrast of minus 0.07 g per cm^3 between water-saturated and petroleum-saturated sandstone is the only contrast related solely to the petroleum content of the sandstone. Measurements by the author of a few siltstone samples from units above and below the Spalding zone suggest that the in situ density of the enclosing nonpetroliferous units is 2.52 g per cm^3. Some interstitial water is almost certainly present in the petroliferous part of the Spalding reservoir, although the percentage is not known; because of the negligible water production despite relatively high porosities and permeabilities of the reservoir rocks, 100-percent saturation within the reservoir by petroleum fluid is assumed. Moreover, because of the low structural relief of the reservoir and the lack of structural complexities or evidence of postconsolidation upfolding, it is also assumed that vertical gradients of in situ density above and below the reservoir are the same throughout the area and therefore can be ignored in the gravimetric computation. Extreme structural complexity along and beneath the north-dipping San Cayetano thrust fault many thousands of feet north of the field ensures that these simplified assumptions are not completely correct. Nevertheless, the assumptions are made for purpose of illustration and, in part, are basic to conversion of the geologic section, plate 3*B*, to the density model, from which the gravimetric effects are computed.

The gravimetric effects of the petroleum-bearing and the water-saturated parts of the hypothetical profile of the Spalding zone have been separately computed for four subsurface levels: sea level, minus 8,000 feet, minus 11,000 feet, and minus 12,000 feet. The separate and combined effects are plotted as relative gravity profiles (pl. 3*B*).

At sea level, approximately 13,300 feet above the highest part of the zone, the amplitude of the gravity anomaly caused by the low density of the reservoir rock is only 0.01 mgal, and its width is so great that a distinct low would not be perceptible even under optimum conditions. The anomaly produced at sea level by the much larger volume of the water-saturated sandstone has an amplitude greater than 0.05 mgal but is similarly so wide in relation to its height that its identification as a discrete anomaly would only be possible under extremely good operating conditions. The difference in the gravity anomaly that would be produced by replacing the petroleum fluid of the reservoir by water is clearly well below the level of perceptibility.

At minus 8,000 feet, about 5,300 feet above the highest point of the reservoir, the anomaly produced by the petroleum-bearing part of the reservoir has an amplitude of 0.04 mgal, half of which occurs within a horizontal distance of 5,000 feet from a point directly over the middle of the reservoir. The anomaly produced by the water-saturated part of the reservoir has an amplitude of 0.14 mgal, half of which occurs within a horizontal distance of slightly more than 5,000 feet from a point over the porous unit. The combined effect of the two differently saturated parts of the sandstone body is a slightly asymmetrical gravity low having an amplitude of 0.17 mgal. The slight asymmetry is due to the presence of petroleum fluids instead of water in the sandstone. The greatest amplitude of the anomaly is minus 0.012 mgal, enough to cause distinct divergence and convergence of contour lines on a detailed gravity map having a contour interval of 0.5 mgal.

At minus 11,000 feet, 2,300 feet above the highest part of the reservoir, the amplitude of the anomaly produced by the petroleum-saturated rock is 0.075 mgal, well within the range of effects measurable by precise gravity surveys. Moreover, two-thirds of that amplitude occurs within a horizontal distance of 3,500 feet from a point directly above the middle of the reservoir. The anomaly caused by water-saturated reservoir rock downdip from the productive edge of the sandstone body has an amplitude of 0.21 mgal, half of which occurs within 3,700 feet of a point directly above that mass. The 0.24-mgal composite anomaly that is produced by the rock saturated with the two fluids is markedly asymmetric, and the north limb of the anomaly is marked by a slight but distinctive concavity caused by the petroleum-saturated part of the reservoir. This distinctive concavity has an amplitude of minus 0.017 mgal, enough to be recognized by local divergences and convergences of lines of equal Bouguer gravity anomaly values on a carefully contoured map of precise Bouguer gravity values. Under ideal operating conditions an anomaly of this magnitude would be separable from other effects for a reservoir of the size, shape, and physical properties of the Spalding zone at a depth of only 2,300 feet, although alternate interpretations of the anomaly would be admissible.

At minus 12,000 feet, only 1,300 feet above its top, the petroleum reservoir produces a narrow symmetrical gravity minimum of 0.12 mgal, of which 0.06 mgal occurs within 1,000 feet horizontally of its midpoint. At this level, the density contrast produced by the high porosity and water of the water-saturated part of the sandstone (relative to the low porosity and low water content of the impermeable siltstones) produces a symmetrical gravity minimum of 0.27-mgal amplitude. The composite effect of both parts of the reservoir sandstone is a gravity minimum having an amplitude of 0.31 mgal, of which 0.15 mgal occurs within 3,600 feet of a point above the higher part of the water-saturated sandstone. The anomaly is notably asymmetric; the north limb is noticeably steeper and more depressed and concave than it would be if the entire sandstone body were water saturated. The amplitude of the component of the anomaly due to petroleum fluids is nearly 0.04 mgal, but even so, the composite gravity anomaly is not greatly different from the one that would be produced by a sandstone saturated only by water. If the presence of such a stratigraphic trap were already suspected and its possible location somewhat delimited by surface geology, subsurface data, or seismic data, careful use of detailed and precise gravity maps could aid in deciding whether, and where, to drill a prospect well. Only in unusual circumstances could gravity data alone be a satisfactory basis for prospecting.

For analytical purposes, suppose that the Spalding reservoir unit thinned and pinched out updip even more abruptly than is shown on plate 3*B*, that it thickened downdip to several times the maximum 300-foot thickness, and that the total vertical extent of petroleum-saturated rock approached 1,000 feet, five times that actually found at Fillmore. With such dimensions, the volume of rock having low density because of the petroleum saturation would be many times that of the Spalding pool. The gravity minimum produced at the surface, several thousand feet above such a reservoir, would have an amplitude of several tenths of a milligal or more. Such a large stratigraphic trap, having a great profit potential, might be conspicuous on a gravity map and yet very difficult to find by other procedures. If the porosity of the reservoir rock were near the maximum of 36 percent for a depth of 4,000 feet (fig. 4), and if the petroleum fluid density were appropriate for that depth, the density contrast between the water-saturated and petroleum-saturated parts of the reservoir unit would be doubled to 0.13 g per cm^3 (fig. 8*B*), thereby further multiplying the effect of the reservoir relative to surrounding rocks. With these limiting assumptions, gravity anomalies in excess of 1 mgal can be imagined as arising wholly from the low in situ density of a stratigraphic trap.

Taking a different view point, suppose that the Spalding reservoir possessed a notably greater porosity in the zone of petroleum saturation than in the zone of water saturation. Considerable published and unpublished data suggest that petroleum and natural-gas reservoirs of all kinds generally tend to be zones of maximum relative porosity. Heald and Anderegg (1960, p. 572, and fig. 1) suggested this explanation for uncemented miniature lenses and pockets in the otherwise thoroughly cemented Silurian Tuscarora Sandstone of Virginia and West Virginia; Adams (1964, p. 1575) extended Heald and Anderegg's explanation to much larger high-pressure low-volume gas reservoirs found in drilling in the "lower Morrowan, Pennsylvanian, sandstones of northwestern Oklahoma." Thomson (1959) review the occurrences, characteristics, and possible mechanisms of sandstone porosity variations relating to pressure solution, and Lerbekmo (1961) emphasized the difficulty of distinguishing the textural effects of silica cementation versus pressure solution of quartz in such sandstones.

To make an extreme assumption, consider the gravimetric effects of the Spalding reservoir if porosity in the petroleum-bearing sandstone were unchanged and porosity in the water-bearing part and the siltstone were reduced to zero by consolidation, preferential cementation, and pressure solution. The density contrast between the impermeable sandy siltstone and the reservoir rock would be increased from minus 0.21 g per cm^3 to minus 0.32 g per cm^3 because of reduced porosity of the siltstone. The density contrast between the impermeable sandy siltstone and the water-saturated sandstone would decrease from minus 0.15 g per cm^3 to minus 0.06 g per cm^3 at a maximum (fig. 12). Assuming no change in the gross geometry of the parts of the sandstone unit, the gravimetric effects of these changes would be to amplify the relative gravity minimum due to petroleum-bearing rock at any depth by the factor 0.320/0.213, and to attenuate the relative gravity minimum due to the non-petroleum-bearing sandstone by the factor 0.060/0.146. Thus, the effect at the minus 12,000-foot datum of the reservoir proper would be the symmetrical minimum shown on plate 3*B*, enlarged to a total amplitude of 0.18 mgal instead of 0.12 mgal. Of equal practical importance is the diminution of the 0.175-mgal minimum resulting from the water-saturated reservoir to 0.11 mgal upon the expulsion of water and replacement by silica. Combining the two resultant partial negative anomalies gives a complex composite minimum of approximately minus 0.25 mgal nearly centered over the reservoir.

It is unlikely that the extreme conditions assumed in the foregoing argument are present anywhere in nature. Porosity reduction to zero in any part of the reservoir rock is unlikely without complete recrystallization. A great reduction of porosity in one part of the reservoir rock without any reduction in the petroleum-bearing part is also unlikely. Porosity at moderate depths might, in an extreme case, decrease 8 percent (from 18 to 10 percent) for the reservoir proper and 17 percent (from 18 to 1 percent) for the water-bearing part of the sandstone. However, even such a differential reduction of porosity would be accompanied by notable changes in bulk density in situ and corresponding large changes in gravimetric effects. For a stratigraphic trap in which the zone of petroleum or natural-gas saturation is also the only zone of porosity, prospecting by surface gravimetry may be the cheapest, and perhaps the only, fruitful method. As we have seen, the thickest, shallowest, most porous, and areally largest reservoirs are those which should be easiest to discern by surface gravimetry. The reservoir most likely to be detected by gravimetric methods is also the reservoir most likely to be profitable.

All the subsurface gravimetric effects of petroleum and natural-gas reservoirs mentioned in this paper may be conveniently summarized by reference to plate 3*B* and in the discussion of the hypothetical gravimetric effects calculated for the Spalding stratigraphic trap at Fillmore oil field, California.

For the very small and deeply buried Spalding pool, horizontal variations in the relatively negative component of gravity produced by the petroleum-bearing part of the reservoir unit range from an imperceptible 0.014 mgal at sea level through 0.041 mgal at minus 8,000 feet, 0.078 mgal at minus 11,000 feet (2,300 feet above the top of the pool), to 0.122 mgal at minus 12,000 feet (1,300 feet above the pool). That part of the negative gravimetric effect due solely to the presence of petroleum fluid, instead of water in the reservoir pore space, ranges from minus 0.004 mgal at sea level to minus 0.012 mgal at minus 8,000 feet, and minus 0.04 mgal at minus 12,000 feet. Although effects at the sea-level datum are almost certainly virtually imperceptible because of instrumental limitations and the attenuating effect of the reservoir's great depth, the amplitude and the amplitude-width ratio of the anomalies at minus 8,000 feet are both within range of detectability by precise surface gravity surveys, if rough terrain or disturbing density contrasts of nearby large-volume masses do not mask the anomaly. Therefore, a subsurface gravity survey above the Spalding pool at minus 8,000 feet, using a borehole gravimeter equal in sensitivity to modern surface gravimeters, should detect this anomaly, provided adequate corrections are applied to remove the effects of the rocks above the subsurface datum and provided other large effects do not mask the anomaly. The anomaly would be more conspicuous in borehole gravimeter surveys at greater depths.

It is obvious from plate 3*B* that the gravimetric effects of the water-saturated part of the reservoir sandstone dominate the effects of the oil-producing part of the sandstone at depths through minus 12,000 feet This, as pointed out, previously would not be so if the sandstone porosity were wholly or largely restricted to the oil pool. Inasmuch as porosity in the Spalding reservoir appears, from the sparse published data, to be nearly uniform, irrespective of reservoir depth or reservoir fluid, the interpretation of the composite gravity anomaly produced at any level by the entire volume of reservoir sandstone is inherently ambiguous. However, the value of multilevel underground gravity surveys for reducing the number of possible alternative interpretations of the relatively negative composite anomaly is considerable and can be appreciated from further scrutiny of plate 3*B*.

The broad composite negative anomaly of 0.067 mgal at sea level could be interpreted in numerous ways. Similarly, the 0.170-mgal composite anomaly at the minus 8,000-foot level could be produced by one or several lenses or layers of low-density rock; neither the number, thickness, depth, nor density of the disturbing masses can be determined solely from the size or shape of the anomaly. The same statement is valid, in the strict sense, for the anomaly at the minus 11,000-foot level, although at this great depth the restricted width of the anomaly relative to its 0.24-mgal total amplitude and its clear asymmetry both suggest one mass or a few masses of sharply negative density contrast in a restricted space directly beneath the minimum. Differences in amplitude, width, and asymmetry between the gravity profiles observable at the minus 8,000-foot and minus 11,000-foot levels would be clearly distinguishable in two sets of measurements made along the profile, if a sensitive gravimeter were used in three or more wells spaced at approximately 3,000-foot intervals. These differences between profiles constructed at different levels would restrict notably the number and kinds of geologic choices open to the interpreter and would guide him in the general direction of the correct interpretation.

Suppose, further, that a single deep exploratory well penetrated the water-saturated reservoir sandstone downdip from the Spalding pool, and that a borehole gravimeter survey in the well demonstrated that the steep vertical gravity gradient prevailing within the Spalding sandstone interval eradicated the full amplitude of the family of gravity minimums observed at levels above the unit, thereby indicating the uniqueness of that unit as a source of the anomaly. This information at once would eliminate several of the unknown or questionable factors required for a unique interpretation of the multilevel profiles at higher levels. Not only would the uniqueness of the source of the gravity anomaly be established, but the vartical gravity gradient in the reservoir unit (and hence the density and density contrast) and its thickness would be fixed, leaving only the configuration and density distribution of the updip part of the sandstone for interpretation. Analysis of the multilevel profiles in terms of these variables would, of course, not yield a completely unambiguous result, but the range of possibilities would now be so restricted that the question of whether or not to drill another wildcat well (and where to bottom it if one were drilled) presumably could be answered with a very high probability of correctness.

Consideration of both the horizontal and the vertical variations in gravity shown on plate 3*B* focuses attention anew on the vertical gravity gradient variations in this plane and their possible utility (Evjen, 1936; Smith, 1950, p. 614). From borehole gravimeter measurements above the Spalding pool, of the kind hypothesized in the preceding four paragraphs and shown on plate 3*B*, a profile could be prepared of observed variations in vertical gravity gradient corrected for surface terrain and known subsurface geology. The residual variations in such a profile would be the products of geology that is not yet understood. As mentioned previously, only those departures from the normal gradient of gravity that exceed ±0.03 mgal per 1,000 feet could be perceived, using present techniques of measuring density in situ. Above the Spalding pool, departures from the normal gradient of gravity, calculated from the geologic model (pl. 3*B*), do not exceed 0.03 mgal except below minus 10,000 feet but increase notably below that depth (to values in excess of minus 0.07 mgal at minus 11,500 feet), especially in the regions above the southern edge of the oil-water interface. Limited in application, as this technique thus appears to be, it nevertheless may prove extremely helpful in some circumstances, particularly where, as directly over the middle of the Spalding pool, the rate of change as a function of depth of the vertical gradient of gravity is relatively very great.

GENERALIZATIONS REGARDING GRAVIMETRIC EFFECTS OF PETROLEUM AND NATURAL-GAS RESERVOIRS

The author has shown by the results of model studies just presented that petroleum and natural-gas reservoirs, like other rock masses that are notably less dense than their surroundings, produce variations in surface measurements of gravity that are relatively negative for locations nearly or directly above a reservoir as compared with locations a considerable horizontal distance from the reservoir. Because of the small volumes of most reservoirs, and the small volume-to-area ratio of many large-volume reservoirs, such negative effects are of small amplitude or of small height-to-width ratio, and may therefore be masked at many sites by the more obvious effects of density contrasts or density variations involving much larger rock volumes. Moreover, even though the low density of most petroleum fluids makes a porous rock containing such fluids exceptionally low in density, negative density contrasts are also caused by many factors other than petroleum saturation, and, therefore, negative gravity anomalies in general are not uniquely indicative of petroleum or natural-gas reservoirs.

The potential value of high-accuracy surface gravity surveys for direct detection of reservoirs of petroleum and natural gas is inherently limited but has certain unique strengths which should be exploited.

The small size of the gravimetric effects generally requires that gravity surveys have the highest accuracy. Topographic irregularities, near-surface geologic complications, instrumental limitations, or data-reduction procedures that introduce errors of 0.05 mgal or more into the final Bouguer anomaly map may lower the signal-to-noise ratio sufficiently to conceal some of the effects of interest. Reservoirs of small to moderate size, at depths of 2,000–5,000 feet and more, produce anomalies that are detectable by accurate surface gravity surveys only if (1) porosity is restricted to the reservoir or is much greater within the reservoir than outside it, or (2) density of the reservoir fluid is extremely low (gas or gas condensate reservoir), or (3) density of the nonreservoir rock is very great (nonporous carbonate rock or dense, well-compacted argillaceous rock), or (4) masking effects of other density contrasts involving rock units of large volume are absent or can be fully evaluated from fairly detailed knowledge of both the shapes and the densities of those rock masses. Large reservoirs of moderate porosity (10–20 percent) and containing fluid of intermediate gravity (30°–40° API) at depths of 5,000–10,000 feet produce anomalies that are recognizable most readily if the ratio of reservoir thickness to width is in the range greater than 0.1. As this ratio decreases below 0.1, the width-to-height ratio of the resultant gravity anomaly is large enough to make recognition difficult in many geologic situations, although some moderate depth reservoirs where the ratio is 0.003 produce recognizable anomalies. From consideration of these limiting factors, it is evident that any program of petroleum exploration by precise surface gravity surveys, aimed at direct detection of the negative gravimetric effects of rocks saturated by hydrocarbons, must be accompanied, from the planning stages, by full and thoughtful utilization of all other available geological and geophysical data.

Although limited by the aforementioned factors, exploration for petroleum and natural-gas reservoirs by detection of small-amplitude local negative gravity anomalies presents several unique and potent advantages. Purely stratigraphic traps (Busch, 1959; Sabins, 1963)—traps related to isolated and unpredictable zones of residual primary porosity, " * * * secondary, solution-formed porosity * * * " (Adams, 1964, p. 1575), or secondary fracture porosity (Thomas, 1951; Hubbert and Willis, 1955)—should produce diagnostic negative gravity anomalies if reservoir size, shape, depth, porosity, and fluid density are appropriate. Detailed gravimetry thus provides a means of exploring for such traps where other methods have failed or have been applied with great difficulty and high risk. Similarly, traps associated with minor faults or with anticlinal structures of very small closure also may be detected by precise surface gravimetry where other methods, aimed toward first finding the structure and then the trap, fail or present nearly insuperable difficulties. This same statement may also be made for traps in which the petroleum accumulation is located away from the structurally highest position because of hydrodynamic conditions (Hubbert, 1953). In addition to these unique advantages, the largest and most distinctive negative gravity anomalies produced by reservoirs are those related to reservoirs which, for one or more of the following six reasons, present the most favorable circumstances for exploitation and the highest probability of profit: (1) Reservoirs (or groups of superposed reservoirs) that are large in volume relative to their area produce the largest and most conspicuous anomalies. (2) Reservoirs that have the largest pore volume relative to total reservoir rock volume produce the largest and clearest anomalies. (3) The shallowest reservoirs produce the sharpest anomalies of greatest amplitude. (4) Reservoirs that have the greatest vertical columns of petroleum-saturated rock, and those that contain gas, petroleum of high gravity, or petroleum of high gas-oil ratio produce the largest anomalies for their size. (5) A reservoir fluid containing a small proportion of interstitial water produces a larger anomaly than an analogous reservoir fluid containing more interstitial water. (6) Lastly, the fairly general tendency for petroleum gravity to increase with increasing reservoir depth (Barton, 1934; Haeberle, 1951), where other factors are invariant, partially compensates for the diminution of the height-to-width ratio of the produced gravity anomaly caused by attenuation and porosity reduction associated with increased depth.

In many regions, broad delineation of surface or subsurface structure is less difficult or costly than evaluation of known structural highs in terms of their petroleum-producing potential. In such regions, if there is reasonable assurance that salt (or other low-density evaporite rocks), coal, or diatomite is not present beneath the surface to produce gravity minimums over structural highs, surface gravity surveys may aid significantly in the evaluation of structures prior to costly drilling campaigns.

In late Cenozoic basins, some pronounced anticlinal folds (such as the San Miguelito anticline) produced by very youthful uplift following deep burial and consolidation may display only positive gravity anomalies. Such folds cannot be quickly diagnosed without appropriate filtering of the gravity data by trend-surface analyses or suitable derivative calculations. However, other folds produced by postconsolidation uplift in such areas may display small local minimums surmounting broad maximums. Such folds are very likely to be productive from reservoirs at shallow to moderate depths. Still other prominent anticlinal structures in late Cenozoic basins may be accompanied by a prominent local gravity minimum only, in some instances amounting to 1–2 mgal in amplitude. Such folds are almost certain to be productive of petroleum and (or) natural gas and are likely to be richly productive from large reservoirs of high porosity at moderate depths.

In Mesozoic or Paleozoic basins, time has been sufficient to cause a high degree of consolidation at most depths, with the result that isopycnic surfaces are nearly level in monolithologic sequences and follow bedding surfaces consistently where strongly contrasting lithologies (such as quartz sandstone versus shale) are present. In such basins, gravity minimums produced by petroleum reservoirs may be conspicuous if the reservoir occurs in a monolithologic sequence or in an area of gentle structural relief and is of appropriate depth, volume, porosity, and fluid density. On the other hand, such gravity minimums may be completely masked by the effects of deformed strata in a region of heterogeneous lithology and large structural relief.

Studies of hypothetical models based on well-drilled oil fields also show that precise subsurface gravimetric surveys, accompanied by careful utilization of subsurface geologic density data, should afford a powerful tool for overcoming the attenuation due to depth of the negative gravimetric signal produced by porous reservoir rocks and by the low density of hydrocarbon fluids in the pores of such rocks. Such surveys probably would be most valuable in extensively explored areas where wells already drilled provide inexpensive access as well as the tight geologic control needed to interpret the subsurface gravity measurements.

SUMMARY OF PRINCIPAL OBSERVATIONS AND CONCLUSIONS

The length of this paper, the diversity of its subject matter, and the potential commercial importance of certain of its implications make the following summary of principal observations and conclusions desirable:

1. Precise and detailed gravimeter surveys show that small local gravity minimums are associated with some known shallow natural reservoirs of petroleum and natural gas (fig. 1; Miller, R. H., 1931, Tsimel'zon, 1956a, b, and 1959a). Such gravity minimums range in amplitude from almost zero to more than 1 mgal.
2. The densities, under reservoir temperature and pressure conditions, of pure water, brine, and petroleums and natural gases of various compositions vary widely. However, a sedimentary rock of any porosity is less dense when saturated with petroleum fluid of 30° API gravity, or higher, and a gas-oil ratio of 500 cu ft per bbl, or higher, than when saturated with pure water or brine. For example, the density contrast between rock of 30-percent porosity saturated with water and the same rock saturated with hydrocarbon fluid at a temperature and pressure appropriate to a depth of 4,000 feet ranges from 0.11 g per cm^3 (for petroleum of 30° API gravity and 500 cu ft per bbl gas-oil ratio) to 0.29 g per cm^3, for pure methane (fig. 9).
3. Consideration of the hypothetical gravimetric effects of well-explored reservoirs indicates that all porous rocks containing low-density petroleum and natural gas produce relatively negative gravity anomalies but that such effects may be masked or too attenuated to be detected in many places. Factors that tend to conceal the negative gravimetric effect of a reservoir are: (a) Small volume; (b) great depth; (c) low porosity; (d) low petroleum gravity and low gas-oil ratio; (e) high interstitial water content; (f) large area-volume ratio; (g) strong density contrasts between other nearby rock masses of large volume; (h) pronounced distortion of isopycnic surfaces outside the reservoir because of very recent deformation of young rocks or highly consolidated lithologically heterogeneous rocks of large structural relief. Factors that tend to make the negative gravimetric effects of a reservoir conspicuous are also factors which tend to make a reservoir commercially attractive. These are: (a) large volume; (b) high porosity; (c) shallow depth; (d) high gravity petroleum or high gas content, or both; (e) large reservoir volume-area ratio; and (f) low interstitial water content. Additional factors that make the negative gravitational effects conspicuous are: (a) geologic simplicity in the rocks surrounding the reservoir; (b) negligible to moderate structural relief and distortion of isopycnic surfaces; and (c) thorough consolidation of surrounding nonpetroliferous rocks.
4. Although the low densities of petroleum and natural-gas reservoirs account for many of the relatively negative gravimetric effects observed over oil fields, several other natural factors tend to produce the same effects. These factors are not examined individually in this report, nor are the observed negative gravimetric effects of known oil fields compared quantitatively with hypothetical effects.
5. Most reservoir rocks are sufficiently dense in spite of the low-density hydrocarbon pore fluids that other, more porous, water-saturated rocks may be equally or even less dense. However, sandstones of the maximum probable or possible porosity at any given depth—those that are in general late Cenozoic in age—possess uniquely low densities when saturated with petroleum of 30° API, or higher, and gas-oil ratio of 500 cu ft per bbl, or higher. The nearly unique densities of these rocks are probably sufficient in themselves to label the rocks as petroleum bearing if a satisfactory method is available of measuring density in situ in boreholes, unless salt, coal, or diatomite is a known or suspected constituent.
6. Hypothetical subsurface gravimetric effects of well-drilled petroleum reservoirs of moderate and

small size suggest that most promising extensions of the relatively negative surface gravimetric effects of reservoir rocks can be expected from the application of a borehole gravimeter (or gravity gradiometer) having a sensitivity equal to that of modern surface gravimeters.

Such expectable extensions should prove exceptionally helpful in the evaluation and exploitation of new reservoirs, and in the elucidation of many problems of importance to petroleum reservoir engineering. Moreover, subsurface gravimetric measurements are certain to be of great and novel value in exploring for deeper pools and lateral extensions of known pools in partly explored oil fields, particularly those of the stratigraphic entrapment, fracture porosity, or unpredictable residual and solution porosity types. Lastly, systematic gathering and analysis of subsurface gravimetric data could prove highly beneficial, in conjunction with surface gravity data, in support of any wildcat exploration campaign, but particularly in exploration in basins or regions where much is already known, from previous drilling, about subsurface structural and stratigraphic variations and isopycnic configurations.

RECOMMENDATIONS

On the basis of the data, observations, and conclusions that form the body of this report, the following specific recommendations follow or stand out by implication:

1. Precise gravity maps of many petroliferous regions should be examined, preferably first by suitable trend-surface analyses or graphical or numerical derivative procedures, for evidence of local gravity minimums of small amplitude associated with known and explored oil fields in various regions. Thereby, an empirical basis could be established for seeking previously unrecognized reservoirs by this method of direct gravimetric detection.
2. Further efforts should be made to calculate from density models of well-drilled oil fields their gravimetric effects for comparison with gravity variations actually observed over these fields. By this means, an improved understanding could be reached of the factors that control the sizes and shapes of both the small surface and the larger subsurface gravity anomalies produced by reservoirs of petroleum and natural gas and their surrounding rock masses, and a basis would be established for judging the reliability of such models.
3. Efforts should be intensified to construct an experimental borehole gravimeter (or a gravity gradiometer) of sensitivity and accuracy equivalent to the best presently available surface gravimeters. Even a large-diameter prototype of limited temperature (and therefore depth) tolerance would be of great value in exploring this fascinating frontier of exploration and exploitation geology.
4. Investigations should be conducted to determine the utility of precise ocean-bottom gravimeter surveys or traverses over seismically determined structures as a means of predicting, before drilling, the relative productive potential of such structures from their local gravimetric effects. Determination of generalized sub-ocean-bottom structure in water of moderate (and even great) depth at sea has now become comparatively simple and reliable. Analysis of precise gravity measurements made on the ocean bottom over potential trapping structures, located by such accoustic methods, offers the prospect of greatly reducing exploration risks or greatly enhancing ability to bid wisely in competition for an offshore area, the structure of which is moderately well understood.
5. Where known stratigraphic traps and fracture porosity reservoirs are suspected of having unexploited extensions, precise gravity surveys should be conducted to determine the feasibility of locating such suspected extensions by their relatively negative gravimetric effects.
6. Because of their probable future critical importance in investigations of the variations of the underground vertical gradient of gravity, conventional cores from wells already drilled should be carefully conserved.

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