2 Fundamentals of Quantitative Log Interpretation

Almost all oil and gas produced today comes from accumulations in the pore spaces of reservoir rocks — usually sandstones, limestones, or dolomites. The amount of oil or gas contained in a unit volume of the reservoir is the product of its porosity by the hydrocarbon saturation.

In addition to the porosity and the hydrocarbon saturation, the volume of the formation containing hydrocarbons is needed in order to estimate total reserves and to determine if the accumulation is commercial. Knowledge of the thickness and the area of the reservoir is needed for computation of its volume.

To evaluate the producibility of a reservoir, it is necessary to know how easily fluid can flow through the pore system. This property of the formation rock, which depends on the manner in which the pores are interconnected, is its permeability.

The main petrophysical parameters needed to evaluate a reservoir, then, are its porosity, hydrocarbon saturation, thickness, area, and permeability. In addition, the reservoir geometry, formation temperature and pressure, and lithology can play important roles in the evaluation, completion, and production of a reservoir.

POROSITY

Porosity is the pore volume per unit volume of formation; it is the fraction of the total volume of a sample that is occupied by pores or voids. The symbol for porosity is ϕ. A dense, uniform substance, such as a piece of glass, has zero porosity; a sponge, on the other hand, has a very high porosity.

Porosities of subsurface formations can vary widely. Dense carbonates (limestones and dolomites) and evaporites (salt, anhydrite, gypsum, sylvite, etc.) may show practically zero porosity; well-consolidated sandstones may have 10 to 15% porosity; unconsolidated sands may have 30%, or more, porosity. Shales or clays may contain over 40% water-filled porosity, but the individual pores are usually so small the rock is impervious to the flow of fluids.

Porosities are classified according to the physical arrangement of the material that surrounds the pores and to the distribution and shape of the pores. In a clean sand, the rock matrix is made up of individual sand grains, more or less spherical in shape, packed together in some manner where the pores exist between the grains. Such porosity is called intergranular, sucrosic, or matrix porosity. Generally, it has existed in the formations since the time they were deposited. For this reason, it is also referred to as primary porosity.

Depending on how they were actually deposited, limestones and dolomite may also exhibit intergranular porosity. They may also have secondary porosity in the form of vugs or small caves. Secondary porosity is caused by the action of the formation waters or tectonic forces on the rock matrix after deposition. For instance, slightly acidic percolating waters may create and enlarge the pore spaces while moving through the interconnecting channels in limestone formations, and shells of small crustaceans trapped therein may be dissolved and form vugs. Conversely, percolating waters rich in minerals may form deposits that partially seal off some of the pores or channels in a formation, thereby reducing its porosity and/or altering the pore geometry. Waters rich in magnesium salts can seep through calcite with a gradual replacement of the calcium by magnesium. Since the replacement is atom for atom, mole for mole, and the volume of one mole of dolomite is 12% less than that of calcite, the result is a reduced matrix volume and corresponding increase in pore volume.

Stresses in the formation may also occur and cause networks of cracks, fissures, or fractures, which add to the pore volume. In general, however, the actual volume of the fractures is usually relatively small. They do not normally increase the porosity of the rock significantly, although they may significantly increase its permeability.

SATURATION

The saturation of a formation is the fraction of its pore volume occupied by the fluid considered. Water satura-

tion, then, is the fraction (or percentage) of the pore volume that contains formation water. If nothing but water exists in the pores, a formation has a water saturation of 100%. The symbol for saturation is S; various subscripts are used to denote saturation of a particular fluid (S_w for water saturation, S_o for oil saturation, S_h for hydrocarbon saturation, etc.).

Oil, or gas, saturation is the fraction of the pore volume that contains oil, or gas. The pores must be saturated with some fluid. Thus, the summation of all saturations in a given formation rock must total to 100%. Although there are some rare instances of saturating fluids other than water, oil, and gas (such as carbon dioxide or simply air), the existence of a water saturation less than 100% generally implies a hydrocarbon saturation equal to 100% less the water saturation (or $1 - S_w$).

The water saturation of a formation can vary from 100% to a quite small value, but it is seldom, if ever, zero. No matter how "rich" the oil or gas reservoir rock may be, there is always a small amount of capillary water that cannot be displaced by the oil; this saturation is generally referred to as irreducible or connate water saturation.

Similarly, for an oil- or gas-bearing reservoir rock, it is impossible to remove all the hydrocarbons by ordinary fluid drives or recovery techniques. Some hydrocarbons remain trapped in parts of the pore volume; this hydrocarbon saturation is called the residual oil saturation.

In a reservoir that contains water in the bottom and oil in the top the demarcation between the two is not always sharp; there is a more or less gradual transition from 100% water to mostly oil. If the oil-bearing interval is thick enough, water saturation at the top approaches a minimum value, the irreducible water saturation, S_{wi}. Because of capillary forces, some water clings to the grains of the rock and cannot be displaced. A formation at irreducible water saturation will produce water-free hydrocarbons. Within the transition interval some water will be produced with the oil, the amount increasing as S_w increases. Below the transition interval, water saturation is 100%. In general, the lower the permeability of the reservoir rock the longer the transition interval. Conversely, if the transition interval is short, permeability will be high.

PERMEABILITY

Permeability is a measure of the ease with which fluids can flow through a formation. For a given sample of rock and for any homogeneous fluid, the permeability will be a constant provided the fluid does not interact with the rock itself.

The unit of permeability is the darcy, which is very large; so the thousandth part is generally used: the millidarcy (md). The symbol for permeability is k.

In order to be permeable, a rock must have some interconnected pores, capillaries, or fractures. Hence, there exists some rough relationship between porosity and permeability. Greater permeability, in general, corresponds to greater porosity, but this is far from being an absolute rule.

Shales and some sands have high porosities, but the grains are so small that the paths available for the movement of fluid are quite restricted and tortuous; thus, their permeabilities may be very low.

Other formations, such as limestone, may be composed of a dense rock broken by a few small fissures or fractures of great extent. The porosity of such a formation can be low, but the permeability of a fracture can be enormous. Therefore, fractured limestones may have low porosities but extremely high permeabilities.

RESERVOIR GEOMETRY

Producing formations (reservoirs) occur in an almost limitless variety of shapes, sizes, and orientations. Fig. 2-1 shows some of the major reservoir types; almost any combination of these is also possible.
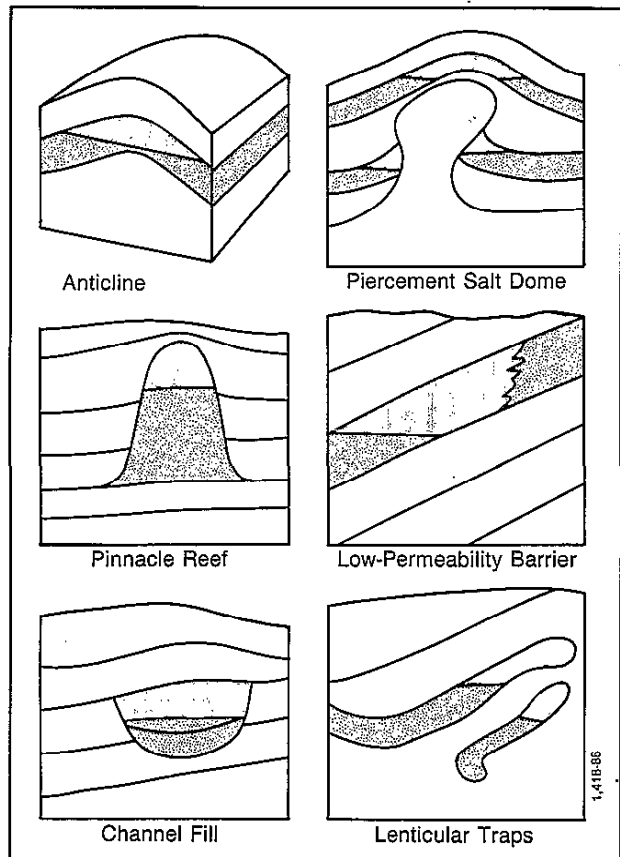

Fig. 2-1—Some typical reservoir shapes and orientations.

The physical shape and orientation of a reservoir can bear heavily on its producibility. Reservoirs can be wide or narrow, thick or thin, large or small. Giant reservoirs, such as some in the Middle East, can cover hundreds of square miles and be thousands of feet thick. Others are tiny, far too small to complete a well in. Configurations vary from simple lens shape to the tortuously complex.

Most reservoir-forming rocks were supposedly laid down in layers like blankets or pancakes. Their physical characteristics thus tend to be quite different in different directions, a condition called anisotropy. This non-uniformity is a very important consideration in reservoir engineering and completion design.

Normally, the permeability of such formations is much higher parallel to than perpendicular to the layering, and the permeabilities of the various layers can also vary widely.

Reservoirs that did not originate as deposited layers of grains do not conform to this laminar model of anisotropy. Carbonate rocks that originated as reefs, rocks subjected to extensive fracturing, or rocks with vuggy porosity are examples.

TEMPERATURE AND PRESSURE

Temperature and pressure also affect hydrocarbon production in several ways. In the reservoir rock, temperature and pressure control the viscosities and mutual solubilities of the three fluids — oil, gas, and water. As a result, the phase relationship of the oil/gas solution may be subject to highly significant variations in response to temperature and pressure changes. For example, as pressure drops gas tends to come out of solution. If this happens in the reservoir rock, the gas bubbles can cause a very substantial decrease in the effective permeability to oil.

The relationships between pressure, temperature, and the phase of hydrocarbon mixtures are extremely variable, depending on the specific types and proportions of the hydrocarbons present. Fig. 2-2 is a simple two-component phase diagram.

Ordinarily, the temperature of a producing reservoir does not vary much, although certain enhanced-recovery techniques (such as steam flood or fire flood) create conspicuous exceptions to this rule. However, some pressure drop between the undisturbed reservoir and the wellbore is inevitable. This pressure drop is called the pressure drawdown; it can vary from a force of a few pounds per square inch (psi) up to full reservoir pressure.

LOG INTERPRETATION

Unfortunately, few of these petrophysical parameters can be measured directly. Instead, they must be derived or inferred from the measurement of other physical parameters of the formations. A large number of parameters can now be measured. They include, among others, the resistivity, the bulk density, the interval transit time, the spontaneous potential, the natural radioactivity, and the hydrogen content of the rock.

Log interpretation is the process by which these measurable parameters are translated into the desired petrophysical parameters of porosity, hydrocarbon saturation, permeability, producibility, lithology, etc.

This translation is further complicated by the drilling process itself. In drilling through a formation, the fluids in the pores of the rock surrounding the borehole may be displaced or contaminated by the invasion of the drilling fluid. Occasionally, the rock matrix may even be altered.
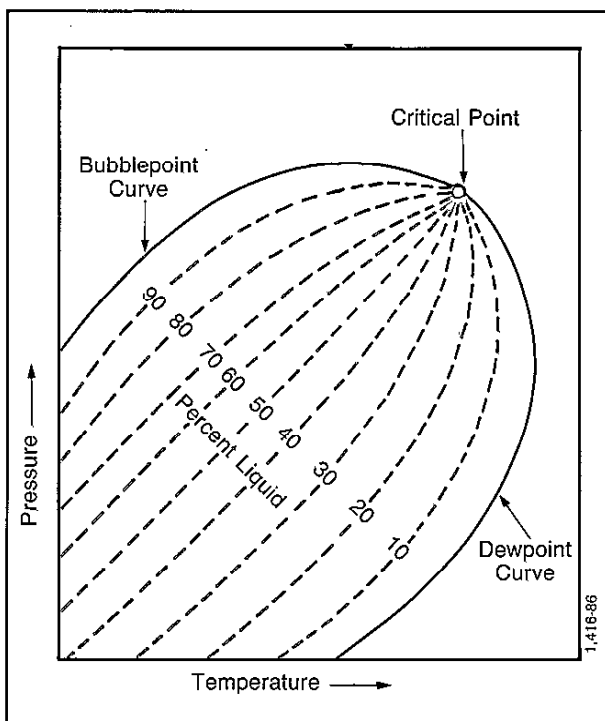

Fig. 2-2—Two-component phase diagram.

Since the petrophysical parameters of the virgin, uncontaminated formation are usually needed, the well logging tool must be able to "see" beyond the contaminated zone into the virgin formation; alternately, the interpretation techniques must be able to compensate for the contamination. In well logging, both approaches are used. Where the physics of the measurement permit, the tool has been designed to have a very significant depth of investigation. When the physics of measurement precludes deep investigation, the interpretation techniques must consider the mud filtrate invasion issues.

It is the purpose of the various well logging tools to provide measurements from which the petrophysical characteristics of the reservoir rocks can be derived or inferred. It is the purpose of quantitative log interpretation to provide the equations and techniques with which these translations can be accomplished. Actually, the basic fundamental premises of log interpretation are few in number and simple in concept.

THE INVASION PROCESS

During the drilling of the well the hydrostatic pressure of the mud column is usually greater than the pore pressure of the formations. This prevents the well from "blowing out." The resultant pressure differential between the mud column and formation forces mud filtrate into the permeable formation, and the solid particles of the mud are deposited on the borehole wall where they form a mudcake. Mudcake usually has a very low permeability (of the order of 10^{-2}-10^{-4} md) and, once developed, considerably reduces the rate of further mud filtrate invasion (Fig. 2-3).

Very close to the borehole most of the original formation water and some of the hydrocarbons may be flushed away by the filtrate. This zone is referred to as the flushed zone. It contains, if the flushing is complete, only mud filtrate; if the formation was originally hydrocarbon bearing, only residual hydrocarbons.

Further out from the borehole, the displacement of the formation fluids by the mud filtrate is less and less complete, resulting in a transition from mud filtrate saturation to original formation water saturation. This zone is referred to as the transition or invaded zone. The extent or depth of the flushed and transition zones depends on many parameters. Among these are the type and characteristics of the drilling mud, the formation porosity, the formation permeability, the pressure differential, and the time since the formation was first drilled. Generally, the lower the formation porosity, the deeper the invasion. The undisturbed formation beyond the transition zone is referred to as the noninvaded, virgin, or uncontaminated zone.

Sometimes in oil- and gas-bearing formations, where the mobility of the hydrocarbons is greater than that of the water because of relative permeability differences, the oil or gas moves away faster than the interstitial water. In this case, there may be formed between the flushed zone and the uninvaded zone an annular zone with a high formation water saturation (Fig. 2-3). Annuli probably occur, to some degree, in most hydrocarbon-bearing formations. Their influence on log measurements depends on the radial location of the annulus and its severity (i.e., magnitude of formation water saturation in the annuli

Horizontal Section Through A
Permeable Water-Bearing Bed

Radial Distribution Of Resistivities
($R_{mf} \gg R_w$, Water-Bearing Bed)   1,589-86

Radial Distribution Of Fluids In The
Vicinity Of The Borehole, Oil-Bearing Bed
(Qualitative)

Radial Distribution Of Resistivities
($R_{mf} \gg R_w$, Oil-Bearing Bed, $S_w \leqslant 50\%$)
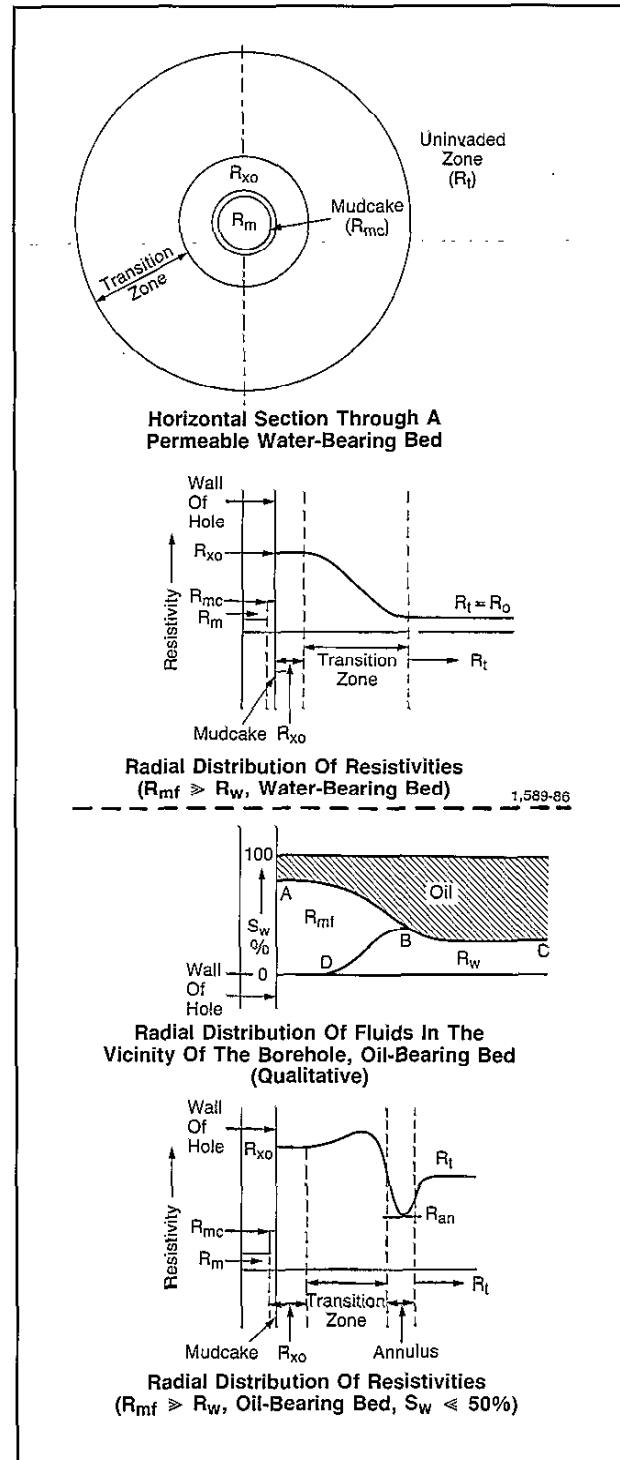
Fig. 2-3—(Upper)—Schematic representation of invasion and resistivity profile in a water-bearing zone.

(Lower)—Invasion and resistivity profile in an oil-bearing zone showing resistivity annulus.

relative to the formation water saturation in the noninvaded zone). Annuli do disappear in time through dispersion.

In fractured formations the mud filtrate invades easily into the fractures, but it may penetrate very little into the unfractured blocks of low-permeability matrix. Therefore, only a small portion of the total original formation fluids (formation water and, if present, hydrocarbons) is displaced by the filtrate — even very close to the borehole. In this case, no true flushed zone exists.

RESISTIVITY

The electrical resistivity of a substance is its ability to impede the flow of electrical current through the substance. The unit used in logging is ohm-meter^2/meter, usually written as ohm-m. Electrical conductivity is the reciprocal of resistivity and is expressed in millimhos per meter (mmho/m).

Most formations logged for potential oil and gas saturation are made up of rocks which, when dry, will not conduct an electrical current; i.e., the rock matrix has zero conductivity or infinitely high resistivity. An electrical current will flow only through the interstitial water saturating the pore structure of the formation, and then only if the interstitial water contains dissolved salts. These salts dissociate into positively charged cations (Na^+, Ca^{++}, ...) and negatively charged anions (Cl^-, SO_4^-, ...). Under the influence of an electrical field these ions move, carrying an electrical current through the solution. Other things being equal, the greater the salt concentration, the lower the resistivity of the formation water and, therefore, of the formation. The greater the porosity of the formation and, hence, the greater the amount of formation water, the lower the resistivity.

Of all the rock parameters measured by today's logging tools, resistivity is of particular importance. It is the one measurement for which tools having a deep depth of investigation (up to several feet beyond the borehole) exist. Resistivity measurements are essential for saturation determinations — particularly saturation determinations in the virgin, noninvaded portion of the reservoir. Resistivity measurements are employed, singly and in combination, to determine formation resistivity in the noninvaded formation (called true resistivity, R_t). Resistivity measurements are also used to determine the resistivity close to the borehole (called flushed-zone resistivity, R_{xo}), where mud filtrate has largely replaced the original pore fluids. Resistivity measurements, along with porosity and water resistivity, are used to obtain values of water saturation. Saturation values from both shallow and deep resistivity measurements can be compared to evaluate the producibility of the formation.

FORMATION FACTOR AND POROSITY

It has been established experimentally that the resistivity of a clean, water-bearing formation (i.e., one containing no appreciable amount of clay and no hydrocarbons) is proportional to the resistivity of the brine with which it is fully saturated. The constant of proportionality is called the formation resistivity factor, F. Thus, if R_0 is the resistivity of a nonshaly formation rock 100% saturated with brine of resistivity R_w, then

$$F = R_0/R_w . \qquad \text{(Eq. 2-1)}$$

For a given porosity, the ratio R_0/R_w remains nearly constant for all values of R_w below about 1 ohm-m. For fresher, more resistive waters, the value of F may decrease as R_w increases. This phenomenon is attributed to a greater proportionate influence of surface conductance of the rock matrix.

For a given saturating brine water, the greater the porosity of a formation, the lower the resistivity R_0 of the formation, and the lower the formation factor F (from Eq. 2-1). Therefore, the formation factor is inversely related to porosity. It is also a function of pore structure and pore-size distribution.

Archie proposed, based on observations, a formula relating porosity, ϕ, and formation factor, F; the relationship is

$$F = \frac{a}{\phi^m} , \qquad \text{(Eq. 2-2)}$$

where m is the cementation factor or exponent. The cementation exponent and the constant a are determined empirically.

Over the years, experience has generated general acceptance of the following formation factor-porosity relationships (dependent on lithology or pore structure):

$$F = \frac{0.62}{\phi^{2.15}} \text{ for sands, and} \qquad \text{(Eq. 2-3a)}$$

$$F = \frac{1}{\phi^2} \qquad \text{(Eq. 2-3b)}$$

for compacted formations.

The first relationship is popularly referred to as the Humble formula; the second, as the Archie formation factor relationship.

To eliminate the fractional cementation exponent, the Humble formula is sometimes simplified to

$$F = \frac{0.81}{\phi^2} . \qquad \text{(Eq. 2-3c)}$$

Within their normal range of application, these two ways of expressing the Humble formula yield quite similar results.

While the Humble formula is satisfactory for sucrosic rocks, better results are obtained using $F = 1/\phi^2$ in chalky rocks and $F = 1/\phi^{2.2}$ to $1/\phi^{2.5}$ in compact or oolicastic rocks. In some severely oolicastic rocks, m may even be as high as 3.

The Humble and Archie formulas for several values of m are presented graphically on Chart Por-1.

WATER SATURATION

Neither oil nor gas conducts electrical current; both are excellent insulators. Indeed, oil is widely used as an insulator in some electrical equipment. Thus, in a formation containing oil or gas, the resistivity is a function not only of F and R_w but also of S_w. S_w is the fraction of the pore volume occupied by formation water and $(1 - S_w)$ is the fraction of the pore volume occupied by hydrocarbons.

Archie determined experimentally that the water saturation of a clean formation can be expressed in terms of its true resistivity as

$$S_w^n = \frac{FR_w}{R_t}, \qquad \text{(Eq. 2-4a)}$$

where n is the saturation exponent.

Although laboratory measurements do show some variation in the value of n, most formation samples yield a saturation exponent of about 2. Therefore, in log interpretation practice, n is taken equal to 2 unless it is known to be otherwise.

Accepting $n = 2$, Eq. 2-4a may be written as

$$S_w = \sqrt{\frac{FR_w}{R_t}}. \qquad \text{(Eq. 2-4b)}$$

This equation is often popularly referred to as the Archie water saturation equation. It is the foundation stone of most electrical log interpretation techniques.

In Eq. 2-3, FR_w is equal to R_0, the resistivity of the formation when 100% saturated with water of resistivity R_w. The water saturation equation, Eq. 2-4b, may then be written:

$$S_w = \sqrt{\frac{R_0}{R_t}}. \qquad \text{(Eq. 2-5)}$$

Early quantitative electric log interpretation used this formula. It simply involved the comparison of R_t, recorded in a potential hydrocarbon-bearing reservoir rock, to R_0, recorded in a known 100% water-bearing reservoir rock. Its use assumes that the two beds have similar porosities and formation factors and contain formation waters of similar salinity. The most appropriate application of Eq. 2-5 is therefore a thick reservoir rock of constant porosity, which has a water column at its base and an oil column at its top.

The ratio R_t/R_0 is called the resistivity index. A resistivity index of unity implies 100% water saturation; a resistivity index of 4 corresponds to 50% water saturation; an index of 10, to 31.6% water saturation; an index of 100, to 10% water saturation; etc. Chart Sw-1 graphically solves the Archie water saturation equation.

The water (mud filtrate) saturation, S_{xo}, of the flushed zone can also be expressed by the Archie formula (Eq. 2-4a) as

$$S_{xo} = \sqrt{\frac{FR_{mf}}{R_{xo}}}, \qquad \text{(Eq. 2-6)}$$

where R_{mf} is the resistivity of the mud filtrate and R_{xo} is the resistivity of the flushed zone. S_{xo} is equal to $(1 - S_{hr})$, S_{hr} being the residual hydrocarbon saturation in the flushed zone. S_{hr} depends to some extent on the hydrocarbon viscosity; it generally increases as the viscosity increases.

The comparison of the water saturations obtained in the flushed zone (Eq. 2-6) and in the noninvaded zone (Eq. 2-4b) determines the bulk-volume fraction of oil displaced by the invasion process. Since $S_h = (1 - S_w)$ and $S_{hr} = (1 - S_{xo})$, the bulk volume of moved oil is ϕ $(S_{xo} - S_w)$. The ability of the mud filtrate to displace or move oil in the invasion process implies that the formation exhibits relative permeability to oil; conversely, oil production can be expected when the reservoir is put on production.

Eqs. 2-4b and 2-6 can also be combined to yield the ratio of the saturation in the virgin, uncontaminated zone to the saturation in the flushed zone. Dividing the first equation by the second gives

$$\frac{S_w}{S_{xo}} = \left(\frac{R_{xo}/R_t}{R_{mf}/R_w}\right)^{1/2}. \qquad \text{(Eq. 2-7)}$$

Empirical observations suggest that $S_{xo} \approx S_w^{1/5}$. Substituting this relationship into Eq. 2-7 gives

$$S_w = \left(\frac{R_{xo}/R_t}{R_{mf}/R_w}\right)^{5/8}. \qquad \text{(Eq. 2-8)}$$

Chart Sw-2 is a graphical solution of this equation. The chart also provides for S_w solutions when the residual oil saturation is other than average.

This method for determining water saturation is sometimes referred to as the ratio method. It does not require knowledge of porosity or formation factor. It does, however, imply finite values for these parameters. The implied values can be obtained by working back through Eq. 2-4b (or Eq. 2-6) solving for F, and then solving for ϕ, once S_w (or S_{xo}) has been determined from Eq. 2-8 (and Eq. 2-7).

These equations are good approximations in clean formations with fairly regular distribution of porosity (intergranular or intercrystalline porosity). In formations

with fractures or vugs, the equations are still used, but the accuracy may not be as good. (See Chapter 8.)

Resistivity Logging

Evaluating a reservoir for its water and hydrocarbon saturation involves the saturating formation water resistivity, R_w; the formation factor, F, or porosity, ϕ; and the true formation resistivity, R_t. Flushed zone resistivity, R_{xo}, is also of interest because it can be used to obtain S_w when porosity is unknown, to indicate hydrocarbon movability, and where invasion is deep to obtain a better value of R_t.

The resistivity parameter of greatest interest is R_t, because of its relationship to hydrocarbon saturation in the noninvaded, virgin formation. Determination of R_t is, therefore, of paramount importance. In determining R_t and R_{xo} from resistivity logs, several perturbing factors affecting the log readings must be taken into account. These are

- the borehole, filled with fluid,
- the adjacent formations, and
- the influence of R_{xo} (invasion) on the R_t measurement and vice versa.

The effects of the first two factors can be minimized by using logging tools designed to minimize borehole effect and to provide good vertical definition. The third is resolved by using several resistivity devices having different depths of investigation (see Chapter 7).

When $R_{xo} > R_t$ and formation resistivities are low to moderate, the DIL* dual induction log is recommended for R_t determination. This survey, consisting of a deep induction log, a medium induction log, and a shallow investigating resistivity log, will furnish good values of R_t for beds thicker than 4 or 5 ft if invasion is not too deep. Adding a microresistivity log to the suite will permit a better evaluation of R_{xo}, and thus R_t, in more deeply invaded formations. Interpretation charts are available to correct the various induction logs for borehole, adjacent formation, and invasion effects.

When $R_{xo} < R_t$ and formation resistivities are high, the DLL* dual laterolog is recommended for R_t determination (see Fig. 2-4). This log provides a deep laterolog and a shallow laterolog. Adding a microresistivity log to the suite will permit a better evaluation of R_{xo} and R_t. Charts are also available to correct for borehole, adjacent bed, and invasion effects.

Water Resistivities

In addition to formation factor or porosity, values of formation water resistivity, R_w, and mud filtrate resistivity, R_{mf}, are needed for the water saturation calculations. Mud resistivity, R_m, mudcake resistivity, R_{mc}, and R_{mf}

are generally measured at the time of the survey on a mud sample from the flowline or mud pit. These values are recorded on the log heading. If a measured value of R_{mf} or R_{mc} is not available, Chart Gen-7 provides an estimate. Since the resistivity of a material is a function of temperature, R_m, R_{mf}, and R_{mc} must be corrected to formation temperature (Chart Gen-9). The accuracy of these values can be improved by using the AMS auxiliary measurement sonde; it makes continuous borehole in-situ measurements of R_m and temperature versus depth.

Formation water resistivity, R_w, can be found from the SP curve, water catalogs, produced water sample, or water saturation equation (Eq. 2-4a) in a 100% water-bearing formation. In a clean formation, the SP curve response is

$$SP = -K \log \frac{R_{mf}}{R_w}, \qquad \text{(Eq. 2-9)}$$

where K is a temperature-dependent constant. Charts SP-1 and -2 solve the SP equation (Eq. 2-9) for R_w.
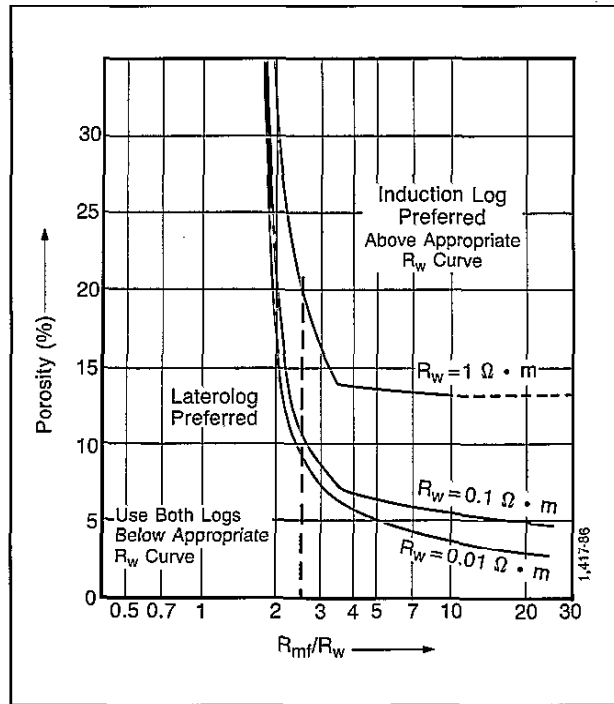

Fig. 2-4—Preferred ranges of application of induction logs and laterologs.

Porosity

Porosity can be obtained from a sonic log, a density log, or a neutron log provided the lithology of the formation is known. If lithology is not known or if mixtures of known minerals exist, a combination of two or more

porosity and lithology-sensitive logs can be used to define the lithology and to provide an accurate value of porosity.

The porosity logs are also somewhat sensitive to the nature of the saturating fluid(s) within the pores investigated by the tool. A combination of two porosity logs can sometimes detect the presence of gas or light oil in the formation.

The sonic tool measures the interval transit time,(t) or the time in microseconds for an acoustic wave to travel through 1 ft (or 1 m) of formation along a path parallel to the borehole.

Porosity can be derived from the interval transit time using an empirical weighted-average or time-average relationship,

$$\phi = \frac{t - t_{ma}}{t_f - t_{ma}}, \qquad \text{(Eq. 2-10)}$$

where t_f and t_{ma} are the transit times in the pore fluid and rock matrix, respectively. This time-average relationship is good for clean, compacted formations of intergranular porosity containing liquids.

Another empirical relationship for porosity from the interval transit time is

$$\phi = c\left(\frac{t - t_{ma}}{t}\right), \qquad \text{(Eq. 2-11)}$$

where $c \approx 0.67$. This empirical relationship is restricted to the same conditions as the time average relationship except that it can be used in noncompacted as well as compacted formations. Chart Por-3 graphically solves these equations.

The density tool responds to the electron density of the material in the formation. For common formation materials, the electron density is proportional to actual density.

Porosity is derived from the bulk density of clean liquid-filled formations when the matrix density, ϱ_{ma}, and the density of the saturating fluids, ϱ_f, are known:

$$\phi = \frac{\varrho_{ma} - \varrho_b}{\varrho_{ma} - \varrho_f}. \qquad \text{(Eq. 2-12)}$$

Chart Por-5 graphically solves this equation.

The presence of shale or gas in the formation complicates the response, but this can be resolved using an appropriate combination of porosity logs (see Chapters 5 and 6).

In addition to a bulk density measurement, the Litho-Density* log also provides a measurement of the photoelectric cross section. This cross section is influenced primarily by the mineralogy of the rock matrix. Used in combination with porosity logs, the composition of complex mineral mixtures can be defined with the photoelectric cross section measurement.

The neutron log responds chiefly to the presence of hydrogen atoms. If the pore space in the formation is liquid filled, the response is basically a measure of porosity. The log is usually scaled in porosity units on the basis of a limestone or sandstone matrix. Corrections must be made if the formation lithology differs from that for which the tool is calibrated. Again, shale and gas affect the porosity readings and must be accounted for (see Chapter 5). Chart Por-13 converts the neutron log reading into porosity.

Shaly Formations

Not all rocks are perfect insulators when dry. Many ores, such as galena and chalcopyrite, have high conductivities and conduct electrical current even when totally dry. Obviously, the resistivity and water saturation equations, which assume that the saturating fluid is the only electrically conductive medium, do not apply when the rock matrix is also conductive. Fortunately, in most oil provinces a significant quantity of conductive mineral in a potential reservoir rock is rare, but when the rock does contain a conductive mineral, the log interpretation must consider that conductivity.

Clays and shales, however, are not rare, and they do contribute to formation conductivity. Shale exhibits conductivity because of the electrolyte that it contains and because of an ion-exchange process whereby ions move under the influence of the impressed electric field between exchange sites on the surface of the clay particles. The effect of the shaliness on shaly sand conductivity is often disproportionately large relative to the quantity of shale. The actual effect depends on the amount, type, and distribution of the shale and on the nature and relative amount of the formation water.

Evaluation of shaly formations, usually shaly sands, is somewhat complex. All logging measurements are influenced by the shale, and corrections for shale content are required.

Through the years, investigators have proposed various interpretation models for shaly sands. In some cases, the model is based upon the shale existing in a particular geometry within the shaly sand; for example, the shale may exist in the form of thin laminae between layers of clean sand, or as grains or nodules in the sand matrix structure, or may be dispersed throughout the pore system of the sand in the form of accumulations adhering to or coating the sand grains. Other shaly sand models are based upon some specific characteristic of the shale, such as its cation exchange capacity or surface area.

Regardless of the basic assumption, most shaly sand interpretation models employ a weighted-average technique to evaluate the relative contributions of the sand and shale phases to the overall shaly sand response. For ex-

ample, in the case of bulk density as measured by a density log, the relationship is

$$\varrho_b = \phi\ (S_{xo}\ \varrho_{mf} + S_{hr}\ \varrho_h)$$
$$+ V_{sh}\ \varrho_{sh} + (1 - \phi - V_{sh})\ \varrho_{ma}, \quad \text{(Eq. 2-13)}$$

where V_{sh} is the bulk-volume fraction of shale, ϱ_{sh} is its density, ϱ_h is the apparent density of the hydrocarbon, and the other terms are as previously defined.

There are many formulas that relate resistivity to water saturation in shaly sands. Most are generally of the form

$$\frac{1}{R_t} = \frac{S_w^2\ (1 - V_x)}{FR_w} + \frac{CV_x}{R_x}\ , \quad \text{(Eq. 2-14)}$$

where V_x is a term related to the volume, or some specific volumetric characteristic, of the shale or clay; R_x is a term related to the resistivity of the shale or clay; and C, if it occurs in the formula, is a term related to the water saturation, S_w.

It should be noted that when the shale volume is zero (i.e., a clean sand), the equation (Eq. 2-14) reduces to the Archie water saturation equation (Eq. 2-4a). This is true for all shaly sand water saturation interpretation techniques.

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