The Petrophysics of Problematic Reservoirs

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Introduction

Petrophysics provides the building blocks for integrated reservoir models. It encompasses the analysis of well logs run on wireline and drillstring, conventional and special core analysis, mud logging, and formation testing and fluid sampling. The subject has open- and cased-hole cultures. For deviated and horizontal wells, and/or in the presence of dipping beds, petrophysical analysis is 3D and it should account for formation anisotropy, particularly transverse/longitudinal differences in rock properties where reference directions are relative to bedding. To manage the current task, the discussion notionally refers to water-wet reservoirs sensed by openhole well logs, although there are exceptions where the reservoir also is the source. Beyond this, the subject matter has been selected on the basis of topicality.

Petrophysical Evaluation

Most commonly, petrophysics is concerned with the technical evaluation of laboratory data and downhole measurements for reservoir properties such as shale-volume fraction V_{sh}, porosity ϕ, permeability k, net/gross reservoir, water saturation S_w, and net/gross pay. The subject has a philosophy of indirectness, in that, often, it is not possible to measure a required reservoir property directly. Therefore, it is necessary to measure some other property that is related to the required property. For this reason, petrophysics is built around a framework of interpretive algorithms that relate measurable parameters to reservoir parameters. Usually, these algorithms are empirical with some conceptual reference. This means that quantitative petrophysical interpretation is, mostly, data driven and that the interpretive algorithms change from reservoir to reservoir. This, in turn, requires that each reservoir be investigated separately and thoroughly. For general formation evaluation, see Warner and Woodhouse (2007); for net-pay evaluation, see Worthington (2010a).

Archie Reservoirs. Petrophysical interpretive procedures usually are described in terms of an idealized clastic reservoir, which is the textbook reference and is sometimes termed an "Archie" reservoir because it broadly matches the requirements for the application of the fundamental Archie equations that provide the quantitative basis for well-log analysis (Archie 1942). Attributes of an Archie reservoir are listed in **Table 1.** Although these conditions were not itemized explicitly by Archie (1942), they are implicit in the use of the Archie equations on the basis of many years of application.

A workflow for the petrophysical evaluation of an Archie reservoir is shown in **Fig. 1.** This workflow is applied to well-log-sampling levels, typically 15 cm apart. The suite of logs used in the evaluation of Archie reservoirs comprises spectral gamma ray and spontaneous-potential (SP) logs, density and neutron logs, laterolog and induction logs, and sonic logs. Essentially, an interval must be clean (i.e., free of dispersed, laminated, and structural shales). This is assured by use of lithology logs, such as the spectral gamma ray and SP logs. Porosity is evaluated by use of density, neutron, and/or sonic logs with groundtruthing through conventional core data, where available. The first Archie equation is used to determine formation (resistivity) factor F from ϕ, where F is defined as the ratio of the resistivity of a fully water-saturated rock R_o to the resistivity of the saturating water R_w. The next stage is to calculate the resistivity index I_r, where I_r is defined as the ratio of the resistivity of a partially water-saturated rock R_t to the resistivity of the same rock fully saturated with identical water R_o. By algebraic manipulation, I_r can be expressed as a function of F, formation-water resistivity R_w (ideally from sample analysis), and formation resistivity R_t obtained from a laterolog

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or an induction log. The second Archie equation then is used to calculate S_w from I_r. For Archie conditions to apply, I_r must be independent of formation-water salinity and, hence, R_w. If I_r satisfies this condition, F does too.

The first and second Archie equations are governed by the porosity exponent m and the saturation exponent n, respectively. These exponents, which are central to formation evaluation, are obtained from graphs of F vs. ϕ and I_r vs. S_w, respectively **(Fig. 2).** They have default values of $m=n=2$, but they should be quantified through special core analysis. Where Archie conditions apply, m and n are independent of R_w, which usually happens where shale/silt content and R_w are low. Here, an asterisk is used to denote this specific case (Figs. 1 and 2). With this convention, the first and second Archie equations can be combined:

$$(1/R_t)=(1/R_w)\,\phi^{m^*}\,S_w^{\,n^*}. \quad \ldots\ldots (1)$$

Eq. 1 allows S_w to be evaluated after ϕ has been determined. Often, permeability is estimated through correlations with porosity, enhanced by some form of core-data partitioning.

Note that the workflow in Fig. 1 can be enacted deterministically as shown, with sequential quality control, or geomathematically through the solution of log-response equations with simultaneous error distribution. To allow audit, a favored approach is to use deterministic methods supported by geomathematical methods, especially as reservoirs become more complex.

Non-Archie Reservoirs. Any departures from the Archie conditions in Table 1 usually are regarded as special cases with distinctive petrophysical problems. These problematic reservoirs require more-complex workflows for petrophysical evaluation because Eq. 1 is not sufficiently representative of reservoir character. Such reservoirs are the subject of this paper. Departures from Archie conditions can occur in both conventional and unconventional reservoirs. The nature of these departures for different types of reservoirs is mapped through the matrix of **Table 2,** which lists the problematic reservoirs discussed here. The departures give rise to interpretive problems that call for additional core and log measurements beyond those shown in Fig. 1. However, provided that the problem is identified correctly, a petrophysical database can be tuned optimally so that it is fit for purpose. In so doing, note that the departures in Table 2 can coexist.

TABLE 1—CRITERIA FOR AN "ARCHIE" RESERVOIR

No.	Archie Criteria	Non-Archie Conditions
1	Single rock type	Multiple electrofacies or petrofacies: thin beds
2	Homogeneous	Heterogeneous (e.g., variable mineralogy/texture)
3	Isotropic at micro- and mesoscales	Anisotropic (e.g., ellipsoidal grain shape, laminations)
4	Compositionally clean	Clay minerals
5	Clay free	Argillaceous
6	Silt free	Silty
7	No metallic minerals	Pyrite and other minerals
8	Unimodal pore-size distribution	Multimodal pore-size distribution including microporosity
9	Intergranular porosity	(Micro)fractures/fissures/vugs
10	High-salinity brine	Fresh water
11	Water-wet	Mixed wettability
12	I_r is independent of R_w	I_r varies with R_w

Database Considerations

A critical petrophysics task is to match data acquisition to reservoir complexity. This task is comparatively straightforward for an Archie reservoir (Fig. 1). For non-Archie reservoirs, it is more difficult to achieve a match because data-driven

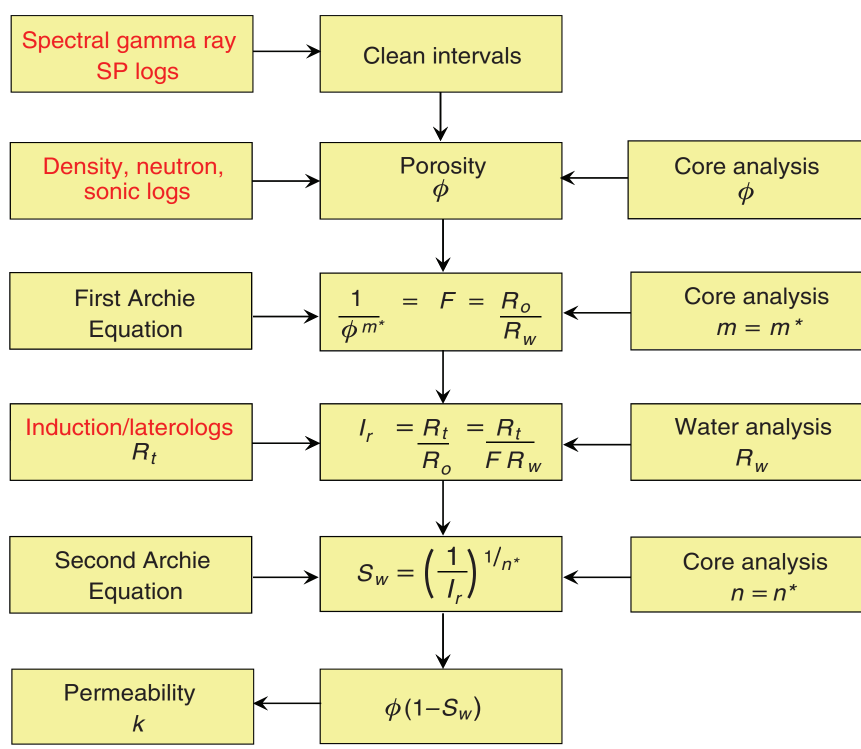

Fig. 1—Simplified workflow for petrophysical evaluation of Archie reservoirs through standard logs (in red) supported by core analysis. Note that m and n are required to be independent of water salinity.

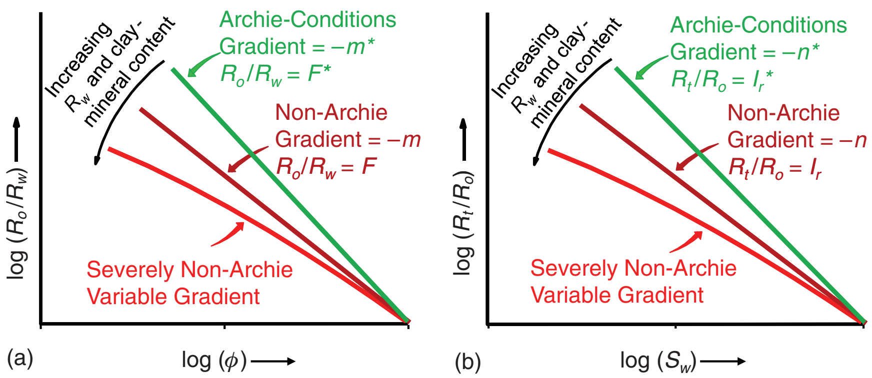

Fig. 2—Schematic graphs of (a) F vs. ϕ and (b) I_r vs. S_w showing the intrinsic data trends and departures caused by high clay-mineral content ("shaliness") and high R_w (low water salinity). Note that n can be significantly greater than 2 for oil-wet reservoirs.

perceptions of reservoir complexity often are too simplistic. In other words, generally, there will be a lag between an acquired core and log database and a data set that is needed for a definitive petrophysical evaluation. This state of affairs can be improved by adopting the key-well concept (Worthington 2004), whereby a well that is representative of an appraisal front is cored, logged, and tested comprehensively with the objective of establishing a workable interpretation procedure for application across the field. Once that interpretation procedure is established, the requisite database is defined and any data shortfalls can be identified.

A second issue concerns the role of core analysis in groundtruthing a log-evaluation exercise. This role becomes more important with increasing reservoir complexity. Part of this role is assessing mean values of reservoir properties and quantifying interpretive algorithms, both of which generally become more complex as reservoirs depart further from Archie conditions. A key question is, "How much core information is needed to achieve a statistically meaningful outcome?" The answer is different for each distinct task and each discrete reservoir (zone). A solution is approached most effectively by constructing a library of analogs, then using these analogs to guide core-data acquisition. The statistical foundations for this approach were outlined by Corbett and Jensen (1992) and by Worthington (2002).

Another aspect of using core data to groundtruth log analysis concerns reconciliation of different scales of measurement. In many situations, the exercise is more meaningful if core data are scaled up to the well-log scale with the corresponding log-response function used as a filter. This application is especially important in permeability prediction. It is essential where log-derived (static) estimates of permeability are compared with (dynamic) estimates inferred from well tests.

These comments about the need for good core data can be extended to include the requirement for uncontaminated, representative samples of formation water.

Data acquisition, quality assurance, and archiving together with database management often do not receive appropriate attention in petrophysics. It is worth reiterating that geoscience and reservoir-engineering models, as beneficiaries of petrophysics, are only as sound as the data that underpin them.

TABLE 2—DEPARTURES FROM ARCHIE CRITERIA OF PROBLEMATIC RESERVOIRS DISCUSSED HERE

	Archie Criteria (as numbered in Table 1)											
Reservoir type	1	2	3	4	5	6	7	8	9	10	11	12
Shaly sand	x			x								x
Fresh water										x		x
High capillarity					x	x		x				
Carbonates	x	x						x	x			
Thin beds	x	x	x	x				x				
Tight gas					x	x						
Shale gas	x	x	x	x	x	x	x	x	x	x	x	x
Coalbed methane		x	x				x	x	x			
Gas hydrates	x											

Problematic Reservoirs—Conventional

Conventional departures from Archie conditions include shaliness, fresh formation waters, fine grains, microporosity, differences between clean (shale-free) sandstones and carbonates, thin-bed reservoirs, and combinations of these cases (Table 2). If these departures are unrecognized, water saturation can be overestimated, and this can result in loss of opportunity (Worthington 2000). In general, problematic conventional reservoirs are evaluated through variations of Fig. 1 together with additional specialized logging tools supported by advanced core analysis. Exceptions are those shaly sands within which the formation water is saline and naturally fractured reservoirs, especially where the matrix is tight. Fractured reservoirs are not discussed here *per se* because where fractures are the main contributors to transmissibility, reservoir characterization shifts from the petrophysical scale to the interwell scale.

Shaly Sands. This departure from Archie's conditions is attributed to the presence of clay minerals within porous reservoir rock **(Fig. 3).** Therefore, the phrase "shaly sands" is something of a misnomer because although associated shale beds contain clay minerals, they rarely do so exclusively.

Constituent minerals of siliciclastic reservoir rocks show a negative surface charge. This charge attracts positive ions in the formation water, and the attraction gives rise to a cation-rich layer of electrochemically bound water

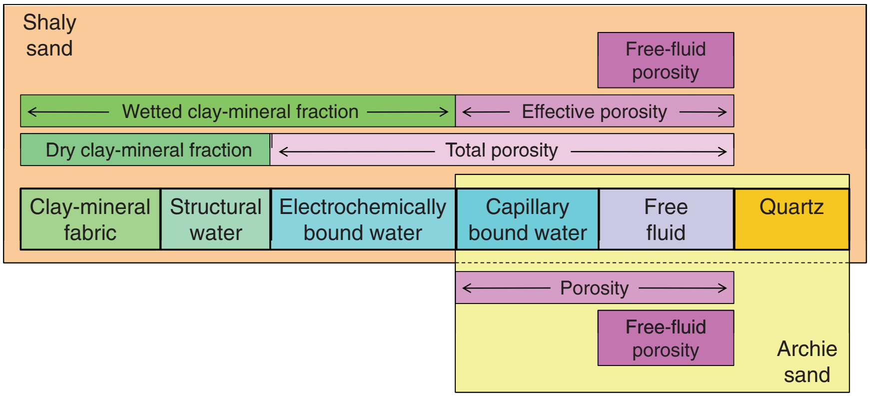

Fig. 3—Solid and fluid constituents of Archie and shaly sands.

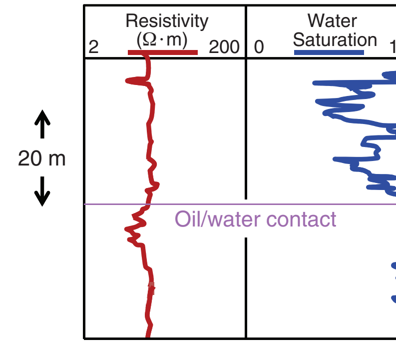

Fig. 4—Very fresh formation water causes low contrast in deep resistivity between the oil and water zones. S_w has been inferred from the quadrature component of the laterolog signal (Saxena and Sibbit 1990).

at the mineral surface. The cation-rich layer adds an additional conductivity to the system, and this can manifest itself in a suppressed response of resistivity logs. Because of the high surface area of clay minerals, the effect of this charge is much greater in shaly sands than in clean sands. Where the effect is highly significant, Eq. 1 is no longer applicable. An extra conductivity term X is added to the right-hand side, so that, for example (Waxman and Smits 1968):

$$(1/R_t) = (1/R_w)\phi^{m^*} S_w^{n^*} + X S_w^{n^*-1}. \quad \text{.................. (2)}$$

In high-salinity reservoirs, R_w is small and Eq. 2 reduces to the composite Archie equation (Eq. 1), provided that X is small. There still is no downhole measurement for X. Therefore, X is interpreted in terms of parameters that are notionally measurable downhole or can be inferred from other downhole measurements. Examples of secondary parameters within the X term of Eq. 2 are V_{sh} and cation-exchange capacity per unit of pore volume Q_v. Other secondary parameters and many different equations have been proposed, but expressions of the form of Eq. 2 continue to have widespread use. In the absence of a direct downhole measurement of X, the petrophysical evaluation of S_w in shaly sands requires some form of groundtruthing. The most pertinent data are core-extracted water saturations from preserved plugs through Dean-Stark analysis. The core should be cut with synthetic- or oil-based mud whose aqueous phase is tracer-tagged and with a low-invasion bit. Unfortunately, reference data of this kind often are absent from databases for complex reservoirs. This is a major shortcoming of contemporary petrophysics. It has ramifications for many studies of problematic reservoirs.

Usually, shaly sands are recognized from a high gamma log reading in conjunction with a high apparent porosity from the neutron log. Once identified, a choice must be made of whether to evaluate porosity and water saturation in the effective-porosity system or in the total-porosity system. In the former, electrochemically bound water is included within the clay-mineral volume. In the latter, it is included within the porosity (Fig. 3). For porosity evaluation, the total-porosity approach functions better if the mineralogy is fairly consistent. For evaluating water saturation, and, hence, hydrocarbon saturation, variations of Eq. 2 can be applied to both systems of petrophysical interpretation. In the absence of Dean-Stark water-extraction data, recourse can be made to a cross check through the inferred value of S_w in a water zone. However, this cross check is not conclusive because residual hydrocarbons might be present therein. Note that the effect of X on inferred S_w is even greater where S_w is small. If this influence is unrecognized and Eq. 1 is used instead of the appropriate Eq. 2, S_w can be overestimated substantially.

Freshwater Bearing. These reservoirs infringe the Archie requirement for high-salinity brine (Tables 1 and 2). There is no generic limiting salinity below which Archie conditions are no longer satisfied because the degree of departure also is governed by X and S_w. Even very clean formations, such as river gravels, can show departures from Archie conditions if R_w is sufficiently large. The reason is that even small charge densities associated with the mineral surfaces of clean (shale-free) rocks can have an amplified conductive effect on F and I_r in the presence of low-salinity formation water. The result is that the porosity and saturation exponents in Eq. 1 can be much less than the intrinsic (default) values (Fig. 2). They are designated m and n, respectively, because they are not independent of R_w. When Eq. 1 is used with such non-intrinsic exponents, it is called a pseudo-Archie application. Note that algorithms such as Eq. 2 also can break down in freshwater-bearing reservoirs. The recommended approach is to apply Eq. 1 with pseudo-values of m and n as measured in the laboratory using the prevailing formation-water salinity. If special core analysis has not been undertaken, indirect methods of estimating m and n can be applied (e.g., analogs).

Resistivity logs furnish the only high-resolution deep-sensing measurements available, and that is why solutions are preferentially set in the context of these data. Salinity-independent methods that use dielectric, carbon/oxygen, and nuclear-magnetic-resonance (NMR) tools can avoid the use of the Archie equations. However, they relate to the near-wellbore region and, therefore, in the presence of invasion they primarily sense the flushed zone. **Fig. 4** illustrates a low contrast of deep resistivity between oil and water zones in northeastern India, where formation-water salinity is approximately 2 g/kg of NaCl equivalent.

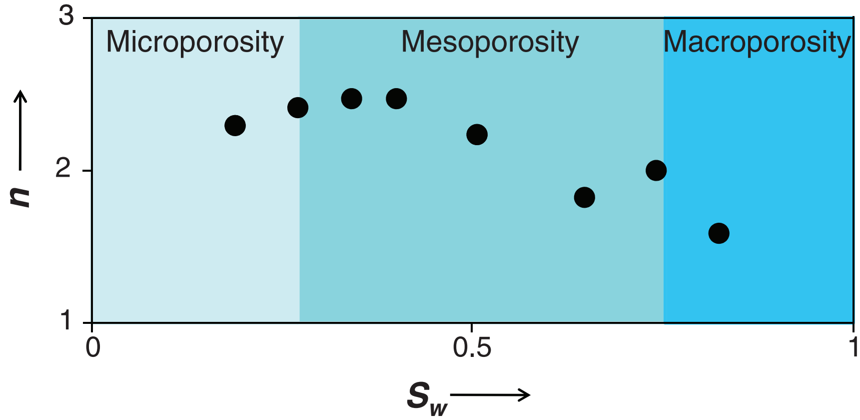

Fig. 5—Simulated variation of n with S_w for a trimodal-porosity system with desaturation notionally occurring from right to left (Petricola et al. 2002).

High Capillarity. These rocks include fine-grained (silty) reservoirs and those showing microporosity (pore-throat diameter ≤1 µm), either within the grains, as in the case of chert, or within mineral overgrowths. These types of reservoirs have high immovable-water content. Capillary-bound water is not the same as electrochemically bound water, but both are immovable (Fig. 3). Capillary-bound water offers a preferential conducting path to current during resistivity-log measurement. This can result in a low resistivity and, hence, a very high interpreted S_w that might cause the interval to be overlooked even though much of the water would not be produced. For fine-grained reservoirs, a solution is to use NMR logs to distinguish capillary-bound water saturation. The value of n can be tuned to furnish this value of S_w where irreducible conditions prevail, such that Eq. 1 can be used in pseudo-mode. For microporous reservoirs, mercury injection of core offcuts furnishes a pore-throat-size distribution that usually is multimodal. The plot of I_r vs. S_w becomes nonlinear, and changes in gradient (and hence values of n) can be correlated with changes in pore-throat size. **Fig. 5** illustrates how an otherwise "intrinsic" value of n can vary with S_w for a trimodal pore system. The usual practice is to select the value of n that corresponds to conditions of irreducible water saturation. Note that NMR logs also have an application in microporous systems, but these logs deliver pore-size distribution rather than pore-throat-size distribution.

Carbonates. Sandstones are characterized through mineralogy as electrolithofacies units. Carbonates are character-

Scenario	Bed Thickness	Pluggable	Identifiable
A	10–60 cm	Yes	Yes
B	3.0–10 cm	Yes	Yes
C	1.0–3.0 cm	No	Yes
D	0.1–1.0 cm	No	No

TABLE 3—SCENARIOS FOR THIN-BED EVALUATION (MAJID AND WORTHINGTON 2011)

ized mostly through pore-size distribution as electroporefacies units, a key exception being dolomitization, which often serves as an indicator of reservoir quality. Carbonates are more heterogeneous than clastics because a primary interparticle pore system coexists with a complex system of fractures and dissolution voids. Therefore, in carbonates, the concept of a standard logging suite should be extended to include an electrical micro-imaging tool for identifying fractures and dissolution conduits, an NMR tool for pore-size analysis, and an elemental-analysis tool for determining magnesium content as a dolomitization indicator. Core analysis encompasses measurements on whole core where this is required to ensure that sample size is much greater than the largest pore size. A reservoir-classification scheme must take into account the connectivity between microporosity, mesoporosity, macroporosity, vugs, and fractures. Currently, there is no universal carbonate-classification scheme that takes proper account of reservoir storativity and transmissibility. Indeed, some of the "standards" are proving to be insufficiently diagnostic. It may be that such a scheme can be described only skeletally, with a reservoir-specific overprint. Unlike macroporous sandstones, in carbonates otherwise intrinsic values of m and n can show pronounced variations with ϕ and S_w, respectively. The example of Fig. 5 is pertinent here. This type of variation must be accommodated in a petrophysical-evaluation scheme for carbonates. For further discussion of the status of carbonate petrophysics and a contemporary workflow, see Bust et al. (2011).

Thin Beds. A thin bed is one that cannot be resolved by logging tools that are used for petrophysical evaluation (Passey et al. 2006). A bed is resolved if it contains at least one log-data-sampling point at which the tool delivers a correct parametric value for the bed after borehole and invasion corrections. Tool resolution is the smallest bed thickness that allows this to happen. It is a function of tool type, logging speed, and the degree of contrast with shoulder beds. Other definitions are in use, but they are not as meaningful [e.g., an interval that accounts for

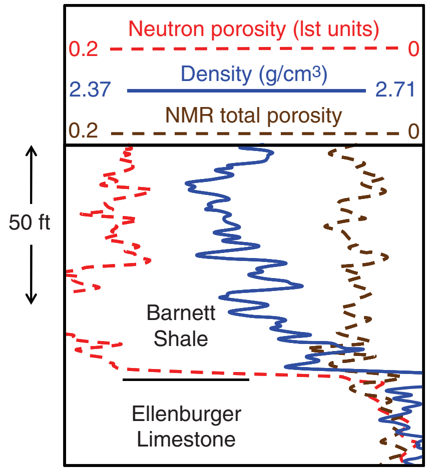

Fig. 6—Comparative insensitivity to rock matrix of the NMR approach to porosity evaluation in the Barnett shale (Jacobi et al. 2008).

a (large) specified percentage of the tool response].

A workable approach to thin-bed evaluation is the scenario approach, whereby different petrophysical workflows are prescribed for discrete ranges of bed thickness. A four-scenario scheme is shown in **Table 3.** Taking Scenario C in the context of a sand/shale sequence, the beds are too thin to plug exclusively so any solution is entirely log derived. However, bed boundaries can be identified by an electrical micro-imager. This exercise delivers a laminated-shale-volume fraction V_{lam}, from which sand resistivity R_{ts} can be calculated, here by use of a multicomponent induction log. For this scenario, total porosity in sand and shale ϕ_t is evaluated preferentially through the density log. A prerequisite is a density-log-resolvable shale bed within the same depositional system as the thin beds. This allows shale total porosity ϕ_{tsh} to be evaluated. Sand total porosity ϕ_{tsd} then can be calculated. If there is no thick shale bed, recourse must be made to an alternative approach, such as one that uses NMR data. For evaluating water saturation, a pseudo-Archie approach is preferred, perhaps one that uses analog values of *m* and *n* from elsewhere within the same depositional system. The approach for the effective-porosity system is more complex. Workflows can be generated for the other scenarios in Table 3. For example, Scenario D uses the compositional equations articulated by Juhasz (1986). The workflows are supported implicitly by mud logs.

Problematic Reservoirs—Unconventional

The topical subjects of tight gas, shale gas, coalbed methane (CBM), and gas hydrates are discussed in the following subsections. The departures from Archie conditions are listed in Table 2. Remedial workflows are still evolving.

Tight Gas. Tight gas reservoirs sometimes are classified as conventional, but here they are grouped with unconventional reservoirs. It has long been known that traditional log analysis can break down in tight sands and that alternative approaches are required (Newsham and Rushing 2001).

A major reason is high pore-surface area, which can give rise to a large integrated surface charge and, hence, an extra conductivity term similar to that in Eq. 2 (even if the reservoir rock contains no clay minerals). The effect of this charge in suppressing log-derived formation resistivity is amplified in the presence of low-salinity formation water. Moreover, the same high pore-surface area will have an associated high capillarity with a correspondingly large irreducible water saturation that also will reduce the measured formation resistivity. Thus, once again, different causes of departures from the Archie conditions can coexist and can even reinforce mutually.

Another issue is whether logging tools are capable of delivering accurate parametric values of physical properties that are known to be related to reservoir properties. In other words, does formation tightness take conventional well logs beyond their calibration and performance limits? This matter can be resolved only by reference to service-company standards.

With this caveat, petrophysical evaluation of these reservoirs is best approached by use of the pseudo-Archie principle. This is because Eq. 2 will be difficult to apply if the cause of the excess conductivity is not shale related. However, a key question is whether groundtruthing core analysis can be undertaken in tight gas sands with the same accuracy as in conventional reservoir rocks and, if so, whether the data are as representative. For example, in poor-quality rock, conventional air permeability can be considerably greater than the true effective permeability to gas at irreducible water saturation. Again, core-derived matrix properties can be highly variable, a characteristic that suggests use of NMR logs, which have a reduced dependence on matrix properties.

Finally, it has proved especially difficult to identify net reservoir and, hence, net pay in tight gas sands. The problem is rooted in cutoff selection and whether the selected cutoffs allow all potentially recoverable volumes to be represented, given that tight reser-

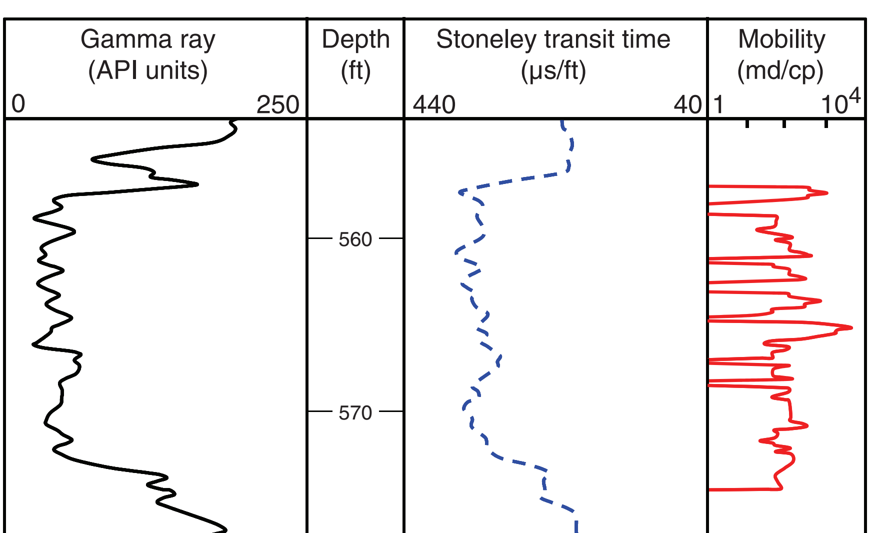

Fig. 7—Coal-seam mobility from Stoneley-wave analysis (Dey 2010).

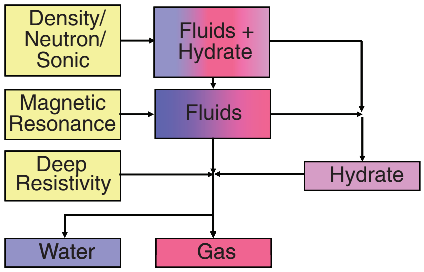

Fig. 8—Simplified workflow for petrophysical evaluation of sub-ocean gas hydrates (Worthington 2010b).

voirs can be markedly heterogeneous and, consequently, that recovery factors can be highly variable. The key is to approach data acquisition and analysis in a fit-for-purpose manner. In particular, cutoffs should be tied to dynamic properties on a reservoir-specific basis. Experience has shown that if there is doubt, one should retain rather than exclude hydrocarbon volumes.

Overall, petrophysics is inextricably linked to seismic and geomechanical properties through rock flexing and, hence, the occurrence of natural fractures as well as to fracture stimulation.

Shale Gas. Shale constitutes the (mature) source rock, the seal, and the reservoir. Here, the word "shale" is used in the sense of a geological formation rather than a specific lithology, so the shale can include other lithologies such as sandstone and limestone "sweet spots" (potentially with a shale "catchment"). In particular, shale in the lithological sense may comprise as little as 30% clay minerals. Note that because the shale is also a seal, the lithological sweet spots may not contain hydrocarbons.

Shale-gas reservoirs are characterized by ultralow-to-low interparticle permeability, low-to-moderate porosity, and complex pore connectivity. They are distinguished further from tight gas sands by the presence of kerogen and by adsorbed and absorbed gas. The shale may be naturally fractured. Because of this complexity, log analysis is strongly dependent on groundtruthing laboratory data.

Key technologies are horizontal drilling and hydraulic-fracture stimulation. Their application draws upon knowledge of hydrocarbon storativity, pore connectivity, geomechanical properties, and the rock-stress state. The required petrophysical deliverables are (variations in) mineralogical composition, total organic carbon (TOC) (kerogen), interconnected porosity (adjusted for kerogen), gas saturation, gas pore volume, gas-desorption isotherms, brittleness and fracturability, effective permeability to gas, and reservoir flow capacity. Challenges in securing these deliverables include accommodating a highly variable mineral composition and texture, identifying and correcting for organic content, designing functional programs of core analysis, managing markedly variable formation-water salinity, compensating for large shale effects on the evaluation of hydrocarbon saturation S_h, and determining how the gas is stored.

The response to these challenges calls for an extended logging suite beyond standard logs, at least in key wells. These advanced tools include an acoustic- or electrical-imaging tool (for recognition of bedding and fractures), an elemental-analysis tool (for complex lithology, including a silica log as an indicator of brittleness), and an NMR tool (for matrix-independent porosity and fluids evaluation). The high matrix dependence of density and neutron logs is illustrated for the Barnett shale in **Fig. 6.** In contrast, note the comparative matrix independence of the NMR log, which leads to a more-realistic indication of porosity, an outcome that can be exploited more fully in the evaluation of shale-gas reservoirs.

Log analysis of shale-gas reservoirs draws on methods developed for source-rock evaluation. Resistivity and porosity logs are central to the identification of TOC, which often occurs in the form of parasequences. TOC is especially important because it is related to gas content. As noted, log analysis requires a more comprehensive groundtruthing in the form of fit-for-purpose core analysis to guide rock typing, the recognition of electrofacies, and the identification of factors governing gas storage. However, core analysis can be more challenging in shale-gas reservoirs because of the representativeness of the data and difficulties in making the measurements at ultralow-to-low permeability. Yet, there is a strong role for technologies such as X-ray diffraction in support of mineralogical analysis (e.g., directed at matrix density).

A comprehensive petrophysical workflow for shale-gas reservoirs is still evolving. This evolution is expected to include some standardization of data-acquisition procedures, at least in key wells. However, primary petrophysical targets will remain quantification of TOC from core-calibrated logs and of fracturability as a function of (sonic) shear properties and brittleness. More-comprehensive descriptions of the petrophysical evaluation of shale-gas reservoirs include Passey et al. (2010) and Sondergeld et al. (2010).

CBM. Coal is a dual-porosity organic sedimentary rock comprising matrix and natural fractures, or cleats. Coalbeds constitute both source rock and reservoir rock. Methane is adsorbed onto the internal structure of the coal matrix where it adheres to carbon molecules such that large quantities of gas can be stored. The gas is released when reservoir pressure drops below a critical desorption pressure. CBM reservoirs often show microporosity and low interparticle permeability. Desorbed gas is transmitted through the network of cleats or joints. Therefore, the transmissibility of CBM reservoirs is strongly dependent on in-situ net stress, which affects cleat aperture. Produced gas is primarily, but not exclusively, methane.

Coalbeds can be identified by standard logging tools provided that they are sufficiently thick; very thin coalbeds can be suppressed in log responses. The log signature includes low gamma ray, low density, high neutron porosity, and high sonic-transit time. The evaluation of gas in place requires more intermediate steps relative to conventional reservoirs. Key petrophysical deliverables include ash content, carbon volume, moisture volume, gas content, cleat density and orientation, cleat permeability, and stress orientation. Ash content usually is obtained through correlation with density-log response. Low ash content indicates potentially good reservoir quality. Ash content also correlates with carbon volume and moisture volume. These correlations draw on laboratory data. Once these properties have been quantified, gas in place can be estimated through gas-desorption isotherms. Note that these procedures depend strongly on the density log, and that a well-developed cleat network can cause borehole instability that degrades the density-log measurement. The evaluation process is moving to include other standard logs (Bhanja and Srivastava 2008), as well as advanced tools such as the elemental-analysis log.

A key challenge for formation evaluation is to ensure the effectiveness of the cleat network, a prerequisite for commercial gas exploitation. A dipole-sonic log, used in conjunction with an electrical micro-imaging tool, can identify a well-developed cleat network. Cleat transmissibility can be sensed through the attenuation (i.e., loss of signal strength) of Stoneley waves—low-frequency waves within a sonic-log wave train that travel along the borehole wall. See the example of **Fig. 7,** in which the gamma ray log identifies the presence of a coal interval and the Stoneley wave delivers estimates of permeability for mobility and transmissibility. Although quantitative information about potential gas production cannot be obtained from these logs, such indicators can guide formation testing for pressure and produced fluids (Schlachter 2007).

An optimum exploitation strategy might use multilateral wells drilled through cleat-transmissive coalbeds, directionally guided by the stress regime, and followed by hydraulic-fracture stimulation as appropriate.

Gas Hydrates. Gas hydrates comprise compressed molecules of gas (usually methane) within a solid lattice of water molecules. They form where there are sources of water and methane under favorable thermodynamic conditions of relatively high pressure and low temperature. A volume unit of methane hydrate in situ dissociates or thaws (with increasing temperature or decreasing pressure) to yield approximately 164 units of methane at standard conditions and approximately 0.8 units of water. Gas hydrates are found in permafrost continental environments and in shallow marine sediments beneath deep water on continental margins. Methane hydrates can form as massive layers, as thin interlayers, as structural nodules (discrete "grains" within sediments), or they can be distributed within the pore spaces of silts and sands, especially where porosity is high.

Fig. 8 shows a simplified workflow for hydrate evaluation in the absence of permafrost. A key point is that the NMR tool does not see hydrates. This is because the tool records the characteristics of precessional relaxation of protons as they re-align in the direction of a reference magnetic field after the temporary application of a second field. The real-time realignment of protons is measurable downhole only in fluids. Therefore, hydrate volume can be inferred from the difference between conventional porosity (from the responses of the standard porosity tools—density, neutron, and/or sonic) and the NMR "porosity." In permafrost, it is necessary to distinguish between hydrate and ice, and this would call for an additional log such as a dielectric tool or a carbon/oxygen log.

Conclusions

Problematic reservoirs present petrophysical challenges that can be met only by departing from classical methodology. For conventional reservoirs, unrecognized departures from the Archie conditions can result in sizable hydrocarbon accumulations being overlooked. It is important to obtain sufficient information for non-Archie effects to be recognized at an early stage in the life of a field. For unconventional reservoirs, early awareness should guide the identification of fit-for-purpose data sets as foundations for meaningful formation evaluation. Here, it is important to avoid being constrained by rigid adherence to traditional practices. In both cases, a successful petrophysical outcome requires that data acquisition and interpretation be matched to reservoir complexity. The key-well approach offers an efficient and effective way of doing this. The petrophysics of problematic reservoirs continues to evolve. Progress will be founded on thoroughly investigated case histories that can serve as analogs, either across the same depositional environment or for field studies elsewhere.

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Nomenclature

F = formation resistivity factor
I_r = resistivity index
k = permeability
m = porosity exponent
n = saturation exponent
Q_v = cation-exchange capacity per unit pore volume
R_o = resistivity of fully water-saturated rock
R_w = resistivity of saturating water
R_t = resistivity of partially saturated rock
R_{ts} = resistivity of sand
S_h = hydrocarbon saturation
S_w = water saturation
V_{lam} = laminated-shale-volume fraction
V_{sh} = shale-volume fraction
X = extra conductivity term
ϕ = porosity
ϕ_t = total porosity
ϕ_{tsh} = shale total porosity
ϕ_{tsd} = sand total porosity

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