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ADVANCES IN CORING AND CORE ANALYSIS FOR RESERVOIR FORMATION EVALUATION

C. E. Ubani[1], Y. B.Adeboye[2], A. B.Oriji[2]

[1]*Department of Petroleum and Gas Engineering, University of Port-Harcourt,P/H,Nigeria.*
[2]*Department of Petroleum and Gas Engineering, University of Lagos, Nigeria.*

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Abstract

The objective of coring and core analysis is to reduce uncertainty in reservoir evaluation by providing data representative of the reservoir at in situ conditions. The advances in coring and core analysis techniques provide the premise to measure required petro-physical properties and to acquire simultaneously other reservoir rock dependent parameters. Core derived data have been integrated with other field data to minimize reservoir uncertainties that cannot be addressed by other data sources such as well logging, well testing or seismic. The quality and reliability of core data have become more important with the ever-increasing pressure to optimize field development. The business objective, value of information and operation cost are some of the driving forces for development of new techniques of coring and core analysis. Techniques are constantly being improved or new ones are introduced. In core analysis, the concept of automatic geological core description is growing with the use of the mini-permeameter and the proliferation of sophisticated analysis methods such as SEM, X-ray CT, and NMR. These Hi-Tech methods provide a wealth of micro structural and microscopic information previously undreamed of. This paper provides an overview of recent and emerging developments and trends in coring technology and core analysis as to enhance the reservoir evaluation processes.

Keywords: Coring; Core Analysis; Quality Control; and Technology Advancement**.**

1. Introduction

The task of the reservoir geoscientist is to describe the reservoir as completely and accurately as possible using a variety of methods, from seismic and well testing to logging, cuttings analysis and coring. These methods present the engineers with a valuable range of scales from photomicrograph of a single filament of illite, to the log investigating up to several feet around the borehole, to the well test probing hundreds to thousands of feet into the formation. Many of these methods allow the engineer to estimate three key formation descriptors-porosity, fluid saturation, and permeability. But different methods may lead to different values. Porosity, for example, measured on a core, which is removed from in situ pressure, temperature and fluid, then cleaned, dried and re-saturated may not become close to porosity determined from log measurement. To form a commercial reservoir of hydrocarbons, a formation must exhibit two essential characteristics. There must be a capacity for storage and transmissibility to the fluid concerned, i.e. the reservoir rock must be able to produce and maintain fluids, when development wells are drilled. In general, several objectives must be met when taking core samples. But in the prime place, a careful on-site examination for hydrocarbon traces is desirable (e.g. gas bubbling or oil seeping from the core, core fluorescence on a freshly exposed surface, fluorescence and staining in solvent cuts etc.). Advances in technology continuously make new improved measurements and experiments available to the industry. Today this process seems to move faster and there is a demand for new standards both for coring and core analysis. Even with the current possibilities in computer technology, much energy is used in the process of transporting data between different software systems and different formats. A potential for improving acquisition and analysis at reduced cost is obvious. In this paper, the basic concepts of coring and core analysis was reviewed and used the developmental advances as the main goal.

2. Basic concepts of coring and core analysis

Coring and core analysis form an integral part of formation evaluation and provide vital information unavailable from either log measurements or productivity tests. Core information includes detailed lithology, microscopic and macroscopic definition of the heterogeneity of the reservoir rock, capillary pressure data defining fluid distribution in the reservoir rock system, and the multiphase fluid flow properties of the reservoir rock, including directional flow properties of the system. Also, selected core data are used to calibrate log responses, such as acoustic, or neutron logs used to determine porosity. As a result, core data becomes an indispensable source in the collection of basic reservoir data directed toward the ultimate evaluation of recoverable hydrocarbons in the reservoir.

2.1 Wellsite activities

Coring high-quality core material is absolutely crucial to the success of a rock characterization study. The coring program must minimize damage to the rock and maximize recovery. Equally important are core handling and preservation procedures used prior to the arrival of the core at the laboratory [13]. Mishandling core can invalidate even the most carefully designed laboratory test. Several recent innovations in coring technology contribute to acquisition of more reservoir-representative rock. A shift toward the coring of unconsolidated sediments, as the case in Niger Delta, has accelerated the use of disposable inner barrels and liners. Fiberglass, aluminum, and plastic inner barrels have effectively replaced rubber-sleeve methods for coring complex lithologies. Specialized core catchers permit complete closure of the inner barrel before surfacing the bottom-hole coring assembly and are highly effective in recovering unconsolidated rocks [4]. The invasion of drilling fluid into highly permeable rock is damaging and reduces the volume of uncontaminated rock available for analysis. Sidetrack coring is an emerging technology that will have a great impact on the way coring is performed in soft sediments (Eaton, personal communication). This system allows for the acquisition of a full-diameter continuous sidewall core where it is difficult for the geologist to predict the formation top of a potential pay zone and drilling rates are high. The benefit of such a system becomes clear when one considers the economics of coring offshore, for example, in the Gulf of Guinea.

The increase in horizontal drilling activity and the need to understand more about lateral reservoir characteristics have led to the development of reliable horizontal (medium-radius) coring systems [14]. Electronic multi-shot instruments (EMI) are available for the accurate orientation of core using a standard three-point scribing system. In fractured formations, the EMI can provide a high density of shot points, unlike previous methods that relied on photo-mechanical technology. Oriented core is useful in examining fracture strike, in situ stresses, and directional reservoir properties, e.g., permeability and depositional patterns. The paleo-magnetic orientation of core is an alternative to the EMI method when operational and geological conditions are favorable. Another method to evaluate reservoirs targeted for exploratory horizontal drilling involves the use of vertical pilot-hole coring [14]. A combination of field and laboratory rock characterization technologies is used to assess borehole stability, reservoir fracture potential, and basic reservoir properties to optimize horizontal wellbore placement and azimuth.

The slim-hole, high-speed, wireline-retrieved, continuous core-drilling method is an innovative, cost-effective means to explore for hydrocarbons [19]. This technology, adapted from the mining industry, presents a new opportunity to rock-characterization generalists. In an economic environment in which it is often difficult to obtain budget approval for any coring program, the slim-hole method provides continuous core from the surface through the zone of interest (to 12,000 ft). Real-time well-site processing and evaluation methods have been developed to take advantage of the wealth of detailed information available to define rock properties on a continuous basis. Conceptually, this technology may replace traditional drilling technology in remote, difficult, and environmentally sensitive areas.

A developing technology with a high potential is coiled-tubing-conveyed (CTQ coring. Coiled tubing is a continuous string of pipe spooled onto a reel and mounted on a portable drilling rig. The main advantages of CTC coring are the savings in trip time since coiled tubing is run continuously with no connections, and circulation can be maintained during tripping to help remove cuttings and cool down-hole tools. This technology is now used to drill directional and horizontal wells and may be capable of coring vertical wells to depths of 50,000 ft with down-hole mud motors.

The pressure-retained coring method, widely used during the early 1980's to recover in situ fluid saturations, is rarely used because of its high cost. Alternatively, many operators have resorted to sponge-coring systems to accurately measure reservoir fluid saturations. Significant effort has been spent refining sponge-core analytical procedures [3]. have developed proton nuclear-magnetic-resonance (NMR) spectroscopy methods to determine oil saturation in sponge core. In general, the sponge-coring method can provide additional reservoir data at a cost no more than twice that of a conventional core.

Wireline-conveyed percussion sidewall coring and mechanically drilled sidewall-coring methods can be an invaluable supplement to log interpretation when conventional core is unavailable. In soft rocks where percussion methods are used, advances in the measurement of particle size distribution using laser optics has added a new perspective to petro-physical interpretation and well completion strategies. The mechanically or rotary-drilled sidewall coring technique continues to be an excellent means to obtain undamaged plug samples suitable for special core testing. Recent innovations in rotary sidewall coring include greater sample capacity, improved reliability, and better tool performance.

2.2. Core Handling and Preservation

Well-site core handling and preservation procedures should follow the best possible practices because the value of all rock characterization is affected by these initial operations. The objectives of a core handling program are to obtain rock material representative of the formation and to minimize physical alteration of the rock during handling and storage. The major problems confronting those who handle and preserve reservoir rocks for rock characterization are selection of a non-reactive preservation material, and preventing fluid loss or the adsorption of contaminants. Further, the operator must specify appropriate core handling and preservation methods based upon rock type, degree of consolidation, and fluid type.

2.3 Well-site Core Testing

In its early days, core analysis was often performed at the wellsite. As measurement technologies became more sophisticated, core analysis shifted from a wellsite activity to one that was performed exclusively in the laboratory. The advantages of collecting rock characterization data in the field are clear:

(1) measurements are performed on core in its most pristine saturation state,

(2) data are collected quickly without transportation of the core,

(3) data can be used with mud logs, wireline logs, or other field data more effectively to make completion decisions.

Virtually any analytical instrument or core analysis apparatus can be operated in the field. Unfortunately, the high costs associated with mobilizing core analysis equipment and skilled personnel can be prohibitive for service companies and operators. A resurgence of this concept in the mid 1980's was unsuccessful because of declining oil prices and instability in the petroleum industry.

Today, wellsite core testing is performed only when the parameter to be measured is highly time-dependent. This technique involves measurement of the change in core dimensions after recovery with displacement transducers fixed to core surfaces. These data supply principal stress direction and are useful in optimizing the azimuth of directional wellbores and in predicting borehole-stability problems.

Rock wettability remains one of the most difficult rock properties to quantify and reference to in situ conditions. Recommended practices include the measurement of wettability as soon as possible after removing the core from the formation so that a reference point for wettability is established.

Alteration of the in situ wettability can adversely affect petrophysical and reservoir engineering tests. Although rock wettability is rarely measured at the wellsite, some progress has been made toward maintaining rock wettability using special preservation methods

2.4 Core analysis

Basic (routine) core analysis involves the measurement of the most fundamental rock properties under near-ambient (atmospheric) conditions. Porosity (storage capacity for reservoir fluids), permeability (reservoir flow capacity), saturation (fluid type and content), and gross lithology all provide critical information in deciding whether a wellbore will be economic.

Recent efforts by the American Petroleum Institute (API) to examine recommended practices for determining permeability of porous media, API RP27 (1952), and core analysis procedures, API RP40 (1960), will result in a long-awaited revision of these documents.

2.5 Fluid Saturation

Basic core analysis begins with the extraction (cleaning) of fluids contained in the pore space of rock. Cleaning may be accomplished by passive Dean-Stark or Soxhlet extraction, solvent-flushing in a pressurized core holder or centrifuge, or gas-driven solvent-extraction. The more time consuming and nondestructive Dean-Stark distillation method provides an accurate measurement of fluid saturation(s) and allows for restored-state testing on the solvent-extracted sample. The summation-of-fluids method, which requires retorting the sample, is still commonly used in the evaluation of percussion sidewall samples. However, this method of obtaining fluid saturations is not used for cleaning. Retorting is destructive and its use in consolidated rocks is dwindling. Research by [17] has shown that the Karl Fischer titration technique can be used in many cases to more accurately define water saturation. When the objective of the analysis is to obtain saturation information, X-ray computerized tomography (CT) [2,17] are alternatives to the time-honored extraction methods. Magnetic-resonance techniques have the advantage of being able to distinguish bound from movable fluid as well as to estimate other critical reservoir parameters, e.g., permeability, wettability. All solvent-extraction techniques affect the rock wettability to some degree and this must be considered when designing special core tests.

2.6 Porosity

A number of techniques are employed for the measurement of porosity in consolidated rocks. Boyle's-law helium-expansion is a standard method for measuring either pore volume or grain volume. Bulk-volume measurements are generally determined by fluid displacement (Archimedes principle) or by callipering plug samples. With Boyle's-law and bulk-volume data, bulk and grain densities can be determined by also weighing the sample. These methods are accurate and reproducible if proper operating procedures are followed.

Several operators have established quality-assurance programs in an attempt to improve data quality from vendor laboratories. Despite the apparent simplicity of these measurements, systematic and operator errors are common. Standard methods are labor intensive and can be time consuming in low-permeability rocks.

Although significant progress has been made in both CT and MRI to measure the porosity of saturated cores, these instruments are not widely available. Few commercial laboratories have CT capabilities and none offer MRI services. Both CT and MRI instruments are expensive and require highly skilled operators. As the costs for these instruments continue to decrease, their availability should increase. Tomographic imaging using thermal neutrons is another emerging technology that takes advantage of directly imaging the hydrogen content of samples and thus measures porosity with high sensitivity [9]. A major limitation of this technique is the availability of neutron sources that are not reactor-based. As new, more intense sources are developed, this technique may become practical for basic core analysis.

2.7 Permeability

Routine single-phase permeability measurements are fundamental to understanding fluid flow in porous media. Darcy's law is the empirical expression used to explain the relationships among the variables involved in the flow of fluids through rocks. Permeability can be estimated indirectly using wireline logging and pressure transient methods, or directly with core-based techniques. Indirect methods often prove to be unreliable; however, integration of methods at all scales yields the best estimate of reservoir permeability. The nuclear magnetism log measures movable formation fluid and spin-lattice relaxation times. One of the more promising indirect permeability technologies employs spin-echo magnetic-resonance technology [10]. Formation testers, acoustic (Stoneley-wave velocity), and nuclear (geochemical) logging tools are also commonly used to estimate permeability; however, core-based permeabilities are considered the standard to which all other measurements are compared.

Direct (core-based) single-phase permeability measurements can be separated into four major categories: those utilizing a flowing gas under steady-state or unsteady-state (transient) conditions, or a flowing liquid under either condition. Most routine permeability measurements are made with gas, e.g., air, nitrogen, or helium. Liquid permeability measurements are more time consuming; however, water permeabilities may provide more realistic data for some formations. Nonetheless, [12] concluded that comparisons of liquid and air permeabilities show a strong correlation supporting the use of air permeabilities in evaluating reservoir quality.

The use of unsteady-state single-phase gas permeability technology has increased since the mid 1980's. Porosity, air permeability, equivalent nonreactive liquid permeability (Kiinkenberg gas slippage), and Forcheimer (inertial) factors can be measured at overburden conditions in a single automated experiment. These data are useful in reservoir-engineering calculations and can be acquired quickly, even in low-permeability rocks.

Significant progress has been made in developing instrumentation to perform probe (mini permeameter) permeability measurements. This concept was first described by [5], however, recent interest in small-scale reservoir heterogeneities, reservoir characterization, and outcrop evaluation has revitalized this technology. The probe permeameter has the advantage of making localized, nondestructive, and rapid measurements of permeability with a high resolution at a low cost. Permeability distribution may be examined in heterogeneous formations and explained in terms of depositional environment and diagenetic controls without cutting core plugs.

Probe-permeameter measurements are performed by injecting compressed nitrogen or air through a small diameter injection tip, which is pressed against a rock surface. A rubber seal is used to prevent gas leakage past the probe. If the gas-flow geometry is known, permeability can be calculated from flow-rate and pressure measurements using an appropriate form of Darcy's law. Both steady-state and unsteady-state versions of the probe permeameter are in use. Unless the rock is an isotropic, homogeneous porous media, gas flow around the probe tip must be represented by an empirically derived geometric factor. The flow model is then tested and calibrated with core plugs of known permeability [7] have taken this technology one step further with the introduction of an automated laboratory-probe permeameter. As with all gas-permeability measurements, slippage and turbulence factors, rock saturation state, and equipment limitations must be taken into account in evaluating data quality. Because of the vast number of probe-permeability measurements possible on core and outcrops, one of the greatest challenges will be the statistical treatment of these data.

3. Special Core Analysis

Special core analysis involves tests that are supplementary to the basic core analysis program. Special core analysis includes laboratory measurements used in reservoir engineering, petro-physical evaluation, and drilling-and completion-engineering evaluation

3.1 Capillary Pressure

Several other techniques besides centrifuge have been used for measuring capillary pressure. These include the porous-plate, mercury-injection, and water-vapor de-sorption methods. Porous plate is the original technique to which all others are referenced. [2] have demonstrated a new method of generating capillary-pressure curves from centrifuged samples using magnetic-resonance images to obtain fluid saturation distribution in Berea sandstone cores. The development of capillary-pressure instrumentation has far exceeded advancements in theory. Automated mercury-injection instruments can now attain pressures in excess of 60,000 psi. [10] recently compared different techniques including water vapor desorption for obtaining capillary-pressure data in the low-saturation region. Clearly, differences exist in measurement techniques and each method has its inherent limitations.

With advances in slow constant-rate mercury-injection technology, it is now possible to perform detailed pore-space evaluation beyond the simple calculation of capillary pressure [18] describes APEX (apparatus for pore examination) porous-media technology that resolves pore space into pore bodies (subisons) and pore throats (risons) each of which is characterized by entry pressure and volume. Distribution functions are used to express macroscopic rock properties in terms of pore-scale properties. APEX technology can be used to estimate electrical and flow properties, measure critical gas saturation and irreducible water saturation, improve petro-physical evaluation, evaluate fluid trapping tendency, and predict formation-plugging potential.

3.2 Relative Permeability

Relative permeability is one of the most important reservoir parameters measured in the laboratory. These data are used for prediction of reservoir performance and determination of ultimate fluid recoveries. This information is critical in designing various fluid-injection schemes, evaluating water and gas-coning behavior, examining formation-damage potential, and in the development of pseudo-functions for numerical reservoir simulation. The relative permeability of a rock to each fluid phase can be measured by either steady-state or unsteady-state methods. Under steady-state conditions, a fixed ratio of fluids is forced through the test sample until saturation and pressure equilibria are established. Unsteady-state relative-permeability measurements can be made more rapidly than steady-state measurements; however, the mathematical analysis of unsteady-state data is more difficult and, like centrifuge data, interpretation remains controversial. The unsteady-state technique is an operationally simple test that can be performed by viscous or centrifugal displacement. The unsteady-state technique can be hampered by capillary end effects. These effects can be reduced by injecting fluid at high rates, so that capillary forces become negligible. In many cases flow rates may become impractically high and formation damage can occur. For this reason and others, unsteady-state methods are becoming less desirable for reservoir engineering calculations [15] suggest that a combination of steady-state and unsteady-state methods be used to obtain optimum two-phase flow characteristics. This approach allows the range of relative-permeability information to be extended without increasing the complexity of the steady-state experiment and improves the definition of the relative-permeability curve.

Researchers have placed great emphasis on interpreting relative-permeability behavior in terms of rock and fluid properties. The details of core handling, preservation, drilling fluids and drilling parameters should be known prior to performing relative-permeability tests. Current research is concerned with understanding the effects of fluid saturation, saturation history (hysteresis), wettability, pore-space architecture (especially small-scale heterogeneities), experimental conditions (pressure and temperature), retrograde-condensate flow behavior, and three-phase relative-permeability characteristics.

3.3 Wettability

Wettability is defined as the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids. The importance of wettability has long been recognized as affecting the measurement of special rock properties. Wettability is a major factor controlling the location, flow, and distribution of fluids in rocks. Undoubtedly, in situ wettability is one of the most difficult reservoir parameters to quantify. It is virtually impossible to core a reservoir rock and be certain that its in situ wetting preference has not been altered. The goal of the core analyst must be to mitigate wettability alteration during core acquisition and sample preparation. It may be possible in some rock types to restore the original wetting preferences of the rock by cleaning, saturation with reservoir fluids, and aging. The most common methods to measure wettability include USBM, Amott, contact angle (parallel crystal plate) techniques, and variations on these basic methods [1] review the use of the dynamic Wilhelmy plate for measuring the wetting character of oil, brine, and rock systems. This method is simpler and less operator-dependent than standard contact-angle procedures and can be used to examine the effects of contaminants such as drilling-fluid components.

3.4 Pore Volume Compressibility

Pore-volume-compressibility (PVC) data are used to compute pore-volume reduction during pressure depletion of a reservoir. This variable can play a major role in the prediction of hydrocarbon recovery. The majority of PVC tests conducted by service laboratories are performed under hydrostatic load. An empirical uniaxial correction factor is then applied to hydrostatic data to estimate rock behavior under reservoir stress conditions. These factors assume linear-elastic strain conditions, equal horizontal stresses, the Biot pore-elastic constant equal to one, and a value for Poisson's ratio. Unfortunately, hydrostatic loading rarely reflects in situ stress conditions.

Efforts by experts in rock mechanics and by core analysts have resulted in improved PVC technology. The preferred method of measuring PVC is uniaxial strain (triaxial stress) with pore pressure to approximate in situ conditions. The total vertical stress (overburden) and lateral strain are maintained constant during pore pressure depletion (reservoir pressure drop during production). Stress-path dependence is evaluated and elastic constants are measured directly. Although this approach is more complicated, it is more representative of reservoir conditions than hydrostatic loading. Nevertheless, some authors [11] argue that theoretical corrections to hydrostatic tests are accurate for most reservoir situations. Bulk-compressibility factors critical in subsidence studies as well as in the evaluation of core compaction factors should also be measured triaxially

3.5 Electrical Properties

Perhaps one of the more elucidating studies in special core analysis in the last decade involved the evaluation of rock electrical properties [16] under the auspices of the Society of Core Analysts, a chapter-at-large of the Society of Professional Well Log Analysts, organized a study to assess the electrical-resistivity measurement capabilities of 25 laboratories. Standard plug samples of Berea sandstone, Bedford limestone, and porous Alundum were sent to each of the laboratories. The goals of the study were to :

(1) determine the reproducibility of different standard methods of measuring electrical resistivity and the extent of agreement between different methods,

(2) assess the suitability of different methods for obtaining formation factor, cementation exponent, and saturation exponent.

The results of this study were quite surprising. The diversity of measurement techniques and lack of standard laboratory methodology led to a wide range in the experimental data. On a positive note, four subcommittees were then formed to recommend guidelines for:

(1) preparation of brine and determination of brine resistivity for use in electrical resistivity measurements,
(2) sample preparation and porosity measurement,
(3) the mechanics of electrical resistivity measurement on rock samples and
(4) saturating and de-saturating core plugs during electrical resistivity measurements.

Numerous papers have been published on the measurement and analysis of Archie parameters. The effects of laboratory procedures on the measurement and analysis of the saturation exponent have shown this variable to be one of the most difficult petro-physical variables to quantify. Both MRI [2,16] imaging have been used to show fluid-saturation (distribution) problems during the de-saturation phase of the resistivity-index measurement. As de-saturation progresses, the saturation exponent can vary because of non-homogeneous saturation distribution. The impact of petro-physical properties on the observed curvature in log resistivity-index versus log water-saturation plots can be significant [6].

More than 50 different models are currently in use to determine shaly-sand parameters. Conductivity interpretation in shaly sands requires corrections for clay conductivity [18] describes procedures by which conductivity, membrane potential, and induced-polarization measurements are made simultaneously to improve shaly-sand interpretation. Membrane-potential measurements are used to directly determine clay conductivity. The membrane-potential procedure is preferable to methods that use conduct metric titration to determine conductivity of clay coun-terions. Unlike previous methods, the membrane-potential technique is performed with the clays in the rock intact, thus clay conductivity is not dependent upon empirical shaly-sand parameters.

Dielectric-constant (relative-permittivity) measurement research continues to be of interest with the introduction of several newly developed high frequency dielectric-constant logging tools. Other areas of electrical properties research include the development of laboratory "induction-like" instrumentation. This apparatus will be used to coaxially measure induction parameters at 100 kHz on 4-in. full-diameter core. Another innovative technology uses high-resolution electrical-resistivity imaging of whole and half core to provide a calibration of down-hole electrical imaging logs [8]. The resistivity imaging of core is sensitive to the same fabric and structural detail as down-hole electrical image data and provides a means of converting electrical resistance images into physical properties. Resistivity images are explained in terms of sedimentary fabric and small-scale petro-physical features. Resistivity anisotropy can be examined by directionally constraining electrical current flow.

4. Geological testing

The most important geological technologies in rock characterization are:
(1) petrography- used in the visualization, description, and systematic classification of rocks and minerals, especially thin-section microscopy,
(2) compositional analysis- a branch of geochemistry that deals with the identification and quantification of minerals (for the purpose of brevity, organic geochemistry and fluid analysis will not be covered),
(3) sedimentology- the study of processes by which sedimentary rocks are formed, e.g., diagenetic evaluation, interpretation of depositional environment.

All three technologies are used in the interpretation of basic and special core analyses. Petro-graphic and compositional data are critical in the evaluation of petro-physical, completion, and drilling engineering data, e.g., mineralogy, clay morphology and distribution, rock texture and fabric, and formation-damage potential technique, details of pore in-fills in sandstones, matrix in shales, and fine-scale inter-layering of clays is revealed. Image-analysis technology has added exceptional power to CT, MRI, and other tomography methods. Imaging technology can be used to non-destructively examine pore-space rock-frame relationships, determine mineral and fluid type and distribution, and study petro-physical parameters.

4.1 Compositional Analysis

Virtually all of the routine methods used to determine the composition of rocks and minerals are semi-quantitative, e.g., X-ray diffraction (XRD), energy and/or wavelength dispersive spectrometers (EDS), polarized-light microscopy, Fourier-transform infrared spectroscopy (FTIR).

Accuracy and precision in the rock and mineral composition laboratory can be a major problem. As with most rock-characterization techniques, the lack of standards for rock preparation, reference materials to ensure consistency among laboratories, and instrument design can lead to discrepancies in compositional results. Laboratory rock and mineral determinations are the standard by which in situ measurements are compared, e.g., nuclear-spectrometry logging tools (geochemical logs). Caution must be exercised when using laboratory-derived mineral and elemental data. Each method must be examined carefully to determine experimental limitations, accuracy and precision in testing, as well as potential mineral alteration processes that can occur when a rock is removed from its environment.

4.2 Sedimentology

Sedimentology is a very broad (mostly qualitative) geo-science dealing with the study of sedimentary rocks and the processes by which they are formed. Examination of full-diameter core is useful in determining the depositional environment of a formation and with other data can be used to explain facies relationships. Understanding the genesis of sedimentary structures, textural features, and porosity evolution adds a new dimension to the quantitative assessment of physical properties. Integration of Sedimentology into the rock characterization program adds valuable insight to the design of core preservation methods, core sampling procedures, and laboratory tests.

5. Conclusions

Coring and core analysis techniques have advanced to a great extent in the past few years. These advancements are attributable to developments in technology conceived for other industries, e.g., medical imaging devices, or in response to the need of calibrating other in situ measurement tools, e.g., wireline logging tools. Dealing with large and diverse data sets will become routine and statistics will play a major role in determining how these data can be utilized effectively. Reconciling rock data collected at different scales will be a major challenge of the future. Hence, the rock analyst must be versed in many scientific and engineering disciplines to effectively use laboratory data.

We must continue to develop and refine our understanding of fundamental rock properties. It is, of course, fairly easy to predict gradual changes, but only the lucky analyst could predict the next great advancement in coring and core analysis. The key words of the future are imaging, resolution and integration.

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