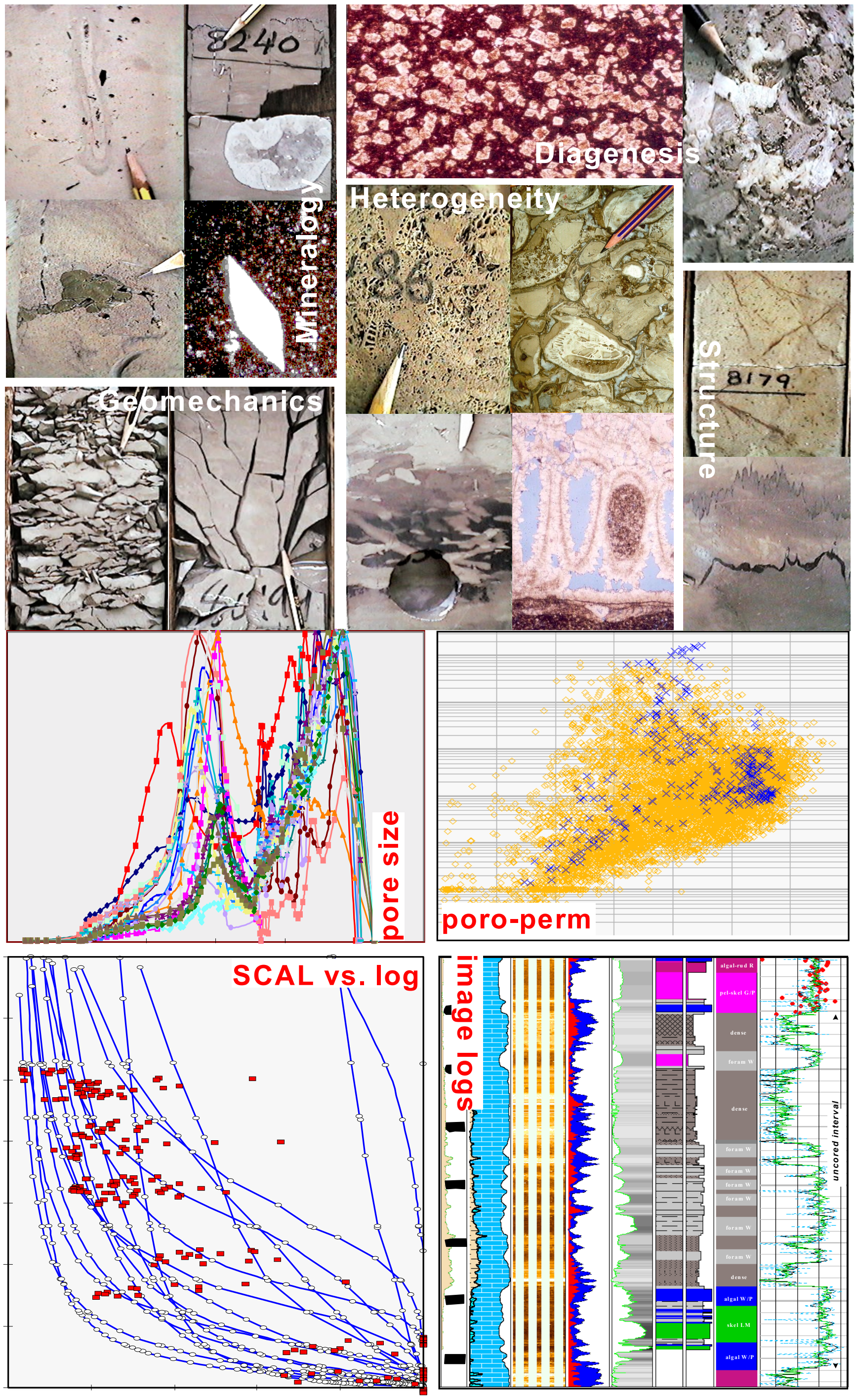
CARBONATE ROCKS

Most of the world's giant fields produce hydrocarbons from carbonate reservoirs. Distinctive and unique aspects of carbonate rocks are their predominantly intrabasinal origin, their primary dependence on organic activities for their constituents and their susceptibility to modification by post-depositional mechanisms. These three features are significant such as to distinguish the productivity of carbonate rocks from other sedimentary rocks including sandstone and shale.

COMPLEXITY OF CARBONATE RESERVOIRS



Carbonate rocks contain more than 50% of the world's hydrocarbon reserves. Carbonates are formed in special environments and they are biochemical in origin.

Organisms play an important role and have direct role in determining the reservoir quality. Processes like compaction, lithification and other diagenetic events result in large variations in the reservoir quality of carbonates.

Sedimentology

Carbonate sediments are particularly sensitive to environmental changes. Carbonate sedimentation is rapid but easily inhibited. Temperature variations influence biogenic activity and affect sediment production; thus most carbonate production is strongly depth dependent. When conditions are favorable for carbonate sedimentation, organic productivity is high; when unfavorable, organic productivity ceases.

Carbonates form in special environments, and, in contrast with sandstones, are biochemical in nature. Environments range from near-shore lagoons, platform organic buildups, and shelf margin shoals to slope and basinal settings. Carbonates typically are found in warm, shallow, clear marine water in low latitudes.

Carbonates are essentially autochthonous, as they form very close to the final depositional sites. Texture is more dependent on the nature of the skeletal grains than on external influences. Intrabasinal factors control facies development. In contrast, sandstone and shale were formed of sedimentary particles derived from sources outside the depositional basin. Reefs, bioherms and biostromes are examples of in-place local deposition where organisms have built wave-resistant structures above the level of adjacent time-equivalent sediments. Many reefal deposits are commonly composed of fragmented, locally-transported skeletal debris and a minor volume of in situ framework organisms. Biofacies and lithofacies often correlate, or in other words, organisms produce typical lithofacies. Substrates control inhabiting organisms.

Basin configuration and water energy are the dominant controls on carbonate deposition. Organic productivity varies with depth and light (photic zone); upwellings and water agitation influence organic productivity.

Diagenesis

Carbonates are particularly sensitive to post-depositional diagenesis, including dissolution, cementation, recrystallization, dolomitization, and replacement by other minerals. Abundant unstable aragonite (in bioclasts and cements) converts to more stable low-magnesium (or high-magnesium) calcite. Calcite can be readily dolomitized, sometimes increasing porosity. Complete leaching of grains by meteoric pore fluids can lead to textural inversion which may enhance reservoir quality through dissolution or occlude reservoir quality through cementation. Burial compaction fracturing and stylolithification are common diagenetic effects in carbonates, creating high-permeability zones and permeability barriers or baffles, respectively.

Reservoir characterization

Reservoir characterization issues, including the geological framework, rock fabric, facies, and porosity and permeability distributions, are some of the most widely investigated production issues today. Many challenges exist in characterizing, quantifying, and predicting carbonate reservoir quality. The key to understanding carbonate reservoirs is recognizing the critical link between geological heterogeneity and reservoir quality and performance. Finding the link between geological heterogeneity and reservoir quality often becomes a matter of finding the appropriate data and sampling the heterogeneity at the appropriate scale. For example, many carbonates are characterized by abundant macrofauna and macroflora that are larger than the scale of some sampling methods, such as 1" core plugs, and may be better sampled with longer, whole cores or wireline logs. In this case, geological heterogeneity must be sampled at greater scales to be valid. In another example, very fine-grained mudstones may be extremely uniform in reservoir quality at a scale much smaller than a 1" core plug. The recognition of the appropriate scale of investigation is, therefore, critical to reservoir characterization efforts in carbonates.

Classification

Carbonates have a special textural classification (Dunham, 1962) based on the presence or absence of lime mud and grain support. Textures range from grainstone, rudstone, and packstone (grain-supported) to wackestone and mudstone (mud-supported); where depositional texture is not recognizable, carbonates are classified as boundstone or crystalline. Other workers have classified carbonates based on fabric selective and non fabric selective pore types (Choquette and Pray, 1970). Porosity under this classification includes (1) fabric selective (interparticle, intraparticle, intercrystal, moldic, fenestral, shelter, and framework) and (2) non-fabric selective (vug and channel, cavern, and fracture).

Heterogeneity

Carbonates are characterized by different types of porosity and have unimodal, bimodal and other complex pore size distributions, which result in wide permeability variations for the same total porosity, making difficult to predict their producibility (***Fig. 2***). The term "vug" and its descriptive forms, "vuggy" and "vugular", are some of the most commonly used carbonate porosity terms, and may have had the most widely varied definitions and usage. A vug is a

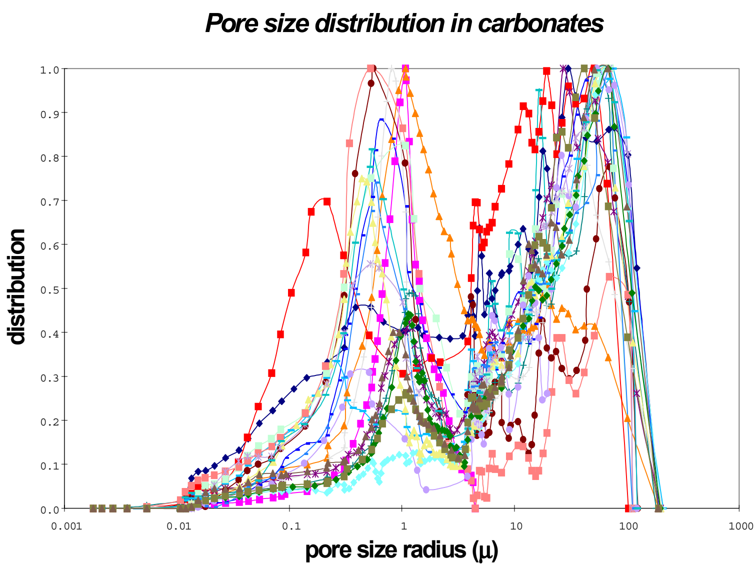


Fig. 2

pore that (1) is somewhat equant, or not markedly elongate, (2) is large enough to be visible with unaided eye (diameter > 1/16 mm) and (3) does not specifically conform in position, shape, or boundaries to particular fabric elements of the host rock. Vugs and channels are similar in that neither is fabric selective. They differ in shape, however, as a vug is the more equidimensional pores and "channel" is used for pores that are markedly elongate or continuous in one or more dimensions. Vuggy porosity can be subdivided into connected and disconnected types.

Several porosity types coexist giving mixed log responses (***Figs. 3, 4***). Carbonates are microscopically heterogeneous. Logs respond differently to different components of porosity. Integrated interpretation of the logs is necessary to quantify heterogeneity with a limitation of the fact that various logs respond differently due to different geometric responses of the tools, investigating volume of the formation, and vertical resolution.

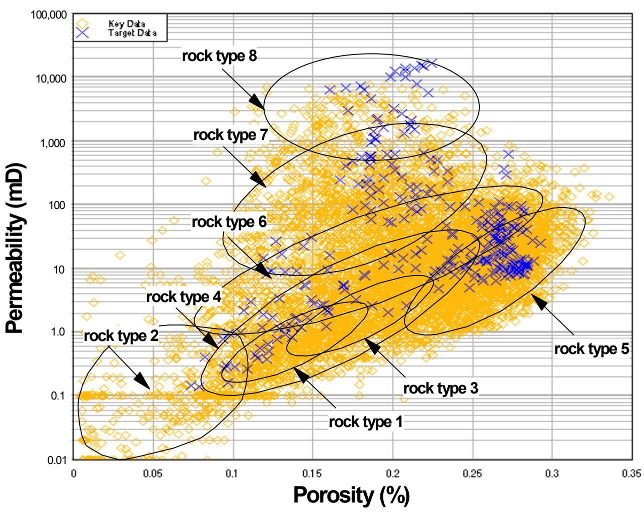


Fig. 3

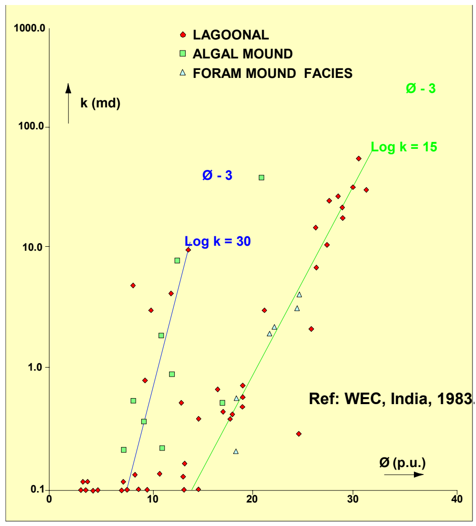


Fig. 4

Mineralogy

Carbonate mineralogy is usually simple - principal minerals are calcite, dolomite, and minor clay. Secondary minerals like anhydrite, chert, and quartz are common. Accessory minerals like phosphates, glauconite, ankerite, siderite, feldspars, clay minerals, pyrite, etc. are also present depending on the environment of deposition and diagenetic history.

Disseminated pyrite present in minor quantities can effect the resistivity logs and result in apparently pessimistic estimation of oil saturation. Total gamma ray logs are insufficient to estimate clay volumes because of the presence of phosphate or organic matter, which result in relatively high uranium content. Diagnostic crystal structure of the different carbonate minerals is revealed by x-ray studies; these indicate that chemical tests for magnesium, a common basis for the classification of limestones and dolostones, are insufficient to prove the existence of the mineral dolomite. High magnesium calcite occurs in many carbonates, often indicating little diagenesis. Correct mineralogy is important for accurate estimation of porosity using nuclear devices. Elemental concentration spectroscopy logs provide valuable information to address this problem. Also, there may be a relationship between mineralogy and reservoir quality.

Petrophysical analysis

Carbonate pore geometry and wettability influence the cementation exponent(m) and saturation exponent(n) of Archie's equation. Cementation exponent 'm' varies constantly which has a significant effect on the computation of water saturation using resistivity logs (***Fig. 5***). Vugs may not be connected, giving higher values of 'm'. Fractures result in lower cementation exponent 'm' values. In the absence of correct cementation exponent (m) values, the presence of isolated vugs, fractures, and microporosity increase uncertainty on the estimation of water saturation.

To develop a quantitative petrophysical method that covers all features and aspects of carbonates is a difficult challenge. In the absence of proper log suites for such interpretation, the results are subject to large errors. Lithofacies characterization is central to carbonate interpretation. Evaluation of various aspects of carbonates requires specific special log suites and interpretation techniques, which are essential in predicting the fluid flow behavior. Electrical imaging and sonic shear imaging logs would be useful for identification of fractures and vugs, and nuclear magnetic resonance (NMR) logs are important for quantification of the individual porosity types, pore size distribution, and permeability estimation. Wireline formation testing (MDT and equivalents) is very useful for calibrating the permeability estimations from logs. Advanced techniques like model-based interpretation methodology and artificial neural networks for rock type analyses are important to the successful evaluation of carbonates, given sufficient diagnostic log suites that are needed for a specific field (depending on the recognized degree of complexity).

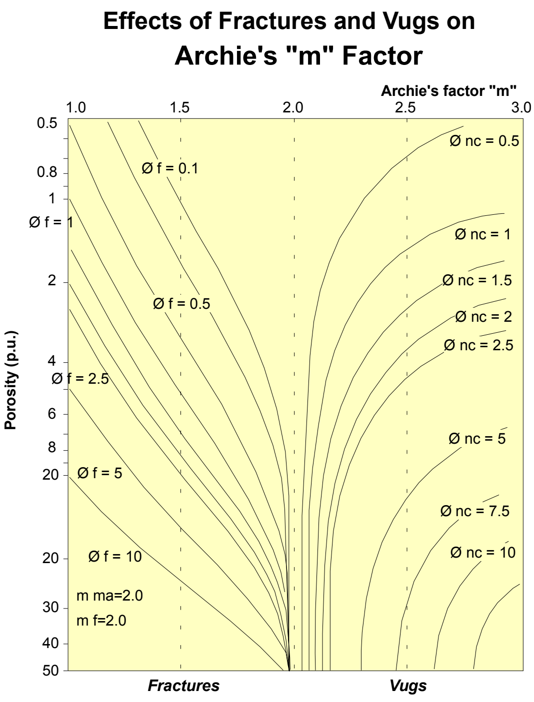


Fig. 5

Core sampling

Core samples provide a valuable data source for investigating geological heterogeneity and understanding reservoir quality and performance. Many analytical techniques are employed to investigate heterogeneities at different scales (***Fig. 6***), such as slabbed core description, thin section petrography and mineralogy, core plug analyses, special core analyses, geomechanical analyses, and wireline log/seismic data calibration. As an initial effort, very small-scale heterogeneities are examined using thin sections and samples from slabbed cores, such as reservoir texture, fauna/flora, grain size, mineralogy, and diagenetic history. Conventional core plugs examine a larger scale heterogeneity and reveal pore size distributions, reservoir quality (such as porosity and permeability), fluid saturation, and capillary pressure variations. Special core analyses of whole core samples examine a larger scale and provide data on relative permeability, saturations, capillary pressures, and restored state. On a local or semi-regional scale, geomechanical studies of core samples provide data concerning stress-strain relationships, rock properties, and fracture and fault trends. Finally, calibration of core-derived heterogeneities with wireline logs and seismic response provides data concerning field-wide reservoir quality and performance at the largest scale.

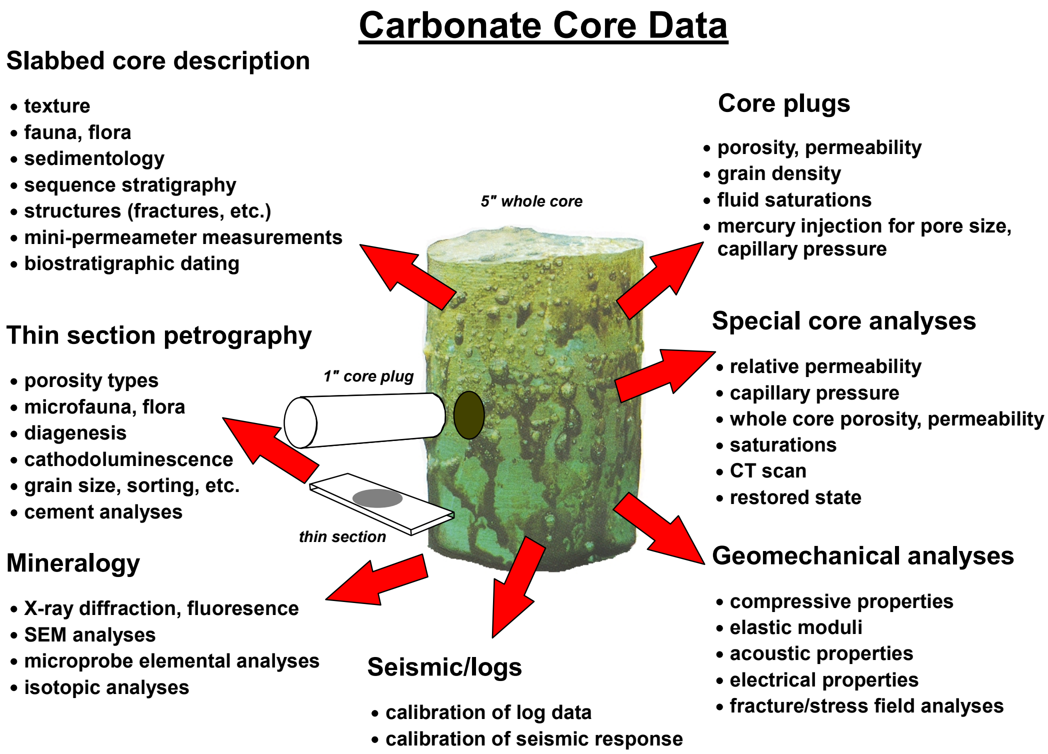


Fig. 6

Core recovery and quality are of serious concerns in carbonate reservoirs. Cores from fragile formations are lost or damaged leading to depth matching issues and unreliable measurements of reservoir properties. Mechanical aspects of coring like retrieval, surface handling, preservation, transportation, plugging, washing, and drying need special attention. Each coring technique (sponge coring, gel coring, pressure coring and horizontal coring) has certain advantages and disadvantages. The use of specific coring techniques depends on the objective and understanding of the formation characteristics. Optimization of drilling fluids and coring parameters are important factors for achieving efficiency, quality and best recovery.

Factors that effect the reliability of the measured properties are preserved vs. restored samples, cleaning efficiency for the contamination caused by mud filtrate invasion, precipitation of wax, asphaltene & high-end components during retrieval by reduction in temperature and pressure, drying and oxidation during transportation and storage, burial history, hysteresis of adsorption/deabsorption, etc. Appropriate sampling (plugs) for physical measurements is very important for representing the reservoir in highly heterogeneous cases. It is important to understand and define the different scales of heterogeneity so that SCAL and field-scale data can be compared.

Overburden will change pore size, shape and aspect ratio. As pore structure controls relative permeability(Kr), pore structure and connectivity must not be altered for Kr measurements representing in-situ conditions. Irreversible changes occur to rock properties, as stresses are relieved during coring and retrieval. Representative pore pressure and overburden must be used in lab experiments. Core porosity, cementation factor (m) should be measured under appropriate overburden conditions covering all RRT. Overburden corrections to the core porosity should be based on the RRT, as different rock types may respond differently to confining pressure.

Carbonates have mixed wettability. Saturation exponent (n) which is an important parameter in log analysis, depends on the wettability. Alteration of wettability in the process of coring, transportation, and storage is another issue which needs careful consideration. Different RRT, mixed wettability, faults, anisotropy and heterogeneity in the reservoir result in different Kr and capillary pressure (Pc). Porous plate/centrifuge data are preferred over mercury injection data for S_{wi} in rocks that are texturally complex (i.e. where different pore types coexist). The directional measurement of the properties on core plugs is important. The orientation of flow in a core sample (plug or whole core) must be identical to the alignment of sedimentary stratification in the formation.

Fluid contacts

The interpretation of fluid contacts involves many factors. Improper evaluation and understanding result in the misinterpretation of the fluid contacts. Long transition zones may result from low and varying permeability near the oil-water-contact. The reaction of sulfate-reducing bacteria near the oil-water interface may result in the precipitation of calcite, forming a seal between oil and water parts of the reservoir and limiting aquifer support to the oil reservoir. In some cases, this is the reason for the presence of H_2S near the oil-water-contact. Another complication is highly vuggy carbonates with closed vugs, which may contain oil in the vugs even below the oil-water-contact, as the oil may have been trapped during migration and flow channels may have been sealed due to post-migration diagenesis. Also, oil and water may coexist in the matrix and fractures in fractured carbonate reservoirs.

Geomechanics / anisotropy

Dynamic geomechanical models are of significant value for carbonates due to the elastic nature and susceptibility of carbonates to in-situ stress changes. Production of fluids results in pore pressure changes and may contribute to alteration of reservoir rock properties. Permeability is highly dependent on the in-situ state of stress. Secondary permeability generated by small fractures can have an impact on the effectiveness of fluid injection and production. Mobility of fluids is much higher in the direction of maximum principal stress than in the direction of least principal stress. Natural fractures trending in the direction of maximum horizontal principal stress are more permeable as they often remain open, whereas fractures perpendicular to the maximum horizontal principal stress are generally sealed.

The challenge is the evaluation of the stress state (both magnitude and orientation) and the rock strength. This can be achieved by estimating the magnitude of minimum principal stress and other geomechanical parameters, like Young's modulus, Poisson's Ratio, bulk modulus, shear modulus, etc. The main inputs to this processing are acquired through Dipole Shear Imaging (DSI). Leak-off or extensometer tests can be made on some wells to calibrate or verify the log results. Orthogonal calipers, and other data from FMS and FMI for example, are also used to determine the direction of in-situ stresses.

Removing the wellbore cylinder alters the ambient stress field and considerable strain is imparted upon surrounding rock after drilling a hole. After such alteration, the principal component directions could be rotated, in particular if they were not aligned vertically with the maximum component in the beginning. Tectonic stresses could easily rotate the principal components out of a simple frame of reference.

In the classically used relationship, elastic strain is neglected (assumed zero) which can not represent the case of fractured media when the fractures are open by post burial process, either by stress or pore pressure. The issue is to distinguish between elastic deformation and permanent non-elastic modification. By definition, elastic strain is reversible and recovered when the applied stress is released. However, tectonic processes produce large-scale non-elastic deformation, some of which might be described as the cumulative result of long-term elastic strain components. The amount of true in-situ elastic strain in fractured media is difficult to gauge.

Geomechanical model of the field is helpful to address the drilling issues in carbonates like thief zones, differential sticking, oval holes, over-balanced mud causing permanent wellbore damage, high invasion into formation/core, and induced fracturing producing irreparable vertical communication between zones. Induced fractures may be either thermally-induced (account for thermal and poro-elastic back stress due to cold water injection, water/oil mobility effects, dual porosity, varying rock compressibility, leak-off and differing degree of voidage replacement), pressure induced (effect of injecting above the formation parting pressure), or depletion induced (drop in pressure due to production of reservoir fluids).

Forces that induce elastic anisotropy also induce permeability anisotropy. But the tie between the two is not routinely done, nor is it fully understood. It is required to establish the elasticity-permeability tie for anisotropy. Anisotropy in Kr behavior is expected because rock characteristics have strong directionality. This is more crucial in vertical flow than in horizontal flow. Therefore, gravitational and structural features impact flow behavior.

Modeling

A 3D, RRT-based, geological model accounting for the heterogeneity is vital for the development of the field. Geological modeling in carbonates is arguably more complex than in sandstones due to the presence of discontinuous bodies, large lateral and vertical variations, and uncorrelatable units.

Key issues in our effort to predict complex flow/displacement processes in reservoirs are wettability and its distribution, mass transfer/extraction processes created by viscosity variation and distribution, impact of heterogeneity and anisotropy on flow behavior (upscaling issue), integration of discrete and continuum approaches for fracture modeling and 3D multiphase flow. There is a need for a correct predictive model of flow description in heterogeneous anisotropic reservoirs from a fluid-flow perspective and physics of reservoir flow (including thermo-mechanical effects) and upscaling. It is required to model stress changes around wellbore due to fluid injection and its pressure/thermal effects and the resulting sensitivity of the properties (like permeability) that respond to changes in stress, to predict altered stress-state for infill drilling and bore-hole stability. Efficient numerical and computer code, which can handle tensorial representation with flexibility for multiphase flow behavior, geomechanical and thermal simulation, is the need of the hour.

Reservoir monitoring and management

Carbonate rock texture produces spatial variations in permeability and capillary bound water volumes. Complex rock texture in carbonates produces complex interrelationships between porosity, permeability, Swi, Sor, wettability, and capillarity. Understanding of reservoir connectivity issues like existence/orientation of flow-barriers, high permeability streaks, vertical interconnection of layers (Kv) to determine upward migration of gas, cross flow of injected fluids, gravity drainage, coning, oil trapping, etc. are important. An accurate RRT-based, 3D geological model accounting for the flow barriers, highly permeable streaks/channels, fractures, faults, connectivity of lithologic units and boundaries is at the heart of reservoir management. Sophisticated techniques for reservoir monitoring (permanent downhole sensors) and proper reservoir management with midcourse corrections at appropriate intervals to arrest irregular front advance, uneven distribution of injection, vertical communication, localized pressure sinks, over-pressurized regions (compartmentalization) and vertical cross-flow (water coning and gas migration) are required for maximizing the recovery.

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