

## **Relationship between Sedimentary Facies and Reservoir Rock Types to Construct the Facies Modeling and Reservoir Evaluation of an Mixed Reservoir in SW of Iran**

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Sedimentary facies are important in reservoir characterization because flow properties are commonly assigned using facies-specific correlations. On the other hand, reservoir rock types are defined strongly based on reservoir properties, such as porosity permeability, mercury injection capillary pressure and pore size distribution curves. Facies modeling is not only commonly used to determine spatial arrangement of facies, but also provide information about architecture have "flow-units" and "flow-barriers and baffles". The evaluation of the formation heterogeneity is important for facies and petrophysical modeling as well as fluid simulation studies.

Facies analysis and reservoir rock type determination were carried out on the upper cretaceous sediments in a giant field in the south west of Iran. Facies modeling of the sequence in the field provided a better understanding of the three-dimensional geometry, facies architecture, and internal heterogeneity in reservoir intervals. Reservoir properties of the sedimentary facies are a product of depositional environment, and control fluid migration and compartmentalization in other deposystems.

In this investigation eleven sedimentary facies related to the wide variety of depositional environments such as distal and proximal open marine, shoal, seaward and leeward shoal, lagoon, and delta identified. On the other hand, integration of petrophysical data with petrographical information deduced to the eight reservoir rock types. These sedimentological characteristics and their related reservoir rock types control fluid migration and compartmentalization in the reservoir, and can be utilized in geostatistical fluid flow models to improve efficiency in the exploration and production of oil in the carbonate basins. Correlation between sedimentary facies and reservoir rock types in this manner shows more than 80 percent coverage.

## **Determination of Reservoir Rock Types Based on Wire Line Logs by Using Fuzzy Logic Method in a Mixed Siliciclastic and Carbonate Reservoir in SW Iran**

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Finding and developing oil and gas resources requires an exact analysis and knowledge of the reservoir's behavior and its fluids. The first step in prediction of reservoir's behavior during production is identification of reservoir rock types. Distinction of reservoir rock types is necessary to distinguish of flow units and their vertical and horizontal connection.

Determination of reservoir rock types in traditional method is based on three main parameters including lithology, pore geometry and range of porosity and permeability. This approach is not only time consuming but also very expensive (because of preparation of cores, as the main source data). Therefore, in the present study, Fuzzy Logic and Fuzzy Possibility applied as an artificial intellect for identifying reservoir rock types on the basis of wire line logs. Wire line logs data were used in this study are belonged to six wells in a giant field in southwest of Iran.

Results of this research show that the Fuzzy Logic method has been proved to be successful in determining of reservoir rock types. By using the method, not only all the reservoir rock types were recognized but also accuracy of the results in some reservoir rock types is more than 80% in comparison to the traditional method.

## **Identifying Hydrocarbon Potential in Thin Bedded Reservoirs**

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Recent declining output from conventional reservoirs has led to an increased interest in unconventional reservoirs characterized by fine scale heterogeneity. Due to the presence of thin shales, the distribution and connectivity of the sands within these reservoirs are associated with high uncertainty. Historically, these reservoirs have not attracted attention as exploration targets because of their inherent low deliverability and because it has been difficult to recognize net pay with conventional technology.

A geological modeling method to generate detailed 3D near-well-bore models in thin bedded reservoirs has been used to identify hydrocarbon net pay below the level of petrophysical log resolution. Several case studies are presented to demonstrate how this modeling technique can be used to produce model-derived net-to-gross (N/G) curves based on a geologically realistic distribution of sand and shale. Conventional estimates of N/G are typically based on cut-offs using gamma ray well logs. The N/G estimates are very sensitive to the cut-off used and the resulting uncertainties from cut-off based values are typically high. Compared with modeling-derived N/G curves, cut-off based curves tend to underestimate the net sand in areas with intermediate gamma ray values. Core descriptions and fine scale models of these thin bedded reservoirs show that the "sand intervals" consist of thin-bedded interlayered sandstone/shale successions, usually with good lateral connectivity. The improved estimation in net pay from fine scale modeling has contributed to improved estimates of recoverable oil and gas reserves for the E&P industry.

## **Digital Analysis of Reservoir Compaction Processes**

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Reservoir compaction is of significant concern to the oil and gas industry. Compaction leads to issues of reservoir productivity. It might aid in production by squeezing oil from the rock, but can also reduce permeability and thus production. Compaction may also effect ultimate recovery. Understanding the interplay of these effects for various production scenarios is essential.

We have previously demonstrated an ability to image sedimentary rock in 3D at the pore/grain scale. We have also demonstrated an ability to directly measure rock fabric and texture from 3D digital images of core material and developed robust techniques for partitioning the pore space of a porous material. In this paper we

describe studies of the progression and contribution of various compaction processes in 3D using micro-CT imaging and 3D grain analysis. Studies of compaction are undertaken on an idealized monodisperse grain pack, unconsolidated quartz sands and on consolidated quartz sands. During the experiment individual grains are tracked allowing one to observe and quantify the grain displacement processes. These results can lead to a better understanding of the role of various compaction processes (e.g. grain rotation, deformation, slippage) on reservoir compressibility. Analysis of the pore space of the image allows one to quantify the degree the pore space is squeezed. Direct simulation of permeability on samples under different compaction conditions is undertaken and permeability reduction is correlated to the mode of compaction. Changes in the pore morphology/topology and their effect on relative permeability and ultimate recovery is also considered.

## **Reservoir Modeling and Geosteering - a Synergistic Approach**

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The importance of building a successful geological model of a reservoir not only serves as a basis for future development of the reservoir but it also holds the key to drilling of future development wells. The key to the successful placement of such wells is existence of geological model which can be continuously updated. Today with the advent of more sophisticated tools such as Petrel™, a 3D geological model of the reservoir honouring channel geometry can be built. Horizontal wells can be planned with great precision in such a model. In addition, virtual wells can be simulated in such a model and property logs can be simulated along the proposed well paths. A curtain section can be extracted from the geological model. Such a curtain section is actually a vertical plane containing the well path with all the horizons. This curtain section is transferred to RTGS™ (real time geosteering screen). Once the geology is properly in place, all one needs to do is square the logs from an offset well and propagate the section with the petrophysical properties. During the execution phase one needs to model the logs, and modify structure as encountered during drilling. The pre-job modeling ascertains the risk involved during the geosteering job. Since continuous updates are available during the drilling process the model is updated dynamically in realtime. This further minimizes the uncertainty and helps engineers and geoscientists take crucial decisions. Quite a few horizontal wells have been drilled in Kuwait using this technology

## **Shallow Reservoirs and the “Gas-Effect”, Tinta 3 Well, an Oligocene and Eocene Case in Burgos Basin, Mexico**

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Burgos Basin covers an area of 50000 km<sup>2</sup>, is located in the west side of Gulf of Mexico and the north east of Republica Mexicana, in Tamaulipas and Nuevo León states mainly.

In the last years it has become in the most important non associated gas producing basins of Mexico.

Tinta field was discovered in the fifties, it was reactivated with the drilling of the wells Tinta number 3 in 2003 and Tinta number 12 in 2005. The log response for the NPHI and DPHI, from the density (LDL) and neutron (CNL) was amazing, because of the high over crossing, which is called “gas effect” in really shallow sandstone reservoirs, the relevance of this kind of reservoirs is the depth: 125 to 645 m, with good production and rock quality index.

This kind of reservoir varies in thickness from 3 to 16 meters and are located in sicciclastic sediments from Eocene and Oligocene, in the formations Jackson, Frio Marino and Frio no Marino. All have good and excellent porosity “ $\phi$ ” (18 to 34 %) and permeability “k” (1.6 to 825 mD) obtained from cores.

The “gas effect”, Rock Quality Index and mineralogy of this producer sands is described; based on the study of some plugs, cross-plots, petrography images, electronic microscope (SEM) and study from spectroscopy log with cross-plot.

The sands have produced gas and condensate and have gas rates from 0.3 to 1.67 mmcf/d, pressure ranges of 400 to 900 psi. The cumulative production oscillates from 0.8 to 4.0 bcf.

## **Understanding the Stress Dependence of Velocity in Unconsolidated Sands**

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Understanding the stress dependence of velocity is critical to the interpretation of time-lapse seismic studies. The stress dependence of rock properties must be understood so that their influence can be differentiated from the influence of saturation changes. In-situ stress values correlate with the stress dependence of velocity — as in-situ stress increases, the stress dependence decreases.

We establish a strong correlation between pore volume compressibility (Cp) and the velocity at in-situ stress. The value of Cp is dominated by the physics at grain contacts. This is demonstrated by a well-established relationship between Cp and contact length. Grain contacts also dominate the stress dependence of the velocity. As the stress dependence of velocity increases, the contact force between the grains decreases. In contrast sands with low compressibility and long contacts display lower velocity stress dependence.

The change in velocity with stress is also impacted by the presence of load-bearing ductile grains, which directly impacts the frame modulus, weakening it and causing a large stress dependence in velocity. Authigenic clays precipitated in primary pores influence in-situ velocity but not its stress dependence, because they are not typically in load bearing positions.

This paper demonstrates these basic attributes of the stress dependence of velocity in unconsolidated sands.

## **Modeling of Miscible Filtrate Cleanup with Wireline Formation Testers**

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Acquisition of representative fluid samples in Wireline Formation Testers (WFTs) is of paramount importance and has been greatly impeded by miscible oil-based mud (OBM) filtrate contamination. Predicting pumpout times needed to obtain representative formation samples is essential for planning, interpretation, and the design of new generation WFT probes/snorkels that can operate in OBM filtrate environments with enhanced efficiency.

Analytical as well as numerical models reported in the literature rely predominantly on simplifying assumptions in terms of the compositions of flowing fluid phases and typically assume either single phase or 2 to 3-component hydrocarbon phases in cases of black-oil/extended black-oil formulations. As a result, accurate modeling of the flow dynamics into has been difficult to achieve because modeling of the OBM invasion process is quite complex and very different from the water-based mud invasion process. Here, we take a different approach. We have constructed a numerical model for OBM filtrate cleanup using a compositional fluid-flow simulator that honors the physics of multi-component fluid flow and the thermodynamics of phase behavior. We have simplified the effect of invasion by initializing an invasion profile at the time of sampling using a depth of invasion parameter, allowing the inclusion of nonzero crude oil fractions at the sand face when required. We have focused on building a geometrically realistic model of the probe and its surroundings and identifying the various invasion, formation and fluid parameters that most affect the sampling process. To verify the robustness of the model, history matching has been performed on a number of field data sets. Without little tuning if any, excellent agreement has been obtained between predicted and observed cleanup profiles during sampling. Our modeling results are not tool specific and can be used by anyone involved in the design and operation of new and existing sampling probes.

## **Understanding Reservoir Architecture: Combining Continuous Fluid Facies Mapping, Pressure Measurements, Downhole Fluid Analysis, and Geochemical Analyses**

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Identifying compartmentalization and understanding reservoir structure are of critical importance to reservoir development. In deep water and similar high cost operating environments, the traditional methods, drill stem tests (DST) and extended well tests (EWT) often become impractical, with costs approaching the costs of new wells and with emissions becoming increasingly undesirable. Thus, compartments often have to be identified by some other means. Individually, fluid analysis while drilling (FAWD), pressure measurements, Downhole Fluid Analysis (DFA), and geochemistry are known to provide important information about reservoir architecture. When these powerful methods are systematically combined and applied to the dataset, the synergy delivers a much more robust picture of the reservoir.

In this paper, we review a number of case studies in which we have successfully combined continuous fluid facies mapping, pressure and gradient measurements, downhole fluid analyses, and geochemistry for reservoir continuity assessment in a diverse range of geological settings including a wide range of field sizes, structural environments, reservoir lithologies, and oil types.

Particular emphasis is placed on comparing the strengths and limitations of the different techniques in revealing reservoir architecture, especially vertical permeability barriers. We present a number of unambiguous cases, for which the multiple data streams might be viewed as being somewhat redundant. More ambiguous cases, in which the multiple data streams are required to make a robust assessment of key reservoir properties, are also presented.

## **Predicting Magnetic Resonance Permeability and Porosities from Triple Combo Data for Cost Effective Field Development**

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Frequently, during field development, only a small fraction of wells have porosity, permeability, bulk volume irreducible fluid and micro porosity available from either Magnetic Resonance log or core data. Reservoir simulation modeling and field development can be improved if magnetic resonance porosity, permeability, bulk volume irreducible fluid and micro porosity are available from every well. We have developed a post processing interpretation work flow which computes all of these parameters for every well in the field from triple-combo or quad combo data. The computation is based upon associations developed by a neural network that has been trained using wells having triple-combo and magnetic resonance logs or core data.

A field wide clustering procedure (Facies Profile<sup>SM</sup>) is run on every well after data normalization of the triple combo data to ensure that associations developed in one well can be applied to another. In essence, the geology of the wells is confirmed to be similar, as seen by the logs.

The resulting electro-facies are also of use to the sedimentologist to confirm facies identified from core analysis and to the geologist to validate formation tops. In some cases, these types of analyses indicate significant change in the formation geology or formation fluids. Observed changes may trigger action to run another Magnetic Resonance Log.

The interpretation work flow and some Field examples are presented. In addition, variations of this technology to predict triple combo data (LWD or wireline) from pulsed neutron capture data and to repair "bad" logging data (from washouts, rugosity, etc), or to correct logs for gas effects will also be presented.

## **Applied Rock Mechanics in the Ram Powell Redevelopment Project, Deepwater USA, Gulf of Mexico**

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This paper describes the method used in the Ram Powell Redevelopment Project for defining a stable pressure window to maximize the efficiency of the drilling process. The method combines formation evaluation, log and laboratory derived rock properties, well site pressure integrity testing, geophysical data, and actual minifrac results. As a result of using this synergistic approach, the subject extended reach wells were drilled with no wellbore-related down time.

The process begins with a definition of the pore pressure cells, both in magnitude and position, generally delineated by studying the seismic profile along the projected wellbore and analyzing log and pressure testing data. The pore pressure data and rock properties are used to model the minimum wellbore pressure for stable drilling. A study of the changing seafloor profile along the well path is used to adjust the overburden pressure, which is then combined with rock properties to estimate the in-situ stresses, resulting in an estimate of the fracture gradient, or the maximum allowable wellbore pressure to avoid drilling fluid losses.

The approach is applied to two extended reach wells and the paper documents the entire process from planning to drilling and completion.

## **Use of Log-Derived High-Resolution Mineral-Based Lithofacies from Borehole Spectroscopy Logs and Microresistivity Images for enhanced Formation Pressure Sampling and Vertical Interference Tests**

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Downhole pressure sampling and vertical interference tests are being conducted more and more as standard practice in the Gulf of Mexico. A key input into the planning of these operations is an accurate understanding of the subsurface lithology, including subtle reservoir internal baffles and barriers. In order to improve planning downhole sampling operations and post-operation calculations, log-derived high-resolution mineral-based lithofacies can be used. These are computed using borehole spectroscopy and high-resolution micro-resistivity image data. Spectroscopy data is used to classify the rocks into dry-weight mineralogy-based lithofacies based on a specifically designed ternary-diagram classification system. Calibrated high-resolution micro-resistivity image data is integrated with the generated dry-weight mineralogy-based lithofacies to compute a final mineral-based high-resolution set of lithofacies. The final lithofacies can be presented as a detailed geological column, or input as numerical data for additional computation and modeling.

These lithofacies can be used to make sampling and pressure point selections. The output can be quickly delivered to the decision makers whether in the office or at a remote location. The geological display of the lithofacies makes it readily usable and preferred for choosing sampling locations, whether for pressure or fluids. The inherent mineralogical content combined with the higher resolution bedding directly addresses the need to identify potential zones of interest otherwise indistinguishable. Critical depositional events such as maximum flooding surfaces, condensed sections, reservoir seals such as marl layers and shales, continuous or interbedded, are immediately identifiable with these lithofacies.

The use of log-derived high-resolution mineral-based lithofacies helps place the tool probes and/or packers at optimum formation and depth locations, thereby reducing risk and operating time, easing interpretation, and maximizing data and sample recovery.

## **A Novel Technique for Formation Evaluation in Fractured Basalts by Integration of Elemental Capture Spectroscopy, NMR and Dipole Sonic logs**

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This paper presents an innovative approach for enhanced formation evaluation of fractured basaltic reservoirs. The study was based on integration of high-tech logs, i.e., Elemental Capture Spectroscopy, Dipole Sonic and Nuclear Magnetic Resonance and calibration with special core analysis data. The main interpretation challenge in basalts is the lack of matrix response data due to the complex mineralogy. Using conventional logs, i.e., neutron, density, resistivity and sonic, often leads to questions, such as, where is the hydrocarbon, is porosity correct, where should I perforate, will it flow? For example, porosity estimation using neutron-density logs is often inaccurate due to matrix-density uncertainty. Moreover, permeability in basalts is of vital importance in selecting the best zones for perforation and deciding the optimal completion strategy. We used the conventional logs in conjunction with the elemental dry weights (iron, silicon, calcium and sulfur) from elemental capture spectroscopy and NMR porosity logs as inputs in a multimineral petrophysical evaluation, which was calibrated with available core porosity, X-Ray diffraction and petrography data, in order to derive an accurate mineralogical model across the basaltic sections. Cross-plots of P-wave and S-wave velocity vs. Poisson's ratio exhibited a distinct response over the weathered basalts and thus assisted in facies characterization. Moreover, NMR and Stoneley logs were used for estimation of intrinsic and fracture permeability, respectively. This synergistic approach assisted in deriving more accurate reservoir properties and delineating the high productivity pay zones. The well was tested across the altered basaltic zone and flowed more than 2,000 BOPD.

## **Evaluation of Source Rock Using Well Logs**

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The use of petrophysical techniques arises out of the need to assess source rocks basin studies in various geological settings, where the database is restricted to basic log data and little or no geochemical information. Using deterministic

formation analysis techniques, it is possible to quantify the volumes of OM, shale, matrix and porosity that would be required to give the recorded log responses.

A practical method, the  $\Delta\log R$  technique, for identifying and calculating total organic carbon in organic-rich rocks has been developed using well logs. This method, allows organic richness to be accurately assessed in a wide variety of lithologies and maturities using common well logs.

The  $\Delta\log R$  technique uses common, widely available well logs to identify organic rich source rocks and to calculate their TOC content.

The  $\Delta\log R$  separation will display by properly scaled transit-time and resistivity curves, can be used to determine accurately organic richness with a vertical resolution of about 1 m. for rocks of low thermal maturity, the relationship between  $\Delta\log R$  and TOC exists primarily, because of the porosity curve component of  $\Delta\log R$ .

$\Delta\log R$  separation not associated with organic-rich source rocks can occur, but in most cases, such anomalous  $\Delta\log R$  intervals can be easily recognized.

In this paper, we show how standard petrophysical processing using  $\log R$  method, can be applied for quantitative and semi-quantitative evaluation of organic content and therefore source rock potential.

## **Real Rocks, Real Data - Ways to Enhance Reservoir Knowledge**

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This paper provides examples of several ways in which drill cuttings can be utilized to provide additional information to an exploration or development project that can potentially enhance the value of the project and assist the decision process.

The basic methodology of reservoir micro analysis or rock typing to estimate permeability first developed by Bob Sneider has been extensively used in North America to interpret permeability from drill cuttings. Outside of North America in countries such as Australia this technique is almost unknown.

In many cases petrophysical evaluation plus a more detailed knowledge of the rock properties from the cuttings is all that may be required but more information can be extracted from the data if additional techniques are applied. By utilizing special core analysis data and drill stem test results, a technique has been developed to convert ambient permeabilities estimated from examination of drill cuttings to in-situ permeability. This can provide an estimate of potential flow rates from a reservoir. The development and subsequent use of this method has been extremely successful and results correlate well to information obtained by more expensive techniques.

Further innovative uses of drill cuttings include integration of detailed reservoir data from existing wells into regional studies and high grading of exploration acreage; using textural properties for determining depositional environments to locate follow-up wells; detailed well correlation utilizing reservoir properties and unconformity surfaces recognized from features in the cuttings. This assists the understanding of the reservoir system and subsequent production characteristics.

Using just one or a combination of these techniques has helped a number of companies gain additional valuable reservoir information by utilizing this relatively low cost alternative of reservoir evaluation.

## **Successful Identification of Depleted Sands Utilizing a Formation Tester While Drilling Tool**

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In the last two years, formation testing while drilling (FTWD) tools have been proven to be an alternative to wireline formation testers in different applications. The latest generation of FTWD tools utilizes a probe packer design, similar to conventional wireline formation testers. These tools are deployed on the drilling string and can be utilized during the drilling process. For example, pressure tests can be taken shortly after a zone has been drilled or while tripping out of the hole after reaching total depth. The use of this latest generation of FTWD tools to acquire a pressure test requires that the drill string be stationary for about 10 to 15 minutes in either a circulation or non-circulating mode.

This paper presents a case history from Asia Pacific area in which a FTWD tool was used on a highly deviated well to identify hydraulic conductivity between producing zones and two nearby aquifers. Data from other sands, which were of interest because they were thought to be depleted, was also acquired. Because of the deviated well profile, it was not possible to use a traditional wireline formation tester (WFT). Using a drill pipe-conveyed wireline formation tester would have been a costly alternative. Furthermore, the well plan placed the casing shoe too far up the hole for a sidewall-entry sub to be deployed. This placement made use of a drill pipe conveyed WFT impossible for the desired depth without introducing a complicating change to the well plan. Running an FTWD tool avoided these complications. Running this tool on the drill string required no casing or hole size change. This plan represented a much more viable and cost effective choice.