

## **GEO 2006 SELECTED GEOTECHNOLOGY ABSTRACTS**

The following abstracts were accepted for presentation at GEO 2006, the Seventh Middle East Geoscience Exhibition and Conference that was held in Bahrain on March 27–29, 2006. GEO 2006 was organized by Arabian Exhibition Management (AEM), the American Association of Petroleum Geologists (AAPG), the European Association of Geoscientists and Engineers (EAGE), and was supported by the Society of Exploration Geophysicists (SEG) and the Dhahran Geoscience Society (DGS). The abstracts that are published here represent subjects dealing with specialized techniques including basin modeling, geochemistry, geophysics, formation evaluation, information technology, log analysis, petrophysics, well design and reserves estimation. In the future GeoArabia will publish the remaining abstracts that primarily deal with exploration, reservoir characterization and stratigraphy.

### **Complex near-surface problems management using the CFP technology: part 2 – applications**

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Part 1 of this presentation (see abstract by Verschuur and Al-Ali) described the *common focus technology* (CFP) principles that resolve seismic imaging problems caused by the complex near-surface zone. In this presentation, we demonstrate some of the applications of this technology using real 2-D seismic data. These applications include wave-theory based redatuming, velocity-model calculation and *pre-stack depth migration* (PSDM). The one-way focusing operators, which are the primary product of the CFP analysis, can be used in various imaging applications. They can be directly used to redatum to a certain reflector. If accurate depth maps are available from the surface to the new datum reflector, then the redatumed images can be directly used in the interpretation with their significant improvements. Otherwise, the focusing operators can be used to calculate a velocity model via tomographic inversion and hence determine such depth maps. However, the fidelity of this velocity model improves significantly if focusing operators for various depth levels, particularly around significant interval velocity variations, are included. Having determined a velocity model, redatuming to a certain flat-depth level below the surface can be performed by calculating a new set of imaging operators from this level to the surface. This can easily be performed by direct ray-tracing or by solving the Eikonal equation. In addition, the resulting velocity model can directly be used to perform PSDM. It is interesting to note that the PSDM process includes one iteration because the the focusing operators fulfill the imaging principles before obtaining the velocity model.

### **Improved core quality through application of a low-invasion, water-based mud tracer technology, half moon inner barrel coring, and improved well site core handling in a sandstone reservoir in north Kuwait for oil-in-place calculations and development planning**

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Two carefully selected wells were recently cored in the lower Burgan reservoir in Sabiriyah field in North Kuwait to improve reservoir description, reservoir performance prediction, and to reduce uncertainty on remaining reserves. In these cored wells, the coring objectives were to obtain: (1) complete coverage of the oil-bearing section of the lower Burgan reservoir for sedimentological and petrographic description; (2) high-quality samples for water-flood and electrical SCAL (special core analysis) measurements from representative reservoir facies. These planned SCAL measurements are (a) relative permeabilities, (b) wettability, and (c) capillary pressure; and (3) conventional core analysis. The lower Burgan reservoir comprises fragile sandstone, which requires careful handling. The coring and core handling must be carried out without disturbing the fabric of the rock to ensure minimal alteration of *in situ* fluid saturations, and without irreversibly modifying the wettability of the rock. This means that low-invasion coring techniques using a water-based bland mud system and very careful surface handling of the core are required to minimize any damage. Additionally, the core-acquisition program was designed to plug and trim the SCAL plugs and preserving both the plugs and trims immediately at the rig site. This should provide

fresh-state and representative center plugs for saturation and SCAL analysis. D2O Tracer was mixed with the mud system to enable quantification of the filtrate invasion. Onsite gamma-ray recording was applied and about 50% of the recovered cores were preserved. In one of the cored wells, a half-moon inner barrel was used for the first time in Kuwait with the low-invasion, water-based mud.

### **Overcoming structural uncertainties in a reef-developed, thin-oil reservoir in the Middle East**

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Development drilling operations in a carbonate reservoir in the United Arab Emirates involve drilling and placing horizontal wells within layers of uneven surfaces. The structure of these surfaces is not well defined due to a lack of seismic resolution and limited offset data. Karsts and general undulations in the subsurface coupled with the presence of shale lenses make the planning and drilling of these wells a difficult task, as major lateral changes are a common occurrence. A radical new approach was undertaken to improve the length and also placement of horizontal wells in this field. A team of specialists was formed, comprising geoscientists and drilling engineers. Also, cutting-edge well-placement technology was utilized in order to provide the team with distance-to-boundary information. The presentation describes how an expert team, based in the head office, overcame the challenges by monitoring the progress of the well and making real-time decisions on the changes required to the well trajectory for optimum placement. The success of the new approach lies in the cross-discipline of advisors in the team, the application of new distance-to-boundary technology, and the continuous communication with the well-site geologist and directional drilling engineer. All well objectives were met. Also, an improved understanding of the regional geology of the area around the well was achieved, thus helping to update the existing geological model for better description of the reservoir.

### **Porosity partitioning for permeability and texture analysis in the Thamama and Shu'aiba formations**

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Data from eight wells in four Abu Dhabi onshore fields were gathered and interpreted. The objective was to evaluate a new methodology for porosity and permeability analysis in carbonates with inter-granular and macroporosity. The methodology uses NMR log data, and electrical image data when available, to partition porosity into micro-,

meso- and macro-components, and then uses that partition to reconstruct the permeability and conduct a facies analysis. The results of the interpretation were validated against core plug permeability and a traditional *reservoir rock-type* classification. The main conclusions are: (1) the methodology and its underlying model of pore-to-pore connectivity is widely applicable to carbonate formations such as the Thamama and Shu'aiba reservoirs. (2) The methodology can be applied without whole core. We established optimum formation-specific parameter values, which gave reasonable results when compared with results obtained by using parameters that best fit core data on a well-by-well basis. The interpretation results are therefore reasonably analyst-independent. (3) Spot measurements of permeability or mobility, from formation test data or sidewall coring, are strongly encouraged to validate the results. (4) When available, electrical image data help identify and quantify the macro-porous zones. (5) NMR logs respond to both the pore size and to oil properties. In one well the oil signal dominated and it was not possible to compute an accurate permeability. (6) The log-derived facies correlate with the broad features of the traditional *reservoir rock-type* definition. This is encouraging, even though more work is needed there.

### **From 1-D to 3-D: new views and applications in formation evaluation**

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A full understanding of log data and its relationships to reservoir properties provides the basis for all reservoir characterization and modeling work, and for almost every aspect of exploration and field development. Traditional log displays are designed to simultaneously show many properties at once with no regard to spatial distribution other than depth. Multi-dimensional cross plots provide abstract space for correlating logs. A visualization tool for reservoir modeling is good at viewing one, or at most, a few properties simultaneously whilst depicting their spatial distribution. Integrating all three visualization methods extends not only our ability to work with these logs, but also our ability to understand more readily petrophysical data sets and their relationships to major reservoir properties. The 3-D visualization *new views* and applications in formation evaluation are: (1) multi-dimensional cross plots; (2) spider maps; (3) histogram surface; (4) log normalization plots; (5) composite plots; and (6) 3-D volume extrapolation. The logs from exploration wells penetrating Jurassic formations of North Kuwait are used to display: (1) log correlations, normalization, and correction; (2) quick visualization of reservoir property in 3-D reservoir space; and (3) display logs with geological models.

### Random noise removal of seismic attribute data via complex-valued wavelets

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Volumetric curvature and coherent energy gradient attributes can improve the detection of linear geologic features but may introduce high-frequency noise. Existing edge-preserving smoothing algorithms can be used to minimize the high-frequency noise but they typically do not adequately preserve small vertical lineaments. This presentation introduces a new 3-D seismic noise-reduction technique that preserves very small features and lateral discontinuities (edges) without introducing high-frequency noise or phase distortion. Phase distortion is minimized through the use of a non-orthogonal, complex valued, log-Gabor wavelets in the frequency domain. The theory and examples of its application to both synthetic and real 3-D data from Saudi Arabia are described. These examples clearly show a reduction in random noise along with the preservation of vertical lineaments and high-frequency signal.

### New technology applications in the Rub' Al-Khali Desert

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The South Rub Al-Khali Company Ltd. (SRAK) carried out magnetotelluric (MT) and TDEM (time-domain electromagnetic) surveys in the Rub' Al-Khali Desert. 116 full tensor MT data were acquired using up to ten 24-bit GPS-synchronized 5-channel Metronix ADU-06 recording units including a fixed remote reference MT station. Time series were processed using robust remote referencing. TDEM data were acquired at each station using the Sirotem Mk3 system. The acquisition problems associated with the high resistivity in the sand dunes resulted in poor quality MT data, while the data collected in the inter-dune areas resulted in very good quality. Modifications of the recording equipment to overcome the data quality issues related to resistivity in sand dunes are discussed. The MT data collected between the dunes was interpreted using 1-D and 3-D inversion techniques.

A seismic spectroscopy experiment, using amplified high-sensitivity (HSG) 3C geophones ("low frequency acquisition" or "LF acquisition") was carried out in SRAK's contract area 2 in the Saudi Arabian Rub' Al-Khali Desert. The experiment was designed to assess whether such a technique can be used as a DHI. While initial indications for a DHI are rather weak, a number of interesting observations have been made, including a weak relation between one of SRAK's prospects and some spectral features in the low-frequency noise spectrum. In this presentation we will describe the

modified instrumentation, the field implementation and the processing of the LF data as well as briefly review the interpretation of the data and integration with seismic and potential field data.

### The Hasbaya asphalt (Lebanon) revisited some remarks from detailed field mapping, petrographic and geochemical studies

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The asphalt of the Hasbaya locality occurs in Coniacian to Maastrichtian strata (Chekka Formation) consisting of soft, light-colored clayey marls and chalky limestones. Equivalent formations are known to include major source rocks in the Eastern Mediterranean Basin. This contribution discusses some results from detailed field mapping of the hydrocarbon occurrence, petrographic and geochemical (e.g. stable isotope and gas chromatography) analyses. The total thickness of the strata overlying the Chekka Formation in the Hasbaya area (approximately 1,500 m) results in insufficient overburden settings for oil maturation, even at high geothermal gradients (approximately 45° C/km). Previous studies indicated that the Hasbaya asphalt is immature and located in its source rock. Detailed field mapping was achieved to assess the hydrocarbon impregnation intensity of the chalky lithologies. A color index chart was prepared from the differentially impregnated rocks, including a scale from one (dark brown, highly impregnated) to ten (cream, not impregnated). Plotting and superposing the impregnation intensity contours on the geological map showed that the Hasbaya hydrocarbons are fault controlled. Although most of the analyzed samples exhibited severe degradation, those less altered revealed elevated amounts of branched aliphatics and elevated contributions of n-alkanes. This distribution may characterize organic matter of a clear thermogenic origin, which was exposed to biodegradation processes. Consequently, results of this study suggest that the structurally controlled Hasbaya asphalt may contain hydrocarbons migrated from deeper sources. This is also supported by the total thickness of the overlying strata (insufficient for oil maturation) and the geochemical data that could invoke a thermogenic origin.

### Regional overpressure modeling in onshore Kuwait: impact on pressure prediction before drilling and petroleum system behavior

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The entire Jurassic section, and in some areas the Lower

Cretaceous section, in onshore Kuwait are characterized by high overpressures, well above the hydrostatic regime. This pattern extends apparently down to the Triassic and Paleozoic section. The understanding of the pressure regime and its causes is important for pressure prediction before drilling, as well as for hydrocarbon exploration, because pressure drives the flow of hydrocarbons. The pressure regime has been investigated through a review of available pressure data (well tests, mud weights) and an integrated 3-D basin modeling study. A consistent pressure model has been developed, including four aspects: (1) the presence of tight shales in the Ratawi Formation in north and northwest Kuwait, responsible for overpressure in the Lower Cretaceous section; (2) the presence of an impervious fault corridor to the north separating hydrodynamically the Sabiriyah and North Rhaudatain fields in the Cretaceous section; (3) the regional extent of very low permeability Gotnia salt, which acts as a pressure barrier throughout Kuwait, locally incised by poorly permeable faulted areas (east and west of Burgan field), acting as "security valves" for the overpressure regime, but allowing the hydrocarbon to leak into the Cretaceous section; (4) the existence of lateral barriers within the Jurassic section in northwest Kuwait, isolating the Mutriba and Kra Al Maru area from the Jurassic of north, east and west Kuwait, which appear to be relatively well connected. The pressure model characteristics in terms of permeabilities related to the lithologies will be presented, together with its prediction for drilling depending on the geological context.

### **Pre-stack 3-D TAU migration and velocity analysis: focusing 3-D data from offshore Abu Dhabi**

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The 3-D data set from offshore Abu Dhabi has suffered from shallow velocity anomalies concentrated in the center of the surveyed region and above the critical reservoirs area. Previous processing results, which mainly ignored such anomalies, produced images that lacked reflection signatures in that critical region. Even those processing methods that tried to predict the anomaly, but were based on pre-stack depth migration, failed to focus the image at the center. Thus, we used the inherent stability features of representing the image and all previous processes in the TAU instead of the depth domain to estimate the interval velocity model for this 3-D data set. The process is based on pre-stack 3-D migration velocity analysis and thus honors the complex heterogeneity up-shallow in that region. The final estimated interval velocity model in the TAU domain provided low residuals in the imaged sections from different offsets and agreed well with the four wells located in the area. This velocity model also encompassed all the main features of the region like the shallow, low-velocity zone and the major fault present in the middle of the region. Using the velocity model we applied 3-D

pre-stack TAU migration to the full data as opposed to subsets of the data as done in the velocity development stage. As a result of using the TAU domain, we focused the image much better than in previous attempts. Using the new images, we identified the location of the major sealing fault, and recognized the major structures in the central zone.

### **Fast and easy near-surface correction of an Arabian Peninsula seismic line using the topographic datuming operator**

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We apply a methodology for seismic data redatuming in the presence of rugged topography and geophysically complex near-surface using a new pre-stack operator, the Topographic Datuming Operator (TDO), on synthetic and real data. TDO, unlike static corrections, allows for the movement of reflections laterally to their true locations corresponding to the new datum level. Thus, it mitigates mispositioning of events and the velocity bias introduced by the unphysical time-invariant vertical shifts carried out by static corrections. The application to synthetic data of the proposed methodology demonstrates the ability of TDO to remove the detrimental effects on the data of a rugged topography and a complex overburden similar to those encountered in the Arabian Peninsula. As a result, conventional post-stack processing and migration yields a good image of the deeper low-relief structures. Using shallow velocities estimated from refracted events, TDO provides a superior continuity to reflections and focusing for real onshore Arabian Peninsula data than that obtained from conventional static corrections. The marginal additional computational cost and the possibility of estimating (after TDO redatuming) stacking velocities that are not affected by a spurious positive bias (as in the case of static corrections to a deep datum) are further advantages of the proposed methodology.

### **Petroleum systems in onshore Kuwait: from Paleozoic deep targets to Cretaceous**

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A comprehensive 3-D geological synthesis and basin modeling study has been carried out on Kuwait onshore, with the objectives of understanding the hydrocarbon generation, migration and entrapment process, as well as the potential of new exploration targets. New geochemical data have been acquired, including isotopic gas measurements, sulfur studies on Jurassic source rocks and compositional kinetic parameter determinations. The origin and volume of the Cretaceous giant accumulations

is mostly related to the sulfur-rich, prolific Najmah/Sargelu source-rock complex of marine type. The hydrocarbons have crossed the efficient Gotnia salt seal, through weakness areas represented by the few faults crossing the seal. These faults control the high overpressure observed in the Jurassic and below. The Cretaceous pressure regime controls the vertical distribution of some Cretaceous accumulations, which present significant gas-to-oil ratios (GOR) and specific oil gravity difference. The Jurassic hydrocarbon accumulations mostly originated from the same Jurassic source-rock complex, although some locally high specific oil gravity and GOR accumulations can be partly related to a much deeper source, probably of Paleozoic origin, and partly related to oil to gas cracking within the reservoir themselves. Recent gas/condensate shows discovered in the Triassic Sudair and Khuff formations are also of probable Paleozoic origin, as suggested by new isotopic gas data and modeling. The 3-D model characteristics will be presented, including the predicted pressure regime, the organization of drainage areas, and the consequences for the gas/condensate potential in deep targets, and overall HC resources remaining to be delineated in Jurassic prospects.

### **Hydrocarbon potential of the Al-Qassim region, Central Saudi Arabia**

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Gas shows have been observed for many years in many water wells in the northeastern part of Al-Qassim region. The author, since the early 1980s, has been visiting and collecting data about gas shows in the area. He outlined the "Gas Zone" and located seeping gas in the Buraidah-Tarafiyah road cut in the Permian-Triassic Khuff limestone. Gas samples were collected from two wells. The gas samples were analyzed and gas analysis showed that the gas is composed of methane and traces of ethane. The analysis indicates that the presence of methane is probably due to over maturation of other gas components, ethane and propane to methane. Associated ethane, though traces, indicate the possibility of natural gas accumulation in the Al-Qassim region. The water wells with gas shows are shallow. It is more likely that the gas is seeping from the deeper reservoirs to shallower aquifers.

### **Seismic frequencies: a robust interpretation tool**

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Amplitude and frequency are the main seismic attributes that are used in seismic interpretation and stratigraphic analysis. The amplitude, which is an attribute of the layer boundary, is studied in both the pre-stack and post-stack domains. However, the utilization of the frequency, which is an intrinsic attribute, is not as common as the amplitude attribute. Both of the attributes compliment each other.

In this presentation we shed light on the interpretation of seismic frequency data and its robustness in mapping reservoir quality, thickness and fluid type. Pre-stack frequency analysis is one of the tools that was investigated. It was found that using the mid-offset, stack-attenuation attribute is best in mapping areas with excellent reservoir filled with gas. This can be attributed to the quality of the data, lesser multiple effects and lesser noise, and might also be related to the angle of incidence. Post-stack data were also investigated and it was found that frequency-tuning phenomenon can be used to map pinch-outs, which can be used to delineate channels or any other geological features. We have extended this knowledge to even estimate the thickness of thin reservoirs.

### **Qatif 3-D survey: a case history of a large transition zone survey**

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In pursuit of structural imaging and stratigraphic understanding of a producing Jurassic carbonate reservoir, Saudi Aramco is acquiring 1,300 sq km of 3-D transition seismic data. Challenges begin with the variety of topographies including sand dunes, sabkhas, transition zone marshes, shorelines, and shallow-water depths finishing with deeper marine zones. In addition, the land portions contain very densely populated towns, large agricultural areas and huge power plants. All of these issues demand the application of critical and accurate steps in order to ensure a seamless product free of false structures and processing artifacts. The acquisition includes four independently configured source types: dynamite, vibrator, shallow and deep airgun. Associated with these are the different seismic receiver types: geophones, marsh phones, hydrophones and dual sensors. These produce an extremely complex processing environment, with unique challenges that must be met before producing a final volume for successful interpretation. This unique multi-environment processing task requires instrument matching, source matching, dual sensor summation, generation of datum statics corrections for various source and receivers, noise handling for different conditions, velocity analysis, and pre-stack time migration. The time slice extraction from the final volume shows no source or receiver footprint due to the irregular shooting geometry and transition zone conditions.

### **The polynomial method: an accurate tool to estimate reservoir depths**

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Estimating accurate depths of geologic tops is a major concern when planning wells. Seismic data has been

widely utilized in conjunction with well control to predict such depths. Depth predictions have been attained through various means, such as average and interval velocities as well as pre-stack depth migration. This work applies the polynomial method to accurately predict the reservoir depths over a Saudi Arabian oil field using seismic times and depths from existing wells. This method finds the polynomial that best fits seismic times to reservoir depths at existing wells, and subsequently applies such a polynomial to estimate tops at future wells. This method proves to be effective as it provides a measure of the prediction uncertainty as well by running blind tests over nearby wells. Velocity, which may be thought to be overlooked, is implicit in the polynomial coefficients. This method requires dividing the oil field based on structure and well distribution into different compartments in which each has its own polynomial. Besides its accuracy and the error estimate that it provides, the method is remarkably fast as it does not require interpreting the whole seismic volume or gridding any data. However, it needs to be utilized with caution in the presence of anomalous velocities.

### **Linking diagenesis and porosity preservation to sequence stratigraphy of reservoir sandstones in the Lower Devonian Jauf Formation, eastern Saudi Arabia**

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Porosity preservation in deeply buried (present depth 13,630-16,830 feet) Lower Devonian Jauf Reservoir sandstones is controlled by diagenetic alterations. The spatial and temporal distribution of these diagenetic alterations is linked to the depositional facies and sequence stratigraphic framework. The best quality reservoir sandstones are typically encountered in the tidally influenced channel and estuarine sandstones interpreted as a transgressive systems tract (TST). Poor quality reservoir sandstones are concentrated in the shoreface of a highstand systems tract (HST). Diagenetic alterations played a critical role in porosity preservation and destruction. Eogenetic alterations include cementation by pyrite, siderite and dolomite, infiltration of grain coating clay, and dissolution and kaolinitization of mica, mud intraclasts and feldspars. The occurrence of kaolinite, mainly in the HST, is attributed to efficient meteoric water flux into sandstones during fall in the relative sea level. Mesogenetic alterations include the formation of illite, chlorite, quartz overgrowths and outgrowths, and ankerite cements; as well as pressure dissolution of quartz grains and transformation of kaolinite into dickite. Illite was formed mainly by the transformation of infiltrated smectite, mud intraclasts and kaolinite, whereas dickite was more resistant towards illitization.

Porosity destruction in the HST sandstones is common due to the prevalence of quartz overgrowth and outgrowth containing small amounts of infiltrated, grain-coating illite. Porosity preservation in the TST sandstones is due to significant amounts of grain coating illite, preventing extensive cementation by quartz overgrowth. This illite coating resulted from the transformation of the ubiquitous infiltrated clays, which are closely linked to the TST and formed by tidal pumping.

### **Diagenetic controls on Precambrian-Cambrian Ara carbonate reservoir quality: a case study from the South Oman Salt Basin**

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Dolomite reservoirs in the SOSB have been proven to be prolific oil and gas producers since the late 1970s. Current exploration efforts require understanding of diagenetic controls on reservoir properties to mitigate the risk involved. A case study from the South Oman Salt Basin (SOSB) has been selected to illustrate the sedimentary and diagenetic controls on reservoir quality and the timing relationship to hydrocarbon charge. The Ara stringers comprise six evaporite-dolomite cycles (A1–A6) encased in salt. In the study area, the A2C carbonate stringer is subdivided into 5 sequences, which record the deposition of platform carbonate sediments in an evaporitic basin. Geochemical and detailed petrographical studies suggest early, intermediate and late diagenesis control reservoir quality. Early diagenesis mainly represented by replacement dolomitization, preserves original sedimentary textures, and generates porosities of between 1.0 and 14.0%. Intermediate diagenesis includes cementation by dolomite, halite and anhydrite, which partially occludes pores and is contemporaneous with a first hydrocarbon charge. This first charge is locally altered to bitumen, probably as a result of burial and stringer break-up. Bitumen reflectance data show high temperatures and the potential for thermal cracking and/or TSR. Late diagenetic processes involve dissolution of, and re-precipitation of dolomite, anhydrite dissolution and a late phase of halite cementation. The dissolution phase, if combined with proximity to intra-salt source rock and maturation timing succeeds in creating a successful reservoir. Late hydrocarbon charges can be interpreted by the different bitumen textures. Understanding diagenetic control on reservoir properties is crucial in exploration risking of stringer plays.

### **Restoring high resolution in surface seismic data**

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Higher seismic resolution has always been one of the main objectives of oil and gas exploration and development.

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The resolution of seismic data is affected by many factors such as acquisition layout, strength and directivity of the source, and attenuation in the earth. It is well known that seismic energy is scattered and attenuated as it propagates through the subsurface and particularly, in the near-surface weathered layers. Unlike surface seismic data, VSP energy propagates through the subsurface layers just once and therefore is less susceptible to the greater loss in high frequency. We propose a technique that utilizes high-resolution, zero-offset VSP data to derive time- and depth-variant filter operators, which are then used to recover the attenuated frequency components of the surface seismic data. The methodology is quite simple. We analyze the frequency decay of the VSP direct arrivals as a function of receiver depth, calculate time- and depth-variant filter operators based on this decay, and then convolve these filter operators with the surface seismic data to recover the attenuated high-frequency components. The VSP data analysis can be performed in either the time or the frequency domain, which produces inverse filter operators at each consecutive receiver depth. The analysis assumes that the earth's filtering response is spatially invariant over the entire survey area. A successful implementation of this methodology using 3-D seismic data is shown in the presentation to illustrate the robustness of this technique.

### **Integrated approach of a successful geosteering project targeting a low permeability reservoir in the partitioned neutral zone between Kuwait and Saudi Arabia**

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South Fuwaris oil field was discovered in 1957 and is located in the southwest corner of the Partitioned Neutral Zone (PNZ) between Kuwait and Saudi Arabia. A 3-D seismic survey, recorded in 1996, revealed that the field is a NW-SE doubly plunging anticlinal feature on the Lower Cretaceous Ratawi level of the Thamama Group. The field produces mainly from thin carbonate stringers within the Ratawi Limestone reservoir. The thick, porous Ratawi Oolite reservoir underlies the Ratawi Limestone reservoir and possesses good hydrocarbon saturation with a clear oil/water contact. The very low productivity of the oolite reservoir in vertical and slant holes is attributed to its abnormal low permeability. As a result, the Ratawi Oolite was historically ranked as low priority compared to the limestone reservoir on top despite its immense reserves. Oriented core data, full suite of open-hole logs, formation imaging, magnetic resonance and sonic imaging tools were integrated with a walk-away VSP of a pilot hole and 3-D seismic data to annotate the reservoir sweet

spot and to predict a preferred azimuth for horizontal well trajectory. Based on this integrated study, project uncertainties were fully captured, addressed, analyzed and resolved. A pre-job geosteering model was built to address different scenarios pending reservoir architecture and log response from pilot and adjacent older wells. Real time LWD and Imaging Logs were utilized for the first time and applied to predict, resolve and geosteer the horizontal well for optimum well placement to maximize reservoir exposure within the sweet spot. Outstanding results and a ten-fold increase in production rate are the outcomes of this integrated approach and teamwork. Several horizontal wells are planned to mimic this success for optimum productivity of the oolite reservoir that was underdeveloped for decades.

### **Saudi Aramco implements new LWD technology for well placement in complex clastic and carbonate reservoirs**

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Saudi Aramco regards well placement or geosteering as a key discipline within its organization. It plays an important role in maximizing recovery factor and optimizes the applications of real time technology. Consequently the application of new LWD technologies is fundamental in the continuous improvement of the geosteering process. Traditionally, the steering of horizontal wells was based on LWD measurements, which rely on the sensors to actually arrive at the formation and obtain a measurement that can be then used to make the correct steering decision. This approach is a reactive approach. The implementation of deep and directional electromagnetic measurements that can detect approaching bed boundaries up to fifteen feet enabled us to implement a proactive steering approach. In this presentation we will describe how the well placement team implemented new technologies and workflows to address challenges associated with placing horizontal wells in both complex clastic and carbonate reservoirs. The second example is from an offshore clastic environment. The challenges faced by the well placement team here were related to the lateral variations associated with a deltaic depositional environment. This presentation will describe the workflow of the new technique and the learning points from the case studies presented here.

### **Fracture porosity inversion from P-wave AVOA data along 2-D seismic lines**

*Abdullatif Abdulrahman Al-Shuhail (King Fahd University of Petroleum and Minerals, ashuhail@kfupm.edu.sa)*

A method is presented for inverting the fracture porosity from 2-D P-wave seismic data using amplitude variation with offset and azimuth analysis with examples. The method is based on the assumption that a negative sign of the anisotropic AVO gradient indicates a gas-saturated reservoir, while a positive sign indicates a liquid-saturated reservoir. This assumption is accurate as long as the crack aspect ratio is less than 0.1 and the P-wave/S-wave velocity ratio is greater than 1.8, two conditions that are satisfied in most naturally fractured reservoirs. The inversion then uses the fracture strike, crack aspect ratio, and P-wave/S-wave velocity ratio to invert fracture porosity from the anisotropic AVO gradient after inferring the fluid-type from the sign of the anisotropic AVO gradient. Applying this method on dip and strike lines from the oil-saturated zone of the fractured Austin Chalk of southeast Texas, I found that the inversion is accurate along the dip line and significantly deteriorates along the strike line, which is expected by the theory.

### **Exploration data management at Saudi Aramco: making data pay**

*G.S. Steve Adcock (george.adcock@aramco.com) and Tawfeeq Al Faraj (Saudi Aramco)*

During the past five years Saudi Aramco has implemented several initiatives to improve exploration data management. These included design and construction of new data management infrastructure, the development and deployment of indexing and delivery applications, and the indexing, scanning and secure online storage for all legacy data. This effort led to the recovery of much lost and misplaced data and improved accessibility for thousands of seismic up-holes, seismic lines and reports, well logs and well reports, exploration maps, and for thousands of exploration reports and studies. Saudi Aramco's data management strategy was redesigned to support distributed data repositories. A minimum metadata model was applied across different data repositories, and the use of data dictionaries was enhanced and standardized. Indexing and scanning for over 400,000 documents converted hardcopy to over five terabytes of searchable and retrievable electronic images. This process aided the design and implementation of effective document-level security protocols and web-based delivery applications. Applications such as portals to consolidate access to applications, which control data, interfaces to support semi-automated data indexing and loading, and map-based search and discovery tools for users were all designed and implemented as part of this data management effort.

Data attributing and an "Exploration Thesaurus" were built to support data storage and discovery. These efforts enhanced Saudi Aramco's ability to supply exploration data rapidly and efficiently to our clients, resulting in faster and easier access of data for our customers.

### **Onset of overpressures and their relationship with depth, stratigraphy and tectonic settings in Kuwait**

*A.M. Manowar Ahmed (aahmad@kockw.com), Saifullah Khan Tanoli, Meshal Al-Wadi and Ahmed Al-Edan (KOC)*

Onset of overpressures is encountered within Valanginian Ratawi Shale Formation in most of onshore Kuwait. However, in the northeastern part of the country, overpressures are experienced in the lowermost part of the Barremian Zubair Formation. The Ratawi shale records the initiation of clastics influx after a predominantly carbonate sedimentation during the Early Cretaceous and has a thickness ranging between 350 and 425 feet. The onset of over-pressuring is primarily related to static loading (overburden) and originates out of compaction of predominantly shaly sections of Ratawi sand/shale sequence in north, where expelled water entrapped in discontinuous sand stringers of the formation gets over-pressured. A similar phenomenon is also noticed in the Lower Zubair interval. Furthermore, it is observed that the magnitude of Ratawi pore pressure relates to the reservoir thickness and size within the formation. Generally, the increase in pressure appears to be gradual; onset is below 9,000 feet and rarely relates to tectonic settings. This understanding is helpful in predicting reservoir pressures and, therefore, for smooth drilling operations and in selecting exploration targets.

### **Predicting log properties from seismic data using abductive networks**

*Osama A. Ahmed (osamaa@kfupm.edu.sa) and Radwan Abdel-Aal (King Fahd University of Petroleum and Minerals); and Husam AlMustafa (Saudi Aramco)*

In this study, an abductive network is used to predict reservoir log properties from seismic attributes. Statistical approaches have been used to model the relationship between the seismic data and the reservoir parameters. The idea of using multiple seismic attributes to predict log properties has been widely used and several case histories have been reported in the literature using multi-linear stepwise regression and neural networks. The input to any statistical method is a series of attributes extracted from the seismic data. There is, however, a large number of attributes that can be extracted from the seismic data. Therefore, an efficient subset of these attributes has to be selected before prediction. An exhaustive search of all

attribute combinations is computationally infeasible. As a solution, linear stepwise regression has been proposed, which is based on linear relationships between attribute combinations and log data. Therefore it is suitable for linear regression. For nonlinear regression, such as neural networks, an attribute selection method that embodies the nonlinearity between attribute combinations and log data is desirable. Abductive networks should in many ways help in this regard. (1) Abductive networks can automatically select a statistically representative subset of optimum predictors from the available set of seismic attributes. (2) Abductive networks are nonlinear predictors, which are proven to outperform linear predictors. (3) Unlike various neural network paradigms, abductive networks can provide a closed-form analytical relationship between the selected seismic attributes and the modeled parameter; this can help in fully understanding the geographical structure of the area.

### **Removal of surface and internal multiples from land data: experience from North Africa data**

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The appearance of surface-related and internal multiples is a major problem in land seismic data. Over the last decade, the data-driven surface-related and internal multiple prediction and subtraction methods, that have been mainly developed for the marine case, have been cross-fertilized towards the land data problem. However, whereas the marine case generally involves high-quality data with deterministic surface multiples, the land case is characterized by poor quality reflection events, disturbance by surface waves and near-surface propagation and irregular trace spacing. Therefore, proper pre-processing to enhance and regularize the seismic reflections, which will act as the multiple prediction operator, and the removal of noise are key elements for a successful wave equation-based multiple suppression. This study discusses a methodology and sequence of data processes that improve the signal-to-noise ratio (SNR) of land data prior to multiple estimation. The method is applied on pre-stack data in the CMP gather domain under the assumption of local lateral invariance of the earth. The improved SNR and regular offset sampling is obtained by forming CMP supergathers from each group of CMP gathers, which allows for trace mixing, regularization and the signal enhancement in the NMO-corrected domain. Some examples illustrate the successful application of the method of noise suppression and multiple suppression. After conditioning and attenuating the pre-stack gathers from surface and internal multiples, the velocity picking procedure can be performed with more accuracy, which is very crucial for structural interpretation.

### **Adaptive subtraction of multiples: a case history from the Middle East**

*Jaafar Ali (jaafar.ali@pgs.com) and  
Ronald Van Borselen (PGS)*

In this case study, examples are shown of the application of data-driven multiple removal techniques to land data sets from the Middle East. Typically, these data are characterized by the presence of severe noise, high-amplitude free-surface multiples and internal reverberations, and weak primaries. This presentation will discuss some of the practical aspects of applying these data-driven multiple removal techniques. In particular, the pre-conditioning of data is discussed, as well as how existing methodologies can be modified to subtract the predicted multiples from the data optimally while preserving weak primaries. Also, the role of forward modeling and QC procedures are discussed. Pre-stack or post-stack modeling is used to identify the key internal boundaries that generate the multiples. By using reflectors present in the data, predicted multiples are compared to the multiples present in the data to verify their contribution to the multiple problem. Using this information, interbed multiple removal can be optimized to predict internal multiples effectively and efficiently. Finally, the study discusses how QC tools can be used in production processing to ensure that only multiples are removed from the data while preserving the weak primaries.

### **Oil-oil correlation of Asmari and Bangestan reservoirs in giant Marun oilfield, Southwest Iran**

*Bahram Alizadeh (alizadeh\_b@cua.ac.ir) and  
Fareid Tezheh (Jondishapour University); and  
Mohamed Hosein Adabi (S. Beheshti University)*

Oils from the Oligocene-Miocene Asmari and Cretaceous Bangestan reservoir of Marun oilfield were studied geochemically. Gas chromatograms and stable isotopes of carbon and sulfur in different oil fractions were studied. Normal alkanes  $nC_{15+}$  are as high as 93% with saturate percentage up to 53.9%, which reveals high maturity of the Asmari and Bangestan reservoir paraffinic oils. The Carbon Preference Index of both reservoir oils is around 1.0, indicating mature oil samples.  $Pr/nC_{17}$  and  $Ph/nC_{18}$  ratios have confirmed this conclusion. The  $Pr/Ph$  ratio is less than 1.0 and a plot of  $\delta^{13}C_{Aro}$  (‰) versus  $\delta^{13}C_{Sat}$  (‰), both indicate a marine-reducing environment during deposition of their source rocks. The organic matter deposited in these sediments is of kerogen Type II (algal). The Albian Kazhdumi Formation pyrolyzed by Rock-Eval VI, shows high TOC, HI and PI and is introduced as the best source rock of the Marun oilfield;

these results are in accordance with other geochemical data. Stable carbon isotope results versus the Pr/Ph ratio indicate that both oils originated from the same shaley limestone of Mesozoic age. This study also proves that the H<sub>2</sub>S gas-polluted Asmari oils have similar isotopic ranges as the Bangestan-reservoired oil; hence the source of contamination originated from the Bangestan reservoir. Isotopic and geochemical results for the first time introduce three oil families in the entire Marun oilfield: two H<sub>2</sub>S-polluted families and one non-H<sub>2</sub>S-polluted oil family.

### **Hydrodynamic petroleum entrapment potential in the Arabian Platform**

*Arif I. Alkalali (Saudi Aramco, arif.kalali@aramco.com)*

Active hydrodynamics in the Arabian Platform can potentially create a non-conventional family of traps in major parts of the basin, when combined with structural styles that are not usually considered prospective in traditional exploration practice. Hydrodynamics, resulting from gradients in groundwater potential, have been previously reported in the Arabian Platform, and were known to cause tilting in oil-water interfaces. Based on theoretical and numerical simulation analyses, such hydrodynamic forces are natural products of gradients in groundwater potential and can exist across the entire platform due to the regional topographic configuration, geological history, and hydrogeological stratification. The presence of such gradients offers an additional subsurface hydrocarbon trapping force, allowing structures such as noses, monoclines, and plunging anticlines with no traditional four-way structural closure, called here hydrodynamic conjugate structures, to trap hydrocarbons; given that the appropriate structural and hydrodynamic conditions are satisfied.

A simple numerical model, simulating Hubbert's oil-driving forces in the subsurface, reveals that entrapment by a combination of two opposing forces. The first is the buoyancy force provided by hydrodynamic conjugate structures, while the second is the hydrodynamic force resulting from down-dip drop in groundwater potential (known in the Arabian platform). These two forces can entrap hydrocarbons in a multitude of scenarios. The scenarios are created by variations in the magnitude of regional and local structural gradients and geometries, magnitudes of groundwater potential gradients, and the densities of both formation water and the hydrocarbon phases. The hydrodynamic analyses conducted here for parameters known in the Arabian platform, combined with conceptual and numerical basin hydrogeological models, provides a predictive tool and prospect generating methodology for additional non-conventional petroleum reserves.

### **Integrated crosswell seismic, an advanced technology to improve reservoir description: case histories**

*Massimo Antonelli (massimo.antonelli@agip.it),  
Claudio D'Agosto and Francesco Miranda (ENI)*

This presentation describes the results achieved in applying the Integrated Crosswell Seismic (ICS) technology in several oil fields worldwide. ICS is an innovative methodology to improve the description of the internal geometries of the reservoir between two or more wells, which has evolved from being primarily an exploration tool, to a development and reservoir management tool. ICS requires the joint measurement and interpretation of two different seismic events: (a) direct arrivals for tomographic inversion; and (b) reflection arrivals for reflection mapping. This new approach yields several practical advantages: (1) extremely high resolution (2 to 3 feet vertically) of the geology and structural imaging (10 to 100 times better than that achievable with surface seismic); (2) measurements directly referenced in depth; (3) near-surface effects (topography, weathering or gas sands, etc.) entirely bypassed; and (4) seismic, log and core data integration. This technique can image the interwell fluid movement if applied in time-lapse mode. In fact, it can be sensitive to variations that are induced by the production. In the last two years crosswell seismic data were acquired in several oil fields as part of a reservoir characterization project being conducted by Eni on Italian and overseas fields. The case histories were collected from fields with different reservoir lithologies and related to different geological frameworks. The selected case histories show the high flexibility and applicability of the methodology in the reservoir management activities for different types of challenges: (1) higher resolution structural and stratigraphic imaging; (2) geological model building and validation; (3) petrophysical properties estimation; (4) identification of "infill" drilling targets; and (5) time-lapse interwell monitoring and fluid-flow imaging.

### **Investigation of the effect of cementation factor on original-oil-in-place in an Iranian carbonate reservoir**

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The estimation of original-oil-in-place (OOIP) is one of the important calculations in field development and management. The OOIP is usually calculated by either a volumetric method or material balance studies. In both calculations the water saturation determination

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is necessary. In 1942, Archie's laboratory experiments established a relationship between porosity, water resistivity, rock resistivity measured by the log, and water saturation. Archie's equation evaluates the hydrocarbon reserves continuously versus depth with much less cost and effort with respect to previous methods. Based on log interpretation and core analysis data of an Iranian carbonate reservoir, the appropriate distributions for saturation-equation parameters are fitted. Then, the uncertainty and the relative importance of parameters are evaluated by means of a Monte Carlo type simulation, where the relevant properties are drawn from the fitted distributions for Archie's parameters and combined into an estimate of water saturation, through the relevant equation for this case. At the end, the effect of the cementation factor on OOIP is studied. The results of this analysis show that porosity and total resistivity are the most important parameters affecting uncertainty in Archie's water saturation equation in the proposed reservoir. Also, a new practical correlation has been presented for cementation factor as a function of porosity.

#### **A multi-azimuth VSP experiment for fracture orientation detection in HMD field, Algeria**

*Foudil Babaia (f-babaia@enageo.com) and Farid Chegrouche (ENAGEO)*

Natural micro-fractures are very important in the control of production in the hydrocarbon reservoir. The presence of the vertical fractures in the rock mass causes the incident shear wave to split into two approximately orthogonal components with different velocities. Split shear wave analysis permits the estimation of fracture orientation. In the offset VSP experiment, converted Sv waves are generated with varying strengths at nearly all depths. Consequently, the converted Sv waveforms partially overlap with direct P waveforms, which renders the analysis of separate event difficult and inaccurate. In this study, an automatic picking technique was used to accurately compute travel time of P and Sv down-wave. The polarization angles are determined from particle-motion analysis. The interval velocities Vp and Vs were then computed using the travel-time inversion technique. In this study, an attempt was made to determine the orientation of natural fractures by two analysis methods: shear-wave splitting and P-wave velocity anisotropy based on an anisotropic ratio computed from four offset VSP data. The VSP data was acquired with different azimuths in the same well using the following formula:  $\text{Tau} = (\text{Vmax} - \text{Vmin})/\text{Vmax}$ ; where Tau is the anisotropy ratio, Vmax is the maximum velocity assumed to be equal to the oblique velocity, and Vmin is the vertical velocity calculated from the zero-offset VSP. In the results, we have found that offsets B, C and D are practically equal (similar angles of incidence), but the corresponding anisotropy ratios are different. Consequently, the velocity variations are rather related to the azimuth and the fracture

orientation direction, which corresponds to the smallest anisotropy ratio of about 78°.

#### **Sedimentology and reservoir characteristics of the Tertiary Yabus and Samaa formations, Agordeed Belt, Adar Yale field, Melut rift basin, Sudan**

*Amani A. Badi (amani\_badi@hotmail.com), Omer B. Ali and Abdalla G. Farwa (University of Khartoum); and Osman M. Abdullatif (King Fahd University of Petroleum and Minerals)*

The Melut rift-related basin of interior Sudan is regionally linked to the Mesozoic-Cenozoic central and west African rift system. The sandstone reservoir of the Yabus and Samaa formations, which occur at shallow depths, was deposited within fluvial/lacustrine environments. This study includes facies analysis based on cutting, cores and wire-line logs. Thin-section petrography, x-ray diffraction (XRD) and scanning electron microscope (SEM) analysis were also used to investigate the sandstone composition, diagenesis and porosity evolution. The reservoir sandstone heterogeneity shows vertical and lateral variation along and across the basin, reflecting tectonic, and depositional and post-depositional controls within proximal to distal fluvial and lacustrine environments. The reservoir facies are dominated by channel and bar made of planar cross-bedded, trough cross-bedded and horizontally bedded sandstone interbedded with laminated to massive siltstone and mudstone. The sandstone of the Yabus Formation ranges from subarkosic to arkosic arenite, while that of the Samaa Formation is mainly arkosic arenite to litharenite. The sandstone is fine- to medium-grained, poorly to moderately sorted and sub angular to sub rounded. Quartz and feldspars dominate the grain framework; rock fragments are rare in the Yabus Formation and dominant in the Samaa Formation. Heavy minerals contents generally are low in both formations. Clays and mica predominate as matrix and carbonate and clays are the main cements. Porosity of sandstone ranges from 3.0% to 50.0% with an average of 19.0%. A number of factors have combined to significantly reduce the porosity including kaolinite precipitation, presence of clay matrix, carbonate cement and pore filling, moderate grain packing and mild compaction. The reservoir quality is improved by the development of secondary porosity through dissolution of feldspars, partial dissolution of carbonate cement and grain-coating hematite.

#### **Basin modeling study of the Anaran block, Iran**

*Balazs Badics (Norsk Hydro, balazs.badics@hydro.com) and Mehrab Rashidi (NIOC)*

The petroleum system of the Anaran exploration block in Iran was investigated using basin-modeling techniques. The study focused on the potential source rocks, their

maturity and the timing of hydrocarbon generation. The emphasis of the study was to match the predicted and observed fluid properties in known accumulations, in order to predict hydrocarbon properties in undrilled prospects. The main source units were studied in well and outcrop sections. The thermal and maturity histories were investigated with a basin modeling software package. A detailed 3-D basin model was built from seismic maps. The most likely source rock in the area is the Garau Formation, which increases in thickness towards the north. The formation is only penetrated by a few wells but forms good outcrop sections at Kabir Kuh and Tang-e-Haft. The Kazhdumi Formation forms an organic-lean platform facies under most of the area. Additional source rock potential might exist in the Cenomanian Ahmadi and Coniacian Surgah shales. The maturation of the Garau and Ahmadi source rocks started in the Middle Miocene, and peak-oil expulsion occurred between 7 and 4 million years ago (Ma) in the main synclines. The main trap-formation event was during the late Miocene folding and uplift of the Zagros, between 8 and 2 Ma. Trap formation was coeval with the main oil charge resulting in large under-saturated oil fields. Hydrocarbon migration modeling, which includes proprietary multi-component source rock kinetics and PVT analysis, matched all known fields and their fluid types, and correctly predicted the gas/oil ratio (GOR) and oil gravity (API) of the Azar structure before drilling.

### **Characterization of permeability in a heterogeneous clastic and carbonate reservoir, Asmari Formation, Iran**

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Mohammad Mohammadnia, Hossein Hosseinpoursiami  
and Aliakbar Rahimibahar (NIOC-RIPI)*

Knowledge of permeability, the ability of rocks to flow hydrocarbons, plays a critical role in reservoir characterization and modeling. Permeability is directly determined in the laboratory from cored rock taken from the reservoir. Due to the high cost associated with coring and some technical problems, few wells in any given field are cored whereas most wells have wire-line logs that are commonly used to gain information about permeability. In this study, statistical and artificial intelligence techniques such as fuzzy logic and neural networks were employed to identify permeability based on limited data obtained from core analysis supplemented by well log data, RFT measurements and geological interpretations in a heterogeneous clastic and carbonate reservoir in Iran. The Ahwaz field is located near the Gulf at the foothills of the Zagros Mountains. The Asmari reservoir in Ahwaz field consists of interbedded limestones, dolomites and clastic sediments. The mixed siliciclastic and carbonate reservoir has undergone post-depositional diagenesis, which has had an impact on reservoir characteristics. Calcite cementation and dissolution, dolomitization and

particularly precipitation of anhydrite cements have destroyed porosity and affect the permeability in both the carbonates and siliciclastic sands in the field. The Asmari Formation in Ahwaz field has 16 wells that have recovered cores. To test the permeability prediction, the techniques were calibrated in 11 cored wells and blind tested in 5 cored wells to see how well estimated permeability fit the actual core and RFT permeability. Permeability was obtained from wire-line logs from the 325 wells. A geostatistical methodology was then used to estimate permeability over the field.

### **Meeting the challenges in saturation modeling of a complex reservoir**

*Ali Mohammad Bagheri (bagheriam@ripi.ir) and  
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Rezazadeh and Tor Røsaasen (Statoil); and  
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An IOR study has been performed of the Asmari Formation of the giant Ahwaz Field in southwestern Iran. This presentation describes challenges with regards to determination of water saturation as input to the construction of a 3-D geomodel used as basis for the IOR drainage strategies studies. Water saturation modeling on the Ahwaz field is complicated by heterogeneous rock quality and limited core data. The estimated value of water saturation is based on petrophysical data combined with a saturation equation. Both the choice of equation and its input parameters may result in systematic uncertainties, which are known as troublemakers in uncertainty reduction on estimated water saturation. Wire-line interpretation using Indonesia equation was employed to determine water saturation and then hydrocarbon saturation in the field. The high value of the calculated water saturation and the distribution of the estimated residual oil saturation with the negative medians in water-flooded zones suggest that the input parameters in the water saturation should be reconsidered. In order to illustrate the relative importance and uncertainty of each parameter, a Monte Carlo simulation was used to calculate ranges, probability distributions and relative uncertainties. The results of this analysis show that the cementation factor from Archie parameters is the most important parameter affecting uncertainty in estimated water saturation. Different methods were applied to estimate the cementation factor from core data and wire-line logs separately but the resulting saturation was still high. To reduce the uncertainty in the estimation of water saturation, a core-derived water saturation model was also developed based on centrifuge gas-oil and oil-water and porous plate gas-water and oil-water capillary pressure measurements. This saturation-height function approach has been successfully applied and water saturation was calculated from log porosity and free-water level without formation resistivity and Archie parameters.

### Waveform lateral classification for regional facies prediction

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This study addresses the regional exploration potential of the Carboniferous-Permian Unayzah Formation by examining lateral stratigraphic variations and the seismic expressions of reservoir trends. A consistent seismic reprocessing flow, using Residual Amplitude Processing (RAP), was applied over a number of 2-D seismic lines covering large areas to maintain a consistent wavelet treatment. Seismic waveform is the main seismic attribute adopted in this regional study. It recognizes Waveform Lateral Variations (WLV), which are interpreted to be indicative of regional stratigraphic trends and depositional environment transition zones. The Unayzah Formation is characterized by laterally varying sedimentary facies due to different depositional environments, e.g. aeolian, playa lake and fluvial. Additionally, structural controls both at the Hercynian unconformity and later, affected the distribution of the lower and upper Unayzah reservoirs. Neural clustering generated from WLV is consistent with the lateral facies variations. Furthermore, transition zones recognized on the waveform analysis on 2-D seismic lines, were consistent with an acoustic impedance model generated from a 3-D survey within the area of interest. Other regional geological models, such as gross sand, porosity and net sand showed similarity in the lateral variation. Application of waveform classification on RAP-processed 2-D seismic composites helps the integration of seismic and regional geological models generated from the well data. This is exemplified by the good correlation between the waveform classification results and the well-based geological models in this study. Furthermore, the results suggest that seismic waveform classification could be used as a reservoir prediction tool in a regional geological framework.

### Estimating the value of seismic data before a survey is shot; special reference to 4-D

Karl A. Berteussen (The Petroleum Institute, Abu Dhabi, [kberteussen@pi.ac.ae](mailto:kberteussen@pi.ac.ae))

Bayesian theory is used in order to make estimates of the monetary values (EMV) of seismic information before acquiring the data. The procedure is illustrated on a hydrocarbon detection problem, on a 4-D case, and on a structural resolution problem. Applying this procedure for calculating EMV one might compare a seismic project on an equal footing with any other projects competing for available funds. Obviously the parameters applied will be field dependent. However, making sensitivity plots help

with the problem of not knowing the *apriori* probabilities exactly. The approach can also be used to evaluate seismic tenders. Typically they are separated into two groups, technically acceptable and unacceptable and the job is given to the lowest bidder in the technically acceptable group. Calculating the EMV for each alternative one will be able to assign a value to a survey depending on the parameters applied, say give a value to resolution power, to time and spatial sampling rates, fold or proven processing algorithm performance etc. This should end up with selecting the survey acquisition or processing alternative that in fact is best for the problem at hand. Finally, before a survey is initiated, 4-D or ordinary survey, this methodology might be used to help estimate how much an oil company actually could pay for such a survey, which should be useful information both for the receiver and producer of a tender.

### Subsalt imaging: beyond depth migration and model building

Biondo Biondi  
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Large hydrocarbon reservoirs are located below salt bodies in several areas of the world, such as the Gulf of Mexico, the Arabian Gulf and offshore West Africa. In these areas, economical recovery of the hydrocarbons depends on our ability to image the reservoir with seismic data. Seismic imaging below salt bodies is a challenging task that pushes the limits of current imaging methods. The difficulties are associated with the complexity of the wave-propagation phenomena that occur when the seismic wavefield interacts with the salt body (e.g. multi-pathing, scattering, mode conversion) and with the structural complexity of the salt bodies and the target reservoirs. The routine use of 3-D pre-stack depth migration, and in particular of wave-equation migration, had a positive impact on many exploration projects. However, simple migration has difficulties to produce artifact-free images where the salt geometry prevents an even illumination of the subsalt reflectors from surface data. A promising research direction is to go beyond simple wave-equation migration and instead iteratively invert 3-D wave-equation operators. I will illustrate this idea by describing two research projects. The first project aims at improving the image of poorly illuminated areas by inverting a 3-D one-way wavefield operator. The second project developed a robust Migration Velocity Analysis (MVA) method based on wave-equation operator that can be used where conventional ray-based tomography fails. This method bypasses the difficulties involved in tracing high-frequency rays through a complex salt body and accurately models finite-frequency wave propagation.

### **Pore space inversions for petrophysical rock type identification: application to a large carbonate reservoir**

*Gregory N. Boitnott (boitnott@ner.com) and William T. Lauten (New England Research Inc.-Saudi Aramco); E.A. Clerke and J.J. Funk (Saudi Aramco)*

Carbonate reservoir characterization is commonly hampered by difficulty in relating dynamic reservoir properties to a geologically consistent rock-type classification system. Traditional approaches of log and core analyses do not produce satisfactory definition of rock type or flow performance. Furthermore, the geological models of carbonate reservoirs are typically not well linked to the reservoir flow units. We present a case study from a complex carbonate reservoir with large vertical variability in production. By combining routine laboratory measurements with an integrated pore space inversion analysis, we constructed detailed pore structure models and identified rock types from the calibration suite of plugs. The analysis led to a fundamentally different rock type classification scheme, yielding meaningful correlation with the geologic model of the reservoir and allowing identification of dual pore system samples and composite samples. The dual porosity samples themselves were divided into multiple rock types based on cross-plots of inferred pore structure parameters. We show that systematic use of a pore structure-based approach leads to a classification, which is fundamentally different from traditional schemes using permeability, porosity, and capillary pressure alone. Owing to the broad based petrophysical and data-driven nature of the approach, the resulting classification system automatically inherits direct ties to a wide range of petrophysical properties. The pore structure inversion method thus satisfies requirements of linking the classification scheme to static and dynamic reservoir properties, as well as to the geophysically measurable properties used in log based characterization.

### **Seismic noise estimation and error propagation applied to post-stack seismic inversion**

*Michael K. Broadhead (Saudi Aramco, michael.broadhead@aramco.com)*

Inversion of post-stack surface seismic amplitudes for estimation of acoustic impedance is routine in the industry, today. Not yet routine is the assessment of uncertainty in the impedance estimate. This missing step could be critical in the Middle East, where land seismic data quality issues dominate. For example, in Saudi Arabia, impedance volumes are often used for development well location in stratigraphically controlled clastics reservoirs. The mathematical techniques for uncertainty analysis have been available for many years, but, historically, little use has been made of them in exploration geophysics. However, this is beginning to change as

interest in the problem grows. Saudi Aramco is currently pursuing an internal project to assess this problem, and this presentation will review some of the progress that has been made. Some of the issues addressed are: (1) can the uncertainty analysis proceed post-inversion, or must it be included as part of the inversion process? (2) Making a clear distinction between error propagation and the estimation of errors (to be propagated). (3) Error propagation techniques – including method of moments and Bayesian methods (the latter offers the opportunity for improved impedance estimates, as well). (4) Solution methods for the Bayesian problem. (5) Assumptions in the mathematical model for computational tractability. (6) Estimation of seismic noise covariance matrices. (7) Wavelet covariance and start model/low-frequency trend uncertainty. Both synthetic and real data examples will be shown and outstanding problems discussed. Finally, applications of inversion uncertainty analysis to porosity uncertainty estimates for reservoir model building, automatic history matching, and reserves analysis will be discussed.

### **Phase and polarity issues in modern seismic interpretation**

*Alistair R. Brown (Consulting Reservoir Geophysicist, alistair@airmail.net)*

Zero phase is the objective of almost all seismic data processing today and its interpretive benefits are well known. However it is difficult to achieve. No more than 50% of seismic data achieves zero phase sufficiently closely for its benefits and accuracy to be properly enjoyed. Furthermore 90° phase is a remarkably common accident and, if not identified, can cause havoc to detailed seismic interpretation. All interpreters should know how to visually assess the phase and polarity of their data. I regularly meet those who discover late in the interpretation that the data has a different phase or opposite polarity to what was first thought. In this presentation recommendations for phase and polarity assessment will be made, and several phase circles will be presented. For zero phase data time and amplitude are collocated, and many interpretive procedures on modern workstations are based on this fact. For other phases complications arise, because time and amplitude are in different locations. Suggestions will be offered for handling the all-too-common 90° phase data.

### **Intelligent integrated operations management**

*Ian Brown (Matrikon-Napier University Edinburgh, ian.brown@matrikon.com) and Warren Mitchell (Matrikon-University of Alberta)*

Companies have invested significant resources to achieve short-term production rate optimization and improved long-term reservoir management leading to enhanced recovery. Some of their investments have included automation technology, data storage and retrieval, as well

as reservoir and well/network modeling. The industry has received incremental value from their investments as reflected in today's enhanced recovery rates. However, these new systems generate mountains of data and information. Upstream organizations have clearly struggled with managing not only the sheer volume of data now available from these assets, but presenting it in context to the right person in their organization at the right time so as to facilitate timely action and maximize benefit to the organization. Industry pacesetters have recognized the value of *Integrated Operations Management* and are effectively tying these systems together, mining useful information from them and presenting manageable, actionable information to the appropriate user in support of defined business processes. Pacesetters are realizing significant production improvement as well as enhancing reservoir recoveries. Benefits in the range of 5% of current production and 2% enhanced recovery are being achieved today.

### **Improving reservoir characterization using the 3-D-CRS stack method**

*Michele Buia (michele.buia@agip.it), Paolo Marchetti, Alfonso Iunio Marini, Renzo Zambonini and Falah Owaina (ENI)*

3-D zero-offset, *common reflection surface* (CRS) stack data can improve the structural image and optimize the amplitude/phase control for quantitative seismic reservoir characterization, even starting from a low signal-to-noise (S/N) dataset. This data-driven imaging method has been proven to accurately characterize events in the pre-stack domain. It takes advantage of data redundancy, using an 8-parameter stacking surface instead of a single stacking trajectory (velocity). Fold is dramatically boosted, since traces lying in the projected Fresnel zone are used; therefore calculation robustness and reliability increase. Additional information is also recovered, i.e. very detailed NMO velocities, geometrical spreading and projected Fresnel zones.

Processed log data from five wells were integrated to a 100-sq-km-sized seismic dataset. Starting from a petroacoustic approach, a seismic-lithology characterization of a giant oil field was achieved. High impedance sandstone and soft sealing shale define the reservoir sequence. Internal seismic response is semi-transparent, while sealing/reservoir interface waveform varies according to both reservoir porosity and sealing shale type (dual nature). Initial analyses ascertained the reliability of CRS data, the appropriate high S/N and its zero-phase condition. Model-based seismic inversion was used to solve the reflectivity ambiguity, estimating physical rock property cubes, and virtually increase the resolution by removing the wavelet signature from CRS data. Results validation implied the inversion error estimate, also performing "blind tests" on additional wells. Results encouraged proceeding towards an acoustic impedance calibration to effective porosity.

Neural-network multi-attribute and linear calibration of acoustic impedance transformed seismic into porosity volumes. Prediction accuracy ranges from 2-4 PU, upon the used technique. 3-D-CRS significantly increases the S/N and amplitude/phase consistency when compared to conventional data; therefore it's a suitable input for reliable quantitative seismic and reservoir characterization.

### **Stochastic AVO modeling and Bayesian AVO inversion to predict hydrocarbon versus brine occurrence in sand reservoirs**

*Maurizio Cardamone  
(ENI, maurizio.cardamone@agip.it)*

This presentation provides the summary of some 10 years of experience with a new approach at exploiting seismic AVO information. The request for increased effectiveness and reliability and in general of a more advanced implementation of the AVO method, capable of quantitatively predicting the distribution and characteristics of fluids, or even the petrophysical characteristics of the reservoir was set years ago as a top level development goal. This need has been targeted by implementing a Bayesian inversion of seismic AVO data, which is based upon a stochastic AVO modeling phase, that allows "interpretation-steered" extrapolation of known AVO information from the available wells in the area. The method is aimed at determining the probability that an assigned AVO response, measured from real pre-stack seismic data, can be ascribed to the presence of brine, gas or oil in a sand reservoir, given the specific geological parameterization. The developed saturation tool compares the real AVO response at the several targets in the study area with a generalized I/G model, which takes into account the expected (or guessed) variability of all the petrophysical parameters, which are expected to impact onto the AVO phenomenon. This probabilistic model is developed through the statistical analysis of all available wireline logs and borehole processed data in a large area of interest. From a practical viewpoint, the AVO fluid inversion allows effective and powerful extrapolation of the AVO information to any new exploration target belonging to a homogeneous geological-petrophysical scenario. The computation results, typically provided in the form of fluid probability maps, represent a new way to leverage pre-stack seismic information to benefit the prospect generation and ranking process.

### **Unconventional ways to support formation evaluation in fractured reservoir using mudlogging data**

*Carlo Carugo (carlo.carugo@agip.it), Cecilia Peduzzi and Luca Ferrario (ENI)*

The fractured reservoirs currently represent one of the most interesting sources for hydrocarbon production in

different countries. In the future, an increase of production coming from this type of reservoir is also expected. Conventional Formation Evaluation (Logs and Imaging) could be challenging in this complex environment. The main reasons are related to the evaluation of reliable petrophysical parameters to apply in the reservoir modeling, to the correct spotting and count of productive events (open fractures) and to the identification of formation fluids contacts. In order to support and integrate the conventional FE methodologies, an original approach, based on Mud Logging data, has been applied during the development phase of a large oil field in southern Italy. These cost-effective data are routinely acquired while drilling and available in near real time. The approach is carried out by: (1) mud gas analyses, using the GWD (Gas While Drilling) methodology, to identify the more porous intervals defining a preliminary net/gross pay. Also information about the formation fluid type can be achieved. (2) Drilling mud microlosses analysis, to identify and characterize the permeable zones. The combination of these two analyses, integrated with the other information acquired at wellsite (conventional and image logs, cores, formation testing, PLT), can provide a more complete and reliable reservoir description. A better identification of porous and permeable zones enables the optimization of critical well operations such as formation testing, coring and selective acid jobs. Moreover, in hostile environment (for example bad hole conditions) where logs cannot be run, the Mud Logging data are the only way to obtain a qualitative Formation Evaluation.

### **New drilling technologies and their implications on the quality of well data for geological and geochemical interpretation: problems and solutions**

*Riccardo Cerri (riccardo.cerri@eni.it), Graziano Capone, Carlo Carugo, Angelo Riva, Marcello Riva and Fabrizio Zausa (ENI)*

The success or failure of a well may depend on the accuracy of the interpretation carried out using well data directly collected at the rig site, such as drill cuttings and hydrocarbon shows. These data can be often critical to complement the traditional formation evaluation techniques. The steady development of both drilling technologies and fluids systems in recent years has increased the impact of the drilling environment on well data quality. Some of the related effects cannot be remediated, affecting the evaluation and even leading to misinterpretation. PDC bits, combined with turbines and mud motors, because of their shear and thermal effects, dramatically modify the original texture of the rocks ('metamorphosed' cuttings), affecting lithology evaluation (e.g. calcimetry overestimation particularly in carbonates), destroying biofacies (microfossils and palynomorphs) and altering physical and mechanical properties (e.g. density and strength). As to drilling fluids pollution, internal

studies have shown that OBM, SBM hydrocarbon-based components and glycols systems, difficult to be removed by cleaning processes, strongly interfere on source rock evaluation and distribution of free hydrocarbons both on cuttings and fluid samples. Furthermore, some organic additives (especially fatty acid-based lubricants) degrade at high temperature to alcoholic components that influence the gas chromatograph response, being detected as alkanes ("false" gas shows). In other cases, these chemicals can mask the true response of formation fluids so as to impair oil shows analysis. Several case histories due to the above problems are presented and solutions are proposed, together with some hints for improving PDC bit configuration and selecting the most suitable drilling fluid systems. Finally, shared practices between drilling, fluid engineers and operations geologists involved in well construction are suggested.

### **Oil and gas fingerprinting in onshore Kuwait: implications for the petroleum system**

*Pierre-Yves Chenet (pierre-yves.chenet@beicip.fr), Nicolas Bianchi and Michel Pernelle (BEICIP-FRANLAB); Alan Prinzhofner and F. Lorant (IFP); Swapan Bhattacharya, Awatif Al-Khamiss and Mubarak Al-Hajeri (KOC)*

Recent and existing analyses on oil and gas samples in onshore Kuwait field, combined with a 3-D petroleum system modeling approach infer the origin of the present-day hydrocarbon accumulations and evaluate the impact on the exploration strategies. Existing GC-MS oil analyses from Cretaceous and Jurassic oils confirm that the main source rock is the Najmah and Sargelu formations. Recent analyses of Najmah source rock show high organic sulfur content (up to 3%), which is responsible for the high sulfur content observed in the Cretaceous oils. Lower sulfur content in Jurassic oil is probably the consequence of oil cracking due to higher maturity, as suggested by petroleum system modeling. There is little evidence of a significant contribution of a Paleozoic source rock to the Jurassic and Cretaceous oil accumulations. However, locally high specific gravities (API°) and recent C-Isotope and rare gases measurements of gases associated to the oils support a minor contribution of this deep source (Silurian Qusaiba shale?) in a few areas of onshore Kuwait. The petroleum system modeling suggests the existence of a rather efficient regional seal at the base of the Jurassic (Triassic Jilh evaporite), responsible for the very high overpressure measured below. This seal is locally fractured in the vicinity of the main faults encompassing the Jurassic and the Paleozoic. These weak zones control the overpressure regime but allow for some minor hydrocarbon flow from deep sources up to the Upper Jurassic accumulations. The presentation discusses the recent analyses results in the framework of the petroleum system modeling and analyses the gas/condensate supply system from the deep Paleozoic source toward the Paleozoic/Triassic reservoir.

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### **The Rosetta Stone Project – I: spectral analysis of pore geometries and their relationships to depositional facies for the Arab D limestones**

*Edward A. Clerke (edward.clerke@aramco.com) and Harry W. Mueller, III (Saudi Aramco)*

The Rosetta Stone project was launched to investigate the observation that one class of depositional facies descriptors (Hadley, Wendte, Mitchell – Clerke modified, HWM-C) also clearly subdivided the sample set by pore system properties. In 2001, Saudi Aramco acquired a much more extensive data set from 10 cored wells and containing: geological, petrophysical and reservoir property data. This massive mercury injection capillary pressure (MICP) data set was acquired on 484 samples from ten wells in a major carbonate reservoir. Plug sample MICP data were all analyzed using the Thomeer method. Statistical reduction of the frequency occurrence of Thomeer parameters that arise from these fits to the Rosetta Stone samples showed a new carbonate porosity concept observation – Porositons, which are distinct and separable pore throat size distribution modes and their counterpart - Porobodons, is conjectured, which are distinct and separable Pore Body size distribution modes. Four porositons are the fundamental building blocks of the Arab D limestone pore systems (M: macroporosity and Type 1, 2, 3 microporosity). Porositon M carries 99.98% of the permeability of the multimodal pore systems. Porositon 1 is a form of microporosity prevalent in the best reservoir rocks. The Arab D limestones contain only nine porositon combinations, which are made up from one or more of the four porositons, e.g. M\_1. Each of the HWM-C geologic facies is characterized by a small number of the porositon combinations. A common limestone matrix pore system, M\_1, acts to a first approximation as a dual porosity-single permeability system. The presence of porositons and potentially porobodons, infers that mode analysis of NMR signals can be applied for Arab D limestone facies detection.

### **The Rosetta Stone Project – II: spectral analysis of the pore geometries and their relationships to reservoir properties for the Arab D limestones**

*Edward A. Clerke (Saudi Aramco, edward.clerke@aramco.com)*

The Rosetta Stone project was launched in 2001 to acquire a much more extensive data set from 10 cored wells and containing geological, petrophysical and reservoir property data. Four porositons (distinct and separable pore throat size distribution modes) are the fundamental building blocks of the Arab-D limestone pore systems. The “M” porositon (macroporosity) carries 99.98% of the permeability of the multimodal pore systems. Of the three forms of microporosity, the one with the largest pore throats (porositon 1) is prevalent in the best reservoir

rocks (that is, they have an “M\_1” porositon combination). The presence of macropores and micropores, e.g. M\_1, in certain of the HWM-C facies types causes them to act to a first approximation as dual porosity-single permeability system. Conclusions about the relationships between porositons and reservoir properties include: (1) efforts on permeability modeling are now focused on the M porositon resulting in an improved permeability model. (2) Relative permeability shows significant pore geometrical controls in addition to wettability, especially in that microporosity contributes to measurable relative permeability primarily through a water saturation offset (an “ineffective” water saturation). (3) Among a range of M\_1 dual porositon samples prepared consistently with regards to wettability, Type 1 microporosity volumes control the water saturation value at which the oil relative permeability curve, Kro, starts to decrease from 100%. (4) Among a range of M\_1 dual porositon samples prepared consistently with regards to wettability, the curve shape of the oil relative permeability curve, Kro, as it declines from 100%, is controlled only by the permeability (property only of the M porositon) and steepens as that permeability increases. (5) Ultimate recovery forecasts from relative permeability concepts require knowledge of the micro and macro pore systems.

### **Near-well bore black-oil simulation to evaluate fracture flow potential in a tight reservoir in Kuwait**

*Sefer B. Coskun (sefer.coskun@bakerhughes.com) and S. Ismail Ozkaya (Baker Hughes); H.J. Lewandowski and Ricardo Oosthuizen (KOC)*

A horizontal well was drilled to evaluate the fracture flow potential of a tight reservoir, which intersected the top three units of the reservoir. Borehole image logs show that the uppermost unit has a 3–5-ft-thick brittle, highly fractured layer. The other two units are ductile with 3–5-inch-thick brittle fractured beds. The middle unit has good porosity, but matrix permeability is low in all units. A single well dual-porosity simulation was performed to validate findings from borehole image logs regarding flow potential of fracture corridors, faults and layer-bound fractures. The basic geological model is taken from the interpretation of borehole image logs. The geological interpretation shows one major and a few minor fracture corridors. These were explicitly represented in the simulation models. The basic conclusion from the simulation study is that without considering fractures it is not possible to achieve a history match for the observed matrix permeability values. One or two major fracture corridors are sufficient for history match. The rate of pressure and production decline is much steeper for the simulation model than the observed decline rates. This suggests that some additional agents of high permeability are required, such as high matrix permeability or

fractured layers with interconnected fractures. The stochastic fracture model shows that fractures are within subpercolation range and fractures occur as clusters but not as a totally interconnected network of infinite extent. It is also possible that the fractured layers have lenticular shapes with finite lateral extension.

### **Rock type assignment using correlations between dynamic rock and fluid property interaction data (capillary pressure and relative permeability) and the porosity**

*Youssef Dabbour (ydabbour@adco.ae), Salma Al-Hajeri, Mohammed Ayoub and Maria Ribeiro (ADCO)*

This presentation discusses a methodology where measured dynamic rock and fluid interaction data (capillary pressure and relative permeability) are correlated against porosity to define the reservoir rock types for a carbonate reservoir zone in Abu Dhabi, United Arab Emirates. The reservoir rock type can be defined as “a unit of rock experienced similar depositional process resulting in a unique porosity-permeability relationship, pore throat and capillary pressure profiles for a given height above the *free water level* (FWL)”. The technique has been successfully applied to the same reservoir productive zone in two nearby fields in Abu Dhabi, using data from two extensive *special core analysis* (SCAL) studies. This zone of interest is characterized by a narrow range of low permeability, 0.5–5.0 mD, and a wide range of porosity, 5–25%. The analysis of the SCAL data indicated a strong dependency on porosity values. Therefore, porosity was used as the independent variable and correlations were developed to describe dynamic rock and fluid interaction data as a function of porosity. The application of these correlations was tested in dynamic flow simulation models in form of 18 rock and fluid interaction properties tables. Model initialization resulted in excellent matches of log saturation profiles and oil in place. The methodology and its application to two nearby fields in Abu Dhabi are discussed.

### **Monitoring reservoir fluids using microearthquake technology in a Middle East carbonate oil field**

*Shiv Dasgupta  
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The majority of the giant oil fields in the Middle East produce from prolific carbonate reservoirs. Collectively these carbonate reservoirs hold well over 50% of the world oil reserves. The high rigidity of the limestone-dolomite reservoir rock matrix, a small contrast between the elastic properties of pore fluids, low gas-to-oil ratio and mixed salinity water are responsible for the weak 4-D seismic effect from oil production in the reservoir under study. An alternative reservoir fluid monitoring technique, between

wells, was therefore considered. Permanent seismic sensors installed in a borehole and on the ground surface over a producing field will record passive monitoring of microseismic activity from reservoir pore pressure perturbations. Reservoir production and injection operations create these pressure or stress perturbations that are induced by shear stress release along zones of weakness in these rocks. The injection operation generates reservoir pore pressure increase which creates shear stress increase affecting the stability along the planes of weakness in reservoir rocks like joints, bedding planes, faults and fractures. Similarly reservoir production operation or fluid withdrawal creates a pore pressure sink that affects the stability in zones of weakness. The microseisms or minute earthquakes emanated from the reservoir would be recorded simultaneously at a large number of multicomponent seismic sensors that are deployed permanently at various levels in the borehole and over a surface area surrounding the borehole. Special geophones capable of measuring frequency response over 100–1,000 Hz frequency range would be installed. Reservoir heterogeneities affecting the fluid flow could be mapped by recording the distribution of hypocenter locations of these microseisms or small earthquakes.

### **Petrophysical and reservoir quality evaluation of the Shu'aiba Formation in the Reshadat field, offshore Iran**

*Rouhollah Dashti  
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The petrophysical and reservoir quality of the Shu'aiba Formation were evaluated using different methods in the Reshadat field, offshore Iran. The geological setting and sedimentary environment of this formation was also determined. All the available data from the 32 wells in the field were used in the project conducted for the Iranian Offshore Oil Company (IOOC). The sedimentary environment of the Shu'aiba Formation was found to be the deeper part of a shallow carbonate shelf, which dominated the Reshadat field region in the Aptian times. The porosity does not significantly change over the field, but generally improves towards the crest and eastern flank. This trend can be related to microfractures, which are observed in the cores. The dominant type of chalky porosity formed at the top of the Shu'aiba Formation as a result of the overlying Aptian unconformity. Water saturation was computed using Archie's equation and mapped over the field. Bukles plot was used to determine irreducible water zones. The constant of 0.07 was obtained for Swir zones, which means zones with Bukles constant lower than 0.07 are considered to be in Swir status. Permeability is not very high in the formation. Three petrophysical zones are proposed in the Shu'aiba Formation, of which the uppermost one (zone 1) has the best petrophysical quality (best porosity and permeability and lowest water saturation) and is the main oil producing

interval. It indicates that the Aptian unconformity had a major effect on reservoir quality of the formation, mostly in the upper part.

### **Structurally-controlled hydrothermal dolomite reservoirs: characteristics and rock fabrics**

*Graham R. Davies (Graham Davies Geological Consultants, gdgc@telus.net) and Langhorne Smith (New York State Museum)*

Hydrothermal dolomite (HTD) reservoirs are major producers in the Ordovician, Devonian and Mississippian of North America, and are receiving increased global attention. HTD is formed under burial conditions (often less than 500 m) from Mg-charged brines emplaced *via* structural conduits into a carbonate host, typically limestone, at temperature and pressure greater than the ambient T and P of the host formation. Original limestone facies and permeability play a major role in lateral extent of dolomitization, replacement textures, pore type, and pore volume. Associated leached limestones may also be productive. Saddle dolomite in both matrix-replacive and void fill phases is characteristic but not necessarily diagnostic of an HTD system. Transient, short term but high temperature (tTI) hydrothermal events may result in 'forced maturation' of kerogens in this setting. Extensional and strike-slip (wrench) faults are the preferred structural locations for hydrothermal dolomitization, with a bias toward the upper hanging wall site. Transtensional or dilational bends, offsets and shears along wrench faults, often in *en-echelon* arrays, are common loci for fluid upflow, but with transpressional structures adding complexity. The seismic signature for dilational or pull-apart sites is a structural 'sag', often with high positive correlation to HTD distribution. Underlying sandstone aquifers, basement highs, and shale top seals and internal aquitards are other variables in localization of HTD facies. Rock fabrics in an HTD system record short-term ('instantaneous') shear stress and pore fluid pressure transients. They include dilational 'floating clast' breccias, rimmed microfractures in shear sets, boxwork vugs and zebra fabrics compartmentalized by shear microfractures, and hydrofracturing of low-permeability hosts. Younger tectonic fracturing may be a critical factor in economic production and high flow rates.

### **Geochemical characterization and interpretation of Khuff reservoir fluids, North Dome**

*Daniel Dessort (daniel.dessort@total.com), Gerard Caillet, Marc Lescanne, Enzo Insalaco and Francois Montel (Total)*

The North Dome structure is the largest single gas reservoir in the world. Despite the importance of these reserves several important questions regarding the reservoir fluids

remain poorly addressed and unsatisfactorily answered. The aim of this study was to geochemically characterize and interpret: (1) the acid gas (H<sub>2</sub>S, CO<sub>2</sub>); (2) the gas condensates; and (3) the organic-rich layers occurring in the Upper Khuff reservoirs of the North Dome. The study has focused on two main questions. The first is whether the Silurian hot shale is the only hydrocarbon source rock for the Khuff reservoirs? The Silurian hot shale has been considered the only hydrocarbon source rock for the Khuff reservoirs in the Qatar Arch. Molecular and isotope geochemistry of these condensates, and the intra-Khuff organic-rich layers, demonstrate that a single source rock is unlikely. The second question is "what is the origin, or origins, of the acid gases (H<sub>2</sub>S and CO<sub>2</sub>), and methane, and why don't the condensates appear to be thermally altered?"

Thermo-chemical reduction of hydrocarbons by sulphates (TSR) can partly account for the occurrence of acid gas. The occurrence of TSR-generated gas can be unequivocally demonstrated by isotopic and molecular geochemical (occurrence of the thiadiamondoid series) studies. Analysis of mass balance of condensate thermal alteration shows that secondary cracking of the condensates could not have generated all the methane in place. The studies also show that the characterization, interpretation and distributions of the Khuff hydrocarbons, and their associated gases, is highly complex - being multiphased and strongly linked to the burial history, structuration of the field, reservoir sedimentological heterogeneity and regional setting. Hence, the only way to better understand and eventually predict these fluids is by applying multiscale and pluridisciplinary approaches.

### **Fahud changing image: seismic processing contribution to the rejuvenation of Oman's oldest oil field**

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Fahud is PDO's oldest and largest oil field. It measures 17 by 2.5 km, with an STOIP of more than 6 billion barrels of oil and produces from the Natih carbonates. The topography of the Fahud field is a rugged limestone jabal (mountain) underlain by soft Fiqa shales. The anticline is dissected by wadis (dry river valleys), with surface elevations varying between 140 and 350 meters. The 1994 seismic data was reprocessed in 1997, without resolving all data quality issues. After thorough analysis of the data, and a 2-D/3-D pilot project, a new 3-D seismic survey was acquired in 2004 combined with acquiring 20 up-holes, drilled to a depth of 150 m AMSL. Significantly improving the seismic image quality for the field required solving the complex surface and near-

surface problems. This was achieved through building a high-fidelity velocity model, for the near surface and the deeper velocity variations, used to tackle both the static and dynamic positioning errors through application of statics and pre-stack depth migration. The model incorporated elevations, up-holes, well tops, check-shots, near surface geology, remote sensing data, interpretation of near-surface seismic reflections and seismic velocities. The presentation will demonstrate how this was crucial to extract value from Fahud and how this contributed to the rejuvenation of the FDP for Oman's oldest and largest oil field.

### **Porosity destruction in carbonate platforms**

*Stephen N. Ehrenberg (Statoil, sne@uaeu.ac.ae)*

The important thing to understand about carbonate diagenesis is not necessarily how porosity is created, but how it is destroyed. Detailed core observations from two deeply-buried carbonate platforms (Finnmark platform, offshore north Norway, and Khuff Formation, offshore Iran) show that most vertical porosity variation can be accounted for by only two or three factors, including: (1) stylolite frequency; (2) proportion of argillaceous beds; and (3) anhydrite cement. The spatial distribution of these factors is determined by the depositional distribution of clay minerals (important for localizing chemical compaction) and the occurrence of hypersaline depositional conditions and associated brine reflux (important for localizing anhydrite precipitation). However, the intensity of chemical compaction and consequent porosity loss in adjacent beds by carbonate cementation also depend upon thermal exposure (temperature as a function of time). To the extent that the Finnmark and Khuff platforms may be regarded as representative of carbonate reservoirs in general, recognition of the above porosity-controlling factors can provide the basis for general models predicting carbonate reservoir potential at both reservoir and exploration scale. Distributions of clay and anhydrite should be predictable from stratigraphic architecture, whereas variations in thermal exposure can be mapped from basin analysis. In the present examples, factors that do not need to be considered include eogenetic carbonate cementation and dissolution, depositional facies (other than aspects related to clay and anhydrite content), and mesogenetic leaching to create late secondary porosity.

### **Uranium decrease marks the Permian/Triassic boundary in the Khuff Formation, offshore Iran: why?**

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Profiles of bulk chemistry, isotope analyses, and plug

porosity through 450 m of continuous core in the Khuff Formation reveal large-scale stratigraphic cycles involving dolomitization, anhydrite content, and porosity. In cores from three wells, the approximate position of the Permian/Triassic boundary (PTB) is identified by abrupt negative shifts in bulk-carbonate oxygen and carbon isotopes. This surface shows no apparent relationship to the boundary of a cycle of sedimentary accommodation, but occurs within a grainstone interval 5–6 m thick, which is bounded above by a bed of microbial boundstone and below by muddy tidal-flat facies. The isotopically defined surface is also marked by a sharp drop in bulk-rock uranium content: from mostly 1.5–4 ppm below to mostly 0.2–0.8 ppm above, a change that is persistent throughout the 154 m-thick Triassic section and is clearly visible on the gamma-ray log. Similar shifts are apparent at the PTB on published gamma-ray profiles from Khuff wells in neighboring countries, indicating that the drop in uranium content is a regional characteristic. A possible explanation is that Triassic strata were more extensively recrystallized in oxidizing meteoric waters that leached uranium, but this is inconsistent with the global extent of the stable-isotope shifts and the lack of any regional aquiclude associated with the PTB. Our preferred explanation is that earliest-Triassic seawater was depleted in organic matter due to the end-Permian biotic crisis, resulting in lesser incorporation of uranium in marine sediments.

### **Combining new core data with surveillance sharpens the geological understanding of a decades-old GOGD field development**

*Edward J. Follows (edward.follows@pdo.co.om), Saud Salmi, Abdullah Zeidi, Gerbert de Bruijn, Andrew Beck, Alia Bahry, Richard Singleton, Volker Vahrenkamp, Talal Musallami, Andrew Farmer and Livio de Pieri (PDO)*

Historic management of the GOGD process (gas oil gravity drainage, dependent on fractures and matrix permeability) within an elongate, tilted carbonate reservoir had been relatively hands off. This was based on the understanding of that GOGD occurs over long periods of time with little enhancement possible beyond the existing well stock. Cores recovered in 2003–2004 for understanding the waterflood in the same field have provided continuous recovery of reservoir fabrics over the GOGD layers. A diagenetic study has promoted a new burial model. Combining fabric characterization with the diagenesis has upgraded the understanding of matrix production in this GOGD field. A review of existing borehole image data has complementarily linked the matrix with fracture description, extending this new understanding into the horizontal development wells. Integration of production log surveillance has enabled a dynamic characterization of the matrix-fracture interaction as occurring in individual wells, rather than general conceptual models. This has sharpened the geological understanding used for

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reservoir management, revealing opportunities for infill drilling, beyond a traditional approach of GOGD oil rim lowering.

### **Case history of automated evaluation of mineralogy and porosity in complex carbonates**

*Nasser H. Gomaa (ngomaa@adma.ae),  
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Significant oil and gas reserves in the United Arab Emirates, Qatar, and elsewhere occur in carbonate formations containing anhydrite and quartz disseminated within calcite and dolomite reservoirs. Accurate evaluation of mineralogy in these complex carbonates, while critical to computing porosity, hydrocarbon density and well-to-well correlation, is challenging when a conventional logging suite is used. The problem is that the number of unknowns in the formation exceeds the number of available independent measurements. Mineralogy evaluation of a complex carbonate in the studied well was greatly improved when nuclear spectroscopy logs were incorporated into the evaluation. These logs measure calcium, sulfur and silicon, which directly map to the key mineralogical components – carbonates, sulfates (anhydrite) and quartz/chert. The resulting evaluation was far more accurate when compared to mineralogy evidence from core samples obtained on the same well. Many such carbonate reservoirs have formation waters with salinity in excess of 200,000 ppm. Drilling fluids used to drill the well also have high salinity. In order to reduce the environmental effects on the neutron porosity log, an epithermal neutron porosity tool was run in the subject well. We demonstrate through comparison to core data the improvement in the accuracy of porosity evaluation through the use of epithermal neutron data. We show that the combination of nuclear spectroscopy and epithermal neutron porosity improves both the accuracy and the precision of porosity and mineralogy evaluation. Detailed uncertainty analysis further substantiates the accuracy and precision improvement in lithology and porosity through the use of these measurements.

### **Reflection tomography for validation of subtle structures: a case history from southern Tunisia**

*Harald Granser (OMV, harald.granser@omv.com) and  
Oezsen Refik (Paradigm Geophysical)*

Recent exploration success for oil and gas in Triassic reservoirs in the Ghadames Basin in eastern Algeria suggests a similar potential in the Tunisian part of the basin. Due to the subtle structures of the Triassic reservoir strata, the exploration success has been hampered by inaccurate seismic trap definition, the main causes being static

problems due to sand dunes at surface with low velocities but also by uncertainties in depth conversion because of velocity variations in the deeper section. Trap definition errors caused by variable seismic interval velocities within the Mesozoic section related to the presence of evaporite units may exceed the uncertainties caused by static problems. Existing well control in the area indicates that also velocity variations in the shallow, sometimes outcropping Cretaceous carbonate layers may also cause significant variations in the depth conversion. Reflection tomography was applied to validate a subtle time closure identified within OMV's exploration block. This lead has a closure of 15 milliseconds and modest velocity variations in the overburden may have a significant effect on the size and even validity of the prospect. Location and closure also varies substantially depending on the processing vintage used. This is primarily due to differences of the static corrections. A critical prerequisite before embarking on tomography was therefore proper pre-processing with special emphasis on the static solution. The effects of the horizon based tomographic velocity model update on the depth sections (PSDM) are subtle but significant, resulting in a horizontal shift of the prospect.

### **In-situ water salinity and saturation determination from simultaneous logs**

*Roger J. Griffiths (Schlumberger, rgriffiths@mussafah.oilfield.slb.com)*

With secondary and tertiary recovery becoming increasingly common, the problem of assessing formation saturation becomes more complex as injected fluids mix with the original waters resulting in variations in the water salinity (and hence water resistivity,  $R_w$ ) across a field. By deriving two independent water saturations from measurements with differing sensitivities to formation water salinity we demonstrate how the water salinity and saturation can be determined simultaneously. The recent introduction of a Logging-While-Drilling (LWD) Thermal Capture Cross-Section (Sigma) measurement acquired very close to the resistivity measure point on the LWD tool has opened the possibility of comparing the open-hole pre-invasion Sigma-derived saturation with that from a traditional open-hole Archie-derived saturation. As both are acquired at close to the same depth at the same time, the saturations should match if the assigned water salinity (and hence water resistivity and water sigma value) is correct. As the Sigma and resistivity measurements differ in their response to changing water salinity, any discrepancy between the two saturations can be used to determine simultaneously both the *in-situ* water salinity and the actual formation water saturation by varying the water salinity until a water saturation match is achieved. We review field examples showing the application of this technique to Middle East carbonate reservoirs.

### **The sensitivity of water saturation calculation and modeling to the uncertainties of the petrophysical inputs**

*Mostafa Haggag (mhaggag@adco.ae) and Rowan Stanley (ADCO)*

Water saturation ( $S_w$ ) spatial distribution within a hydrocarbon-bearing zone is a critical factor influencing reservoir management and directly impacts business-critical processes including reservoir economics, production performance and facilities. However, derivation of the saturation parameter itself is subject to a large degree of uncertainty in terms of both its calculation and also its distribution within the inter-well spaces. Describing and quantifying the  $S_w$  uncertainties prevalent in all reservoir models is an important element of understanding and mitigating risks inherent in reservoir management. This work documents a case study from a producing carbonate reservoir in Abu Dhabi, United Arab Emirates. The saturation data was interrogated at two scales: (1) 1-D analysis of the calculation of  $S_w$  itself from petrophysical, core analysis and special core analysis (SCAL) inputs. (2) 3-D analysis of the spatial population of the reservoir model with  $S_w$  data. In 1-D, the input petrophysical parameters derived from log and SCAL data such as porosity, cementation factor, saturation exponent, formation water resistivity, true formation resistivity and capillary pressure data are subject to different uncertainties related to data acquisition and analysis. In 3-D, the static distribution of initial  $S_w$  is sensitive to structural variations relative to hydrocarbon contacts, distribution of reservoir rocktype to which the saturation formula may be tied, the careful selection of data unaffected by production related fluid displacements and also resolution effects related to the dimensions of the cellular framework itself. For the reservoir featured, detailing the sensitivity of the  $S_w$  calculation and its subsequent distribution proved crucial in providing a numerical description of the uncertainties.

### **Depth imaging a 2-D Saudi Aramco seismic line**

*Mike Hall (mhall@gxt.com), Svetlana Bidikhova and Valery Miroshnikov (GX Technology)*

The near surface of certain parts of Saudi Arabia presents severe challenges for seismic exploration. This presentation investigates various issues involved in performing pre-stack depth migration (PreSDM) of a Saudi Aramco 2-D line from a difficult area. Prior to depth imaging it is important to perform pre-conditioning of the data. This particular data contains quite severe surface wave energy that obscures the signal. The application of a filtering technique that successfully attenuates this is demonstrated. It is also very important to obtain a good near-surface velocity model prior to depth migration. A successful application of refraction tomography will be shown. This technique is strongly dependent on the timing

accuracy of the first arrivals. Picking of first arrivals in this data is difficult; an approach to displaying these for both picking and quality control will be described. The seismic resolution is enhanced within the Vibroseis signal bandwidth using a novel deconvolution technique. PreSDM is then performed on the conditioned seismic data. The most important aspect of PreSDM is building an accurate interval velocity depth model. Several techniques will be shown to obtain this model using both layered and gridded approaches. The advantages and disadvantages of these techniques will be demonstrated. It will also be shown how these techniques may be used together to build the interval velocity in an optimal manner. The effects of performing constrained tomographic inversion in the depth domain and of algorithm parameterization will be demonstrated. Finally it will be shown how detailed analysis of the interval velocity structure infers the presence of a fault not suspected through the application of conventional time processing.

### **Effects of reservoir properties upon the reservoir models: a case study from blocks 1, 2 and 4, Muglad Basin, Sudan**

*Nouradaim Abdel Hameed (nhameed.khartoum@gnpoc.com) and K.B. Trivedi (GNPOC)*

Reservoir characteristics are a major consideration for formulating any well-test design. Permeability dictates the flow rate and duration of the test. Test flow rates and flow times must satisfy several criteria. (1) The test must be long enough to obtain data beyond near-well bore effects, such as well bore storage distortion, formation damage, or stimulation. (2) The test must also reach the desired radius of investigation and evaluate a representative volume of the formation. In low-permeability reservoirs, the flowing time required to satisfy both criteria can be prohibitive, especially when flaring gas. The duration of the well bore storage period depends on well bore volume and fluid compressibility, reservoir porosity, permeability, net pay thickness, and fluid properties. Reductions in well bore storage period can be achieved by running bottom-hole valves in the tubing string, which allows to shut-in the well just above the sand face rather than at the surface. The time to reach a desired radius of investigation in a reservoir increases with decreasing permeability. Drawdown varies directly with flow rate and inversely with permeability. For higher permeability wells, a given flow rate will cause a smaller pressure drawdown than in lower permeability wells. To increase the pressure drawdown, a higher rate must be used. Higher rates will require larger separators and meter runs at the surface. Higher flow rates will also waste more gas through venting and flaring unless the well is connected to a pipeline. Higher rates can create larger pressure drawdown that may result in retrograde condensation in gas condensate reservoirs or formation sloughing in unconsolidated sandstones damaging the reservoir immediately adjacent to the well bore. With

the help of case history we have built a reservoir model and standards for testing the wells effectively in the most economical manner.

### **Injection well testing: a case study from Unity area, Muglad Basin, Sudan**

*Nouradaim Abdel Hameed (nhameed.khartoum@gnpoc.com) and K.B. Trivedi (GNPOC)*

Testing injection wells is particularly important for efficient planning and operation of both secondary and tertiary recovery projects. Satisfactory injection performance over a long period of time and the prompt detection of increasing well bore damage are important to the economics of recovery projects. We have studied both injectivity and falloff testing in liquid-filled, unit-mobility-ratio reservoirs. We will discuss the methods for determining average reservoir pressure and for analyzing composite systems in non-unit-mobility ratio reservoirs and well testing, and its analysis using the step-rate method. A mobility ratio of less than one suggests an efficient, "piston-like" oil displacement process, while mobility ratios greater than one may result in inefficient displacement. In the present study, it is observed that the mobility ratio between the injected and *in-situ* fluids is near unity, the analysis techniques for injection tests are similar to those developed for production tests. Unit-mobility ratio approximation applies to both mature waterflood, which initially had mobility ratios significantly different from unity, and early in the life of Tertiary recovery projects, when little fluid has been injected, and the injected fluid bank appears as a skin effect. When the unit-mobility-ratio condition is satisfied, injection well testing is analogous to drawdown testing, while shutting in an injection well results in a pressure falloff that is analogous to a pressure buildup test. Injectivity testing is pressure transient testing, and is analogous to drawdown testing for both constant and variable injection rates. If the mobility ratio is not unity and radius of investigation has not exceeded the radius of the injected-fluid bank, then, the effective permeability and skin factor (but not static drainage-area pressure) in the inner zone can still be determined. The authors will discuss a real case history that has significantly helped in effective reservoir management in the Unity area of Muglad basin.

### **Visualizing and presenting the subsurface data in ArcGIS**

*Salima Hamdan Harthy (salima.h.harthy@pdo.co.om), Jan Schreurs and Alban Rovira (PDO)*

The aim of this presentation is to demonstrate how to manage a wide range of subsurface data with ArcGIS software while enabling explorers to make more efficient use of the vast amounts of available information. Traditionally geological data was compiled in various

reports with many maps and drawings. With large amounts of data accumulating through time the accessibility of such data becomes more and more difficult, hampering fast reviews of such data. It was therefore decided to capture subsurface data in ArcGIS, not only for easy, graphic accessibility of such data, but also to systematically organize such data for future updates and reviews. The goal of the subsurface data structure built into ArcGIS is to home all geological layers based on a project or a study indexed by hierarchical stratigraphic codes. This hierarchical system follows the definition of Oman's stratigraphy and is also linked to corporate well databases and digital document storage. It allows an easy, graphic communication of geological information. The effort to create a geological layer structure has involved many people and many intense discussions. Geologic maps can be extremely complex with many different types of information displayed. This provides a significant challenge when attempting to structure this data. The process of compilation also presents data quality issues; problems often result from field data collection to data compiled in spreadsheets, historical cad drawings, power point, hard copies and disparate databases. Such problems may include incomplete and inconsistent data, data duplications, synonyms, and ambiguous references to data, lacking referential integrity. Users are unable to quickly search or visualize data for geological reviews. All of these issues clearly point towards the necessity of utilizing a properly structured graphic interface to corporate databases to properly manage and homogenize geological data.

### **Evolution of pre-stack multiple suppression based on velocity discrimination**

*Mahmoud E. Hedefa (mahmoud.hedefa@aramco.com), Weihong X. Zhu and Khalid O. Rufaii (Saudi Aramco)*

Separation and removal of multiple energy from seismic data can be a very challenging task. Currently, the seismic industry accomplishes multiple suppression in two principle venues: velocity dependent and velocity independent methods. Multiple identification and removal is essential in both marine and land data due to the extensive masking of primary reflection data at potential reservoir levels. Marine data are characterized with multiple arrivals, which can be modeled quite easily. Land data multiples can be very difficult to model due to near-surface complexity. Here, we present an overview of velocity-dependent Radon and FK filtering techniques that identify and remove unwanted multiple energies. We have carried out a comparative study of several pre-stack multiple suppression techniques utilizing different commercial and in-house developed software. We demonstrate the shortcomings of using FK and Radon (hyperbolic/parabolic) filters, which impact the original texture of the seismic signals in terms of amplitude and frequency. We also demonstrate the success of a new

inhouse-developed multiple-suppression technique. This new velocity-dependent technique is based on the path-summation approach and utilizes FK and step-variant median filters. In a real land data case, this technique appears to preserve relative amplitudes while successfully attacking the multiples.

### **CRS-stack-based seismic imaging considering top-surface topography**

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Markus Von Steht, Ingo Koglin, Tilman Kluever and  
Christoph Jaeger (University of Karlsruhe)*

In the current situation of rapidly growing demand in oil and gas, on-shore exploration, even under difficult conditions, becomes again more and more important. Unfortunately, rough top-surface topography and a strongly varying weathering layer often result in poor data quality, which makes conventional data processing very difficult to apply. As recent case studies demonstrated, the Common-Reflection-Surface (CRS) stack produces reliable stack sections with high resolution and superior signal-to-noise ratio compared to conventional methods. Particularly for land data, the increased computational expense required by the generalized high-density velocity analysis preceding the CRS stacking process may be worthwhile. In order to define optimal stacking operators, the CRS stack extracts for every sample of the zero offset section an entire set of physically interpretable stacking parameters. These so-called kinematic wavefield attributes, obtained as a by-product of the data-driven stacking process, can be applied to solve various dynamic and kinematic stacking, modeling, and inversion problems. By this means, a very flexible CRS-stack-based seismic reflection imaging workflow can be established. Besides the CRS stack itself, the main steps of this processing workflow are residual static correction, the determination of a macrovelocity model via tomographic inversion and limited aperture Kirchhoff migration. The presented extension of the CRS-stack-based imaging workflow provides support for arbitrary top-surface topography. Final results of its practical application to a challenging real data set from Saudi Arabia will be presented.

### **Fracture sealing in sedimentary rocks: micro- to basin-scale processes**

*Christoph Hilgers (c.hilgers@ged.rwth-aachen.de),  
David Sofie Nollet and Janos L. Urai (RWTH Aachen);  
Kirschner (Saint Louis University); and  
Jean-Paul Breton (BRGM)*

Fractures significantly enhance the bulk permeability of rock following the cubic law. Sealed fractures originally acted as fluid conduit, its microstructure giving constraints on the fracture aperture. In this contribution, we will summarize our numerical and experimental

approaches, which explore the fundamental principles of fracture sealing on a microscale. Numerical modeling shows the variation in microstructure, leaving almost no fracture aperture to form fibrous veins. Lateral along-fracture transport seals the inlet, as shown by analogue and hydrothermal experiments. Results are used for case studies of reservoir rocks (limestones in Oman and sandstones in Germany) covering micro- to regional-scale aspects. We present the temporal evolution of fluid systems in these two different settings and estimate the fluid overpressures causing vein formation. Seven different sets of calcite veins were observed in Mesozoic limestones, which are consistent across a 2,500 sq km anticline. Stable isotopes of calcite veins show an early rock-buffered system, which opened to meteoric waters with the onset of normal faulting. Triassic sandstones were sealed with bedding-normal calcite veins, overprinted with anhydrite veins. Locally, halite veins displaced the latest phase. Calcite veins formed in a compacting sediment. Anhydrite veins were derived from Zechstein evaporites, as indicated by sulphur isotopy. Fluid inclusion and basin subsidence data were used to derive the timing and p-T conditions of the externally derived fluid. Anhydrite may have precipitated due to a pressure drop caused by hydrofracturing and ongoing basin subsidence.

### **Microstructures in halite veins and their implication on the bulk permeability of rock**

*Christoph Hilgers (c.hilgers@ged.rwth-aachen.de),  
Zsolt Schleder and Janos L. Urai (RWTH Aachen)*

Veins are localized precipitates grown in dilatational sites. They are of great importance as they emplaced in fractures, which significantly change the bulk permeability of rocks. This study gives an overview of various halite vein microstructures and discusses the process of vein formation. Fibrous and elongate to elongate-blocky halite veins were sampled in sandstone, marly beds and rock salt (Poland, Germany). Their microstructures are visualized with gamma-irradiated halite and polished and etched surfaces, which allows deducing the deformation mechanism and strain rate, as well as the differential stress. Fibrous halite veins are about 5 to 10 cm wide and the microstructure only locally shows growth subgrains aligned parallel to the grain boundaries and inclusion bands oriented normal to fiber orientation. Earlier fibrous veins imply a more complex evolution with abundant deformation-related subgrains and show growth zonation indicative of deformation, recrystallization and subsequent overgrowth. Elongate blocky veins hosted in sandstone and rock salt are a few cm wide and are filled with cm-sized grains showing growth zonation. Such microstructures require large fracture increments during vein growth, which in turn implies higher bulk permeability of the rock. Syntectonic vein formation suggests the presence of fluid overpressures in our samples. The orientation of veins may be used to infer

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paleostress directions during vein formation. Plastically deformed halite vein microstructures are used to deduce differential stresses, and fibrous veins track the opening direction of the fracture over time.

### **Characterization of early diagenetic cementation in the Natih Formation, Oman, and its impact on reservoir sweep**

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Mike Caputi, Yaduo Huang, Conxita Taberner and  
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The Albian-Cenomanian Natih Formation is a key reservoir in Oman. It was deposited on a shallow-water carbonate platform, and is dominated by inner and mid-ramp skeletal wackestones and packstones that are intercalated. Towards the top of the upward shallowing cycles, laterally discontinuous layers of rudist grainstone form thin layers of high permeability contrast. Much of the reservoir succession is dominated by apparently monotonous successions of bioturbated packstone and wackestone. Microcrystalline marine calcite cements have pervasively overprinted these bioturbation fabrics, resulting in a 'pseudo-nodular' fabric. In general, the Thalassinoides-dominated burrow network is cemented, and is surrounded by a leached halo with an adjacent compacted, and occasionally dolomitized, host matrix. The pre-compactional texture and isotopic data are consistent with cementation from marine fluids, probably immediately below the sediment-water interface. There is some variability in the type of bioturbation, and consequently in the distribution of cements, as well as in the degree of compaction and leaching.

Differential cementation of the bioturbated fabric results in a centimetre-scale heterogeneity. This can be characterized by a number of rock types that differentiate variability in flow properties and saturation profile. With ongoing efforts to improve recovery from fields producing from the Natih Formation, it is necessary to understand the fine scale variability in rock properties associated with pseudo-nodular cementation. In particular the correct representation of the saturation, absolute and relative permeability of the fabrics within reservoir models is a key to targeting bypassed oil. This is a major challenge, which requires recourse to detailed experimental techniques and simulations, as well as careful upscaling, before more conventional modeling approaches are adopted.

### **Linear model for low-frequency pore liquid oscillations observed in hydrocarbon microtremor analysis (HyMAS)**

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Hydrocarbon Microtremor Analysis (HyMAS) is an innovative passive technology identifying the hydrocarbon content of geological structures by analyzing low-frequency seismic signals. Hydrocarbon indicating information is extracted from spectral modifications of naturally occurring seismic background noise waves in the 0.01–10 Hz range passing through hydrocarbon bearing porous structures. In this presentation, a simple description of this reproducibly observable phenomenon in terms of a one-dimensional linear model of an oscillating liquid-filled porous medium is presented and its relevance for an explanation of the underlying basic HyMAS signal creating mechanisms and related parameters are discussed. Observed values of about 3 Hz for the oscillation and 2.10<sup>-6</sup> m/s for the amplitude of the vertical surface movement velocity could be reproduced by introducing realistic parameter values for the geophysical properties in the model. As a direct hydrocarbon indicator, HyMAS is an ideal complement to 2-D- and 3-D-seismic structural imaging technologies. Numerical modeling of suitable geological structures both in the macroscopic as well as in the microscopic domain shows how the seismic background noise spectrum can be modified in a different way when interacting with geological structures containing hydrocarbon filled pores compared to interacting with similar structures not containing hydrocarbons. Pure HyMAS data can already be used to qualify areas for adequate geological programs. Integrated with existing geophysical and geological data, HyMAS allows for cost and time saving optimization of well placement during exploration, appraisal and production. HyMAS is fast, safe, cost-effective and environmentally unobtrusive.

### **Prediction of the permeability via neural networks and fuzzy logic in a heterogeneous carbonate reservoir, Iran**

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This presentation describes the use of the "intelligent" technique to predict heterogeneous carbonate reservoir permeability using routine well logging data. Permeability measures the ease with which fluids can flow through a reservoir and has a significant impact on petroleum fields operations and reservoir management. In heterogeneous reservoirs, the prediction of permeability via conventional statistic methods is difficult. The use of permeability versus porosity cross-plots to predict the permeability in an offshore Iranian reservoir was not successful. This study presents an intelligent technique using neural network and fuzzy logic to determine permeability in a heterogeneous carbonate reservoir. In this process, at first, fuzzy logic is used for selecting and ranking the best related well logs with core permeability data. This is followed by

the application of the back-propagation neural network method to develop a transformation between the selected well log data and core data. Also this model was blind tested with data from another well, which was withheld from the modeling process. The results of this study show that BPNN model permeability predictions are consistent with core data.

### **Role of fractures in enhancing quality of Triassic gas reservoirs in western Kuwait**

*Riyasat Husain (rhussain@kockw.com), Abdul Aziz Sajer, King Hoi Lau, Nadia Al-Zabout and Reyad Abu Taleb (KOC); and Haiqing Wu (Chevron)*

Deep Triassic reservoirs have been successfully explored for free gas in the Mutriba and Kra Al-Marzu fields in West Kuwait. These structures are NNW-trending doubly plunging elongated anticlines. The western flanks of the structures are steeper in the proximity of NNW/SSE faults. Superimposed upon this dominant grain is a cross trend, roughly at right angles to the trend of the axial trace, which is reflected in offsets of the crest. The prospective section has been analyzed for lithofacies, reservoir properties and fractures. The reservoir facies are characterized by a complex lithological suite consisting of dolostone, anhydrite and shales. Conventional reservoir rock quality is poor as porosity is commonly occluded by replacive and pore-filling anhydrite. Intercrystalline micropores are present in the dolostones with matrix porosity values ranging from less than 1% to 5.4%. Matrix permeability values typically are less than 0.01 mD.

Core and log data are analyzed for fracture characterization and integrated with seismic interpretation to build a geomechanical model for fracture evaluation. The model is based on fault framework, and provides fracture density, direction, and possible types in observation points around these faults. The fractures are confined to dolomudstones and do not cross cut bedded anhydrites. Fracture-related permeability in these intervals is dominant and much higher than the matrix permeability. Spatially, fracture density value is higher in Kra Al-Marzu as compared to Mutriba. Fracture plays a key role in the distributions of effective porosity and permeability in more brittle dolomudstone intervals. Also, higher flow rates have been observed in areas with higher fracture density.

### **Land surface waves: a quantitative geophysical tool**

*Adamy Jerome (jerome.adamy@sismocean.com), Mouton Edouard and Durand Gregory (SISMOCEAN)*

One way of characterizing the subsoils at shallow depth, is to determine the shear wave velocity ( $V_s$ ) depth profile. This is now recognized as a pertinent

non-invasive method for the evaluation of the material properties (shear modulus) in soil and rock deposits. The shear modulus ( $G_{max}$ ), as other moduli such as Young's modulus ( $E$ ) or the compression modulus ( $M$ ), provides valuable information for settlement calculations or for finite-element modeling. The multi-channel surface wave (MASW) technique is capable of producing an easily understood depth profile. Changes of the soil properties can be detected by a MASW profiling system. For large survey areas, a fast acquisition is obtained by operating gimbaled geophones, which can be dragged over the soil. Otherwise, classical coupling between soil and geophones is performed. The cost of the time spent in the field is often a limiting factor to the amount and eventually also to the quality of the data that are collected in geotechnical investigations. A geotechnical investigation can be easily optimized by running a MASW survey that highlights the soil conditions at a very reasonable cost compared to other techniques. SISMOCEAN uses different types of seismic sources: hammer blow, dynamite or natural noise (micro-tremor). The capability of working with micro-tremor allows us to acquire data in noisy conditions (urban areas, industrial plants, etc.). The seismic data are typically recorded with 24 to 72 geophones equally spaced (typically from 1 to 3 m). Representative examples and results are shown in this presentation. We will also show how cavities can be perfectly detected using natural noise as a seismic source.

### **Underwater marine surface waves**

*Adamy Jerome (jerome.adamy@sismocean.com), Mouton Edouard and Durand Gregory (SISMOCEAN)*

Nearshore and coastal surveys are scheduled to acquire soil data for the design of pipeline landfalls, pipeline routes in shallow water, jetties and breakwaters, loading/unloading facilities for LNG and oil terminals, and other coastal developments. The underwater multichannel analysis surface wave [U-MASW] is a very efficient quantitative geophysical tool to investigate the upper part of the seabed. It is also complementary to standard geophysical tools such as subbottom profilers, seismic reflection that give qualitative information. U-MASW data are collected using a bottom-towed acoustic source and a low-frequency hydrophone streamer. The data processing is briefly addressed in this presentation. The output is a number of continuous shear wave [ $V_s$ ] depth profiles covering the surveyed area. The  $V_s$  depth profile delivers quantitative soil data directly linked to the shear modulus. This can be used to position boreholes in order to sample a maximum number of soil configurations over the surveyed area. The U-MASW is also perfectly well adapted to investigate or localize areas where very soft soils are encountered. Several sites have already been investigated by SISMOCEAN using the U-MASW tool, and representative examples are shown in this

presentation. The U-MASW allows for a penetration depth ranging from 3 m below seabed [bsb] to 50 m bsb. The penetration depth is totally independent of the water depth. The sailing speed during acquisition is 2 knots. Thus, 24 nautical miles can be surveyed per 12 hours shift. A route of 100 km long is surveyed in less than 3 shifts, which makes the U-MASW a tool that should be considered for pipeline route surveys, as well as for harbor development and pre-dredge surveys.

### **Impact of the initial model on acoustic impedance inversion**

*Timothy H. Keho (Saudi Aramco, timothy.keho@aramco.com)*

Interpretation of an acoustic impedance volume requires an understanding of the relative contributions of seismic and well data to the inversion process. In some cases the initial impedance model, which is generated by interpolating and/or extrapolating the well impedances along the seismic event times, can dominate the final impedance inversion, thus overweighting the well information and underweighting the seismic data. In Saudi Arabia, a very strong impedance contrast occurs between the Permian Khuff carbonates and the pre-Khuff Unayzah clastics. Vertically smoothing the well impedance across such strong contrasts can create a bias in the initial model, which impacts the inverted impedance for the underlying clastic reservoir. In particular, model-based inversions that constraint the output impedance to remain within a specified percent of the initial model are susceptible to this problem. Seismic inversion is not sensitive to slowly varying changes in the initial impedance model, which correspond to frequencies outside the seismic bandwidth. This is true not only for vertical variations, but also for lateral variations. For this reason it is important to compare impedance slices from inversions that were generated using multi-well initial models, to impedance slices that were generated from inversions using either a single-well initial model or a constant impedance initial model. Other approaches include subtracting the initial model from the final inversion to highlight the contribution from seismic data, or to use geostatistical methods that allow the user to control the relative contributions of the well information and the seismic to the final inversion results. Several examples are shown to illustrate problems and solutions related to both vertical and lateral variations in the initial impedance model that are below the seismic bandwidth.

### **Synthetic seismogram analysis of Unayzah reservoirs in Saudi Arabia**

*Timothy H. Keho (timothy.keho@aramco.com),  
L. Wayne Smith, Michael K. Broadhead and  
Fernando A. Neves (Saudi Aramco)*

The quality of Carboniferous-Permian Unayzah reservoirs in Saudi Arabia can vary significantly depending on the depositional environment. Reservoir facies vary laterally from braid plain, to meandering fluvial, to lacustrine sands and silts, to dune, interdune, and sheet sands, with the dune facies usually having the best reservoir quality. Porosity-permeability relationships can also vary significantly depending on facies. A proper understanding of the seismic response is necessary to detect reservoirs, delineate the lateral extent of reservoirs and to identify reservoir sweet spots. Both pre-stack and post-stack synthetic seismograms are presented to illustrate the variety of seismic responses that are expected due to variations in porosity, thickness, lithology and fluid type. Synthetic models indicate that a simple, yet effective technique for optimizing the locations of Unayzah wells is to look for bright amplitudes immediately below the base Khuff seismic event. The presence of gas, higher porosity sands, and greater reservoir thickness all result in larger reflection amplitudes. However, modeling shows that there is no observable AVO response that will discriminate fluid type within the reservoir. Variations in AVO are observed, but these are due to changes in lithology, not fluid saturation. Due to the large impact of porosity on acoustic impedance, a high porosity wet sand can cause a brighter reflection than a low porosity gas sand. In general, impedance contrasts within the Unayzah are small, resulting in weak reflection amplitudes even for gas-filled reservoir rock. Because of the weak impedance contrasts, multiples and sidelobes of adjacent reflections are sometimes larger than primary reflections, making interpretation of seismic attributes difficult.

### **The benefits of updates on geological and petrophysical understanding of Lower Burgan reservoir in Sabiriyah field, north Kuwait**

*Ali Nasar Khan (ankhan@kockw.com),  
Talal Mohammed Shehab, Nouf Abdulla Al-Mayyas,  
Moudi Fahad Al-Ajmi and Ealian H. Al-Anzi (KOC)*

The Burgan Formation in Sabiriyah field, a layered clastic reservoir deposited in Early Cretaceous time, is underlain and overlain by the Shu'aiba and Mauddud carbonates, respectively. The reservoir is divided into lower, middle and upper Burgan zones. The Lower Burgan zone is the most prolific of the three and consists of lower massive sands and upper-layered channel sands. The lower massive sand section, more than 250 ft in thickness, consists of medium- to coarse-grained well-sorted sand deposited by a fluvial system. The upper-layered channel sands consist of intercalated sand and shale beds. It is relatively less thick and the reservoir has lower quality. The depositional setting is interpreted to be an estuarine and river channel system where the marine influence increases towards the top of the reservoir. The reservoir has been in production for more than four decades and to date most of the oil

reserves of the massive section have been produced. The major share of present-day production is from the layered upper section where most of the remaining reserves exist. Both massive and layered reservoirs are produced under natural active water drive energy. The encroachment of formation water in producing wells and limited surface facilities for handling produced water along with sands of limited aerial extent poses a great challenge in firming up infill drilling locations having good reservoir quality and thickness. Detailed geological studies on cores cut in recently drilled wells has led to a better understanding of the depositional system and upgraded existing geological knowledge of the reservoir. Analysis done on cores for rock and fluid properties along with advanced logging techniques adopted and periodical mapping of water encroachment pattern down to the level of flow units have resulted in an aggressive infill drilling plan. The development scheme of the reservoir has been modified and resulted in the addition of production and reserves.

### **Multiscale analysis of well logs**

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The trend towards more cost-efficient hydrocarbons exploration, field development and production requires a detailed and accurate understanding of the subsurface geology. Over geological time, strata are laid down at various scales reflecting changes in the environment at the time they were deposited. Based on an investigation of well logs, a number of geophysical rock properties have proved to exhibit non-stationary multiscale behavior. Moreover, because of the complex chain of processes by which climatic changes and plate tectonics are transformed and encoded in the strata, typical geological characteristics are unlikely to exhibit simple sinusoidal cyclicity. Conventional spectral analysis may not then be appropriate to identify and evaluate characteristics of well logs, such as superimposed cycles, scale-invariance and abrupt changes in the geological trends. In this study, a multiscale analysis is proposed to disentangle both local and global subdivisions of such complex phenomena and to provide the necessary tools for the characterization of the subsurface complexity. It will be shown that the continuous wavelet transform (CWT) possesses the required power and flexibility to extract various multi-scaling patterns from well logs. The wavelet transform will be first introduced and the guidelines for the selection of a suitable wavelet kernel will be outlined. The mechanisms of the CWT will be demonstrated through synthesized computer simulations. Finally, the performance of the proposed wavelet transform in detecting cyclicity, zonations, and other abrupt changes in sedimentary successions will be demonstrated using real well logs.

### **The potential of blind source separation techniques for multiple suppression**

*Faouzi M. Khene (King Fahd University of Petroleum and Minerals, mfkhene@kfupm.edu.sa)*

Blind Source Separation (BSS) has received much attention in the context of acoustic mixtures. Most algorithms that separate convolutive mixtures exploit the spatial selectivity of an array of microphones. It is natural therefore to put convolutive BSS into the context of multiple suppression. BSS techniques can be formulated as the problem of separating or estimating the waveforms of the original sources from an array of receivers without knowing the characteristics of the transmission channels, i.e. the subsurface. In this work, we assume that the seismic data, referred to as the output, is modeled by a linear convolutive mixture of primaries and multiples, referred to as sources. We will describe various approaches, methods and techniques to blind and semi-blind source separation, especially principal and independent component analysis. The goal of this work is to investigate the potential of BSS techniques in handling the primaries and multiples separately. The efficiency of the proposed algorithms will be assessed using synthetic models with increasing complexity.

### **3-D pre-stack depth migration of a land survey with considerable multiple interference: a case study**

*Frederick Kierulf (frederick.kierulf@aramco.com), Adam Fox and Luke F. LaFreniere (Saudi Aramco)*

Saudi Aramco has started the application of 3-D pre-stack depth migration to improve seismic imaging of deep targets. Historically, processing that included dip moveout and post-stack depth migration effectively imaged most of the shallow exploration and development targets. Recently, some of the deeper, faulted targets required the use of 3-D pre-stack depth migration (PreSDM). Applying 3-D PreSDM on high-fold seismic surveys, reaching up to 960 fold, presents a unique challenge. Such large data sets have tested the limits of software and computer resources. Much effort was focused on the initial velocity model development. Several models were created using check shots, sonic logs, pre-stack time migration root mean square velocities and pseudo apparent interval velocities. Velocity model updating was also challenging due to multiple energy contamination. An innovative approach was internally developed to attenuate multiples on high-fold common mid-point gathers. The application of this method on common image gathers proved to be effective in improving the velocity model updating procedure. The pre-stack depth migrated results show better imaging of the primary reflections leading to better fault definition and positioning. These imaging improvements have allowed more effective placement of exploration, delineation and development wells.

### **The charging system of the lower Cambrian-Ordovician gas reservoirs of North Oman**

*Sulaiman Kindy (sulaiman.a.kindy@pdo.co.om),  
Steffen Ochs, Paul Taylor and John Millson (PDO)*

A new 3-dimensional maturity model of the top Huqf source rocks was constructed using the latest mapped seismic horizons, well data, and geochemical data. The model highlights several maturity provinces with distinctive HC gas-expulsion histories. Several migration scenarios were used to model the current distribution of Haima gas accumulations. These scenarios capture the reconstruction of both the Ara Salt and the impact of deep-seated fault systems. An integrated charge model is provided to explain the Haima gas types and distribution. Modeling suggests two distinctive charge pulses took place across the Ghaba Salt Basin: a mid-to-late Paleozoic 'wet' gas charge and a later Mesozoic 'dry' gas charge. Within the basin, the earlier 'wet' charge was flushed from the lower Haima Amin/Miqrar by a later 'dry' gas charge, but is preserved and is generally retained in the Barik reservoirs. The effectiveness of the regional Al Bashair seal and the timing of activation of intra-Haima faults and trap formation are critical elements determining the mixing of dry and wet gas of trapped gas in this region. On the western flank of the basin, the Al Bashair seal thins providing opportunity for gas mixing in the Haima reservoirs on the basin flanks. In the Fahud Salt Basin, a lower thermal maturity profile suggests a more recent 'wet' gas charge. A causal link between charge timing (coupled with migration pathways) and the preservation potential of primary porosity of the clastic Haima reservoirs has been identified.

### **Anatomy of a world-class source rock: distribution and depositional model of Silurian organic-rich shales in Jordan and implications for hydrocarbon potential**

*Sadat Kolonic (Shell, sadat.kolonic@shell.com)*

Silurian organic-rich ("hot") shales have sourced large amounts of hydrocarbons in northern Gondwana, with supergiant and giant fields in Saudi Arabia, Iran, Qatar, Libya and Algeria. A study of these black shales has been carried out in Jordan where they represent the source for the Risha gas field. Two organically enriched horizons occur in the Silurian in Jordan, termed the *Lower and the Upper Hot Shale*. Deposition of the transgressive Lower Hot Shale occurred during the early Llandovery and was restricted to earliest Silurian palaeodepressions. Three Lower Hot Shale depocentres have been identified in Jordan, which are located in the western Risha, eastern Wadi Sirhan and Jafr areas. The eastern Risha area was part of a larger-scale palaeohigh covering northeast Jordan, most of Syria and Iraq, and north-central Saudi Arabia (Qusaiba area). At least in Jordan the high

coincides with the depocentre of the latest Ordovician glaciation. Sedimentation of the Upper Hot Shale took place around peak sea-level during the late Llandovery-Wenlock and was limited to the distal parts of the shelf (Risha area), in front of the prograding silty-sandy deltaic front. Thermal maturity increases from immature in the Southern Desert outcrops to late/post-mature in northern Jordan. Organic-richness and pyrolysis data deteriorate significantly with increasing thermal maturity due to hydrocarbon generation. Prior to maturation, maximum organic richness is interpreted to have well exceeded 10% with good S<sub>2</sub> yields, as reflected in the values of the immature Lower Hot Shale in shallow borehole BG-14 in the Southern Desert Outcrop area and exploration well JF-1 in the Jafr area.

### **Black shale deposition on the northwest African Shelf during the Cenomanian/Turonian oceanic anoxic event: climate coupling and global organic carbon burial**

*Sadat Kolonic (Shell, sadat.kolonic@shell.com)*

High-resolution geochemical records from a depth transect through the Cenomanian/Turonian (C/T) Tarfaya Basin (northwest African shelf) reveal high-amplitude fluctuations in accumulation rates of organic carbon (OC), redox-sensitive and sulphide-forming trace metals, and biomarkers indicative of photic zone euxinia. These fluctuations are in general coeval and thus imply a strong relationship of OC burial and water column redox conditions. The pacing and regularity of the records and the absence of a prominent continental signature suggest a dynamic depositional setting linked to orbital and higher frequency forcing. Determining the dominant frequency depends on the definition of the OAE2 and its duration. We propose that eccentricity is the main forcing factor at Tarfaya that controlled fluctuations in wind-driven upwelling of nutrient-rich, oxygen-depleted intermediate waters from the adjacent Atlantic Ocean and the periodic development of photic zone and bottom water euxinia on the mid-Cretaceous northwest African Shelf. Accumulation records clearly identify the basin centre as the primary site of sediment deposition with highest temporal variability and an up to six-fold increase in OC burial from  $\sim 2 \text{ g/m}^2\text{-yr}$  prior to the OAE2 to  $\sim 12 \text{ g/m}^2\text{-yr}$  during the OAE2. Photic zone and bottom-water euxinia alternated with periods of greater oxygenation of the water column in response to climate forcing. Mass balance calculations imply that  $\sim 2\%$  of the overall global excess OC burial associated with the OAE2 was deposited in the Tarfaya Basin, an area that represented only  $\sim 0.05\%$  of the total global C/T ocean floor. In fact, the lateral extent of similar black shales along the African continental margin indicates that this part of the ocean contributed significantly to the global increase in organic carbon burial during the OAE2.

## **H<sub>2</sub>S production in petroleum reservoirs during steam injection process: TSR experimental simulation**

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François Lorant (IFP)*

The *thermo-reduction of sulphates* (TSR) naturally occurs in deep petroleum reservoirs. TSR can also artificially be induced by the injection of hot water during *enhanced oil recovery* (EOR) operations in shallow reservoirs containing heavy oils. Due to the high temperatures ( $150^{\circ}\text{C} < T < 300^{\circ}\text{C}$ ) reached in the reservoirs during hot-water flooding, chemical reactions involving oil, water and mineral matrix enriched in sulphates can lead to a significant increase of H<sub>2</sub>S production. In order to better understand TSR mechanisms and to tentatively estimate the risk of H<sub>2</sub>S occurrence during hot water stimulated enhanced recovery operations, experimental pyrolyses were undertaken under conditions as close as possible to those prevailing in reservoirs during hot water injection. The purpose of this set of experiments was to measure H<sub>2</sub>S production rates at various temperatures, then to tentatively derive a numerical model of H<sub>2</sub>S formation due to artificial TSR. The three primary processes involved in induced TSR [i.e. (1) oxidation of organic matter (vulcanisation), (2) sulphate reduction and (3) thermal cracking], were independently simulated in laboratory conditions and the results compared to those obtained from experiments simulating the complete TSR phenomena.

Artificial simulation using an n-alkanes mixture, elemental sulphur, water and mineral were conducted using an inert closed system pyrolysis at variable temperature for different residence times. TSR induced by hot water injection during EOR can thus be reproduced under laboratory conditions generating high amounts of H<sub>2</sub>S. The reduction of sulphates under the used conditions was confirmed, notably, by the presence of secondary MgCO<sub>3</sub>. TSR and vulcanisation seem to be kinetically controlled in our experimental conditions. However the rate of vulcanisation is very high compared to that of TSR. Therefore the alteration of hydrocarbons and formation of H<sub>2</sub>S are kinetically controlled by the rate of sulphates reduction.

## **Automated fault plane and polygon generation in a large, mixed 2-D and 3-D seismic data set**

*Michael Kumpas (mkumpas@kockw.com),  
Srinivasa Narhari and Hanan Al-Owihan (KOC); and  
Andrew Corley (Chevron)*

Automated processes for generating spatially consistent fault planes are available in a 3-D seismic interpretation environment, but not in 2-D. Automation of this process in a mixed 2-D and 3-D seismic environment was achieved

by applying existing Landmark technology so that it became possible to simultaneously process some 450 assigned faults and 14 horizons interpreted on mixed 2-D and 3-D seismic data. The maximum spatial extent of the 2-D and 3-D data sets was used to define a conventional 3-D volume. Interpreted horizons were imported into the empty 3-D volume from respective original projects regardless of their 2-D or 3-D origin. Horizon interpolation ensured seamless horizons between 2-D and 3-D data. Correlated and assigned fault segments were imported in an identical manner. All interpretation data are thus defined by spatial coordinates in a common 3-D data volume and can be processed using 3-D applications. All fault segments are 're-ribbed' in the 3-D domain. 'Re-ribbing' is run in both the x and y directions separately to account for faults subparallel to either ribbing direction. 'Re-ribbed' fault segments and seismic horizons are processed in 'Surface Tool' to calculate fault heaves and polygons. Fault polygons are generated for all selected horizons maintaining fault-plane integrity and polygon consistency among horizons. Conventional gridding and contouring of interpreted horizons is performed incorporating fault polygons. The method is an efficient tool that can be applied to any 2-D/2-D-3-D data for quick and accurate fault mapping across numerous horizons, without compromising fault plane integrity.

## **Integration of remote sensing data with geology and geophysics: case study from Bahrain**

*Andreas Laake (WesternGeco-Schlumberger; laake1@gatwick.westerngeco.slb.com) and Habib Al-Alawi (BAPCO); Rutger Gras (Schlumberger)*

The objective of the integration of remote sensing data with surface geological and geophysical data is to improve seismic survey design and data processing. Remote sensing data from satellites provides densely sampled information about the Earth's surface. When integrated with surface geological data, estimates of the elastic properties of the surface can be obtained to assist in planning the acquisition of seismic data. In particular, multispectral remote sensing data are interpreted for geomorphological characteristics such as sabkha and karst features, which are known to degrade seismic data quality. Developing surface elastic property estimates prior to the start of the seismic survey supports the selection of vibrator sweep parameters tailored to surface conditions, thereby improving survey data quality. This case study from the Awali field in Bahrain shows how integration of multispectral data and surface geology could improve surface seismic data quality. The success of the method is demonstrated through a karst feature (doline) and coastal sabkha. The results are presented in a Petrel database, which allows further integration with subsurface geological and geophysical data to improve the understanding of hydrocarbon reservoirs in the Middle East. The visualization comprises map images,

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virtual 3-D images, and virtual fly-through movies. The project shows, in a reservoir database, the benefits from combining surface seismic data and satellite imagery.

### Using low-frequency ambient seismic vibration spectra to detect hydrocarbon reservoirs: a numerical approach

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Federal Institute of Technology*); and Yuri Podladchikov  
(*University of Oslo*)

Ambient vibration measurements are successfully applied to identify and characterize low-velocity surface layers. The method is based on the analysis of characteristic features of the ratio between the amplitude spectra of the horizontal and vertical ground motion (H/V-ratios) caused by the ambient vibration. Similar to such features in the *Nakamura* H/V-ratios, characteristic signatures can occur in the spectra of the ambient vibration, which are likely to be caused by hydrocarbon-bearing structures in the subsurface. During several measurement campaigns conducted by Spectraseis Technologie at different oil field locations throughout the world, the presence of such signatures was observed and a high degree of correlation to the presence of hydrocarbon reservoirs could be established. In this presentation the impact of hydrocarbon-bearing structures on the surface velocity spectra is investigated by numerical simulations. The numerical algorithm is based on 2-D explicit finite differences with staggered grids, and solves the elastodynamic equations, which are formulated as a first-order hyperbolic system. The ambient vibration wave field is generated using the method proposed by the SESAME project (Site Effects Assessment Using Ambient Excitation). The model domain consists of a 3 km wide and 2.5 km deep elastic body. The hydrocarbon-bearing structure is represented by a 100 m thick and 1,000 m wide layer, located at a depth of 500 m, which has different geophysical properties than the surroundings. Results show significant pattern changes of the surface velocity spectrum depending on the magnitude of various parameters. The characteristic spectral patterns can therefore identify potential hydrocarbon-bearing structures similar to the *Nakamura* H/V-ratio peaks for identifying low-velocity surface layers.

### Deriving fracture attributes from seismic anisotropy: a case study

Pierre Lanfranchi (*planfranchi@cgg.com*),  
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Jean-Luc Piazza and Jean Perrot (*Total*)

Over the last few years there has been significant interest in the analysis of open fluid-filled fractures from P-wave azimuthal anisotropy. This presentation shows the results

of a recent study on the Tin Fouyé Tabankort field in the Illizi Basin (Algeria). The goal of this study was to characterize the seismic anisotropic fractures from root mean square (RMS) amplitude maps on a small volume of the field. Using an integrated workflow that combines azimuthal-friendly processing with a proprietary geostatistical decomposition technique, we obtained robust quantitative estimation of the anisotropy attributes. The approach was applied to a wide-azimuth 3-D land dataset from the Tin Fouyé Tabankort gas field in order to investigate the seismic fracture distribution in the interval top Ordovician to basement. One of the key issues for successful seismic fracture characterization is the preservation of the azimuthal information throughout the processing sequence. In order to ensure the minimum loss in azimuthal information, the binning grid was selected to generate a homogeneous offset and azimuth distribution. Azimuthal anisotropy analysis was performed on an area of 40 sq km using RMS amplitude maps extracted at each horizon. Although no well data were available for cross-validation, the quality of the estimated anisotropy attributes was assessed with seismic fault interpretation and seismic coherency maps. In addition, analysis of the source geometry was performed to evaluate the possible impact of acquisition footprint in the final fracture maps. A good correlation was observed between the extracted fracture intensity and orientation, the seismic coherency maps and the fault interpretation. Such results contribute to a better evaluation of the fracture networks.

### Quality control in today's recording systems

R. Malcolm Lansley  
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Over the last two decades the oil industry has seen a significant increase in the number of recording channels used for land 3-D surveys. Not only has the lateral extent of the active recording spread increased, but the spatial sampling has also decreased, resulting in an even greater increase in the number of channels required. Modern seismic data recording systems are capable of recording many thousands of channels. To manually perform adequate quality control of the data acquisition would be extremely inefficient and, therefore, most modern systems have automated methods of testing and analysing performance. Beyond the usual instrument performance checks, quality control measurements of both the sources and the receivers can be generated and automatically logged into a database. For example, ground viscosity and stiffness below vibrator baseplates can be estimated in addition to the measurement of ground force, phase and amplitude. Several studies have demonstrated the application of these measurements to estimate the spatial variations in near-surface velocities and hence improve the near-surface model for static corrections. For the receivers, the quality of the sensor plants can be assessed from analysis of the measured tilt angles. This, together

with the geographical coordinate information and the source quality measurements, permits the calculation of the actual fold of the survey being recorded. This presentation will review improvements in quality control in modern recording systems and information that is available for use in data processing that unfortunately, in many cases, is not fully utilized.

### **Uses, abuses and examples of seismic-derived acoustic impedance data: what does the interpreter need to know?**

*Rebecca Latimer (Chevron, rlatimer@chevron.com)*

Inversion of seismic data into acoustic impedance provides a natural tie to the log impedance data and forces the geoscientist, in analyzing seismic data, to extract appropriate wavelets, determine the phase and amplitude of the data, determine whether or not the phase is stable throughout the volume, and very intimately tie the well log impedance data to the seismic data. Utilizing inverted data at the beginning of the interpretation process requires that the geoscientist understand the rock properties in their target area before embarking on an “attribute” interpretation. Even when the P wave impedance data do not clearly distinguish between fluids or lithologies, value is added by using these data as the first interpretation tool. The simplicity in knowing that the change of values represents a change in rock properties without the complexity of wavelet variability is a distinct advantage to the interpreter and the sequence stratigrapher. This initial process is critical to undertaking any interpretation of seismic data. Inverted data, a layer property, are a more intuitive geologic tool that allows interpreters to utilize their natural ability to “see” the geology in the seismic data. This presentation will demonstrate the necessity for inversion and explain why it is beneficial in an interpretation and sequence stratigraphic workflow. It will examine both the strengths and drawbacks of using inverted data as compared with the seismic data and the original rock data. It will also show: (1) how scale differences between various data types can affect the results; (2) how the interpreter and the sequence stratigrapher utilize the inverted data; and (3) how to spot pitfalls in the overuse of impedance data.

### **The use of seismic impedance to locate a discovery well south of Ghawar field**

*Thomas Loretto (thomas.loretto@aramco.com) and Adel Al-Mousa (Saudi Aramco)*

A seismic impedance volume derived from seismic amplitude inversion was used as second-order control, in conjunction with first-order structural control, to assist in the location of an oil discovery, in Saudi Arabia. The impedance volume enabled us to locate vertically coincident estimates of high porosity in the two target

reservoirs, within the target structure. The upper target, the Jurassic Hanifa reservoir, flowed oil. The lower target was the Carboniferous-Permian Unayzah reservoir. The discovery, at well 2 was a follow-up to a discovery in well 1, in an independent structure about 10–15 km from well 2. In well 1, the Hanifa reservoir flowed oil and the Unayzah was wet. The impedance log from well 1, and seismic horizons at the two reservoirs, were used to define the initial model for the inversion. Impedance attribute maps showed that the initially proposed location for well 2 did not fall within an impedance minimum. The impedance minimum is ideal, given an inverse relationship between impedance and porosity. Due to the exploration nature of the well, structural considerations played the primary role in its location. Structure maps at both targets showed that there was freedom to move the proposed location to the final location, into an estimated impedance minimum at both reservoirs, and stay at the same structural position. A comparison of the predicted impedance from seismic, with the impedance from well 2, shows that the inversion did a good job of predicting the impedance at the discovery well, in both the Hanifa and Unayzah reservoirs.

### **Expanding imaging areas using transmitted waves and multiples in VSP data**

*Yi Luo (yi.luo@aramco.com), Yuchun Wang and Mohammed N. Alfaraj (Saudi Aramco); Qinglin Liu (WesternGeco)*

The presentation shows two new methods for imaging VSP data. For the first method, we demonstrate that mode-converted transmitted waves observed in VSP data can be used to image areas above horizontal wells, which traditional VSP cannot due to lack of recorded reflections. We verify with real data examples that transmitted-wave migration coupled with the reduced-time theory can indeed image geologic horizons above a horizontal well in an offset VSP survey. As reflections can be used to image areas below geophones, transmissions can do the same for the areas above. Therefore, incorporation of mode-converted transmitted waves significantly expands the area illuminated by seismic data. For the second method, we will illustrate, with real and synthetic VSP data that multiples can be used to enlarge the imaged areas based on the newly developed interferometry theory.

### **Early detection of biodegraded oil using NMR downhole logs and hydrocarbon GC-MS analysis on sidewall cores**

*Anna Maria Lyne (annamaria.lyne@agip.it), Patrizio Gossenber and Angelo Riva (ENI)*

Detection of biodegraded oil at an early stage in exploration wells is quite important due to their poor characteristics with respect to good quality, less viscous

oils. Traditional logs, such as resistivity, porosity and gamma-ray logs, show the position of the reservoir and its hydrocarbon content but are unable to provide information regarding the hydrocarbon quality, it being sometimes difficult even to differentiate between liquid and gas accumulations. During an acquisition of wireline logs in an offshore exploration well, an NMR log was run, aimed at integrating the traditional set of logs to better define porosity, permeability and Swi. Because of the lithological complexity of the reservoir, sidewall cores were cut and petrophysical values such as porosity and permeability were measured. The presence of high viscosity biodegraded oil accumulations was suspected early on due to the “peculiar” signature of the NMR log in the hydrocarbon-bearing rocks. Very low mean T2 values, which using the traditional partitioning of the NMR T2 distribution indicate high volumes of clay- and capillary-bound fluids, were measured in oil-bearing layers within the reservoir. A detailed molecular study was performed on the residual oil extracted from the sidewall cores and showed different levels of biodegradation in various sections of the reservoir depending on both depth and proximity to the OWC. The good relationship between the mean T2 value from the NMR log and the biodegradation level found through GC-MS analysis gave us confidence in NMR logs for early detection of these kinds of oils in reservoirs where cores are not available.

### **Optimum 3-D geometry design for minimizing acquisition footprint**

*Weining Ma (wanglj@bgs.com.cn), Xinwen Liu, Mengchuan Duan and Xueqiang Chen (BGP)*

To have a reliable geological interpretation, geologists need reliable seismic information. The acquisition footprint caused by 3-D geometry gains more and more attention from geoscientists. This presentation first analyzes the influence on acquisition footprint due to 3-D geometry parameters such as receiver line interval (RLI), shot line interval (SLI), cross-line roll distance, and different patterns of geometry and different depths of targets through building up an ideal model and then clarifies the direction of efforts to minimize the acquisition footprint through 3-D geometry design. Secondly, the presentation proposes optimal 3-D geometry design compromising the field acquisition cost and acquisition footprint without sacrificing geologic targets.

### **Joint analysis of PP and PS data from a 3-D-4C OBC seismic survey over a clastic reservoir in the Arabian Gulf**

*Costas G. Macrides (konstantinos.makridis@aramco.com), Fernando A. Neves and John S. Eberle (Saudi Aramco)*

In 2002 Saudi Aramco conducted its first ever 3-D,

4-Component (4-C) ocean bottom cable (OBC) seismic survey in the Arabian Gulf. The main objective was the delineation of the Cretaceous fluvial stringer sands of the target reservoir overlying the massive main sands of the Zuluf field. A pre-survey modeling study based on Vp and Vs logs indicated that the use of converted waves holds promise of improved structural and stratigraphic imaging of the target reservoir, which is typically characterized by weak acoustic impedance contrasts. Commensurate with the objectives of the experiment, the 100 sq km survey was acquired with an in-line swath shooting geometry employing two seabed receiver cables, with a symmetric split spread deployment of the 4-C sensors. There were six sail lines per swath with a single boat dual source flip-flop configuration. The data was processed through dual-source summation, horizontal-component rotation and PP/PS pre-stack time migration. Post-stack enhancement in the form of non-stationary Gabor deconvolution proved particularly beneficial in view of the low-frequency content of the acquired converted wave data. Well-to-seismic calibration for both PP and PS data, at five wells, greatly aided in the interpretation of the data. In the end, five key horizons were interpreted and correlated between the PP and PS sections. Joint post-stack analysis of the interpreted horizons, using both amplitude and interval time information, enabled us to map the lateral variations of the Vp/Vs ratio within the survey area. Although it was not possible to fully resolve individual sand stringers, these maps of the Vp/Vs ratio allowed us to estimate the overall net pay zones of the sand-shale sequences of the target reservoir.

### **Meeting seismic data quality expectations: new dimensions in seismic survey design**

*Paul Matheny (paul.cp.matheny@pdo.co.om) and Said Abri (PDO)*

During the past 10 years, the methods used to improve seismic data quality were based on increasing fold, denser subsurface coverage, and full 3-D geometries. Experience has shown that (ultra) high-fold surveys do not always deliver the expected improvements, decreasing the bin size has similarly failed to deliver the higher frequencies. Designing land acquisition geometries for PDO now requires that all past experiences in an area be modeled and explained in order to set realistic expectations. The process starts with the subsurface targets and objectives. A subsurface 3-D model is built and synthetic seismic data is modeled using the finite difference technique in elastic and acoustic modes or with the full 3-D pre-stack Kirchhoff formulation. The system is therefore quite flexible and easily implemented. Full 3-D pre-stack data is created based on an inhomogeneous subsurface model for a plurality of acquisition geometries. At a minimum, all past 3-D acquisition geometries are modeled as well as the proposed new acquisition geometry. The 3-D volumes are processed through migration to create

products for evaluation. The process recreates the characteristics of prior acquisitions and demonstrates the expected benefits of new acquisition in the area. Further, the created 3-D synthetic volumes are used to test new processing strategies and algorithms. The key value-add by deploying this technology is the ability to model the full life cycle of seismic acquisition and processing. With the 18 months experience of consistently applying this practice, we are now able to review our predictions with real 3-D data results.

### **Good 'seismic' vibrations in Fahud**

*Paul Matheny (paul.cp.matheny@pdo.co.om) and  
Said Mahrooqi (PDO)*

Fahud, PDO's largest field, produces oil from the Natih fractured carbonates. Most production is from shallow layers via gas oil gravity drainage. Waterflooding is planned to tap the large remaining reserves from deeper layers. Waterfloods in potentially fractured reservoirs is challenging and an accurate subsurface model is critical for success. 3-D seismic covering Jebel Fahud (acquired in 1994) is noisy over the crest of the field due to acquisition problems associated with gaps in coverage, coarse sampling, and absorption/scattering of energy in the weathered near-surface layers. An integrated project team covering acquisition, processing, interpretation, and reservoir geophysics was set up in 2002 to justify, plan, and execute a new 3-D survey. A 2003 field pilot was executed to evaluate source and receiver coupling, lateral sampling and statics control requirements. The pilot concluded that Vibroseis data quality is generally better than dynamite data, receiver coupling is not a limitation, and that the critical factor for data quality is source and receiver sampling and good statics control. The 2004 3-D seismic survey resulted in a nominal coverage at target that is 16 times higher than the 1994 acquisition. The key success factors for operational and HSE goals were early planning, digital elevation maps of the mountain, and the use of professional mountaineers. Preliminary results indicate that the new seismic data is superior to the 1994 data, particularly under the roughest topography.

### **Detection of oil/condensate droplets in a gas reservoir**

*Rashad Mohamed Masoud (rmmasoud@adco.ae) and  
Dewanto Odeara Surja (ADCO)*

Condensate dropout takes place in a gas reservoir whenever the reservoir pressure has declined below the dew point pressure. This presentation will describe a case study of a well producing gas and condensate from a giant late Cretaceous carbonate reservoir on land in

Abu Dhabi, where the produced gas was recycled and re-injected back into the reservoir to maintain the original reservoir pressure. Open Hole Density-Neutron logs acquired in some wells, in particular in the south part of the field including the case study well, show apparent liquid behavior at the bottom section of the reservoir rather than the gas effect seen in most other wells. Anti-correlation on the Neutron-Density (N-D) overlay usually indicates the effect of gas in the formation. Lack of such anti-correlation on N-D overlay is usually due to effect of either presence of liquids or mud invasion. Other observations support the presence of liquids in the formation rather than mud invasion: (1) Production data of some wells show decline in Condensate Gas Ratio (CGR), which may indicate the possibility of condensate dropout the reservoir. (2) Moreover, inspite pressure support by gas injection, the *pressure build up* (PBU) data show a decline in the reservoir pressure in this part of the field. In order to acquire more data to confirm the presence of liquids in the bottom section of the reservoir, conventional logs and down hole compositional Fluid Analyzer (CFA & LFA) data as well as three PVT samples from the top, middle and bottom of the reservoir have been collected and analyzed. The results from PVT samples analysis confirm the results of down hole fluid analyzer. These results confirm the presence of liquid column, condensate droplets, at the bottom part of the reservoir.

### **Land seismic static corrections in the Rub' Al-Khali Desert**

*Pieter van Mastrigt  
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Near-surface static corrections significantly impact the quality and reliability of the seismic image on many land datasets. This is particularly true for the south Rub' Al-Khali Desert, where hydrocarbon objectives exhibit closures of several tens of milliseconds in the presence of significant surface anomalies (dunes, shallow karsts, buried wadi systems) that can create static anomalies of well over one hundred milliseconds. A number of test lines have been processed through the application of different methods, which all attempt to correct for the static delays as well as corrections to the final reference datum, whilst at the same time yielding a time section and corresponding velocities that represent, as close as possible, the true subsurface after depth conversion. One modern vibroseis line has been processed by five companies using four significantly different approaches between them. Those include: (1) dune-modeling; (2) refraction statics; (3) application of tomostatics; and (4) near-surface modeling with upholes. In this presentation we will compare the methods used and highlight the learning points and pitfalls from each method.

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### **Haban gas field: Oman's first amplitude-supported play**

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Gas was discovered in the Cretaceous carbonate Natih Formation in the Haban field in 1985. The field is characterized by an elongated north-dipping structure and a major E-trending fault with large vertical displacement. The field is penetrated by five wells in different fault blocks. Mapping and delineation of the field was performed on 2-D seismic. In 2004, the first 3-D survey was acquired to improve the field delineation and supporting the field's development plan. The Haban 3-D data is one of the best 3-D data sets in the PDO inventory. Volume interpretation over the field identified bright amplitude zones. Delineation of the extent of the amplitude anomalies indicated strong correspondence in time and depth. Seismic modeling of the top Natih reservoir showed that high amplitudes are associated with gas zones transitioning into a dimmer response in the water leg. The modeled amplitude behavior corresponds with the signal response as seen in the 3-D volume. Constrained sparse spike inversion (CSSI) conducted over the field allowed better definition of the different reservoir units and the distribution of the gas zones. Based on the seismic analysis results, two appraisal wells are planned to target the gas accumulation in high amplitude zones in 2005. Further work is ongoing in the down-thrown side of the main fault to calibrate the bright amplitudes anomalies, lower the risk and unlock the exploration potential.

### **Near-surface models for transition zone data in the Arabian Gulf**

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In the transition zone 2-D and 3-D seismic has been acquired, and a near-surface model is required which will tie this to *a priori* land and marine data. On land, datum is a smooth representation of the surface and is generally 60 m deep. At the water's edge the datum is at an elevation of -60 m. The marine data has been processed to mean sea level (MSL). A single datum could not be used for the model without introducing a considerable time shift from the shore line to the marine data. All the transition zone models have correction statics referenced to the land datum and to MSL.

The initial static corrections were calculated from the single layer velocity model. This model is derived from upholes, and extrapolated from the shore line to the transition zone as no velocity data was acquired there. The initial model is revised where the transition zone has

mud infilling an irregular solid surface which may have no surface expression at the water bottom. Source gathers are extracted from the seismic data, a correction has been applied for the depth of water. One side of the spread is interpreted to derive the depth and velocity characteristics which are modelled at source location producing a two layer model. The land surface has sand dunes over which the revised model is enhanced with refraction statics. The near surface modeling techniques have resulted in a consistent near-surface correction static solution.

### **Porosity semivariogram parameters for carbonate reservoirs**

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Geostatistical models are a routine part of the reservoir appraisal and development process. The stochastic algorithms that are used to populate reservoir models use the semivariogram as the measure of spatial continuity. For reservoirs with abundant, good quality well log data the semivariogram parameters can be defined and their uncertainty established from the field data. For fields with few wells the semivariogram parameters are usually taken from an analog or inferred from the likely geometry of depositional elements. In data limited cases, it is difficult to assess appropriateness of the analog derived parameters or assign appropriate ranges to the parameters as part of an uncertainty assessment. This review of porosity semivariogram parameters is based on carbonate reservoirs from the Permian Basin, western Canada, Kazakhstan, and the Middle East with abundant good quality porosity well logs. Some key findings include: (1) the semivariogram range parameter is typically 1,000–2,000 m; (2) most carbonate reservoirs do not show significant porosity anisotropy; (3) the variation of semivariogram parameters between reservoirs is similar to the variation by stratigraphic interval within a reservoir; (4) the variation of the semivariogram range parameter for different sequence stratigraphic layers within a reservoir is typically a factor of three; (5) the minimum reported range is 150 m and the maximum is 6,500 m; (6) there is no correlation of the range parameter with depositional age and only a slight correlation with depositional setting; and (7) there is no difference in the range parameter for limestone dominant and dolomite dominant reservoirs.

### **Diagenesis of the upper Khuff (Permian-Triassic) Formation and its impact on reservoir characterization**

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The Upper Khuff carbonate reservoir (Permian-Triassic) is a complex carbonate system with various fine-scale

heterogeneities that have a direct impact on the reservoir quality distribution and dynamic behavior. The porosity distribution and the permeability architecture of the Khuff reservoirs are the result of a complex interplay between depositional controls (facies, texture) and diagenetic overprints that have had both favorable and unfavorable impacts on reservoir quality. The complexity of the Khuff poroperm network results from a series of diagenetic overprinting events including: (1) dissolution, (2) calcite cementation, (3) pore-filling and replacive anhydrite, and (4) dolomitization. Understanding the diagenetic evolution is, consequently fundamental in better understanding the reservoir heterogeneity and constraining the 3-D distribution of Rock-Types. This presentation shows the results obtained from the petrographic and geochemical characterization of the Khuff diagenetic products, their stratigraphic distribution and their reservoir impacts. The diagenetic interpretation has allowed the construction of conceptual diagenetic models to guide reservoir quality prediction. A particular emphasis has been placed on characterizing the dolomitization processes because each type of dolomite is formed in a specific diagenetic environment leading to different body geometries and distribution. As some of these dolomites present distinctive reservoir properties (good porosity and very high permeability values), it is essential to evaluate and map the geometry and the extent of the different dolomite bodies to be able to predict the dynamic behavior of the field.

### **The impact of Nubia reservoir quality on reservoir management, Gulf of Suez, Egypt**

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The Nubia Sandstone is the primary reservoir in the Gulf of Suez. However, the Nubia is not a single uniform sandstone unit; it ranges in age from the Paleozoic (e.g. Nubia C) to the Cretaceous (e.g. Nubia A) and was deposited in alluvial/fluvial to paralic environments. This study investigates the influence of the reservoir architecture and changes in rock quality on reservoir performance. A complete integration of available conventional core analyses, petrographic data, and openhole wireline logs throughout the Gulf of Suez was conducted. The specific aim was to understand the commonly observed deterioration in rock quality with depth. Although this reduction in rock quality may be only a couple of porosity units it has an order of magnitude effect on permeability. A more focused investigation of reservoir performance including production logs was then performed on the October (Nubia A) and Ramadan (Nubia C) fields. In the Ramadan area Nubia reservoir performance is primarily a function of grain size and clay content; however, in the October field it is more influenced by lithofacies changes. The changes in rock quality have resulted in different reservoir management practices in these two

mature oil fields. In October field, reserves have been maximized through a programme of successive water shut-offs isolating each reservoir layer as it waters-out. Whereas in Ramadan by-passed oil is in the deeper, lower permeability zone and was recently accessed by drilling a horizontal well.

### **Profiling complex flow in deviated wells: a North Sea case study**

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The keys to proactive production and reservoir management are production logs that profile fluid entries and diagnose problems in producing wells. Designing optimal production strategies and remedial operations requires high-confidence diagnosis. Production logging in deviated wells producing mixtures of various phases is challenging because of complex flow regimes. This is further complicated by fluid recirculation in the well bore, causing the heavier phase to fall back towards the bottom of the well bore, resulting in negative velocity on the low side. We present a field example that uses a new compact, integrated production-logging tool that incorporates the latest technological advances and best practices to address complex production-logging requirements. We also present the logging results in similar wells during the same campaign that were logged with a conventional production services platform tool. We are able to demonstrate the added value in terms of comprehensive flow diagnosis. A production logging operation using the new tool, which specializes in horizontal and deviated well logging, was planned to obtain key inputs for the reservoir model and investigate reasons for low well productivity. The well was producing from multiple horizons, and it was critical to obtain an accurate flow profile and infer the extent of depleted layers in the field. Production logs from the new tool resulted in accurate flow diagnosis and led to better understanding of complex flow mechanisms across multiple producing zones. Future steps after this logging operation include re-perforation and hydraulic fracturing of selected intervals. The tool provides a recording of holdup and velocity profiles along the vertical cross-section diameter of the borehole. The direct measurement of the velocity and fluid holdup profile enhances the capability of the analyst to determine the downhole phase.

### **Diagenetic studies of Devonian sediments in the Zagros basin, southern Iran**

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A sequence of Devonian clastic sediments (Zakeen Formation) located 103 km north of Bandar Abbas in southwest Iran was studied. The objective of the study was to determine the types, roles and relative age of cements

in the Zakeen Formation. 168 surface samples from a 155 m column of the Zakeen Formation were prepared for thin section studies. The types of cement and their relative frequency of occurrence were determined, and the relationship among cement types was investigated. Seven types of cement were found in the sandstone: syntaxial overgrowth quartz, iron (Fe) oxide, carbonates, silica, phosphate, clay and spotty Fe oxides. Among these cements, the most frequent type is syntaxial overgrowth and the least frequent type is spotty Fe oxides. Syntaxial overgrowth forms about 40% of the cements of the Zakeen Formation sandstones. Diagenetic processes altered the quality of porosity in 4 steps. These steps have been divided into two main categories: early and late diagenesis. Clay, phosphate, calcite mosaic type 1 and Fe oxides type 1 cements formed during early diagenesis. Syntaxial overgrowth, void-filling calcite and Fe oxides type 2 cements formed during the late diagenesis. The winnowing of Zakeen siliciclastics in a shallow-marine, high-energy shelf resulted in the deposition of clean sandstone and consequently the development of extensive quartz overgrowth. This was followed much later by the microfracturing of grains and overgrowth, which resulted in the formation of high porosity sandstones in both the Zakeen and Lower Permian Faraghan formations.

### **An integrated 3-D surface and borehole seismic approach to better understand a complex reservoir: case history from west Kuwait**

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New technologies in borehole seismic and surface-seismic data acquisition and processing have allowed the integration of borehole information, such as walkaway zero-offset VSPs and dipole sonic logs, with surface seismic data. The aim of this integration is to produce seismic images of superior resolution, which can subsequently be optimally conditioned for inversion and reservoir characterization. This presentation describes some of these new developments and the results from a project in Minagish field, onshore west Kuwait. The main reservoir, Minagish Oolite, of Cretaceous age is around 120 m thick. Secondary reservoirs are in the Upper Cretaceous and Jurassic layers. Apart from a series of normal faults running east-west through the centre of the field, there is evidence of a large number of small faults and lineations, which could act as barriers for fluid movement. While the seismic data quality in the field is generally good, the Minagish Oolite reflection is disturbed by karsts in the overlying Shu'aiba Formation and interference from inter-bed multiples from the shallow horizons. Integration of the borehole data with 3-D seismic data was utilized for relative true-amplitude recovery, multiple suppression and anisotropic corrections. Relative true-amplitude recovery was based on VSP-derived inelastic

attenuation factors, anisotropic geometric-spreading corrections and transmission-loss compensation factors obtained from the VSP data. Anisotropy corrections accompanied velocity analysis, which was guided by the borehole velocity function, enabled accurate distinction of primary reflection events from multiple events. The final results of the processed seismic data were quantitatively appraised by the quality of the tie between the final migrated data, synthetic seismogram and VSP corridor stack from a number of wells. The integration of various data sets resulted in improving the seismic image, with overall higher resolution that enabled a robust and accurate inversion.

### **A novel approach to processing transition zone vibroseis data**

*Mohamad Samir Nahhas (snahhas@adco.ae),  
Martin Boekholt and Fatema Al-Shekaili (ADCO)*

A large vibroseis survey over sand dunes and coastal plain and an adjacent dynamite/airgun transition zone survey were jointly reprocessed. Key to the processing was zero-phasing for the vibroseis and the impulsive data, before picking first breaks for refraction statics. The objective is a more reliable seismic image of these oil fields. The vibroseis survey was reprocessed jointly with an adjacent transition zone survey in Abu Dhabi. The area covers two major low-relief oil fields. Data of high temporal and lateral resolution and of good structural and stratigraphic accuracy is required for mapping subtle faults and improved reservoir characterization. Accurate long and short wavelength statics solutions and reliable stratigraphic wavelet processing are critical. The vibroseis survey comprised an area of sand dunes, hard sabkha plains and flat lying shoreline. The transition zone survey comprised dynamite sources in land and shallow water, and airgun sources in deeper water. Geophone and hydrophone receivers were employed on both surveys. Starting the processing by zero-phasing the wavelet was employed to deliver consistent data character across the surveys. Excellent statics results were achieved in reprocessing due to careful first break picking after zero-phasing, and integrating both uphole and refractor delay time information. The successful reprocessing of the merged transition zone and land surveys is due primarily to good teamwork, open two-way communication and critical project management between ADCO and PGS.

### **Limitations of 3-D seismic to meet its objectives: a case history**

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A 3-D seismic survey was acquired in 1992 over a carbonate field in the Arabian Gulf area with parameters that were considered adequate at that time. The fold of this vibroseis

data is 32. The data set suffered from multiples, statics and low signal-to-noise ratio. Imaging of the subsurface fault patterns and improving the data quality to allow for confident interpretation of the sedimentary section for exploration and field development purposes were of great importance. In recent reprocessing, careful attention was given to horizon-based stacking velocity picking and the selection of accurate refraction static model. This resulted in data with good lateral continuity. The reprocessed and interpreted seismic data were used for the new generation of reservoir model for the field. It helped in the selection of new wells. Detection of the internal geometry within the reservoirs using seismic amplitudes was necessary. Although reprocessing of this seismic data has shown improvements in horizon tracking and fault imaging, it was not enough. Reprocessing of the data has been taken to its technical limit and cannot produce the needed high-resolution image to meet the team's objectives. The mapping of many reservoir units was not possible with this data due to its poor vertical resolution. Deterministic and statistical studies clearly indicate the value gained from acquiring new high-resolution 3-D seismic far exceed the cost of acquisition.

#### **When should we use seismic inversion results for porosity prediction? A case study from Dhulaima and Lekhwair-East fields**

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Yousuf Al-Aufy (PDO)*

Constrained sparse spike inversion (CSSI) is often used for reservoir characterization. The accuracy of the prediction is dependant on seismic data quality, strength of porosity-impedance relationship and consistency of the bounding lithology. In this case study, we focus on the impact of porosity-impedance relationship and variability in bounding lithology. The Dhulaima and Lekhwair-East fields have proven oil reserves in the Cretaceous carbonate Shu'aiba Formation. The largest accumulations are found in the Lower Shu'aiba unit. Smaller amounts of oil are found in the Upper Shu'aiba unit. The seismic data quality of the two fields was comparable and sufficient well coverage existed. Therefore, CSSI was run on both fields with the aim of delineating the good reservoir zones and predicting porosities where possible. Petrophysical analysis of the well data showed an acoustically homogeneous layer over both fields bounding the Upper Shu'aiba units. The analysis also showed that the porosity-impedance relationship is stronger within the lower Shu'aiba unit. The thickness of the lower Shu'aiba unit was also found to be consistently above the tuning thickness over the two fields. This together with an acoustically more consistent Upper Shu'aiba unit bounding the lower Shu'aiba over the Dhulaima field allowed for porosity prediction to be made

in this layer from the inverted seismic data. On the other hand, the variability in the bounding Upper Shu'aiba over the Lekhwair-East field did not allow porosity prediction over this field. Porosity predictions of the Upper Shu'aiba layer itself were not attempted due to a weak porosity-impedance relation.

#### **Multi-attribute seismic volume facies classification for predicting fractures in carbonate reservoirs**

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Understanding the fault and fracture distribution and orientation prior to drilling and completion of production and injection wells is critical for optimal oil production and maximizing recovery. In recent years multi-volume seismic attributes have been used more efficiently to help map these localized faults or fractured zones within reservoirs. In this study, covering a portion (about 750 sq km) of the Ghawar field in Saudi Arabia, unsupervised seismic facies volume classification was applied to multiple seismic attribute cubes to predict fracture zones in the Arab-D carbonate reservoir. The pre-stack time-migrated 3-D seismic dataset was processed to preserve relative amplitude information. Attribute analysis of the input seismic volume showed several areas containing E-W-oriented lineaments. Many of these lineaments were not clearly observed either in time or horizon seismic amplitude slices. For lineament mapping, each lineament must be recognizable in more than one seismic attribute volume. The mapped seismic lineaments were interpreted to be small faults (or fractures) through which natural drainage may facilitate fluid migration through the reservoir. The long extent of these lineaments (several kilometers in length) suggests they are probably faults. A binary scheme (two seismic facies) of multi-volume seismic facies classification of fault-related seismic attributes was successful in clustering areas of the field where optimum oil flow rate wells have been observed. This analysis of post-stack seismic attributes helped improve the understanding of observed well performance by mapping the distribution of fracture systems within the reservoir.

#### **3-D seismic acquisition in a complex urban area of Yumen City, western China**

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Some 3-D seismic surveys have been acquired in urban areas where the S/N ratio is relatively high. However similar urban seismic surveys have not been performed in complex areas of western China where the data quality

is not so good, especially along foreland thrust belts and mountain fronts. In 2004, BGP conducted a 3-D seismic project in the urban area of Yumen city, located at a complex substructure of a foreland belt in Yalaobei area of the Jiuquan Basin. In this survey, many difficulties in seismic exploration were encountered. Firstly, some shots and receivers were difficult to deploy because of the presence of underground pipelines and cables and basic infrastructures. Secondly, there are many noisy sources in the urban area and oilfield installations, particularly the non-stop interference of strong broadband energy from an urban refinery and power plant. The subsurface of the urban area is characterized in shallow targets, steep-dip structures and laterally variable faults and strata, which cause very complex seismic wavefields. Considering the urban buildings and structures, BGP designed the relevant geometry and implemented the real-time analysis of shot/receiver points around the civil construction, which resolved the layout issues of shot/receiver, and guaranteed the completeness of the shallow data. Through careful study of the property of noises, a set of seismic data acquisition and processing methods in complex interference region were formulated, which solved the shooting and receiving problems and gained satisfactory results in the urban area.

### **Investigation of the effect of temperature and pressure on interfacial tension and wettability of Shu'aiba reservoir, Saudi Arabia**

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Both interfacial tension (IFT) and wettability of the fluids/rock system affect the distribution of fluids within reservoir rock material. The fluids distribution strongly affects the flow behavior and oil recovery. Most of the available data on wettability of core samples including contact angle and IFT for crude oil/brine systems are for room temperature and atmospheric pressure. Since actual values of reservoir temperature and pressure are frequently encountered in oil field simulation models, a need to study IFT and wettability at reservoir conditions was recognized. This study is an investigation of the influence of temperature and pressure on IFT and wettability of Lower Cretaceous Arabian carbonate reservoir. Contact angle measurements were used to quantify wettability on calcite crystal and natural rock material. Experimental results of IFT for both dead oil-brine and live oil-brine systems as well as contact angles of live oil-brine/calcite and live oil-brine/rock material systems over a range of temperature and pressure are reported. The IFT between dead oil and brine decreased with increasing temperature and increased with increasing pressure at constant temperature. For live oil-brine system an opposite trend of increase in IFT values with temperature was found. A

significant increase in IFT values occurred with time. At reservoir conditions, the IFT of live oil was higher than that of dead oil. Contact angle values for live oil-brine/rock material system (at  $P = 3,000$  psig) increased with temperature and with aging time. Four to six days are required to stabilize and obtain constant values of contact angle. Data reflects neutral to slightly water-wet character of Shu'aiba reservoir rock material.

### **Fracture detection by P and C wave anisotropy from multi-offset VSP**

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Fractures in carbonate reservoirs affect both the porosity and permeability. The characterization of fractures is therefore essential for successful exploration and production of the reservoir. Multi-component VSP data can identify fracture density and orientation by measuring the P and S wave anisotropy caused by the fractures. Recently, a deviated well was drilled in a direction perpendicular to possible reservoir fracture orientation in the Qatif field in Saudi Arabia. A multi-azimuth VSP was acquired for the purpose of characterizing the vertical fractures within the Arab and Lower Fadhili reservoirs. The VSP data consist of a total of seven offsets including two nearly orthogonal pairs. This carefully designed survey data provides an opportunity to employ different methodologies for the fracture characterization including: 4C-pseudo Alford rotation method, C-wave hodogram, and P-wave traveltimes analysis. Analysis of the P-wave traveltimes from symmetrical shot points and shear-wave hodogram provide a clear indication of fractures within the reservoir units. The prominent fracture orientation is confirmed by the rotation analysis of the orthogonal shot point data.

### **Investigating Lamé's parameters for identification of gas-bearing Unayzah Formations at Awali field, Bahrain**

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Lamé's parameters are usually denoted by lambda ( $\lambda$ ) and mu ( $\mu$ ) and can be derived from P and S wave velocities. They provide alternative information in identifying gas-bearing formations.  $\lambda$  measures the incompressibility of a rock formation and is sensitive to fluid within the rock fabric, whereas  $\mu$  measures the rigidity and is sensitive to the rock matrix only. Hydrocarbon gas has been established in the clastic Permian Unayzah Formation in Awali field. The Unayzah Formation in Awali field is about 400 ft thick with facies of sandstone, siltstone, shale

and mudstone and is bounded by unconformities. The porosity of the Unayzah sandstone ranges from 5–20%. Sonic logs exhibit sudden drops in seismic velocities from carbonate (Khuff) to clastic (Unayzah). Within Unayzah section, clean sand exhibit higher sonic velocity as compared to shaly sand. Correlation of estimated  $\lambda$  and  $\mu$  from well P and S velocities with Unayzah gas-bearing sands have been investigated and presented in this study. The salient points of the study are summarized as below: (1) sudden drop in  $\lambda$  and  $\mu$  values from carbonate to clastic section. (2) positive  $\lambda$  and  $\mu$  separation against water-bearing formation. (3)  $\lambda$  and  $\mu$  cross over against gas-bearing reservoirs within the Unayzah section. Cross plot of  $\lambda$  and  $\mu$  separations with Poisson's ratio show distinct trend from carbonates to clastic. The cross plots show low Poisson's ratio against high negative  $\lambda$  and  $\mu$  separation. When projected on well logs, large negative  $\lambda$  and  $\mu$  separations correlate with gas-bearing reservoir sands (high resistivity and low gamma ray). The model will be used as a criteria to delineate the Unayzah gas reservoir from inverted 3-D seismic over the Awali field.

### Uncorrelated data-driven vibroseis deconvolution

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The theory of exploiting a linear frequency modulated signal corrupted by Gaussian noise for pulse compression can be traced back to several independent radar patents in the 1940s and 1950s. This early work on matched filter theory is now routinely used in the field when the recorded vibroseis signal is cross-correlated with the desired input source signature (pilot sweep). Unfortunately, the actual ground-force signal includes additional higher and lower-order harmonics introduced by the non-linear effects of a spatially varying vibroseis-earth system. As a result, the conventional pilot sweep will only compress the fundamental sweep and uncompressed harmonics will give rise to high-amplitude apparent dispersive near-surface waves. To remove these effects, an accurate estimate of the ground-force is needed. The high fidelity vibroseis system is one such method that estimates the ground force signal from the reaction mass and baseplate accelerometers. But these measurements are sensitive to local non-linear distortions of the vibrator system. We propose a new method based on our observation that the harmonics are preserved in the near-surface wave propagation modes. Using the uncorrelated air-coupled Rayleigh wave we can model the near-field ground force signal. This spatially varying ground-force estimate now includes useable harmonic distortion frequencies up to 150 Hz. Using this signal to design an optimum inverse filter yields higher-resolution results when compared to conventional correlation. This new ground force estimation method offers a new approach to improving the seismic resolution by removing the uncompressed harmonic arrivals and improved signal compression.

### Evolution of a near-surface model in an area of complex topography

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Complex topography has promoted the evolution of near surface modeling concepts and techniques that attempt to adequately resolve datum static corrections. In a study area, *jebels*, *wadis*, and *sabkhas* generate large velocity contrasts. The 2-D seismic lines were modeled with a single layer velocity model. This velocity model was derived from uphole control and was adequate for most prospective areas. However, irregular uphole distribution under-sampled the near-surface velocity field leaving some local anomalies unresolved. The 2-D technique of shallow horizon interpolation to solve local anomalies was inappropriate for recently acquired 3-D seismic data.

Local anomalies were still evident after building a two-layer model that defined weathered and sub-weathered layers. This two-layer model was enhanced by extra upholes and control points in order to better define the near-surface geology. While this revised model defined the regional trends, local structure confirmation still required model improvements where near-surface anomalies remained.

Source gathers from a sparse 3-D survey over the study area contained relatively large near trace offsets. Refraction methods were considered but were not pursued due to insufficient near offset data. Acquisition did include extra near-trace 30 m offset data for selected inlines. 3-D source gathers similar to 2-D source gathers were extracted from these near offset inlines. The direct arrival and first refractor were interpreted, yielding derived control points that were used to build the final two-layer model. This approach created a 3-D model in which the seismic time horizons on a 3-D inline validated a time structure similarly seen in a corresponding 2-D line.

### Multiple suppression by the Common-Reflection-Surface technique

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Multiple suppression generally relies on the filtering of multiples if their kinematic behavior significantly deviates from the traveltimes of primaries. Otherwise, multiple prediction and subtraction may be appropriate, using information either from a subsurface model or from seismic data attributes. Such information is required in the case of land data, where high-velocity rocks may be present up to the surface, leading to a similar kinematic behavior of primary and multiple reflections. That information is

required in high accuracy and detail since the multiple generating interfaces cannot be assumed to be perfectly flat and uniform, and moreover the multiples are further obscured by near-surface effects, i.e. velocity variations and ground roll noise. Very detailed information on the kinematic characteristics of seismic data is provided by the Common-Reflection-Surface, or CRS imaging technique. At each point of the image, this technique derives a locally adapted traveltimes approximation. The corresponding local imaging parameters, i.e. the CRS attributes, comprise surface related incidence angles and wavefront curvatures that may well be used to identify and model multiple arrivals. The multiple reflections can be identified by their behavior in the CRS attribute domains. For this task, three CRS attributes are available from 2-D data, and eight attributes from 3-D data. The CRS traveltimes approximation is then used to model the multiple arrivals in the pre-stack data around the considered image location. Since the CRS traveltimes approximation is valid beyond the image CMP location where the multiple was identified, the multiple can be suppressed at the surrounding CMP locations as well, without additional identification efforts.

### **The role of seismic coherence attributes in mapping the fracture network and improving the productivity from a thin, tight and fractured reservoir**

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This presentation describes a case study of utilizing 3-D seismic coherency data to define and map fracture network pattern that was integrated with well testing to improve the productivity from a thin, tight and fractured reservoir in the Bahrain field. The middle Cretaceous Ab zone is a thin, tight, highly faulted and irregularly fractured limestone reservoir. The difficulty with this 15 ft, 1 mD reservoir has prevented an efficient recovery. The average production of wells is 15 barrels of oil per day (bopd). This has prompted a detailed integrated study plan to increase the wells' productivity. It is well known that seismic coherence data is a key to defining and mapping the fracture network, while well testing is a key to understanding the reservoir dynamics. However the new approach that links transient well testing and production data, with fracture network indications derived from seismic interpretations, has resulted in improving productivity considerably. This was accomplished through re-entering old wells and designing special trajectories to intersect productive open fractures. The productivity was significantly increased to 60 bopd with sustained performance. The presentation describes in detail our approach and methodology to understand the reservoir and its drive mechanism and to increase productivity and recovery beginning with

analyzing core data up to designing special configuration wells. The presentation further highlights the pitfalls of the conventional workflow approach in modeling such difficult reservoirs.

### **The "hands-off" approach to seismic for the 21st century: a case study in the use of very high channel recording systems**

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Very high channel count seismic recording systems open new avenues in the search and exploitation of hydrocarbons in the Middle East. Vast leaps in hardware and software development since the 1980s allow manufacture of electronics capable of recording over 20,000 channels in a cost-efficient manner. In addition, these advances in technology have allowed the use of higher fidelity processing algorithms and techniques such as pre-stack time migration in routine processing, which previously were only possible in theory or in research using the largest computers available at that time. However, the general philosophy used to record seismic data is still based on the 2-D paradigms of the 1980s where recording systems were able to record 96 to 480 channels for each shot. Even the highly successful 3-D seismic technique, is still based on the paradigms developed for 2-D recording and limited channel counts. As the demands for the information provided by seismic data have increased from providing a structural picture to detailed reservoir information in the inter-well space, fold of the 3-D seismic surveys has increased to very high levels to try and deliver the hi-fidelity seismic data sets required for such analysis. Especially in the Middle East, where strong coherent surface generated noise is prevalent, a plateau has been reached to how much information the seismic data can provide. This case study shows how changing the paradigms used for 3-D seismic acquisition and processing, made possible by very high channel count systems, can extend the usefulness of 3-D surface seismic acquisition further than with conventional acquisition and processing techniques.

### **Constraining 3-D modeling of structure, porosity and permeability using a combination of geology-controlled deterministic and stochastic techniques to minimize uncertainty: example from a giant carbonate reservoir, onshore Abu Dhabi, United Arab Emirates**

*Luis Ramos (lramos@adco.ae), Shamsa Al-Maskary,  
Gerard Bloch and Avni Kaya (ADCO)*

Applied to a giant undeveloped carbonate reservoir located onshore Abu Dhabi, a comprehensive and

effective workflow using stronger geological controls on 3-D modeling of structure, porosity and permeability is described. Depth grids are constructed using 3-D seismic and isochores. Geology honoring positive or negative depth trends are used respectively for porous and dense intervals isochores. Porosity modeling starts, at well locations with overburden correction of core porosity followed by a linear correction of log porosity controlled by the former. To honor the core porosity and account for the uncertainty of measurements, a stochastic technique using the residuals between core and log corrected porosity was developed. Then 3-D porosity models are created through stochastic modeling using porosity versus depth trends and a base case is selected. Permeability modeling uses a mixed deterministic/stochastic technique. Missing permeability intervals from wells with production tests are edited using porosity versus permeability plots and Kh derived from test results or dynamic history matching, minimizing the multipliers need. Geology based power lines fitted to porosity versus permeability clouds are then used to convert the base case porosity model into a 3-D synthetic permeability model lacking the well data variability. This is re-incorporated through stochastic simulations of the residuals between the synthetic and real well values and a base case permeability model is selected. Finally, a permeability multiplier volume is generated to match test results. Uncertainty is accessed through creation of high and low cases. Produced static models were successfully used in dynamic simulations with very limited adjustments.

### **Imaging of Cretaceous fault system: a 3-D seismic case study in onshore Bahrain**

*Cheruku Babu Reddy (babu\_reddy@bapco.net) and  
Naji Ahmed (BAPCO)*

The study was focused on the effectiveness of 3-D seismic data for imaging subsurface faults of the Cretaceous System. The interpretation was carried out through standard horizon and fault correlation tools on vertical displays, as well as through generation and interpretation of time slices and horizon seismic attributes (e.g. dip and azimuth displays), which afford a quick and conclusive alignment of the lineaments. The 3-D interpretation effort brought out a detailed fault pattern imaging. Though the observed faults are predominantly oriented in a north-south direction inline with previous work, 3-D data demonstrates that this complex fault zone actually consists of numerous fault blocks. In addition, a NW-SE trending younger fault system, not observed in earlier studies, offsetting the N-S fault system has been identified in this study, mainly due to capabilities of horizon attribute analysis. Such enhanced fault pattern imaging immensely helped in appreciating the regional

and local stress field orientations, thus supplementing the present-day understanding of fault tectonics at the field scale. It will also be useful in planning of development effort of the Cretaceous oil reservoirs in the Ahmadi, Wara, Maaddud and Nahr Umr formations. Present work reveals and reaffirms the undisputed imaging capability of the 3-D technique in the search for potential subsurface geological features, signifying its applicability in the central part of the Gulf through some characteristic illustrations extracted from one of Bahrain's onshore 3-D surveys.

### **Oil and gas reserves estimating – we have met the enemy, and he is us**

*Peter R. Rose*

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Whether reserves predictions are expressed deterministically or probabilistically, they are still estimates, subject to vagaries of nature, human error, and various biases. But probabilistic estimating has 5 important advantages: (1) forecasting accuracy can be measured; (2) use of statistics improves estimates; (3) reality checks can pre-detect errors; (4) it is more efficient, results being directly input into portfolios; and (5) it promotes better communication of uncertainty. Faithful to decades of engineering practice, reinforced by US SEC-approved standards, "Proved Reserves" is a deterministic number that refers to a specified volume (or more) of hydrocarbons that the estimator is "reasonably certain" will be recovered. However, this is actually a probability statement, except that no confidence level (= probability) is specified. Accordingly, proved-reserves estimators cannot be accountable. Reserves estimates are also susceptible to bias because larger estimates may benefit the value of estimators' own shares, annual bonuses, repeat business, or organizational status. On the other hand, various negative career and legal consequences may ensue if the "reasonably certain" estimate turns out to be too optimistic. This constitutes a self-made, illogical, and insupportable professional conundrum.

Today, Petroleum E&P is a divided industry: modern Exploration has adopted probabilistic methods for estimating recoverable volumes of oil and natural gas from prospects, given discovery. But the Production side of E&P generally remains stuck in the old rut of inferior deterministic methodology. A simple remedy would facilitate the transition to probabilistic methods for the entire E&P Industry: for members of all professional geotechnical and engineering societies to specify that when they use the term "proved", they are explicitly affirming 90% confidence in their estimates, regardless of outmoded and illogical SEC definitions.

### **Halite and solid bitumen plugging in the intra-salt carbonate stringers of the south Oman salt basin**

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Halite-plugged carbonate “stringers” in the South Oman Salt Basin (SOSB) are enclosed in large domal bodies of Ara Salt and are buried to a depth of 3 to 5 km. The stringers represent an intra-salt petroleum system of infra-Cambrian age, known as the Ara carbonate stringer play, which represents a six-cyclic carbonate to evaporite sequence. Transitions from carbonate facies to salt and from salt to carbonate facies are commonly characterized by the occurrence of a roof and a floor anhydrite. The carbonate stringer play has been successfully explored in recent years. Some stringers revealed poor reservoir performance despite a favorable primary reservoir facies. Detailed thin section studies of these stringers revealed a widespread cementation by halite and solid bitumen. Early halite is interpreted to have cemented pores of the carbonates due to the infiltration of supersaturated seawater brine, as the deposition of a roof anhydrite didn't occur. The high minus (halite-) cement porosity is also consistent with an early origin for this halite. Geochemical and maturity analyses of the solid bitumen indicate a precipitation from oil by enhanced temperature in the basin. The fracture-plugging halite post-dates this solid bitumen and is therefore interpreted as diagenetically late. The most likely origin of the second halite is a phase of salt tectonics in the SOSB, where the increasing burial and stress changes led to the formation of fractures and advection of brines inside the intra-salt stringers. The spatial distribution of halite and the resulting reduction of flow properties can be heterogeneous, even at the scale of meters.

### **Petrography and geochemistry of solid bitumen in the intra-salt carbonate stringers of the South Oman Salt Basin**

*Johannes Schoenherr (j.schoenherr@ged.rwth-aachen.de), Janos L. Urai, Ralf Littke, Peter A. Kukla (RWTH Aachen); Mark Newall, Nadia Al-Abry and Zuwena Rawahi (PDO)*

Solid bitumen-plugged carbonate “stringers” in the South Oman Salt Basin (SOSB) are enclosed in large domal bodies of Ara Salt and are buried at depths of 3 to 5 km. The stringers represent an intra-salt petroleum system of infra-Cambrian age, known as the Ara carbonate stringer play. Several wells have successfully explored the stringers but some of these wells have failed to produce at significant rates. Detailed microstructural investigations by SEM imaging, transmitted and reflected light

microscopy revealed that 80% of 75 investigated stringer cores of those wells are plugged by solid bitumen. Mostly, this solid bitumen is observed as intergranular cement, which covers the pore-walls and occurs in microfractures. Microstructure-correlated maturity analysis shows that paleo-temperatures of the SOSB, obtained by reflectance measurement (BR %), are significantly higher than present-day well temperatures. In most stringers a very heterogeneous distribution of paleo-temperatures (BR (%)-values) is recorded and few samples clearly contain a low and a high reflective generation of solid bitumen. Geochemically, the solid bitumen-bearing rocks were analyzed by Rock-Eval pyrolysis and biomarker analysis. Some of the solid bitumen shows features indicative of very high temperatures (> 200 °C), which acted in the stringers leading to the formation of imponite and coke structures. These high temperatures are probably related to hot fluids, deriving from deeper strata, which infiltrated the stringers during times of tectonic movement. This observation has severe consequences with respect to our understanding of salt permeability.

### **Integrating geological maps with GIS leads to optimum well locations**

*Fahad Shamsan (fahad\_shamsan@bapco.net) and Kandaswamy Kumar (BAPCO)*

With the increased industrial progress over the past few years in Bahrain, the field development activities of the Bahrain Petroleum Company are facing a number of constraints. The major constraint is the availability of land. Consequently, when selecting locations for development wells, there is a tendency to give more importance to only surface features. This may result in choosing less optimum locations for development. It was realized that by combining GIS maps of the surface features with the geological maps, optimum locations can be selected. Therefore, the structure and property maps were superimposed on the GIS maps. On these composite maps, the locations selected by the engineers based on wells and reservoir performance analyses were plotted. This has led us to selecting development well locations satisfying all the agencies while at the same time giving us the best results. This poster illustrates how the application of the GIS has led to a consistent approach in optimization of the selection of surface locations for development wells by integrating with subsurface maps.

### **High-resolution stochastic modeling conditioned to seismic rock property inversions: practical workflows for Middle East reservoirs**

*Gordy G. Shanor (Ødegaard-Reservoir Seismic Services, WesternGeco, Gshanor@slb.com)*

Utilizing robust seismic reservoir characterization

outputs as inputs to detailed reservoir models is not a new or particularly difficult concept to understand. The application of this workflow is, unfortunately, under-utilized by both exploration and development asset teams. Seismic data provides excellent spatial resolution for structural interpretation, and seismic inversion processing, especially AVO inversions to rock property cubes, provides tremendous insight into the spatial distributions of reservoir rock properties and fluids in two-way time. Well log data and their derived interpretations (petrophysics, facies, rock physics, etc.) provide excellent vertical resolution and insight into the distribution of the logs and interpreted variables at the well locations. High vertical resolution reservoir modeling is often performed based solely on mapping and well-log interpretations without direct integration with seismic reservoir characterization results, leading to discipline independent 3-D models generated through interpolation or geostatistical modeling. The reservoir modeling workflow described provides integrated reservoir models, which couple the spatial coverage of 3-D seismic inversions with high vertical resolution reservoir modeling through applications of conditional geostatistical simulation techniques. This study presents several carbonate workflow examples from the Middle East and the North Sea that incorporate seismic reservoir characterization such as full stack impedance and AVO rock property inversions with high resolution geostatistical analysis and conditional stochastic simulation of petrophysical data.

### **Silica occurrences in the Upper Jurassic Arab carbonate reservoirs, Saudi Arabia**

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Silicification of carbonates involves the precipitation of silica in the form of pore-filling silica cement as well as the replacement of carbonate by chert. Presence of quartz in the Jurassic carbonate sequence of Saudi Arabia was first recognized by Powers in 1962. He pointed out a thin chert zone just below the base of the middle Arab-D, which corresponds to the top of Zone-2B, as a marker traced over the Ghawar field in most of the wells. These minor occurrences have not been of interest to investigators to date. Silica occurrences in the Arab-D intervals have been identified by conducting XRD analyses on continuous veneer samples and visual inspection of cores from five wells. Most occurrences are encountered in dolomitic layers of Zone-2B of the Arab-D reservoir. Silica in the Arab-D occurs as chert nodules, thin chert beds, mottled microcrystals and drusy silica cement. Dominantly microquartz, some megaquartz and chalcedony are the petrographic chert varieties observed in the studied samples. Silt size detrital quartz grains are

also observed in a single interval. Cherts were originated from infiltrated silica containing brines, which also caused dolomitization in the carbonates. Saline water expelled from the dewatering of the overlying evaporites became enriched in silica by dissolving sponge spicules and later precipitated chert in the Arab-D carbonates. Silicification increases microporosity, but matrix permeability remains very low. Microfractures developed due to the brittleness of the chert contribute to fluid transport. Porosity and pore throat sizes in most silica occurrences are greater than those of the associated micritized carbonate layers and contain more hydrocarbons. The recognition of chert is also significant for the calibration of wireline log responses to lithology for more precise evaluation of the formation.

### **Hydrothermal dolomitization and leaching of carbonate reservoirs**

*Langhorne B. Smith (New York State Museum, lsmith@mail.nysed.gov) and Graham Davies (GDGC)*

Hydrothermal alteration of carbonate reservoirs occurs when relatively high-pressure, high-temperature fluids flow at high rates up active faults and into permeable formations that underlie sealing shales, evaporites or other low permeability strata. Most reservoir-enhancing diagenesis is associated with strike-slip and especially transtensional faulting. Because of the spatial link to faults, hydrothermal alteration commonly produces heterogeneity in reservoir quality and distribution. Hydrothermal alteration products include, but are not restricted to, saddle and matrix dolomite, recrystallized limestone (including development of microporosity), pore- and fracture filling calcite, anhydrite, quartz, fluorite, barite, bitumen, authigenic clay minerals, sulfides, and more. Significant leaching of limestone, dolomite, and other minerals by hydrothermal fluids is a common occurrence and can be a primary control on reservoir quality. Hydrothermal leaching likely occurs from cooling, low pH fault-derived hydrothermal fluids. Cooler fluids can hold more carbonate and CO<sub>2</sub> in solution than relatively warmer fluids so cooling fluids should become progressively undersaturated and more acidic. Some brecciation, leaching and microporosity development previously attributed to meteoric diagenesis may be hydrothermal in origin. Hydrothermally altered carbonate reservoirs appear to be very common in the Middle East. The Permian-Triassic Khuff Formation has common saddle dolomite cemented breccias, zebra fabrics and sulfide deposits. Fault-related dolomitization also occurs in some of the overlying Jurassic and Cretaceous reservoirs, but hydrothermal alteration in these units more commonly consists of leaching and microporosity development. A better understanding of the processes, products and indicators of hydrothermal alteration will help improve the bottom line.

AD

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### 3-D seismic attributes reveal Unayzah reservoir secrets in South Ghawar, Saudi Arabia

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Integrated interpretation of 3-D seismic and well data from south Ghawar field, Saudi Arabia, provided better understanding of facies distribution and structural style of the study area. The objective of this study is to evaluate the Unayzah reservoir potential. Several north-south and east-west well cross-sections reveal thickening and thinning pattern of pre-Khuff clastic units. It thickens on the flanks of the structure and thins on its crest. "Detect" and "Curvature" analyses resulted in defining four major north-south fault trends and a minor east-west fault. These north-south faults controlled the topography during the Hercynian event and resulted in the Unayzah filling the paleolows. A difference amplitude map was generated from the maximum and minimum amplitude of the reservoir interval. The result shows good correlation between amplitude anomalies and high potential reservoir development areas. Strong amplitude anomalies have been used in combination with structural closures to identify the future potential in the area.

### High-resolution processing: from data preparation to imaging and velocity models to inversion

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The need to resolve the reservoirs better has triggered a flurry of activity in the high resolution (HighRes) arena, from acquisition to processing. There is a good amount of newly acquired HighRes data and Geotrace has answered the challenge by developing methods capable of handling these data and delivering HighRes products. These methods have also been successful at injecting new life into old prospects by reprocessing existing data. They also provide more accurate evaluations of reserves, drilling prospects and can resurrect prospects and bring them back to life. Geotrace has fully embraced the HighRes revolution by developing methods that extract more information from the data. These work by mining the existing bandwidth or extending the original spectra to recuperate higher and higher frequencies. This has been done while ensuring the preservation of the correct amplitude and phase, as well as the low-frequency components critical in setting trends and regional information. We will present several examples of these techniques at work. Firstly in the context of *pre-stack depth migration* and *velocity model building*, where our *multi-scale high resolution tomography* has allowed

us to build high-resolution velocity models. Secondly, an example will be presented of *high frequency imaging* (HFI) and its application to *impedance inversion*.

### Seismic attribute analysis in Paleozoic hydrothermal dolomite

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To optimize geophysical subsurface interpretation, it proves beneficial to place seismic attributes into their proper geological context. This case study captures prognostic exploration play characteristics for populating a geological model within which each dominant reservoir property is expressed as a risk parameter that in turn can be resolved by a seismic attribute. Seismic attribute analysis permits illumination of specific subsurface compartments and associated reservoir properties, specifically: (1) fractures; (2) dolomitization; and (3) high porosity. For instance, fracturing can be detected via low similarity values (event terminations) and dip azimuth maps, whereas the transition from tight limestone (non-reservoir) to porous dolomite (reservoir) is paralleled by a characteristic impedance reduction coupled with a subtle polarity reversal. Variant composite seismic signals can be binned using artificial neural network topology. Some wells drilled on impedance anomalies encounter intraformational shale plugs that resonate at identical impedance values to porous dolomite, thus decreasing the predictive power of impedance as a diagnostic attribute. However, this increased stratigraphic complexity is resolved by geological data indicating that dolomitization should preferably occur at the formation base. Application of this model doubles the chance of setting pipe in this North American play. A novel look at applied subsurface interpretation firmly based on geological models would lend itself to widespread use in the seismic attribute analysis of carbonates hosted by the Arabian platform.

### Petrophysical analysis of a Cretaceous reservoir of a large oil field in onshore Abu Dhabi

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Image analysis of thin sections and core-slab samples of the Early Cretaceous age reservoir, can quantify their pore-size distribution and detailed porosity components. The results show the distribution of pore sizes ranges from  $4.2 \times 10^{-5} \text{ mm}^2$  to  $7.68 \text{ mm}^2$  in thin section, and  $0.023 \text{ mm}^2$  to  $630.7 \text{ mm}^2$  in core slab. The pore-sizes distribution can be classified into 3 groups such as micropore, mesopore and macropore, based on the minimum resolution of thin-

section image analysis ( $6.5 \times 10^{-3}$  mm), and the average intersection-point value of pore-size distribution curves from thin sections and core slabs (0.858 mm). A linear relationship of a cross plot between mesoporosity plus macroporosity and core-plug permeability on a semi-log plot, shows the influence of large pores on formation's flow behavior. The comparison of pore-size distribution from core slabs to NMR-T2 distribution shows a strong relationship between tails at the high end of T2 distribution and the presence of macropores in the formation. Thus, the NMR log can be used qualitatively as a vug indicator. The detailed distribution of porosity components in the formation is able to provide more precise petrophysics-based flow-unit determination that subdivides certain Reservoir Rock Types into smaller zones with specific characterization of flow capacity and storage capacity. The pitfalls from the 2-D techniques used in this study are the derived porosity from image analyses are less than the actual values, due to the exceeded blue-colored shades of epoxy in the thin-section, and the pores that lie at the edges of the core-slab images, were excluded from the pore-size quantification.

#### **Identification of subsurface structures on Sarajeh gas field with 3-D seismic survey designing for gas storage and IOR purposes**

*Siavash Tarkhan IV (Khazar Exploration and Production Company, saeedtarkhan@yahoo.com) and Hoda Tahani (NIOC)*

The Sarajeh gas/condensate field is identified as a suitable candidate for underground storage of natural gas. The field is a NW-trending anticline about 15 x 1.5 km in extent. The vertical closure is at least 750 m and the original gas/water contact depth is 1,819 m from the surface. Initial exploration of Sarajeh field goes back to the 1950s. At that time geological and geophysical surveys were performed and the anticlinal trap was discovered in the Qum Formation. Reprocessing and reinterpretation of the old seismic data indicated it is poor due to the low signal to noise ratio, especially over the crestal area of the structure. The main target layers are the caprock and the Qum D Member. For better definition of the subsurface structure of the Qum-E reservoir, a 3-D seismic survey was recommended to improve the image of the structure. With knowledge of the target depth, frequencies, interval velocities and other critical parameters, a 3-D seismic survey was designed for the area. Three options with different parameters were initially considered to be suitable. After further investigation and comparison of the fold-distribution map, azimuth diagram, minimum offset and maximum offset diagrams, in-line and cross-line bin sections in the three different options, we selected a geometry that is most suitable for imaging of subsurface structures for gas storage and IOR purposes.

#### **Understanding the geological controls on fluid properties in the carbonate stringer play of South Oman**

*Paul Taylor (PDO, paul.taylor@pdo.co.om); Erdem Idiz (Shell); Gordon Macleod (University of Edinburgh); Mohammed Al Ghamhari (University of Newcastle) and Steffen Ochs (PDO)*

The carbonate stringer play in the infra-Cambrian Ara Group of South Oman contains oil and gas in carbonate reservoirs encased in salt. There is a wide range of reservoir depths (2 km to > 5 km), temperatures (60 to 125°C) and pressures (from hydrostatic to almost lithostatic pressure gradients). Fluid properties within the reservoirs are highly variable; e.g. gas/oil ratios range from 180 to > 4,000 m<sup>3</sup>/m<sup>3</sup>. Simple reservoir depth, pressure and temperature relationships were insufficient to explain the full variability of fluid properties observed in the fields and the occurrence of oil versus gas. Therefore a study was initiated to understand the underlying causes of the fluid property variability in the stringer reservoirs. This study utilised data from source rock pyrolysis, oil to gas cracking kinetic measurements, geochemical characterization of oils, gases and mud gas samples and PVT analysis data. This approach showed that the bubble point pressures of the fluids were higher than could be explained by *in-situ* maturation of the stringer source/reservoir systems alone. Gas geochemistry data and PVT modeling showed that the elevated bubble points were, in fact, the result of mixing of oil and oil-associated gas with a separate gas charge, probably derived from highly mature pre-salt source rocks. Our observations and resulting charge models allow gas risk for a stringer prospect to be addressed in terms of its burial depth, proximity to base or top salt and location in relation to pre-salt highs. We have also gained new insights into the nature of the mixed petroleum systems needed to explain the fluid properties in the carbonate stringer play and their implications for intra-salt and pre-salt prospectivity.

#### **Perfect pitch – the use of tuning in reservoir characterization in the Harweel cluster, Oman**

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Seismic tuning is often considered to be an insidious effect that overprints and masks key reservoir information. However, in the Oman Harweel Cluster of nine oil and gas fields, we are using tuning effects to better define reservoir edges and structural geometry. In addition, our modeling suggests that caution must be applied to reservoir property inferences from acoustic impedance inversions when significant seismic tuning is present. Recent drilling in the Harweel Cluster yielded a challenging result when

a 100-m-thick carbonate reservoir was completely absent despite the appearance of simple structural continuity on the seismic data. The post-drilling analysis showed that noise, side-lobe effects and multiples contributed to the original illusion of continuity. However, modeling and seismic attribute analysis showed that tuning between the reservoir horizon and an overlying anhydrite unit (with intervening salt) could very precisely delineate the termination of the reservoir. From this work, we now understand that tuning is one of the primary controls on the reservoir's seismic amplitude variations. And we use these anomalies to more precisely define pinch-outs, structural truncations and thickness variations. Of particular value have been horizon amplitude ratios – using one horizon as a “reference” and one as a test horizon. In addition, of interest to many inversion projects, our seismic modeling shows that standard acoustic impedance inversion may not adequately “de-tune” the seismic data and that amplitude artifacts may exist in the inversion volume. These artifacts, where not properly recognized, could easily be misinterpreted as reservoir property variations.

### 3-D CRS imaging for recovering high subsurface resolution from sparse 3-D seismic surveys

*Henning Trappe (trappe@teec.de), Guido Gierse and Radu Coman (TEEC); Simon J.E. Møller, Nielsen Robinson (Maersk Olie og Gas AS); and M. Owens (Anadarko)*

Seismic acquisition in frontier areas represents a high risk when dealing with remote areas with difficult access, limited operation times due to seasonal influences and governmental restrictions, and a large uncertainty in the design of optimum acquisition parameters. Under such circumstances, high-fold 3-D seismic surveying is not feasible, but 2-D surveying may also not be appropriate to describe the areal extent of potential targets. Sparse 3-D surveys are frequently used as a compromise. A land data example from North Africa is presented here where large bin sizes (50 x 50 m) and low data fold kept the acquisition costs below given limits. Seismic investigations focused on flat target horizons, and low-throw faulting in the target regions. As expected, the results of standard time processing could not compete with results from nearby high-fold surveys. A much lower signal-to-noise ratio provided a very restricted resolution of the subsurface. As an alternative, a CRS time processing was applied to these data. This method is well suited to tackle noise problems in low-fold data, since it uses a much higher stacking fold than conventional time-domain imaging. CRS obtains the high fold by assuming subsurface reflector elements with dip and curvature. CRS imaging of the sparse 3-D data provided a strong increase in subsurface resolution, and signal-to-noise ratio. It also resolved the faulting that was almost completely buried in noise in conventional

images. The combination of sparse 3-D acquisition with CRS processing thus proved to be a suitable strategy for achieving good subsurface resolution with a limited acquisition effort.

### CRS processing – a key to improved static and dynamic corrections in seismic data from Saudi-Arabian deserts

*Henning Trappe (trappe@teec.de) and Juergen Pruessmann (TEEC)*

Static shifts from near-surface inhomogeneities very often represent the key problem in the processing of seismic data from arid regions. In this case study, the deep bottom-fill of a wadi strongly deteriorates the image quality of a 2-D seismic dataset. The resulting static and dynamic problems are solved by both conventional and CRS processing. A straight-forward approach derives conventional refraction statics from picked first breaks, and further goes through several iterations manual velocity picking and residual statics calculation. The surface-induced static and dynamic inhomogeneities, however, are not completely solved by these conventional methods. In CRS processing, the local adaptation of the CRS stacking parameters results in very detailed dynamic corrections. They resolve local velocity inhomogeneities throughout the seismic section that were not detected by manual picking of stacking velocities, and largely compensate for the surface-induced deterioration in the stack. The subsequent CRS residual statics calculations strongly benefit from the large CRS stacking fold that increases the numbers of estimates for single static shifts. This improves the surface consistent averaging of static shifts, and the convergence of the static solution which removes the remaining static shifts in the 2-D seismic data. The large CRS stacking fold also increases the signal-to-noise ratio in the final CRS stack. An almost identical resolution is obtained by an alternative CRS stack based on every second shot only. This indicates that the acquisition fold could be halved without deteriorating CRS image quality.

### Improved AVO analysis based on the CRS method

*Henning Trappe (trappe@teec.de) and Juergen Pruessmann (TEEC)*

The *common reflection surface* (CRS) method, which was developed in recent years, has increasingly been used for the high-resolution imaging of complex subsurface structures. Assuming subsurface reflector elements with dip and curvature, the CRS method renders a better signal-to-noise ratio and additional subsurface information in comparison to conventional

NMO/DMO time-domain imaging. These advantages of the CRS method, however, may as well be used for an improved Amplitude Versus Offset (AVO) analysis. A conceptual case study shows that the more realistic subsurface assumptions, and the increased fold of the CRS imaging, allow to extend AVO analysis into noise zones. The signal-to-noise ratio of the CRS AVO gradient stack is much higher than in conventional AVO. Extreme fluctuation of AVO parameters is removed, and AVO anomalies are enhanced. In the case study, the CRS AVO gradient stack clearly distinguishes an anomaly at a known gas-bearing reservoir. Small anomalies above the reservoir disappear, indicating that they were due to local noise contamination. Cross-plots of the AVO intercept versus gradient show a better separation of anomalous zones, which may be classified in order to identify the top and base of the gas deposits. Based on the local CRS imaging solution, the general increase of the signal-to-noise ratio implies an improved AVO analysis by CRS for many types of data. Significant benefits of CRS AVO are especially expected in areas of strong dip, and at deep targets with a low signal-to-noise ratio.

### **New life from old data processing and interpretation of older diplogs with modern techniques, and an example of glacial environment interpretation**

*James W. Tucker*

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Dipmeter logs of various types have been collected since the late 1950s for subsurface structural and stratigraphic definition. Early diplogs correlated microresistivity curves to define bedding dips. These microresistivity logs were collected by electrodes on 3-, 4-, or 6-calipers extending away from the logging tool axis and contacting the borehole wall. Logs have evolved to more detailed borehole wall imaging by microresistivity and acoustic log techniques, which may be used to define bedding, fractures and other structural and stratigraphic features. Computer software for processing and interpreting these modern borehole image logs may, however, also be used to display images of older diplogs. Geological interpretation may then be done on these redisplayed data to define bedding, and possibly other features present in the borehole. These bedding determinations may vary widely from computer dip calculations done originally after the logs were run, and will be more accurate determinations of bedding features than machine calculations. An example is shown from an Ordovician interval near the Central Arabian Arch drilled and originally dipmeter logged in 1989. This log was reprocessed and bedding dips interpreted on the pseudo-image log then produced. The bedding dip groups in the Ordovician Sarah Formation are a few feet to ~20 feet thick, and are omnidirectional when looked at in gross form. These distinct bedding groups are similar to

bedding dip groups from the Ordovician glacial section in Libya.

### **Complex near-surface problems management using the CFP technology: part 1 – principles**

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The Common Focus Point (CFP) technology provides a unique solution to imaging challenges attributed to the complex near-surface. This solution is based on a wavefield propagation approach aiming at determining one-way focusing operators from the data itself via an iterative updating process. In other words, this is obtained without deriving a complex near-surface velocity model. The latter can be determined subsequently by tomographic inversion of the focusing operators. The CFP technique aims at simulating a walk-away VSP experiment where the receiver is positioned at the subsurface gridpoint under consideration, and the sources are located at the acquisition surface. Via an updating procedure a set of one-way focusing operators is obtained, describing the wave propagation between the surface locations and points at a chosen target reflector below the complex near-surface. In part one of this presentation, two different approaches of how to estimate the focusing operators are described, being the automatic modeling approach and the focusing approach. The latter assumes subsurface consistency while the automatic approach assumes surface consistency. The automatic approach is based on parameterization of the one-way focusing operators and can be used as a good initial estimate for the focusing approach. One important aspect of the focusing approach is that picking of events is done after inverse wave field extrapolation, which gains a great deal from the summation processes involved, and hence, resulting in an improved the signal-to-noise ratio. The two approaches will be illustrated using 2-D land seismic data.

### **Removing multiples or using multiples: new challenges for land data**

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Most of the approaches to remove multiples – both surface-related as well as internal multiples have been geared towards the marine application. Especially the so-called data-driven methods, where the seismic data is used as a multiple prediction operator, have been quite successful for the marine case. In the last decade, more effort has been put in translating these methodologies for the land data situation. It appears that the multiple problem for land data can be quite different from the marine case: the clear, almost perfect, mirror at the water surface is being replaced by a fuzzy reflector for the land

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situation, where besides reflection at the free surface other phenomena play a role, like near-surface scattering, internal multiple generation by shallow reflectors and conversion from P-wave to S-wave energy. That is why the surface-multiple content in land data appears much lower, or surface multiple energy may not be always recognized as such. Besides this issue, the data quality and acquisition geometries are quite different from the marine case. Therefore, a lot of attention needs to be paid to carefully pre-processing the land seismic data for use in marine-type algorithms. Despite these issues, both surface-related and internal multiple removal strategies have been applied to land data with success, which will be demonstrated in this presentation. Furthermore, the next challenge is to utilize information in land data multiples to learn something about the near-surface properties or to fill in missing data. Therefore, some hints will be given to transforming multiples from a source of troubles into a source of information.

### Geostatistical recipes for near surface modeling

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The near surface inhomogeneities encountered in the Arabian deserts cannot be modeled accurately, using conventional seismic data designed and acquired for deep targets. Sharp irregular boundaries of *wadis* and *jebels* divide formations with velocities varying from 600 to 3,000 m/s. These are often also associated with abrupt elevation changes of tens of meters. The seismic spatial sampling of the near surface is insufficient both laterally and vertically for the purpose of modeling and correcting for the time distortion manifested in the deep target images. *Ad hoc* 3-D reflection/refraction surveys can solve this problem in principle, but their cost in hostile environments of the Middle East can be prohibitive. For this reason, potential cost-effective alternatives such as satellite imagery, vibrator plate data, and others have become attractive.

With the goal of eliminating the lack of proper near surface sampling we introduce a few algorithms to complement the seismic with other geophysical data. The uphole contribution, while being too sparse in most cases, does constrain the main shallow structures at a regional scale, in terms of both vertical layering and defining the major velocity trend. Satellite imagery provides a minor contribution in delineating soil properties, while direct arrival analysis of seismic records yields the best estimate for the weathering velocity. The Plus/Minus method provides a robust estimate for velocity and depth from refracted arrivals, in a depth ranging from surface to 100 m. In the areas where it is not applicable, then co-kriging of other seismic attributes with Plus/Minus delay times and upholes can fill the gaps in 3-D. The mentioned

techniques are tested at two different fields in the Arabian Peninsula.

### The MEBE GIS database: a tool for Middle East geology

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The MEBE relational database is built to integrate the geological data collected and synthesized during the Middle East Basins Evolution Programme (MEBE). It aims at providing an interactive interface between the MEBE, observations, analysis and syntheses and the users. The data base includes tectonic, stratigraphic, sedimentological, geochronological data for the Middle-East, Caucasian and Black Sea domains revisited during field works. Most of information consisted of cross-sections, biostratigraphical charts and figures, subsidence curves, paleostress maps, stratigraphic charts and logs, sedimentological logs and maps, tectonic logs and maps, stratigraphic charts. The recorded data was displayed in jpeg format, which was useful for synthesizing our observations and analysis. Thus the MEBE database is not restricted to raw data. The accurate data was included in a linked tabular database. The MEBE Database is being developed using Microsoft Access and ESRI ArcGIS. Particular filters will be available to help the users in their request. The final product will run under ArcGIS 9 and display interactive maps of the Middle East area. A considerable effort was dedicated to provide online manipulation and visualization tools that are available on desktops. The MEBE spatial database combines digital topographic (SRTM tins 30" and 3") and geological maps (1:1,000,000 and/or 1:200,000 scales at least), and various types of original geological information concerning the Mesozoic to Present geological evolution of Middle East. The GIS MEBE database is an important tool for geoscientists examining the geological and geodynamical evolutions of the Eurasian, Arabian and African lithosphere in the Middle East since the Mesozoic times.

### Use of interbed multiple prediction in acoustic impedance modeling: example from an eolian dune reservoir, Saudi Arabia

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The uppermost member of the Permian Unayzah Formation is an accumulation of eolian dunes and related

deposits, and is an important reservoir of non-associated gas. The seismic data over these rocks appear to be of reasonably high quality. However, due to large contrasts in rock properties in the overlying section, these data are heavily contaminated with coherent interbed multiples. Importantly, these multiples mask primary energy at the reservoir level. The presumption that seismic data is primarily "clean" is inherent in most conventional acoustic inversion software packages -- all energy in the seismic trace is assumed true signal and must therefore be accounted for in the final result. Several acoustic impedance (AI) models have been generated over the formation using these software packages and, while results have been acceptable for limited purposes, the calculated impedance has always understated and underestimated actual porosity in the field. As such, these acoustic impedance models have not been considered useful for pre-conditioning geocellular models of the reservoir. A methodology has been recently introduced which incorporates predicted multiple energy into the generation of synthetic seismograms and uses these in the generation of an acoustic impedance model. During calculation of the model, the algorithm separates presumed signal from predicted noise; the final product is an AI model, which if properly calibrated, produces a residual error that consists largely of coherent interbed multiple noise. The resulting AI model as run over the reservoir is far more optimistic as a predictor of porosity and has successfully predicted the porosity of a well in a blind test; such data can now be properly incorporated into a geocellular model of the reservoir. The result is a true integration of both geological, geostatistical and geophysical data into the final result.

### **Origin of hydrocarbons of East Abu Gharadig sub-basin, western Desert, Egypt**

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The Abu Gharadig Basin is located in the northern part of the Western Desert of Egypt. The Abu Gharadig Basin is composed of two main troughs, west and east troughs. The western trough sourced hydrocarbons from the Jurassic as well as the Lower and Upper Cretaceous. The eastern trough sourced hydrocarbons mainly from the Jurassic, as the Cretaceous appears to have been, and still is, too immature for generation of hydrocarbons. Recently Apache and Repsol discovered oil from the eastern trough at the Karama oil field in 2001. Since that time Apache has continued exploration activities in the area and discovered 24 additional Jurassic-sourced oil fields in the area to the south of the eastern trough. In order to identify the origin

of hydrocarbons in the area, oil from different structures were analyzed. The correlation between the different oils in East Bahariya area suggest that these oils are quite similar and appear to be generated from the same source at probably similar thermal maturity. However, the recorded differences in the light-end content can be attributed to the variable water washing and biodegradation affecting the oil traps further away from the depocenter of the trough at shallower structural levels to the south. Basin modeling analyses for wells in the east Abu Gharadig area indicate that oil in the area is believed to be generated from Type III source rocks in Upper Jurassic, presumably Upper and Lower Safa shales of the Khatatba Formation.

### **Worldwide compilation of the formative properties of giant and supergiant carbonate fields sealed by bedded evaporites**

*John K. Warren (Universiti Brunei Darussalam, jwarren@brunet.bn)*

Without exception, the largest of the various oil and gas fields sealed by bedded evaporites are hosted in partially dolomitized marine platform carbonates. The evaporites not only hold back the hydrocarbon column, but also helped create and maintain reservoir quality. The most impressive examples are the various Arab D reservoirs in the Middle East, with smaller but still volumetrically significant accumulations in oil pools in San Andres Formation of west Texas and the Smackover Formation in the Gulf of Mexico. Variations in subevaporite reservoir quality is the end product of a combination of depositional facies and varying intensities of evaporite plugging, dissolution, reflux dolomitization and burial stage leaching, dolomitization and cementation. Lateral and vertical variations in all but the latter stages of diagenesis are indicated by facies variations in the seal itself. Yet, for much of the oil industry, evaporite plugging and reflux dolomitization are associations that geologists and geophysicists do not quantitatively integrate into a reservoir model. The usual question asked "Is it thick enough?" Once the integrity of an evaporite seal is established, further study of the seal properties or textures is not considered relevant, other than hoping for, or establishing, its lateral persistence. But porosity/permeability in an evaporite-sealed system continues to evolve to varying degrees, long after the reservoir has subsided into the mesogenetic realm and early evaporite plugging (via brine reflux) of the subsalt interval has ceased. In some fields the burial (fault-related) overprints are significant and can control reservoir quality, in others they do not.

## **Dolomitization and reservoir quality in the Upper Jurassic Arab and Asab formations, United Arab Emirates**

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Dolomitization is one major control on the reservoir quality of Arab-Asab carbonates. Overall, the dolomites have higher porosities and permeabilities than the limestones. Petrography and stable isotopic analysis reveal the presence of two types of replacive dolomite with different reservoir properties. Type-I dolomite is finely crystalline, planar, and facies-controlled, occurring almost exclusively in sabkha, tidal flat and lagoonal sediments. Type-I dolomite occurs paragenetically early, and is interpreted as having precipitated from evaporitic brines generated within sabkhas and lagoons.  $\delta^{18}\text{O}$  values for Type-I dolomite are consistent with precipitation from a fluid with  $\delta^{18}\text{O}$  up to +4‰ SMOW (Jurassic seawater – 1.2‰ SMOW) at temperatures between about 35° and 100°C. Neomorphism of early-formed dolomite could have occurred in a meteoric or mixed marine-meteoric fluid  $\delta^{18}\text{O} < -1.2\%$  SMOW. Type-II dolomite is coarsely crystalline, non-planar, not facies-controlled, but aurally restricted. “Ghost” textures indicate that Type-II dolomite post-dates significant compaction, is paragenetically late, and precipitated from evolved brines at high temperature.  $\delta^{18}\text{O}$  values for Type-II dolomite are consistent with precipitation from a fluid with  $\delta^{18}\text{O}$  as high as +3.8‰ SMOW, at temperatures up to 140°C (maximum burial temperature). Type-II dolomite is intimately associated with late-stage anhydrite. It is proposed that late-stage dolomitization and anhydritization were linked. The permeability and total porosity of Arab-Asab dolomites are largely independent of primary (limestone) texture. In both dolomite types, permeability tends to increase with increasing porosity but, for a given porosity, Type-II dolomites tend to have the higher permeability.

## **Geological data integrity and quality control for correct decision making**

*Wayel Mohamed Adham Younis (wyounis@adco.ae) and Warda Awadh Al-Braiki (ADCO)*

Complete, valid and quality controlled geology, geophysics and petrophysics data have a very important and profound impact on performing fully integrated reservoir studies and better decision making in the E&P business. Healthy data and data flow enhancement by using flexible an extensible data storage system like “Finder” will have the profoundest impact on accuracy of the integrated reservoir studies and all these issues will enable engineers and team management to make the best decision for any activity in the oil and gas fields.

This presentation will concentrate on the geological data integrity in the database by using “Finder” as a master database storage and main data source for all users. The geology data integrity and quality control can insure the efficiently between geology data owner in asset team and data administration engineers in data management community. Finally timely access to accurate exploration and production data is key in today’s exploration and production decision-making and successful operations. Therefore, the accurate geological data and smooth data workflow in “Finder” will have a positive impact on integrated reservoir studies, and enhance correct decision-making.

## **Model-driven land multiple suppression - the third generation**

*Weihong Zhu (weihong.zhu.1@aramco.com), Khalid Al-Rufaii and Panos Kelamis (Saudi Aramco)*

Land data, unlike marine data, are characterized with multiple arrivals that are neither continuous nor predictable due to near-surface and subsurface anomalies. An even greater problem is caused by deeper non-surface related interbed reverberations where the multiple stacking velocity is close to that of the primary. This interbed multiple phenomenon is caused by the typical regional geology, which is characterized by relatively shallow fast carbonates being interspersed with slower shales and clastics. In this presentation we present an elegant and powerful approach that suppresses multiple energy. This new technique is a macromodel-based approach that operates as a multi-step process. It is ideal for AVO analysis, imaging, and detailed structural and stratigraphic interpretation. In this technique the seismic wavefield is separated into four main components; primary reflections, multiple reflections, random noise and residuals of both the primaries and the multiples. The multiple energy is suppressed using a multi-step process beginning with the separation of the random noise using localized FK filtering. Then, far offset weighted median filtering is applied to separate the primary reflections from the multiples. These two components are then removed from the data and a localized path-summation methodology is used to model the remaining multiples at every time sample and along every trace. Finally, the modeled multiples are subtracted from the raw input data. The use of the residual components ensures a more realistic model and helps stabilize the final results. Both synthetic and real data examples are shown to illustrate this new technique better preserves both the amplitude and frequency of the primary reflections while effectively suppresses the multiple energy.

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