GEO 2008 Conference Abstracts

*T*he abstracts of the GEO 2008 Conference presentations (3-5 March 2008, Bahrain) are published in alphabetical order based on the last name of the first author. Only those abstracts that were accepted by the GEO 2008 Program Committee are published here, and were subsequently edited by GeoArabia Editors and proof-read by the corresponding author. Several names of companies and institutions to which presenters are affiliated have been abbreviated (see page 262). For convenience, all subsidiary companies are listed as the parent company.

(#117804) Sandstone-body geometry, facies architecture and depositional model of Ordovician Barik Sandstone, Oman

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The Lower Paleozoic siliciclastics sediments of the Haima Supergroup in the Al-Haushi-Huqf area of central Oman are subdivided into a number of formations and members based on lithological characteristics of various rock sequences. One of the distinct sandstone sequences, the Barik Sandstone (Late Cambrian-Early Ordovician) of the Andam Formation is a major deep gas reservoir in central Oman. The sandstone bodies are the prospective reservoir rocks, whereas thick shale and clay inter-beds act as effective seals. Parts of the Barik Sandstone, especially the lower and middle parts, are exposed in isolated outcrops in the Al-Haushi-Huqf area as inter-bedded, multi-storied sandstone, and green and red shale. The sandstone bodies are generally up to 2.0 m thick and can be traced laterally for a few hundred metres to a few kilometres. Most of the sandstone bodies show both lateral and vertical amalgamation. Two types of sandstone facies are identified on the basis of field relationship: (1) a white sandstone facies usually capping thick red and green shale beds; and (2) a brown cross-bedded sandstone facies overlying the white sandstone facies. An attempt was made to study the relationship of fluvial, fluvio-deltaic and tidal processes on the basis of lithofacies characteristics. This presentation summarizes the results of a preliminary study carried out in the Al-Haushi-Huqf area to analyze the characteristics of the sandstone-body geometry, internal architecture, provenance and diagenetic changes in the lower and middle parts of the member.

(#119029) Offshore Mediterranean seismic data processing challenges

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The application of a modern processing sequence that focuses on noise and multiple attenuation demonstrated how careful reprocessing can add significant value to existing data sets and improve exploration decision making. The results of a recent 3-D seismic reprocessing effort over approximately 1,800 square km of data from the Mediterranean Sea has brought renewed interest in deep, pre-Messinian structures. Historically, the reservoir targets in the southern Mediterranean Sea have been the Pliocene-Pleistocene and Messinian/Pre-Messinian gas sands. These are readily identifiable as anomalous *bright* amplitudes on the seismic data. The key to enhancing the deeper structure is multiple and noise attenuation. The Miocene and older targets are overlain by a Messinian-aged, structurally complex anhydrite layer, the Rosetta Formation. This layer is of variable thickness and is highly fractured in places. The quality of seismic data beneath it tends to be inversely proportional to the thickness and complexity of the layer. The Rosetta Formation also generates a significant amount of complex multiple energy. On the seismic data, these multiples are not well defined. Many methods of multiple attenuation are therefore only partially successful, and the residual multiple often appears as a *fuzz* of noise on near and middle offsets. Attenuation of this residual multiple noise was one of the keys to the success of the reprocessing effort. This presentation outlines a carefully executed processing flow to enhance the signal-to-noise ratio and improve the time imaging for the pre-Messinian structures in the southeast Mediterranean Sea. The success of the reprocessing meant that acreage that was due to be relinquished was extended, and is now a location for new seismic activity and possibly, new drilling.

(#117249) Organic geochemical evaluation of the Lower Cretaceous Minagish Reservoir Formation in Kuwait

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The Lower Cretaceous Minagish Formation is one of the major oil reservoirs in southern Kuwait. The middle oolitic member is the main reservoir interval and is capped by the upper carbonate mudstone member. The reservoir is productive in the Burgan, Minagish, Mutriba and Bahra fields in Kuwait, and in the Wafra, South Fawaris, Hout and Dorra oil fields in the Kuwait-Saudi Arabia Partitioned Neutral Zone. The specific gravity of the Minagish-reservoired oil ranges from 28º to 33.4º API and the average sulfur concentration is 2.6%. The reservoir in

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the Minagish field contains a 50–100-ft-thick tarmat and very high-density oil at the base of the oil column. This interval has blocked the base of the reservoir and caused a decrease in reservoir pressure. An understanding of the nature and composition of the oil column throughout the reservoir may identify zones of low- and high-density oil, as well as tarmat and pyrobitumen. Applying this analysis may help in production and enhancing oil recovery. The analysis can be conducted by using organic geochemical methods applied on rock samples or oil in the formation. The purpose of this study is to evaluate the nature of the hydrocarbons in the Minagish Formation using the Rock Eval-Reservoir method as one of the tools to identify zones of heavy and light hydrocarbon zones. It is anticipated to show the homogeneity of the hydrocarbon along the reservoir, both vertically and horizontally. A total of 72 core samples were collected from four oil fields in southern Kuwait; Burgan, Magwa, Minagish and Umm Gudair fields. They will be analyzed using the above method and the results will be tabulated. Calculations will be carried-out on the result to identify the nature of hydrocarbons along each of the study well.

(#117808) Reservoir heterogeneity and development strategy of the Mauddud Reservoir undergoing pattern water flooding in Raudhatain field, northern Kuwait

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The Albian Mauddud Formation contains a giant carbonate reservoir in the Raudhatain field. It has a production history of 45 years, divided into two phases: production from depletion drive for the first 40 years followed by inverted 9-spot pattern injection. During the first phase the reservoir pressure dropped close to the bubble point with less than 3.0% recovery. The reservoir has no aquifer support and the reservoir properties deteriorate towards the flank and to the bottom. The analysis of static and dynamic data has brought-out the inherent heterogeneity of the reservoir. On a macro-scale, faults act both as baffles and conduits to fluid flow. Reservoir layers show distinct variation in flow properties, both areally and vertically. The uppermost producing layer is more productive towards the flank of the field. The integration of production logs (PLT), core and log data indicated the layer to have more fractures with lighter oil in such areas. Higher production in crestal areas from other layers is due to the development of secondary porosity and the preservation of primary porosity due to early oil migration. With pattern sea-water flooding, carbon-oxygen (C/O) logging is being used to monitor the water movement. Thief zones have been identified from PLT and core data and substantial water sweep occurs in these zones even though these are not perforated in most of the producers. Water encroachment is being closely monitored and remedial action is being taken to

improve the sweep efficiency. The flank areas of the reservoir with inferior flow properties and heavier oil are being strategically developed. Seismic attribute analysis, zonal testing and fluid characterization from advanced logging techniques are being used to delineate these areas. This presentation will discuss a multi-pronged strategy of mapping reservoir heterogeneity and its use in optimal field development.

(#118698) Partnering to develop a national workforce: Practical challenges and solution

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The challenges facing the Middle East region include increasing the oil production capacity and ageing of the production facilities. To meet these challenges we must have a national workforce capable of achieving these goals. The creation and subsequent development of this national workforce is not an easy task. This presentation concentrates on the practical challenges that face all national oil companies in the region and how to overcome them so as to develop the required local force that can deal with the industry's technical challenges. The presenter has trained more than 2,500 geoscientists and engineers from the entire region since 2004. The analysis of these short and long-term training sessions has led to the identification of some barriers to build this national workforce; for example: English language skills, sequential courses without on-job-training, early jump toward software-learning before walking through the technical basics, the wrong person in the wrong course, course contents, unqualified instructors, student's aptitude and attitude and non-technical culture. The solutions to these obstacles include updating the course contents, using local examples, improving the work ethic of local employees, training them on character and not only technical skills, involving supervisors more with participants, using domestic experts as teachers, increasing the cooperation between academia and operating companies, and making sure the right attendee is in the correct course. The Middle East contains 67% of the proven world oil reserves. It has a talented and young generation and owns the technology to make it happen. What we need to do is to *walk the talk*.

(#117418) Early to late diagenetic dolomitization of a carbonate platform, Upper Jurassic gas reservoir, Mozduran Formation, Kopet-Dagh Basin, northeast Iran

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Platform carbonates of the Upper Jurassic Mozduran Formation consist of widespread limestone and thick dolomite. The Mozduran dolomites comprise the main gas reservoir of the Kopet-Dagh Basin. However, inspite of their scientific and economic significance, the diagenetic origins of these rocks have been little studied. Reserves

of about 500 billion cubic meters of gas were discovered in the Upper Jurassic and Lower Cretaceous sediments in the Khangiran field. Thick shale intervals and gypsum provide good caprocks, and the hydrocarbon source rocks are believed to be the marlstones of the Middle Jurassic Chaman-Bid Formation. Petrographic, elemental and isotopic data indicated that the Mozduran dolomites were subjected to a complex diagenetic history, ranging from a wide spectrum of early-to-late diagenetic dolomitization. In this study, five varieties of dolomite have been recognized. Variations in dolomite types may reflect differences in formation time, formation mode, or the composition of the precursor limestone. The presence of higher concentrations of organic carbon (measured by Carlo Erba) in dolomites, compared to the limestones, may indicate that dolomitization was favored in those limestones that originally had higher concentrations of organic matter. The preservation of a large amount of organic matter, which corresponds to relatively high $\delta^{13}C$ values in the Mozduran dolomites, may be due to high rates of burial or dysaerobic (oxygen-deficient) conditions. The estimated maximum burial depth of the Mozduran Formation is about 4,0 km. Calculated temperatures from stable, oxygen-isotope compositions of late diagenetic dolomites suggest that these dolomites formed between burial depths of c. 3.5 and 4.5 km. According to the paleotemperature analysis, gas traps were formed during the Late Alpine Orogeny (about 10 Ma).

(#118651) Khuff carbonate reservoir modelling: A case study from Oman

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The Khuff Formation of the Akhdar Group was deposited during the Permian-Triassic as platform carbonates in northern Oman. In the Fahud Salt Basin, the Khuff contains sour hydrocarbons. Since the formation underwent a complex diagenetic and structural history, any reservoir modelling has to be based on a thorough understanding of the processes and 3-D features impacting hydrocarbon flow. The presented workflow was designed to better translate a detailed conceptual geological model into a coherent static reservoir model. Overall its target was to facilitate a *fit-for-purpose* evaluation of identified subsurface uncertainties thereby providing a robust concept selection basis for a future field development. A core- and log-based stratigraphic framework, sedimentological and depositional model and diagenetic history are presented. For the identified flow units, so-called *reservoir model elements* were defined, which include the key depositional and diagenetic uncertainties, such as the distribution of oolitic grainstones, and dolomite-limestone, respectively. These reservoir model elements were translated, with the help of log-based electro-facies, into rock types. Eight significant rock types were defined. The 3-D distribution of rock types was in turn

used to influence the distribution of porosity and permeability using well-defined petrophysical rock-property trends based on core measurements. Seismic data was also used to constrain the distribution of reservoir units in some layers based on well-calibrated seismic facies and mounded features.

(#117617) Uncertainties and risks associated with prospectivity of Mauddud Formation in the Bahrah area, Kuwait

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The Bahrah area is located on the Kuwait Arch, between the giant Burgan field to the south and the Sabiriyah field to the north. Although the first exploration well in Kuwait was drilled in the Bahrah area in 1936, exploration and delineation of Bahrah's reserves remained difficult due to the complexity of the structural setting, minor oil columns, widely varying oil and reservoir qualities, and uncertainties associated with seismic mapping. Out of 16 penetrations so far, only three wells have been completed in the Mauddud Formation, of which two are producers. Data acquired to date represent different vintages of wireline logs, seismic surveys and scant pressure records. Observed contacts (oil-water-contact, ODT and WUT) on logs and structural closures do not appear to be consistent. This may be due to uncertainties in time-depth conversion and/or trapping mechanism related to the role of faults and/or stratigraphic components, all of which remain to be understood. Oil samples collected from the Mauddud show variations in API gravities ranging between 23° and 29°. The oil qualities, saturation profiles and structural development during the geologic past appear to be related. Careful interpretation has revealed that better quality oil can be predicted in areas where early migration and retention of oil conformed to lesser post-migration structural deformation. To address the exploration challenges, a strategy has been devised towards intensive data acquisition including cores and fluids. This will enable us to establish a vertical zonation in terms of reservoir and oil qualities, and to propose horizontal wells in sweet zones.

(#118420) Origin of H_2S and hydrocarbons from the Permian-Triassic Khuff Formation using fluid inclusion technology

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Fluid-inclusion analysis was conducted from onshore and offshore fields in Saudi Arabia, supported by detailed petrography and integration with existing geochemistry, reservoir and sedimentological data. The objectives were to determine the temperature of *thermochemical sulphate*

reduction (TSR) and H₂S generation, petroleum phases and API, gas-to-oil ratio (GOR) of liquid petroleum in inclusions, as well as filling history. Results confirmed that H_2S in the Khuff Formation is due to TSR. The absolute quantity of produced H_2S is reflected by the quantity of anhydrite that was converted to calcite, and was taken to suggest degree of TSR advancement. Petrographic and fluid-inclusion data suggested that TSR was controlled by temperatures, distribution of finely disseminated anhydrite and hydrocarbon liquid or gas phase in the Khuff reservoirs. Fluid-inclusion analysis revealed that the initial charge was oil, later displaced by condensate and dry gas. The analysis also showed that TSR occurred at temperature between 110° and 135° C. Oil found as inclusions is consistent with the emplacement of a maturity-controlled sequence beginning with 35° API oil through to a 55° API oil at temperatures of up to 140° C, with methane-dominant gas emplacement above 140° C to approximately 155° C. The absence of oil inclusions in other wells could be due to: (1) oil never having resided in the Khuff Formation in these wells because they were too deep for a palaeo-oil floor, or the lack of source rock in local areas for the reservoir; (2) an insufficient number of samples were examined to find rare oil inclusions; (3) oil, initially trapped, leaked-out of inclusions into free pore space and was then diluted by gas; and/or (4) oil cracking to gas within fluid inclusions.

(#123134) The Barik Sandstone Member, northern Oman: Stratigraphic traps and review of a tight gas play

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The Barik Sandstone Member (Cambrian-Ordovician Haima Supergroup) in northern Oman is the most productive deep and tight gas unit in Oman. The majority of existing discoveries are conventional structural closures but much of the remaining potential resides in stratigraphic traps. The Barik Sandstone Member comprises a variety of reservoir facies within an overall continental braid-plain to marginal marine/offshore setting. Through time, the position of the Barik coastline oscillated across northern Oman. Better reservoir developments are associated with sand-rich, fluvial-dominated systems, contemporaneous with regional progradational events, and exhibit abrupt contacts with adjacent marine mud-prone intervals. These progradational units are probably a result of forced regression. Barik stratigraphic-trap configurations rely on the northerly pinchout of these sandstone systems. Major flooding surfaces, ichnofacies and magnetostratigraphy have assisted in defining a detailed intra-reservoir, regional correlation framework for the *barren beds* of the Barik Sandstone Member. This framework gives some regional control on intra-Barik reservoir distribution and connectivity

and facilitates improved understanding of local changes in palaeogeography, providing a correlation resolution of less than one million years. With limitations on the seismic definition of reservoir distribution regional, Barik well penetrations, integrated with outcrop studies, provide the main input into geological models for the Barik Sandstone Member and the basis for play maps. All data have been used in facies modelling, core-log calibration, depositional environment interpretation, provenance, palaeocurrent analysis and reservoir quality determination. These parameters have been mapped to generate play maps that assist in defining and testing the stratigraphic pinchout traps in the Barik Sandstone Member and in early appraisal activities in discovered stratigraphic traps.

(#121716) Early grain-coat formation in modern eolian sands: Implications for prediction of deep porosity

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Early-formed grain coats preserve favorable reservoir quality in deeply buried sandstones by inhibiting formation of high-temperature quartz cement during later burial. Deep eolian reservoirs with grain-coat-preserved porosity include the Norphlet, USA; Rotliegendes, Germany; and Unayzah, Middle East. Petrographic observations and quartz-cement modeling indicate that coat effectiveness in cement inhibition increases with greater coat continuity. Infiltrated/illuviated clays, diagenetic clays, and microcrystalline quartz all have been shown to form effective grain coats. Consequently, reliable deep-porosity prediction requires accurate models for the presence, continuity, and composition of early grain coats. A joint Saudi Aramco-ExxonMobil study was undertaken to document the distribution and genesis of grain coats in modern eolian settings. Water and sand samples were collected from a range of depositional environments in arid and semi-arid settings (Saudi Arabia and New Mexico, respectively). Coat characteristics were evaluated using petrographic analyses and laboratory experiments. Early results indicate that most continuous infiltrated coats in eolian environments are clay, formed either by percolation of muddy water into wadi sediments, or illuviation of airborne dust into dunes and sand-sheets during early soil formation. Coated grains blown from wadis or soils into active dunes lose their coats by abrasion during eolian transport. Climate appears to be a control on coat formation and preservation. In arid climates, dunes remain active, and illuviated coats are abraded more quickly than they can form. Dunes and sand-sheets in semi-arid settings, however, are stabilized during wetter climatic periods. This stabilization allows longer-term illuviation and drives a multicyclic process of coat formation and abrasion.

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(#118994) An innovative approach to characterizing fractures for a large carbonate field of Kuwait by integrating borehole data with the 3-D surface seismic

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Developing fractured carbonate reservoirs has always been demanding for the geoscientists of the oil industry. The main challenge, in this regard, has been modeling the fracture system. To build a DFN (discrete fracture network) model, different geostatistical techniques are used to extrapolate the fractures beyond the well locations and populate them between the well control. However, due to inherent uncertainty DFN predictions have not always been correct, so the industry needs a way by which DFN models can be constructed with a higher degree of certainty. This presentation discusses an innovative workflow by which the borehole-scale fracture data is integrated with the surface seismic using the Fracture Cluster Mapping (FCM) technique to locate fracture clusters. The most important step in this approach is to obtain a good understanding of the fracture system intersected by boreholes that have certain expressions on the drilling record, borehole images, petrophysical logs, cores and production data. Generally the discrete fracture occurrences would not have any expression on the surface seismic. However when fractures of bigger dimensions form clusters/swarms, they tend to have larger vertical and horizontal extents, as observed in several outcrops in the Middle East and other countries.

In this workflow, surface-seismic data processing is optimized for it to be used for fracture clusters / corridors detection. Having a good understanding of fractures' pattern in the field and optimally processed 3-D seismic data, Ant Tracker (which is an essential part of FCM for automatic extraction of lineaments from the seismic data) is run on the seismic cube. The Ant Tracker set of parameters are conditioned based on the fracture data, gathered from boreholes, in such a way that they highlight fracture clusters/corridors of certain orientations and width. The workflow was tested on the study area of about 1,400 square km for the carbonates of low porosity, low permeability and about 3,000 ft thickness. There were 12 wells drilled in the study area and ten of them had image logs and cores (from selected zones) to get information on fractures. One well test, one production log, and mud loss data from half of the wells, and total well production data were used to understand the fracture behavior. Wellbore images and cores in the study area invariably showed existence of fracture clusters/swarms of width greater than 100 ft and length greater than 500 ft.

(#118953) Application of neural network in intelligent reservoir characterization: A case study from Ahwaz oil field, southwest Iran

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Porosity and permeability are the most important hydrocarbon reservoir properties. There are two methods for determining porosity: directly by core analysis with helium injection, and indirectly by well-log analysis. Similarly, permeability can be determined in the laboratory from core samples by dry-air injection or well-testing methods. These methods are costly and time-consuming. Due to economic reasons and the inability to core horizontal wells, core data is available in a limited number of wells. However, most wells have well-log data. In the present study, intelligent computing neural networks, which are widely used nowadays in the petroleum industry, were used to predict porosity and permeability in the Asmari Formation. The MATLAB software was used to process neural networks for core and well logs data, including porosity and permeability. These networks were developed using an error back-propagation algorithm within feed-forward networks. After comparing the measured and network-predicted results, the parameters of the artificial neural networks (ANN) were adjusted for a desired network. The correlation coefficient between the core results and the ANN-predicted porosity and permeability were 0.92 and 0.82, respectively. These results show that intelligent neural network models predicted porosity and permeability accurately. Finally, the above-mentioned networks were generalized to a third well that had no core data.

(#116094) Seismic array response in the presence of laterally varying thickness of the weathering layer

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Wavelet response analysis of seismic arrays is a more convenient and direct method of analysis than using their conventional time-harmonic responses. This is because wavelets, rather than sinusoids, are actually generated by the seismic source. This study involves an investigation of the effect of lateral variations in thickness of the weathering layer over the array length on the array response. Three types of variations were studied; namely, dipping-bottom boundary, channel and irregular bottom boundary of the weathering layer. The investigated parameters were the number of elements (12 and 24 elements), the weighting function (equal and triangular), the incident wavelet (Ricker and Klauder) and the error amount. The degradation in the *root-mean square* (RMS) amplitude responses generally increased with the error amount. RMS amplitude responses were

more degraded in the channel case than the other two cases. Errors affected triangularly weighted arrays more than equally weighted arrays. Klauder wavelet array responses were more affected by these errors than Ricker wavelet responses. Vertically traveling waves (i.e. signals) were more affected than the horizontally traveling waves (i.e. noise). Since these variations cannot be inferred from the surface topography, they can affect the array responses without being detected, unlike topographic and element's positional errors. Therefore, it is recommended to test for these effects prior to array layout. Solutions to this problem are to record single-element data and correct these during processing before summing, or to move the array away from the sources of these effects.

(#119077) Potential of Iraqi oil system

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Early exploration surveys in Iraq started at the end of 19th Century. In 1901 the first exploration well in the Middle East, Chai Sorkh-1, was drilled in northern Iraq by a German Company. In 1909, using an old cable tool drilling rig, the first discovery well, Chai Sorkh-9, encountered heavy oil. The first commercial discovery in Iraq was in the Naft Khan-1 well near the Iranian border. In 1925 the Iraq Petroleum Company (IPC) obtained a concession agreement that covered nearly all of the country for 75 years, without relinquishment. In 1927, the first significant oil discovery in Iraq was in well Kirkuk-1, which tested about 100,000 barrels of oil per day. The Iraqi resources are unique when compared to other Middle East countries because Iraq is one of the vastest and least-explored countries in the region. It has an ideal petroleum system with multiple source rocks, reservoirs, cap rocks and trapping systems. The petroleum system extends from the shallow Cenozoic down to deep Paleozoic sequences. Iraq may prove to have one of the greatest petroleum resource bases in the world, with potential oil resources in excess of 215 billions barrels and proven reserves in the region of 114 billions barrels. Moreover, its exploration and development costs are low – amongst the lowest in the Middle East countries. Iraq also is estimated to contain at least 110 trillion cubic ft of natural gas. The country is a focal point for regional and international security issues. Nevertheless, Iraq's oil is especially attractive to the major international oil companies for several reasons including geographical location, low-risk exploration, low cost per barrel, good oil quality, multiple pipeline access and huge recoverable reserves.

(#116768) Silurian Tanf Formation prospectivity in the Euphrates Graben Petroleum System, Syria

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This study aims to characterise the potential of Silurian strata as a co-source rock in the Euphrates Graben, Syria. The main Paleozoic source rock in the Arabian Plate is found in the Lower Silurian section (Tanf Formation in Syria), which is mature to overmature in the study area. However, the two main source rocks of Upper Cretaceous age in the study area are carbonates of the Shiranish Formation and the lagoonal, cherty Rmah Formation. 82 oil samples from reservoirs of different ages were analysed by whole oil gas chromatography and detailed analysis of biomarkers and aromatic hydrocarbons by gas chromatography-mass spectrometry. Additionally, 16 Silurian rock samples are still under investigation for this study. Based on compositional parameters such as the pristane/phytane ratio, three geographical areas representing different depositional environments were recognised. In addition, oils from the southeastern part of the graben seem to be highly mature; for example based on light hydrocarbons and the occurrence of diamondoid hydrocarbons whose concentrations are relatively high due to the thermal cracking of the major oil constituents. In contrast, conventional biomarker maturity parameters had already reached equilibrium values in the oils from the southeastern part of the graben due to overmaturity. The gammacerane index shows relatively high values referring to hypersaline conditions. Therefore oil mixing from different sources has to be taken into account. Because Cretaceous source rocks may also reach high maturity levels, compound specific stable carbon and hydrogen isotopes will be elaborated upon as an additional oil-source rock correlation tool to better understand the potential role of the Silurian strata.

(#120057) The concept of entrapment: Towards expanding the paradigm

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The current conceptualization and approach of exploration sets a specific timing for hydrocarbon migration and entrapment and certain geometries for accumulation. The simplest of those is the anticlinal four-way dip closure in which the lighter hydrocarbons migrate up-dip due to their density contrast with the water to arrive to a pseudo-stagnant state. Such an understanding of a simple fluid behavior led to the discovery of huge reserves worldwide. Although successful, limiting the migration and entrapment model to only such physical conditions can be limiting to our hydrocarbon-finding ability. An expansion of the migration and entrapment model that recognizes the dynamic behavior of hydrocarbons than just the pseudo-stagnant model can define new exploration opportunities. The model is supported by analyzed discovery fields, laws of physics, physical and numerical models. The new paradigm states that: (1) hydrocarbons are in continuous movement during basin evolution; (2) entrapment is a phase of the hydrocarbon movement;

(3) massive volumes of expelled hydrocarbons continue to move on a geological time scale; (4) perfect seals are not in line with known behavior of even the tightest rock over a geological time scale; and (5) hydrocarbons will become stagnant only in a site of subsurface hydrocarbon energy minima, which is rarely sustained during the life of an accumulation. The above paradigms define a new set of traps and real examples supported by physical and numerical models are presented. A set of mapping techniques to identify those traps is proposed. The Arabian Platform tectonic and depositional history, and hydrodynamic conditions form a hydrocarbon-prospective region to apply such new concepts and techniques.

(#120058) Understanding subsurface pressure data signature in a hydrogeological context

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Pressure data are often used to understand the conductive properties of the rock framework, such as compartmentalization and sealing. While using such data is well-justified, the lack of understanding of basinal hydrogeology prevents a more comprehensive and thus accurate interpretation. Using a wealth of pressure data from mature basins and a numerical basin-hydrogeology model, a set of guidelines for understanding the pressure regimes and their implication on the hydrocarbon system are outlined. In subaerially exposed basins, the upper 10,000 ft or so are usually normally-pressured and dominated by a gravity-driven flow system. In these basins groundwater descends starting at topographic highs and then flows laterally before it ascends at topographic lows. Intermediate and local flow systems also develop at a smaller scale due to local topographic variations. Sometimes the flow may be short-circuited by flow conduits between horizons, such as evaporite or shale layers. The gravity-driven flow system is usually superimposed on a deeper, abnormally-pressured system whose genesis can be due to multiple aspects. Among those are compaction, hydrocarbon generation and tectonic compression. The movement of groundwater within these systems and the interaction of such flow systems with the geological framework can generate a multitude of pressure signatures, both on a local and regional scale, which when properly interpreted, can lead to better exploration and development strategies. The developed guidelines are outlined and applied to flow systems observed in the Arabian Platform and the potential implications on understanding the hydrocarbon system is proposed in view of the observed data.

(#115431) Efficient high-resolution seismic data for near-surface corrections

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Accurate corrections for topography and near-surface complexities of surface seismic data from the Arabian Peninsula require accurate modeling of the near-surface and an effective correction algorithm that uses of the model. Refraction and residual statics-based modeling, though they help improve results, have fallen short of what is required in complex regions in the area. In fact, almost all the existing near-surface correction methods require an accurate near-surface velocity model. In some cases, however, the model is impossible to estimate from conventional low-resolution seismic data in which the near-surface inhomogeneities occur within the near-field region of wave propagation. Through numerical modeling, we show that a reasonably accurate shallow-velocity model can be obtained from applying conventional horizon-based velocity analysis on shallow high-resolution seismic data. The model proved to be effective in correcting the conventional deep seismic image using either the simple static shifts or wave-equation datuming. We also present a novel idea to acquire high-resolution shallow seismic data in a cost-effective way. The novelty of the approach is in the spacing of the receivers, in which we used conventional acquisition configurations to acquire the high-resolution data with minimal additional cost. We investigated the resolution limits achieved from conventional configurations. A real experiment in the Riyadh region shows the possible resolution limits obtainable using this approach.

(#115428) Straight-ray datuming in 3-D media: Fast and flexible

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Common datuming approaches, like the Kirchhoff or finite-difference methods, require reasonable sampling of the sources and receivers. This becomes a serious limitation for datuming data acquired using 3-D conventional land-acquisition layouts, because of the typical sparse spacing of either the sources or receivers. To combat this, we extend Alkhalifah and Bagiani's (2006) *straight-ray datuming* (SRD) to handle 3-D acquisition geometries. As in the 2-D case, 3-D SRD is based on the straight-ray assumption above-and-below the datum with Snell's Law honored in between. This allows for the application of SRD to common-shot gathers in one operation (no need to sort the data to common receivers). Similarly, it can be applied to common-receiver gathers without the need to sort the data back to common-shot gathers. This feature allows for more flexibility in acquisition as it requires, unlike in the conventional case, either the sources or receivers to have a complete fine coverage of the area. In addition, SRD does not require a detailed description of the near-surface velocity model; information from refraction static or any other commonly used method to obtain near-surface time shift suffice. SRD, in addition to carrying out redatuming, can be used to map irregularly sampled spatial data at the acquisition surface into regularly sampled data at the datum. In fact, since the

operation is a partial migration, it suppresses diffractions generated from inhomogeneities above the datum. The computational cost of applying 3-D SRD is larger than static corrections, but because of the limited spatial extension and analytical formulation, it is far less than Kirchhoff re-datuming.

(#117285) Rock physics guided AVO: A holistic approach to sand detection

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Rock physics plays a critical role in lithology and fluid prediction, and amplitude-versus-offset (AVO) modeling. It is a quantitative tool and a necessary step in understanding and interpreting seismic amplitudes for predicting lithofacies distribution. In this case study, I employed AVO inversion, guided by rock physics, to detect reservoir quality sands in the Unayzah Reservoir in central Saudi Arabia. The inversion scheme is a simultaneous pre-stack inversion algorithm based on Zoeppritz's equations. The procedure uses near- and far-angle stacks and angle-dependent wavelets to determine the elastic parameters: P-wave impedance, S-wave impedance and Vp/Vs ratio. To interpret the pre-stack inversion results the data was constrained by rock physics. Initially *rock physics templates* (RPT) were built, which are geologically driven, basin-specific, theoretical rock physics models. Geologic constraints on RPT included lithology, mineralogy, porosity, depth (pressure) and temperature. RPT cross-plots were built for acoustic impedance (AI) versus Vp/Vs, which were overlain by trends for lithology and porosity. This allowed performing rock physics analysis, not only on well log data, but also on seismic data (pre-stack inversion results). Initially, RPT were validated by well-log data before applying them to seismic data. Input data and model assumptions affect the accuracy of the information obtained from the template. I used RPT to guide the classification of the seismic inversion results. The pre-stack inversion of AI and Vp/Vs within the target zone was projected onto the template to generate lithofacies map that help distinguish reservoir sands from silty shales.

(#141214) Sequence stratigraphy of Kuwait Jurassic section: An approach to proceed forward

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During the Jurassic Period Kuwait formed part of the northeastern Arabian Plate along the passive Tethyan margin. By the Late Jurassic it was located between three well-established sub-basins. Only a few published studies describe Kuwait's Jurassic section in detail, and these generally refer to data and geological settings from nearby regions. The geological data often lack definite age control due to the restriction of the basin during Jurassic time and the quality of the analyzed samples. The geophysical data also has limitations when used

for seismic stratigraphic studies. This work attempts to overcome these limitations and to establish the sequence stratigraphic framework for Kuwait's Jurassic section. In 1996 KOC acquired 2-D seismic data with a grid spacing of 2 to 3 km; this data was sufficient to map potential stratigraphic traps. However, the vertical seismic resolution was insufficient to adequately interpret the Jurassic and deeper section. Moreover, inter-bed multiples contaminated all of Kuwait's seismic data, especially at the deep targets. KOC, in its search to resolve the above problems and limitations, has recently acquired high-resolution, 3-D single-sensor seismic data in order to properly sample the wave field and to improve both the spatial and vertical resolution. Also, several successful studies have been carried-out for multiple attenuation. Both the newly acquired and reprocessed data have good potential to form the basis for understanding the stratigraphic framework. In exploration all data counts to minimize the risk of failure. As the subsurface image becomes clearer the model can be adjusted to maximize the likelihood of success. Therefore the existing 2-D and 3-D seismic data were used to validate the model and highlight new exploration opportunities.

(#118355) Challenges for seismic imaging using explicit wavefield extrapolation

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For imaging complicated subsurface structures, downward-continuation imaging algorithms are more powerful than their ray-based counterparts, such as the Kirchhoff methods. Space-frequency explicit wavefield extrapolation is an attractive downward-continuation algorithm because it accounts for strong lateral velocity variations. In this method, the wavefield at each output point is computed using a different extrapolator that is calculated using the velocity at that location. This algorithm, however, has the following limitations: (1) numerical instability of the wavefield extrapolator: (2) computational expense; and (3) inability of short operators to handle the steep dips. The numerical instability arises because the amplitude and phase spectra of the ideal operator, in the wave number-frequency domain, have discontinuities at boundaries separating the wave-like and evanescent regions. The numerical instability also increases as the spatial extent of the extrapolator decreases. Shorter operators are often more desirable than long ones because they are computationally more efficient, but they cannot handle the steep dips. In this presentation, I will discuss different approaches that can be used to design stable operators. Also, I will show how short operators can handle the high angles of propagation. I will use impulse response examples to illustrate the stability and the accuracy of the designed wavefield extrapolators. Then, the designed wavefield extrapolators will be used to image two synthetic datasets that have strong velocity variation and strong topographic variations. Finally, the algorithm will be implemented in pre-stack time and depth migrations of real data examples.

(#118389) Modeling the near-surface using high-resolution seismic data

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Complex near-surface geology, usually of Quaternary or Tertiary age, is a major problem in land seismic data. It degrades the stacking coherency, and therefore affects velocity analysis as well as the quality of the time-image. Furthermore, long-wavelength anomalies introduce erroneous time structures, a serious interpretation pitfall. Yet more serious, the near-surface might introduce dynamic errors, which influence the isochron technique of mapping and interpretation. The solution to this problem is to remap the data to a datum below the problematic zone. Whether you intend to use simple static corrections or one of the more numerically demanding techniques of wavefield extrapolation (i.e. datuming), the first step is to build a near-surface velocity model. Traditional method, such as uphole-based or refraction-based techniques proved to be effective in limited cases. In this presentation, we propose the use of high-resolution seismic data to model the near-surface. The shallow seismic method is a major tool of investigation in engineering and environmental applications. The purpose of this work is to exploit this method to build an equivalent near-surface macro-velocity model. The methodology involves three steps: (1) data acquisition and processing; (2) obtaining the velocity information; and (3) relating this information to borehole data. The result of applying this methodology to synthetic data was an accurate reconstruction of the near-surface model. We have also applied this method to real field data from the Arabian Peninsula. The model we obtained resolved deep anomalies (about 350 m deep), which are not usually penetrated by shallow upholes. When comparing our stacked section with a refraction-based one, we noticed marginal improvements in quality, but noticeable differences in time structures. Uphole and geological information in that area support our model.

(#114245) Late Cenozoic structuring in Kuwait: Evidence and wider exploration and production implications

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The role of Late Cenozoic stresses in forming trapping structures and in modifying production behaviour is well-established along the Zagros Fold front in Iraq and Iran. The extent to which Cenozoic stresses have affected structuring farther within the Arabian Plate is less clear. We present seismic and outcrop evidence for significant Late Cenozoic uplift of the Burgan structure in central Kuwait. Seismic data from the margins of the Burgan structure show uplift of the Umm Er Radhuma to Fars succession (Palaeocene to Miocene). This represents a modest reactivation of a structure that was largely defined in the Mesozoic. Outcrops show that much of the Cenozoic uplift occurred concurrently with deposition of the Wadi Batin fan gravel sheets (Miocene to Pleistocene). The southern margin of the gravel sheet adjacent to the Burgan structure has been uplifted tens of metres relative to deposits in equivalent radial positions on the fan. Regional information and Kuwait outcrop data suggest that the Late Cenozoic uplift of the Burgan structure was either synchronous with, or immediately posted-dated, uplift of the margins of the Red Sea and Gulf of Aden. This raises the possibility that lithosphere intra-plate stresses generated by Arabian Plate margin uplift played a role in this structuring. This in turn implies that Late Cenozoic movement on appropriately oriented structures could be widespread across much of the Arabian Plate. Kuwait's giant Burgan field, for example, lies on a structural trend that continues southwards into Saudi Arabia. Such Late Cenozoic structures may be of modest amplitude, but their significance could range from trivial to substantial, depending upon the local exploration context and on the production geology of the specific fields affected.

(#118378) Porosity correction in the Najmah Kerogen Formation

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The Najmah Formation has recently been established as a major gas-condensate reservoir and source rock in northern Kuwait. Vast economic reserves have been estimated from this Middle Jurassic formation. The formation is mainly composed of inter-bedded cemented peloidal packstone, argillaceous and bituminous (kerogen-rich) limestone. The kerogen-rich intervals are characterized by high Uranium content and extremely high apparent porosity as observed from conventional porosity logs. A standard approach for determining the effective porosity from conventional porosity logs provided highly exaggerated porosity values, which are not acceptable when compared to the lithological composition of the formation and core-derived porosity. A study was performed to obtain more realistic values of effective porosity for the high-kerogen intervals. Three key wells were selected for the study, based on the available nuclear magnetic resonance logs and core porosity. A relationship of core porosity and/or NMR data with the effective porosity (PHIE) was found to be reasonably consistent for the three key wells and was considered to be related to the kerogen content. Another approach was carried-out by establishing a relationship between NMR, conventional porosity and uranium content. The output of this relationship is presented by corrected porosity (PHIK). Therefore, a fair estimate of derived PHIK, in the absence of core or direct NMR measurements, was achieved. However, such an approach is relatively lower in accuracy when compared with the core and NMR porosity benchmarks.

(#115934) Mishrif Formation oil biomarkers used to assess hydrocarbon generation, migration path and accumulation sites in the Ratawi, Zubair, Rumaila North and South oil fields, southern Iraq

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The reservoir rocks of the Mishrif Formation in Iraq have a porosity of between 25% and 28%. Oil analysis indicated that the source rocks have the following properties: (1) carbonate rocks inter-bedded with shale deposited in reduced marine environment with low salinity and type II kerogen. This is based on biomarkers of Carbon Preference Index (CPI), Phytane, Pristane, n-alkanes of steranes and hopanes, as well as Early Cretaceous in age based on the sterane ratio of C28/C29 and C26/C29 (C=Carbone), the presence of the dinoflagellate cyst species *Pseodoceratium pelliferum*, and the ratio CPI, TS/(Ts+Tm), Pr/nC17 and Ph/nC18 biomarkers, and the brown colour of the dinoflagellate cysts and Tasmanites under light microscope. This oil analysis indicated that most of the oil accumulated in the Mishrif Formation might have been sourced from the Upper Jurassic Najmah and Sargelu and the Lower Cretaceous Sulaiy formations. Palynological analysis was conducted on samples taken from cores. Based on the abundance of amorphogen palynofacies, increasing foraminiferal test linings, and the thermally mature high total organic carbon (up to 8%) it appears that the main oil expulsion was mainly from the Sulaiy Formation. This formation was deposited in a distal suboxic-anoxic basin. Moreover, pyrolysis analysis of these core rocks indicated oil and gas generation from the Sulaiy Formation. This conclusion was based on their position in the diagram of Van Krevlen, scattered remains of hydrocarbon with TOC, and the hydrogen index with Tmax. The oil was generated and expelled during the Miocene from a depth of 5,000-5,357 m and charged the Mishrif reservoir in the traps formed earlier during the Late Cretaceous Period.

(#117092) Middle Miocene Jeribe Formation hydrocarbon sources and accumulations, Diala district, northeastern Iraq

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The stratigraphic section between the Middle Jurassic Alan Anhydrite and Middle Miocene Lower Fars Formation contains an important petroleum system in northeastern Iraq. Both the Alan Anhydrite and Lower Fars Formation constitute regional seals. In the Diala District this section includes oil and gas reservoirs in the Jambour, Pulkhana, Qumar and Mansuriya fields. This study focused on the source rocks of this system. Gas chromatography-mass spectroscopy (GC-MS) analysis

of the oil in the Middle Miocene Jeribe Formation (especially from the Jambour oil field) identified several molecular fossils (biomarkers) parameters. Pristine/n17 versus Phytane/m18, Ternary sterane diagram, Tricyclic terpane scatters and Pristane/Phytane versus carbon-isotope ratios indicated kerogen sources types II and III. The kerogen shows very low biodegradation and high maturity, and consists of marine algae deposited in suboxic-anoxic palaeoenvironments within carbonate sediments. The graphical presentation of other biomarker parameters suggested an Upper Jurassic and Lower Cretaceous age for the source rock: (1) C28/C29 sterane ratio of 0.9; (2) oleanane value of 0.2; and (3) a low value of tricyclic terpane (0.48) versus time. The age of the source rocks was confirmed by oil palynomorphs. Based on kerogen enrichment, type and maturity, rock types and petroleum potential, the source rocks might belong to one or more of the local formations Chiagara, Balambo and Sarmord.

Pyrolysis analysis of 232 core rock samples of Jurassic and Cretaceous strata are presented on a Van Krevlen diagram (Hydrogen index versus Oxygen index), Kerogen type and maturity (Hydrogen index versus Tmax) and kerogen conversion and maturity (Production index versus Tmax) have indicated types II and III for all the studied formations. The Chiaga and Balambo formations are within the oil window and zone of generation and expulsion. The Shiranish Formation is immature whereas the Sargelu Formation has no molecular fossil contribution to the oil found in the Jeribe Formation. The Chiagara and Balambo formations have a distal suboxic-anoxic deposition as indicated in the Ternary kerogen plot, and hence are correlatable with the oil molecular fossil of the Jeribe Formation. The Jeribe Reservoir has a permeability of 30 mDarcy and good porosity as indicated by electrical logs (10–24%, consisting of intraparticle, fracture, vuggy and channel types). It is sealed by the anhydrites of the Lower Fars Formation and found in predominantly NW-trending anticlinal traps, which formed during the Late Miocene-Pliocene compressional tectonism associated with the closure of Neo-Tethys Ocean along the Zagros Suture. The Jeribe Reservoir closures were therefore sealed before the main phase of oil and gas generation, which continues to the present-day. Gas accumulations occur further northeast in Mansuriya field, near the Diala River, whereas oil accumulation occur towards the north-northeast within the Jambour oil field, near Kirkuk.

(#123291) Palynofacies and hydrocarbon generation potential for the rocks of the Upper Triassic Baluti and Kurrachine formations in Mosul Block, northwestern of Iraq

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Three exploration wells were selected near Mosul city

(AZ-29, BM-15 and KD-1) to study the palynofacies and hydrocarbon-generation potential of the Upper Triassic Baluti and Kurrachine formations. This study was completed into two phases. The first was a study of palynofacies and their palaeoenvironmental indications, degree of preservation, diversity of palynomorphs, and organic maturity of the rocks according to palynomorphs color using a microscope. More than 80 slides of organic matter were used for this study. Four palynofacies were tentatively recognized. (1) The first palynofacies is diagnostic of the Baluti Formation in the AZ-29 and KD-1 wells; (2) The second palynofacies appeared at different depths in the Kurrachine Formation in three wells. (3) The third was only found between the depths 4,534–4,685 m in the well AZ-29. (4) The fourth was only found between the depths 3,500–4,590 m in the well BM-15. A distal coastal marine environment is suggested for the Baluti Formation and a restricted lagoonal environment for the Kurrachine Formation. The second phase used organic geochemical analyses to confirm the suggested palaeoenvironment and hydrocarbons generation potential and maturity. Three techniques were used (TOC, pyrolysis and pyrolysis-gaschromotography) for more than 35 samples from different depths in three wells. The analysis proved that a sufficient quantity of organic matter occurs and has suitable maturity for hydrocarbons generation potential of oil and gas.

(#120809) Hydrocarbon potential of the Middle Jurassic Sargelu Formation, Zagros Fold Belt, northern Iraq

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Microscopic and chemical analysis of 162 rock samples from exploratory wells and outcrops in northern Iraq indicated that limestone, black shale, and marl within the Middle Jurassic Sargelu Formation contain abundant oil-prone organic matter. For example, one 7-m (23-ft) thick section averages 442 mg HC/g S2 and 439° C Tmax (Rock-Eval pyrolysis analyses) and 16 wt% TOC. The organic matter, comprised principally of brazinophyte algae, dinoflagellate cysts, spores, pollen, foraminiferal test linings, and phytoclasts, was deposited in a distal, suboxic to anoxic basin and can be correlated with kerogens classified as Type A and Type B (Thompson and Dembiki, 1986) or, alternatively as Type II. The level of thermal maturity is within the oil window with TAI = 3– to 3+, based on microspore colour of light yellowish brown to brown. Accordingly, good hydrocarbon generation potential is predicted for this formation. Terpane and sterane biomarker distributions, as well as stable isotope values, were determined for oils and potential source rock extracts to determine valid oil-to-source rock correlations.

Two subfamily carbonate oil types-one of Middle Jurassic age (Sargelu) carbonate rock and the other of Upper Jurassic/Cretaceous age, as well as a different oil family related to Triassic marls, were identified based on multivariate statistical analysis. Middle Jurassic subfamily A oils from Demir Dagh oil field correlate well with rich, marginally mature, Sargelu source rocks in well MK-2 near the city of Baiji. In contrast, subfamily B oils have a greater proportion of R28 steranes, indicating they were generated from Upper Jurassic-Lower Cretaceous carbonates such as those at Gillabat oil field north of Mansuriyah Lake. Oils from Gillabat field thus indicate a lower degree of correlation with the Sargelu source rocks than do oils from Demir-Dagh field. One-dimension, petroleum-system models of key wells were developed using IES PetroMod software to evaluate burial-thermal history, source-rock maturity, and the timing and extent of petroleum generation; interpreted well logs served as input to the models. The oil-generation potential of sulfur-rich Sargelu source rocks was simulated using closed-system, Type II-S kerogen kinetics. Model results indicate that throughout northern Iraq generation and expulsion of oil from the Sargelu began and ended in the late Miocene. At present, Jurassic source rocks might have generated and expelled between 70 and 100% of their total oil.

(#116918) Prediction of apparent cohesion, angle of internal friction and Poisson's ratio of various types of rocks using laboratory measured unconfined (uniaxial) compressive strength

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The evaluation of Mohr-Coulomb failure criterion, as well as other mechanical properties for reservoir rocks, is essential for well planning, development and characterization of oil and gas reservoirs. This is because the understanding of the rock-stress relationship can solve many reservoir problems and avoid the cost of remedial work. For example, a Mohr-Coulomb failure criterion may be used for borehole instability analysis, water-injection design, hydraulic-fracturing design, production-optimization techniques, compaction and sand-production prediction, etc. A Mohr-Coulomb failure criterion is a function of the apparent cohesion ($f$äo) and the angle of internal friction (fÖ). The evaluation of these two parameters requires testing of many rock samples using an expensive and time-consuming triaxial testing set-up. In this study, a correlation between the apparent cohesion and the unconfined (uniaxial) compressive strength was developed. It is based on laboratory data of more than 400 rock samples of different types obtained from the literature. The correlation coefficient of the developed correlation equals to 0.88. Verification of the developed correlation using data from other references has shown an average error of estimation less than 10%.

Unfortunately, some odd predictions were also noticed and can be attributed to measurement errors. Therefore, the Mohr-Coulomb failure criterion's parameters as well as Poisson's ratio can be estimated using the developed correlation based on fast and cheap measurements of the unconfined (uniaxial) compressive strength.

(#119062) Fundamental controls on organic-matter preservation in a clastic-starved intra-shelf basin: The Upper Cretaceous Natih B sediments (Natih Formation) of northern Oman

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It is often argued that enhanced organic-matter preservation (up to 15% total organic content) in the Mid- to Late Cenomanian Natih B intra-shelf basin (maximum water depth circa 80 m) is caused by the presence of anoxic bottom-water conditions. Mechanisms that underpin organic-matter enrichment in intra-shelf basinal settings, however, are complex. They are controlled by a balance between primary (both organic and inorganic) productivity, clastic input, rate of sedimentation and early diagenesis. In this study possible mechanisms for organic-matter preservation other than persistent bottom-water anoxia are investigated. The results of this study will help improve the understanding of the distribution of source rocks in intra-shelf basins. Natih B sediments (collected from both core and outcrop in northern Oman) have been investigated using a combination of optical and electron-optical (back-scattered electron imagery) techniques, which provide additional data to those gathered by traditional field and geochemical methods. Natih B lithofacies alternate between two main types: organic-rich mudstones and cement-rich wackestones. The organic-rich mudstones are typically, fine-grained, dark-grey, unlaminated, and paler-coloured where burrowed. These units commonly contain planktonic foraminifera, coccoliths and organic matter. In addition, *in-situ* thick-shelled bivalves (including *"Exogyra* sp.") are present. The cement-rich wackestones are lighter in colour and extensively bioturbated. This lithofacies comprises a mix of skeletal fragments, echinoderm debris, bivalves, brachiopods, calcispheres and rare foraminifera, cemented by fine-grained carbonate. Given these observations, it is likely that bottom waters during deposition of the Natih B intra-shelf basinal sediments were oxygenated. Organic-matter accumulation here, therefore, cannot have been controlled by the presence of persistent bottom-water anoxia. Instead, short-term enhanced organic productivity, rapid delivery of organic components to the sediment-water interface, optimal rates of sediment accumulation and episodic burial were probably the fundamental parameters that controlled facies variability.

(#118877) Fractures detection and characterization for the Jurassic carbonate reservoirs using 3-D P-wave pre-stack seismic data in Saudi Arabia

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Pressure well data have indicated a communication between two hydrocarbon-producing Jurassic Carbonate reservoirs: Arab D and Hanifa, in an oil field in eastern Saudi Arabia. Detecting and characterizing the existing fracture system(s) in our area-of-interest (AOI) using 3-D P-wave pre-stack seismic data is the main objective of this azimuthal anisotropy study. A relatively wide-azimuth full-offset 3-D P-wave seismic survey has been acquired over the oil field. The 3-D pre-stack P-wave seismic data has been analyzed to investigate the azimuthal variations of the normal-move-out (NMO) velocities and *amplitude-variation-with-offset-and-azimuth* (AVOA) as they pertain to the presence of fractures in the Arab D and Hanifa reservoirs in addition to upper Fadhili reservoir. The azimuthal pre-stack seismic anisotropy analysis for the target reservoirs suggests the existence of two dominant orthogonal anisotropy (i.e. fractures) orientations trending in general NE (c. 50–70º from N) and SE (c. 140–160º from N). AVOA anisotropy also suggests that the NE-trending anisotropy (c. 65–70º from N) is the most dominant fractures orientation at the reservoirs levels, which is consistent with the results obtained from borehole image logs. The NMO velocity and AVOA ellipticity maps provided insights about the fractures network and their intensities, offering a tool to assist in optimizing well planning and reservoir development. These conclusions are consistent with pressure data. Further enhancements can still be achieved by optimizing our data acquisition and processing techniques. This is the first successful published application of 3-D P-wave pre-stack seismic azimuthal anisotropy analysis for fracture detection and characterization in a carbonate reservoirs in Saudi Aramco.

(#115926) Sequence stratigraphy and reservoir compartmentalization in the lower Wasia, offshore Saudi Arabia

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High-resolution sequence stratigraphy analysis was applied at the lower part of the Wasia Formation (Khafji, Safaniya and Mauddud members) of Albian age in the offshore Saudi Arabia. Core analysis, wireline logs, biostratigraphy and fluid data were used in the analysis. Two third-order sequences were identified within the lower part of the Wasia Formation. The Wasia Formation (Albian/Turonian) in Saudi Arabia is represented by seven members; from bottom to top: Khafji, Safaniya, Mauddud, Wara, Ahmadi, Rumaila and Mishrif. The Wasia is bounded by two pronounced regional un-

conformities related to major tectonic events: the pre-Wasia (Albian/Aptian) and pre-Aruma (Campanian/Turonian). The lower sequence starts at the base of the Khafji Member with the lowstand Khafji Main Sand followed by transgressive Khafji sand stringers with a maximum flooding limestone marker named the Dair Limestone. This sequence was terminated with the highstand Khafji stray sands; a very thin continuous sand overlying the Dair Limestone. The upper sequence starts with the lowstand Safaniya reservoir sandstone followed by the transgressive and maximum flooding surface of the Mauddud Limestone. The sequence ends with the highstand thin carbonates and shales of the upper Mauddud Member. Detailed tectono-stratigraphic analysis of the lower part of the Wasia Formation in the offshore fields indicated that the Lower Khafji Main Sand was deposited as fluvial filling of the tectonically-controlled irregular basin topography. The deposition of the remaining section of the two sequences was primarily controlled by the sea-level eustacy with weak tectonic imprints. Tertiary reactivation of the faults cutting the pre-Wasia section has resulted in compartmentalization of the lower Wasia reservoirs.

(#123978) Using high-resolution sequence stratigraphy for characterizing the Khuff C Reservoirs in Hawiyah, Ghawar Field, Saudi Arabia

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The Permian-Triassic Khuff carbonates were deposited during a major marine transgression on the Arabian Plate. The Khuff Formation is made up of four subsurface members: stratigraphically D, C, B and A. In Ghawar field, the Late Permian 270-foot-thick Khuff C carbonates contain three reservoir-bearing high-resolution sequences: Khuff C1 to Khuff C3 (KC1 to KC3). The reservoir facies indicate heterogeneity in rock fabric and reservoir quality. Lithological and porosity-based stratigraphy does not necessarily honor the time-equivalent relationships of different rock and reservoir facies. Taking a sequence stratigraphic approach to defining reservoir architecture, however, presents a temporal framework within which porosity can be tied to depositional and diagenetic facies. Hence, predictive mapping of porosity within layers of time-equivalent heterogeneous facies is possible. It also provides a stratigraphic architecture that is much better suited to the analysis of diagenesis and related geological events that altered sediments and impacted both primary and secondary porosity development. The Late Permian Khuff C sequences are defined by their bounding, Ghawar-wide, disconformities/sequence boundaries. The transgressive and highstand systems tracts (TST and HST) and component cycle sets for each sequence are mappable along the length of Ghawar field. Exposure surfaces in core are defined by pedogenic features, which can be identified on gamma-ray logs. This identification allowed mapping of the

high-resolution sequences and cycle boundaries of the TST and HST in cored and uncored wells. Reservoir developed in both the TST and HST, with inter-crystalline porosity in the HST of KC2 and KC3, whereas moldic porosity developed in the late TST of KC3.

Taking a closer look at these reservoirs using the current sequence stratigraphic framework derived from extensive core and log correlation has enabled better numeric modeling of the distribution of porosity in the reservoir. This core-and-log based sequence stratigraphic framework is a genetic-based layering scheme that has become a predictive foundation for numeric modeling of such layers. Numerical modeling of facies distributions within the framework is also possible, but more challenging, especially when grainstone facies are fully cemented by anhydrite and are indistinguishable as such on wireline logs. If it becomes possible to define controls on anhydrite cementation, more refined predictive models can be put forth. Iterative studies between conceptual and numerical models, which account for diagenesis, can provide the best refined predictive models.

(#118352) Umm-Roos prospect: New Jurassic hydrocarbon play in West Kuwait

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Jurassic development activities in western Kuwait are limited to the Minagish, Abduliyah, Dharif and Umm Guddair fields. Until recently, Kra Al Maru was the only Jurassic accumulation outside these fields. Systematic exploration since 2000 has resulted in the Kahlulah and Rahayiah discoveries along the Minagish-Kra Al Maru and Minagish-Rahayiah trends. Significant leads occur as the continuation of good reservoir facies within the Marrat Reservoir in the main Minagish field. In these new discoveries the oil/water contact in the Marrat Reservoir is 1,400–1,500 ft deeper and the oil is lighter (42° API). Structural mapping of the entire western Kuwait region incorporating both 2-D and 3-D seismic data has helped in understanding the off-structure prospectivity of the area. The predominance of EW- and NS-trending strike-slip faults, with very limited vertical throws, are well-recognized throughout the studied 3-D seismic volume. Faults extending into the 2-D seismic data area can thus be mapped with greater confidence. The 2-D/3-D composite structural map of the Jurassic reservoirs highlighted the fact that the Minagish-Rahayiah Trend is further compartmentalized by mostly EW-trending strike-slip faults. The Umm-Roos prospect is one such compartmented faulted closure. The reservoir characteristics of the Marrat Formation were predicted based on a model of the regional depositional setting and by detailed seismic multi-attribute analyses, calibrated with well data from the Minagish and Dharif fields. The fracture potential was also evaluated using map-based curvature and geomechanical analysis. The astounding success in the Umm-Roos discovery has established new

off-structure play concepts for exploring entrapment beyond conventional anticlinal traps. The discovery has added a large area of Jurassic prospectivity to Kuwait.

(#118337) Arifjan discovery, a boost to Jurassic exploration in southeastern Kuwait: Learning from the interplay of elements leading to commercial discovery

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A detailed analysis of an unsuccessful Jurassic well, located in the northern part of the Ahmadi Ridge in Kuwait, identified the missing link that explained the absence of hydrocarbons at a crestal point in the structure. The knowledge acquired from the dry hole was used to identify prospective areas and resulted in the Arifjan well discovery. Located to the east of Burgan field, the Ahmadi Ridge is a narrow NS-trending anticline with an high-gradient slope to the east. The Arifjan structure is located along the southern part of the Ahmadi Ridge, which is separated to the west from the Burgan Dome by a well-defined but intermittent low. Various play elements, such as entrapment, seal, reservoir quality, migration pathway and a host of other factors, were reviewed for the Ahmadi Ridge. The analysis suggested that these play elements were consistent with the pre-drill prospect analysis. However, the absence of salt within the Gotnia section and extensive fracturing in the overlying Hith and Gotnia anhydrites were identified as possible causes of seal failure; other evidence also corroborated seal failure. A process was used to identify key aspects for hydrocarbon-bearing structures in similar settings in Kuwait. The process was applied to the Ahmadi trend resulting in a focused exploration effort on the Arifjan prospect. This process down-played major structural culminations that exist in the northern part of Ahmadi Ridge because of seal risk. Detailed seismic mapping also identified several EW-trending strike-slip faults that intersect the Ahmadi Ridge. These faults segment the structural high trends into several blocks that define multiple structural traps. The commercial success of the exploratory well in the Arifjan structure in the Middle Marrat reservoirs opened a large area for this trend, which was previously considered low in prospectivity.

(#123725) An integrated approach to decipher the depositional environment of Wara Formation, Burgan oil field, Kuwait

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The middle Cretaceous Wara Reservoir in Burgan oil field was deposited above the Mauddud limestone and is capped by the Ahmadi shale. The reservoir has an average thickness of about 250 ft, a porosity ranging from 20 to 30% and an average permeability of about 500 md. Visual and microscopic analysis of core and log data revealed that the reservoir sandstone was deposited essentially in a mixed channel levee complex with channel systems consisting of stacked multistory bodies in places.

This presentation captures the spatial variation of rock types based on the log-derived effective porosity data. Based on these data maps were prepared for three major units that represent different depositional environment: Wara Upper, Wara Middle and Wara Lower. The findings, constrained by episodic tectonics, helped define reservoir complexities and the underlying drive mechanism.

(#118985) Facies and core-based sequence stratigraphic framework for Shu'aiba Reservoir, Shaybah field

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The objective of this study was to construct a detailed facies-based sequence stratigraphic framework using cores, logs and available isotope data for reservoir characterization and development. This framework, when integrated with petrophysical data, should lead to better reservoir and simulation models. This study will also help refine our understanding of global climate and sea-level history in the Early Cretaceous. The succession consists of a composite sequence of seven high-frequency sequences and is dominated by 400,000 years (Ky), fourth-order sequences and 100 Ky parasequences. Sequence 1 and part of sequence 2 formed the transgressive systems tract (TST) of the composite sequence with a deeper open-platform of Palorbitolina-Lithocodium wackestone.

The remaining subsequences developed a platform rimmed by rudist rudstone and backed by rudist floatstone back-bank and lagoonal fine skeletal peloidal packstone; slope facies are fine skeletal fragmented packstone. Aggradational subsequences 3 to 5 make up the early highstand systems tract (HST). Progradational subsequences 6 and 7 are within the late HST marking the deterioration of the Offneria rudist barrier and deposition of widespread lagoonal deposits. Shu'aiba deposition on the platform was terminated by long-term sea-level fall, followed by exposure and karsting. The presence of 400-Ky fourth-order sequences and 100-Ky parasequences, which were driven by long- and short-term eccentricity, respectively, suggests that early Cretaceous climate may have been cooler than generally believed and was not an ice-free greenhouse world. This is pertinent to the debate concerning whether the Aptian was a time of green-house climate typified by small precessionally-driven sea-level fluctuations, or whether there were small ice sheets at the poles that generated moderate-amplitude, fourth order fluctuations, driven by eccentricity.

(#122164) Evaluation of the slip-sweep technique near southwest Ghawar field, Saudi Arabia

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A 14-swath seismic acquisition experiment was conducted in November 2006 over a prospect area southwest of Ghawar field. The objective of this experiment was to compare four source designs with various numbers of vibrators in flip-flop or slip-sweep modes. The receiver geometry (4,400 receivers, interval 50 m) and sweep frequency range [4–94 Hertz]) were kept constant throughout the test. For each array, the parameters were as follows: (1) number of vibrators/fleet 5 3 2 1; number of fleets 2 4 4 12; (3) Sweep length (second) 15 15 15 42; (4) Slip time (second) Flip-flop 11 9 5; (5) Source density (VP/km) 200 400 800 800; (6) Actual productivity (km/hour) 0.51 0.54 0.32 0.8. It is clear that the slip-sweep method can provide a very significant improvement in productivity compared to flip-flop acquisition.

Two questions remain: (1) is vibroseis source-generated noise or ambient noise the limiting factor? (2) How will the additional noise associated with the slip-sweep method affect the seismic image? The conventional five-vibrator source array design has proven to improve the initial signal-to-ground roll and ambient noise ratio. These source arrays can be decomposed into single-vibrator, point-source efforts, maintaining the same source density per area while increasing the sampling density. This improved source sampling optimizes source-generated scattered noise attenuation methods. Preliminary analysis of stack data showed equal quality for the five-vibrator and the three-vibrator data; but the single-vibrator achieved better quality although the square-root theory predicted a signal-to-noise ratio of 3.5 decibels lower. This seems to indicate that source-generated direct and scattered noise is indeed the problem in this area and that it is serious enough to mask the additional noise associated with the slip-sweep method.

(#114074) Gas while drilling-fluid reservoir characterization – a new geochemical approach to characterize Radhuma's heavy oils

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In Kuwait Oil Company (KOC), a geochemical mud log (GML) was developed to help analyze the quality of hydrocarbons associated with the different formations in real time utilizing Haworth's Ratios as recorded by the gas chromatograph. By using this cost-effective GML tool it is now possible to reliably identify promising hydrocarbon zones. It is also possible to predict the composition and the nature of the subsurface fluids. A rela-tionship has been identified that links total gas counts to the commerciality of accumulations, while GML ratio parameters predict the nature of fluids present. Therefore, integration of the GML ratio parameters with total gas counts can quickly identify potential hydrocarbon zones. When used in combination with drilling rate, lithology and other e-log parameters, the method appears to be a useful method to help select intervals for perforation. Recently, KOC has produced the GML in real-time thereby, helping us prepare and or modify the forward programme. However, with further evaluation we have found that there are some limitations to GML interpretations. During drilling, KOC often uses two types of drilling fluids: water-based mud to drill the section down to the upper Barremian - lower Hauterivian Zubair Formation, whereas, the deeper section is often drilled with oil-based mud. Here we have chosen four exploratory wells A, B, C and D with GMLs distributed across the Greater Burgan field to illustrate the lateral differences in hydrocarbon quality. They are also important in our evaluation of heavy-oil accumulations in secondary reservoirs in the same area such as the Radhuma Formation (Paleocene). Therefore, GML analysis of the gas and or fluid system seen while drilling may indicate higher potential than currently believed. GML evaluation can also provide evidence of: (1) biodegradation and its extent; (2) possible mixing of microbial and thermogenic gases; and (3) the vertical distribution of hydrocarbon quality.

(#123731) Integration of formation evaluation results with core data and it impact on production in Marrat Formation

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The Marrat Formation has recently been established as a major hydrocarbon reservoir in northern Kuwait. Substantial commercial reserves have been estimated from this Middle Jurassic formation. The formation is composed of a sequence of dense micritic limestone with secondary wackestones, packstones and frequent interbeds with anhydrite, dolomite and rare shale. This presentation shows the results of formation evaluation of complex lithology integrated with core data to obtain the most suitable testing intervals in Marrat Formation. The study was based on the integration of log analysis with conventional core porosity and permeability analyses results, in addition to fracture characterization from core and borehole image data from two wells drilled in Raudhatain fields Three main Marrat subdivisions were identified: Upper Marrat, Middle Marrat and Lower Marrat. The main reservoir in the formation is the Middle Marrat, which has been subdivided into three units, from top: A, B and C. The subdivision of Middle Marrat was based on presence of fractures, porosity distributions and lithology. Due to the good porosity development and presence of massive fractures, only the B and C units were recommended for testing.

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(#119011) Lithofacies attributes, reservoir qualities and depositional setting of the Oligocene carbonates, Al-Khod area, Oman

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The Oligocene strata of the Al-Khod area consist of cyclic sedimentation of basal siliciclastic-dominated units that grade upwards to (locally sandy to pure) carbonates. The siliciclastic units (less than 5% of each cycle) vary from poorly-cemented granular conglomerates to coarse-grained sandstone lithofacies (Lf1). The dominant carbonate portion of each cycle is divisible into two parts: a lower biostromal (c. 20–25% of each cycle) and an upper biohermal coral reef facies (c. 70–75%). The biostromes are characterized by inter-beds of laterally discontinuous to continuous lithofacies of algal-foraminiferal packstone/grainstone (Lf2), algae-dominated, meter-scale biohermal mounds (Lf3) and peloidal wackestone to floatstone with large *Nummulites* and *Assilina* shells (Lf4). Large, partially to completely leached-out mollusks are present throughout the biostromal lithofacies. The biohermal coral reef facies (Lf5) is represented by massive coral framestones (e.g. *Stylopora, Poccillopora, Platygyra, Lobophyllia and Galaxea*) with subordinate, localized algal mounds. The stacking nature of the strata suggests intermittent basin subsidence with hinterland uplifting. The latter acted as loci of short-term siliciclastic provenance, whereas the former promoted creation of accommodation space for the prevailing carbonate lithofacies, which evolved from initial stages of stabilization and colonization (biostromal facies) to more developed stages of diversification and domination (biohermal coral reef facies). The diagenetic features of the carbonate facies include marine and shallow burial calcite cementation, micro- and megaquartz cements, meteoric dissolution and localized dolomitization. Amounts of preserved pore spaces vary among the various lithofacies and include large (cm-scale) vuggy (mainly due to mollusk and coral dissolution), inter- and intra-granular and fracture porosity. The coral framestones show the best reservoir qualities with porosity as high as 15–20% and thus suggest the existence of similar porous reefs offshore the Al-Batinah Coast of northeastern Oman.

(#123688) Advances in 3-D geologic modeling at Saudi Aramco

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3-D geologic modeling of Saudi Aramco oil and gas reservoirs has evolved over the last three decades. Technical processes have ranged from simple hand-drawn 2-D maps and cross-sections to using the latest, sophisticated 3-D modeling computer software and hardware technology. Early on, 2-D modeling was time-consuming and tedious. Interpretation results took longer to produce and critical decisions regarding drilling and field development were sometimes made at a cost. Later, as newer computer applications became available, modelers have had more technical capabilities designed to better image the subsurface geology and reservoir properties in full 3-D perspective. *State-of-the-art* technology was always at the forefront of any 3-D geological modeling practice at Saudi Aramco. The use of the geologic models varies from well planning and placement, field development, reserves calculation, strategic field optimization to enhanced field recovery. To leverage the largest gas and oil fields of the world requires embracing up-to-date technology in terms of the most modern modeling applications with high-caliber professionals. The aim of this presentation is to show the major technical advances that 3-D geologic modelers have implemented over the past 30 years with the goal of producing the most accurate representation of the geology of Saudi Arabia's gas and oil reservoirs. Chronological illustration of modeling techniques will be covered based on the capabilities and limitations of the modeling applications.

(#115618) Basin evolution of the Paleozoic successions of Iraq

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The study addresses the basin evolution of the Paleozoic sequences in Iraq. It integrates petrographical and lithological data from deep exploration wells and outcrops in northern Iraq to better understand the sedimentary environments and to evaluate the depositional and tectono-sedimentary evolution of the basin. The Paleozoic successions are represented by five intra-cratonic sedimentary sequences. These are dominated mainly by siliciclastic and mixed sedimentary packages, and are separated by major and minor unconformities. These cycles are: (1) Ordovician cycle, represented by the Khabour Formation; (2) Silurian cycle, represented by the Akkas Formation; (3) Mid- and Late Devonian to Early Carboniferous cycle, represented by the Chalki, Pirispiki, Kaista, Ora and Harur formations; (4) Permian-Carboniferous cycle, represented by the Ga'ara Formation; and (5) Late Permian cycle, represented by the Chia Zairi Formation. The Ordovician Khabour Formation appears to have been deposited in a shallow-marine environment during several transgressive and regressive cycles. The Silurian Akkas shale was deposited in an open-marine environment. The Late Devonian to Early Carboniferous depositional regimes are considered to be continuous and set in a vast subsiding basin that reflected epicontinental or epeiric seas in a homoclinal ramp setting. The Permian-Carboniferous Ga'ara Formation was deposited in a deltaic to fluvial environment, while the Late Permian Chia Zairi Formation represents carbonate platform deposition. The potential source rocks may include some shale beds of the Khabour Formation, the hot shales of Akkas Formation and the shales of the Ora Formation. The sandstones of the Khabour, Akkas and Kaista formations

have good reservoir potential. The Late Permian carbonates of Chia Zairi Formation may be self-sourcing and contain multiple reservoirs. Basin analysis demonstrates the evolution and architecture of the basin and gives an insight into the effects of the Caledonian and Hercynian epeirogenic movements on the tectonostratigraphy history of the region.

(#119018) A geophysical investigation in eastern Abu Dhabi, United Arab Emirates

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A geophysical investigation has been conducted to the southeast of the Al-Jaww Plain, eastern Abu Dhabi Emirate. The area underwent numerous deformations, which can be used to model the geological history of Upper Cretaceous and Tertiary structures. The aim of the study was to determine the contact between the Semail Ophiolite and Tertiary carbonate rocks, and a reverse fault that has been imaged by seismic data. Three days were spent acquiring the data. The first two were spent in surveying and gathering the gravity and magnetic data. The final day was spent in collecting seismic data. The gravity and magnetic surveys were acquired along a grid system that runs 70° NE. The interval distance between the grid lines was 200 m with gravity stations spaced at 100 m and magnetic stations at 50 m. Different corrections were applied to the gravity data including drift, elevation, latitude, free air and Bougaur. For the magnetic data, diurnal and IGRF corrections were applied. ProMax software was used to process the seismic reflection data. From the gravity and magnetic data, contour maps have been produced, which show the distribution of gravity and magnetic anomalies. The gravity contour map indicates the possible location of the reverse fault. The magnetic contour map clearly shows the contact between the Semail Ophiolite and Tertiary carbonates. Also, the seismic reflection data show the possible geometry of the fault. Moreover, the gravity model indicates the contact between the Semail Ophiolite and sedimentary rocks, as well as the approximate position of the reverse fault.

(#116596) Compositional modeling of northern Kuwait Jurassic hydrocarbons for GOR and API prediction

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The prediction of fluid properties in reservoirs prior to drilling is important for new prospective areas in order to reduce exploration risk and to estimate petroleum resources. Compositional modelling studies involving Temim 2-D and 3-D software have been carried-out with the objective to predict hydrocarbon composition and properties, and to quantify resources of various reservoirs within the Jurassic succession of northern Kuwait.

The Temis 3-D block of northern Kuwait was derived from a previous block developed for a regional study and updated with new structural maps covering a large area including Bahrah, Dhabi, Sabiriyah, Umm-Niqa, Raudhatain and NW Raudhatain. 2-D models were constructed for calibrating the Najmah source kinetics against API gravity and GOR (gas/oil ratio) and oil chemical composition on known accumulations. Temis 2-D was then used to predict hydrocarbon fluid properties potentially accumulated in Jurassic reservoirs under supercritical PVT (pressure-volume-temperature) conditions. In-place resource estimates were derived from map-based Temis 3-D. In the Cretaceous reservoirs the oil's API gravity ranges between 30° and 34° and the GOR is relatively low. In contrast the oil in the Upper Jurassic (Najmah, Sargelu and Marrat) reservoirs has an API gravity greater than 45° and high GOR (greater than 5,000 standard cubic ft/barrel). These differences are explained by a model in which the early generated Najmah-sourced oil migrated into the Cretaceous reservoirs through the faulted Gotnia Salt. More mature oil, expelled later from the Najmah source rock, remained trapped in the Upper Jurassic, where it underwent secondary cracking affecting mainly the aromatic and nitrogen, sulfur and oxygen fractions. The Najmah and Sargelu reservoirs rapidly reached hydrocarbon saturation due to their relatively low-storage capacity. The surplus of hydrocarbons spilled downward into the Marrat Reservoir, particularly the Middle Marrat, and occasionally down to the Lower Marrat.

(#123692) Seven microseismic projects in Oman: What have we learned?

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Since 1999, a total of seven microseismic projects have been acquired by Petroleum Development of Oman (PDO). These were deployed with a range of monitoring objectives including hydraulic fracturing, reservoir compaction and steam injection. In some cases, the projects have proved very successful and are still monitoring today. For other projects, however, they either failed or gave ambiguous results. The failures have been due to poor planning and project management and/or equipment failure. But, in both the successes and failures, PDO has gathered a wealth of knowledge and experience, which are now being incorporated in the planning of upcoming microseismic projects. This knowledge ranged from technical to managerial to operational. In this presentation we will share some of our key experiences with examples from the seven projects and provide a preview of some that are in preparation.

(#118581) Sequence stratigraphy and sedimentology of the Upper Jurassic Arab and Hith formations with emphasis on anhydrite deposits, Abu Dhabi, United Arab Emirates

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The Kimmeridgian-Tithonian Arab and Hith formations are part of the highstand sequence set of a second-order supersequence, built by five third-order composite sequences (J70, J80, J90, J100, and J105) and bounded on top by sequence boundary J110_SB. The overall depositional environment envisaged for the Arab Formation is that of a barrier-shoal complex with open-marine, offshore sedimentation to the east and a protected, evaporitic, intra-shelf basin to the west. A barrier-shoal complex was developed along the platform margin and deposition was dominated by oolitic grainstones. Concomitant deposition of sabkha, tidal flat, salina and lagoonal sediments occurred westwards, and open-marine mudstones and wackestones were deposited eastwards of the barrier-shoal complex. The reservoir quality is strongly controlled by the depositional environment and the lithofacies types. The best reservoir is present within grain-dominated lithofacies types of the barrier shoal complex. Relatively poor reservoir quality is characteristic of mud-dominated lithofacies types that occur in open-marine environments. In the intra-shelf basin the dominantly dolomitized lithofacies types show quite good reservoir qualities within thin intercalated packstone to grainstone layers, interpreted as tidal channels or washovers. During Hith time, the restriction of the intra-shelf basin increased and predominantly salina-type anhydrite after gypsum was deposited. The focus of this study is on the depositional environment of the anhydrite sediments, as it is important to distinguish between salina-type (saltern) and sabkha-type evaporites. In contrast to sabkha-type deposits, where the evaporites are forming within the host rock (sediment-dominated: late highstand and lowstand systems tracts), salina-type deposits represent subaqueous evaporite precipitations (evaporite-dominated: late lowstand and transgressive systems tracts deposits). Distinguishing between the different anhydrite depositional environments is crucial for the correct sequence stratigraphic interpretation of the Arab and Hith carbonate-evaporite successions.

(#114048) Reservoir monitoring logging campaigns in offshore Abu Dhabi are handled with Collaborative Quality Value Assurance Project Management Approach

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Monitoring of logging campaigns are conducted annually as part of reservoir management tasks. Such vital logging operations require the involvement of a multi-disciplinary subsurface team as well as that of the Support, Logistics and Field departments. Maintaining the communication and collaboration between team members is a key to success, which is measured in terms of knowledge transfer, best practices, process implementation and fast access to control the project phases. Moreover, reservoir requirements have to be transformed to logging programs and operational plans that have to be implemented successfully to assure high data quality acquisition. To assure this project's annual success, the project team introduced a new approach named (QMVA). This approach organizes the logging monitoring task into five phases.

QMVA is an electronic program that runs on a personal computer. The program is connected to databases and accessible through a defined security system. After two years of utilizing QMVA it is clear that this project management and follow up has become much easier, faster and well-maintained. The success of having virtual team collaboration was achieved with continuous management support that realized the direct benefit of this system. This presentation goes through all the stages of the QMVA system development and successful implementation.

(#122316) Integrating geological models, well data and geophysical methods in mapping the top salt interface over the stringer reservoirs

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The Neopretorozoic carbonate reservoirs of the South Oman Salt Basin are considered the oldest producing reservoirs in the world. These carbonate stringer units, fully encased in salt, form a unique hydrocarbon system with proven economic viability. The greatest challenge in exploring and producing hydrocarbons in these stringer reservoirs, lies in the ability to confidently visualize them and predict their properties. An additional challenge is mapping the top of the salt. This impacts the time-to-depth conversion of the reservoir interval and hence the geometry of the structure, which has direct bearing on the calculated hydrocarbons-in-place. Over the years, the top salt pick was solely made based on the seismic data. Gravity data, which in general has a good lateral resolution and poor vertical resolution, was mostly used to validate this pick. This worked well in areas where the top salt interface forms a strong reflector. This occurs where the salt is overlain by a thick carbonate unit, or in places where a significant impedance contrast exists with the overlying conglomerates or sand of the Haima pods. Integration of well and seismic data, using seismic modelling and seismic-to-well ties, showed that mapping the top salt depended on the ability to predict the

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lateral extent of the carbonate layer overlying the salt. By combining the understanding of the seismic response. together with a basic geological model of the extent of the carbonate, facilitated capturing the uncertainties in the top salt map.

(#119083) Impact of results from complex data-intensive wells on understanding fault, fracture and clinoform geometry: Examples from a maturing carbonate oil field in Abu Dhabi, United Arab Emirates

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In an effort to accelerate field redevelopment, opportunities have been identified to re-activate wells through horizontal sidetracks and acquire geological data to evaluate potential discontinuities, irregular water front advance and uneven pressure distribution. The studied reservoir has been producing mainly from the south of the field, from platform interior and margin deposits. The north of the field is complicated by the presence of clinoforms and common faulting. Progradational clinoform belts in the north show rapid alternations of reservoir properties. Lack of crestal pressure support and uneven waterfront advance confirmed high reservoir complexity, with the main uncertainties being: (1) up-dip extension of barriers (dense limestone) related to third- and fourth-order transgressions within clinoforms; (2) continuity and sealing capacity of NW-trending faults; (3) connectivity between poorer quality clinoform bottomsets and the topsets of unit 1; (4) NS-trending discontinuities impacting pressure dissipation from flank-to-crest; and (5) detection and characterization of fractures (spatial extent, orientation and transmissibility). Recent drilled wells have included: (1) pilot holes with cores, borehole image logs and pressure/fluid measurements to evaluate the up-dip extension of dense units within clinoforms; (2) horizontal drains crossing several clinoforms and faults aimed at resolving complex structural and sedimentary geometries (*distance to boundary* logging and borehole imaging); and (3) borehole image logging in pilot holes and horizontal sections to characterize facies, fault and fracture distribution The integration of results from these wells with complementary studies (e.g. seismic attribute analysis, sequence stratigraphy, core studies, dynamic modelling) forms the foundation for optimizing the development scheme, extending field plateau life, and maximizing recovery.

(#118961) Geology and rock properties correlation: Outcrop analogue study of a Cretaceous reservoir, United Arab Emirates

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Geological and petrophysical investigation has been performed in an outcrop located at the northeast of Ras Al Khaimah, where Lower Cretaceous rocks of the Thamama Group dip gently into the subsurface. The area is of stratigraphic significance because it can be used as an analogue model for the Thamama reservoirs of the United Arab Emirates. The aim of this study is to better characterize and correlate the geology and rock properties of the exposed rock, and use it as an analogue for Thamama Group. This work combined the results of the following methodologies: (1) geological analysis, which included description, stratigraphic column and mapping of the outcrop; (2) rock properties analysis, which included porosity, permeability, porosity type, and mineralogy of 17 outcrop samples; and finally (3) correlation between outcrop and reservoir field properties. Our preliminary results indicated that the studied outcrop consists of mudstone-wackestone that has been crystallized with no major lateral changes. Seven main lithological units have been recognized on the basis of their depositional and/or horizontal continuous fractures. In addition, the outcrop samples display a considerable number of vertical joints filled with calcite. Horizontal open fractures are clearly present, which affect permeability. Few units have small burrows (1.0–2.0 mm) that slightly increase the porosity. Some of the lower and intermediate units contain relatively high concentrations of iron, which reduces resistivity. Finally, our observations showed that, in contrast with the subsurface Thamama reservoirs, the exposed units have very low porosity as a result of local cementation.

(#123518) Seismic data tracking and recovery in the exploration effort: The Seismic data TREE

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2-D and 3-D seismic data undergo various processing and interpretation stages within the exploration workflow. To track down the effort that was invested in every seismic line or survey is an immense challenge. The aim of this study is to find a method of tracking and recovering all the effort that was invested on seismic data, whether in acquisition, processing or interpretation. The new proposed method manages both data and knowledge to maintain a seismic Tracking and Recovery within Exploration Effort (Seismic TREE). The proposed process enhancement technique is based on the LEAN processing enhancement technique. Lean manufacturing is a generic process management philosophy derived mostly from the Toyota Production System but also from other sources. It is renowned for its focus on reduction of the original Toyota 'seven wastes' in order to improve overall customer value. The LEAN method is often linked with Six Sigma because of that methodology's emphasis on reduction of process variation. Using the LEAN method, we minimized the waste as well as captured all varieties of seismic data for knowledge management purposes.

(#118407) Organic geochemical indications for source potential and hydrocarbon generation from Late Jurassic-Early Cretaceous Sulaiy Formation, southern Iraq

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This presentation describes an organic geochemical analysis of the Late Jurassic and Early Cretaceous (Tithonian to Valanginian) Sulaiy Formation in the Basrah region in southern Iraq. Samples from six wells were used to analyze thermal maturation and measure sedimentary organic matter parameters. The analyses included quantitative studies such as elemental analysis, pyrolysis, fluorescence spectroscopy (ultra-violet) and total organic carbon (TOC). Additionally, qualitative studies involved textural microscopy that was used in evaluating amorphous organic matter for palynofacies analysis leading to hydrocarbon assessments. The Sulaiy Formation was rated as a source rock for oil with some gas because of its high TOC content and mature organic matter. The kerogen is type II of mesoliptinic type. The Sulaiy Formation is also recognized as a source rock, not only in Iraq, but also in neighboring Kuwait and Saudi Arabia.

(#119607) Using GPR and resistivity methods to detect subsurface karst cavities

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Ground penetrating radar (GPR) and resistivity methods were used to detect the subsurface karst cavities in Jubaila Formation, west of Riyadh, Saudi Arabia, These features may cause geological or environmental hazards to buildings and constructions. The aims of this study are to understand the physical properties of subsurface cavities, the response of the formation structure to these geophysical techniques and to evaluate them in geotechnical and engineering studies. By 250 MHz frequency, GPR was found to be clearly effective in detecting variations of the electrical properties of shallow subsurface structure up to a depth of 6 m, and to 8 m with lower resolution. The GPR images detected strong and continuous reflections from horizontal layers with similar positions and depths (at a depth 4.75 m), which have an electrical resistivity value between 180–300 ohm-meter. The GPR sections did not detect any caves in the layers; i.e. the caves are not continuous nor extensive, but rather showed a homogenous structure in the lower section. The GPR results were improved-upon by the electrical resistivity method. This method detected the horizontal layers, which in parts showed zoning of the resistivity. The zones show a distributed field with a semi-circular gradient and a sharp value in the center. Based on drilling, the central point was found to be a limestone layer with facies change, hardness or indurations. The resistivity of the central point reached 280 ohm-meter, while the

surrounding media's resistivity is 120 ohm-meter. The results of GPR and resistivity methods are supported with geotechnical drilling, which were in agreement with the interpretation.

(#116243) The new exploration challenge: Finding the basin center resources

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Unconventionally trapped oil and gas will play an important role in meeting the world's thirst for hydrocarbon products in the next few decades. Basin center gas (BCG) accumulations are one of the important economic unconventional hydrocarbon plays that is known to exist in many basins of the world. It is also referred to as tight gas sand, deep basin gas, and continuous gas accumulation. It has been the subject of exploration and production for the last three decades in the United States and Canada. Thousands of wells have been drilled and geologic models for this resource, which promises to be vast, have been established. Generally, basin center gas is characterized as being a regionally extended accumulation of gas that is not conventionally trapped, abnormally pressured (high or low), commonly lacks a down-dip water contact, and has low-permeability reservoirs. The accumulation ranges from single, isolated reservoirs, a few feet thick, to multiple stacked reservoirs that are several thousand feet thick. To find and exploit these resources, many challenges have to be addressed. These challenges include geological, geophysical, drilling and completion techniques. In immature basins, such as the Arabian basin, the exploration for basin center gas requires a shift in exploration thinking that may impact the data acquisition, processing, and interpretation methods. Under these conditions, technology plays a major role in optimizing the exploration results.

(#119233) Managing water in mature fields for increased recovery

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Well management is a continual exercise in optimizing the yield of the system and to evaluate the potential of initiating measures that can increase production. The management of produced water occupies a priority area in the oil and gas industry as water severely complicates production, and sometimes even makes it non-profitable. Based on an estimate, approximately 250 million barrels of water is produced every day worldwide. Furthermore, the water-to-oil ratio increases over the life of a well, which means that mature wells produce up to 9.5 barrels of water for each barrel of oil. Some wells produce at a water cut above 90%; a number that often cause operators to abandon wells instead of pursuing

interventions. These factors make it imperative to develop and apply the right technology to handle the large amounts of produced water. Tractoring on wireline has proven to be an efficient method for managing water in horizontal and highly deviated wells.

With this technology, a series of attractive possibilities are unlocked: (1) enhanced production; (2) greater recoverable reserves; (3) prolonged lifespan of mature fields for more profitability; (4) reduced gas-to-oil ratio; (5) environmentally-responsible handling of produced water; and (6) increased safety on job. A solid track-record of applying tractor technology on wireline has already been established. With reliable results, mechanical down-hole solutions on wireline are capable of managing the flow control while providing certainty of execution and key-hole precision in water management. Additionally, these services mean large cost reductions and value-creation as will be illustrated in this presentation.

(#118686) Dolomitization and reservoir characterization of the Cretaceous Qamchuqa Group, Khabaz oil field, Kirkuk area, northern Iraq

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The Lower Cretaceous (Aptian-Albian) Qamchuqa Formation, in the Kirkuk area of northern Iraq, consists of thick shelf carbonates. It is here recommended that it be raised to a group status consisting of three formations; the upper and lower Qamchuqa formations that are separated by the Sarmord Formation. The upper and lower Qamchuqa formations were deposited as platform carbonates in a wide spectrum of shelf subenvironments, whereas the Sarmord Formation consists of basinal facies. Pervasive dolomitization affected the Qamchuqa formations and their reservoir properties. This study examined cuttings, cores, and different types of wireline logs, as well as production data from seven wells in the Khabaz oil field. The analysis revealed important links between sedimentary facies, dolomitization, eustatic fluctuation and the heterogeneity of reservoir rocks. A wide range of dolomite fabrics were identified including microcrystalline, planar-e, planar-s, planar-c, planar-p, as well as saddle and non-planar types. These imply successive phases of dolomitization, which profoundly influenced the enhancement of reservoir character. Intercrystalline microvuggy, and micromouldic porosity are the most important products of this dolomitization. Fracturing and the retained primary sedimentary fabric of the undolomitized, or partly dolomitized, facies contributes to the collective porosity and permeability of the reservoir. Linking these modes of dolomitization to the eustatic cycles of the sequence shows that part of the intensively dolomitized sections are associated with highstand episodes.

(#123726) Estimating static shifts by deconvolving stacking velocity profiles

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Seismic exploration aims to provide high-quality data in order to optimize finding hydrocarbon reserves and to minimize drilling costs. However, for land seismic data, near-surface irregularities act as a noise generator and create static problems, which can considerably degrade seismic images. We have investigated a potential and unconventional approach to extract static shifts from seismic data. This approach extracts time delays, generated by near-surface irregularities, from a stacking velocity profile for a given seismic reflector. This is accomplished by deconvolving the stacking velocity profile with the impulse response of the seismic acquisition spread. The impulse response is basically the stacking velocity profile due to the interaction between the acquisition spread and a single near-surface impulse time delay. We applied the method on a synthetic model that consisted of five horizontal layers and three near-surface irregularities. The lateral extents of the irregularities are equal to the full, half, and one-quarter of the spread length, which was 1,500 m. The time delays corresponding to the three near-surface irregularities were held constant at 8.0 millisecond. The stacking velocity profile from the third interface was hand-picked and showed high oscillations under the near-surface irregularities. This picked stacking velocity profile was deconvolved by the impulse response to estimate the time delays that caused the oscillations. The errors in the estimated time delays were consistently less than 10%, which demonstrates the ability of the proposed method to recover time delays from stacking velocity profiles.

(#118579) Land seismic noise suppression: Tough challenge, intelligent implementation

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Land data, unlike marine data, are associated with complex surface and near-surface geology, which generate a suite of coherent and non-coherent noises. The suppression of such types of seismic noise has long been a great challenge for both 2-D and 3-D seismic data processing. This is because signal and noise share the same range of seismic characteristics such as velocity and frequency. In this presentation, we introduce a new methodology for noise suppression that is based on the principle of localized transforms. We demonstrate that utilizing localized transforms, unlike other conventional methods, ensures preserving the integrity of the seismic signal in terms of its amplitude and frequency contents. Our methodology focused on the suppression of mainly two types of seismic noise: linear and strong-energy randomly generated noise. Our approach is model-based and operates in 2-D

and 3-D pre-stack modes. A key characteristic is that it tapers and scales-down the noise rather than muting it out. The linear noise is first suppressed by implementing a localized 3-D filter in the frequency-wave number (F-Kx-Ky) domain. Next, for each localized filtered data, an average amplitude spectrum is computed. Finally, a certain threshold value is assigned for trimming or scaling-down the linear noise, followed by an inverse transform back to the time-offset domain. These steps are repeated continuously with overlaps in time and space. The strong energy noise, being narrow band-limited, is tapered in a slightly different manner. The processes involve 1-D Fast Fourier Transform (FFT), decomposition via band-pass filtering, and median-filtering. The effectiveness of our proposed noise-suppression methodology is illustrated with both synthetic and field land data example.

(#115939) Use of reservoir compartments concept in management of western flank area of a mature field in Kuwait

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The objective of this study was to apply the concept of compartmentalization in the Greater Burgan field. It focused on a western flank area of a specific reservoir and applied the best reservoir management techniques to find or delineate pockets of bypassed oil. The developed sands in the field are continuous and act as such for a long time during production. However, the identified compartmentalization effect was only evident at a later stage following the long production interval associated with a single oil-water contact behavior. This was a result of variations in the regional water contacts, which had structural and stratigraphic implications in the study area. The task involved the determination of the volume and location of remaining oil, and subsequently the technical and economic assessment methods to recover it. The remaining mobile oil is located in a number of predictable locations in the reservoirs depending on their structural style and facies. The main task is to re-develop the bypassed oil rims and attic oil in faulted sandstone reservoirs. The compartments were assumed to have the same oil-water contact. Attic oil along faults is perhaps the simplest configuration to redevelop and contains sizeable oil volumes. Calculations of the remaining oil-in-place used the most recent maps with updated Pulsed Neutron Capture log data interpretation to generate the most recent oil-water contact data. The study included benefits such as: (1) a better way of estimating and identifying remaining oil in a particular compartment; and (2) easier diagnosis of reservoir actions needed by reservoir management.

(#118645) Index fossils of the Late Palaeocene-Early Eocene Jafnayn Formation, Al Batinah Coast, northern Oman

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The Jafnayn Formation is an Early Paleogene carbonate unit that crops out widely along the Al Batinah coastal plain of northern Oman. It unconformably overlies the uppermost Cretaceous Al-Khod Conglomerates and is overlain by the Lower to Middle Eocene Rusayl Formation. The Jafnayn Formation is informally divided into two members that are separated by a biostratigraphically identified unconformity. The lower member comprises an upsection sequence of low to moderate energy, inner-shelf to lagoonal strata of (1) mudstones and wackestones, (2) massively-bedded, pseudonodular, bioturbated wacke-packstones, and (3) bioclastic mudstones. The lower member is dated as Late Palaeocene (Thanetian) based on the occurrence of the foraminifera *Lockhartia diversa*, *Daviesina persica*, *Kathina* sp. and *Nummulitoides margaretae* (NP8?). The upper member is Middle to Early Eocene (Ypresian) as suggested by the occurrence of *Sakesaria cotteri*, *Heterostegina ruida* and *Nummulites globulus*. It comprises coral and red algal-rich, well-bedded, occasionally rudaceous, nodular packstones-grainstones and cross-bedded calcarenites deposited in a shallow (less than 10 m), fairly high-energy open-marine shoal environment with nearby patch reefs supplying coral debris. The base of the upper member is marked by a locally distinctive thin (1–3 m) pebble bed rich in various siliciclastic grains and clasts reworked from the underlying member. The pebble bed was deposited immediately after a distinctive depositional hiatus corresponding to the upper part of the Upper Palaeocene and lower part of the Lower Eocene i.e. approximately two nannoplankton zones (NP9–NP10) representing the upper part of the *Alveolina (Glomalveolina) levis* zone to the lower part of the *A. cucumiformis/A. trempina* zones. Although this hiatus is recognised lithologically and biostratigraphically at Wadi Rusayl, at other localities it is only detected through detailed micropalaeontological analysis.

(#123990) Tectonic evolution of the Jurassic Humma Marrat structure, Kuwait and Saudi Arabia Partitioned Neutral (Divided) Zone

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The Humma structure is an elongated, NNW-oriented, doubly plunging anticline situated in the southwestern corner of the Partitioned Neutral (Divided) Zone (PNZ) between Kuwait and Saudi Arabia. It produces from the

Jurassic Marrat reservoirs and is the only Jurassic producer in the PNZ. It was discovered in 1998 following several unsuccessful wells that targeted Cretaceous reservoirs beginning in the 1950s. Data from open-hole logs (formation imaging tools, magnetic resonance elemental capture spectroscopy, shear sonic, and Stonely permeability) have been integrated with both the oriented core data and 3-D seismic interpretation to reveal the stratigraphic genesis and the tectonic evolution of the Humma structure. The complexity of the Jurassic Marrat reservoirs is attributed to the rapid change in facies from north to south, as well as from base to top. Depositional environments for the Lower Marrat are predominantly low-energy inner-shelf (inner ramp to lagoonal) settings. The Lower Marrat reservoirs possess a combination of inter-crystalline and moldic porosity with tectonic fracture to breccia porosity. The Middle Marrat reservoirs are a stacked succession of individual and overall shallowing upward cycles. Deposition was in a protected sub-tidal, open shelf lagoon to largely filled intra-shelf basin as part of a progradational parasequence set. Open fractures of massive dolomite matrix characterize the Middle Marrat reservoirs.

Both kinematic and dynamic analyses for the Humma structure revealed that the NNW-trending structural axis for the Humma closure is in-parallel with the major fault that bounds the structure. The NE-SW to NW-SE oriented open fractures are the manifestation of a dextral strike-slip wrench tectonic system as depicted by a simple shear tectonic model. The tectonic evolution of the Humma structure was initiated in the Late Jurassic (Kimmeridgian), culminated during the Early Cretaceous and continued throughout the Late Cretaceous. The simple-shear tectonic model applied to the Humma field is well-expressed by a flower structure associated with both the Jurassic Marrat and Cretaceous Thammama Group. The expression is also interpreted from 3-D seismic of the Shu'aiba Formation, oriented core and borehole image data. The tectonic model applied herein is believed to be applicable elsewhere in the Gulf region. The data integration, assimilation and analysis approach, proposed in this presentation, is recommended for similar complex reservoir studies in other parts of the Gulf region.

(#123758) Stratigraphic framework of the Mafraq Formation, northern Oman

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The mixed clastic-carbonate Mafraq Formation (Late Triassic-Middle Jurassic) is the lowermost unit of the Sahtan Group in Oman. The formation comprises a fluvial to shallow-marine succession that onlaps the tilted Akhdar Group (Permo-Triassic) unconformity from the northwest to the southeast. Despite producible gas and oil indicators, the Mafraq Formation has remained largely underexplored and is poorly understood in Oman. A regional stratigraphic framework for the Mafraq Formation has been developed, which incorporates seismic, well,

outcrop, core and biostratigraphic data. This permitted an assessment of the depositional and structural controls on the distribution of the Mafraq Formation. Improved understanding of the Mafraq play suggests potential for both conventional and stratigraphic trapping configurations. The Mafraq Formation is a complex diachronous depositional system including offshore, shallow-marine, coastal-plain, fluvial and alluvial-plain environments with stratal termination patterns visible on seismic. Several transgressive-regressive cycles can be identified including: (1) a Late Triassic regression that resulted in the deposition of fluvial sandstones in the northwest; 2) a Late Toarcian regression leading to the deposition of a fluvial system in the central part of northern Oman; (3) an Early Aalenian flooding that deposited shallow-marine oolitic limestone in the northwest; and (4) a Mid- and Late Bajocian flooding resulting in the deposition of marine sandstone in the southeast. Two principle trap types have been identified, namely conventional structural traps (either fault-bounded or salt-induced) and stratigraphic traps including isolated channel, pinchout, truncation and onlap traps. The play is largely dependent on reservoir and seal thickness variations controlled by primary depositional processes and halokinesis and fault-related accommodation.

(#123306) Parameter estimation of velocity function in unconsolidated sand via semblance velocity analysis

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Previous theoretical and field studies suggest the existence of continuous velocity-depth functions in unconsolidated sand layers. One such function is $V(z) = V_0 \sqrt{(1+kz^{1/3})}$, where V_0 and k are the velocity function parameters which depend strongly on the layer porosity (Φ) and water saturation (S_w), and to a lesser extent, on the properties of the sand matrix, pore water and air. To properly understand seismic wave propagation in an unconsolidated sand layer, it is important to know its velocity-function parameters. This study proposes a procedure to estimate the velocity-function parameters in unconsolidated sand layers. Velocity-function parameters are generally independent. However, it was possible to relate V_0 and k of the above $V(z)$ function because both parameters depended strongly on Φ and S_w. The relation

$$k(V_0) = 278 - \frac{1.4 \times 10^4}{V_0} + \frac{4.9 \times 10^5}{V_0^2}$$

was found to fit k-V_0 curves within 10% error for all Φ and S_w values lying within the ranges $0.1 < \Phi < 0.65$ and $0 < S_w < 0.9$. Next, a table of $V(z)$ functions corresponding to these Φ and S_w ranges was generated using Φ and S_w increments of 0.05. These $V(z)$ functions were then used to calculate the corresponding time-offset (T-X) curves of the direct wave in the layer. The calculated T-X curves

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were fit to the observed T-X curve using the semblance velocity method by scanning for the V_0 value that generated the highest semblance value. The corresponding value of k was finally calculated using the above $k(V_0)$ relation. The procedure was successfully applied to a synthetic T-X dataset.

(#122487) Learnings from a vertical seismic profiling (VSP) programme

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Petroleum Development Oman (PDO) has been acquiring VSP (vertical seismic profile) data for the past 30 years. The different types of VSP data have been used for different objectives. ZOVSPs (zero-offset vertical seismic profile) and OVSPs (offset vertical seismic profile) are considered valuable and are used for time-to-depth calibration, seismic-to-well matching and identification of multiples on surface seismic. The OVSP is normally carried-out in deviated wells or over steeply dipping layers. We will show that the processing of ZOVSP and OVSP is not trivial and how erroneous processing steps or changing assumptions can lead to very different results. This will be demonstrated with a case study of processing ZOVSP with different contractors. WAWVSPs (walk away vertical seismic profile) have typically been used in an attempt to obtain better structural imaging and for time-lapse studies with limited or no successes. In PDO the confidence level in WAWVSPs is often low, resulting from an often-observed poor match of the processed WAVSP data with surface seismic data. This mismatch is observed in the form of: (1) considerable differences in structural dip; (2) events that could be interpreted as faults, which are not present in the surface seismic; and (3) wrong amplitudes differing from surface seismic. In addition to these problems, the bandwidth of the VSP data is not higher than surface seismic, contrary to expectation. These problems will be illustrated with examples of processed WAWVSPs from different fields.

(117637) Sequence stratigraphy and basin modeling of the Eocene succession from Kurdistan region, northeastern Iraq

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The Eocene strata of the Zagros segment in Sulaimaniya area, northeastern Iraq, have been interpreted to contain two third-order sequences. The oldest Ypresian third-order sequence is represented by transgressive and highstand (TST and HST) system tracts and reflects syn-sedimentary tectonic activities, mostly resembled by Sinjar formation. It is divided into two fourth-order cycles each consisting of parasequence sets. The overlying Lutetian third-order sequence consists of carbonates deposited in a ramp setting. It is also divided into two fourth-order sequences that consist of highly permeable and porous carbonates. The red molasses of the Gercus Formation indicate a lowstand fan deposit and a probably fifth-order cycle. The youngest Eocene third-order sequence is represented by the evaporites and carbonates of the Sagerma Formation, and probably reflects climatic changes. Remnants of the foreland basin, located in front of the Cretaceous accretionary complex, played an important role in the paleo-configuration of the Eocene ramp-rimmed shelf basin. This is reflected by a stratigraphic gap and unconformity (sequence boundary type 1) at the Paleocene/Eocene boundary. The Ypresian basin evolved from a shallow-marine ramp, to shoal and mixed carbonates–siliciclastics sequences. In contrast, the Lutetian basin started as a Nummulitic algal carbonates ramp that underwent a *catch-up* phase followed by a rapid *give-up* stage. The Nummulitic carbonates are very thick, and contain good hydrocarbon reservoirs. The carbonate ramp is overlain by thin Gercus red clastics, whereas in the southern sector it is overlain by lagoonal carbonates and evaporites. This paleogeography may reflect the reactivation of a strike-slip fault that changed the ramp basin to rimmed shelf. Forming a very thick, permeable, Nummulitic reservoir, and reflecting the early phase of the continent-continent collision between the Arabian and Iranian plates during the Middle Eocene.

(#117259) Revised lithostratigraphy and biostratigraphy of the Tarbur type section, Kuh-e-Gadvan, northeast of Shiraz, Fars area, Iran

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The type section of the Upper Cretaceous (Maastrichtian) Tarbur Formation (692 m thick) was defined by James and Wynd (1965, AAPG Bulletin, v., 49, p. 2218) in the paper: *Stratigraphic nomenclature of Iranian oil consortium agreement area*. We have revised the definition based on field observation and thin section studies. Above the Tarbur Formation, we did not recognize the previously defined Sachun Formation, consisting of red and green marls. Instead we found the upper boundary of the Tarbur Formation to be bounded by a fault, which renders it indistinguishable from the Sachun Formation. Accordingly we propose a new type section for the Tarbur Formation in Kuh-e-Chel Cheshmeh, Kherameh, southeast of Shiraz city. Our study also recognized that marls with pelagic facies that yielded abundant planktonic foraminifera (*Gansserina gansseri- Contusotruncana contusa* subzone) are Mid-Maastrichtian in age. These marls may occur as a tongue followed by alternating marls and limestones, and finally by a thick-to-massive rudist reefal limestone (34 m thick).

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(#117262) Sachun type section lithostratigraphic and biostratigraphic reappraisal, Kuh-e Sachun, Fars province, Iran

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The type section of the Paleocene-Early Eocene Sachun Formation (revised age and thickness 944 m, previously 1,444 m) was originally defined by James and Wynd (1965, AAPG Bulletin, v. 49, p. 2220-2221) in the paper: *Stratigraphic nomenclature of Iranian oil consortium agreement area*. The type section of the formation in Kuh-e-Sachun, south of Darab city, was reappraised using new field data and microscopic studies. New evidence showed that no evaporitic sediments occur in the lower third of the formation; instead this section consists of thick-bedded to massive rudistic reefal limestone with pelagic and coraliferous marls. The lower section resembles in lithology, facies and morphology the underlying Tarbur Formation. A palaeosol horizon was observed between the Tarbur and Sachun formations and it is correlated to the Cretaceous-Tertiary (KT) boundary. The new data, together with field data from the Tarbur Formation, required revising the definition of both formations. The boundary between them has been repositioned between the Tarbur rudistic limestone and the first Sachun evaporites. These revisions, including the revised age and thickness, resolve the contradictions in the published definitions, and clarify the stratigraphy in boreholes and outcrops in the Fars Province.

(#120510) Correlation of upper-Khuff equivalent Palaeotethyan sediments of the Alborz Mountains, northern Iran

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Late Permian upper-Khuff equivalent sediments (thickness up to 200 m) crop out over large parts of the Alborz Mountains, northern Iran, and are represented both by continental and marine facies. The continental facies is represented by the Gheshlagh Formation cropping out mostly to the south and east, consisting of fluvial quartz-arenites and lateritic horizons with occasional dark shales (with plant fragments) inter-bedded. This unit inter-fingers with the marine Nesen Formation, which in places is very organic rich. In the Central Alborz, the Nesen Sequence thins out rapidly and in the south, it is usually less than 20 m thick. Preliminary analyses on the vitrinite reflectance of the Nesen Formation suggests that Ro falls in the lower part of the oil-window.

The organic matter appears to be mostly of land plant origin. The Nesen Formation is rich in fossils including brachiopods (which form very diversified assemblages), palynomorphs, rugose corals, small foraminifers and fusulinids. Five brachiopod biozones have been erected allowing detailed correlation between five widely separated sections between Elikah (in the west), Dashnt-Nadir Bear, Mangol and Abrendan (in the east). The brachiopods suggest a Late Permian (Wuchiapingian-Changhsingian) age for the biozones. Independent evidence supports this assignment including the presence of the Wuchiapingian-Lower Changhsingian conodont *Hindeodus julfensis* and the Changhsingian palynomorph *Triquitrites proratus*. Trends in $\delta^{13}C$ from carbonates indicate the presence of the Permian-Triassic boundary close the base of the overlying Elikah Formation and biotic trends, including proportional extinction rates, there can be related to mass extinction.

(#114504) Predicting the Mishrif Reservoir quality in the Mesopotamian Basin, southern Iraq

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The middle Cretaceous Mishrif Formation contains a widespread carbonate succession of Cenomanian-Early Turonian age in the Mesopotamian Basin of southern Iraq. More than one third of the proven Iraqi reserves are found within the rudist-bearing carbonate reservoirs of the Mishrif Formation. Rudist facies coincide with the crestal areas of many fields in the region, particularly in those anticlines that show evidence of synsedimentary structural growth. However, other structures have also proven to be non-productive at this level because of the presence of tight or microporous offshore facies instead of rudist-bearing reservoir facies. Difficulty in predicting reservoir distribution is due to the complex palaeogeography. It would appear that following drowning of the uniform and extensive Albian carbonate platform, the Mishrif Formation was established along a NW-oriented zone that is largely bounded by the East Baghdad and Hamrin-Makhul structures and their continuation towards Iran (as the Bala Rud zone). To the southwest of this zone, the intra-shelf basin carbonates of the Rumaila Formation were deposited. Whereas to the northeast, the sub-basinal carbonates of the Dokan Formation were deposited. Across the Mishrif Formation facies belt, sequences show stacked or sometimes shingled geometries. As a result, each field shows different combinations of pay zones, barriers and seal geometries. Detailed palaeogeographical reconstruction on a systems tract basis can be used to construct play fairway maps for exploring this carbonate system, particularly with respect to finding stratigraphic traps. Many existing anticlines, tested by one or more wells that are thought to be 'dry', may turn out to have productive facies along strike, or down-dip on the flanks. In addition, pure stratigraphic

traps may be found in relatively undeformed 'synclinal' areas between the major anticlines. However, exploring such trap types will require 3-D seismic to pin-point tune the positions of the external and internal shelf margins via the application of high-resolution sequence stratigraphy.

(#122488) Iran's Sanandaj-Sirjan Terrane: Fact or phantom?

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The southern Sanandaj-Sirjan Zone was subdivided transversally into: (1) northeastern region (Esfahan-Sirjan Block) consisting of Phanerozoic sedimentary rocks with a typical Central Iranian succession; and (2) southwestern region (Shahrekord-Dehsard Terrane), which is intensely faulted and consists of thick Paleozoic and Mesozoic metamorphic rocks. The Jurassic and Cretaceous rocks in the latter region are slightly metamorphosed and contain intercalations of intermediate volcanic rocks. Minor evidence occurs in the Hamedan area for an extension of the terrane to the north of the Sanandaj–Sirjan Zone, but this is unproven and requires further studies. The southwestern and the northeastern regions are separated by a deep reverse fault, which is locally traced as the Abadeh Fault between Golpayegan and Neyiriz. The fault is covered by Quaternary sediments in Recent depressions in southeastern Neyriz. The fault generally strikes N60°–45°W (parallel to the Main Zagros Thrust). Slickensides in the shear zones indicate that transcurrent movement also took place along it. In the Triassic time a spreading ridge, Neo-Tethys 2, was created and separated the Shahrekord-Dehsard Terrane from Gondwana. The Zagros sedimentary basin formed on a continental passive margin to the southwest of this ocean.

(#117081) Comparison of LP sparse spike, model-based and band-limited methods of seismic inversion: A case study

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Seismic inversion involves converting a seismic section into an acoustic impedance section. In this presentation, three methods of seismic inversion techniques including LP sparse-spike, model-based and band-limited will be discussed to show the capability of each one in inverting 3-D seismic data for the reservoir under study. First, a zero phase wavelet was statistically extracted from the seismic data at the reservoir interval. Then, well logs to be used in the inversion process (sonic and density) were edited to eliminate spikes and noise bursts to avoid generation of spurious reflections. A synthetic seismogram was computed for each well using the well-driven reflection coefficients and the statistical zero phase wavelet.

Good correlations were obtained between each synthetic seismogram and the seismic data at the well locations by squeezing-and-stretching the synthetic seismograms. Squeezing and stretching the synthetic seismogram in time domain is equal to phase rotation in frequency domain. It should also be noted that misunderstanding of the phase concept is the main cause of the error in seismic interpretation; hence the calibration process of the synthetic seismograms with the surface seismic should be carried out carefully. After the calibration stage, a nonzero phase wavelet was extracted using the wells and seismic data and seismic data was inverted using this wavelet for all three methods. In comparison with other methods, the acoustic impedance resulted from the LP sparse-spike technique had the best correlation with the well-driven acoustic impedance. The total impedance correlation of this method was 0.846 over the whole field under study. The model-based method did not achieve good results, most likely because of the limited number of picked horizons in the reservoir interval. The results of the band-limited method were close to those of the LP method, as theoretically expected. Finally the LP sparse-spike method was selected as the best one to invert the seismic cube.

(#118170) CO_2 Injection in the nearly depleted K12-B North Sea gas field

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Two different CO_2 injection field tests were carried-out in the nearly depleted K12-B gasfield, offshore Netherlands, in different compartments. The CO_2 originating from the produced gas (the methane contains a fraction of 13% CO_2), is separated on the production platform and re-injected into the reservoir. The first test, completed in 2004, consisted of CO_2 injection through a single well in a depleted reservoir compartment to test the injectivity. The second test is ongoing in a nearly depleted reservoir compartment comprising two gas production wells and one CO_2 injection well. This presentation describes the simulation results based on a detailed geological model and history match to the production data until December 2005. A highly accurate match has been obtained. In March 2005, two tracers have been added to the injected CO_2 such that injected CO_2 could be discriminated from resident CO_2. Breakthrough of the tracers has been observed for both producing wells after 130 days (in 2005) and 463 days (in 2006). For the first well the simulation results for CO_2 breakthrough have been compared to the tracer time. Results were accurate within a few days. For the second well the comparison has not yet been made since injection and production data were not available at the time of writing this abstract. This work is in progress.

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(#123461) Platform cover and sedimentary basins of Yemen: Lithological characterization and hydrocarbon prospectivity

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Based on lithostratigaphic and geological studies, and structural patterns of the platform cover of the southern Arabian Peninsula, three types of depositional sedimentary basins were recognized. (1) Paleozoic Basins: (a) the southern flank of the Rub' Al-Khali Basin contains Paleozoic and Mesozoic sedimentary successions and is bounded by the Hadramawt Arch (oriented approximately E-W). (b) The San'a Basin, in which deposition started in the Paleozoic and continued up to the Late Jurassic times. (c) The southern Permian-Triassic Socotra Basin is probably linked with the Karoo Rift. (2). Mesozoic sedimentary rift basins initiated along the ancient Najd Fault System (NW-trending) in the Late Jurassic. Subsidence continued up to the Early Cretaceous in the west and in Late Cretaceous/Paleogene? in the east. These basins evolved as sub-parallel features, and their axes rotated from NW in the west, to WNW in the centre and to W-E directions in the east. Five sedimentary rift basins are developed from west to east; Siham-Ad-Dali', Sab'atayn, Balhaf, Say'un-Masilah and Jiza'-Qamar. (3). Cenozoic sedimentary rift basins developed and formed along major ENE-oriented transform faults, mostly in the offshore area along the northern side of the Gulf of Aden (Aden-Abyan in the west, Hawrah in the centre and the Mukalla-Sayhut in the east) and along a NNW-trending fault system parallel to the main Red Sea trend (Tihamah basin). The rift basins along the Gulf of Aden propagated from east to west in the late Early Oligocene and continued up to the Pleistocene. The Tihamah Basin developed on- and offshore during the Late Oligocene and continued up to the Pleistocene as a result of Red Sea rifting. This study will discuss the hydrocarbon system of all the sedimentary basins in detail. It will review the proven and potential source rocks, reservoirs (and their quality), seals and traps styles.

(#118695) Evaluation of cementation factor in Iranian carbonate reservoirs

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The cementation factor is one of the most important parameters in the equation to calculate water saturation. A lack of data on the cementation factor, due to limited core samples, introduces great uncertainty in estimating water saturation and consequently original-oil-in-place. For zones without any core analysis the cementation factor can be estimated by correlations based on laboratory measurements and log analysis data. This method results in a continuous estimate of the cementation factor. This presentation will describe a case study for a carbonate reservoir in the Sarvak Formation, the second-most oil-productive formation in Iran. Most petrophysical parameters in Iran's reservoirs usually do not clearly correlate with one another, thus causing great uncertainty in reservoir evaluations. Initially, we investigated all those parameters that may affect the cementation factor. The most important ones were identified and correlated to the factor based on laboratory data from two oil fields. Log interpretation results were also used to confirm the laboratory data. The results were compared to previous correlations and constants that are commonly used in oil companies to predict water saturation. All the cementation-factor correlations have the same values for high-porosity reservoirs. For low-porosity reservoirs the correlation trends were completely different. Thus, using an improper correlation causes significant errors for water-saturation determination. In this study, it has been shown that the Shell formula, which is usually used for estimation of the cementation factor in Iranian oil reservoirs, may not be an appropriate choice for the Sarvak Formation.

(#118334) Model-based depositional framework of northern part of Punjab Platform, Pakistan

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The Punjab Platform depicts several geological variations due to changes in eustatic controls. In the past decades the eustatic variations and associated depositional trends in the Punjab Platform have not yet been considered and modeled collectively. With the help of seismic profiles, seismic Atlas 1998, well data, final well reports and cross section, the basin subsidence rate, relative rise and fall of sea level and sedimentation rate are combined with the study of basin tectonics (subsidence and uplift) and Indian Plate orientation. By considering these parameters, the study area has been classified into four zones: from east to west as zone A, B, C and D respectively. These zones reflect the depositional history associated with basin tectonics, burial history and their significance for future petroleum prospect. Within each zone, the shale acts as a primary source rock for eastern sandy facies of Paleozoic and Mesozoic ages. The relative rise and fall in sea level along with basin burial history describe the presence of heavy oil at 1 to 2 km depths in the eastern part and light oil (2–5 km) in the western down warps. Moreover, three-dimensional models for the basement and overlying strata are also prepared to show the present-day situation.

(#123515) Data in harmony: Use of discovery metadata, taxonomy and thesaurus in Saudi Aramco Exploration

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We describe the method used in Saudi Aramco Exploration to build and implement our standard set of generic *discovery metadata elements*, taxonomy and thesaurus. The goal of this work is to implement consistent metadata and to reduce exploration cycle time by enabling end-users to quickly find and retrieve data even when distributed across several databases and repositories. The data management group first developed a discovery metadata standard – the correct minimum set of attributes necessary to retrieve exploration data, which include well logs, seismic data, core samples, as well as geospatial data. We developed a thesaurus based on industry standards and modified to our requirements; this was used to generate a unique taxonomy for Saudi Aramco exploration. The taxonomy helped unstructured data content to be categorized and added further richness to metadata. The resulting *data harmonization* enabled geoscientists to share a common vocabulary at appropriate business levels, independent of organization and geographical location. Information on data access, versioning and content ownership were essential for inclusion to ensure proper protection and maintenance. The use of a standard discovery metadata enabled a centralized metadata catalogue for all exploration data types to be designed. Practical implementation involved continual user consultation and cooperative liaison with software developers and end-users. We will show examples of the significant value gained by sharing common metadata across a decentralized working environment, and implementing a thesaurus to enable rich metadata extraction capabilities.

(#118341) Early development of a compartmentalized, naturally fractured formation with compositional fluid behavior

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This presentation describes a systematic approach to simultaneously appraise and develop a string of discoveries in naturally fractured reservoirs while mitigating geological risk. The key to success in economic optimization was in full alignment of diverse and specialized skills of technical professionals, integrated data management and technology implementation. The consultant/client team provided the needed analyses. At decision time, 12 wells over 5 structures and two formations in a 1,100 square km area had produced rich gas and volatile oil during short-term tests in several wells. In the naturally fractured formations, reservoir extent and continuity is a major risk that needs to be mitigated. Multiple fluid properties added another dimension to the reservoir complexity. The traditional approach before making major capital investment in wells and facilities under high uncertainty, was to collect additional data by drilling appraisal, delineation wells and test their performance. This approach would have deferred strategic development of the much needed gas and lowered the net present value (NPV) of the successful case. The *reservoir-centric* view provided an alternative. A multi-disciplinary knowledge of analogous formations, rock and fluid properties and fracture geometry was incorporated in a dynamic model calibrated with limited test data. The model allowed the team to run multiple characterization scenarios to calculate production forecasts. Economic modeling provided NPV values that pointed towards a staged approach in facilities construction with mitigated risk. An early production facility was planned to obtain long-term test data from a few key wells. Staged development will provide early cash flow while maintaining flexibility in plant capacity, design and location throughout the development cycle. Aggressive drilling activities are being implemented in order to meet the strategic production targets.

(#118707) Evaluation of the hydrocarbon potential of the Upper Jurassic Barserin Formation using biomarkers, Kirkuk and Taq Taq oil fields, northern Iraq

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The source rocks from the Jurassic Barserine Formation were studied from two wells in Kirkuk and Taq Taq oil fields in northern Iraq. The GC, saturate GC/MS, and saturate and aromatic carbon isotopes (δ^{13} C) of 12 extracts and two oil samples were evaluated for oil-source rock and oil-oil correlations. The GC, biomarkers and isotope data of the extracts and oil indicate and they were all derived from marine carbonate source rocks, composed of predominantly algal-bacterial organic matter deposited under anoxic condition. Very minor variations in biomarkers characteristics are present among the extracts and between the extracts and oils, which may be due by minor variations in organic facies and depositional condition (relative anoxicity) within the Jurassic source rock unit. The sterane maturity ratios suggest both the rocks and oils have comparable maturities and are moderately mature; the Taq Taq oil is exceptional having a slightly higher maturity. The estimated maturation of the Tertiary Kirkuk oil and the extracts are within the 0.70–0.80% Ro range. The maturity of the oil from the Cretaceous of Taq Taq could be about 0.85–0.90% Ro. The somewhat higher maturity of the Taq Taq oil is also shown by the GC data (Pristane/n C17 versus Phytane/n C18 relationship).

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(#116594) Enhancing the low-frequency content of vibroseis acquisitions with maximum displacement sweeps: A case history from Kuwait

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Several applications of the seismic method to hydrocarbon exploration and reservoir characterization would greatly benefit from the presence of energetic low frequencies in the acquired data. Some of these applications are deep imaging, imaging beneath high-velocity and highly absorbing formations, inversion of surface waves to characterize the near-surface elastic properties, velocity model estimation in geophysically complex areas and acoustic impedance inversion. Unfortunately, the generation and the accurate recording of low frequencies was and, to some extent, remains challenging in both marine and land seismic. In the case of land seismic acquisition, the growing use of accelerometers in surface and borehole seismic enables the acquisition, with an high signal-to-noise ratio of frequencies lower than 2 Hertz. On the source side, hydraulic vibrators, which are the most widely used onshore seismic sources, have their output energy limited at low frequencies by mechanical constraints such as the maximum reaction-mass displacement. Only low actuator forces can be used to drive the vibrators at these low frequencies, which in turn can yield extremely long sweeps in the absence of a design criterion or if a too-conservative one is used. In this presentation, we first analyse the reasons why the above-mentioned seismic applications do benefit from the presence of energetic low frequencies. We then focus on two of these applications, namely: (1) imaging beneath high-velocity formations, and (2) acoustic impedance inversion. We show the enhancements obtained during a recent point-receiver surface seismic survey over the Minagish field in Kuwait acquired using a sweep design method (maximum displacement sweep) developed to enhance the low-frequency content of land seismic acquisition.

(#119913) Reducing uncertainty in water saturation in carbonate reservoirs of southern Iran: A regional correlation for cementation factor

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The calculated value of water saturation (Sw) in a field is based on petrophysical parameters combined with a saturation equation. The exactness of calculated water saturation values depends on accuracy of the input parameters. Monte Carlo modeling of water saturation in different wells in southern Iran revealed that the cementation exponent (m) is one of the most important parameters dominating uncertainties in calculated Sw.

The cementation exponent is normally measured in laboratory from core experiments. Alternatively it can be estimated from resistivity and porosity logs in the clean water-saturated intervals using Archie's equation and Pickett plot methods. Applying a constant value for m using above methods resulted in very high uncertainty in calculated water saturation (negative median in oil zones and higher than 100% in water zones). This abnormality suggests that the input parameters in the water saturation evaluation should be reconsidered. The cementation exponent is affected by several factors including lithology, porosity, type of pore system, tortuosity, shapes and sorting and packing of the particulate system. Therefore the m value is not a constant over a well, but varies depending on many physical parameters and lithological attributes of porous media. A practical correlation was developed for m as a function of porosity and lithology using measurement data of several fields in the area and a variable m from this correlation was created for all wells. Applying a variable m successfully reduces the amount of uncertainty in calculated water saturation.

(#124035) Organic geochemistry of petroleum system in the Shushan-Matruh Basins, Western Desert, Egypt

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Recent hydrocarbon discoveries in Egypt indicate that an increasing proportion of oil and gas will be produced from the Western Desert. The Western Desert consists of a series of basins, with the Shushan-Matruh basins occupying the northern part of the region. Petroleum system analysis has become an increasingly important aspect in assessing the hydrocarbon potential of a given basin. Interest in hydrocarbon gases encourages research towards deeper areas of sedimentary basins in order to understand the processes that occurred therein. This study included rock samples from the Jurassic Khatatba Formation and oil samples collected from wells located throughout the Shushan-Matruh basins. The purpose of this geochemical study was to evaluate the crude oil samples in order to interpret source rock depositional environments, related oil families, thermal histories and probable migration directions. The analysis resulted in a direct link between oil families and source rocks. Furthermore, one of the objectives was to evaluate the extent of gas generation from the deeply buried intervals within the Khatatba Formation. In order to achieve the objectives, detailed organic geochemical analyses have been applied on the collected oil and rock samples. The analyzed oil samples are of medium gravity and waxy character, and have very low sulphur content. Their present maturity and by reaching the main oil zone, indicates that the Khatatba intervals have generated oils. Comparison of the data showed that the carbonaceous intervals in the Khatatba Formation have the best correlation with the analyzed oils. Furthermore, pyrolysis experiments verified that the Khatatba rocks have the

potential for gas generation at higher maturity levels. All the molecular geochemical properties of the crude oil and rock samples have been integrated within the geological framework in order to derive petroleum geological interpretations for the study area.

(#123995) Bio-chronostratigraphy and sequence stratigraphic interpretation of the Triassic succession of Socotra Island, Yemen

Marco Balini (University of Milan, Italy <marco.balini@unimi.it>), Maurizio Gaetani (University of Milan, Italy), Martino Giorgioni (University of Milan, Italy), Alda Nicora (University of Milan, Italy) and Giulio Pavia (University of Turin, Italy)

Along the eastern coast of Socotra Island (Yemen) a 220-m-thick marine Triassic succession is rather well exposed. The succession rests on a crystalline basement of Proterozoic age and is truncated by Jurassic sediments with slight angular unconformity. The Triassic of Socotra was deposited on an epicontinental setting and sedimentation was mostly controlled by sea-level changes. Its peculiar feature is the unusually rich paleontologic record consisting of conodonts, ammonoids, brachiopods and megalodontid bivalves. Three stratigraphic sections were studied at Ras Momi and Ras Falanj. The lithology is dominated by marls and limestones, often organized into shoaling upward cycles. Dolomitization occurs in the upper part of the succession. From the lithostratigraphic point of view the succession is attributed to one formation, divided into two members. The lower member is mostly calcareous, while the upper member mainly consists of dolostones. The detection of sequence boundaries, transgressive and highstand systems tracts (TST and HST) allow the identification of five depositional sequences from Olenekian to Late Carnian age. The age of the first three cycles is especially well-constrained with conodonts and ammonoids. The five depositional sequences can be well correlated with the Sharland et al. (2001, 2004) peri-Arabian sequences Tr30, Tr40, Tr50, Tr60, Tr70. However, the high-resolution conodont and ammonoid bio-chronostratigraphic data from Socotra allow the re-calibration of the age of sequences Tr40 and Tr50.

(#118905) Breakthrough team performance: Amplifying the impact on E&P teams

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The petroleum industry is faced with a significant set of challenges that include: (1) accelerating the discovery of reserves; (2) improved exploitation of proven reserves, be it by shortened time to first-oil production or improved recovery; and (3) maximizing production to infrastructure capacity for brownfields. At the same time, the industry needs to recognize and address the shortage of skilled professionals and to accelerate the training and knowledge transfer to the younger generation of professionals and future graduates. *Breakthrough team performance*, described as changing the way that teams work and collaborate, is what the industry should consider adopting. It could help overcome the current set of constraints and amplify the impact that technical professionals can have on business results. This is realized by delivering integrated drilling and production operations, maximizing team collaboration to overcome resource constraints and accelerating the exploration process. This presentation will describe some game-changing technology and approaches that are drastically improve the way teams work and consequently the impact that they are having on the company's bottom line. The real examples that are presented indicate that our industry is already well on its path towards *breakthrough team performance*.

(#118670) Use of interval pressure transient testing to improve reservoir characterization of Mauddud carbonate reservoir in Sabiriyah field, northern Kuwait

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The front-tracking and monitoring of pattern waterflooding are crucial reservoir management practices in the Mauddud carbonate reservoir in Sabiriyah field, located in northern Kuwait. It is important to run the *interval pressure transient testing* (IPTT) in this reservoir in order to have a complete understanding of the vertical connectivity between the layers in conjunction with other geological and dynamical data. IPTT tests were run in the Mauddud Formation at different depths in selected newly drilled wells in order to obtain a representative reservoir K_v/K_h (vertical/horizontal permeability ratio). This is in order to understand the vertical connectivity between high-permeability zones and the surrounding less-permeable zones, to support the PLT (production logging tool) result, which shows large contributions from high-permeability *thief* zones. The test was run by producing-from or injecting-into one set of perforations, and measuring the pressure response at another set. It was important to investigate the dual-porosity behavior and inter-connectivity between layers, if any, which was not observed during the pre-water flooding period. For field development and reservoir management, it is important to describe the layering in terms of the vertical communication between layers. The number and placement of both injection and production wells requires an accurate description of the layering. IPTT has been used to calibrate both log and core data, with the advantage of conducting these tests under real reservoir conditions. The test results were excellent; they indicated very good connectivity between the Mauddud layers, and provided useful and valuable information about the inter-layer connectivity, reservoir heterogeneities and anisotropy.

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(#123698) AVO Response of a visco-elastic porous layer

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Determination of fluid characteristics in a petroleum reservoir from its seismic response is an interesting problem. For this purpose the amplitude-versus-offset (AVO) response of an oil-bearing formation must be computed. Amplitudes of seismic waves and reflection coefficients must be computed when seismic waves propagate in a viscoelastic porous medium. The existence of a slow P-wave, in addition to a normal-travelling P-wave and S-wave, in a porous medium that depends on such characteristics like fluid viscosity and permeability, has been predicted on theoretical grounds. Seismic waves suffer different degrees of attenuation while propagating through the Earth's layers, especially in the presence of fluids in the pore spaces. The attenuation of waves makes it imperative to consider all such media as visco-elastic, whether porous or non porous. A numerical experiment has been carried out to generate the synthetic AVO response of a porous viscoelastic formation underlying a porous elastic medium. The boundary problem has been solved, and the theoretical results have been cast into a form resembling Zoepprtiz's equations for computation of reflection and transmission coefficients. The nature of reflection pulses associated with the slow P-wave have been investigated for fluids of different properties (density and viscosity). The objective is to be able to detect the type of fluid from some attribute of the pulse shapes and its variation with offset.

(#117999) The ups and downs of inter-bed multiple attenuation

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We present a comprehensive discussion of the main steps involved in applying data-driven *surface-related multiple attenuation* (SMA) and *inter-bed multiple attenuation* (IMA) algorithms, illustrated with field data examples from the Middle East. Despite recent advances (e.g. Kelamis et al., 2002), inter-bed multiple attenuation continues to present a formidable problem due to sparsity of data acquisition, noise, statics and the difficulty in distinguishing between primaries and multiples in many geologic settings. We demonstrate that accurate identification of key multiple generators is an important first step in applying IMA and describe a vertical seismic profile (VSP) deconvolution technique that may be helpful in analyzing multiple-generation mechanisms. Based on this analysis, we apply both post-stack (1-D) and pre-stack (1.5-D) multiple attenuation. In the case of pre-stack multiple attenuation, we address the data regularization procedures necessary to reconstruct the regularly and densely sampled common mid-point (CMP) gathers that are required for successful application of IMA. We

also show that surface-related multiple attenuation is an important step in the pre-stack case and discuss how to overcome statics-related problems that arise during the application of SMA. Finally, we describe the trade-offs involved in choosing adaptive subtraction parameters in areas with overlapping primaries and multiples. We conclude that in the target reservoir zone, the application of pre-stack CMP-domain, data-driven, multiple-attenuation methods resulted in significant structural interpretability improvements. The signal-to-noise ratio was further enhanced through an application of a novel post-processing curvelet-based coherent noise attenuation technique, described in detail in the companion presentation by Neelamani et al.

(#118625) A new approach to reservoir zonation of the Dariyan Formation in an Iranian field

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The Dariyan Formation and its equivalent Shu'aiba Formation in the Gulf consist of microporous, slightly argillaceous algal, peloidal, and orbitolinids lime mudstone and wackestone and grain-dominated fabrics with abundant rudist and coral debris in buildups. The two formations were deposited in a shallow-marine to lagoonal environment. Because of their commercial importance, and lateral and vertical variations in lithofacies and reservoir properties, the both formations have been intensively studied. The present study is based on 29 m of core material from one well, more than 300 thin sections from six wells, petrophysical logs and data, scanning electron microscope (SEM) photomicrographs, X-ray diffraction (XRD) analysis, mercury injection capillary pressure (MICP) data and pore size distribution curves. This data was used to identify facies associations and reservoir rock types (non-reservoir, poor and moderate). These, in turn, were used to define nine reservoir zones as consistent with Alshrahan (1985). The scheme was placed in a sequence stratigraphic framework. Seven facies associations were attributed to four depositional environments as follows: lagoon, leeward shoal, shoal and open-marine.

(#114276) Easy integration of seismic velocities in time-depth conversion: A case study in the Garet El Guefoul field, Ahnet Basin, Algeria

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In exploration areas, well control is often limited and mainly concentrated in the crestal zones of anticlinal structures. Therefore, depth maps prepared by converting seismic time maps using only well velocities will be optimal in the area covered by wells but more inaccurate away from them. Besides the lack of wells, the subsur-

face crests of structures are generally eroded, making the stratigraphic section more incomplete in comparison to the flanks. This is one factor, among several, that can make the extrapolation of velocities over an area of interest unrepresentative. A reliable time-depth conversion is one that will not only tie the existing well tops but accurately predict depths at new well locations. In order to generate the most reliable depth map, stacking velocities, derived from the best-quality 2-D seismic lines and borehole information are both integrated in time-depth conversion procedure. In addition to a velocity model derived only from wells, two methods have been tested here. The first one used the seismic velocities calibrated with average velocities at wells, while the second employed the seismic velocities with formation tops from wells. These methods were used to prepare a depth map for an Ordovician horizon in the Garet El Guefoul field, located within the Ahnet Basin of Algeria. The computations were done using the GeoFrame softwares. In this presentation, we highlight some limitations associated with velocities derived from wells in preparing a reliable depth map. We also discuss and compare the results yielded by the methods after presenting of the principle for each method.

(#118914) Charge evaluation of the South Rub' Al-Khali Basin, Saudi Arabia (Part I, for Part II see Nederlof et al.)

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The South Rub' Al-Khali Company (SRAK) is exploring for gas and condensate in two contract areas which together encompass an area of approximately 200,000 square km. In order to quickly identify the most prospective areas in this large, yet relatively under-explored area, it was necessary in the first years of the venture to quantify the risk of source rock presence, the degree of maturation and predict the hydrocarbon mixture generated upon reaching maturity. Therefore, the regional geology of the Silurian-aged Qusaiba Formation was reviewed and the kinetic behaviour of the organic-rich shale was investigated in order to predict the likely phase of any hydrocarbon accumulation as well as the variations of condensate-to-gas ratios across the entire basin. The initial basin model identified the most prospective parts of the basin, and as more seismic data became available, the model was constantly updated. The kinetic behaviour of the Qusaiba Shales was measured using kerogen isolated from immature outcrop samples. Prior to the drilling of the first exploration well in 2006, predictions were made on the presence of source rock at the well location, its quality and the degree of maturation. This presentation will compare the outcome of the modeling with the actual well result, and is complimented by Part II (see Nederlof et al.)

(#118644) Monitoring variations in carbonate biofacies: Studies from Tertiary outcrops of Oman

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The most complete succession of Tertiary carbonates in the Middle East is exposed along the southeastern Arabian Platform margin in Oman, which serves well for outcrop studies. The Late Paleocene-Early Eocene time slice involved widespread subsidence, extensive transgression over the Arabian Platform and aggradation of the first carbonate platform stage. The shallow-shelf environment is represented by the deposition of carbonates with alveolinid foraminifera, coralline algal nodules and scleractinian corals. In the Mid-Eocene, regional subsidence of the Arabian Plate was accompanied by extensive transgression and aggradation of the second carbonate platform stage. Thick nummulite shoals and banks accumulated along the platform margin. The Upper Eocene calcarenitic shallow-shelf deposits are characterized by a rich macrofauna (molluscs, echinids and corals). In the Oligocene, the emergence of the Arabian Platform was related to the opening of the Gulf of Aden. Forced regression and shelf-margin platform progradation-aggradation developed at the edge of the Arabian Plate. Carbonate platform collapse and resedimentation along the margin occurred at the beginning of this stage. The limestones with marly and sandy intercalations contain patch reefs with scleractinian corals and an abundant macrofauna of echinoids, gastropods and bivalves. During the Tertiary mechanisms like climate, tectonic movements, eustatic sea-level changes and siliciclastic influx controlled the dimension and biofacies distribution on the platform. These triggering mechanisms influenced the fauna (foraminifera) and flora (calcareous algae) during the different time-slices causing changes in the sedimentologic and biotic composition.

(#122810) Why time lapse seismic (4-D) works better than expected

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Time-lapse seismic (4-D) has become a standard and highly valued tool in production optimalization in areas like the North Sea and the Gulf of Mexico. The basic principle is to acquire two 3-D seismic surveys some time apart, and process them with the aim of estimating the difference caused by the reservoir production activity. This technique has generally not become a standard tool in carbonate reservoirs. A main reason for this is that feasibility studies generally have concluded that the time-lapse effect is too weak to be detectable by seismic

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methods. There are obvious reasons for that. However, one experience from the clastic reservoirs, where this has been routinely used for some time, is that the observed 4-D effects are larger than predicted. In feasibility studies one typically estimates fluid content at the initial survey time and at the final survey time. Then the seismic response for each model is calculated and the difference estimated. This is done for the existing, typically very homogeneous reservoir model. When the method is being used one is, however, looking for the anomalies, typically barriers to flow or high permeability zones, which in their nature will have more extreme 4-D effects than the modeled ones. The general effect is that one systematically underestimates the 4-D signal. In this presentation we discuss and illustrate some of the reasons why that is the case. These arguments are important to bear in mind, because if one does not take these effects into account one might underutilize a tool, which could be of great commercial value for the reservoir production strategy.

(#116098) Reservoir characterization and reservoir modeling of tight gas reservoir of Guangan field, China

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The Guangan field produces gas from a very thick Triassic sandstone reservoir that covers an area of 60 square km in southern China. A reservoir characterization study was undertaken to assist in proposing well locations. The model was based on geological, geophysical and engineering data available from 15 vertical and horizontal wells. This data was integrated and used to define different rock types of the sandstone reservoir based on to their reservoir properties. A static model using Petrel^{TM} was used to visualize the reservoir distribution throughout the field. The interplay of initial composition, depositional environment and diagenetic overprint determine reservoir quality. Thin-section studies showed that the heterogeneity of the rock is controlled by grain size, pores, cementation and fractures. This results in a significant variation of reservoir characteristics. The importance of the varying diagenetic histories is that the major differences in initial composition and diagenesis are reflected in pore geometry, which controls reservoir properties. Flow-zones studies defined four zones that have similar fluid flow characteristics. The classification of these zones identified no-reservoir zones and the best reservoir zones in the rock. The defined reservoir zones have been compared to well-test results and production data. A net-sand model, based on seismic attributes, has been used to supervise the petrophysical model and flow-zone model. For the best exploitation we must choose the prime regions using 3-D models for locating new wells. The highest quality of the reservoir occurs in its upper part and recommended for coring, logging and perforation.

(#118417) Next-generation seismic imaging: High-fidelity algorithms and high-end computing

Dimitri Bevc (3DGeo Inc., USA <dimitri@3dgeo.com>), Francisco Ortigosa (Repsol YPF, USA), Antoine Guitton (3DGeo Inc., USA) and Bruno Kaelin (3DGeo Inc., USA)

Future development of the Middle East's hydrocarbon resources will include exploration in increasingly complex environments such as the Red Sea, necessitating increasing advances in computationally intensive imaging technologies for both exploration and exploitation. Among these technological advances, *reverse time migration* (RTM) yields the best possible images. RTM is based on the solution of the two-way acoustic wave-equation. This technique relies on the velocity model to image turning waves. These turning waves are particularly important to unravel subsalt reservoirs and delineate salt-flanks, a natural trap for oil and gas. Because it relies on an accurate velocity model, RTM opens new frontiers in designing better velocity estimation algorithms. The chief impediment to the large-scale, routine deployment of RTM has been a lack of sufficient computer power. RTM needs 30 times the computing power used in exploration today to be commercially viable and widely used. To overcome these challenges, the *Kaleidoscope Project*, a partnership between Repsol YPF, Barcelona Supercomputing Center, 3DGeo Inc. and IBM brings together the necessary components of modeling, algorithms and the uniquely powerful computing power of the *MareNostrum Supercomputer* in Barcelona to realize the promise of RTM, incorporate it into daily processing flows, and to help solve exploration problems in a highly cost-effective way. Uniquely, the *Kaleidoscope Project* is simultaneously integrating software (algorithms) and hardware (Cell BE), steps that are traditionally taken sequentially. This unique integration of software and hardware will accelerate seismic imaging by several orders of magnitude compared to conventional solutions running on standard Linux Clusters.

(#118418) Wavepath tomography for complex velocity areas

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In complex velocity models, such as below rugose salt bodies, wavefield continuation migration is usually superior to Kirchhoff methods because of multi-pathing, sharp velocity contrasts and the band-limited nature of seismic-wave propagation. Wavepath tomography offers a way to build the velocity model in a manner that is consistent with the migration operator. Instead of tracing rays to backproject residual velocities, a *wavepath* is constructed using the actual wavefield continuation

operator. The operator represents the wave propagation between surface source-receiver pairs and subsurface reflection points by multiplication of impulse responses downgoing from the surface location and upgoing from the reflection point. The size of the inversion matrix is kept to a manageable size by restricting the wavepath to the first Fresnel zone. The considerable expense of computing a single wavepath kernel can be partially offset in comparison to ray tomography, by the smaller number of backprojections that are required to sample the velocity model adequately. To streamline the velocity-model updating process, we have implemented an automatic method of signal detection that eliminates the need for manual reflector picking by scanning the seismic data volume with prediction-error filters and automatically selecting back-projection points based on dip coherency and semblance strength. This approach can save months of human time on a typical 3-D seismic imaging project and, thereby, shortens seismic imaging project turnaround time while exploiting the full redundancy of the recorded data.

(#117643) Predicting pore types in Khuff reservoirs: A step towards improved permeability predictions

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The Upper Permian Khuff-B reservoirs of Saudi Arabia are prolific gas producers, with much of the production coming from stacked grain-rich shoals. While such stacked shoals often have excellent primary inter-particle porosity, this is frequently superseded by a phase of pore cementation and grain leaching. Thus, ooid- and peloid-rich reservoirs are frequently characterized by oo- or pel-mouldic pore systems. Such pore systems may contain significant hydrocarbons but connectivity may be limited due to the isolated nature of these pores. The detection of the relative abundance of poorly connected oo-mouldic porosity is essential for applying accurate porosity-permeability transforms. This study investigated the use of conventional wireline log data to identify relative percentages of well-connected and poorly-connected pore systems in Khuff-B reservoirs. Detailed core descriptions were carried out on two calibration wells, producing digital tracks of five major classes of pore types. Careful depth matching and correlation with reprocessed wireline logs created a highly constrained dataset. A combination of sonic, density and neutron logs produced predictive algorithms which identified calibrated zones of poorly connected porosity. Blind-testing of these same algorithms on a wireline log suite from a third Khuff-B well produced a very good match. Ongoing work is now investigating the transform from pore-type distribution to improved permeability predictions. These new algorithms act as a proxy for creating boundaries to the permeability distributions; the resultant transforms match the datasets significantly better than a simple linear transform method, and can be routinely used as part of the process of Khuff-B reservoir assessment.

(#123950) An integrated approach to determine flow units in a complex Jurassic carbonate "Marrat" Reservoir in Burgan Oil Field, Kuwait

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The carbonates of the Marrat Formation in the Magwa area of Kuwait's Greater Burgan oil field were deposited in a shoal lagoonal complex, essentially in a ramp-to-rim environment. An inferred highstand systems tract holds substantial oil reserves in the middle Marrat reservoirs. The upper and lower Marrat are argillaceous with poor reservoir characteristics. This reservoir starting producing in 1984 and its depletion was driven with very little aquifer support. However, because asphaltene flocculation with pressure drop inhibit smooth production, a water-injection program is planned. It is therefore critical to understand the reservoir geology and flow units in order implement the program. An integrated approach was adopted which included: (1) rock-type transforms to quantifiable petrophysical based flow units; (2) sequence stratigraphic framework; and (3) laboratory-derived continuous porosity and permeability data from a well. The study established three flow units within the reservoirs. The graphical tools used to determine the flow units were: (1) Winlands porosity-permeability cross-plot, (2) stratigraphic flow profile, (3) stratigraphic modified Lorenz plot, and (4) cumulative flow and storage capacity. This well-proven methodology for identifying flow units will provide the basis for the water injection and perforation strategy and will influence the future business decision strategy for a successful water-flooding program.

(#123699) Preserved amplitude processing of complex transitional zone 2-D seismic

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This presentation provides a sequence of results on relative amplitude processing and interpretation of complex transitional zone 2-D seismic data in the Arabian Gulf. Interpretation of the previous seismic data revealed dynamic mistie problems, which were caused by phase matching of seismic from several different energy sources, geophones and recording systems, as well as multiples and refraction static corrections. Low-relief structures and stratigraphic traps are the primary targets, and therefore the seismic data needed to be processed while preserving relative amplitude. This would permit inversion processing to image the structures as well as provide wavelet processing for seismic stratigraphy. Dynamite, mud-gun and air-gun sources were phase-matched to vibroseis to approximate zero-phase the data prior to the refraction static evaluation and calculations. A relative amplitude-consistent processing sequence of the data was applied throughout. The minimum amount of noise attenuation was used to achieve a bal-

ance between enhancing the signal-to-noise ratio, while preserving amplitude. A surface-consistent, triple-gate, second-zero crossing, predictive gap deconvolution was applied to avoid boosting the amplitude of multiples by whitening effects of a spiking deconvolution. Post-stack time migration (PSTM) was applied for additional enhancement of the signal, which improved the apparent post-stack frequency by reducing wavelet smearing in the stack process. Improved seismic to well log ties will be shown as well as solving the seismic mistie problems in the interpretation of events.

(#119063) Best practices in static modeling of giant carbonate reservoirs, onshore Abu Dhabi, United Arab Emirates

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Over the last few years, the static reservoir modeling effort in ADCO has been significantly increased. Larges carbonate reservoir models have been either updated or generated for the first time. These models cover areas of 500–2,000 square km and reservoir thicknesses in the range of 15–450 ft. Average grid size of 50–250 m in the X and Y directions and 1–5 ft in the vertical axis are resulting in static model sizes of 2–40 million cells. The following practices have been shown to add considerable value to the static modeling effort: (1) integration of *high-resolution sequence stratigraphy*; (2) detailed definition of *flow units*, in line with dynamic requirement, captured in the static model as individual sub-zones; (3) geologically derived *trend maps* to constrain facies, thickness and porosity; (4) introduction of the *shoulder bed* concept to more accurately model reservoir property and avoid vertical leakages of properties; (5) thorough-core description and integration of thin sections, poro-perm and mercury injection capillary pressure (MICP) data to define *reservoir rock types*; (6) careful *validation of core permeability data*; (7) integration of core permeability values with well-test horizontal permeability (kh) and/or Production Logging Tool (PLT) data where available and derivation of actual *K multipliers*; (8) replacement of permeability values honoring well test kh and/or PLT results in un-cored sections and considering them as *additional hard K data* to improve dynamic history-matching; (9) integration of log saturation using *J functions* to link saturation to porosity, permeability and reservoir rock types; (10) *Power Law* linking porosity to permeability and stochastic modeling of the *residual permeability* to capture heterogeneity; (11) systematic production of *quality-control plots*. Some of these practices are still being refined and feedback from the audience will be very much appreciated.

(#119451) Fracture characterization using borehole acoustic reflection: theoretical modeling and field data applications

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Characterization of borehole fractures is important because they provide conduits for reservoir fluid flow. Borehole Stoneley waves have been used as a means for fracture analyses, which however, are a difficult task to interpret because borehole changes (e.g. washout) and bed boundaries also cause reflections. We used theoretical modeling to characterize fracture-induced reflections. Fractures were modeled as localized, highly permeable structures embedded in a varying borehole environment (e.g. washout). The modeling led to an important result; namely that permeable fractures/structures generally cause Stoneley wave reflectivity to increase towards low frequencies. This result was used to provide a dual-frequency Stoneley reflection method for fracture characterization. The reflection data were processed in two different frequency ranges (e.g., 0–1,000 Hertz and 1,000–2,000 Hertz). Fracture-induced reflections were characterized by low-frequency reflectivity, which is significantly higher than high-frequency reflectively. This method has been applied to fractured reservoirs with promising results. The fractures measured by the acoustic method agreed well with those from borehole image data. The presentation proposes a refined acoustic reflection method for fracture characterization. It demonstrates the practicality and robustness of the proposed technique in field data applications.

(#118681) Formation evaluation in Palaeozoic gas reservoirs of the South Rub' Al-Khali Basin, Saudi Arabia

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Acquiring accurate subsurface data forms a key objective for the South Rub Al-Khali Company in its currently ongoing exploration drilling campaign in the remote and challenging environment of the South Rub' Al-Khali Desert. Exploring for non-associated gas in Paleozoic formations brings significant well data gathering challenges. These include logistics and planning, hole conditions, depths and associated temperatures and pressures. The combination of often poor reservoir properties and deep invasion can result in impaired reservoirs that cannot be sampled or tested with conclusive results. In order to maximise the chance of obtaining a petrophysical evaluation with conclusive results in terms of reservoir quality and fluid content, an extensive dataset has been acquired during the exploration campaign. The data set comprises cores, ditch cuttings, compositional analysis of the various gas show components, and surface sampling of any shows. Petrophysical data include logging-while-drilling data, open-hole electric wireline logs, pressure measurements, sampling and multiple

offset VSP's. Data obtained while drilling was repeated on electric wireline to spot invasion effects as a result of the mud system used. The presentation will focus on the data gathering strategy and planning and how this has been catered for in the well design. Lessons from the first well were captured in a structured review process leading to cost savings in subsequent wells without impacting the quality of the dataset acquired. Integration of the extensive data acquired has lead to a better understanding of the various play elements resulting in a robust risking of all exploration prospects.

(#118694) Advances in marine seismic acquisition

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Three recent developments in marine seismic acquisition will be presented. The first is solid hydrophone cables and Sercel's new navigation system. Due to their construction, the solid hydrophone cables better preserve low-frequency seismic signals, while the signal-to-noise ratio at the higher frequencies is improved by the dense spacing of the individual hydrophones. With these superior characteristics the recorded seismic data not only provide a better structural image of the subsurface geology, they also allow for a more reliable computation of rock parameters and pore fluids. The combination with Sercel's new *Nautilus System* for integrated navigation and streamer positioning helps to more reliably record weak 4-D signals in reservoir monitor surveys. The solid cables also reduce risks to the environment, since they are not filled with oil. The second development is wide-azimuth acquisition, which yields a better image of complex geological structures. Some of the geophysical and operational experience will be presented. It allows for true 3-D processing like 3-D attenuation of multiples and multiple diffractions and derivation of fractures and their orientations. An efficient dual depth acquisition geometry is being introduced yielding extra enhancement of the lower frequencies. The third development is the application of feasibility studies to determine the optimal acquisition geometry for meeting the survey's objectives. This can only be established after analysis of available data and modelling, done by specialists in different fields of geoscience. It may include towed hydrophone cables or 4C seabed nodes or cables. Some examples will be shown.

(#117082) Issues in uncertainty estimation for time-to-depth conversion

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Generating a structure map from depth conversion of a time seismic horizon is a standard practice in seismic interpretation. For most methods, however, a depth uncertainty estimate is not provided. Geostatistical methods are the exception in this regard. Some commonly used approaches such as cokriging the depth markers from well control and kriging with external drift, provide uncertainty estimates through the kriging variance, where the time horizon is incorporated as soft information. A shortcoming of these methods is that no accommodation is made for including time-horizon uncertainty. We provide a simple approach to remedy this by using kriging to interpolate average velocity, which we then use to convert the time-horizon to depth. We obtain a depth uncertainty by combining the average velocity uncertainty (obtained from kriging variance) with the time-horizon uncertainty, using standard methods from the theory of propagation of errors. Another issue for all of the above methods is: *how good an estimator of local error is the kriging variance?* We address this with a data example, where we blind-test our results with some wells that were held out of the analysis. We also introduce an attribute that we call a *gridding sensitivity indicator*, which gives another uncertainty measure in addition to kriging variance. This attribute extends the concept of cross-validation to a map view by displaying the standard deviation of all of the maps generated by the *leave-one-out method*. We also discuss other alternatives for local error estimation such as conditional simulation.

(#115435) Water movement controls in an Early Cretaceous reservoir: An integrated analysis from a large offshore field, Abu Dhabi, United Arab Emirates

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A Thamama carbonate reservoir in a major offshore field has experienced early water breakthrough with rapidly increasing water cuts. Concern over this production challenge and its impact on water handling, wellbore completion, sweep efficiency and ultimate recovery prompted a study to improve the understanding of the geologic controls over reservoir quality variations, how to properly capture them in static and dynamic reservoir models and mitigate their impact on reservoir performance. A multi-disciplinary, integrated study of relevant geoscience and engineering data has been undertaken to address this issue. The study focused on several geological components including depositional facies, diagenesis and tectonic factors. A deepening upward succession of carbonate ramp facies have been identified and characterized from examination of slabbed core, thin sections and SCAL data from over 35 wells in the field. Diagenetic overprints have impacted the original porosity and permeability resulting in inter-beds of moderately to highly porous zones, which exhibit significant variations in permeability. The diagenetic overprint has, in part, been correlated to major faults zones in the field. These faults and diagenetic effects have resulted in the formation of fractures within the reservoir. Cased-hole log and pro-

duction data has been instrumental in the identification of the spatial and stratigraphic distribution and timing of water movement. Results indicate that water breakthrough is controlled by variation in permeability due to depositional texture and diagenetic overprints and fracture enhancement on the original reservoir character. These variations are stratigraphically controlled near the top and base of the reservoir, resulting in a potential lack of sweep and recovery from the middle portion.

(#123759) Whole-core analysis for effective characterization of inter-well permeability from a horizontal well

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Whole-core analysis is critical for characterizing porosity and directional permeability in heterogeneous, fractured and/or anisotropic rocks. Whole-core measurements are essential because small-scale heterogeneity may not be appropriately represented in plug measurements. Additionally, for characterization of multi-phase flow properties (special core analysis) in heterogeneous rocks, whole-core analysis is required. Special whole-core analyses are not frequently conducted on whole cores because of experimental difficulties, such as establishing representative water saturation. It is rare that cores are taken and whole-core analysis is conducted from a horizontal well in a carbonate reservoir. The objectives and results of this presentation are: (1) show permeability variability at inter-well scale from a horizontal well in a carbonate reservoir in Abu Dhabi. (2) Compare vertical permeability in whole cores obtained from a horizontal well to vertical permeability obtained from an adjacent vertical core. (3) Analyze gas-oil relative permeability measurements conducted on whole cores. These were modeled and compared with gas-oil relative permeability data at plug scale. Klinkenberg-corrected permeability on whole cores under reservoir net-confining stress was measured and the results were compared with plug analysis from the same interval. (4) Demonstrate quality-control and data-analysis procedures for whole-core analysis. Uncertainty in routine and special whole-core analysis data were quantified and quality-control and data-analysis procedure are presented.

(#123957) The origins of inter-facial tension and implication on the wettability of carbonate oil reservoirs

Jan J. Buiting (Saudi Aramco <johannes.buiting@aramco.com>)

The distribution of water saturation within an oil reservoir is of paramount importance for hydrocarbon volume, reserves and production assessment. Inter-facial interactions between oil, brine and rock determine the fluid saturations and distributions within the pore system. Only two fundamental electrostatic forces, acting between neutral molecules, are responsible for all of these interactions, i.e. the dispersive and the polar forces. It will be demonstrated that the latter interaction is the dominant force field for all the interactions at the interfaces with water and control the capillarity of an oil reservoir. These molecular forces determine the inter-facial tension between crudes and brines (σ) and the contact angle (θ) between the liquids' interface and the surface of the rock. The resulting quantity $\sigma.\cos(\theta)$ is the effective capillary stress resisting the buoyancy of the penetrating oil and strongly determines the ultimate amount of oil in the pores. Experimental work on these quantities has not progressed greatly over the last decennia, in particular for those related to carbonate reservoirs. In this presentation the physics related to intra-molecular attraction and the resulting inter-facial interaction is analysed. For example it will be shown that the gases dissolved in the crudes greatly affect the electrostatic properties of the crudes, effectively reducing the interactions with the brines and reservoir rocks. Moreover, it will be demonstrated that, owing to the properties of the carbonate rocks, the $\sigma.\cos(\theta)$ values for carbonate oil reservoirs could be substantially lower than for clastic reservoirs. All these conclusions affect the apparent wettability of the reservoirs, with possible far-reaching consequences for reserves and production.

(#118404) Fiber-optic 4C seabed cable for 4-D permanent reservoir monitoring

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We present an optical system that utilizes passive optical telemetry and sensors to replace traditional seismic acquisition hardware that uses conventional sensors and in-sea electronic modules. The optical system eliminates the costly electronics and problems associated with them, providing a more reliable, less expensive, safer system to operate. We then will describe the system construction and compare data quality between the fiber optic and conventional systems. The optical system utilizes Dense Wavelength Division Multiplexing (DWDM) to optically power the sensors; optical interferometers are used to construct sensors. An optoelectronic/acquisition cabinet provides laser source to the optical sensors. The source passes through an interferometer, where outside stresses cause a phase shift in the light passing through the interferometer. The phase information is extracted back in the cabinet to output a signal equivalent to the input stress. Field test of an optical cable was conducted 2006 using a conventional reference cable. The cables were deployed parallel to each other in the Gulf of Mexico. Advances in fiber optic technology provide a system for 4-D reservoir monitoring. A successful demonstration in the Gulf of Mexico shows the optical system meets the requirements permanent reservoir monitoring. Advances in a 3-axis optical accelerometer, have turned this system into a practical tool for 4C permanent reservoir monitoring. We

have demonstrated the systems capabilities in deepwater with high channel count over many kilometers while maintaining high dynamic range, low crosstalk and low distortion. The optical system is an excellent fit for and a preferred solution for permanent reservoir monitoring systems.

(#118347) Residual water-bottom multiple attenuation in the Arabian Gulf

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This presentation will discuss the identification and resolution of a water-bottom multiple problem encountered in the Arabian Gulf. In 2002, Saudi Aramco acquired and processed an ocean-bottom cable (OBC) survey configured with hydrophone and geophone sensors designed to attenuate seismic energy trapped in the water layer. Subsequent interpretation of the 3-D data volume at the target horizon revealed wavelet variations that mimicked the water-depth profile. This was of concern, as the target was not expected to be conformable to the water bottom. An investigation of the issue determined a significant amount of unwanted energy remained in the data, even after use of industry standard processing and acquisition methods. After careful analysis we found that rapid changes in the water-bottom reflection coefficient may have compromised the results by inadequately suppressing water-borne energy. A key diagnostic display in the common water-depth domain indicated it was possible to isolate the periodicity of this unwanted energy such that inverse filters could target and suppress it. A new workflow was then designed such that an algorithm utilizing multi-domain deconvolution could identify and suppress the errant energy while maintaining structural and wavelet integrity at the target horizon. The new workflow proved to be more efficient than traditional single channel deconvolution methods with respect to isolating the periodic nature of the water-borne energy. A repeat of the diagnostic displays indicated the new workflow was measurably more effective at suppressing the residual water bottom multiple.

(#119912) Stratigraphic processing for AVO and AVZ analysis

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We present a stratigraphic processing flow which prepares wide-azimuth, long-offset, 3-D seismic data for amplitude-versus-offset (AVO) and amplitude-versus-azimuth (AVZ) analysis. Simultaneous analysis of the variation of amplitude with offset and azimuth is necessary for an integrated study of lithology, fluids and fractures. The processing flow extends the general concepts of AVO processing to include the azimuth domain. Our approach is target oriented. We use an interpreted seismic horizon to define the design window for pre-stack operators. We begin by applying all available time corrections from previous processing. This includes datum statics, residual statics, normal moveout corrections and structural time corrections. By using structural time corrections we are taking advantage of the gently dipping nature of the geology as typically found in the Eastern Province of Saudi Arabia. Next we apply 3-D linear noise removal simultaneously on all offsets and azimuths. We then run cascaded multi-channel, surface consistent, amplitude and frequency analysis. Each pass includes separate terms for source, receiver, offset and azimuth. We use azimuth- and offset-friendly algorithms. This means that unless the record is operated on as a whole, each process must accommodate offset and azimuth terms. At several stages during the processing flow we employ quantitative quality control checks by analyzing a variety of pre-stack attributes along key horizons. Finally, we define an important quality control guideline that states our AVZ decomposition must bear similarities to the anisotropy ellipse. We illustrate this approach using a wide-azimuth, long-offset, survey recently acquired over a Jurassic reservoir in Saudi Arabia.

(#123702) Impact of an integrated reservoir geological model on well placement: A case study from Saudi Arabia

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The objective of this study is to build an integrated geological model for a Jurassic reservoir in Saudi Arabia utilizing all available static and dynamic data to optimize field development plan and well placement. The Late Jurassic Arab Formation is one of the most important reservoirs in the Middle East. During this period a carbonate platform developed in most of the Arabian Gulf and extended to the Zagros Mountains in Iran and central Iraq. The reservoir consists of 45–50 ft of packstone to grainstone reservoir overlain by 5–15 ft of anhydrite. A total of 533 ft of cores from 13 wells have been studied and also results from 54 wells including well logs and well performance have been used. In this study, different sources of data with different scales were integrated to produce a single model that best represents the reservoir. This project was carried out through three main stages. The first stage was a detailed reservoir characterization study for the reservoir including core description, rock and facies types, pore geometry and diagenesis. The second stage involved univariate and multivariate statistical analysis of input data such as well logs. In the third stage, an integrated stochastic reservoir model was built using different geostatistical modeling techniques. This newly generated model captured the reservoir heterogeneities and was used to optimize placement of horizontal wells and to predict reservoir performance. So far a total of seven horizontal wells have been drilled with 29,000 footage based on this study and the results are very satisfactory in matching expectation.

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(#115107) Effluent water disposal in two giant oil fields in northern Kuwait

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Two major carbonate reservoirs are being used for effluent water disposal in the Raudhatain and Sabiriyah oil fields in northern Kuwait. These are the Paleocene Radhuma and Maastrichian Tayarat formations. A detailed reservoir characterization study of these formations was initiated in 2006. The purpose of the study was to develop an understanding of the injectivity capabilities of the reservoirs and to determine the medium-term plan for water-injection capability over the period to 2010 to ensure zero surface disposal of water to evaporation pits. A 3-D model was built, which included the 39 major faults located in both fields. Seismic inversion was applied, and a petrophysical interpretation of the limited log data set was used to populate the property model. The model illustrated that the upper Radhuma layers have the best porosity and permeability, although to date the injectivity data suggested a lower Tayarat dolomite layer has the best capability for water disposal. Dynamic testing and history-matching of the model demonstrated that the crestal area of both fields will likely pressure-up in the near-term, especially in the immediate vicinity of the disposal wells, but the flanks of both fields will undergo relatively moderate pressure build-up over a four-year injectivity period. The dynamic modeling suggested that the flank and mid-flank areas of both fields, where porosity and permeability are present, may be the best areas to locate effluent water wells that will have good injectivity and moderate pressure gain over a sustained time period.

(#119455) An integrated approach to predict filling history and fluid composition of satellite prospects

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In mature basins, most of the exploration is oriented towards satellite prospects. The difficulty in their detection lies in a reliable evaluation of their economic interest. Indeed, the interest in such prospects is very sensitive to the trap volume and the quality and composition of the producible hydrocarbon fluids. Trap volume and hydrocarbon quality can only be predicted through a detailed reconstruction of the reservoir and its hydrocarbon infilling evolution. It is necessary to take into account, as a function of the geological time: (1) the structural evolution and faulting of the area; (2) the initial facies distribution and diagenesis; and (3) the fluid maturation and migration with a fine compositional description. Such a time-related filling is classically taken into account at basin-scale but rarely applied to the fetch area of giant fields where the satellites are searched for. Here we propose an integrated approach that takes advantage of the well-known geochemical information from the discovered large structures to calibrate the trapping and composition of the satellite structures. The approach, which uses softwares originally developed for basin-scale exploration, is based on the combination of tools for structural reconstruction (Kine3D), fine simulation of facies distribution (Dionisos), high-resolution compositional kinetics and migration/dismigration scenarios (TemisSuite) and uncertainty evaluation (QUBS).

(#122667) Value of NMR logging to heavy oil reservoir characterization

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Recent advancements in nuclear magnetic resonance (NMR) logging have made it possible to address the particularly challenging heavy-oil reservoir characterization problem. Because viscosity varies substantially in different heavy-oil fields, no single NMR technique works for all situations. Three methods were employed for characterizing heavy-oil reservoirs in clean sands, shaly sands, and formations containing bitumen/tar, respectively. In clean sand or some carbonate formations, direct NMR fluid-typing is usually sufficient for quantifying heavy oils. For shaly sands, where NMR responses to heavy oil and bound water significantly overlap, we developed a conventional log-constrained inversion technique to better discern heavy oil from bound water. For bitumen at low-reservoir temperature, NMR relaxation time is too short to detect by the current NMR logging tools; analysis of porosity deficit is a robust means to identify and quantify tar mats. Those techniques have been successfully employed in Venezuela, Kazakhstan, Canada, USA and the Middle East. In contradistinction to cuttings, NMR logs allow us to precisely determine the depth of heavy oil that is crucial for water-flooding applications. Also, NMR can quantify movable water in the heavy-oil reservoirs – critical information for predicting producibility. Furthermore, NMR provides crude oil constituent information far beyond a single bulk-viscosity estimate. This can be used for identifying sweet spots in heavy-oil reservoirs. The component analysis is essential for separating light and heavy oil volumes with their corresponding viscosities in dual-charged reservoirs where each charge to the reservoir brought in oils having different viscosities.

(#116572) Minor reservoirs in northern Kuwait: Reserves growth and production opportunities

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In the Development Plan of Kuwait Oil Company, production from several minor reservoirs in northern Kuwait

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is scheduled to increase by about 10-fold by 2015–16. These reservoirs were not previously studied in detail because of limited experienced staff, most of whom had focused on the accelerated development of the major reservoirs in the country. Some of the minor reservoirs are complex, discontinuous and require further delineation. In some fields they are stacked and can potentially add many billions of barrels of oil in reserves growth. In order to accelerate the appraisal of these reservoirs, a multi-pronged approach was adopted to identify reserves growth and increased production opportunities. The approach involved: (1) identifying existing wells for testing; (2) deepening and testing of planned wells to the deeper Cretaceous Zubair and Ratawi reservoirs; (3) utilizing the Jurassic wells that penetrated through the Zubair and Ratawi reservoirs to acquire data; (4) identify opportunities to acquire data in wells penetrating through Tuba and Mid Burgan during the ongoing drilling activities for major reservoirs; and (5) continued surveillance in the Burgan and Mauddud reservoirs in Bahra field, so as to assess the pressure-production performance. In order to expedite the tasks, a management-level steering committee was formed to supervise the implementation of a blueprint that listed all the activities in terms of timelines, priority matrices.

(#118612) Meeting the challenges of static modeling of a *mid-life* giant Middle Eastern oil field, Abu Dhabi, United Arab Emirates

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A giant carbonate oil field, located in Abu Dhabi, has been producing from Lower Cretaceous reservoirs since 1973. The current *field development plan* (FDP) is based on a reservoir model, which has evolved in stages, with input from many field and laboratory studies over the past 20 years. The most recent static model has been built incorporating the results from significant new core characterization and sequence stratigraphic studies (over 110 cored wells), in addition to a more thorough integration of well, geological, production and 3-D (and 4-D) seismic data. Modeling such a large and active field (more than 600 wellbores) presents real data management challenges. These challenges include the choice of geo-modeling software, accessing and maintaining the corporate database, and ensuring that all engineering and geosciences disciplines are able to easily contribute and use the final integrated model. This new *Phase-3* static model has been built primarily to provide a more detailed reservoir description to the dynamic model to further optimize the FDP, as we complete the current infill drilling campaign and move to the tighter infill production. The model is also meant to provide a longer-term, more robust geological characterization for future enhanced oil recovery (EOR) activities. A recurring theme for the team is also the challenge to find the appropriate balance between incorporating 3-D seismic data and using data from the densely located wellbores. Other new demands on our modeling workflows include the need to quantify volumetric uncertainties by generating model scenario's and multiple realizations for proven SEC (US State Securities and Exchange Commission) deterministic and probabilistic reserves reporting. The new workflows will also allow a more rapid model updating as new wells are drilled.

(#119041) Multi-survey acquisition and processing in the Nile Delta

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The challenges associated with acquiring and processing multi-environment data in Egypt's Nile Delta are presented. In 2006, approximately 1,200 square km of new land, transition (TZ) and ocean-bottom cable (OBC) seismic data were added to approximately 1,600 square km of existing data in the western Nile Delta. Two contractors, operating in concert with two recording systems, three source types, and four different detector types proved operationally challenging but not impossible to coordinate. Continuous processing of the field data resulted in several fast-track volumes providing interpreters with new data to analyze. Following the successful acquisition and delivery of preliminary processing volumes, the project area was expanded considerably to include data from adjoining surveys. Merging the newly acquired land, TZ, and OBC 3-D seismic data with existing multi-vintage streamer and OBC data provides nearly 3,000 square km of continuous data for pre and post data interpretation and analysis. There are, however, significant data processing challenges in producing a continuous volume.

The challenges included deriving a consistent demultiple solution for adjoining land, OBC and towed marine data, as well as regularizing the noise levels in these diverse data sets. To achieve a seamless final data set, a broad portfolio of demultiple and noise-attenuation techniques were needed. Results from the multi-survey methodology will be presented. With increasing activity in the Mediterranean Sea and Nile Delta, data-sharing agreements are becoming more common. This has brought into focus the need for robust data processing solutions for multi-vintage data, as well as acquisition systems and crews that can operate cooperatively.

(#122499) Depositional architecture of the Upper Shu'aiba Formation exploration play in the greater Lekhwair area, Block 6, northern Oman

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The success of the Late Aptian, Upper Shu'aiba Formation play in Block 6, northern Oman has been driven by an

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increased understanding of the depositional architecture of the basin. It is founded on the integration of seismic attribute data with a well-based sequence stratigraphic framework, palaeo-environmental data and data from analogue fields. The Upper Shu'aiba sequence was deposited along the southern margin of the Bab Basin in the Late Aptian, during a regional lowstand. In northern Oman, deposition occurred in a strait between the isolated Safah Platform and the early-Late Aptian Shu'aiba margin to the southeast. The succession on the northern flank of the strait, which is largely mirrored on the south, is characterized by progradational geometries, with carbonate shoals intercalated with argillaceous limestones or marls. The shoal trends can be imaged seismically as a succession of amplitude and spectral decomposition tuning belts and have been modelled in Petrel^{TM}. The clinoforms have ramp or distally steepened ramp morphologies, with palaeo-water depths ranging from 100 m to less than 5 m, with facies transitions from outer-ramp mudstones, through mid-ramp wackestones and packstones into inner-ramp shoal or build-up facies, locally with low-energy backshoal facies. The shoals vary from rudist-dominated rudstones and floatstones in Ufuq to coated-grain and miliolid-dominated grainstones in Dafiq, which reflect variations in depositional energy regimes and accommodation space during the gradual infilling of the strait from the north (and south). Reservoir properties are largely controlled by the primary depositional fabric, however, significant diagenetic overprinting, both enhances and degrades the reservoirs.

(#119019) Improving understanding of 3-D distribution of diagenetic processes with digital outcrop modeling: Example from the Natih Formation, Jabal Madmar, Oman

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One of the challenges in carbonate reservoir characterization is to quantify the 3-D distribution of diagenetic processes responsible for determining poroperm distributions. Digital outcrop modeling techniques (GPS, Lidar) are normally used to map the 3-D distribution of depositional facies, but can be also used to quantify the extent of diagenesis, associated diagenetic products and processes. Commonly, the interiors of Middle East carbonate platforms are modeled in a homogeneous *layer-cake* fashion. Nevertheless, several km-scale (i.e. inter-well-scale) outcrops of epeiric platform carbonates revealed a complicated internal stratigraphic architecture, comprising depositional geometries such as platform-top incisions and clinoforms. These clinoforms and incisions have a wide range of heterogeneities due to the diagenetic overprint, such as dolomitization, early meteoric cementation, silicification and late leaching. One of the objectives of this study was to quantify the

diagenetic processes observed in the field and determine their origin in the context of structural and basin evolution. These data then can be used to improve subsurface reservoir models in inter-well correlations, and can provide analogue data for exploration and appraisal. Digital outcrop modeling combined with detailed sampling, petrography (transmitted-light, ultraviolet-fluorescence, and cathodoluminesce microscopy), and geochemistry (stable carbon and oxygen isotopes, fluid inclusions, X-ray, and BSEM) was used to determine the 3-D distribution and origin of dolomitized incisions and silicified clinoforms of the outcrops of Jabal Madmar, Oman. These data have been linked with the structural evolution and basin evolution of the field area, in order to provide predictive rules for the subsurface.

(#124893) Structural Evolution of the Hawasina Window (Oman Mts) and its Relation to Hydrocarbon Generation

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Extensive field studies in the Hawasina Window region of the Oman Mountains led to the recognition of four major structural processes, linked with: (1) intra-oceanic obduction; (2) emplacement of ophiolites onto the Arabian continental margin; (3) unroofing of the subthrust margin; and (4) Tertiary folding and extension. The first Cenomanian process is not relevant to the formation of hydrocarbons in the Arabian margin. The second Turonian process led to the formation of out-of-sequence nappes and ductile extension. It provided tectonic burial of the margin. An omnipresent NE-vergent syn-cleavage folding is also associated to emplacement. The shortly following tectonic unroofing rafted ophiolite blocks away from the window areas. Break-up of the nappes is suggested along a pre-existing strike-slip fault system. Isostatic compensation led to uplift and folding of the nappe succession. Finally the Tertiary Period was characterised by across-strike normal faulting and numerous steps of folding, ramp-thrusting and transpression. This process uplifted potential reservoir sections in Late Tertiary times. The play concept proposes classical Natih source rocks and reservoirs in the autochtchon. Since original porosity is reduced due to tectonic loading, fracture porosities in the limestones and Upper Permian-Triassic dolomites are considered viable in the reservoir rocks. Seals are formed by shaly sections of the autochtchon (Salil, Nahr Umr and Muti formations) and of a regional evaporitic detachment at the base of the Hawasina Nappes. The major upwarp of autochtchon and three local antiforms in the Hawasina Window form the potential trap(s). Vitrinite reflectance and clay mineralogy both reflect anchimetamorphic conditions for the Hawasina Nappes. Thermal conditions probably did not exceed late-stage, gas maturity levels. The main burial is

estimated to have lasted for 10 million years. Therefore the Hawasina Window area is considered gas-prone. Both MOL Hungarian Oil & Gas Plc and Hawasina LLC Oman Branch wish to thank the Exploration Directorate of Ministry of Oil & Gas of the Sultanate of Oman for the continuous support to the work.

(#119023) Fracture reactivation and diagenesis in the Asmari Reservoirs (Dezful Embayment, southwest Iran) during the Zagros Orogeny: Implications for fractured reservoirs modeling workflows

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Production from the Asmari carbonates of the Dezful Embayment, southwest Iran, provides a *textbook example* of the dynamic behavior of fractured reservoirs. In these reservoirs, fracture modeling is therefore a key task of any characterization workflow. This study presents recent findings on the relationship between fracturing, diagenesis and folding in the Zagros Foreland Basin and their practical consequences on fractured reservoirs modeling workflows. Based on the structural description of outcrops, the synthesis of image log interpretations and the analysis of fracture filling (both in outcrop and subsurface), we first propose a chronologic framework for the fracturing events in relation to paragenetic sequence in the Asmari Formation. This emphasizes the pre-folding origin of the main fracture sets affecting the formation. During these early events, the *pre-Hercynian* NS basement trends that affected the Arabian Plate, strongly controlled the spatial distribution of fractures. This stage of fracturing was associated to the growth of burial stylolites and successive stages of dolomite and calcite cementations. In a second stage, during folding, most of the deformation was accommodated by reactivation of pre-existing fractures. These fractures were associated with the precipitation of ferroan calcite in the exposed rocks, anhydrite in the reservoir and the first stages of hydrocarbon emplacement. A 100 x 100 square km 3-D model, which includes outcrops and reservoirs, will be discussed. Contrary to the growing use of such a method to control fracture density, we advocate that it better provides a good proxy for fracture reactivation potential and associated flow paths.

(#124197) Passive seismic field pilot for Arab-D Reservoir monitoring

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Passive seismic methods have been traditionally applied to study the Earth's internal structure using earthquake data. It is only recently that these methods have been used in petroleum reservoir delineation. Monitoring of fluid pathways in a producing reservoir is imperative for optimal reservoir management and maximal oil recovery. A pilot microseismic experiment has been designed and implemented in a Saudi Arabian oil field for mapping of Arab-D Reservoir drainage patterns. The experiment is unique because of the large array of permanent multi-component seismic sensors that are deployed at various levels in the borehole and over a surface area surrounding the borehole. The passive microseisms are recorded simultaneously in the surface and borehole sensors. The field pilot will test the ability for recording microseismic events caused by Arab-D Reservoir production and injection activities. The combined surface and borehole-based measurements are designed to provide a wide areal coverage over the reservoir. The sensor network is designed to capture events of greater than Richter magnitude -3, with frequencies from 10 to 1,000 Hertz within two kilometers of the hypocenters. In addition to microseismic, permanent pressure and temperature sensors were installed in the wellbore. Fluid-flow anisotropy in the area is evident from production behavior and well test data but the flow pathways and mechanism for the anisotropy are not resolved. Microseismic data could provide the location and relative fracture density that will improve the reservoir-flow, simulation models. Monitoring microseismic events over time will enable better prediction of fluid-flow behavior and the planning of production and injection well locations for optimizing reservoir production and ultimate recovery.

(#118633) Jurassic sequence stratigraphy in the Raudhatain-Sabiriyah area of northern Kuwait

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Exploration of multiple Jurassic carbonate reservoirs has increased after the discovery of hydrocarbons below the prolific Tertiary-Cretaceous section across Kuwait. The Jurassic of northern Kuwait has been studied in terms of sequence stratigraphy based on 2,686 ft of core and 12 borehole wireline logs. Six sequences have been identified. The key surfaces are sequence boundaries, maximum flooding and flooding surfaces. Each sequence comprises a transgressive systems tract (TST) and a highstand systems tract (HST). Sequence 1 corresponds to the Lower Marrat section, which consists of at least six carbonate/evaporite cycles. Sequences 2 and 3 are referred to the Middle Marrat where carbonates are arranged in shoaling upward parasequences ranging from a few feet to 10s of feet in thickness. Sequence 4 corresponds to the Upper Marrat section where evaporites occur below an MFS revealing a transgressive depositional environment. The Dhruma and Sargelu formations comprise Sequence 5, whereas Sequence 6 consists of the Najmah shale overlain by Najmah carbonate. The study of cores, combined with petrophysical analysis, has identified seven different lithofacies: lime grain-

stones to packstones, lime packstones to wackestones, lime wackestones and mudstones, algal boundstone, crystalline dolomite, bituminuous calcareous shale and anhydrite. The results of the study show an improved understanding of the Jurassic carbonate depositional architecture, and its control of hydrocarbon generation and entrapment in northern Kuwait. The results will be used for further exploration and development work in the area.

(#118168) Tectonic fracture network characterization in the giant Hassi-Messaoud oil field, Algeria

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The objective of this presentation is to show the methodology used to characterize the tectonic fracture network in the giant Hassi Messaoud oil field located in Algeria. This field is characterized by a significant number of wells (One Thousand Five Hundred) and data of various origins and forms. The data includes borehole image logs in 100 horizontal wells, cores from 1,000 wells, 2,500 square km of 3-D seismic, as well as dynamic data (production, pressure and water/gas breakthrough) for most of the wells. The fractures are complex objects to analyze. Because their scale is greater than the diameter of the borehole, it is necessary to take into account all the indices (seismic, physical and dynamic) to characterize them. In the Hassi-Messaoud field, tectonic fractures are clustered and associated with faults, and/or organized in fracture swarms. When they are cemented and the matrix is damaged by silica, they behave as barriers. In contrast, when the fractures are open, they provide a preferential path for fluid flow. The fracture network induces anisotropy of permeability, which has a strong impact on the development of the field. A synthetic map, which combined all available information, was constructed to predict and model conductive and barrier trends. The fracture network characterization improved the development of this mature field.

(#118903) Lateral facies variations of Upper Cretaceous carbonate ramp deposits, Jebel Nefusah, northwest Libya

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The Upper Cretaceous (Cenomanian) platform carbonates of Jebel Nefusah, northwestern Libya, were deposited as part of a regional prograding low-angle ramp system. These deposits are well-exposed in the Jebel Nefusah area but are poorly documented in the literature. Strata in this area are relatively undeformed making this system ideal for the study of lateral facies variation. The Cenomanian Stage is a major cyclic transgressive event over the regional unconformity that overlies the Aptian-Albian fluvio-deltaic sandstones of the Chicla Formation. The system contains an extensive oolitic to rudist-rich member that serves as an alternative analogue for Middle Eastern reservoir-prone facies. Field stops at 17 localities and five detailed sections over an area of 200 km form the base of a stratigraphic correlation panel, including the stacking pattern and depositional context of the recognised members. A geological model is proposed showing three third-order systems tracts during Cenomanian platform evolution. The first unit (less than 40 m thick) consists of inner ramp, tidally-influenced shallowing upward sequences. The second unit is characterised by progradational, inner-ramp oolitic shoal (40 m thick), which pass laterally into the mid- to outer ramp bioclastic, rudist boundstone and rudstone facies. This facies is a regionally developed (more than 200 km wide) member, 4–8 m in thickness. The two units are known as the highly dolomitised Ain Tobi Formation. A third regressive unit, the Yefren Formation, reaching 80 m in thickness, is formed by restricted inner-ramp marls with inter-bedded evaporitic gypsum layers. The depositional environment corresponds to a supra-tidal to sabkha setting. The architecture and geometry of the Cenomanian passive ramp system was controlled by eustatic sea-level changes rather than localised, abrupt tectonic events.

(#118654) Stratigraphic framework of the Natih Formation in Oman

Henk J. Droste (Shell, Oman <henk.droste@shell.com>)

Carbonates of the Albian to Turonian Natih Formation are important hydrocarbon reservoirs in Oman. A regional sequence stratigraphic study integrating seismic and well data of interior Oman led to a better understanding of the reservoir and seal distribution as well as the stratigraphic trapping potential. Deposition took place on an epeiric shelf with carbonate platform development at the ocean-ward margin, located in northern and eastern Oman, whereas clastics predominated along the exposed Arabian Shield in the southwest. Lateral shifts in clastic and carbonate facies belts, driven by changes in relative sea level and climate, resulted in a hierarchical stacking of depositional cycles of several 10s up to some 150 m thick. Two major flooding events, with widespread deposition of pelagic carbonates, occurred in the Late Albian and Late Cenomanian. Both are associated with the creation of significant depositional topography (up to 100 m) as a result of aggradational carbonate growth along the margin. This was followed by a strong platform progradation over more than 100 km towards the interior of the epeiric shelf. Variations in the type and amount of sediment input, both in time and space, caused major variations in reservoir geometry and properties within these prograding complexes. A major fall in sea level in the Mid-Cenomanian led to exposure and channel incision of the platforms and a major influx

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of clastics. Fine-grained clastics also covered most of the Lower Cenomanian platform during the initial stage of the following relative sea-level rise. Quartz sands trapped between the exposed carbonate platforms may provide opportunities for stratigraphic traps.

(#117447) Multi-disciplinary inversion of Earth models

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Now that Earth-modelling packages are used routinely by most petroleum companies, efforts are under way to adapt multi-disciplinary data inversion techniques to better constrain these models by geological, geophysical and dynamic data. There is a convergence between techniques developed in various fields of application, such as Bayesian or geostatistical inversion, regularisation-based optimisation or data assimilation. Geostatistical conditional simulations are usually built using *sequential gaussian simulation* or by generating non-conditional simulations and conditioning them with a kriged correction. These approaches allow conditioning simulations by any kind of data, as long as these data can be approximated by a linear combination of the inverted Earth model parameters. Kriging, the average of all realisations, gives the best estimate in a least-squares sense. This is illustrated by examples where we invert multi-offset seismic data into higher-resolution realisations of the logarithm of P- and S-impedances. Sensitivities to the various input parameters, such as the variogram, are discussed in detail. In this linear context, a regularized inversion of borehole and seismic data should lead to similar results to those obtained by kriging. In the same way, both geostatistical stochastic inversion and Kalman Filtering should produce similar a *posteriori* probability density functions of model parameters. Unfortunately, the forward model cannot always be approximated by a linear operator. This happens when production data must constrain a 3-D dynamic reservoir model. In these situations, algorithms such as *Markov Chain Monte Carlo* (MCMC) are required. *Ensemble Kalman Filtering* (EnKF) appears to be less time-consuming than many other MCMC methods, albeit it is not quite as rigorous. An example is given of a recent application of EnKF to an inversion problem on a UK field.

(#118183) A novel approach to reservoir characterization using seismic inversion, rock physics and Bayesian classification scheme

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Rock-physics analysis can provide the relationship between the parameters (or seismic attributes) that govern seismic-wave propagation (e.g. Vp, Vs and density in isotropic media) and the reservoir property of interest, such as rock or fluid type, porosity, pressure and satura-tion. In this process, we need to account for the quality of the seismic data and derive the appropriate uncertainties associated with the seismic data, such as noise, resolution, and inversion artifacts into the reservoir property estimation. In this presentation, we show how to quantitatively propagate seismic data quality issues such as resolution, noise, and inversion accuracy into the lithology estimation in a clastic basin. The method consists of several steps: seismic inversion to obtain elastic parameters, petrophysical well-log analysis to define a classification scheme based on Bayes' Theory and probability density functions (PDF); upscaling the PDF's to seismic scale using Backus' Theory and finally, applying the final scheme on seismic attributes (Vp, Vs and density) derived from the first step. The use of full-waveform inversion and Bayesian classification techniques provides a mathematical framework that enables us to model and directly relate data quality input into the uncertainty associated with reservoir properties prediction. The final output of this process is a map in 2-D and a cube in 3-D, of rock and fluid types with confidence levels associated with each property at each common mid-point (CMP) and time sample. We illustrate the procedure with examples from several clastics basins: Gulf of Mexico and India. This methodology can be easily applied to data from carbonates areas as well where inversion techniques are known to yield porosity, pay and fracture properties.

(#116595) Designing seismic surveys in Greater Burgan field, Kuwait, utilizing forward modeling concepts

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The Greater Burgan field consists of the Burgan, Magwa and Ahmadi structures. The Burgan structure is an anticlinal dome with a large number of faults. The three main reservoir units in the Greater Burgan field are the Wara, Mauddud, and the massive Burgan sandstones. The deeper reservoirs, namely the Lower Cretaceous Ratawi and Minagish limestones and the Jurassic Marrat Formation also contain significant oil reserves but are less substantial. Between 1976 and 1987, 2-D seismic data were acquired across the field. From 1996–1998 3-D conventional seismic data was acquired and during 2005, two pilot surveys were acquired utilizing single-sensor technology to assess the applicability of this technology in enhancing both spatial and temporal resolution. Processing and analysis of legacy and single-sensor data indicated that the signal/noise ratio and bandwidth of the reflection response might be strongly influenced by near-surface transmission effects. We used finite-difference modeling to understand these effects and to test whether various acquisition techniques employing surface and buried sources and/or receivers might im-

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prove data quality. Near-surface visco-elastic property estimates, derived from log data, combined with geostatistical simulations of lateral Earth properties were used to generate 1-D and 2-D models. These data were processed to illustrate the effects of the shallow geological section on deeper reflection returns. It is anticipated that based on this study future field trials can be designed so as to provide a step change in the seismic data quality in the Greater Burgan field.

(#118588) Controlling structural uncertainties in static and dynamic modeling of faulted reservoirs

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Modeling and reservoir management became an issue in an highly faulted onshore Abu Dhabi field. This presentation reviews the methodologies of controlling structural uncertainties in building the 3-D geological model for the reservoir. The great number of faults and their components such as throw, continuity and segmentation were the major issues in building the structural framework of the model. Integration of well logs and seismic data was implemented to enhance the seismic interpretation, aiming at defining the sub-seismic fault patterns, types and throws. Special attention was focused on the conductive nature of the fault plane and the communication among reservoirs. The driver behind this analysis was the recognition from available dynamic sources that the reservoir zones at the fault planes act as hydraulic communication corridors and have a controlling influence on the reservoir development strategies. Moreover, fault information derived from different seismic interpretation has not effectively clarified the issues. More than 30 wells that intersect faults were reviewed to define the fault throws accurately. The throw of many faults were found to be greater than interpreted from seismic data. Other faults were characterized as fault zones composed of many sub-seismic faults. In addition, the borehole image logs over the fault zone indicated conductive features within the fault plane. This investigation improved the understanding of zonal juxtaposition at the faults and the potential of hydraulic communication pathways between the reservoir zones. As a consequence of this work, both the 3-D static and dynamic models became more robust.

(#123799) Integrated estimation of porosity in a reservoir composed of thin layers of dolomite, using different inversion methods, multi-attribute analysis and neural networks

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The reservoir is composed of very thin dolomite and anhydrite layers. In the available 3D seismic data, these layers are not resolved and generate a composite seismic response, making reservoir characterization difficult through conventional single attribute analysis. We first inverted the 3D seismic volume to obtain an acoustic impedance cube using three different inversion algorithms. The inversion integrated log and seismic data into a full band acoustic impedance model of Earth. This process improved the vertical resolution and resolved the reservoir layers of interest. Different inversion methods were compared according to the cross validation results. In the next step of this study, acoustic impedance attribute beside other attributes, extracted from seismic volume, were analyzed using multi-attribute regression and neural networks. These linear or nonlinear combinations of attributes for porosity prediction resulted in an improved match between the derived porosity and predicted one. To estimate the reliability of the derived multi attribute transforms, cross validation was used. Finally, a multi-attribute transform was used in a stepwise regression to select attributes with minimum cross-validation error for porosity prediction. In addition to constructing a 3-D porosity cube, several porosity maps from different reservoir layers were prepared.

(#114032) Well placement services used in optimizing production in a large carbonate reservoir

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The Ratawi reservoir in the Wafra field is a Lower Cretaceous oolitic limestone located in the Partitioned Neutral Zone between Kuwait and Saudi Arabia. The development of the field started with 95 vertical wells, which were drilled between 1956 and 1999. The strong water drive resulted in severe coning in the vertical wells in 1999, a very successful campaign of horizontal drilling commenced (new drilling and horizontal sidetracks). As a result, Ratawi production increased 50% in a 2-year period. The horizontal development plan can be divided into three phases: (1) 1999–2002: 53 horizontal wells were drilled geometrically, using only MWD/gamma-ray measurements; (2) 2003–2004: 41 wells were drilled using geostopping strategy based on resistivity; and (3) 2005 to present: 26 wells were drilled by geosteering, well placement, using the geological and log-while-drilling resistivity forward model. In this phase geosteering was crucial to remain in a very narrow target of ± 5 feet from the top of the pay zone and away from water coning, water breakthrough and the current oil water contact. Due to the successful implementation of the well placement services, all 20 planned horizontal sidetracks wells for 2007 will be drilled using this method. This case study highlights the benefits of steering in field development in terms of efficiency improvements in geological analysis. It also shows how well-steering decision-making maximized oil production through optimum well placement.

(#116102) Locating and evaluating bypassed oil in the Minagish Oolite reservoir, Minagish field, West Kuwait

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Locating and producing bypassed oil due to water injection is one of the most challenging problems in reservoir management. A successful case from Minagish field in west Kuwait is presented. The Minagish Oolite reservoir is a limestone sequence, about 400 ft thick, whose facies consists of high-permeability ooidal grainstones, interbedded with low-permeability facies that act as baffles and barriers. A tarmat zone is known to occur at the base of the oil column leg. Integration of well-surveillance, geological and 3-D seismic data led to a better understanding of the distribution of bypassed oil above the oil-water contact (OWC) and/or tarmat. Also simulation sensitivity study included core studies, analysis of offset wells, and inverted 3-D seismic data indicated the possibility of high oil production rates. A 78° deviated well was drilled down the northeast flank of the Minagish structure. The geological uncertainties associated with this well path were: (1) structural top; (2) reservoir quality; and (3) the presence and thickness of tarmat zone(s). To minimize the risk associated with these uncertainties, two advanced measurement technologies were utilized while drilling. A magnetic resonance imaging LWD (logging-while-drilling) tool was employed to characterize fluids in real time to discriminate bypassed zones of light oil from tarmats. Also, laser-induced breakdown spectroscopy was used to measure the elemental geochemistry of cuttings while-drilling, in order to chemostratigraphically confirm borehole position and identify tarmats. Tarmats could be identified with this technology from elevated levels of Ni and V (and sometime S) in the tar mat zones. Use of these technologies resulted in the identification of two zones of mobile oil in the upper reservoir above the tarmat, as well as a high-permeability layer influenced by water coming from nearby injector wells.

(#119611) Effect of clay content on Tertiary oil recovery

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This work deals with the study of oil displacement by surfactant slug driven by a protective slug of a polymer solution against the driving water. The study is performed on a dimensionally scaled laboratory model. The used porous medium consists mainly of packed sand, but with variable percentages of clay. The results indicated that the recoverable oil is generally affected by both the surfactant slug concentration and clay content. It is directly proportional to the surfactant slug concentration and inversely to the clay content. An optimum value of surfactant slug concentration at each clay content was also determined. The Tertiary oil recovery of a sandstone reservoir, like that of the Rudeis formation pay zone in July oil field can by increased with increasing the surfactant slug concentration according to three considerations: (1) In the case where the clay content is less than 10%, it is more efficient to use a large pore volume of surfactant slug with low concentration 4–5%. (2) For clay content greater than 15%, it is recommended to use a small pore volume of surfactant slug, with high concentration (greater than 5%) to compensate for the surfactant loss and consumption. (3) When clay content exceeds 20%, it is not recommended to use the surfactant polymer flood method.

(#117981) Near-surface attenuation estimation of P and S waves from Middle East data

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Seismic waves propagating through the Earth are attenuated by conversion of a fraction of the elastic energy to heat. In seismic studies, attenuation provides more information about rock properties than available from seismic velocities alone. This is particularly important for the characterization and monitoring of hydrocarbon reservoirs because attenuation affects both the amplitude and the phase of the seismic data. In laboratory, as well as field measurements, accurate estimation of attenuation is difficult since seismic amplitudes are not only affected by intrinsic damping, but also by other mechanisms such as geometrical spreading, reflections, refractions, scattering and topography. These effects should be accounted for if we want to measure the true intrinsic attenuation. Current attenuation-estimation methods lack accuracy and rarely use the complete seismogram for recovering attenuation properties. To improve this situation, we developed a method to recover the near-surface attenuation properties for realistic geological settings. The method was based on visco-acoustic wave-propagation modelling and included the influence of the source wavelet and the presence of significant surface topography. The technique provided an acceptable result when applied to a data set recorded in the Middle East. Here, we extend the method to the visco-elastic case. Numerical simulations and measurements on field data demonstrate its effectiveness.

(#119444) What would be the minimum subsurface information before making a decision to develop the field? A case study from El Toor field, Muglad Basin, Sudan

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The El Toor field was discovered in 1996 and oil production started in early 2000. Cumulative production as of 2004 was 34 million stock tank barrels (MMSTB). El Toor is a fault-bounded anticlinal structure in the Muglad Basin, Sudan. The main reservoir consists of the sandstones of the Lower Cretaceous Bentiu Formation. The Upper Cretaceous Aradeiba E and F sands are secondary oil accumulations. Both sandstone reservoirs are layered and separated by continuous barriers over most of the field. After one year of sustained production, wells started to produce water. Both PCP and ESP are used for artificial lift. A team from the Sudanese Petroleum Corporation (Sudapet) has conducted a *field development plan* (FDP) to evaluate long-term production, reserve estimation and techno-economics. The El Toor field FDP will be presented as a case study. The FDP study maximized our geological and reservoir knowledge of the field and specifically the lateral quality of the reservoirs. The subsurface information that was required for the FDP included: (1) seismic data control; (2) structure maps; (3) pay-zone thickness; (4) facies information; (5) petrophysical data; (6) core analysis; (7) fluid contact; (8) fluid properties; (9) water salinity; (10) estimated original-oil-in-place; and (11) well test analysis. The Greater Nile Petroleum Operating Company provided Sudapet with all the available subsurface data. The main problem was the lack of core and VSP data and accordingly data from neighboring fields was used. This resulted in uncertainty for the seismic velocity and difficulty in correlating core porosity to log porosity. The study recommended cutting cores and running vertical seismic profiles (VSP) in the future infill wells.

(#123536) Diagenetic history and its control on reservoir properties in a heterogeneous carbonate field, Kangan/Dalan Formation, Iran

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A section of 445 m through the middle-upper Khuff Formation from three wells was selected for the study. A detailed description of the depositional facies and depositional cyclicity was first performed. The diagenetic processes were described by investigating more than 800 thin sections. A paragenetic sequence was established and the most important diagenetic processes with respect to reservoir quality were identified. All thin sections were described and categorized according to diagenetic facies. Important factors in this type of classification are mineralogy, cement type, cement volume and poretypes. The distribution of diagenetic facies will typically not correspond to the lithofacies distribution, since similar lithofacies may be subjected to different diagenetic processes, even within short distances. However, a higher-order correlation between sedimentary units and diagenetic facies can be demonstrated. The study has shown that this reservoir has been subjected to heavy diagenesis and that these processes, to a large degree, have altered the primary properties of the sediments. A better correlation between reservoir quality and diagenetic facies, rather than to sedimentary facies, can be demonstrated. The diagenetic overprinting therefore has a major control on reservoir quality distribution in the section, which therefore has important implications for the fluid-flow properties of the reservoir. The diagenetic facies have been grouped into associations according to their reservoir properties. These groups were identified with a high level of confidence on wireline logs making it possible to predict diagenesis and reservoir type outside cored sections.

(#122473) Geophysical reservoir monitoring: Where we are!

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In our land environment, areal reservoir monitoring is not just 4-D seismic. It can best be achieved by a combination of various geophysical techniques integrated with well-based surveillance methods. These techniques include active seismic (surface and downhole), passive seismic (microseismic), surface deformation (GPS and satellite), electromagnetic induction, and gravity measurements. Enhanced oil recovery (EOR) projects are the prime candidates for the application of geophysical reservoir monitoring techniques because of the expected large acoustic effect and the large potential value. With EOR techniques becoming ever more important the use of reservoir monitoring techniques will increase significantly. Over the years several blockers for time-lapse (4D) seismic have been identified including: (1) limited changes of acoustic properties at seismic scale caused by low yearly production rates, (2) poor sweep, (3) stiff carbonate matrix, (4) dense surface infrastructure, (5) small areal scale of an injection pattern, (6) lack of suitable baseline surveys, and (6) difficult reservoirs. The critical success factor for those geophysical reservoir-monitoring projects is the full integration with the well-based monitoring data into the dynamic reservoir model. Involvement at the beginning of a field development program by geophysicists is essential for the success of such projects, as tailor-made solutions require adequate attention for project management, scoping, justification, technical design, tendering and contracting. Based on recent experiences a five-step approach evolved for geophysical reservoir monitoring projects. These include: (1) opportunity screening and selection of relevant technologies, (2) detailed design, (3) implementation, (4) data acquisition and processing, and (5) detailed integrated interpretation.

(#123783) A fully-integrated approach for rock typing: A new approach to reservoir characterization

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The goal of this study was to develop a methodology for rock-typing in reservoir characterization and modeling. Our proposed method is a multi-disciplinary approach to identify the optimal number (statically and dynamically) of effective rock-types from well logs, core descriptions, routine core analysis and Special Core Analysis (SCAL) data, based on partitioning, correlation and comparability. This approach was used with the aid of multi-variate statistical and neural-network methods. The method consisted of three parts: (1) data partitioning and electrofacies determination using multi-variate statistical methods of Principal Component Analysis (PCA), cluster analysis and neural networks, to classify the data into a desired number of electrofacies; (2) electrofacies-derived correlation with core descriptions using correspondence analysis for the identification of an optimal number of static rock types; (3) *dynamic rock-typing* (DRT), which is determined by the interpretation of SCAL data (capillary pressure and relative permeability curves) within flow units. We applied our technique to a recently discovered giant carbonate reservoir in southern Iran. We focused on limited data from six exploration wells and sought more accurate results to define rock types for an effective model and reservoir simulation. In this reservoir, by applying the proposed methodology, seven electrofacies were identified from well log data. By using *correspondence analysis* on the identified electrofacies and core description facies, five static rock types were recognized. At the final stage, two dynamic rock types in which fluid flow occurs were obtained using SCAL data of available core samples.

(#114113) The effect of Cimmerian Unconformity in Late Jurassic-Early Cretaceous sediments and its impact in hydrocarbon exploration in Egypt: A case study in western Wadi El Rayan concession area

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The central part of the Western Desert in Egypt contains many hydrocarbon prolific sedimentary basins. The Abu El Gharadig Basin is one of the major basins, which originated in Mesozoic time. It contains a thick section of Jurassic and Cretaceous clastics and carbonates. Jurassic and Cretaceous reservoirs, sealed by sand and limestone, are oil and gas productive in this region. These reservoirs were charged from Jurassic and Cretaceous source rocks. A regional to local unconformity that occurs in the Upper Jurassic and Lower Cretaceous succession in the central Western Desert is related to the Cimmerian orogeny or event. This unconformity represent a major hiatus that occurred between the Late Jurassic limestone-dominated Masajid Formation and Early Cretaceous sand-dominated Alam El Bueib Formation. This time gap affected mainly the structural highs in the central part of the Western Desert and northern Sinai Peninsula. This unconformity is seismically detectable and mappable. We interpreted seismic images in the study area, in addition to outcrop analogues in northern Sinai for the equivalent time interval, in order to better understand one of the major play system in the Western Desert of Egypt.

(#117629) Ara stringer carbonate modelling: A case history

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The Ediacaran-Early Cambrian Ara Group intra-salt carbonates located in the South Oman Salt Basin are a unique hydrocarbon system, which currently produce oil and gas from the oldest (producing) reservoirs to be found. The depositional model, facies associations and subsequent diagenetic overprint of these reservoir units provide a challenge to reservoir description and static model construction. *A field* in southern Oman offers an excellent example of how these reservoirs are modelled. The first step is to capture the uncertainties in facies architecture and property distribution. The second step involves integrating these uncertainties iteratively with dynamic data to produce a robust reservoir model. The field was discovered in 1978 and was brought on stream in 1982. With ever increasing gas-to-oil ratio (GOR), additional oil production is constrained by the ability to handle the produced additional gas. A robust depositional model exists for the A4C Ara Group carbonate stringer. The reservoir zonation is based on sequence stratigraphic correlations that form the framework for the reservoir architecture and reservoir zones. Reservoir properties are highly variable. There is evidence for a porosity/depth trend, which may or may not be related to porosity reduction below a hydrocarbon-water contact. There is pervasive salt, anhydrite and bitumen plugging throughout the reservoir, however the effects of these plugging agents are localised. The A4C stringer exhibits an excellent relationship between facies and porosity, with porosity modelling biased towards facies, using facies transition simulation. There is no evidence of compartmentalisation, as confirmed by interference and formation pressure data, which exhibit good connectivity and communication between the wells. Flow units have been identified based on the integration of static and production log data. These have improved the history-match for the field and also our ability to predict production and GOR from the producing wells.

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(#117436) Supporting exploration and production with satellite radar data processed by means of the PSInSAR™ technique

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Permanent Scatterers SAR Interferometry (PSInSAR™) is today one of the most advanced and successful remote sensing technology used for surface deformation monitoring. In PSInSAR™ long series of satellite radar acquisitions, gathered repeatedly over the same target area, are processed. The analysis resolves, with millimetric precision, surface motions and small-scale features, including displacement rates of individual targets as oil pump, pipeline, plants, buildings, etc. PSInSAR™ data provides a depiction of spatial deformation over the surveyed area with an unprecedented accuracy. Information about surface displacements leads to a better understanding of the terrain and better coordination of production drilling. During production, the possible risks to the local environment can be continuously monitored. The dynamic of ground displacements of an oil-field area in the Middle East, subsidence phenomena and seismic faults in North America and Europe are some of the case studies that will be presented. These examples will show the potentialities of the PSInSAR™ in assessing the environmental impact of drilling activities and storage areas.

(#118658) Geomechanics contribute to improved well-delivery in deep gas wells, northern Oman

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Gas is being developed from the Lower Cambrian Amin Formation at depths of over 4,000 m (true vertical depth sub-sea) in northern Oman. Development drilling in some of the fields has been hampered by well stability problems in the overburden, as well as in the reservoir sections. An extensive data gathering (including time-lapse calliper) and geomechanical analysis program was executed to understand the mechanism that control well stability. The derived geomechanical model for a specific northern Omani field confirmed a present-day stress environment with high horizontal compression (in excess of the overburden) as seen elsewhere in northern Oman. In addition, stress orientation and magnitudes appear to vary somewhat across the field, probably due to the proximity of a major active fault zone close to the field. These ambient stress conditions strongly influence wellbore stability during drilling. Five major well failure mechanisms were identified: (1) clay stability, (2) rock matrix failure, (3) fault-related failure, (4) fracture-related losses, and (5) fracture-related rock failure. Time-lapse caliper logs indicated that rock-matrix failure occurs rapidly, after which the borehole becomes stable for at least two months. Utilizing this information, upper and lower mud-window bounds for future vertical development wells were calculated. Subsequently, optimal mud-weight plans for different hole sections, including mediation plans for the various failure mechanisms, were developed. Following the implementation of the study results, together with further optimisation initiatives, significant gains on well-delivery times have been made by up to 50%.

(#118951) 3-D visualisation on a plate scale model over the Middle East and North Africa

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With continuing improvements in technology, it is now possible to develop plate-scale regional 3-D subsurface models. We present a new 3-D approach towards understanding stratigraphic development at plate-scale rather than the more traditional field- or play-scale approach. This development requires consistent stratigraphic picks across continents – we have developed a global sequence stratigraphic model that allows us to achieve this. Regional depth maps have been constructed from public sources and then constrained to stratigraphic picks in many hundreds of published wells. Importing these surfaces into an RMS Cube on a grid of 1,000 m x 1,000 m, with dimensions of 3,000 km by 8,000 km, provides a striking plate-scale visualisation tool. Stratigraphic Modelling functionality allows the generation of intermediate surfaces - whilst following set rules, i.e. tie to wells, truncate above/below. Multi-angle cross-sections and views of the regional depth maps enable rapid assessment of adjoining basin stratigraphies, from which potential seals, reservoirs and sources rocks can be examined. Once the regional depth maps have been constrained first, second and third-order isopach maps can be generated, identifying areas of sediment accumulation and subsidence. 2-D Gross Depositional Environment maps can be draped over corresponding 3-D horizons providing a powerful visual prediction tool for the locations of possible reservoirs. This also enables basin-scale datasets to be potentially extracted from the plate-scale model and developed into 3-D flow simulation grids, allowing petrophysical cell properties and transmissiblities to be entered. All of this offers the opportunity to undertake detailed regional analysis of petroleum systems.

(#118990) A novel pre-stack inversion technique investigating a carbonate reservoir's rock properties

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A case study is described that investigated rock properties in a carbonate reservoir. The study used a novel pre-stack seismic inversion technique that integrated both broad-bandwidth seismic data and borehole data into the inversion workflow. The study used a 3-term pre-stack inversion methodology. The methodology is based on the application of the Aki and Richards *linearized Zoeppritz equation* for P-wave reflection amplitude as a function of incidence angle. A conditioning sequence was applied to the input pre-stack time-migrated gathers including, critically, an imaging step that provided broad-band, high-frequency seismic data. This high-frequency conditioning provides a stable wavelet across the seismic gather. This in-turn allowed both a better measure of the curvature term in the three-term equation, and also constrained the Earth model. Rock reflectivities were calculated from the amplitude-versus-offset (AVO) terms and integrated for the rock properties P-wave velocity (V_P), shear modulus (μ) and bulk density (ρ), with well logs used to constrain the inversion at various stages. These rock properties were combined with a macro-Earth model (created using well data) and high-frequency gather velocity analysis to yield absolute rock properties. The picked horizons were used to guide model population. A key step in the workflow was the generation and analysis of seismically derived and borehole-constrained elastic modulo cross-plots that allow the combination of several elastic parameters into a single composite geobody attribute. The visualization of such attributes, using *state-of-the-art* computer graphics techniques provided a valuable tool for understanding and interpreting reservoir lithology and fluid content.

(#121092) Production logs and well shut-offs in a GOGD giant field

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New chemical and mechanical shut-off technology has been applied to a giant carbonate field that is being produced under mixed *gas oil gravity drainage* (GOGD) and waterflood. The shut-off technologies have aimed to minimise unwanted gas and water influxes by isolating fractures and permeable sub-layers. The trials included: (1) chemical shut-offs in the heels of horizontals to prevent vertical gas coning (fracture/cement bond issues); (2) mechanical shut-offs in the toes to seal gas under-runs through highly fractured layers; and (3) use of *external casing elastomers* (EZIP) to compartmentalise wells, and even isolate individual fractures malignant to well performance. Wellbore influxes were mapped-out

from a campaign of horizontal-well production logs. The results included shut-in pass water-flow logs run in water-cut GOGD wells. They illustrated the inflow and exit of injected or aquifer water at individual fractures that used the wells as conduits for cross flow. Drill-fluid losses into producers have recently provided likely fracture pathways, as confirmed in one case with production logs. Some of these pathways follow a fracture trend that was identified in outcrop data overlying the field but not previously considered in the subsurface. Monitoring the outcome of the shut-off trials has further revealed reservoir behaviours.

(#119302) Preservation of pre-rift sediments and development of accommodation zones during the initial phase of Red Sea rifting

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Successful exploration in the Red Sea requires a thorough understanding of the structural controls on reservoir and source-rock distribution. *Pre-rift* reservoirs are one major exploration objective, mainly comprising fluvial to shallow-marine clastics of Early Eocene, Paleocene and Cretaceous age. In the giant October and Ramadan fields in the Gulf of Suez, hydrocarbons sourced from the Upper Cretaceous "Brown Limestone" are produced from pre-rift reservoirs ranging from Cretaceous to pre-Carboniferous in age. Across the Red Sea region, the present-day distribution of pre-rift reservoirs and source rocks is controlled by both depositional paleogeography and the subsequent post-depositional structural history. The underlying Neoproterozoic basement fabric exerts a fundamental structural control on preservation of pre-rift sediments. During the initial rifting phase in the Late Eocene to Oligocene, pre-rift sediments were preserved in hanging wall blocks formed by extensional reactivation of two major sets of sub-vertical lineaments: *Najd shears* trending (azimuth) 125–130°, and faults trending N-S. Along the Saudi Arabian coastal plain, pre-rift sediments are found in hanging walls located in the *SW quadrant* of the intersection of these two sets of basement lineaments.

Accommodation zones in the Red Sea region formed during the initial rift phase, and their location and trend is again related to the underlying Neoproterozoic basement fabric. The orientation of the Duwi accommodation zone in the northern Egyptian Red Sea is directly linked to the underlying Najd shear trend. Similarly, the newly identified Jeddah accommodation zone in Saudi Arabia (mapped from 2-D seismic data) follows the same Najd shear trend observed in the surrounding basement rocks. Discovery and analysis of the Jeddah accommodation zone will enable more accurate structural mapping of pre-rift fault blocks in the subsurface, together with more accurate prediction of potential syn-rift (Miocene) reservoirs.

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(#114659) Origin of burial diagenetic illite and its effect on porosity and permeability of Unayzah sandstone reservoirs (Permian-Carboniferous) of Saudi Arabia

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Burial diagenetic illite and quartz are the primary cements, which affect porosity and permeability in deep Unayzah reservoir sandstones in Saudi Arabia. The ultimate source of illite is the alteration of feldspar, mainly K-feldspar. Feldspar is altered to kaolinite to varying degrees during early burial. During later burial to depths where temperatures exceed about 100°C, remaining feldspar reacts with kaolinite to form illite via the reaction: K-Feldspar + Kaolinite = Illite + Quartz. The amount of illite that forms is limited by the amount of reactant in least supply (kaolinite or feldspar). When either of the two reactants is exhausted, illite can no longer be generated by this reaction. Accordingly, Unayzah sandstones can be classified as *Feldspar-Limited* or *Kaolinite-Limited* based on which reactant is consumed first and thus is the limiting factor on the amount of illite formed. Feldspar-limited sandstones typically have less diagenetic illite than Kaolinite-Limited sandstones. Feldspar-Limited and Kaolinite-Limited sandstones have distinct geographic distributions. The distributions may partly be related to provenance (original feldspar content), but early invasion of meteoric water into the basin margin is interpreted to have played an important role as well. This early leaching of feldspar partly controls the distribution of Feldspar-Limited sandstones and thus the subsequent distribution of illite. There is no evidence to support continued illite formation directly from feldspar after kaolinite is consumed, e.g. $3KAlSi_3O_8 + 2H^+ = KAl_2(Si_3Al)O_{10}(OH)_2 + 2K^+ + 6SiO_2$.

(#114658) Origin and evolution of pore water in coastal and inland clastic sabkhas and salt pans of Saudi Arabia

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Coastal and inland sabkhas of Saudi Arabia are primarily quartzose clastic sabkhas. In some cases they have developed on older aeolian dunes now submerged beneath the present-day water table. Models of early cementation of ancient sabkha deposits frequently called for precipitation of carbonates and sulfates from sea water by evaporative pumping: the inflow of sea water through the sabkha to replace pore water evaporated at the sabkha surface. The landward extent of the sea-water influence was usually not addressed. Pore water samples collected along transects from the sea, coastal sabkhas and inter-dunal sabkhas, more than 100 km inland, were analyzed to determine the extent of sea-water influence. Included in this study are pore waters from Sabkha Matti, one of the largest sabkhas in the world. Stable isotopes, ion chemistry and strontium-isotope composition of these sabkha waters indicated that the influence of marine water is limited to a narrow zone within a few kilometers of the coast. Landward of this narrow band, meteoric water appears to be the sole source of sabkha pore waters and is a significant component in some coastal salt pans. Even in the present-day low-lying, hyperarid desert of southern Saudi Arabia, the water table rises inland and the hydraulic head tends to drive meteoric water seaward preventing incursion of marine water into sabkhas except in a narrow band very near the sea. Results of this study have implications for interpreting early cements in ancient desert sediments like the Permian-Carboniferous Unayzah of Saudi Arabia.

(#117097) Geochemical characterization of petroleum in Jurassic reservoirs south of Ghawar field, Saudi Arabia): Implications for the petroleum system

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Geochemical characteristics of recently discovered petroleum in Jurassic reservoirs of the Halfah, Yabrin, Dirwazah and Tukhman fields, south of Ghawar field (Saudi Arabia) are different from typical Jurassic crudes in the Abqaiq, Ghawar, Mazalij and other fields. The latter fluids correlate well with the excellent oil-prone source rocks from the Tuwaiq Mountain and Hanifa formations of the Arabian Basin. These classic *Ghawar-type* medium-gravity oils represent high-sulfur crudes (greater than 1%), have pristane/phytane (Pr/Ph) ratios typically less than 0.8 and contain biomarkers indicating that the oils are derived from source rocks deposited in a marine carbonate environment under anoxic, reducing conditions. Characteristic biomarker parameters that support this interpretation are C29-hopane/C30-hopane ratios that exceed 1.0, relatively low abundances of diasteranes, and dibenzothiophene/phenanthrene (DBT/P) ratios typically exceeding 3.0. The Halfah-Yabrin-Dirwazah-Tukhman crudes, south of Ghawar field, have low-sulfur contents (less than 1.0%), Pr/Ph ratios ≥1.0, C29-hopane/C30-hopane ratios less than 1.0, and relatively high amounts of diasteranes and the C24 tetracyclic terpane. Most of the differences in sterane and hopane biomarker distributions compared to the *Ghawar-type* fluids appear related to differences in the abundance of clay versus carbonate in the source rocks. These data provide evidence for a source rock organic facies change south of Ghawar field. This presentation discusses recent results related to oil-oil and oil-source rock correlations, genetic relationships, and their implications for exploration in the southern part of the Arabian Basin.

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(#123139) Information management for the asset team

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Managing the growing volumes of information and data is fast becoming a significant issue for most E&P asset teams. Schlumberger Information Solutions has developed a unique set of solutions using the ProSource™ suite of software to manage across multiple projects and multiple data stores the asset team's information. Data stores include Petrel™, GeoFrame™, OpenWorks™ and Finder™, with connections to any other data stores that are OpenSpirit™ enabled.

Key workflows include, globally searching across multiple projects and multiple data stores using a single application console that centralizes the project data management, eliminating project by project data management. Visualizing the information via GIS or in spreadsheets, automated quality control assurance for data integrity using data compare tools which brings confidence and data consistency to the end user, quality tagging of the data, capturing of milestones of interpretation data into a vendor neutral repository for easy retrieval for partners. Creation of an audit trail for your E&P studies and regulatory reporting.

If these solutions fit your E&P needs the ProSource suite of solutions can help you manage your E&P asset teams and minimize the time administrating and maximize the quality and consistency of the data being used by your asset team.

(#123997) Reservoir characterisation of a heterogeneous hydrocarbon field, Khuff (Kangan-Dalan) Formation, Middle East

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Analysis of previously unpublished data from a major Middle East gas field has resulted in an integrated study of the Khuff Formation. Conceptual geological models for the field will be presented, providing an opportunity for comparison with other published data in the region. Detailed sedimentological work of three extensively cored wells has enabled the identification of a suite of lithofacies, which are grouped into seven facies associations. Depositional settings range from marine grainshoals, through to restricted tidal flat settings with common evidence of exposure. Shallowing-upwards cycles form the basic building blocks in the sequence stratigraphic framework. Cycles are organised into packages, termed *high-frequency sequences* (HFS), which possibly re-

flect fourth-order relative sea-level variation. At a larger scale, HFS's are grouped to form four major depositional sequences (K4 – K1). These are comparable to the third-order sequence described by Sharland et al. (2001). Cycles show distinct trends in thickness variation, which can be traced in all cored wells. Thicker cycles typically occur within marine ooid-grainstone facies of the transgressive systems tract (TST) of large scale sequences, whilst thinner cycles are more typical of restricted facies of the highstand systems tract (HST). Diagenesis has significantly modified the primary depositional facies. The key diagenetic processes include: (1) cementation: primarily calcite and anhydrite; (2) dissolution: dissolution of grains, in particular ooids; (3) dolomitisation: both early evaporitic (in late HST) and hydrothermal processes associated with faults. Reservoir potential is related to the interplay of primary depositional facies and subsequent diagenesis. The best reservoir quality is associated with dolostones, although overdolomitisation and anhydrite cementation are commonly detrimental. TST grainstone facies are prone to calcite cementation; however, dissolution of grains significantly improves porosity. Conceptual geological models have been built based on the HFS stratigraphic framework, and these models are the input for the flow-unit and geo-modelling.

(#123736) First microseismic monitoring results for a Middle East carbonate reservoir: Minagish oil field case study, western Kuwait

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During the first quarter of 2006, a microseismic monitoring pilot was implemented in Minagish field, western Kuwait. The target zone was the Minagish Oolite, a microporous carbonate reservoir, about 350 ft thick and around 9,600 ft deep (below mean sea level). The monitoring antenna, an SST-500 wireline tool of four 3C-geophones, was temporarily deployed in an abandoned well on the eastern flank of the field. The purpose of the surveillance was: (1) to assess the occurrence of microseisms induced by the production operations and especially the water injection along the flank; then (2) to characterize such microseismicity; and finally (3) to measure the effective network sensitivity with depth. Such a microseismic pilot survey should provide insight on the added-value that this monitoring technique may bring to the production and reservoir engineers. During the 50 days of effective monitoring, about 2,000 microseisms were identified and 600 events, from magnitude -2.0 to 0.3, were located. The large majority was distributed on the western side of a NNE-trending line as consistent with the direction of the local oil-water contact. A more detailed analysis also highlighted clusters of microseisms between injection-production doublets. In fact, one doublet was believed to be connected, which has

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been confirmed. Additionally, the depth survey showed that microseismic monitoring was still efficient above the Shu'aiba Formation. The pilot's objectives were successfully attained and the results were beyond our expectations. Hence, it is proposed to deploy a cost-effective and optimized microseismic network suitable for the entire Minagish field.

(#122321) Production attribute mapping workflow to assess remaining resource potential and distribution of water in the First Eocene reservoir at Wafra field, Partitioned Neutral Zone, Saudi Arabia and Kuwait

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The First Eocene reservoir at Wafra field was discovered in 1954 and has produced about 290 million barrels of 17-19º API, high sulfur oil. The estimated oil-originally-in-place exceeds 9 billion barrels. Previous studies, which have relied on static data, were not able to quantitatively predict water-cut and water-saturation trends within this reservoir. A production attribute mapping workflow was developed that incorporated static and dynamic data. The workflow has been used to define the current distribution of oil and water within the reservoir and provide an estimate of *remaining hydrocarbons in-place* (RHIP) by area and stratigraphic layer. Estimation of RHIP utilizes a workflow in which full-field saturation maps representing reservoir conditions at the end of 2006 are generated using production attribute mapping techniques. The saturation map is combined with original net pay porosity-thickness values to generate a map of RHIP. Defining the current distribution of water within the reservoir is a complex task due to the long production history and large number of wells in the reservoir. A workflow was developed to map water-cut through time, with a focus on the earliest producers in the reservoir. Preliminary results suggested that the waterfronts initially move primarily from the north and south in structurally low areas. After about 12 months, the waterfronts begin to converge and appear to fully converge within about 120 months. Migration from the southwest may not be related to structure, but may be influenced by facies distribution. Results from the production attribute workflow will be used as part of on-going reservoir management decisions as well as to update current static and dynamic reservoir models.

(#119606) Tectono-stratigraphic comparison of two petroliferous provinces in the northeastern Iraqi portion of the Arabian Plate

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Rushdi (Iraq Oil Exploration Company) and George J. Grabowski (ExxonMobil, USA)

Northeastern Iraq has two contiguous, petroliferous tectono-stratigraphic provinces that lie at similar regional structural elevations and yet have contrasting play elements, owing to their different Late Mesozoic to Cenozoic evolution: (1) Kirkuk embayment foldbelt ("Kirkuk", from the Hamrin Mountains northeastward in the Kurdistan part of Iraq), with Tertiary reservoirs in high-relief anticlines; and (2) northwestern Mesopotamian foreland ("NW Mesopotamia", the northern Mesopotamian Plains, from the Hamrin Mountains southwestward to the Euphrates River), with Cretaceous reservoirs in low-relief traps. Both provinces were within the Gotnia Basin during the Late Jurassic and in similar carbonate-prone depositional environments until the Late Cretaceous. Late Cretaceous obduction of Tethyan ophiolites onto northeastern Arabia created an orogenic load and sedimentary provenance that affected Kirkuk and NW Mesopotamia differently. Kirkuk was in a NW-trending foredeep, with clastic input on its northeast flank and deep-water, reservoir-poor carbonates on its southwest flank. NW Mesopotamia remained part of the Arabian platform with deposition of reservoir-prone carbonates. Tectono-stratigraphic differentiation between the obduction-related Kirkuk foreland basin and the NW Mesopotamian platform lingered through the Paleogene and Early Miocene. The Kirkuk foreland accumulated several hundred meters of Eocene to lower Lower Miocene carbonates that are its principal reservoirs. In contrast, NW Mesopotamia accumulated much thinner Paleogene to Lower Miocene carbonates. Collision of the Arabian and Eurasian plates in the Neogene created first the Taurides and then the Zagros Mountains. Kirkuk underwent northwestward-increasing truncation of Paleogene reservoirs beneath a pre-late Early Miocene unconformity, then rapid burial in the Zagros Foreland Basin, and finally uplift, as large anticlinal traps grew as far southwest as the Hamrin trend. Meanwhile, NW Mesopotamia subsided as part of the Zagros Foredeep.

(#118178) Structural genesis of hydrocarbon traps of Iraq

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Iraq's hydrocarbons (134 billion barrels of oil and oil-equivalent: OPEC, 2004) occur in many structural habitats. Using major fields, we illustrate structural styles from Iraq's four main hydrocarbon provinces and give interpretations of their genesis. The Kirkuk embayment in northeast Iraq involves Late Miocene and younger SW-verging, fault-propagation folds (Zagros-driven) fed by slip along Lower Jurassic detachments. The principal Tertiary reservoirs at the Kirkuk field include an Eocene through Lower Miocene carbonate-prone section beneath a lower Middle Miocene angular unconformity along which truncation increases to the northwest. The

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post-unconformity Middle Miocene section carries the topseal. In southern Iraq, within the southwest flank of the Mesopotamian Foredeep (Zagros Foreland Basin), the major traps (e.g. Rumaila and Zubair fields) are large, N-trending anticlines, each with several crestal culminations and gently-dipping flanks (2° to 4°). The Mesozoic reservoirs are little faulted. Long-lived, episodic evacuation of infra-Cambrian Hormuz Salt beginning as early as Late Jurassic controlled trap-genesis. Basement grain, reactivated during the *Hercynian*, controlled the N-S trend of the later evacuation synclines. In contrast, Central Iraq's Mesopotamian traps have NW-trending basement-involved faults, some of which had reverse slip (transpression?) during both the Late Jurassic and the Neogene and others of which had normal slip (transtension?) during the Late Cretaceous. Iraq's lightly explored Western Desert has Paleozoic-sourced exploration potential at depths much shallower than elsewhere in Iraq, owing to (1) post-Late Jurassic to pre-Albian southward tilting, uplift, and erosion; and (2) Late Cretaceous N-S extension. Iraq's structural styles reflect variable impact, from one region to the next, of (1) basement grain and faults, (2) Hormuz Salt distribution, (3) *Hercynian* orogeny, (4) creation of Tethyan passive and transform margins and their destruction resulting from Arabia's collision with Eurasia.

(#118431) Integration of sedimentology, sequence stratigraphy, and seismic stratigraphy of the Lower Cretaceous Shu'aiba Formation in an oil field of northwest Abu Dhabi, United Arab Emirates

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The Lower Cretaceous (Aptian) Shu'aiba Formation is an important carbonate reservoir of the subsurface of Abu Dhabi. At an oil field located in northwest Abu Dhabi, the reservoir is comprised of interior platform, platform margin, clinoform belt (prograding wedges) and intra-shelf basin deposits. Sedimentologic and petrographic core description identified 12 lithofacies types, ranging from shallow-marine, rudist-rudstone to deep-marine, planktonic foraminifera wackestone and shale. Caprinids (*Offneria* sp.) dominate the Shu'aiba platform margin and the proximal clinoform belt. Algal-stromatoporoid facies and caprotinid debris are indicative of the distal clinoform belt. Planktonic foraminifera wackestone and shales dominate the intra-shelf basin deposits (Bab Member). The Shu'aiba deposits at an oil field located in northwest Abu Dhabi fit well into the sequence stratigraphic framework established for a giant oil field of central Abu Dhabi. Shu'aiba transgressive and early highstand sequence sets are built by the Ap2 and Ap3 sequences, Shu'aiba late highstand sequence set comprises the Ap4 and Ap5 sequences, and the Bab lowstand sequence set is represented by the Ap6 sequence.

However, the platform margin appears to be steeper in northwest Abu Dhabi, as the area of the Upper Aptian (Ap4 and Ap5 sequences) distal clinoform belt is narrower than the one encountered at central Abu Dhabi. Three-dimensional seismic analyses allow mapping of the platform to basin geometries. The areal extent of the interior platform, the platform margin, the clinoform belt, and the Bab Basin can be outlined by seismic cross-sections and seismic amplitude maps. All available data were successfully incorporated in a new 3-D static model, addressing uncertainties in terms of structure, stratigraphy, and reservoir quality.

(#112821) Multi-lateral horizontal well application for improving the oil recovery of a mature field, Intisar 103N, Libya

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This presentation examines the performance of a horizontal well with multi-lateral completion in the mature Upper Sabil Reservoir in the Paleocene Zelten Formation in Intisar 103N field. The hydrocarbon trap in an anticline that houses 14.4 million stock tank barrels (MMSTB) of oil-initially-in-place. The reservoir is highly under-saturated with oil of 42° API gravity. The initial field development with a vertical well resulted in a poor recovery, 1.3 million barrels of oil in 19 years of production (equivalent to a recovery factor of 9%). The recovery mechanism in the reservoir is mainly rock-fluid expansion with marginal support from flank aquifers. The poor recovery can be attributed to thin pay thickness, poor reservoir quality, large well spacing, and the lack of pressure support from aquifers. The vertical well revealed a nearly constant production rate for the last 17 years indicating the drainage area is much larger than one well can deplete in a reasonable time frame. The incentive of reducing well-spacing existed but the question was how to reduce the well spacing: *by drilling many vertical wells or a lesser number of horizontal wells?*

A reservoir simulation study in 2003 indicated that drilling vertical wells in a very thin reservoir of poor quality was not cost-effective. Hence, an horizontal well was drilled and completed at the top of the porosity zone with two lateral legs extending 1,632 and 2,811 ft. Two lateral sections were branched-out from the same spot in the well with a 47° angle between them and completed open-hole in the reservoir. The stabilized oil production rate of the horizontal well was approximately three times greater than that of the vertical well, whereas the drilling cost of the horizontal well was about 1.3 times higher. The production from the horizontal well showed no negative impact on the production performance of the existing vertical well. The oil reserves, as a result of putting the horizontal well on stream, are expected to increase by 1.8 million barrel. It is evident that horizontal wells with multi-lateral completions can improve oil recovery, accelerate oil production and reduce production cost. The reduced pressure gradient in the reservoir,

near the wellbore associated with the long completion intervals, reduced the water-coning and eventually production cost.

(#116597) Sedimentation framework and tectonostratigraphic development of the Muglad Basin Sudan

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The Muglad Basin, located in southwest Sudan, forma a major part of the Sudan Rift System, which in turn, is a main component of West and Central African Rift System . The rift started to develop during the Late Jurassic and Early Cretaceous times. This intra-continental rift system evolved through a three-phased tectonic history spanning Berriasian to Cenomanian, Coniacian to Maastrichtian and Paleocene to Pliocene. The sediments in the Muglad rift basin consist of Lower Cretaceous to Upper Tertiary non-marine cyclic sequences of lacustrine and fluvial/alluvial facies and directly rest upon the Proterozoic basement. Concentrating on the first rift cycle, this study reviews the sedimentation framework as a function of subsidence and thermal contraction. The database is mainly from proprietary exploration work consisting of 2-D and 3-D seismic data, well logs, core and borehole image logs. The Abu Gabra Formation is a typical argillaceous facies dominated by cycles of lacustrine shale prograding to deltaic sands. This lacustrine shale provides good hydrocarbon source rock while the deltaic sand proved to be a good quality reservoir. This cyclicity could be due to the fact that accommodation space was created by rift pulses rather than through continuous subsidence. After the cessation of rifting, thermal contraction probably occurred and created accommodation space, which was then gradually filled by the Bentiu Formation, consisting mainly of arenaceous fluvial sequences. These sands represent main reservoir units in the basin. Seismic data, logs and borehole image logs show a clear angular unconformity between Abu Gabra and Bentiu formations.

(#118965) Facies analysis and depositional environment of the Upper Devonian Geirud Formation in the Tuyeh area, eastern Alborz Mountains, northern Iran

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The Upper Devonian Geirud Formation is a mixed carbonate and siliciclastic succession in the Alborz Mountains of northern Iran. It was deposited on the passive Paleo-Tethys margin of northern Gondwana. It is over 250 m thick and is bounded by the post-Lower Ordovician and the basal Carboniferous unconformities. Facies analysis of the Geirud Formation in the Tuyeh and adjoining areas of eastern Alborz recognized various clastic, mixed carbonate-clastic, carbonate and storm facies related to a ramp platform setting. The clastic facies comprise inter-bedded sandstone and shale demonstrating fining upward (fluvial) and coarsening upward (deltaic/shoreface) cycles. Cross- lamination/cross-bedding and hummocky cross-stratifications have been recognized in the deltaic and shoreface environments. Mixed carbonate-clastic shoal facies consist of cross-bedded sandy echinoderm bioclast grainstone and fossiliferous subarkose. Carbonate facies comprise girvanella bioclast grainstone (inter-tidal), gastropod/foraminifer mudstone to packstone (lagoon), echinoderm/brachiopod grainstone (barrier) and bioturbated fossiliferous mudstone to packstone (open marine). The carbonate and mixed clastic-carbonate facies are arranged into meter-scale shallowing upward cycles. Both clastic and carbonate storm deposits related to delta/shoreface, lagoon, barrier, proximal open-marine and distal open-marine environments were recognized. The storm facies fine upwards and are characterized by the presence of basal erosional surface, hummocky cross-stratification, intraformational conglomerates and mixed component of various facies.

(#124762) From planting the seeds to harvesting the crop

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As the world's largest petroleum company (in terms of proven reserves and production), Saudi Aramco, is acutely aware of the current shortage in specialists in such fields as geology and geophysics. By 2010, the exploration and production industry is estimated to have a 38% shortfall of engineers and geoscientists if no action is taken to fill the gap. This presentation demonstrates how the Exploration Organization of Saudi Aramco focuses on developing geoscientists to meet the present and future demands for geoscientists. To implement Saudi Aramco's strategy, the company has established a multi-phase process. This begins with the *College Degree Program* (CDP), a company-wide educational program offering college degree scholarships in a variety of selected specialities. The aim of the CDP program is to introduce the participants, as early as possible, to critical technologies. Under this program the Exploration Organization sponsors a number of carefully selected Saudi Arabian high-school graduates who want to pursue undergraduate degrees in Geology or Geophysics. Exploration nurtures these young candidates through their undergraduate studies and provides them with the guidance necessary to ensure their success.

The organization's role does not end with graduation. To maintain the technical quality of the professionals, these graduates are carefully developed through a series of well-planned programs over a 10 to 12 year span. They attend targeted technical courses during this time, and also participate in directed projects and assignments. The main advantage of these programs is that they ensure alignment of the professional's individual development and the organization's business requirements. The most

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prominent programs are the *Professional Development Program* (PDP) and the *Specialist Development Program* (SDP). The PDP develops newly graduated professionals. This on-the-job training program provides them hands-on training in all the organization's departments, which complements their graduate studies. The SDP provides more specific and focused career paths supplemented by the guidance of a mentor. The professional becomes a specialist in one of the geosciences. We have established that this initial investment in selection, education, screening and hiring of candidates, along with focused training and mentoring, returns high dividends. This phase of planning for the future was started in the 1990s. We are now reaping the rewards of this foresight. While many companies are facing recruitment problems, our Technical Development Programs have provided the organization with the critical manpower needed to ensure Saudi Aramco's position as the leader in the Oil & Gas industry.

(#118941) Valanginian-Turonian second-order sequences from the southern Tethys and their exploration significance

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The Valanginian-Turonian stratigraphic sequences described from Arabia by Sharland et al. (2001, 2004) can be grouped into two second-order sequences recognisable in successions from Morocco to Yemen. The analysis of sequences from outside the Arabian Plate has improved the biostratigraphic resolution with which the sequences can be dated and correlated, whilst improvements have also been made to the criteria used for the physical placement of the surfaces in any given succession. Within both sequences the second-order MFS is coincident with an Oceanic Anoxic Event – a time of enhanced production and preservation of organic carbon. Early Aptian MFS K80 calibrates to OAE1a, whilst basal Turonian MFS K140 calibrates to OAE2. Where these MFS occur in intra-shelf basins, they are linked to locally important source rocks - intra-Shu'aiba in the United Arab Emirates, Oman and Iran (K80); Natih B (Oman), Bahloul (Tunisia) (K140). Key second-order sequence boundaries occur in the Early Valanginian (K40 SB) and latest Aptian (K90 SB). Biostratigraphic calibration of these boundaries from correlative conformity locations demonstrates that they are also present in basins across the globe. They must therefore be primarily eustatic in origin. However, across the southern Tethys these sequence boundaries were also tectonically enhanced (primarily in response to increases in Atlantic spreading rates). This drove pronounced clastic sediment supply from the shield and the consequential presence of clastic reservoirs, associated with the lowstand and transgressive systems tracts, overlying these sequence boundaries. Source rocks may

also have developed because of freshwater overhang in front of the deltas so formed.

(#117608) AVO inversion for Lame's parameters in a VTI medium and its applications in reservoir characterization

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Seismic attribute analysis is a powerful tool in reservoir characterization, seismic interpretation, monitoring and simulation of hydrocarbon reservoirs. Seismic attributes can be used to map geological features, reservoir properties and to interpret depositional environments. Goodway et al. (1997) were the first authors to show how to extract Lame's parameters (lambda and μ) using attributes that are estimated from pre-stack seismic data. Amplitude-versus-offset (AVO) inversion for Lame's parameters provides additional insights in complex geological settings. Conventional methods for extracting Lame's parameters consider relations between changes in seismic amplitude and the offsets of the source and receiver. These methods, however, are only effective in an isotropic medium. On the other hand, the properties of anisotropic rocks are important for seismic imaging, seismic interpretation and reservoir characterization. They also affect the quality of pre-stack seismic analysis, amplitude analysis, velocity analysis, and rock-property inversion. In this presentation, we introduce a formula for extracting Lame's parameters in a VTI medium. We show the application of the inversion method to this formula for extracting reflection coefficients of P- and S-wave velocities in a VTI medium. Finally, we show the application of this method to a carbonate reservoir in southwest Iran. Results of this research indicate that if anisotropy parameters are used in steps while extracting lambda and μ, we can distinguish between reservoir zones with different lithology and fluid content.

(#123690) Mapping the Upper Shu'aiba in northern Oman: How to get the best out of difficult seismic data and specifically how to pick the formation top and identify the presence of good reservoir?

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The Upper Shu'aiba stratigraphic play is being pursued in the northern part of Petroleum Development Oman's (PDO) Block 6 (Petroleum Development Oman). To date, three fields have been discovered and our understanding of the play and its seismic expression has progressed significantly. The area is mostly covered by 3-D data of poor to medium quality, characterised by the pervasive presence of inter-bed multiples. Furthermore, when good reservoir subcrops the Nahr Umr regional shale, there is

no impedance contrast and the expected Top Shu'aiba hard-kick will actually be Base Reservoir. The Bab Basin is a shallow basin with limited accommodation space showing progradation of low-angle clinoforms, alternating clean carbonate and argillaceous units. The targeted reservoir units generally consist in proximal, high-energy shoal/build-up facies. A regional high-resolution sequence stratigraphic model shows progradational infill of the basin from its respective margins. The combined seismic response of successive inclined units may cause a tuning effect. In these cases some weak clinoform geometries may be seen on vertical sections and tuning bands appear on amplitude maps in spectral decomposition seismic volumes. The seismic approach is coupled with building and updating the sequence based Petrel™ 3-D geological model. This integration has become an essential part of our exploration process. Finally, we increase the value of the seismic data from reprocessing (multiple attenuation and velocity picking) and sparse-spike inversion. Also our current acquisition of new higher fold 3-D data and better sampling of the near-surface should contribute to improved imaging of the reservoir units.

(#119609) Sequence stratigraphy and depositional history of the Eocene-Miocene carbonates and evaporites in the subsurface of the northern Mesopotamian Basin, northeast Iraq

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Our integrated study of plankton biostratigraphy, petrography, Sr87/Sr86 age dating, and well-log correlation for IPC wells is leading to a new, unified sequence-stratigraphic framework and a revised depositional history for the Middle Eocene to Lower Miocene in northeast Iraq. Subaerial-exposure and flooding surfaces define progradational shelf-margin sequences in the Upper-Middle Eocene limestones of the Avanah and Pila Spi formations. The shelf margins become steeper towards the top, reflecting increasing accommodation in the basin. Time-equivalent basinal carbonates of the Jaddala Formation have flooding surfaces and interpreted hardground surfaces that define parasequences that are uniform in thickness. Two sets of progradational shelfal to shelf-margin limestones of the Oligocene Kirkuk Group pass laterally into basinal globigerinid limestones. Tops of shelfal sequences were subaerially exposed and eroded, and the prograding shelf margins again become steeper towards the top. The Ibrahim Formation is time-equivalent to the Tarjil Formation and part of the Palani Formation and in places to the upper part of the Jaddala. The Anah and Azkand formations are approximately time-equivalent to the Bajawan and Baba formations. The Serikagni Formation consists of many parasequences of basinal carbonates defined by regional flooding surfaces and is Chattian. It is over-

lain by the Euphrates Formation, a shelfal deposit with multiple higher-order cycles bounded by subaerial-exposure surfaces and anhydrites. The overlying Dhiban Formation consists of basin-filling anhydrite and argillaceous-limestone beds. The anhydrites are dated to 21.0–22.2 Ma, placing the Euphrates and Dhiban formations within the late-Aquitanian lowstand. The overlying Jeribe Formation consists of shelfal limestones of the Late-Aquitanian HST and the basal-Burdigalian sequence, which are separated by a regional subaerial-exposure surface. Shoaling-upward parasequences stack aggradationally and lap onto the margins of the basin.

(#124013) Subduction-related deformation processes in the Makran accretionary prism, offshore Iran

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The Makran accretionary prism is regarded as one of the most extensive subduction complexes on Earth. It provides an ideal example of an accretionary prism to study processes related to subduction at plate boundaries, such as frontal accretion and sediment underplating-underthrusting. The rear portion of the wedge is uplifted and extended by normal faulting and ductile flow. Spectacular shale diapirs and mud volcanoes are present all along the external part of the prism and can be seen on the regional 2-D-seismic section presented in this study. The Himalayan Turbidites sequence is the main detachment level for the imbricate fan and extensional faults of the Makran accretionary prism. It is also assumed to be the main source for rising shale diapirs and mud volcanoes along the imbricated thrusts within the wedge. Evidence of active sediment remobilization is prevalent in the mid-slope morphotectonic province of the accretionary prism. It is proposed that the initiation of diapirism appears to be spatially coincident with the onset of underplating processes in the rear portion of the prism. The rapid uplift of the prism and the onset of extensional faults favour the extrusion of overpressured sediments and fluids/gas along thrust faults on the seaward side of the prism. The extensional faults above the deep zone of underplating have been mildly inverted, which implies there has been episodic alternation of compression and extension.

(#124001) Seismic physical modeling for the Arabian Peninsula: Laboratory set-up and early results

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Mohammed Alfaraj (Saudi Aramco)

The geology of Saudi Arabia is covered by variable and complex overburden, which makes it difficult to image subsurface reservoirs in some areas. Therefore, novel processing and data acquisition methods need to be devel-

oped that yield improvements to seismic images, while maintaining a cost-effective approach. Constructing scaled physical models, with the expected geological and geophysical characteristics of the problem areas, provides a low-cost means for testing and evaluating different seismic acquisition and processing techniques. In 2006, Saudi Aramco commissioned the building of a physical modeling system in order to develop a capability to simulate the seismic data acquisition in various oil field and exploration target areas. This, in turn, would allow the data, acquired with an emphasis on representing a complex overburden, to be processed with knowledge of ground-truth geology and geophysics. The system uses ultrasonic sources and receivers to simulate seismic data acquisition. The modeling system can record 16 receiver channels and is probably the most advanced automated recording system in the world. Land surveys are simulated by the receivers being in direct contact with the surface so that statics and other near-surface anomalies can be investigated. Marine surveys are simulated by adding water and moving submerged sources and receivers above the model. It is capable of simulating a wide range of vibrator and explosive source signatures with any receiver array configuration. Conventional 2-D, 3-D, 3C, walk-away VSP, cross-well tomography, and micro-seismicity can all be simulated. This presentation will discuss the unique recording capabilities offered by this physical modeling system, and review data recorded to simulate seismic acquisition conditions over a typical Arabian Peninsula subsurface geology overlain by a complex overburden.

(#125563) The Saudi Aramco Technology Test Site

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Saudi Aramco's EXPEC-ARC (Advanced Research Center) has spearheaded the establishment of the *Saudi Aramco Technology Test Site (TTS)* for developing new engineering and geoscience technology. The TTS will facilitate the development and early deployment of technology, which will help Saudi Aramco increase recovery factors, increase exploration discovery rates and reduce costs. The primary purpose of this site is to provide the facilities to test new data acquisition methodologies and equipment in an actual operational oil field environment. The test site is a 5 x 10 km area within the central portion of a giant producing oil field. The initial set up of the site will include a vertical test well completed in the Arab-D Reservoir, and four shallower geophysical boreholes. A comprehensive set of data will be acquired to fully characterize the test site for calibration of all future tests. These data will include the most complete set of cores and well logs ever collected in a single well in Saudi Arabia.

The testing and research program at the TTS will include development and calibration of new exploration and production logging tools, as well as development of surface technologies, and surface to borehole technologies. Many of the projects will be cooperative efforts between Saudi Aramco and industry service companies and academic institutions.

(#123296) Refining the carbonate paradigm for revamping mature oil fields: Integration of regional-scale and high-resolution stratigraphy in the Upper Cretaceous Natih Formation, Oman

Carine Grélaud (Bordeaux University, France <carinegrelaud@yahoo.fr>), Philippe Razin (Bordeaux University, France), Peter Homewood (Oman Geo-Consultants, France), Henk Droste (Shell, Oman), Anne Schwab (Aberdeen University, UK) and Volker Vahrenkamp (PDO)

Seismic stratigraphy is commonly used by industry, at regional scales, to identify and define plays and targets. This study combines a high-resolution sequence stratigraphic study carried out by fieldwork on outcrop, together with seismic forward modelling of both regional scale features and discrete geobodies, and the iteration with high-resolution 3-D industry seismic covering areas adjacent to the outcrops. The resulting high-resolution seismic stratigraphic and sequence stratigraphic interpretations of a targeted field lying further away were significantly enhanced by the general regional model. Iteration between 3-D seismic, cored wells, outcrops and forward modelling has clarified the packaging of strata, or architectural elements, at different scales. Individual geobodies, at the scale of geomorphic units such as channels or carbonate shoals, may be resolved on attribute maps but are generally sub-seismic in scale. A larger-scale grouping of strata, architectural elements, here named "depositional assemblages", is defined by both clinoform geometries and by seismic stratigraphic context. Facies associations of such units, identified from cored wells, proved to be significantly different, defining assemblage-specific depositional systems. The combination of high resolution sequence stratigraphy from outcrop studies, with the analysis of corresponding 3-D seismic and with forward seismic modelling provides a significantly more detailed geological model upon which to base the static reservoir models required to assess the re-engineering potential of a mature giant field.

(#119068) Low-frequency hydrocarbon microtremors: Case studies around the world

Robert M. Habiger (Spectraseis, Switzerland <rob.habiger@spectraseis.com>), Erik Saenger (Geologisches Institut, Switzerland) and Stefan Schmalholz (Geologisches Institut, Switzerland)

A growing number of surveys at different oil and gas fields throughout the world have established the presence of hydrocarbon microtremors with a high degree

of correlation to the proven location of these reservoirs. These tremors can be used as a direct hydrocarbon indicator for the optimization of borehole placement during exploration, appraisal and production. The ever-present seismic background noise of the Earth acts as the driving force for the generation of hydrocarbon indicating signals. In contrast to conventional 2-D and 3-D seismic technologies, the investigation of hydrocarbon microtremors may be entirely passive not requiring artificial seismic excitation sources. The results of several surveys over gas and oil fields in different countries are presented. Data were acquired using ultra-sensitive, portable 3-component broadband seismometers with various survey designs. The raw data was processed in multiple steps. Data processing included removing or attenuating signals that are not related to subsurface structures (mainly surface noise generated by road traffic, industrial activities, wind and rain) and correcting the dataset for temporal and near-surface geology-related variations. Finally, maps of different seismic attributes were integrated to form a hydrocarbon potential map. The results are compared with known information of the reservoir (geological model including reservoir depth, drainage area of producing wells and information from borehole measurements). A systematic analysis allows determining reservoir-specific characteristics of hydrocarbon microtremors occurring around the world.

(#118938) Feasibility study of steam injection in one of Iranian naturally fractured heavy-oil fields

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Steam injection in naturally fractured heavy-oil reservoirs provides an extremely challenging problem but also a potentially effective and efficient improved-oil-recovery method. Coupling of the two distinct and contrasting matrix and fracture systems results in a highly non-linear problem, which becomes even more complicated due to the steep changes in fluid properties caused by the thermal effects of steam injection. Modeling and designing an optimum steam-injection operation in such systems requires an accurate characterization and representation of a naturally fractured heavy-oil reservoir and steam injection operation parameters and dynamics. This study focused on an undeveloped Iranian fractured heavy-oil field. A thermal dual-porosity model was developed for a sector of this field, and some sensitivity analysis tests were performed. A comprehensive and comparative study was conducted in order to understand the relative effects of naturally fractured heavy-oil system and injection operation properties on the oil-recovery performance. This work showed that steam injection could take oil recovery from zero to about 17%, and therefore would qualify for producing this field. The results indicated the importance of grid-block size, injection rates, temperature and quality of injections on the simulation

process. The study should help us to design the optimal recovery operation and pressure-maintenance program. It also determines the confidence level for an oil-recovery operation in this field using steam injection.

(#117995) Novel-liner system improves coring performance, rig safety and wellsite processing

Larry M. Hall (INTEQ, Baker Hughes, UAE <larry.hall@inteq.com>) and Bob T. Wilson (INTEQ, Baker Hughes, UAE)

A one-piece aluminum inner barrel liner system has been employed to protect and containerize core material during coring operations with conventional and wireline core barrels. The system offered enhanced safety features and improved core handling on the rig floor. The integral one-piece liners securely containerized the core during acquisition and prevented jamming, leading to increased core recovery when compared to other liner systems. Vent holes allowed expelled gas to escape during recovery to the surface, improving safety during core retrieval and handling. The companion *non-rotating inner tube stabilizer* system eased separation of the 30-ft liner joints, thus improving wellsite handling procedures and safety during extended core runs. The design allowed the liners to be opened quickly and easily at the surface for rapid examination and sampling of the core material. Case history data from Arabian Gulf wells are presented.

(#119053) Modern seismic imaging of a vintage 3-D seismic survey offshore northern Emirates

Michael A. Hall (GX, Canada <mhall@gxt.com>), Svetlana Bidikhova (GX, Canada) and John Faragher (GX, USA)

This presentation covers the issues involved in the pre-stack imaging of a vintage offshore 3-D dataset and preparing it for modern processing technologies. The spatial sampling of 3-D seismic surveys was considerably more coarse two decades ago than it is today. Within the survey is a substantial gap in short offsets due to the under-shooting of platforms. This paucity of acquired data creates problems for pre-stack migration, especially around the under-shoot areas. The data acquisition used an analogue streamer resulting in strong variations in sensitivity between hydrophone groups. The data suffered from several issues relating not only to acquisition but to transcription and this presentation will address how these were satisfactorily dealt with. Common to this part of the Arabian Gulf is a guided wave noise train that obscures reflections on the longer offsets. An effective attenuation of this unwanted noise is presented that preserves the desired signal and allows the inclusion of longer offset data into the stack. This region is also renowned for severe multiple reflection problems both from the water layer and from strongly reflecting inter-

faces in the Earth itself. A new approach will be shown to attenuating both surface related and inter-bed multiple reflection energy. Well data and geological information were carefully integrated in the construction of the velocity model to yield improved imaging of the primary reflection data. Comparisons will be made for pre-stack time migration using the sparsely recorded data only against interpolating and regularizing this data prior to migration.

(#114633) CHFR can better monitor gas sand pay zones hydrocarbon potential

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The ability to detect and evaluate bypassed hydrocarbon and track fluid movement in sandstone reservoir is vital in the quest to improve production and increase recovery. The main technique, which has been used for monitoring reservoir saturations, is the *thermal decay time* (TDT) tool. However it is difficult to interpret the TDT data in reservoirs with low-salinity formation water. This problem cannot be solved because TDT measurements depend on the salt content in formation brine. Instead the *cased hole formation resistivity* tool (CHFR) is proposed to overcome many of the limitations associated with pulsed-neutron tools. This presentation compares the results of reservoir-saturation monitoring obtained from TDT and CHFR logs recorded in wells in an oil field in the Sinai Peninsula, Egypt. The results are referenced to open-hole resistivity logs. It was found that water saturations calculated from CHFR logs are more accurate than TDT log in most cases. Moreover, when a quick decision is required the initial interpretation of CHFR logs always agreed with its quantitative interpretation. In contrast the quick interpretation at TDT log was generally found to be very difficult, and not to agree with its quantitative interpretation.

(#115935) Implications of lineaments trends from Ghawar field and adjacent areas

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Lineaments traced from satellite images (scale 1:250,000, band 7) over the giant Ghawar field and adjacent areas indicated major trends of N55°W and N35°E, and minor and lesser trends of N15°E, N5°W, and N35°W. The total number of traced lineaments was 413 with variable lengths of 2 to 5 km. The major N55°W and minor N35°W, N25°W and N45°W trends are generally coincident with the NW-trending high-angle wrench faults that cut the older Paleozoic and basement rocks (Najd Fault System). The major and minor NW and major NE (N35°E) trends may also be related to structures formed by the Zagros stress regime, which acted in the NE-SW direction during Early Tertiary and continues at present. The Zagros stress regime may also have partially caused and/or enhanced structures trending N15°W and N5°W. Those northerly trends are also parallel to the major faults system present within the Precambrian Shield. The general trend of the Ghawar field also follows this general northerly trend. Minor N65°–75°E and N65°W trends may be related to structural features formed by the Oman stress regime (acted in E-W direction during Paleozoic and Mesozoic times).

(#122826) Enhanced seismic interpretation using multiple seismic volumes over an offshore field, Abu Dhabi, United Arab Emirates

Christopher E. Harris (ExxonMobil, USA <christopher. e.harris@exxonmobil.com>), Mary K. Johns (ExxonMobil, USA), Joe M. Reilly (ExxonMobil, USA), Gregg A. Zelewski (ExxonMobil, USA), Andy M. Gombos (ExxonMobil, USA), Zygmunt J. Shevchek (ZADCO) and Naeema Khouri (ZADCO)

New seismic data reprocessing has improved seismic interpretations for a major Middle East offshore oil field. Significant new fault patterns have been identified within a Kharaib carbonate reservoir using multiple seismic volumes. These were generated from post-stack reprocessing of a full-field 1,500 square km data volume and full reprocessing from field tape of a crestal 200 square km data set. The new fault framework will be incorporated into geologic models for simulation modeling that will help drive the development plan for the field. The full-field post-stack reprocessing flow was designed to reduce noise, thereby enhancing stratigraphic detail and fault definition. Near-, mid-, far-, and full-stacks, spectral whitening and spectral decomposed data show different degrees of resolution. The full reprocessing from field tape used a processing flow that was specifically designed to address severe water-bottom energy surface noise and variable short-period reverberatory multiples. It used separate processing flows for hydrophone and geophone data. Noise reduction from the reprocessing allowed consistent and efficient automated horizon picking. The interpretation approach included the generation of new horizons and a disciplined approach to fault identification using multiple volumes and attributes. From the new data, automated horizons were picked, which led to better identification of small faults using horizon-based attributes. The new data allowed us to identify pervasive NE-SW and N-S faults in parts of the field and to subdivide major faults into smaller faults at different stratigraphic levels. These encouraging results motivated us to plan full-field full reprocessing from field tape.

(#123987) A method to determine acquisition equivalency

Richard Hastings-James (WesternGeco, UAE <richard@dubai.westerngeco.slb.com>) and Peter van Baaren (WesternGeco, UAE <baaren@dubai. westerngeco.slb.com>)

Often a choice must be made between different acquisition schemes when designing a seismic survey. Therefore it is of interest to quantitatively compare designs in terms of the quality of data that they will produce. Such a comparison is necessarily complex, and involves many considerations that are target-specific, including data azimuth and offset distribution. However, there are certain attributes that can be calculated that are largely target-independent, and which are of fundamental importance to data quality, resolution, and final image quality. These attributes include signal bandwidth and signal-to-noise ratio. In this presentation we calculate on the basis of acquisition geometry, field effort and local conditions the signal bandwidth and signal-to-noise ratio of the acquired data, including the effects random and coherent noise. Conditions for equivalency between two crews of differing configurations are presented. Equivalency in effect permits the direct substitution of a crew of one configuration by the other crew of a different configuration with no change to signal-to-noise ratio and bandwidth. In particular this analysis permits a direct quantitative comparison between single-sensor and conventional acquisition.

(#119066) Accelerating development of geoscientists and applications engineers using competency mapping and certification processes

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Due to rapid growth, major workforce age gaps, and a large workforce population nearing retirement, traditional formal training programs that stretch over years of personal development are no longer effective. Training alone doesn't ensure competency. New methods that combine mentoring and targeted competency development are needed to drive personal development and effectively transfer skill and knowledge from senior to the recently hired or inexperienced workforce. A formal program has been developed utilizing competency mapping and a certification process that provides clear direction for self and guided development of internal Geoscientists and Applications Engineers. This program is designed to accelerate development in areas of company core competencies, guide and align career path expectations with personal development and act as a retention mechanism for senior geoscientists by broadening technical career opportunities. The program consists of a competency map, a list of core competencies and skills that define the competency map, a formal certification process and tracking system that ensures the Geoscientist meets or exceeds the requirement for each core competency, and guidance counselors (mentors) who oversee the Geoscientist through the entire certification process. Nine standard geoscience certifications and six advanced geoscience certifications are offered in areas of *Geology, Geophysics, Geomechanics, Formation Evaluation and Petrophysics, Reservoir Navigation, Integrated Pressure Management, Wellbore Integrity, Completions and Production, and Reservoir Engineering*. The program is flexible and efficient. It fosters personalized development plans through engagement between mentors and candidates and ensures learning and development specifically targets areas where skill gaps exist. It also provides an essential tie between competency development, required peripheral training and the Geoscience and Applications engineering career ladder.

(#117969) Cablefree land acquisition technologies: Choices, benefits and case studies

Robert G. Heath (Ascend Geo, USA <rgheath@ btconnect.com>) and William Ayres (Ayres Group, UAE)

Internationally, a growing section of the oil industry acknowledges that cable-free land seismic systems are here to stay. Such technology economically answers the demand for improved HSE exposure and massively increased channel counts for better geophysical imaging, especially of mature fields. However, for viable operations with 15–50,000 live channels, it is imperative to review what can be expected from the latest hardware. This study researches cable-free recording, while looking at new approaches to acquisition, both active and passive. It offers an appraisal of the benefits of this new approach, especially as it applies to the challenges affecting the Middle East. We demonstrate that planning surveys and operating cable-free systems offer opportunities to implement new approaches and methodologies which make the most of what this new technology has to offer. With this knowledge, we can plan to use its advantages for maximum effect, and increase competition in the market. Results will be presented, including data acquired with cable-free hardware and case studies of systems used internationally in real field conditions. Knowledge and experience of the cable-free's pros and cons are growing. Some experts predict that more than half the channels sold by 2010 will be cable-free. We offer real data presentations and recommendations of the way forward for active and permanent (4-D) recording. We conclude that the cable-free approach to, land exploration geophysics opens up new possibilities for making progress in all of these areas.

(#118892) Geothermal gradient study of Asmari Formation in Dezful Embayment, Zagros, Iran

Mohammad H. Heidarifard (NIOC, Iran <heidarifard1344@yahoo.com>), Mohammad Seraj, II (NIOC, Iran), Masoud Shayesteh (NIOC, Iran) and Hormoz Ghalavand (NIOC, Iran)

This study was focused on determining the geothermal gradient of the Oligocene-Miocene Asmari Reservoir in the Dezful Embayment, Iran. It involved preparing an isothemal map of the reservoir, recognition of a temperature anomaly zone and the study of related parameters,

such as Ro and TTI. The geothermal gradient of the Asmari Reservoir and mean geothermal gradient (average slope between the temperature at the surface and the top of Pabdeh Formation) were determined in 180 wells from different oil fields. The results were checked by geochemical analysis (Tmax) and oil-generation modeling. The study showed that the geothermal gradient in the Agha Jari, Haft Kel, Masjid-e-Suleyman and Naft-Safid fields is greater than in other fields. The results suggested considerable differences in the geothermal gradient between wells in the same field; for example in Marun, Pazanan and the above-noted fields. Variations in the geothermal gradient between wells, implies that their source rocks should show different maturations. For example geochemical studies of Marun and Pazanan fields suggested that the source rock is more mature in wells MN-123 than MN-222 and PZ-23 than PZ-117. Moreover the Oleanane biomarker was found in the oils from these fields. Studies also detected a relationship between an anomalous temperature zone (high gradient) and a paleohigh in the Zagros Basin. Based on a structural study, the boundaries of the paleohigh are correlated to basement lineaments. Investigations further confirm that faults are one of the important factors that produce greater geothermal gradients. Thus by integrating the results of the geochemical and structural studies we found that: (1) the geothermal gradient can vary in oil fields or in wells in the same field. (2) These variations are strongly controlled by basement lineaments, which increase the geothermal gradient. In turn the greater gradient leads to higher maturation (oil generation) of the Pabdeh Formation as confirmed by the Oleanane biomarker. (3) In the high-gradient zone, the oil-production rate is higher than in other zones.

(#118972) Uncertainty assessment and risk analysis for a future field development phase in a carbonate reservoir, onshore Abu Dhabi, United Arab Emirates

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Quantifying, ranking and weighting of reservoir uncertainties based on several variables can be a real challenge for volumetric estimation. This is because the variables are related to many parameters such as tool measurements, seismic processing, velocity modeling, petrophysical evaluation, geological interpretation, modeling parameters, saturation functions among others. The oil field potential assessment in the current study was based on the first phase of a development drilling campaign and recent appraisal drilling over a less controlled area in shallow waters. A stochastic uncertainty analysis, using the JACTA (Gocad^{TM} plug-ins) software, allowed a decision on the location of the latest appraisal well and an inference on the further development phase scheme for the field. The study included vertical, deviated and

horizontal wells within Phase I and new development phase areas. A large number of simulations revealed a statistical distribution of the reservoir volumes and its connectivity. In general, the major uncertainties are from three main categories: structural, petrophysical and fluid parameters. The inter-dependence among parameters was properly captured during the uncertainty workflow. The different realizations from the static model (P90, P50 and P10) were upscaled to fit the dynamic model grid-size limitations. The upscaled models along with the other dynamic data from the fluid properties (pressure, volume and temperature data), special core analysis, well completion and production/injection data were used to build the dynamic simulation models. The P50 model was then initially tested and history-matched before using it to forecast the different development scenarios to select the most viable option against the P90 and P10 models.

(#118931) Depositional setting of Cretaceous Reservoirs, southern Yemen and northern Somalia

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The Say'un-Al Masila Basin of southern Yemen and the Al Mado Basin of northern Somalia are Mesozoic sedimentary basins developed during the disintegration of Gondwana. The two basins formed one single rift (Say'un-Al Mado Graben) with intermittent tectonic disturbances, which affected the carbonate-clastic basin-fill architecture. The Cretaceous Say'un-Al Mado graben had a funnel shape in plan view, tapering northwestward (in Yemen) and open southeastward (through northern Somalia) to the Tethys Ocean. The Cretaceous fill of the Say'un–Al Mado rift consists of siliciclastic sequences predominant in the western flanks of the basin (Tawila Group in Yemen and Yesomma Formation in northern Somalia), and carbonate sequences predominant in the southeastern areas (Mahra Group and Tisje Formation, respectively). The sandstones of the Tawila Group (Qishn and Harshiyat formations) and the Yesomma Formation were deposited in a complex system of braided to low sinuosity meandering rivers, tidal-dominated estuarine and deltaic environments. The terrigenous influx decreased southeastward where carbonate sedimentation flourished in a shallow-marine environment (Mahra Group in Yemen and Tisje Formation in northern Somalia). Carbonate sand shoals, lagoonal wackestones, mudstones and rudistic buildups are the main lithofacies of the carbonate strata. The Qishn Formation is highly porous (18 to 23%) and permeable (up to ten darcies) and contains estimated reserves of over one billion barrels of recoverable oil. Unlike the relatively strong hydrocarbon exploration activity in Yemen, Somalia's hydrocarbon resources are under-explored. However, the little geological knowledge from the Yesomma and Tisje formations implies they contain good reservoir intervals (up to 300 m thick and 14% porosity) with interbeds of source

shales. Many of the drilled wells contain oil stains and gas shows. Maturity of these hydrocarbons ranges from immature to post-mature with good intervals within the oil window.

(#115102) Paleomagnetic study of Upper Cretaceous-Lower Tertiary rocks in northeastern Iraq

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The following rock units in northeastern Iraq were sampled for a paleomagnetic study: (1) Paleocene-Lower Eocene Naoprdan Limestone Formation at Chwarta and Zainal, (2) Maastrichtian Aqra Limestone Formation at Maukaba and Zardabe, (3) Valanginian-Turonian Balambo Limestone Formation at Azmar locality and igneous gabbros intrusions at Kanaroe and Waraz. Twelve hand samples and 200 oriented drilled cores were collected from these localities. The remnant magnetization (NRM) was measured using a spinner magnetometer (Baghdad University) and the cryogenic magnetometer (Oklahoma University, USA). The remnant magnetization in the Aqra Formation is of a depositional origin and carried by a detrital magnetite grains. In other localities (Chwarta, Zainal, Azmar, Kanaroe and Waraz), secondary haematite or maghemite is dominant. The rocks of the Chwarta, Zainal, Azmar, Kanaroe and Waraz localities are not good indicators for the paleomagnetic direction. Results from Maukaba and Zardabe rocks (Aqra Limestone) provided reliable paleomagnetic results. These rocks showed reverse paleomagnetic directions. All computed virtual geomagnetic poles (VGP) correspond to a reverse polarity, and the overall mean VGPs position of the Maukaba locality is paleo-latitude (Plat) of 44.4° S and paleo-longitude (Plong) of 279°, and for Zardabe locality (Plat = 57.1° S, Plong = 235°) with co-latitude (-14°) and (-13.9°). Accordingly, the paleo-latitude of the Maastrichtian Aqra Limestone basin was between 13.9° and 14° N. This suggests that the Neo-Tethys Ocean was located to the north and northeast of northeastern Iraq during the Maastrichtian time. The closure of this ocean occurred between the Maastrichtian and Early Tertiary. The paleo-position of the Aqra Limestone basin clearly suggests that the northern part of Iraq was still in warm environmental conditions during Maastrichtian times. This means that the oil accumulation can be found in rocks of ages for Maastrichtian and older than Maastrichtian.

(#117248) Mesozoic to Recent structural evolution of the eastern Rub' Al-Khali, Saudi Arabia

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Two main structural trends are evident in the eastern Rub' Al-Khali Basin: a NNE trend, similar to the dominant structural trend in the United Arab Emirates; and a NS trend, similar to the one observed in the major oil fields of Saudi Arabia. Understanding the interplay between these two trends and their relationship to deep-seated older basement structural components, as well as their Phanerozoic reactivation history, is critical to obtaining a robust exploration risk assessment for these structures in this area. Data used to underpin the structural analysis are regional analogue structural data, 2-D seismic data from eastern Saudi Arabia, and structural observations from core and dip-meter logs. Together with geochemical and stratigraphic analyses this has resulted in a robust kinematic model for the structural evolution of the NS-trending structures. Several phases of structural development have resulted in the present-day composite NS-trending arch-like configurations. The main phase of growth occurred during the Late Cretaceous as a result of NW-SE compression, further phases of growth were recognized during the Late Cretaceous Maastrichtian, Paleocene to Early Eocene, Mid- to Late Miocene and Pliocene times. The rotation of the stress field to a present-day ENE-WSW position for the maximum horizontal stress was recognized through observations from core and seismic data and has resulted in several phases of fracturing, including the reactivation of older fracture systems.

(#123305) Clay mineralogy of Gurpi Formation at its type section and Ziloee oil field, Dezfool Embayment, Zagros Mountains, Iran

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Studying the Tu/K ratio on NGS logs of the Gurpi Formation in well No. 8 of the Ziloee oil field, Izea zone of Zagros Province, indicated the occurrence of smectite and illite. Moreover, field studies and calcimetric analysis were conducted on samples collected from the type section of the Gurpi Formation (Dezfool Embayment of the Zagros Mountains). The samples consist of limestone, marl and shaley marl. However, X-ray diffraction (XRD) analysis of selected samples with lesser amounts of $CaCO_3$ indicated the existence of smectite, illite and chlorite. The coexistence of smectite and illite, and absence of kaolinite, in these deposits indicates temperate climatic conditions prevailed during the latest Cretaceous and Early Paleocene in the Zagros region. Moreover, semi-quantitative analysis of the XRD data identified an upward increasing trend of smectite and decreasing trend of illite and chlorite in the sedimentary column. These trends suggest a deepening upward trend in the basin as consistent with global sea-level curves. Based on the

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covariance trend of illite and chlorite and scanning electron microscope (SEM) images, we suggest a diagenetic transformation of illite to chlorite in these samples. Also the SEM images indicated a diagenetic origin for smectite, which can form during fluid exchange with maphic and detrial clay minerals (e.g. detrial smectite, illite).

(#118608) Sedimentation and high-resolution sequence stratigraphy of the Upper Cretaceous Simsima Formation, onshore Abu Dhabi oil field, United Arab Emirates

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An important carbonate oil field, located onshore Abu Dhabi, has been producing from the Upper Cretaceous (Maastrichtian) Simsima Formation since 1983. A detailed sedimentological and high-resolution sequence stratigraphic study has been carried out, integrating approximately 7,000 ft of core material, approximately 3,500 thin sections, and all available well-log data from 46 wells. Core description, together with semi-quantitative petrographic examination of thin sections, established a new depositional model for the Simsima Formation. Sixteen lithofacies types (LF1 to LF16) representing a wide variety of depositional environments, ranging from upper ramp, rudist-bioclastic shoals to open marine mid to outer ramp mud-dominated settings. The newly developed, high-resolution sequence stratigraphic framework suggested that the Simsima Formation comprises one complete third-order composite sequence and the transgressive systems tract of an overlying second third-order composite sequence. These third-order composite sequences include seventeen high-frequency, fourth-order sequences (HFS). HFS 1 to HFS 12 build the older, third-order composite sequence, HFS 13 to HFS 17 form the transgressive system tract of the overlying, younger third-order composite sequence. The fourth-order, high-frequency sequences were tied to re-processed and re-interpreted 3-D seismic data. Fourth-order sequences 1 to 6 clearly show onlap on a pre-existing high (pre-Simsima unconformity surface) whereas the top part of the Simsima Formation (sequences 13 to 17) show erosion on seismic cross-sections. The established high-resolution sequence stratigraphic framework will provide the layering scheme for the new Simsima 3-D static model, which will be used as input for reservoir flow modeling.

(#115611) Geophysical pressure prediction for ultra-deep wells: When the reservoir becomes the enemy

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In recent years, drilling requirements have become more challenging as ultra-deep wells have demonstrated that basic undercompaction models are inadequate to predict pressures in high-pressure/high-temperature (HP-HT) environments. The requirements of these wells have forced pressure prediction to adapt to environments where diagenetic processes and hydrocarbon maturation are dominant (unloaded environments), and where chemical compaction takes over from undercompaction as the dominant factor in determining rock property changes (secondary compaction environments). Adding to the complexity of the pressure prediction process is the interplay between shales and reservoir rocks. As pressure increases, the window between the formation pore pressure and fracture pressure narrows. In HP-HT environments, the lateral extent, structural position, and architecture of the reservoirs become much more critical to the viability of a prospect. They also determine the range of safe depths where a specific reservoir can be penetrated without the risk of a pressure influx that could jeopardize the drilling operation. In this setting, geopressure prediction and reservoir pressure modeling become an essential component of prospect risking. While explorationists desire large reservoir bodies in deep prospects to allow sufficient reserves to justify the high cost of an ultra-deep well, they must also recognize that large reservoir extents can also threaten the viability of the prospect. To mitigate this risk, the exploration team must use all the available information to determine the extent of the reservoir, its structural position, and its interaction with faults and other potential flow conduits. This information can then be integrated with 3-D pressure volumes to predict column heights for specific fluids and the reservoir pressures at any specific penetration point in the subsurface. The accurate prediction of the reservoir pressures at a specific penetration point can be the difference between an efficiently managed drilling operation and a potentially catastrophic pressure influx event.

(#118382) Using biofacies and lithofacies to determine palaeoenvironments and depositional cyclicity of the Sulaiy and Yamama formations of subsurface Saudi Arabia

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The Sulaiy and Yamama formations of Saudi Arabia consist of Late Jurassic (Tithonian) to Early Cretaceous (Berriasian) carbonates. Although exposed in Saudi Arabia, the Sulaiy is difficult to access and the Yamama is very poorly exposed. The Sulaiy Formation lies unconformably on evaporites of the Hith Formation at outcrop, but overlies carbonates of the Manifa Member of the Hith Formation in the subsurface. The Manifa is currently being evaluated as being genetically linked with the Sulaiy rather than its traditionally assigned Hith Formation. Micropalaeontology and sedimentology of the Sulaiy and Yamama formations in subsurface have revealed a succession of clearly defined shallowing upwards depositional cycles, of 50 ft average thickness.

These typically commence with a deep-marine biofacies within wackestones and packstones, capped with a mudstone-wackestone maximum flooding interval and an upper unit of packstone to grainstones containing shallow-marine biofacies. The upper part of the Sulaiy Formation is highstand-dominated with common grainstones that host the Lower Ratawi reservoir and is capped by karst that defines the sequence boundary. The Yamama Formation, in contrast, contains fewer grainstones, and is predominantly transgressive. Although smaller grainstone units host the Upper Ratawi reservoir, it is considered that the highstand-associated, main reservoir facies equivalent to the Lower Ratawi reservoir must have been deposited but was removed by the very extensive episode of erosion that accompanied the major sea-level fall during the Valanginian. It is tantalising to contemplate the destination of the transported highstand grainstones as they would provide excellent stratigraphically trapped pre-Buwaib reservoirs elsewhere within the basin.

(#118387) New aspects of Saudi Arabian Jurassic biostratigraphy

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Age determination of the Saudi Arabian Jurassic carbonate succession was originally based on outcrop macropalaeontology and micropalaeontology, and the essential chronostratigraphy of the formations and members was completed by 1968. It is to the credit of the earlier workers that their age assignments have been largely retained to the present-day. Subsequent biostratigraphic investigations of outcrop samples using ammonite, nautiloid, brachiopod and echinoid macrofossils refined these earlier age determinations. New ammonite and nautiloid determinations have further added to this refinement. In the subsurface, where macrofossils are rarely encountered or preserved within exploratory well samples, lithostratigraphic assignment relies heavily on lithofacies characteristics. Such methodology becomes difficult within intra-shelf basin areas where the defining shallower lithofacies are either poorly developed or absent. In such circumstances, micropalaeontological evidence is essential, with support from nannofossil and palynology. Current research is being focused on the micropalaeontological, nannofossil and palynological calibration between the exposed, macropalaeontologically dated, type or reference sections and subsurface core and cuttings samples. Of these, palynology is beginning to provide new stratigraphically useful data, including outcrop samples, where palynomorph recovery has previously been assumed to be poor and of limited value. Such an approach, using their biostratigraphic fingerprint, is proving successful to assist exploration activities by identifying formations in historical wells where lithostratigraphic units had been miss-assigned resulting in mis-correlations.

(#118384) Micropalaeontology and palaeoenvironments of the Wadi Waqb Member, Jabal Kibrit Formation, and its reservoir equivalent, Saudi Arabian Red Sea

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The Saudi Arabian Red Sea stratigraphy consists of a variety of lithologies that range from evaporites, deep- and shallow-marine siliciclastics and carbonates, biostratigraphically constrained to range from the Late Cretaceous (Campanian) to Late Pliocene. The Midyan area of the northern Red Sea offers a unique window into the Cretaceous and Miocene succession that is otherwise only present in the deep subsurface. The sediments are of hydrocarbon interest because of the presence of source rocks, siliciclastic and carbonate reservoirs. The Wadi Waqb reservoir is hosted within the Wadi Waqb Member of the Jabal Kibrit Formation, and is of Early Miocene age. This member is exposed on the east flanks of the Ifal Plain, where it is represented by a discontinuous fringing rhodolith and coral reef complex that is welded to steep cliffs of granitic basement. Exposures of the member in Wadi Waqb, located in the middle part of the Midyan region, consist of pelagic, planktonic foraminiferal dominated packstones that contain abundant shallow marine allochthonous bioclasts. These shallow-marine bioclasts are considered to have been derived from the rhodolith-coral reefs exposed to the east. The Wadi Waqb reservoir is located in the central part of the Ifal Plain, approximately midway between the *in-situ* rhodolith-coral reefs and the mixed allochthonous and authochthonous facies in Wadi Waqb. The reservoir consists of biofacies that compare well with those exposed in Wadi Waqb, and therefore testify to the presence of a deep-marine environment, in excess of 50–75 m water depth, located less than 25 km to the west of the fringing reef source of the shallow bioclasts.

(#118385) Micropalaeontology of the Saudi Arabian Rus, Dammam and Dam Formations exposed at the Dammam Dome

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The Dammam Dome represents a unique feature in Saudi Arabia as it forms a local topographic high along the otherwise flat extent of the eastern flank of the Kingdom. Its origin is attributed to episodic upwards movement of a deep-seated infra-Cambrian evaporite plug. The Rus, Dammam and Dam formations are exposed, of which their diminished thickness, relative to the adjacent subsurface, testifies to the region being regionally positive during the Tertiary. Micropalaeontological analysis with revised taxonomy of old and new exposures has improved palaeoenvironmental interpretation. The Paleocene to Early Eocene Umm er Radhuma is the lowermost Tertiary formation, but is not exposed in any accessible locations and will not be considered here. The

Rus Formation was defined on the Dammam Dome, and includes lower carbonate and upper carbonate-evaporite unit. A new exposure on the Dammam Dome provides evidence for a lowermost Rus unit consisting of inter-bedded transgressive marls and clean highstand carbonates. An Early Eocene age is assigned on stratigraphic position as microfossils are rare owing to predominantly shallow-marine, periodically hypersaline conditions. The Dammam Formation includes the Midra, Saila, Alveolina and Khobar members. The Alveolina and Khobar members contain rich and diverse benthonic foraminiferal biofacies, including Middle Eocene *Alveolina, Nummulites* and *Discocyclina* species. A new Dhahran Member is proposed for the transgressive marls between the Alveolina and Khobar highstand carbonates. The pre-Neogene angular unconformity underlies the Middle Miocene Dam Formation. The Dam Formation includes a basal stromatolite unit that is overlain by a coral and rich benthonic foraminiferal succession that contains *Borelis melo*.

(#118676) Tectonic controls on Triassic stratigraphy and hydrocarbon prospectivity in Kuwait

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The Triassic System in Kuwait comprises ramp carbonates, anhydrites and clastics deposited in supra-tidal to inter-tidal settings. The N-S trending Kuwait Arch with flanking basins (offshore Kuwait in the east and Dibdibba Trough in the west) exercised control on deposition and preservation of Triassic strata and prospectivity. The Triassic encompasses the Upper Khuff, Sudair, Jilh and Minjur formations. The Upper Khuff consists of carbonates, which grade into argillaceous dolomites in the Sudair Formation. An additional dolomudstone-prone unit, provisionally named as Kra Al Maru Formation, is preserved locally between the Sudair and Jilh formations in the Dibdibba Trough. The Jilh Formation is evaporitic, divided by intra-formational salt. The thickness of the Lower Jilh decreases over the Kuwait Arch, whereas the Upper Jilh and Minjur formations thicken to the southeast with increased clastic influx. The tectono-stratigraphic imprint represents re-activation of structural grain inherited from *Hercynian* and older tectonism. Upper Khuff, Sudair, Kra Al Maru and Lower Jilh are influenced by uplift of the Kuwait Arch. Jilh Salt represents a major interface at the onset of tectonic inversion. The Upper Jilh and Minjur formations are influenced by southeasterly slope and clastic influx from the south. The Triassic sediments over the Kuwait Arch have diagenetically degraded reservoir properties. Evaporites and dolomudstones with fracture-related reservoir development in western Kuwait and shallow- to open-marine carbonates with conventional reservoirs east of the arch are prospective. Recent exploration wells have established flow to surface of sweet gas and gas condensate from Kra Al Maru. The Minjur Formation is prospective in the south where sandstone inter-beds have improved reservoir characteristics.

(#118996) Oil below oil-water contacts: Implications on the structural evolution of Minagish Oolite Reservoir, Minagish oil field, Kuwait

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A study of the structural evolution of the Minagish oil field revealed that the trapping structure began in Early Cretaceous time as a minor dome at the SSE flank of a NW-trending Jurassic anticline. The Minagish anticline assumed the present-day motif by Maastrichtian time, gently tilted towards the NNE and was dissected by an E-W fault during Tertiary times. The fault separated two main compartments of the Minagish Oolite reservoir: an up-thrown symmetrical northern sector, and a wrenched and down-thrown asymmetrical southern sector. The incipient Minagish structure affected the thickness and deposition of the oolitic facies of the Minagish Oolite. Subsequent regional NNE tilts had a minor effect on shifting the position of superior oolitic facies in relation to present-day structural peaks of the Minagish Oolite reservoir. However, Tertiary differential displacement of the two main compartments influenced the thickness and position of the occluded tarmat layers, and preserved a record of Tertiary oil/water contacts. The structural evolution of the Minagish Oolite explains the preservation of sealing tarmats within superior oil-bearing reservoir facies above and below the present-day oil/water contact in the northern sector, and the preservation of tarmats within the relatively inferior and water-bearing facies below present-day oil/water contact in the southern sector of the Minagish Oolite reservoir. Hence, technically there appears to be producible oil sealed by tarmats below the present-day oil/water contact in the northern sector of the Minagish Oolite reservoir of Minagish oil field.

(#117424) Fault development and hydrocarbon entrapment in the Mutriba area, western Kuwait

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Mutriba is a prominent NNW-SSE trending anticline in western Kuwait with confirmed hydrocarbons at the Triassic, Jurassic and Cretaceous levels. A study was conducted to enhance fault imaging and to improve the understanding of structural architecture of this faulted anticline. The seismic data in the Mutriba area is contaminated by multiples and has poor quality and resolution. Nevertheless the application of attribute and image enhancement algorithms on 3-D seismic data successfully

mapped the faults. Additionally analytical techniques were applied to investigate the structural evolution through sequential reconstruction. Fault dislocation and formation fracture density were estimated using seismic data and geomechanical models. The Mutriba structure at pre-Cretaceous levels is dissected by two prominent fault sets trending NNW and EW. The NNW trend is older and is probably related to structural development during Paleozoic time. The younger EW trend offsets the original structural geometry so that the northern segment trends NNW and the southern trend approaches NS. The latter faults appear to have developed during the Late Jurassic and to have been re-activated during Cretaceous and Tertiary times with major uplift. These strike-slip faults cut across the older trend and have segmented the structure into a number of discrete fault blocks. The fault compartmentalization has been studied with regard to hydrocarbon entrapment. Core studies and fracture modeling suggested that the fracture network developed by these fault systems have contributed to improved migration to and within Triassic and Jurassic reservoirs. Fault compartmentalization has controlled Jurassic hydrocarbon occurrences among fault blocks. Integration of regional geological understanding, seismic and geochemical studies and geomechanical modeling has indicated areas for further exploration.

(#119020) Source rock formation and characteristics of Shiranish Formation, Euphrates Graben, Syria

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The Euphrates Graben is one of the most important petroliferous basins in Syria. One known source rock is the marine Upper Cretaceous Shiranish Formation, but no detailed information exists about its source rock potential. The aim of the investigation is to: (1) identify the variations in source rock characteristics due to changes in paleoceanography, and (2) to correlate these variations with their effect on the timing of petroleum generation. Two organic facies with different characteristics of petroleum generation were identified: Type II facies with hydrogen index (HI) values of > 350 mg HC/g TOC, and a Type II/III facies with HI values of < 350 mg HC/g TOC. Both organic facies are considered likely sources of paraffinic-naphthenic-aromatic petroleum with variable amounts of gas based on the pyrolysis gas chromatography scheme of Horsfield (1989). Bulk kinetic experiments have shown that predicted petroleum formation temperatures are closely similar within each of the facies, but different between the facies, with onset (TR 10%) temperatures of 136°C for the Type II facies and 144°C for the Type II/III facies. This corresponds to ap-

proximately 600 m difference in burial depth or delayed onset of petroleum generation by 5.75 million years for a 3.3 K/my heating rate. Facies analysis of well logs indicated that Type II/III facies of the lower Shiranish Fm. was influenced by terrestrial input of different intensity. During the Upper Shiranish Formation. a progressive deepening of the depositional environment was probably coupled to an enhanced marine paleoproductivity leading to Type II facies.

(#116589) Role of regional structural elements in the hydrocarbon prospectivity of Bahrain offshore blocks

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Bahrain Island and its offshore exploration blocks are located in the northern Gulf infra-Cambrian Hormuz Salt Basin, a prolific petroleum habitat hosting the major oil fields of the Arabian Plate. The fields are located on the rising flanks of the Qatar Arch to the east and En Nala Anticline (Ghawar-Berri high) to the west, separated by a syncline from which the hydrocarbons were sourced. Exploratory efforts in Bahrain offshore acreages were concentrated on drilling low-relief structural prospects, which gave hydrocarbon indications. Regional lineaments play a dominant role in the generation-migration-entrapment cycle. This presentation will show a conceptual *regional structural elements* model that integrates all the available data. The objective was to focus exploratory efforts on identifying fault-bounded traps as the dominant structural play in the offshore area. An integrated review of regional geology, seismic, gravity and satellite image data has brought out three dominant regional lineament trends corresponding to the NW-trending Najd strike-slip system, NE-SW Wadi Al Batin-Dibba trend and NS/NNW basement trend. These trends were reactivated during various phases in the tectonic evolution of the basin. The NE trend was active during Jurassic and the NW trend was dominant during Cretaceous. The oldest, NS-NNW basement trend was reactivated during the Late Cretaceous to Early Tertiary compressional phase resulting in the present-day structures. The predominant structural grain in the area is NS and associated with wrench tectonics analogous to the Abu Dhabi model (Marzouk an Abd El Sattar, 1995). A review of prospectivity of the offshore blocks, based on the present structural model, has brought-out many potential fault-closure traps. Finer scale mapping and fault-seal analysis are vital to establish trap integrity. The role of these trends in determining preferred flow directions in the reservoirs of the Awali field in Bahrain requires further investigation.

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(#122813) A chemistry-based expert system for determining lithology and mineralogy of carbonates

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Effective carbonate reservoir characterization and evaluation requires knowledge of the lithology and mineralogy. Dolomitization of limestone, for example, can produce secondary porosity and permeability and significantly enhance reservoir productivity, while anhydrite can cement primary porosity and lower reservoir permeability. Finely disseminated pyrite in carbonates can alter resistivity, which leads to the miscalculation of water/oil saturations. Other minerals also affect the accuracy of petrophysical interpretation and influence important rock properties (e.g. mechanical properties). Conventional logging techniques have a limited ability to characterize complex carbonate mineralogy, and thus geologists primarily rely on core and cuttings analysis to determine lithology and mineralogy. To address these limited abilities, we have developed an expert system which uses down-hole nuclear spectroscopic measurements to derive lithology and mineralogy from elemental data. The elements Ca, Fe, Si, Mg, C, S, Al and Cl from FLEX^{TM}, a new pulsed-neutron spectroscopy tool, and K, Th and U from SpectraLog II^{TM}, a natural gamma-ray spectroscopy tool, provides the input for the expert system. Our approach addresses the challenge of converting an underdetermined chemical system into a significant number of minerals by first determining the general and specific lithology thereby minimizing the number of unknown minerals. The algorithms that provide lithology and mineralogy were developed from an extensive core database containing geochemistry, lithology and mineralogy data. We discuss the FLEX^{TM} instrument interpretation algorithms and the core database, and present results from several logs to demonstrate the effectiveness of the expert system for carbonate reservoir characterization.

(#119446) Salt diapirism in the fold-thrust belt and foreland basin in the eastern Fars Province, Iran

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The Hormuz Series crop out as salt plugs in the Zagros Fold-Thrust Belt or as islands forming circular dome-shaped structures in the Persian Gulf. The 7 to 12–km-thick sedimentary cover is decoupled from its basement by the Hormuz Salt layer and deformed by large-scale folding and thrusting that started in the Miocene Epoch. Recent emergent diapirs occur above the crests of pre-existing domes, at the crest, nose or plunging axes of the folds. We also observed Hormuz residual along some thrust or wrench faults in the inner part of the fold-belt. A study of salt diapirs in the fold-thrust belt and foreland basin of eastern Zagros was based on seismic and well data analysis, field observations and analogue modeling. Several regional cross-sections were constructed from the Persian Gulf to the Zagros Suture Zone. They allowed us to investigate: (1) the kinematic scenarios for the main structural elements; (2) the role of deep-seated fault on deformation; (3) the role of pre-existing dome and salt intrusions during folding; and (4) evaluate the thickness of the Palaeozoic sedimentary pile. Finally, they present a reference for the pre-folding attitude and activity of salt domes in the foreland basin compared with the fold-and-thrust belt area. Salt plugs in the eastern Fars Province initiated as early as the Palaeozoic time, and were reactivated by subsequent tectonic events. They formed either: (1) emergent diapirs forming islands, especially in the Paleogene to Neogene Sea at the front of the fold-thrust belt, or (2) buried domes. Pre-existing salt diapirs strongly influenced the development of the compressive structures formed during the Neogene Zagros folding, as well as the style of deformation and the localization of the folds.

(#123681) Improved drilling performance in re-entry wells using high-performance water-based drilling fluid in Bahrain's Awali field

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Bahrain's Awali field, the Arabian Gulf's first field discovered in the 1930s, has declined in production by almost 50% over the past 30 years. Specialized drilling techniques, such as re-entry drilling, have brought new life to the field. Due to the highly deviated and challenging horizontal sections often encountered on re-entry wells in the Middle East, non-aqueous fluid (NAF) systems have typically been required to provide maximum drilling performance, wellbore stability and deliver lower overall well costs. However, environmental constraints, disposal restrictions, and risks associated with the handling of the NAF systems negate the benefit of their use. While providing the necessary level of compliance, conventional water-based mud systems used in the Awali field have proven to be particularly ineffective at providing acceptable rates-of-penetration and wellbore stability. As a result, non-productive time (NPT) has increased and larger holes sizes are needed for successful liner placement. A high-performance water-based mud (HPWBM) has been successfully used by the Bahrain Petroleum Company (Bapco) in the Awali field as an environmentally compliant and cost effective alternative to traditional NAF. The HPWBM was able to provide considerable improvement in WBM performance in these

re-entry wells. It also provided the necessary wellbore stability and reduced formation damage required for open-hole completion. Additionally, pre-planning and communication with Bapco's engineers resulted in the targeting of potential problems, such as limited hydraulics and zones of poor hole cleaning, allowing corrective action to be taken throughout the drilling process. This presentation discusses case histories of several re-entry wells that have been drilled in the area, along with a detailed overview of the HPWBM system and its benefits. Additionally, a discussion of the engineering that went into the planning and execution of these successful re-entry wells is presented.

(#123804) A comparative study of facies and diagenesis of Arabian Peninsula sabkhas

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Models of modern and ancient sabkhas tend to be biased by the extensive studies on the Holocene coastal sediments of the United Arab Emirates. Results from the present study and other recent studies along the coastlines of the Arabian Peninsula provide new insights into the variability of sabkha systems. These results reveal that modern sabkhas vary in facies types, facies proportions, evaporite-mineral suite and water chemistry. Antecedent topography, winds, currents, the Holocene sea-level rise and fall, and sediment supply are primary controls on sabkha sedimentation and diagenesis. Based on these controls, continental, coastal-carbonate and coastal-clastic sabkhas are recognized and have differing implications for facies, diagenesis and reservoir-quality distribution. Arabian Peninsula sabkhas have a common sea-level history. Most formed after a Holocene sea-level highstand approximately 4,000 to 6,000 years before present. Sabkhas have in common a very low relief, deflation, depositional surface. Consequently, very little hydrostatic head develops within sabkha sediments. Topographic relief from proximal headlands is sufficient to introduce meteoric waters into sabkha systems. Antecedent relief is an equally important control on marine circulation systems and consequent sediment-dispersal patterns. Sedimentary responses to physical processes like wind and marine circulation led to the development of a range of facies patterns observed in sabkhas. Knowledge of how physical controls may interact helps in the application of sabkha models to reservoir prediction and characterization. Like all sedimentary systems, sabkhas record an interplay of controls. Accordingly multiple working models should be considered in characterizing other modern and ancient sabkha systems.

(#123766) AVO analysis in order to hydrocarbon detection in a Gulf oil field

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Amplitude-versus-offset (AVO) analysis is one of the important approaches used to detect hydrocarbon reservoirs. In this presentation, we will first explain the theoretical principles of AVO analysis. We will then show how we applied the technique to seismic data from one of the Persian Gulf's field to directly detect hydrocarbons. For this purpose, we selected a seismic line and two wells along it. Special seismic data processing was used to maintain amplitude. The Radon transform was utilized to attenuate noise and remove multiples. The interpretation used Hampson-Russel software to identify anomalies recognized by the AVO technique. Using well logs, we constructed a synthetic seismic model using Zoeppritz's equations. The reference model used the inversion of a gas-saturated reservoir. The target interval was divided into three areas with Poisson's ratios corresponding to gas, oil and water zones. We also obtained a P-wave velocity section with a low-velocity anomaly, which exactly coincides with the observed anomalies from AVO indicators. Finally, using these results, observed anomalies were interpreted as the gas envelope in the field.

(#122833) Applications of Non-Rigid Matching to 3-D converted-wave imaging

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Processing limitations in the time domain to accurately ray trace, or meticulously model, the full-waveform expression of converted-wave moveout in the presence of lateral heterogeneity and polar anisotropy, often culminate in imaging discrepancies between different azimuth sectors of a 3-D converted wave (P-Sv) seismic data volume. To compensate for lateral or temporal divergence of converted-wave imaging as a function of azimuth, a two-tiered workflow for applying a non-rigid matching (NRM) algorithm is applied to combine two distinct 3-D azimuth sectors of a P-Sv pre-stack time migration (PrSTM) dataset to form a final enhanced 3-D P-Sv volume with superior stack response and continuity. The method allows for the crossline artifacts from the effect of azimuthal anisotropy on the converted wave moveout to be almost completely removed. Furthermore, the severe acquisition footprint, from insufficient crossline aperture as a result of a sub-optimum survey design, is effectively mitigated. Seismic data examples of 3-D inlines, crosslines and time slices taken from a typical 3-D/4C survey acquired from the Gulf of Mexico and processed in 2006, demonstrate the compelling benefits of the NRM application and the robustness of the developed workflow. Furthermore, the output NRM displacement attributes (voxel time-shift values) are found to possess a qualitative value which are not only powerful indicators of azimuthal anisotropy, but also through calibration, may yield valuable information on the magnitude of shear splitting and principal directions of polarization.

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(#122988) Anisotropic P-P and P-Sv pre-stack depth migration of 4-C seismic data, offshore Trinidad

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In 2004, EOG Resources acquired an ocean-bottom cable (OBC) 4-component swath survey across the Pamberi-1 well location in the Columbus Basin, offshore Trinidad. The motivation from EOG was because a previously acquired conventional 3-D towed-streamer survey failed to adequately image the potential reservoir under the main fault. Details of the P-P and P-Sv processing of this dataset through anisotropic pre-stack time migration were previously described by Johns et al. (2006) in which it was demonstrated there existed a qualitative correlation between derived parameters and attributes from P and Sv anisotropic migration velocities, overpressure and known regional geology. This observation was quite remarkable considering that only a limited effort to validate and constrain the parameters was performed. Under the *Future Work* section of the previous publication, it was suggested that further data quality enhancement in preparation for more quantitative rock-property classification could only be achieved after pre-stack depth imaging. In this presentation, we discuss that next phase in the 4C processing, advancing the P-P and P-Sv data through anisotropic pre-stack depth migration. The Pamberi-1 well was used to constrain the anisotropy in the shallow section, with the deeper spatial trend guided by the anisotropy derived previously in the time processing with further updates from detailed event registration. Prior to the depth tomography, the nature of birefringence from the presence of azimuthal anisotropy was first examined to assess its potential impact on the radial P-S signal. The shear splitting analysis revealed polarization alignment with the regional stress direction delineated by fault blocks acting as pressure seals.

(#123145) How much tar is too much? Novel methods for tar identification and quantification for real-time reservoir assessment

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New techniques for assessing reservoir impairment by tar have progressed using analytical, computational and dynamic methods. A particular application of Saudi Aramco's *Pyrolytic Oil-Productivity Index* (POPI)

technology has been the determination of tar volumes for assessing permeability impairment and optimizing injection and production well placement. Through the integration of real-time POPI tar volumes with *formation pressure while drilling* (FPWD) and LWD data, unimpaired and tar-impaired reservoir can be clearly differentiated. Combined POPI, FPWD, and modeled results suggest that the critical range of tar saturation is from 10% to 25% of the available pore space. If pore space filled with tar is less than 10%, reservoir performance is not significantly impacted. These tar volumes are consistent with new permeability occlusion calculations for the Arab D pore systems performed by E. Clerke. Traditional well-log tar-detection techniques cannot resolve these low tar volumes. Pyrolytic characterization methods provide direct assessment of residual hydrocarbons present in core or cuttings samples. POPI instrumentation and methods can accurately quantify tar volumes over a wide range of concentrations to within 0.5% of whole rock volume and provide the data in real time. Once tar saturations reach approximately 15% of pore volume, significant signs of reservoir degradation are often seen in FPWD data. At 25% or greater tar saturation, reservoirs often show no fluid mobility. Thus, tar saturations reach critical levels while the non-tar component is 75% to 90% of the available pore space. Cuttings-based POPI tar volume measurements are an important new data stream for this problem.

(#118167) Geomechanics approaches to oil and gas production at the Russian sector of the Barents Region

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The operation of oil and gas fields, without taking into account geomechanical processes, can result in destructive or even catastrophic events. Besides losses involving people's safety and damage to infrastructure, the field may remain underexploited. To address the issue of providing safety, a synergetic approach has been realized. We analyzed the geomechanical processes for the evolution of a nonlinear, nonequilibrium, natural-production system (NPS) for offshore oil-and-gas fields. We analyzed a graphic model of the NPS evolution based on an algorithm that involves interchanging the stable cycles and bifurcations. We developed a geomechanical model of the offshore gas-condensate Shtokman field. The model takes into account the spatial geometry and fluid-saturation in this tectonically block-faulted field. The model predicted the development of the deformation processes and the geodynamical regime during the field's production. It provided geodynamical and geoecological safety criteria as a basis for a production monitoring system under Euro-Arctic conditions. Geomechanical estimates have also been conducted for the existing oil-and-gas transport systems as well as designed and planned systems in the Russian sector of the Barents Sea region.

(#122984) Heat-flow measurements: Fundamental information for structural and geodynamic interpretation

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Seismic data provide clear images of the subsurface geology that often clarify geodynamic processes. In general, it is a crucial advantage to have an even better understanding of the dynamic processes of pore water or hydrocarbons. Marine heat-flow measurements provide additional information regarding the dynamics of sedimentary basins or continental shelves at regional or local scales. For example, heat-flow measurements at the South American active continental margin revealed convective water movements along the decollement zone. On a smaller scale, dewatering along a fault zone was detected by increased heat-flow values. Together with $\delta^{13}C$ analysis of carbonate samples, a pathway of hydrocarbons through a gas hydrate stability zone could be proven. A small-scale example for the use of heat-flow measurements was the Haakon Mosby mud volcano off northern Norway. From measurements across the volcano, expulsion rates could be determined. On a regional scale, thermal conditions of continent-ocean transition are often unclear, especially if borehole information is scarce in undeveloped basins. As geothermal heat flow is a measure for crustal age, measurements can help to decipher the tectonic evolution of continental margins. On these different spatial scales, from sites as small as the Haakon Mosby mud volcano to basin-wide exploration, the measurements of the thermal field assists in answering questions regarding fluid convection and tectonic history at a relatively low cost.

(#122479) Unlocking STOIIP of Permian Gharif Clastic reservoirs in central Oman

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The Permian Gharif reservoirs of central Oman represent one of the major producing hydrocarbon reservoirs with significant remaining upside potential locked in low-relief structural/stratigraphic traps. The Sadad field, which was discovered in 1986 and brought on stream in 1990, is a low-relief anticline (c. 45 m vertical closure and approximately 100 square km areal closure) located about 30 km to the west of the Mukhaizna field in central Oman. The oil is produced from the Upper Gharif, which comprises a terrestrial succession of arid, fluvial deposits contained within a predominantly muddy floodplain, resulting in a relatively low net/gross of about 30%. The oil is 24° API with a viscosity of 42 cP. Initial development of the Sadad field until 1998, was based on the drilling of high-angle, deviated wells that aimed to penetrate the reservoir both laterally and vertically. This proved largely unsuccessful and cost-intensive due to the low success rate of finding producible reservoir within the highly heterogeneous Upper Gharif Member. Thus, a new development strategy was instilled, comprising multiple cost-effective, vertical wells (*peepholes*) that could tolerate the expected low success rate and improve the understanding of the reservoir model to reduce uncertainty in targeting productive sand trends. The first peephole campaign of 20 wells was drilled in 2001 with a success rate of 60% resulting in a production increase. The second peephole campaign drilled another 12 wells and netted a success rate of 66%. Both campaigns achieved the economic and geological success criteria from the peepholes. Several marginal discoveries were also made on similar low relief structures around the Sadad Field in the early 80's with a single well. Many of these discovery wells were not tested due to poor perceived net/gross, despite good oil shows. Using the Sadad analogue, it could be interpreted that these single wells do not represent the potentially high oil-in-place (STOIIP) of these accumulations, and so warrant further investigation. Additional peephole drilling and possible 3-D seismic acquisition are proposed to support the search for more Gharif oil in central Oman.

(#118981) Estimating porosity and thickness from combined seismic amplitude and isochron analysis

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We present a deterministic method and a statistical method for analyzing amplitude anomalies. Both methods use, as a constraint, the isochron measured from a shallower event. In our example, the amplitude anomaly is modeled as due to a target consisting of three thin layers. Thickness changes in any of the layers results in both amplitude and isochron variations. The deterministic approach consisted of creating one 3-D cube of synthetic zero-offset traces by varying the porosity and thickness of one layer. Each inline of the cube corresponds to a thickness value, and each x-line corresponds to a porosity value. Additional cubes were created by varying the properties of other layers. These data were compared to determine which porosity-thickness pair resulted in the best match with the observed amplitude and isochron. In the statistical approach, we varied two layers simultaneously. The parameters that were varied were P-wave velocity, density, and thickness. We generated 50,000 synthetics by randomly sampling uniform distributions for the six parameters. Before proceeding, we used the isochron as a constraint. If the peak amplitude in a synthetic trace was delayed by more than observed, that trace was rejected. The conclusion from the statistical approach was consistent with that from the deterministic approach; namely that the anomaly is most likely due to decreased impedance in layer 1. In addition, it illustrates that the properties of layer 1 dominate to such an extent that variations due to changes in the porosity of layer 2 would be difficult to observe. Thus, two different, yet reasonable, approaches to the modeling gave similar results, increasing confidence in our conclusions.

(#116080) Structure trap characterization in the eastern Arabian Basin

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Basement fabric and stress phase are interpreted to be the main factors controlling location, size and orientation of structural traps in the eastern Arabian Basin. Surface and subsurface investigations supported with 2-D and 3-D seismic, gravity, magnetic and satellite images in selected areas were used to achieve this interpretation. This study unraveled a wide range of diversified structures; compressional, extensional and strike-slip-related. Major north-south and east-west faults, and their related folds, represent the main hydrocarbon trap styles in the eastern Arabian Basin. These major structures are associated with smaller structures including north-south reverse faults, E-W strike-slip faults, and *en-echelon* E-W faults and folds. Other associated structures that were observed in the surface, and possibly exist in the subsurface, include folds related to releasing and restraining fault bends, tight detachment folds and key-stone grabens. The basement fabric, that controlled the location, size, and orientation of the structural traps, was established during the late Neoproterozoic compressional phase during the accretion of the Arabian Plate. The hydrocarbon structural traps were formed through two major compressional phases. The first phase spanned from Late Devonian to Mid-Permian. Some structural traps were developed over the pre-Devonian reservoirs. The second phase spanned from the Late Mesozoic to Recent. The majority of the structural traps were formed during this phase primarily through the reactivation along the structures that were formed in the first phase. Also, in the second phase, all structural traps were rotated eastward in response to the tilting of the Arabian Plate due to thermal uplifting of its western part.

(#120359) Integrated G&G evaluation to constrain glacial paleo-topography, Sarah Formation, Saudi Arabia

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Glacial topography of the Ordovician Sarah Formation in the South Rub' Al-Khali Basin is an important factor for prospectivity assessments as it influences reservoir distribution and hydrocarbon migration. Analogue models are known from North Africa and Arabian outcrop areas but little attention, as yet, has been given to subsurface implications for hydrocarbon exploration in the South Rub' Al-Khali Basin. Within the exploration areas of the South Rub Al-Khali Company (SRAK) in Saudi Arabia, indications for such topography can be seen on 2-D seismic lines. Additional integration of well and potential field datasets and actual geometries measured in outcrop enabled the construction of a 3-D model of glacial topography for the South Rub' Al-Khali Basin. This 3-D model can be used to assess the likelihood for a variety of trapping configurations that may be prospective for hydrocarbon exploration. The presentation will discuss actual subsurface examples from the South Rub' Al-Khali Basin.

(#119375) Integrated fracture characterization of Najmah-Sargelu Reservoirs, Umm-Neqa structure, Kuwait: Its implications on hydrocarbon exploration

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The recent exploratory efforts in the Umm-Neqa structure, in northern Kuwait, established the presence of light oil and gas in the Najmah and Sargelu reservoirs. These reservoirs are very tight carbonates with a matrix porosity of between 2.0% to 4.0% and permeability of less than 0.01–1.0 mD. Despite the low matrix permeabilities, the presence of natural fractures in the reservoirs is believed to have enhanced the permeability by several folds, as is evident by the high production rates. This presentation shows the results of fracture characterization studies to provide a better understanding of the complex fractured Najmah and Sargelu reservoirs in Umm Neqa structure. The study was based on the integration of core and borehole image log data from the two wells drilled in the structure. The natural fractures in the reservoirs were characterized in terms of size, aperture, density, orientation and sealing properties. The fractures mostly range from 5–8 inches in height; however some fractures are longer and a few exceed 3 ft in height. The fracture aperture varies between 0.2–0.3mm. Most of the fractures are open or partially open and steep (70–80o). Two dominant fracture sets were identified using borehole images; one set trends NNE-SSW and the other NW-SE. Borehole breakouts suggest that the direction of principal horizontal compressive stress is NE-SW, and natural fractures that strike in this direction are mostly open. These fractures are capable of transmitting fluids and enhancing the permeability. Horizontal boreholes, oriented perpendicular to the strike of high-permeability fracture sets, hold great promise for maximizing primary production.

(#118729) Diagenetic imprints and their impact on reservoir characterization of the Jurassic Middle Marrat Member, northern Kuwait

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The Lower Jurassic Marrat Formation in Kuwait is divided into Lower, Middle and Upper members. The Middle Marrat section is the most prolific Jurassic gas

and oil producer in northern Kuwait. It was deposited in an inner to middle ramp setting and consists of grainstones, packstones, wackestones, with mudstones, algal packstone, anhydrite and crystalline dolomite in minor proportions. The dominant allochems are oncoids, ooids, peloids, intraclasts, echinoiderms, molluscs, gastropods and forams. Anhydrite mostly occurs as nodules and show *chicken-wire* texture with rare bedded anhydrite. Reservoir quality is highly variable in the Middle Marrat section and is mostly independent of depositional facies. Both primary and secondary matrix porosity, as well as fracture porosity, are present, with rare styloporosity. Primary inter-particle pore spaces are found in grainstones, and the porosity has been mostly reduced by isopachous and blocky calcite cements. Scattered moldic porosity is present. Secondary inter-crystalline porosity is formed by replacement of calcite by dolomite. Good preserved inter-crystalline porosity is seen in completely dolomitized sequences having sucrosic texture. Multiple diagenetic events from micritization to fracturing have been observed. Dolomitization is the dominant control on the diagenetic modification and both mimetic and non-mimetic dolomites are present. Dolomitization was caused by either evaporative reflux or hydrothermal processes. Anhydrite occurs as early cement associated with sabkha evaporation as well as late burial cement. Late stage diagenetic events are represented by poikilotopic anhydrite, pyrite, saddle dolomite, calcite cement (including rare dedolomite) and fractures. Crystalline dolomite is formed by the replacement of calcite and represents diagenetic rather than depositional facies. The better understanding of the diagenetic pattern of the Middle Marrat section has allowed the selection of favourable location for delineation drilling.

(#122654) A neuro-fuzzy approach for the estimation of porosity to reservoir characterization

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The link between reservoir characteristics and well log data has been established either through statistical or physics-based approaches. The statistical approaches become more useful only when *apriori* information regarding nonlinear input-output mapping is available. In the case of physics-based approaches, simple models may be inaccurate because of numerous unrealistic assumptions, whereas complex models may require adding extra equations to better approximate the phenomena. A third useful approach involves intelligent computing approaches, and especially combined ones such as the neuro-fuzzy technique. We used an *adaptive neuro-fuzzy approach* (ANFIS) for estimating porosity. ANFIS is an adaptive neuro-fuzzy inference system that implements a Takagi-Sugeno fuzzy inference system and has a five

layered architecture. The first hidden layer is for *fuzzification* of the input variables while T-norm operators are deployed in the second hidden layer to compute the rule antecedent part. The third hidden layer normalizes the rule strengths and is followed by the fourth hidden layer where the consequent parameters of the rule are determined. The output layer computes the overall input as the summation of all incoming signals. ANFIS uses backpropagation learning to determine premise parameters, and least-mean square estimation to determine the consequent parameters. In the study, one well was used for training and checking and another well for testing. After development of the ANFIS model, the porosities were estimated with a high accuracy.

(#118976) Deterministic inversion results in a difficult seismic acquisition environment: Example from a carbonate reservoir in United Arab Emirates

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Transition zones between land and deep-marine environments are known to be difficult areas in which to acquire good quality seismic data. The objective of this study was to apply inversion techniques to better image a carbonate reservoir located in a difficult transition zone. The use of various sources and receivers during seismic acquisition resulted in a challenging dataset for reservoir characterization studies. An integrated seismic inversion approach, combined with special processing, was successfully applied to improve the reliability of the reservoir characterization results in the problem transition zone. A prior inversion study revealed a seismic data quality problem, which led the asset team to embark on an AVA (amplitude versus angle) study to improve the seismic image. A detailed evaluation of different anglestack cubes showed that better quality subsurface images with higher signal-to-noise (S/N) ratio occurred over the near- to mid-angle range. The high S/N ratio angle-stack was found to be the key to obtaining more reliable inversion results for reservoir characterization. The integrated workflow used all available geological, petrophysical, producing and geophysical resources. The work emphasized obtaining detailed well ties to the seismic data for stable wavelet estimates, an improved structural definition and realistic geologic constraints for a more reliable inversion. Industry-leading, constrained sparse-spike inversion was employed to invert the seismic for an acoustic impedance model. An acoustic impedance-to-porosity relationship from well control was used to produce a porosity model. Upon completion, a qualitative map was produced, which showed the mismatch between the inversion and the input seismic. This map was used to identify low confidence problem areas, which had a high correlation to the bathymetry over the field.

(#119024) A novel approach for quantifying a dual-porosity system and its permeability distribution in a carbonate reservoir: A case study from Al Khalij field, Qatar

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The Al Khalij field, located offshore Qatar, is quite a spectacular example of a complex carbonate field. It displays unusually high volumes of moveable water. The complexities are related to diagenesis (patchy cement), mixed and unpredictable wettability and lateral facies changes. The reservoir has been modeled with a dual-porosity model whereby *path* (productive) and *fabric* (non-productive) pore volumes were defined. Quantifying these volumes has proven very difficult with standard petrophysical tools. Nuclear magnetic resonance (NMR) logs were acquired (pipe conveyed) in horizontal in-fill wells to evaluate and potentially quantify the dual-porosity system, fluid saturations and permeabilities. Other log data included logging-while-drilling (LWD) gamma-ray, resistivity, neutron and density porosity, and borehole image logs. In addition we acquired formation tester data including four mini-DST datasets as well as between 20–30 single-probe tests in each well. Post-processing and petrophysical interpretation of the NMR logs, in combination with the other available data, resulted in an improved understanding of the porosity (pore size) distributions and rock-quality variations in the various reservoir layers. The partial porosity distributions characterize the pore (throat) size distribution for each layer very clearly, adding to the geological understanding of the reservoir rock.

Deriving permeability from NMR for complex carbonate formations is known to be very challenging. We applied the recently published (Di Rosa et al., 2006) pore-connectivity-based permeability model to analyze this carbonate formation. By introducing a pore connectivity constant "p" to modify the Coates permeability model, our novel approach determined the path and fabric pore volume, as well as the permeability more realistically than that from the original Coates model. The connectivity factor "p" was determined using the formation tester mini-DST and probe-test permeability data. Using this approach, it became evident that each reservoir layer displays its own, distinct "p" value, clearly related to rock type. On the other hand, the default carbonate T2 cut-off value and the Coates parameters were kept invariable for all layers, making the interpretation much simpler and explainable. Once the calibrated "p" value was found, a "p"-corrected MBVMC was calculated. This MBVMC can be regarded as the productive *path* porosity, whereas MBVI + the volume by which MBVM has been reduced represent the nonproductive *fabric*. Fluid saturations derived both directly from the NMR logs as wells as from using LWD basic log data were then superimposed onto the newly derived pore volume distributions.

(#123991) Assessment of the geology of deep saline aquifers and its feasibility for CO^2 storage in the Arabian Peninsula

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Carbon dioxide gas (CO^2) is a natural component of the Earth's atmosphere and has been present throughout most geological times. However, since the industrial revolution, the concentration has risen by about a third (from 280 to 370 parts per million) and may well reach at least twice the pre-industrial level by 2100. Many scientists believe that this increase will lead to global warming of 2.0° C or more, stimulating climate change and severe weather conditions. One way to combat climate change is to stabilize CO^2 concentrations gradually in the atmosphere at or below 550 parts per million: An enormous challenge! The combustion of fossil fuels emits an estimated 23 Gtonnes of CO^2 annually. If captured and stored, in combination with the other mitigation measures (e.g. energy efficiency and renewable energy), it would significantly help the goal of reducing these emissions. Deep, highly saline aquifers have the potential to provide very large storage capacity worldwide. Recent studies suggested that the storage capacity in geological reservoirs in northwest Europe alone could be as high as 800 Gtonne CO^2. There are a number of places where these aquifers have been used as buffer reservoirs for natural gas, giving confidence that CO^2 could be stored safely for thousands of years in carefully selected reservoirs. CO^2 injection in many of these aquifers will partly dissolve in the saline water and/or be trapped in the pores. Research activities are underway in Europe and Australia to map and assess the storage capacity of offshore salt-water reservoirs, while similar research in Canada and the USA is looking at onshore salt-water reservoirs. On the other hand, limited information on the geological formations of the Middle East deep saline aquifers has been published. The aim of this presentation is to show the latest database of deep saline aquifers in Arabian Gulf area and to identify potential ones for CO^2 storage.

(#119770) Multi-disciplinary and multi-cultural IOC and NOC field education: An example from modern sabkha environments, Qatar

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The challenge of multi-disciplinary and often multi-cultural teams in today's oil companies is finding common educational experiences. Over the past several years ExxonMobil, along with several NOCs in the Middle East, have jointly developed a practical, field-based educational program. Field work provides a means of providing education in various aspects of reservoir description for people with disciplines as diverse as petrophysics, reservoir quality, stratigraphy, geologic modeling and reservoir simulation. Unlike a classroom setting where information flows from teacher to student, this experience provides: information exchange between *specialists* and *generalists*; an opportunity for individuals/teams to teach themselves and each other through hands-on experience; and a platform for open discussion of technical issues and problem solving. Educational experiences range from measuring outcrop sections of subsurface analogs to mapping modern carbonate-siliciclastic-evaporite systems. In the example presented, Qatar's geographic setting provides a unique opportunity to study modern sabkha depositional systems. Aside form formal instruction, multi-disciplinary teams were assigned to map three areas (approximately 3 to 5 square km), representing upper-, middle- and lower-sabkha environments; all interpretations were integrated at the conclusion of the field work. Participants developed skills which include: (1) understanding of grain, textural, and lateral facies and diagenetic relationships; (2) identification of the physical controls on exploration, development and production-scale depositional trends; (3) discussion of scaling issues related to reservoir-property distribution in three-dimensional geologic models and reservoir simulation. In conclusion, the field-based integrated education structure allowed for scientists from diverse cultural backgrounds to build and expand their skill-sets as well as develop important cultural awareness and an appreciation for diversity.

(#119769) Biostratigraphy, chemostratigraphy and subsurface correlation of the Permian-Triassic interval in the Arabian Platform and the Musandam Peninsula, Ras Al-Kaimah, United Arab Emirates

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This study examines the biostratigraphy and chemostratigraphy of the Permian-Triassic Khuff Formation. It integrates these disciplines with concepts of modern carbonate sedimentology and facies analysis and current sequence stratigraphic concepts to generate a basin-wide, high-resolution chronostratigraphic framework. The Khuff Formation in the subsurface of the Arabian Platform and its time-equivalent strata span a range of approximately 12.5 million years (My). Based on foraminifera identification, chemostratigraphy, and regional correlation, age assignments for the Bih, Hagil, and Ghail formations are slightly younger than previously recorded. The base of the study interval (below prominent "white bed"/breccia within the Bih) is Midian-Capitanian in age based on regional correlation and is time-equivalent to the Khuff K5 interval in the subsurface. The Bih Formation correlates to the Khuff K4 and K3 in the subsurface. Regional correlation, suggest that the Hagil ranges in age from Griesbachian (possibly as old as Changhsian) to Spathian and correlates to the Khuff K3 to K1 zones and the Sudair Formation. The Permian-Triassic (PT) boundary is tentatively placed in a zone straddling the Bih-Hagil contact. The Hagil–Ghail contact marks the base of the Anisian and not the PT boundary as previously published. The zone (10 ft) proximal to the Hagil-Ghail contact represents nearly 2–3 My of missing time. The Ghail is time-equivalent to the Sudair Formation in the subsurface. This framework provides a model for assessing the distribution of reservoir and seal during exploration, and for layering the reservoir during field development.

(#118925) Application of stratigraphy specific shale compaction curves in pore pressure prediction: A basin modeling approach

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Basin modeling, apart from its primary use in source rock maturity and hydrocarbon migration modeling, is also commonly used as a complimentary tool for the prediction of pore pressure. Although each pressure-prediction methodology has its pros and cons, an integrated workflow using various relevant parameters can give better solutions. The present study discusses the control of compaction disequilibrium in pore-pressure development in the offshore Krishna-Godavari Basin, India. Assigning stratigraphy-specific shale compaction curves (derived from a density log) in the PetroMod™ 1-D and 3-D (IES, Germany) model gives a better match to the observed pore pressure than the widely used methods of single compaction curve. The application of a similar technique in the 3-D model enhances the understanding of the regional distribution pattern of pore pressure, both vertically and spatially. In addition to present-day pore

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pressure prediction, determination of paleo-pore pressure in conjunction with its relation to migration can also be achieved through this method. Hence, this method has been employed successfully in different parts of the Krishna-Godavari Basin where the observed and predicted pressures were found to be of close proximity.

(#123742) Architecture, paleoenvironment and depositional patterns of the Levant Platform

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We studied the Late Barremian-Turonian evolution of the Levant Platform in surface sections of west-central Jordan, the Golan Heights and the central part of the Sinai Peninsula. A high-resolution carbon-isotope record has been used for stratigraphic refinements, global correlations, and cyclostratigraphic reconstructions. In contrast to the few outcrops showing the early platform-stages (with laterally changing platform geometries), the late platform stages are widespread and laterally uniform (with prevailing inner platform environments that are intersected by intra-shelf-basins only).

Variations of the platform architecture are mainly affected by (1) sea-level fluctuations and (2) paleoceanographic events. (1) Sea-level changes are reflected by large-scale stacking patterns with frequencies commonly below 1.0 million years, and correlate well with those from neighbouring regions. Their particular importance, as a major controlling factor of platform deposition, is indicated by synchronous cyclicities and concordant distribution patterns of the microbenthos within individual sequences and systems tracts.

High accumulation rates allow for a high temporal resolution and for the study of high-frequency cycles: laminated limestone cycles in the mid-Cenomanian of central Jordan will likely even resolve sub-Milankovitch cyclicity. (2) The impact of Oceanic Anoxic Events on the Levant Platform resulted in changing sedimentary patterns: during OAE1 the shallow water production first continued and later culminated in mesotrophic to eutrophic orbitolinid beds. The oxygen-limited conditions during OAE2 were measured with a multi-proxy geochemical and palaeontological approach to reconstruct the paleoenvironmental conditions throughout the critical intervals. A model combining long-term mineralogical anomalies in the hinterland - nutrient influx and productivity changes with short-term intervals of enhanced organic matter preservation is discussed.

(#122017) Pitfalls in seismic amplitude interpretation: Lessons from Oligocene channel sandstones

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An high-amplitude 3-D seismic anomaly in an Upper Oligocene clastic sequence depicted a channel depositional signature and was interpreted as a bright spot generated from gas-sands. Upon drilling, however, it was found water-bearing. The post-drill appraisal, based on the interpretation of pre-stack time-migrated data using 3-D visualization techniques, reconfirmed the bright spot and large channel. The geostatistical cross-plots between net-sand-thickness and seismic amplitude showed a direct proportionate relationship. Impedance versus lithology cross-plots showed varying inter-relationships. Gas-bearing sandstones have higher impedance in some wells and lower impedance in other wells with respect to the enclosing shales. The bright spot was produced by thick, high-impedance porous sandstones deposited in a fluvial to estuarine channel. The amplitude-versus-offset (AVO) responses of water-sands in a new well did not show an AVO anomaly, whereas gas-bearing sands in an existing well showed a good class-II anomaly. The interpretation pitfalls could have been avoided by more studies like AVO.

(#119014) Structural interpretation of the Oued Gueterini field, Algeria

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The small Oued Guetrini field, located in the Tellian Nappes in northern Algeria, was investigated with about 180 wells. Currently this field produces about 3,000 cubic meters/year of light oil. The field is situated between two deep faults (pre-Atlasic and Tellian faults) in an extremely complex geological setting involving thrust and collapse tectonics. Because of the complex tectonic setting the search for other fields in the area has not been successful.. Two structural models were previously considered for the evolution of the region. The first related the deformation to gravity tectonics (collapse structure) using the theory of allochthonous rock masses (Kiken, 1977). The second utilized a major deep detachment fault along a basal Triassic shearing-plane (BP, 1994; IFP 2005). Our structural interpretation of the seismic data showed that the zone is much more complex and that three detachment planes occur. The interpretation revealed that a combination of thrust and gravity tectonics affected the sedimentary cover (mixed model involving collapse and thrust features). The two tectonic regimes produced a ridge involving progressive deformation with a constant constraint direction. Nappes were emplaced during two stages: (1) thrust tectonics along deep detachment faults during the Triassic-Jurassic and Aptian-Albian; and (2) collapse tectonics related to the Bibanics Uplift. With this model it is possible to develop new plays.

(#118336) Regional Hanifa Reservoir fairways in the Eastern Province of Saudi Arabia: An integrated approach

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The Late Jurassic Hanifa Formation in Saudi Arabia consists of a succession of shallow- to deep-marine carbonates. It contains both prolific oil-producing reservoirs and important source rocks. Prediction and mapping of the regional reservoir fairways have been achieved through an integrated approach involving the study of microbiofacies, lithostratigraphy, core-based sequence stratigraphic analysis, well-log correlation, petrophysical characterizations and interpretations, and attributes extraction and modeling of a vast area of 3-D seismic data. The Hanifa Formation consists of the lower and upper Hanifa members. The lower member is composed of predominantly argillaceous limestones and laminated organic-rich mudstones, which constitutes a major Jurassic source rocks. The upper Hanifa member is a major reservoir comprised of mostly shallow-water, higher energy grainstone and skeletal packstone facies. Regional well correlations, core studies and seismic interpretation revealed an extensive intra-shelf basin. A series of clinoforms offlap into the intra-shelf basin from the carbonate ramp edges, which were established in response to carbonate deposition and base-level falls in Late Oxfordian time. Seismic mapping and attributes analysis have provided a robust reservoir fairway map that depicts the intra-shelf basin and the Hanifa shoaling complexes at the ramp crests. The results of this integrated study have opened-up new exploration opportunities in stratigraphic plays.

(#123489) 4-D Modeling of inter-actions between salt ridges, salt diapirs and folding: A new interpretation of the southern Zagros and offshore Iran structures

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The salt diapirs of the southern Zagros and offshore Iran, have been revisited in order to discuss their relationships with the geodynamic history. Field and seismic studies show that nearly all the diapirs of the studied area developed before the Zagros folding, either as emergent diapirs forming islands in the Neogene Sea or as buried domes formed at least in late Palaeozoic. Salt-cored detachment folds and thrusts developed in the Zagros Fold-Thrust Belt during the Neogene, triggering the reactivation of pre-existing domes. Analogue modelling

has been performed to investigate the parameters controlling salt diapirism, and the role of existing domes and salt ridges on Zagros folding. The models demonstrated that the main parameter, which controlled the diapir-building phase, is the strength of the overburden (or roof thickness). When thick roofs are too strong to be pierced by gravitationally pressured salt, it requires regional erosion, extension or compression to reach the surface. These phenomena can trigger, accelerate, or localize the diapir growth. The consequences of theses models for the Zagros diapirism are as follows: (1) salt plugs, now at the surface, would have emerged soon after salt deposition in Cambrian or during an Ordovician tectonic phase, and remained at or near the surface while sediments accumulated around them; (2) the buried domes observed onshore and offshore had a thick roof that was too strong to be pierced by gravitationally pressured salt alone; and (3) various Palaeozoic ridge and diapir patterns can explain present-day salt extrusions and fold patterns, with or without basement faults reactivation.

(#118991) Optimisation of the BED 15 A/R "C" Reservoir water-flooding project based on robust integrated reservoir modeling

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The success of water-flooding in complex reservoir systems depends largely on the robustness of the model used in the study. Therefore the complex reservoir architecture and heterogeneities should be optimally captured in the 3-D static models used for history-matching and forecasts. This case study illustrates the impact of an integrated reservoir-modeling study on our reservoir management strategy, which aimed to maximize oil production and the field's ultimate recovery. The BED 15 field is located in the Badr-El-Din Concession in the Western Desert in Egypt where oil is trapped in the Cretaceous Abu Roash C tidal sand channel reservoir. When production declined due to the lack of pressure support, a secondary recovery scheme was initiated with water injection (3 producers and 2 injectors). However, the existing first-pass model was too coarse to explain the unexpected early water breakthrough observed in some of the producers. Therefore, it was decided to construct a more detailed model ensuring full utilization of all reservoir analogue data, knowledge and concepts in the subsurface study. To build reservoir models that captured theirs most significant and sensitive aspects, seismic, wireline log, core data and geological analogues were used. A wide range of 3-D static models, ranging from homogeneous and highly heterogeneous, were constructed prior to validation with dynamic simulation modeling. The models used both deterministic and probabilistic methods that represented various scenarios for reservoir thickness (conditioned to seismic data), lateral sand development, internal facies and reservoir property distribution. The more heterogeneous models provided the best history match and were used to fore-

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cast production and optimize the reservoir development plan. Based on this work, it was decided to drill a new well in 2007 in an unswept area identified in the northeast of the field.

(#115925) Backthrusting and reverse faulting along the western margin of the Semail Ophiolite in the Al Wadiyein area, Buraimi, Oman

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A north-south range of peridotite hills lies in the center of Al Wadiyein. To the west are NS-trending hills of Hawasina carbonates, whereas the Kawr Group limestone is exposed on a ridge to the north. Gravity and seismic surveys (Ali et al., 2006) revealed that the contact between the ophiolite and the Hawasina carbonates is a buried, east-dipping reverse fault. The survey also revealed that the Hawasina carbonates overlie the ophiolite along a shallow, west-dipping contact that lies on strike with a shallow, west-dipping thrust fault, 1.5 km north of the geophysical survey lines. At this location, a nappe of the Kawr Group limestone was backthrust over the ophiolite, with locally up to three thrust slices of gabbro, and Kawr Group limestone at the base, each approximately two to three meters thick. A moderate to steep east-dipping, NS-striking shear zone, one km east of the reverse fault, cuts the underlying peridotite and the backthrust. The shear zone has the same strike and dip as the reverse fault. It is concluded that backthrusting of the Kawr Group limestone and Hawasina carbonates over the ophiolite was followed by reverse faulting. These events may mark the latter stages of obduction of the ophiolite in response to the cessation of westward displacement of the allochthonous carbonate sequences. The termination of the ophiolite along the reverse fault at a shallow depth suggests that the ophiolite may extend farther to the west at depth in the Wadiyein area.

(#119044) Attenuation of acquisition footprint on sparse land and ocean bottom data using least squares pre-stack time migration

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Seismic migration algorithms usually assume that the input data are recorded on a regular, fully populated grid. If this assumption is not met, the migration process will introduce noise in the data; this is often referred to as an acquisition footprint. This noise is usually offset- and time-dependent and hence can be partially hidden by the stacking process of high-fold data. However, this is not sufficient for low-fold and shallow data, nor for pre-stack analysis such as amplitude-versus-offset (AVO) or amplitude-versus azimuth (AVAZ). A common approach to this problem is to interpolate data on to a well-sampled, regular grid before migration. This can have problems if the signal-to-noise ratio of pre-stack data is low, as often occurs for onshore recording. An alternative approach is to perform an iterative, least-squares migration. In this approach, a forward migration is performed to obtain an estimate of the Earth's reflectivity followed by a reverse diffraction. This diffracted data is then compared in a least-squares sense to the original field data to determine if the estimate of the reflectivity is valid. Iterating this process leads to an improved migration result with a substantially reduced acquisition footprint. This process is computationally intensive but is practical for Kirchhoff pre-stack time migration (PSTM). Decimation trials have been run on an onshore dataset that was originally shot with high fold. Reducing the original data by dropping every second shot line and every second shot point within a line causes noise to be introduced on the stack after conventional PSTM. Least squares migration reduced this noise significantly.

(#118661) The role of evaporites in a holistic investigation of Arab sequence stratigraphy and the related depositional sequences in the northern part of the Eastern Province, Saudi Arabia

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Middle East Arab reservoirs are among the most prolific in the world and their hydrocarbon-bearing intervals are well studied. The attempt to complete the understanding of the Arab Formation requires detailed analysis of the intervening non-reservoir rocks and evaporites as well. This study presents preliminary results of our investigation into the genesis and genetic relationships between Arab carbonate and anhydrite strata. It provides a detailed analysis of both types of strata and evidence for the evolution of thick anhydrite deposits through replacement processes whose initiation is intimately related to relative sea-level changes. We employed a descriptive classification for anhydrite in order to establish recurring patterns in the development of anhydrite strata and to distinguish between anhydrite of subaqueous depositional and diagenetic origin. Further analysis of relict carbonate found within anhydrite sections provided data about the composition of carbonate hosting diagenetically-emplaced anhydrite. The result of this study established that thick anhydrite intervals formed through an active consumption (Pacman-Anhydrite) of carbonate lithofacies interpreted to have a subtidal origin. Centimeter- to dm-thick polymictic carbonate breccias found in the carbonate and locally associated with anhydrite point toward anhydrite solution cumulates. Our correlation of core descriptions tied to wireline logs establishes the presence of anhydrite sections where open-marine carbonates should be. An integration of seemingly disjointed results led to the realization of a

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sequence stratigraphic model in which anhydrite replacement of carbonate facies is intimately related to migrating groundwater tables during sea-level lowstands. This evolving sequence stratigraphic analysis has the potential of creating a high-resolution framework for defining new exploration opportunities. Perhaps more significantly it creates a paradigm for other investigation of carbonate-evaporite couplets.

(#123517) Well data tracking from wellsite to corporate database

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In an organization where a large corporate well database is populated and updated by different departments, shortening the time between data gathering and loading of the new data into the corporate database is a significant challenge. This study presents a strategy deployed to ensure that well data is loaded to the corporate database completely and in a timely manner. It involved deploying a highly automated tracking and notification system that tracked activities at the wellsite and data loading in the corporate database. Furthermore, the system was designed to automatically compare information gathered from the drilling activities with the data loaded to the corporate database and generate the automatic email notification and statistics. Data managers can view both the drilling status and the data loading status via a dash-board style web interface.

(#117619) Rapid assessment of Khuff Reservoir potential in Saudi Arabian exploration wells

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Porosity breaks are routinely cored in Khuff exploration (wildcat) wells. These cores are rapidly described to assess reservoir potential prior to logging the well. This procedure ensures that timely and well-informed decisions can be made for further evaluation and testing of the well. Assessing reservoir potential while drilling an exploration well requires rapid acquisition of the following data: (1) percent visual porosity in each bed/cycle; (2) relative abundance of carbonate pore types to assess potential permeability; (3) rock types; (4) lithology (dolostone *versus* limestone); (4) carbonate and evaporite cement; (5) sedimentary structures; and (6) high-resolution sequence stratigraphy, identifying laminae/bed, cycle (parasequence), cycle set (parasequence set), high-frequency sequence, and composite sequence packages of strata. Thin-section petrography, scanning-electron microscopy (SEM), and biostratigraphy follow rapid core description and add information on chronostratigraphy, lithostratigraphy, depositional environment, and aspects of reservoir properties that are not evident macroscopically. Standard SEM images characterize the rock and porosity very well, but SEM images of relief pore casts characterize the pore system better by imaging the pore system three-dimensionally. Combining all of this information provides a comprehensive assessment of the cored section and also improves the understanding of open-hole log signatures and potential log-calibration problems.

(#118725) Ghawar Arab-D Reservoir: Widespread porosity in shoaling-upward carbonate cycles, Saudi Arabia

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The Arab-D reservoir in the Ghawar field is composed of two composite sequences in outcrop and the subsurface, which are the D-Member of the Arab Formation and the upper Jubaila Formation. The upper composite sequence boundary is marked by local collapse and transported breccia into small sinkholes and is overlain by transgressive, subaqueous anhydrite. The lower composite sequence boundary is marked by transgressive, middle ramp, stromatoporoid and coral-rich cycles over ramp crest grainstone cycles. Deposition was on a broad, arid, storm-dominated carbonate ramp, which consisted of: (1) inner ramp (lagoon with localized intertidal islands and a diverse benthonic foram microfauna); (2) ramp crest shoal (skeletal-oolitic grainstones/packstones); (3) proximal middle ramp (stromatoporoid and coral biostromes and mounds with sheltered areas of Cladocoropsis banks); (4) distal middle ramp (mud-rich sediment with firmgrounds overlain by storm-derived rudstone/floatstone deposits); and (5) outer ramp (mud-rich sediment with sponge spicules, smaller benthonic forams and firmgrounds, with no storm-derived sediments covering the firmgrounds). The ramp-crest shoal and proximal middle ramp facies, abundant in the upper composite sequence and at the top of the lower composite sequence, contain the best reservoir quality. Limestone, the dominant lithology in the reservoir, contains a mixture of interparticle, moldic, intraparticle, and micro porosity. Dolostones, the subordinate lithology within the reservoir, form thin to thick strata-bound beds and contain moldic, intercrystal and intracrystal porosity. Fractures are locally present. Diagenetic effects include widespread dissolution, recrystallization, physical compaction, and slight cementation. Dolomitization is mostly strata-bound within transgressive mud-rich cycles and along vertically oriented fractures.

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(#117614) Depositional cyclicity and palaeoenvironments of the Middle Dhruma Formation, Saudi Arabia

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The Dhruma Formation forms a major component of the Shaqra Group of Saudi Arabia and in outcrop consists of at least 1,300 ft of Middle Jurassic, Bajocian to Bathonian, carbonates. Sequence stratigraphic analysis of stacking patterns of individual cycles, cycle sets and high-frequency sequences (HFS) and microbiofacies provided important insights to the stratigraphic location of three hydrocarbon reservoirs in the subsurface. A new road cut at Khashm al Mazru'i exposes over 300 ft of continuous carbonates, part of which is assigned to informal zones D5 to D6 of the Bathonian age Middle Dhruma. The upper part of zone D6 includes grainstones that host the Lower Fadhili reservoir in the subsurface of eastern Saudi Arabia. The western flank of the outcrop belt is characterized by impoverished foraminifera typical of a proximal shallow lagoon. In the eastern subsurface, Lower Fadhili reservoir carbonates yield higher-diversity foraminiferal assemblages together with encrusting and branched stromatoporoids typical of a more distal lagoon and bank depositional setting. The Middle Dhruma consists of a succession of high-frequency sequences, with transgressive systems tracts composed of mud-rich to marl-rich cycles and packstones/grainstones in highstand systems tracts. A typical 40–65 ft thick HFS contains 12-18 individual carbonate cycles that form 2–5 cycle sets. Thin karst features, filled with terra rosa, cap some HFS.

(#117972) Preservation potential of carbonate and halite polygons of the Abu Dhabi coastline

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Polygons have previously been described as ubiquitous features of the Abu Dhabi sabkha and coastline, yet there has been little effort to quantify these features or assess their preservation potential in the stratigraphic record. This study compared the morphology, mode of formation and preservation potential of evaporite polygons from the upper inter-tidal to supra-tidal zones with carbonate polygons from the lower inter-tidal zone of the Abu Dhabi coastline. Very large-scale peritidal polygons were identified as forming in hardgrounds over an extensive area of the peritidal environment. These polygons were sampled and their morphology was accurately mapped to produce a quantitative description of polygon characteristics and a genetic model for their formation. These polygons are interpreted to have developed through lateral expansion due to the growth of displacive calcite cements. In the upper inter-tidal zone a number of sites were defined (1 to 25 square meters)

and regularly photographed and described to construct a graphic record of temporal changes in surface morphology. This study demonstrated that the upper intertidal zone is a dynamic sedimentary environment with many of the sabkha surface features in a constant state of flux. Meter-scale halite polygons formed as a result of the evaporation of surface and near-surface pore waters. The precipitation of salts resulted in lateral displacement and uplift of polygon margins as tepee structures. Uplifted margins are susceptible to aeolian abrasion and dissolution during humid summer months. Conversely, episodic winter rainfall ponds in dish-like polygon centers with consequent dissolution of salts to leave a residual rim tepee structure. During extended periods of rainfall total dissolution and removal of halite polygons may occur.

(#123981) Mechanical modeling of diapirism in the Zagros simply folded zone

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The objectives of this presentation are to discuss: (1) the cause for the distribution of the latest Proterozoic-Early Cambrian Hormuz Salt Series in the Zagros Province, (2) the timing of salt diapirism, (3) the influence of compressional strain on the early flow of salt, and (4) the location of the salt diapirs relative to structural elements. The current tectonic activity in the Zagros fold-thrust belt is the consequence of continental convergence between the Arabian and Eurasian plates since the Late Cretaceous. The Zagros fold-thrust belt is a key region for studying the early processes that occur in convergence zones. The tectonic evolution of the Zagros fold-thrust belt is complicated by the occurrence of a Phanerozoic sedimentary cover, which is partially decoupled from its underlying basement, above a mechanically weak layer of Hormuz salt and anhydrite. Additionally, a Proterozoic sedimentary section (known in Oman) most probably occurs below the Hormuz basal detachment in some parts of the Zagros Province. Following the deposition of the Hormuz Series, a long period of remarkable tectonic calm lasted from the Paleozoic to middle Cretaceous times. We used analogue modeling to study: (1) the mechanisms of salt diapirism, and (2) the role of pure constriction strain on the overburden and extrusive salt. Based on the study of ETM satellite images and geological observations, we carried-out analogue sand-box experiments using several non-linear viscous plasticines that were imaged using Computed Tomography scans to distinguish the salt structures. Our results suggest a considerable influence of the strain rate on the geometry of the deformed folding and overburden. We will show how salt flows from the deformation of the overburden, before diapirs are exposed in the core of the anticlines and along faults. Understanding the formation and de-

velopment of the Hormuz diapirs is a very important issue, both for reservoir prediction and hydrocarbon trapping in the Zagros Province.

(#123980) Analysis of kinematical folding mechanisms under analogue modelling of plane strain

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The purpose of this presentation is to discuss the analysis of kinematical folding mechanisms using analogue modeling of plane strain. We studied mathematical functions that represent the geometry of folded surface profiles under analogue modeling. This analysis can be made by attempting to find theoretical folds that fit natural or experimental folds by the use of the point transformation equations for the basic mechanism. To demonstrate the impact of strain rate on the growth of varying folds under plane strain, we investigated a stiff layer consisting of non-linear viscous Kolb grey plasticine that was embedded in a weak matrix. The matrix consisted of non-linear viscous Beck's green plasticine, with the layer trending parallel to the X-axis of the constrictional strain ellipsoid. The invariable strain rate was c. 3.5×10^{-4}. The viscosity ratio between the non-linear viscous layer and the upper matrix was set at c. 7.9, with the lower matrix ranging from 7.9 to 20.6. Additional experiments were conducted in which a stiff layer was embedded in a weak matrix, and the matrix parameters were varied up-and-down for the stiff layer (for example density and viscosity); these experiments are similar to nature. Different runs were carried-out in which the layer (S) was oriented perpendicular to the principal strain axes (X>Y>Z). Our results suggest that the strain rate has a considerable influence on the geometry of the deformed stiff layer, including its thickness. The change in arc length and geometry of folds was obvious at a strain rate, which corresponded to a viscosity ratio. The new results might be interesting for those workers who are dealing with deformed rock salt or melt-lubricated shear zones.

(#116251) 2-D transition-zone seismic processing on the Arabian Gulf coast of Saudi Arabia: A case history

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From July 2005 until February 2007, a 2-D transition zone seismic survey, covering the Arabian Gulf coast of Saudi Arabia, was acquired and processed. The purpose of the project was to further delineate previously identified leads, locate any further leads and to extend and tie the interpretation of known horizons from the land to the marine environment. The 2-D seismic data was acquired using three source and three receiver types on a 10 x 10 km grid. The survey extended from water depths of 30 m in the marine environment, to elevations of 30 m on land. The challenges that were encountered included: (1) consistent phase for the three sources and three receiver types; (2) effective ocean-bottom cable (OBC) dual-sensor summation; (3) near-surface statics solution, including line ties; (4) surface-consistent processing; and (5) tying the velocities. An example line is used to show how each challenge was approached and solved, with special emphasis on the OBC dual-sensor summation and the near-surface statics solution. The tying of the data, both in time and velocity, was of paramount importance to the success of the project, and the methodology for both is demonstrated, including the use of a 3-D solution to resolve the 2-D time-tying problem. New methods and software were developed to further enhance the processing and quality-control capabilities to ensure consistency in our solutions, and these will be highlighted. Finally, we will show how the final migrated data was tied to an existing 2-D marine streamer survey enabling the interpretation of the two surveys to be unified.

(#119067) Depositional environments and reservoir characteristics of the Late Carboniferous-Permian Juwayl Member (Wajid Sandstone), southwestern Saudi Arabia

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This study was conducted to characterize the sedimentary facies, depositional environments and reservoir characteristics of the Juwayl Member of the Wajid Sandstone in southwestern Saudi Arabia. The facies analysis of the Juwayl Member revealed ten lithofacies and two main glacio-fluvial and braided river environments. The glacio-fluvial environment is characterized by pebbly to conglomeratic sandstone facies suggesting medium to high energy within a proximal depositional setting. In contrast, the braided river facies are dominated by medium to coarse grained trough- and planner cross-bedded sandstone facies. These lithofacies suggest a distal depositional environment characterized by laterally switching channels within an extensive braid plain system. The lithofacies, depositional environments and the stratigraphic positions indicate that Juwayl has similarities to the Unayzah B and C members in central Arabia. The Juwayl sandstone is classified as a quartz arenite with good to very good porosity and permeability. The cements, grain-size variation, quartz overgrowth, clay mineral types and matrix are the main factors controlling porosity and permeability in the member. Characterization of the hydraulic flow units indicates that it contains 15 such units. Relatively lower values of the Reservoir Quality Index and the Flow Zone Indicator correspond to the fluvial facies, whereas higher values correspond

to the glacio-fluvial facies. Statistical analysis indicates a normal distribution for the porosity and a log-normal distribution for permeability in both the glacio-fluvial and fluvial facies. The reservoir heterogeneity analysis indicates that the Juwayl Member can be considered to be heterogeneous to very heterogeneous reservoir.

(#118928) Passive seismic (Ipds®): An outstanding technology for discovering structural and stratigraphic traps

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Passive seismic - IPDS® (infrasonic passive differential spectroscopy) represents an outstanding technology for discovering structural and stratigraphic (non-structural) traps. Non-structural hydrocarbon prospects result from lithofacies variation at angular unconformities, or are due to diagenetic transformations, volcanic intrusions, morphological ante-deposition features, etc. Stratigraphic traps result from a variety of sealed geological containers capable of retaining hydrocarbons, formed by changes in rock types or pinch-outs, unconformities, or sedimentary features such as reefs, porous carbonates or sandstones zones. Such structures may trap hydrocarbons. However, detecting non-structural traps requires detailed geological work. Traditional seismic methods, principally focused on structural features, may miss the above-mentioned non-structural traps. In this regard, passive seismic – IPDS® is a technology for direct *reservoir hydrocarbon indication* (RHI) that is independent of reservoir type. This technique is based on the principle that the hydrocarbon reservoir is a multi-fluid system in a porous medium, which has an unconventional (non-linear) transfer characteristic for acoustic waves. Hydrocarbon fluid in porous system of reservoir rocks can be detected as a characteristic deformation of the Earth's natural noise spectra in the acoustic low-frequency range between 0.2 and 10.0 Hertz. Blind-test wells in several petroleum-bearing basins, under various geological conditions, have shown that the IPDS® predictions are about 80% successful. The correlation coefficient between cumulative *net pay zone* thickness (cNPZ) and IPDS® data is very high, often in the order of 80–90%.

(#118634) The Upper Devonian trough from Saoura to Fegaguira, northwest Sahara, Algeria: Geodynamic and environmental aspects

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The northern part of the Saoura Valley, in the northwestern Saharan Platform, is located to the 250km northwest of the Fegaguira area, situated around Djebel Hech in Algeria. Palaeozoic deposits, mostly hidden by the "Grand Erg Occidental", were deposited between Saoura to Fegaguira. This study constructed a paleodynamic Saoura–Fegaguira transect, which documented as Gondwanan trough. The Saoura–Fegaguira Trough is probably the result of the rejuvenation of the Pan-African paleosutures during Caledonian and Hercynian orogenic phases. In the trough the Upper Devonian successions is mainly composed of terrigenous rocks intercalated by minor limestones. The limestones at the base of the Upper Devonian are called "griottes" after their nodulour aspect. The southern Fegaguira part of the trough is filled by argillaceous deposits intercalated with some limestones layers. These thick slumped argillaceous deposits prograded into the deeper part of the trough. The uppermost Devonian layers onlap the edge of the trough and tend to disappear towards the north. The Late Devonian (Frasnian and Lower Famennian) epeirogenesis and sea-level changes are recorded as retrograding systems tracts by the "griottes" limestones. The prograding systems tracts are evident from the slumped Upper Famennian turbidites. The stacked systems tracts form genetic sequences of the second type in the third-order framework of Vail and al. (1987). Sequences of the first type and same order are recorded in the deeper part of the trough. The Saoura-Fegaguira Trough rests on the "Ougartiennes" NW-trending fault network, and forms an unstable tectonic junction zone between the Pan-African and Western African Craton. The trough probably extends several kilometers towards the southeast.

(#124196) Using wired pipe LWD-FE data in real-time: Experiences and lessons learned

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Real-time *formation evaluation* (FE) processing has been accomplished in the *logging-while-drilling* (LWD) environment via wired pipe communications with sensors and raw data processors in an LWD *bottomhole assembly* (BHA). This demonstrated that FE processing is practical while LWD acquisition is active and drilling ongoing. Advanced FE processing in the past has been done using data acquired from an LWD tool after the BHA has been retrieved to surface and the LWD tool's memory has been dumped, thus limiting its real-time value. The present advancement is the first-time in which full-memory data for real-time processing was available, using wired pipe, for what was formerly only possible after the BHA was brought to surface. The wider bandwidth offered by the wired pipe communications network enabled the transfer to surface, with minimal time delay, of uncompressed downhole LWD FE and drilling data. This data is richer, both in quality and volume, than that delivered by either

mud pulse or electromagnetic telemetry, which are the conventional LWD transmission methods. The data, on receipt at surface, are processed and stored in a database, which is periodically replicated from the wellsite to a secure data center. Advanced FE processing is applied to the LWD data after it is replicated, so that real-time processing is now a function of the database update and processing times. The ability to tightly couple traditional post-acquisition processing in real-time with wired pipe telemetry optimizes the full value from the logging tools in the drilling assembly. For example, by using wired communications to the steering unit, geosteering commands were not only sent securely and directly to the tool at the rigsite, but also remotely from shore-based locations, facilitating control and improving reservoir navigation. Targeted applications enhanced by wired pipe include reservoir navigation, drilling dynamics, pressure testing, advanced resistivity array processing, acoustics, nuclear magnetic resonance, image rendering and dip processing.

(#114244) Improved characterization and modeling of unconventional fractured Jurassic reservoir

Saad A. Matar (KOC <smatar@kockw.com>) and Fahed Al-Medhadi (KOC)

The development of a fractured reservoir is, in most cases, a hazardous task due to the difficulty in understanding the organization of the natural fracture network and its exchange with the matrix. This study demonstrates the first ever attempt to model a complicated naturally fractured reservoir in Kuwait. It illustrates the modeling methodology, history matching and future performance prediction of Najmah-Sargelu reservoir in Minagish field in western Kuwait. The Najmah-Sargelu reservoir was discovered in 1985 and it contains commercial quantities of light oil. The reservoir is composed of tight carbonate layers interbedded with organic-rich source rocks that are transected by subvertical fracture and fault sets of different sizes, orientations and intensity. Initial reservoir pressure (12,500 psia) has dropped drastically to 7,000 psia in the crestal area during natural depletion through production; but it is still greater than the asphalten onset pressure (approximately 5,000 psia through lab tests) or saturation pressure of 2,600 psia.

This presentation discusses the development of a dual-porosity model for the Najmah-Sargelu reservoir using the discrete fracture network model. It discusses how the model can be used to narrow the uncertainties in reservoir properties and therefore develop an off-take strategy with different drive mechanism that improves recovery. In particular, it will be shown how the model has helped to estimate the matrix contribution to fluid flow. Rock wettability, as well as average permeability, were tuned to achieve a good history match of water production. The reliability of the model to predict the future reservoir performance has recently been tested with the successful forecast of water breakthrough of two producers.

(#119017) Reservoir management in a mature carbonate environment

Frederic Maubeuge (Total, UAE <frederic.maubeuge@total.com>) and Emmanuelle Baud (Total, UAE)

Increasing oil demand requires greater efforts and imagination to develop hydrocarbons in increasingly difficult conditions: deep offshore, tight reservoirs, heavy oil, acid gas, etc. In this context, re-development of mature fields requires innovative solutions and often significant investments. A proper quantification of the stakes through a correct understanding of production mechanisms is necessary in order to optimise end-of-life developments and the timely implementation of the appropriate solution for curbing production decline. The Abu Al-Bukhoosh field, located offshore Abu Dhabi, has been producing for nearly 40 years. Total has been the operator since 1974. The successive phases of the field's development over the past decades to further evaluate the field's resources in response to its growing maturity will be described. Good volumetric sweep has been achieved in most of the reservoirs through extensive drilling, combination of water and gas injection and improved reservoir management by extensive focus on reservoir description, monitoring and modelling. Various IOR/EOR techniques were then implemented in subsurface (tertiary gas injection, horizontal drains), drilling (splitter well heads, multi lateral drilling), well activation and surface (process, water and gas management). Today, the field is definitely living a pivotal turn with decreasing oil stakes and higher investments for a second EOR generation and surface facilities revamping. The maturity level of the field provides new opportunities to start tackling relevant subsurface issues. Those issues concern the growing importance of secondary heterogeneities through field life, proper data acquisition strategy in highly swept environment or even an adapted use of emerging technologies. This is a matter of importance since the field resembles other giant carbonate fields of the United Arab Emirates and the Middle East, which will reach maturity in a few decades from now.

(#117645) The geology of Khuff outcrop equivalents in the United Arab Emirates

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A revision of the stratigraphy of late Paleozoic and early Mesozoic carbonates in the Musandam Mountains near Ras Al Khaimah (United Arab Emirates) clarifies the presence of deposits that are age-equivalent to the Late Permian-Early Triassic Khuff Formation. Biostratigraphic markers including benthic foraminifera (e.g. *Paradagmarita, Louisettita, Globivalvulina*) and calcareous algae (e.g. *Permocalculus, Gymnocodium*) indicated a Late Permian (Lopingian) age ranging from Late Wuchiapingian to Late Changhsingian, correspond-

ing to the K4 and K3 reservoir units in the subsurface. Sedimentological features, stacking patterns and microfacies of the outcropping carbonates show strong affinity to the KS4 to KS3 Khuff sequences, dominated by high-energy bioclastic pack- and grainstone. Outcrop gamma-ray data were used to identify the position of the Permian/Triassic boundary and to correlate the measured section with age-equivalent reservoir units. Some stratigraphic intervals in outcrop were affected by pervasive dolomitisation and therefore the studied carbonates do not reflect the same rock properties as their subsurface counterparts. However, depositional facies showed clear resemblances to the reservoir facies, and the studied outcrop is palaeogeographically probably the closest location to the Khuff gas fields in the United Arab Emirates and Qatar.

(#122992) Prospect risking for stratigraphic traps

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The South Oman Salt Basin, a prolific source of oil from carbonate stringers of Neoproterozoic-Early Cambrian age, contains many prospects. The stringers are unique in that they represent a self-contained petroleum system such that each stringer includes source and reservoir units within an insulated system. Early discoveries were based on structural traps but it became clear that the trapping mechanism is the Ara Salt, within which they are encased, and that any stringer is a potential stratigraphic trap. Risking new prospects requires a unique approach that must be updated as the prospect inventory is drilled. Existing risking methods include reviewing the five factors for hydrocarbon entrapment from traditional standpoints where each parameter is risked independently. The stringer play, dominated by stratigraphically trapped reservoirs, benefits from a statistical approach to risking. Compiling a database of stringer wells and conducting post-mortems is the most acceptable base from which to risk new prospects. Examples include stringers sealed up-dip by salt, with base-seal risks and where internal compartmentalisation is required to make an effective trap. Methods used to assist de-risking include analogy, seismic attribute displays and statistical analysis. The South Oman Salt Basin stringer play has benefited from traditional interpretation; however to improve the success rate a more detailed results-based analysis is used to focus the risking. More recent results indicated that this process demonstrates that the risking of prospects is improving which benefits the whole exploration process.

(#117639) Opportunity: Perspectives of a young geologist

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Over the last decade the demographic decline of junior geoscientists in the North American petroleum industry has not only become increasingly apparent, but has now become a matter of significant concern to E&P companies, especially to those with significant domestic North American operations. Over the last few years, representatives from industry human resource departments, research firms, trade societies, and even retired individuals have presented their perspectives on the absence of the younger generation in our industry, and specifically on the growing scarcity of qualified, talented youth to eventually replace retiring, well-trained, experienced, *baby-boomer* geologists. Previous presentations have focused on displaying statistics recording this generation gap, and have concluded that the industry may now benefit from recruiting efforts, mostly from colleges. In contrast, the author will provide considerable, first-hand insight into the unique challenges the industry has presented to aspiring geologists of the *lost generation*, and the industry practices and attitudes that have contributed to this shortage. Results of interviews with majors, larger independents, and recruiting agencies will be shared on the current status of industry efforts to attract, retain, and most importantly, to develop young talent. The presentation will also provide forward-looking statements placing these youngster's careers relative to the remaining life of the petroleum industry.

(#114649) The Wafra First Eocene Reservoir in the Partitioned Neutral Zone (PNZ), Saudi Arabia and Kuwait: Geology and reservoir modeling for the large scale steamflood pilot

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The Eocene-Paleocene First Eocene reservoir at Wafra field was discovered in 1954 and has produced about 300 million barrels of 17-19° API, high sulfur oil. The estimated original-oil-in-place for the reservoir is 9 to 12 billion barrels. The reservoir is mainly composed of pervasively dolomitized packstones and grainstones with minor mudstone and anhydrite/gypsum. The sediments were deposited in shallow water on a gently dipping, low-energy inner-shelf or ramp under arid to semi-arid conditions. The reservoir average porosity is 35% and the average permeability is 250 mD. Individual core-plug measurements range up to 50% porosity and 5,000 mD permeability. The *large scale steamflood pilot* (LSP) consists of 16 inverted 5-spot patterns covering 40 acres. A total of 60 wells are in the LSP area, 56 of which were drilled in 2007 (including four cores) affording an unprecedented opportunity to quantitatively assess and model the reservoir at a small scale. To support early reservoir development decisions, a detailed geostatistical model was generated using a 5 m areal cell size. The well-based data is supplemented by a recently acquired high-resolution 3-D seismic volume and historical production data. Geostatistical analysis yielded semivariogram models with an areal (XY) range parameter of 200-900 m and a vertical (Z) range parameter of 0.3–0.8

m. While these values are substantially less than those reported for a prior full-field study using wells largely drilled on a 500-1,000 m spacing, the range parameters are several times the average well spacing in the LSP.

(#117271) Sedimentary characteristics of Ilam Formation in Mansouri and Abteymour wells and Izeh outcrop

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The Ilam Formation (Santonian-Campanian) contains an important reservoir in the Ahvaz oil field in the Dezful Embayment, Iran. One outcrop section in Tang-e Rashid, Peyon area, and two subsurface sections in Mansouri and Abteymour fields were studied in order to understand microfacies, sedimentary environments and diagenetic processes. Petrographic analysis showed that the Ilam carbonates consist of different non-skeletal grains and different fossils. Facies analysis and petrographic studies led to the recognition of different microfacies that were deposited in four facies belts: tidal flat, lagoonal, bar and open marine in a platform ramp environment. Cementation, dolomitization, dissolution, neomorphism, bioturbation, compaction and silicification are major diagenetic processes in the Ilam Formation. Mouldic, intercrystalline, interparticle and vug porosities are the main types of porosity; these are highly significant in characterizing the Ilam carbonates. Dolomicrite, dolomicrosparite, dolosparite and vein dolomite are the major types of dolomites. Dolomicrite formed in the near surface in supratidal to intertidal sub-environments based on several lines of evidence; such as: the very fine to fine crystal size, silt size quartz grains, evidence of original texture and absence of fossils. Different generations of sparry calcite cementation are recognized in the Ilam limestones, varying from marine through meteoric to some burial cements. Cathodluminescence studies illustrated marine, meteoric and burial cementations. This information was confirmed by isotopic data. Geochemical studies illustrated that these carbonates were affected by meteoric diagenesis in a closed diagenetic system. Some petrographic evidence, such as acicular to fibrous isopachous calcite cement, resemble modern aragonite morphologies. Shattered micritic envelope and spalled ooids also indicate aragonite dissolution during meteoric diagenesis. Elemental and isotopic analyses along with an high Sr/Na ratio suggest original aragonite mineralogy.

(#123996) Stratal architecture of the Permian-Carboniferous lower Unayzah Formation, subsurface eastern Central Saudi Arabia compared with the Juwayl Formation at outcrop, Wajid Region, southwest Saudi Arabia

John Melvin (Saudi Aramco <john.melvin@aramco.com>) and Arthur K. Norton (Saudi Aramco)

The Juwayl Formation at outcrop and the Unayzah C and B reservoirs in the subsurface of Saudi Arabia are considered stratigraphically equivalent units deposited during the Late Paleozoic Gondwanan glaciation. This is supported by their stratigraphic architecture as well as sparse biostratigraphic data. The Juwayl at outcrop and on satellite imagery commonly occupies elongate features interpreted as glacial paleovalleys. In the subsurface, much of the lower Unayzah, particularly the Unayzah C, is clearly mappable as a paleovalley system: these typically seismically transparent paleovalleys are defined by well control. Significant mid-Carboniferous uplift, with associated widespread erosion and sediment bypass, occurred prior to deposition within these paleovalleys. Evidence exists that an antecedent drainage system controlled paleovalley distribution, as did the Lower Paleozoic subcrop pattern, with preferential erosion of finer grained rocks. The lower Juwayl outcrop consists of high-energy pebbly sandstones and conglomerates deposited in relatively proximal braided rivers. The subsurface Unayzah C comprises sandstones and minor conglomerates, deposited in a relatively distal braided fluvial system. These braided fluvial sandstones represent pro-glacial outwash deposited during times of glacial retreats. In some outcrops, the lower Juwayl paleovalley-fill displays zones of horizontal dislocation and related severe overfolding. Within the Unayzah C sandstones, substantial thicknesses of relatively undeformed sediment are separated by distinct zones of low-angle shear. This deformation is interpreted as the result of glacial re-advances and the formation of glacio-tectonic push moraines. At outcrop the upper Juwayl Formation displays glacio-lacustrine and diamictite facies. In the subsurface, the Unayzah B overlies the Unayzah C and comprises many depositional facies, dominated by glacio-lacustrine sediments, including diamictites. These sediments represent the final meltout phase of the Gondwanan glaciation.

(#119299) Application of seismic-resistivity conversion to reservoir characterization: An advanced study

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In the last decade, several formulations for reservoir characterization have been introduced that involve optimizing the seismic amplitude information associated with various types of pre and post stack seismic data. The purpose of all such techniques is to predict, away from control points, for example reservoir fluid or petrophysical properties by calibrating seismic amplitudes. This presentation describes a method for converting acoustic impedance to resistivity with an example of its application to real data. The method utilized the seismic amplitudes of near-offset stacked data to predict fluid type in saturated rocks. The resulting predicted resistivity distribution was then compared to the observed

resistivity in blind wells by constructing a resistivity section. It is based on Gassmann theory that the shear wave relatively does not change as significantly as compressional wave when a small portion of gas replacing water in a porous rock. We inferred that the acoustic impedance generated from nearly normal-offset seismic data was taken to represent fluid composition, whilst the elastic impedance in the mid and far offset seismic data is less influenced by fluid content. In this study, we applied the conversion formula (Mendrofa, 2006) to a shaly sand gas reservoir to study the lateral reservoir and hydrocarbon distribution with a satisfactory result of quantitative Resistivity and Net pay volumes. In addition, given a sufficient resistivity contrast, we see a potential for this technique to discriminate between oil and brine by its use in classifying the resistivity cut-offs for gas, oil and brine.

(#115284) Analytical approach of seismic-derived resistivity

Denny M.F. Mendrofa (Premier Oil, Indonesia <dmendrofa@premier-oil.com>) and Bambang Widarsono (Core Laboratory Service, Indonesia)

Nowadays, there are several seismic-petrophysical researchers investigating the relationship between seismic waves and water saturation in rocks. Unfortunately, the results always end-up in terms of empirical relationships, even when using geostatistical methods. The application of artificial neural network techniques, as published in recent research papers showed a robust correlation between the two, despite the result being a poorly defined relationship. This suggested that there may be an analytical relationship between seismic characteristics and water saturation in porous rocks. In this research, we have considered the electrical properties of porous rocks as they are related-to and influenced-by water saturation. We succeeded in deriving several conversion equations to prove a valid analytical relationship between acoustic impedance and resistivity. This was followed by satisfactory testing on well data. The theory is based on the analytical definition of acoustic impedance involving a common bulk density and Gassmann's acoustic velocity formula. We also used the modified Archie equations for a shale-sand model and by arranging those variables within the mathematical operations, we were able to derive true rock resistivity as a function of acoustic impedance. For further application, the constructed amplitude of reflected seismic energy in the range of nearly-normal incidence was used for identifying fluid type in saturated rock, whilst porosity and shale volume can be derived respectively from density, neutron, velocity and gamma ray log from well data.

(#117258) CO_2 miscible flooding in tight reservoirs: Experimental procedure and application

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The petroleum industry is increasingly concerned with carbon-dioxide emission and the resulting green-house effect. The research effort undertaken in numerous universities around the world with the support of major oil companies is resulting in an abundant literature on this subject. A whole new environmentally friendly carbon-dioxide industry is pointing to the horizon. An important part of this industry is related to the use of carbon dioxide for enhanced oil recovery applications. In the Middle East, where the future is closely tied to the oil industry, this new CO_2 industry can hardly be overlooked. A research program addressing the use of carbon dioxide as a miscible agent in marginal oil reservoirs has been initiated two years ago at KFUPM and is still in progress. This presentation discusses a general procedure describing the guidelines for such a program. A research work on carbon dioxide miscible flooding will be incomplete without an investigation on minimum miscibility pressure involving carbon dioxide and crude oil from the Middle East. This implies phase behavior, slim tube studies and correlation evaluation as well. Finally, the results will be meaningless without core flooding experiments performed at reservoir conditions. This presentation addresses the experimental procedure and application pertaining to miscible CO_2 flooding. Furthermore, the difficulties faced are also discussed when carbon dioxide miscible flooding is applied specifically to oil reservoirs in the Middle East. An example is also presented to illustrate some of the technical problems encountered and their solutions.

(#123737) Reservoir geology of Upper Burgan and prediction of water encroachments: Raudhatain field, northern Kuwait

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The presented study involved the integration of logging, coring, sedimentological and dynamic data to build a geological model of the Upper Burgan Reservoir and to predict future water encroachment in it. The Upper Burgan reservoir is the upper part of clastic Burgan Formation, which is the most prolific producer in northern Kuwait. The producing sands were deposited in a deltaic to shoreface environments. Open-hole logs and core data were used to identify and calibrate the quality and type of sands and shales. Correlation of the layers was carried across the field with 20 key wells. A struc-

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tural map was prepared using a seismic depth of the top Upper Burgan, which was tied to these wells. Isopach maps were prepared using correlation picks. Using cut-offs in gamma-ray logs, the sand reservoirs were picked and mapped for each layer. Conventional electrical logs were used to pick the oil-water contact. Time-lapse pulsed neutron logs were used to map the water encroachment. The major sand bodies were deposited as NE-trending channel sands, as consistent with the direction of sediment transport. The quality of the reservoir of the sand bodies improves towards the southwest. The direction of water encroachment is predominantly along the channels. Due to better reservoir quality and proximity to the source, the southwestern part shows a more rapid advancement of the water than the northeastern part. The shoreface sands are relatively poorer quality reservoir and are predominant in the lower part of the Upper Burgan. Due to the low production from these sands, no significant water encroachment was predicted. Deposition in channels in the Upper Burgan controls the flow behavior and is demonstrated to be an important aspect for predicting the future water encroachment in the reservoir.

(#118188) Reservoir connectivity: Definitions, strategies, and applications

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Reservoir connectivity and compartmentalization are critical areas of research and business application. A general review of *reservoir connectivity* reveals significant differences among companies and academics regarding its definition, measurement, modeling and action. However, most agree that connectivity depends on a field's structural framework, stratigraphy and fluid characteristics. We approach reservoir connectivity by first defining two types: *static* and *dynamic*. Static connectivity refers to the original state of a field, prior to production start-up. Evaluation of static connectivity is the basis for proper assessment of original hydrocarbons-in-place and prediction of fluid contacts in untested compartments. Dynamic connectivity describes movement of fluids in response to production. Initiation of production perturbs original fluid distributions, as pressure and saturation changes propagate in a complex fashion across field compartments. Barriers and baffles play varying roles over field life, becoming more-or-less important over time, suggesting that *compartment boundary* is itself a dynamic designation. Analysis of dynamic connectivity is essential to estimating ultimate recovery. Our technology called *reservoir connectivity analysis* (RCA) investigates static field compartments and associated connections. We define a static compartment as a trap with no internal boundaries (e.g. faults, channel

margins) so that over geologic time, it can develop only one gas-oil and/or one oil-water contact. Connections between compartments include fault juxtaposition windows and erosional scours between channels. Examples of RCA application and its impact on our fields are discussed. In these mature producing fields, RCA has explained production anomalies, generated new drill well opportunities, and boosted field reserves above original estimates.

(#118936) Geosteering long horizontal drains in Al Khalij field thin layers: An integrated approach

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Accurate and efficient geosteering is a fundamental requirement for optimum reservoir development. It is becoming every day more challenging as fields are increasingly developed through long horizontal drains targeting thin reservoir layers. Such a situation occurs in the Al Khalij field, a carbonate *layer-cake* of alternating good and poor quality limestone reservoirs. Each good reservoir layer, whose 2–3 m thickness is far below seismic resolution, is surrounded by essentially water-bearing layers exhibiting similar porosity responses. This presentation describes an integrated approach and innovative template developed to overcome the challenge of proper geosteering of long horizontal wells beyond 3,000 m in such a geological context. All geosteering information, from real-time borehole images to drilling parameters, logs and mud logging data, is gathered in an integrated software which includes a borehole data-management tool to process the geological information and a visualisation template. This template provides a clear structural view of the well within a real-time, updated geological cross-section. This innovative visualisation tool integrates all the well data and provides, in real time, a synthetic image of the drain, which improves geosteering decisions and helps maximise the net pay along the well path.

(#116923) Aeronian and early Telychian chitinozoans from Central Saudi Arabia

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Chitinozoan occurrences from three shallow boreholes penetrating the lower Silurian Qusaiba Member in central Saudi Arabia have been calibrated against graptolite-based age control. The age of the graptolite-bearing portion of the Qusaiba Member in the Qusaiba Depression is Aeronian and assigned to the Lituigraptus convolutus Biozone. Four chitinozoan assemblages were recognized from convolutus Biozone strata. The fifth assemblage, characterized by a new species of *Linochitina*, was from

above the highest graptolite-bearing level in the Qusaiba Depression borehole. The Qusaiba Member in the Baq'a area ranges in age from the convolutus Biozone to the early Telychian middle part of the *turriculatus* Biozone sl. The Baq'a Qusaiba succession is significant in that the Angochitina hemeri and A. macclurei biozone boundary is identified in core for the first time. *Angochitina hemeri* Paris and Al-Hajri 1995 occurs with graptolites indicating the ?convolutus Biozone to just below the First Appearance Datum (FAD) of Spirograptus guerichi Biozone graptolites. The FAD of *A. macclurei* Paris and Al-Hajri 1995 defines the biozone base and occurs five feet below the FAD of guerichi Biozone graptolites indicating a revised level at, or near, the Aeronian-Telychian boundary. The Last Appearance Datum of *A. macclurei* is just below the highest recognized occurrence of turriculatus Biozone sl graptolites. A younger Telychian chitinozoan-bearing interval without graptolites occurs in the upper part of the Qusaiba Member. The macclurei Biozone is here succeeded by *Tanuchitina obtusa* (Taugourdeau and de Jekhowsky 1960) and is followed by *Euconochitina silurica* (Taugourdeau 1963). They are considered to be Telychian based on the absence of *Margachitina margaritana* (Eisenack 1937) in the succession. In addition to calibration of chitinozoan ranges with those of graptolites, five new local subzones were recognized.

(#116590) Application of velocity deviation log to fracture identification of one of the Iranian southwestern reservoirs

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Natural fractures, one of the most common and important geological structures, have a significant effect on reservoir fluid flow. Petroleum in naturally fractured reservoirs is a growing target of exploration and development, so that finding new methods to successfully predict and characterize fractures is a critical issue. This study presents how fractures were identified in the studied reservoir using the *velocity-deviation log* (VDL). The VDL, which is calculated by combining the sonic log with the neutron-porosity or density log, was computed for three wells in an oil field in southwest Iran. In general, there is an inverse porosity-velocity correlation, but significant deviations occur from this relationship for certain pore types. The VDL was calculated by first converting the porosity log data to a synthetic velocity log using the time-average equation of Wyllie. The difference between the real sonic log and the synthetic velocity log from porosity logs can be shown as the VDL. Deviations to right or left on the VDL mark different pore types. In order to calculate the sonic and neutron-density porosities precisely, Geolog^{TM} was used. Also all the calculations and log plots were done using this software. Finally borehole image logs were used to confirm the VDL results. This study indicated that negative deviations are reasonably matched with the results from the borehole image logs.

(#118875) Reservoir characterisation through a multi-well interference test in the giant Mauddud carbonate reservoir, Sabiriyah field in northern Kuwait

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The Mauddud carbonate reservoir of Sabiriyah field, northern Kuwait, is a giant depletion-drive reservoir. It is presently undergoing re-development with inverted-9 spot pattern water-flood that was started in 2000. All the active patterns in the reservoir are in the process of conversion to inverted-5 spots through an infill drilling programme. The Mauddud reservoir is a multi-layer faulted reservoir with high permeability contrast between layers. A three-cycle interference test comprising two pressure fall-off and one injection period with a total test duration of 800 hours was conducted in one of the patterns situated at the central part of the reservoir. The injection well of the pattern, which is encompassed by two major faults, was used as the active well, whereas the surrounding six production wells were used as observation wells for measuring the transmitted pressure signals. The prime objectives of the test were to: (1) characterise the two faults with respect to their conductivity and sealing nature; (2) confirm inter-well connectivity; (3) estimate transmissivity and storativity; and (4) identify permeability-anisotropy, if any. The test will assist in: (1) ongoing pattern conversion; (2) reservoir modeling work; and (3) future water-tracer programme. Both type-curve matching using Saphire software, and semi-log straight-line of the derivative of the exponential integral function were used for individual interpretation of each cycle of the test for all the observation wells. Computer program was developed for extracting the correct pressure drop from the exponential integral function for use in type-curve matching for the second and third cycle of the test. A user-friendly work-sheet tool-kit was also developed for the derivative method. Invaluable insights regarding reservoir characteristics in a large influence area were obtained by detailed analysis of the multi-well interference test.

(#122990) Stratigraphic hierarchy and architecture of the upper Thamama (Cretaceous) Lekhwair, Kharaib and Shu'aiba formations at a giant oil field, offshore Abu Dhabi, United Arab Emirates

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At a giant oil field located in offshore Abu Dhabi, the Lekhwair, Kharaib, and Shu'aiba formations record deposition during a second-order supersequence. This supersequence comprises at least three second-order composite sequences that, in turn, are composed of a stack

of third-order sequences. Major third-order sequence boundaries or their correlative conformities are interpreted at the base of the Thamama III, below the base of the Thamama IIIA reservoir unit, the top of Thamama III, the top of Thamama II, and above Thamama IA reservoir units. The vertical distribution of lithofacies in the Lekhwair, Kharaib and Shu'aiba formations is remarkably similar from well to well, and predictable field-wide. Consistency in lateral facies distribution across the field suggests that deposition occurred on a highly aggradational, flat-topped platform with no appreciable depositional geometry.

The Thamama III consists of stacked fourth-order parasequence sets. Porous and permeable packstones/grainstones dominated variously by rudist debris, coated grains and algal lumps comprise the reservoir units that form the highstand portion of these fourth-order cycles. These units in turn are sharply overlain and separated by non-porous and impermeable *dense* units that consist of stylolitic wackestones/packstones and grainstones with common ostracodes, dasycladacean algae, miliolid foraminifers, and intraclasts. These dense units are interpreted as forming the transgressive portion of the fourth order cycles. Similarly, within the Thamama II, lithofacies associations seen in cores have a predictable vertical succession, and represent a classic shallowing-upwards succession. In ascending order these are: peloidal-skeletal wackestone-mudstone; orbitolinid-peloidal-skeletal wackestone-packstone; algal-intraclastic-peloidal packstone-mud-lean packstone; fining-upward cycles of floatstone-rudstone-boundstone grading up into skeletal-peloidal mud-lean packstone-grainstone; and miliolid foraminifer-dasycladacean algae-sponge spicule wackestone-packstone. The Thamama IA shows an overall deepening-upwards succession of lithofacies associations. In ascending order these are: *Lithocodium-Bacinella* floatstone-boundstone; skeletal-peloidal packstone; skeletal-peloidal packstone-wackestone; foraminiferal wackestone/mudstone; and planktonic foraminifer-skeletal wackestone-mudstone. No obvious sequence boundary is seen at the top of the Thamama IA, suggesting that offshore, this surface is a correlative conformity.

(#116415) Enhancement of OIP through reservoir modeling of a multi-layered siliciclastic reservoir: A case study from Muglad Basin, Sudan

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Toma South field is located in Block 1A of the Greater Nile Petroleum Operating Company (GNOPC) concession area, in the Muglad Basin, Sudan. The trap is a structural closure located on a tilted up-thrown side of a normal fault block. The trapping mechanism is a combination of fault and dip closure. Most faults in this structure approximately trend NW. One exception is a small normal fault that is oriented almost perpendicular to the major fault that divides the field into two parts. The main reservoir is the Early Cretaceous Bentiu sand. The Aradeiba main sand (Late Cretaceous) is a secondary oil accumulation. Both are layered sand reservoirs with continuous barriers between these layers over a large area in the field. Production started in 1999, and as of 2005 cumulative production was 112 million stock tank barrels (MMSTB). Both PCP and ESP are used, however, a rapid increase in water cut was experienced in this field, which affected oil production. Accordingly GNPOC out-sourced a full-field study to Research Institute of Petroleum Exploration Development (RIPED), Beijing, China. Geoframe™ and Petrel™ software were used to develop the fault/structure and 3-D geological model of the field. In addition a seismic inversion study was undertaken to develop fault and structural models. A facies model was built from the 3-D seismic cube using seismic attributes. A facies and property model was built for all the cells of the 3-D geological model. After remodeling and the identification of the architecture of the sand bodies, the extent the oil-in-place was recalculated resulting in a 21.8% increase in original-oil-in-place and a 37.4% increase in the estimated ultimate recoverable reserves.

(#118621) Geomechanical behavior of reservoir rocks in the Sarvak Formation southwest Iran

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Cost-effective improvements in the technology needed to develop and manage reservoirs in challenging environments require an increase in our understanding of geomechanical behavior. The knowledge of rock strength is important in assessing wellbore stability problems, effective sanding and the estimation of *in-situ* stress field. Geomechanical properties are determined directly from *in-situ* tests and core analysis in laboratory in reservoir conditions. This method is time-consuming, expensive and can only be applied in limited intervals in wells. Reservoir rocks are generally layered, fractured, faulted and jointed, and these factors have an influence on their mass properties. Moreover cutting and recovering cores in these rocks is very difficult. Alteration of cores during and after drilling may also influence the results. In this study a method has been used that is based on down-hole measurements of sonic-wave velocity and other petrophysical logs. In most wells the shear-wave velocity (Vs) is not measured. We therefore measured compressional and shear wave velocities from 31 core plugs taken from the Sarvak carbonate formation in four wells. The measurements were conducted in both dry and saturated samples under reservoir condition. The laboratory results were calibrated with compressional and shear wave velocities measured using the DSI tool in one well, and a suitable relationship was obtained for estimating the shear wave velocity from compressional

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wave velocity and porosity logs. We then used compressional and shear wave velocity logs, in conjunction with the bulk density log, to interpolate the *in-situ* measurements and calculate the geomechanical parameters on continuous logs. Using these parameters, unstable intervals and sand-productive zones were identified in the reservoir.

(#119071) Development of a mechanical Earth model for Qatari reservoirs

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Qatar is rapidly gaining ground as one of the world leaders in the production of natural gas. In order to keep-up with the growing demand for gas production it is essential that non-productive time be reduced. Another hurdle is that new wells are being drilled in more challenging environments, and thus better forecasting methods while-drilling become a necessity. The aim of this presentation is to show the development of a *mechanical Earth model* (MEM) for Qatar's reservoirs, using the principles pioneered by Plumb et al. The MEM is a mathematical representation of the state of stress as well as rock mechanical properties for a specific stratigraphic section in a field. This model will allow efficient drilling and stimulation of new wells, both technologically and economically. For the development of this model, several parameters were included: mechanical strength, elastic properties, *in-situ* stresses and pore pressure. These parameters can be determined from sonic, caliper and density logs, core sample analysis, geophysical data and real-time drilling data such as drilling rates, kicks and cuttings. Laboratory data included strength, elastic properties, porosity and permeability. A significant benefit of this research was preparing an updated stress map for Qatar. The MEM is useful for planning drilling operations, multi-lateral design of wells, as well as reservoir modeling and management. The Qatar MEM can be adapted to other regions of the Middle East and forms a reference database for future projects.

(#123961) Impact of structural history and style on the petroleum system of the Central Basin in the Saveh-Qom area, Iran

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The Central Basin in the Iranian Plateau lies between the geologically better known regions of the Zagros and Alborz mountains. Exploration in the Central Basin of Iran by PTTEP and NIOC has revealed the details of the

Late Oligocene-Recent evolution of the basin, based on seismic reflection data, geological fieldwork and satellite interpretation. The basin has a multi-stage history commencing with a broad sag-type subsidence with isolated normal faults, in the Oligocene-Early Miocene. It evolved to a transtensional basin in the early-middle Miocene, with up to 8 km of Upper Red Formation section being deposited in some parts of the basin. The upper part of the Upper Red Formation is associated with a change to transpressional deformation, with the development of thrusts and folds, which form the traps for the Alborz and Sarajeh fields. The latest (probably Late Miocene-Pliocene) deformation was transpressional, with a mixture of basement-involved strike-slip and thrust faults and thin-skinned folding and thrusting detached on Oligocene evaporites. Higher local detachment levels in the stratigraphy also exist. NW-SE to NNW-SSE dextral to compressional faults dominate the area with subordinate E-W (restraining bend) and N-S (strike-slip) orientations also present. Structure plays an important role in many aspects of the petroleum system: locally influencing the thickness and facies of the Qom Formation (reservoir/source unit) due to underlying salt movement; trap timing-migration is complex, fracture systems are important for reservoir permeability, whilst the combination of modern stress state, fractures and Upper Red Formation evaporite seal have resulted in high overpressures in the Alborz and Sarajeh fields (and the very large Alborz-5 blow-out).

(#122978) Reservoir modeling of Lower Devonian tight gas reservoirs in the Zerafa block, Western Desert, Algeria: A workflow from geological concepts to 3-D models

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The Lower Devonian clastic reservoirs in the northern Zerafa block (Western Desert, Algeria) are relatively unexplored, while some of the existing discoveries seem to be tight gas reservoirs. The reservoir consists of shallow-marine clastic sequences dominated by fluvially and subordinately tidally influenced deltas. These units alternate with thick packages of non-reservoir, lagoonal and offshore marine sequences. The reservoir properties are typically poor to moderate due to burial and diagenetic overprint; this can result in some parts of the reservoirs being tight gas zones. Key uncertainties are the definition of net-versus-gross reservoir, productivity and connectivity. We will present the results and the process of a detailed study of the stratigraphy, sedimentology, facies types and their diagenetic overprint, structural setting and evolution, followed by integration of all other available reservoir quality and well test data. The facies types and associations of the Devonian reservoirs seem to point towards the identification of paleovalleys in which thicker and confined gross reservoir packages with better reservoir quality were deposited. These pack-

ages are probably genetically related to early transgressive systems tracts, estuarine-valley systems. However, lateral changes in seismic character of key reservoir horizons would suggest that lateral facies variability may be related to changes in depositional paleo-environment due to different responses to relative sea-level changes and related accommodation space. Possible relations between diagenesis, burial and depositional-stratigraphical setting and the reservoir properties will be discussed. Conceptual geological models have been translated into various 3-D static model realizations, which have been evaluated against different development concepts. The modeling results have been used to aid the design and decision-making for the ongoing appraisal campaign.

(#118370) New insights on the sedimentology and stratigraphy of the glaciogenic Late Ordovician Sanamah Member, Wajid Sandstone Formation, southwest Saudi Arabia

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Recent field investigations in the Wadi Ad-Dawassir area, southwest Saudi Arabia, have provided new insights on the stratigraphy and sedimentology of the Late Ordovician Sanamah Member of the Wajid Sandstone Formation. Three main stratigraphic units were recognized and are characterized by considerable variation in thickness and lateral facies changes. These variations reflect the complex depositional and erosional processes associated with the evolution of the Late Ordovician ice-sheet margins through time. The lowermost unit (Unit 1) consists of a deformed heterogeneous assemblage and basal till overlain by a thick package of outwash deposits that recorded high sedimentation rates associated with high water discharges (climbing dunes, large-scale soft-sediment deformation). In outcrop, the top of Unit 1 is marked by a regionally extensive iron-cemented horizon, which is overlain by Unit 2. This second unit mostly consists of rain-out till made of red, poorly bedded, pebbly sandstone containing boulder-size drop-stones. This passes upwards to a coarser assemblage with thick beds of melt-out till, outwash cross-stratified and massive sands, and gravity-flow deposits, often showing large-scale soft-sediment deformation. The top of Unit 2 is also marked by an iron-cemented horizon overlain by Unit 3. The latter displays comparable sedimentological and compositional characteristics to Unit 2. In places, the bases of both Units 2 and 3 are characterized by thin, laterally discontinuous erosive, transgressive beach sand, which marks the onset of each sedimentation cycle. The top of Unit 3 is also characterized by an undulated erosional surface associated with coarse sands and conglomerates, which could represent either a base Silurian or pre-Khusayyayn unconformity.

(#123455) Reservoir characterization of Sarvak Formation from velocity deviation log and cutting sample studies, Dezful Embayment, Iran

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Faeze M. Tabesh (Azad University, Iran)

The Dezful Embayment in southwestern Iran is surrounded by three main structural features (1) Balarud bend, (2) mountain front bend and (3) the Kazerun fault zone. The Sarvak carbonate reservoir, which is located in the Dezful Embayment, was deposited on a flat ramp in mid-Cretaceous (Cenomanian) times. The Sarvak Formation consists of seven main microfacies and two reservoir zones. Based on studies of cutting samples, three pore types were found to be dominant: fracture porosity, microporosity and vuggy porosity. The Sarvak reservoir was also evaluated by using the velocity deviation log (VDL), which is calculated by combining the sonic log with the neutron-porosity or density log. This artificial log can determine the main pore types in carbonates. This study shows that the pore types distinguished from cutting samples have a good correlation with the VDL results.

(#123724) Reservoir evaluation of Bangestan Group, southwestern Iran

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In southwestern Iran, deposition during the middle Cretaceous to middle Miocene was affected by tectonism and structural trends that are parallel to the Zagros Suture. The depositional environment involved a flat ramp and the studied field has no structural expression in outcrop. According to our investigations, four oil zones were distinguished in the oil field: (1) Zone 1 includes the Asmari Formation and probably its lateral equivalent Ghar Formation. This zone consists of four subzones. It has medium porosity and water saturation respectively 13% and 18%. The dominant lithology is limestone with intercalation of sandstones, which indicates a good permeability with high reservoir parameters. (2) Zone 2 occurs in the Ilam Formation, with average porosity, water saturation and shale volume percentages of 11%, 38% and 4%, respectively. The dominant lithology of this zone is limestone. According to the reservoir properties this zone has three subzones. (3) Zones 3 and 4 occur in Sarvak Formation. Average porosity, water saturation and shale volume percentages are respectively 10%, 30% and 18%. Zone 3 according to reservoir properties has three sub zones.

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(#114180) A work flow for modeling the fractured reservoirs

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Historically, borehole imaging logs are acquired to locate major structural features, such as faults and fractures. The latest developments in interpretation techniques have broadened the scope of image interpretation. It is now possible to develop a more accurate simulation model of fractured reservoir by using fracture data from image logs. This project will try to combine the single well (10 wells) data and to come up with a model to evaluate a fractured reservoir field. The objectives of this fracture study are: (1) fracture characterization from 10 image logs. (2) Correlation between densities of fractures, well-by-well, in simulation. (3) Develop a more accurate simulation model by using fracture data from image log. In order to accurately model the fractured reservoir, we need to have detailed information about the fracture network in the reservoir. Having these data we need to run the simulation with the dual-porosity option, which is included in the conventional simulators. Using this technique we need to prepare certain engineering parameters for the two media and the flow through them. These data may be provided by well testing, core analysis, logs and geophysics analysis. The well log data can be used to better model the fluid flow in the media. The fracture density, aperture, orientation, porosity and permeability, which come from image logging data, are very useful information for dual-porosity modeling. Fracture density is a parameter that gives an idea about the matrix block size in the model. This is useful in the estimation of sigma, which represents the transmissibility between matrix and fracture. By using the aperture information, we can estimate the fracture permeability and porosity. The fracture orientation helps us in aligning grid coordinates with the flow direction.

(#119048) Possible contribution of 4-D microgravity to reservoir monitoring

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Monitoring of fluids in reservoirs has become an essential tool for the control of the development of hydrocarbon fields. Repeated microgravity measurements can determine gas-water or gas-oil contact displacement in time. Gravity modelling was performed to test its effectiveness in the case of gas-water movement in reservoirs (pumping, water-flooding, etc.). Several aspects of the gas-saturated reservoir were changed in the model including its size, depth, porosity and the density contrasts between fluids. The process of gas or steam injecting/pumping was also simulated. It was found that such processes can be observed by time-lapse (4-D) microgravity, but the success depends on local conditions. As an example, a water-flood process in a semi-horizontal 20-m-thick reservoir layer with 10% porosity was modeled. The results proved the feasibility of detecting the gravity signal caused by the moving flood-front even at a depth of about 2,000 m.

However, in some real cases, the conditions may differ from the model's assumptions; for example the gas-water density contrast can vary due to pressure and salinity. Therefore, each proposed application of the method has to be preceded by a feasibility study based on 2.5-D, 3-D and 4-D gravity modelling using all available local parameters. Another application is the monitoring of CO^2 sequestration. With respect to the low-amplitudes for the expected gravity signals, the measurements have to be highly accurate, and the vertical displacements have to be controlled. The monitoring system could be significantly improved by the application of repeated borehole gravity measurements. The efficiency of the technique has already been proved by time-lapse surveys in Alaska, France, the Netherlands, Italy and elsewhere, where the gravity response to fluid movement far exceeded the signal confidence level.

(#118164) Reservoir surveillance and logging applications for brownfield optimization

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As more of our fields come to the later stages of their life, there is a drive to optimize production. To do that reservoir management and surveillance is crucial for the understanding of the reservoirs. Due to difficulties in completing surveillance programs and logistical constraints, limited surveillance has resulted in large uncertainties. The past decade has seen tremendous growth in the number of high-angle and horizontal wells while the declining production from mature fields has presented us with complex well-production issues.

New production logging technology is now helping to provide a better understanding of fluid movement and enabling high confidence in decisions leading to successful interventions. Production logging in high-angle wells that produce a mixture of fluid phases is challenging because of the associated complex flow that radically changes the physics and technology of the measurement. Depending on the borehole deviation, the velocity and fluid holdup of different phases can change dramatically for a given flow rate. We present field examples that show the value of regular surveillance and some of the methods that can be used in obtaining good results. We will demonstrate the added-value of comprehensive flow diagnosis and the positive implications for various surveillance objectives during brownfield optimization. The benefits are two-fold: successful well interventions in the short term, and valuable information for reservoir management in the medium to longer term.

(#118648) Applications and pitfalls of stochastically built static model realizations on reservoir characterization and STOIIP distribution of clastic reservoirs of southern Oman oil fields

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The oil fields of southern Oman consist mainly of fluvial to glacio-fluvial rocks of Palaeozoic age. The two oil fields that were studied comprise stacked clastic reservoirs with large variation in NTG and scale of heterogeneity. The geological characteristics of these reservoirs posed significant challenges in constructing and selecting static model scenarios for simulation and field development. The static models of A and B oil fields, which have 29 reservoir zones, were constructed using stochastic methods and history-matched. These reservoir models presented unique combinations of properties in terms of GRV, NTG, well density and height of the transition zones. This provided an opportunity for testing the impact of these parameters on stochastic model realizations in terms of facies and oil-in-place distribution. The low- and high-case static model scenarios were constructed following two different methods. In the first, low and high case facies logs were created using different petrophysical cut-offs, and used for building low- and high-case static models. The second method used an automated workflow in Petrel^{TM} to generate 60 stochastic realizations of each base-case model. The facies distribution and oil-in-place ranges of the static models, from both methods, were analysed and compared. The results were used to optimise the selection of model scenarios for simulation and field development planning.

(#116083) Potential fields: An effective guide for hydrocarbon exploration and development

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Improving prospect assessment and field structure mapping was achieved with the guidance of specially filtered gravity and magnetic data. The potential fields data was augmented with 2-D and 3-D seismic data to analyze several case studies in the eastern Arabian Basin. New approaches were integrated involving the tectonic development of the Arabian Plate, local stress and strain partitioning that control the location, size and orientation of the hydrocarbon structure traps. Several case studies showed the success of this technique, particularly where hydrodynamic data was incorporated. Tilt-filtered gravity and magnetic data, residual gravity data with different wavelengths, and the magnetic Theta mapping filter proved to be very effective techniques for enhancing the basement shape, edges and detailed geometries. It was also observed that the basement architecture controlled the basins geometry and their filling history. Several sub-seismic faults with different trends were interpreted. The EW-trending fault zones appear to be strain-partitioning faults where different closures at the two sides of each fault proved to be hydrodynamically separated.

The interpretation indicated that a strong penetrative basement structural grain controlled the traps. This grain is believed to cause compartmentalization between some closures. In summary, integrating the specially filtered potential field data, seismic and hydrodynamic data with the new approaches in the tectonic development of the eastern Arabian Basin can support and enhance the seismic image of reservoirs in both exploration and development case studies.

(#118369) Forward seismic modeling of Khuff-equivalent outcrops, central Saudi Arabia

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Rocks equivalent to the Permian-Triassic Khuff-A and -B reservoirs crop out near Buraydah in central Saudi Arabia. An outcrop-based geocellular model 600 m x 385 m x some 30 m was used to compute 3-D synthetic seismic models used to evaluate how much improvement in resolution of conventional seismic would be required in order to detect stratigraphic variability visible in the outcrops. The outcrop-based geocellular model was scaled up for seismic modeling by addition of a similar but simpler model below it as well as acoustically constant buffer layers above and below to make a final model 110 m thick. Based on laboratory velocity and density measurement from outcrop plugs, an average acoustic impedance value for each facies was used to convert the facies model into an impedance volume with appropriate values.

The 3-D synthetic seismograms were produced using both a 1-D vertical-convolution algorithm and a 3-D exploding-reflector algorithm at 30, 60, 120 and 240 Hertz (Hz) peak frequencies. The 30 Hz models show no apparent seismic impact of the underlying geological model. At 60 Hz and above vertical and lateral variation in reflector character is observed. This variation, when mapped, is a useful approximation of stratigraphic variation across the geocellular model. Current acquisition and processing techniques, providing peak frequencies around 30 Hz, do not appear to provide data from which Khuff stratigraphic variation may be detected. Based on this study it is reasonable to assume that improvements in acquisition and processing, raising the peak frequency to around 60 Hz, may provide data from which such interpretations can be made.

(#118722) 3-D VSP's provide high-resolution seismic images for improved reservoir monitoring and characterization

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Enhanced reservoir characterization and monitoring is necessary to optimize and increase production from the huge Middle East oil fields. Currently surface seismic is used to image reservoir structure and aid in the prediction of reservoir property changes away from borehole control points. With borehole seismic or vertical seismic profile (VSP) images, which provide better vertical resolution and higher signal-to-noise ratio, it is possible to observe more detail and build more accurate reservoir models. In an effort to overcome the limitation of surface seismic to characterize reservoir properties, such as porosity and fluid saturations, a new VSP approach was undertaken. Two high-resolution 3-D VSPs were acquired simultaneously with a new surface seismic survey. At two wells an integrated team comprised of specialists in engineering, drilling, geophysical operations, geophysical applications and seismic interpretation planned and executed two 3-D VSP projects together with a new 3-D surface seismic survey. A 126-level multi-component geophone tool, combined with thousands of source points, made this the world's largest 3-D VSP. The 3-D surface seismic and 3C 3-D VSP were acquired with the same source points to minimize the associated costs and allow for detailed integration between them. The 3-D VSPs can also be used to monitor saturation changes in the reservoir. A 3-D VSP can be repeated more often and at lower cost than a full-field surface 3-D seismic survey. The results of a time-lapse VSP can be used to determine if 4-D or time-lapse effects are detectable and verify when a full-field 3-D surface seismic should be acquired. Based on the success of this 3-D VSP pilot, other 3-D VSP projects are being planned to help overcome production and monitoring challenges.

(#119006) Diagenesis of the Asmari Formation (Oligocene-Early Miocene), Dezful Embayment, southwest Iran: Implications on rock-typing and reservoir modelling of a giant oil field

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The reservoir quality of the Asmari Formation in southwest Iran is believed to be primarily controlled by fracturing and diagenesis. This contribution refines the diagenetic evolution of this formation, providing invaluable data for assessing reservoir heterogeneities and optimising rock-typing. About 250 thin sections from five wells were analyzed through conventional cathodoluminescence and fluorescence microscopic techniques. Representative samples were studied by means of scanning electron microscopy. $\delta^{18}O$, $\delta^{13}C$, and $^{87/86}Sr$ signatures for major host-rocks and diagenetic phases. Microprobe and fluid-inclusion analyses were also performed.

A paragenetic sequence has been projected onto the burial curve of the field. Some of the featured diagenetic phases (e.g. equant/sparry calcite, dolomite, anhydrite) induce bulk-rock porosity enhancement or destruction. Seepage-reflux dolomitisation during burial produced dolomicrospars (polymodal, planar-e dolomites, crystal size: 10-100 μm). Where the matrix is completely replaced by these dolomicrospars, inter-crystalline porosity is enhanced. Coarser crystalline dolomites (greater than 100 μm) exhibit aggrading neomorphism resulting in tight inter-locking crystalline texture (less porous). Fluid inclusions analyses demonstrated that the coarse dolomites precipitated at temperatures around 70° C. With increasing burial and fracturing, sparry calcite cement prevailed and seems to have incorporated early phases of oil. Compression post-dated the calcite phase and resulted in tectonic stylolites, some of which were subsequently opened during renewed fracturing, dissolution and anhydritisation. Finally, additional phases of fracturing and dissolution pre-dated oil emplacement. The results of this study have been incorporated in the workflow of rock-typing, which proved to be necessary for effective reservoir modelling and subsequent improved-oil-recovery of the studied field.

(#122666) Fault-plane migration in the Bidhand strike-slip fault system by anti-clockwise rotation, southern Qom in central Iran

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The NNW-oriented Bidhand strike-slip fault system cuts the Cenozoic rocks of the Urumieh-Dokhtar volcanic arc in the southern Qom area, (200 km south Tehran) central Iran. Structural evidences show that the Bidhand Fault is a major strike-slip fault in this area with at least 16 km of horizontal displacement across the Eocene volcanic rocks. The *Z shape* of the fault geometry indicates two compressional terminations are in the northwestern and southeastern areas. The structural observations indicate that most of the displacement occurred in the western block and the major extension occupied in the southwestern termination. Numerous sills were intruded along the feather-shaped tension fractures in the southwestern ter-

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mination of the fault. Counter-clockwise rotation of the northern part of the Bidhand Fault and the northwestern compress ional termination resulted in a change from strike-slip to reverse movement along the northern segment. This phenomenon caused the termination of the fault to become too long compared to the length of the Bidhand strike-slip fault in the straight central segment. Also, young volcanic rocks were intruded along the fault due to the creation of free space by rotation. The extensional termination of the fault in the southwestern area was also folded, rotated and thrust to the east of fault due to the counter-clockwise rotation of the Bidhand Fault. By this rotation, new fault planes were generated along the central segment of the Bidhand strike-slip fault that cut the earlier generated fault planes.

(#118956) Characterizing petroleum fractions for compositional reservoir simulation

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In compositional reservoir simulation, equations of state (EOS) are extensively used for phase behavior calculations. Proper characterization of petroleum fractions, however, is essential for proper EOS predictions. In this paper, the most common characterization methods for *pure*, *undefined*, and *plus* fractions are presented. A set of equations for predicting the physical properties of *pure* components is proposed. The equations require the carbon number as the only input. They accurately calculate properties of pure components with carbon numbers in the range 6-50 while eliminating discrepancies therein. Correlations for characterizing the *undefined* petroleum fractions assume specific gravity and boiling point as their input parameters. If molecular weight is input instead of boiling point, however, the same molecular weight equation is rearranged and solved nonlinearly for boiling point. This makes their use more consistent and favorable for compositional simulation.

Most experimental studies of hydrocarbon mixtures group components with a carbon number higher than six in one component referred to as the plus fraction or C_{7+}. Splitting (re-extending) and lumping (grouping components into several pseudo-components) methods of C_{7+} enhance EOS predictions. The widely-used splitting and lumping methods are revised. A worthwhile aspect of the paper, however, is that it proposes a new splitting method. The new method compared well with other methods for all tested data sets. Another aspect of the paper is that all coding has been done in an object-oriented manner. Whereas most phase behavior coding has been developed using the traditional FORTRAN language, which is a natural choice from the view point of continuity in downstream data processing. This natural choice may not necessarily be the optimal one. In fact, the use of an object-oriented language offers flexibility in programming and allows the different parts of the code to be described easily as if they were real world objects.

(#123474) The use of spectral decomposition and seismic attribute volumes in mapping of truncating carbonate units

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The mid-Cretaceous Natih Formation produces oil and gas in northern and central Oman. It consists of seven main carbonate members intercalated with shales of variable seal quality. The carbonate and shale sequence forms a total thickness of about 500 m. Previous and ongoing work suggested that conventional structural plays are creamed and that the future of Natih exploration lies in identifying stratigraphic sub-plays. The Natih truncation play consists of carbonate units truncating against the base Tertiary unconformity. Mapping of the truncating carbonate units is critical in verifying existing leads and identifying new ones. Various seismic volumes were examined out of which spectral decomposition slices volume (frequency slices), seismic envelope volume (instantaneous amplitude) and a coloured impedance volume (seismic inversion) proved useful for mapping the lateral extent of Natih truncations. These volumes yielded two comparable sets of truncating Natih unit trends. Most of the trends are compliant with well data and modelling results. Furthermore, a new well drilled to target a deeper objective confirmed a Natih trend. Despite this confidence, imprints of seismic data quality were noted and a seismic re-processing project was initiated to overcome observed seismic artefacts. Combining available well results with the seismic data and associated attribute volumes resulted in refining current Natih interpretation that allowed for an improved understanding of some Natih prospects.

(#117609) Seismic attribute analysis in understanding the facies distribution of Minagish Formation in western Kuwait

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Hydrocarbon production from the Valanginian Minagish Formation in Kuwait is limited to the western Kuwaiti fields like Minagish and Umm Gudair. Exploratory efforts in other parts of the country for this play-equivalent have met with limited success. The primary reason for this was the lack of trap integrity in the western part of the country and unfavorable facies development in the north and northeast. This presentation examines the integration of seismic analysis and geological understanding in deciphering the paleo-basin configuration for this play in the western part of the country. Based on the application of seismic attributes and seismic waveform analysis techniques, an edge of the prograding, high-energy facies was interpreted. This facies corresponds to the middle unit of the Minagish Formation, the main producing interval in the western Kuwaiti fields. A 2-D seismic dataset has provided the general trend of the facies, whereas with the help of the 3-D seismic it was

possible to delineate the approximate edge of the facies boundary. Spectral decomposition and other seismic attributes were applied in the interval of interest when mapping the zone of facies change. This study has highlighted a potential stratigraphic-structural exploration play fairway corresponding to the Minagish Formation. Seismic-attribute mapping and seismic-waveform characterization were found to be efficient tools in understanding the distribution of facies for this play. Recent drilling results have corroborated the interpretation by encountering a thin reservoir facies coincident with the zone of seismic facies change.

(#116766) Middle Miocene stratigraphic traps in Drava Depression, Croatia

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The main aim of this study is to present an interpretation of potential stratigraphic traps by using seismic attributes and well data. It is possible to predict the occurrence of stratigraphic traps and the spatial distribution of facies through the interpretation of depositional paleoenvironments. The area of interest is in the northwestern part of Drava Basin, situated in the southern rim of Pannonian Basin, Croatia. The interpretation was applied to the Miocene Moslavacka Gora Formation consisting of lithotamnium limestones and biocalkarenite sandstones. These sediments form one of the main reservoirs in the largest onshore Croatian gas-condensate Molve field. We integrated well data from this field and seismic attributes from an undrilled area to reconstruct the paleoenvironment. Coherence, amplitude and peak-spectral frequency slices for flattened seismic horizons revealed sedimentary bodies suitable for delineation as potential stratigraphic traps. Based on the well data and seismic-attribute maps, a sediment thickness map was constructed. A high-energy fluvial delta system was interpreted. Stratigraphic traps are proposed in linear sandy distributary channels, mouth bars and backreef sediments. Deltaic sediment bodies were very complex to interpret and sometimes impossible to track. However the seismic attributes helped us to obtain a clearer picture of the depositional environment. We used recent delta systems as analogues for the occurrence and possible thickness of sediments. Due to the mature exploration stage of this area and lack of undrilled structural traps, it is necessary to apply techniques that will introduce stratigraphic traps as a main exploratory target.

(#118915) Charge evaluation of the South Rub' Al-Khali Basin, Saudi Arabia (Part II; see Bell et al. for Part I)

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The South Rub Al Khali Company (SRAK) is exploring for gas condensate in two contract areas, which together encompass an area of about 200,000 square km. For the evaluation of SRAK's first exploration well in the Rub' Al-Khali basin, a comprehensive geochemical analysis program was implemented. The latest mud-gas technology (Geoservices' Flex-Flair Technology) was deployed to accurately measure gas compositions and isotube sampling was performed for mud-gas isotope logging. Cores were taken in the Silurian Qusaiba Formation for source-rock evaluation, as it was recognised that source-rock quality and characteristics could be markedly different from the nearest calibration point, which is several 100 km away. Finally, *fluid inclusion screening* and *crusher-CSIA* (compound specific isotope analysis) were performed to provide an integrated analysis of the petroleum systems. Crusher-CSIA is a Shell proprietary analysis that measures the composition and carbon-isotope ratios of gas trapped in fluid inclusions or adsorbed to cuttings. Based on these carbon-isotope ratios, gas-to-source rock correlations were made, and it was shown that at the well location, at least two different Paleozoic gases were present. Finally, these results from the geochemical well evaluation were added to the model to produce an updated view on the Paleozoic petroleum systems in the Rub' Al-Khali Basin.

(#117991) Field data performance of curvelet-based noise attenuation

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This study presents the efficacy of curvelets, a recently developed mathematical transform, in attenuating random and coherent linear noises in a stacked dataset from the Middle East. Our main motivation to seek a new, advanced noise-attenuation tool is that even though conventional filtering techniques such as median filtering and FX-deconvolution remove respectable amounts of noise, they also harm the signal. The curvelet transform is a recently developed mathematical tool that represents an image using a linear, weighted combination of special elementary functions that resemble small pieces of a band-limited seismic reflector (Candes and Donoho, 1999). Each curvelet elementary function has a characteristic dip, frequency (thickness), and location. The localized nature of curvelet functions, along with their dip and frequency characteristics, makes the curvelet transform particularly suitable for attenuating noises in seismic data. In seismic data, most noises differ from the underlying geological signal in terms of the dip, frequency, and/or location. Consequently, signal and noise separate more effectively in the curvelet transform domain than in other conventional transform domains that do not simultaneously exploit all these attributes. This powerful property enables us to separate the geologic signal from the noise by carefully muting appropriate curvelet components of noisy data. Our results demonstrate that the curvelet-based approach provides superior noise attenuation, with minimal impact on the desirable signal components. In conjunction with the preceding multiple

attenuation steps that were employed on the dataset (see presentation by Baumstein et al for details), the noise suppression significantly improved the structural and quantitative interpretability of the dataset, thereby validating the efficacy of our approach.

(#122326) A comparison between different rock physics models in carbonate reservoirs for fluid substitution

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The accuracy of estimation of saturation changes in carbonate reservoirs, using time-lapse seismic or amplitude-versus-offset (AVO) studies, depends on several factors such as repeatability, rock-physics models, fluid and rock properties. The precision of these methods is highly dependant on the accuracy of the rock-physics models, which vary from carbonate to sandstone reservoirs. There are several theories that compare the elastic properties of dry and saturated rocks. These theories are divided in two main groups: poroelastic theories and effective medium. Poroelastic theories include Gassmann's theory and Biot's theory; the former being the most commonly used in rock physics. Models based on Gassmann's theory use special assumptions that are based on the properties of loose sandstone at low frequencies. These properties, in some cases, cannot be used for other lithologies (e.g. carbonates). Effective-medium theories include the *differential effective medium* (DEM) theory and *self-consistent* (SC) theory. Generally, if a rock's microstructures are compatible with the model's assumption, then the model can be effectively used. In the rocks with spherical and connected pores (i.e. loose sandstone) Gassmann's equation is suitable at low-frequency. For granular rock (i.e. sandstone), SC models provide the best match. In most of carbonate rocks, there are isolated pores and fractures, and these microstructures are compatible with the DEM assumption. This presentation will review previous works, and provide a comparison between the mentioned models using laboratory tests on carbonate and sandstone core samples from a field in southwest Iran. The results will show that the DEM model is most compatible with the dense and low-porosity carbonate samples.

(#123717) Outcrop study and petroleum implication to identify reservoir quality trend on potential deepwater play system at Kendeng Zone, eastern Java, Indonesia

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Exploration success in the deep-water turbidite play at Makassar Strait, Kutei Basin, Indonesia, has interested explorationists to review the geological setting for other deep-water turbidite system. BPMIGAS exploration team responded by evaluating Indonesian basins with possible deep-water turbidite plays, including the Kendeng Zone. The evaluation was based on studying the regional trend of proven deep-water plays in the Makassar Strait and the field geology of the Kendeng Zone. The EW-trending Kendeng Zone forms a deep trough that contains deep-marine turbidites. In the Pliocene-Pleistocene, the setting was shallow-marine and fluviatile on its eastern part. The source rocks occur as part of the turbidite system and exclusively in association with the sands and siltstones, which contain type III terresterial kerogen. The traps are formed by a combination of stratigraphic components and anticlines associated with gravity-driven extension-toe-thrust systems. The structures become younger to the east (outer belt). Hydrocarbon migration was most likely along vertical pathways. The Kendeng Zone is similar to the Makassar Strait in some aspects. It also is a toe-thrust structure, which becomes younger to the north or to the outer belt. The presence of several oil and gas seeps and dead oil in conglomeratic sandstone in the Kabuh Formation indicate an active petroleum system. In outcrop, the Kerek Formation includes a fan lobe with cleaner sand in the turbidite systems. Unfortunately, volcanic material has reduced the reservoir quality in the southern part of Kendeng Zone. Source rocks are predicted from the Pelang and Ngimbang formation. Miocene-Pliocene rocks in the Kendeng Zone are potential reservoirs. The reservoir quality of the turbidite system improves from south to north. The toe-thrust system at outcrop may cause the trapping to be less effective. The blind-toe thrust, onlap-trapping to the toe thrust system may provide a play geometry. Another play may be the subthrust trapping on the toe thrust system.

(#123490) Deposition, age and Pan-Arabian correlation of late Neoproterozoic outcrops in Saudi Arabia

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Ongoing field mapping and sample analyses of late Neoproterozoic outcrops in Saudi Arabia has provided insight into the deposition and correlation of these strata across the Arabian Plate. Outcrops of the Jibalah Group display the same three-fold internal stratigraphy regionally across the Arabian Shield, indicating deposition within a single, laterally continuous basin that evolved from proximal fluvial conditions at its base, to a marine shelf setting at the top. Furthermore, distal marine limestones of the Muraykah Formation appear directly correlatable across the Arabian Plate with the Khufai Formation of Oman based on similarity of facies, relative stratigraphical position, carbon-isotope stratigraphy and age dating. SHRIMP analyses of zircons from tuff beds within the Muraykah Formation have yielded robust U-

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Pb ages of 588–600 Ma. The newly identified Kurayshah Group in northwest Saudi Arabia comprises a sequence of terminal Neoproterozoic fluvial clastics and basalts that unconformably overlie the Jibalah Group. In one location, basal Kurayshah conglomerates contain sandstone clasts from the underlying Muraykah Formation. Field relationships also indicate that Kurayshah outcrops are older than the pan-Arabian, basal Cambrian unconformity of c. 540–520 Ma. The Kurayshah Group most likely represents backarc sedimentation and volcanism associated with the final stages of Arabian Shield terrane assembly during the late Neoproterozoic. A distinct sequence of post-depositional structural events is regionally mappable within the Jibalah Group in northwest Saudi Arabia, beginning with an initial phase of mild transpression and folding, followed by a major extensional collapse and culminating with Najd-trending shearing, folding and uplift. A final, terminal Neoproterozoic phase of Najd shearing and transtension preserved both the Jibalah and Kurayshah outcrops in small pull-apart grabens on the Arabian Shield, prior to the pan-Arabian, Early Cambrian uplift and peneplanation of c. 540–520 Ma.

(#123983) Visualization of pre-stack P-wave seismic data anisotropy

Ru Nie (China University of Mining and Technology <nr@cumt.edu.cn>) and Jianhua Yue (China University of Mining and Technology)

It is now widely accepted that seismic anisotropy is taken as a lithological indicator. The derivation of subsurface anisotropy yields numerous benefits for both exploration and development of hydrocarbon reservoirs. In this presentation a novel method for visualizing anisotropy from pre-stack P-wave seismic data is shown. The method is helpful for both building anisotropic velocity models of the subsurface and characterizing lithology. Furthermore we are certain that measuring subsurface anisotropy is the first necessary step for exploration and development of oil and gas reservoirs.

(#118349) Small fields modelling from satellite image to subsurface: Reducing the uncertainty on the position of a field-bounding fault

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This field in South Oman was studied in PDO by an integrated team using a multi-disciplinary approach. The modelling effort focussed on capturing the main uncertainties and assessing the impact on the field development. For the field, one of the main uncertainties was the position of the field-bounding fault. The field consists of an half-anticline terminating against a graben fault in the north. This graben fault is the southern fault of a prominent graben. The graben faults are seen on

satellite images of the area. The wells start in the graben and drill through the graben fault in the overburden. To constrain the location of the graben fault, all available data was used to construct a mechanically consistent 3-D fault interpretation. The resulting mechanical interpretation was compared to the 3-D seismic interpretation of the fault. The seismic interpretation placed the fault considerably further south. Seismic imaging of the fault was problematic due to the extent of the graben faults all the way to the surface, and strong multiples of the overburden. Multiple 3-D models were created based on both mechanical and seismic interpretations to assess the impact of the fault positioning on field size and development planning. The mechanical interpretation has been driving an attempt to drill the field further north than previous wells, which has resulted in a successful well in 2007. This presentation describes the methodology to quantify the uncertainty around the graben fault position and the impact of the uncertainty on field development planning.

(#118667) 3-D pore pressure prediction using seismic data in an oil field in southwest Iran

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Overpressure in a formation, caused by abnormally high fluid pressures, is a concern during all phases of oil field operations including exploration, drilling, well completion and reservoir management. Pressure prediction from seismic data is an important step for both the exploration and the drilling processes. During the exploration process, pressure information can provide insight into fluid behavior, seal integrity and reservoir presence. The pore pressure prediction method, based on the seismic velocity field, is a common method for constructing a 3-D pore pressure cube. In this study, the resolution of stacking velocity was improved using sonic logs and a geostatistical calibration method. In this calibration procedure, the differences between the velocity derived from sonic logs and stacking velocity were calculated, and then the calibration parameters were obtained. These parameters were interpolated in the velocity grids. Effective pressures were calculated using the measured pore pressures and the calculated overburden pressures at well locations. The coefficients of Bowers equation were calculated using borehole data. Using the Bowers equation the calibrated stacking velocity cube was converted to the effective pressure cube. The pore pressure cube was constructed by computing the differences between the overburden pressure cube and the effective pressure cube. Finally the predicted pore pressure cube was calibrated with regard to the measured pore pressures at well locations. In an oil field in southwest Iran, some carbonate formations encounter abnormal pressure zones. In the area of study, the stacking velocity was improved, and then the pore pressure cube was made accordingly. The predicted pressures

show good agreement with regard to the measured pressures at well locations.

(#115613) Gulf of Aqaba Paleostresses status and rifting events

Abdelwahab Noufal (Cairo University, Egypt <anoufalus@yahoo.com>) and M. Dia Mahmoud (GEOPEX Limited, Egypt)

Natural fractures and faults are the primary pathways for hydrocarbon migration along with production in many reservoirs. In addition, critically stressed faults (pre-existing faults active in the present stress field) can systematically control permeability, and hence high fluid flow. The Gulf of Aqaba represents the arm of the Red Sea, which separates between the Arabian Plate and the Sinai Peninsula; it considered as a part of the complex East African Rift System. Despite its unique strike-slip fault system that is considered one of the world's finest natural laboratories for investigating the different stages of development of strike-slip basins, it is the least understood of all basin types. This field-based study will integrate the paleostress status of the Gulf of Aqaba blocks including Wadi El-Ghaib, Morakh District, Wadi Quseib and Wadi Tueiba-Wadi Taba. Slip data of more than 3,000 minor faults were measured. Processing and analyses of this data, set in reference to detailed mapping and field relations of the syn-rifting and pre-rifting lithologic units, revealed four tectonic events through the geologic history of the gulf. These are: (1) Aquitanian-Burdigalian (Early Rifting) event of σ_1 43°/WSW, σ_2 45°/ESE and σ_3 10°/SE; (2) Late Middle to Late Miocene (Synrifting) event of σ_1 35°/SW, σ_2 42°/SW and σ_3 12°/SE; (3) Pliocene (Late rifting) event of σ_1 38°/SSW, σ_2 of 50°/SE and σ_3 of 10°/SW; and (4) Post Pliocene-Late Holocene (Postrifting) of σ_1 50°/SSE, σ_2 of 30°/SSW and σ_3 of 10°/SSW.

(#115614) Mechanisms of fractures-microfaults initiation and propagation, west-central Sinai Peninsula, Egypt

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The Suez rift basin is accompanied by many fractures and small fault swarms that are smaller in scale than 1.0 m. They play an extremely important role in hydrocarbon-trap integrity and related exploration risks, as well as controlling most of the geomorphologic features that are manifested along the Gulf of Suez. In this study the fractures and the microfaults were analyzed in the area that extends from Wadi Sidri to Gebel Abu Lasaf, on the eastern side of Sinai Peninsula and along the Gulf of Suez. An outcrop-based analysis of the fracture and microfaults architecture, along the well-exposed rocks, was undertaken to determine the controls and the predictability of fracture elements. The aim was to provide a guide for subsurface fracture and microfault swarms as

well as a means to predict damage zone prediction. The fracture analysis revealed that the variation in the fracture spacing is often proportional to bed thickness. The spatial distribution of faults, hybrid fractures and pure open-mode fissures with wide variations in strike, appear to be related to their location relative to the center of the Suez Rift initiating stress tensor. Most fractures and microfaults in the Gulf of Suez have a strike that trends NE (oblique to the spreading-normal direction), whereas those with Gulf-trends are less common. Most of the rock units are dominated by the NE- to EW-trending fracture and microfaults; however the Eocene rock units, Nukhul and Rudeis formations, show the dominance of the NW trend. This pattern may be related to the events that affected the Gulf of Suez rift basin.

(#117425) Enhancement of static correction by turning-ray tomography

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The presentation deals with the use of turning-ray tomography to reconstruct the velocity image of the near-surface from the first arrival of seismic data. This technique is a velocity-inversion procedure, which uses turning-rays (diving rays, continuously refracted direct rays) from any acquisition geometry to iteratively solve for velocity in the near-surface between the source and receivers. This technique does not require simplifying assumptions such as a constant velocity layered model with lateral homogeneity. The method is highly efficient and capable of recovering velocity structures in geologically complex areas. The efficiency of this tomographic technique has been tested on synthetic data. We used a data set from southern Algeria to evaluate a typical case. The results clearly showed improvements in the quality of the seismic section using the static corrections obtained by turning-ray tomography when compared to one based on classical method known as DRM.

(#114185) Accurate calculation of hydrocarbon saturation based on log data in complex carbonate reservoirs in the Middle East

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To generate saturation functions (capillary pressure drainage curves or J-functions) to initialize complex carbonate reservoir simulation models always presents challenges to petrophysicists and reservoir engineers. This is especially the case when Special Core Analysis Laboratory (SCAL) data is neither available, nor rock-property trends such as the porosity-permeability relationship, which are used to assign a saturation function in 3-D models. As a start, the proposed method required the initial water-saturation distribution in the 3-D

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model. It can be calculated by log-derived J-functions if the permeability distribution is available. Otherwise, it can be calculated using a software program that is based on water-saturation log data. For each *reservoir rock type* (RRT), the capillary pressure calculated from the height function, was plotted versus log-derived water-saturation. Depending on the data scatter, ranges of water saturation can be determined in order to generate a capillary pressure (Pc) curve for each range. The Pc curves per RRT were based on water-saturation ranges regardless of the rock properties trends. To differentiate between such saturation functions, a script file was written to discriminate between these regions per RRT. Saturation numbers were then assigned for each region and these were used to initialize a massive and complex carbonate reservoir simulation models (Shu'aiba Formation) in the United Arab Emirates. The initial water-saturation profile from log data matched the water-saturation calculated by the dynamic model in 90% of the wells (more than 100 wells at initial water saturation). The difference in original-oil-in-place calculations between the static and dynamic models was less than 2%.

(#118675) Effect of temperature and pressure on interfacial tension and contact angle of Khuff Gas Reservoir

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Knowledge of reservoir fluid properties is essential during the development phase in order to implement an optimal reservoir management strategy for properly exploiting the reservoirs. Interfacial tensions of reservoir fluids, as well as contact angle, are important parameters for many reservoir engineering studies. Examples are imbibition studies and calculation of fluid saturation in the gas-oil transition zone. Both *interfacial tension* (IFT) and contact angle of the fluids/rock system affect the distribution of fluids within reservoir rock material. The fluids distribution strongly affects the flow behavior and hydrocarbon recovery. Most of the available contact angle and IFT data for gas/brine systems are for room temperature and atmospheric pressure. Since actual values of reservoir temperature and pressure are frequently used in reservoir simulation models, a need to study IFT and contact angle at reservoir conditions was recognized. This study is an investigation of the influence of temperature and pressure on IFT and contact angle of Khuff gas and condensate fluids. Experimental results of IFT for the Khuff-C gas/brine system and condensate-A, B and C/brine system, over a range of temperatures and pressures, are reported. Also, results of contact angle for various samples of condensate/brine/rock material system are documented. The IFT between the Khuff-C gas and brine decreased with increasing temperature at reservoir pressure. Condensate composition affects IFT values for various condensate samples (from Khuff-A, B, and C). Contact angle values for Khuff-C gas/brine/ rock material system decreased with both temperature and pressure.

(#119040) Polarisation analysis of ocean bottom 3C sensor data

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In this study we analysed vector fidelity of direct P and reflected P-S arrivals from multi-component ocean-bottom (OB) data, by mapping apparent polarisation as a function of azimuth and angle of incidence at the seabed. This demonstrates vector fidelity of seabed sensors at its root, i.e. as the amount of distortion of the incoming wave's polarisation. We compared data from a cable system with data from nodes, as well as buried and unburied cable sensors. As expected, nodes show overall best vector fidelity. For OB cable data, on the other hand, buried sensors showed significantly better vector fidelity than unburied sensors, both for downgoing direct P-waves and upgoing P-S reflected waves. While both buried and unburied cable sensors exhibit vector infidelity to some degree in the direction along the cable, unburied sensors show in addition poor fidelity in the crossline direction. Vector infidelity of the unburied sensors may be misinterpreted as azimuthal anisotropy with a symmetry axis parallel to the cable.

(#118400) Sedimentology and petrographic study of the Upper Carboniferous-Lower Permian Unayzah Formation, Block C, Rub' Al-Khali, Saudi Arabia

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The lower boundary of the Khuff Formation has not been consistently established, since the basal siliciclastic unit is included by some authors in the Unayzah Formation and by others in the Khuff Formation. A regionally correlatable unconformity marked by thick caliche, soil horizons and colour changes is considered to be representative of fundamental changes in the depositional environment that marked the onset of the marine conditions of the Mid to Late Permian. Four siliciclastic depositional units were recognized below the pre-Khuff unconformity: basal Khuff clastics, Unayzah A, B and C depositional units. These units were related to regional tectonic and climatic events that prevailed during the Late Carboniferous to Early Permian times. The regional interpretations suggest the occurrence of the Unayzah C unit throughout Block C, Rub' Al-Khali Desert, Saudi Arabia. The presence of Unayzah B sandstone is likely in the southern part of the block, however the northern part is characterised by relatively less sandstone presence. A similar distribution with relatively good sandstone reservoir quality in the south and mixed reservoir/non-reservoir facies to the north is expected in the Unayzah A unit. The basal Khuff clastic unit is probably

characterised by relatively thin sandy reservoir facies throughout the block. The petrographic results indicate that the basal Khuff clastics and Unayzah A units may retain intermediate reservoir quality if the grains are sheltered from quartz cementation by illite coatings. The Unayzah B and C units do not show illite coatings and need to be sheltered from quartz cementation by other porosity preserving mechanisms, such as early hydrocarbon migration.

(#118193) Petrography and petrology of Rebat Intrusion, southern Sanandaj-Sirjan Zone, Iran

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A number of mafic-ultramafic intrusive bodies of Late Triassic-Jurassic age are exposed 30 kilometers to the south of Rebat village (east of Hearat city, Yazd Province) and southwest of Shahrebabak city (Kerman Province) in Iran, These bodies have a variable lithology consisting of wherlite, olivine-pyroxenite, serpentinized dunite, anorthosite, olivine-gabbro, gabbro, monzo-gabbro, quartz-bearing monzo-gabbro to quartz monzonite. The results of geochemical studies indicate a cumulative character for both mafic and ultramafic rocks for these intrusions. The mafic rocks seem to have originated from magmas with low-silica alkaline elements (including titanium) and high calcium and magnesium content. Differentiation and contamination of the magma at the final stages of crystallization gave rise to a wide range of intermediate rocks. The assessment of the (La/Yb) N ratio points towards the formation of mafic-ultramafic rocks from mantle material that were highly depleted, signifying that their parent rocks were poor in garnet. The magmatic series of the mafic rocks fall within alkaline compositions, whereas the differentiated ones belong to sub-alkaline varieties. Comparison of mafic-ultramafics with normalized patterns of primary mantle indicates that they formed due to extensive partial melting of mantle rocks. The tectono-magmatic environment of the mafic rocks falls in the realms equivalent to alkaline basalts of intra-cratonic rifts, whereas that of the differentiated rocks have affinities with continental basalts.

(#123780) Stratigraphic interpretation of the Cenozoic and Cretaceous succession of Kurdistan, northern Iraq: New evidence from well and outcrop data

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Following the successful drilling of the Tawke-1 discovery well in the Dihok PSA licence in Kurdistan, northern Iraq, a sequence of development and appraisal wells have been drilled in the area. Current geological studies are focusing on the integration of regional fieldwork, seismic data, lithostratigraphy, wireline log and biostratigraphic data. In order to improve the understanding of the stratigraphy and intra-field correlation of the study area biostratigraphic analysis has been conducted using ditch-cuttings samples primarily, together with selected field samples. Biostratigraphic analysis employed the integration of quantitative micropalaeontological data (thin section and routine), nannofossil and selected palynological data. Data generated from the current exploration programme, together with unpublished research study data from one of us (SS) suggests that significant revisions of the age of parts of the Cenozoic succession should be considered, *vis-à-vis* current published ages (van Bellen et al., 1959). The faunal and floral content and age relationships of the Pila Spi, Gercus, Khurmala and Kolosh formations are also described. High-resolution micropalaeontologic and nannopalaeontologic sampling of the Shiranish, Mushora, Kometan, Gulneri, Dokan and Qamchuca formations has refined their ages, and further revisions are suggested to the existing published stratigraphic summary (van Bellen et al., 1959). The application and integration of the biostratigraphic data derived to date (chronostratigraphy and palaeoenvironmental interpretation), to intra-field correlation and regional geology is considered. These new findings provide a strong tool in the continued exploration of the area.

(#119032) Ride out the storm or set a new course: Tackling the oil industry labour and skills crisis

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Faced with a critical shortage of professionals in key technical and operational areas, oil and gas companies are bringing back retirees, tapping new sources for skills, looking to accelerate professional development, and raising sign-on fees to attract seasoned staff. As activity and investment in the petroleum sector continues to put huge strain on delivery capacity, the industry has been unable to keep pace with building its human resources. A combination of an ageing workforce, increasing workload, specialist skill requirements, limited supply of new graduates, and escalating people costs, suggests a *perfect storm* is brewing that will stall the growth ambitions of many.

(#123502) Delineation of upper Unayzah reservoir sand from seismic inversion: A case study from Awali field, Bahrain

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The Unayzah Formation is a Lower Permian non-marine siliciclastic unit immediately underlying the Permian-

Triassic Khuff Formation. The Unayzah is bounded by unconformities and comprises lithologies ranging from quartzose sand, argillaceous sandstone, silty sandstone, mudstone and minor carbonaceous shale. Gas was discovered in Bahrain in the Unayzah Formation during 1940–1950 at about 11,000 ft. The formation is typically 350–400 thick at Awali field. There is a characteristic vertical succession of two major fining upward cycles; the lower cycle (130–250 ft) consists of lower and middle Unayzah and the upper cycle (135–220 ft) corresponds to upper Unayzah. The upper Unayzah is upward-fining with massive sand at the base and inter-bedded sand at the top. The stacked sands in the lower interval were possibly deposited in a braided channel system. The inter-bedded interval represents channel margin and flood-plain facies. The upper Unayzah reservoir sands are characterized by lower acoustic impedance based on evidences from the well logs. The presentation elaborates on a seismic inversion study carried-out for the delineation of the upper Unayzah reservoir sands based on seismic-impedance characteristics. The steps involved in the study included well-to-seismic correlation utilizing statistical and well-derived wavelets, structural model-building and model-based inversion of the Awali 3-D seismic data. From the evaluation of the seismic inversion results, it was inferred that the upper Unayzah reservoir sands are better-developed in the southwestern part of the Awali structure.

(#116091) Sedimentary environments and sequence stratigraphy of the Asmari Formation, northwest of Dezful Embayment, SW Iran

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The Oligocene-Miocene Asmari Formation is the most productive reservoir in the folded belt of the Zagros Basin, in southwestern Iran. In the study area, it is of Early Miocene age, and composed mainly of limestone, dolomite, sandstone, anhydrite, siltstone and shale. Its lower contact with the Pabdeh Formation (Paleocene-Oligocene) is conformable and its upper contact with the Gachsaran Formation (Middle Miocene) is unconformable. Detailed petrographic and well-log analysis of the formation led to the recognition of five facies belts, which were deposited in a distally steepend ramp platform. Two third-order depositional sequences were recognized. The sequence boundaries of the older AS1 sequence are type one (SB1). The maximum flooding surface (MFS) of AS1 is near the top of Pabdeh Formation and its highstand systems tract (HST) occurs in the Asmari Formation. The younger AS2 sequence has a lowstand systems tract (LST) that can be recognized by deep basinal evaporites of the Kalhur Member and sandstones of Ahwaz

Member. The TST is thin, whereas the HST is thick with permeable facies. The sequence boundaries of AS2 are type one (SB1). The lowstand systems tract of the AS2 sequence formed during the fall of sea-level in Early Miocene. In the deep narrow paleo-seaway of the study area, deep basinal evaporites of the Kalhur Member were deposited. Interfingering of pelagic facies with the evaporites and the presence of thick salt is the best criteria for deep-water evaporites. The carbonates, situated updip of these evaporites, may be the most productive units in the Asmari Formation. Their productivity may be due to the preferential distribution of reservoir facies along the break of ramp and the spatial relationship of dolomitization with evaporites. Accordingly stratigraphic traps could be developed with the best reservoir units situated in the HST.

(#119613) Hydrocarbon system model for the Arabian Plate

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The thermal maturity of Arabian Plate source rocks was modeled using ExxonMobil's Stellar™ basin-modeling software utilizing new plate-wide structure-contour maps at 19 unconformities spanning the Phanerozoic Era. The amount of sediment eroded at these major unconformities was estimated. Timing of generation and hydrocarbon yields were constrained by kinetic analysis of samples of source rocks, and the results were integrated with maps of source-rock distribution to arrive at the volume and extent of oil and gas generation. Lateral migration from the areas of mature source rocks was evaluated using the structure-contour maps, and the results were calibrated with hydrocarbon occurrences and geochemical correlations. The amount of missing section affects the timing of hydrocarbon generation for some source rocks in the Arabian Plate, which may be important for understanding the timing of migration relative to trap formation. Some reservoirs were apparently filled with oil soon after they were deposited. Geochemical correlation and characterization of oils from the region suggests lateral migration of at least 150 km from some areas of mature source rocks. Regional seals limit the extent of vertical hydrocarbon migration for most hydrocarbon systems. However, there are *holes* in many regional seals, caused by erosion or by faulting and fracturing, that allow oil and gas to migrate vertically to younger reservoirs. Some seals appear to be *leaky*, especially fine-grained siliclastic formations, which contain residual oil stains from migrating fluids. Kinetic analyses show that most source rocks on the Arabian Plate behave as anticipated by their organic-matter type. One exception is the Silurian Qusaiba Formation, which yields mainly gas and light liquids slightly earlier than a standard Type-II source rock.

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(#117993) Basin analysis of the southern Yemeni Red Sea: Significance of halokinesis upon subsalt source rock maturities and hydrocarbon migration dynamics

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An integrated seismic stratigraphy and 2-D basin-analysis investigation of the relatively unexplored southern Yemen Red Sea suggests significant hydrocarbon potential exists. In particular, the study revealed the significance of halokinesis upon dynamic trap structuring, fault-migration pathways, and the concomitant *cooling* effects of salt thermal refraction upon sub-salt source rock maturities. The integration of supra-salt borehole lithologic and geochemical data with reprocessed 2-D seismic reflection and refraction data provided a constrained 2-D basin analysis of sub-salt to supra-salt stratigraphy. Such observations revealed that this region is the product of four principle tectonic phases of rifting and crustal stretching ß's: (1) Pre-18 Ma, ß = 1.22; (2) 18–14 Ma, ß = 1.195; (3) 11–5 Ma, ß = 1.21; and (4) post-5 Ma, ß = 1.24. The second episode mobilized the salt and created primary fault and structural migration pathways. Cumulatively, these stretching episodes and concomitant heat pulses modeled both as steady-state and rifting-model end-members suggest that source rocks of the supra-salt South Gharib B and those of the sub-salt clastics are under all conditions mature enough to generate hydrocarbons. Important to reservoir GOR fill and migration pathways, the modeling demonstrates that maturities and timing of expulsion and migration vary between the two models, and thus the chronology of the fault mechanical stratigraphy is critical. By applying a *lithologic replacement* approach, the temporal and spatial effects of the sub-salt strata can be shown to have cooled significantly owing to heat refraction and thermal conductivity of overlying salts. As permeability of the faults is unknown, two spectral end-members of fault-pathway potential were modeled to bracket the uncertainties. Resulting migration vector-volume fill maps for the four scenarios (steady state, rifting, permeable faults, impermeable faults) differ markedly in structural fill and GOR of potential hydrocarbons.

(#118955) Determining the effective viscosity of a shear-induced state (SIS) surfactant, C16TMASal, during injection into a porous medium

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This presentation explains an experimental study that was performed to determine the effective viscosity and the suitability of surfactant C16TASal for use in en-

hanced-oil-recovery. This surfactant has dilatancy properties that could be effective for mobility control during a water-flood. The project involved extensive injection of a single-phase brine with various concentrations of surfactant into a core sample taken from a carbonate reservoir in West Texas. From the data collected, the effective viscosity as well as the effect of time on viscosity ware defined. From the results, it was found that the fluid did have favorable fluid characteristics but required very large volumes of surfactant before the behavior occurred. This large volume requirement indicated that adsorption could be occurring within the core sample. This presentation will indicate whether this formulation was a good candidate for enhanced oil recovery projects. It also discusses some possible future studies that could be conducted to find a new or different surfactant formulation, or other potential co-surfactants to reduce adsorption.

(#124896) New data on the geological build-up of the central Oman Mountains

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In 2006 and 2007 geologists from MOL-Hawasina LLC conducted field trips to examine the structures in the central Oman Mountains. Bedding, cleavage, fold and fault data were recorded during the field work. We found numerous differences from the otherwise excellent published BRGM map. According to this fieldwork, we re-drew the published geological map, and compiled new geological cross-sections across the Hawasina Window. Three main structural units build-up these mountains: (1) the uppermost Semail Ophiolite, (2) the oceanic Hawasina Nappes, and (3) the lowermost tectonic unit, the Arabian Platform. Within the Hawasina Nappes, the slope-facies Sumeini Unit, the abyssal Hamrat Duru Unit and fragments of the oceanic island Umar Unit can be differentiated. In the Hawasina Window, the oceanic nappes come to the surface from beneath the ophiolites. Five main differences are noted between our interpretation and the formal geological map. (1) The original stack of Hawasina Nappes underwent out-of-sequence thrusting, and at least three complex nappes were recognised. (2) The tectonic boundaries of the Hawasina Window are steep, normal- or strike-slip faults, crosscutting the original nappe boundaries. (3) Two main strike-slip corridors in the southern and northern edges of the Hawasina structure were mapped. (4) Three main antiforms were recognised inside the Hawasina Window. (5) We observed several occurrences of small gypsum diapirs in the Wadi Dil-Wadi Hawasina area; these evaporite bodies rise from beneath the Hawasina Nappes. We suggest that they belong to the Palaeozoic of the underlying Arabian Platform. Both MOL Hungarian Oil & Gas Plc and Hawasina LLC Oman Branch wish to thank the Exploration Directorate of Ministry of Oil & Gas of the Sultanate of Oman for the continuous support to the work.

(#118710) Hierarchical framework basis for multi-scale Khuff reservoir modeling

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The Khuff platform is a carbonate-evaporite ramp with wide facies belts that experienced a multi-phase diagenesis. This resulted in a complex pore-type architecture with a wide scatter of petrophysical properties. Traditionally, lithostratigraphic correlations, tailored to environmentally specific facies successions, were used as layering schemes. Such correlations, although locally robust, become uncertain when crossing facies or property boundaries. In order to build robust subsurface models, we employed a hierarchical layering scheme, based on a combination of different tools such as sequence stratigraphy and acoustic impedance contrasts. The purpose of this approach was to link data from exploration to pore scale in a genetic framework. At the highest-level faults and key markers, derived from seismic were used to build the structural framework. An intermediate *acoustic level* was established from the integration of well data, blocked open-hole log and synthetics using a Shell in-house tool. The next level was based on correlatable Khuff facies sequences. The lowest level was populated with geobodies based on outcrop analogue studies from the Oman Mountains that integrate LIDAR, global positioning system data (GPS) and outcrop gamma-ray logs. This hierarchical approach allowed partitioning of the complex Khuff property continuum into genetically related classes: matrix pores, fault-related solution-enlarged pores and facture pores in genetically related layers and structural elements. Thus, a hierarchical framework was established; (Level 1) key seismic markers; (Level 2) acoustic boundaries; (Level 3) Khuff facies sequences that are infilled at (Level 4) with geobodies. An example of the workflow from the Yibal field of northern Oman will be shown.

(#118649) Mapping Lower Zubair channel sands using 3-D seismic data: A case study

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The Lower Cretaceous Zubair Formation is a 1,300–1,400 ft thick clastic unit consisting of alternating sand-shale sequences. At the base of the formation thin sands were encountered in many wells in Sabiriyah field. The sands are discontinuous and not mappable from 2-D seismic data due to limits in seismic resolution, lateral facies changes and the complexity of fault system at the Zubair level. Mapping of the sands from 3-D seismic data was accomplished when a thick reservoir fluvial sand (of about 54 ft) was encountered in a single deep exploratory well in Sabiriyah field. To map the areal distribution of the sand we used a 3-D seismic data set (bin size of 25 m x 25 m) together with borehole data and a structural map at the top of sand. Horizon flattening and seismic amplitude, at the level of interest, were used to delineate the configuration of the sand channels. Illumination of reservoir sand by spectral decomposition brought-out differences in sand thickness. Subsequent drilling of the play confirmed the channel geometry of the reservoir. The study, for the first time, upgraded the prospectivity of the Zubair Formation in the field and highlighted potential sweet spots for further exploration and development.

(#118714) Saudi Aramco Permian-Carboniferous (Unayzah) stratigraphic nomenclature of Saudi Arabia

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Saudi Aramco is pursuing an aggressive non-associated gas exploration and development program of Permian-Carboniferous sandstone reservoirs. This has resulted in a considerably increased understanding of the depositional facies, systems tracts, and stratal architecture of these biostratigraphically lean and lithologically heterogeneous siliciclastics, typical of continental successions. Various nomenclatures, which include numerous inconsistencies, are in use throughout the industry with no clear standards that adhere to the rules of stratigraphic nomenclature. A stratigraphic nomenclature is proposed, which defines a number of discrete units within a sequence stratigraphic framework. These sequences can be mapped across Saudi Arabia and into correlative units defined elsewhere on the Arabian Plate. The Unayzah Group is defined as those rocks above the Hercynian unconformity and below the pre-Khuff unconformity. They range in age from mid-Carboniferous to Early Permian. This group is subdivided into the glacio-fluvial to glacio-lacustrine Juwayl Formation, overlain by the post-glacial (fluvial, playa and eolian) Nuayyim Formation. The Juwayl Formation is further subdivided into the Serpukhovian? to Asselian Ghazal Member (which includes the Unayzah C Reservoir) and the Asselian to Early Sakmarian Jawb Member (which includes the Unayzah B Reservoir). The Nuayyim Formation is subdivided into the Late Sakmarian Wudayhi Member and the Artinskian Tinat Member (which includes the Unayzah A Reservoir). These newly defined stratigraphic units are separated from each other by unconformities (*sensu lato*). Middle Permian and younger siliciclastics above the pre-Khuff unconformity retain their original name, the Basal Khuff Clastics. Those rocks contain the Khuff Clastics Reservoir.

(#119021) Integration of borehole images and shear sonic anisotropy for quantitative fracture evaluation

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The characterization of natural fractures can greatly improve recovery in many hydrocarbon reservoirs. Surface seismic, borehole seismic and borehole sonic techniques are commonly used to estimate effective anisotropic elastic properties, but interpretation is often ambiguous. Effective medium theories used to infer fracture properties from seismic or sonic data usually assume the cause of the anisotropy without necessarily taking into account the *in-situ* geological complexity. However, in boreholes, the measurements of borehole images provide a very high-resolution picture of the borehole wall under geological conditions. The quantitative link between geological fractures observed *in-situ* and the effective elastic properties of the near-wellbore region is often missing. We developed a methodology to model and interpret borehole dipole sonic anisotropy related to the effect of geological fractures using a forward modeling approach. We used an excess-compliance fracture model that relies on the orientation of the individual fractures, the compliances of the fractures, and the compliances of the host rock. We extracted the orientation of individual fractures from borehole image log analysis. We validated the model using borehole resistivity images and sonic logs in a reservoirs in the Middle East region, where we observed significant amounts of sonic anisotropy and numerous fractures. We will show that using a few adjustable fracture compliances, we can explain the fracture-induced anisotropy response. Predicted fast-shear azimuth and slowness anisotropy are compared to the measured ones and help to discriminate natural fractures and stress effects. This information can be used as input to seismically constrained fracture characterization workflows.

(#120519) Changing paradigms: A stratigraphic record from a carbonate-clastic incised valley fill formed during Holocene sea level rise, Doha, Qatar

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Observations made from construction excavations, surface mapping, and historic photographs in the vicinity of Doha, Qatar, revealed details of the Holocene transgression and its depositional history. We interpret the sediments as a product of a transgressive systems tract, which filled an incised valley of the Eocene Dammam Formation. This channel was cut during sea-level lows from the Tertiary through approximately 20,000 years before present (YBP). The incised valley is aligned north-south, parallel to the shoreline. Eastward-directed fluvial runoff from the peninsula was redirected at the coast by erosional remnants of Pleistocene carbonates, which form shoreline-parallel ridges along the present coastline of Qatar. As sea level rose, transgressive sediments filled the channel and were preserved by resistant, cemented hardgrounds and a topographic high to the east. Sediments in the incised valley recorded a nearly complete record of Holocene transgression. Earliest channel-fill sediments are aeolian-derived quartz sand, deposited under shallow-marine, tidal conditions. These sediments were likely sourced from dunes migrating southeasterly across the Qatar Peninsula, which overwhelmed early transgressive marine carbonate systems. As sea level rose and the source of quartz sand was reduced, marine carbonate conditions predominated and an open-marine succession was deposited, culminating in a series of hardgrounds. C^{14} age dates, facies analysis and previous studies suggest that sea level rose rapidly to present shoreline levels as early 8,060 YBP. Transgression culminated with a 5,500-7,000 YBP highstand at least 2 m higher than present-day levels. Since that time, sea level has fluctuated within 2 m of present sea level in short duration cycles. In addition to revising the Holocene history of Qatar, this study documents that carbonate depositional systems may form reservoir facies tracts within demonstrably fluvial, subaerial incisions.

(#124186) Using GIS 4-D technology for analyzing and monitoring oil & gas production in Awali field, Bahrain

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The Awali field is located in the central part of the main Bahrain Island. The field is an asymmetrical anticline trending NS with multiple stacked carbonate and clastic reservoirs cut by an extremely complex faulting system. The field has been producing since 1932 and contains 16 oil-producing and 6 gas-producing reservoir zones. Awali field has a complex production history and is in a mature state with a gas-injection scheme that has been in operation for many decades. The field requires close monitoring while history-matching is a challenging effort. In order to monitor the changes in subsurface and surface logistics efficiently, a 4-D GIS technology was implemented for the field. It yielded cost-savings and an easy procedure to follow. In addition to the petroleum engineering tools, like reservoir simulation and management studies, the 4-D GIS technology readily helped in tracing the injected fluid (gas and water) chronologically. This has not only helped time management but also the evaluation of reservoir performance. This presentation highlights the impact of the GIS technology, which will be very useful for other oil companies in the region to implement.

(#122167) Paleogene stratigraphy and petroleum potential of largely volcanic play Jatibarang Formation, onshore northwest Java Basin, Indonesia

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The northwestern Java Basin in Indonesia is a prolific hydrocarbon province that has attracted extensive exploration and production activities for many decades. The morphology of the basin, as imaged by seismic data, suggests several features that may be attributed to a remnant volcanic system. The basin is filled with an epiclastic sequence comprised of various alluvial deposits, as well as pyroclastic, volcanogenic and lake sediments. The lowermost sequence rests uncomformably on fractured/rubbled Upper Mesozoic basement rocks, and consists of pyroclastics, volcanogenic and sedimentary rocks of the Jatibarang Formation. The volcanic rocks occur as primary proximal volcanic deposits inter-layered with fall volcanic rocks (tuff and tuffaceous sand). In turn, the Jatibarang Formation is unconformably overlain by fluvial, deltaic and marine sedimentary rocks of the Talang Akar Formation. In comparison to the Jatibarang tuffs, the Talangakar tuffs are more basaltic in composition and have a greater amount of subvolcanic lithic rock fragments (coarse-grained volcanic rock), which consist of diabase and microdiorite. Log analysis revealed a proximal to distal distinction between the volcanic facies, pyroclastic to *volcanogenic* clay content, and diagenetic modification due to mineralogical instability of the volcanic section. The reservoir potential may have been preserved within the naturally fractured volcanic rocks. Both formations are considered to hold viable petroleum plays provided by the inter-woven volcanism-sedimentation processes and multiple subsequent tectonic activities during inversion.

(#118335) Delineation of Mauddud carbonate reservoirs in Raudhatain and Sabiriyah fields of northern Kuwait using seismic inversion and porosity modeling

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Raudhatain and Sabiriyah fields were discovered during mid-1950s and approximately 500 wells have been drilled over the two structures. The Upper Cretaceous Mauddud limestone is one of the main producing reservoirs in both fields and it has good porosity development, which ranges between 15–35%. In both fields, well-productivity is highly variable due to rapid lateral variation of porosity and permeability. The key challenge is to improve the description of the reservoir and its internal heterogeneity so as to guide infill drilling. Seismic inversion has emerged as an invaluable tool for characterizing the reservoirs and quantifying their properties. It combines geophysical, geological and petrophysical data through a robust inversion scheme to extract more meaningful reservoir information. In this study, the Mauddud carbonate reservoirs in Raudhatain and Sabiriyah fields were used to demonstrate the benefits of deterministic seismic inversion. A relationship between acoustic impedance and porosity was established using well data. It was applied to the acoustic impedance volume to transform it into porosity volume. This porosity volume was then used to generate porosity maps for the Mauddud reservoir interval. The generated map showed additional areas of good porosity development in around both field areas. This study has provided a better understanding of the internal reservoir heterogeneity and facies variation. Moreover it has provided a strong base from which to refine the planning of development, placement of new exploratory wells in and around the structures, and in optimizing the oil production.

(#124000) Utilizing seismic-derived rock properties in well planning, drilling and geosteering Khafji stringer sands, Zuluf field, Saudi Arabia

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The northern offshore Khafji Stringer Sands contain substantial oil reserves, yet imaging these sands has up to now been elusive. The target sands and shales do not have sufficient acoustic impedance contrast to appear in normal incident seismic data and the distribution is too erratic to be predicted with subsurface stratigraphic techniques. *Simultaneous Offset Inversion* was used to separate sands from shales in the angle-stack domain based on elastic rock properties. Used for the first time at Saudi Aramco, the results have made it possible to target thin sands using geosteered horizontal wells to maximize reservoir contact, production and ultimate recovery while reducing horizontal well tortuosity and drilling time. In this case study we will review the simultaneous offset inversion methodology and implementation as successfully applied to three horizontal wells.

(#123984) Delivering an efficient, robust and comprehensive petrophysical evaluation in carbonate environments

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Several researchers have shown that petrophysical properties in carbonates are strongly correlated to pore

microgeometry. Therefore, accurate petrophysical evaluation requires the integration of texture-sensitive logs such as nuclear magnetic resonance (NMR), borehole images and full waveform acoustic logs. Lithology and porosity evaluation in the presence of anhydrite requires the use of capture spectroscopy logs. A comprehensive and accurate petrophysical evaluation of carbonates requires the use and integration of a large suite of logs. As a result, an easy-to-implement workflow is needed to rapidly and reliably integrate all this data. This presentation shows an interpretation methodology and workflow that facilitates the easy integration of logging measurements essential to accurate carbonate evaluation. The workflow, which is the result of decades of research into carbonate petrophysics, shows that the method provides a rapid, robust, and comprehensive petrophysical evaluation including lithology, porosity, tar quantification, pore-geometry evaluation, permeability and rock types, fluid saturations, relative permeability, and primary drainage capillary pressure curves. Examples are presented from major Middle East carbonate reservoirs. We also present a software implementation that leverages the methodology through an intuitive and user-friendly workflow, enabling the delivery of a comprehensive report on-time. The method has been applied on several wells in the Middle East within a few hours of the receipt of log data at the processing center. On a couple of the wells the results were available before the tools had been pulled out of the well, permitting decisions on subsequent data acquisition and on the completion of the well.

(#119007) Evidence for top Shu'aiba exposure and incision in Block 5, offshore Qatar: Regional consequences

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An integrated subsurface data set has provided evidence for the presence of karst fissures and platform incision at the top of the Shu'aiba Formation in Block 5, offshore Qatar. These observations have significant implications for the Late Aptian palaeogeography and related understanding of the distribution of Late Aptian-Early Albian siliciclastics in the region. Well-log correlations show an incised-valley feature reaching a maximum depth of about 30 m. A seismic time slice at this stratigraphic level displays the geometry of the incision, which has a strongly meandering shape, is multi-storey, and reaches locally a maximum width of 8 km. Core from the incised channel shows an overall deepening up trend. The infill starts at the bottom of the valley with tidally influenced fluvial sandstone deposits, rich in organic matter and amber, followed by estuarine tidal channel and bar deposits; and, finally, tidal bar and shoreface deposits at the top. This was interpreted as a transgressive back-fill succession of a major valley system. Additional evidence for exposure comes from numerous clay and sand-filled fissures at the top of the Shu'aiba Formation. These observations show that the Shu'aiba in Block 5 was exposed before deposition of the Nahr Umr. From a palaeogeographical point of view, it means that the Bab Basin was separated from the siliciclastic sources in the northern part of the Gulf area. The presence of the large river systems does, however, provide a solution for the large-scale influx of siliciclastics during early Nahr Umr deposition.

(#122644) Predicting reservoir quality in the Ara stringer reservoirs, South Oman Salt Basin

Zuwena Rawahi (PDO <zuwena.rawahi@pdo.co.om>) and Xiomara Marquez (PDO)

Hydrocarbon production from exploratory wells penetrating the Neoproterozoic-Cambrian Ara stringers in the South Oman Salt Basin (SOSB) have had variable results due to a heterogeneous pore system, multiple evaporitic cements and bitumen plugging. Ongoing sedimentary and diagenetic work, integrated with geochemistry and the structural evolution of the SOSB, showed that porosity enhancement is controlled by multiple dissolution events. The present-day porosity distribution is predominantly secondary, formed by dissolution in the deep burial environment. Pore-reducing processes started with the formation of reservoir bitumen, followed by anhydrite and then halite cementation. Two types of immobile non-pyrolisable bitumen can be distinguished petrographically and are thought to have precipitated from migrating or trapped hydrocarbons. The first bitumen phase occurred as thin rims, lining and partially filling secondary inter-crystalline and stylolite-related pores. It was observed in the earliest developed inter-crystalline secondary pores, suggesting migration soon after early burial replacement dolomitisation and a first dissolution event. The second phase of bitumen was observed as droplets in large dissolution vugs and is associated with microfractures, saddle dolomite and late diagenetic calcite. Mobile, pyrolisable bitumen has not been observed in thin section; its presence is indicated by geochemistry data. Other important pore-occluding phases are halite and anhydrite cementation. Preliminary results indicated that although cementation is abundant, its extent at reservoir scale can be laterally limited, and locally, trends can be mapped. Bitumen plugging is difficult to predict due to its multiple origins, this requires a better understanding of the relative timing of generation, expulsion and charge events.

(#117802) Providing new petroleum engineering graduates with the right development "*kick start*"

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Petroleum Development Oman (PDO) has launched a novel development program for graduates from Sultan

Qaboos University and UK scholars joining petroleum engineering. This program was jointly developed with training experts from Network of Excellence in Training (NExT) and first executed in September 2005. *Young professionals* are offered a multi-disciplinary *Blended Learning* opportunity called "PE for All", which combines formal *NExT* lectures customized to PDO needs, with a *red thread field development plan* (FDP) exercise from northern Oman. It consists of classroom discipline modules, syndicate work, practical experience in subsurface modeling, lectures in facilities, economics and project management with the final objective to present a FDP proposal to PDO managers. It raises the technical proficiency of recruits from different academic qualifications and social background to a similar minimum level of knowledge, such that they are better prepared for working in integrated high-performance teams. Development is evaluated using skill assessments by NExT assessors, combined with short tests after each module. Students are also evaluated on communication and behavioral skills and team-building. Final interviews match expectations and ambitions with business requirements before assignment to new departments. Once assigned, *work-place learning*, coaching, core-discipline training programs and facilitated-group events further develop real application skills. To date, some 130 recruits have successfully followed the *PE for All* foundation program, providing a sound basis for accelerated staff development and an important first step toward closing the middle gap between *old hands and new hires*. This is underpinned by pro-active recruitment at universities and structured on-boarding to ensure an exciting and motivating career start!

(#124025) Geophysical and geological modelling of potential carbonate reservoir of the Batu Raja Formation and its development strategy in western Java, Indonesia

Adi Ringoringo (Pertamina, Indonesia <afmringoringo@pertamina.com>) and Joko Padmono (Pertamina, Indonesia)

The Pondok Tengah field development project involves drilling 44 wells in two years in the carbonate reservoir of the Batu Raja Formation (BRF). The NW-trending field also produces from the fluvial deposits of Talang Akar Formation (TAF. This Batu Raja carbonate reservoir consists of a progradational sequence that is 150–200 m thick. Some zones with a porosity of 10–20 % have produced upto 1,500 bopd during tests. Currently the production is 4,000 barrels of oil per day from six wells. The hydrocarbon distribution in Batu Raja reservoir is controlled by a combination of both structural and stratigraphic aspects (facies changes), of which the latter is predominant as confirmed by 10 recently drilled wells. Two major faults impact the secondary fracture porosity.

The Batu Raja carbonate reservoir is regionally correlated southeastwards with the carbonate reservoir of Tambun

field. Several models from 3-D seismic data (attribute, variance and acoustic impedance) were constructed to understand the lateral and vertical continuity of the reservoir. The model is updated as new wells are completed. Some cores and advance logging were also conducted to determine the lateral and vertical heterogeneity of the facies distribution. Based on these studies plans are to produce 20,000 barrels/day for 15 years starting in 2009. This presentation will describe the geologic model within the field and strategy to develop the reservoir.

(#137294) Exploration Challenges in Oman

Abla Riyami (PDO, Kuwait)

This is a special session and abstracts are not submitted.

(#123763) Comparison of early structural evolution of the Red Sea and Gulf of Mexico: Exploration lessons

Donald A. Rodgers (Landmark Graphics, USA <drodgers@lgc.com>), James Pindell (Tectonic Analysis Inc.), Cokes Barn (Consultant, UK) and Thomas C. Connally (Consultant, Netherlands)

Significant exploration lessons result from the comparison of the early-mid Mesozoic evolution of the Gulf of Mexico and the Miocene-Recent evolution of the Red Sea. The Red Sea, a developing spreading margin preserving details of its evolution, varies from the *break-up unconformity* stage in the south to the *syn-rift* stage in the north. *Spreading phases* occurred concurrently rather than successively along this margin. A substantial salt basin developed early in the Red Sea spreading process. The Red Sea opening produced numerous half-grabens separated by basement blocks. Salt and post-salt sections along the Yemeni-Saudi Arabian coast exhibit raft tectonics, while diapirism predominates along the northwestern Saudi Arabian coast. Red Sea plays include pre-salt carbonates, clastics and post-salt clastics. The Gulf of Mexico Basin is a broad rift zone with subdued tectonically driven topographies during early deposition. The Triassic half-graben of the Gulf of Mexico Basin contains thick clastic sequences with no reported pre-salt carbonates. Thick salt sequences, separated by buried basement blocks, developed down-dip in numerous basins. Post-salt plays include the Norphlet sands, Smackover carbonates and younger Jurassic carbonates and clastics. The Red Sea tectono-stratigraphic model is roughly equivalent to the lower Upper Jurassic Louark Group. Post-salt Red Sea clastics are equivalent to the Norphlet, and Pleistocene and Recent carbonates correlate with the Smackover section. Red Sea pre-salt carbonates may correlate to the Gulf of Mexico Werner Anhydrite. Red Sea pre-salt production suggests the Gulf of Mexico pre-salt section should be re-examined. In both regions, half-graben clastics are unproductive and are not viable exploration targets.

(#123628) Reservoir simulation of a heterogeneous carbonate field, key sensitivities and dependencies, Kangan/Dalan Formation, Iran

Jens H. Rolfsnes (StatoilHydro, Norway <jrol@statoilhydro.com>), Daniel Berge Sollien (StatoilHydro, Norway), Arild Eliassen (StatoilHydro, Norway), Arnstein Waldum (StatoilHydro, Norway), Joanna Garland (Cambridge Carbonates Ltd., UK) and Ali A. Taghavi (Reslab Integration, Norway)

Gas-condensate production from a strongly heterogeneous carbonate field of the Kangan-Dalan (Khuff) Formation was studied through reservoir flow simulations. The dynamic behaviour and production performance were investigated for reservoir simulation models resulting from different geologic modelling strategies. Simulation models were scaled-up from 3-D geologic reservoir models populated with properties based on different stochastically generated facies distributions. Results for two qualitatively different stochastic modelling procedures were compared; one using a depositional facies model and another that includes diagenetic facies to account for diagenetic overprint of reservoir rocks and the corresponding alteration of properties. The differences in predicted production, resulting from the different modelling strategies, demonstrate the control on fluid-flow properties by diagenesis. Simulation results from the heterogeneous models were compared with those from a simple *layer-cake* -type model obtained from averaging well-log data in each reservoir zone. The results showed the impact of heterogeneity on production rates and ultimate production. Key model sensitivities in the prediction of fluid flow, initial fluid volumes and recoverable volumes will be discussed. In particular, the dependencies on choice of up-scaling techniques, the modelling of initial water saturation and the determination of residual gas saturation to water flooding are demonstrated.

(#119012) Faulting and fault interaction in porous siliciclastic reservoirs: insights from outcrop modeling of analogous reservoir rocks in Sinai (Egypt) and Utah (USA)

Atle Rotevatn (University of Bergen, Norway <atle.rotevatn@cipr.uib.no>), Haakon Fossen (University of Bergen, Norway) and John Howell (University of Bergen, Norway)

Fault overlap zones are generally considered to have a positive effect on fluid flow across otherwise sealing faults within subsurface hydrocarbon reservoirs. This study's aim is to assess the validity of this assumption, and to quantify the effects of relay zones on fluid flow. Overlapping faults (relay zones) have been studied and mapped in Arches and Canyonlands National Parks, Utah, using conventional as well as novel (Lidar scanning) techniques. Outcrop models were built and flow simulation was undertaken in order to increase the understanding of the effect of relay zones on fluid flow. Previous studies as well as our own show that overlapping faults commonly are associated with an over-thickened damage zone enveloping the entire overlap zone. As input to the reservoir models, the cores and damage zones of the faults in question were replicated based on detailed studies of tectonic deformation in sandstones in western Sinai (pre-rift Nubian Sandstone) as well as in Utah. Our results indicated that relay ramps nearly always represent a better conduit for flow than a low-permeable fault itself. However, our results also demonstrate that: (1) the presence of very low-permeable damage zone elements (e.g. cataclastic deformation bands) may destroy a relay zone's capabilities as a conduit to flow. (2) Pressure communication across relay ramps may be poor despite the geometric connectivity created by the ramp. (3) Depositional facies of the affected rocks have a significant bearing on how relay zones influence fluid flow.

(#119058) Recent advances on the facies and stratigraphy of the Dibsiyah Member of the Wajid Sandstones, southwestern Saudi Arabia

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The Dibsiyah Member forms the lower part of the Wajid Sandstone in southwest Saudi Arabia. In the type locality the section, as described on the geological map, is about 150 m thick and rests unconformably on the basement. The lowermost unit consists of a thin fluvial conglomerate passing upwards into fluvially-dominated coarse to gravely cross-bedded sandstones. The main part of the member is fully marine and includes tidal dunes and sand-wave complexes, intensively bioturbated sandstones (skolithos ichnofacies) and a subordinate amount of shoreface and beach sandstones. In detail, this marine succession shows superimposed cycles with tidal dunes at the base, bioturbated tidal deposits and finally thick, entirely bioturbated intervals. These cycles are interpreted as third- to fifth-order sequences, which are in turn organised in a larger transgressive second-order cycle as shown by the increase of the size of tidal bedforms and upward increase of bioturbation. The lack of chronological data for this formation does not easily allow a comparison with other Cambrian-Ordovician formations of Saudi Arabia. However, because both the Sajir and Risha members of the Saq Sandstone display similar transgressive trends including tidal features, we propose to correlate the Dibsiyah Member to one of the Saq Formation members as defined in northwest Saudi Arabia. If this working hypothesis is valid, the base Sanamah Member glacial erosion could have removed the entire Qasim Formation in this area. This is also supported by the total lack of storm- and wave-dominated

facies, which are very common in the Qasim Formation and absent in the Dibsiyah Member.

(#118908) Structural model of the Algerian offshore: Impact on style and dimension of traps

Nabil Saadallah (Sonatrach, Algeria <nabil7300@hotmail.com>) and Mohamed S. Tighilt, Sr. (Sonatrach, Algeria)

Algeria is structurally subdivided into two major tectonic provinces that are separated by the South Atlas Fault zone. In the south, the Sahara Platform is characterized by a thick sedimentary series with structures that formed during the Paleozoic Era. In the Northern Province, the Alpine domain is marked by Cenozoic mountain chains (Alpine orogenesis). The Sahara Platform holds most of the country's hydrocarbon resources, and intensive exploration has resulted in a more certain estimate of its petroleum reserves and resources. The Northern Province, including the Algerian offshore, remains underexplored. Because it is a part of the Alpine domain, the geology of the Algerian offshore is extremely complex, The Algerian offshore covers a surface area of approximately 100,000 square km located in the southern part of the Mediterranean Sea. The stratigraphy and petroleum systems of this basin are very poorly known. Borehole penetrations include one well (HBB-1) and two core drills (ARZ-1 and ALG-1). In addition 9,000 km of 2-D seismic data were acquired. The interpretation of the seismic data revealed important aspects such as basin geometry and the thickness of the sedimentary cover. The interpretation led to the subdivision of the stratigraphic units in the eastern part of Algerian offshore. This presentation will show a more detailed geodynamic model with a new interpretation of each sedimentary sequence. It will discuss their deformation style, show balanced cross-sections and the calculated extensional rates. The proposed structural model suggests an architecture involving pull-part basins. The impact of this structural modeling on the petroleum system will be related to the prediction of trap dimensions in the sedimentary cover.

(#118192) Seismic facies analysis based on hierarchical clustering in Jofair oil field, southwest Iran

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In complex sequences, particularly those boundary sequences with a low contrast in seismic impedances, neither seismic nor well data alone provide a full image of the subsurface architecture. Interpretation of 3-D seismic facies could help in understanding the complexity of the internal stratigraphic geometries of such sequences. The Gadvan Formation in Jofair oil field, southwest Iran, is an example of a complex sequences. In this study, an *agglomerative hierarchical clustering* procedure was utilized to categorize the seismic facies of this formation. In the hierarchical clustering, different seismic attribute cubes are integrated and divided into clusters of similar patterns. In order to make a feature space, which can discriminate different stratigraphic patterns, 10 seismic attribute cubes were generated using Paradigm's software. The application of principal component analysis reduced redundant data and noise by representing the main data variances with a few vector components in a transformed coordinate space. By projecting data onto these components, we eliminated attributes that have a linear dependency, without considerable loss of information. According to the eigenvalues of the covariance matrix of the attributes, seven principal components represented 94% of the data. Clustering was done based on a proximity matrix between samples. Several distance definitions were tested in order to build a meaningful cluster tree. By applying this method to the Gadvan Formation, we concluded that: (1) correlation and cosine distances provide the best results in the interpretation of the internal architecture of the formation, and (2) the cube derived from clustering appears to be more diagnostic for lateral variations than the original seismic reflection data or a single attribute.

(#118596) Verification of structural relationships in the Kazerun-Borazjan Fault Zone

Seyed H. Sajedi (NIOC, Iran <sajedi@niocexp.org>) and Farnoush Gholami (NIOC, Iran)

The Zagros Fold-Thrust Belt of southern Iran is a Neogene orogen that resulted from the collision between the Arabian Plate and Iranian terranes in the Eurasian Plate. In this mountain belt a set of N-trending faults that are, basement structures disrupt the NW-trending longitudinal Zagros folds. One of these faults, the Kazerun-Borazjan Fault Zone, stretches from the eastern termination of the Recent Zagros Main Suture, in the north, to the Iranian Coastline in the south. This zone is associated with anticlines and folds, and at the surface, it is delineated by two NS-trending linear structures that correspond to major dextral strike-slip faults. These faults are clearly evident on satellite images and seismic sections. In the vicinity of the Kazerun–Borazjan Fault Zone, joints that strike preferentially N-S are interpreted as shear-type features related to present-day tectonism. In addition, many minor strike-slip faults have affected the morphology of this area. One of the major effects caused by the strike-slip faults is the anti-clockwise rotation of Gisakan Block.

(#122656) Young professionals geoscientists and the power of networking

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People are social by nature and cannot live in isolation. Networking by all means between all levels is key to

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effective communication in today's organizations that are striving for excellence in their operations. The *Young Professionals* (YP) network was established in Oman in 2005 to bring together the diverse parts of the petroleum community including geologists and geophysicists, with a particular focus on new university graduates entering the industry. The YP network is part of a wider network that involves other disciplines to improve the integration between them as none of them work in isolation. The mission for the YP network is diverse and growing. It provides a means to share issues and build working relationships between people as well as their organisations. It allows young staff to be guided through new arrival complexities and accelerating development through understanding; providing direct contact to upper management It helps ensure work-place learning techniques are available to a wider group and helps in solving the approaching talent gap. It engages development discussions with the responsible parties guiding staff development. It provides partnership with active societies such as SPE, or more specialised ones like the GSO (Geological Society of Oman). It provides a voice for a different prespective on dealing with today's and future challenges. Engaging this *new blood* in any organization, with the right balance of freedom and guidance, maximizes the utilization of such force and keep the motivation at high levels.

(#124010) Fracture population of carbonate geological models using digital outcrop data

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The fluid-flow behaviour of carbonate reservoirs is, to a large degree, governed by the spatial configuration of discontinuities, particularly by the fracture network. The quantification of these discontinuities in subsurface data is highly challenging, in particular at an exploration stage when only seismic data might be available. We propose a novel methodology for populating fracture sets in carbonate geological models. The first step consists of extracting the stratigraphic and structural framework from the 3-D seismic. A 3-D stratigraphic method combined with ant-tracking allows the mapping of large-scale discontinuities and their associated attributes. This set of primitives is defined as a model repository. The second step is to populate the geological model with fracture sets by conditioning the discrete fracture network generation (DFN) on seismically observable features, such as horizon-folding (curvature) and fault displacement. The output fracture sets, generated by the DFN method, are tailored to the geomechanical history of the specific geological case by conditioning the DFN on characteristics

of the fracture distributions extracted from analogues. A major challenge in the development of the new methodology was to extract and quantify the fracture distributions from the outcrops in an automated manner. The parameterization of the distributions was chosen to be the fracture length, orientation and density in relation to stratigraphy, lithology and fault characteristics. The integration of the simulated fractures into the geological model leads to the generation of a detailed mechanical stratigraphy model which is useful for further permeability tensor computation and flow simulation.

(#119614) Structural characterization of the Cenozoic-Mesozoic at Balad field, Iraq, with emphasis on superposed structures

Kirk W. Schafer (ExxonMobil, USA <kirk.w.schafer@exxonmobil.com>) and Richard P. George (ExxonMobil, USA)

Balad field is located 60 km north of Baghdad on the western flank of the Mesopotamian foreland basin. Primary reservoirs are the Upper Cretaceous limestones of the Hartha, Sa'di, and Khasib formations. Interpretation of available seismic data over Balad reveals a superposition of structures that we use to constrain the structural evolution of central Iraq. Structures interpreted from 2-D and 3-D seismic data include: (1) sub-parallel, right-stepping, *en-echelon* faults that offset Upper Cretaceous reservoirs and that define two grabens (each about 4.0 km wide) oriented NW-SE; (2) a roll-over anticline within each graben affecting the Lower Cretaceous; (3) a fault-bounded anticline (half-wavelength of about 3.0 km) affecting the Triassic-Jurassic, with the long axis sub-parallel to the directly-overlying graben axis; (4) subtle anticlines (half-wavelength of about 1.0 km) affecting the Tertiary through Cretaceous, with long axes approximately perpendicular to the graben axes.

Interpreted syn-kinematic deposition of the Sa'di and Hartha constrains graben development to the Santonian and Late Campanian. Graben faults do not offset the Tertiary. Interpretation of several 2-D lines indicates that the Jurassic- and Triassic-level anticline may have developed as early as the Jurassic or as late as the Neogene. Importantly, the Triassic does not appear to be offset, in a normal-fault sense, by the overlying (Upper Cretaceous) graben faults. Hence, it is difficult to explain graben development by a continuous, upward-propagating, basement normal-fault.

The following conceptual models of structural evolution are considered both individually and in tandem: (1) extension and folding associated with left-lateral reactivation/inversion of an inferred basement fault; (2) contraction during the Jurassic followed by Late Cretaceous decoupled extension along inferred Triassic or Jurassic detachment(s). Subsequent loading from the Zagros during the Neogene induced regional tilting and subtle contraction.

(#123807) Unlocking the Upper Shu'aiba stratigraphic play in northern Oman

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Three years ago Petroleum Development Oman (PDO) started unravelling a Shu'aiba stratigraphic play in Oman. The reservoirs are thin prograding units deposited on the margin of the shallow Lower Cretaceous Bab Basin. They are sealed above by thick shale (Nahr Umr Formation) and laterally by intercalated argillaceous carbonates. The best reservoir is found in the subcroping shoaling part of the prograding unit. The reservoir units are generally too thin to be resolved by seismic. However, the clinoform geometries, despite the very gentle dips (1° to 2°), are sometimes visible on seismic mainly highlighted by tuning effects. In 2003-2004 a re-processing effort involving receiver-consistent "Al Burj" decon, a simple and practical high-order move-out method combined with a carefully revised velocity field, improved the data quality significantly and permitted the identification of several new Upper Shu'aiba features. To build a better understanding of the multiples and their generation, we have also been using a new kinematic multiple prediction method. The method has been proven robust as we have successfully predicted multiples that have been clearly identified on seismic and later validated by the wells. The detail of the method will not be covered in this presentation but examples will be given. This relatively simple and practical processing sequence has to a large extent been a key to unlock the Shu'aiba potential for PDO and should be of interest for others facing similar geological challenges. It is on-going work but since this play concept was first successfully proven in the PDO concession in 2003, the newly processed data has had significant impact on the play.

(#119065) Low-frequency hydrocarbon microtremors: Theory and seismic attributes

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Narrow-band, low-frequency (1.0–6.0 Hertz) microtremor signals are observed worldwide over hydrocarbon reservoirs. These so-called *hydrocarbon microtremors* possess remarkably similar spectral and signal structure characteristics, pointing to a common source mechanism, even though the depth, fluid content (oil or gas) and reservoir type may be quite different. Two possible mechanisms generating hydrocarbon microtremors are acoustic resonance scattering and resonance amplification. Resonance scattering occurs on the macro-scale and the characteristic spectral anomalies in the surface particle velocities are generated due to multiple reflections and scattering of seismic background acoustic energy between the reservoir and the surface, and within the reservoir. Reflections and scattering are caused by

complex impedance contrasts between a reservoir and the surrounding rock. Importantly, the effective impedance contrast can be enhanced or solely generated by abnormally high attenuation in the reservoir rocks caused by poroelastic effects. The second mechanism, resonance amplification, occurs on the micro-scale. Direct numerical simulations using Navier-Stokes equations and analytical solutions demonstrate that partially saturated pores exhibit a resonance frequency. This resonance mechanism can be approximated by a linear or nonlinear oscillator model. The spectra, spectral ratios, polarisation and time-variations of the measured surface particle velocities are considered for seismic attributes associated with hydrocarbon microtremors that may be identified and quantified. Understanding seismic attributes associated with different reservoir types enables verification for the theoretical explanations described above. Additionally, seismic attributes may provide typical reservoir-fingerprints for distinguishing different types of hydrocarbons. Reverse time modelling is applied to identify the origin of the microtremors.

(#118901) Reservoir characterization of fault-related dolomite bodies from outcrop analogs: Application to carbonate reservoirs

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Many subsurface carbonate reservoirs contain evidence for dolomitization associated with tectonic fluid circulation that has significant impact on reservoir properties. However, reservoir geometry and internal reservoir characteristics (diagenetic phases, porosity types, heterogeneity of pore networks) remain often poorly understood. Outcrop analog studies of Jurassic-Cretaceous carbonate platforms in France and Spain have potential application to dolomite reservoirs in the Upper Khuff Formation (Permian-Triassic) and the Garian Formation (Cretaceous, Libya). Depositional textures in the outcrop examples range from mudstone to oolitic grainstone. The transtensional tectonic setting was conducive to dolomitization by ascending Mg-rich fluids. Geometry and reservoir characteristics were studied using traditional and Lidar outcrop mapping, petrography, petrophysics, and 3-D-scanner pore network imaging. Fault conduits exerted a dominant control on dolomitization near fault corridors. Length and width of the resulting dolomite bodies vary from m-scale to 100s of m. Despite heterogeneous internal reservoir distribution, good reservoir properties are correlated with advanced dolomitization stages, whereas host rock texture has little influence. Pore networks are vuggy and inter-crystalline. With

increasing horizontal distance from faults, stratigraphy and local discontinuities (bedding planes, porous facies, burrows, fracture networks) controlled fluid movement. Planar and lenticular bodies of porous dolomites commonly are developed in permeable horizons. Bodies usually are dm- to m-thick, and they extend laterally between 10s of meters to several km. Despite the good reservoir properties often associated with fault-related dolomites, and the presence of suitable seal rocks, the fault corridors have an associated risk of hydrocarbon escape. Increased reservoir connectivity may result in high recovery and water production.

(#123722) Lebanon and Cyprus: New offshore opportunities in the Eastern Mediterranean Basin

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Lebanon and Cyprus have not to date been explored for oil and gas although they are highly prospective and located close to proven hydrocarbon systems. But this is likely to change. Newly acquired 2-D and 3-D seismic data in offshore Cyprus and Lebanon have imaged several structures that show indications of hydrocarbons. This area has already generated high interest in the petroleum industry with the launch of the first license round for offshore Cyprus. It will further gain attention when the forthcoming license round for offshore Lebanon is launched. There are several reasons why the eastern Mediterranean Basin is considered highly prospective. These include the regional sealing Messinian Salt, numerous reservoir intervals, large structural closures and well-known source sequences within the Mesozoic, which appears to be productive elsewhere in the region.

(#123137) The effects of rock texture and pore type on sonic velocity in dolomite

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In order to assess the controlling parameters for velocity in dolomites, the sonic velocities of 129 dolomite samples with different porosities were measured and their petrologic textures were determined using microscopy. The results revealed that sonic velocity is a function not only of total porosity but also of the pore type and rock texture. The measured velocities showed an inverse correlation with porosity, but departures from the general trends of correlation can be as high as 1,500 meter/second. These deviations can be explained by the occurrence of different crystal shapes, pore type, rock type and crystal size. When crystal shape and pore type were combined to classify the dolomite many relationships became apparent. Seven texture combination types were distinguished in the study samples. Rocks with texture combinations of anhedral and moldic (A + M) have relatively high velocities, whereas those with mostly euhedral shapes and inter-crystalline pore types (E + I) have relative low

velocities. Rock types partially explained the variations of velocities. Generally, grainstones have relatively high velocities, whereas mudstones have relative low ones. Breccias have the lowest velocities. Crystal size itself is very poorly correlated to sonic velocity except that large crystal sizes do not have slow velocities. However, if the crystal size of each combination-type is evaluated, the correlation improves. Because total porosity, together with pore type and rock texture, control sonic velocity in dolomite, it is possible to predict the velocity from these parameters. The highlight of this research is an empirical formula that predicts the velocity of dolomite.

(#116410) Understanding the gas hydrates in offshore eastern India

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Natural gas hydrates bind immense amounts of methane in sea-floor sediments of the Krishna-Godavari Basin in the eastern offshore India. Estimating hydrate resources is a difficult task because of the poor understanding of how they are distributed in their host sediments. The present study attempted to identify the gas hydrate zones, understand their distribution in the Krishna-Godavari Basin and to characterize their petrophysical properties with advanced borehole imaging and other tools. The geologic setting of the basin resulted in substantial volumes of sand being deposited as turbidites in channels and associated features within the zone of hydrate stability. The escape of gases or fluids through the sea floor, due to various factors, produced a variety of morphological features that can alter the physical properties of Recent sediments. Gas hydrate has been observed in several different forms associated with sediments, including isolated lenses and nodules, vein and fracture fill, finely disseminated crystals, and filling pores in coarse clastic units. The greatest concentrations of gas hydrate are found in sands and gravels where gas-saturated water can flow through the sediment. In these settings hydrate may fill most of the pore space. New-generation borehole imaging tools helped in understanding the texture and structure within the gas hydrate zone. They also helped in characterizing the petrophysical properties of the gas hydrates in eastern offshore India.

(#123967) Production from Najmah-Sargelu Reservoirs: A formation damage perspective

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Unconventional oil reserves occur in the Gotnia Basin, where the Jurassic Najmah, Sargelu and Marrat reservoirs are the main producing targets. The Najmah and Sargelu are predominantly carbonate formations, which have low matrix porosity and permeability; production

from these reservoirs relies mainly on fractures. During drilling, the pore matrix and fractures (including hairline and microfractures) can be invaded by filtrates and mud solids, and the presence of shale exacerbates the problem. In this situation, the selection of an appropriate drilling fluid is crucial. In the production phase, the damage to flow channels is usually due to the migration of fine particles, particularly after stimulation, and the damage may occur because of the accumulation of invaded particles in the near-wellbore area due to increased flow rates. The Najmah and Sargelu are proven reservoirs in many fields in northern Kuwait. Production in these fields was assisted by high fracture density and high API gravity. In some fields in northern Kuwait, production from these reservoirs was below expectations, which is attributed to the poor fracturing network. Hydraulic fracturing is the conventional way to improve the production in such wells. Nonetheless, the poor fracturing network will render the induced fractures less prolific due to slow recharge. For the full exploitation of these reservoirs, it is vital to have good rock characterization, including rock mineralogy, formation wettability, pore size and pore-throat size distribution. This will assist in selecting the optimal drilling and stimulation fluids. Moreover, the application of best-drilling practices, in combination with the selection of the appropriate perforation techniques, perforation density and length will help in maximizing production from these deep, high-temperature/high-pressure reservoirs. To increase the production from low-producing wells, suitable stimulation methods, (like fracture acidizing or proppant fracturing) can be adopted in a procedural manner. A detailed laboratory study, using reservoir cores with the consideration of geomechanical and mineralogical aspects, is crucial to create conductive and stable fractures.

(#118998) Facies, depositional environment and reservoir properties of the Devonian-Carboniferous Khusayyan Member, Wajid Sandstone, Saudi Arabia

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The Devonian-Carboniferous Khusayyan Member represents an important part of the Wajid Sandstone aquifer of southwest Saudi Arabia, and also a potential hydrocarbon reservoir in Rub' Al-Khali Basin in the Kingdom. This study attempted to characterize the facies, depositional environments and petrophysical properties of the member using integrated outcrop facies analysis, petrographic and petrophysical analysis. The facies analysis revealed that the Khusayyan Member consists of channel and bar sequences that were deposited in a proximal to medial fluvial settings within shallow low-sinuosity braided streams. The facies predominantly consist of planar and trough cross-bedded sandstones, with minor horizontally bedded sandstone and scour-fill facies. The fluvial architecture shows vertically and laterally stacked sandstone bodies of channel and bar types. Petrographic studies revealed that the sandstone facies are composed of a mature quartz arenites, predominantly medium- to coarse-grained, rounded to sub-rounded, moderately well-sorted to poorly sorted. The mature quartz arenite suggested shallow burial conditions. Under such conditions, alterations by eudiagenesis may have played a role in the digenetic history that is manifested by shallow compaction, cementation, grain-alteration and dissolution, and quartz overgrowth. Kaolinite is the main clay mineral, and occurs both as grain coat and pore fill. The porosity of the Khusayyayan Member is moderate to very good, whereas the permeability is good to very good. The depositional facies and their architecture, as well as the diagenetic history, were the main factors that controlled the porosity and permeability evolution and the reservoir heterogeneity of the Khusayyayan Member.

(#118711) Reservoir characterization and modeling for a carbonate field

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The study area contains highly heterogeneous Ordovician carbonate reservoirs with potential to produce both oil and gas. The reservoirs consist of heterogeneous fractured carbonates, which are difficult to characterize because of limited data and large well spacing. The aim of the study was to reduce exploration risk by enhancing the understanding of the depositional environment, digenetic overprint and the reservoir distribution. An integrated approach was required to understand the vertical and lateral distribution of the reservoir. This was achieved by using geological, geophysical, petrophysical and engineering data. A 3-D static model was constructed in order to visualize the distribution of the reservoir characteristics. Core description, thin-section analysis borehole geological interpretation and petrophysical analysis were combined to assess the pore level control on reservoir quality. A 3-D seismic interpretation and multi-attribute seismic analysis were used to identify seismic facies. The seismic facies were compared and classified based on pore volume distribution and anomalies. These were used to supervise the reservoir properties distribution and modeling in this highly heterogeneous reservoir.

(#117242) Converting CRS attributes to interval velocities: An approach to build an initial velocity model for pre-stack depth migration

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Pre-stack depth migration is proven to enhance the seismic image but only when accurate velocities are used.

Conventional methods for building an initial velocity model fail in the presence of structural deformations and severe lateral velocity variations. Therefore, for depth imaging of complex structures, a different approach is required. The velocity attribute derived from the *common reflection surface* (CRS) technology offers an alternative method to build an initial velocity model for such a geological setting. In this presentation I propose a methodology that exploits the CRS attribute values to estimate interval velocities. The CRS method is based on optical concepts and indirectly provides root-mean square (RMS) type velocities. It is data-driven and honors horizontal and vertical velocity changes. It also provides continuously sampled results with better data statistics, but the conversion to interval velocities is still not straightforward. One of the methods to handle the high variability of the CRS attribute is to use geological constraints for editing and smoothing. The editing of extreme values is done according to a general velocity trend, while smoothing utilizes a structural model provided by the interpreter. Therefore, it is possible to convert CRS attributes to plausible interval velocities. The proposed methodology was successfully applied to obtain initial macro-model velocity estimates for several onshore 2-D lines acquired in complex salt tectonic geology, near the Red Sea of Saudi Arabia. As a result, the required number of pre-stack depth migration iterations was reduced, and the final seismic image was enhanced.

(#123507) Low-salinity surveillance from cased-hole logs in the Mauddud carbonate waterflood, Kuwait

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Kuwait Oil Company (KOC) plans to increase production in the Raudhatain and Sabiriyah fields of northern Kuwait. One key to achieve this goal is to optimize the current water-flood performance of the Mauddud carbonate reservoir in these fields. KOC is using cased-hole logs to identify and evaluate low-salinity sea water movements in the early stage of a field-wide water-flood implementation. An active cased-hole logging program illustrated that injected and produced water was moving predominantly through high-permeability thief zones, while the lower permeability zones contributed only minor amounts of water in comparison. Examples of this reservoir flow distribution were observed from injector-producer comparisons of PLT logs (spinner, temperature and fluid density), pulsed neutron logs (PNL, such as sigma and carbon/oxygen ratios) and cased-hole resistivity logs in producing wells. Future cased-hole logging programs at KOC are only one part of a comprehensive surveillance program. Repeated time-lapse PLT and PNL logs, in existing wells and baseline PNL logs in newly drilled infill wells, will be required to successfully monitor the vertical and lateral reservoir sweep of the sea water injection program in the Mauddud reservoirs.

(#123477) Property modelling in a carbonate field with complex diagenesis, an example from the Kangan and Dalan formations, Iran

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Detailed studies of the sedimentology, sequence stratigraphy and diagenesis were conducted on the Permian-Triassic Kangan and Dalan formations of Iran. The objective was to reveal links between sequence stratigraphy, depositional and diagenetic processes. The identified relationships and the methodology used to distribute reservoir properties in a geocellular model is the focus of this presentation. Detailed descriptions of depositional facies and the depositional stacking pattern were followed by characterisation of diagenetic facies. The dataset consisted of more than 800 m of core and more than 800 thin sections from three wells penetrating the Kangan and Dalan formations. The analysis showed that the reservoir quality varies according to depositional facies and is extensively modified by diagenetic processes. However, the diagenetic processes can, to a certain extent, be related to the sequence stratigraphy and depositional facies. The trends are not unique and other controls must be applied when reservoir properties are to be distributed. These controls need to be obtained from standard log suites, because cores are available from only a limited number of wells. In order to model the 3-D distribution of reservoir properties, the modelling work has focused on capturing the spatial distribution of both depositional and diagenetic facies. The depositional facies have been modelled using high-frequency cycle-specific conceptual models. For the distribution of diagenetic facies, a novel approach using trends from calculated volume fractions of calcite, dolomite and anhydrite was used. Alternative geocellular models will be presented and differences between these discussed. Flow simulations have been performed, and the results were used to identify key sensitivities and controls.

(#123969) A dual-sensor towed marine streamer cable: Acquisition and processing

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Traditionally, towed marine cables measure the seismic wavefield using only hydrophones. A new solid core dual sensor cable has been introduced that measures simultaneously the pressure using hydrophones and the vertical component of the particle velocity using motion sensors. The two wavefield measurements are made at the same

locations in a single streamer, which facilitates the data acquisition. The first of many advantages of measuring the dual wavefield is that the two measurements can be combined to separate the wavefield into up-going and down-going components. This method may be used to derive the up-going pressure field, thereby eliminating the receiver ghost. This gives increased bandwidth for both low and high frequencies, which consequently enhances resolution and signal penetration. Another advantage, and the reason for the added low frequencies, is that since the receiver ghost can be suppressed, the streamer can be towed at greater depth. This results in reduced acquisition noise thus improving the ability to acquire data during rough weather. The up- and down-going wavefields can be extrapolated and summed to reconstruct the total wavefield at any recording depth. The ability to separate wavefields is also advantageous for suppressing surface-related multiples. These applications are illustrated using 2-D field test data that was acquired concurrently with a survey that used a standard (hydrophone only) cable.

(#118610) Feasibility modeling and a VSP-repeatability test demonstrate that time-lapse reservoir monitoring of thin layers during gas and wag injection is possible in Middle East carbonates with both land-vibrator and marine-air gun sources

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The ability to proactively adjust and enhance the sweep efficiency of an injection project has the potential to improve recovery and avoid costly problems. Rock-physics feasibility modeling results suggested that when sufficient water replaces *in-situ* oil or a free gas layer develops during a WAG or gas injection, 4-D anomalies can result. The ability to observe 4-D responses due to reservoir saturation changes in relatively thin layers depends on the seismic images' vertical resolution and the level of background noise. Modeling suggested that seismic data, with a maximum frequency of 100 Hertz or greater, is required for 30 ft or thinner layers. To achieve the needed high-frequency and low background noise levels, a time-lapse vertical seismic profile (VSP) was determined to be the most appropriate monitoring technology. Results from 2-D VSP repeatability tests successfully demonstrated that high-resolution VSP data can be collected and are repeatable in the Abu Dhabi carbon-

ate environment. Similar quality results were observed between a marine air gun and land vibrator VSP. The results from this study showed that background noise levels below 1.0% of the original VSP amplitudes can be achieved. Both the marine and land VSP results were observed to achieve a maximum frequency of around 100 Hertz. Both the P-wave and converted shear wave signals were found to be of good quality and repeatable. The positive results from the repeatability pilot and feasibility modeling study indicate that time-lapse 3-D VSPs could provide a useful means for monitoring reservoir saturation changes in carbonate fields. The results of this study are encouraging and support the idea of using time-lapse 3-D VSP images to monitor saturation and pressure changes in carbonate reservoirs.

(#123738) Application and seismic recognition of a new Permian-Carboniferous exploration paradigm: Unayzah C glacial paleovalleys, Ghawar field, eastern Saudi Arabia

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The Unayzah C reservoir is one of the significant gas exploration and development targets in Saudi Arabia. Recent extensive core-description work tied to regional mapping of wireline log signatures has documented the existence of relatively narrow, deeply incised linear features, which overlie the widespread *Hercynian unconformity* across portions of the Ghawar field. Core evidence shows that these linear features are typically filled with stacked sets of tightly-cemented to semi-friable glacio-fluvial channel sands, often separated by relatively-thin brittle and ductile shear deformation zones, which were recently interpreted as evidence of glacial overthrusting and moraine formation. These rocks are frequently, though not always, overlain by glacio-lacustrine Unayzah B and/or fluvio-eolian Unayzah A sediments. In the Hawiyah area of Ghawar field, these rocks were previously assigned to the uppermost part of the Devonian Jauf Formation despite their lack of distinctive palynomorphs or other age-datable material. This assignment was purely based of their stratigraphic position above the known Jauf reservoir sandstones. However, cores tied to wireline logs from recent Hawiyah wells showed that these rocks exhibit typical Unayzah C sedimentology and wireline-log signatures; namely stacked, variable-thickness sections of low gamma-ray and *spiky* high-resistivity profiles. Pressure profiles from these intervals also indicated that they appear unrelated to nearby Jauf production. Recent development mapping in the Jauf reservoir showed that this overlying Unayzah C trend extends northward into the 'Uthmaniyah area of Ghawar field. Several west-east 3-D seismic acoustic impedance profiles through central 'Uthmaniyah exhibited valley-shaped, low-impedance (gas-charged?) zones. These zones represent a significant, hitherto unsuspected *in-field* exploration and development target.

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(#123729) Integration of core-based chemostratigraphy and petrography of the Devonian Jauf sandstones, 'Uthmaniyah Area, Ghawar field, Saudi Arabia

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The Devonian Jauf sandstones are important gas reservoirs for the economy of Saudi Arabia. Correlation of reservoir sand bodies between 'Uthmaniyah area wells in the giant Ghawar field is complicated by erosional truncation at the top of the Jauf, absence of a high-resolution biostratigraphy, rapid vertical facies variability and differential clay and quartz diagenesis. Chemostratigraphic correlation and thin-section petrography were used to unravel this complexity. Cores spanning the Upper and Lower Jauf intervals from two wells spaced 5 km apart were described, assigned facies, and closely sampled (approximately one sample per foot) for chemostratigraphic and petrographic analyses. Thin-section samples were taken from standard porosity and permeability plug-end trims and statistically point-counted, with chemostratigraphic samples taken immediately adjacent to them; all facies were sampled, especially shale and mudstone intervals. Chemostratigraphic correlation identified six geochemical packages and 23 individual units, correlatable to intervals as thin as 10 ft between the two study wells. Various elemental ratios recorded provenance, climatic, diagenetic and facies signals, and revealed a previously-unknown intra-formational unconformity within the Lower Jauf. Point-count data were used to validate the geochemical data, and provided evidence of a cementation history that alternated between clay-dominated and quartz-dominated diagenetic events, which strongly influenced reservoir quality. Results from the core facies descriptions and chemostratigraphic correlation were also incorporated into an object-based geocellular model, and used as the basis for a comprehensive reservoir-layering scheme. Petrographic results are currently being evaluated for input into sandstone diagenetic modeling software, for use in future geocellular model updates.

(#116419) Eocene Rus Anhydrite: Limitations on exploration, production, and seismic interpretation

D. Mark Steinhauff (Saudi Aramco <david.steinhauff@aramco.com.sa>), Arthur E. Gregory (Saudi Aramco) and Christian J. Heine (Saudi Aramco)

The Eocene Rus Anhydrite is an important seismic reflector in the Arabian Peninsula where it is present above the Mesozoic and lower Cenozoic carbonate platforms. It provides reservoir top-seal locally (e.g. Partitioned Neutral Zone, Kuwait and Saudi Arabia). Understanding the deposition and diagenesis of the Rus Formation has broad implications in understanding the limitations on exploration and production, and for better seismic planning, acquisition, processing and interpretation. The Rus Formation typically comprises meter-thick anhydrite parasequences inter-bedded with thinner limestone, dolomite, and marly beds with a gross thickness, in the shallow-basin centers, of more than 700 ft. Sub-meter scale, anhydrite bed sets can be traced on wireline logs for 100s of kilometers. Typically, the Rus has distinctive physical properties, including strong impedance contrasts with over and underlying strata. Less common are seismic zones lacking coherent reflectors and distinctive physical properties. Borehole penetrations show that many incoherent reflectors typically include rubble. These zones present challenges in applying static corrections and interfere in our ability to correlate deeper reflectors. Previous work has shown that the Rus Anhydrite thins or is absent above many structural highs including much of the Qatar Arch, Ghawar field, Dammam Dome and other large anticlines. Features attributed to karst are noted in many areas. The absence of anhydrite can be explained by: (1) non deposition because the structures were moving; (2) deposition followed by erosion; or (3) extensive subsurface dissolution of carbonate and sulfate-evaporites under Mid- Pleistocene wet climatic conditions. Even though the aforementioned structures probably have unique depositional and tectonic histories, some combination of the three proposed processes likely affected them all.

(#117971) Evolution of the Early Permian Haushi Sea of Oman and comparison with other Gondwanan post-glacial marine sequences

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The Early Permian Haushi Sea covered most of northern Oman and parts of southeast Saudi Arabia. Its southern extent was controlled by high elevation and by prograding coastal sediments, and its eastern extent by the Huqf Arch. The Haushi Sea, being fully marine, must have been sourced from the Tethys but the position of ingress is unknown. The shallow Haushi Sea persisted through the Late Sakmarian, but a regressive trend halted limestone deposition and replaced it with fluvial and minor lacustrine palaeoenvironments in a low accommodation space setting (Middle Gharif Member). Palynology indicates increasing hinterland aridity during deposition, while microfacies, stable isotopes and brachiopod diversity indicate a trend from eutrophic to oligotrophic conditions and progressive marine closure and isolation.

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$\delta^{18}O$ values of –3.7 to –3.1‰ from brachiopods at the base probably relate to glacial melt water. Above this, increase in $\delta^{18}O$ may indicate either (1) ice accumulation elsewhere in Gondwana, or (2) a period of evaporation related to marine isolation, as suggested by the biota. After the Haushi limestone was deposited, possible sub-aerial exposure and downward penetration of meteoric water during Middle Gharif times precipitated poros-ity-destroying calcite cement turning the Haushi lime-stone into a regional seal. The interplay between Early Permian glacio-eustatic sea-level rise, local topography and tectonic subsidence controlled the distribution of post-glacial marine sediments in the Tethys margins. The earliest transgressions (e.g. in India), produced low-diversity, cold-water fauna and limestones. In Oman, the transgression did not occur until later Early Permian times. Later post-glacial limestones such as the Haushi and Callythara Formation (western Australia) are tem-perate with diverse fauna.

(#117967) Downhole high-resolution palynozonation of the Al Khlata Formation in the Mukhaizna field, Oman, based mainly on cuttings samples

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Palynology is the main method of correlating the sub-surface glacigene Al Khlata Formation of Oman, due to lateral variability of facies, and poor seismic resolu-tion. Up to now, however, it has been difficult to apply a palynozonation using mainly cuttings samples because published in-house schemes use mainly quantitative variations in palynomorph groups, which tend to render the use of cuttings samples difficult, due to downhole caving. Studies in the Mukhaizna field in Oman have revealed a small number of palynomorph types, which combined with quantitative assemblage character, distinguish five biozones working downhole with cut-tings samples. The highest, Biozone A, is consistently associated with the Rahab Shale, which was deposited in a large deglacial lake covering much of southcentral Oman. Biozone B is associated with shaley diamictites and sands with considerable lateral variability. Biozone C is associated with thick sequences of shaley diamictites that occur throughout the field with relatively little lateral variability, suggesting very long-lived, large, proglacial or subglacial lakes. The lowest of the biozones, Biozone D, is associated with mainly thick, stacked sandstone sequences and sandy diamictites with extremely high lateral variability. The thickness of the upper biozones, A to C, is relatively constant, and log character is fairly consistent. However, Biozone D varies greatly in thick-ness. Biozone D may be considerably older than Biozone C, and may represent the first Gondwana glacial activity in the Namurian-Westphalian, while the biozones above represent the later, more intense, glaciation of latest Pennsylvanian and earliest Permian.

(#118639) Strontium-isotope chemostratigraphy and rudists of the Qahlah and Simsima Formations (Campanian-Maastrichtian), United Arab Emirates and Oman

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The Qahlah and Simsima formations follow unconform-ably over the Semail Ophiolite, or various units of the Hawasina and Sumeini groups. Numerous studies fo-cused on the biostratigraphy of the fossiliferous Qahlah and Simsima formations, concluding on a broadly Campanian-Maastrichtian age, but without further chronostratigraphic precision. Correlation – even over short distances – is complicated by lateral changes in lithofacies, intra-formational angular unconformities, and periods of nondeposition and subaerial exposure; all features indicative of a pronounced topography of the eroded allochthonous units, and active tectonics during the Campanian-Maastrichtian. We used numeri-cal ages derived from strontium isotope stratigraphy to obtain a precise chronostratigraphical framework for the Qahlah and Simsima formations. The Qahlah Formation is diachronous, of Campanian age in the region of Al Ain and of Early Maastrichtian age in the north of the United Arab Emirates (UAE). This is also evident in significantly different associations of rudist bivalves, which provide excellent index fossils. While the Simsima Formation shows a deepening upward trend in the UAE-Oman border region, a continuous shallow-water carbonate platform sequences that straddles the Cretaceous/ Palaeogene boundary is exposed in the region of Sur (Oman). Previous stratigraphical interpretations of this sequence are revised, and the importance of this locality for the evaluation of environmental change at the K/P boundary is discussed.

(#119079) Fracture detection and reservoir property estimation using full-wave, full-azimuth seismic data

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A full-wave data volume using *state-of-the-art* fully digi-tal 3-component sensors, combined with a full-azimuth, full-offset, sampling acquisition design, was recorded over gas fields in southern China. These highly fractured reservoirs exhibit azimuthal anisotropy that is detectible in both the compressional wave (P-P) and converted wave (P-S) data. We present a unique processing flow that isolates fracture orientation and magnitude combined with elastic inversion results. This new and innovative approach identifies both lithological and stratigraphic features and is capable of delineating new reservoir loca-tions within the highly productive fractured zones.

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(#118428) High-resolution sequence stratigraphy and reservoir characterization as input to geological modeling of upper Thamama reservoirs (Lower Cretaceous Shu'aiba and Kharaib formations), Abu Dhabi, United Arab Emirates

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A new sequence stratigraphy-keyed geological model has been built for the upper Thamama (Lower Cretaceous) Kharaib and Shu'aiba formations. The Kharaib Formation contains two reservoir units (Lower and Upper Kharaib Reservoir Units) with 80 and 170 ft thickness, respectively, separated and encased by three low porosity and permeability dense zones. The overlying Shu'aiba Formation is separated from the Kharaib Formation by the Upper Dense Zone (Hawar) and contains two reservoir units, only partly separated by dense intervals. The thickness of the Lower and Upper Shu'aiba Reservoir Units is approximately 55 and 90 ft, respectively. Core and well-log data of a giant onshore oil field in Abu Dhabi, as well as outcrop data from Wadi Rahabah (Ras Al-Khaimah) were used to establish a lithofacies scheme and a sequence stratigraphic framework. The scheme is applicable to all four reservoir units and the three dense zones. The Lower and Upper Kharaib Reservoir Units, as well as the Upper Dense Zone, are part of the late transgressive systems tract (TST) of a second-order supersequence, built by two third-order composite sequences. The overlying Lower and Upper Shu'aiba Reservoir Units belong to the late TST and highstand systems tract (HST) of this second-order supersequence built by four third-order composite sequences. The six third-order composite sequences are composed of twenty-six fourth-order parasequence sets that form the basic building blocks of a new generation static model. On the basis of faunal content, texture, sedimentary structures, and lithologic composition, fourteen reservoir lithofacies and ten non-reservoir (dense) lithofacies are identified from core. Reservoir units range from lower ramp to shoal crest to near back shoal open platform environments.

(#118419) The vertical sabkha sequence at Mussafah Channel, Abu Dhabi, United Arab Emirates

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Studies of recent sediments can add greatly to our interpretation of features observed in core and outcrops deposited many millions of years ago. The Mussafah Channel is a man-made shipping canal cut perpendicular to the coastline, located to the southwest of the city of Abu Dhabi, and is ideal for studying costal depositional processes. The canal wall reveals a few meters of horizontally stratified Holocene sabkha and inter-tidal to shallow subtidal lagoonal sediments that vary significantly along its depositional strike direction and overlie Pleistocene dune deposits. Superb exposure of classic sabkha anhydrite occurs as highly contorted, enterolithic discontinuous bands. Sedimentology, petrography, x-ray diffraction and radiocarbon age dating analyses carried out along the vertical sabkha sequence show the following results: (1) uncemented, non-bedded calcareous sandstone: reworked aeolianite (ca 26,000 years BP - YBP); (2) uncemented cross-bedded to non-bedded calcareous sandstone: aeolianite/reworked aeolianite (ca 23,000 YBP); (3) crinkly-laminated microbial mat: inter-tidal deposits (ca 6,200 YBP); (4) fine-grained, grey-greenish interval with root marks, laterally grading into fine- to coarse-grained intervals with iron-stained, cross-bedded Cerithid-rich beds: lagoonal and tidal-channel deposits (ca 6,200 YBP); (5) cemented Cerithid- and bivalve-rich beds (hardgrounds): discontinuous, lithified channel lag deposits (ca 5,700 YBP); (6) cross-bedded, Cerithid-rich, bioclastic beds, grading laterally into intervals displaying gypsum rosettes and nodular to enterolithic anhydrite and microbial laminated carbonates: longshore beach bars and spits (ca 5,000 YBP). The sabkha sequence at Mussafah Channel represents the post-glacial Flandrian transgression resulting in the reworking of the Pleistocene aeolian dunes and the deposition of inter-tidal to shallow subtidal carbonate sediments. During the subsequent sea-level fall, these carbonates were overprinted (replaced) by gypsum and anhydrite. The observed lateral facies variations reflect primary reservoir quality variations, an important aspect to be considered for geological facies and reservoir quality modeling.

(#118564) High-resolution sequence stratigraphy and reservoir characterization of Upper Lekhwair (Lower Cretaceous) reservoir units of a giant Abu Dhabi oil field

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An extensive core-based sedimentological and high-resolution sequence stratigraphic study has been carried out on two Upper Lekhwair (Thamama Group, Barremian) Reservoir Units (ULRU1 and ULRU2) of a giant oil field onshore Abu Dhabi, with the aim of improving our understanding of the reservoir architecture. ULRU1 and ULRU2 are part of the highstand systems tract (HST) of a third-order depositional sequence, and are interpreted

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to represent two fourth-order parasequence sets built by eight fifth-order parasequences. ULRU1 and the underlying dense zone consists of burrowed, organic-rich, stylolitized, wispy laminated, packstones with echinoderms, shallowing-upward into wackestones, packstones and grainstones with rare rudists, foraminifera, peloids, and intraclasts. ULRU1 together with the underlying dense zone forms one parasequence set built by four parasequences. ULRU2 and the underlying dense zone consists of burrowed, organic-rich, stylolitized, wispy laminated skeletal wackestones and packstones, coarsening-upwards to grain-dominated, rudist-rich packstones, grainstones, floatstones, and rudstones. Like ULRU1, the reservoir facies of ULRU2 together with the underlying dense zone forms one parasequence set built by four parasequences. Best reservoir quality is developed in ULRU2 (permeability exceeds 1.0 Darcy), corresponding to rudist-rich, grain-dominated lithofacies representing laterally discontinuous shoals. Porosity and permeability trends follow the established high-frequency sequence stratigraphic framework. Our newly developed sequence stratigraphy-based geological (static) model improves prediction of flow behavior in ULRU1 and ULRU2.

(#123808) Petroleum system of the Paleozoic and Mesozoic intervals in the northern Arafura Sea, Papua, Indonesia

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The Arafura Sea is situated in the eastern region of Indonesia. This region is tectonically unique since it has been formed by complicated interaction between three converging plates: the Eurasian and the Indo-Australian (continental) and the Pacific (oceanic). The tectonic regime around the area started during the early breakaway phase of the Australian Plate from Gondwana during mid Mesozoic time. Some outcrop and well samples have been collected during this study. A standard geochemical analyses and a 1-D modeling have been applied to the samples. Two oil and gas source rocks have been identified in this area. The first one is the Permian Aiduna Formation. It has relatively good quality source rocks (TOC=1.28–6.55% and Ro=„b0.55%) with a coaly and calcareous character. The second source rock is the Jurassic to Cretaceous Kembelangan Group. This group comprises four formations, i.e. Kopai, Woniwogi, Piniya, and Ekmai formations. The Lower Kembelangan (Woniwogi and Kopai) source rocks are generally shaly with interbedded minor sandstone and has shown organically fair to good quality oil and gas source. Thermal maturity modeling has indicated that the lowermost sediments in the Lower Kembelangan had entered late maturity for hydrocarbon generation (Ro = 1.2%) about two million years ago. Furthermore, it was concluded that the lower unit of the Kembelangan Group had reached the level of maturity to generate hydrocarbons

some 5 to 10 million years ago. The Paleozoic formations reached their maturation during Mesozoic at approximately 3.6 seconds two-way seismic time. The possible reservoirs are in some of the Mesozoic formations, such as Tipuma, Woniwogi, and Ekmai. Scanning electron microscope analysis on these formations provides an estimated porosity ranging from 5–15% and permeability of 10–20 mD.

(#123791) Process-based modeling of deep-water depositional systems

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ExxonMobil has developed a process-based forward numerical model for simulating deep-water depositional systems. The model is based on the physics of fluid flow and sediment transport. It replicates most of the important processes found in deep-water depositional systems. This model has been used to simulate East Breaks Basin 4, Gulf of Mexico. An interpreted surface from a high-resolution 3-D seismic survey was depth-restored and used as the initial basal surface. The model's inlet location for turbidity flow was also interpreted from the seismic. A trial and error approach was used to determine the discharge of the flow as well as the volumetric concentration and the size distribution of the particles in the flow. Simulation results were converted to synthetic seismic and compared with actual seismic from the basin. The comparisons show that the simulated sediment body geometries and stacking patterns closely resemble those observed in the seismic. The study has demonstrated that the forward numerical model is a powerful new geologic modeling tool. Prerequisites for effective modeling include: (1) accurate restoration of basin paleo-topography; (2) realistic flow characteristics including flow discharge and sediment concentration; and (3) estimates of sediment size distribution in the flow. These data are not routinely obtained from subsurface studies, but can be derived through integrated analysis of seismic volumes and well and core control. Including such analysis in the seismic interpretation and reservoir-characterization workflow is essential for the development and application of forward numerical models as next generation Earth models.

(#116417) Application of seismic attributes to resolve stratigraphic and structural uncertainties: Examples from northern Kuwait

Mohammed Ismail Syed (KOC <smismail@kockw.com>), Samar Al-Ashwak (KOC), Bader Al-Ajmi (KOC), Ghassan Rached (KOC) and Bashar Al-Qadeeri (KOC)

Conventional 3-D seismic interpretation is often inadequate for mapping stratigraphic-structural features and complexities that have a direct bearing on character-

izing reservoir geometry. An example of this challenge is represented by the depositional sequences of the carbonate and clastic reservoirs of northern Kuwait. To characterize these sequences more unconventional techniques and work-flows are required to accomplish the task. The purpose of this presentation is to demonstrate an unique workflow using multi-attribute analysis and visualization techniques that were applied to selected carbonate and clastic reservoirs to delineate their stratigraphic/structural features. We targeted the problems in two steps. The first was to improve the signal-to-noise ratio of the available 3-D seismic data using appropriate processing steps to better image the depositional geometries and structural features. The second step was to highlight and isolate those specific geological features in 3-D using different seismic attributes. By integrating these approaches with subsurface data it was possible to speed-up the interpretation. The results showed that reprocessing, multiple-attribute analysis and 3-D visualization significantly improved the seismic data quality. This helped resolve stratigraphic-structural uncertainties leading to a more accurate characterization of the reservoir geometries.

(#124183) Presenting seismic stratigraphy and attribute analysis as pioneer techniques for delineation of reservoir quality sand bodies in Indus offshore, southwest Pakistan

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It is generally believed that various exploration failures in nearby offshore areas of Pakistan are due to the absence of a mature petroleum system. But a few gas shows and 0.55–3.24% TOC drove us to suggest that Middle-Upper Miocene lowstand systems tract (LST) exist that possesses organic, paleo-environmental and sequence stratigraphic characteristics of a potential source rock. The objective was to highlight the presence and delineate the slope and basinward facies through seismic stratigraphy and seismic attribute analysis as a new approach in southwestern Lower Indus Basin of Pakistan. Working within a sequence stratigraphic framework, four sequences have been marked on the basis of reflection termination patterns, and a sea-level curve was constructed to represent coastal onlap. A hypothetical curve was also generated by employing the spectral analysis Fourier transform function, which was found to be similar to the real one. Two coarse-grained sand wedges in the lowstands were distinguished on the basis of Wheeler's Diagram, which were the result of fluvial incision following forced regression. Seismic attributes of total amplitude, maximum absolute am-

plitude and average instantaneous frequency were then studied for these sand bodies to identify their seismic signature as a *gas saturation zone*. Finally, a cross-plot of these attributes was generated to show the anomaly for these potential zones. It was concluded that good TOC values at a location where incision took place favours the accumulation of a reasonable amount of hydrocarbons in basin floor fans; this was further supported through seismic attributes. The present study has opened new dimensions for identifying the prospective zones for future exploration in the Indus offshore of Pakistan.

(#118362) Rock types from cores and well-log electrofacies in support of regional reservoir fairways mapping: The Hanifa Formation, Saudi Arabia

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The Late Jurassic Hanifa Formation is one of the major oil-producing reservoirs in Saudi Arabia. Regional reservoir fairways have been recognized through an integrated approach of sequence stratigraphy, petrophysical characterization and seismic attributes. This study identified rock types from core descriptions, petrographic data, and well-log electrofacies, which supported the regional Hanifa reservoir fairways. The Hanifa Formation overlies the Tuwaiq Mountain/Hadriya sequence and is overlain by the Jubaila Formation. The lower Hanifa consists of predominantly lime mudstone and laminated organic-rich mudstones, which constitute one of the major Jurassic source rocks. The upper Hanifa Member is composed of mostly shallow-water, higher-energy grainstones and packstones, which represent an overall shoaling-upwards sequence in response to carbonate deposition and relative sea-level falls.

Five rock types were identified using core descriptions, petrographic and capillary pressure data. Rock type I is dominated by well-sorted and cross-stratified oolitic, skeletal and intraclastic grainstones, and shows best reservoir quality. Rock type II is characterized by variably sorted fine-grained grainstones and weakly burrowed muddy skeletal grainstones and packstones with good reservoir quality. Rock type III consists of muddy, poorly sorted skeletal/peloidal packstones, and burrowed algal-rich packstones, which are moderate to poor quality reservoirs. Rock type IV is dominated by variably burrowed packstones, wackestones, and micritic limestones, which are very poor reservoir. Rock type V is predominantly argillaceous limestones and laminated organic-rich lime mudstones, which constitute the source rocks. The identified rock types were used to calibrate the electrofacies derived from well-logs using the neural-network technique.

(#117434) Incised valley system and associated hydrocarbon entrapment: An example from the Early Cretaceous Zubair Formation in South Kuwait

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The presentation outlines two themes; firstly an example of back-filling of an incised valley, and secondly an associated play development. The top of the Ratawi Shale Formation is an established hiatus of Late Valanginian age during which a drop in base level resulted in sub-aerial exposure in southern Kuwait. Drainage by north-easterly and easterly streams developed and incised the subaerially exposed areas. The sedimentation in these channels marked the initiation of deposition of the Zubair Formation, which overlies the Ratawi Shale Formation. Pre-existing structures along the NS-trending Kuwait Arch partly controlled the drainage. Incised valleys were developed in the flank areas of the highs. Crestal parts of the structures initially remained exposed as non-depositional surfaces. This understanding was applied for delineating potential hydrocarbon-bearing area for exploration. The facies sequence within one of the incised valleys, in ascending order, consists of stacked fluvial sediments followed by estuarine channel sediments, which in turn are overlain by inter-fluve sediments and finally succeeded by beach sediments. This vertical stacking pattern of facies is a good example of incised valley back-filling during the base-level rise. The laterally constrained channel-fill sandstones are hydrocarbon-bearing along the northern flank of the Burgan High. This entrapment resulted from sealing by the transgressive systems tract (TST) related fine-grained sediments which impinge southward onto the High. No entrapment exists where vertical and lateral seal is lacking. The study incorporated seismic, log and core analysis and can serve as an example for exploration in similar traps elsewhere.

(#124479) Integrated core information management system

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Saudi Aramco has acquired a large wealth of core information from more than 20,000 ft of core since the 1930s. Ensuring the preservation of cores and the core-related data became a challenging task, given the quantity, the types of analyses and the frequent handling. Saudi Aramco's *integrated core information system* is a web-based system that was designed to preserve and safeguard the company's high investment in coring. It makes all the core-related information available *on the desktop and at the finger tip* of every Saudi Aramco geologist. This system also enables the exploration organization to track the progress of the core study, which eliminates hours of data searches and many phone calls. This system has had a major impact on the efficiency of the core-lab studies and a significant impact on the core-lab study processes. In this presentation, the impact of integrating the core-related data on the core-lab studies will be discussed.

(#122987) 4-D seismic feasibility modeling of a giant offshore oil field

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Transferring successful 4-D seismic experience in siliciclastic reservoirs to more challenging carbonate reservoirs requires a disciplined and collaborative approach among national and international oil companies. Production at a giant offshore field in the Middle East is anticipated to be increased primarily through infill drilling and optimization of water-flood patterns. Acquiring 4-D seismic data to compare with a 2001 ocean-bottom cable (OBC) survey may help reach the production goal more efficiently through identification of fluid movement and improved reservoir characterization. Given the challenging rock physics and limited industry 4-D experience in carbonates, significant technical effort is required to appreciate the technical risks and potential improvement in the understanding the reservoir before implementing 4-D seismic technology at this field. A 4-D feasibility modeling study was undertaken to predict the 4-D seismic response from water saturation and pressure changes between 2001 and possible monitor surveys in 2008 and 2015. Full-field 4-D modeling consisted of: (1) determining petrophysical relationships from well logs and core analysis; (2) applying those relationships to the geologic and reservoir simulation models to create a 4-D seismic property model; (3) generating synthetic 4-D datasets for each timestep; (4) adding appropriate levels of 4-D noise; and (5) extracting attributes to determine the interpretability of the predicted 4-D response. The modeling results showed the expected change in seismic amplitude due to production within the reservoir will be less than 10–15%. Thus, a successful 4-D program will require highly repeatable data acquisition and processing, which is challenging in the shallow OBC environment for this field. Finally, the results showed that 4-D seismic will be able to help identify the main water-bank movements but will not be able to directly detect water movement in thin, high-permeability layers.

(#118162) ISBA3D: Innovative solutions for 3-D exploration in complex areas

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In the current context of continuous supply of energy, the discovery and development of new fields will rely on the ability to detect reservoirs in deeper and structurally more complex targets with greater technical and

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financial risks. These play areas stretch the capabilities of currently available 3-D exploration software, which can not provide a realistic geometrical description of geological structures during their tectonic evolution. Proper handling of the kinematics of structural deformation and the evaluation of the pressure regime and temperature history, at exploration scale, will remain a challenge for years to come. We are currently working on new technological solutions in structurally complex environment to minimize exploration risk. This research provides significant challenges to geoscientists. These results are integrated in the new generation of 3-D exploration software. The feasibility is conducted on real case studies in different environments (compressional, extensional and salt tectonics). The methodology will be shown for a compressive regime in the Gaspe Peninsula, in the Quebec Province of the northern Appalachian Mountains of northern America. The present geometry of this belt is complicated because the rocks were deposited on, and deformed over, a previously structured foothills-type basement. Its present geometry is constituted by two imbricate fold and thrust belts, which were recently imaged by 2-D seismic profiles. Although the geological setting appeared to be non-prospective, recent gas reservoirs have been discovered indicating the presence of an active petroleum system.

(#122320) Sequence Stratigraphy of the Maastrichtian Wafra carbonate reservoir in the Partitioned Neutral Zone (PNZ), Kuwait and Saudi Arabia

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The Maastrichtian (Upper Cretaceous) reservoir at Wafra field was discovered in 1959 and has produced about 20 million barrels of oil; less than 1.0% of the estimated original-oil-in-place. The Maastrichtian sediments were deposited during arid conditions in shallow water on a gently dipping ramp in normal marine and restricted lagoonal settings. They are dominated by subtidal dolomite and limestone inter-bedded with thin organic-rich shales. Facies types are dominantly wackestone, rudist rudstone, peloidal packstone, and localized grainstone, with minor mudstone and rudist floatstone. Moldic, inter- and intra-crystalline porosity are common. The average porosity is about 15% and reaches 30–45% in productive zones. Permeability averages about 30 mD with readings as high as 4.0 Darcy. Previous stratigraphic studies of the Maastrichtian interval at Wafra field, largely based on five cores along the crest of the structure, resulted in a field-wide and regional stratigraphic framework. This study, utilizing additional data from cored flank wells, examined the relationship between reservoir characteristics and depositional/stratigraphic controls. Core and thin sections were described with particular attention to depositional texture, grain types, pore types, diagenetic features and stratigraphic surfaces. Depositional facies maps constructed for each stratigraphic surface within

the reservoir interval indicated that facies belts are generally oriented in a northwest to southeast trend, parallel to the paleo-shoreline. These depositional environment maps revealed that facies bodies have geometries ranging from arcuate to elongate. The refined stratigraphic framework and depositional model has been incorporated in an updated reservoir model to validate reservoir development strategies for this important heavy oil resource.

(#119031) Interpolation of sparse, wide-azimuth onshore and ocean-bottom seismic data using a global, 5- dimensional interpolator

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Many 3-D land surveys do not fulfill the requirements of seismic processing techniques, such as migration, which have strict requirements on data sampling in the input seismic data. Although not a substitute for well-sampled field data, interpolation can provide useful data pre-conditioning that allows migration and other processes to work better. Seismic data interpolation has been around for a long time, but only recently have we been able to use complex multi-dimensional algorithms that have the capability to infill large gaps in wide-azimuth 3-D land or ocean-bottom surveys. Earlier algorithms attempted to interpolate data using just three dimensions, whereas in fact data is recorded in five dimensions (shot-x, shot-y, receiver-x, receiver-y and time). If we use all 5 dimensions in an iterative, minimum-norm weighted inversion, we can use all the available information for interpolation and hence obtain optimum results. Furthermore, there is less overlap of aliased and non-aliased data in 5-D than 3-D, and this relaxes the traditional constraints on interpolation. The algorithm has been applied to a number of problems such as: (1) reducing bin size to remove aliasing prior to migration; (2) increasing fold and azimuth distribution within common mid-point bins to allow improved estimation of fracture patterns; and (3) regularization of bins to reduce migration induced noise. These techniques have been used in a variety of structural environments.

(#122812) The petroleum systems (!) of Muglad Basin, Sudan: Evolution, growth and entrapment

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The Muglad Basin of southern Sudan owes its origin to rifting and drifting of the African Plate from Gondwanaland, which was synchronous with intra-continental rifting within western and central Africa, during Late Jurassic-Early Cretaceous times. The basin evolved as a consequence of the Sudanese rift, which is a main

component of western and central African rift related system. Accommodation created by these rifts resulted in the deposition of continental-fluvial sediments of Cretaceous and Tertiary age, which in the deeper part of basin are estimated to be 15–20 km thick. The application of sequence stratigraphic concepts to understand the facies distribution pattern indicated that the fluvial system was draining to the marine or lacustrine realm. Changes in lake and sea levels and the graded profile of the rivers, affected the channel type, sediments and environment. Hence the sediments can be partitioned into predictable packages as a function of base-level position. These concepts have helped in identifying key surfaces and allocyclic control upon stratal architecture. Cycles up to fourth-orders are being identified and these have helped in understanding and better defining the main source rock (Abugabra Formation) and reservoir (Bentiu Formation). In the acreage under study, 80% of hydrocarbon entrapment is structurally controlled. The major elements are listric normal faults and entrapment is controlled by fault throw, type and juxtaposition of lithology across the fault. Studies of the structural evolution have helped in understanding the plays in the Muglad Basin and has added value for the exploration in hitherto enigmatic and lesser explored basin.

(#115921) Why color inversion?

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Many inversion techniques such as model-based and stochastic inversions are commonly used to derive acoustic impedance. Impedance values could be related to lithology, porosity or fluid content. While these methods are popular, another approach called *color inversion* (CI) is also available and gradually gaining acceptance by many geophysicists. Color inversion has several advantages over conventional approaches. The main advantage is that it is conceptually simple and exceptionally easy to run. Unlike conventional inversions that are difficult to understand and involve complex procedures, CI derives and applies a simple convolution filter to seismic data to obtain band-limited impedance. Due to its filtering process, CI is so fast that job turnaround time is in hours. Using conventional inversion, and not counting preparation time, the same job could easily take five or ten times that of CI. When dealing with large 3-D datasets, CI thus affords more time for interpretation and assessment of exploration targets. Another advantage of CI is that it is data-driven. It does not need an initial impedance model in the inversion process. Any observed anomaly or change in impedance is driven by the input seismic data. This is in contrast to the conventional inversion in which the initial model is required and has a significant contribution to the final inverted impedance. This is important in dealing with exploration prospects where few wells are available. In this presentation, examples will be provided from Saudi Arabia to demonstrate the advantages and applications of color inversion.

(#118967) Reconciling well test permeability with geological heterogeneities in a giant carbonate field, northern Oman

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A significant development target in this giant carbonate reservoir is the Natih E unit, which is an approximately 150-m-thick, third-order, shallowing upward succession of intra-shelf basinal to lagoonal depositional settings. Plug data show mainly low to moderate matrix permeabilities. However, a subset of the plug data and a number of well tests suggested that permeability may be an order of magnitude higher in some cases. This may be related to under-sampling of plugs due to sample failure in highly leached (friable) layers. or to fracturing or a combination of both. The implications for development designs are considered significant. Thief zones can be related to either layers with very high matrix permeability or to dense layers with highly connected, bed-bound fracture systems. Both types have been observed and their occurrence can be related to a combination of depositional setting, depositional cyclicity and a complex diagenetic overprint. Layers crossing larger fractures superimposed on the complex matrix system are a significant additional heterogeneity, which can give rise to well tests with high permeability. A key uncertainty is the connectivity of the fracture system. Previous modelling efforts indicated limited lateral connectivity between fracture sets and highlighted shortcomings in using stochastic methods to place fractures in areas of extensive well control. In our new models, fracture corridors have been model-constrained by high-resolution seismic attributes. Bed-bound, distributed fractures were represented by matrix permeability scalars with limited vertical transmissivity. An improved understanding of the field's kinematic history, combined with field data (evidence of short-cutting, tracer tests, PLTs), was used to constrain those components of the fracture system associated with higher permeabilities. Combining static models that contain various combinations of thief zones and layer-crossing fracture systems resulted in arrays of models, which – after history match – were used to optimize field development.

(#123497) Prospectivity and interpretation challenges in the Afar region of Oman

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The Afar region of Oman lies along the junction of the Maradi Fault Zone (MFZ) and the forelands region of the Oman Mountains. The recent development of several new prospects, in this structurally complicated part of the region, illuminates the potential of this area. At Sulan

Salakh, immediately south of the *Salakh Arch*, four prominent prospects have been identified, along with several lesser potential leads. These prospects and leads evolved, more or less, simultaneously as a result of the complex interactions of the two main tectonic elements operating in northern Oman since the latest Mesozoic times. The Salakh Arch, which acts as a northern boundary for the Afar structures, was developed along the southern limit of the deformation induced by southward-verging Oman Mountains compression. The initial structural aspect developed during the emplacement of the Semail Ophiolite, with subsequent structuring resulting from late Tertiary development of the Oman mountains. Northwesterly trending shear-related structuring, along the northern part of the MFZ, was due to Late Cretaceous emplacement of the Masirah Ophiolite. The Afar region, and the Sulan Salakh prospects lie in a zone where both of these structural influences merge, giving rise to complicated structural relationships. A variety of trap types were formed by the complex structural interactions. Potentially prospective intervals range from Cambrian to Upper Cretaceous. Proterozoic source rocks provide for local sourcing, with probable remigration charging the structures at the time of formation, or immediately thereafter. In this setting, understanding the nature of tectonics and its impact on hydrocarbon entrapment is a challenge for the interpreters. This study gives an overview of the challenge to prospect evaluation in the Sulan Salakh area.

(#117796) Rock-typing in carbonates: Getting out of the maze

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Rock-typing in carbonates is a challenging task requiring the coordination of key factors: (1) effective project management; (2) detailed knowledge of the reservoir geology from regional to pore scale; and (3) a consistent well data set. This presentation reviews the rock-typing approaches used in Total for the past 35 years and evaluates them in terms of accuracy (capacity to represent the petrophysics and its variation in the reservoir) and efficiency (ability to be easily managed while allowing a good history matching and reserve prediction). Best practices are pointed out, depending on the reservoir complexity, dataset quality and reservoir study objectives. To ensure a successful rock-typing in carbonates several aspects should be considered: (1) the pore network should be characterized at micrometric scale, (2) links between petrophysical laws and geology should be established as soon as possible; (3) the propagation of rock-types between wells should honour the sedimentological model including diagenesis distribution; and (4) rock-types could be propagated on a log-response basis, even when supported by micrometric features (CT scan textural analysis). The transition from static to dynamic

rock-typing is another important issue. Flow units (homogeneous Krow-Pcow) are not only related to static rock-types. Wettability can significantly vary within the same reservoir according to structural position and permeability. In carbonate reservoirs, an efficient rock-typing should not follow any *golden rule* but rather a pertinent workflow that is adapted to the data set quality. Integration of geological and petrophysical data, use of a geological driver at micrometric scale and implementation of new techniques should efficiently improve the rock-typing studies.

(#118947) Multi-scale heterogeneity modelling in a giant carbonate field, northern Oman

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A giant carbonate reservoir in northern Oman has been producing for some 40 years under primary depletion and secondary development schemes. Now the next brown field development phase is being prepared. Costs and potential rewards are substantial and require sound decision making. Geological, petrophysical and production data has revealed a multi-scale heterogeneity system. The driving forces for heterogeneity are sedimentary fabrics, depositional environments, large and small-scale depositional cyclicity, diagenesis, and fracturing/faulting. Hydrocarbon storage and flow through the matrix is fundamentally influenced by variations in pore types on a scale much below that of normal static and dynamic reservoir models. With the goal of building reservoir-size dynamic models the extensive heterogeneity on a centimetre-decimetre scale provides a significant upscaling problem both for static and dynamic properties. In order to populate reservoir-size models with realistic properties reflecting small-scale heterogeneity, both statically and dynamically, an approach has been chosen to define and model heterogeneities hierarchically. Small-scale heterogeneities were captured and simulated in *mini-models* (less than 1.0 cubic m in size), which provided pseudo-properties for volume cells in reservoir-size models. *Principle rock types* (PRT) are the fundamental building blocks of the matrix system. They cover and categorize the full range of pore types, sizes, pore-throat size distributions, capillary entry pressures, relative permeabilities, etc. PRTs were organised into *Rock-type associations* (RTA) based on sedimentary fabric (bioturbation, cross-bedding, layering, etc.). Mini-models were constructed using borehole image logs (BHI) data for all RTAs and their internal property variations. The distribution of RTAs in the reservoir is driven vertically by depositional cyclicity and laterally by facies dimensionalities. The key tools to distribute RTAs in the larger reservoir models are seismic data and the BHI logs, which provide control on both fabric and property heterogeneity.

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(#118988) Composite Barremian to Turonian carbon isotope curve of Oman

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Carbon-isotope stratigraphy is a valuable tool to constrain time lines and hence the architecture of Early to mid-Cretaceous shallow-water platform carbonates. Using subsurface cores and published outcrop data, a composite curve has been compiled for the Barremian to Turonian time interval of Oman. The curve contained some 738 data points from the Kharaib (48), Shu'aiba (143), Nahr Umr (76) and Natih formations (471). Overall the curve has an excellent match with published reference curves from pelagic sections of the Tethys and hence provides a much-improved time resolution compared to biostratigraphy available for these shallow-water carbonate sequences. The base of the Hawar Member of the Kharaib Formation is characterized by a pronounced negative carbon isotope spike, which correlates with a negative isotope excursion during the earliest Aptian. The Oceanic Anoxic Event 1b is recognized in the lower part of the Nahr Umr Formation, which places the boundary between the Shu'aiba and the Nahr Umr formations in the latest Aptian. A positive carbon-isotope excursion in the lowermost Natih Formation (F and G reservoir units) correlates with an Albian/Cenomanian boundary event. A most likely interpretation of the carbon-isotope curve of the Natih Formation stretches its duration from the Late Albian to the Early Turonian. In addition, several intra-formational time lines can be assigned. A carbon isotope peak during the Natih C&D units corresponds to a Mid-Cenomanian event. A distinct negative excursion during the Natih B is either of local origin related to organic matter deposition or it corresponds with a weak negative trend on the global curve during the Middle Cenomanian. A final positive shift during the Natih A places the top of this unit near the Cenomanian/Turonian boundary. Aspects worth further investigation are shifts in parts of the carbon-isotope curve towards heavier and lighter values compared to pelagic sequences and further time anchor points from Sr-isotope dating.

(#121865) Field management: Using reservoir and well performance data effectively

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Increasing production in large complex reservoirs requires current and historical performance of the reservoir and facilities, to drive the field-depletion plan and investment strategy. In most companies, the field-development strategy is included in the annual budgeting round and becomes a financial exercise in allocating capital based on the number of production wells to be drilled. Yet this is insufficient to optimise the rates and recovery. More complex reserves distribution requires an interaction between the reservoir management, production and financial disciplines. There are three issues to consider here. (1) Consideration of the annual budgeting and capital allocation process: many leading companies now separate the annual review of the field development strategy from the annual budgeting round. (2) The availability and transparency of well performance data; both production rates and costs. Often production and financial data are stored in separate systems, making it difficult to determine the cost per unit production on a well-by-well basis. (3) Intra-year monitoring against budget is difficult – a simple question such as: *How are you getting on against your budget*, is difficult to answer. We consider that the solution to these issues involves making well production and cost data transparent and easily available to decision-makers. Web-enabled, performance-management systems are now available in the market that integrate data from disparate sources to present a more complete picture. The technology is available to link well performance data to capital allocation. *Does the industry want to use it?*

(#118986) Stratigraphic architecture of the mid-Cretaceous reservoirs of the Al Shaheen field, offshore Qatar

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In the mid- and Lower Cretaceous succession of Block 5 (offshore Qatar) six reservoir zones are distinguished. These reservoir zones differ strongly from each other in lithological and sedimentological facies composition, in stratigraphic architecture and in structural context. Different development strategies, including very long horizontal wells, have been applied to obtain the most optimal production from these reservoirs. The following reservoir units are distinguished. The Kharaib B and C reservoirs are low-angle, carbonate ramp systems that show a layer-cake architecture. In contrast, the overlying Aptian-age Shu'aiba Formation, shows a very high lateral facies variability, due to a platform-to-basin transition. The Shu'aiba platform is incised and overlain by Nahr Umr sands and shales. The producing sands are very thin, below seismic resolution, and show significant lateral facies changes. The Mauddud/Khatiyah carbonates are again characterized by platform-to-basin facies changes. The top of this unit has been strongly affected by local uplift. Detailed geological knowledge of these reservoirs has provided the basis for the successful development of the Al Shaheen field, allowing for optimal well planning, and has provided essential support for geosteering and completion of long horizontal wells. A full-field. high-resolution 3-D seismic data is being acquired to complement the assessment, understanding and development of these producing reservoirs.

(#123462) Evolution of the Oman Salt Basins during Late Proterozoic-Cambrian transpressional tectonics

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Prior work on the nature and evolution of Oman's infra-Cambrian salt basins has suggested that the western margin of the South Oman Salt Basin was a focus for deformation, characterised by chaotic stratal patterns and significant reversal/inversion of structures. This style of deformation, however, was not observed within the salt basins themselves. Attempts to reconcile the variability in both seismic data quality and apparent structural style resulted in numerous models for the evolution of the salt basins and the nearby *Western Deformation Front*. Early compressional models eventually gave way to a rift model to explain the genesis of the salt basins, leaving a number of observations not integrated and issues unresolved. The objective of this study was to re-evaluate the prevailing structural model (rift) in the context of recent observations. With the help of a regional framework provided by the interpretation and integration of gravity, magnetic, seismic and well data, a consistent regional structural interpretation has been made within the context of global plate tectonic models. This work strongly indicates that the salt basins formed (and later deformed) during transtensional and transpressional local tectonics within a *supra-regional* compressional plate setting (i.e. Pan African amalgamation of Gondwana).

(#118628) New insights into the Amin Formation by the integration of basin and field scale data

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As gas operator on behalf of the Oman Government, Petroleum Development Oman (PDO) has been active in a mature basin for about 23 years. One of the focus areas for gas exploration and development in the north has been on deep Haima reservoirs. One of the main reservoirs in the deep Haima is the Early Cambrian Amin Formation. The information in outcrop and from sparse well data provided insights in basin-wide trends and reservoir quality factors for this formation. Information from relatively dense well data in a field development can be used to focus on higher-frequency lateral and vertical variations and the mechanism steering these differences. Outcrop data were tied using core and regional trend maps to the Amin geology in a northern Oman field. Detailed correlation and core evaluation, combined with seismic control, provided new insights in the Amin Formation geology, including: (1) a grainsize trend was observed in core data, (2) erosion at the Amin-Miqrat

boundary suggested that sweet spots with reworked sediments may exist in the basin, (3) Apart from the usual reservoir quality factors (depth of burial, facies, contact position), additional factors have been identified including: fault proximity, zones subject to intense deformation, porosity enhancements due to leaching and fracturing. These new insights are being incorporated in the exploration strategy of the basin and in the development approach and modelling of fields. They allow for a better definition of pre-drill risk and recovery effectiveness, as well as more robust production forecasts and well placement.

(#118724) Cause, timing and distribution of GOR/CGR variations in Central Saudi Arabia and its consequences for prospectivity in the western Rub'Al-Khali Basin

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Major controls of GOR/CGR (Gas/Oil and Condensate/Gas ratios) in Saudi Arabia's petroleum systems include water washing. In central Saudi Arabia, oil and gas/condensate in the Unayzah reservoirs exhibit variations in GOR in the range of 150 to 10,000 standard cubic ft/barrel. Furthermore oils are extremely undersaturated with gas despite having gravities in the range of 44–47° API. Assessment of independently measured parameters used to determine water washing of crude oils has shown a strong relationship between water washing and GOR. Investigations on neotectonism affecting the Arabian Plate showed that an important denudation of the shield from the Miocene Hofuf Formation, onwards (about 12 Ma), documented by a huge fan delta southeast of Ghawar field and the thick sedimentary sequences in the foreland basin. After a Pliocene localized fore-bulge uplift phase on the eastern flanks of the Arabian Plate, the Pleistocene-Holocene exhibited an accelerating northeast tilting. This recent tectonic activity had profound repercussions on the hydrodynamics and consequently the water washing. Considering the Late Tertiary and Quaternary as the main timing for strong hydraulic flows, then the *entry points* of surface water to the Unayzah aquifers can be derived from the study of the drainage system on the Arabian Shield and the distribution of major Quaternary gravel deposits. On the western flank of the Rub'Al-Khali Basin, besides the Central Arabian case, two other areas were identified where severe water washing can be postulated.

(#124616) Isharat-1 multi-azimuth VSP

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On its first exploration well SRAK successfully acquired a multi-azimuth vertical seismic profile (VSP). In addition to zero-offset data, four azimuths were acquired at large offsets from the wellhead (greater than 3 km).

Acquisition of this VSP data involved the manufacture and mobilization of dedicated equipment and was hampered by considerable logistical challenges. These resulted from the remoteness of the well location, multitude of suppliers, tool failures and timing, all of which provided invaluable knowledge and experience on VSP operations. After processing of the data and an integrated evaluation, we improved our understanding of the seismic-to-well match, and in particular, we developed a better appreciation of the presence of multiple systems in the surface seismic data. This is of significant importance as these multiple systems mask part of the targeted sequence, and a better understanding yields an improved outlook on their removal. The imaging results within a very large VSP aperture remain challenging; however, after careful review, we found hints as to how the source-rock sequence may have been deposited. In this presentation we will discuss the design, acquisition, processing, and evaluation of the data, and the experience that was gained for future VSP programs in this environment.

(#117989) Tectonic heat flow modelling for basin maturation: Methods and applications

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Basement heat flow is one of the most influential parameters on basin maturity. Although rapid progress has been made in the development of tectonic models capable of modelling the thermal consequences of basin formation, these models are hardly used in basin modelling. Consequently heat flow is considered a user input, often marked by a constant value without temporal or spatial variation, resulting in erroneous maturation assessment. To better predict heat flows we have developed a multi-1D probabilistic tectonic heat-flow model, incorporating a variety of tectonic scenarios (including rifting, underplating and mantle upwelling). The model is capable of inversion of burial histories, calibrated to temperature and maturity data. Calibration and sensitivity analysis is done through Monte Carlo sampling analysis using an experimental design technique for computational efficiency. The model has been applied for a range of basin settings including the Arabian Peninsula and its offshore margins. For (frontier) deep-water basins, we showed that basin maturation is significantly higher and occurs much earlier when adopting tectonic heat flow instead of a constant heat flow extrapolated from shallow-water and onshore wells. For mature basins, we showed that tectonic heat-flow scenarios considerably aid in identifying and understanding underexplored play systems, by putting temporal and spatial constraints on paleo-heat flow. In particular modelling results indicated that the interplay of rifting, underplating, inversion and (Zagros) foreland formation, has resulted in much stronger temporal and spatial tectonic heat-flow variations than hitherto assumed.

(#124004) Successful application of neural network technique for rock typing Marrat carbonate reservoirs of West Kuwait

Naveen Kumar Verma (KOC <nverma@kockw. com>), Fahed Al-Medhadi (KOC), Christian Perrin (Schlumberger, Kuwait), Rasha Al-Moraikhi (KOC), Eman Al-Mayyas (KOC) and D. Natarajan (KOC)

Application of the neural-network technique using electro-logs for rock-typing carbonates is challenging because the initial depositional fabric is often overprinted with diagenesis and tectonics. This presentation shows the first successful application of the neural-network technique for rock-typing the Marrat carbonate reservoirs in two producing oil fields in Kuwait. Conventional electro-logs from ten key wells were used for the rock-typing, whereas unconventional nuclear magnetic resonance (NMR) and borehole image logs from four of these wells were integrated to understand and quantify permeability enhancements.

Core descriptions identified nine litho-facies: (1) calcareous-shale, (2) argillaceous-limestone, (3–7) limestones (mudstone, wackestone, packstone, grainstone and oolitic grainstone), (8) dolomitic-limestone, and (9) anhydrite. A quality check using log data (gamma-ray, neutron and density) was performed for depth matching, environmental correction and normalization. The log response of lithofacies was analyzed where good correspondence was observed for eight electro-facies. This provided 'log signatures' that were used to identify the key zones and to train the neural network model. Validation of the electro-facies was performed using core lithofacies from eight wells.

In addition, thin-section micro-facies, ϕ/K and mercury injection capillary pressure (MICP) data from three wells were used to qualify the electro-facies as 'rock types'. The results were consistent with the sequence stratigraphic framework. The neural network identified *rock-types* satisfactorily for the cored and non-cored intervals, including a blind test cored well and a non-cored well. Furthermore, unconventional logs were integrated where NMR helped to quantify vugs and fractures, while, image logs helped to differentiate fractured from non-fractured wackestones. Rock-types were derived for all non-cored wells and propagated through seismic control to build a fine-resolution geological model in one field. The model is expected to facilitate better management of pilot water-injection under implementation besides assisting further field development.

(#137293) New Technologies for Challenging Exploration Opportunities

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This is a special session and abstracts are not submitted.

(#116763) Sedimentological and biological signature of the Permian / Triassic boundary, southern Rub' Al-Khali Basin, Saudi Arabia: Role of the microbial activity

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The palaeoecological and sedimentological events associated with the Permian/Triassic transition are described for the eastern part of the Rub' Al-Khali Basin. A sequential architecture within a reliable chronostratigraphic framework was assessed from cores and cutting samples, and general facies distribution. Some environmental breaks are better understood at a small-scale with the help of a high-resolution sequence-stratigraphic framework. The Permian/Triassic transition occurred during a major flooding event on an extensive flat platform, associated with a drastic palaeoecological crisis and favourable development of microbial activity. In low-energy environments, microbialites exhibit different growth strategies from laminated stromatolites to thrombolites at different stratigraphic levels. Some features of the thrombolitic facies suggest large variations in salinity. This schizohaline effect can take place at a regional scale within isolated intra-shelf lows (subtidal setting), where freshwater and marine flooding can quickly alternate. At a larger scale, it seems that the paleohighs were drowned, connecting different palaeogeographical domains that were isolated during the Late Permian. In this context, a drastic change in the global oceanic circulation pattern may have occurred. In a high-energy context, the microbial activity was also intense but susceptible to erosion and generated coated grains and/or oncoïdal flat pebbles associated with oolites. In this case, microbial activity favoured early cementation processes. To conclude, several microbial events occurred during the maximum flooding events of the Late Permian-Early Triassic sequences. This Permian/Triassic extinction is not viewed as a unique event but interpreted as a multiple-steps crisis inducing progressive environmental deterioration.

(#124033) Quantification of Holocene and Pleistocene heterogeneity of a carbonate depositional system, Bar Al Hikman, Oman

Brigitte Vlaswinkel (Shell <b.vlaswinkel@shell.com>), Peter Homewood (Independent Consultant), Henk Droste (Shell, Oman), Erwin W. Adams (Shell), Cathy Hollis (Shell) and Monique Mettraux (Independent Consultant)

Spatial heterogeneity is a basic characteristic of carbonate depositional systems. Poor seismic resolution and the limited density of well data are not always adequate to extract sufficient information on the geometric characteristics of depositional facies and their horizontal extent at the reservoir scale. Examining and quantifying spatial depositional patterns, in modern analogs, may elucidate depositional dynamics, assist in facies interpretation in the subsurface, and predict the distribution patterns that are required as inputs for geologic models. Various quantitative modern analog studies, mainly in the Bahamas, have assisted in predicting carbonate reservoir attributes; however, in other regional settings, quantitative analog data on a reservoir scale remains very limited. This study investigated the Bar Al Hikman region in Oman, which represents a ramp-type, progradational system, which underwent a forced regression involving significant structural influence. The co-existence of Holocene and Pleistocene deposits is ideal for a comparative study of several geomorphic features (e.g. barrier bars, beach ridges, sand waves, lagoons, reefs), and addresses the fundamental issue of the preservation potential of modern sediments. Satellite and airborne remote-sensing tools, in particular, provided an efficient way to quantify the regional spatial complexity of the depositional system in plan view. The main objective was to explore trends of facies attributes (e.g. abundance, size, shape, facies interrelationships) of the various depositional features. The results will help to predict the heterogeneity at the field or interwell scale and thus establish the likelihood of communication between geological bodies within producing fields. This is particularly relevant in many mature Cretaceous fields, where prediction of interwell heterogeneity is increasingly critical in the drive to enhance hydrocarbon recovery.

(#114656) NIOC partnership with Iranian education institutions to fulfill its future demands

Iraj Vosoughi-Niri (University of Tehran, Iran <info@dr-vosoughi.com>)

Increasing worldwide demand by the petroleum industry for experts has encouraged industry decision-makers to participate with educational institutions in order to educate more professionals. The National Iranian Oil Company (NIOC) has played an active role in participating actively with some selected Iranian institutions and schools. It supports them both financially and practically. NIOC also involves academic institutions by involving them in industry research and development programs and many other important projects in different areas. This presentation will discuss NIOC's important role in education and the growth of higher education in Iran.

(#116765) Skill and serendipity: Exploring for gas-condensate in the South Rub' Al-Khali Basin, Saudi Arabia

Walter Rainer Voggenreiter (SRAK, Saudi Arabia <walter.voggenreiter@srak.com.sa>) and Patrick Allman-Ward (SRAK, Saudi Arabia)

The South Rub Al-Khali Company Limited (SRAK) is an incorporated Joint Venture formed on 17th December 2003 by Shell Saudi Ventures Limited (40% share), Saudi

Arabian Oil Company (30% share) and Total Ventures Saudi Arabia (30% share) in order to explore for non-associated gas in the South Rub' Al-Khali Basin in Saudi Arabia. The realities of the business environment and conditions of operations in Saudi Arabia, the size, remoteness and challenging terrain of the Contract Areas, and the limited availability of pre-existing data, represented a particularly tough set of challenges unique to the SRAK Joint Venture. In order to maximise the chances of achieving its commitments within the timeframe of the First Exploration Period, a play-based rather than prospect-based exploration strategy has been devised during the start-up of the Venture to maximise the chances of identifying working hydrocarbon systems and to optimally position the Company for a Second Exploration Period. Within its overall exploration strategy and methodology, SRAK has followed a three-pronged approach of *Sweetspot Identification* (Regional Framework Studies), *Portfolio Build* (Potential Field and Seismic Data Acquisition and Processing) and *Probability of Success Polarisation* (Technology Applications) in an attempt to define a *Portfolio of Choice* for the Venture to select from during the drilling execution phase. In 2006, SRAK entered a new exploration phase with the spudding of the first of up-to-seven exploration wells. The Isharat-1 well proved the presence of critical play elements and the viability of the Paleozoic hydrocarbon plays in the South Rub' Al- Khali Basin. This presentation will discuss the strategies, methodologies and results of SRAK's initial exploration program.

(#123530) Log-based permeability prediction in a complex carbonate hydrocarbon field, Kangan and Dalan Formations, Iran

Arnstein Waldum (StatoilHydro, Norway <awald@statoil.com>), Arild Eldøy (StatoilHydro, Norway), Arild Eliassen (StatoilHydro, Norway), Tore Amund Svånå (StatoilHydro, Norway) and Reidun Rovde (StatoilHydro, Norway)

The excellent dataset available from this field has been utilized in the search for a log-based permeability model. The resulting model required input from the 'basic' suite of logs available in all production wells and the sonic log was therefore not included. The main depositional lithofacies of the Kangan and Dalan Formations in the area of interest are ooid-peloid grainstones and lagoonal wackestones-mudstones. Diagenesis (dissolution, cementation, dolomitization) has modified initial pore textures and ideal reservoir rocks (grainstones) have partly been transformed into low permeability-high porosity oomoldic rocks. Dolomitisation of more muddy lithofacies enhanced the reservoir quality and high permeability-moderate porosity conduits for fluid flow were formed. The key to successful prediction of permeability thus becomes the identification of pore textures. This was done through the application and adaptation of concepts developed by J. Lucia. The resulting model was developed using logs and core data-descriptions from three extensively cored wells. The model was subsequently

applied to a number of production wells, where production logs confirmed the predicted permeability profiles. Nuclear magnetic resonance and sonic measurements can also provide independent estimates of permeability along a wellbore. In the cored wells, these data exist, and interpreted permeabilities are available. Results are presented and discussed in a rock-fabric context.

(#138102) From data acquisition to simulator: fracture modeling in a carbonate heavy oil reservoir (Lower Shu'aiba, northern Oman)

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A dedicated appraisal campaign and modeling study was carried on an heavy oil, fractured Shu'aiba field in northern Oman to assess the feasibility of steam-assisted GOGD EOR. In this field, key to a successful SAGOGD is a well-connected fracture network, which was investigated by drilling three horizontal wells. Borehole image, sonic and resistivity logs were run in the wells to understand static fracture characteristics; dynamic behavior was assessed with drill stem tests and PLTs. The fracture models were built with forward modeling algorithms using Shell's SVS fracture modeling software. They are based on fracture characterization that integrates the well data with 3-D seismic, the field kinematic structural evolution and the regional understanding established by PDO's long-term activities in the area and analogue sandbox models. This integration renders the fracture models more realistic than purely stochastic fracture models that only honor the field data. Interdisciplinary collaboration during data acquisition and all stages of the modeling assured that only the features relevant to the dynamic behavior of the reservoir were modeled while at the same time the geological details of matrix and fracture models were captured sufficiently in the simulator. Simulations were run in dual-porosity dual-permeability thermal mode in Shell's dynamic simulator. Three loops of full static-dynamic modeling were completed which streamlined and focused the model building without compromising the details. The results are fully integrated model scenarios that are directly and quantitatively comparable to the PDO fractured Shu'aiba fields facilitating management's technical decision-making on the EOR strategies for the fields.

(#117788) Geosteering horizontal wells in the mid-Cretaceous Shu'aiba Formation, Oman

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Petroleum development Oman (PDO) has been using geosteered horizontal wells in the Qarn Alam area to

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maximize oil-recovery rates, production and minimize attic oil. The Shu'aiba Formation is a mid-Cretaceous carbonate platform in this area, and its top is represented by a four million year old erosional surface. To complicate matters, the formation is also faulted, fractured and has erosional channels cut into its top surface. The mid-Cretaceous Nahr Umr shale conformably overlies the Shu'aiba and provides the seal for the reservoir. Unfortunately the log characteristics of the Shu'aiba carbonate and the Nahr Umr shale are very similar with very low resistivities of 1.0–4.0 Ohm for the Shu'aiba oil reservoir and 0.6–1.0 Ohm for the Nahr Umr shale. The objective of geosteering is to stay within a zone 0.5–1.5 m below the top Shu'aiba erosional surface where the reservoir characteristics are best, without exiting into the overlying shale. Currently this technique has been tried in three fields in the Qarn Alam area using three different log-while-drilling (LWD) contractors and five different LWD tools.

The resistivity response is the main geosteering tool used; gamma-ray and rate of penetration (ROP) are also important. Geosteering has so far resulted in wells being drilled within the 1.0 m target-window more than 80% of the time, and exits into the overlying shale are less than 0.4 exits per km. This presentation will concentrate on the continuing development of the technique and log-response characteristics for geosteering the wellbore.

(#123516) Managing data for well geosteering operations

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Well data management is a key element in geosteering and operations activities. It requires the well data to be updated in the corporate database in a timely manner, and that the key operations projects have consistent and properly populated well data. With the widespread application of log-while-drilling and monitor-while-drilling (LWD/MWD) technology, satellite data communications with the wellsite, and interpretation in various application projects, the flood of the incoming data requires enhanced data management practices and procedures to ensure that the corporate well data repository is complete and accurate.

We have developed a workflow to inspect and integrate the well data in various master and operations projects, which synchronizes them with the corporate database. Collaboration with geologists working in these projects is essential to ensure completeness and accuracy of the data. The data managers ensure the validated well data is loaded into the corporate database and subsequently propagated across related operations projects to ensure consistency for geosteering activities. Several tools have been developed to automatically execute quality assurance and control (QA/QC) procedures. Two examples are used to show the benefits from such a data management approach.

(#118388) Climate-controlled meteoric diagenesis in carbonates below unconformities

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Sedimentologic and diagenetic data are important for the petrophysical characterisation of carbonates because they parameterise reservoir properties and help to predict flow units below the resolution of seismic lines. Among many control factors, meteoric diagenesis affected most carbonate platforms during sea-level lowstands. This diagenetic environment is commonly believed to be associated with increases in porosity, permeability and pore throat diameters. Using data from three carbonate localities, amelioration or deterioration of reservoir parameter was rigorously tested with a three-step approach. In the first step, the study characterized meteoric dissolution and the subsequent late diagenetic products that filled the pore systems. In the second step, sedimentological and diagenetic data was transformed into petrophysical data. In the third step, the importance of climate, especially humidity and aridity, was considered in order to understand meteoric dissolution and infill. The goal of the study is to make petrophysical predictions. Data from outcrop, slabs, thin section and stable isotopes were used to establish three scenarios that summarized significantly different processes involving meteoric diagenesis below unconformities: (1) increase of porosity and permeability and their preservation through time; (2) increase of porosity and permeability and subsequent pore system occlusion; and (3) decrease of porosity and permeability and creation of a barrier for pore fluids. Knowledge of the texture of the host rock, the time span involved in meteoric diagenesis and the climate regime are necessary to predict porosity and permeability of meteoric pore systems. The study provided evidence that a well-connected karst system is likely to be filled with sediment and cement, whereas smaller pore systems have the potential to remain open during basin development under more arid conditions. Depending on the aforementioned parameters, end-members of meteoric diagenesis are either seals or rocks with good reservoir properties.

(#123765) Basin platform transitions in Upper Jurassic carbonates of the Amran Group, Yemen

Christian Weiss (Institute of Palaeontology, Germany <weiss@pal.uni-erlangen.de>)

The Amran Group consists of an 800–1,200-m-thick carbonate sequence. Outcrops in the Yemen mountains consist of shallow-water facies types with shallowing upward cycles. In the study area, the Marib Province, those facies types inter-finger with basinal facies types of the Marib-Sabwah Basin. Facies analyses made on thin sections of several profiles, X-ray diffraction (XRD) analyses of the insoluble residue and geochemical data-sets were used to reconstruct the transition between the

deeper-water basin facies and the shallow-water facies types of a carbonate platform. A sedimentary ramp setting can be reconstructed by the lateral distribution of the different facies types. They show a low slope with ooid sandbars and lagoonal facies types, which change to fossil wacke and packstones of a deeper-water setting. The basin facies is represented by mudstones. The stratigraphy is based on foraminifers, and supported by clay mineral and chemostratigraphic analysis. One focus of the study is the position of reefs on the carbonate ramp. They appear as different types depending on water depth, and can be divided based on the composition of reef-building organisms.

(#124027) Seismic character of a fractured reservoir: A physical model study

Robert W. Wiley (Apex Spectral Technology, USA <rwiley@apexspectral.com>), Byron Golden (Halliburton, USA), Peter Wilson (Apex Spectral Technology, USA) and Scott Peters (Apex Spectral Technology, USA)

We designed a physical model to study the effect of a swarm of vertical fractures on seismic data. The physical model was constructed by placing several glass slide covers between two large glass blocks. This was then embedded in resin to represent the bounding lithologic layers above and below the fractured zone. The glass slide covers were approximately 0.5 mm in thickness and adequately represented fractures when scaled. 3-D seismic data was collected over this model using high-frequency transducers with a variety of offsets. By comparing the amplitude-versus-offset (AVO) response over the glass blocks with the AVO response over the fractures, we determined the variations in AVO due to the fractures. We were also able to analyze spectral variations between the fractures and the unfractured block. In addition, we determined spectral variations with offset of the fractured portion of the model. These results will enable the explorationist to better determine the location and orientation of fractured reservoirs.

(#124032) Seismic frequency variations of a reservoir: Lessons from a spring

Robert W. Wiley (Apex Spectral Technology, USA <rwiley@apexspectral.com>), Peter Wilson (Apex Spectral Technology, USA) and Scott Peters (Apex Spectral Technology, USA)

In studying wave propagation and attenuation in the Earth, it is often convenient to use simplified models. One of these models is a mass, spring and dashpot to model oscillation and attenuation. By analyzing the motion of a spring using different forced oscillations, we studied the effect of the system's characteristics on the transmitted frequency. In particular, we observed that if the forced oscillations are above the system response, the predominant output will be at the system characteristic. For lithologic layers, the system characteristics depend,

in part, upon the Poisson's ratio, matrix and the fluid velocities. With reservoirs having different fluid velocities and often different Poisson's ratios from the surrounding rock; this implies that hydrocarbon reservoirs could have a measurable spectral character based upon their unique system or rock properties and that these characteristics could be estimated with seismic data.

(#121860) The Demographic Challenge

Hamish A.M. Wilson (Paras Ltd., UK <hamish.wilson@paras-consulting.com>)

The demographic challenge in the oil industry is well-known with the average age of professional staff at around 50 or more. There are two related issues arising from this statistic; *is this demographic profile a problem* (i.e. loss of experience) *or part of the solution* (retiring people who are resistant to change)? Over the last decade there have been dramatic improvements in productivity. Now the industry is further driven to increase productivity. Yet a major barrier to the necessary continued improvements is massive industry conservatism. Productivity gains are only part of the solution. The demography challenge mainly concerns the international oil companies. Yet in Asia, Africa and Russia there are large numbers of graduates eager to enter the industry. In the UK and USA the issue regarding talent is how to attract it to the oil industry. The public has a perception that the industry is dying-out based on the premise that *oil is running out*. The oil industry is not going to die because we run out of oil. Yet the globe cannot afford the consequences of continued unconstrained use of hydrocarbons; i.e. the effects of climate change. The industry's role in both providing the energy for the global economy and removing green-house gases suggests that this is anything but a dying industry. We've got to tell people about it! We all therefore have a collective challenge to raise the profile of the industry to attract the brightest talent to solve two of world's greatest problems; energy and climate change.

(#121861) Cycle time reduction and integration - seismic to simulator

Hamish A.M. Wilson (Paras Ltd., UK <hamish.wilson@paras-consulting.com>) and Olivier S. E. Van Belle (Paras Ltd., UK)

The industry continues to search for ways to increase productivity and reduce overall finding and production costs. Integrated processes are critical to achieving the necessary productivity gains. The *seismic to simulator* process is fundamental to reservoir management. Huge gains have been achieved in the time taken to rebuild a reservoir model, however further challenges remain. Consider two issues. Firstly, The increasing availability of real-time production information from *smart field*-type initiatives requires the reservoir model to be updated more frequently, perhaps in real time. We are struggling to combine the long reservoir model cycle with real-time production data. Production operators should be able

to use the reservoir model to support day-to-day field management decisions. Secondly, reservoir performance data should be used to inform the static model and influence the geological and geophysical interpretations. Both *systems and people barriers* have to be overcome in order to achieve the further productivity gains outlined above. On the systems side, barriers remain in the integration of the static to dynamic model. Within the static domain, technologies like OpenSpirit™ plus the efforts of Schlumberger and Halliburton have enabled huge gains in static model integration. Yet moving geological models into the simulator is not easy. These challenges can only be addressed by considering the subsurface model as a single integrated process. Yet in many companies, geologists, geophysicists and engineers are in separate organisational structures that do not communicate. We have to solve the people problem first before addressing the systems integration issues.

(#118189) Reactive transport modeling and reservoir characterization: recent advances in geoscience and engineering applications

Yitian Xiao (ExxonMobil, USA <yitian.xiao@exxonmobil.com>) and Gareth Jones (ExxonMobil USA)

One of the key challenges in reservoir characterization is the accurate prediction of reservoir quality distribution and alteration associated with various diagenetic reactions at both geological and production timescales. Reactive transport modeling is an emerging technology that can be used to simulate ground-water flow coupled with chemical reactions to facilitate predictions of the dynamic reservoir behavior of multi-phase fluid-rock interactions. We have applied reactive transport modeling to a number of case studies that significantly advanced our reservoir characterization capabilities for both geoscience and engineering applications. For example, we have developed the first fully-coupled 3-D reactive transport models for dolomitization in both early reflux and late fault-controlled hydrothermal systems. The modeling results revealed complex spatial and temporal variations of limestone, dolomite, and anhydrite distribution and the significant implications on carbonate reservoir quality. Other successful applications included modeling early diagenesis associated with a fresh-water lens in an isolated carbonate platform; geothermal convection and burial diagenesis in a salt-buried isolated platform; and fault-induced hydrothermal flow and illitization and permeability reduction in a sandstone reservoir. For engineering applications, we applied reactive transport modeling to study formation damage associated with water and steam injections in sandstone reservoirs; acid stimulations and worm-hole development in carbonate reservoirs; and the long-term fate and risks of injecting CO^2 and H_2S in saline formations. Modeled positive and negative feedbacks induced *by artificial diagenesis* provided guidance to optimize injection strategies. Reactive transport modeling, when sufficiently integrated with traditional methods and calibrated with field data, has the potential to generate physically viable predictive

concepts and reduce the uncertainty in predicting the spatial distribution of reservoir properties that impact both geoscience and engineering business decisions.

(#118368) Structural restoration as an effective tool for detecting the evolution and timing of structural development: A case study from the Muglad Basin, Sudan

Mohamed Abdelgader Yassin (Sudapet, Sudan <mohamedgadir@gmail.com>)

The area under investigation is located in the Muglad Basin, which is mostly covered by 2-D seismic data with fair to good quality. Three wells were drilled in this area, two of them were dry and the other one is currently producing from reservoirs such as AG-2 and Bentiu. Faults in the study area trend E-W whereas in the rest of Muglad Basin they trend NW-SE. The main objectives of this study were: (1) to evaluate the vertical migration through the faults; (2) establish the time when the structural trap formed; and (3) understand the geological evolution of the area. Five regional 2-D seismic lines were selected to conduct a structural restoration. An inclined shear algorithm was utilized because of it's applicability for extensional tectonic regimes. Both reconstruction and flattening approaches were applied. The extension ratio (Beta) was used to predict the rift-sag periods. The rift stage was characterized by high Beta values (e.g. 1.2), while the sag period ranges for Beta varied from 1 to 1.1. This sub-basin evolution history consisted of three rift phases. The first occurred during the Early Cretaceous and was the most long-lasting. The second phase, which occurred during the Late Cretaceous, many faults were initiated and others were re-activated. In the third rift phase, which occurred during the Tertiary, many faults were initiated. The study area is located near the Central African Shear Zone, which control the faults orientation. Generally the faults were formed by dextral oblique movements. The validity of the traps has been confirmed through a restoration process.

(#123312) Workflow automated services for well logs

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Saudi Aramco's Reservoir Description Division (RDD) provides well log services to the company's professionals including archiving, processing and publishing in a timely and efficient manner. In recent years the volume of work has increased considerably and this has prompted RDD to seek assistance from the Formation Evaluation Systems Group (FESG) to implement the Workflow Automated Services for well Logs (WASL) System. The workflow allows E&P producers and users to collaborate in delivering higher quality certified well log results. Also, the system provides RDD engineers with an easy mechanism to archive raw well log data, and then track

and monitor their processing. The results are automatically published into a corporate repository where they are accessible by authorized well log users throughout Saudi Aramco. The system monitors service companies and Saudi Aramco responsiveness and accountability. It ensures timely well log service availability to Saudi Aramco well log users.

(#119289) Improved wellbore stability modeling in fractured formations

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(Knowledge Systems, USA)

One of the most prominent features of the Earth's upper crust is the presence of joints and fractures. Many petroleum reservoirs are situated or inter-bedded in these fractured porous formations. For instance, fractured carbonates and fractured laminated shales are prevalent in the giant and prolific fields of the Middle East; the Ekofisk formations in the North Sea comprise fractured chalks. Drilling in these fractured formations presents wellbore stability challenges because the fractured rocks have larger shear failure zones and smaller fracture gradients. This results in a narrower safe mud-weight window, and wellbore instability-related costs can become great because of lost time or, in the worst case, a lost well. A double porosity poroelastic model has been proposed and the finite-element method was applied to obtain a wellbore stability solution. This method considered the effects of both fractures and porous media on wellbore stress redistributions, and hence can better model fractured porous media. A case study in Oman was examined, where claystones were weak and carbonate rocks were heterogeneous and contained natural fractures. Wellbore-stability incidents, such as drilling fluid losses and massive wellbore breakouts, frequently occurred while drilling. These problems were mainly caused by the narrow mud-weight window available for maintaining wellbore integrity. Increasing mud weight caused drilling fluid losses, but lowering mud weight induced wellbore breakouts. After modeling, analysis, and calibration in the offset wells, the correct mud-weight window and casing intervals were recommended for proposed wells to avoid wellbore shear and tensile failures.

(#117456) Managing and populating scanned exploration geology and geophysics data in GIS

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Many oil and mining companies are increasingly leveraging the power of geographic information systems (GIS) to better manage geospatial data. This includes massive scanned (from hard copies) geological and geophysical (G&G) data such as cross-section, well logs, 2D/3D seismic, even exploration reports. They are also seeking to insure that cross-disciplinary spatial data is readily available to their geoscientists and explorationists, because most exploration geodata is spatially-enabled and time-associated. In order for geoscientists to use the powerful and extensive GIS environment for G&G projects, G&G geodata (including scanned) are firstly required to spatially enable them in GIS database like ArcSDE with open standards and data models like PPDM, POSC. The presentation briefly reviews two of current commonly-used techniques for managing G&G geodata, including project-based E&P databases and the Documentum technique, and some disadvantages. And then, it mainly presents how to spatially manage scanned G&G geodata in GIS database; and explain how to integrate and populate those geodata for any E&P projects in order to reduce risk in exploration activities. From a perspective of G&G management, I will also discuss how to ensure the scanned G&G geodata are complete to deliver so that explorationists can receive them under various spatial query criteria and time conditions, no matter where and when the exploration projects happen.

(#122491) Prediction of top surface movements due to SAGD (steam assisted gravity drainage) based on coupled thermal pressure deformation models

Xing Zhang (Schlumberger, UK <xzhang24@ bracknell.oilfield.slb.com>) and Nick Koutsabeloulis
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Steam assisted gravity drainage (SAGD) is a new oil production technology for the recovery of heavy oil and bitumen. In these fields, the top surface movements that are caused by thermal expansion of reservoir rocks due to injected steam, is a major concern in many environment issues. This is particularly true for those faulted reservoirs that are close to the top surface. A coupled thermal-pressure-deformation model has been used to predict the movements of overburden on a cross-section of a studied field, the associated changes in stress and strain and the potential for fault reactivation during a production period of 33 years. This field has a reservoir thickness of about 250 m, overburden thickness of about 350 m, temperature change of up to 190° C and pressure depletion of up to 190 psi. The intact rock was simulated as an elasto-plastic material and the faults were simulated as Mohr-Coulomb materials. Four scenarios were examined to account for the uncertainty in mechanical properties of overburden and reservoir rock, such as Young's modulus, Poisson's ratio and thermal expansion coefficient. After 33 years of production, about 0.155 m of upward movement at the top surface above the reservoir was predicted under the given conditions. Also there is a high risk for fault reactivation due to the expansion of the reservoir rock. The predicted upward movement of the overburden decreases with decreasing Young's modulus and thermal expansion coefficient, and increases with increasing Poisson's ratio due to the increase in bulk modulus.

(#122641) Investigation of effects of well configurations on reservoir recovery efficiency based on coupled geomechanical models

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The impact of well configurations on reservoir recovery is investigated based on a coupled geomechanical model. This areal model simulated 36 months of production and injection in 49 wells in a stressed and fractured-faulted reservoir, which is geologically similar to the Gullfaks reservoir in the North Sea. The coupled model is capable of simulating the interaction between reservoir rock deformation and permeability changes, both in intact rock and in fractured-faulted rock. The intact rock was simulated as an elastoplastic material, and the faulted-fractured rock as a Mohr-Coulomb material. Three scenarios of well configurations were investigated. The same sequence of random, uncorrelated pressure changes at wells was input in each case, and the consequent production and injection rates at wells were output for analysis. In Case 1, there were 25 producers and 24 injectors, in which each producer was surrounded by 4 injectors. In Cases 2 and 3, there were 28 producers and 21 injectors with 4 rows of producers and 3 rows of injectors, but the direction of rows was different in relation to the regional horizontal stress direction and the major faults. Due to the difference in well configurations, significant fracture-related permeability enhancement occurred in Cases 1 and 3, which resulted in significant difference in total production rates and injection efficiency. The total production rate was about 75% higher in Case 1 than in Case 2, and the injection efficiency was about 20% higher in Case 1 than in Case 2. In addition, Spearman rate correlation coefficients were used to identify the most efficient production-injection wells. The study revealed a very strong influence of geomechanics on the reservoir performance.

(#118921) Spatial reservoir localization using seismic emission

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All geological media are active seismic systems that, in themselves, generate microseisms. Microseismic energy generation is generally disregarded in most theories, but not in seismology and microseismic studies. In particular, seismic tomography can be used to model *noisy objects* (microseisms) localized in an half-space model of the Earth, including hydrocarbon reservoirs. We have conducted experiments, using three-components accelerometers, to investigate natural seismic-acoustic emis-sion (SAE) with a view to applications to hydrocarbon reservoirs. The goals of the experiments were to investigate the SAE's character, its frequency content and distribution for all three components along test lines. The final objective was to develop a special technology for the spatial localization of the reservoir and the definition of its parameters. We found that the SAE activity of the vertical and horizontal components along the test lines correlated with the location of the hydrocarbon reservoir. There were some different frequency ranges in the amplitude spectrum of the SAE, which relate to different noise sources; these difference may be due to the origin or location of the sources. The data analysis showed that special processing based on the principles of seismic tomography may be used to localize the areas of possible reservoir development. The analysis also identified interstitial zones below the mapped reservoir zone, which may be fault-related, oil-migration pathways. We also found that it is possible to use industry vibroseis data and standard technologies for tomographic analysis of the SAE.

(#118435) Restoration of seismic amplitude using a frequency-dependent gain function

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It is well known that the Earth absorbs acoustic energy and that high frequencies lose their energy faster than lower frequencies. The loss of seismic energy can be attributed to several factors such as absorption, geometrical spreading, and scattering of energy at an interface due to reflection, refraction, conversion, and transmission. Deconvolution and (Q) attenuation-compensation operations are usually performed in order to restore as much of the attenuated high-frequency energy as is justified by the signal-to-noise ratio. The conventional approach for amplitude recovery is to compute and apply a time-dependant gain function. Here, we extend the conventional exponential gain function to account for the inelastic attenuation effect as well. We introduced a frequency factor into the computation and application of the exponential gain function to account for the inelastic attenuation. This process was performed in the frequency domain. There were three steps involved in the computation. First, a 1-D forward Gabor transform was applied (small windows fast Fourier transform). Next, frequency-gain curves and inelastic attenuation were computed and applied for each Gabor slice. Finally, the data was transformed back to the time domain. It is worth mentioning here that the geometrical spreading, which causes the loss of seismic amplitude can be recovered either before or after the 1-D Gabor transform with no visible difference as was indicated by our extensive testing. Moreover, the two processes of the seismic-energy restoration are reversible. This further enhances the robustness of our methodology. We demonstrate the accuracy and effectiveness of our proposed approach using both synthetic and real data examples.

(#117089) Reservoir characterization and 3-D modeling using combined techniques from well logs to reservoir simulation: Case study in the Serie Inferieure, Hassi R'Mel field, southern Algeria

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Reservoir characterisation is a key aspect in building a robust reservoir model for reliable simulations, especially in our case where the reservoir is not yet producing. This presentation describes a method used to build a geological model that was converted into a reservoir model for the Tagi Series of Hassi R'Mel South field (HRS), located onshore in north-central Algeria. The study used Petrel™ software combined with new techniques to preserve the complex variations of the reservoir. Optimising field development required a level of reservoir description that adequately defined vertical and lateral variations in reservoir quality. The method consisted of integrating seismic, petrophysical and geological interpretation. The HRS reservoir formation, known as the Serie Inferieure (SI), has medium to low reservoir quality. The structural model showed great complexity. The results of drilling of three wells, gave 8 m of oil with an average permeability of 50 mD. This encouraged us to develop this reservoir by drilling additional wells before starting production. The SI reservoir represents a challenge for optimising the field development because the heavy oil is located in a highly heterogeneous fluvial reservoir with poor petrophysical conditions. The most important obstacle is that some of the well logs are difficult to interpret due to the naturally radioactive host rocks. The high gamma-ray logs have a high-amplitude response, which masks the reservoir. Another difficulty is that water saturations appear to be very high when interpreted from well logs. To address these problems a multi-disciplinary team used both geological and engineering techniques to develop 3-D numerical models for the effective porosity, permeability, water saturation and facies distribution. These models will be used to calculate the hydrocarbons-in-place and to plan future wells.

(#121712) Middle Jurassic estuarine systems of the southeast part of the Uvat region, western Siberia

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Middle Jurassic deposits of the Tyumen Formation represent a phase of active fluvial to coastal-plain sedimentation during a relative sea-level rise. The main reservoir facies of the southeastern Uvat region is a series of bay-fill delta deposits. A typical sequence comprises bay-head delta sandstones at the base, which represent lowstand to early transgressive deposits, and onlapping transgressive bay-fill mudstones. Fluvial and tidal coarse to fine-grained sandstones of the J5 and J4 units are up to 135 m in thickness and were deposited during a slow rise in sea level. The major architectural feature of the estuarine deposits is the superposition of the multi-lateral and multi-story sandstone complexes, being 20–40 m in thickness and inter-bedded with finer grained coastal-plain deposits. The channel amalgamation rate varied with cyclic sea-level variations, which controlled the sandstone-bodies geometry. The J4 sedimentation was followed by a decrease in sediment supply, which resulted in the deposition of fine-grained sediments of the J-3 unit during an increase in the rate of sea-level rise. Heterolithic strata of J3 unit are interpreted as coastal-plain and central-basin mudstones, and are typically finely laminated or lenticular-bedded, sometimes rooted and weakly burrowed. Thin sandstone are developed mainly as elongate, laterally restricted sandstone bodies embedded in finer coastal-plain deposits and mudstones of brackish transitional origin. Mud and mixed sand-mud inter-tidal flat deposits of J3 are overlain by differently burrowed fine- to middle-grained sandstones of estuary-mouth deposits of the J2 unit, which in the turn are erosively overlain by heavily burrowed fine-grained shoreface sandstones.

The following abbreviations are used for the names of companies and institutions to which presenters are affiliated.

ADCO	: Abu Dhabi Company for Onshore Oil Operations, United Arab Emirates
ADMA-OPCO	: Abu Dhabi Marine Operating Company, Abu Dhabi, United Arab Emirates
ADNOC	: Abu Dhabi National Oil Company, United Arab Emirates
Al Furat	: Al Furat Petroleum Company, Syria
EGAS	: Egyptian Natural Gas Holding Company
GFZ-Potsdam	: GeoForschungsZentrum Potsdam
GNPOC	: Greater Nile Petroleum Operating Company, Sudan
GX	: GX Technology Corporation, USA
IFP	: Institut Français du Pétrole, France
IOOC	: Iranian Offshore Oil Company, Tehran, Iran
KACST	: King Abdulaziz City for Science and Technology, Riyadh, Saudi Arabia
KFUPM	: King Fahd University of Petroleum and Minerals, Saudi Arabia
KOC	: Kuwait Oil Company, Kuwait
Millennia	: Millenia Stratigraphic Consultants, United Kingdom
Neftex	: Neftex Petroleum Consultants, United Kingdom
NAM	: Nederlandse Aardolie Maatschapij, The Netherlands
NIOC	: National Iranian Oil Company, Iran
PDO	: Petroleum Development Oman, Oman
PGS	: Petroleum Geo-Services
PNZ	: Partitioned Neutral (Divided) Zone between Kuwait and Saudi Arabia
RIPI	: Research Institute of Petroleum Industry, Iran
Saudi Aramco	: Saudi Arabian Oil Company, Saudi Arabia
SRAK	: South Rub Al-Khali Company Limited, Saudi Arabia
Spectrum	: Spectrum Energy and Information Technology, UK
TPAO	: Turkish Petroleum Corporation
USGS	: United States Geological Survey, USA
ZADCO	: Zakum Development Company, United Arab Emirates