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# GEO 2006 SELECTED EXPLORATION AND RESERVOIR CHARACTERIZATION ABSTRACTS

The following abstracts were accepted for presentation at GEO 2006, the Seventh Middle East Geoscience Exhibition and Conference that was held in Bahrain on March 27–29, 2006. GEO 2006 was organized by Arabian Exhibition Management (AEM), the American Association of Petroleum Geologists (AAPG), the European Association of Geoscientists and Engineers (EAGE), and was supported by the Society of Exploration Geophysicists (SEG) and the Dhahran Geoscience Society (DGS). The abstracts that are published here describe exploration and reservoir characterization case studies.

## MIDDLE EAST EXPLORATION CASE STUDY

### Exploration prospectivity in the Sharkiyah Region, southeast of Block 42

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The area of interest is located along the eastern coast of the Sharkhiyah region in the Sultanate of Oman. It is covered by old sparse 2-D seismic data with two exploration wells (Ramlat Wahiba-1 and Jabal Fayah-1). Geologically, the area is located between the NNE-trending Al-Huqf Arch and the deformation zone along the eastern coast. The last exploration phase was undertaken by Compact in 1997. The interpretation of seismic data along the flank of the Al-Huqf Arch suggests the existence of infra-Cambrian salt associated with structural depressions. This salt is believed to be part of the Ghaba Salt Basin that extends northeastwards of Block 6. The Permian-middle Cretaceous platform of this part of the Oman foreland basin tilted towards the Al-Huqf Arch due to the Late Cretaceous ophiolite emplacement, which was later responsible for creating an angular unconformity between the platform carbonates and the younger Fiqa Formation. This structural/stratigraphic configuration may form a potential trapping mechanism for hydrocarbons assuming good sealing capability provided by the Fiqa shale. Deeper formations are more promising targets due to the erosional level of the shallower sections. Future exploration in the area depends on better seismic imaging to define the above-mentioned prospects and to delineate untested plays analogous to productive plays of the proven Ghaba Salt Basin. In addition, the extension of the Ghaba Salt Basin from Block 6 northwards into the area of interest opens-up unrecognized exploration opportunities.

### Play concept of offshore Salalah, Oman

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The area of interest is located offshore Salalah, in the southern part of Block 52 in the Sultanate of Oman. It covers an area of more than 3,000 sq km with bathymetry of less than 1,000 m. The area is covered by 2-D seismic, gravity and magnetic data. Geologically, the area lies within a Cenozoic Basin. The rifting of the Gulf of Aden is the key player in the formation of trapping styles in the area. Structural traps are represented by horsts, footwall highs and tilted fault blocks that were interpreted from seismic data. In addition, the deeper Lower Paleozoic thrust system might form additional exploration targets. Moreover, the Ashwaq Formation, represented by Oligocene reefs from onshore Salalah Plain-1 well, and the Tertiary and Upper Cretaceous turbidites from Salalah far offshore, might form stratigraphic traps. The Oligocene reefs are an excellent reservoir with connected porosities up to 30%. The Tertiary and Upper Cretaceous tubidites, and Jurassic clastics and carbonates are likely to have good reservoir quality. Mudstone facies of Cenozoic and Mesozoic ages are expected to be effective source rocks and better developed in the offshore compared to onshore (Salalah Plain-1). The Upper Cretaceous Dhalqut Formation could contain possible source rocks. In addition, the deeper Huqf source rock facies might be present as indicated from offshore regional geology. In summary, the play elements that are present in the offshore Salalah area, in both shallow and deep stratigraphic sections, may form multiple exploration targets. New seismic acquisition in deeper-water areas, away from the existing seismic coverage, could open-up new opportunities.

## Aspects of petroleum geology of Block-34, Al-Jazir, Southeast Oman

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Block-34 (Al-Jazir) is an exploration acreage located on the southeast coast of Oman. Previous exploration resulted in the acquisition of 13,417.7 km of 2-D seismic and the drilling of four wildcat wells. The geographical position of Block-34 along the eastern margin of the Arabian Plate and the diverse tectono-stratigraphic history of the surrounding region provides a more challenging exploration task in the block. This is because Cambrian to Triassic erosion/non-deposition relative to sedimentation was considerably high in the area. Consequently potential source, reservoir and seal units of this period are absent. Based on seismic data, the structures in the northern part of the block are mainly extensional and evolved through different geological periods. The faults observed in the Proterozoic units were probably formed due to Proterozoic extension and due to the Najad Rift event. The influence of the separation of the Indian Plate from Africa and Arabia was probably marked by the faulting associated with the base Cretaceous horizon. The Cenozoic-aged faults could have formed after the Late Cretaceous obduction. In contrast, the structures in the southern part of the block are mainly compressional, and possibly evolved due to the left-lateral, strike-slip faulting induced by the rifting event in the Gulf of Aden. Preliminary geochemical studies have proven the presence of effective source rock facies in both the Dhahir area (Khufai Formation) and Hathnar area (Masirah Bay Formation) along with potential source rock facies in the Shuram, Buah, Natih formations and Aruma Group. However, major risks are associated with hydrocarbon generation and migration timing with respect to structural formation.

## Insight on the new exploration potential in the northern Ghawar environs, Saudi Arabia: new support from technology and structural analysis

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After 70 years of successful exploration and production from the Eastern Province of Saudi Arabia, new technologies supported by structural analysis have led to the identification of undrilled gas prospects near Ghawar field. The objective of this study is to investigate the remaining Paleozoic gas potential along the eastern flank of Ghawar field. Integrating new 3-D seismic and potential field data provided reliable structural maps of the Devonian sandstone (Jauf Formation) and the Permian-Triassic carbonates (Khuff Formation). The study revealed the existence of an undrilled fault closure where the seismic coherency analysis, dip and curvature attributes indicate a push-up fault-related anticline. East-west compression during the Late Cretaceous pushed up this anticlinal closure along a major NS-trending fault located east from the Shedgum anticline. The northern and southern terminations of the closure are controlled by two left-stepping ENE-striking faults that act as strain-partitioning elements. Seismic acoustic impedance inversion at the Khuff reflection indicates the development of a carbonate reservoir. Furthermore the analysis of the seismic amplitude map indicates the occurrence of potential hydrocarbon. The lower Silurian Qusaiba hot shale is predicted to be a mature source rock and to charge the closure. Paleozoic gas exploration opportunities are highly prospective along the eastern flank of the Ghawar field. Particularly, the hydrodynamic analysis indicates that the east-west to east-northeast faults constitute effective lateral seals between different compartments along the eastern flank of Ghawar field.

## Exploration risk reduction by accurate delineation of channel sand bodies in the Lower Zubair Formation in northwest Raudhatain area of Kuwait using post-stack seismic attributes

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The Lower Cretaceous Zubair Formation is generally divided into lower, middle and upper units. The middle unit is the main hydrocarbon producer in northern Kuwait, in the area bounded by the Sabariya, Raudhatain, Abdali and Ratqa oil fields. In NW Raudhatain, which lies outside the Cretaceous four-way closure of Raudhatain field, three wells were drilled primarily to explore deeper pre-Cretaceous formations. From the electric logs only the lower Zubair section was interpreted to contain hydrocarbons in these wells. The sand bodies in the pay zone were deposited in tidally influenced channels within an estuarine environment. The main exploration challenge is to accurately identify and delineate these channel sand bodies. Due to the sparse well control, the channel facies are difficult to accurately map. Consequently, various types of post-stack seismic attributes were used to identify and map the channels in order to reduce the exploration risk. The study area is covered by 3-D seismic data but the resolution is insufficient to map the channel sand bodies by conventional methods. To overcome this difficulty, horizon slices and various post-stack seismic attribute maps were used to identify and map the channel sand bodies. This paper discusses how this new seismic interpretation technique is useful in accurately mapping the target stratigraphic features.

## An integrated study that opened new opportunities

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In the Tinat field, eastern Saudi Arabia, the Unayzah A reservoir consists of an eolian sandstone with an average porosity of about 17%. Most of the wells that penetrated this sandstone flowed high rates of gas and condensate. Two wells, however, encountered water in the same reservoir at a higher level than the base of the gas in other wells. This paper presents an analysis of the significance of these two wells in relation to the level of the oil/water contact. The work was done by a multi-disciplinary team that was formed to evaluate the reservoir and better understand the field. Seismic, petrophysical, petrographic, engineering, geochemical, stratigraphic and structural studies were conducted and their results were integrated. In particular, seismic forward modeling provided a tool to map the fluid type within the reservoir. The modeling showed that gas caused a higher amplitude than water. This attribute was used to show the existence of exploration and delineation potential in the field, despite the two water-bearing wells.

## Mesozoic and Neogene sedimentary rift basins of Yemen: lithostratigraphic correlation and hydrocarbon potential

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This paper describes the updated stratigraphy, tectonic history and petroleum systems of the Mesozoic and Neogene rift basins of Yemen, with particular attention to integrating the existing knowledge to provide a play concept for each basin. Following the separation of India and Madagascar from Africa and Arabia, major sedimentary extensional basins formed in Yemen during the Late Jurassic and Early Cretaceous. The location and orientation of these basins, including the Sab'atayn, Say'un-Masilah and Jiza'-Qamar basins, were controlled by the Proterozoic structural grains within the Arabian Shield. The well-explored Sab'atayn and Say'un-Masilah basins were filled with syn- and post-rift sediments with similar source and reservoir rocks; however, the Tithonian evaporite is absent in the latter. The turbidites below the Tithonian salt trap significant oil in the Sab'atayn Basin. The less explored Jiza'-Qamar Basin has good exploration potential on its eastern onshore sector, which continued to subside during the Paleocene. It has a marly-limestone reservoir that was sourced by the Upper Cretaceous coal-shale source rock. The Neogene rift basins are related to the Oligocene-Miocene rifting phases of the Gulf of Aden (the Mukalla-Sayhut, Hawrah and Aden-Abyan basins) and the Red Sea (Tihamah Basin). Most of the offshore wells drilled in the Mukalla-Sayhut Basin have encountered oil shows in the Cretaceous and Neogene successions. In contrast to the Neogene rift basins of the Gulf of Aden and the Red Sea, no volcanic activity was associated with the formation of the Sab'atayn and Say'un-Masilah extensional basins. We also identify two relatively small basins (the Ad-Dali' and Balhaf grabens) running from onshore southern Yemen to the buried Jurassic petroleum system, which formed before the Gulf of Aden rift event.

## Shu'aiba Formation, an unconventional reservoir in Kuwait

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This paper investigates the potential of the Shu'aiba Formation as an unconventional (low pressured with extreme permeability) oil- and gas-bearing reservoir in northern Kuwait. Potentially large reserves of oil and gas with high production rates are predicted. This paper will discuss how the Shu'aiba Formation was recognized as an unconventional reservoir. A variety of conventional exploration methods interpreted differently were the key to recognizing the unconventional nature and potential of the Shu'aiba. This paper discusses the unique interpretation of typical exploration methods used to evaluate unconventional formations. Interpretation of the results from routine methods such as drill cuttings analysis, petrophysical analysis, mud logging, geochemistry, through-casing temperature logs, seismic review and pressure determination, as well as drilling records, will be reviewed. Maps, well-logs, cross-sections, geochemistry, drilling records and seismic demonstrate the need for a multi-disciplinary approach to evaluate and exploit these types of reservoirs even more so than conventional reservoirs. Many low-pressured carbonate reservoirs may have been over looked worldwide but with a logical interpretation approach of the information many new reservoirs can be established. To exploit unconventional reservoirs fully under-balanced drilling methods will be explained and why they must be applied. In November of 2005, an under-balanced drilling test of the Shu'aiba Formation in the Raudhatain field will be conducted in North Kuwait. High production rates are expected based upon current disposal well injection rates, establishing the Shu'aiba Formation as a major oil producer.

## Infra-Cambrian sequence: new petroleum play in the south-western Sahara, Algeria

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The sedimentary Eglab Range is located half in Mauritania (Taoudini Basin) and half in Algeria (Yetti Basin and part of the Iguidi Basin). The petroleum potential of the infra-Cambrian sequence in the range is now beginning to be better understood. The stromatolitic limestone reservoirs, where gas has been found by Texaco in the Central Taoudini Basin in Mauritania, is a stratigraphic unit within the infra-Cambrian sequence. A drill test flowed at 480,000 cubic feet of gas per day. Geochemical analysis has been made on surface samples (outcrop) of stratigraphic intervals of the infra-Cambrian (El Mretti Group and Bir Amrane). The results showed the excellent characteristics of the source rock, with a TOC greater than 5% for the shales, despite the weathering conditions. This means that the TOC in the subsurface must be much greater. The interpretation of the thermal history shows two phases of heating corresponding to Paleozoic burial and Jurassic dolerite intrusion. The stromatolitic limestones constitute the main reservoir targets in this region. This horizon is buried under the overlying section of the upper infra-Cambrian-Paleozoic in the Reggane Basin, where it has been recognized from well sections. It was reached by the well Brini-301, and may be present in the Tindouf Basin. Further field work is required to better assess the source rocks potential and reservoir quality.

## The silicilyte play in Oman

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The silicilyte play in Oman was developed in the late 1980s, and in 1989 the first oil discovery in the Athel Formation was made in the Al-Noor field. The first success was followed by number of "interesting data points" before the Al Shomou field was found in 1995. Al Noor contains very light oil and is currently producing. The Al-Shomou field to-date faces substantial development challenges, despite its similarity to the Al-Noor field. None of the other Athel penetrations is commercial, although hydrocarbons were encountered in some of them. The enthusiasm for the Athel play followed the "ups-and-downs" of the exploration campaign. The play has been dormant since the late 1990s until a review was started in 2004. In this project a pragmatic approach was taken by comparing various intra-salt lithologies in selected key wells based on the petrophysical, seismic and derivatives-of-seismic data. Qualitative criteria to distinguish a "good" Athel Formation from other intra-salt lithologies were developed. The integration of information from various disciplines was a key factor for the success of the project. The identification of "good" Athel (a hydrocarbon-bearing silicilyte of good porosity) is considered to be realistic; however the prediction of flow-rates carries a large uncertainty based on the current understanding and the even sparser calibration points. Intermediate results of dedicated seismic reprocessing confirmed the validity of the new criteria. The criteria were used to revise the risking recipe for the Athel play and changed the portfolio of Athel leads substantially.

## Evaluating the Paleozoic gas potential of the Euphrates Graben, Syria

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To date no significant discoveries have been made below the Mesozoic in Syria. In the past, most wells stopped drilling when a dry Carboniferous section was encountered. The pre-Pennsylvanian (late Carboniferous) section was often unmapped and never a primary objective when the prolific Late Triassic-Early Cretaceous oil play was successfully being explored. A renewed effort was made to explore the pre-Carboniferous geology of the Euphrates Graben. With the Iraqi Ordovician-Silurian Akkas gas field nearby, the uppermost Ordovician is the main objective of the study. The work has, however, highlighted several secondary targets such as a possible turbidite play in the Silurian and an unknown (Devonian?) sequence that thus far remains undrilled. The main geological risk is the presence of producible reservoir. Although the basin is under-sampled, the reservoir appears heavily cemented and in the case of discovery, we anticipate the need to hydraulically fracture the reservoir. The principal execution risk of the project is the anticipated high temperature around the total depth level (greater than 180$^o$ C). There is a risk that the well may not reach the planned total depth of 5 km and that data acquisition will be compromised in the bottom section of the well. At the time of writing the well was planned to spud in September 2006.

## Undeveloped fields and remaining potential of a typical Sirte Basin graben, Libya

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A 3,600 sq km area covering a 14,000-ft-thick Upper Cretaceous-Miocene graben and parts of two platforms in the Sirte Basin was studied for undeveloped fields opportunities and remaining exploration and producing potential. The study found that a number of early discoveries remained unproduced including a field with reserves of more than 100 million barrels of oil. The

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tectonic evolution of the studied area can be divided into five stages: (1) Pre-rift intra-cratonic Paleozoic basin stage, Hercynian uplift and regional Triassic and Jurassic erosion; (2) Early Cretaceous incipient Sirte Basin rift; (3) Late Cretaceous syn-Sirte Basin rift; (4) Late Cretaceous Maastrichtian transitional stage; and (5) Paleocene post-Sirte Basin rift sag. The tectonic history overprinted four groups of evolving local structures: (1) Pre-rift structural anomalies; (2) Syn-rift structural anomalies; (3) Transitional stage structural anomalies; and (4) Post-rift structural anomalies. The operating petroleum system is charged by the source rocks of the Upper Cretaceous Sirte Shale, and it can be divided into three subsystems on the basis of Kerogen type, domain and time of maturation. In all three, the presence of proximal source rocks, and any combination of the seven proven reservoirs within a voluminous structural closure does not create a successful trap. This is because the critical factor is the presence of an effective seal such as the Upper Cretaceous Sirte Shale or Paleocene Hagfa Shale. The petroleum system of this graben can be used as a model for other Sirte Basin grabens.

## Structures, kinematics and petroleum system of the Algerian deep water offshore

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The Algerian offshore domain represents the main southern part of the occidental Mediterranean deep-water sea. It is part of the unexplored Algero-Provencal Basin where more than 10,000 km of speculative seismic data have been recently acquired and interpreted to establish the architecture of this basin. The most prominent seismic markers are referred to as: (1) base Miocene, (2) base Messinian salt; and (3) Messinian unconformity. Based on seismic stratigraphy and facies geometry studies, the succession was subdivided into stratigraphic units, which provided an improved understanding of both the stratigraphic and structural evolution of the Algerian offshore basin. The seismic interpretation and mapping of all types of structures within the associated stratigraphic units were correlated to the gravity, magnetic and geological maps. The results established the main mechanisms for the formation of the Algerian offshore sub-basins. The proposed structural model, kinematics and the geometry of these sub-basins suggest similar architecture with pull-apart basins. The seismically derived stratigraphic chart shows both hypothetical pre-Messinian and Pliocene total petroleum systems with the presence of some direct hydrocarbon seismic indicators. The deep-sea basin, located north of the Bejaia-Jijel Bay, is considered as the most prospective basin, and its southern border is considered as the most prospective.

## Exploration potential of lower Cretaceous section in Raudhatain field of Kuwait

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Raudhatain field, discovered in the mid-1950s, is an established structural closure with the major production from the Upper Cretaceous Mauddud, Burgan and Zubair reservoirs. Despite active exploration and production for the past 50 years in this field, very few wells have penetrated the entire Cretaceous section and consequently the understanding of Lower Cretaceous is limited. A few wells that have penetrated the Lower Cretaceous succession have encountered potentially prospective fractured reservoirs in the Raudhatain area. Fracture development is presumed to be accentuated due to rapid structural growth of Raudhatain during the post-Mishrif (Turonian) period. Detailed fault mapping using multiple attribute volumes and visualization techniques using 3-D seismic data were carried out in this area. Application of these techniques helped in understanding major fault trends and mapping subtle and minor lineaments, which could have a bearing on fracture development. Integration of this seismic analysis with unconstrained geomechanical modeling led to the identification of areas with relatively higher fracture potential. Results from some of the recently drilled wells that targeted the deeper reservoirs in these potentially good fracture zones, have shown promising results. Dedicated exploratory test locations based on these studies have been identified and await drilling.

## Hydrocarbon entrapment mechanics in the eastern Mediterranean Nile delta cone: consequences of an overpressured environment

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The overpressure in the Nile Delta Tertiary sediments influences the various elements and processes of the petroleum system throughout geologic time, particularly the integrity of seals/traps. As a result, geopressure analysis becomes a critical risk element for hydrocarbon entrapment. Trap-fill can be considered as a dynamic process that maintains a constant pressure and subsequently a constant hydrocarbon column at the top of the reservoir. Leakage of natural gas from traps in Tertiary-aged rocks result in gas chimneys, which are mostly related to faults in the Nile Delta. Sealing rocks are generally sufficiently tight to hold a significant hydrocarbon column, except where structural collapse occurs at the crest. Generally the hydrocarbon column (seal capacity) approaches a few hundred meters in the area of interest. Moreover, the majority of unsuccessful exploration wells show evidence of a residual or paleo-hydrocarbon column. This pattern suggests that the caprock is critically stressed (seal breaching) with respect to the ambient overpressure and stress buildup during or following the period of hydrocarbon charge. The pressure lateral seal "centroid" is an extra potential risk for hydrocarbon entrapment and drilling hazards in over-pressured dipping reservoirs. This does not rule out tectonic fault re-activation as an additional reason for hydrocarbon entrapment failures in the Nile Delta and North Sinai basins.

## Production of natural gas from unconventional low-permeability sandstone and shale reservoirs- analogs from the USA

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Production of natural gas from low-permeability sandstone and fractured-shale reservoirs accounts for about 24% of total annual gas production in the United States of America (USA). The past few decades have seen a dramatic increase in the number of wells producing gas from these reservoirs in several basins in the USA, including the Uinta-Piceance Basin, Greater Green River Basin, Appalachian Basin, Michigan Basin, Gulf Coast and Fort Worth Basin. The availability of production data from several thousand wells in low-permeability sandstone and fractured-shale reservoirs has allowed us to construct production-decline curves and Estimated Ultimate Recovery (EUR) distributions. Median EURs of wells from many low-permeability sandstones reservoirs range from 100–700 million cubic feet (3–20 million cubic meters) of gas, and maximum EURs range from 5–15 billion cubic feet (0.14–0.42 billion cubic meters) of gas. Although there is less production data for fractured shales, median EURs of wells from fractured-shale reservoirs range from 300–600 million cubic feet (9–17 million cubic meters) of gas, and maximum EURs range from 1–7 billion cubic feet (0.03–0.2 billion cubic meters) of gas. Geologic "sweet spots" within both of these types of reservoirs can have higher median and maximum EURs. The EUR distributions served as a quantitative guide to the assessment of potential resources in the unexplored parts of various USA basins, but the EUR distributions might also be valuable as analog production curves for the assessment of potential Silurian and other sandstone and fractured-shale reservoirs in the Middle East.

## Play concept evolution and exploration success for the Marrat Formation in Kuwait

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Based on sparse and generally poor-quality data the Early Jurassic Marrat Formation was historically characterized by basinal facies deposited in a simple carbonate ramp setting across the northern part of Kuwait. Hence, the formation was long considered as non-prospective in this region. Ongoing sedimentological and petrological studies of ditch cuttings and newly acquired conventional cores, coupled with the interpretation of newly acquired seismic and wireline logs, now suggest a broad embayment with ramp margins, which extends the Marrat's prospectivity northward.

The Early Jurassic is marked by the transgressive lowermost Marrat, which unconformably overlies the Triassic Minjur Formation. Cyclic deposition of mud-dominant carbonates and grain-dominant carbonates, locally with interbedded anhydrites, resulted in a ramp morphology for the Marrat (?Sinemurian-Toarcian). The Middle Marrat reservoirs are primarily controlled by structural development, and are typically associated with inner-ramp highstand shoal systems. Cyclicity and diagenesis are critical elements to the ongoing assessment of Marrat stratigraphic traps. Dolomitization plays a key role in reservoir development in the middle to outer-ramp mud-dominant facies. The Middle Jurassic Dhruma (Bajocian-Bathonian) shale lies unconformably over the Marrat as the top seal.

Aggressive drilling has resulted in a highly successful Marrat exploration play in northern Kuwait, involving a low to moderate matrix porosity system enhanced by fracturing. With individual short-term and long-term test rates of 2,400–5,700 barrels oil per day of light gravity crude and 4–18 million cybic feet of gas per day, the exploration program has confirmed Marrat prospectivity across Kuwait and is adding substantial commercial reserves.

## Unayzah Formation in subsurface Kuwait: implications for deep play exploration

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The Carboniferous-Permian Unayzah Formation hosts prolific oil, gas and condensate reserves in the Arabian Peninsula and is of great exploration significance. The

formation was recently encountered for the first time in deep exploration wells in North Kuwait. Conventional and sidewall cores from these wells were studied. Stacked conglomerate and sandstones are developed in the lower part of the formation. In the middle, several stacked fining-upward fluvial sequences, consisting of medium- to coarse-grained sandstones, are developed. These sediments were deposited relatively proximal to the source, most likely due to ephemeral flash braided streams. The sequences are capped by flood plain origin red mudstone paleosol horizons. The upper part of the formation consists of three cycles of well sorted fine-grained quartz arenites separated by a series of bioturbated and rooted sandstone-siltstone and locally black carbonaceous shales, deposited in coastal plain setting. The overlying "Khuff clastics" consists of transitional to shallow-marine fine-grained sandstones with locally developed dolostone beds merging upward into the carbonate succession of the Khuff Formation. The pre-Khuff unconformity is not clearly demonstrable while the pre-Unayzah unconformity is well developed. The porosity in the formation is highly variable and largely facies dependent. It is better developed and preserved in the coarse-grained facies where clay coating on grains has impeded cementation. The interbedded paleosols and basal part of the Khuff Formation could provide local and regional seals for the hydrocarbon accumulations. These observations have important implications for deep gas exploration in Kuwait.

### Temperature structure of the Jafurah Low, Eastern Saudi Arabia: enigma or opportunity?

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The Jafurah Low in eastern Saudi Arabia is a tectonic sag basin elongated in the north-south direction (200 km by 50 km). It is surrounded by the Ghawar, Abqaiq, Dammam, Awali and Dukhan fields, and discoveries on the Niban terrace immediately north of the Qatar Arch-Jawb Platform. Second-order structures include the Niban terrace, and low structural culminations (Harmaliyah, Kharma and Tinat) paralleling the basin margin. Subsurface temperature patterns within this tectonic province show a progressive pattern of lower geothermal gradients in more basinward areas. There is a discontinuity in the gradient trends, approximately in the Permian-Triassic stratigraphic intervals. Temperature data above this interval all follow similar trends, with a subsurface temperature gradient of approximately 17.5°F/1,000 ft (3.2°C/100 m). These gradients are consistent below the Permian-Triassic, although they are offset to cooler values in more basinward wells. For example, the expected subsurface temperatures at 15,000 ft (4,572 m) depth are some 20–25°F (11.1–13.9°C) lower for basinward wells than basin flank wells, which are 15–20°F (8.3–11.1°C) lower for basin-edge wells. Therefore, greater depths may be drilled in this basin away from its flanks before subsurface temperatures become prohibitive, opening up a large area of the Jafurah Low to future exploration. Explanations for this subsurface temperature pattern include an isothermal basement, producing lower average thermal gradients away from the basin flanks toward the basin center. Also, subsurface fluid-flow through the base of the Mesozoic section from basin center to flanks would remove heat and explain the temperature discontinuities near this stratigraphic level.

## RESERVOIR CHARACTERIZATION AND SIMULATION

### Static and dynamic modeling of an offshore field, United Arab Emirates

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An integration of all geophysical, petrophysical, geological and reservoir engineering data have been used to characterize a middle Cretaceous carbonate reservoir in an offshore structure in Abu Dhabi, United Arab Emirates. The structure, defined as an undulating faulted anticline with a structural relief of 180 ft and an area of 112 sq km, was originally formed by the movement of the infra-Cambrian salt during the Cretaceous times. The main producing Mishrif Formation consists of a carbonate section that was deposited over an extensive carbonate ramp platform with reefal facies in the upper part of the reservoir. A rock-type scheme for the Mishrif reservoir resulted in generating fourteen lithofacies. The petrophysical properties of these lithofacies have been analyzed to develop a basis for thin reservoir layers, constructing a 3-D static model and simulation studies. The main pore types within this reservoir are inter-particle porosity ranging from 11–27%, with an average of 23%. The permeability ranges from 0.1 to 750 milliDarcy (mD), with an average of 65 mD. The properties of the reservoir have been populated geostatistically with different algorithms within the framework of the field. After modeling the facies using the sequential-indicator simulation, the porosity was populated using the sequential Gaussian simulation algorithm. The cloud transform technique has been used for modeling the permeability. The resulting static model improved the understanding of the flow regime within the field and adequately matched the dynamic data from the wells.

## Faults representation impact on multiphase fluid-flow in production simulation models

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With only 10% worldwide drilling success, oil exploration is considered a high-risk activity. Faults play a major role in this risk. Faults are fundamental to prospect and play assessment as well as to production and field development. They are commonly an overlooked component in the evaluation of hydrocarbon accumulation and migration. The last decade has seen a rapid growth in our understanding of the variables that control fault sealing potential. Despite the current understanding of such variables, practical techniques are few and faults are commonly risked in an intuitive, qualitative manner. Few studies, however, demonstrated that using qualitative fault seal analysis, using those few techniques available, improves successes ratios and reduces costly errors in field development.

In this study, the effects of two different representations of faults on the derived history match are compared for the Pierce field, North Sea. In the first case, fault transmissibilities were tuned and the faults were extended in order to improve the history match (conventional history matching). In the second case, a step-by-step derivation of the fault transmissibilities in the Pierce field was adopted based upon the integration of collected and upscaled properties of the host rock along with some empirical relationships. A detailed analysis, supported by microstructural and petrophysical as well as capillary pressure mercury injection fault-rock data were used to assign a spectrum of transmissibility multipliers along fault planes to capture the effect of the buoyancy force generated by the hydrocarbon column height on the sealing capacity of the faults. History production data were used to compare the effectiveness of the two methods. The results demonstrate the effectiveness of the derived transmissibilities model in generating a satisfactory history match in a relatively short time period.

## Reservoir architecture of the Triassic Khartam carbonate sequence, Khuff outcrop analogue in Al-Qasim, central Saudi Arabia

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The Permian-Triassic Khuff carbonates were deposited during a major marine transgression on the Arabian Plate at the terminal Paleozoic to form a huge, east-facing, arid ramp. The up to 194-meter-thick Khuff Formation outcrop in Al-Qassim region, central Saudi Arabia, overlies Permian-Carboniferous siliciclastics and is overlain by Sudair Triassic fine-siliciclastics. The Khuff outcrop is mainly composed of carbonates mixed with shale/mud, evaporites and some sandstone, and is divided into four members (in stratigraphical order): Huqayl, Midhnab, Duhaysan and Khartam. The Triassic Khartam sequence boundary coincides with the Permian-Triassic Boundary that overlies a reddish paleosol. The studied interval is the transgressive system tract (TST) of this sequence with an initial flooding of restricted facies with shallow subtidal microbial heads overlain by the cliff-forming upper Khartam carbonates of high-energy cross-bedded ooid channels and sheets, and low-to-medium energy bedded peloidal pellet packstone/wackestone. This later TST package exhibits lateral variability controlled by the depositional setting of good reservoir quality (dominated by moldic porosity) grainstone bars, channels, and sheets within adjacent non-reservoir muddy carbonates. The 26-m-thick Khartam Member is time equivalent to the Triassic Khuff B and A carbonate gas reservoirs in the Ghawar field. The outcrops exhibit reservoir character similar to that observed in the subsurface and tied to similar rock fabric signatures. These outcrops offer outstanding exposures in two-and-three-dimensions enabling the mapping of these reservoir bodies in detail with their rock fabric and spatial extent, as well as the stacking patterns. Correlating these outcrops with the subsurface helps develop better predictive models of the Khuff gas reservoirs.

## Detailed depositional architecture of the Wara Formation in the water-flood pilot area of Greater Burgan field

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This study attempts to resolve the detailed depositional architecture of the Cretaceous Wara Formation in an area of the Greater Burgan (Magwa) field, where a water-flood pilot project is currently being implemented. The Wara consists of sandstones interbedded with siltstones and claystones. This interval was deposited in a tidally influenced marine shelf/shoreface environment that included mouth bars, channels sands, bay head delta sands and intertidal mud flats. The geometry of the sand bodies vary from elongated channels and sand bars to more laterally extensive sheet sands. Recently acquired single-sensor seismic data, in conjunction with reprocessed 3-D seismic data, VSPs, and information from eight new wells drilled as part of the project, are expected to increase our understanding of the structural and stratigraphic framework of the Wara sands. It is anticipated that seismic inversion will also assist in resolving the vertical

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and lateral distribution of the sands. Improved imaging and resolution should lead to a more accurate geological model, which will enhance our understanding of the movement of water in the Wara sands and test the ability of increasing oil production from them through water flooding.

## Unified structural and stratigraphic model for a giant ADCO field

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The Unified Modeling project was conducted in two phases with the first involving the construction of the structural and stratigraphic model of the three Bu Hasa reservoirs. The main objectives of Phase I were: (1) construct a structural framework across all Bu Hasa reservoirs to avoid overlap between them since the existing models were built independently. (2) incorporate revised seismic interpretation (surfaces and faults) based on seismic inversion. (3) use of a common seismic depth conversion method and a single integrated interpretation for all three reservoirs. In Phase I, a consistent set of structural definitions was used for all three reservoirs. In addition, a unified 3-D structural (surfaces and faults) and stratigraphic model and a common 3-D grid for all three Bu Hasa reservoirs were also constructed. In Phase II, models of the three reservoirs were constructed and 3-D simulation grid and upscale parameters were constructed. For all three reservoirs, refined facies and petrophysical properties were determined from petrophysical interpretations. For Reservoir C, the analysis also incorporated an Integrated I Dense Study (Thickness/distribution). This project also developed a methodology to integrate the lithofacies properties into the sequence stratigraphy framework. The seismic inversion (porosity cube) was used to constraint the modeling process.

## Rapid assessment techniques for reservoir optimization and monitoring: Mauddud reservoir, Awali field, Bahrain

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This poster describes the application of a practical process to develop: (1) a systematic workflow for production optimization and reservoir analysis; (2) identify and highlight reservoir trends, patterns and anomalies; (3) identify and highlight under-performing wells/areas and recommend solutions; and (4) identify essential patterns for consideration in overall development plan. It was required to quickly identify infill locations, reserves, and underperforming areas in the Mauddud reservoir in the Awali field, Bahrain. The area used for the study consists of 431 wells. The challenge was to evaluate large data sets in a short time and in a cost-effective manner.

The technique uses a streamlined workflow of reservoir assessment processes. It requires a sequence of data gathering, formatting and validation associated with both the static and dynamic models of the reservoir. Quick interpretations of these models generate opportunity regions, re-completions and workover candidates, and new infill potential in the reservoir. Based on the processes, the reservoir performance and main issues associated with the development of the Mauddud zones were better understood (water production, gas injection, potential transfer areas), and underperforming wells and potential undrained areas were highlighted (high remaining reserves zones with low water-cut and low gas-oil ratio). The main focus was to rapidly analyze the reservoir and identify areas that may contain potential for additional production and identify anomalies in the wells that could lead to a production enhancement campaign in the field.

## Characterizing and locating conductive faults/ fractures via pressure data

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This paper presents a multi-source data integration approach for the detection and location of a geological feature causing communication between two reservoirs separated by 500 feet of non-reservoir rock. The technique used involved plotting the interpreted distance to a possible conductive fault/fracture corridor established from multiple well tests to establish its most likely location. The nature and extent of the feature was constrained by available image-log and seismic data. Dynamic data together with drilling information confirmed the presence of local vertical communication across a thick non-reservoir zone. An interference test indicated the communication where a pressure response in a producer in the upper reservoir was observed when changing the water injection rate in an injector in the lower reservoir. Although this data confirms the presence of vertical communication, its qualitative nature makes it impossible to use to characterize the location and geometry of the feature. The technique described in this paper provides a more quantitative assessment of the feature's location.

Inter-and intra-reservoir communication through fractures are a common feature of many oil and gas fields, however, often little or no information is available to describe the physical characteristics and location of these fractures. Circulation loss while drilling horizontal wells, together with production log and other production and pressure data, provide evidence of existing conductive faults and fractures. Better reservoir management decisions and more focused development strategies can be achieved through the integration of the quantitative pressure transient analysis and integration of transient results with all other available data.

## Single and multi-story sandstone bodies, their geometry, stratal pattern and relevance for identification of facies heterogeneity in Muglad Basin, Sudan

*Mohamed Abaker Abdalla (mabaker_9@yahoo.com) and K.B. Trivedi (GNPOC)*

The Muglad Basin of Sudan evolved as one of the main component of West and Central African Rift System (WCARS). Located in southwestern Sudan, it encompasses the largest and most important oil-producing area. The basin occupies an area of about 120,000 sq km and contains a Cenozoic continental sedimentary succession, more than 13 km thick. We investigated the facies, depositional environment, stacking pattern of single and multi-story sandstone and shale bodies in the west Kaikang trough wells. The different scales of facies heterogeneity from micro to macro were recognized in both the Zarqa and Aradeiba formations (Santonian-Campanian). The geometry of sandstone bodies was mapped and the average Width:Thickness (W:T) ratio of single-story sandstone bodies was calculated as 64:1 and 17:1. The thickness range between 1–11.3 m and 8–25 m, width ranges from 15–33 m and 110–400 m for these formations, respectively. The multi-story sandstone bodies range up to 6.1–99 m and 1–52 m thick and over 1,900 to 3,000 m wide in the same formations. On the basis of architectural elements, different types of reservoir settings were identified. These are clean sandstone and sandstone intercalated with mudstone (facies type 1), and sandstone intercalated with discontinuous thin layers of mudstone (facies type 2), and medium- to coarse-grained sandstone sheets intercalated with the lenses of over-bank/flood plain (facies type 3). These reservoirs are intensively faulted by a post-Cretaceous tectonic episode. The major units of these reservoirs testify to environmental changes in response to the main tectonic pulses during the Cenozoic rifting phase in the Muglad Basin. A facies type and architecture model for the tectonic episode is being developed. It will lead to a better understanding of paleoenvironment and distribution of the channel sands in this exploration area.

## Outcrop analog for a Paleozoic shallow-marine sandstone reservoir: geological and geostatistical models of the Quwarah Member, Saudi Arabia

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This study presents geological and geostatistical models, using an outcrop analog, for the Paleozoic oil and gas sandstone reservoir in central and eastern Saudi Arabia. The Late Ordovician Quwarah sandstone member of the Qasim Formation was selected as an outcrop reservoir analog for this study. Field facies analysis and examination of the petrographic and petrophysical properties were used to document the macro- and micro-scale heterogeneity. The Quwarah sandstone represents the top of a coarsening shallowing upward succession. At the base it is mainly an offshore/shelf shale (Ra'an Member) and passes up to a tide-dominated sandstone. The lower Quwarah section is characterized by burrowed thinly interbedded, fine-grained sandstone and siltstone facies. It passes upwards to moderately to thickly bedded fine- to medium-grained herringbone cross-bedded, trough cross-bedded and horizontally laminated sandstone. The depositional and diagenetic heterogeneities have an impact on porosity and permeability development and evolution. These include depositional architectural elements, vertical and lateral facies changes, the Quwarah sandstone composition and sorting, cement and clay matrix. The outcrop studies were used to develop a geostatistical model of the porosity/permeability variations within the Quwarah sandstone. The results are in good agreement with the outcrop porosity and permeability distribution.

## "Layer-cake" gas reservoirs in Triassic carbonates of The Netherlands: understanding an analog for the Khuff of Arabia

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The Muschelkalk dolomites currently produce gas in the Dutch De Wijk field. This study evaluates the depositional factors controlling the development of this particular type of "layer-cake" reservoir, which shows many similarities to the Khuff on the Arabian Platform, including (super)giant fields in Saudi Arabia and Qatar. (1) Geotectonic and climatic setting: characterized by overall low subsidence, a very low but extensive depositional gradient and very low accommodation potential developed during a phase with semi-arid climate and high frequency, low-amplitude sea-level changes. (2) Depositional processes and model: mud-dominated carbonates were deposited on an extensive storm-dominated epeiric carbonate ramp.

Higher energy mid-ramp environments include thin, shoreline-detached and patchily developed carbonate sheet sands. Depositional units show very subtle lateral facies transitions and are laterally continuous for at least many tens to hundreds of kilometers. (3) Reservoir facies: the best reservoir facies is recognized in distal, inner-ramp, laminated dolo-mudstones (permeability up to 32 mD). The reservoir quality of dolo-mudstones decreases markedly in the landward and seaward directions from the inner ramp. (4) Sequence stratigraphy and reservoir architecture: the aggradational stacking of relatively thin (decimeter- to meter-thick) reservoirs can be explained by a four-fold hierarchy of depositional cycles. This leads to the "layer-cake" seismic pattern commonly recognized in epeiric settings. However, very low-angle depositional shingles are inferred on the subseismic scale. (5) Paleogeography and reservoir distribution: patches of reservoir facies are frequently located above paleohighs. Their lateral extent may be detected with seismic data. These insights may aid reservoir prediction and characterization during exploration and development of the Khuff Formation in the Middle East.

## Reservoir characterization of Sarajeh field: application in underground gas storage, Qom, Iran

*Ali Aminzadeh (National Iranian Oil Company, ali.aminzadeh@gmail.com)*

The Sarajeh gas field is located in central Iran and is a candidate for an underground gas storage project. This field is located 140 kilometers south of Tehran and currently has 9 wells of which three are producing gas. The fractured carbonates of the Oligocene-Miocene Qom Formation constitute the reservoir at a depth of about 2,700 meters. The Qom Formation is equivalent to the Asmari Formation, the main reservoir in the southern Iranian oil fields. The Qom Formation is divided into eight members, but only the top member (e member) contains hydrocarbons. Anhydrite beds of Upper Red Formation form the caprock. Based on 2-D seismic data the structure consists of two culminations. Eight wells were previously drilled in the east culmination. To evaluate the effects of gas injection, a ninth well was drilled in the western culmination. The well did not encounter any hydrocarbons implying the reservoir is only developed in the eastern culmination.

A 3-D seismic survey was acquired over the field and it showed that no major faults occur in the upper part of the Qom Formation. A fracture study using core data, seismic inversion, well logging and outcrop data indicated that most of the fractures are limited to the upper 70 meters of the reservoir. The fractures are sharp or curvilinear in form, either open, or completely or partially filled by calcite cement. Core studies showed that the horizontal permeability is low (0.01–2.2 mD) and that fractures form the main flow zones. Based on the well-logs and core data, the average net porosity is 7.0% and water-saturation is 30%. These results suggest that the Qom reservoir is suitable for underground gas storage. A time-lapse seismic survey is planned one year after the reservoir is depleted.

## Microfacies and depositional environments of Fahliyan Formation in the Dezful Embayment, Zagros Basin, Southwest Iran: implications for porosity distribution

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In our research project, the Fahliyan Formation (Neocomian) was investigated in one outcrop (Kuh-e Dal) and a section in the Dashtak-1 borehole. Twenty-one microfacies were recognized and grouped into four facies associations: (1) A (tidal flat); (2) B (lagoon); C (bar); and (4) D (open marine). Vertical microfacies changes suggest that the Fahliyan Formation was deposited as a transgressive and deepening-upward sequence. Based on the microfacies, the depositional environment of the Fahliyan Formation was interpreted as a gently dipping shallow ramp. Secondary porosity due to dolomitization and stylolitization played an important role in increasing reservoir quality. Other types of porosities are cemented and do no contribute to the quality of the reservoir.

## Integrated static and dynamic modeling in one of the major gas reservoirs of onshore Abu Dhabi

*Amr Badawy (abadawy@adnoc.com), Adham Hathat, Abdul Rahman Darwish and Salama Al Suwaidi (ADNOC)*

Integration of static and dynamic modeling is one of the issues often raised in reservoir management. It is the link between a facies-based model incorporating depositional and sequence stratigraphic characteristics, and its use during dynamic simulation. In this presentation, we will introduce a concept of modeling based on reservoir rock-type approach. This approach was used in one of the major producing gas reservoirs in a NE-trending giant field in central onshore Abu Dhabi which has dimensions of 40 by 30 km. The main reservoir zones are part of the Lower Cretaceous Thamama Group. The overall depositional environment is characterized by its location on the Arabian carbonate platform within an intra-shelf basin. Applying sequence stratigraphy principles, the reservoir is divided into two parasequence sets. The lower part comprises a progradational interval overlain by a retrogradational package, with the boundary between each package marking a stillstand. Five lithofacies were identified in the reservoir, bioclastic peloidal grainstone, algal packstone/floastone, bioclastic peloidal packstone, algal wackestone/floastone and bioclastic peloidal wackestone/packstone. These lithofacies are believed to have been deposited on a homoclinal carbonate ramp that dipped gently seaward.

Porosity and permeability are well preserved in the reservoir section due to a lack of pore-filling cement. In the field, a clear general trend of down-flank porosity deterioration of more than 10% from the crest down to the water-bearing zone occurs. This is mainly due to the compaction effect during hydrocarbon migration and infill of the structural trap. Analysis of both thin-section descriptions and high-pressure mercury injection led to the identification of five distinctive rock types. Each reservoir rock type has a certain effective pore throat size distribution, which produces particular capillary pressure, relative permeability curves, porosity and permeability.

## Carbonate facies analysis and geological modeling of Cenomanian-Turonian sediments (Sarvak Formation) in a giant field in the southwest of Iran

*Bijan Beiranvand (NIOC-RIPI, biranvandb@ripi.ir)*

The Sarvak Formation in the southwest of Iran is composed of shallow and deep-water carbonates and correlates to the Mauddud (Albian-Cenomanian), Rumaila (Cenomanian), and Mishrif (Cenomanian) formations in adjacent countries. The formation is a significant carbonate reservoir in southwest Iran. This work presents a major part of a sequence stratigraphical investigation related to reservoir characterization and the preparation of a geological model for a giant field in southwest Iran. The aim of the work is to model the reservoir facies and their changes due to depositional environments. This study is based on interpretation of cores, cuttings, and wireline logs of six wells in the field. These sequences were deposited on an extensive Cenomanian-Turonian carbonate platform. Facies analysis shows that the formation mainly consists of: (1) deep-marine Oligostegenid limestone with poor reservoir characteristics; (2) extensive basin-margin patchy rudist buildups as a good reservoir; and (3) lagoonal and leeward shoal facies as nonreservoir. A transitional boundary occurs between the transgressive Oligostegenid-bearing Sarvak limestone and the underlying Kazhdumi. The Sarvak Formation is disconformably overlain by the Laffan shales.

## Mapping and classifying flow units in upper Cretaceous reef and shoal reservoirs in a giant field in the southwest of Iran

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Finding and producing oil and gas in an efficient and economical manner requires a reservoir model to predict its performance. The model should account for different development scenarios, including supplemental recovery, and aid in designing and planning the appropriate reservoir management strategy. Reservoir characterization should be based on geological data that represent vertical and lateral variability of reservoir properties (e.g., porosity and permeability). This study describes a reservoir model for the upper part of the Sarvak Formation in a giant field in southwest Iran. Fluid-flow units were identified, mapped and classified as part of an integrated reservoir characterization study. Pore categories by origin, pore and pore-throat geometries, pore-scale diagenetic history and core-scale depositional attributes were logged with conventional petrographic and lithological methods. The results were combined with core descriptions, mercury-injection capillary pressure data, wireline logs, and geophysical data to produce flow-unit maps at field scale. The field produces from shoal grain-dominated facies. The classification of grain-dominated fabrics within the shoals was found to have significant influence on pore facies and flow-unit quality classifications, and ultimately on reservoir quality. Shoals and reefs are composed of four fabric categories. Results of this study have improved our understanding of the complexity of shoal and reef reservoirs. In so doing, the results have improved our ability to characterize and model complex reservoir architecture, pore systems and flow-unit quality from pore to core to field scale.

## A full-field model of the Khuff reservoir over the North Dome field

*Isabelle Billat (isabelle.billat@total.com), Ole-Petter Hansen, Emmanuel Cassou, Enzo Insalaco, Marie-Corinne Devilliers, Christian Fraisse and Claude Legorjus (Total)*

The Permian-Triassic Upper Khuff carbonates form the reservoir of the North Dome field (among the world's largest offshore gas field). They are characterized by a complex depositional facies distribution and strong diagenetic overprint, generating fine-scale reservoir heterogeneities, which impact strongly the dynamic behavior of the field. In order to conceptually best represent the reservoir heterogeneities, logtypes were defined, each with distinct static (porosity and NTG) and dynamic (permeability and capillary pressure) reservoir characteristics. The logtypes are propagated in

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the 3-D geological model using: (1) depositional trend maps per sequence, integrating core descriptions, well-log correlations, isopachs per logtype and the regional knowledge of the Khuff reservoir. (2) Variograms with varying azimuths and ranges depending on the logtype and the position within the sequence stratigraphic framework. (3) Logtype probability maps using the depositional trend maps for guidance.

The result was a full-field, geological fine-gridded model, which integrates all inputs from the sedimentological, diagenetic and stratigraphic models. The model encompasses the Khuff reservoir heterogeneities, both the petrophysical and dynamic characteristics. The geological model was then upscaled vertically and horizontally. Vertical upscaling was made so as to best capture the fluid composition variations, vertical barriers and distinct reservoir drains. Although the resulting reservoir model has to be refined whenever new data is available (wells, 3-D seismic, production already existing and anticipated), it allows for the simulation of gas production, CGR, and up to a certain extent $H_2S$ evolution, everywhere on the North Dome field.

## Yibal field, Oman: an integrated approach to reservoir characterization

*Deborah M. Bliefnick (Badley-Ashton and Associates, deborahbliefnick@badley-ashton.co.uk); Paul V. Grech (Baker Atlas); and Patrick Hogarty (Petroleum Development Oman)*

Yibal field in Oman produces from the Cretaceous upper part of the Shu'aiba Formation. A reservoir quality evaluation integrating sedimentology, petrology, core analysis, sequence stratigraphy, borehole image analysis and field-wide correlations was used to determine the depositional and diagenetic controls on reservoir quality and identify relationships between the development of firm-grounds, low-porosity streaks, water fingers and production behavior. Overlying the mid/outer ramp Lower Shu'aiba sediments, the Upper Shu'aiba was deposited as a series of prograding sediment wedges in a lowstand systems tract that was subsequently overlain by the transgressive mudrocks of the Nahr Umr Formation. The pore system throughout the Upper Shu'aiba is dominated by micropores created by meteoric and burial fluids. Increased porosity and permeability development near the top of the formation is due to dissolution by a combination of fluid types. Sporadic enhancement of porosity deeper in the formation is due to a combination of depositional and diagenetic factors. A series of better-cemented horizons, termed low porosity streaks (LPS), have been identified in the field. Some of these streaks correspond to depositional/diagenetic features such as argillaceous-rich and/or firmground horizons. Adjacent to some of these horizons are intervals of enhanced porosity that are interpreted to have formed by the interaction of the LPS with migration of burial fluids up faults and fractures.

The boundaries of some of the identified reservoir zones correspond to observed LPS-argillaceous-firm-ground horizons. These horizons may serve as baffles to flow and the adjacent intervals of enhanced porosity development may serve as possible "thief" zones. Since both types of flow unit are related in part to depositional features, their distribution may be more confidently predicted than features that are controlled by diagenesis alone. In such a scenario, higher concentrations of unproduced hydrocarbons may occur in intervals of relatively low reservoir quality that lie in between intervals with enhanced porosity.

## Integrated static and dynamic modeling approach in one of the Thamama gas reservoirs of onshore Abu Dhabi

*Abdel Rahman Rasheed Darwish (adarwish@adnoc.com), Salama Al-Suwaidi, Amr Badawy and Adham Hathat (ADNOC)*

The ability of integrated software to existing solutions is evolving rapidly and has shifted to emphasize on what a best-practice modeling approach should be. One of the issues often raised is the link between a facies-based model incorporating depositional and sequence stratigraphic characteristics, and its use in dynamic simulation. In this presentation, we introduce the concept of modeling based on reservoir rock type. As an example we use a major producing gas reservoir in a giant field in central onshore Abu Dhabi. The structure is NE-trending and has dimensions of 40 by 30 km. The main reservoir zones are part of the Lower Cretaceous Thamama Group. The depositional environment is characterized by its location on the Arabian carbonate platform within an intra-shelf basin. Applying sequence stratigraphy principles, the reservoir is divided into two parasequence sets. The lower part comprises a progradational interval overlain by a retrogradational package, with the boundary between each package marking a stillstand. Five lithofacies were identified in the reservoir, bioclastic peloidal grainstone, algal packstone/floastone, bioclastic peloidal packstone, algal wackestone/floastone and bioclastic peloidal wackestone/packstone. These lithofacies are believed to have been deposited on a homoclinal carbonate ramp that gently dipped seaward. Porosity and permeability are well-developed in the reservoir section due to a lack of pore-filling cement. In the field, a clear general trend occurs of down-flank porosity reduction of more than 10% from the crest downwards to the water-bearing zone. This is mainly due to the increased abundance of stylolites formed during burial diagenesis when hydrocarbons migrated and filled the structural trap.

## Characterization of fracture-fault systems in an Early Cretaceous reservoir, offshore Abu Dhabi: implications in mature field development

*Henry Ewart Edwards (ewart@zadco.ae), Sandeep Chakravorty and Hamad Bu Al-Rougha (ZADCO)*

Within the lower Cretaceous reservoirs of offshore Abu Dhabi, matrix properties dominate fluid-flow. However, fracture corridors and fault zones act as through-going flow features. They are 'diffuse' mechanical layer-related linear features. Integration of core and borehole image features provide the means for characterizing these structural systems. We present a conceptual model that incorporates three dominant styles of deformation whose interaction at the local to field scale governs the heterogeneity of fluid-flow. (1) Fractured layers: stratigraphical distribution of diffuse features clustered within mechanical layers and at strength contrast interfaces. (2) Fracture corridors: conduit paths of swarms, sub-vertical, often through-going open features. (3) Fault zones: complex damaged zones involving cementation, breccia generation, visible offsets, fracturing and reactivation and highly variable permeability.

We present examples of all three styles and describe their core and borehole image characteristics. The first type consists of stratigraphically controlled microfracture systems. Emphasis is placed on 'diffuse fractured layers' because of their importance to water influx and possible sweep inefficiency. An important aspect of fractured layers is the variability of spacing, style and types of fractures within zones in the dense intervals compared to the reservoir zones. The mechanical properties of layers also control the nature of the fractures, their density and distribution, layer/unit thickness, diagenesis/stylolitization and oil-charge. These 'fractured layers' commonly occur at the top and base of the reservoirs and are associated with prominent cemented haloes to the stylolitized surfaces. The identification of these mechanically controlled fractures is an integral part of structural reservoir characterization in this mature offshore field. This is especially critical for the fault-distal areas, allowing flank-to-crest variability to be addressed.

## Seismic structural characterization of fault zones in Lower Cretaceous carbonates, offshore Abu Dhabi

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Fault zones developed within Lower Cretaceous reservoir facies and intervening dense limestones are due to predominantly wrench-reactivation activity on deep basement faults in offshore Abu Dhabi. They are highly linear, with small vertical offsets and an anatomizing to en-echelon nature. Based on seismic attributes, the faults are vertically linked and organized in continuous patterns. These patterns include relays, soft linkages and sometimes discontinuities. The pattern occurs in response to the alternating dense-reservoir heterogeneity of the sequence. Similar changes occur through sealing sequences, highlighting distinct stratigraphic controls on fault propagation. Reservoir-dense limestone fault zones display differences in several ways: (1) fault-zone character; (2) individual structural elements and internal structure; (3) fault rock types; (4) fault behavior; (5) reactivation susceptibility; (6) cementation and structural accessed diagenetic reservoir degenerative effects; (7) associated damage zone and fracture areole development; and (8) complexities inherent from juxtaposition of thin-layered reservoirs.

Such complexities cause fracture-dominated 'conductive' zones and cemented/smeared 'sealed' damage zones in the reservoirs, particularly within the more thinly layers (metric to several meters thick sequences). The deformation style and fault continuity becomes less heterogeneous in thicker reservoirs. In these layers the array of effects is less diverse and fault behaviour and fracture zone effects are more limited and predictable. The identification of kinematic activity (predominantly wrench reactivation), fault linkages and tectonic model (repeated reactivated 'shuffling' on deep faults propagating rheologically controlled fault segments into cover sequences) provide an improved framework for understanding fluid-flow. We conclude that the production from thinner pay zones behave in contrasting fashion, with proportionately more fracturing and faulting and reservoir degenerative effects, to thicker zones.

## Modeling a fractured reservoir for a brown field by integrating geologic and production data

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Ras Gharib field, located in the Gulf of Suez, Egypt, is a structurally complex field with a large number of faults and complex stratigraphy. The field has been producing since the 1930s. The operator recognized that a reservoir model could better predict reservoir performance so as to optimize the recovery of the remaining reserves. Previously, only limited reservoir characterization studies were performed, but the reservoir models did not match the field production data despite significant modifications of the petrophysical properties. Accordingly, the field development plans did not rely on these models. Once the factors that adversely affected the previous models were screened, it was realized that the fractured nature of the main producing reservoir was not accounted for.

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A modeling workflow was developed to improve the fracture characterization although the required data was limited. Faults were identified and fault-induced fractures were inferred from the fault patterns in the field. The descriptive fault patterns were further quantified and validated using the production data. Because no image-logs were available, production logs and drilling mud logs were used to calibrate the fracture properties. A quantitative analysis, based on an enhanced geostatistical technique, was used to integrate the logs with the production data and faulting-induced fracture properties. The new reservoir model provided a very good early history-match to the field production data.

## High-frequency inter-bedding of dune and extradune sediments in the Cambrian Amin Formation in North Oman: control on reservoir properties (with analogues from modern sediments of Oman)

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The Amin Formation is a thick sequence of quartzose sandstone with chert pebbles that is widely distributed in Oman. Despite this rather uniform aspect, the Amin sandstones of North Oman have a wide range of reservoir quality, with the best reservoir rocks commonly occurring as thin layers. This intercalation of very good reservoir with poor reservoir is the result of high-frequency intercalation of dune and extra-dune sediments. Additionally, local re-cycling of aeolian sands into fluvial and playa depositional systems has enhanced reservoir quality in some places. The root causes of these patterns are not well understood. The phenomenon of small-scale intercalation of dunes with extra-dune sediments may have occurred due to rapid movement of dunes across low-relief terrains during a time of limited accommodation space. This process appears to have occurred most widely during deposition of the youngest Amin sediments, with the result that the best reservoir is often near the top of the formation. Additionally, secondary porosity and fracturing appear to be a strong driver of reservoir quality, in both fluvial and aeolian sediments.

The effect of primary facies on reservoir quality is so strong that at present, with limited well control, the depth-porosity curve shows an increase in porosity with depth below surface. This is due in part to the presence of aeolian dunes, or re-cycled aeolian sands in the most deeply buried Amin. Modern sediments of Oman provide instructive analogues for most of the facies in the Amin, including high-frequency inter-bedding of dune and extradune sands. These include the dune-fluvial system of the Wahiba Sands along Wadi Batha, and sabkha sands of the Huqf and the Umm As Samim.

## Sharyoof's shifting shorelines

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The Sharyoof oil field is situated in Block 53 in the Masila Basin, onshore in the Republic of Yemen. Sharyoof was discovered by Dove Energy in 2000 with their second exploration well, located 550 km east of Sana'a, the Yemeni capital. Block 53 was awarded to Dove in 1998 in relinquished acreage (ex Total) adjacent to the prolific Block 14 (16 producing fields), operated by Nexen. Sharyoof was put on stream 10 months after project commencement in 2001, with a surface pipeline into the Masila system to the Ash Shihr terminal on the Gulf of Aden coast. The Sharyoof structure is a south-easterly tilted and gently folded fault block striking NE-SW in the northcentral region of the Masila Basin. The sedimentary succession started in the Late Jurassic with major rifting. The main source rocks are the synrift Late Jurassic Madbi Formation organic-rich marine shales in the deep sub-basins surrounding the tilted fault block highs. The postrift Sharyoof reservoir consists of the Upper Qishn Clastics of Early Cretaceous age. The sandstones are fine-to medium-grained of shallow-marine to fluvial origin, often showing strong tidal influence, with common, field-wide, calcite-cemented zones. Variations in reservoir communication and fluid contacts are associated with the depositional environments and subsequent facies related diagenesis that resulted in this layered reservoir. Top seal is provided by the Qishn Carbonate Member, which marks a marine transgression across the Masila Basin rifted margins.

## Modern and ancient analogs provide geological control and scale for reservoir layering and property distribution in a 'wet' eolian depositional system, Saudi Arabia

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Four distinct depositional facies have been identified in a Saudi Arabian reservoir; namely: dune, sandsheet, playa and paleosol. The depositional lithofacies identified on image-logs were compared against detailed core descriptions, which demonstrated the reliability of the image-log interpretation. From core and image-log studies, the eolian reservoir was classified as a 'wet' transverse dune depositional system. The reservoir was then layered based on a 'wet' eolian depositional model using the Permian Cedar Mesa Formation outcrop in Utah as an ancient analog. In well-log cross-section, the 'wet' and 'dry' depositional cycles were recognized and incorporated into the geocellular model layering scheme as 'time lines', based on field observations from Permian-age wet eolian deposits in Utah.

An object-based modeling technique was used to condition the size, shape and orientation of the objects assigned to each lithofacies. The transverse dune facies were modeled as 3-D objects oriented with the dune crest striking N-S based on image-log data. Wet interdune/playas were modeled as elongate 3-D objects with a N-S orientation paralleling the transverse dunes. This dune-interdune relationship is recognizable on satellite images of modern-day transverse dune fields in Saudi Arabia. The resulting geocellular model was viewed in a flattened cross-section, which displayed the characteristic alternating 'wet' and 'dry' cycles observed in the Cedar Mesa outcrop. The 'wet' inter-dune deposits behave like permeability baffles within the reservoir, while the more extensive playa deposits act like barriers across the reservoir. In map view, the facies distribution in the geocellular model captured the look we see in satellite images from a transverse dune field today.

## Seeing is believing: object-based facies distribution and porosity modeling using facies-based external histograms puts geology back into geostatistics

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In a thinly bedded reservoir, porosity can be over represented or under represented in a final geostatistical distribution using traditional modeling techniques. Historically, a geocellular model was considered 'very good', if the porosity distribution of the interpolated grid 'matched' the porosity distribution of the wells. But, in a reservoir where the contacts between facies is sharp rather than gradational, attributes such as porosity and permeability tend to get 'smoothed' across the bed boundary. Logging tools such as gamma-ray, sonic, density and neutron have a three-foot averaging window, even though data is recorded every 1/2 foot. This translates into at least one foot of transition measurement on each side of a sharp contact. This 'smoothing' of the log data can be seen in the histograms of the well porosity, especially when it is split-out by facies. The porosity distribution will have a wide range and a skewed mean, reflecting the 1/2-foot sampling across sharp bed boundaries. The most extreme example of smoothing in a thin-bed reservoir is visible in turbidities, where sand and shale beds can typically repeat on a centimeter scale. External histograms derived from core data and grouped by facies provide a more accurate representation of the reservoir property. The external histograms will tighten the data spread and move the mean higher for the dune facies and lower for the playa facies, thus reducing the 'smoothing' seen in the 1/2-foot re-sampled log-derived histograms. The resulting geocellular models show distinctly sharper contacts between layers and an overall crisper porosity distribution within the facies objects.

## New geological data from a pilot campaign illuminates the understanding of existing water-flood development

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In an elongated, tilted carbonate reservoir, focused water-flood development with long strike-parallel horizontal wells has co-existed with gas-oil-gravity-drainage. New geological data from a pilot project in this mature field (over 35 years production) has illuminated the understanding of the water-flood process and the need for integration with surveillance and production data to optimize the current development wells.

Four inverted 5-spot pilot patterns, each with 2 dedicated observation wells, have been drilled in 2004–05 to test the feasibility of field re-development. The data gathered has assisted the interpretation of the surveillance data acquired from the existing water-flood. As part of this program cores were cut in 8 vertical wells over the field. The cores reveal a multitude of heterogeneity that was not previously recognized over the field life. This is a function of the remarkable core recovery achieved in a carbonate reservoir with marked contrasts in cementation. Examples include cemented and corroded features that influence these wells on a range of scales. The integrated data gathering in the pilots has enabled a ranking of the impact of this heterogeneity.

This new knowledge bank has been applied to understanding the well performance of the existing water-flood. The interpretation of recent production logs in many of the existing horizontal injectors has been tied to existing borehole image-logs. The additional data and models from the vertical pilot data have been particularly useful in understanding the balance between matrix and fracture reservoir influences on well performance. The understandings have also been used to further assist the completion of deeper horizontal water-floods in the same field that was not originally targeted for study by the pilots.

## High-resolution reservoir correlation – an integrated approach with sequence stratigraphy, geochemical and biostratigraphical studies of the Permian-Triassic transition within the Khuff (Dalan/Kangan) Formation

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The Khuff Formation (Dalan and Kangan formations) contains some of the most important reservoirs in the

Middle East Gulf region and the world. The upper Khuff Formation can be subdivided into four major reservoir units from K4 to K1 (from base up), with the K4 and K3 generally regarded as Permian, whilst the K2 and K1 are considered Triassic. However the precise nature of the K3–K2 reservoir transition, and thus the Permian-Triassic boundary, has always been problematic with many interpretations being put forward. Among the different proposed scenarios, some models suggest a major sequence boundary at the top of the K3 (Top Permian), and a significant stratigraphic time gap between the Permian and the Triassic. Other models suggest no major sequence boundary at the top of the Permian and a continuous transgression with no major sedimentation break. These different models have a major impact on the correlation strategy of the K2 reservoir interval at both reservoir and Gulf scale. In order to resolve these issues, a detailed multidisciplinary study was launched on a large Gulf-scale database (subsurface and outcrop) examining the details of the Permian-Triassic boundary and the K3–K2 reservoir transition. This study integrates at high-resolution: (1) sedimentology, (2) sequence stratigraphy, (3) geochemistry, (4) biostratigraphy, and (5) wireline log interpretations. The implication of the results were tested on the correlation of the K3 and K2 reservoirs between a number of fields in the Gulf. The resulting models reconcile the sedimentological, stratigraphic, paleoecological, geochemical and petrophysical data for this K3–K2 transition. Moreover the study illustrates that over-relying on a single discipline (e.g. sequence stratigraphy or biostratigraphy) no matter how "convincing" the data may appear, can lead to miscorrelation of reservoir units.

## Which reservoir layering for carbonate reservoirs? Depositionally or diagenetically driven?

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The architecture, heterogeneities and petrophysical properties of carbonate reservoirs result from a combination of platform morphology, related depositional environments, relative sea-level changes and a variety of diagenetic events. The reservoir layering built for static and dynamic modeling purposes should reflect the key heterogeneities (depositional or diagenetic), which govern the fluid-flow patterns. The layering needs to be adapted to the goal of the modeling, ranging from full-field computations of hydrocarbon volumes, to sector-based fine-scale simulations to test the recovery improvement and its control.

This paper illustrates from subsurface and outcrop studies, various reservoir layering types, including schemes dominated by depositional architecture, and those more driven by the diagenetic overprint. The examples include carbonate platform reservoirs from different stratigraphic settings (Tertiary, Cretaceous, Jurassic and Permian) and different regions (Europe, Africa and Middle East). This review shows how significant stratigraphic surfaces (such as sequence boundaries or maximum flooding surfaces) with their associated facies shifts, can be often considered as key markers or intervals to constrain the reservoir layering. Examples are given of reservoir layering, which are driven by the depositional heterogeneity at both the layering and the intra-layering scale. Conversely, this paper also outlines how diagenesis, resulting in units with particular poroperm characteristics, may significantly overprint the primary (depositional) reservoir architecture by generating flow units that cross-cut depositional sequences. To demonstrate how diagenetic processes can create reservoir bodies with geometries that cross-cut the depositional fabric, different types of dolomitization and karst development are illustrated.

## Distribution and mechanisms of overpressure generation and deflation in the Neoproterozoic South Oman Salt Basin

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Neoproterozoic intra-salt Ara reservoirs of the South Oman Salt Basin represent a unique self-charging system with respect to hydrocarbon and overpressure generation and dissipation. Reservoir intervals frequently contain low permeability dolomites that are characterized by high initial production rates due to reservoir overpressures. A database of more than 30 wells has been utilized to understand the distribution and generation of overpressures in intra-salt reservoirs that can be separated by up to 350 meters of salt. A temporal relationship of increasingly overpressured reservoirs within stratigraphically younger units is observed, and two distinctly independent trends emerge from the Oman dataset; one hydrostatic to slightly above hydrostatic and one overpressured from 17 to 22 kPa/m, almost at lithostatic pressures.

Current pressure modeling and data inversion suggests that overpressure generation is driven by fast burial of the stringers in salt, with a significant contribution by kerogen conversion. Numerical modeling, however, is unable to predict the hydrostatic pressures observed in several reservoirs and it is proposed that present-day hydrostatic stringers have seen lithostatic overpressures in their earlier geologic evolution. Evidence for these initial overpressures in currently hydrostatic reservoirs is provided by hydrocarbon-veined cores from halite overlying the reservoirs. A proposed pressure deflation mechanism can be related to the complex interplay of salt tectonics and Haima deposition. Today, hydrostatic stringers are likely to be encountered where the salt is thinnest and/or the stringer is in contact with Haima sediments.

## Traditional geological model, Humma Marrat reservoir, Kuwait-Saudi Arabia Partitioned Neutral Zone (PNZ)

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The Humma Marrat field was discovered in 1998 and is located in the southwestern part of the Partitioned Neutral Zone between Kuwait and Saudi Arabia. Six wells, drilled on the long linear NNW-trending doubly plunging anticline, are producing more than 8,000 barrels per day of 20–33° API oil from the Jurassic carbonate reservoir. The study involves the sequence stratigraphic interpretation, reservoir layering, petrophysical interpretation, 3-D seismic interpretation, building a faulted fine-grid static model and shares experiences in overcoming data limitations. High-resolution sequence stratigraphic framework provides a good control for reservoir layering, environment of deposition and porosity distribution. The five informal reservoir units Marrat A, B, C, D and E are related to the sequence stratigraphic framework. Porosity development in the Marrat-A and Marrat-E is controlled by Highstand (HST) and Late Highstand (LHST) higher energy carbonates deposited in a protected inner-ramp environment and dolomitized inner ramp packstone/wackstone, respectively. Marrat-C deposited in a middle-outer ramp environment has chalky porosity and is a minor contributor. Faulted static fine-grid model built in Gocad has 25 million cells and 681 layers. Data limitation is overcome by biasing the population of properties with the regional depositional strike and depositional model, understanding using SGS and SGS with collocated co-krigging. Pore-Perm transforms show a fairly good relationship. P10%, P50% and P90% volume estimates are based upon OWC/LKO ranges. The study also contributes to the modeling practices in a difficult carbonate setting where well control is limited.

## Constraining 3-D geological models by their diagenetic overprint - an example from the Khuff Formation

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The Khuff Formation is one of the most important reservoir formations in the Middle East Gulf Region and one of the world's largest gas reserves. In these reservoirs a complex diagenetic history has had a major impact on the final static and dynamic reservoir properties. To optimize production and future field development, it is necessary to understand the type, impact and timing of the main diagenetic phases at all scales from regional to the fine-scale reservoir heterogeneities. This understanding allows us to develop approaches to effectively incorporate the most significant ones into the static reservoir model. Dolomitization is one of the most crucial diagenetic phases since it strongly constrains the permeability architecture of the reservoir. Detailed diagenetic studies suggest that there are various types of genetic dolomite types (including evaporative, mixed evolved sea-water-freshwater and late thermobaric dolomites). These genetic dolomite types have different stratigraphic and geographic distributions, and geometries. Each dolomitization type can be associated with a specific process, and linked to a paleogeographic setting, stratigraphic position and structural setting. The description of the diagenetic fabrics and analysis of their spatial distribution allows empirical rules regarding the 3-D distribution of these products to be established. The modeling approach is geologically driven and based on the relationships between dolomite type, stratigraphic position, paleogeographic position, depositional facies, and proximity to fault/fracture zones. The results are then quality-controlled to ensure coherency with the conceptual models.

## Lessons learned as multidisciplinary team investigates poor injectivity to optimize current development and design future water-flood expansion in Raudhatain-Zubair in North Kuwait

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In Raudhatain field - Zubair reservoir, the Phase 1 injection program was started in mid-2001. The primary objective was to provide near-term pressure maintenance, understand injection characteristics, and evaluate the pressure response prior to the Phase 2 injection and recovery of secondary reserves. Unfortunately, Phase 1 injection performance was poor. Consequently, systematic investigations were undertaken to understand the cause of this poor injectivity.

Various remedial actions in the wells have in general been unsuccessful. Laboratory studies indicated that the sandstone was prone to progressive plugging due to the inherently small pore-throat size, thus resulting in declining matrix injectivity. This highlighted that the specification of the injected water is a key factor for matrix injectivity. Analogs suggested that maintaining these specification was impractical. Successively, Step Rate Tests (SRTs) indicated that the desired injectivity is achievable above fracture zones. The earlier Phase 2 expansion plan required injection above fracture pressures to sustain the desired injection targets. However, the SRTs indicated that the fracture gradient was greater than that assumed in the previous Phase 2 plan. Therefore, Phase 2 surface injection pressure requirements were redefined, resulting in significant changes to the existing design. Poor Phase 1 injectivity affected pressure maintenance

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thus slowing production ramp-up to prevent secondary gas production. A unique zonal depletion plan has been developed through a detailed full-field model to optimize the development and arrest production decline.

This paper summarizes the systematic field and laboratory investigations undertaken by an integrated team to understand Phase 1 injectivity decline, the impact of higher fracture gradient on future Phase 2 water-flood expansion and the unique depletion plan that optimizes current development.

## Humma Marrat reservoir, Kuwait-Saudi Arabia Partitioned Neutral Zone (PNZ) case study. Part 1: reservoir geology and stratigraphy

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The Jurassic Humma Marrat carbonate reservoir is located largely within the Kuwait-Saudi Arabia Partitioned Neutral Zone (PNZ). The reservoir was discovered in 1998 and produces from five wells. Additional delineation wells were drilled in 2005. The reservoir is a relatively simple anticline oriented N150˚E and may be open to the south towards the Jauf structure in Saudi Arabia. The Marrat reservoir interval is divided into six units known informally as the Middle Marrat A, B, C, D and the Lower Marrat DL, and E zones. Porosity development occurs in shallowing upward para-sequences (inner-ramp/inner-shelf setting) and was controlled by depositional setting and dolomitization. The average porosity within productive intervals varies between 12–22%. Average permeability is 1–10 mD. Based on limited PLT data, approximately 70–75% of the current oil production is from the more strongly dolomitized E zone.

The structural setting of the western portion of the PNZ is dominated by the 250 mile long Humma-Fuwaris-Wafra-Burgan trend that extends from Saudi Arabia to Kuwait. The Marrat Formation has been folded over deeper-seated horst blocks present in the Paleozoic or older basement. Multiple tectonic events reactivated the structure and resulted in folding and fracturing in the Marrat. Fractures, though uncommon in core or borehole image data, are oriented N165˚E. Well test-derived permeability values that are higher than core values and indicate some fracturing, particularly in the A zone.

Thermally mature Paleozoic source rocks are stratigraphically adjacent to or beneath the Marrat Formation. Though thermally immature in the PNZ, the source rock sequences are mature in the adjacent basinal areas. Lateral migration of hydrocarbons could come from the Arabian Gulf basin to the north and east or from the Dibdibah trough to the west.

## Humma Marrat reservoir, Kuwait-Saudi Arabia Partitioned Neutral Zone (PNZ) case study. Part 2: reservoir evaluation and optimization

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A design of experiments (DoE) workflow was used to evaluate the Jurassic-age Humma Marrat reservoir in the Partitioned Neutral Zone (PNZ). The Humma Marrat reservoir consists of productive limestone and dolomite intervals separated by very tight limestone and/or shaly limestone zones. Connectivity and volumetric uncertainties were evaluated using 13 earth models defined by parameter combinations given in a Plackett-Burman design of experiments (DoE) table. The response variable was cumulative oil production through 30 years. Parameters included in the first level DoE analysis were structural uncertainty (seismic interpretation and time-to-depth conversion), facies distribution, porosity and water-saturation (Sw) histograms, original oil/water contact, porosity semivariogram range, permeability multiplier, fault compartmentalization, and fault transmissibility. Only the porosity histogram emerged as statistically significant.

The second level DoE focused on “traditional” dynamic uncertainty parameters including aquifer support, rock compressibility, heavier oil distribution, vertical and horizontal permeability (kv/kh), PI multiplier, Sorw, and krw@Sorw. An additional uncertainty included in the second-level analysis was the extent to which the Humma structure may be open to the south towards the Jauf structure in Saudi Arabia. This was studied using a pore volume multiplier in the southern-most portion of the model. Only the earth model and PI multiplier uncertainties were statistically significant. The results of the DoE analysis were used to define the reservoir models for development optimization. The P50% model was used to screen development options that included well spacing, well type, and horizontal well length. Economic analyses were conducted to select the optimum development scenario using the P10%, P50% and P90% reservoir models.

## Humma Marrat reservoir, Kuwait-Saudi Arabia Partitioned Neutral Zone (PNZ) case study. Part 3: historical look-back at volumetric uncertainty during delineation and development

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A consistent design of experiments (DoE) based evaluation process was used to assess the magnitude of oil-in-place (OOIP) uncertainty as well as the relative contributions from uncertainty sources as a function of the historical development of the Humma Marrat reservoir in the Partitioned Neutral Zone (PNZ). The Jurassic-age limestone and dolomite Humma Marrat reservoir was discovered in 1998 and currently has five producers. The two additional delineation wells and two horizontal sidetracks drilled in 2005 are included in the study. Within the Marrat interval, three stratigraphic layers, known informally as the A, C, and E zones, are known to produce significant oil. Based on limited PLT data, approximately 70–75% of the current oil production is from the lower-most E zone, 15–20% from the A zone, and the remainder from the C zone.

The uncertainty sources in the DoE-based evaluation were: (1) structure (time-to-depth conversion and seismic interpretation uncertainty; (2) original oil-water contact (OOWC); (3) porosity histogram, and; (4) oil saturation histogram. All uncertainties except structure were evaluated independently for the A, C, and E zones. High, mid, and low-case values were determined using only the well-log, core, and seismic data available after each well was drilled or as significant new data became available (e.g. reprocessed seismic volume in mid-2004). The time period covered by this look-back is from 2000 to late 2005. Analysis of the DoE-based results show that the statistically significant contributors to OOIP uncertainty varied considerably as wells were drilled. The study results suggest that consistent use of a quantitative uncertainty assessment tool such as DoE may reduce the number of delineation wells needed and significantly impact delineation well location decisions.

## Impact of Earth model workflow and up-scaling on fluid-flow response reservoir modeling in mature fields

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Scoping studies suggest that simple workflows that use essential stratigraphic and geological constraints capture overall reservoir fluid-flow response as well as complex workflows that use detailed stratigraphic and facies constraints. Thus, considerable time and cost saving may be realized during initial model building and updating if simple, but appropriate, workflows are used. The reservoirs studied include a Permian-age carbonate reservoir in New Mexico, a Middle Cretaceous sandstone reservoir in Kuwait, an Eocene-age shallow-water clastic reservoir in Venezuela, and an upper Miocene deepwater clastic reservoir in California. 2-D cross sectional models of the deepwater clastic reservoir showed that cumulative production and water breakthrough times were essentially the same if two major stratigraphic picks or 12 detailed internal stratigraphic picks were used as constraints. 3-D streamline simulation was used to demonstrate that adding two facies and seven rock type constraints had little impact on recovery factors for the carbonate reservoir scoping project. Likewise, a complex workflow for the shallow-water clastic data set constrained by eight facies and 16 stratigraphic picks yielded the same reservoir response as a simple, two facies, four major stratigraphic picks constrained workflow. These studies suggest that for reservoirs with moderate to high net to gross (> 30–40%) or with small differences in the porosity versus permeability trends of facies/rock types that simple workflows are adequate. Vertical up-scaling by factors commonly used for full-field simulation has little impact on fluid-flow response. However, areal up-scaling significantly alters the fluid-flow characteristics and warrants additional study.

## Enhancement of oil-in-place through reservoir modeling of a multilayered siliciclastic reservoir: a case study from Muglad Basin, Sudan

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El Toor field is located in Block 1A of the Greater Nile Petroleum Operating Company concession area, Sudan. It was discovered in 1996 and production started in early 2000. Cumulative production as of 2004 was 34 million barrels. The field is a fault-bounded anticlinal structure. The main reservoir is the Lower Cretaceous Bentiu sandstone. The Upper Cretaceous Aradeiba E and F sandstones are secondary oil accumulations. All the reservoirs contain continuous barriers between the porous layers over the majority of the field. After one year of sustained production, many wells started to produce water. Accordingly, a team from the Sudanese Petroleum Corporation (Sudapet) conducted a study to remodel the field. Software mapping packages and seismic attributes were used to map the faulted structure and develop a 3-D lithofacies model of the field. After remodeling and identification of the sand-body architecture, the extent of the oil-in-place was recalculated for the finely gridded 3-D geological model consisting of 42 vertical layers. The oil-in-place was calculated for 1P, 2P, and 3P cases as 232, 251 and 261 million barrels, respectively. The study increased the oil-in-place by 48.7% for the 2P case.

## Reservoir characterization and 3-D modeling of Hassi R'Mel South field (Algeria) using workflow tools

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The Hassi R'Mel South (HRS) field is located onshore in north-central Algeria. It produces from Triassic sandstones known as the TAGS (reservoir "A"), which have medium to poor reservoir quality. Reservoir deterioration is due to either its fine granulometry or evaporitic cement filling the pore volume. The "A" reservoir is affected by NNW-SE normal faults, with large throws. Production testing and pressure data indicate that the field is not in communication with Hassi R'Mel field. The objectives of our study were: (1) rebuild the structural model; (2) map the 3-D evaporites distribution; (3) explain the geological nature of the facies heterogeneity; (4) characterize channel bodies within the Triassic "A" reservoir; and (5) prepare an optimized field-development plan. To build an accurate geological model, we integrated a new seismic interpretation. Core description from 35 wells were used for a facies classification and subdivision of the "A" reservoir into 19 layers. The gas/oil and water/oil contacts were identified using RFT and MDT tests. These data combined with the locations of major faults resulted in a model consisting of 12 compartmental blocks. The compartmentalization was used to calculate hydrocarbon volume-in-place for individual blocks. The permeability was determined from cross-plotting the K and PHIE core data. 3-D numerical models of effective PHIE, K, $S_W$ and facies distribution were built. The analysis resulted in additional details to the field, such as the presence of small evaporite barriers controlled by the NW-SE faults. These faults act as a guide for channel stacking within a paleovalley, and demonstrate the best PHIE and K quality.

## Outcrop study combined with 3-D Petrel modeling of a Khuff Reservoir analog: insights into "layer-cake" stratigraphy

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In the framework of a joint ENI-university research consortium, the Triassic Muschelkalk carbonates in the South German Basin were studied as an analog to the "layer-cake" type Khuff reservoir system in the Middle East. Similar to the Khuff, the Muschelkalk carbonates were deposited in an epicontinental, very gently inclined carbonate ramp; reservoir facies consist of skeletal and oolitic carbonate grainstones, and are organized in a pronounced hierarchy of cycles. A pilot study was focused on a paleogeographically and stratigraphically selected portion of the Muschelkalk. Previous outcrop sedimentology and correlation suggested simple layer-cake stratal patterns. However, high-resolution 3-D modeling of sedimentary body geometries and spatial distribution using Petrel imposed new correlation strategies between vertical outcrop sections (pseudo-wells) and provided new insights: the apparent layer-cake stratigraphy turned out be a "pseudo-layer-cake". While the boundaries of sedimentary cycles remain continuous over many tens of kilometers, the carbonate grainstone reservoir bodies within the cycles show various stratal architectures. In particular, considerable differences between the geometries of the sedimentary bodies during progradation and retrogradation could be demonstrated. This "pseudo-layer-cake model" might be crucial in defining typical subseismic reservoir heterogeneities of epeiric carbonate systems: continuous seismic reflectors represent major cycles (time lines), while for example subtle off-lapping geometries of smaller-scale cycles are likely "hidden" between the reflectors, but fundamental for the assessment of the fluid-flow continuity inside the reservoir itself.

## Delineation of Wara Ac reservoir sand from multi-attribute analysis of well and seismic data: a case study from Awali field, Bahrain

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The sandstones of the prolific Wara Ac reservoir (early Cenomanian age) have a porosity and permeability ranging from 25–38% and 1,000 mD, respectively. The Wara Formation overlies the Mauddud limestone and consists of white-to-tan, fine-to-medium grained, friable well-sorted sands grading laterally into silty shales. The presence of hydrocarbons within the Ac reservoir has been established well beyond the limit of the Mauddud oil/water contact. A paleostructural study indicates that the Ac sandstones may have been deposited in a wedge against the flanking escarpments of paleo-grabens. Therefore the Ac sandstones have high exploration potential at the flanks of the field. However because the sandstone distribution is discontinuous their delineation is a challenging task.

The delineation of the Ac sandstone was attempted using a neural network model. The model generates a pseudo-gamma ray volume derived from multi-attribute analysis of well and seismic data. This presentation illustrates the workflow and outcome of the study. The essential components of the workflow were: (1) well-to-seismic correlation; (2) neural network-based seismic inversion; (3) estimation of seismic attributes; (4) step-wise multi-linear regression for selecting the optimum seismic attributes based on least-error criteria; (5) training of the neural network with a selected set of attributes; and (6) estimation of the pseudo-gamma ray from the trained neural network. Nine wells were used to estimate the optimal set of attributes and to train the neural network. The sandstone distribution map was prepared by extracting pseudo-gamma ray within the window corresponding to Ac reservoir. The resulting sandstone distribution adequately matched the wells that were not included in the analysis and outlined the Ac reservoir distribution in the area.

## Uncertainty quantification in a micro-porous, fractured limestone reservoir (Kharaib Formation, Lekhwair field, Northwest Oman)

*Michael C. Pöppelreiter (michael.poppelreiter@shell.com) and Linda Poyser (Shell)*

The paper presents an integrated-iterative workflow to manage uncertainties and sequentially improving predictability. It is illustrated at a microporous, fractured limestone reservoir, covered by poor quality seismic. The workflow includes: (1) Uncertainty Identification, (2) Uncertainty Quantification and Ranking (Experimental Design, Monte Carlo Modeling, Distribution Curve, Tornado Chart), (3) Uncertainty Mitigation (Decision Tree, Data Acquisition), (4) Revised Uncertainty Ranking and Mitigation (repeat steps 2 and 3). Field performance and previous models were used to estimate the key uncertainties on oil-in-place and recovery. Several simple static models were constructed and simulated, changing one uncertainty at the time. Historic production was used to select meaningful models. Simulation also revealed the key uncertainties: fracture properties, saturation behavior and top structure. Experimental design provided a matrix to guide construction of deterministic models by combining uncertainties in a statistically meaningful way. Alongside, a workflow was set-up to vary these uncertainties probabilistically (Monte Carlo). An oil-in-place distribution curve was generated and probabilities (P15%, P50% and P85%) values were determined. Deterministic models with oil-in-place close to the P15%, P50% and P85% values and additional models were simulated to provide a production forecasts envelope. A decision tree was established to guide data acquisition in new wells. Well results revealed good predication of saturation and fractures except along faults. Top structure uncertainties were under-predicted, particularly along faults. Well results were used to update models. New wells will probe structure and fractures at fault but disregard saturation. The workflow is an 'evergreen' method that provides statistically meaningful production forecast and iteratively reduces uncertainties to optimize field development.

## Potential opportunities below the oil-water contact of the Arab D reservoir, Awali field, Bahrain

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This study investigated the distribution of oil below the original oil/water contact (OOWC) of the Arab D reservoir in Awali field, Bahrain. Distinct vertical and lateral facies variation account for residual oil entrapped below the OOWC. The inferred residual oil limit depends on the value of PhiHSo (porosity-thickness-oil saturation) irrespective of the depth and differs from the eastern to the western flanks of the field. Estimates of the residual oil-in-place are based on the weighted average water-saturation and weighted average porosity with two water-saturation cut-offs (Sw > 30% and Sw> 40%). It was observed that high PhiHSo values occur in the crestal part of the field with a NNW-SSE orientation. Preferential alignment of high values corresponds to better reservoir facies as observed in core data.

The analysis integrated 3-D seismic attributes with petrophysical and geological data. Composite-window, seismic-horizon attributes (amplitude and frequency) across the Arab D interval provided qualitative support for a relationship with facies variation. The 3-D seismic attributes identified a distinct attribute anomaly in the NNW-SSE direction, suggesting some prospective untested locations in the lower Arab D reservoir. The implied residual oil-in-place in several Arab D intervals, below the oil/water contact, is substantial in a relatively narrow strip. It may be appropriate to recover using enhanced oil recovery in the future.

## Integrated fracture characterization and modeling in carbonate fields using Novel modeling software and sandbox models

*Pascal Richard (Petroleum Development Oman, pascal.richard@pdo.co.om); Keith Rawnsley and Peter Swaby (Shell)*

A large proportion of Petroleum Development Oman (PDO) future production resides in fractured reservoirs. In order to support the development of these volumes, a strong element of fracture characterization and modeling has been included within a number of subsurface studies. The key enabler for these studies is the software technology, SVS (Simple Visualization Software), developed by the Carbonate Development Team (CDT), in Shell EP-Research. PDO has not only taken a lead role in software implementation but is also steering the ongoing development of SVS according to the needs of active field studies. Currently, SVS is applied to the three themes of Oman's fractured reservoirs: (1) slightly fractured containing light oil (2) medium/highly fractured containing light oil; and (3) highly fractured containing medium-heavy oil. The key pillar of the SVS workflow is a detailed fracture characterization that leads to the elaboration of a series of conceptual models that capture the range of the subsurface uncertainties. Once the conceptual models have been developed, these can be transformed into discrete fracture models with attached attributes (such as permeability anisotropy, fracture spacing, etc.). These models may be transformed into reservoir simulation properties as per study requirements. This paper's main objective is to illustrate the SVS

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workflow with particular emphasis on the borehole image analysis and the use of a web-based sandbox model database, to help constrain the fault geometries and the structural understanding of the fields.

## Depositional environment and diagenesis of the Fahlyian Formation southwest of Iran

*Leila Soori (lsoori@khayam.ut.ac.ir) and Hossein Rahimpour Bonab (University of Tehran)*

The Fahlyian Formation (Neocomian) is one of the petroleum reservoirs in Southwest Iran and was deposited over the Fars Province and northeast of Khuzestan and Lurestan provinces. In this research, the formation was studied in two sections in Khuzestan Province: (1) Haftkel-61 well located 8 km northwest of Haftkel oil field; and (2) outcrop sections at Kuh-e Mungasht and Tang-e Malagha located 30 km east of Izeh city. Each section has a thickness of 450 m. Based on microscopic studies and wireline well-logs (gamma-ray and neutron), four facies belts were recognized in the formation. (1) Tidal flat facies belts consisting of pelloid, ooid, pelloid-ooid, bioclast-pelloid, bioclast-ooid and intraclast-ooid grainstones, stromatolite boundstone and lime mudstone. (2) Lagoonal facies including bioclast, pelloid, bioclast-pelloid, intraclast-pelloid and bioclast-intraclast packstone, bioclast and algal wackstone and fossiliferous lime mudstone. (3) Barrier facies containing ooid, pelloid, ooid-pelloid, intraclast-ooid and algal grainstone, lithocodium and coral boundstone. (4) Open-marine facies consisting of lime mudstone, bioclast wackstone, shale and resedimented carbonates (calciturbidites). Vertical and lateral facies changes suggest that the Fahlyian Formation was deposited in a transgressive and deepening basin. Based on depositional features a shallow, distally steepened carbonate ramp was suggested for the Fahlyian Formation. The most important diagenetic processes are cementation, micritization, neomorphism, dolomitization, dissolution and compaction. Among them dolomitization and dissolution seem to have enhanced reservoir quality.

## Intra-salt carbonate stringers: where's the reservoir?

*Mia Van Steenwinkel (Petroleum Development Oman, mia.vansteenwinkel@pdo.co.om); and Joerg Mattner (GeoTech)*

Proterozoic to Cambrian carbonate stringers, encased in the salt of the South Oman Salt Basin, form one of the oldest reservoirs in the world. The predominantly self-charged reservoirs occur at depths between 3,000 and 5,000 m and are often over-pressured. Organic-rich bacterial laminites and mounded thrombolites, together with redeposited fabrics thereof reworked by waves or currents, are the primary stringer facies. Diagenetic pore plugging and reservoir deterioration of initially good reservoir facies has occurred through salt plugging, bitumen plugging and carbonate cementation. This presentation highlights the evidence for Charge-Related Porosity Preservation above paleo-oil-water contacts. Away from salt- and bitumen-plugged areas, reservoir properties are likely to be preserved in areas with early charge, whereas below the paleo-oil/water-contact, reservoir properties have deteriorated through calcite cementation. Evidence for this model is based on (1) log data: sudden decrease of average porosities beneath a certain depth, coinciding with (2) changes in production (PLT), (3) petrography, (4) the occurrence of a bitumen mat near the paleo-contact, and (5) structural considerations. Stringers encased in the middle of the salt sequence have undergone complex multi-stage halokinetic structuration and tilting. In these cases, paleo-oil-water-contacts are difficult to recognize and predict. Paleo-oil-water-contacts are easier to recognize in stringers located close to the base of the salt. These stringers are less affected by halokinesis and therefore the early established fluid contacts – and their diagenetic effects – changed little over time and are more predictable. Despite the fact that additional local reservoir deterioration by salt and bitumen plugging is currently hard to model, this aspect of Charge-Related Porosity Preservation is a giant step forward in understanding, modeling and predicting reservoir properties in the stringers.

## Integrating information from multiple sources to generate geologically-realistic models: the multiple-point statistics/facies distribution modeling workflow

*Sebastien Strebelle (stsb@chevrontexaco.com) and Rachel Preece (ChevronTexaco)*

Building geologically realistic reservoir models that honor well data, seismic-derived information, and production history, remains a major challenge. Conventional variogram-based modeling techniques typically fail to capture complex geological structures while object-based techniques are severely limited by the amount of conditioning data. This talk presents two new reservoir facies modeling tools developed at Chevron that improve both model quality and efficiency relative to traditional geostatistical techniques: Multiple-Point Statistics (MPS) simulation and Facies Distribution Modeling (FDM).

MPS simulation is an innovative depositional facies modeling technique that uses conceptual geological models as training images to integrate geological information into reservoir models. Replacing the variogram with a training image allows MPS to capture complex spatial relationships between multiple facies, and model non-linear shapes such as sinuous channels. In addition, because MPS is not an object-based, but still a pixel-based algorithm, MPS can account for very large numbers of wells, seismic data, facies proportion maps and curves, variable azimuth maps, and interpreted geobodies, reducing dramatically uncertainty in facies spatial distribution.

Facies Distribution Modeling (FDM) is a new technique to generate facies probability cubes from user-digitized facies depocenter maps and cross-sections, well data, and vertical proportion curves. Multiple sources of information (well-logs, cores, seismic, and dynamic data) can be used to generate FDM probability cubes. These cubes can be weighted and merged to be used as soft constraints in geostatistical modeling. Such constraints are critical, especially in sparse well environments, to ensure that the spatial distribution of the simulated facies is consistent with the depositional facies interpretation of the field.

A workflow combining MPS and FDM has been successfully used for the last three years to model more than thirty prominent Chevron assets in both clastic and deepwater environments. Some examples of those MPS/FDM modeling projects are presented in this talk.

## Oil-rim development under an exploited and cycled gas cap – optimization through 2G&R integrated stochastic workflow

*Patrick Tardy (patrick.tardy@total.com), Claude Gout, Said Hunedi, Jean-Pierre Fossey and Laure Moen-Maurel (Total)*

Optimizing the development of condensate gas fields has always been very challenging. The field presented in this paper is a horst structure located in the Euphrates Graben of Syria, and is characterized by an oil-rim underlying a rich and significant gas cap. This gas cap was developed several years ago while the oil-rim still remains unexploited. Hydrocarbon transfers have been evidenced between the oil-rim and the gas-cap regions. Therefore an integrated subsurface study was undertaken to accurately describe the transition zone between the gas and the relatively thin oil-rim (around 60 m initially) in order to predict the evolution of fluid transfers. The structural and geological complexity of the field (object modeling of fluviatile channels) was characterized by stochastic modeling. Advanced fluid thermodynamics and compositional simulations were used to handle the critical aspects of the fluid column. The impact of the main uncertainties were assessed in order to identify and quantify possible solutions for the development of the oil-rim, together with a risk assessment providing the necessary data for management decision.

The optimization strategy requires a compromise between the different involved companies, since their interest lies in maximizing the production of either the gas cap or the oil-rim, depending on whether their contract relates to dry gas or to liquid hydrocarbons production. The originality of the method was to provide different geological and reservoir models, with a final objective of ensuring the robustness of all possible developments. The study considered all the models and encompassed a wide range of uncertainty.

## Fracture modeling methodology based on continuity cube data

*Claudio Toscano (claudio.toscano@eni.it), Rosa Atena, Giuseppe Bellentani, Federico Cappanera and Arrigo Francesconi (Eni)*

The target of this methodology is to build a DFN model and the relevant fracture petrophysical parameters evaluation. With the seismic data we can subdivide the brittle events in two different sets based on their scale: seismic faults (kilometric) and continuity cube scale events (hectometric). If well data are available we can insert in the models a third set of fractures: the so-called "log scale" fractures (decametric). The seismic scale faults can be introduced in a deterministic way directly from the static model. The interpreted continuity cube events are filtered and then utilized to obtain a fracture intensity grid considered as the conceptual model to distribute the fracture at this scale. The information coming from the continuity cube, 3-D-seismic and borehole-image-log interpretation are utilized in order to get an expanded grid property distribution that represents the geological driver to distribute the fractures at the log scale. Obviously, the final model has to honor the borehole-image interpretation, in terms of orientation and number of fractures intersected by each well.

The dynamic validation of the DFN models has to be made using dynamic data such as well test, interference test, etc., but if they are not sufficient or not available at all, the Reiss approach (1980) or analog data are alternative ways to get the petrophysical evaluation of the fracture network from the DFN model. Moreover, a 3-D grid indicating the enhancement of porosity and permeability can be extracted directly by the fracture-intensity grid without any fracture network petrophysical evaluation.

## Testing static concepts used for discrete fracture network modeling of Najma-Sargelu reservoir of West Kuwait

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A 3-D Discrete Fracture Network (DFN) model of the Najmah-Sargelu unconventional fractured reservoir covering four oil-fields of West Kuwait was built. The model used petrophysical data from 54 wells including core and image-logs, supplemented with seismic facies analysis and production data calibration. Subsequent to the construction of the model, new data became available from a horizontal well and two vertical wells drilled in three different oil fields. Fractures described in a new core from one well was used for fracture characterization and the same was calibrated using higher resolution image-logs available for the first time in these reservoirs. 'Fracture swarms' related to sub-seismic faults were segregated from 'diffuse joint sets' based on fracture morphology, orientations and distribution in a well-by-well analysis. Systematic analysis of geological drivers such as mechanical bed thickness and brittleness was carried out to derive fracture spacing, intensity and dispersion to compare with earlier data-set. Qualitative reservoir dynamic calibration was attempted using production logs from the horizontal well acquired recently for the first time in this reservoir. Static modeling concepts used for building the DFN model were tested rigorously with the help of additional well data. Besides providing assurance on predictive capabilities of the model including limitations thereof, the present effort succeeds in identifying opportunities and directions for further refinement. In the short term, well locations and paths are being optimized with the help of a DFN model, to intercept minor fracture swarms using deviated wells for the first time. The appraisal and development wells targeting fracture 'sweet spots' will address multi-reservoir development besides generating necessary data for cost optimization. Parallel efforts to build full-field reservoir models, in the longer term will lead to the cost-effective development of these unconventional fractured reservoirs.

## Reservoir characterization and stochastic modeling of the Second Eocene dolomite reservoir, Wafra field, Kuwait-Saudi Arabia Divided Zone

*Mohamad Rafiq Wani (m84041.wani@kgoc.com) and Sondos Khalil Al-Kabli (Kuwait Gulf Oil Company)*

The Wafra Second Eocene reservoirs are dolomitized carbonates associated with anhydrite deposited under shallow sub-tidal to sabkha environments. These are characterized by high porosity and permeability, mainly due to vugs formed by enhancement of the predominantly intercrystalline porosity by leaching and dissolution. This vug-dominated heterolithic pore system cuts across the depositional fabric that has largely been obliterated by dolomitization. A relatively simple method of porosity modeling, using zonation based on high frequency cycles (HFCs) has been attempted with good results. Based on core petrographic and electrolog studies, the reservoir has been divided into eight HFCs, further divisible into 14 'zones'. Porosity distribution is closely related to this HFC-based zonation. Core porosities show a decreasing upward trend between successive HFCs and the lower zone of each HFC has a higher porosity than the upper. Mostly, the vugs are localized to zones overlying the tighter, anhydrite-rich crusts of the respective lower HFC.

The presentation describes stochastic modeling of the reservoir properties and their distribution in a high-resolution 3-D grid of nearly 10 million cells covering an area of about 350 sq km and average thickness of 500 feet. Vertically the grid was divided into 14 stratigraphic layers based on the subdivision of the eight HFCs. Porosity was distributed by sequential Gaussian simulation, constrained by semivariogram models generated for each stratigraphic layer. Permeability was distributed by applying powerlog porosity-permeability transforms developed for each stratigraphic layer from core data. Water-saturation distribution was further constrained by the model porosity distribution and the oil-water transition zone.

## Building a discrete feature network model of fractures within the reservoir property model: Humma field, Kuwait-Saudi Arabia Partitioned Neutral Zone

*Sherilyn Williams-Stroud (Midland Valley Exploration, sherilyn@mve.com); Stewart Griest and Scott Meddaugh (Chevron)*

Fractured reservoir models can be built from static properties or from properties derived from a restoration of the interpreted structural history of the reservoir. Strain-based fracture models ideally require some knowledge of the rock properties, at the time of deformation, in order to predict fracture orientations and intensity. In order to evaluate the importance of the geologic history relative to measured and known reservoir attributes related to fractures, a Discrete Feature Network (DFN) fracture model was generated from properties defined within the reservoir geocellular model. Fracture orientation properties obtained from selected wells were distributed through the reservoir away from well data locations using an interpolation algorithm. Key wells were withheld from the distribution calculation to test the validity of the distribution of the final DFN. Other properties in the geocellular model (porosity, density and seismic coherency) were used to constrain fracture intensity and were combined with the fracture-orientation properties to generate fractures throughout the reservoir model. Properties calculated from the DFN are output directly into the reservoir-property model as properties, in addition to existing matrix properties to create a fracture-permeability property model ready for input to a flow simulator. Because the calculation is fast, and can be done within the property model, it allows adjustments to be made where needed by using the well-production data to constrain the fracture length and aperture values. A fracture model was developed that honors well data that can be used to further develop a field or plan enhanced recovery methods.

## Strontium (Sr) isotope stratigraphy of the Upper Jurassic Arab and Asab formations, United Arab Emirates

*Wayne R. Wright (Fugro Robertson, wayne.wright@beg.utexas.edu); Christian J. Strohmenger, Suleiman Ali, Abdelfatah El-Agrab and Rafael M. Rosell III (ADCO)*

A pilot study was undertaken to assess the viability of using whole-rock strontium isotope ratios as a means to verify the established sequence stratigraphic framework for the Arab and Asab formations of the United Arab Emirates. Several key observations were made during the course of the strontium (Sr) isotope study. Firstly, results revealed that the method produced usable data regardless of sample lithology (i.e. limestone *versus* dolomite *versus* anhydrite). Secondly, in contrast to a previous study, a time-related isotopic trend and signature is apparent in the studied Jurassic carbonates and anhydrites. Thirdly, a correspondence exists between the calculated ages of the rocks and the established third-order sequence stratigraphy framework, thereby validating the overall correlation. However, higher fourth-order and fifth-order cyclicities in the units may be below the resolution of the technique. Fourthly, the strontium isotope ratios unambiguously identify the transition from the underlying Asab Formation and the overlying Habshan Formation. Lastly, although, fourth-order and fifth-order cycles pose problems for direct age dating correlations, whole-rock strontium isotope ratio data excursions and overall trends have excellent potential as correlation tools. Many researchers have disregarded the use of the whole-rock strontium data as containing too many ‘hidden’ problems but potentially this study indicates that given geologically and petrographically constrained samples, from rocks of certain ages, very viable data may be yielded using this method.

## Uncertainty analysis in geomechanics modeling for fracture prediction

*Haiqing Wu (Chevron, hwu@kockw.com); Mohammed D. Al-Ajmi, Nikhil Banik and Neema H. Al-Ajmi (Kuwait Oil Company); and Andrew Corley (Chevron)*

Geomechanical modeling is a powerful tool in predicting the distribution of fractures in reservoirs. A better understanding of its uncertainty and limits helps improve our prediction and reduces inaccuracy. Several uncertainty sources in the modeling have been identified and discussed: (1) seismic interpretation, (2) paleostress orientation, (3) stress status, and (4) lack of hard data for validation. Since issues (2) and (3) are related to the knowledge of regional geology and tectonic history our focus in this paper is the impact of seismic interpretation on the results of geomechanical modeling. We chose the Jurassic section in west Kuwait where the 3-D seismic image is relatively blurred. The fracture models are based on two extremely different interpretations, one based on regional geology and the other is locally focused. The main differences between these two interpretations are common to other areas and are: (1) fault size in the horizontal plane, (2) fault dimension in the vertical direction, (3) fault location, and (4) fault geometry. They also show some similarities: (1) fault orientation, (2) fault density, and (3) cutting relationship. The comparison and analysis of the results show that the uncertainty in fracture orientation is much higher than that in fracture density distribution. Finally, we quantitatively evaluate and list the uncertainty of predicted fracture versus interpretation differences.

## Miscibility investigation of Bangestan gas in Asmari reservoir oil of a southwestern Iranian field

*Mehdi Zeidouni (zeidouni.m@nisoc.com) and Seyed Ahmad Alavian (NIOC)*

To date gas is injected in several saturated Iranian reservoirs. In undersaturated reservoirs where the main recovery mechanisms are rock and fluid expansion (depletion) and water encroachment, gas is not injected as yet. In this type of reservoir miscible gas injection can lead to very high recovery. The Asmari reservoir is currently at 2,450 psia and undersaturated, and the abandonment pressure of the reservoir is almost equal to the bubble point pressure (1,628 psia). Therefore the reservoir will remain undersaturated up to the end of its life that it is a good candidate for miscible gas injection. Conveniently rich gas is available for injection from the underlying Bangestan reservoir. To determine the miscibility conditions and parameters requires characterizing the PVT for the reservoir fluids. The Minimum Miscibility Pressure (MMP) has been estimated as 5,371 psia. This pressure will be increased to 8,550 psia for the first contact miscibility. To achieve miscibility at current reservoir pressure of 4,090 psia the Asmari oil needs to be enriched with NGL. The Minimum Miscibility Enrichment (MME) is also calculated 8.63 mole percent. Based on this 66 STB of NGL is required to enrich 1.0 MMSCF of Bangestan gas to achieve the miscibility at current Asmari reservoir pressure of 4,090 Psia. The Asmari reservoir rock is highly fractured causing a significant increase in the MMP/MME values. This issue is addressed based on a literature review.