Integrated Multidisciplinary Analysis of the Rankin Trend Gas Reserviors North West Shelf, Australia

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An integrated geological study of the Rankin Trend of the North West Shelf, Australia, was completed to underpin the development of giant gas fields. The study applied an improved understanding of the regional stratigraphy in conjunction with interpretation of the regional scale Demeter 3D seismic survey, focussed on existing fields, un-developed discoveries, and exploration prospects. The study included a redescription of 1500 metres of core, a new facies based petrological analysis, a revision of the biostratigraphic framework and a seismic stratigraphic analysis. It also included the integration of reservoir production and hydrodynamic data. Improvements in the stratigraphic framework were supported by a broad range of depositional and facies analogues and a system-wide sequence stratigraphic approach to understanding lateral and vertical stacking patterns of the reservoir succession. The latest visualisation and modelling technology were also employed to more adequately describe genetic reservoir packages.

Specific outcomes include, improved correlation techniques, recognition of palaeosols as key stratigraphic marker horizons and application of appropriate subsurface depositional analogues to field descriptions, resulting in a more consistent regional interpretation framework. This forms the basis for seismic stratigraphic interpretation away from well control.

The regional geological model has enabled the linkage of exploration, development and production understanding across the North West Shelf assets as well as management of geological uncertainties.

Subsurface Architecture of the Late Triassic Brigadier Formation in the Goodwyn Field Area, North West Shelf, Australia

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Reservoir management and field development planning within the Goodwyn area rely on the ability to resolve the complex reservoir architecture of the Late Triassic Brigadier Formation. The reservoir heterogeneity of these marginal marine deposits is captured by a high resolution depositional and sequence stratigraphic framework which allows for subdivision of the reservoirs on a flow unit scale. Interpretation is based on the integration of representative cores and logs, high resolution seismic imaging, and significant pressure and production/ injection/ tracer study data in an unfaulted field. The Brigadier Formation in the Goodwyn area comprises downdip depositional equivalents to the underlying fluvial Mungaroo Formation; it is characterized by tidally-influenced, lower delta plain and marginal marine deposits. The succession comprises individual progradational parasequences that retrograde in response to lower order transgression. The depositional model and sequence stratigraphic framework form the basis for defining and evaluating reservoir opportunities and further optimisation of development planning in the Goodwyn Field area.

Advances on 3D characterization of fluvial reservoirs using a process-based modeling approach. Examples from the Permo-Carboniferous Gharif Formation, Oman

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A number of ‘fit-for-purpose' workflows have been adopted by the hydrocarbon industry that facilitate the effective static modelling of fluvial channel architectures, using a combination of both deterministic and stochastic modelling techniques. However, significant challenges remains when it comes to the sub-surface identification and modelling of the complex deposits associated with highly sinuous meandering systems where lateral migration and the deposition of point bar deposits within meander belts results in a reservoir of highly complex and variable static connectivity. A new stochastic / process-based tool (Flumy) aiming to model meandering channels and their associated floodplain deposits is being developed and could represent a potential step-change in the 3D modelling of such depositional systems. Migration of the meandering channel within a well-defined channel belt results in the deposition of true-to-nature sedimentary units comprising lenticular point-bar deposits. Initial results, when compared with data from the Permo-Carboniferous age, Gharif Formation (Haushi Group) of Oman, appear promising. Sedimentary architectures characteristic of both high and low accommodation conditions are modeled effectively using this new technique. The resulting sedimentary architecture is both realistic and yields a much more ordered arrangement of facies than the object or pixel-based modelling techniques applied previously. Work is ongoing, particularly in the area of conditioning the models to key outcrop and sub-surface data (e.g. well logs and cores), and hopes to deliver new insights into the effective modelling of such systems resulting in more accurate predictions of reservoir performance.

Extorting the Subsurface: Development Planning in Vertically-heterogeneous, Shallow-marine Reservoirs using an MPS Depofacies-based Geostatistical Simulation Model

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The Takula field in offshore Angola, Block 0, is a mature giant oilfield that produces from five separate formations. The Albian-age Upper Pinda Formation is a secondary producing interval that contributes from a gross 800 feet of shallow-marine, mixed clastic and carbonate sandstone units. The field has been producing since the mid-1980's and has recovered 800 MM barrels primarily by depletion drive. A single-well pilot water injection program that was implemented

in the mid 1990's has shown a positive response. However, variable water breakthrough indicates significant uncertainty in the vertical permeability profile of the thin, stacked sand intervals. A detailed reservoir model was built to address this uncertainty and help analyze alternatives for waterflood expansion.
The sequence stratigraphic framework suggested that porosity and permeability would best be modeled using a depofacies-based method. Sedimentologic and stratigraphic interpretations were digitized into training images in a geocellular model that provides the basis for Multi-Point Geostatistical Simulation (MPS) of reservoir properties. The inherent speed and flexibility of this application allowed for the expedient simulation of a variety of scenarios pertaining to reservoir continuity and connectivity. Iterative refinement of the MPS-populated geocellular models in the history-matching phase proved to be a vital path to building a dynamic simulation model adequate for development planning.

Stochastic 3D Modeling for Supporting The Santa Barbara – Pirital full field Compositional Simulation, Eastern Venezuelan Basin

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The Santa Barbara - Pirital field is located in the Monagas state, next to Carito and Furrial fields. The field is defined as an asymmetrical anticlinal, presenting a considerable level of heterogeneity as result of a combination of geological events, including complex compressional faulting and a diversity of sedimentary environments.
Available data for this study include lithology and petrophysical well logs, 3D seismic, core analysis and production history (started in 1989 by well SBC-1E) for both Oligocene and Cretaceous reservoirs.
A high resolution modeling grid of 62 millions cells was built using corner-point geometry and incorporating 188 faults. Finally, reservoir properties were distributed using stochastic 3D non-stationary modeling for both facies and petrophysics.
Facies modeling was performed for each one of the twelve genetic units, combining Truncated gaussian simulation and Sequential Indicator Simulation tools to describe sub-environments (large-scale heterogeneity), and sand/shale distributions inside sub-environments (finer scale). The resulting realizations reproduced the conceptual sedimentologic model.
For petrophysical modeling, a Sequential Gaussian Simulation algorithm with trends was used. Blocked well log data was inspected to check the distribution and spatial variation of effective porosity and permeability within each facies.
Three realizations were produced and re-scaled in order to measure uncertainty. After flow simulation, the one with the best match to historical data was selected as the most representative.
This is the first full-field geostatistical model to honor reservoir heterogeneity. It will be used to simulate the further development of the field and to maximize oil recovery through water and gas injection processes.

Multiple-Point Statistics (MPS)/Facies Distribution Modeling (FDM) of Carbonates – an Isolated Platform Example

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We have explored the use of MPS/FDM modeling in a carbonate reservoir. We have modeled the platform top of an isolated platform example and tested various scenarios for the distribution of grainstone facies.
The training image is a 3D conceptual model of the reservoir, containing information about facies dimensions and relationships among facies. Five facies were considered: Bar crest = best reservoir quality due to sorting in “highest energy” setting; Bar flank = good reservoir quality between bar crests, includes flanks of bars and intervening tidal channels; Island = localized areas where permeability is enhanced by dissolution during meteoric diagenesis; Deeper platform = poorer reservoir quality in platform areas away from bars and channels; and Background = “tight” intervals due to muddier facies or to porosity-plugging cementation.
The facies probability cube allows controlling the spatial distribution of the facies in the MPS model. First, facies depocenter maps were generated for deeper platform, bar flank, bar crest and island. Then, the stratigraphy of the reservoir was modeled by digitizing a vertical proportion curve reflecting the variations of facies proportions with depth. Three alternative vertical proportion curves were created, representing respectively a gradual trend, cyclicity at the scale of composite sequences, and high cyclicity at the scale of individual sequences. Corresponding alternative facies probability cubes were generated for these three cases.
Several scenarios were run: the gradual, cyclic and highly cyclic cases; both narrow and wide bar crests and bar flanks; and with constant and variable azimuth. The wide bar crest/bar flank and very cyclic simulation produce results that qualitatively appear most reasonable in both cross section and map views. Flow simulation of the various models highlights their significant differences.

Map-based vs Grid-based Calculation of NRV & OOIP: Methods, Comparisons, & Recommendations in Turbiditic Depositional Environments, Block 14, Angola

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When calculating NRV and OOIP, earth scientists have two choices of estimation methods: 2D map-based and 3D grid-based. Use of map-based NRV and OOIP estimations are considered historically reliable, verifiable by all stakeholders, and simple in concept. Volumetric grid-based modeling has enabled sophisticated development and use of grid-based objects for estimations of NRV and OOIP; grid-based methods have a shorter history of confidence checking, are usually time intensive to create, involve complex processes, and more difficult to independently verify.
While map-based solutions are convenient and standard approaches to estimating NRV and OOIP, they often do not adequately represent the subsurface and can result in overly-optimistic estimates of NRV and OOIP in turbidites. The most significant limitations of map-based estimations of NRV and OOIP include: inability to accurately identify the number of individual reservoir sub-units, layering configuration, and spatial location of reservoirs.
Grid-based calculation methods can be superior to map-based methods in that accurate spatial representation of NRV

can be realized by using reservoir properties from 3D seismic methods resulting in more accurate OOIP estimates. Grid-based calculation of NRV enables visual comparison of the spatial distribution of reservoir rock.
Qualitative and/or quantitative comparisons of map-based and grid-based NRV and OOIP estimates are difficult to achieve due to problems in evaluating data presented in different dimensional formats. Map-based and grid-based NRV and OOIP estimation results have been evaluated for turbiditic environment reservoirs in Block 14, offshore Angola. Comparison of results supports utilizing grid-based objects as soon as possible in development mapping efforts.

Compositional Grading: Its Causes and Use in Subsurface Characterization

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Compositional grading in reservoirs is a common phenomenon. Grading refers to changes in hydrocarbon properties, such as bulk properties or chemical components, within a reservoir with distance or elevation.
The magnitude in grading of a parameter can vary greatly, depending on the geological/geochemical environment or history. Where grading is significant, it is a powerful tool for subsurface characterization, particularly in deepwater oil and gas development where uncertainty is large and appraisal costs are high.
However, grading is often a misunderstood phenomenon and is under utilized as a tool. For example, in the past significant grading was often not recognized or not enough samples were taken to be able to understand it or utilize it as a tool for subsurface characterization. This misunderstanding is partly due to a communication gap between the geochemical and reservoir engineering communities.
The purpose of this paper is to use field examples to demonstrate a) some of the geological/geochemical aspects controlling grading to give greater understanding of where and where not grading is significant and b) how grading can be used to improve subsurface characterization, such as predicting fluid properties away from well bores and compartmentalization.

Application of Time-Lapse Geochemistry (TLG) for Reservoir Surveillance at the Horn Mountain Field in the Deep-water Gulf of Mexico

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Oil is produced at the Horn Mountain field (Mississippi Canyon 126/127) from M and J middle Miocene reservoirs deposited in sand-filled channels and associated levees environments. Several barriers and baffles were identified in both reservoirs prior to production through the integration of seismic, pressure, PVT, and geochemical data. During production, reservoir surveillance is a vital task aimed to understand how petroleum is swept in a reservoir. In addition to traditional surveillance technologies, we applied Time-Lapse Geochemistry (TLG) to visualize petroleum sweep by monitoring changes in fluid compositions across reservoirs. In this technology, pre-production fluid samples are first analyzed to map fluid types across a static reservoir. Then, a surveillance program in which fluids are taken from producing wells at regular time intervals is designed and executed. The obtained production samples are geochemically “fingerprinted” and compared with the pre-production fluids from the same well and surrounding wells. Interpretation of geochemical data allowed us to “see” how oil moves across the M reservoir and prompted the team to re-evaluate reservoir models and reduce risks in managing reservoir performance. In the J reservoir, an untapped compartment was identified, and an additional producer was justified. TLG results were consistent with and complimentary to other surveillance data available to date. Our study demonstrates that TLG is safe and cost-effective technology, which reduces uncertainties associated with other reservoir surveillance methods and appears to be valuable for reservoir management.

Using the Fused Fault Block Technique to Model Low Angle and Thrust Faults

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Reservoir grids often have problems in correctly modeling low angle and thrust faults. Pillar gridding methods of fault modeling have limitations when fault dips are less than 45 degrees; it is usually difficult if not impossible to stair-step, or regularize, the cell edges in Z along these faults. Fault/fault intersections of low angle faults also present their own sets of difficulties; modeling systems often do not allow staircasing of two intersecting low angle faults. As vertical cell edges are frequently desired for a simulation grid, faults are shifted or modified to meet the requirements of the modeling system. The limitations thus prevent the reservoir engineer from using a correct geologic model, and different parts of the asset team no longer use a truly shared earth model. The fused fault block approach to fault modeling eliminates these restrictions. This technique does not use pillars or nodes to define a fault network, but rather uses a modified binary tree where implicit fault relationships do not require an explicit definition in the tree. Using this technique, not only can a correct geologic model be built, but the reservoir grid calculated from this model can be generated with aligned or staircased cells as the engineer desires. With thrust faults, the staircased grid maintains the layer connections across the faults, allowing this grid to be used for facies modeling, attribute modeling, or reservoir simulation. All parts of the asset team can now use the same model, even in areas with extremely complex fault patterns.