POSTERS CONTENTS

Abstracts only

Downhole separation technology —past, present and future

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Presenter: Charlie Gao

In the 1990s, a new water management tool, downhole separation technology, was developed. It separates oil and gas from produced water inside the wellbore and injects the produced water into the disposal zone. Based on the different fluid the separators handle, they are categorised as downhole oil-water separators (DOWS) and downhole gas-water separators (DGWS). Two types of separators have been used: hydrocyclone and gravity separators. The authors reviewed the previous 59 DOWS installations and 62 DGWS installations worldwide, and discovered that only about 60% achieved success. Some major issues—including high costs, low reliability and low longevity—have slowed down its industrial adoption. Based on the field experiences, a good candidate well must have a high-quality disposal zone with sustainable permeability. To improve the performance of downhole separation tools, it is crucial to better understand the behaviour of the separator under downhole conditions and the behaviour of the injection zone under the invasion of various impurities in the produced water.

Australian deep water—the Holy Grail or an expensive myth?

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Deep water, which for the purposes of this poster is considered to be water depths in excess of 200 m, has long been considered the future of global oil and gas exploration. This is partly as a result of both the growing energy demand and the diminishing number of shallow-water opportunities of economically significant magnitude.

The petroleum systems in Australia's deep waters can be differentiated from many others of the world, as sediments are mostly Jurassic and Cretaceous in age, while those from other parts of the deepwater world tend to be of Tertiary age. As technology has advanced, so has the feasibility of exploration and development in more extreme environments. Deep water has been a key source of production growth in recent years—a trend likely to continue into the future.

This poster will investigate the theory that in Australia, since the 1970s, companies have progressively spent a smaller proportion of their exploration budgets on onshore and shallow-water targets, where discoveries have been regular yet unspectacular, in favour of the deeper waters where higher risks are involved but the potential exists for significantly higher returns. The deepwater, shelf and onshore environments will be compared and contrasted. Principle topics will include reserve additions by year, acreage release and licensing opportunities, discovery locations and future forecasts. The poster will use the IHS database, containing historical and current data, to illustrate and examine the increasing interest in the Australian deepwater environment.

Risk management strategies during early field development

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Oil and gas companies are continually striving to increase the net value of their hydrocarbon deposits. By taking a holistic view of risk management early enough in the field development life cycle, oil and gas companies have the opportunity to achieve an optimum solution to minimise risk and maximise value.

This poster describes how companies can minimise risk and maximise value by presenting strategies for managing asset risks and safety and environmental risks. To achieve the optimum solution companies must be able to:

- eliminate and minimise inherent risks; and,
- reduce and control operational risks.

The earlier the risk management process begins, the greater the opportunity for success. Typical strategies that can be employed early on are:

- developing asset management, safety and environmental goals;
- taking account of life-cycle risk; and,
- applying effective decision support tools.

Effective decision support tools provide an invaluable contribution to achieving the optimum solution and also in demonstrating that risks are as low as reasonably practicable. Typical decision support tools used during the early field development phases are:

- RAM modelling;
- formal safety assessment; and,
- environmental impact assessment.

Taking a unified perspective of risk provides the key to achieving the optimum solution…how do you presently strive for the optimum solution?

The petroleum exploration potential of the Australian Infracambrian (Ediacaran) of the Amadeus and Officer basins

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Late Neoproterozoic (Ediacaran) source rocks (Dey Dey Mudstone) have been identified in the Officer Basin of South Australia, where they are associated with minor hydrocarbon shows in scattered exploration wells. In the Amadeus Basin, the Dingo and Orange gas fields contain dry gas reservoired in the basal arkoses of the latest Neoproterozoic-earliest Cambrian synorogenic Arumbera Sandstone and the older Julie Formation. They are hosted in simple, relatively unfaulted, anticlinal closures and are generally thought to be sourced from the underlying Pertatataka Formation shales.

While it is tempting to correlate the Dey Dey and Pertatataka formations—as both are fine-grained siliciclastic units of the original Centralian Superbasin—and to assume the Pertatataka Formation is also a source rock, actual correlation of discrete lithostratigraphic units (defined formations) is sometimes difficult. Correlations using wireline logs from exploration and stratigraphic drill holes have potential for correlation when the boreholes are relatively close, especially if formation horizons can be tied between wells by seismic profiles. However where well spacing is large and there are no seismic data, or seismic profiles of sufficient quality, correlations rapidly fail. This technique is even more tenuous when attempting inter-basinal correlations. Carbon isotope trends can be employed to assign equivalences, and this works reasonably well in most instances, but again, if palynological information becomes available for correlation purposes, the isotopic equivalencies may no longer be robust. This study has used all these correlative tools to determine inter-basinal correlations, which are presented as lithostratigraphic and chronostratigraphy well-log correlation panels.

The Dingo Field gas is dry, with 10 mol% nitrogen, 86.4 mol% methane, and 3.1 mol % ethane, whereas the Orange–2 gas is 55 mol% nitrogen, 42.9 mol% methane and <0.01 mol% helium. These analyses suggest an over-mature source rock for the Orange accumulation. The source rock had previously been assumed to be the underlying Pertatataka Formation, however, the limited geochemical analyses of the putative source beds show that the formation is extremely lean. A source in the underlying evaporitic Bitter Springs Formation (Cryogenian) is considered more likely.

Queensland's coal seam gas, energy of the future

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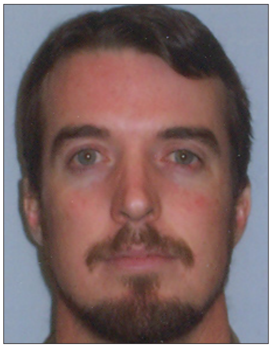
Presenter: Ross Randall

Surging exploration and development activity has made coal seam gas a stand-out sector of the Queensland petroleum industry in the past five years. From a relatively low base of just two petajoules (PJ) in 1998, total production has risen to be in excess of 60 PJ produced in 2006. Coal seam gas has proven itself to be a reliable, long-term energy resource. High levels of drilling activity have been maintained with explorers and producers concentrating on appraisal and development drilling to further expand reserves. To date more than 4,000 PJ of 2P reserves have been certified and this figure is set to increase.

During the 1980s and 1990s, coal seam gas exploration largely centred on the Permian coal measures of the Bowen Basin in central Queensland. Discoveries at Fairview–Spring Gully near Injune, Peat-Scotia near Wandoan and at Moranbah southwest of Mackay, demonstrated that large volumes of coal seam gas could be produced from the Permian coal measures in the Bowen Basin. In early 2006, production commenced from the Jurassic Walloon Coal Measures of the Surat Basin in southern Queensland. Exploration has also been carried out in the Permian coal measures of the Galilee Basin, the Triassic units of the Ipswich Basin and the Tertiary-aged coal units within the Nagoorin Graben south of Gladstone.

The poster will highlight trends in the drilling activity, identification of reserves and the development of production in the different coal seam gas areas in the Bowen and Surat basins plus other basins in Queensland.

Identifying false positives in Synthetic Aperture Radar (SAR) data over the southern Timor Sea, northwest Australia—implications for remote sensing and acoustic seepage studies



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A cost-effective method of screening offshore environments, particularly frontier regions, for potential indicators of hydrocarbon seepage is through remote sensing and acoustic technologies. However, none of these tools in isolation are diagnostic of seepage, and as such, accurate identification of false positives within individual datasets is critical. The Timor Sea region of the North West Shelf is one of natural hydrocarbon accumulation and seepage, and the present model for the spatial distribution of that seepage is partly based on Synthetic Aperture Radar (SAR). SAR identifies areas in which the capillary waves on the ocean surface have been damped and therefore it is a highly successful tool in delineating natural hydrocabon seepage that forms oil slicks. Damping of capillary waves may occur, however, through a variety of alternative processes. Multibeam swath bathymetry and acoustic doppler current profile data indicate that tidal current flows may have contributed to the formation of slicks previously documented in the Timor Sea. Additionally, annular to crescent-shaped SAR slicks over carbonate reefs and shoals in the region that exhibit wind- or wave-driven feathering are interpreted to be caused by a regional coral spawning event. Reinterpretation of these false positives may assist in accurately constraining the extent and frequency of active hydrocarbon (particularly oil) seepage in the region. A similar process of judicious false positive screening is being applied to SAR over frontier exploration areas such as the central North West Shelf and with application of archived echosounder data to differentiate between seepage and biological phenomena.

Active seepage detection, identification and correlation using geophysical and geochemical methods, Yampi Shelf, Australia

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Two recent offshore surveys (GA S276 and AIMS SS06/2005) have been carried out over the Cornea oil and gas discovery. Plumes of gas were observed using side-scan sonar (100 and 500 kHz) rising up from reflective blocky features a few metres across and/or pockmarks up to 10 m across and ~1 m deep. Active seepage was found around areas of attenuated seismic signal or high velocity pull-up on 3D and 2D data, related, presumably, to secondary carbonate cementation. The plumes were also observed using hull-mounted echo sounders (12, 120, 200 kHz) and were most intense during low spring tides. A range of cemented tubes were sampled using dredges during both surveys. These ranged from clearly identifiable Sabelariid worm tubes to highly encrusted carbonate tubes that may be abiogenic. Analysis of highly encrusted tubes revealed a range of n-alkanes from C13 to C32, maximising around C16 with no odd over even preference.

In one area gas was seen at the surface, and bubbles broke with thin oily films. Moreover, oily globules were observed in the water column during sampling (SS06/2005). Gas bubbles were collected and analysed for molecular and isotopic composition, revealing a very dry gas (99% methane, d13C = -41‰). This composition is very similar to the gas analysed from the Cornea reservoir and indicates that seeping hydrocarbons are either derived from the reservoir or a similar hydrocarbon source. The location of this active seep area (0.5 x 1.4 km) has also shifted more than 1 km between the two surveys.

The Mentelle Basin—a deepwater, frontier Gondwanan basin

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The Mentelle Basin is a large (36,000 km^2) unexplored basin in close proximity to the producing Perth Basin and Western Australian infrastructure. In 2004–06 Geoscience Australia acquired 1,650 km of modern long-cable 2D reflection seismic data, reprocessed 2,000 km of seismic data in the southern Perth Basin as well as collected and interpreted SAR data across the region. Several wells in the Vlaming Sub-basin were resampled and their biostratigraphy recalibrated. Regional-scale basin analysis and petroleum systems study is now in progress. The first key results of this study are:

- a large depocentre with at least 6 km of inferred Middle–Late Jurassic to Early Cretaceous stratigraphy underpins the western deepwater part of the Mentelle Basin;
- a series of extensional depocentres with at least 4 km of sedimentary section occur in the shallower water eastern Mentelle Basin;
- potential source kitchens in the Mentelle favour long-range up-dip migration and trapping in the shallower water eastern parts of the basin;
- the thick Mentelle basin-fill is likely to have similar source rock intervals and geochemical characteristics to those documented in the Vlaming Sub-basin; and,
- the late synrift and early postrift section of the Mentelle Basin (inferred Jurassic–E. Cretaceous age) is likely to be the most prospective for hydrocarbons

Geoscience Australia is now undertaking further project work to assess the petroleum potential of the Mentelle Basin.

3D geological model building using remotely sensed satellite data

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Recent availability of high-resolution digital elevation models (DEMs) from the SRTM mission and from SPOT Image have provided geologists with regional (90 m resolution) and licence-specific (20 m resolution) datasets that allow construction of 3D models to aid hydrocarbon exploration.

At a basic level, the DEMs are used to provide good regional and detailed perspective views of structurally complex localities using imagery or geological data draped over wire-frame models derived from DEMs. The visualisations can then be flown through, allowing virtual field trips to demonstrate particular structural style.

The next phase allows for extraction of dip values by relating dipping flat irons to slope values. Isolating true dipping surfaces and calculating dips by displaying the DEM as a slope and slope azimuth map provides structural control over large areas for a fraction of the cost of mobilising field teams in often inaccessible or hostile terrain. Using this dip data, topographic profiles are extracted from the DEM and are used with geology derived from satellite-based mapping as the basis of 2D cross-section generation, as in examples from the Lengguru Foldbelt shown here.

In the 3D domain, it is possible to define stratigraphic boundaries from multispectral satellite imagery and then tie the contacts to the DEM and produce a grid of elevations for a particular stratigraphic surface. These are then input into a gridding program to produce structural contour maps of important intervals near the surface, or, by means of extrapolation, deeper levels. This technique is illustrated by examples from Yemen.

Relative significance of various basement and crustal controls on hydrocarbons maturation: towards quantitative assessment

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We have identified five major basement and crustal controlling factors that determine depth to hydrocarbon maturation windows: depth of subsidence; thickness of the crust; thickness of the lithosphere; heat production in the crust; and, heat production in sediments.

We have carried out first-pass estimates of relative significance of depth of subsidence, heat production in the crust, and thickness of the crust for positioning of hydrocarbon maturation windows. Assessment of relative significance of thickness of the lithosphere (including dynamic topography) and heat production in sediments requires further research. The Jupiter–1 well on the Australian northwest margin was selected to run the tests due to the availability of VIRF data and a well-established palaeo water depth model.

We estimated shifts of maturation windows in response to equal percentage variation (+30%) of each of the parameters tested relative to the preferred model. The results clearly show that variation in subsidence (due to variation in interpreted Triassic thickness) has a relatively minor effect on the position of maturation windows, because sediment radioactivity effectively replaces basement radioactivity if the crustal heat production is low. The effects of basement heat production and crustal thickness are between 1.4–3.4 times greater from the top of the oil maturity window to the base of the dry gas maturity window.

These estimates allow the requirements for accuracy of the underlying measurements to be determined. Accuracies of +1.08 km for Triassic thickness, +0.06 µWm-3 for basement heat production and +0.54 km for crustal thickness are required to position base of dry gas maturity window within +50 m accuracy.

Review of geological storage opportunities for carbon capture and storage (CCS) in Victoria

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The Victorian State Government is committed to developing the Latrobe Valley brown coal resources in an environmentally responsible manner. One possible technology for low emission industries is carbon capture and storage (CCS) and, in particular, geological storage of CO_2. This study has reviewed the Late Palaeozoic to Cenozoic sedimentary basins of Victoria as to their overall suitability for CO_2 geological storage, based on geological, geographical and industrial characteristics. These include factors such as tectonic stability, basin size and depth, reservoir or coal quality, intensity of faulting, existing resources and industry maturity.

A qualitative comparison between the various basins indicates that the offshore Gippsland Basin has the best overall potential for CO_2 geological storage. This basin has an extensive sedimentary fill with numerous reservoir and seal horizons, with mature hydrocarbon fields and an established infrastructure framework. The offshore Gippsland Basin was followed in the rankings by the onshore Otway Basin, the offshore Otway Basin and the onshore Gippsland Basin. The Cenozoic and Late Palaeozoic basins show little potential for CO_2 storage opportunities because they are either too small, too shallow or without suitable geological horizons. If an onshore site is required then the onshore Otway Basin provides the best potential for CO_2 storage, whilst if storage in coal is required (in association with enhanced coal bed methane) then the onshore Gippsland Basin has the most favourable characteristics.

Overall, the geological settings of the State of Victoria and its adjacent waters show considerable potential for CCS opportunities. The adoption of CCS technologies can be an important part of the solution to the problem of reducing large volumes of greenhouse gas emissions to the atmosphere.

The influence of basement structure on Late Cretaceous basin fill in the Otway Basin

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Presenter: Sandy Menpes

Two major offsets in Late Cretaceous extension influence basin fill in the Otway Basin. The first offset in Late Cretaceous extension occurs between the Tartwaup Fault and the Mussel Fault in the central Otway Basin. The offset is coincident with, and is attributed to, the Miakite Creek basement fault. The offset separates the Late Cretaceous section of the Otway Basin into the Morum Sub-basin west of the Miakite Creek Fault and the Nelson Sub-basin to the east.

The Late Cretaceous structural and depositional histories of the Morum and Nelson sub-basins are significantly different. The Late Cretaceous section in the Morum Sub-basin is generally sandier than that in the Nelson Sub-basin. The sandier section is thought to be related to a decline in extension rates that occurs earlier in the Morum Sub-basin than in the Nelson Sub-basin. Onshore the Morum Sub-basin section is sandy from the Coniacian onwards, whilst offshore the section is sandy from the younger Santonian onwards.

The offset in Late Cretaceous extension caused by the Miakite Creek Fault has influenced sand distribution in the eastern part of the Morum Sub-basin. The Discovery Bay High is a zone of thinned Sherbrook Group between the Morum and Nelson sub-basins, coincident with the Late Cretaceous offset. Waarre C and Flaxman C sands were confined to the Morum Sub-basin and the western side of the Discovery Bay High during the Turonian. During the Campanian, Paaratte Formation river systems were focussed west of the offset.

The second major offset in Late Cretaceous extension occurs between the Mussel Fault and the Sorell Fault. This offset is coincident with, and is attributed to, the Moyston basement fault. All of the presently known Late Cretaceous gas fields of the Otway Basin occur in this area known as the Shipwreck Trough and the Port Campbell Embayment. In contrast the analogous area associated with the Miakite Creek basement fault, referred to as the Discovery Bay High, is as yet only very lightly explored.

Monitoring environmental compliance using airborne video

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The Petroleum & Geothermal Group in Primary Industries and Resources of South Australia has a regulatory responsibility to ensure seismic operations are carried out with minimal impact to the environment. As part of this role, continual improvements are made to techniques that are employed in monitoring compliance of seismic field operations with environmental requirements.

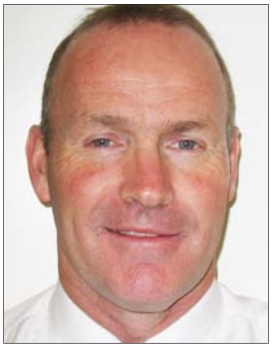
An innovative airborne video monitoring system has been developed to improve the effectiveness of assessing seismic field outcomes on the environment. This system increases the efficiency and effectiveness of monitoring extensive seismic lines in often environmentally sensitive or logistically challenging areas.

This system complements traditional ground-based methods of inspecting seismic operations. The aim of these inspections is to ensure that correct procedures are employed during seismic line preparation and that appropriate restorative work is carried out, to facilitate natural recovery of seismic lines.

The primary characteristics of the surveillance system are that it enables a stable and continuous video recording of many transects along seismic lines in a short time, observations are environmentally non-invasive and observations can be made over terrain that may otherwise be difficult to access by ground-based systems.

The airborne system has been developed using low-cost, compact, readily available and proven technologies and equipment. It has proven to be economic and versatile for a variety of airborne monitoring operations.

Hot rocks in Australia—national outlook



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Evidence of climate change and knowledge of enormous hot rock resources are factors stimulating growth in geothermal energy research in Australia, including exploration, proof-of-concept appraisals, and development of demonstration pilot plant projects.

In the six years since the grant of the first geothermal exploration licence (GEL) in Australia, 16 companies have joined the hunt for renewable and emissions-free geothermal energy resources in 120 licence application areas covering ~ 67,000 km^2. The associated work programs correspond to an investment of A$570 million, a tally that excludes deployment projects assumed in the Energy Supply Association of Australia's scenario for 6.8% (~ 5.5 GWe) of Australia's base-load power coming from geothermal resources by 2030.

Australia's geothermal resources fall into two categories: hydrothermal (from relatively hot ground water) and the hot fractured rock Enhanced Geothermal Systems (EGS). Large-scale base-load geothermal electricity generation in Australia is expected to be derived predominantly from Enhanced Geothermal Systems. Geologic factors that determine the extent of EGS plays can be generalised as:

- source rock availability in the form of radiogenic, high heat-flow basement rocks (mostly granites);
- low thermal-conductivity insulating rocks overlying the source rocks to provide thermal traps;
- the presence of permeable fabrics within insulating and basement rocks that can be enhanced to create heat-exchange reservoirs; and
- a practical depth-range, limited by drilling and completion technologies (defining a base) and necessary heat exchange efficiency (defining a top).

A national EGS resource assessment and a roadmap for the commercialisation of Australian EGS are expected to be published in 2008. The poster will provide a synopsis of investment frameworks and geothermal energy projects underway and planned in Australia.

Best practice regulatory framework for upstream petroleum and geothermal industries

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Michael Malavazos (pictured) and Belinda Close

An effective and efficient regulatory framework is critical to establishing a commercially and environmentally sustainable industry that achieves standards of environmental, safety and social performance acceptable to the community. Such a framework must elicit community confidence in the performance of both the industry and the government agency regulating the industry.

It is widely recognised that one such framework is delivered by the Petroleum Act 2000 (the Act) and associated Petroleum Regulations 2000. The Act was established on the basis of five key principles: certainty; openness; transparency; flexibility; and, efficiency. The philosophy of the Act is to focus regulation on the practical achievement of outcomes that meet both investor and community expectations.

Compliance and enforcement is administered under the Act through the adoption of a four-step enforcement-pyramid model. The model aims to focus regulatory and industry attention at step one, constituting preventative measures elicited by compliance with the Act's requirements. As a result, only in rare cases are any of the persuasive, compulsive and punitive regulatory measures in steps two, three and four respectively required.

Since the promulgation of the Act in September 2000, the Petroleum & Geothermal Group continues to review the effectiveness of the Act to ensure that it continues to facilitate acceptable industry behaviour and performance in relation to environmental protection, public health and safety, security of gas supply and protection of other land user rights. As a result of this review process, amendments to the Act have been proposed. These amendments aim to improve the clarity, efficiency and effectiveness of licensing and activity approval processes, while sustaining the prevailing regulatory philosophy and principles of the existing Act. A Green Paper detailing proposed amendments to the Act was released for public consultation in December 2006, with comments invited until 29 June 2007.

Fault plane attribute mapping reduces fault seal risk in the Gambier Embayment of the onshore Otway Basin, South Australia

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Presenter: Peter Boult

Juxtaposition of Late Cretaceous marine shales against fluvial/marginal marine reservoir sands in fault-bounded, three-way dip closures and horsts are the main trapping mechanism close to the coast of South Australia in the Gambier Embayment of the onshore Otway Basin. Considerable risk, however, is associated with correlation of faults across 2D datasets because Karst topography significantly degrades the seismic signal in many places, thus obscuring reflectors at the main reservoir level. To reduce risk of fault correlation, fault plane modelling and displacement mapping in 3D space has been used in our interpretation and a robust understanding of cross-fault geometries and displacements at depth has ensued.

Three sets of faults are distinguishable, being early northwest–southeast basement-related faults, later north-northwest–south-southeast cover faults that show displacement highs at the K/T boundary, and neotectonic east-northeast–west-southwest thrust faults. Interpretation demonstrates that shale beds of at least 220 m and 240 m thick are needed to provide robust juxtaposition seals for leads at the top Flaxman and Waarre formations respectively. Nearby well intersections indicate that shale beds will have sufficient thickness. Non-commercial oil, along with commercial CO_2 is produced from the base of the Late Cretaceous in Caroline–1 and oil sands were described at the base of the Tertiary in SAOW-2 in 1926.