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MONDAY

SESSION 1B—INNOVATIVE APPROACHES TO ENGINEERING AND PETROLEUM PRODUCTION

Towards development of Australia's large deepwater gas fields

B. Ronalds

Presenter: Beverley Ronalds
CSIRO Australia

Session 1B: 2:00 pm, Meeting rooms 1 and 2

Australia can anticipate a more extensive gas production future than any other OECD country. At the same time, much of our gas resource is located in large, remote, deepwater reservoirs. There is very little experience in bringing such fields to market, although several current developments internationally indicate that a new era of deepwater gas production is beginning. The limited knowledge base suggests that Australia could, and indeed should, take a lead in developing strategies and technologies necessary to produce major deepwater gas and gas-condensate fields in an economically, environmentally and socially sustainable manner in the long-term.

This paper draws on a comprehensive database of deepwater field developments around the world to identify specific capability gaps, and the technology breakthroughs that may enable them to be overcome. Emphasis is placed on both floating facilities and all-subsea production solutions, with ultra-long tiebacks and floating LNG bringing particular benefits in the Australian context. Compact GTL is a key enabling technology for remote deepwater fields with associated gas.

John Brookes gas field development

A.J. McDiarmid, P.T. Bingaman, S.T. Bingham, B. Kirk-Burnnand, D.P. Gilbert, L.E. Kurylowicz and I. Sigsworth

Presenter: Simon Bingham
Apache Energy Limited

Session 1B: 2:25 pm, Meeting rooms 1 and 2

The John Brookes gas field was discovered by the drilling of John Brookes–1 in October 1998 and appraisal drilling was completed in 2003. The field is located about 40 km northwest of Barrow Island on the North West Shelf, offshore West Australia. The John Brookes structure is a large (>90 km^2) anticline with >100 m closure mapped at the base of the regional seal. Recoverable sales gas in the John Brookes reservoir is about 1 Tcf.

Joint venture approval to fast track the development was gained in January 2004 with a target of first gas production in June 2005. The short development time frame required parallel workflows and use of a flexible/low cost development approach proven by Apache in the area.

The John Brookes development is sized for off-take rates up to 240 TJ/d of sales gas with the development costing A$229 million. The initial development will consist of three production wells tied into an unmanned, minimal facility wellhead platform. The platform will be connected to the existing East Spar gas processing facilities on Varanus Island by an 18-inch multi-phase trunkline. Increasing the output of the existing East Spar facility and installation of a new gas sweetening facility are required. From Varanus Island, the gas will be exported to the mainland by existing sales gas pipelines. Condensate will be exported from Varanus Island by tanker.

Deepwater gas field production from subsea wells into compressed natural gas carriers through a Hybrid Riser Tower

J-F. Saint-Marcoux, C. White and G.O. Hovde

Presenter*: *Jean-Francois Saint-Marcoux
Stolt Offshore Inc.

Session 1B: 2:50 pm, Meeting rooms 1 and 2

This paper addresses the feasibility of developing an ultra-deepwater gas field by producing directly from subsea wells into Compressed Natural Gas (CNG) Carrier ships. Production interruptions will be avoided as two Gas Production Storage Shuttle (GPSS) vessels storing CNG switch out roles between producing/storing via one of two Submerged Turret Production (STP) buoys and transport CNG to a remote offloading buoy. This paper considers the challenges associated with a CNG solution for an ultra-deepwater field development and the specific issues related to the risers. A Hybrid Riser Tower (HRT) concept design incorporating the lessons learned from the Girassol experience allows minimisation of the vertical load on the STP buoys. The production switchover system from one GPSS to the other is located at the top of the HRT. High-pressure flexible flowlines with buoyancy connect the flow path at the top of HRT to both STP buoys. System fabrication and installation issues, as well as specific met ocean conditions of the GOM, such as eddy currents, have been addressed. The HRT concept can be also used for tiebacks to floating LNG plants.

MONDAY

SESSION 1C —NEW TECHNICAL AND COMMERCIAL APPROACHES

Progress in geothermal energy development, Cooper Basin, South Australia

D. Wyborn,
L. de Graaf[1], S. Hann[1] and
B. Nicholson[2]

Presenter: Doone Wyborn
Geodynamics Limited

Session 1C: 2:00 pm, Meeting room 3

Geodynamics Limited is nearing the completion of its 'proof of concept' hot fractured rock (HFR) program to extract superheated hot water for electricity generation from granite buried beneath the Cooper Basin. Difficult drilling conditions were discovered in the target granite when the Habanero–1 well penetrated permeable sub-horizontal fractures at more than 4,000 m depth. The well was completed at 4,421 m with overpressures in the fractures around this depth exceeding pressures projected from a hydrostatic gradient by more than 5,000 psi. The static rock temperature at the bottom of the well is about 250°C.

The overpressures assisted in the development of the world's largest underground heat exchanger, a volume of rock more than 0.7 km^3 defined by more than 11,700 micro-seismic events located on-site during the injection of 23 ML of fresh water into the granite fracture network. The horizontal heat exchanger is more than 2 km north–south, more than 1 km east–west and more than 300 m thick. During its development there was no evidence of direct upwards growth towards the sedimentary cover, which is at about 3,700 m, though a small number of events were observed above the main cloud of events. From production logging surveys, a major fracture at a depth of 4,254 m is interpreted to have taken most of the flow during the injection.

The second well (Habanero–2) was located 500 m south-west of the first. Before intersecting a major fracture, interpreted to be an extension of the dominant fracture in Habanero–1, it was drilled to a depth of 4,325 m. At this depth, total drilling circulation losses were encountered which were only partially overcome with the pumping of calcium carbonate lost circulation material. During the operation the lower 245 m of the drill stem was irretrievably lost, and the well was subsequently sidetracked to a total depth of 4,358 m, just below the main fracture.

Flow and circulation testing between the two wells in early 2005 is designed to demonstrate the economic potential of the far-field geothermal system and the heat exchange volume between the two wells.

Pre-drilling prediction of petroleum composition

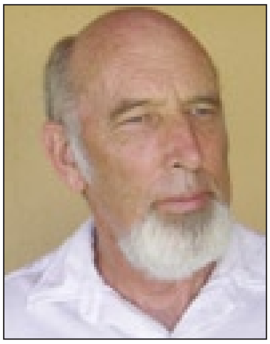
B. Horsfield and
R. di Primio

Presenter: Brian Horsfield
GFZ-Potsdam

Session 1C: 2:25 pm, Meeting room 3

The composition of reservoired petroleum is controlled by the physical, chemical and biological processes that have acted on the source-carrier-reservoir system over geological time. Because phase behaviour in carrier systems has been identified as being the major control of gas-oil ratio in many of the world's petroleum provinces, we have established a modelling protocol that can be applied in advance of drilling as part of a risk reduction strategy. We begin with the organofacies concept, which states that kerogen abundance and composition are relatable to depositional settings. Our facies, five in all, are based on potential petroleum type and are determined by open system pyrolysis of kerogens or asphaltenes. Having used this as a secondary screening tool, coming after the usual Rock-Eval primary screening procedure, bulk kinetic parameters are then determined for generation characteristics. Petroleum compositions are then assigned to the activation energy distributions using MSSV Pyrolysis, a method whose utility has been proven by regional calibrations, including mass balance modelling studies in Canada and Mexico. The pyrolysis data is essentially ready as it is for direct import into PVT models, except for gas composition which has to be tuned to take account of the different radical reactions occurring within gas-forming intermediates in nature versus in the laboratory. Selected studies in the Norwegian North Sea and West Africa demonstrate the quality of the tuned compositional predictions for different organic facies types, with error in black oil property predictions being close to 10% (e.g. GOR or saturation pressure).

Advances in risking exploration prospects



D.C. Lowry, R.J. Suttill and R.J. Taylor

Presenter*: *David Lowry
Origin Energy Resources Limited

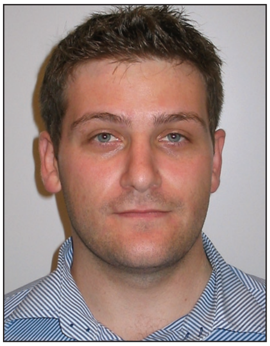
Session 1C: 2.50 pm, Meeting room 3

Assessment of prospect risk is a vital exploration activity, but technical literature on the subject shows few advances in methodologies in the last 20 years. Origin Energy has found that published procedures are not always adequate. Three perceived shortcomings are examined and techniques are proposed to overcome them.

- **Cases where prospect risk is dependent on reserve size. Traditional methodologies assume the two are independent. This assumption is clearly inappropriate for, say, a prospect for which the success case value is based on the mapped closure, but which has suspect seal capacity that may limit the column height to something less than full-to-spill. A way forward is to build a variable risk array for a range of column heights and calculate the incremental risked NPV for each layer. The expected monetary value (EMV) is computed for a range of column heights based on the NPV of cumulative risked reserves;**
- **Cases where the estimation of chance of success (COS) based on traditional geological information needs to be combined with direct hydrocarbon indicators (DHIs) from seismic data. DHIs are not infallible indicators, however, and cannot be used to set the COS for elements such as charge to say 100%. Bayes' Theorem can be used to combine the two sets of uncertain information.**
- **Cases where prospects are risked on very limited data. Traditional risking does not adequately incorporate the level of knowledge on which risk assessments are made. Inadequacies are identified in existing methodologies, but no simple and satisfactory solutions can be identified. We do suggest a way forward, however, for a related problem—testing the sensitivity of the EMV calculation for an exploration prospect for uncertainties in COS.**

SESSION 2B —INNOVATIVE APPROACHES TO ENGINEERING AND PETROLEUM PRODUCTION

Production optimisation via multi-phase flow metering



A.J. McArdle, A.J. McDiarmid and T.E. Asbey

Presenter: Andrew McArdle
Apache Energy Limited

Session 2B: 3:45 pm, Meeting room 3

Apache has developed a number of small oil fields using unmanned minimum facilities platforms close to Varanus Island, on the North West Shelf of Western Australia. Production from each platform is commingled into a single production trunkline. Wells producing at high watercut are artificially lifted using gaslift. Production monitoring and well allocation uses multi-phase flow meters situated on each platform. The use of these meters minimises total infrastructure cost, while still allowing the direct testing of each well. Test results are used for production optimisation of the individual wells, optimisation of the integrated production network, well and field production allocation and troubleshooting. Meter performance has been satisfactory, resulting in an additional unit being deployed on the Stag field where production is affected by high gas rates, slugging and sand production.

Implementation of the BP choke model on the Woodside operated Cossack Pioneer FPSO

M. Buchanan, P. Robinson and C. McCaffery

Presenters: Mike Buchanan
Woodside Energy Limited;
Colin McCaffery
BP Exploration Operating Company Limited

Session 2B: 4:10 pm, Meeting room 3

The choke model evolved from a BP campaign started in the early 1990s to improve production operating efficiency. The choke model is a software tool (Access 2000) designed to enable this process to be consistently applied across all BP's producing assets. It enables losses to be identified and categorised relative to the system capacity or installed production capacity across four primary production chokes—the reservoir, wells, plant and the export system. The volume of losses (measured relative to the installed production capacity) is recorded and the source and cause of the loss are identified and categorised. The latter are then analysed for trends and opportunities are identified and prioritised for improvement. This paper describes the choke model and the collaboration between Woodside as Operator of the Cossack Pioneer, and BP, to implement the choke model and to improve production operating efficiency across the Joint Venture's oil assets.

The operating efficiency benefits and typical losses are analysed and discussed, learnings through the implementation process are described and improvements for the future are identified. Key conclusions and learnings from the implementation process include:

- the choke model is an operations improvement tool that helps support a production improvement process;
- definitions of Installed Production Capacity;
- need for standardisation of the sources and causes of losses (people interpret these differently); and
- the need for consolidation of pre-existing reporting systems into one common database.

4D reservoir geochemistry as an aid to interpreting production dynamics, Legendre Field, Eastern Dampier Sub-basin

R.C. Davis, K.R. Leischner, A.P. Murray and P.G. Ryles

Presenter*: *Bob Davis
Woodside Energy Limited

Session 2B: 4:35 pm, Meeting room 3

Reservoir geochemistry is a low cost, field development/appraisal tool resting on the principle that fluids isolated by flow barriers show slight compositional and/or isotopic differences. Such differences reflect subtle variations in charge history related to the location of the source kitchen and the source rock maturity at the time of expulsion, as well as post fill processes such as water washing and leakage. High resolution gas chromatography (HRGC), multi-dimensional gas chromatography (MDGC) and compound specific liquid and gas isotope analysis (CSIA) were performed on a time series of fluids, comprising stored oil from two drill stem tests, and produced fluids from six points in the Legendre field, Dampier Sub-basin, to investigate changes in fluid composition as production proceeded. The Legendre field contains high gravity (46° API), low viscosity oil, hosted in two culminations (North and South) in a thin, high quality clastic reservoir of Berriasian age. Fluids from different wells within the Northern accumulation are indistinguishable, indicating the oil is in communication and no compositional gradient exists. By contrast, compositional and isotopic differences between fluids from the Northern and Southern accumulations demonstrate that these pools are not in communication, and should therefore be treated separately from a development planning perspective.

The differences in initial fluid compositions have been successfully used in conjunction with operational parameters to explain the increase in gas/oil ratio (GOR) of oil from Legendre South–2H that occurred after only 13 months of production. Comparison of pristine, pre-production separator samples with fluids collected after the observed increase in GOR, revealed that solution gas injected at Legendre West–1 has migrated rapidly into the southern part of the field. Integration of geochemical data with regional petroleum system concepts and a full 3D charge model has greatly assisted our understanding of these observations.

SESSION 2C—COMMERCIAL AND CORPORATE

Australia—Sovereign risk and the petroleum industry

D. Young, R. Brockett and J. Smart

***Presenter**: Doug Young*
Blake Dawson Waldron

Session 2C: 3:45 pm, Meeting rooms 1 and 2

Australia has rejoiced in its reputation for having low sovereign risk and corresponding rating, for decades. This reputation was bruised in the first decade after the High Court introduced Native Title into Australian law by the legislative response of the then Government, but has since recovered, and enjoys the world's lowest country risk rating, and shares the worlds best sovereign risk rating with the USA. A number of government precipitated occurrences in recent times, however, raise the question: for how long can this continue?

This paper tracks the long history of occasional broken resource commitments—for both petroleum and mining interests—by governments at both State and Federal level, and the policies which have driven these breaches. It also discusses the notorious recent cancellation of a resource lease by the Queensland Government, first by purporting to cancel the bauxite lease and, after legal action had commenced, by a special Act of Parliament to repeal a State Agreement Act. This has raised concerns in boardrooms around the world of the security of assets held in Australia on a retention, or care and maintenance basis.

The paper also looks at the cancellation of the offshore prospecting rights held by WMC, with no compensation. This was a result of the concept that rights extinguished by the Commonwealth, with no gain to the Commonwealth or any other party do not constitute an acquisition of property, thereby denying access to the constitutional guarantee of 'just terms' supposedly enshrined in the Australian Constitution where an acquisition has occurred.

Some other examples are the prohibition on exploration in Queensland national parks last November. This cost some companies with existing tenures a lot of money as exploration permits were granted, but then permission to do seismic exploration refused (Victoria). Several losses of rights occurred as a result of the new Queensland Petroleum and Other Acts Amendment Act after investments have been made.

Changes in fiscal policy can also impact on project viability, and some instances of this are considered.

This paper also explores ways these risks can be minimised, and how and when compensation might be recovered.

Risk appetite: A hunger for the unknown or stranglehold on growth?

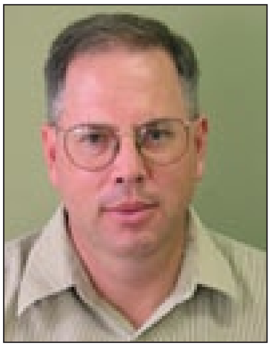
B.K. Johnson

***Presenter**: Brian Johnson*
PricewaterhouseCoopers

Session 2C: 4:10 pm, Meeting rooms 1 and 2

The recent extreme volatility in the petroleum markets has introduced a level of volatile earnings for exploration and production companies (E&P) that has not been seen since the Gulf war in 1990–91. Many companies have reduced their hedging activity to increase exposure to rising oil prices and have consequently benefitted considerably. Rapid increases in oil prices historically have been followed by just as rapid decreases. Although oil prices are a key value driver for E&P companies so is exploration and development success, production variability, operational management, and, for companies who do not report in $US, foreign exchange rates. All these value drivers contribute to top line revenues and earnings so hedging oil price in isolation from other value drivers can have adverse financial consequences. The quarterly focus by investors of listed companies on meeting earnings targets/guidance creates the pressure for the board of directors of E&P companies to focus on the degree of earnings stability that is acceptable to the market. This is reflected by a company's aversion to risk, or risk appetite. The collective management of the value drivers as a portfolio of risks allows companies to understand the potential for earnings variance, or earnings at risk during reporting periods. This, in turn, can provide companies with a degree of confidence in meeting earnings targets and the opportunity for companies to increase their transparency in terms of disclosure/communication of how effectively it is managing core value drivers of the business.

Why are the insurance underwriters reviewing our exploration well risks?



J. Embury

Presenter*: *Jim Embury
Safety and Risk Practice Pty Ltd

Session 2C: 4.35 pm, Meeting rooms 1 and 2

The increased level of exploration in Australia and New Zealand has resulted in insurance underwriters taking a closer look at the region. A number of unfortunate onshore blowouts during 2003 and 2004 have focussed their examinations to determine whether these were symptomatic, regional problems or just one-off events.

One of the tools being used to determine the level of exposure when insuring a well in Australia or New Zealand is the well risk review. The reviews typically involve an examination of a number of the drilling contractor's key documents. This allows the reviewer to gain an understanding of the technical difficulty of the well, any environmental impact should an incident occur and the capabilities of all supervisor personnel and the match between the need to drill the well and the capability of the rig and the planning completed. It is the operator's responsibility to comply with any recommendations that eventuate from the review and failure to do so may void the control of well insurance.

Typically, the underwriters carry the cost of these reviews which have highlighted a possible issue with the competency of rig personnel as the industry grapples with the shortage of experienced people in an expanding market. To complicate the issue for the industry, many of the more experienced personnel are nearing retirement age and suitably experienced replacements are few and far between.

The well risk review process should be seen as complementary to the State regulatory reviews and will, along with initiatives being undertaken by some participants in the industry, contribute to a safer industry with fewer incidents.

SESSION 3A—FRONTIER EXPLORATION: WEST AND NORTH

Petroleum potential of the Ceduna Sub-basin: Impact of Gnarlyknots–1A

D. Tapley, B.C. Mee, S.J. King, R.C. Davis and K.R. Leischner

***Presenter*: Ben Mee**
Woodside Energy Limited

Session 3A: 11:00 am,
Main Auditorium

The Ceduna Sub-basin, located in the eastern Bight Basin, is one of the few frontier deepwater provinces in Australia whose hydrocarbon potential remains largely untested. The sediments of the sub-basin span an area of over 95,000 km^2—comparable to the combined area of the Exmouth, Barrow and Dampier sub-basins on Australia's North West Shelf. Prior to 2003, exploration wells had been drilled only on the present day shelf area of the sub-basin. The recent Gnarlyknots–1A well, drilled in May 2003 by the Woodside operated joint venture in EPP29, has provided the first calibration point in the under-explored deepwater area of the sub-basin.

The well was the culmination of a basin analysis project that integrated results from prior drilling in adjacent areas, existing seismic surveys, regional gravity and magnetics interpretations, and a newly acquired 16,000 line km 2D seismic survey. Individual play elements of reservoir, seal, and hydrocarbon charge were analysed and combined to form play maps for key stratigraphic intervals. The Gnarlyknots prospect was chosen from more than 40 leads as the best location to test multiple play levels in an area interpreted pre-drill to be favourable for reservoir, seal, and charge.

Gnarlyknots–1A confirmed the presence of several favourable play elements but failed to encounter commercial hydrocarbons. Excellent quality sandstone reservoirs, marine shale top seals and thermogenic hydrocarbon shows—indicating the presence of a hydrocarbon source rock in a mature kitchen area downdip—were all encountered in the well. The failure of the well is attributed to the absence of fault seal on the updip bounding fault of the drilled hanging wall structure. The implications of this well result for the prospectivity of the Ceduna Sub-basin have been analysed, and provide encouragement for Woodside to pursue future exploration programs in the region.

Canning Basin and global Palaeozoic petroleum systems—A review

G.M. Carlsen and K. Ameed R. Ghori

***Presenter*: Greg Carlsen**
Department of Industry and Resources

Session 3A: 11:25 am,
Main Auditorium

There are more than 131 giant and super-giant oil and gas fields with Palaeozoic source and reservoir that are similar to the Canning Basin. These include Palaeozoic basins of North America, North Africa, and the North Caspian Basin of Kazakhstan and Russia.

The productivity of these Palaeozoic petroleum systems depends on timing of generation and preservation of charge. Thick Ordovician, Permian, and Triassic evaporite deposits played a very important role in creating and preserving the North American, north Caspian, and north African giant oil and gas fields, respectively.

The Mesozoic–Tertiary charged Palaeozoic systems are typically more productive than the Palaeozoic charged systems as exemplified by the north African basins.

The Ordovician sourced and reservoired giant oil fields of the North American Mid-Continent are also highly productive. Within the Canning Basin, Ordovician sourced oil has been recovered on the Barbwire Terrace (in Dodonea–1, Percival–1 and Solanum–1) on the Dampier Terrace (in Edgar Range–1 and Pictor–1) and along the Admiral Bay Fault Zone (in Cudalgarra–1, Great Sandy–1, and Leo–1).

The Canning Basin may be the least explored of the known Palaeozoic basins with proven petroleum systems. The Palaeozoic basins of North America are the most explored with 500-wells/10,000 km^2 compared to the Canning Basin with only 4-wells/10,000 km^2.

The presence of five oil fields, numerous oil and gas shows and the well density in the Canning Basin (200 wells in 530,000 km^2) suggests that further exploration is warranted. Critical analysis of the distribution of source rock, reservoir, seal, timing of generation versus trap formation and post accumulation modification for each tectonic unit of the Canning Basin is required.

An overview of the hydrocarbon potential of the Northern Territory's onshore sedimentary basins

G. Ambrose

Presenter*: *Greg Ambrose
Northern Geological Survey

Session 3A: 11:50 am,
Main Auditorium

The prospectivity of the Northern Territory's sedimentary basins remains largely untested as initial exploration programs undertaken in the 1960s to early 1990s were far too sparse to adequately gauge the region's potential. In addition, difficulties in negotiating access to prospective land has in the last decade impeded exploration, but recently several new title grants portend a continued increase in exploration activity.

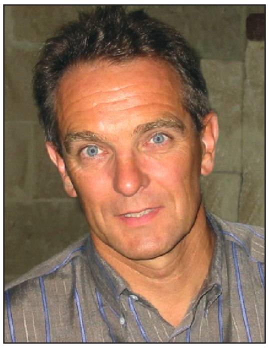
Several basins contain important oil-prone Palaeozoic petroleum systems including the Pedirka Basin (Permian Purni Formation), Amadeus Basin (Ordovician Horn Valley Shale), Georgina Basin (Middle Cambrian Arthur Creek Formation) and possibly also the southeast Bonaparte Basin (Carboniferous). The Beetaloo Sub-basin has a well documented Mesoproterozoic petroleum system. Over the last 5–10 years, studies of these basins and their associated petroleum systems have led to an enhanced understanding of their potential leading to increased exploration activity targetting mainly Palaeozoic oil systems. It is pertinent that in the Northern Territory in the last four years 22 new petroleum exploration licence applications have been made by nine new operators and three new permits have been granted in the last year.

There is also an impetus for gas exploration given the current gas supply contracts for Darwin expire in early 2009 and additional supply for other resource/industrial projects should arise in the next 5–10 years. The Neoproterozoic in the Amadeus Basin is an attractive gas target, particularly in the southern portion of the basin where large structural and combination plays could provide a major gas resource through fractured reservoirs (Heavitree Quartzite). This play and many other Palaeozoic oil plays will be described in more than 50 papers to be presented at the Central Australian Basins Symposium (CABS) to be held in Alice Springs this August.

Presentation only.

SESSION 3B—INNOVATIVE APPROACHES TO ENGINEERING AND PETROLEUM

A multi-disciplinary approach delivers quality results to a complex formation evaluation problem



T.J. Magee, T.A. Gray, J.C. Kelly and L.B. White

Presenter: Trevor Magee
ChevronTexaco Australia Pty Ltd

Session 3B: 11:00 am, Meeting room 3

This paper illustrates the benefits of a multi-disciplinary approach to formation evaluation in an interbedded sand/shale reservoir sequence. The Egret–3 appraisal well was drilled to obtain information to evaluate the commercial viability of the Egret oil field. A key objective of the well was to test for the presence of a gas cap and, if present, to confirm the gas-oil contact (GOC).

A number of analytical techniques were employed to distinguish between oil and gas in the reservoir; these included analysis of mudlog gas ratios, evaluation of separation between the density and neutron logs, pressure gradient analysis, formation fluid sampling and PVT and geochemical analyses. Each method confirmed the presence of a gas cap, but indicated a different GOC. It was only by combining the full suite of tools that the uncertainty associated with the GOC could be accurately defined.

Key elements contributing to the success of the program included: clear recognition of the significance of gas cap to commercial viability of the Egret oil development; design and planning of an appropriate formation evaluation program; flexibility in implementation of the program and determination and alignment amongst all disciplines to overcome operational difficulties.

A quick-look evaluation of the sanding potential of production wells in the Yolla Field

Z.J. Pallikathekathil, J.R. Marsden, R.J. Suttill, M. Mussared and L. Qiuguo

Presenter: Zach Pallikathekathil
Schlumberger Oilfield Australia Pty Ltd

Session 3B: 11:25 am, Meeting room 3

The preliminary downhole completions and surface facilities for the Yolla field had been designed based on the well test results from the Yolla–1 well. This well had produced insignificant sand during production testing, but during the field development planning, there was a concern raised regarding the propensity of some zones to sand. If the zones were prone to sanding, then the design of completions and surface facilities would have to be re-worked on with steps taken to mitigate any sanding. Mitigation steps would include perforation strategy (selective zone perforation, oriented perforation), sand screen or gravel pack.

Therefore, a quick-look evaluation of the sanding potential of the particular zones of interest was undertaken to be completed within the project time frame. The sand zones analysed were Sand–2718, –2755, –2809, and –2973 from the Eastern View Coal Measures(EVCM).

Yolla–2 well had the most complete data set available. A mechanical earth model (MEM) containing information on rock properties, pressures and in-situ stresses was constructed based on open-hole log data from the Yolla–2 appraisal well. Laboratory tests provided some uni-axial compressive strength (UCS) data for calibration of the model. The MEM data were input into sanding analyses, for various reservoir depths and for selected completion and perforation options. Since some MEM parameters were poorly constrained, best- and worst-case scenarios and sensitivities were evaluated to assess the influence of geomechanical parameters on sanding propensity.

When Yolla–3 and –4 were drilled, more complete sets of logs were acquired and used to improve confidence in the earlier evaluations, and to check the validity of certain assumptions that had been made. With revised evaluation for Yolla–3 and –4, decisions on the completion strategy and perforation intervals were taken and implemented in the field development plan

After completion, both Yolla–3 and Yolla–4 were tested and sanding rates were monitored. After initial transient production of sand during clean-up, sand rates produced were insignificant. This confirmed the results of the quick-look geomechanical analyses that had been conducted.

TUESDAY

Protecting the crown jewels—Well management and integrity

D. Rubalcava, J. Davies and P. Marszal

Presenter*: *Daniel Rubalcava
Woodside Energy Limited

Session 3B: 11:50 am, Meeting room 3

Increasingly, hydrocarbons are being produced at the edge of current technical boundaries (deep water, subsea, HP/HT and big bore wells). Wells in particular must be able to support long-term deliverability within design criteria, construction defects and changing operating conditions. Failure to do so can lead to catastrophic consequences. The management of well integrity during the operating phase is the topic of this presentation.

Woodside Energy Ltd has recently revamped its well technical integrity process. This paper explains the management system that has been implemented, and outlines the processes by which well integrity is managed and implemented across the operating assets.

Woodside has created the roles of Technical Integrity Authority and that of Technical Integrity Custodian. This presentation will show how TIC acts as the driver between departments to ensure that all parties maintain well integrity as the highest priority. Meanwhile, the TIA acts as the owner of the whole system and provides independent and unbiased support to all parties.

Finally, of particular interest is the development of big bore wells in the North West Shelf of Australia. The drive for bigger and better wells depicts how all the elements interact to maintain a safe and reliable conduit from the reservoir to the surface. Furthermore, it outlines the difficulties and 'grey areas' associated with these types of wells (i.e. barrier philosophy—these wells have no 'B' Annulus which is a secondary barrier). The reader will be able to answer why well integrity is crucial to Woodside and other operators but more importantly how well integrity is addressed as part of facility, system and business management.

Presentation only.

TUESDAY

SESSION 3C —NEW TECHNICAL AND COMMERCIAL APPROACHES

Coal seam gas exploration, development and resources in Australia: A national perspective

S. Miyazaki

Presenter*: *Shige Miyazaki
Geoscience Australia

Session 3C: 11:00 am, Meeting rooms 1 and 2

A total of 2,223 PJ of proved plus probable gas reserves has been identified in coal seam gas fields and pilot production areas in Australia. The production of coal seam gas is rapidly growing, reaching about 40 PJ per year in 2003. A total of more than 108 PJ will be supplied annually by the end of 2007 under existing contracts, representing about 9% of Australia's projected total primary consumption of natural gas. About two thirds of Queensland's natural gas consumption will be met by coal seam gas by the end of 2007. Further expansion of the coal seam gas industry depends largely on the medium-term production performance of the pioneering production projects now in operation.

The long-term production performance of a coal seam gas well is not well understood. Analogues of conventional natural gas have often been applied to the estimation process of coal seam gas reserves without proper consideration of the fundamental differences in trapping mechanisms and production techniques. Definitions of petroleum reserves recommended by various organisations are not always applicable to coal seam gas, and the inconsistent application of reserves definitions may have resulted in inconsistencies in reserves reporting in Australia.

The Asia Pacific LNG market: Issues and outlook

A.L. Ball and K.M. Schneider

Presenter*: *Allison Ball
ABARE

Session 3C: 11:25 am, Meeting rooms 1 and 2

With rising natural gas demand and limited reserves in many Asia Pacific countries, LNG imports have emerged as an important gas supply source in the region. Rapid uptake of LNG has occurred in Japan, Korea and Chinese Taipei, and new and potential LNG markets are emerging in India, China, the Philippines, New Zealand and the north American west coast, among others. Growth in Asia Pacific LNG demand has encouraged the development of LNG export projects in the region, which has become the world's largest LNG supplier, and the Middle East.

Asia Pacific LNG imports are projected to nearly double by 2015. This will provide opportunities and challenges for LNG suppliers to the Asia Pacific market, including Australia. Competition to retain markets among existing LNG suppliers will be strong, although there will be a key role for new projects. Potential regional LNG supply capacity in the next 10 years is significant: Australia's LNG export capacity has the potential to more than quadruple with a number of new projects scheduled to become operational.

This paper reviews existing LNG demand and supply in the Asia Pacific region and provides an assessment of likely future developments in the market over the period to 2015, including the opportunities for the Australian LNG industry. The analysis in the paper is based on ABARE's Asia Pacific LNG market: issues and outlook, released in November 2004, and excludes later developments.

TUESDAY

Emerging challenges in Australia's domestic gas market

J.P. Feenan

***Presenter*: John Feenan**
Wood Mackenzie Limited

Session 3C: 11:50 am, Meeting rooms 1 and 2

This paper considers emerging challenges to balancing gas supply and demand in Australia's domestic market in the context of the global demand for Australian gas exports. Based on a major 2004 study by Wood Mackenzie, a series of scenario forecasts assessed the balance of gas allocation to domestic and export gas demand to 2020.

Australia is destined to become an increasingly significant global supplier and exporter of gas, primarily as LNG. The recent emergence of major new LNG customers in China and (west coast) north America seeking to secure supplies has ignited a global gas demand-pull on Australia's gas reserves that is competing with domestic demand.

The States of Western Australia (WA) and the Northern Territory (NT) hold more than 130 Tcf or 90% of Australia's total remaining gas reserves. For many years industry and politicians have proposed major transnational pipelines to transport gas out of the remote northwest or from Papua New Guinea to feed the energy-hungry southeast, and supplement existing gas production from the Cooper Basin and Bass Strait.

Striking the right balance between export and domestic gas resource allocation and meeting the needs of producers, customers and policy-makers is emerging as a major challenge within Australia's domestic gas market.

TUESDAY

SESSION 4A—FRONTIER EXPLORATION: WEST AND NORTH

The Wheatstone gas discovery: A case study of Tithonian and Late Triassic fluvial reservoirs

N. Palmer, P. Theologou, B.E. Korn and T. Munckton

Presenter: Nathan Palmer
ChevronTexaco Australia Pty Ltd

Session 4A: 2:00 pm,
Main Auditorium

The Wheatstone gas discovery is located 110 km north-northwest of Barrow Island in the Dampier sub-basin, northwest Australia. The field comprises two non-conformable and interconnected reservoir units consisting of shallow dipping, Triassic fluvial sandstones, and an overlying Tithonian transgressive sand. These units are partially separated by Late Triassic to Early Jurassic sediments.

The Tithonian sand reservoir is instrumental in hydrocarbon accumulation in the Greater Gorgon Area due to its unconformable connectivity to underlying Triassic reservoirs, and its ability to act as a thief zone. It is therefore a significant component in hydrocarbon entrapment. This paper discusses the transgressive Tithonian sand palaeogeography, and environment of deposition as a predictive tool of reservoir risk assessment and play fairway geography.

This study compares and contrasts the rock properties of the latest Triassic sequences and proposes the palaeogeographic make up within the basin. A review of the reservoir properties has identified differences between units which may impact the formation evaluation approach used. The thinly bedded character of the latest Triassic sequences necessitated the use of a non-traditional formation evaluation model that has improved the accuracy of the wireline predicted reservoir properties. Acquisition of probe permeability data through conventionally cored intervals identified the limitations associated with standard core plug sampling procedures, and ensured better net reservoir definition through the sequence.

Recent discoveries in the Pyrenees Member, Exmouth Sub-basin: A new oil play fairway

J.P. Scibiorski, M. Micenko and D. Lockhart

Presenter: Joe Scibiorski
Independent consultant,
c/o BHP Billiton Petroleum

Session 4A: 2:25 pm,
Main Auditorium

Recent drilling by BHP Billiton Pty Ltd in WA-155-P(1) and WA-12-R, on behalf of its partners Apache Energy Ltd and INPEX ALPHA LTD, has resulted in the discovery of four oil fields in the southern Exmouth Sub-basin, namely Ravensworth, Crosby, Stickle and Harrison. These discoveries, together with the earlier discoveries made by West Muiron–5 and Pyrenees–2, define the Early Cretaceous Pyrenees Member play fairway.

The Pyrenees Trend play was first conceived in 1999 following appraisal of the Macedon gas field (Keall, 1999), but the concept remained dormant until the integration of geological information with high quality 3D seismic data led to the recognition of hydrocarbon related seismic attributes in the postulated play fairway.

Ravensworth–1 intersected a 37 m gross oil column below a 7 m gas cap in high quality Pyrenees Member sandstones beneath the regionally significant Intra-Hauterivian Unconformity. Ravensworth, located on a northeast–southwest trending fault terrace, is a complex structural-stratigraphic trap that relies on separate top, base and cross-fault seals. High quality 3D seismic data coupled with recent interpretation techniques were integral to its discovery. In particular, the quantitative interpretation of seismic amplitude populations was a key factor in decreasing exploration risk.

The Ravensworth discovery was followed by successful exploration wells on the adjacent Crosby, Stickle and Harrison fault terraces. Four appraisal wells have since been drilled at the northern ends of the main discoveries.

The oil in the Pyrenees Member discoveries is biodegraded, moderately viscous (8–11 cp) and heavy (18–19° API gravity). Methane-dominated gas caps were intersected in Ravensworth–1, West Muiron–5 and Pyrenees–2.

The recent drilling and coring campaigns by BHP Billiton and others in the Exmouth Sub-basin have significantly advanced knowledge of the stratigraphy and

TUESDAY

depositional environments of the late Tithonian to early Berriasian Macedon, Muiron and Pyrenees Members of the lower Barrow Group. The lower Barrow Group is a third order sequence deposited rapidly in marine to fluvio-deltaic environments in response to the breakup of Gondwana and the onset of active rifting along the West Australian margin.

BHP Billiton and its joint venture partners are assessing the commercial viability of the Pyrenees Trend discoveries.

A reappraisal of the Carboniferous stratigraphy and the petroleum potential of the southeastern Bonaparte Basin (Petrel Sub-basin), northwestern Australia

J.D. Gorter, P.J. Jones, R.S. Nicoll and C.J. Golding

Presenter*: *John Gorter
Eni Australia Limited

Session 4A: 2:50 pm,
Main Auditorium

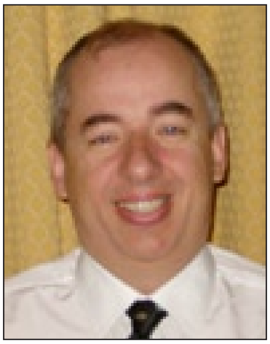
A revision of the latest Tournaisian to Namurian stratigraphy of the Petrel Sub-basin is proposed following the recognition of a series of mega-sequences based on seismic profiles, well logs and new palaeontological information. In late Tn3c, turbidites of the Waggon Creek facies were overlain by a seal, the Milligans Formation (redefined) during the Chadian (V1a, V1b). A basal Arundian (V2a) regression, possibly driven by tectonics, deposited the Yow Creek Formation (new name) with incised valley fills. A basal Asbian (V3a) regression, deposited coarser grained clastics and limestones, the Utting Calcarenite (V3a), forming a possible local reservoir facies overlain by a regional seal, Kingfisher Shale (new name). An intra-Asbian (V3b) regression followed, possibly glaciogenic and/or tectonically driven, with the deposition of the Tanmurra Formation, dominantly coarse clastics, during the Asbian, forming reservoir facies with some source potential. Following a basal Brigantian unconformity, the Sandbar Sandstone (new name) formed a restricted ?aeolian facies, a potential local reservoir. An intra-Brigantian unconformity was followed by deposition of the carbonate Sunbird Formation (new name), generally a tight shelf edge carbonate (V3c), near Lacrosse–1 and Sunbird–1. A major basal Pendleian sea-level fall, probably glaciogenic, with major channel incision and erosion, was followed by Arnsbergian clastics with *G. maculosa*, the Arco Formation (new name) with basinal shales in clinoforms. The latest Arco Formation (earliest Pennsylvanian) was followed by a Late Namurian regression, and deposition of the Aquitaine Formation (new name), consisting of fluvio-deltaic siliciclastics, with minor marine influence, large scale channelling, potentially good reservoirs, and a regional upper shaly seal. This sequence is unconformably overlain by the basal Kulshill Group, which marked the onset of major Gondwanan glaciation.

TUESDAY

TUESDAY

SESSION 4B—IMPROVED SEISMIC IMAGING AND FINDING MORE OIL

Multiple removal success in the Carnarvon Basin with SRME



A. Long, P. Zhao, P. Gatley, D. Cooke, R. van Borselen, M. Schonewille and R. Hegge

***Presenter:* Andrew Long**
PGS Marine Geophysical

Session 4B: 2:00 pm, Meeting room 3

In 2003, Santos Ltd revisited a poor data quality area in the northern Carnarvon Basin, offshore Western Australia, where both short and long period multiple energy prohibits imaging of the underlying geology. Previous reprocessing efforts had failed to satisfactorily improve data quality, or reduce the level of multiple contamination. A two-dimensional (2D) reprocessing project was initiated to establish whether any modern variant of Surface-Related Multiple Elimination (SRME) could have success. Consequently, several versions of SRME were tested, with all output diagnostics being imaged with anisotropic Kirchhoff pre-stack time migration (PSTM). The new SRME results are a significant improvement over previous reprocessing efforts, and provide a much better platform for the picking of anisotropic velocity functions, and the application of PSTM imaging. Most of the multiple energy in this location is actually surface-related, with only a small component of internal multiple reverberations. Both long and short period multiple energy was successfully removed, and interpretation can now be pursued with more confidence in a difficult data location. Many out-of-the-plane events still appear to contaminate the final 2D result, so a full three-dimensional (3D) production project was then pursued using standard (2D) SRME processing applied to 3D data gathers.

Despite many noise challenges existing within the 3D field data, the final data images shed new light on a challenging geological environment, and prove the merits of SRME processing. A new generation of 3D acquisition and processing technology is now required to improve upon existing results, so a brief consideration is also given to the potential applications of 3D SRME processing to 3D seismic data from the North West Shelf. A brief example from offshore Brazil is used to illustrate the potential benefits of 3D SRME.

3D pre-stack depth migration: A tool for reducing exploration risk in the Swan Graben, Timor Sea

P. Bocca, L. Fava and E. Stolf

***Presenter:* Paola Bocca**
Eni E&P Division

Session 4B: 2:25 pm, Meeting room 3

3D pre-stack depth migration (PSDM) reprocessing was conducted in 2003 on a portion of the Onnia 3D seismic cube, located in exploration permit AC/P-21, Timor Sea.

The main objective of the reprocessing was to obtain the best seismic depth image and the most realistic structural reconstruction of the sub-surface to mitigate the risk factors associated with trap definition (trap retention and trap efficiency). This represents one of the main challenges for oil exploration in the area.

The 3D PSDM methodology was chosen as the most appropriate imaging tool to define the correct sub-surface geometry and fault imaging through the use of an appropriate velocity field. An integrated approach to building the final velocity model was adopted, with a substantial contribution from the regional geological model.

Several examples are given to demonstrate that the 3D PSDM reprocessing significantly improved the seismic image and thus the confidence in the interpretation, contributing strongly to the definition of the exploration targets.

The interpretation of the new seismic data has resulted in a new structural picture in which higher confidence in seismic imaging has improved fault correlation. This has enabled better structural definition at the Middle Jurassic Plover Formation level that has reduced the complexity of the large Vesta Prospect, in the centre of the Swan Graben to the northwest of East Swan–1. Improved understanding of the fault reactivation mechanism and the structural elements of the trap (trap integrity) were eventually incorporated in the prospect risking.

In the Swan Graben 3D PSDM has proved to be a very powerful instrument capable of producing significant impact on the exploration even in an area with a complex geological setting and a fairly poor seismic data quality.

Pore pressure prediction based on seismic attributes response to overpressure

R. Ciz, M. Urosevic and K. Dodds

Presenter*: *Kevin Dodds
Australian Petroleum CRC

Session 4B: 2:50 pm, Meeting room 3

A seismic attribute-based quantitative methodology for remote prediction of effective stresses is proposed in this study. The algorithm uses neural networks as a non-linear interpolator between a set of seismic attributes to predict changes in differential pressure. This method is based on the relationships between specific seismic attributes and differential pressures, which were established through a series of laboratory tests. A number of ultrasonic elastic measurements simulating normal compaction, fluid expansion and tectonic mechanisms of overpressure were performed on reservoir sandstone and shale core samples. The effects of different stress paths on seismic attributes derived from experimentally recorded wavelets were investigated. Positive relationships were established between differential pressure and several seismic attributes for the first time in these tests. It has been found that instantaneous frequency, weighted mean frequency, instantaneous phase, instantaneous pseudo-Q factor, instantaneous bandwidth, instantaneous dominant frequency and autocorrelation function are sensitive to differential pressure changes. The relationships between those attributes and differential pressure follow Eberhart-Phillips' stress-velocity empirical relationship. This implies that seismic attributes could be used for a quantitative prediction of overpressure. Moreover, our experimental results show that frequency-based seismic attributes exhibit a greater sensitivity to changes in differential pressure than does seismic velocity. The proposed methodology has been tested on a 3D seismic dataset from the North West Shelf of Australia. Predicted pore pressure values are in good agreement with available borehole data.

TUESDAY

SESSION 4C—COMMERCIAL AND CORPORATE

Corporate social responsibility—A new era or a false dawn?

D. Byers

***Presenter**: David Byers*
ExxonMobil

Session 4C: 2:00 pm, Meeting room 6

The oil and gas industry has become a focal point for a number of debates in modern society. Issues such as response to climate change risk, the debate about future energy sources and the complexities of resource development in developing countries are intersecting with broader debate on corporate governance and the power and place of corporations in modern economies.

In response to these issues, it is widely believed that corporations need to broaden their scope and purpose-adopting corporate social responsibility, sustainability and attending to the triple bottom line.

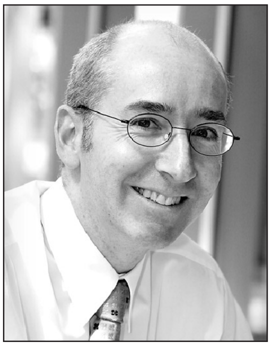
Are these concepts genuine attempts to address concerns held by the wider community, or are they an effort to gain approval from sectional interests who claim to represent the wider community?

Is there a danger that the fundamental role of corporations in a free market economy—the creation of shareholder value—is being undermined by attempts to place other, often arbitrary, social performance benchmarks on the same footing? Do they detract a corporation's attention from the achievement of its central goals? Are businesses assuming responsibility for social policy agendas that are properly within the province of others to pursue?

In this paper, ExxonMobil will outline its approach to the pursuit of profitable business opportunities in an economically, environmentally and social responsible manner. ExxonMobil's approach to corporate citizenship brings together all of the activities and commitments that underpin its commercial success—paying attention to the larger society but not assuming responsibility for matters it is not equipped nor intended to deliver.

Presentation only.

Is there a future for State Agreements?



A.G. Castledine and M. Lamattina

***Presenters**: Graham Castledine and Maria Lamattina*
Minter Ellison

Session 4C: 2:25 pm, Meeting room 6

State Agreements are agreements between private proponents and a State government which aim to facilitate the development of resources and processing projects and associated public infrastructure. State Agreements have been used extensively throughout Australia and each has been given varying levels of legislative recognition and effect, which in turn affects whether the rights and obligations arising under them have statutory or merely contractual effect. This ambiguity highlights the need to balance within State Agreements the private rights of the proponents with the public interest. The public interest critically involves third party rights to access infrastructure or services developed by proponents under the State Agreement. The introduction of National Competition Principles and regulatory regimes has affected the balance of these interests in favour of the public interest which has, in turn, led to a more stringent approach to State regulation under State Agreements. In particular, States are compelled through inter-governmental, federal and international competition and trade agreements to limit the extent to which it can negotiate its terms in a purely commercial way, embodying concessions in favour of proponents or preferences in favour of the State over other states or countries. Where a State Agreement expressly confers a benefit on third parties associated with access, third parties have successfully sought to enforce those benefits through the Courts, resulting in increased risks and costs for proponents that may not have been originally anticipated. Coupled with the political risks associated with changing governments and government policies, State Agreements, which have historically played a significant role in State development, are increasingly losing their ability to meet the commercial objectives of proponents.

TUESDAY

Can governance initiatives deliver value to the oil and gas industry?

M.R. Puzey and S.Q. Benson

Presenters: Mark Puzey and Simon Benson
KPMG

Session 4C: 2:50 pm, Meeting room 6

The objective of this paper is to provide food for thought to executives on how governance initiatives can deliver value—and not just be a compliance cost—with the focus on oil and gas organisations in Australia.

We have seen increased governance legislation around the world following the collapse of companies such as Enron. In Australia we have the ASX governance principles.

We will explore the lessons learnt from the implementation of compliance by US-listed companies with their Sarbanes-Oxley legislation and what it means to us in Australia.

Governance initiatives can be costly—there is, therefore, a need for us to leverage off these initiatives, driving business value where we can, by proactively focussing in the right areas.

This paper focusses on practical suggestions for obtaining value from governance initiatives, and is accessible to readers without a strong financial background.

TUESDAY

SESSION 5A—TRAP INTEGRITY

Strain localisation and trap geometry as key controls on hydrocarbon preservation in the Laminaria High area

A. Gartrell, W. Bailey and M. Brincat

Presenter*: *Anthony Gartrell
CSIRO Petroleum ARRC

Session 5A: 3:45 pm,
Main Auditorium

A strong relationship between the distribution of Late Miocene to recent (post-rift) strain, trap geometry and remaining oil columns is recognised in the heavily re-activated Laminaria High area. Preferential localisation of post-rift strain onto larger faults in the population resulted in the smaller faults accommodating progressively less strain with time. The strain localisation process appears to have protected some fault-bound traps with favourable geometries from breaching during fault re-activation, but promoted breaching of others. Where faults with high post-rift strain are located at the crest of a trap, oil columns are not preserved. In contrast, where high strain post-rift faults are located down-dip of the trap crest, oil columns are preserved down to the depth of the critical high strain fault-top reservoir intersection. These observations suggest that a relatively simple assessment of the basic structural geometry of a trap may provide a first order approximation of trap integrity risks and could also be predictive of preserved hydrocarbon column heights.

A systematic fault seal evaluation of the Ladbroke Grove and Pyrus traps of the Penola Trough, Otway Basin

P.J. Lyon, P.J. Boult, M. Watson and R.R. Hillis

Presenter*: *Richard Hillis
Australian School of Petroleum

Session 5A: 4:10 pm,
Main Auditorium

Juxtaposition mapping of lithology onto the Ladbroke Grove Fault plane shows that the Pretty Hill Sandstone reservoir, which hosts a 90 m gas column, juxtaposes massive shale units in the hangingwall. Retention of the column at Ladbroke Grove can thus be attributed to favourable across-fault, reservoir-seal juxtaposition. The free water level (FWL) of the Ladbroke Grove column coincides with an abrupt change in strike of the fault from east–west to northwest–southeast. Fault re-activation risking using the FAST (Fault Analysis Seals Technology) technique indicates that the northwest–southeast striking segment of the fault is critically oriented within the in-situ stress field for re-activation, whereas the more east–west trending segment is associated with a relatively lower risk of fault re-activation. Hence recent slip along the northwest–southeast segment may have created permeable fracture networks along this part of the fault plane and thus limited the extent of the column to that bounded by the east–west trending fault segment. This hypothesis is supported by data on soil gases acquired across the fault which suggest that the fault is leaking CO_2 across its northwest–southeast striking segment, but not across its east–west striking segment.

The Pyrus Fault is not presently sealing by across-fault, reservoir-seal juxtaposition. The throw on the fault plane is sufficient to juxtapose the Katnook Sandstone in the hangingwall against the Pretty Hill Sandstone reservoir in the footwall, providing a sand-on-sand juxtaposition leak point at the structural apex of the trap. Fault re-activation along this fault is likely to have caused fracturing of any shale gouge veneer that may have been present along this sand-on-sand contact resulting in across-fault leakage of hydrocarbons into the Katnook Sandstone and leakage up the fault along permeable fracture networks. FAST predictions of fault re-activation show that the fault is critically oriented within the in-situ stress field for re-activation and soil gas measurements at the surface suggest the fault is leaking CO_2.

Geochemical evidence of multiple hydrocarbon charges and long distance oil migration in the Vulcan Sub-basin, Timor Sea

K. Liu, S. Fenton, T. Bastow, B. van Aarssen and P. Eadington

Presenter*: *Keyu Liu
CSIRO Petroleum

Session 5A: 4:35 pm,
Main Auditorium

Hydrocarbon accumulation and migration processes in the Vulcan Sub-basin, Timor Sea, were investigated using the Total Scanning Fluorescence (TSF) technique and phenol and carbazole abundances in both reservoired and inclusion oils. The TSF spectral signatures have delineated multiple groups of oils within the Vulcan Sub-basin, largely identifying with the different oil families previously identified by biomarkers and isotope data. An apparent correlation between diminishing carbazole concentration and increasing distance from the source kitchen was found in reservoired oils within the Vulcan Sub-basin, providing evidence for long distance oil migration of up to 80 km. In the southernmost part of the Vulcan Sub-basin a possible light hydrocarbon charge rich in benzene and other low-molecular-weight aromatic hydrocarbons is believed to be responsible for the observed anomalously high phenol concentrations in oils from the surrounding wells. A previously unknown, possibly a Cretaceous-or-younger, source kitchen may be present along the eastern margin of the Vulcan Sub-basin and was probably responsible for the palaeo oil accumulations in the Tancred and Osprey structures as revealed by the TSF spectral signatures and biomarkers from the fluid inclusion oils.

TUESDAY

SESSION 5B—IMPROVED SEISMIC IMAGING AND FINDING MORE OIL

Australian MegaSurveys—The key to new discoveries in maturing areas?

H. Edwards, J. Crosby, N. David, C. Loader and S. Westlake

Presenter: Huw Edwards
PGS Reservoir

Session 5B: 3:45 pm, Meeting room 3

In a maturing province such as the North West Shelf, it is time-critical to find remaining hydrocarbon resources as well as to develop small finds before existing big field installations and their associated infrastructure are decommissioned. Finding the remaining smaller fields with subtle geophysical expression is a challenge, and a thorough understanding of the petroleum geology is essential. To achieve this, the subsurface structure and depositional systems must be understood in a regional as well as a local context.

To date, exploration companies' regional models have been based on a mixture of 2D and 3D seismic of varying vintages, orientations, and quality. Consequently they have been incomplete and lacking detail. To address this problem, PGS initiated the MegaSurvey Project, merging a number of 3D surveys into large, consistent 3D data sets. For the first time, the regional picture and prospect-size detail are both available from a single dataset.

Two MegaSurveys for the North West Shelf are now available; the Vulcan Sub-Basin MegaSurvey (VMS) and the Carnarvon MegaSurvey (CMS).

The MegaSurvey seismic data and consistent horizon interpretation (tied to released well control) enables asset-focussed oil companies to concentrate on the more detailed search-for-the-subtle-trap to find, understand, and develop remaining reserves. Interpretation of the first MegaSurvey (Vulcan Sub-Basin) was completed in 2004 and work is focussed on the Carnarvon MegaSurvey, the interpretation of which will be completed in March 2005.

The PGS 3D MegaSurveys allow visualisation of the subsurface both on a scale and resolution that has hitherto been unavailable. They provide an essential new tool to help fully unlock the remaining potential of the North West Shelf.

Analog reservoir modelling of channel sands

D. Sherlock, G. Weir and K. Dodds

Presenter: Donald Sherlock
CSIRO Petroleum

Session 5B: 4:10 pm, Meeting room 3

This paper outlines the results of analog modelling of a sandy deepwater channel reservoir to gain insight into issues of uncertainty in reservoir simulations and their seismic expression. The project is unique in that it integrates seismic and reservoir engineering research in a controlled laboratory environment. Unlike numerical modelling investigations, this laboratory-based modelling study provides real data that does not rely on assumptions and is, therefore, a useful case study for comparing the actual production and seismic response against numerical predictions.

The 1 m^2 model comprised two intersecting synthetic sandstone channels within a transparent acrylic matrix. The model was initially oil-saturated with irreducible water and was produced through waterflooding of the upper channel. Careful attention was paid to scaling of both the fluid dynamics and the seismic properties to ensure that the response of the model was representative of the field-scale environment. Scaled time-lapse seismic data was recorded before and after production and data such as water cuts, recovery rates and pressure drop between injector and producers were also recorded.

Analog reservoir modelling (ARM) provides a new tool that allows seismic attributes to be evaluated against ground truth results and the performance of seismic inversion schemes to be critically assessed.

Norne case study: The first Q-on-Q

Lead author Richard Goto

R. Goto, D. Lowden, J. Paulsen, M. Tang, B. Osdal and H. Aronsen

***Presenter*: Keith Myers**
Schlumberger

Session 5B: 4:35 pm, Meeting room 3

The case study covers the first use of Q-Marine technolgocy for both the baseline and monitor surveys of a 4D seismic project. In this presentation we concentrate on the steered streamer aspect of the system and present the results and repeatability analyses of the acquisition and data processing.

The very high repeatability of source and receiver positions, the fast turnaround of 4D difference cubes and the deterministic processing sequences were all key issues for this project. A 4D amplitude difference volume was produced on the vessel within 10 days of the end of the survey and a 4D acoustic impedance difference cube was generated within two days. Statoil were able to adjust their horizontal drilling plans, within 30 days of the monitor survey's completion, based on the ultra fast-track onboard processed dataset. The estimated savings made by moving the pre-planned well path to a more productive track were 200 million NOK. The two vintages were also processed onshore using more computer intensive de-multiple and imaging algorithms to further refine the initial results and enable analysis on pre-stack migrated data.

Presentation only.

TUESDAY

SESSION 5C—MEETING ENVIRONMENTAL CHALLENGES

Does self-regulation improve corporate ecological-efficiency? An empirical investigation into the Australian petroleum industry from 1996 to 2002

T.K. Sarker and R.L. Burritt

Presenter*: *Tapan Sarker
School of Business and Information Management, The Australian National University

Session 5C: 3:45 pm, Meeting room 6

This study presents a detailed description of greenhouse gas emissions and reduction strategies adopted by the Australian petroleum industry from 1996–2002. An empirical analysis has been undertaken to examine the impact of such strategies in improving overall industry environmental performance and has ranked them to establish their relative importance in improving corporate ecological-efficiency ratios, a relative measure of environmental performance that compares the production of oil and gas and their environmental impact added. Two major classes of environmental self-regulatory activities identified are greenhouse gas management strategies and greenhouse gas influence strategies; where the latter was found highly inconsistent throughout the study period. We found that investment in emissions abatement activities, environmental collaboration and staff training, implementation of greenhouse policies and environmental reporting act as better greenhouse gas management strategies. In contrast, changing consumer behaviour or demand side management and supporting research and development on projects that reduce greenhouse gas emissions act as better influence strategies. We predict that the two classes of environmental strategies are highly inter-linked and that an optimal combination is needed for achieving better corporate environmental performance. The study provides a basis for the improvement in greenhouse gas management that may help in attaining an effective emission management plan for the industry.

Seabed sediment transport and offshore pipeline risks in the Australian southeast

F. Li, C. Dyt, C.M.Griffiths, C. Jenkins, M. Rutherford and J. Chittleborough

Presenter*: *Fangjun Li
CSIRO Petroleum

Session 5C: 4:10 pm, Meeting room 6

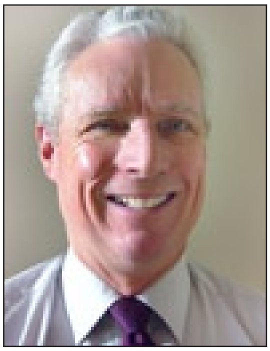
The Australian seabed is influenced by extreme weather conditions of various types: cyclones, high tidal ranges, offshore currents and storm waves. In the past two centuries substantial progress in our understanding of the seabed and environmental conditions has been made by studies of the seabed sedimentology, hydrodynamics, and through habitat mapping. As part of the CSIRO Wealth from Oceans Flagship program the authors are involved in a new five-year study to investigate and predict the effect of possible climate change scenarios on the seabed in the next 50 years. Those changes will assess undersea infrastructure installations such as pipelines in a changed regime of seafloor stability, burial, erosion and abrasion.

As an initial phase of this project the authors have extrapolated the current climatic conditions into the next 50 years. It was found that (under an extension of present day climatic conditions):

- **the majority of terrigenous sediment carried down by major rivers (Murray River, Snowy River, Tamar River, etc) is trapped in the inland lakes or estuaries. Only a marginal fraction of fine grain sediment reaches the continental shelf;**
- **a high energy wave climate, significant tidal currents, and the frequent surges of wind-driven currents make the local seabed highly mobile and sensitive to the modern hydrodynamic changes. Both results imply that an exposed pipeline may suffer from local scour and fatigue damage due to oscillatory loads induced by vortex shedding behind the pipelines; and**
- **there are several high risk zones in the region where turbidity current and submarine slope failure post a great threat to offshore pipelines.**

The next phase of the project will be to provide testable predictions of the changes under a variety of global warming scenarios.

Technologies for risk assessment, monitoring and verification of CO_2 capture and geological storage projects



A.J. Rigg

Presenter: Andy Rigg
CO2CRC

Session 5C: 4:35 pm, Meeting room 6

Over the last 10–15 years, research into CO_2 capture and storage (CCS) in geological formations as a potential greenhouse gas abatement strategy has progressed rapidly to the stage where there are now a few full-scale projects in operation (both for storage and also EOR) with several more planned, as well as several smaller scale pilot and demonstration projects.

The existence of these current and future projects has focussed on the need for a transparent and easily understood risk assessment methodology which needs to be applied during each of the planning, approval, operational, closure and post-closure phases of the projects; it also needs to be applied to each part of the project from the source of the CO_2 through capture, transportation, injection, storage, monitoring, abandonment of facilities and ultimately at transfer of responsibility. It also needs to be able to accommodate any progress from research during the life of the project and in particular, the experience gained internationally from other storage projects.

Today's assessment of the operational risks associated with CCS is largely based on experience from the oil/gas industry where CO_2 capture and separation from natural gas streams is routinely done to achieve gas delivery specifications, and long-distance pipeline transportation and subsequent injection of CO_2 are considered safe and routine by the EOR industry. One difference that will need to be taken into account is the scale of these EOR activities vs the scale of projected storage projects which may be required, for example, for large scale CCS from power stations.

Technologies that are already used by the oil and gas industry for both exploration and production of hydrocarbons look to be readily applicable both for the prediction by modelling of the sub-surface behaviour of CO_2 in the storage reservoirs and for monitoring this behaviour, at least during and immediately post injection. However monitoring of the CO_2 once it starts dissolving in the formation water and forming new minerals will be more challenging. Study of naturally occurring CO_2 accumulations provides assistance in this endeavour.

The major area where integration of technology development and use, monitoring and risk assessment comes together is in the assessment of containment of the storage volume in the storage reservoir, and in particular the assessment of the likelihood of, and monitoring to confirm or deny leakage from the storage site. This will be required both for public and regulator assurance and also for verification of the volume stored.

Risk assessment methodology can be applied from longer-term natural analogs such as CO_2 accumulations or gas chimneys to look at both the likelihood of potential leakage by naturally occurring pathways or events (such as faults, imperfections in the seal, earthquakes etc) or based on a much more limited history for man-made pathways and events (such as wells, pipelines, compressors etc). Monitoring can take place both in the reservoir and parts of the overlying geosphere, biosphere, and atmosphere to assist in this analysis. Risks associated with the man-made pathways and events can be successfully addressed and managed, but the challenge is to develop technologies which are able to model and detect any leakage predicted to occur in the event of natural events or events caused by the storage project itself.

Presentation only.

TUESDAY

SESSION 6A—FRONTIER EXPLORATION: WEST AND NORTH

Seismic evidence for reverse and wrench fault tectonics—Cliff Head oil field, Perth Basin

C.C. Hodge

***Presenter*: Christopher Hodge**
Mitsui E&P Australia Pty Ltd

Session 6A: 11:00 am,
Main Auditorium

Seismic interpretation of the Cliff Head oil field has shown it to be structurally complex with reverse faults, wrench faults and listric faults mapped at both field and reservoir scale within the Permo-Triassic section.

The Cliff Head field overlies the Abrolhos Transfer Zone and has strong similarity to the progressive evolution, internal structure and rhomboid map geometry in experimental models of restraining stepovers in strike-slip systems. It is concluded that the Cliff Head oil field is a pop-up structure formed during the Permian and early Cretaceous within a restrained convergent wrench system—the result of sinistral transpression.

A similar style of faulting could be applied when mapping seismic data in other offshore areas and especially the onshore Perth Basin with its poorer seismic data quality.

Interpretation of prospects with a strong reverse or wrench component has implications for the timing of hydrocarbon emplacement and the potential for seal breach and leakage. Furthermore, paleo-structural style will determine fracture density and orientation and may be critical in determining optimum design of producer and injection wells during field development.

It is recommended that interpreters of seismic data in the Perth Basin treat the fault patterns and structural trends of the Permian and early Cretaceous as different structural packages. The two should only be linked when it is very clear that there is a strong early Cretaceous overprint.

Complex modified thrust systems along the southern margin of East Timor

M. Keep, L. Beck and P. Bekkers

***Presenter*: Myra Keep**
The University of Western Australia

Session 6A: 11:25 am,
Main Auditorium

Seismic structural interpretation of data across three basins along the southern coast of East Timor (the Suai, Beaco and Aliambata basins) reveals a complex deformation history dominated by intense thrust deformation within the thick (>3 km) Plio-Pleistocene sequence.

Our interpreted deformation sequence of the clay-dominated rocks includes a series of south-directed, low-angle thrusts creating extensive thrust piles, and in places, antiformal stacks. These thickened piles exhibit later modification by crestal collapse. Rapid thickening destabilised the growing thrust packages, and caused regional-scale slumping of material into the Timor Trough to the south. The slumping disrupted thrust fronts and caused significant offset at the sea floor. Finally, shale injection and diapirism along the slump faults re-elevated some of the hanging-walls of the slumps.

Oil and gas seeps, which occur mainly in southern East Timor, follow structural trends parallel to those offshore. Although sourced from proposed Triassic source rocks, uplift, exposure and subsequent leakage from these seeps probably occurred within the last 2 Ma, and possibly even later, co-eval with Plio-Pleistocene deformation. The proximity of oil seeps to fold and thrust deformation raises the possibility that additional Triassic or other Mesozoic section may occur at various structural levels within the deformed sedimentary wedge.

Stable hydrogen isotope ratios of sedimentary hydrocarbons: A potential method for assessing thermal maturity?

D. Dawson, K. Grice and R. Alexander

Presenter*: *Daniel Dawson
Centre for Applied Organic Geochemistry, Curtin University of Technology

Session 6A: 11:50 am,
Main Auditorium

A relationship has been identified between the maturity level of source rocks and the stable hydrogen isotopic compositions (δD) of extracted saturated hydrocarbons, based on the analysis of nine sediments and five crude oils from the Perth Basin (WA). The sediments cover the immature to late mature range. Distinct δD signatures are observed for the immature sediments where pristane and phytane are significantly depleted in deuterium (D) relative to the *n*-alkanes. With increasing maturity the difference between the δD values of *n*-alkanes and isoprenoids reduces as pristane and phytane become progressively enriched in D. The *n*-alkane–isoprenoid δD signature of the crude oils, including one from a different source facies, is similar to mature–late mature sediments representative of the peak oil–generative window. Enrichment of D in isoprenoids is attributed to isotopic exchange associated with thermal maturation. Average δD values of pristane and phytane correlate well with vitrinite reflectance, as does the biomarker maturity parameter Ts/Tm. The limited data set suggests that δD values of aliphatic hydrocarbons may be useful for establishing thermal maturity, particularly when other maturity parameters are not appropriate. Furthermore, we suggest δD values may be useful over a wider maturity range than traditional parameters, particularly at very high maturity where biomarker parameters are no longer effective.

SESSION 6B—EXPLORATION IN THE EAST

Approaches to palaegeographic reconstructions of the Latrobe Group, Gippsland Basin, southeastern Australia

T. Bernecker and A.D. Partridge

Presenter*: *Tom Bernecker
Department of Primary Industries

Session 6B: 11:00 am, Meeting rooms 1 and 2

In the Gippsland Basin, the seaward extent of paralic coal occurrences can be mapped in successive time slices through the Paleocene and Eocene to provide a series of straight to gently arcuate surrogate palaeoshorelines within the petroliferous Latrobe Group. Palaeogeographic reconstructions that incorporate this information provide a unique perspective on the changes affecting a siliciclastic depositional system on a passive continental margin where basin development has been primarily controlled by thermal sag. In contrast, the absence of calcareous marine fossils and lack of extensive, widespread and thick fine-grained sediments on the marine shelf and continental slope, beyond the seaward limits of coal accumulation, have contributed to the false impression that the Latrobe Group accumulated in a largely non-marine basin. Based on the proposed model for palaeoshoreline delineation, seismic data, sequence analysis, petrography and palynology can be integrated to subdivide the main depositional environments into distinct facies associations that can be used to predict the distribution of petroleum systems elements in the basin. The application of such palaeogeographic models to the older section of the Latrobe Group can improve the identification of these petroleum systems elements in as yet unexplored parts of the Gippsland Basin. Given the recent attention paid to the basin as a CO_2 storage province, palaeogeographic interpretations may be able to assist with the selection of appropriate injection sites.

Tectonostratigraphy and potential source rocks of the Bass Basin

J.E. Blevin, K.R. Trigg, A.D. Partridge, C.J. Boreham and S.C. Lang

Presenter*: *Jane Blevin
Geoscience Australia

Session 6B: 11:25 am, Meeting rooms 1 and 2

A study of the Bass Basin using a basin-wide integration of seismic data, well logs, biostratigraphy and seismic/sequence stratigraphy has resulted in the identification of six basin phases and related megasequences/supersequences. These sequences correlate to three periods of extension and three subsidence phases. The complex nature of facies relationships across the basin is attributed to the mostly terrestrial setting of the basin until the Middle Eocene, multiple phases of extension, strong compartmentalisation of the basin due to underlying basement fabric, and differential subsidence during extension and early subsidence phases. The Bass Basin formed through upper crustal extension associated with three main regional events:

a) rifting in the Southern Margin Rift System;
b) rifting associated with the formation of the Tasman Basin; and,
c) prolonged separation, fragmentation and clearance between the Australian and Antarctic plates along the western margin of Tasmania.

The final stage of extension was the result of far-field stresses that were likely to be oblique in orientation. The late Early Eocene to Middle Eocene was a time of rift-transition and early subsidence as the effects of intra-plate stresses progressively waned from east to west. Most of the coaly source rocks now typed to liquid hydrocarbon generation were deposited during this rift-transition phase. Biostratigraphic studies have identified three major lacustrine episodes during the Late Cretaceous to Middle Eocene. The lacustrine shales are likely to be more important as seal facies, while coals deposited fringing the lakes are the principal source rocks in the basin.

Geochemical analysis of oils and condensates from the Gippsland Basin: Implications for future prospectivity

G. O'Brien, C. Grant and C. Boreham

Presenter*: *Geoff O'Brien
Australian School of Petroleum

Session 6B: 11:50 am, Meeting rooms 1 and 2

The Gippsland Basin is a premier hydrocarbon province and contains a number of giant fields that have contributed greatly to Australia's oil self-sufficiency. The basin is, however, in terminal decline, with increasing water cuts and with production rates outstripping reserve replacement. Traditionally, the strong spatial compartmentalisation, and to some extent the composition, of oil and gas fields within the Gippsland Basin have been attributed principally to a combination of first-order generation-migration processes and, more locally (in the north-west part of the basin) to a Late Tertiary over-printing related to invasion of the hydrocarbon-bearing aquifer system by fresh-water. The location of many of the large gas fields around the northern and northwestern flanks of the basin are considered to be controlled principally by the long-distance migration of (thermally) over-mature gas. To rigorously test these concepts, the gas-chromatography traces of oils of 114 samples from 28 fields were analysed to characterise their light (C_5-C_8 range) hydrocarbon composition.

The oils/condensates displayed considerable variations in composition due to the effects of secondary alteration processes such as biodegradation and water washing. However, these effects appear to be relatively minor modifiers of the primary petroleum system—the first-order alteration process affecting hydrocarbon composition and distribution within the basin appears to be phase fractionation, most likely the result of evaporative fractionation processes (similar to those described by Thompson, 1987). The hydrocarbons in the Gippsland Basin could be classified into three families, namely pristine oils, evaporative products and residual products. Evolving (i.e. intermediate) residual and evolving evaporative phases were also recognised. The lighter evaporative products typically have a high abundance of normal alkanes with a low waxy component and depleted aromatics. The residual products have a high waxy component with a low abundance of normal alkanes and an enrichment of aromatics.

The hydrocarbons in wells along the northern flank have compositions which suggest that they are dominantly the residual products of phase fractionation. These residual products are typically reservoired at deeper depths (2,000–3,500 m) and have API gravities between 30º and 40º. Hydrocarbons interpreted to be principally evaporative products dominate the northwestern flank of the basin, with some wells also containing, at deeper levels, the residual products from which the evaporative products appear to have been sourced. Evaporative products typically occur at shallow depths (<2,000 m) and have high API gravities (typically 45–60º). Pristine oils are largely confined to the central part of the basin and are characterised by API gravities of between 40º and 50º. These pristine oils have compositions consistent with them being capable of sourcing both the evaporative and the residual products. Four wells contain both shallower evaporative products and deeper residual products, thereby providing strong support for the process of phase/evaporative fractionation. Whiting–2 contains an evaporative product at a depth of 1,409 m and a residual product at a depth of 2,615 m. Recombination of the GC traces from the shallower and deeper samples resulted in a composition similar to a pristine oil, such as typically observed in the central part of the Gippsland Basin.

The interpretation of phase/evaporative fractionation as a primary process driving the spatial compartmentalisation of the oil and gas fields within the Gippsland Basin has significant implications for future exploration strategies. Depending upon the interactions between variables such as the timing of charge, the depths of reservoirs at the time of charge, charge rate and trap/fault seal integrity through time, potentially large, residual phase oil accumulations may exist either beneath, or inboard from, the evaporative phase fields, especially along the northwestern flank of the Gippsland Basin.

Presentation only.

SESSION 6C—MEETING ENVIRONMENTAL CHALLENGES

The technical, environmental and cultural challenges of drilling on the edge of a national park

J.E. Coleman, L.N. Franks and M.D. Berry

Presenter:* *Jo-Anne Coleman
Magellan Petroleum Australia Limited

Session 6C: 11:00 am, Meeting room 3

Magellan Petroleum, operator of the Palm Valley Gas Field, successfully drilled the Palm Valley–11 (PV–11) gas development well situated on aboriginal land adjacent to the Finke Gorge National Park, Central Australia. The drilling site was located within the Palm Creek catchment area, an environmentally significant and internationally renowned area which feeds the rare and endangered red cabbage palm (*Livistona mariae*).

Although no commercial gas flow was encountered, the well was a success in terms of the technical, environmental and cultural heritage challenges faced during the 71-day drilling program.

Several mitigation measures not generally required in petroleum drilling operations were incorporated in the PV–11 Drilling Program and Environmental Management Plan (EMP).

This paper describes the Commonwealth and Northern Territory approval processes required to ensure all risks were identified and addressed; the challenges of drilling the PV–11 well using under-balanced techniques in difficult conditions; and the mitigation measures adopted to address these challenges.

Assessment of biological impacts resulting from the discharge of produced formation water from Harriet Alpha platform on the North West Shelf, Australia

L. Howitt, S. King, C. Humphrey, C. Bennett, J. Mondon, M Haasch, S. Zhu, J. Muelle and M. Shaw

Presenter:* *Libby Howitt
Apache Energy

Session 6C: 11:25 am, Meeting room 3

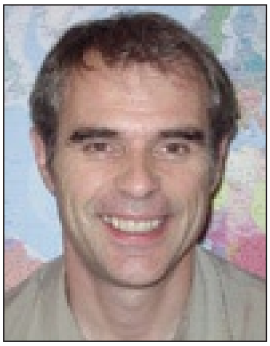
A comprehensive biological and chemical assessment of the fate, effects and potential environmental risks associated with produced formation water (PFW) discharge at Harriet Alpha platform on the North West Shelf of Australia was undertaken in May 2003. The field and analytical work was done by scientists from the Australian Institute of Marine Science and their collaborators and continues on from earlier pilot studies which concluded that there was potential for biological effects on fish populations exposed to PFW around the Harriet Alpha platform.

A controlled field exposure experiment was conducted using 90 stripey sea perch (*Lutjanus carponotatus*) deployed in 6 separate galvanised steel cages set 1 m sub-surface at 3 stations; Site A (near field, within 300 m of Harriet A), Site B (far field, about 1,000 m from Harriet A) and Site C, a reference site to the north of Harriet A, close to the Montebello Islands. A suite of biomarkers were examined by sacrificing caged fish at 1, 3 and 10 days after in-situ exposure to produced formation water. In addition, water column samples were collected at all three sites to measure in-situ concentrations of petroleum hydrocarbons and metals.

A summary of the results are presented. Harriet Alpha platform is located 3 km to the east of the Montebello/Barrow Islands Conservation Reserve. The proximity to the conservation reserve and the implications for environmental risk assessment and management of discharges of produced formation water from Harriet A is discussed.

Presentation only.

A state-of-the-art shore crossing



E.P. Jas and A.T. McPhee

***Presenter*: Eric Jas**
Atteris Pty Ltd

Session 6C: 11:50 am, Meeting room 3

An insight is provided into the design and construction of the shore crossing of the export pipeline system for the Otway Gas Project in Western Victoria. The development of the Otway Gas Project, which is now underway, requires the installation of a 20-inch gas pipeline and a 4-inch glycol service line across the shoreline in the Port Campbell National Park along the Great Ocean Road, one of the major tourist attractions in Australia. An account is given of the landfall site selection process, the collection of required site data, the identification of geo-hazards, the development of a unique construction method based on a combination of retractable micro-tunnelling and horizontal directional drilling, and an outline of the construction challenges. These include the complex geo-technical conditions, the ever present high-energy Southern Ocean swell, and the environmental significance of the site. The design and construction work performed demonstrates that trenchless technology can successfully be applied for the installation of pipelines across shorelines provided detailed attention is paid to a number of design and construction aspects; bearing in mind that horizontal directional drilling design guidelines are generally limited with respect to these crossings.

WEDNESDAY

SESSION 7A—FRONTIER EXPLORATION: WEST AND NORTH

Depositional conditions of the northern onshore Perth Basin (Basal Triassic)

K. Grice, R.E. Summons, E. Grosjean, R.J. Twitchett, W. Dunning, S.X. Wang and M.E. Bottcher

Presenter*: *Kliti Grice
Centre for Applied Organic Geochemistry, Curtin University of Technology

Session 7A: 2:30 pm,
Main Auditorium

An oil-source rock correlation has been established for the northern onshore Perth Basin (Western Australia) based on unusual aromatic and polar biomarkers attributed ultimately to a green sulphur bacterial source. Several of these biomarkers have been identified throughout the entire Sapropelic Interval of a proven petroleum source rock intersected within a recently discovered marine Permian-Triassic Perth Basin borehole (Hovea–3) and several Perth Basin crude oils. Today, green sulphur bacteria live in the anaerobic zones of stratified lakes or in marine environments with restricted water circulation, where the upper sulphide limit coincides with the lower limit of oxygen. The presence of photosynthetic pigments and carotenoids of green sulphur bacteria, or their diagenetic alteration products in sediments provide unequivocal evidence for photic zone euxinic conditions in the paleowater column. Multiple lines of evidence for photic zone euxinia and euxinic depositional conditions for the Hovea–3 source rock have been obtained from biomarker analyses. Photic zone euxinia is usually associated with the widespread deposition of organic-matter-rich sediments that constitute important source rocks for petroleum deposits that are being exploited today. With the exception of the Perth Basin, such organic-matter-rich sediments are virtually absent from Upper Permian and Lower Triassic sediments globally. Several lines of evidence indicate localised surface ocean productivity may have played a key role in the deposition of a petroleum source rock at this location, although photic zone euxinia was globally more widespread during the Permian-Triassic Superanoxic Event.

Reassessing potential origins of synthetic aperture radar (SAR) slicks from the Timor Sea region of the North West Shelf on the basis of field and ancillary data

A.T. Jones, G.A. Logan, J.M. Kennard and N. Rollet

Presenter*: *Andrew Jones
Geoscience Australia

Session 7A: 2:55 pm,
Main Auditorium

The Timor Sea region of the North West Shelf is one of natural hydrocarbon accumulation and seepage, which has been investigated by integrated remote sensing studies in the past 10 years. One of the primary tools incorporated in these studies has been Synthetic Aperture Radar (SAR). During a recent Geoscience Australia marine survey to the Yampi Shelf area, active hydrocarbon seepage was directly observed in the form of gas plumes rising from the sea-floor. Active seepage was not observed in areas associated with dense clusters of elongated to irregular-shaped features in the SAR data, which have previously been interpreted as natural hydrocarbon seepage slicks. These slicks, and another dense cluster of slicks across the Browse–Bonaparte Basin Transition Zone, are reassessed in the context of alternative formational processes.

Mapping of bathymetric channels directly beneath the SAR slicks using multi-beam swath bathymetry and measurement of tidal currents using an acoustic doppler current profiler indicates that tidal current flows may have contributed to slick formation over the Yampi Shelf headland. In contrast, coral spawning may have contributed to the formation of annular to crescent-shaped SAR slicks associated with submerged reefs and shoals over the nearby transition zone. Subsequent to identifying potential alternative origins for these two types of SAR features, the remaining slicks across the area were re-categorised on the basis of their size and shape in the context of ancillary hydrographic and environmental data. An alternative non-seepage origin was established for most of the 381 SAR slicks previously identified as being related to natural hydrocarbon seepage. This may necessitate a significant downgrading of the extent and frequency of active hydrocarbon (particularly oil) seepage in the region.

Clues to fill histories of gas fields in the Caswell Sub-basin—Evidence from the distribution and geochemistry of palaeo-oils

H. Volk, M.P. Brincat, S.C. George, J.M. Kennard, D.S. Edwards, C.J. Boreham, M. Ahmed and M. Lisk

***Presenter*: Herbert Volk**
CSIRO Petroleum

Session 7A: 3:20 pm, Main Auditorium

Geochemical characterisation of palaeo-oil accumulations in the Caswell Sub-basin, Browse Basin, has been undertaken to add further constraints to the source of the early oil charge identified from previous petrographic studies. The molecular geochemical composition of five fluid inclusion (FI) oils has been used to assess the source and maturity characteristics of these palaeo-oils. Heywood–1 FI oil and North Scott Reef–1 condensate have geochemical compositions that indicate derivation from clay-rich source rocks deposited under oxic conditions, containing a significant terrestrial input, most likely Jurassic claystones. In contrast, source-specific biomarker data of Brewster–1A, Argus–1 and Dinichthys–1 FI oils indicate that these oils have a more marine character with a greater contribution of algal and/or bacterial organic matter, and a lesser contribution of terrestrial plant matter. The most probable source rock of these FI oils is the Early Cretaceous Echuca Shoals Formation. Interestingly, aromatic maturity parameters are unusually high for the Brewster–1A FI oil in particular, but also for the FI oils from Argus–1 and Dinichthys–1. Brewster FI oil has a higher maturity than almost all known free oils. It is likely that these FI oils were thermally-altered due to burial after inclusion trapping. Collectively, these new geochemical results will assist in developing better source and charge models to aid prospectivity assessment in this frontier region of the Browse Basin.

WEDNESDAY

SESSION 7B—KEY TAX AND LEGAL ISSUES FOR THE INDUSTRY

Greenhouse gas issues—One for the Australian taxation office?

J.H. Murray and E.A. Burns

***Presenter*: John Murray**
PricewaterhouseCoopers

Session 7B: 2:30 pm, Meeting rooms 1 and 2

In the 21st century we are constantly bombarded with issues on the need to do more to protect the environment and deal with greenhouse gas issues. The petroleum industry world-wide has come under fire for the emissions produced as a by-product of the petroleum refining industry and all primary producers and refiners must develop strategies to reduce atmospheric carbon dioxide emissions. While it is probably fair to say Australia's appetite for production and consumption of natural gas or LNG is much more environmentally friendly than the days of fossil fuel sources such as coal, there is still a long way to go to minimise emissions in the industry.

Global oil and gas companies operating in Australia are leading the way to develop ways to reduce greenhouse emissions. Two examples are Gorgon joint venture plans for carbon dioxide sequestration for its gas development project and perhaps BHP Billiton's comments that it sees potential for similar sequestration into coal seams onshore Australia in Queensland, South Australia or New South Wales.

The costs of projects to re-use or re-inject or sequestrate greenhouse gases are likely to be significant. But are these operating costs of the taxpaying entities in question and would they qualify for tax relief for income tax or petroleum resource rent tax purposes? This paper looks at some of the projects now underway in Australia to reduce greenhouse emissions in the petroleum sector and assesses whether the type of costs likely to be incurred in such projects might qualify for tax relief under existing legislation.

Accounting standards reform—Will there be havoc?

M. Williamson

***Presenter*: Max Williamson**
Wiltax Consulting Pty Ltd

Session 7B: 2:55 pm, Meeting rooms 1 and 2

Australia's corporate regulatory authorities have been extensively lobbied during the last 10 years to move to adopt an international set of accounting standards that the major nations of the world have evolved. Following the establishment of the International Accounting Standards Board (IASB) in the UK, that body has moved to promulgate a broad range of accounting standards. Australia has been a member of the IASB from its early days.

The IASB has moved to promulgate some accounting standards. The Australian Accounting Standards Board (AASB) has moved to adopt these same standards. In effect, the intent of those standards has been converted to Australian terms. The bulk of these new accounting standards (AASBs) will be effective for the first time to accounts of reporting entities for the years after 1 January 2005.

The intention of the adoption of these standards has been to provide a consistent platform for the preparation of accounts in all of the major countries of the world. The expectation is to promote consistent reporting and more ready comparability between participants in various industries and between industries and from year to year.

For a number of oil and gas listed companies, however, the short to medium-term is likely to produce the exact opposite in results and comparability terms. Accounting results for years prior to the adoption of the new AASBs will in certain circumstances bear results so dissimilar that their usage will be misleading.

The conversion effort from the old standards to the new standards will involve considerable effort by all participants in the oil and gas industry; this should have started months ago. There will also be spin-off problems causing many legal documents, including borrowing agreements and performance bonus agreements that will need to be re-written.

There will only be havoc in an administrative context if those oil and gas companies have not prepared themselves well and in a timely fashion. There may be financial havoc if the changes in accounting policies via the International Financial Reporting System (IFRS) make it difficult to raise new capital or cause problems under existing borrowing covenants.

WEDNESDAY

Buying and selling petroleum interests—Impact of tax consolidation and other tax reform measures

R. Henderson, C. Franchina and H. Wiseman

Presenters: Rod Henderson and Carlo Franchina
KPMG

Session 7B: 3:20 pm, Meeting rooms 1 and 2

The new tax consolidation system, together with a number of other recent tax reform measures, has lead to a paradigm shift in the way in which the acquisition and sale of petroleum interests are treated for taxation purposes in Australia. In an industry where ownership interests in exploration and production fields regularly change hands, it is important that senior executives and decision-makers have a clear understanding of the impact of the new tax rules.

This paper focusses on the commercial impact of these tax changes and is aimed at executives in the oil and gas industry with commercial, technical, legal or financial responsibilities.

Board members will also have an interest to ensure that the risks arising out of the new rules are adequately addressed, and that shareholder value is being preserved.

WEDNESDAY

SESSION 7C—ACHIEVING HEALTH AND SAFETY EXCELLENCE

Managing helicopter risk

J. Hart

Presenter*: *Jed Hart
Hart Aviation Services

Session 7C: 2:30 pm, Meeting room 3

Annually, a million hours are flown by helicopters for the international petroleum industry. About 90% of this flying is offshore, and involves around 10 million passengers. Each year some 25–35 accidents are recorded, an average of 22 passengers and crew lose their lives, and a higher number are injured. Some 45% of these accidents stem from technical causes, a similar number are pilot related, and the remainder are linked to other causes. Helicopter accident rates are 10 times higher than those of airline travel.

Strategies to tackle both technical failures and pilot related accidents have emerged, although application of these strategies around the world is inconsistent.

One way in which helicopter technical issues have been addressed is by the introduction of Health and Usage Monitoring (HUMS) equipment. To tackle the pilot related accidents, lessons have been drawn from the airline industry's use of Flight Data Management (FDM) programs, which allow pilots to learn from deviations from pre-defined normal parameters during routine flying. The helicopter version of FDM is the Helicopter Operations Monitoring Program (HOMP). Another important training tool is flight simulator training to allow simulated emergencies to be flown and practiced.

Petroleum companies have the opportunity through their own aviation policy and standards to stipulate flight crew experience and training, the technical specifications for their contracted helicopters and the application of advanced safety programs, such as HUMS, and HOMP. Compliance and continuous improvement in line with these standards can be verified and facilitated through operational and technical audit. Only with such active involvement can helicopter risk be managed downwards.

The role of incident response and emergency management in commercial and corporate governance

A. Standen and M. Jakins

Presenter*: *Alf Standen
Corporate Incident Management Associates

Session 7C: 2:50 pm, Meeting room 3

Commercial and corporate governance requires organisations both large and small to preside over their business dealings in a manner which ensures compliance with both external and internal best practice. A recent development, the National Off and On-Shore Major Hazardous Facility Incident Response (OMIR) competencies have been created by industry to assist that purpose. These competencies, endorsed in June 2004, are about providing: accurate role definitions; industry led training outcomes; assessment against recognised standards; evidence that personnel are competent to perform the roles assigned to them; and the ability to meet the accountabilities or responsibilities of those roles.

This paper explores the relationships between commercial and corporate governance and the symbiosis between systems, obligations, competencies and people. Based on the Australian Stock Exchange definition of governance the paper looks at the drivers within organisations that lead to the implementation of the frameworks and systems which result in corporate confidence that they are addressing safety in a governance context.

By using appropriate risk assessment and management processes it is suggested any oil and gas company can identify areas of potential concern. The paper asserts that incident response and emergency management planning are vital to minimise any affects a real incident or emergency could have on employees, the environment, plant and equipment, company finances, and business reputation.

The paper concludes with two significant messages for small and large organisations;

- that there are a variety of consequences for organisations failing their governance obligations; and
- that there are specific benchmarks for the demonstration of governance obligations being fulfilled through the competency process. Examples of how this can be achieved will be provided.

Presentation only.

WEDNESDAY

Driving excellence

G. Marshall

Presenter*: *Graham Marshall
An Mea

Session 7C: 3:08 pm, Meeting room 3

A short review of the websites or annual reports of the oil majors quickly illustrates a single, dominating expectation about safety outcomes. The common expectation is easily summarised as a demand for zero fatalities. While recent years have seen steady improvement in recorded fatalities, one area continues to hold back industry progress in achieving zero.

The crisis situation is driving-related fatalities. The deaths of employees and contractors; occurring in 2003, illustrate the nature of the crisis that confronts the oil majors. For example, BP recorded 14 vehicle-related deaths, with a further 28 fatalities involving members of the public; Shell recorded 19 road deaths.

This presentation explains why the focus of the oil majors has been unable to solve the crisis of fatalities that confronts them each year. Specifically, it explains how the crisis of fatalities results from the application of an inappropriate model of competency that suggests fatalities will be eliminated when drivers develop the necessary skills associated with vehicle operation. I explain why a narrow focus on improving drivers' skills by commissioning advanced driver training programs is a waste of money and that competency for driving at skill level will not eliminate the fatalities crisis. More importantly; however, I then offer a new competency model and associated program that, if implemented, can assist companies to reduce the road toll towards zero.

The Driving Mastery Model (DMM, 2004) and its associated safety program suggest that fatalities can be eliminated when drivers develop competency to a level defined within the model as mastery level. The DMM defines mastery by integrating three key competency elements within a single safety program. The new program operationalises the elements within people's behaviors and attitudes. Within the DMM, the elements that lead to competency at mastery level are the right driving skills; as well as the necessary awareness and knowledge of the hazard management process. In that sense, the DMM is represented in summary form thus: Mastery = Awareness of hazards + Knowledge of the hazard management process + Skills of vehicle operation (M = A + K + S). The rest of the presentation explains and defines the elements of the model and its associated safety program and it demonstrates how the programs application works to motivate positive safety outcomes.

Presentation only.

Vision into reality—How will success be measured?

J. Clegg

Presenter*: *John Clegg
NOPSA

Session 7C: 3:26 pm, Meeting room 3

One of the presentations given at the 2002 APPEA Conference provided a vision of what offshore safety would look like in the year 2010. This vision was widely supported at the time and provided much of the philosophical underpinning for the development of NOPSA.

NOPSA started operations on 1 January 2005 and after just 100 days of operation, I will:

- **report on progress in developing NOPSA into an effective and efficient regulator,**
- **explain how the vision set out in the 2002 APPEA presentation is being realised, and,**
- **provide a series of indicators that industry and the workforce can use to judge if NOPSA is meeting its goals.**

In particular, I will provide a view on how we can realise the full potential of the safety case approach, by making them more practical documents of real use to companies and their workforces and not just another compliance hurdle on the way to final project go-ahead. This involves ensuring that the company and its workforce is the prime customer for a safety case and not the regulator and by giving particular focus to the links between hazards, risks, their control measures, the management system and by developing appropriate performance standards.

Presentation only.

WEDNESDAY