

THE 2006 APPEA CONFERENCE
Abstracts Volume



**Abstracts of Technical, Commercial and
Environmental papers and posters of the
2006 APPEA Conference
in date and session order**

CD-ROM Version

2006 APPEA Conference
7-10 May 2006
Gold Coast, Australia

ISSN 1326-4966

SESSION 1A— Acreage release 2006

Monday, 8 May 2006
Arena 1, Ground Floor
Gold Coast Convention Centre

Introduction and overview



J Hartwell
*Department of Industry, Tourism
and Resources*

Time: 2:00 pm, Arena 1

John Hartwell is Head of the Resources Division, Department of Industry, Tourism and Resources, Canberra Australia.

In addition to his divisional responsibilities, he is the Australian Commissioner for the Joint Petroleum Development Area of the Timor Sea and Chairman of the National Oil and Gas Safety Advisory Committee. He is serving on two industry/Government leadership groups delivering reports to Australian Government on a Strategy for the Oil and Gas Industry and a Uranium Industry Framework. He served on

the Strategic Leaders Group which delivered a report to government on minerals exploration and is involved in the implementation of a range of resource related initiatives under the Government's Industry Action Agenda process, including Mining and Technology Services, Minerals Exploration and Light Metals. Previously he served as Deputy Chairman of the Snowy Mountains Council and the Commonwealth representative to the Natural Gas Pipelines Advisory Committee.

He has worked in Treasury, the Department of Trade, Department of Foreign Affairs and Trade and the Department of Primary Industries and Energy before the Department of Industry, Science and Resources. From 1992-1996 he was a Minister-Counsellor, in the Australian Embassy, Washington, with responsibility for agriculture and resource issues and also served in the Australian High Commission, London (1981-84) as the Counsellor/Senior Trade Relations Officer.

He holds a MCom (Econ) Honours degree from the University of New South Wales and prior to joining the Australian Government, worked as a bank economist.

2006 Release of offshore petroleum exploration areas



Jenny Maher
Geoscience Australia

Time: 2.25 pm, Arena 1

Jenny Maher is the Output Leader of the Acreage Release and Petroleum Promotion Projects of the Petroleum & Marine Division at Geoscience Australia. She liaises closely with the DITR Offshore Resources Branch and

the State Designated Authorities in compiling and co-ordinating the annual Australian Government Offshore Petroleum Exploration Area release and its promotion in Australia and overseas. Jenny joined Geoscience Australia, known then as BMR, in 1985 after graduating from the University of Canberra. She has worked in many different areas within this organisation including managing the petroleum databases and the digital data collection housed in Chesterhill prior to the relocation to Symonston building repository. She has been working within the Acreage Release project for the last three annual releases.

The northern Arafura Basin— exploration opportunities from Geoscience Australia's new petroleum program



Heike Struckmeyer
Geoscience Australia

Time: 2.40 pm, Arena I

Heike Struckmeyer is a Principal Research Scientist in Geoscience Australia's Petroleum and Marine Division. She graduated from the

University of Göttingen, Germany, in 1981 and received a PhD from the University of Wollongong in 1989. Since joining Geoscience Australia in 1988, her work has been focused on the evolution and prospectivity of Australia's northern, northwestern and southern margins, and on regional basin analysis and modelling. In recent years, she has worked on projects in the Browse Basin, Great Australian Bight and the Arafura Basin. Member: AAPG, PESA.

Onshore acreage release



Peter Green
*Department Natural Resources,
Mines and Water
Queensland*

Time: 2.55 pm, Arena I

Peter Green holds a BSc App (Geology) (Hons) from the University of Queensland and MSc, University of Reading, UK. He

joined the then Queensland Department of Mines in 1976 and has been involved in regional mapping and analysis of the petroleum potential of Queensland sedimentary basins. In 1999, he became a project officer in Industry Development with an interest in tenure administration and facilitation of the petroleum industry. Late 2001, he was seconded to work on the new petroleum legislation. Peter is now the Manager, Exploration, Mining and Petroleum Strategies, Industry Development, Mining and Petroleum. Member: PESA.

SESSION 1B—PRODUCTION ENGINEERING: RESPONDING TO THE CHALLENGES

Basker-Manta oil development—a first for the Gippsland Basin



A. Young

*Presenter: Andrew A. Young
Anzon Australia Limited*

Session 1B: 2:00 pm, Meeting room 5

The Basker and Manta oil fields were discovered in the early to mid 1980s by a Joint Venture operated by Shell Australia. Serious consideration

for the development of these fields was first addressed by Anzon Australia Limited (Anzon), a start-up company which acquired 100% of the fields in March 2004. Development planning commenced immediately thereafter with initial oil production achieved in November 2005.

The Gippsland Basin is a prolific basin with both oil and gas production since the 1960's. The relatively small Basker and Manta oil fields were held by Retention Leases as they were considered marginal up to the acquisition by Anzon. In planning the development, Anzon sold down its interest and formed a Joint Venture with Beach Petroleum Limited (Beach). At the time of commencement of development

Anzon was the operator with a 62.5% interest and Beach had a 37.5% interest with an opportunity to go to 50% before 15 December 2005.

Anzon as the operator defined the method of development to be by the first time use of an FPSO in the Gippsland Basin. Anzon secured the services of a unique purpose built dynamically positioned mini FPSO called the *Crystal Ocean*, which is ideally suited for the Gippsland Basin operations. Other major equipment was contracted in a period of six months to commence development in August 2005 and included the Ocean Patriot semi-submersible drilling rig, the shuttle tanker *Basker Spirit* and the offshore construction vessel, *CSO Venturer 1*.

A fast track development was adopted and was achieved by sub-contracting the operations to Upstream Petroleum Pty Ltd (UP). The senior management of UP are highly experienced in FPSO operations on the North West coast of Australia, and they provided an already established fully manned operating division for Anzon.

The initial project meeting was held in UP's offices in Melbourne on 1 November 2004. The fast track nature of the project was demonstrated by the fact that initial production was achieved in approximately 12 months and full production will occur in mid 2006.

The paper provides a case history of an innovative approach in a mature basin using state of the art technology to achieve a successful outcome, highlighted by a number of significant first achievements.

Blackback subsea A1A remote well kill



A. J. Williamson

*Presenter: Andrew Williamson
Esso Australia Pty Ltd.*

Session 1B: 2:25 pm, Meeting room 5

Esso Australia Pty Ltd has recently completed a unique wellwork operation to secure the A1A well on its Blackback facility in Bass Strait. The Black-

back facility consists of three subsea wellheads, linked in daisy-chain formation, sitting in 400 m of water depth. The field is approximately 19 km southeast of host platform Mackerel and 87 km from shore.

The Blackback A1A well recently developed leak rates

through the subsurface safety valve and production master valve which exceeded Esso's internal acceptance criteria. Production rates on the A1A well did not justify an immediate workover to restore the integrity of the passing valves. Although there were no immediate environmental concerns, inadvertent damage to the wellhead had potential to create an environmental exposure, so the decision was made to kill the well temporarily until a workover opportunity arose.

An innovative remote well kill procedure was developed, utilising the 23 km gaslift pipeline to pump kill fluids down to the well from host platform Mackerel. The procedure involved a unique and intricate shut-down procedure and pumping strategy. The main operational risks pre-identified and mitigated in the procedure included potential hydrate formation in the pipelines, over-pressure or blockage of the gaslift pipeline, and use of significant volumes of methanol for hydrate management.

The Blackback well kill operation was executed to plan, with no safety, environmental or facility related issues. The A1A well remains in a killed state with positive overbal-

ance, while start-up of the A3 well following the procedure was successfully executed. This achievement has opened new doors for conducting well kill operations on subsea

facilities, with significant cost efficiencies when compared to the alternative—mobilisation of a floating drill rig.

Application of nucleonic instruments in separator profiling: Kuito FPSO case study



B. Beinart

Presenter: Bram Beinart
Tracerco

Session 1B: 2:50 pm, Meeting room 5

The Kuito field lies in the off-shore Cabinda Province, Angola. Kuito was Angola's first deep-water oil and came on stream in December 1999. Kuito oil is produced via an FPSO. Kuito oil ranges 18–22 API. The FPSO has three-phase, horizontal, gravity separation vessels that are used to separate oil and gas from unwanted produced water and solids prior to transportation. The production separators were designed with traditional, single point

transmitters for measurement of the fluid interface and overall fluid levels. These were capacitance type instruments mounted inside the vessels in stilling wells.

Following production start-up, separation problems began to emerge; these were manifested in numerous process upsets and shutdowns. Kuito oil can form emulsions quickly, and calcium naphthenate is produced at higher temperatures. If allowed to cool, it solidifies. The point instrumentation was unable to detect these emulsion and naphthenate layers resulting in the instrumentation becoming fouled and ceasing to function. The separators were operated blind, using tri-cocks located on the side of the vessel, and as the instrumentation was installed in stilling wells inside the vessel, it was impossible to maintain them without shutting down and depressurising the vessels. This paper describes how nucleonic profiling instruments were retrofitted to the vessels and shows how their operation was able to identify the different layers within the separators. This enabled the time of oil production to be increased and allowed the pro-active use of effect chemicals such as emulsion breakers and defoamers to be applied before the plant became unstable.

SESSION 1C —RESPONDING TO THE OPERATING ENVIRONMENT: SECURITY AND SKILLS

Minding the gaps—identifying and filling holes in offshore oil and gas industry protective security



J. Oldfield, L. Horsington and D. Steel

*Presenters: John Oldfield
Ball Solutions*

Session 1C: 2:00 pm, Meeting room 6

The Federal Government, mindful of the pivotal importance of reliable supplies of oil and gas for the economic stability of the nation, has recently passed the Maritime Transport Security Amendment Act 2005. This introduces a security plan for Australia's offshore oil and gas facilities aimed at combating the likelihood of physical attack by terrorists or other organisations.

Here we discuss that security plan, and identify potential gaps of especial significance for the petroleum industry. Our focus is on the intelligence, surveillance and reconnaissance (ISR) capabilities represented by presently available technologies such as unmanned aerial vehicles (UAVs) plus commercial and allied-government

satellites. In this discussion we dispel various myths (for example, the fiction of continuously-available real-time imagery).

Next we consider the near-term future (next 5–10 years) and analyse the improved ISR capabilities that will result from the burgeoning technologies being introduced during that period. These include the next generation of UAVs (including high-altitude long-endurance platforms) and also continuous (but limited resolution) imagery of the whole globe obtained from geostationary orbit. Again we identify potential security gaps that are pertinent from the perspective of the petroleum industry.

On the basis of our capability gap identification we make recommendations with regard to evolving security concerns that the petroleum industry may wish to consider for submission to the Federal Government: given what ISR science, technology and engineering can deliver, what could be done on a whole-of-nation basis to optimise the defence of our offshore facilities?

Finally, we outline the modelling and simulation capabilities that are available specifically to aid such organisations as the Department of Defence and Coastwatch in efforts to anticipate and thus efficiently and effectively ameliorate the potential for such attacks. These may well be of interest to the industry in that they underpin the analysis mentioned above, and inform what could and perhaps should be done to lessen the risk posed to the nation's petroleum industry.

Pathway to petroleum—easing skill shortages through an industry induction program



S. Starling, D.C. Sanders, R. Kemp and N. Haywood

*Presenter: Steve Starling
ANTCER*

Session 1C: 2:25 pm, Meeting room 6

To provide a pathway to employment, petroleum industry employers are sponsoring a standard induction program, delivered through a national network of training centres, which will be recognised as a passport for workers to gain access to oil and gas facilities.

The Australian upstream petroleum industry faces many

staffing challenges including: difficulties recruiting staff for new developments, competition from overseas projects for construction contractors, and the imminent retirement of an aging workforce. This growing employment demand and limited labour supply has created a strong competitive recruitment market that is characterised by skills shortages. Consequently, the industry is having to recruit workers from non-traditional labour pools and engage contractors whose workforce has limited oil and gas experience. Many of these workers are not familiar with petroleum industry processes, safety procedures, or environmental hazards.

APPEA is supporting the development of the Induction Program to raise awareness and commence acquisition of these petroleum industry competencies; to facilitate wider staff recruitment; to up-skill contractors' workforces; and, reduce repeated induction training while ensuring safety standards are maintained. The Induction Program will establish a qualification underpinned by a competency-based approach that is recognised as the minimum standard of entry level training for all workers in upstream petroleum workplaces. The Induction Program will be delivered

through a national network of purpose-built Induction Centres designed to provide practical hands-on training in a simulated workplace environment.

Demonstration of basic awareness, knowledge and skills will lead to the award of an Induction Passport. The Induction Passport will be required to gain entry to oil and gas production facilities and construction worksites. Holders of an Induction Passport will be issued with a personal Induction Card containing log on details for accessing their passport through a web-based competency register.

Establishment of a standard induction program will deliver considerable benefits for the industry, employers and individual workers. Safety standards will be maintained, productivity increased, and training costs reduced. Wider availability of induction training courses will ease recruitment pressures, promote workforce mobility and place individuals on a competency-based career path.

This paper outlines the objectives, planning and implementation of the Induction Program covering the following aspects:

- Induction Program development—APPEA's career development strategy including production of a career guide, the Coaches Handbook and a business case for

the Induction Program;

- Induction Centre design—Transfield Worley Services' series of design workshops to determine industry requirements and to define training needs;
- induction network sponsorship—the formation of Induction Centres Australia, sponsored and directed by major resource companies including Woodside, Alcoa, BHP Billiton, BP, Caltex, CSBP, Mobil and Shell;
- centre construction program—the construction of the first centre in Perth and plans to open centres in Brisbane, Sydney, Karratha, and Geelong by mid-2007;
- induction training delivery—the delivery, training and operation of Induction Centres by the Australian Centre for Energy and Process Training (ACEPT).
- Induction Card and register—development of a card and internet-accessed database to record successful completion of induction training by the Australian National Training, Competency and Employment Register (ANTCER).

The Induction Program provides a pathway to employment in the petroleum industry which will grow the pool of qualified workers and ease skill shortages.

Maximising indigenous employment in the oil and gas industry in Western Australia



**M. Hammond and
D.C. Sanders**

*Presenter: Meath Hammond
Woodside Energy*

Session 1C: 2:50 pm, Meeting room 6

The skilled labour shortage facing the upstream oil and gas industry is encouraging companies who have already begun to examine ways of increasing the number of indigenous

people in their workforce.

It is common practice for companies to use fly-in fly-out solutions to build a stable workforce in remote areas. While this suits many workers and operations, a simpler solution arguably would be to have a skilled workforce who works in their home region. Many resource companies are now placing a renewed emphasis on training indigenous people to take on roles in the oil and gas industry. A highly skilled local workforce will have benefits for industry with a reduction in logistical costs and an increase in retention rates.

This paper describes the challenges facing companies which elect to develop those skills in a largely technically unskilled indigenous community. The paper uses a range of case studies drawn from company experience. It further showcases some success stories and describes where the industry might need to focus its efforts in order to achieve a more equitable training and employment outcome for Australia's indigenous communities.

SESSION 2A— PESA 2005 *industry review*

Monday, 8 May 2006
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Gold Coast Convention Centre

Exploration highlights for 2005



W Muir
MBA Petroleum Consultants

Time: 3:45 pm, Arena 1

Wal Muir has a BSc (Hons) degree from the University of New South Wales (1978) with a double major in Geology, a major in Pure Mathematics and Honours in Geophysics. He has a Master of Business Administra-

tion (1989) from the University of Queensland. Mr Muir has 27 years of experience in the petroleum exploration and production industry, both within Australia and overseas. He has worked for seven companies during his career, rising to Exploration Manager. Since setting up MBA Petroleum Consultants in 2001 he has undertaken projects for many clients in Australia and overseas. Wal is a member of the Australian Society of Exploration Geophysicists, Queensland Petroleum Exploration and is a Distinguished Member of PESA. He has filled all the executive positions at PESA Queensland, and was Federal President of PESA from 1997 until 1999.

Environment updates for 2005



K Davie
RLMS

Time: 4.10 pm, Arena 1

Kym Davie holds qualifications in chemistry and environmental engineering and more than 15 years experience in environmental management. Kym's

experience has included private industry involving the sugar and explosives industry, the public sector and environmental consulting. Consulting projects in the last 10 years have spanned both on shore and off shore petroleum projects covering most states of Australia. Kym is Manager Environment with RLMS and has been responsible for establishing approval processes, managing environmental approvals, environmental clearances and associated community consultation programs.

Production and development updates for 2005



M Krzus
Woodside

Time: 4.35 pm, Arena 1

Mike Krzus earned a Diploma in Oil and Gas Technology from the British Columbia Institute of Technology before graduating with honors from Tulsa University with a BSC in Petroleum Engineering. He spent three years as a Reservoir Engineer with Home Oil in Calgary before joining Woodside in 1986. He worked as a Business Analyst and Senior Production Technologist before moving

to Woodside's Melbourne corporate office in 1990 to re-negotiate key terms of the original North West Shelf Joint Venture agreements. In 1992 he was cross posted to Shell in the Netherlands (NAM) as a Reservoir Engineer. He returned to Woodside in 1996 as Head of Economics and Planning moving through to Woodside's General Manager NWS Interests where he led the formation of the NWS's successful LNG marketing agency, ALNG. In 2000 he returned to Melbourne briefly to re-establish Woodside's office and manage Bass Strait interests. Since returning to Perth in 2002, he has worked in technical General Manager roles developing and managing oil & gas resources in the NWS (Goodwyn Area) and Woodside's Australian oil assets. Mike is currently the General Manager Upstream Development Capability, which involves providing and maintaining Woodside's technical development and resource management capability, as well as responsibility for technology in Woodside.

SESSION 2B —MAXIMISING VALUE FROM PETROLEUM ASSETS: EVALUATION AND EVALUATION TECHNOLOGY

Australia's gas resources, future production trends and challenges to the identified resource base



P. Williamson, M. Bradshaw

Presenter: Paul Williamson
Geoscience Australia

Session 2B: 3:45 pm, Meeting room 5

Recent developments of gas fields and plans for quickly rapid commercialisation of new gas discoveries challenge the common perception of stranded gas in Australia. These developments provide both national domestic gas requirements and the liquefied natural gas (LNG) export market. The reliability of supply and low political risk means that Australian LNG is likely to continue to provide a significant component of imports to its current clients in the Asia/Pacific region and to a growing number of new clients.

In the past the nation has assumed that our gas resources

would last for many decades. Using the definition of reserves employed by the US Securities and Exchange Commission (USSEC), Australian proven plus probable gas reserves including coal seam methane could be depleted in about 10 years, notwithstanding the possible contribution of PNG gas. However, this definition does not take into account resources that could become reserves in the future. In Australia, Economic Demonstrated Resources (EDR) using the McKelvey classification are offered as an estimate of resources that are economic for development. Gas EDR would last 65 years at the current rate of production. If Australia achieves projected LNG developments to supply the Asia/Pacific LNG market with 62 million tonnes per year by 2030, then the current EDR of Australian gas are likely to be depleted in around 25 years. That is only slightly longer than the normal term of a gas contract. Although Australia has significant Subeconomic Demonstrated Resources of gas, it is not clear if all of these will necessarily ever become economic if they are not now. Nevertheless, current Economic and Subeconomic Demonstrated Resources would be depleted in about 35 years. Thus the increasing demand on Australia's gas resources puts a focus on discovering more gas.

Formation evaluation and static modelling of the Wheatstone gas field



P. Theologou and M. Whelan

Presenter: Paul Theologou
Saros Group

Session 2B: 4:10 pm, Meeting room 5

The Wheatstone gas discovery is located about 110 km north-northwest of Barrow Island in the Dampier Sub-basin, northwest Australia. Gas was intersected within the AA sands of the Mungaroo Formation, and within a thin overlying Tithonian sand. Core was acquired

through the base of the Tithonian sand and the upper section of the Mungaroo Formation.

A combination of logging while drilling, wireline logging, core acquisition and special core analysis has formed the basis of an extensive formation evaluation program for Wheatstone-1. The acquisition of this dataset, and associated interpretation, has allowed Chevron to maximise its ability to characterise the reservoir early in the field's history, and thereby has helped our understanding of the uncertainties associated with the formation evaluation and geological modelling of this fluvial system. Petrological studies indicate that reservoir properties and mineralogy are strongly correlated with the mean grain size of the formation. The mineralogy of the sands is relatively simple with minor quartz overgrowth, K-feldspar dissolution and kaolinite precipitation being the dominant diagenetic events. The better quality sands are generally devoid of significant amounts of clays such as illite-smectite. Within the Tithonian sand, more exotic mineral suites are present including glauconitic and phosphatic minerals.

4D planning and execution strategies for Australian reservoir monitoring projects



A. Long, M. Widmaier and M. Schonewille

*Presenter: Andrew Long
PGS Marine Geophysical*

Session 2B: 4:35 pm, Meeting room 5

Time-lapse (4D) reservoir monitoring is in its infancy in Australia, but is on the verge of becoming a mainstream pursuit.

We describe the 4D seismic acquisition and processing

strategies that have been developed and proven elsewhere in the world, and customise those strategies for Australasian applications. We demonstrate how a multi-disciplinary pursuit of real-time acquisition and processing Quality Control (QC) is an integral component of any 4D project. The acquisition and processing geophysicists must be able to understand all the factors contributing to the 4D seismic signal as they happen. Such an understanding can only arise through rigorous project QC and management using interactive visualisation technology. In turn, the production geologists and reservoir engineers will then receive 4D seismic products that can be robustly and confidently used for the construction of accurate reservoir models and the pursuit of reliable reservoir simulations and forecasts.

SESSION 2C—LEGISLATIVE TRENDS FOR PETROLEUM EXPLORATION AND DEVELOPMENT

Petroleum (Submerged Lands) Act 1967—rewrite and beyond



S. Barrymore

Presenter: Stuart Barrymore
Freehills

Session 2C: 3:45 pm, Meeting room 6

In 2005 the Australian Government introduced into Parliament the long awaited Offshore Petroleum Bill (Bill). Often referred to as the rewrite of the Petroleum (Submerged Lands) Act 1967 (Act), the Bill essentially is a redraft of the Act in a bid to improve readability and clarity. A number of policy changes have

been made, albeit most are minor.

The public consultation process undertaken as part of the rewrite of the Act saw a number of other issues raised. As these were beyond the ambit of the rewrite—that is, to improve readability and clarity of the Act—these issues were temporarily parked until the completion of the rewrite process.

Government will now proceed with a process of review and consultation with industry on these parked issues. In a number of areas divergent views of Government and industry can be expected.

It is not clear the extent to which industry in general and APPEA in particular and its members will actively support the review process or whether inertia will prevail, without substantive progress. Reform has the potential to significantly change and enhance the offshore regime from what it is today. While it is early days, questions remain as to whether the process will produce significant changes in an acceptable timeframe.

Queensland's new petroleum legislation—its implementation and operational challenges



P. Green, S. Matheson, D. Ralph, M. Thompson and T. Brain

Presenter: Peter Green
Department of Natural Resources,
Mines and Water Queensland

Session 2C: 4:10 pm, Meeting room 6

Queensland's new petroleum legislation provides for an up-to-date legislative environment for the petroleum industry in that State. The legislation specifically addressed issues in

relation to upstream competition for exploration acreage and provided for storage of petroleum for a third party. It implemented the coal seam gas regime which provides a mechanism for the optimisation of the State's coal seam gas and petroleum resources. The rights of existing holders of petroleum tenure were protected through the continuation of the Petroleum Act 1923 for selected authorities to prospect and petroleum leases. A new safety regime was implemented with the aim of addressing and managing risk rather than the emphasis being on the prescriptive compliance with Regulations. The safety regime covered all aspects of petroleum, from its production, transportation and use. The implementation of the new legislation required the development of work procedures to assist with uniform decision-making under the new legislation. This is particularly important owing to the continuation of the Petroleum Act 1923.

Legal issues for cooperative and concurrent mining and petroleum production



J. Minchinton

*Presenter: James Minchinton
Clayton Utz*

Session 2C: 4:35 pm, Meeting room 6

Increasingly, miners and petroleum producers are seeking rights of access to the same territory to explore for and extract their favoured resource,

particularly in areas where there are commercial quantities of coal seam gas.

Governments are encouraging miners and petroleum producers to maximise the extraction of their respective resources to supply the growing energy needs of Australian and international markets. These powerful drivers have

led to legislation in several states including Queensland to encourage cooperative resource extraction by different parties operating in the same area.

But while legislation provides an overall framework, significant issues are left to resource companies to resolve through the development of technical and commercial solutions for the joint extraction of resources with limited government involvement. Once a technical and commercial solution is agreed, a legal agreement is necessary to cement the arrangement.

What legal issues need to be considered in agreements between miners and petroleum producers? Will exploration need to be addressed separately from production? How can flexibility be built into the agreement to allow for a change in circumstance? How can disputes be resolved and what role is there for courts and tribunals in disputes? Will standard boilerplate provisions be adequate for the agreement in hand?

This paper seeks to answer some of these questions by highlighting the commercial and legal issues relevant to negotiations with particular reference to coordination arrangements for overlapping mining leases and petroleum leases under the Queensland coal seam gas regime.

SESSION 3A—BIOSTRATIGRAPHIC AND GEOCHEMICAL APPLICATIONS

Initial review of the biostratigraphy and petroleum systems around the Tasman Sea hydrocarbon-producing basins



R. Cook, E. Crouch, J. Raine, C. Strong, C. Uruski, G. Wilson

Presenter: Richard Cook
GNS Science, NZ

Session 3A: 11:15 am, Meeting room 5

Understanding the genesis and habitat of hydrocarbons in a sedimentary basin takes knowledge of that basin at many levels, from basic infill geology to petroleum systems, plays, prospects and detailed sequence stratigraphy. While geophysics can define the

basins and their internal structures, biostratigraphy and paleogeography provide greater understanding of basin geology. Micropaleontology and palynology are the chief tools that we need to define both the environment and dimension of time.

As an example, the reconstruction of the Tasman Sea region to the mid-Cretaceous (ca 120 Ma) shows that the hydrocarbon-producing Gippsland and Taranaki petroleum basins developed at similar latitudes and in similar geological contexts. Other basins within the region have been lightly explored and need evaluation as to the value of further exploration.

As paleontology has developed separately in Australia and New Zealand, comparison of biostratigraphic zones and their chronostratigraphy is critical to understand the similarity or otherwise of the sedimentary record of the two regions. Recent refinement of the NZ timescale and comparative studies on Gippsland Basin wells by NZ paleontologists have provided some key insights that enable us to compare the geological history of both regions more closely, and to recognise similarities in petroleum systems that may enhance petroleum prospects on both sides of the Tasman Sea.

A new perspective on exploring the Cooper/Eromanga petroleum province—evidence of oil charging from the Warburton Basin



C. Hallmann, K. Arouri, D. McKirdy and L. Schwark

Presenter: Christian Hallmann
University of Cologne

Session 3A: 11:40 am, Meeting room 5

The history of petroleum exploration in central Australia has been enlivened by vigorous debate about the source(s) of the oil and condensate found in the Cooper/Eromanga basin couplet. While early workers quickly recognised the source potential of thick Permian coal seams in the Patchawarra and Toolachee Formations, it took some time for the Jurassic Birkhead Formation and the Cretaceous Murta Formation to become accepted as effective source rocks. Although initially an exploration target, the Cambrian sediments of the underlying Warburton Basin subsequently were

never seriously considered to have participated in the oil play, possibly due to a lack of subsurface information as a consequence of limited penetration by only a few widely spaced wells. Dismissal of the Warburton sequence as a source of hydrocarbons was based on its low generative potential as measured by total organic carbon (TOC) and Rock-Eval pyrolysis analyses. As most of the core samples analysed came from the upper part of the basin succession that has been subjected to severe weathering and oxidation, these results might not reflect the true nature of the Warburton Basin's source rocks. We analysed a suite of source rock extracts, DST oils and sequentially extracted reservoir bitumens from the Gidgealpa Field for conventional hydrocarbon biomarkers as well as nitrogen-containing carbazoles. The resulting data show that organic facies is the main control on the distribution of alkylated carbazoles in source rock extracts, oils and sequentially extracted bitumens. The distribution pattern of alkylcarbazoles allows to distinguish between rocks of Jurassic, Permian and pre-Permian age, thereby exceeding the specificity of hydrocarbon biomarkers. While no pre-Permian signature can be found in the DST oils, it is present in sequentially extracted residual oils. However, the pre-Permian molecular source signal is diluted beyond recognition during conventional extraction procedures. The bitumens that are characterised by a pre-Permian geochemical signature derive from differing pore-filling oil

pulses and exhibit calculated maturities of up to 1.6% R_c , thereby proving for the first time the petroleum generative

capability of source rocks in the Warburton Basin.

Natural accumulation of CO₂ in coals from the southern Sydney basin—implications for geosequestration



M. Faiz, S. Barclay, N. Sherwood, L. Stalker, A. Saghafi and D. Whitford

*Presenter: Mohinudeen Faiz
CSIRO Petroleum*

Session 3A: 12:05 pm, Meeting room 5

The southern Sydney Basin is an ideal natural analogue for CO₂ geosequestration because of the widespread CO₂ occurrence, extensive data sets available and general knowledge of gas distribution. The CO₂ mainly occurs adsorbed in coal, incorporated into carbonate minerals and dissolved in formation water.

On this basis, an area of ~900 km² has been chosen for detailed examination.

Gas in the coal seams of this area contain mainly CH₄ and CO₂, the CO₂ content ranging from <1 to 20 m³/tonne. The ¹³C values indicate multiple sources including thermal maturation of coal, microbial alteration of pre-existing gases and magmatic activity as the main source. The highest concentrations of adsorbed CO₂ occur mainly in anticlines and between ~300 and 600 m possibly reflecting inverse relationship with CO₂ solubility in formation water. Carbon dioxide appears to have migrated from the deep-seated magmatic sources along faults and permeable strata, towards structural highs and stratigraphically shallower coal seams.

Calculations indicate that about 78 x 10⁶ tonnes of CO₂ are presently stored in coaly intervals in the study area. Assuming a storage capacity of 20 m³/t for these coal seams, the total CO₂ storage capacity for the coaly intervals is ~880 x 10⁶ tonnes. Using the study area as an analogue for enhanced coal seam methane production, 175 x 10⁶ tonnes of CO₂ could be stored, assuming a 50% CH₄ recovery factor and an average CO₂ sorption capacity 1.5 times that for CH₄.

SESSION 3B—MAXIMISING VALUE FROM PETROLEUM ASSETS: NORTH WEST SHELF

Demeter high resolution 3D seismic survey—revitalised development and exploration on the North West Shelf, Australia



K. Bennett and R. Bussell

Presenter: Kieron Bennett
Woodside Energy;

Session 3B: 11:15 am, Meeting room 6

The newly acquired 3,590 km² Demeter 3D high resolution seismic survey covers most of the North West Shelf Venture (NWSV) area; a prolific hydro-

carbon province with ultimate recoverable reserves of greater than 30 Tcf gas and 1.5 billion bbls of oil and natural gas liquids. The exploration and development of this area has evolved in parallel with the advent of new technologies, maturing into the present phase of revitalised development and exploration based on the Demeter 3D.

The NWSV is entering a period of growing gas market demand and infrastructure expansion, combined with a more diverse and mature supply portfolio of offshore fields. A sequence of satellite fields will require optimised development over the next 5–10 years, with a large number of wells to be drilled.

The NWSV area is acknowledged to be a complex seismic environment that, until recently, was imaged by a patchwork of eight vintage (1981–98) 3D seismic surveys, each acquired with different parameters. With most of the clearly defined structural highs drilled, exploration success in recent years has been modest. This is due primarily to severe seismic multiple contamination masking the

more subtle and deeper exploration prospects. The poor quality and low resolution of vintage seismic data has also impeded reservoir characterisation and sub-surface modelling. These sub-surface uncertainties, together with the large planned expenditure associated with forthcoming development, justified the need for the Demeter leading edge 3D seismic acquisition and processing techniques to underpin field development planning and reserves evaluations.

The objective of the Demeter 3D survey was to re-image the NWSV area with a single acquisition and processing sequence to reduce multiple contamination and improve imaging of intra-reservoir architecture. Single source (133 nominal fold), shallow solid streamer acquisition combined with five stages of demultiple and detailed velocity analysis are considered key components of Demeter.

The final Demeter volumes were delivered early 2005 and already some benefits of the higher resolution data have been realised, exemplified in the following:

- Successful drilling of development wells on the Wanaea, Lambert and Hermes oil fields and identification of further opportunities on Wanaea-Cossack and Lambert-Hermes;
- Dramatic improvements in seismic data quality observed at the giant Perseus gas field helping define seven development well locations;
- Considerably improved definition of fluvial channel architecture in the south of the Goodwyn gas field allowing for improved well placement and understanding of reservoir distribution;
- Identification of new exploration prospects and re-evaluation of the existing prospect portfolio.

Although the Demeter data set has given significant bandwidth needed for this revitalised phase of exploration and development, there remain areas that still suffer from poor seismic imaging, providing challenges for the future application of new technologies.

The Perseus field, North West Shelf—a sleeping beauty awakes



E. Reding, S. Abernethy, D. Boardman and P. Carter

Presenter: Etienne Reding
Woodside Energy

Session 3B: 11:40 am, Meeting room 6

The Giant Perseus field is operated by Woodside on behalf of the North West Shelf venture partners and it is the largest single gas accumulation

supplying the LNG plant in Karratha, Western Australia.

The gross column height totals 360 m and the expected in-place volume has been estimated at 11.9 Tcf. The first penetration in the Perseus accumulation in 1972 was the North Rankin-4 well, seen at the time as testing a small fault block off the side of the North Rankin structure. The full size and potential of the field was only recognised after the start of production of the NRA22 deviated well, drilled

in 1991 from the North Rankin facility and after drilling of 6 appraisal wells in 1995–1996. Two more production wells were added in 2001, increasing production four-fold, waking up the sleeping beauty and confirming the huge potential of the Perseus reservoir. Due to vertical and lateral compartmentalisation, the current producing wells only access a portion of the recoverable gas volumes.

The new high quality Demeter seismic survey acquired in 2003 has resulted in a new seismic interpretation that reveals the structural and stratigraphic complexity of the fluvio-deltaic reservoir and helping to improve the mapping of the drainage pattern. The interpretation was integrated into static and dynamic models, which were calibrated with historical production and pressure data. The models have highlighted the need to drill wells across all fault blocks to achieve an optimal and uniform drainage across the whole field.

In order to access poorly drained compartments, six additional wells will be drilled in 2006, three wells from the North Rankin platform and three subsea wells tied back to the Goodwyn production facility. The new wells aim to achieve a balanced pressure depletion of the field and maximise the understanding of the field's behaviour. New well data, along with the integrated static and dynamic models will also be critical to maximise recovery of reserves and to minimise volumetric uncertainty.

Improvements in seismic imaging, Io Jansz gas field, North West Shelf, Australia



J. Hefti, S. Dewing, C. Jenkins, A. Arnold and B. Korn

Presenter: John Hefti
ExxonMobil

Session 3B: 12:05 pm, Meeting room 6

The Io Jansz gas field is situated in the Carnarvon Basin on the North West Shelf of Australia.

It is Australia's largest gas field, estimated to hold over 20 TCF of gas reserves and covering an area of more than 2,000 km². Following a series of

appraisal wells and a 3D seismic survey, this field is moving rapidly towards development. Image quality of the 3D provided significant uplift over existing 2D surveys in the area. Expectations for resolution and business targets have been met through careful planning and the provision of staged deliverables.

Despite the exceptional data quality, a number of technical challenges were encountered that led to operational changes and adaptations by the project team. Source height statics and severe image distortion due to overburden are examples of some of the challenges addressed. Consideration of the exploration history of this field and its associated imaging gives insight into the improvements in image quality that can be realised by careful selection of acquisition and processing parameters, high levels of quality control (QC) and modern processing algorithms. The ultimate success of this project was achieved through close cooperation within interdisciplinary teams comprised of partner technical staff and the seismic acquisition and processing contractor.

SESSION 3C—NEW TRENDS AFFECTING GOVERNANCE AND STRATEGY IN THE PETROLEUM INDUSTRY

Business reporting and communications—a key capital management tool for the Australian petroleum industry



M. Bray

Presenter: Michael Bray
KPMG

Session 3C: 11:15 am, Meeting room 7

In their most recent world investment outlook, the International Energy Agency (IEA) forecast a global petroleum investment requirement of US\$6 trillion through to 2030.

The annual average requirement is very high relative to capital raising levels in the sector. The IEA, however, predicts that the investment gap should be able to be financed.

It goes on to suggest in particular that the future success of the Australian petroleum sector will not be necessarily constrained by access to sufficient capital, rather, the key impediment will be the availability of attractive and viable investment propositions.

Organisations that are able to mount such a proposition will be doing so in the face of present reporting limitations, technological change, cross-sector capital competition, global energy market changes, constraints

of capital markets and short-term perspectives, impacts of regulation, threats on security of licences to operate and the importance of corporate reputations in areas like sustainability and social performance.

A new model of business performance reporting and communications is required for the petroleum sector and businesses to meet these challenges. Definitions of business reporting and communications are set out in Box 1.

Critical areas in a new model are:

- stimulating improved stakeholder understanding of business models;
- synchronising stakeholder decision-making models with business performance reports; and,
- precision in stakeholder decision-making processes based upon insights about performance drivers and risks and the performance outlook.

This paper explains why fit-for-purpose business reporting and communications are critical success factors—not only in attracting the financing to meet the 25-year investment requirement, but, more importantly, in helping Australian petroleum businesses to differentiate their performance from others.

Box 1

Business Reporting

The various reports that a business produces and the processes used to produce and distribute them.

Business Communications

The way in which a business uses its reports to stimulate precise decisions by its key stakeholders, which have an impact on the cost and availability of capital, its reputation and licences to operate.

Whistleblowing, oil, money and risk



D. Young

Presenter: Doug Young
Young Law

Session 3C: 11:40 am, Meeting room 7

Statutory whistleblower laws in the US have resulted in the recovery of billions of dollars of unpaid royalties from petroleum companies over the past decade.

Eighteen months ago, Australia introduced whistleblower laws that could have achieved the same result if the royalty avoidance had occurred here. This paper examines the emergence and application of those laws, and policies of regulators which achieve a similar result. It also argues that the adoption of a whistleblower policy, which includes protection for the whistleblower, is not only desirable, but an essential tool for managing risk.

At a secondary level, it looks at the types of reported actions, typically taken against whistleblowers, that are now outlawed by the new whistleblower protection provisions.

Australia's new international taxation regime—the fiscal impact for the oil and gas industry



**R. Henderson and
D. Watkins**

*Presenter: Rod Henderson
KPMG*

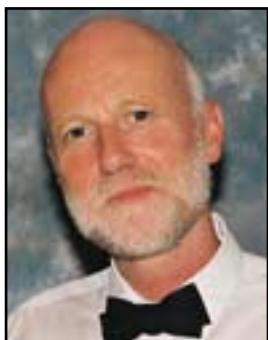
Session 3C: 12:05 pm, Meeting room 7

Changes to Australia's international tax regime as part of the Government's Review of International Taxation Arrange-

ments should be good news for the oil and gas industry. The nature of the industry is that Australian-based companies often look offshore to spread their risk and find new oil and gas opportunities. Likewise, many foreign oil and gas companies have come to Australia. The tax reforms should simplify and encourage greater investment by providing additional exemptions and other concessions to achieve greater tax efficiency. This paper will seek to explain the new reforms and illustrate how they will benefit investors and participants in the oil and gas industry.

SESSION 4A—SMALL INDEPENDENTS' FORUM— NEGOTIATING THE APPROVALS MAZE

Native Title and cultural heritage negotiations



C. Lane

Presenter: C Lane
Victoria Petroleum

Session 4A: 2:00 pm, Meeting room 5

Chas Lane completed a BSc in Applied Geology from RMIT in 1977 and started in the oil patch as a mudlogger in Perth in 1979. During the early '80's

resources boom he moved to Sydney with Australian Aquitaine, then moved his young family back to Perth with Hudbay Australia. In 1983 he joined the young Strata Oil to continue development work on the Woodada Gas Field, and four years later joined Victoria Petroleum, first in new ventures and then as JV operations manager, where he currently holds the position of Exploration Manager. Chas is a past-president of the PESA WA Branch, co-author of an APPEA Best Paper, a keen aviator and is active in Orienteering WA.

Environmental approvals from exploration to production



M. Malaxos

Presenter: M Malaxos
ARC Energy

Session 4A: 2:25 pm, Meeting room 5

Marie has a Diploma in Electronic Engineering and a Post Graduate Diploma in Business Management. She started her working career in the upstream

side of the industry performing a variety of technical and management roles working on the Dampier to Bunbury, Goldfields and Parmelia Pipelines in Western Australia. Her more recent roles have included Engineering, Technical Services, Development and Surface Operations Manager.

Marie joined ARC Energy Ltd in 2002 and was recently appointed Chief Operating Officer. ARC is an independent ASX-listed oil and gas exploration and production company that's rejuvenated exploration and consequently production in the Perth Basin, Western Australia.

Marie is a member of the Institute of Company Directors and is a member of several industry (APPEA and APIA) committees. Marie is married with no children.

Production Licence and safety approvals



A. Young

Presenter: A Young
Anzon Australia Limited

Session 4A: 2:50 pm, Meeting room 5

Andrew A. Young, Executive Director/Chief Operating Officer, Anzon Australia Limited joined the company in March 2006 to lead the oil and gas development of three fields in Gippsland Basin offshore SE Australia. Andrew has an extensive background of

30 years in the industry, having held technical and leading management positions in consulting, operating and contract service companies, including onshore and offshore oil/gas operations, gas processing, transportation, distribution, specialist pipeline engineering services and drilling contract services. Andrew's career has included Exxon, Bridge Oil, NZ Natural Gas Corporation, Century Drilling Limited, and GCA. He has served on the Board of SPE as Asia Pacific Regional Director from 1993 through 1996 and again from 2002 through 2004 as the President (2003). Young serves on the Advisory Board of University of New South Wales School for Petroleum Engineering, recently completed a four-year term as a director of the National Safety Council of Australia, and is a member of the Australian Institute of Company Directors. He holds a BE (Chemical Eng) from Melb University and an MBA from University of Rochester NY.

Frank Krstic of Sydney Gas Co will also be a member of the Small Independents' Forum.

SESSION 4B—GEOLOGICAL SEQUESTRATION OF CARBON DIOXIDE—EXPLORING THE ISSUES

Gippsland Basin geosequestration: a potential solution for the Latrobe Valley brown coal CO₂ emissions



C. Gibson-Poole, L. Svendsen, J. Underschultz, M. Watson, J. Ennis-King, P. van Ruth, E. Nelson, R. Daniel and Y. Cinar

Presenter: Catherine Gibson-Poole
CO2CRC

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

Geosequestration of CO₂ in the offshore Gippsland Basin is being investigated by the CO2CRC as a possible method for storing the very large volumes of CO₂ emissions from the Latrobe Valley area. A storage capacity of about 50 million tonnes of CO₂ per year for a 40-year injection period is required, which will necessitate several individual storage sites to be used both sequentially and simultane-

ously, but timed such that existing hydrocarbon assets are not compromised. Detailed characterisation focussed on the Kingfish Field area as the first site to be potentially used, in the anticipation that this oil field will be depleted within the period 2015–25. The potential injection targets are the interbedded sandstones, shales and coals of the Paleocene-Eocene upper Latrobe Group, regionally sealed by the Lakes Entrance Formation. The research identified several features to the offshore Gippsland Basin that make it particularly favourable for CO₂ storage. These include: a complex stratigraphic architecture that provides baffles which slow vertical migration and increase residual gas trapping; non-reactive reservoir units that have high injectivity; a thin, suitably reactive, low permeability marginal reservoir just below the regional seal providing additional mineral trapping; several depleted oil fields that provide storage capacity coupled with a transient flow regime arising from production that enhances containment; and, long migration pathways beneath a competent regional seal. This study has shown that the Gippsland Basin has sufficient capacity to store very large volumes of CO₂. It may provide a solution to the problem of substantially reducing greenhouse gas emissions from the use of new coal developments in the Latrobe Valley.

Commercial and technical issues for large-scale carbon capture and storage projects—a Gippsland Basin study



B. Hooper, B. Koppe and L. Murray

Presenter: Barry Hooper
CO2CRC

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

The Latrobe Valley in Victoria's Gippsland Basin is the location of one of Australia's most important energy resources—extremely thick, shallow brown coal seams constituting total useable reserves of more than 50,000 million tonnes. Brown coal has a higher moisture content than black coal and generates more CO₂ emissions per unit of useful energy when combusted. Consequently, while the Latrobe Valley's power

stations provide Australia's lowest-cost bulk electricity, they are also responsible for over 60 million tonnes of CO₂ emissions per year—over half of the Victorian total. In an increasingly carbon constrained world the ongoing development of the Latrobe Valley brown coal resource is likely to require a drastic reduction in the CO₂ emissions from new coal use projects—and carbon capture and storage (CCS) has the potential to meet such deep cuts. The offshore Gippsland Basin, the site of major producing oil and gas fields, has the essential geological characteristics to provide a high-volume, low-cost site for CCS. The importance of this potential to assist the continuing use of the nation's lowest-cost energy source prompted the Australian Government to fund the Latrobe Valley CO₂ Storage Assessment (LVCSA).

The LVCSA proposal was initiated by Monash Energy (formerly APEL, and now a 100% subsidiary of Anglo American)—the proponent of a major brown coal-to-liquids plant in the Latrobe Valley. Monash Energy's plans for the 60,000 BBL per day plant include CCS to store about 13 million tonnes of CO₂ per year. The LVCSA, undertaken for Monash Energy by the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC), provides a medium to high-level technical and economic characterisation of the volume and cost potential for secure geosequestration of CO₂ produced by the use of Latrobe

Valley brown coal (Hooper et al, 2005a). The assessment's scope includes consideration of the interaction between CO₂ injection and oil and gas production, and its findings have been publicly released for use by CCS proponents, oil and gas producers and all other interested parties as an executive summary, (Hooper et al, 2005b), a fact sheet (Hooper et al, 2005c) and a presentation (Hooper et al, 2005d).

The LVCSA identifies the key issues and challenges for implementing CCS in the Latrobe Valley and provides a reference framework for the engagement of stakeholders. In effect the LVCSA constitutes a pre-feasibility study for the implementation of geosequestration in support of the continuing development of Victoria's brown coal resources.

The LVCSA findings indicate that the Gippsland Basin has sufficient capacity to safely and securely store large volumes of CO₂ and may provide a viable means of substantially reducing greenhouse gas emissions from coal-fired power plants and other projects using brown coal in the Latrobe Valley. The assessment also indicates that CO₂ injection could well be designed to avoid any adverse impact on adjacent oil and gas production, so that CO₂ injection can begin near fields that have not yet come to the end of their productive lives. However, CCS proposals involving adjacent injection and production will require more detailed risk management strategies and continuing cooperation between prospective injectors and existing producers.

Geosequestration—a solution for Australia?



A. Warburton, J. Grove and S. Then

*Presenter: Allison Warburton
Minter Ellison*

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

Managing its growing greenhouse gas emissions has become a key issue in Australia's energy

and environmental policy.

Geological storage (or geosequestration) of carbon dioxide emissions produced by power stations and gas processing plants is being promoted as an innovative way to combat the threat of climate change. Australian governments and industry are interested in the process

because it would allow Australia to continue to rely on its extensive fossil fuel reserves as an energy source and export commodity into the future. The process, however, is still in an experimental phase. If geosequestration does prove to be a viable technology then regulatory changes will be required to facilitate large-scale commercial use.

This paper discusses the status of geosequestration development in Australia. It considers some of the key legal and regulatory issues that would need to be addressed to allow geosequestration projects to proceed, including:

- jurisdictional issues between State and Commonwealth governments;
- access to land and rights to use storage sites;
- priorities between competing land uses;
- potential application of third party access regimes to geosequestration infrastructure;
- potential legal liabilities, especially in the longer term; and,
- the extent to which a consistent national approach to the regulation of geosequestration may be required.

This paper is general in nature and must not be relied upon as legal advice in any respect.

SESSION 4C—FINANCING AND DECISION MAKING IN THE PETROLUEM INDUSTRY

New equity raising methods for listed companies: jumbos and RAPIDs—optimised rights offers and placements



J. Philips and V. Mathewson

Presenter: James Philips
Minter Ellison

Session 4C: 2:00 pm, Meeting room 7

Traditional methods of equity capital raising by listed companies may not always be the best way to meet the needs of both the companies and shareholders¹.

The timetable for a rights issue (being a pro rata offer to all shareholders to subscribe for shares) may be too long to fund an acquisition or project. A placement (being

an offer to institutional investors for a certain number of shares), while giving a company certainty and a shorter timeframe, excludes the company's shareholders from participation in the capital raising.

Innovative new capital raising structures have been developed. Two of these are known as the jumbo and the RAPIDs™ structures.

Broadly, they both combine aspects of a rights offer and a placement. The rights offer is split into two stages; the first stage involves offering institutional investors on the company's share register their component of the rights offer, which can be done in a short timeframe. This institutional component of the rights offer is combined with a placement to other institutional investors through a bookbuild. The retail component of the rights offer is then conducted on the Australian Stock Exchange Limited's (ASX) normal (longer) timetable. The offer structures enable funds raised from the institutional rights offer and placement to be received quickly, while still enabling retail shareholders to participate in the offer and avoid dilution.

A review of recent Australian E&P transactions



S. Whitaker and R. Williams

Presenter: Simon Whitaker
RISC

Session 4C: 2:25 pm, Meeting room 7

A review of asset transactions conducted in and around Australia in 2005 will be presented. The value of publicly available transactions involving

oil and gas assets, onshore and offshore will be compared and contrasted. Comparisons with transaction volume and value will be made with activity levels in recent years. It is anticipated that this will be the beginning of an annual review of acquisition and divestment activities in the Australian upstream industry.

Sequential and systems approaches for evaluating investment decisions—influence of functional dependencies and interactions



M. Al-Harthy, A. Khurana, S. Begg and R. Bratvold

*Presenter: Mansoor Al-Harthy
Sultan Qaboos University, Oman*

Session 4C: 2:50 pm, Meeting room 7

Development decision-making practices in the oil and gas industry focus on detailed modelling of every decision

parameter—such as reserves, production schedule, facilities design, costs and prices—individually, without due attention to the dependencies and interactions between these parameters. Dependencies and interactions are captured in modelling of uncertainties in some parts of the system (such as reserves and production schedules) but not in others.

Modelling uncertainty without modelling dependencies fails to benefit from investing in the values of flexibility and information. Modelling of dependencies and interactions promotes the integration of all the relevant parameters of petroleum projects in a holistic manner.

Separate and sequential modelling of individual

components of investment decisions limits the ability to examine how changes in one component impact on other components of the system. On the other hand, the systems approach views a development decision as an integrated unit, including components such as reserves, production schedule, facilities design, costs and prices.

This paper hypothesises that modelling dependencies and interactions should not be limited to estimating reserves, but should be extended to model the total petroleum system. We believe that there is potential for adding value to petroleum projects by modelling dependencies and interactions in a holistic systems-based stochastic environment.

The objective of this paper is to demonstrate the impact of functional dependencies and interactions on the development decision of a hypothetical offshore oil field. Specifically, we show the difference between the treatment of functional dependencies and interactions together with their implications for the sequential and systems approaches using Monte Carlo Simulation (MCS) based stochastic modelling to capture uncertainties.

The systems approach captures interactions and dependencies while the sequential approach ignores them. Ignoring interactions leads to under-estimating the mean Net Present Value (NPV) as well as the standard deviation (by 54% and 44% respectively in our example). Furthermore, in our example, the P10, P50 and P90 (NPV's) are all under-estimated by 20%, 50% and 50% respectively. These results clearly show that proper systematic treatment of dependencies and interactions can have significant impact on petroleum project evaluation.

SESSION 5A—EXPLORATION AND DEVELOPMENT: CONCEPTS AND TECHNOLOGIES

Multistage hydraulic fracturing with production intervals—a promising technology for reservoirs subject to reverse faulting stress regimes



M. K. Rahman

Presenter: Khalil Rahman
School of Oil and Gas, UWA

Session 5A: 4:35 pm, Meeting room 5

The performance of hydraulic fracturing technology has not been so promising for some Australian tight-gas reservoirs.

The existence of reverse faulting stress regimes (i.e. the vertical stress is the minimum one) in these reservoirs is found to be one reason among many others. Previous studies have established that the vertical hydraulic fracture initiated from a vertical well in a reverse faulting stress regime severely turns and twists to become horizontal while fracturing fluid is injected for further propagation of the fracture. This severely turned and twisted fracture

impedes the fluid and proppant (engineered sand grains) injection and thus the fracturing job results in a short and constricted fracture. This is considered to be one of the major reasons for premature screen-outs that occur at extremely high-pressure on many occasions in the field, and the subsequent disappointingly low production rates. The aim of this paper is to present the results of an investigation with a model-scale gas reservoir to avoid this problem by carrying out the fracture treatments in a number of stages with production intervals. The basic mechanism that would allow the growth of a long, planar, productive fracture in such a manner is the production-induced stress change around the fracture tip. A simplified propped fracture configuration is modelled in a hypothetical small-scale reservoir with idealistic material properties. Production is simulated in time by varying different parameters and the production-induced stress changes are characterised by coupled fluid flow and deformation analysis. It is found from parametric results that the non-uniform reservoir pressure depletion induces a suitable stress state at the fracture tip for further planar propagation. The duration of production to induce the suitable stress state is found to be dependent on a number of parameters. The paper also highlights the implications and limitations of the concept for hydraulic fracturing in the mentioned reservoir conditions, and discussed further research directions.

Unconventional borehole breakout rotation analysis provides a QC tool for stress models



B. Camac, S. Hunt, P. Boulton and M. Dillon

Presenter: S. Hunt
Australian School of Petroleum, University of Adelaide

Session 5A: 4:10 pm, Meeting room 5

In distinct element (DEM) numerical stress modelling, the principal stress magnitudes and orientations are applied to the boundary of the 3D model. Due to data restrictions and typical depths of investigation, it is possible to have much uncertainty in the conventional methodologies used to constrain the regional principal stress magnitudes and orientations.

A case study from the Kupe Field in the Taranaki Basin, New Zealand is presented where the uncertainty in the input data made it difficult to determine which stress re-

gime—a transitional normal/strike-slip or reverse/thrust—is active at reservoir depth (approximately 3,000 m). The magnitudes and orientation of the principal stresses were constrained using published techniques. A sensitivity analysis was applied to account for the uncertainty in the input data. A model of the Kupe Field incorporating 18 major faults was subsequently loaded under both derived stressed regimes, using the calculated magnitudes.

Borehole breakout analysis was used to acquire interpreted orientations of the maximum principal stress (S_{hmax}). The work presented herein describes a different or unconventional approach to the general petroleum geomechanics methodology. Typically, the breakout data is averaged to get one data point per well location. Here, all breakout data is retained and displayed vertically. The data is actively used and the variations with depth can be seen to show how faults can generate local perturbations of the regional stress trajectory. These data are then used to compare the observed or field indications of the breakouts along the borehole with the modelled S_{hmax} predicted by both end point DEM stress models. This comparison has provided additional confidence in the derived stress regime and the derived stress models for the Kupe field. The stress models are used to predict areas of enhanced hydrocarbon pooling and low seal integrity.

Present-day state-of-stress of southeast Australia



**E. Nelson, R. Hillis,
M. Sandiford, S. Reynolds
and S. Mildren**

*Presenter: Scott Mildren
JRS Petroleum Research*

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

There have been several studies, both published and unpublished, of the present-day state-of-stress of southeast Australia that address a variety of geomechanical issues related to the petroleum industry. This paper combines present-day stress data from those studies with new data to provide an overview of the present-day state-of-stress from the Otway Basin to the Gippsland Basin. This overview provides valuable baseline data for further geomechanical studies in southeast Australia and helps explain the regional controls on the

state-of-stress in the area.

Analysis of existing and new data from petroleum wells reveals broadly northwest-southeast oriented, maximum horizontal stress with an anticlockwise rotation of about 15° from the Otway Basin to the Gippsland Basin. A general increase in minimum horizontal stress magnitude from the Otway Basin towards the Gippsland Basin is also observed. The present-day state-of-stress has been interpreted as strike-slip in the South Australian (SA) Otway Basin, strike-slip trending towards reverse in the Victorian Otway Basin and borderline strike-slip/reverse in the Gippsland Basin. The present-day stress states and the orientation of the maximum horizontal stress are consistent with previously published earthquake focal mechanism solutions and the neotectonic record for the region. The consistency between measured present-day stress in the basement (from focal mechanism solutions) and the sedimentary basin cover (from petroleum well data) suggests a dominantly tectonic far-field control on the present-day stress distribution of southeast Australia. The rotation of the maximum horizontal stress and the increase in magnitude of the minimum horizontal stress from west to east across southeast Australia may be due to the relative proximity of the New Zealand segment of the plate boundary.

SESSION 5B—MAXIMISING VALUE FROM PETROLEUM ASSETS: APPRAISAL AND RE-APPRAISAL

Improving our understanding of Gippsland Basin gas resources—an integrated geoscience and reservoir engineering approach



**T. Hart, B. Mamuko,
K. Mueller, C. Noll, T. Snow
and A. Zannetos**

*Presenter: Andy Zannetos
Exxonmobil*

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

The Barracouta and Marlin gas fields are located within the Gippsland Basin, offshore Australia, and have been on production for more than 36 years. Combined, these fields represent over 6.5 TCF of recoverable gas. Structurally the fields are relatively simple, but they are significantly warped in seismic two-way time by high velocity channels above the reservoir that make time to depth conversion and volumetric assessment difficult.

Fundamental to management of these fields has been

surveillance data and history matching based on simulation of detailed geologic models. In the late 90s, the observation was made that actual contact movement within the fields was lagging behind model predictions, suggesting that the fields were potentially larger than previously assessed.

Results from the 3D seismic surveys acquired in Barracouta in 1999 and both fields in 2001 were used to help answer questions related to contact movement, resource size and remaining recoverable gas. Two significant outcomes from these surveys were the observation of double Direct Hydrocarbon Indicators (DHIs) across both fields, representing both the original and current gas-water contacts (OGWC and CGWC respectively), and mappable amplitude features related to depositional trends.

The double DHIs were used to calculate contact movement and sweep uniformity. The original contact DHI was also used to assist in depth conversion. The position of shorelines and upper to lower delta plain boundaries were extracted from the seismic amplitude features to refine net-to-gross distribution.

The interpreted 3D data are integrated with well logs and surveillance data to create detailed geologic models used for material balance simulation of reservoir performance. A good match was obtained between the model and field measured pressures and contact movement. Based on this work, the estimates of recoverable gas in the two fields were increased by 0.7 TCF, a 14% increase over the previous estimate.

Appraising the Yolla field in the Bass Basin—how effective data collection, analysis and integration increased estimated hydrocarbon volumes in place



**D. Brooks, B. Pidgeon,
A. Hall, R. Taylor and
J. Parvar**

*Presenter: Deidre Brooks
Origin Energy*

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

Between June and October 2004, two development wells (Yolla-3 and -4) were drilled on the Yolla field in Bass

Strait by the T/L1 joint venture. The top and intra-Eastern View Coal Measures (EVCN) hydrocarbon-bearing reservoirs in the field were intersected close to prognosis. A previously undiscovered oil-bearing intra-EVCN sand was encountered in Yolla-4 and the upper EVCN gas and oil bearing reservoir section was completed in Yolla-3 and its productivity confirmed.

A key objective of the development drilling campaign was to collect detailed geological and engineering data to assist in field development and quantification of the resource. Subsequent interpretation of these data led to a revision of the depositional facies and reservoir parameters and provided new inputs into a complex 3D reservoir model.

The new reservoir model resulted in an upward revision in calculated gas in-place volumes for the intra-EVCN gas reservoirs of about 100 bcf ($2,832 \text{ m}^3 \times 10^6$) or 20% of the pre-drill field size to 600 bcf ($16,991 \text{ m}^3 \times 10^6$) and a corresponding increase in recoverable reserves estimates. The upper EVCN is now interpreted to hold 16.5 MMstb ($2,623,005 \text{ kL}$) of oil-in-place and total gas-in-place including the gas cap and the solution gas in the oil leg of 33

bcf ($934.5 \text{ m}^3 \times 10^6$). These volumes add to the gas reserves for the field, and it is expected that the volatile oil leg will contribute to a richer liquids yield when the zone is

produced. The new oil pool in the intra-EVCM has been provisionally estimated at 3.2 MMstb (508,704 kL) oil-in-place with associated solution gas of 2.5 bcf ($71 \text{ m}^3 \times 10^6$).

More wells, more oil—a case study of reserves growth in the Kenmore field



J. Skinner, M. Altmann and T. Wadham

*Presenter: Janet Skinner
Beach Petroleum*

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

The Kenmore oil field in the Eromanga Basin of southwest Queensland was discovered in 1985. Since then, a further 32 wells have been drilled and more than 12.5 MMSTB of oil has been produced from the Birkhead Formation/Hutton Sandstone. Oil production over the last year has averaged

1,220 barrels per day totalling some 0.45 million stock tank barrels (MMSTB)

Oil reserves in Kenmore were originally estimated at 2.2 MMSTB following the Kenmore-1 discovery well drilled in 1985. In the following 20 years, infill drilling, a 3D seismic survey, various reservoir studies and better-than-expected recovery efficiency, have steadily increased the ultimate recoverable reserves to the current estimate of 14.3 MMSTB.

The growth of reserves at Kenmore is primarily attributed to better drainage of the complex reservoir framework within the lower Birkhead Formation resulting from recognition of the variable lateral connectivity of the reservoir. Due to the initial estimate of the ultimate field reserves being significantly smaller than now recognised and the resultant conservative drilling program, the economic value of the field was not maximised. This experience has implications for the ongoing development of the Kenmore field and suggests that other Birkhead/Hutton oil fields should be developed more aggressively to prevent history repeating itself.

SESSION 5C—TAXATION ISSUES AND THE PETROLEUM INDUSTRY

Long-term construction contracts—some issues in relation to the taxation of financial arrangement rules



J. Murray and A. Miller

*Presenter: Amanda Miller
PricewaterhouseCoopers*

Session 5C: 3:45 pm, Meeting room 7

The Gorgon gas development project has an estimated cost of A\$11 billion, the Bayu-Undan gas project has an estimated cost of A\$4.2 billion and the Otway Basin gas project has an estimated cost of A\$1.1 billion. The specialised equip-

ment, technology and labour required for these costly oil and gas infrastructure projects must usually be sourced internationally and as such their costs are typically denominated in United States (US) dollars. Due to the value and long-term nature of these projects, associated foreign exchange gains and losses are often significant.

From an Australian income tax perspective, the treatment of foreign exchange gains and losses has been particularly uncertain and inconsistent for many years. As a result, taxation legislation in this area has recently undergone significant change. The new Taxation of Financial Arrangements legislation introduced in December 2003, has raised some complex and practically challenging concepts in relation to foreign exchange gains and losses on long term construction contracts. This paper will address two such concepts, namely forex realisation event 4 and the short-term foreign exchange rules. In particular, it will consider some of the potential compliance risk areas and how they can be managed when applying these concepts to long-term construction contracts.

Petroleum Resource Rent Tax issues affecting the use of deductions



G. Cathro

*Presenter: Grant Cathro
Allens Arthur Robinson*

Session 5C: 4:10 pm, Meeting room 7

Careful planning is necessary when buying or selling an interest in an offshore petroleum area, farming into a project or setting up operating arrangements for a project within the petroleum resource rent tax (PRRT) net, to ensure maximum use of deductions for exploration expenditure and other costs of the project.

The rules dealing with transfers of interests in petroleum projects and with the transfer of undeducted exploration expenditure from an unprofitable project to a profitable

one, encourage participants to ensure that they hold an interest in the relevant area before they commence exploration activity.

There are special rules applying in the PRRT context to the transfer of interests in a project from one person to another. It is important to understand how these rules apply as they can impact both upon who is liable to pay PRRT on the project and the ability to use and transfer exploration expenditure.

Certain head-office costs are excluded from deductibility when calculating the taxable profit of a project. The manner in which a project is structured may impact on the practical implications of this exclusion.

This paper provides an overview of the PRRT regime, the implications of the transfer of an interest in a project and the requirements which must be satisfied in order to transfer exploration expenditure between projects. The paper then contains a discussion of a number of issues in relation to deductibility and use of exploration expenditure, the transfer of interests in permits and the use of contractors to undertake activities on behalf of joint venture participants maximising the scope of available deductions.

The new loss recoupment rules— good news, bad news



J. Murray

*Presenter: David Lewis
PricewaterhouseCoopers*

Session 5C: 4:35 pm, Meeting room 7

The Federal Government has proposed to change the tests to enable companies to recoup losses for tax purposes. There is some good news and some bad

news. This paper will discuss the changes and comment on how the changes may impact oil and gas companies.

The good news is that the continuity of ownership rules will be changed for widely held companies from 1 July 2002, to simplify compliance. In essence, stakeholders of less than 10% will be attributable to a single notional entity, making it easier to test whether there has been a

sufficient continuity of ownership to pass this test.

The bad news is that the government also proposes to remove the same business test for companies whose total income is more than \$100 million. This is proposed to apply to losses incurred in income years commencing on or after 1 July 2005.

With oil at US\$60 per barrel it is likely there will be a number of oil producers whose income will exceed the \$100 million test, particularly where there has been an accelerated development of the fields. It is also possible given the high costs of exploration and move into production that companies may have undeducted losses for income tax purposes. The problem is that for junior/medium level producers particularly, equity transactions are not uncommon and the opportunities for breaching the continuity of ownership test are increased. Without access to the same business test these losses may be at risk of being lost permanently.

It may be possible to structure an instrument that enables the oil producer to issue paper resembling equity in certain ways, without causing a breach of the continuity of ownership.

The paper discusses this and other issues in relation to the proposal.

SESSION 6A—PETROLEUM FRONTIERS OF AUSTRALASIA

The Morum Sub-basin petroleum system, Otway Basin, South Australia



P. Boulton, D. McKirdy, J. Blevin, R. Heggeland, S. Lang and D. Vinall

Presenter: Peter Boulton
Australian School of Petroleum, University of Adelaide

Session 6A: 11:15 am, Meeting room 5

The Morum Sub-basin (250 x 150 km), lies beyond the shelf edge at the northern end of the Otway Basin and not a single well has been drilled into this 6 s TWT deep, Albian to Late Cretaceous depocentre. A geochemical analysis of an oil show within late Albian-Cenomanian(?) rocks from a well close to the edge of this depocentre, is consistent with an anoxic marine source and strongly suggests that this is migrated oil. The oil show is also consistent with the modelled development of a significant oil-prone source pod in the Morum Sub-basin north of the Discovery Bay High.

Analysis of two key seismic lines (Palmowshi et al, 2004) and potential field data have shown that the Morum Sub-basin is tectonically quite distinct from the Nelson Sub-basin which lies to the south of the Discovery Bay high. Thus the proposed Albian marine source pod is probably absent in the Nelson Sub-basin and the rest of

the Otway Basin where the Cenomanian unconformity is well documented.

Beach strandings of heavy asphaltite (4-9° API) containing mid Cretaceous marine biomarkers are common along a section of the coast nearby to the Morum Sub-basin (Edwards et al, 1998). Here, the summer Bonney Upwelling is supplied by cold waters of the deep-water Flinders Current (Middleton and Platov, 2003) and appears to be focussed upwards onto the shelf by canyons incised in the continental slope. Near the base of the slope one canyon cuts as deeply as 1.6 km into an interpreted toe-thrust inversion structure that may contain the Late Albian source rocks. Numerous sea-surface anomalies have been detected over this canyon using Synthetic Aperture Radar images. Potential gas chimneys, diapiric structures and amplitude anomalies are also interpreted on a regional, deep seismic line that transects the canyon. We postulate that hydrocarbons are migrating upwards along faults to the distal canyon floor where they form tar mats (asphaltite), while lighter hydrocarbons escape to the sea surface. The tar mats are then dislodged from the seabed and swept up the canyon by bottom currents driven by the summer upwelling. Tar balls entrained in the upwelling water are spread across the shelf and eventually moved ashore as beach strandings by winter storms that come in from the west.

A seismic flat-spot, which is observed within an interpreted Turonian lowstand fan complex, indicates that hydrocarbons may occur within a potentially extensive reservoir that could be present in numerous tilted fault structures that lie just above the postulated late Albian source pod.

A new model for the structural framework and tectonic evolution of the Bremer Sub-basin, western Bight Basin



C. Nicholson, B. Bradshaw, D. Ryan and R. O'Leary

Presenter: Chris Nicholson
Geoscience Australia

Session 6A: 11:40 am, Meeting room 5

The Bremer Sub-basin is a frontier depocentre and one of a series of Mesozoic extensional

basins along Australia's southern margin. No petroleum exploration wells have been drilled and to date seismic data coverage has been sparse. As part of the New Oil program, an integrated basin analysis was undertaken based on newly-acquired seismic and dredge rock samples. Structural mapping shows that depocentres are formed by a series of en-echelon fault-bounded half graben perched on the upper continental slope. New seismic velocity data has shown the depocentres contain up to 9,600 m of sediment fill. The east-west to northeast-southwest trending Albany-Fraser mobile belt extends beneath the shelf and has influenced the development and structural architecture of the sub-basin.

Integration of seismic data and dredge samples has identified four main basin phases: a) Late Jurassic upper crustal syn-rift extension leading to the formation of five major half graben; b) Berriasian to Valanginian post-rift thermal subsidence; c) Valanginian to late Aptian

reactivated extension, intra-basin half graben growth and continued thermal subsidence; and, d) late Aptian to Maastrichtian thermal subsidence. Initial terrestrial sedimentation was succeeded by marine deposition in the Aptian prior to Australian-Antarctic breakup, which on this western end of the margin appears to be Turonian. The structural architecture sets up a range of trap styles, primarily anticlines, structural/stratigraphic traps and

rotated fault blocks that formed prior to breakup and the modelled onset of hydrocarbon generation. Dredge sample lithological data supports the presence of viable reservoir, seal and source facies within the pre-Turonian succession. Interpretation of this new data set in the Bremer Sub-basin shows that it has the potential to be a significant untested hydrocarbon province.

Basement and crustal controls on hydrocarbons maturation—lessons from Bremer Sub-basin for other frontier exploration areas



A. Goncharov, I. Deighton, P. Petkovic, H. Tassell, S. McLaren and D. Ryan

*Presenter: Alexey Goncharov
Geoscience Australia*

Session 6A: 12:05 pm, Meeting room 5

A consistent approach to the assessment of basement and crustal controls on hydrocarbon maturation in the Bremer Sub-basin, offshore southwest Australia, has been undertaken as part of the Australian Government's Big New Oil initiative. Geoscience Australia acquired marine reflection seismic survey in this area during late 2004 in conjunction with recording of refraction seismic data by sonobuoys at sea and by land stations in the onshore/offshore observation scheme. One of the key findings of the refraction seismic study is that velocities in the basement are generally in the 5.0–5.7 km/s range, indicating that, contrary to prior expectations, basement in the area is mostly not granitic in composition. Results from the conjugate margin in Antarctica also show low velocities in the basement on the inner side of Antarctic continent-ocean boundary, consistent with results from the

Australian margin. It appears that a ~400-km-wide zone in Gondwana prior to break up had basement velocities significantly lower than the normal continental values of 6.0–6.2 km/s most commonly associated with granites and gneisses. Low-grade metasediments of the Albany-Fraser Orogen and its Antarctic equivalent is the preferred interpretation of this observation. Granites, dredged from the sea floor in the Bremer area, may represent only a small fraction of the basement, as within the basement highs where higher velocities have been detected by refraction work. As metasediments produce substantially less heat than granites, a different scenario for hydrocarbon maturation in the Bremer Sub-basin is possible. To quantify possible heat production in the Bremer basement and crust below it we have used contents of radioactive elements in rock samples taken from outcrops of Yilgarn Craton and Albany-Fraser Orogen onshore, as well as in rock samples dredged from the sea floor in the Bremer Sub-basin. Advanced burial and thermal geohistory modelling in this area was carried out using Fobos Pro modelling software for the first time in Australia without relying on default or inferred values (such as heat flow or geothermal gradient). Modelling showed that subsidence curves can be matched in various basement composition scenarios, but the high heat-producing granitic scenario leads to a present-day surface heat flow of 68 mW/m² predicted by the model—unrealistically high given the context of heat flow measurements on the Australian Southern Margin. Other basement compositions (low heat-producing granite, metasediments, basalts) lead to a present-day surface heat flow of 46–57 mW/m² and cannot be ruled out on the basis of heat flow modelling and data alone. This work details a methodologically consistent approach to burial and thermal geohistory modelling for other frontier areas where appropriate geophysical data have been collected.

SESSION 6B—DEVELOPING AUSTRALIA'S PETROLEUM RESOURCES: NEW TECHNOLOGIES

Large-bore gas well design—application to offshore gas field development



F. Thompson, I. Terziev and I. Taggart

*Presenter: Francis Thompson
Chevron Australia*

Session 6B: 11:15 am, Meeting room 6

Offshore gas development projects including the North West Shelf of Australia continue to develop new technologies in order to reduce development costs. Given that the number of development wells directly relates to capital expenditure, past attempts have focussed on obtaining higher gas rates out of conventional well designs by carefully managing erosional limits, which, in turn, tend to restrict the use of higher offtake rates.

A strategy based on safely flowing gas wells at higher rates results in fewer wells and delays the phasing-in of additional wells, both of which result in economic enhancement. In recent times the industry has increasingly

moved to large-bore gas well technology as a means of realising this strategy. Large-bore gas wells are defined as wells equipped with production tubing and flow control devices larger than 7" or 177 mm. Originally developed for land-based operations, this technology is increasingly moving offshore into totally subsea systems. One factor limiting the speed of adoption of this technology is the trade-off that exists between the increased offtake rates offered by large-bore systems and the risks posed by wear due to erosion in and around the wellhead area caused by any solids entrained in the gas stream.

The problem becomes more acute when different-sized well designs employ the same wellhead configurations, because the upper wellhead area is usually the critical and limiting wear component.

This paper summarises the recent developments in large-bore offshore applications and presents a consistent methodology showing how different gas well designs can be compared using hydraulic and erosional considerations. Additional trade-offs posed by reliable solids monitoring and the adoption of untested wellhead and intervention designs are discussed. In many cases, hybrid designs based on large diameter tubulars but with conventional wellheads may offer a useful balance between higher well rates and adoption of proven technology. The results shown here are directly applicable to alternative well designs presently under consideration for a number of offshore reservoir developments.

The PMR process, an innovative technology for large LNG trains



K. Buijs, J.J.B. Pek and W. Meiring

*Presenter: Wouter Meiring
Shell*

Session 6B: 11:40 am, Meeting room 6

The forecasts in market growth of LNG and the development of large gas fields are a great stimulus for further enhancing the capacity of LNG trains. The increasing cost of upstream development, including the managing of CO₂, deepwater, ice, complex reservoirs and so on, makes downstream economies of scale an imperative. This paper addresses Shell's approach to large LNG trains in the range of 7–10 Mtpa covering

both mechanical and electrical drive options to develop innovative and cost effective designs.

With the standard Propane Mixed Refrigerant (C3/MR) technology, capacities up to 5 Mtpa can be achieved with two GE Frame 7 gas turbines as drivers. Due to maximum size constraints of key equipment, an additional liquefaction cycle is required to realise higher LNG capacities. The following solutions are presently applied to extend the capacity above the 5 Mtpa range:

- adding an additional liquefaction cycle in a three-cycle in series line-up; and,
- a single pre-cool cycle followed by two parallel liquefaction cycles.

Both liquefaction configurations, although of different concepts, have a similar number of equipment items. Shell Global Solutions has developed the latter option as the Parallel Mixed Refrigerant (PMR) process. For pre-cooling either propane or a mixed refrigerant, as used in the Double Mixed Refrigerant (DMR) process, are used. With three well-proven GE Frame 7 gas turbines, 8 Mtpa of LNG production is achieved. With larger drivers such as GE Frame 9 or Siemens V84.2 gas turbines, the LNG capacity increases to above 10 Mtpa.

The PMR process for large LNG trains has a number of attractive features:

- robustness through the use of well-proven equipment;
- high availability by parallel line-up of the liquefaction cycle. For example, the LNG production is designed to continue at 60% of train capacity if one of the liquefaction cycles trips; and,
- the optimal power balance between the pre-cool and the two parallel liquefaction cycles results in a high efficiency.

Shell's electrically driven DMR process is also very attractive, particularly for greenfield applications. This concept is based on a parallel line-up of the refrigerant

compressors around a common set of cryogenic spoolwound exchangers and achieves an LNG capacity of more than 8 Mtpa. The power station is driven by gas turbines. The following considerations play a key role in the selection process of electrically driven plants.

- The gas turbine maintenance is decoupled from LNG production, resulting in a lower downtime. A net increase up to 4% in stream days is possible.
- High efficiency gas turbines can be selected for the power station and efficiency can be further improved by a combined cycle power plant.
- The step change in efficiency achieved in a combined cycle power plant is very beneficial in lowering the CO₂ and NO_x emissions, as well as the feed gas intake.

Deep water drilling rigs year 2006



P. Lindstad

Presenter: P Lindstad
Aker Kvaerner

Session 6B: 12:05 pm, Meeting room 6

To meet the extreme challenges faced in world wide exploration and development drilling in ultra-deep water, cold climate, harsh environment and

ecologically sensitive areas or within areas of great distance from existing infrastructure new rig capabilities will be required. Aker Kvaerner's response is the H-6e design

which is an evolution of the existing Aker Kvaerner rig design with proven performance, and is a result of more than 30 years of experience combined with the latest technology. The rig is the first new build Mobile Drilling Semi-Submersible from a Norwegian Yard since the early 1980's—two rigs are scheduled for delivery in 2008. The paper will focus on the design features of the H-6e Drilling Semi Submersible and its capabilities including:

- key technical features;
- dimensions and capacities;
- drilling systems and arrangement;
- support systems;
- marine aspects; and,
- execution philosophy.

The fabrication and assembly schedule is benefitting from the realisation of numerous fixed floating production and combined drilling/production semis delivered to the oil business all over the world.

SESSION 6C— PETROLUUM INDUSTRY SAFETY

Initiatives to improve safety performance—Veritas takes AIM at behaviour-based safety



S. Hallows

Presenter: Stephen Hallows
Veritas

Session 6C: 11:15 am, Meeting room 7

Veritas DGC is a global provider of integrated geophysical solutions and operates on four continents,

in more than 20 major cities and in all types of remote, logistically challenging and inhospitable environments; land, sea and transitions zones; jungle, arctic and prairie. In addition massive fluctuations in the workforce are regularly experienced due to the short service nature of work contracts. This necessitates employment of local personnel which brings challenges associated with culture, language, management and social status, hierarchy, perceptions and work standards.

This case study will outline the challenges that were faced and overcome in the design implementation and maintenance of an effective behaviour-based safety program in unique and challenging circumstances.

Integrity of bolted joints: hydrocarbon leak reduction by joint-integrity management



R. Noble

Presenter: Robert Noble
Hydratight, UK

Session 6C: 11:40 am, Meeting room 7

Bolted joints are very common in petroleum production facilities. Whereas extensive controls are applied to the production of a welded joint—in

terms of material control and specification, control and competence of the welder, and verification of the integrity of the weld—this is not the case for bolted joints. The consequences of failure of a welded joint and a bolted joint, however, are similar and potentially catastrophic if the contents of the pipeline or vessel are hydrocarbons under pressure. This paper discusses the main issues in producing and maintaining a leak-free bolted joint and makes the case for establishing industry-wide standards for the management of bolted joints that are equally as stringent as those applied to welded joints.

Implementing such a system, whilst improving and assuring the safety and environmental performance of an asset, will also reduce costs due to rework, product loss, schedule slippage and production downtime.

Hydrates—a challenge in flow assurance for oil and gas production in deep and ultra-deep water



R. Freij-Ayoub, M. Rivero and E. Nakagawa

*Presenter: Reem Freij-Ayoub
CSIRO Petroleum*

Session 6C: 12:05 pm, Meeting room 7

Offshore exploration and production is going to deep and ultra deep waters, driven by the depletion of continental shelf reserves and the high demand for hydrocarbons. This move requires the continued extension of existing technologies and the development of new technologies that will make the investment economically viable. Innovative flow assurance technology is needed to support ultra deepwater production, particularly within the concept of platform-free fields where there is a need to minimise interventions.

Hydrates present one of the major challenges in flow assurance. Deep and ultra deep water operations together

with long tiebacks present the ideal conditions for the formation of hydrates which can result in pipeline blockage and serious operational and safety concerns. Methods to combat hydrates range between control and management. One main technique has been to produce the hydrocarbons outside of the thermodynamic stability domain of hydrates. This is achieved by keeping the temperature of the hydrocarbon above the stability temperature of hydrates by insulating the pipeline, or by introducing heat to the hydrocarbon. Another efficient way of combatting hydrates has been to shift the hydrate phase boundary to lower temperatures by using chemicals like methanol and mono ethylene glycol (MEG) which are known as thermodynamic inhibitors. Within the last decade a new generation of hydrate inhibitors called low dosage hydrate inhibitors (LDHI) has been introduced. One type of these LDHI are kinetic hydrate inhibitors (KHI) that, when used in small concentrations, slow down hydrate growth by increasing the induction time for their formation and preventing the start of the rapid growth stage. Another approach to managing hydrates has been to allow them to form in a controlled manner and transport the hydrate-hydrocarbon slurry in the production pipe. In this paper we describe the various approaches used to combat hydrates to ensure flow assurance and we discuss the cons and pros of every approach and the technology gaps.

SESSION 7A—PETROLEUM FRONTIERS OF AUSTRALASIA

A new view of Australia's basins— some insights and opportunities from OZ SEEBASE™



**L. Pryer, J. Blevin, J. Teasdale,
P. Stuart-Smith, T. Loutit**

Presenter: Lynne Pryer
FrOG Tech

Session 7A: 2:30 pm, Meeting room 5

The OZ SEEBASE™ product presents a plate-wide geological model for the evolution of Australia's Phanerozoic sedimentary basins that can be used to assess petroleum prospectivity and identify exploration opportunities. The model provides the basis to systematically classify each basin type and to understand the tectonic events that have controlled the structural and stratigraphic framework of the depocentres. The framework established by Oz Seebase also provides a regional template to understand the spatial and temporal distribution of the six Australian petroleum supersystems. The relationship between base-

ment composition and fabric, the nature of the tectonic events and the resulting basin architecture can be used to access the factors that have controlled the petroleum resource potential of a basin/sub-basin, including overall sedimentary thickness, inter- and intra-basin compartmentalisation, trap style and timing of formation, distribution and depth of burial of principal source rock units and regional heat flow. Further integration of these data can be used to model the subsidence (accommodation) and reactivation histories of a basin, and to develop facies models that show the distribution of potential reservoir, source and seal rocks (e.g. structurally-constrained palaeogeographic maps).

The Canning Basin and Southern Rift System are examples from the Oz Seebase model that demonstrate the diversity in Phanerozoic basin architecture and its link to the underlying basement framework. These rift systems developed over a number of basement terranes, and through the interaction of multiple tectonic events that generated normal to highly oblique extensional stresses. The resulting depocentres vary widely in their resource potential due to the amount of total subsidence, the linkages between depocentres and structural integrity (trap preservation). Using the Oz Seebase model, further assessment of prospectivity can be made through the integration of other data sources such as megasequence isopachs, organic facies maps, and time-series maps of structurally active

Developments in the central and northeastern East Coast Basin, North Island, New Zealand



**C. Uruski, B. Field,
R. Funnell, C. Hollis, A. Nicol
and G. Maslan**

Presenter: Chris Uruski
GNS Science, NZ

Session 7A: 2:55 pm, Meeting room 5

Oil production in the East Coast Basin began in the late 19th century from wildcat wells near oil seeps. By the mid-20th century, geology was being applied to oil exploration, but with little success. In the late 20th century, seismic techniques were added to the exploration arsenal and several gas discoveries were made. At each stage it was recognised that exploration in this

difficult but tantalising basin required more information than was available. Continuing work by exploration companies, as well as by the Institute of Geological & Nuclear Sciences (GNS), has begun to reduce the risk of exploration. Source rocks have been identified and sophisticated thermal models show that petroleum is being generated and expelled from them as shown by numerous oil and gas seeps onshore. Many potential reservoir sequences have been recognised from outcrop studies and depositional models are being refined. All components of petroleum systems have been demonstrated to be present. The most important deficiency to date is the general lack of high-quality seismic data which would allow recognition of reservoir facies in the subsurface.

During early 2005, Crown Minerals, the New Zealand government group charged with promoting and regulating oil and gas exploration, commissioned a high specification regional 2D survey intended to address some of the main data gaps in the offshore East Coast Basin. A broad grid was planned with several regional lines to be acquired with a 12,000 m streamer and infill lines to be acquired with a streamer 8,000 m long. It was expected that the long streamer would increase resolution of Paleogene

and Cretaceous units. Several of the lines were actually acquired with a 4,000 m streamer due to unexpectedly high rates of unserviceability. The resulting 2,800 km data set consists of a series of northwest–southeast lines approximately orthogonal to the coast at a spacing of about 10 km as well as several long strike lines.

GNS was contracted to produce a series of reports covering source rock distribution, a catalogue of reservoir rocks, a regional seismic interpretation, thermal models and structural reconstruction. The data package and reports are available free of charge to any interested exploration company to accompany the licensing round that was announced on 1 September 2005.

The new data set has confirmed the existence of a large, little-deformed basin to the north of North Island and the Bay of Plenty; it has elucidated the complex structure of a large part of the East Coast Basin and has enabled generation of a general sequence stratigraphic model which assists in delineating reservoir targets.

On 1 September 2005, the New Zealand government launched a licensing round covering about 43,000 km² of the East Coast Basin, from the far offshore East Cape Ridge in the north to the northern Wairarapa coast in the south. Four blocks (I, J, K and L) were on offer for a competitive staged work programme bid, closing on 17 February 2006.

Prospectivity of the deepwater Gulf of Papua and surrounds in Papua New Guinea (PNG)—a new look at a frontier region



D. Jablonski, S. Pono and O. Larsen

*Presenter: Dariusz Jablonski
Chinampa Exploration Pty Ltd*

Session 7A: 3:20 pm, Meeting room 5

Despite limited well control and paucity of seismic data, a regional study of the deepwater portion of the Gulf of Papua, Papua New Guinea (PNG), indicates a number of large structures at a variety of stratigraphic levels that are capable of holding significant volumes of hydrocarbons. The main structural elements east of the Fly River Platform the Pandora Ridge, Pandora Trough, Aure Trough, Port Moresby Trough and the northern portion of the Eastern Plateau were established during the Paleozoic and further enhanced by Late Cretaceous to Early Paleocene Coral Sea rifting in the southeast. Structuring in the region is mostly basement involved and extensional, and is overprinted by a later compressional

pulse. Extensional and compressional regimes produce many potential traps. To date, exploration in the Gulf of Papua has been sporadic and mainly focussed in shallow water depths. The new reprocessed seismic data indicate the following Paleozoic to Recent plays, some of which contain multiple reservoir-seal pairs, sourced by non-marine and marine source rocks:

1. extensional Paleozoic rift fault blocks;
2. Upper Jurassic to Lower Cretaceous turbidites (Iagifu-Hedina-Toro sandstone equivalents);
3. Campanian to Middle Paleocene Coral Sea synrift sandstone and basin floor fan equivalents (Pale/Barune Formations and equivalents);
4. Middle Paleocene break-up unconformity fault blocks and intra-basinal highs;
5. Upper Paleocene to Lower Eocene Pima Sandstone equivalent associated with the Middle Paleocene uplift and erosion;
6. Oligocene to Lower Miocene lowstand deltas and turbidites;
7. Miocene to Recent biohermal build-ups (possibly including a new limestone high, the Box Ridge, in front of the Pandora Ridge); Karstified Darai Limestone equivalent sealed by Aure Beds claystones;
9. Miocene to Recent lowstand deltas and turbidites;
10. Eocene to Pliocene stratigraphic onlaps flanking main structural highs; and,
11. compressional plays associated with the Pliocene to Recent collision of the PNG and Pacific plates.

SESSION 7B—COAL SEAM GAS IN QUEENSLAND

The significance of coal seam gas in eastern Queensland



G. Baker and W. R. Skerman

Presenter: Ross Skerman
RLMS

Session 7B: 2:30 pm, Meeting room 6

The commercial production of coal seam gas [CSG] in Australia is only a decade old. Over the last 10 years it has become a significant part of the Australian gas industry, particularly in Queensland where about 31 PJ or 30% of all natural gas used in the State was recovered from coal seams in eastern Queensland. In 2005 CSG was expected to have supplied 55 PJ or 44% of the eastern Queensland gas demand. The mining, mineral processing and power generations in northwest Queensland, serviced

by the Carpentaria Gas Pipeline, will continue to use gas from the Cooper-Eromanga Basin.

The CSG industry is reaching a stage of maturity following the commissioning of a number of fields while some significant new projects are either in the commissioning phase or under development. By the end of 2008 CSG production in Queensland is expected to reach 150 PJ per year, the quantity needed to meet Gas Supply Agreements for CSG that are presently in place.

Certified Proved and Probable (2P) gas reserves at 30 June 2005 in eastern Queensland were calculated to be 4,579 PJ, of which 4,283 PJ were CSG. Gas reserves (2P) for eastern Queensland a decade earlier were less than 100 PJ with those for CSG being less than 5 PJ.

The coal seam gas industry in both the Bowen and Surat Basins—which includes major gas producers such as Origin Energy Limited and Santos Limited along with smaller producers such as Arrow Energy NL, CH4 Gas Limited, Molopo Australia Limited and Queensland Gas Company Limited—is now accepted by major gas users as being suppliers of another reliable source of natural gas.

Discovery and development of the Kogan North and Tipton West coal seam gas (CSG) fields, Surat Basin, southeast Queensland



**R. Day, R. Prefontaine,
P. Bubendorfer,
M. Oberhardt, B. Pinder,
D. Holden and R. Gunness**

Presenter: Brad Pinder
Arrow Energy

Session 7B: 2:55 pm, Meeting room 6

In 2001, Arrow Energy NL, a fledgling coal seam gas (CSG) explorer, drilled the first wells of a multi-well exploration program in two Authorities To Prospect (ATP) permits—ATPs 683P and 676P—that covered an area totalling 13,817 km² of the Jurassic Walloon Coal Measures in the eastern Surat Basin. The objective was to discover significant CSG resources and, if successful, to commercialise to reserve status. Early exploration success in 2002 saw the discovery of the Kogan North and Tipton West CSG fields. This paper reviews the discovery

and subsequent appraisal and development work that Arrow Energy has completed to establish production from these fields.

By 2004, Arrow Energy had independently certified Probable reserves in the Kogan North field of 85 PJ, and Possible reserves of 157 PJ. Results from a five-well CSG pilot operation demonstrated the feasibility of commercial gas flow rates sufficiently to justify commercialising CSG from the Walloon Coal Measures in the Kogan North field. Under the terms of a staged development agreement, CS Energy Ltd—Queensland's largest electricity generator—farmed into the Kogan North Project to earn a 50% interest in PL194 and an adjoining portion of ATP 676P by funding A\$13.1 million of the project's development and appraisal costs. The funds provided by CS Energy covered the majority of the development costs required for Arrow's Kogan North development project. The initial gas sales contract from Kogan North will supply sales gas of 4 PJ/a for 15 years to CS Energy from March 2006. Arrow Energy retains the remaining 50% interest and operates the project.

With 25 PJ Probable, 90 PJ Probable and 1,980 PJ Possible gas reserves certified independently, the Tipton West field could potentially be one of the largest onshore gas fields in eastern Australia. Final appraisal of the Tipton West field is underway with financial close on the development expected in late 2005. Beach Petroleum Ltd has entered into an agreement to fund the A\$35 million required for upstream development to supply the initial 10 PJ/a sales

gas from the field in 2007, in exchange for 40% interest in the Dalby block of ATP683P. Arrow Energy retains the remaining 60% interest and operates the project.

Diligent environmental and land management systems are required with the development of any CSG field. For example, formation water produced from CSG activities needs to be managed effectively. To deal with this water Arrow Energy is developing and implementing several innovative strategies, including forced evaporation dams, water supply to local coal-washing plants and trialling desalination plants to provide drinking water for nearby towns, aquaculture and stock watering.

Arrow Energy has also implemented a Cultural Heritage Management Plan within the development areas in

cooperation with the local indigenous claimant groups, the Western Wakka Wakka and the Barunggam peoples. The plan was designed to minimise risk of any disturbance to indigenous artefacts and areas of significance during the exploration, construction and ongoing operations associated with the development of both gas fields.

The discovery and future development of the Kogan North and Tipton West fields has been achieved by using an appropriate mix of geological evaluation, efficient drilling techniques, innovative well completion methods and successful marketing strategies, integrated with cooperative environmental and cultural heritage management systems.

Geological controls on exploitable coal seam gas distribution in Queensland



J. Draper and C. Boreham

Presenter: Chris Boreham
Geoscience Australia

Session 7B: 3:20 pm, Meeting room 6

Methane is present in all coals, but a number of geological factors influence the potential economic concentration of gas.

The key factors are (1) depositional environment, (2) tectonic and structural setting, (3) rank and gas generation, (4) gas content, (5) permeability, and (6) hydrogeology. Commercial coal seam gas production in Queensland has been entirely from the Permian coals of the Bowen Basin, but the Jurassic coals of the Surat and Clarence-Moreton basins are poised to deliver commercial gas volumes.

Depositional environments range from fluvial to delta plain to paralic and marginal marine—coals in the Bowen Basin are laterally more continuous than those in the Surat and Clarence-Moreton basins. The tectonic and structural

settings are important as they control the coal characteristics both in terms of deposition and burial history. The important coal seam gas seams were deposited in a foreland setting in the Bowen Basin and an intracratonic setting in the Surat and Clarence-Moreton basins. Both of these settings resulted in widespread coal deposition. The complex burial history of the Bowen Basin has resulted in a wide range of coal ranks and properties. Rank in the Bowen Basin coal seam gas fields varies from vitrinite reflectance of 0.55% to >1.1% R_v and from R_v 0.35–0.6% in the Surat and Clarence-Moreton basins in Queensland. High vitrinite coals provide optimal gas generation and cleat formation. The commercial gas fields and the prospective ones contain coals with > 60% vitrinite.

Gas generation in the Queensland basins is complex with isotopic studies indicating that biogenic gas, thermogenic gas and mixed gases are present. Biogenic processes occur at depths of up to a kilometre. Gas content is important, but lower gas contents can be economic if deliverability is good. Free gas is also present. Drilling and production techniques play an important role in making lower gas content coals viable. Since the Bowen and Surat basins are in a compressive regime, permeability becomes a defining parameter. Areas where the compression is offset by tensional forces provide the best chances for commercial coal seam gas production. Tensional setting such as anticline or structural hinges are important plays. Hydrodynamics control the production rate though water quality varies between the fields.

SESSION 7C—ENVIRONMENT, CULTURAL HERITAGE AND PETROLEUM OPERATIONS

Cultural heritage and the petroleum industry



G. Scott

*Presenter: Gavin Scott
Blake Dawson Waldron*

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

Since the introduction of the Native Title Act 1993 (Cth) and its subsequent amendment in 1998, the main focus for developing pipeline projects was on native title issues. Cultural heritage was seen as a more operational matter and not one that would affect the ability to operate or construct pipelines. With higher standards being set by the High Court for native title claimants to maintain a claim, the management of cultural heritage issues (as opposed to the protection of native title rights) are now forming a significant part of negotiations between project proponents

and indigenous groups for the development of petroleum projects.

State, Territory and Commonwealth legislation dealing with Aboriginal cultural heritage also provides a more immediate source of obligations on project proponents. Even when all regulatory authorities and approvals are held, this legislation can provide affected parties the ability to stop projects if proponents ignore the requirements to protect and manage Aboriginal cultural heritage.

This paper briefly examines how cultural heritage issues and native title issues interact from a practical viewpoint and then goes on to provide an overview of cultural heritage legislation throughout Australia including a focus on the unique model adopted in Queensland through the introduction of the cultural heritage duty of care.

This paper then provides examples of what companies will need to do to comply with statutory obligations in minimising harm to cultural heritage through examples of common inclusions in cultural heritage management plans, together with identifying issues that are often forgotten to the detriment of a project in such plans. It also points out why cultural heritage issues may need more immediate actions in comparison with native title issues for the development and construction of new petroleum projects.

Valuing the environmental costs of vegetation removal and ecosystem disturbance associated with petroleum operations, Cooper Basin, South Australia



E. V. Mazourenko

*Presenter: Elena Mazourenko
Flinders University*

Session 7C: 2:55 pm, Meeting room 7

This paper describes the results of a small-scale study that looked at an alternative way of managing the environmental impacts of petroleum developments. The study was based on a contention that an ap-

plication of the contingent valuation method (CVM) in the context of petroleum developments might assist the petroleum industry in achieving the goals of ecologically sustainable development (ESD), while contributing to the change of the community's attitude towards the industry. CVM, based on direct community involvement in determining the environmental costs of the native vegetation removal associated with the petroleum developments in the South Australian Cooper Basin, was applied to the selected groups of interest. The collected data were analysed and discussed in light of the feasibility of a full-scale CVM study, and its potential practical value both for the petroleum companies operating in the Cooper Basin and the regulatory state government authorities. The results of this study showed that the application of CVM in the context of the petroleum industry might yield significant benefits for the industry in terms of ESD. In the long term, it may assist in changing the community's perception of the petroleum industry. This approach does not intend to contradict, but to complement, the current environmental management practices of the petroleum developers.

The Moonie–Brisbane pipeline spill—ecosystem recovery



M. Ames, L. Swann and J. Douglas

*Presenter: Matthew Ames
URS Australia*

Session 7C: 3:20 pm, Meeting room 7

In March 2003, a rupture to the Moonie–Brisbane pipeline (MBP) at Lytton (Brisbane) resulted in a spill of 1.9 million litres (7,000 barrels) of crude oil to two hectares of land and 1.5 km of mangrove-lined drainage channels and small creeks near the Port

of Brisbane.

Due to the swift, coordinated response, no oil reached the Brisbane River and the bulk of the oil spilled was recovered. The response effort included isolation and evacuation of the affected area, containment and recovery of the crude oil and the development and implementation of a clean-up plan (which identified and prioritised response efforts in four primary areas).

Following the emergency response a comprehensive program of remediation and monitoring was implemented, with focus on the recovery of the affected waterways and remediation of affected land.

This paper describes the methods employed during the emergency response and their effect on the:

- initial impact on the environment;
- development and implementation of rehabilitation and remediation options; and,
- potential for ecosystem recovery.