SESSION 1B—IMPROVED DEVELOPMENT AND PRODUCTION: ENHANCED RETURNS

Real-time and on-site reservoir fluid characterisation using spectral analysis and PVT Express


Presenter: Abul Jamaluddin Schlumberger

Session 1B–2.00pm

Obtaining an adequate fluid characterisation early in the life of a reservoir is becoming a key requirement for successful hydrocarbon development. This work presents and discusses a number of new fluid sampling and fluid characterisation technologies that can be deployed either down hole or at surface in the early stages of the exploration and development cycle to achieve this objective. Techniques discussed include methods to monitor and quantify oil-based mud contamination, gas-liquid-ratio (GLR) and basic fluid composition in real time during open-hole formation testing operations. In addition, we demonstrate the applicability of new surface analysis techniques that allow for rapid, accurate, and reliable measurements of key fluid properties, such as saturation pressure, gas-oil ratio, extended carbon number composition, viscosity, and density, on-site within a few hours of retrieving reservoir fluid samples at surface. Finally, prediction tools used to extend these limited measurements to a traditional PVT fluid characterisation are presented along with example measurements from all the techniques described. In conclusion, it is shown that the implementation of these techniques in a complementary program can reduce the risk associated with making key development decisions that are based on an understanding of reservoir fluid properties.

Advances in visualisation technologies: a case study, Laho gas field—offshore Peninsular Malaysia

C.M. Gell, D.E. Meyer, R.A. Majid and D.J. Carr

Presenter: Christi Gell Landmark Graphics Malaysia Sdn Bhd

Session 1B–2:25pm

A typical problem facing oil company asset teams today is the integration of new information into existing fields. Recently acquired 3D seismic for example, can add much needed detail for understanding reservoirs from producing wells. The key step of interpreting faults and surfaces, on which many other results depend, can often be time consuming and delay efforts to bring additional oil and gas production on-line. Using a volume-based approach to seismic interpretation with today’s visualisation technology, however, can lead to more accurate results produced up to four times faster than traditional line-by-line methods.

Over the last four years, visualisation technologies have advanced to the point where these new techniques provide a faster, more geologically correct interpretation and evaluation of potential reservoirs in a shorter amount of time by comparison with line-by-line methods. These advanced techniques include, but are not limited to: multiple attribute voxel interpretation; interpreting fault planes (rather than fault sticks); real-time volume rendering with the ability to create geobodies; quick reconnaissance work in volume; the ability to combine workflows using non-3D volume tools such as wave-form classification with volume interpretation.

This paper provides an example of the Laho gas field, offshore Peninsular Malaysia, where two wells were already producing gas and the operator, Petronas Carigali Sdn. Bhd (PCSB), acquired 3D data to evaluate the possibility of additional drilling locations.
Using real-time LWD data and images to diagnose and manage geomechanics problems whilst drilling

R. Marsden and F. Wijnands

Presenter: Rob Marsden
Schlumberger

Using real-time LWD technologies make it possible for formation data and processed images to be made available to interested specialists in real-time, where it can be used to assist well placement, rig-site decision-making and drilling optimisation.

This paper describes examples where MWD/LWD measurements (including ultrasonic callipers, resistivity data, and images, and down-hole pressure), coupled with real-time data delivery, have allowed geomechanics-related problems to be identified and correctly diagnosed during drilling. Working with and analysing these data away from the rig-site, geomechanics specialists have been able to provide the drilling and well-site teams with the necessary information to manage a variety of problems in a timely, efficient and appropriate manner. It has also permitted geomechanics designs and predictions to be validated as drilling proceeded, thereby ensuring that the most recently acquired and most relevant information was being used to help the rig-site teams lower well construction time and costs, optimise completions, and increase safety. Results have included the avoidance of potential stuck-pipe incidents, lost circulation, borehole failure/loss, and subsequent side-tracks, as well as improving well placement, drilling optimisation and risk management (for which the LWD/MWD data was primarily intended).

Using LWD/MWD information in this way becomes particularly beneficial when drilling high angle wells or in areas of high in-situ stresses, where it may be difficult to avoid formation failure. In these circumstances, LWD/MWD becomes essential to managing instability through effective drilling practices. The real-time information also avoids incorrect diagnosis that can otherwise lead to inappropriate actions that would exacerbate problems and lead to further damage.

This will be a presentation only.

SESSION 1C—ENSURING A HEALTHY AND SAFE INDUSTRY

NOPSA progress team report

P. Wilkinson

Presenter: Peter Wilkinson
Department of Industry, Tourism and Resources, DITR

The Petroleum (Submerged Lands) Amendment Bill 2003 and the Offshore Petroleum (Safety Levies) Bill 2003 were passed by Parliament in November 2003 and received Royal Assent on 4 December 2003. This paves the way, in conjunction with legislative amendments by the States and Northern Territory, for the establishment of the National Offshore Petroleum Safety Authority (NOPSA) to enable it to start operations on 1 January 2005.

In this presentation, the Department of Industry, Tourism and Resources will report on progress in establishing NOPSA and will cover:

• NOPSA's role and responsibilities;
• reporting lines and Governance arrangements;
• location, numbers and types of staff;
• cost recovery arrangements;
• progress on developing NOPSA's systems and procedures; and
• consultation with industry.

The presentation will also cover how the development of NOPSA compares with international practice and will result in a regulatory environment which is:

• more effective and efficient than the current arrangements; and
• will provide for continuous improvement in the health and safety of the industry; whilst
• allowing technical progress to facilitate the development of Australia's oil and gas resources.

This will be a presentation only.
A career development strategy for a sustainable, safe and competitive Australian energy industry

S. Starling and J. Robertson

Presenter: Steve Starling
ANTCER

Session 1C–2:25pm

The Australian upstream oil and gas industry faces many staffing challenges, including:

- shortages of skilled personnel to staff new developments and expansion projects;
- retirement of an aging workforce with consequent loss of experience; and
- low enrolments in university courses predicting a diminished pool of geologists, engineers and technical staff.

APPEA's Workplace Competency Initiative has been addressing these challenges by devising and promoting a career development strategy to encourage the recruitment and retention of staff. This career development strategy also addresses the competent workforce provisions and duty of care requirements of APPEA's safety case guidelines. The principle components of the career development strategies are:

- competency standards—the development of competency standards for production operators and drilling crews;
- career guide—a promotional publication to attract new recruits, retain current staff, and to promote life-long learning;
- coach's handbook—a manual for team leaders, supervisors and managers to encourage staff coaching, competency-based training and career development;
- coach the coach courses—practical one day sessions to promote staff coaching, competency formation and career development;
- group training scheme—an industry sponsored scheme to recruit, place and train production operators; and
- a competency register—development of a competency register to encourage and record workforce safety certificates, workplace inductions and vocational qualifications.

Ultimately this career development strategy will create a sustainable pool of skilled workers, contribute to safer workplaces, and improve the competitiveness of the Australian petroleum industry.

Applying what we know about human error: from theory into practice

E. Grey and P. Wilkinson

Presenter: Elizabeth Grey
Qest Consulting Group

Session 1C–2:50pm

Human error is often said to be at the heart of the majority of incidents and the developing discipline of human factors a way of understanding how these errors occur. There is little debate about this. But do we practise what we preach and are we reaping the benefits of applying the insights? Anecdotal evidence suggests not. Human error is too often interpreted as people being reckless, careless or just ignorant in discharging their duties. This so-called careless worker approach was the unstated assumption behind early moves to improve health and safety. It could be argued in the petroleum industry that we have adopted a more sophisticated approach, emphasising the importance of the engineering integrity of process systems and the role of formal management systems. However, there remains a need to better integrate what we know about human and organisational error. Reason's (1997) organisational accident model has had a profound effect on how accidents are viewed and how we can learn from them. The clarity with which the model is presented does not, however, necessarily translate directly into ease of application. The model is a description of accident causation, but does not provide a method for making assessments about organisational resilience in its own right. As such, individuals wanting to use the model need to be well trained if benefits are to be realised. This paper describes a practical and applied approach to human error training based on principles of adult learning that is designed to tap into trainees' existing knowledge and experiences.
SESSION 2B—IMPROVED DEVELOPMENT AND PRODUCTION: ENHANCED RETURNS

The Chinguetti deepwater turbidite field, Mauritania: reserve estimation and field development using uncertainty management and experimental designs for multiple scenario 3D models


Presenter: Greg Smith
Woodside Energy Limited

Session 2B–3:45pm

The Chinguetti Field was discovered in 2001 offshore Mauritania in 800 m of water. It comprises deepwater, mid-slope turbidite reservoirs, trapped in a dome over a salt diapir. The hydrocarbons are compartmentalised by concentric radial faults, in a low net: gross sequence, with oil mainly in channel sands. The large number of uncertain variables requires a structured approach and a rigorous assessment of the potential sub-surface scenarios. The field is of moderate size and risks in this deepwater environment need to be managed carefully.

The main sub-surface uncertainties were identified by uncertainty framing and are briefly described in the paper. They include:
- structure;
- hydrocarbon contacts;
- fault seal;
- distribution of the channel systems;
- frequency and amalgamation of channel sands;
- shale drape;
- internal channel heterogeneity;
- effective pressure support;
- rock-fluid interaction;
- rock compaction;
- fluid composition/properties; and
- rock properties.

A statistical experimental design determined 27 scenarios should accurately model the probability distribution of reserves. A 3D model was made for each and run through the dynamic simulator to estimate economic ultimate recovery (EUR). Multivariate statistical analysis produced a response equation for EUR and the probability distribution. This is more rigorous than the standard method which produces mid, high and low case models, for which there is no adequate way to assign their probability of occurrence.

The range of scenarios and response equation are extremely useful in testing development options that would otherwise not be apparent. The technique rapidly captures the range of likely outcomes and immediately focusses effort onto a flexible approach to the main uncertainties. This saves considerable re-work and development time.

Logging while drilling images provide the full picture

M. Wilson, F. Advent, T. McGee and S. Horan

Presenter: Michael Wilson
Schlumberger

Session 2B–4:10pm

Logging while drilling laterolog button resistivities produce images of about 1/6th the resolution of wireline formation micro resistivity imaging, adequate to resolve structural bedding, fractures, faults, and borehole mechanical features. Azimuthal density images are produced from the density data, which is binned into 16 sectors around the borehole with vertical resolution equivalent to wireline density tools. Logging while drilling acoustic caliper and gamma ray measurements can also be binned and displayed as images.

Images from all measurements can be recorded and displayed when the logging while drilling string returns to surface or in the case of geomechanical or geosteering applications can be displayed in real time to make real time drilling decisions.

In this paper, two case studies from Australian wells are discussed to illustrate how images can be used for different applications.
Process-knowledge management and its application for drilling in gas hydrate environments

W.F. Prassl, J.M. Peden and K.W. Wong

Presenter: Wolfgang Prassl
Curtin University of Technology

Session 2B–4:35pm

Understanding both the potential benefits and mitigation of risk based on the application of the latest technologies and procedures are essential to the success of any venture within the petroleum industry. To allow this, a process-knowledge management system has been formulated in order to capture the available knowledge, verify its impact, enable reasoning and informed decision-making. Such a system allows exploitation of explicit and tacit process-knowledge, so that information from multiple field experts, company best practice policies and latest technological findings can be gathered and applied. To handle embedded uncertainties according to their nature, type-2 fuzzy set theory is used. The system is realised via individual reasoning blocks that establish a coherent reasoning lattice. The two apparent benefits of this approach are that it:

• allows easy adaptation and upgrading of the system’s knowledge; and
• provides sensitivity for selection of particular reasoning blocks, depending on the current scenario and conditions.

A prototype has been constructed, therefore, to investigate potential gas hydrate related drilling problems. Its main purpose is to enhance well planning and aid the execution of drilling plans, so that safe working conditions as well as economic and technically successful project outcomes can be achieved. The commercial impact of using such a system will:

• lead to a potential increase in well-site security as well as an overall reduction of well costs; and
• initiate developments of process-knowledge management systems for similar domains.

Recent developments in Native Title law and cultural heritage affecting the petroleum industry—certainty, but at a price

D. Young, G. Scott and J. Norris

Presenter: Doug Young
Blake Dawson Waldron

Session 2C–3:45pm

The mosaic of the common law relating to Native Title, which underpins the Native Title and other Acts, continues to be filled in by the courts increasing certainty for all parties. Last year saw the High Court’s Ward decision—the most significant decision for the petroleum industry since Mabo in 1992. Since then there have been three more important decisions, which while not making new law, have shown how the principles enunciated in Ward and Yorta Yorta are being applied. Some of the cases examined include the Daniel and De Rose Hill decisions, which have application to petroleum tenements.

This paper will outline the recent developments, and demonstrate how the decisions have reduced uncertainty, thereby narrowing the areas about which negotiation must occur. The hurdle for proving the existence of Native Title remains high.

It has not all been in favour of industry, however. Increasingly, Native Title cases, such as Daniels have resulted in unexpected findings that some conventional titles had been invalidly granted. Titles which seemingly ought to have extinguished Native Title have turned out to be invalid, and in many cases irretrievably so. The paper looks at the implications of this for industry as well.
The negotiated price of certainty—recent developments in Native Title agreements affecting the petroleum industry

E.J. Vickery

Presenter: Ewan Vickery
Minter Ellison Lawyers

Session 2C–4:10pm

Development of Native Title agreements for Petroleum continues in parallel with the release of Court decisions on the law of Native Title. Negotiated agreements for three bidding rounds in the South Australian region of the Cooper Basin are now concluded, with exploration underway there and some new commercial production.

These agreements were negotiated under the Commonwealth Native Title Act’s ‘Right to Negotiate’. Agreed resolutions are virtually demanded by the competing tensions within the legislative machinery. The need for conjunctivity of title from the exploration to the development stages is now understood and has become accepted by advocates for Native Title claimants. Recent court decisions would appear to ease the path for applications to the National Native Title Tribunal where negotiations fail to reach agreement, expanding the range of strategies open to Petroleum explorers seeking new title grants.

Small negotiating teams facilitated progress. Despite a long first negotiation, subsequent negotiations have developed from that experience to form an efficient and cost-effective model which has now been replicated for more than 35 agreements conjunctive for all phases of activity. All those agreements address the key issues of title grants, both initially and consequently upon discoveries, Aboriginal heritage inspections and accommodation, including practical aides of indicative timelines and budgets for the latter, and compensation.

Adaptation of these agreements is beginning in other parts of Australia. The temptation of Native Title advocates to test the envelope, however, must be expected with each new negotiation. Contrastingly, both the industry and state government agencies are seeking stabilisation of the terms of negotiated agreements to see how they will work in practice.

This paper describes the key terms and temptations encountered so far in this evolving dynamic.

Sustainable Agreement-making in the extractive industries: lessons from the micro and macro-levels

J. Finlayson and D. Saylor

Presenter: Julie Finlayson
ATSIS

Session 2C–4:35pm

This is a dual presentation focussed on the indigenous claimant perspective in reaching sustainable agreements with extractive industries. The first part of the presentation uses case examples of negotiation principles adopted by Queensland South Representative Body Aboriginal Corporation [QSRBAC] as the recognised Native Title representative body in its dealing with exploration and development proposals. The principles or protocols involved provide productive negotiation strategies while representing and protecting indigenous land interests in southern Queensland. Such principles have been successfully applied in negotiations for an ILUA with the opal miners and in the implementation of an agreement between NT Parties and a coal company.

The second part of the presentation briefly raises broader issues under-pinning the sustainability of agreements and the distribution of benefits. The argument draws on material from other areas of Australia and other examples of agreement-making for effective solutions. In particular, attention is given to the scope of the beneficiaries involved and how this might be determined, the nature of the benefits associated with the agreements, and reasons why the construction of robust agreements with sufficient capacity to survive changes and remain relevant must be sought.

This will be a presentation only.
SESSION 3A—IMPROVED DEVELOPMENT AND PRODUCTION: ENHANCED RETURNS

Gas industry policy and the Australian energy market: the reform process scorecard

P. Balfe

Presenter: Paul Balfe
ACIL Tasman Pty Ltd

Session 3A—11:00am

The past decade has been a period of unprecedented change in the Australian gas industry, driven strongly by pro-competition policies introduced by governments in the wake of the Hilmer Report into National Competition Policy in 1993.

In February 1994, the Council of Australian Governments (CoAG) agreed to facilitate developments aimed at stimulating competition, thereby achieving free and fair trade in the natural gas sector. The reform agenda agreed by CoAG has seen far-reaching changes throughout the gas supply chain, ranging from upstream acreage management policies aimed at increasing the level of gas-on-gas competition, through the regulation of third party access to transmission pipelines and distribution systems, and the ring-fencing of retail functions. Retail contestability is being phased in and a large proportion of the overall market by volume is now contestable. Many previously government-owned gas businesses have been disaggregated and privatised. The transmission pipeline network has developed rapidly with interconnections opening up new markets (as in the case of Tasmania) and providing gas shippers and consumers in southern and eastern Australia with increased supply-side choices and improved supply security.

The process of change has not, however, been without controversy. While the stated intention of policy makers was to provide a framework for light-handed regulation, in practice many operators have found the regulatory processes to be onerous and commercially restrictive. The so-called Parer Review of the national energy market presented to the COAG Energy Ministers in December 2002 made a number of recommendations aimed at improving the gas industry policy environment. Subsequently, the Productivity Commission has started a review of the Gas Access Regime, including the National Third Party Access Code for Natural Gas Pipeline Systems.

This paper presents an assessment of the effectiveness of current energy policies in promoting the development of a competitive gas market in Australia. It compares the situation in Australia with markets elsewhere in the world (United States, UK/Europe) and identifies areas in which policy reform could support the further development of the Australian gas market.

This will be a presentation only.

The influence of financial risk on reserves reporting and investment decisions

J.S Boardman, R.J. Williams and G.B. Salter

Presenter: John Boardman
Resource Investment Strategy Consultants

Session 3A—11:25am

The determination of petroleum resources is a technical function executed by geoscientists and reservoir engineers. The determination and valuation of petroleum reserves is a commercial function that requires input from development and cost engineers, economists and financial and risk analysts. While the technical aspects of both determinations are generally carried out with diligence, the financial considerations are frequently given scant regard. Of particular note are the infrequent acknowledgement of risk and the application of appropriately considered discount rates.

It can be demonstrated that inappropriate selection of the discount rate can create material distortions in the determination and valuation of reserves.

Our proposition is that the rate at which the cash flows are discounted should reflect the reserves uncertainty, specifically the relationship between the proved reserves, which can be financed out of debt, and probable reserves that are typically financed out of equity. Specifically, for the valuation of proved+probable reserves, rather than use a corporate WACC, i.e. one which reflects the average ratio of the costs of debt and equity, investors should instead use a WACC which is based on the ratio of proved: probable weighted cost of debt: equity.
Australia’s hydrocarbon provinces—where will future production come from?

T.G. Powell
Presenter: Trevor Powell
Geoscience Australia
Session 3A–11:50pm

The cumulative graph of reserves added to a basin through time is a measure of that basins’ exploration maturity. Additions of reserves through new field discovery are limited in the Bowen-Surat, Gippsland, Cooper-Eromanga and Bonaparte Basins whilst significant discoveries continue to be made in the Carnarvon Basin. The recent discoveries in the Perth Basin represent a significant new phase in the addition to reserves for this basin. Reserves growth in existing fields represents a very significant source of new crude oil reserves. All gas bearing basins including those in eastern Australia show potential for additional gas discoveries. Coal Bed Methane also represents a significant gas resource into the future.

Australia’s production of crude oil has averaged 11% of the remaining reserves over the last decade. In the late 90s, the rate of production has exceeded the rate of addition to reserves and production must decline in the medium term. Medium- to long-term forecasts of future crude oil production are uncertain because of the difficulty in predicting the rate of crude oil discovery, particularly since many of the established plays in established crude oil basins appear to have little remaining potential and success rates and potential for new plays in established and frontier areas of exploration is unknown.

Rates of gas production are not related to existing reserves, but rather to the dynamics of the commercial market which is strongly influenced by regional infrastructure.

SESSION 3B—IMPROVED DEVELOPMENT AND PRODUCTION: ENHANCED RETURNS

Shared infrastructure:
a cost-effective development strategy for smaller fields offshore Australia?

B.F. Ronalds
Presenter: Beverley Ronalds
CSIRO Petroleum
Session 3B–1 1:00am

Future oil discoveries offshore Australia are unlikely to be large fields that can support the development of a one-off self-sufficient facility. Fixed platforms are generally only feasible in shallow water when the water depth (in metres) to well count ratio d/w < 20. Smaller fields around the world are commonly produced with the aid of infrastructure shared with other fields and operators or supplied by contractors. This offshore infrastructure is likely to include both the mobile rig chartered to drill the development wells, and the processing and export facility; the latter may be either a mobile production unit at the field site (commonly leased) or a remote host platform (commonly operated by a third party).

The construction and ongoing re-use of a generic FPSO suited to Australasian field conditions might be of considerable assistance in monetising small oil fields in deeper water. Similarly, aptly located, designed and operated gas hubs could open up large areas for satellite gas development long into the future, aided by new technology to enable ultra-long tiebacks. Both approaches suggest the benefit of overlaying a regional perspective on the oil companies’ field-specific development philosophy.
**Improving field production and the value of assets through enabling real-time workflows**


*Presenter: Bertrand Theuveny*  
*Schlumberger*

Session 3B–11:25pm

Reservoir and production management practices can benefit from the use of information obtained in real-time. This paper focuses specifically on the gains obtained from the continuous monitoring of naturally flowing and artificially lifted wells.

The deployment of real-time production workflows is an important enabler to improve the value of oil and gas assets. The impact is seen in areas such as:

- the improvement of production (well productivity), through the reduction of deferred production and increased productivity;
- reduction of operating costs (OPEX);
- reduction of repair time;
- reduction of capital expenses (CAPEX);
- capture of best (and worst) practices;
- increased operational flexibility; and
- improved efficiency of workforce.

Field examples over a range of applications covering both artificially lifted wells to naturally flowing wells demonstrate the value of real-time monitoring and relevant-time surveillance and diagnostic applications. Examples of permanent monitoring systems installed at subsurface and/or at surface illustrate how operators can optimise the value of new and existing assets. Although much of the technology has been available for years, deployment in actual field operation is still a challenge. Several best practices are suggested to improve implementation success. The human component in this oil field revolution is important and cannot be under-estimated. The success of real-time enabled workflows can only occur if the workforce fully cooperates and buys-in to the solution. The inertia of legacy practices can derail the change management process if not considered early in the implementation.

This paper discusses several industry approaches to product and service delivery of real-time enabled production workflows, and the various possible implementations. The commercial and physical implementations of these production workflows can range from remotely hosted solutions with no footprint on the operator premises, to fully integrated solution using and integrating legacy system of the oil and gas company. A segmentation of these approaches facilitates the selection process depending on parameters such as the size of the asset, legal constraints, availability of expertise. The value of the benefits of each of these approaches also provides a better understanding of the probable gains that may be achieved in the short to long-term time frame.

**Drivers for the development of an integrated supply base and offshore supply chain, North West Shelf, Australia**

**E.D. Graham**

*Presenter: Ted Graham*  
*Mermaid Marine Australia Ltd*

Session 3B–11:50pm

Since the commencement of the major developments on the North West Shelf, the offshore resource industry, during both its construction and operational phases, has faced considerable logistical impediments to cost-effective solutions for the offshore supply chain. These impediments have included distance, scant resources, lack of infrastructure both on and offshore and lack of critical mass.

Throughout the world, offshore projects have greatly benefitted from the availability of integrated services to cater for the transport of equipment from the point of manufacture or distribution to the offshore location.

Within the Australian context the privately controlled Esso Barry Beach and Dampier Woodside facilities are examples of integrated services, but both differ considerably from a public multi-user facility. The model used in the Timor Sea of one vessel or vessels for the use of several operators is another example.

The NorthWest Shelf has now reached the critical mass and it became apparent several years ago that the area needed an integrated supply base available to multiple operators. It would need to include a heavy loadout wharf, laydown areas, slipway and engineering facilities and office space to service forthcoming projects, as well as planning and cooperation amongst all players to maximise efficiency and use of scant resources as drivers for economic benefits to offshore operators in the region.

Furthermore the fallout from the events of 11 September 2001 and continuing threats of terrorism has meant the security of marine assets has become an important part of each operator's everyday life. The introduction of new legislation relating to this security issue is planned for mid 2004.

In 2000 and 2001 Mermaid Marine Australia Limited undertook a major expansion of its Dampier supply base, and established a world-class facility to meet the growing demands of the region.
This complex has for the first time provided the northwest of Australia, particularly the North West Shelf, Carnarvon Basin and the onshore developments on the Burrup Peninsula, with a facility for offloading and loadout of heavy shipments and fabrication and slipway facilities, coupled with the advantages of a large supply base. This facility can also be expanded to meet growth and the emerging requirements related to security.

This paper describes the drivers for change commencing with the earliest supply chains and following through to the integrated service now available. These drivers meet the requirements of the offshore operators in the region as well as showing the benefits anticipated from this integrated service. The paper also outlines in detail the requirements of the International Maritime Organisation for worldwide changes to port and offshore security.

SESSION 3C—APPLYING PETROLEUM INDUSTRY SKILLS TO GREENHOUSE GAS ISSUES

Geological storage of carbon dioxide: modelling the Early Cretaceous succession in the Barrow Sub-basin, northwest Australia

C.M. Gibson-Poole, J.E. Streit, S.C. Lang, A.L. Hennig and C.J. Otto

Presenter: Catherine Gibson-Poole
CRC for Greenhouse Gas Technologies, Australian School of Petroleum

Session 3C—11:00am

Potential sites for geological storage of CO₂ require detailed assessment of storage capacity, containment potential and migration pathways. A possible candidate is the Flag Sandstone of the Barrow Sub-basin, northwest Australia, sealed by the Muderong Shale. The Flag Sandstone consists of a series of stacked, amalgamated, basin floor fan lobes with good lateral interconnectivity. The main reservoir sandstones have high reservoir quality with an average porosity of 21% and an average permeability of about 1,250 mD. The Muderong Shale has excellent seal capacity, with the potential to withhold an average CO₂ column height of 750 m. Other containment issues were addressed by in-situ stress and fault stability analysis. An average orientation of 095°N for the maximum horizontal stress was estimated. The stress regime is strike-slip at the likely injection depth (below 1,800 m). Most of the major faults in the study area have east-northeast to northeast trends and failure plots indicate that some of these faults may be reactivated if CO₂ injection pressures are not monitored closely. Where average fault dips are known, maximum sustainable formation pressures were estimated to be less than 27 MPa at 2 km depth. Hydrodynamic modelling indicated that the pre-production regional formation water flow direction was from the sub-basin margins towards the centre, with an exit point to the southwest. However, this flow direction and rate have been altered by a hydraulic low in the eastern part of the sub-basin due to hydrocarbon production. The integrated site analysis indicates a potential CO₂ storage capacity in the order of thousands of Mtonnes. Such capacity for geological storage could provide a technical solution for reducing greenhouse gas emissions.

Assessing risk in CO₂ storage projects

A.R. Bowden and A. Rigg

Presenter: Adrian Bowden
Business Risk Strategies, a division of URS Australia Pty Ltd

Session 3C—11:25am

A key challenge to researchers involved with geological storage of CO₂ has been to develop an appropriate methodology to assess and compare alternative CO₂ injection projects on the basis of risk. Technical aspects, such as the risk of leakage and the effectiveness of the intended reservoir, clearly need to be considered, but so do less tangible aspects such as the value and safety of geological storage of CO₂, and potential impacts on the community and environment.

The RISQUE method has been applied and found to be an appropriate approach to deliver a transparent risk assessment process that can interface with the wider community and allow stakeholders to assess whether the CO₂ injection process is safe, measurable and verifiable and whether a selected alternative delivers cost-effective greenhouse benefits.
In Australia, under the GEODISC program, the approach was applied to assess the risk posed by conceptual CO2 injection projects in four selected areas: Dongara, Petrel, Gippsland and Carnarvon. The assessment derived outputs that address key project performance indicators that:

• are useful to compare projects;
• include technical, economic and community risk events;
• assist communication of risk to stakeholders; that can be incorporated into risk management design of injection projects; and
• that help identify specific areas for future research.

The approach is to use quantitative techniques to characterise risk in terms of both the likelihood of identified risk events occurring (such as CO2 escape and inadequate injectivity into the storage site) and of their consequences (such as environmental damage and loss of life). The approach integrates current best practice risk assessment methods with best available information provided by an expert panel.

The results clearly showed the relationships between containment and effectiveness for all of the four conceptual CO2 injection projects and indicated their acceptability with respect to those two KPIs. Benefit-cost analysis showed which projects would probably be viable considering base case economics, greenhouse benefits, and also the case after risk is taken into account. A societal risk profile was derived to compare the public safety risk posed by the injection projects with commonly accepted engineering target guidelines used for dams. The levels of amenity risk posed to the community by the projects were assessed, and their acceptability with respect to the specific KPI was evaluated.

The risk assessment method and structure that were used should be applied to other potential CO2 injection sites to compare and rank their suitability, and to assist selection of the most appropriate site for any injection project. These sites can be reassessed at any time, as further information becomes available.

**Carbon dioxide and carbonate cements in the Otway Basin: implications for geological storage of carbon dioxide**

**M.N. Watson, C.J. Boreham and P.R. Tingate**

**Presenter: Max Watson**

CRC for Greenhouse Gas Technologies, Australian School of Petroleum

Session 3C–11:50am

Understanding CO2 source and carbonate cements in natural gas accumulations is important for predicting the behaviour of anthropogenic CO2 in a reservoir system. The Otway Basin offers an excellent opportunity to examine late CO2-derived cements as an analogue for mineralogical storage of CO2. Understanding Otway Basin diagenesis and carbonate cement distribution is also of great significance to petroleum production in the region.

Elemental and textural examination of Otway Basin cements has identified five carbonates in reservoir rock from CO2-rich gas accumulations. These carbonates show an overall increase in Fe2+ and Mg2+ relative to the calcites in CO2-free reservoir rock, indicating cation derivation from CO2 interaction with labile minerals.

δ13C isotopes of 2.18‰ to -6.7‰ PDB from late carbonate cements in reservoirs containing CO2 confirm an inorganic CO2 origin. 3He/4He gas isotopic ratios of R/Ra > 1 indicate a predominantly mantle input for the CO2-rich accumulations. Degassing of magma associated with Pleistocene to Recent volcanics is suggested as the dominant, CO2 source for the existing CO2 accumulations.

CO2 influx from the magmatic source was rapid, and is the most analogous scenario to injection of anthropogenic CO2. Natural influx of CO2 and the opportunity for mineralisation of CO2 is variable, with CO2 dissolving some original carbonate and precipitation dependant on pH, pCO2 and available cations. Positive mineralogical CO2 storage occurs in the Pretty Hill Formation, due to a higher content of labile lithic minerals, with ~36 kg/m2 of CO2 (~48 kg/m2 carbonate) stored in the Ladbroke Grove Field from the current CO2 phase. The Waarre Sandstone has negative mineralogical storage of CO2, with less carbonate than similar reservoir rock without CO2, and therefore more CO2 being released from dissolution of early carbonates.
SESSION 4A—NEW IDEAS AND TARGETS FOR CENTRAL AND SOUTHEAST AUSTRALIAN BASINS

Modern analogues for dryland sandy fluvial-lacustrine deltas and terminal splay reservoirs


Presenter: Simon Lang
Australian School of Petroleum and Australian Petroleum Co-operative Research Centre
Session 4A–2:00pm

Ephemeral sandy fluvial-lacustrine deltas and terminal splay reservoirs are important reservoirs in many basins around the world, in both pericratonic and intracratonic settings (Triassic of Algeria; Triassic of the North Sea; and Pliocene of the Caspian Sea). Research on modern depositional analogues from dryland basins provides insights into these types of reservoirs. Australia’s modern Lake Eyre Basin, an arid to hyper-arid, low-accommodation intracratonic basin in central Australia, provides an ideal natural laboratory.

This paper highlights field observations of modern, sand-prone, reservoir analogues from the Neales Fan, on the western fringe of Lake Eyre, including unique aerial observations of sedimentation from a rare flood event in an ephemeral fluvial system. These rivers flow irregularly in a dryland setting, but are prone to flash flooding and highly variable discharge that moves large volumes of sediment over a few hours or days. Although there are variations in sediment type and discharge, similarities exist with the key reservoir elements common to most modern and ancient dryland fluvial-lacustrine systems.

Distinctive elements include sinuous fluvial point bar and associated over-bank deposits, distributive avulsion channels and down-dip terminal crevasse spays, either on the floodplain or on the playa lake fringe. The terminal spays are formed, where there is not a pre-existing standing body of water, during rapidly decelerating flows with high-flow regime, transitional to low-flow regime conditions. Typical structures include parallel lamination, upward convex parallel lamination, climbing ripples and small-scale 2D and 3D dunes. Flow interference with in-channel and floodplain vegetation is an important sediment-trapping mechanism with reservoir quality implications. Aeolian deflation is also significant as it causes the removal of fine-grained sediments during dry periods. The main controls on sediment preservation include the overall low-accommodation setting and rare major lake-filling events controlled by flooding out-of-phase with flows down the western rivers. Depositional products are either high-net-to-gross fluvial-terminal splay sheet sands or lower net-to-gross fluvial-terminal splay-lacustrine delta sand sheets or stringers.

Post-Early Carboniferous thermal history reconstruction from well data in the Amadeus Basin central Australia

H.J. Gibson, G. Ambrose, I.R. Duddy, P.R. Tingate and T. Marshall

Presenter: Helen Gibson
The Loop Geologic
Session 4A–2:25pm

Apatite Fission Track Analysis (AFTA) combined with maturity data has revealed that four (possibly five) cooling events affected the northern margin of the Amadeus Basin since the Early Carboniferous. A consistent regional thermal history framework is developed, with recognition of cooling events beginning in the Carboniferous/Early Permian (between ~360 and 290 Ma), the Early Jurassic (~200 Ma), Late Cretaceous (between ~80 and 70 Ma) and Tertiary (between ~25 and 20 Ma). We suggest the first of these reflects uplift and erosion associated with the Alice Springs Orogeny, while Early Jurassic cooling reflects uplift and erosion associated with the Fitzroy Movement. Uplift and erosion in the Late Cretaceous probably relates to the breakup of Australia and Antarctica (opening of the Tasman Sea) at about this time. Later uplift and erosion in the Miocene may reflect Neogene collision of the Australian and SE Asian Plates in the region of the Banda Arc.

In Tyler–1 (northern Amadeus Basin), maturation modelling using paleotemperature constraints from AFTA and VR equivalent data suggests the main source rock horizon (Ordovician Horn Valley Siltstone), went through the dry gas window during burial associated with the latter stages of the Alice Springs Orogeny. Basinward (south) of this foreland wedge, the influence of Devonian-Carboniferous loading decreases enabling oil expulsion from the Horn
Mesozoic evolution of the greater Taranaki Basin and implications for petroleum prospectivity

C. Uruski and P. Baillie

Presenter: Chris Uruski
Institute of Geological and Nuclear Sciences Ltd

Session 4A—2:50pm

A paradigm of New Zealand petroleum geology was that the oldest source rocks known in the region were of Cretaceous age, so any older sedimentary rocks were considered to be economic basement. Two major projects have revealed that this is not universally the case and that a Jurassic petroleum system should now be considered.

Firstly, the Astrolabe 2D speculative survey, acquired by TGS-NOPEC in 2001, has revealed that a significant section underlies the traditional Cretaceous petroleum systems. Secondly, the Wakanui–1 well, drilled by Conoco, Inpex and Todd in 1999, which has recently become open-file, penetrated a Mid-Jurassic coal measure sequence.

Jurassic rocks, including coal measure units, are known onshore in New Zealand. They are part of the Murihiku Supergroup, one of the basement terranes comprising the Permian to Cretaceous volcanic arc that forms the basement rocks of the present New Zealand landmass. Wherever they have been seen in outcrop, these rocks generally record low grade metamorphism and have been discounted as petroleum source rocks. Where rocks of the same age were deposited distal to the volcanic arc (and the effects of heat and pressure), however, they may form components of an effective petroleum system.

The New Caledonia Basin, extending more than 2,000 km from Taranaki to New Caledonia, may have been the site of a Mesozoic back-arc basin. Jurassic coal measure successions and their equivalent marine units may be locally, or regionally important as source rocks. Implications of a Jurassic petroleum system for prospectivity of the region are investigated.

SESSION 4B—THE WESTERN MARGIN REVITALISED

GR spectroscopy and porosity-resistivity logs combine for fast and accurate formation evaluation from the wellsite

Z. Pallikathekathil

Presenter: Zachariah Pallikathekathil
Schlumberger

Session 4B—2:00pm

A new approach to near real-time log interpretation product centred on the Platform Express and Elemental Capture Spectroscopy Sonde (ECS) has provided the potential for fast, simple and near real-time log interpretation.

Accurate clay volumes are vital to determining effective porosity. Density and neutron clay corrections become even more important in low porosity shaley reservoirs where corrections of several porosity units become necessary. In a reservoir of 10% porosity, an error of 1pu can remove 10% of the pore volume. Clay volume from gamma ray curve is prone to errors, especially in formations that are radioactively hot. Generally the error is overestimating the clay volume in the clean zones resulting in a reduction of effective porosity.

The capture-gamma ray spectroscopy tool measures element yields then determines the lithology of the formation via an oxide closure model based on an extensive core database. The matrix density and the matrix neutron porosity are computed from the elemental yields and used to provide accurate matrix-corrected neutron porosity and density porosity. Then, using the Wasman-Smiths-Thomas saturation equation and the true formation and flushed zone resistivities, the water saturation is computed for the flushed zone and the virgin formation.

The lithology derived from the capture spectroscopy tool and lithology processing, along with porosity information, is used to compute K-Lambda permeability via previously published geochemical models. Back calculation using the Timur permeability relationship leads to a bound fluid volume and irreducible water saturation.

This will be a presentation only.
The influence of composition, diagenesis and compaction on seal capacity in the Muderong Shale, Carnarvon Basin

G.E. Kovack, D.N. Dewhurst, M.D. Raven and J.G. Kaldi

Presenter: Gillian Kovack
Australian Petroleum Co-operative Research Centre, Australian School of Petroleum

Session 4B–2:25pm

The Muderong Shale blankets most of the northern Carnarvon Basin and is the top seal to over 90% of all commercial discoveries. This study examines the influence that vertical effective stress, mineralogy and diagenesis have on regional variations of seal capacity. Throughout the basin, threshold pressures (determined from Mercury Injection Capillary Pressure (MICP) analyses), range from less than 1,000 psi (equivalent to ~100 m gas column) up to 10,000 psi (~1,000 m gas column). Because the Muderong Shale varies in thickness (5 m to >900 m) and burial depth (~0.5–3.5 km), effective stresses and temperatures also vary. Effective stress and temperature significantly control pore geometry at different depths through compaction and diagenesis. The data from this study show that shale grain size has no direct influence over seal threshold pressure except that finer-grained Muderong Shale (36–45% particles <2 μm) is more compressible than the coarser grain fraction (26–35% particles <2 μm) with increasing vertical effective stress, resulting in higher seal capacities. When the shale reaches a point where pores are less susceptible to collapse under stress (generally at depths greater than 1.5 km in the Muderong Shale), temperature-controlled diagenetic alteration has a significant effect on threshold pressures. Compositional variations of seal capacity in the Muderong Shale comprises inter-stratified illite/smectite, quartz, kaolinite and discrete illite, with actual abundances of each varying across the basin and with depth. Quartz-rich Muderong Shale mainly occurs in the inboard areas (Barrow and Exmouth Sub-basins and Southern Alpha Arch) while illite/smectite abundance increases to ~50% in the north of the basin (Rankin Platform, Dampier Sub-basin and northern Alpha Arch). One of the most common mineral reactions within smectitic shales is the transformation of smectite to illite with increasing temperature. This is an important reaction in the Muderong Shale, as variations in threshold pressures correlate with total illite content (illite in mixed layer illite/smectite + discrete illite). Total illite is highest in the Barrow Sub-basin and Southern Alpha Arch, and lowest in the Exmouth Sub-basin. Although the Muderong Shale is deeply buried (>2.5 km) along the Northern Alpha Arch and Rankin Platform, total illite content is only moderate.

Geochemical and compound specific carbon isotopic characterisation of fluid inclusion oils from the offshore Perth Basin, Western Australia: implications for recognising effective oil source rocks

H. Volk, S.C. George, C.J. Boreham and R.H. Kempton

Presenter: Herbert Volk
CSIRO Petroleum

Session 4B–2:50pm

The molecular composition of fluid inclusion (FI) oils from Leander Reef–1, Houtman–1 and Gage Roads–2 provide evidence of the origin of palaeo-oil accumulations in the offshore Perth Basin. These data are complemented by compound specific isotope (CSI) profiles of n-alkanes for the Leander Reef–1 and Houtman–1 samples, which were acquired on purified n-alkane fractions gained by micro-fractionation of lean FI oil samples, showing the technical feasibility of this technique. The Leander Reef–1 FI oil from the top Carynginia Formation shares many biomarker similarities with oils from the Dongara and Yardarino oilfields, which have been correlated with the Early Triassic Kockatea Shale. The heavier isotopic values for the C_{15}–C_{25} n-alkanes in the Leander Reef–1 FI oil indicate, however, that it is a mixture, and suggest that the main part of this oil (~90%) was sourced from the more terrestrial and isotopically heavier Early Permian Carynginia Formation or Irwin River Coal Measures. This insight would have been precluded when looking at molecular evidence alone. The Houtman–1 FI oil from the top Cattamarra Coal Measures (Middle Jurassic) was sourced from a clay-rich, low sulphur source rock with a significant input of terrestrial organic matter, deposited under oxic to sub-oxic conditions. Biomarkers suggest sourcing from a more prokaryotic-dominated facies than for the other FI oils, possibly a saline lagoon. The Houtman–1 FI oil δ^{13}C CSI n-alkane data are similar to those acquired on the Walyering–2 oil. Possible lacustrine sources may exist in the Early Jurassic Eneabba Formation and are present in the Late Jurassic Yarragadee Formation. The low maturity Gage Roads–2 FI oil from the Carnac Formation (Early Cretaceous) was derived from a strongly terrestrial, non-marine source rock containing a high proportion of Araucariaceae-type conifer organic matter. It has some geochemical differences to the presently reservoired oil in Gage Roads–1, and was probably sourced from the Early Cretaceous Parmelia Formation.
SESSION 4C—COMMERCIAL UNCERTAINTY: CREATIVE MANAGEMENT

Certainty in uncertain times: considering force majeure

S.K. Dharmananda and N.A. Kingsbury

Presenter: Kanaga Dharmananda
Corrs Chambers Westgarth

Session 4C–2:00pm

Force majeure clauses are particularly relevant to at least two types of oil and gas agreements: operating agreements and long-term contracts. Each type of contract is characteristically exposed to calamitous events that can take many years to manifest. However, force majeure clauses in each type of contract need to reflect the commercial realities and bargain represented by each type of contract.

Building cultural capital in the Australian oil and gas industry

L. Doig, R. Griffiths and J. Robertson

Presenter: John Robertson
PetroMarketing Australia

Session 4C–2:25pm

One of the key barriers to significant cost-savings and harnessing opportunities for growth in the Australian oil and gas industry is lack of trust, openness and misalignment between companies, among teams and among individuals.

In research undertaken for APPEA’s Australian Competitive Energy (ACE) initiative over the last three years, one of the top three barriers to growth continually cited by senior and middle level managers has been culture and behaviours. Examples include misalignment between operators and contractors, management and the workforce, joint venture partners, industry and government, and the industry and the community.

In the next five years, the Australian oil and gas industry is facing a skills shortage, technically challenging projects with less people and adaptive challenges. Adaptive challenges (Heifetz and Laurie, 2000) are ones where the:
• problems and solutions are unclear;
• the solution does not work through command and control;
• requires a new way of thinking and acting; and
• requires the entire organisation to be engaged.

Examples of adaptive challenges for our industry are:
• finding new gas markets;
• exploration in sensitive areas;
• high rig mobilisation costs for a small market; and
• retaining a skilled workforce.

These challenges require companies to find new ways of:
• Attracting and keeping talented people;
• Increasing profits and shareholder value; and
• Increasing creativity and productivity.

Adaptive challenges can be achieved by building cultural capital.

This paper outlines:
• Research and feedback from Australian Operations Managers, Supply Managers, Project Managers and Drilling Managers about the need for improving the culture and behaviours;
• The business case for why building a high performance culture is considered the competitive advantage of the 21st century;
• How to measure culture including the diagnostic tool used for the CEO workshop;
• Results from the diagnostic of the CEO group and implications; and
• How to move forward individually, as companies and as an industry.

The purpose of this paper is to foster debate and discussion about developing a high performing culture in the Australian oil and gas industry. We intuitively know that valuing our people makes good business sense. To transform the industry’s culture, it is not the organisations that transform, but the people. Shifting the culture requires leadership, courage and commitment from the industry’s senior management.

**Growth, protection and value realisation using derivatives**

**D.M. Heard and S.J. Grenfell**

*Presenter: David Heard*

*Macquarie Bank*

*Session 4C–2:50pm*

Oil and gas producers are familiar with the use of derivatives to hedge oil price risk. Beyond this, derivatives provide opportunities to enhance more general corporate finance activities.

An example is raising finance for acquisitions or developments. When the maximum senior debt has been obtained, the choice between equity funding or other sources (such as subordinated debt) should also consider the up-front cash available from a structured derivative program—this may lower the overall cost of capital for the acquirer, and directly improve equity returns through lower dilution.

A notable aspect of oil and gas production businesses is the high degree of embedded optionality. Option pricing methods can be used to value and monetise these real options—creating a new source of finance by transferring part of this embedded optionality to a party which can explicitly value and trade it.

Generating value from real options (such as the opportunity to develop a proven, undeveloped reserve) can represent a critical source of finance.

The value of such development assets is not fully recognised by traditional lending banks when the final investment decision remains some way off.

By contrast, monetising real option value can provide funds at a point where they can be applied to appraisal drilling, thus funding the development of the project to a point where conventional debt or project-secured debt becomes feasible.

Companies with both existing unhedged future production and a portfolio of PUD real options are best-placed to benefit from this source of finance.

**SESSION 5A—NEW IDEAS AND TARGETS FOR CENTRAL AND SOUTHEAST AUSTRALIAN BASINS**

**Optimal thin oil column management—the Bream story**

**R.M. Fish and D.J. Zajdlewicz**

*Presenter: Ron Fish*

*Esso Australia Pty Ltd*

*Session 5A–3:45pm*

Originally developed in 1987 for oil, the Bream N-1 reservoir is a Gippsland Basin Top-of-Latrobe oil and gas accumulation. The original oil column thickness varied due to local structure with most of it 13.5 m and with nearly all of it overlain by a large gas cap. The original depletion plan called for maximising oil recovery through a combination drive and included a provision for returning all produced gas to the reservoir. By 2000 this scheme had proven successful with a 60% oil recovery. The remaining life of the oil resource was, however, limited and a study of the optimum time to initiate gas withdrawals was undertaken.

Gas blow-down studies often employ full-field reservoir simulations. This stratigraphically complex reservoir is not suited to full-field modelling due to the interplay of a coning dominated thin oil column with a thinly bedded dipping reservoir. Consequently a different, more efficient tack was taken—key unswept oil areas were identified and studied for their response to a moving oil column, either through mechanistic simulations or analytically.

This study with subsequent revisions concluded that gas export would increase Bream’s oil recovery by as much as 9.6 MMSTB (1.5 GL) through an active campaign of chasing the moving oil column and/or accessing it at local structural traps.

Gas export started in December 2002 after the construction of a new pipeline. Wellbore preparations were initiated in 2001 with the re-activation of previously depleted wells and the re-completion upward of existing wells. These activities have proven successful with Bream cumulative oil recovery now at 66% and oil rates higher than they have been since 1999.
Sediment supply to the Gippsland Basin from thermal history analysis: constraints on Emperor—Golden Beach reservoir composition


Presenter: Ursula Weber
School of Earth Sciences, University of Melbourne

Session 5A–4:10pm

The Emperor and Golden Beach Subgroups are becoming the focus of Gippsland Basin exploration, yet little is known about their composition and distribution. Regional modelling of over 400 apatite fission track analyses in the hinterland constrains the timing, magnitude and distribution of uplift and denudation and hence sediment supply to the basin. The study yielded regional maps through time of palaeotemperature, overburden, denudation rate and palaeotopography, with increasing assumptions and hence uncertainty.

Regionally the >60,000 km² of Strzelecki Group comprises ~90% volcanoclastic detritus and coal with only ~10% basement-derived sediment, but the northern margin of the basin, near Lakes Entrance, is likely to have a higher basement-derived portion resulting in better reservoirs. The basement-derived sediments are probably largely granitic as the Devonian granites were exposed during the Permo-Triassic Hunter-Bowen Orogeny. Regional mid-Cretaceous uplift resulted in increased denudation of basement, but inversion of the basin margins resulted in denudation of the onshore Strzelecki Group sediments. Emperor and Golden Beach Subgroup sediments deposited in the subsiding Central Graben were at least 50% basement-derived, again with higher quality reservoirs predicted near the Lakes Entrance area and poorer reservoirs near to Wilson’s Promontory. The Latrobe Group siliciclastics were at least 80% derived from basement with a substantial portion from northern Tasmania and the Furneaux Islands around 60-50 Ma.

Structure and hydrocarbons in the Shipwreck Trough, Otway Basin: half-graben gas fields abutting a continental transform

D. Palmowski, K.C. Hill and N. Hoffman

Presenter: Kevin Hill
3D-Geo Earth Sciences, University of Melbourne

Session 5A–4:35pm

As part of a regional study of the evolution of the Otway Basin, the Investigator 3D seismic survey has been structurally analysed, using 11 extracted 2D sections and 3D interpretations of key horizons. South-southwest directed extension was widespread in the Turonian forming the Shipwreck Trough, coincident with uplift of the Otway Ranges to the northeast. The Turonian extension, at ~1.5 myrs, resulted in planar faults in the northeastern part of the Trough, but large half-graben above south-southwest dipping listric master faults in the southwest, both fault sets soling into an Early Cretaceous shale detachment. The half-graben propagated north from the Mussel-Tarpwaup Hinge-Zone by footwall collapse and accommodated deposition of reservoir rocks for the known hydrocarbon accumulations. The half-graben die out along strike to the east at tip-points against an accommodation zone that developed into a continental transform (the Shipwreck Fault).

Santonian breakup in the Great Australian Bight coincided with considerable south-southwesterly extension in the Otway Basin juxtaposed against the failed Bassian rift across the Shipwreck Fault. Extension of ~1.21 km to the west of the Shipwreck Fault contrasts with ~0.42 km on the eastern side accommodated by ~0.79 km left-lateral displacement along the Shipwreck Fault. The Belfast Mudstone was deposited during this time, forming the regional seal for the known hydrocarbon accumulations.

Limited slow extension during the Campanian to Early Eocene resulted in a further 0.33 km sinistral slip along the Shipwreck Fault. Late Early Eocene Breakup in the Otway Basin ended the transitional phase, terminating extensional and Shipwreck Fault offset. The breakup caused local uplift and ~1 km erosion of Wangerrip Group sediments. The post breakup phase is characterised by prograding sequences indicating progressive-regressive cycles.

The Thylacine and La Bella gas fields occur in large tilted fault-blocks near the Hinge-Zone. These successful large structures lie along a longstanding High probably sourced from south of the Hinge-Zone. Key elements for a successful hydrocarbon play are deposition of the Turonian Waarre Formation sandstone reservoirs at rift onset and of a thick Belfast Mudstone seal during continuous Coniacian-Santonian extension. Footwall collapse north of the Hinge-Zone, bound by the deepwater Otway Basin and the continental transform, controlled the distribution of traps, regional seal and hydrocarbon maturation.
Breathing new life into the eastern Dampier Sub-basin: an integrated review based on geophysical, stratigraphic and basin modelling evaluation

G.P. Thomas, M.R. Lennane, F. Glass, T. Walker, M. Partington, K.R. Leischner and R.C. Davis

Presenter: Peter Thomas
Woodside Energy Limited

Session 5B–3:45pm

The eastern Dampier Sub-basin on Australia’s northwestern margin has been subject to intensive exploration activity since the early 1960s. The commercial success rate for exploration drilling, however, has been a disappointing 8%, despite numerous indications of at least one active petroleum system. During 2002–2003, Woodside and its joint venture partners undertook an integrated review of the area, aimed at unlocking its remaining potential. Stratigraphy, hydrocarbon charge and 3D seismic data quality were addressed in parallel.

The eastern Dampier Sub-basin stratigraphy was upgraded from the existing, conventional, second-order tectono-stratigraphic framework to a third-order, exploration-scale, genetic stratigraphic framework. The new framework has regional predictive capability in terms of reservoir (and seal) presence and facies, and has led to recognition of new plays and an enhanced understanding of known plays. One new play involves shoreface sands within the Calypso Formation. New light has been shed on the known Lower Cretaceous M.australis sands play (K30), by the creation of gross depositional environment maps at third-order sequence scale. The Upper Jurassic deepwater clastics play of the Lewis Trough has also been developed, by recognition of four prospective, sand-rich gravity-flow intervals in the early Oxfordian (J42 play).

A 3D charge modelling study, underpinned by new geochemical analysis, has allowed delineation of areas of higher and lower risk in terms of hydrocarbon charge and phase (oil versus gas). Key source rocks for oil are identified in the early Oxfordian W.spectabilis biozone, although they are also a likely source for gas in the southwest of the area. The Bathonian-Callovian Upper Legendre Formation is a major source for gas, but could also have contributed minor oil in the northeast of the area. By a combination of geochemical fingerprinting and 3D forward modelling, most hydrocarbon occurrences in the area have been tied to these source intervals, complete with a consistent view of maturities and migration pathways.

Some 1,500 km$^2$ of the Panaeus multi-client 3D survey were reprocessed, with close attention to multiple removal, velocities and imaging. A step-change improvement in seismic quality was obtained, together with improved velocities for depth conversion.

The prospect portfolio has been polarised and much enhanced through these studies, and the results of several existing wells have become better understood. Some new prospects were identified by apparent direct fluid indications, detected in one case by 3D volume AVO screening. Other new prospects are the result of a clearer seismic image, or of the revised velocity model for depth conversion. New plays are still being followed up, while the fresh light cast on existing plays (e.g. K30 and J42), in combination with improved seismic data, has led to development of several interesting opportunities.
Using 2D and 3D basin modelling to investigate controls on hydrocarbon migration and accumulation in the Vulcan Sub-basin, Timor Sea, northwestern Australia

T. Fuji, G.W. O’Brien, P. Tingate and G. Chen

Presenter: Tetsuya Fuji
Australian School of Petroleum, University of Adelaide, now at Japan National Oil Corporation

Session 5B–4:10pm

2D and 3D basin models have been constructed of the southern and central parts of the Vulcan Sub-basin region, in the Timor Sea. This work was carried out to better elucidate the petroleum migration and accumulation histories, and exploration potential, of the region.

2D/3D modelling in the Swan Graben indicates that horizontal and downward oil expulsion from the source rocks of the Late Jurassic Lower Vulcan Formation into the Plover Formation sandstone was active from the Early Cretaceous to the present day. Oil migration from the Lower Vulcan Formation into the Late Cretaceous Puffin Formation extends from about 0.001–30 µm, the presence of bitumen and mobile hydrocarbons in pores and are pore-size specific. As the pore-size range in mudstones extends from about 0.001–30 µm, the presence of bitumen in the small pores detected by SANS indicates the depth of onset of hydrocarbon generation, whereas the presence of bitumen and mobile hydrocarbons in the largest pores detected by USANS indicates a significant saturation and the onset of expulsion.

Although geochemical data imply the existence of a potential gas and oil source rock in the Lower Cretaceous section (Echuca Shoals and Jamieson Formations), the SANS/USANS data indicate significant generation but little or no expulsion. This source limitation may explain poor exploration success for liquid hydrocarbons in the area. The SANS/USANS data provide evidence of intra- and inter-formational hydrocarbon migration or kerogen kinetics barriers. There is no evidence of an oil charge to the Berriasian Brewster Sandstone from the Echuca Shoals Formation, although some gas charge in Brewster–1A is possible. This novel microstructural technique can be used to independently calibrate and refine source rock generation/expulsion scenarios derived from geochemistry modelling.

Hydrocarbon generation and expulsion from Early Cretaceous source rocks in the Browse Basin, North West Shelf, Australia: a small angle neutron scattering study


Presenter: Andrzej Radlinski
Geoscience Australia

Session 5B–4:35pm

Small Angle Neutron Scattering (SANS) analyses were carried out on 165 potential source rocks of Late Jurassic–Early Cretaceous age from nine wells in the Browse Basin (Adele–1, Argus–1, Brecknock South–1, Brewster–1A, Carbine–1, Crux–1, Dinichthys–1, Gorgonichthys–1 and Titanichthys–1). Samples from Brewster–1A and Dinichthys–1 were also analysed using the Ultra Small Angle Neutron Scattering (USANS) technique.

The SANS/USANS data detect the presence of generated bitumen and mobile hydrocarbons in pores and are pore-size specific. As the pore-size range in mudstones extends from about 0.001–30 µm, the presence of bitumen in the small pores detected by SANS indicates the depth of onset of hydrocarbon generation, whereas the presence of bitumen and mobile hydrocarbons in the largest pores detected by USANS indicates a significant saturation and the onset of expulsion.

Although geochemical data imply the existence of a potential gas and oil source rock in the Lower Cretaceous section (Echuca Shoals and Jamieson Formations), the SANS/USANS data indicate significant generation but little or no expulsion. This source limitation may explain poor exploration success for liquid hydrocarbons in the area. The SANS/USANS data provide evidence of intra- and inter-formational hydrocarbon migration or kerogen kinetics barriers. There is no evidence of an oil charge to the Berriasian Brewster Sandstone from the Echuca Shoals Formation, although some gas charge in Brewster–1A is possible. This novel microstructural technique can be used to independently calibrate and refine source rock generation/expulsion scenarios derived from geochemistry modelling.
SESSION 5C—COMMERCIAL UNCERTAINTY: CREATIVE MANAGEMENT

Sustainability: a new era in approvals processes

B. Wylynko and A. Hartley
Presenter: Brad Wylynko
Clayton Utz
Session 5C–3:45pm

With its in-principle approval of the Gorgon gas proposal, the Western Australian government has heralded a new era—the era of sustainability assessments. No longer confined to strict environmental criteria, sustainability assessments will also consider the economic and social aspects of proposed oil and gas developments. This has a number of ramifications for the legal framework within which existing approvals processes operate.

This paper examines traditional environmental assessment as represented by the processes used by Western Australia and the Commonwealth (which will be applied to the Gorgon proposal). It finds that while economic and social factors are expressly included in the legal framework, these factors have not played a large role in either assessing the significance of proposal impacts or in determining the conditions to be placed on the proposals. In the case of Western Australia, in 1996 the Supreme Court overturned recommendations by the Environmental Protection Authority, and a subsequent decision by the Minister for the Environment, on the basis that they had considered extraneous economic factors.

Soon after approving the Gorgon proposal, the Western Australian Government published a State Sustainability Strategy. The strategy calls for sustainability assessments to be built upon existing environmental assessment processes. Having outlined the traditional environmental assessment process, the paper draws out a series of principles that may serve as a starting point for discussion about how to create sustainability assessment processes from environmental assessment processes. Key principles include comprehensiveness and an articulation of the objectives to be met through the assessments.

The notion of sustainability is gradually becoming incorporated into the environmental legal framework. Sustainability assessments may be the next step in the development of that framework.

Legal framework and liability of leaving oil and gas facilities in-situ or deep sea disposal on Australia’s Continental Shelf

I.V. Stejskal
Presenter: Iva Stejskal
Blake Dawson Waldron
Session 5C–4:10pm

Australia’s offshore petroleum industry is beginning to mature and many of its offshore oil and gas production facilities are reaching the end of their operational life. These facilities consist of an array of infrastructure including wells, wellheads, platforms and monopods of various construction, pipeline and flowlines, and anchors and risers. Many of these facilities will need to be decommissioned at the end of their operational and economic life in a safe and environmentally responsible manner.

The Australian government has the jurisdiction to direct a company to remove all facilities associated with offshore production projects located on Australia’s continental shelf, but there is room for discretion for other decommissioning options. The manner in which facilities are decommissioned must be assessed on a case-by-case basis, taking into account factors such as technical feasibility, commercial risk, safety and social impacts, costs and environmental effects.

Two decommissioning options appropriate in some instances are to leave selected facilities in-situ or dispose of a facility to some other location on the continental shelf, preferably in deep water. Residual liability refers to the responsibility and liability associated with leaving facilities on the seabed. If a facility is allowed to remain on the seabed, questions related to residual liability arise:

• who is responsible for any facility left on the seabed;
• who is liable to pay for compensation in the event that this facility is allowed to remain in place on the seabed and injury or damage is caused to a third person or property?

There is no universally accepted practice in relation to residual liability in relation to decommissioning. In some countries, the State assumes responsibility; in other countries the company remains responsible in perpetuity. This issue still needs to be clarified in Australia.
Engaging the education community through petroleum industry sponsored programs

M.A. Battrick, B.R. Bishop and G.A. Edmondson

Presenter: Matthew Battrick
ENI Australia

Session 5C–4:35pm

The Schools Information Program (SIP), a joint venture of the Petroleum Club of Western Australia and APPEA, has operated as a successful model of the petroleum industry engaging with the Western Australian education community since 1991.

Targeted at Year 10 students (15-year-olds) in mainly metropolitan Perth Government and private high schools, the SIP involves the delivery of a short-term (about six weeks) education program—in six parts. The program, together with its course materials and student assessment instruments, is designed to integrate with components of WA’s curriculum for Science, Social Science, Technology and Enterprise, and English. Operating in 22 Perth schools, the SIP framework is structured according to six core areas of the hydrocarbon industry sector:

- exploration;
- drilling;
- production;
- transportation;
- refining; and
- sustainable development.

The program’s mode of delivery is largely via a series of classroom presentations by volunteer professionals drawn from the WA petroleum industry, together with field trips to relevant sites near Perth. The SIP is managed by a part-time co-ordinator (0.6) and the entire program is overseen by a ‘steering committee’, drawn from APPEA, the Board of Governors of the Petroleum Club of WA, along with some of the industry presenters.

Individual companies in the industry are involved at a number of levels: co-ordinating presenters; preparing presentation materials; providing on-going support for students during the program; providing prizes as an incentive to the students; and also providing cash donations to assist with the costs of the Co-ordinator. The course materials consist of standard slide presentations (available in both electronic or OHP format), and are complemented by written worksheets, and a website integrated with the Petroleum Club of WA’s site. During the program, the students, working in groups, compete for substantial industry-related prizes, by completing a research project related to the SIP course content. A separate Board of Review assesses projects formally according to a set of established criteria.

That the SIP is a success is confirmed quantitatively using formal ongoing program evaluation by the students, their teachers, and the industry presenters, and is evidenced by the number of schools seeking the limited places in the program. Other education initiatives (e.g. Speaking of Oil and Gas, and The Introduction to the Petroleum Industry seminars) are also discussed in this paper as they have links to the SIP.
The Thylacine and Geographe gas discoveries, offshore eastern Otway Basin

D.C.B. Cliff, S.C. Tye, R. Taylor
Presenter: David Cliff
Woodside Energy Limited

The Thylacine and Geographe gas fields were discovered in mid-2001 in the offshore Otway Basin, in permits T/30P and VIC/P43 respectively. Geographe is 55 km south of Port Campbell and Thylacine is a further 15 km offshore, in the depo-centre of the Shipwreck Trough, in water depths of 80 m to 100 m. The Thylacine–1 well intersected a 277 m gas column in Turonian to Santonian aged reservoirs. Geographe–1 intersected a 233 m gas column in a similar sedimentary section. Thylacine–2, 5.7 km west of Thylacine–1, confirmed the field extent, and flowed gas at 28 MMSCFD (0.79 Mm³/D). Critical to the discovery of these fields was the Investigator 3D seismic survey, which covered about 1,000 km² of the central Shipwreck Trough. The pre-drill chance of success of both structures was high-graded as a result of excellent structural imaging and the conformance of amplitude and AVO anomalies to mapped closures. The interpretation of this survey and the subsequent drilling of the Thylacine and Geographe Fields have dramatically increased the understanding of the structure and stratigraphy of the offshore eastern Otway Basin particularly in relation to the Shipwreck Trough and the Sorell Fault Zone.

Combined dry gas reserves at the proved and probable level stand at 0.85 TCF and condensate reserves at 10.7 MMBBL. The fields are undergoing integrated subsurface, development and environmental studies with the aim of supplying the nearby southeastern Australian gas markets. The preferred development concept is a small jacket structure at Thylacine, followed by a subsea tie-in of the Geographe Field with onshore processing facilities near Port Campbell.

Compressional growth of the Minerva anticline, Otway Basin, southeast Australia—evidence of oblique rifting

C.L. Schneider, K.C. Hill and N. Hoffman
Presenter: Craig Schneider
School of Earth Sciences, University of Melbourne

The Minerva anticline, on the eastern margin of the Shipwreck Trough, east-central Otway Basin, evolved through Early Cretaceous to Santonian extension, followed by Campanian–Paleocene and Miocene to Recent pulses of compression.

Onshore to offshore correlation of seismic sequences combined with 3D seismic mapping reveals that the Minerva anticline is located above an Early Cretaceous, northeast trending, basement-involved, graben. The graben-forming, northeast and north–south trending faults became largely inactive prior to the end of the Early Cretaceous. During the Turonian to Santonian, the northeast trending Point Ronald anticline and newly formed east–west trending normal faults controlled sediment distribution. The structural style changed in the Campanian as the northeast trending Minerva anticline began to form with a coeval, northwest-trending, axial-perpendicular fault array located along the crest of the fold. The location and orientation of this fault set is consistent with a compressional mechanism for fold growth. Similar compressional folding events during the Miocene–Recent modified and tightened the fold. Isopach maps show that during the Campanian to Maastrichtian, sediment thinned onto the nascent Minerva anticline, but accommodation rate outpaced structural growth, preserving a continuous sedimentary sequence.

The timing of compressional fold growth is enigmatic. Campanian–Maastrichtian compression at the Minerva anticline was synchronous with over 10 km of extension accommodated by the Tartwaup–Mussel hingeline, 50 km to the south. Although the compression may be far-field effects associated with Tasman Basin sea floor spreading, we speculate that the Minerva anticline grew by transpression within a larger left-lateral transtensional Shipwreck Trough.
Fault and top seal integrity at relays and intersections using a 3D distinct element code

B.A. Camac, S.P. Hunt and P.J. Boult

Presenter: Bronwyn Camac
Australian School of Petroleum
University of Adelaide

Session 6A–11:50am

It has long been known that faults and horizon boundaries can greatly affect the magnitude and orientation of the in-situ rock stress state. Significant success has been shown in the geo-engineering disciplines, whereby geomechanical models have been built to model local stress fields generated by rock mass inhomogeneities.

In this work 3DEC (3D) the discrete element code has been applied to model stress perturbations around three simple fault configurations, two relay configurations (relay ramp and horst structure) and one fault intersection. The results show rotation in the principal stress orientation and stress magnitudes of the regional stress field about the faults. The degree of rotation of the principal stress direction and the stress magnitude are dependant on the fault friction angle parameter, the angle of maximum principal stress to the fault plane and the ratio of maximum to minimum principal stress. The degree of perturbation is demonstrated graphically in the surrounding rock mass along the fault strike, the perturbation generated by the fault can be up to 1.4 times the magnitude of the maximum principal regional stress and is highly dependent on friction angle.

Case studies are presented where this 3D numerical technique has been used to truly integrate risking methods on the fault plane and in the surrounding rock mass. Case study examples are given for the Otway Basin, South Australia and the Bonaparte Basin, Timor Sea, where these predictors can be applied to accurately identify high-risk reservoir seals.

SESSION 6B—THE WESTERN MARGIN REVITALISED

Jurassic petroleum systems in the Houtman Sub-basin, northwestern offshore Perth Basin, Western Australia: a frontier petroleum province on the doorstep?

J. Gorter

Presenter: John Gorter
ENI Australia Limited

Session 6B–1 1:00am

The under-explored Houtman Sub-basin, a northwestern offshore extension of the hydrocarbon-productive Perth Basin of southwestern Australia, formed during Jurassic rifting of Gondwana. The sub-basin contains the ingredients for an exciting frontier petroleum province with typical rift architecture. Permian, Triassic and Jurassic petroleum systems are proven from the onshore region, with a productive Triassic-sourced hydrocarbon system recently demonstrated in the adjacent Abrolhos Sub-basin by the Cliff Head oil discovery, and several basal Triassic-sourced oil shows. Gas and oil shows from the Early to Middle Jurassic Cattamarra Coal Measures in Houtman–1, the only well drilled in the 32,000 km$^2$ Houtman Sub-basin, are most likely sourced from the organic-rich Cattamarra Coal Measures and are sealed by intraformational shales and the overlying regional marine shale of the Cadda Formation. The disappointing result of Houtman–1 has coloured perceptions of the prospectivity of the Houtman Sub-basin. Despite this negativity, recent seismic acquisition and reprocessing have demonstrated the presence of large structural closures in the sub-basin that could contain substantial oil reserves as indicated by geochemical modelling of the Cattamarra Coal Measures source rocks. Analyses on GOI indicate a palaeo-oil zone at the top of the Cattamarra Coal Measures in Houtman–1 indicating that the gas-prone perception may not be true. QGF intensities from Houtman–1 suggest oil migration in sandstones beneath intra-formational seals in both the Late Jurassic Yarragadee Formation and the Cattamarra Coal Measures. In addition to reservoir sandstones, source rock intervals occur in the lower Yarragadee Formation, but regional sealing units in this formation are to be confirmed.
A re-evaluation of the hydrocarbon habitat of the northern Perth Basin

B.M. Thomas and C.J. Barber

Presenter: Bruce Thomas
Origin Energy Resources Limited

Session 6B–11:25am

Recent oil discoveries at Hovea, Cliff Head, Jingemia and Eremia have challenged the perception that the northern Perth Basin is largely gas prone and renewed interest in the identification of oil source rocks in the succession. A major geochemical reassessment of all units from the Middle Triassic to the base of the Permian shows that the principal oil prone source rocks are restricted to a discrete zone within the basal Kockatea Shale, the Sapropelic Interval of the Hovea Member (defined herein). The source zone, typically 10–40 m thick, is laterally continuous over much of the onshore northern Perth Basin. It immediately overlies the Permian-Triassic boundary and may form part of a global anoxic event. These are some of the best oil source rocks ever identified in Australia. A combination of diagnostic biomarkers and compound specific isotopic data consistently link the Hovea Member source rocks to all oils analysed from the northern Perth Basin. Gas prone source rocks are developed at several levels in the Permian, and particularly in the Irwin River Coal Measures. In most areas of the basin, oil charge from the Triassic is in direct competition with any gas generated from the Permian, as seen in the large Warradong Kitchen, southeast of the Dongara Field. This has resulted in a predominance of gas discoveries, often with a thin oil leg. The smaller but oil prone Jingemia Kitchen, southwest of Dongara, has sourced the recent oil discoveries at Hovea, Jingemia and Eremia. There is evidence that the Hovea Member source rocks are also widely distributed offshore in the Abrolhos Sub-basin where they appear to have sourced the Cliff Head oil discovery and strong oil shows in Morangie–1 and Livet–1, some 300 km northwest of Dongara.

The northern Perth Basin—from marginally prospective for gas to highly prospective for both oil and gas

A.J. Buswell, W.D. Powell and T. Scholefield

Presenter: Jack Buswell
Origin Energy Limited

Session 6B–11:50am

Recent discoveries of gas in the Wagina Formation by Beharra Springs North–1, in the High Cliff Sandstone by Hovea–2, and of oil in the Dongara Sandstone by Hovea–1, Jingemia–1 and Eremia–1, have changed the perception of the northern Perth Basin from being marginally prospective for gas to one that is highly prospective for both oil and gas. Enhanced quality of 3D seismic over 2D, an analysis of regional gravity data, and in-house reservoir and source rock studies have all played a part in these discoveries. Hovea–2 is significant in that it flowed gas at commercial rates from the Lower Permian High Cliff Sandstone, the first well in the basin to do so from this reservoir. A program involving extensive additional 3D seismic and as many as six exploration wells is planned for 2004, offering the potential for further significant hydrocarbon discoveries.
SESSION 6C—COMMERCIAL UNCERTAINTY: CREATIVE MANAGEMENT

Upstream Australia—good, bad or ugly?

J.P. Feenan
Presenter: John Feenan
Wood Mackenzie Limited
Session 6C–11:00am

This paper will consider how offshore Australia ranks against international competition for upstream investment. Among the factors included in the analysis and based on recent activity will be:

- exploration success rates—focussing on discoveries which are currently commercial;
- distribution of hydrocarbon types and size of commercial discoveries;
- the impact of the fiscal regime on both risks and rewards; and
- the post-risk expected value from exploration.

How does offshore Australia rank internationally and what are expectations for the future—is it good, bad or ugly?

---

Taxation of the Australian offshore industry: a perspective

J.H. Murray and D.W. Young
Presenter: John Murray
PricewaterhouseCoopers
Session 6C–11:25am

There is an extensive list of taxes (direct and indirect) that potentially apply to companies that explore and produce oil, gas or other hydrocarbons in Australia’s offshore waters. These taxes can include income tax, petroleum resource rent tax, royalties, goods and services tax, customs duties and fringe benefits tax. However, are such companies that produce in Australia taxed more than their counterparts in offshore locations elsewhere around the globe? This paper provides an insight into the principal forms of direct taxation that apply to the Australian offshore production industry. It examines the nature of the taxes applied, the rate of taxation and how the tax take has moved over the years since the first offshore exploration permits were granted in Australia in the late 1950s. The paper gives examples of how in practice each of the relevant taxes would apply throughout the life of a field and compares the taxation burden in Australia to that in other key offshore producing jurisdictions such as the UK, US and Norway. The paper concludes by looking at some of the economic and political factors that must be addressed by the Australian Government if Australia is to maintain a fiscally balanced tax regime to encourage further investment in our offshore industry.
Alternative reserve reporting and exploration accounting methods—the need for international accounting standards

B.P. Steedman

Presenter: Brent Steedman
KPMG

Session 6C–11:50am

The objective of this paper is to analyse the different reserve reporting and exploration accounting methods used globally and highlight the key reporting implications for companies that are domiciled in Australia. This has become a critical issue in the oil and gas sector with the impending implementation of International Accounting Standards (IAS), as these standards as they now stand, do not specifically address the oil and gas industry. As a result companies may have the option or may be required to make significant changes to existing accounting and reporting practices.

The paper will analyse the issues, potential implications, and opportunities within the following areas:
1. A brief summary of the history of oil and gas accounting standards and the status of existing IAS.
2. The different reserve reporting practices for exploration accounting and reserve reporting practices between the United States (US), United Kingdom (UK), and Australia, including the different interpretations of reserves within the countries.
3. The alternative accounting outcomes for exploration expenditure depending upon whether successful efforts are applied, area of interest, or full cost accounting.
4. The relationship between reserve reporting and exploration accounting, with examples of how multiple accounting outcomes may result from the same exploration program.
5. The actions required by oil and gas executives to best manage the issues.

The paper will be written and presented in a style such that non-accountants or reserve experts will be able to understand the issues. Detailed analysis of technical issues and industry specific references will be avoided, e.g. accounting jargon.

The paper will be of most value to representatives of Australian independent oil and gas companies, but would also be of interest to international companies.

SESSION 7A—ADVANCING COAL SEAM GAS DEVELOPMENT

Developing coal seam methane in the Sydney Basin

I. Wang, J. Choudhury, W. Barker and S. McNally

Presenters: Ian Wang and Stephen McNally
Sydney Gas Limited

Session 7A–2:30pm

Sydney Gas Ltd (SGL) believes that the growth of the new and exciting coal seam methane (CSM) industry will certainly offer significant economic, social, and environmental benefits to the State of NSW within both the short and the long-term. This paper overviews SGL’s CSM resource development program for the Sydney Basin in general. SGL’s acreage provides an extensive contiguous coverage of the Sydney Basin, and is ideal as it straddles the main gas transmission line from Wollongong to Newcastle.

Gas content is one of the most crucial parameters for CSM resource development. This paper also discusses the method adopted by SGL highlighting the pitfalls in the gas content measurements adopted by previous explorers that caused substantial under-estimation of the CSM resource in the Southern Sydney Basin. Gas content determination comprises three components, i.e. lost gas (Q1), desorbed gas (Q2) and residual gas (Q3). Evaluation of earlier data acquired under an ambient temperature rather than reservoir temperature, was the first source of error which resulted in under-estimating gas content calculation. Zero time for desorption measurements was previously set at core retrieval time rather than core cutting time generating an additional error. That is particularly significant in a highly stress-sensitive coal seam such as the Bulli which is the main target for the CSM resource development in the Southern Sydney Basin.

This paper has also addressed the commercial case for developing CSM as a new energy source in NSW, for so long dependent upon coal and interstate gas.
The rise and rise of coal seam gas in the Bowen Basin

J.M. Riley
Presenter: Martin Riley
Origin Energy CSG Limited
Session 7A–2:55pm

The coal seam gas (CSG) industry has been active in Australia for almost three decades, with interest largely focussed on the Bowen and Sydney basins. Sporadic activity has also occurred in a number of other areas including the Galilee, Ipswich, Clarence–Moreton, Gunnedah, Gloucester, and Otway basins to name a few, with significant recent interest shown in the promising Surat Basin. Of these basins it is the Bowen Basin in eastern central Queensland which has continued to shine as the premier coal seam gas province in the country.

From humble beginnings in the mid-1970s in the Moura area, CSG from the Bowen Basin now supplies around 20% of Queensland gas demand. Since the start of commercial production from the basin in 1996, production has grown to about 20 PJ per year from five separate fields, with three new fields under construction expected to more than double this volume over the next 2–3 years.

The largest contribution to this growth will come from the Comet Ridge region which is proving itself to be a world class CSG deposit. The high-productivity fairway in the south of the region extends over an area about 80 km long and 20 km wide and includes the Tipperary Fairview field, and the Origin Energy Spring Gully project. In the last year proved and probable gas reserves have more than doubled to 1,500 PJ across the fairway, with upside recoverable gas estimated to be 4,700 PJ. The rapid rate of CSG reserves increase in the Bowen Basin demonstrates the key role this industry will play in the eastern Australia gas market.

A technical appraisal of storage of Gorgon CO$_2$ at Barrow Island, North West Shelf

R. Malek, R. Bartlett and B. Evans
Presenter: Reza Malekzadeh
DoIR
Session 7A–3:20pm

The Gorgon gas field lies 70 km west of Barrow Island in 200 m of water. The field is jointly owned by ChevronTexaco Australia, Shell Development Australia and Mobil Exploration and Producing Australia and has certified proven hydrocarbon gas reserves of 272.69 Giga cubic metres (Gm$^3$) (9.63 trillion cubic feet (Tcf)). Carbon dioxide (CO$_2$) comprises about 14 mole % of the raw gas resource.

The Gorgon joint venture is committed to the responsible management of greenhouse gas emissions and this ongoing commitment is reflected in the plan to inject Gorgon CO$_2$ into the Dupuy Formation beneath Barrow Island, unless it is cost prohibitive or technically unfeasible.

This paper summarises the Phase 1 assessment made by the Western Australian Department of Industry and Resources (DoIR) into the technical feasibility of the Gorgon CO$_2$ storage project. Technical feasibility is defined as the ability to inject CO$_2$ in a manner that has acceptable safety, environmental and reservoir risks based on assessments made by both the Gorgon joint venture and regulatory bodies.

DoIR and ChevronTexaco Australia agreed to regularly review the technical work for due diligence purposes. To assist in the assessment, DoIR engaged the services of Curtin University. The Phase 1 review was completed in June 2003 and provided technical assurance on the feasibility of CO$_2$ storage beneath Barrow Island. This provided one of the criteria for the WA State Government’s decision to grant in-principle access to Barrow Island for the project.

The Phase 1 review provided a comparative risk analysis and recommendations related to improving the sub-surface definition of the earth model, further assessment of seal and fault integrity, injectivity, near-well bore reactions and CO$_2$ surveillance and monitoring technologies. Key DoIR recommendations included the need for additional geological data and a long-term monitoring strategy for reservoir management and contingency planning. The second Phase of due diligence commenced in February 2004.
SESSION 7B—THE WESTERN MARGIN REVITALISED

The evolution of the Bernier Ridge, Southern Carnarvon Basin, Western Australia: implications for petroleum prospectivity

A. Lockwood and C. D’Ercole

Presenter: Andrew Lockwood
Geological Survey of Western Australia

Session 7B–2:00pm

The basement topography of the Gascoyne Platform and adjoining areas in the Southern Carnarvon Basin was investigated using satellite gravity and seismic data, assisted by a depth to crystalline basement map derived from modelling the isostatic residual gravity anomaly. The resulting enhanced view of the basement topography reveals that the Gascoyne Platform extends further westward than previously indicated, and is bounded by a northerly trending ridge of shallow basement, named the Bernier Ridge.

The Bernier Ridge is a product of rift-flank uplift prior to the Valanginian breakup of Gondwana, and lies east of a series of small Mesozoic syn-rift sedimentary basins. Extensive magmatic underplating of the continental margin associated with this event, and a large igneous province is inferred west of the ridge from potential field and seismic data. Significant tectonic events that contributed to the present form of the Bernier Ridge include the creation of the basement material during the Proterozoic assembly of Rodinia, large-scale faulting during the ?Cambrian, uplift and associated glaciation during the early Carboniferous, and rifting of Gondwana during the Late Jurassic. The depositional history and maturity of the Gascoyne Platform and Bernier Ridge show that these terrains have been structurally elevated since the mid-Carboniferous.

No wells have been drilled on the Bernier Ridge. The main source rocks within the sedimentary basins west of the Bernier Ridge are probably Jurassic, similar to those in the better-known Abrolhos–Houtman and Exmouth Sub-basins, where they are mostly early mature to mature and within the oil window respectively. Within the Bernier Ridge area, prospective plays for petroleum exploration in the Jurassic succession include truncation at the breakup unconformity sealed by post-breakup shale, and tilted fault blocks sealed by intraformational shale. Plays in the post-breakup succession include stratigraphic traps and minor rollover structures.

Late Cretaceous ponded turbidite systems: a new stratigraphic play fairway in the Browse Basin

J.M. Benson, S.J. Brealey, C.W. Luxton, P.F. Walshe and N.P. Tupper

Presenter: Jim Benson
Santos Limited

Session 7B–2:55pm

Regional seismic and sequence stratigraphic analysis of the Browse Basin identified a new Late Cretaceous play fairway involving ponded turbidite systems deposited within confined basins. This work highlighted the potential for isolated sandstone reservoirs in the Middle Campanian sequence of the Caswell Sub-basin. Extensional faults were expected to provide vertical conduits for charge from underlying Early Cretaceous source rocks.

The play concept was tested by the drilling of two exploration wells in 2001. The Carbine prospect was a potential stratigraphic trap involving deposition of turbidite sandstones within a localised basin set up by slumping in an intra-slope setting. Carbine–1 penetrated a 77 m thick section of high quality, 100% net-to-gross sandstone but failed to encounter hydrocarbons.

A similar ponded turbidite model was invoked for the Marabou prospect although in this case the confined basin was controlled by pre-existing topography at the toe of the slope. The trapping mechanism for Marabou was largely stratigraphic although a small area of anticlinal closure was present. Marabou–1 penetrated 102 m of good quality sandstone with elevated gas readings over the uppermost 22 m. Borehole problems prevented the acquisition of wireline logs or testing but it appears likely that the well penetrated a sub-commercial hydrocarbon column restricted to the four-way dip closure.

The well results confirmed the presence of ponded turbidite systems with excellent reservoir characteristics. Further work is required, however, to address the critical risks associated with hydrocarbon migration and updip seal. Nevertheless, ponded turbidite systems remain attractive exploration targets particularly in basins where updip seal is assisted by structuring and where the reservoirs are intercalated with prolific source rocks.
Permian to Lower Cretaceous plate tectonics and its impact on the tectono-stratigraphic development of the Western Australian margin

D. Jablonski and A.J. Saitta

Presenter: Dariusz Jablonski
Saitta Petroleum Consultants Pty Ltd

Session 7B–3:20pm

The post-Lower Permian succession of the Perth Basin and Westralian Superbasin can be directly related to the plate tectonic evolution of the Gondwanan Super-continent. In the Late Permian to Albian the northern edge of Gondwana continued to break into microplates that migrated to the north and were accreted into what is today the southeastern Asia (Burma–China) region. These separation events are recorded as a series of stratigraphically distinct transgressions (corresponding to the initial stretching of the asthenosphere and acceleration of subsidence rates) followed by rapid regressions (when new oceanic crust was emplaced in thinned continental crust causing uplifts of large continental masses). Because the events are synchronous across large regions, and may be identified from specific log and seismic signatures, the intensity of stratigraphically related transgressive/regressive cycles varies, depending on the distance from the break-up centres and these cycles allow the identification of regionally significant megasequences even in undrilled areas. The tectonic evolution and resulting stratigraphy can be described by eight plate tectonic events:

1. Visean (Carboniferous) break-up of the southeastern Asia (Simao, Indochina and South China);
2. Kungurian (uppermost Early Permian) break-up of Qiangtang and Sibumasu;
3. Lowermost Norian uplift due to Bowen Orogeny in eastern Australia;
4. Hettangian break-up of Mangkalihat (northeastern Borneo);
5. Oxfordian break-up of Argo/West Burma, and Sikuleh (Western Sumatra);
6. Kimmeridgian break-up of the West Sulawesi microplate;
7. Tithonian break-up of Paternoster-Meratus (central Borneo); and
8. Valanginian break-up of Greater India/India.

These events should be identifiable in all Australian Phanerozoic basins and beyond, potentially providing a template for a synchronisation of the Permian to Early Cretaceous stratigraphy.