THE 2003 APPEA CONFERENCE

Abstracts Volume

Abstracts of Technical, Commercial and Environmental papers and posters of the 2003 APPEA Conference in date and session order

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SESSION 1B—HAZARDLESS DEVELOPMENT

Petroleum processing plants—technical surveillance program

J. Gibbeson

Presenter: John Gibbeson
Esso Australia

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

On behalf of itself and BHP-B, Esso operates offshore production platforms in Bass Strait, a crude stabilisation and gas processing plant at Longford and a LPG fractionation plant at Long Island Point, Victoria. The Technical Surveillance Program for these facilities is implemented at both the Operator and Engineering levels. The program has been enhanced by building on existing DCS process control and process information (PI) systems and through development of a more structured engineering monitoring system. The enhanced program continues to register tangible benefits in integrity, product quality, recovery, efficiency and reliability and capacity.

At the operator level, the process is monitored continuously, assisted by process alarms to maintain the plant within the normal desirable operating zone. Safe operating limits define the outside boundary of the safe operating envelope which is secured with shutdown and other automatic protective devices. Alarm and limit conditions associated with these parameters have been incorporated into the DCS control system with pre-defined operator responses appearing automatically on the screen if the condition is reached.

At the engineering level, the surveillance program is a systematic periodic monitoring process focussing on optimum performance and continuous improvement. It is structured using the elements of a management system. Within this framework, engineering spreadsheets have been developed with direct links to process data via process information system software. The spreadsheets assist plant engineers to efficiently monitor the key performance variables; they also pre-define the acceptable operating range, calculate statistical performance, highlight deviations and hyperlink back to the PI system for more detailed troubleshooting. Day-to-day deviations and performance improvements are fed back and reviewed at the working level, more significant issues are formally investigated and reviewed with management. Key data and overall performance is summarised monthly, and formally reviewed by plant and engineering management.

Haz & Zard: Promoting hazard identification, risk assessment and positive safety behaviour in the petroleum industry

G. Marshall

Presenters: Graham Marshall and K. North
An Mea and BHP Billiton

Session 1B: 2:45 pm, Bellarine rooms 1 and 2

The Australian Petroleum Production and Exploration Association (APPEA) represents companies exploring for, and producing, oil and gas in Australia. APPEA has a responsibility to the community and an obligation to its membership to improve the health, safety, and environmental (HSE) awareness of new recruits entering the energy sector from schools and to reinforce awareness and safe behaviour amongst experienced personnel. Unfortunately, however, APPEA noted that school-based HSE training was virtually non-existent and much pre-existing lecture-based HSE training was inconsequential because the traditional death by PowerPoint approach did not enable people to think for themselves. In essence, much safety training has failed to capture the hearts and minds of employees. In response, APPEA, with the financial support of ChevronTexaco Australia Pty Ltd and the professional and technical support of An Meá, developed a hazard identification and risk awareness training activity that promotes safety from the heart by actively engaging the minds of students and employees.

The Haz & Zard Safety Awareness Activity is not a lecture or talking-head experience. Haz & Zard is an active process of adult learning that forces trainees and students to think. At a psychological level, Haz & Zard uses a projective technique with computer-generated HSE images across a range of workplace activities. The projective training process enables participants to identify and assess hazards and associated risks, and then define hundreds of appropriate safe behaviours and practices in response. Intra-group discussions further heighten learning and a participant workbook enables the capture and evaluation of training outcomes. To reiterate the main point, there is no place within Haz & Zard for an HSE lecture. Instead, Haz & Zard enables active participation and advanced discussion of a wide range of HSE issues to enhance learning outcomes and motivate positive safety behaviour.

Effective safety case development

A. Mathers and S. Savva

Presenter: Andrew Mathers
Esso Australia

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

Esso Australia Pty Ltd, in Victoria, Australia has recently been involved in the preparation of over 20 safety cases to meet both offshore (Victoria and Western Australia) [Petroleum {Submerged Lands} Act] and onshore [Victorian Occupational Health and Safety Act] regulatory requirements.

This paper focusses on the development of the onshore safety cases for both Longford and Long Island Point plants to meet the Victorian Occupational Health and Safety (Major Hazard Facilities) Regulations 2000. Both plants have been granted a five-year unconditional licence to operate.

The objectives of the safety case development were to ensure that Esso:

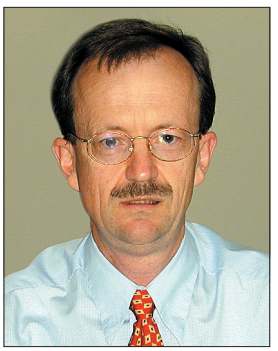
- **addressed major hazard facilities regulatory requirements;**
- **maximised benefit from the process, and to maximise benefit from existing work;**
- **was consistent with site approach to risk assessment/safety culture;**
- **involved appropriate workforce from all areas—operations, maintenance and technical support;**
- **enhanced the effective knowledge and understanding of the workforce; and**
- **developed a communication tool to enable ease of understanding by site personnel.**

Esso's approach of using qualitative risk assessment techniques (familiar to many site personnel) enabled the process to use tools that provided ease of involvement for the non-technical or safety specialists. This paper will explain this approach in greater detail, demonstrating how this successfully met the stringent requirements of the regulations whilst providing Hazard Register documentation readily understood by the key customer—our site workforce.

The hazard register clearly identifies the relevant hazards and their controls, as well as highlighting the linkages to the safety management system and documented performance standards. A comprehensive training program provides all personnel working at site with an overview of the safety case, and the necessary skills and knowledge to be able to use the safety case and hazard register to its maximum advantage. The safety case resource booklet (similar to our offshore approach) is an integral part of the training program, and provides an ongoing reference source for trainees. It continues to receive recognition by both regulators and industry.

SESSION 1C —COMMERCIALISING PETROLEUM RESOURCES—INVESTMENT ISSUES

The fiscal settings that are important to petroleum exploration and development in Australia



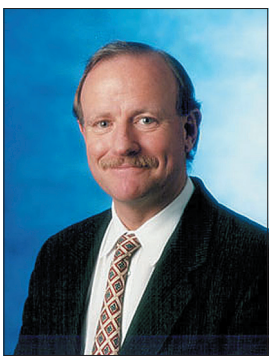
M. Lawry

Presenter: Michael Lawry
Santos

Session 1C: 2:00 pm, Bellarine rooms 4 and 5

A fiscal regime must reflect the underlying characteristics of the petroleum industry. Australia's fiscal settings do not sufficiently reflect the current and future characteristics of the industry, particularly frontier deepwater exploration activity. The fiscal system can encourage greater exploration by providing more immediate access to tax benefits for exploration for all taxpayers, adjustment of the PRRT augmentation rules to better reflect time lags and improving development economics for high risk projects. Competing international regimes exhibit a greater flexibility of fiscal terms required to attract investment. Common petroleum industry arrangements, such as farm-ins should be free from any tax uncertainty. Tax legislation should be amended on a timely basis to correct technical anomalies or uncertainties.

Avoiding capital cost blowout on oil and gas projects



R. Hogarth

Presenter: Rob Hogarth
KPMG

Session 1C: 2:25 pm, Bellarine rooms 4 and 5

Modern corporate practices have been slow to come to grips with the risks of large capital expenditure projects, particularly the processes of due diligence on investment submissions and high level monitoring of project implementation.

Unlike the mining sector where major project cost blowouts have received intense public scrutiny, collection of data on this issue is difficult in the oil and gas sector and there remains a reluctance of companies to share horror stories. The increasing trend towards company acquisitions rather than exploration, the rates of return on capital investments reported by oil and gas companies and the data available on this issue within the mining industry point towards a potential problem for the oil and gas industry and one that, with appropriate corporate practice could be more readily identified.

This paper puts forward the case for more effective corporate practices in relation to large capital projects in optimising return on capital and discusses the role of project owner senior management and the key factors impacting on capital expenditure blowouts.

Effective project due diligence, monitoring of project implementation and integration management are put forward as the three key focuses for Boards and management in ensuring that cost blowouts are avoided.

Commercialising gas: A new process for converting natural gas into hydrocarbon liquids

K. Hall

Presenter: John Read
Synfuels

Session 1C: 2:50 pm, Bellarine rooms 4 and 5

Energy providers globally recognise the need and benefits of an economic GTL process to satisfy the growing world energy demand, replacing crude oil. Australia, with its natural gas reserves, has the opportunity to take a leading role in exploiting the opportunities offered by GTL technology.

The new (non-Fischer/Tropsch) Synfuels GTL process, compared to existing technologies, is much simpler and provides a more economic means of converting the world's extensive natural gas reserves into transport fuels and other liquid hydrocarbon products. Significant progress has been made by Synfuels during the past 12 months in enhancing the performance of its 100 MSCFD pilot plant and advancing the Synfuels project towards commercialization. The commercial viability of the Synfuels process has been confirmed by a leading independent engineering group based in Houston, USA, following audit of the pilot plant performance during extended runs. The design of a 10 MMSCFD full scale plant is in the final stages, with construction expected to commence in the first half of 2003. A recent laboratory test of the natural light gasoline product produced by the pilot plant gave an octane number of 95. Estimated cost of fluids produced is less than US$20 per barrel.

The scalability of Synfuels GTL refineries (10 MMSCFD up to 500 MMSCFD) is expected to facilitate the economic commercialisation of both small and large gas reserves, by both small and large industry players. The level of Australian interest in this innovative new technology is high and Australia is in a strong position to take early advantage of the benefits it offers. Synfuels GTL technology has the potential to spearhead the replacement of oil with natural gas as the next major global energy source.

This will be a presentation only.

SESSION 2B —NEW TECHNOLOGIES TO BEAT THE ODDS

Applications of SpectroLith mineralogy from neutron capture spectroscopy tools for formation evaluation

Z. Pallikathekathil and M. Wilson

Presenter:
Zachariah Pallikathkathil
Schlumberger Oilfield Australia

Session 2B: 3:45 pm, Bellarine rooms 1 and 2

When performing a petrophysical analysis, an accurate understanding of the mineralogy of the formations of interest is important for two main reasons. Firstly, the mineralogy of the formations controls the matrix density, which is fundamental in the evaluation of porosity using conventional methods. Secondly, an accurate estimate of the fraction of clay minerals present in the formation is essential in accurately correcting resistivity-based saturation estimates for the effects of excess clay conductivity.

Accurately evaluating the mineralogy in formations containing both gas and radioactive minerals such as feldspars can be a challenge. Traditional clay indicators such as gamma ray estimate clay volumes which are too high due to the radioactivity coming from matrix grains such as potassium feldspars, feldspar rich volcanolithic grains and muscovite. In formations having light hydrocarbon such as gas or condensate, density-neutron logs under-estimate the volume of clays due to the light hydrocarbon effects on the density and neutron logs. Moreover, if the logs are to be acquired in a borehole with gas, air or foam, only a limited number of tools sensitive to mineralogy may be run. Using the SpectroLith technique, data from neutron capture spectroscopy tools such as the Reservoir Saturation Tool (RST) or Elemental Capture Spectroscopy Sonde (ECS) can be used to provide answers in these challenging situations.

The RST is normally logged in cased hole for the sigma or carbon/oxygen ratio logs useful for determining formation saturation. The SpectroLith processing extracts lithology information, and in turn the weight proportion of clay, quartz-feldspar-mica, carbonate, pyrite, anhydrite and coal. The ECS tool is optimised for providing SpectroLith results at faster logging speeds in larger boreholes.

This paper demonstrates, through examples from Australia, the applications of SpectroLith results derived from RST and ECS measurements. Two examples with the RST and one with the ECS are presented. In one example, the only available source of mineralogical information was from the results of SpectroLith processing applied to RST data. The second example shows how SpectroLith results can complement a through casing petrophysical evaluation. The example using ECS compares the mineralogy from a traditional analysis with that from SpectroLith processing and demonstrates the improvements to the petrophysical evaluation through a more accurate mineralogical description. Although no complete examples are available in gas wells in Australia at present, SpectroLith provides a promising way for accurately estimating mineralogy in gas wells.

Rock physics—Application to geological storage of CO_2

J. McKenna, B. Gurevich, M. Urosevic, and B. Evans

Presenters: Jason McKenna
Curtin University

Session 2B: 4:10 pm, Bellarine rooms 1 and 2

Sequestration of anthropogenic CO_2 into underground brine-saturated reservoirs is an immediate option for Australia to reduce CO_2 emissions into the atmosphere. Many sites for CO_2 storage have been defined within many Australian sedimentary basins. It is anticipated that seismic technology will form the foundation for monitoring CO_2 storage within the subsurface, although it is recognised that several other technologies will also be used in support of seismic or in situations where seismic recording is not suitable. The success of seismic monitoring will be determined by the magnitude of the change in the elastic properties of the reservoir during the lifecycle of CO_2 storage. In the short-term, there will be a strong contrast in density and compressibility between free CO_2 and brine. The contrast between these fluids is greater at shallower depth and higher temperature where CO_2 resembles a vapour. The significant change in the elastic moduli of the reservoir will enable time-lapse seismic methods to readily monitor

structural or hydrodynamic trapping of CO_2 below an impermeable seal. Because the acoustic contrast between brine saturated with CO_2 and brine containing no dissolved CO_2 is very slight, however, dissolved CO_2 is unlikely to be detected by any seismic technology, including high-resolution borehole seismic. The detection of increases in porosity, associated with dissolution of susceptible minerals within the reservoir may provide a means for qualitative monitoring of CO_2 dissolution. Conversion of aqueous CO_2 into carbonate minerals should cause a detectable rise in the elastic moduli of the rock frame, especially the shear moduli. The magnitude of this rise increases with depth and demonstrates the potential contribution that can be made from repeated shear-wave and multi-component seismic measurements. Forward modelling suggests that the optimal reservoir depth for seismic monitoring of CO_2 storage within an unconsolidated reservoir is between 1,000 and 2,500 m. Higher reservoir temperature is also preferred so that free CO_2 will resemble a vapour.

Petrophysical properties derived from X-ray CT images

C. Arns, A. Sakellariou, T.J. Senden, A.P. Sheppard, R.M. Sok, W.V. Pinczewski and M.A. Knackstedt

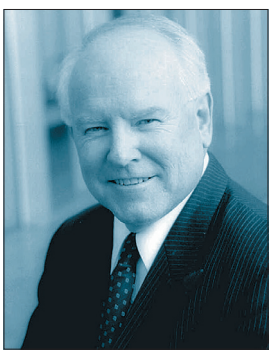
Presenter: Chris Arns
Australian National University

Session 2B: 4:35 pm, Bellarine rooms 1 and 2

A micro-CT facility for imaging, visualising and modelling sedimentary rock properties in three dimensions (3D) is described. The facility is capable of acquiring 3D X-ray CT images of full-diameter cores and core plugs at up to $2{,}000^3$ voxels with resolutions down to 2μm. This allows the 3D pore-space of a rock to be imaged and, with the aid of SEM, to identify regions of different mineralogy. Computational results are presented which demonstrate that accurate predictions of petrophysical properties can be made directly from the digitised tomographic images. Computations of both formation factor and permeability from micro-tomographic images of Fontainebleau sandstone are shown to be in excellent agreement with experimental measurements over a wide range of porosities. Computed elastic properties for dry and water-saturated conditions are shown to be consistent with the exact Gassmann's equations and are in excellent agreement with experimental measurements. Experimental measurements of V_p/V_s ratio for cemented sandstone morphologies are very noisy and cannot be used to infer relationships between elastic properties, mineralogy and rock microstructure. Computations on tomographic images show that the V_p/V_s ratio exhibits predictable limiting behavior which holds for any number of solid phases and is insensitive to the manner in which the phases are distributed. This allows the development of more accurate empirical methods for deriving the full velocity-porosity relationship for cemented sands. The results demonstrate the feasibility of combining digitised images with numerical calculations to accurately predict petrophysical properties of individual rock morphologies.

SESSION 2C—COMMERCIALISING PETROLEUM RESOURCES—INVESTMENT ISSUES

Offshore petroleum exploration in Australia—Acreage bidding systems—work bidding or cash bidding?



A. Thompson and V. Lok

Presenter: Andrew Thompson
Minter Ellison

Session 2C: 3:34 pm, Bellarine rooms 4 and 5

The design and efficiency of offshore petroleum acreage bidding systems bear directly on the risk and cost for participants investing in exploration and development projects offshore Australia.

Companies, financiers and investors who are interested in investing in petroleum exploration and development activities will find a mixed regime of State and Federal legislation governs such activities in Australia.

While the concept of the work program bidding system appears to be sound, the administration of it by the Joint Authorities and Designated Authorities and delegated officers potentially creates many uncertainties for permittees.

The approval process is generally a costly and time consuming one under the work program bidding system and its administrative cost diverts funds that otherwise may have been directed to exploration activities.

Work program permits are also susceptible to uncertainty and dispute as to whether or not the required work program has been met. Issues of proper or improper exercise of discretionary powers can arise, particularly when wide statutory discretionary powers are in practice circumscribed by Administrative Guidelines.

The existence of statutory and administrative discretion requires, in the interests of natural justice, that there be appropriate avenues of appeal for aggrieved permittees. All of the foregoing regulation and cost is removed with cash bid permits. Cash bid permits not only reduce costs for Government but also for industry.

The authors are of the view that offering permits by way of the cash bidding system should be reintroduced, with modifications to ensure its efficiency.

Acess to Australian exploration and production data: a critical factor in attracting investment

P. Williamson and C. Foster

Presenter: Paul Williamson
Geoscience Australia

Session 2C: 4:10 pm, Bellarine rooms 4 and 5

During the past 10 years, Australia has maintained 65–85% self-sufficiency in oil and better than 100% sufficiency in gas. This has generated significant societal benefits in terms of employment, balance of payments, and revenue. The decline of the super-giant Gippsland fields, discovery of smaller oil pools on the North West Shelf, and the increasing reliance on condensate to sustain our liquids supply, however, sharpens the focus on Australia's need to increase exploration and discover more oil. Australia is competing in the global market place for exploration funds, but as it is relatively under-explored there is a need to simulate interest through access to pre-competitive data and information. Public access to exploration and production data is a key plank in Australian promotion of petroleum exploration acreage. Access results from legislation that initially subsidised exploration in return for lodgement and public availability of exploration and production (E&P) data. Today publicly available E&P data ranges from digital seismic tapes, to core and cuttings samples from wells, and access to relational databases, including organic geochemistry, biostratigraphy, and reservoir and shows information. Seismic information is being progressively consolidated to high density media. Under the Commonwealth Government's Spatial Information and Data Access Policy, announced in 2001, company data are publicly available at the cost of transfer, after a relatively brief confidentiality period. In addition, pre-competitive regional studies relating to petroleum prospectivity, undertaken by Government, and databases and spatial information are free over the Internet, further reducing the cost of exploration. In cooperation with the Australian States and the Northern Territory, we are working towards jointly presenting Australian opportunities through the Geoscience Portal (http://www.geoscience.gov.au) and a virtual one-stop data repository. The challenge now is to translate data availability to increased exploration uptake, through client information, and through ever-improving on-line access.

Evolution of the Timor Sea Treaty—Commercial aspects and risks for contractors

S. Barrymore

Presenter: S. Barrymore
Freehills

Session 2C: 4::35 pm, Bellarine rooms 4 and 5

Since the de-annexation of East Timor from Indonesia, the status of the some 15 production sharing contracts issued under the Timor Gap Treaty between Australia and Indonesia has been uncertain. The zone of co-operation has been administered pursuant to interim arrangements agreed between Australia and UNTAET, the United Nations authority responsible for the administration of East Timor. With the exception of the development activities being carried on in connection with the Bayu-Undan Field, work by the contractors under their PSC's has basically halted. The contractors have in effect been in a state of force majeure.

On 20 May 2002, Australia and East Timor signed a Treaty for the further development of the region, now known as the Joint Petroleum Development Area. A number of significant changes have been made. At the time of preparing this abstract the Treaty has not been ratified and the exact form of the production sharing contracts to be offered to the existing contractors is not known. The arrangements under the Timor Sea Treaty are interim only and can be changed upon permanent delimitation of the seabed boundaries. Australia and East Timor have indicated that they intend to proceed to negotiate those boundaries.

This paper will analyse the history of the negotiations and their outcome, the international unitisation agreement, the positions of the existing holders of production sharing contracts and how their rights are to be transitioned through to the new regime. It will also report on the new issues and risks that arise for contractors who have existing titles and those who are seeking to invest in the JPDA and on any changes to commercial terms.

This paper will appear in Part 2 of the APPEA Journal 2003

SESSION 3A—NORTH WEST SHELF—NEW IDEAS, NEW DISCOVERIES

Mid to Late Jurassic shallow marine sequences of the eastern Barrow Sub-basin: The role of lowstand deposition in new exploration concepts

S. Moss, D. Barr, R. Kneale, P. Clews and T. Cruse

Presenter: Steve Moss
Apache Energy

Session 3A: 11:00 am, John Batman theatre

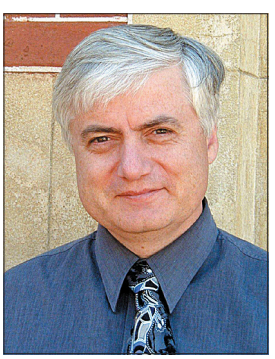
Several wells drilled along the fault-terraced eastern margin of the Barrow Sub-basin of the Australian North West Shelf have shed light on the pattern of Callovian to Tithonian sedimentation in the area. Much of this section has historically been interpreted as a product of deep marine depositional environments.

Sandstone reservoirs cored in Linda–1/ST1, Linda–2 (both *Wanaea spectabilis* b age) and Denver–1/ST1 (*Rigaudella aemula* age) exhibit coarsening-upward cycles typical of marine parasequences, and possess sharp, erosive lower contacts with underlying claystone. In the case of Denver–1/ST1, the sandstones are heavily bioturbated with a distinct shallow marine trace fossil assemblage. Burrows are less evident in the sandstones from the Linda wells, although several thin bioturbated horizons—also with shallow marine trace fossils—are encountered. Similar patterns of shallow marine deposition are observed in previously drilled wells within the study area, and evidence of pedogenesis is found in core from Georgette–1 (*R. aemula* age), suggesting that exposure occurred on some of the higher fault terraces during low-stand conditions in the Middle to Late Jurassic.

Further to the west, deepwater submarine fan sediments, deposited during low-stands, have been recognised. A range of time equivalent low-stand deposits—which are spatially and genetically exclusive—therefore exists within the sub-basin. Indeed such a spectrum should be expected in complex and tectonically active areas such as the Jurassic Barrow Sub-basin.

The recognition of shallow marine deposits in the area has major implications with respect to the location and geometry of reservoir sandstones. The low-stand shoreface model, as opposed to the deep marine turbidite model, leads to the prediction of sandstone deposition aligned roughly parallel—rather than perpendicular—to the palaeo-shoreline and the potential for deeper-water sandstones further downdip.

Flattened time slices—A stratigraphic approach to 3D seismic interpretation in the North West Shelf



K. Martens

Presenter: Keith Martens
Tap Oil

Session 3A: 11:25 am, John Batman theatre

Conventional time slices are a powerful method of integrating horizon picks and fault picks into a unified interpretation and are a handy way of viewing structures, especially in faulted areas. The limitation is that time slices are seldom useful in viewing the morphology of a horizon. A 3D cube is the present day structural volume; it retains any structure imparted on the geology after deposition. When a time slice is defined, the structural dip limits the area of the integral depositional elements that can be imaged. For example, a depositional surface developed as part of a fluvial-deltaic system is seldom one event and it cannot be easily identified and picked in a vertical section. Flattened time slices take out the regional dip and allow a complete depositional surface to be viewed.

The North West Shelf of Australia and especially the Barrow Sub-basin is a particularly suitable place to apply this exploration technique. The entire sedimentary package, laid down in a variety of depositional environments, has been tilted to the northwest by an average of 3°. This strong post-depositional tilt limits the uses of conventional time slices to imaging only the dip-related features of an area. Whereas conventional time slices only make apparent the dip of the section, flattened time slices can reveal subtle and intricate stratigraphic architecture.

This paper describes the seismic features of a number of depositional systems from the Barrow Sub-basin and outlines how complex channel systems can be determined by the use of the flattened time slice approach. Given the importance of stratigraphic plays in the Barrow Sub-basin, the technique outlined in this paper is considered to be an important exploration tool.

The Mutineer Complex and Exeter oil discoveries: Mutiny in the Dampier

K. Auld

Paper not being presented at conference.
Previously Santos, now at Apache Energy

The oil discoveries at Norfolk–1 and Exeter–1 in the Northern Dampier Sub-basin (permit WA-191-P) have realised major commercial potential in an area with a prolonged exploration history. This paper presents the results of the drilling campaign which was undertaken in 2002 comprising two successful exploration discovery and five appraisal wells. The Norfolk–1 (28 m gross oil column), Norfolk–2 (9 m oil column), Exeter–1 (23 m oil column), Mutineer–3 (8 m oil column) and finally Exeter–2 (12 m oil column) confirmed a significant commercial oil volume within the Jurassic Angel Sandstones.

The recent exploration of this area has improved understanding of the geology through the integration of technology with geoscientific understanding. Highs have been revealed from seismic time data using advanced 3D seismic techniques and sophisticated depth conversion processes.

The time structural high of the Mutineer area was first tested by Bounty–1 in 1983 which is now mapped outside the southern limit of closure. Pitcairn–1 was drilled in 1997 discovering three thin oil columns and was followed by a near crestal well at Mutineer–1B drilled 2.6 km northwest of Pitcairn–1 in 1998, discovering an 8m column. The key issue was the understanding of the velocity gradient and depth conversion over the Mutineer Complex which revealed the true structural picture.

This paper summarises results of the exploration and appraisal wells drilled and describes the evolution of the structural/stratigraphic understanding of the area, covering critical components hindering the oil field's early detection. The first component is a significant seismic velocity gradient which causes true structural closure to be significantly offset from the time closure. The second component is the reservoir pressures within the oil reservoir and older sandstone intervals within the Angel and Legendre Sandstones show differences due to hydrodynamic cells and/or depletion resulting from production from the adjacent NWS Venture oil fields. The final component is the oil is primarily reservoired in the top Angel Sandstone, belonging to the J40 sequence and is sealed by a thin shale from the underlying mainly water bearing sandstones (J35/J30 and Legendre Sandstones).

The combined reserves for the Mutineer Complex and Exeter Oil Fields reservoired in these laterally continuous turbidites are estimated to be 70–160 MMBBL recoverable.

SESSION 3B —UNDERSTANDING ONSHORE BASINS—FINDING MORE OIL

The New Royal oilfield: A case history of the discovery and appraisal of a subtle, stratigraphically trapped hydrocarbon accumulation in the Triassic Showgrounds Sandstone, Surat Basin

R. Willink and R. Harvey

Presenter: Rob Willink
Origin Energy

Session 3B: 11:00 am, Bellarine rooms 1 and 2

A fiscal regime must reflect the underlying characteristics of the petroleum industry. Australia's fiscal settings do not sufficiently reflect the current and future characteristics of the industry, particularly frontier deepwater exploration activity. The fiscal system can encourage greater exploration by providing more immediate access to tax benefits for exploration for all taxpayers, adjustment of the PRRT augmentation rules to better reflect time lags and improving development economics for high risk projects. Competing international regimes exhibit a greater flexibility of fiscal terms required to attract investment. Common petroleum industry arrangements, such as farm-ins should be free from any tax uncertainty. Tax legislation should be amended on a timely basis to correct technical anomalies or uncertainties.

TUESDAY

A hydrocarbon generation model for the Cooper and Eromanga Basins

I. Deighton, J. Draper, A. Hill and C. Boreham

Presenter: Ian Deighton
Geoscience Australia

Session 3B: 11:25 am, Bellarine rooms 1 and 2

The aim of the National Geoscience Mapping Accord Cooper-Eromanga Basins Project was to develop a quantitative petroleum generation model for the Cooper and Eromanga Basins by delineating basin fill, thermal history and generation potential of key stratigraphic intervals. Bio- and lithostratigraphic frameworks were developed that were uniform across state boundaries. Similarly cross-border seismic horizon maps were prepared for the C horizon (top Cadna-owie Formation), P horizon (top Patchawarra Formation) and Z horizon (base Eromanga/Cooper Basins). Derivative maps, such as isopach maps, were prepared from the seismic horizon maps.

Burial geohistory plots were constructed using standard decompaction techniques, a fluctuating sea level and palaeo-waterdepths. Using terrestrial compaction and a palaeo-elevation for the Winton Formation, tectonic subsidence during the Winton Formation deposition and erosion is the same as the background Eromanga Basin trend—this differs significantly from previous studies which attributed apparently rapid deposition of the Winton Formation to basement subsidence. A dynamic topography model explains many of the features of basin history during the Cretaceous. Palaeo-temperature modelling showed a high heatflow peak from 90–85 Ma. The origin of this peak is unknown. There is also a peak over the last two–five million years.

Expulsion maps were prepared for the source rock units studied. In preparing these maps the following assumptions were made:

(a) expulsion is proportional to maturity and source rock richness;
(b) maturity is proportional to peak temperature; and
(c) peak temperature is proportional to palaeo-heatflow and palaeo-burial.

The geohistory modelling involved 111 control points. The major expulsion is in the mid-Cretaceous with minor amounts in the late Tertiary. Maturity maps were prepared by draping seismic structure over maturity values at control points. Draping of maturity maps over expulsion values at the control points was used to produce expulsion maps. Hydrocarbon generation was calculated using a composite kerogen kinetic model. Volumes generated are theoretically large, up to 120 BBL m^2 of kitchen area at Tirrawarra North. Maps were prepared for the Patchawarra and Toolachee Formations in the

Cooper Basin and the Birkhead and Poolowanna Formations in the Eromanga Basins. In addition, maps were prepared for Tertiary expulsion. The Permian units represent the dominant source as Jurassic source rocks have only generated in the deepest parts of the Eromanga Basin.

Visualisation of a fluvial channel reservoir analogue from the Birkhead Formation, Merrimelis, Meranji and Pelican Fields, Eromanga Basin

T. Nakanishi, S. Lang and A. Mitchell

Presenter: Takeshi Nakanishi
Japan Oil Company

Session 3B: 11:50 am, Bellarine rooms 1 and 2

The effective production of hydrocarbons from the Birkhead Formation, Eromanga Basin, relies heavily on understanding the complex distribution of reservoir and seal rocks deposited in a fluvial environment. To visualise this complexity, sequence stratigraphic concepts applied to non-marine basins were combined with 3D seismic data visualisation in a study of the Birkhead interval over the Merrimelia, Meranji and Pelican fields.

Fluvial channel, crevasse splay channel, floodplain-crevasse splay complex and floodplain facies were recognised from the well log motifs in the Birkhead Formation. The interval is interpreted as an alluvial transgressive systems tract bounded by flooding surfaces consisting of shaly or coaly intervals. Lateral discontinuity of the fluvial system can be demonstrated between these surfaces. Seismic amplitude distributions in the 3D seismic data in the upper part of this transgressive systems tract illustrate well developed meandering fluvial channels. Combining the spatial distributions of sedimentary facies from the well logs and the seismic amplitudes results in the interpretation of a fluvial meandering channel belt that includes point bars and abandoned channels.

The point bar sandstones in the channel belt should make good reservoirs and the juxtaposition of the point bar and abandoned channel facies can result in a stratigraphic trap component to the reservoir rocks within the channel belt. Although the point bars are known to be wet in the study area, it is still useful to consider their capacity as oil reservoirs, since they may serve as analogues for similar untested point bars elsewhere. Multiple realisations of the distribution of sandstone thickness of the point bars were generated by conditional simulation, using seismic amplitudes to control extrapolation of the well data. This gave a potential reserves distribution with a mean value of 18.8 million bbl in place. The complexity of the fluvial channel systems in the Birkhead Formation described in this paper should aid understanding of the reservoir and seal distribution and help optimise production from this interval in other fields.

SESSION 3C —COMMERCIALISING PETROLEUM—CORPORATE CULTURE ISSUES

Do business ethics really matter?

A. Lagan

Presenter: Attracta Lagan
KPMG

Session 3C: 11:00 am, Bellarine rooms 4 and 5

There are few people today who would dare to say that business and ethics are incompatible forces. This was not the case so very long ago. Despite this shift, the recent spate of spectacular business collapses would seem to suggest that there is still a lag between the values being espoused by today's business leaders, and the resources allocated to ensuring the ethical imperative is embedded in day-to-day decision-making.

This paper seeks to present an overview of where the business ethics debate sits today and how this relates to the current state of ethical play in the oil and gas industry. It reviews the major forces pushing ethics up the corporate agenda and seeks to build the business case for why attention to business ethics will improve overall organisational performance. It does this by reviewing the new business philosophies of sustainability and corporate social responsibility (CSR) and argues that these new business doctrines can be seen as essentially applied ethical practices and present the greatest opportunity to date for embedding the ethical imperative in organisational life.

The author argues that historically it has been the oil and gas industries that have been the first to recognise the interdependence of business ethics and organisational performance and that it is these industries have now moved into stage two phase of sustainability development where they are focussing their efforts on embedding the ethical perspective into their day-to-day performance management systems.

The emergence of corporate social responsibility—issues for the Australian oil and gas sector

A. Keaney

Presenter: Anne Keaney
Gadens Lawyers

Session 3C: 11:25 am, Bellarine rooms 4 and 5

Recent times have seen a rise in expectations in companies' accountability as good corporate citizens. This trend has seen an increased emphasis on corporate governance and director liability. Further disclosure is now required and/or expected against a number of measures including environmental adherence, community activities and employee relations.

At the same time companies are now subject to heightened shareholder activism as well as the growth of ethical investment funds which require companies to meet certain standards of corporate behaviour before they will invest.

With the recent collapse of several major Australian companies and the consequent scrutiny of their corporate behaviour, and the revelation of instances of massive levels of corporate impropriety in the US, the above trend can be expected to grow.

This paper discusses:

- the main platforms of corporate responsibility currently on the public agenda including:
- good corporate governance and director liability;
- environmental responsibility (sustainability rather than compliance); and
- other areas of social responsibility including treatment of employees and preservation of employee entitlements;
- the regulatory issues surrounding corporate responsibility, in particular under the Corporations Act;
- the risks and rewards of engaging in or ignoring this process. The risks might include potential director liability and public relations issues. The rewards may include access to additional public and private capital; and
- issues in this debate of particular relevance to the upstream oil and gas sector.

Drilling deeper—Managing value and reporting in the petroleum industry

T. Hallam

Presenter: T. Hallam
PricewaterhouseCoopers

Session 3C: 11:50 am, Bellarine rooms 4 and 5

How do Australian petroleum executives value the companies they are running? And how do investors and analysts—both here in Australia and most importantly overseas—gauge the performance of these companies?

A global survey for the petroleum industry by PricewaterhouseCoopers entitled, Drilling deeper: Managing value and reporting in the petroleum industry, reveals that investors and analysts believe that key industry performance indicators are not effectively communicated to the marketplace by the majority of oil and gas companies.

The PwC survey shows that significant gaps exist between the petroleum industry's traditional reporting model and the market's demand for more accurate and consistent information. The traditional financial reporting model has limitations. Whilst it looks back in time and focusses on financial measures and tangible assets, it says nothing about future cash flows or some of the most important sources of potential wealth creation within Australian petroleum companies. In short, it no longer meets all the needs of the stakeholders in the global capital markets.

More than ever, investors are on guard against corporate reports that may be technically correct, but fail to provide a true picture of a company's health and prospects. The need for reporting measures and techniques that fully communicate the potential of a company's strategy and operations and promote trust is possibly greater than ever before.

Meeting the needs of the global capital markets will be essential for Australian petroleum companies as we move into 2003 and beyond to continue to attract capital investment both locally and from overseas. This presentation will help interpret the findings of the PwC survey and aid in bridging the information gap.

This will be a presentation only.

SESSION 4A—NORTH WEST SHELF—NEW IDEAS, NEW DISCOVERIES

Migration seal failure and exploration potential of the offshore Canning Basin and northern Carnarvon Basin

G. O'Brien, G. Lawrence, A. Williams, R. Cowley and M. Webster

Presenter: Geoff O'Brien
NCPGG

Session 4A: 2:00 pm, John Batman theatre

The primary goal of this study was to provide a greater understanding of the distribution and nature of mature source rock and hydrocarbon migration fairways within the offshore Canning and far northern Carnarvon Basins. 29 RadarSat Wide 1 Beam Mode scenes and 8 ERS Synthetic Aperture Radar (SAR) scenes were analysed over an area covering over 325,000 km^2. These seepage data have been integrated with assorted regional geological data, seismic DH1 indicators, fluid inclusion history analyses, new water column geochemical sniffer data and other data to provide new insights into the region's petroleum prospectivity.

Overall, the frequency of SAR slicks in the area studied (~1 slick per 13,000 km^2) was more than an order of magnitude lower than that observed in the Timor Sea and also other prolific petroleum provinces world-wide. This difference may relate in part to the fact that the Timor Sea has undergone significant Neogene flexural fault reactivation (which has provided abundant conduits for vertical seepage), whereas the Canning and northern Carnarvon Basins have not. Nevertheless, it appears likely, at least in a relative sense, that the region has lower liquids potential than both the Timor Sea and the central and southern Carnarvon Basins.

Clusters of slicks within the study area were detected in specific sub-basins. For example, clusters were located over and around the major Early to Middle Jurassic depocentre. Slicks also appeared to be distributed preferentially along the almost N–S trending boundary between the outher Rowley Sub-basin and the deepwater Carnarvon basin. A clustering of slicks was also present in the far north-western segment of the Carnarvon Basin, in an area with water depths ranging from 2,500–3,000 m. This suggests the presence of an active, liquids-prone source system in a genuine deep-water frontier province within the Carnarvon Basin, which may become attractive as exploration moves into progressively deeper water.

Clusters of slicks were observed around the Lambert Shelf in the south-western Canning Basin, near and along the approximate location of the regional edge of seal and along the inner part of the north-eastern boundary. Their respective locations suggest that liquids generation has occurred within the Palaeozoic section. The hydrocarbons have then leaked, either at the edge of regional seal or along a major north-west trending, basement-involved fault relay zone.

This paper will appear in Part 2 of the APPEA Journal 2003

The Geryon, Orthrus, Maenad and Urania gas fields, Carnarvon Basin, Western Australia

B. Korn, R. Teakle, D. Maughan and P. Siffleet

Presenter: Bryant Korn
ChevronTexaco

Session 4A: 2:25 pm, John Batman theatre

The Geryon, Orthrus, Maenad and Urania Gas Fields are located in permit WA-267-P in approximately 1,200 m of water, and between 35 km northwest and 70 km north of the Gorgon Gas Field in the offshore Carnarvon Basin of Western Australia. Five wells were drilled in these fields between August 1999 and February 2001 as part of a six-well, three-year obligatory drilling program. The primary objectives were late Triassic sandstones of the upper Mungaroo Formation. The Geryon and Urania Fields are three-way footwall structures, while the Orthrus and Maenad Fields comprise four-way horst structures where progressively older units subcrop against the Callovian Unconformity. All objective reservoirs were amplitude associated and had strong AVO signatures, which was instrumental in the high exploration success rate and excellent exploration prediction of OGIP from seismic data.

This paper will briefly discuss the description of late Triassic and early Jurassic reservoirs and the transition of the AA sand of the Mungaroo Formation from fluvial to marginal marine facies in the Greater Gorgon Area, the recent drilling results of the Triassic Prospects in WA-267-P, and the geophysical attributes of the AA sand Mungaroo Formation reservoirs.

The WA-267-P Triassic Gas Fields are estimated to contain approximately 210 billion m^3 (7.4 TCF) recoverable sales gas. The close proximity of these Triassic gas fields to each other, the clean gas composition and size of resource base suggests these fields are excellent candidates for a future gas development in Western Australia.

The Jansz gas field, Carnarvon Basin, Australia

C. Jenkins, D. Maughan, J. Acton, A. Duckett, B. Korn and R. Teakle

Presenter: Chris Jenkins
Esso Australia

Session 4A: 2:50 pm, John Batman theatre

The Jansz gas field is located in permit WA-268-P, 70 km northwest of the Gorgon gas field in the Carnarvon Basin. The Jansz–1 discovery well was drilled in April 2000 and intersected 29 m of net gas pay in an Oxfordian age shallow marine sandstone reservoir. The well drilled a stratigraphic trap on the western limb of the Kangaroo Syncline.

The Io–1 well was drilled in January 2001 in the adjacent permit WA-267-P (18 km from Jansz–1) and intersected the same Oxfordian sandstone reservoir penetrated by Jansz–1, with a total of 44 m of net gas pay. The Tithonian and the Upper Triassic Brigadier Sandstone gas reservoirs at Geryon–1 (1999) and Callirhoe–1 (2001) in WA-267-P are in pressure communication with the Oxfordian gas reservoir at Jansz–1 and Io–1. Consequently, the three different age reservoirs comprise a single gas pool, with a common gas/water contact. The Jansz gas field has been delineated by four wells and 2D seismic. The gas sandstones have a prominent amplitude versus offset response, which defines the field limits.

The Jansz gas field is confirmed by drilling to be an areally extensive (2,000 km^2) gas accumulation with a gross column height of 400 m and an estimated 20 TCF (566 $G.m^3$) recoverable sales gas, which represents 40% of the discovered gas resources in the deepwater Carnarvon Basin. The size of the Jansz gas field and its remoteness from existing pipeline gas markets suggests that an export LNG project will be the basis for its development.

SESSION 4B —UNRAVELLING OTWAY, BASS, GIPPSLAND—AND ENHANCING PRODUCTIVITY

Structural framework and basin evolution of Australia's southern margin

J. Teasdale, L. Pryer, P.G. Stuart-Smith, K. Romine, M. Etheridge, T. Loutit, and D. Kyan

Presenter: Jon Teasdale
SRK Consulting

Session 4B: 2:00 pm, Bellarine rooms 1 and 2

The structural evolution of all of the Southern Margin Basins can be explained by episodic reactivation of basement structures in respect to a specific sequence of tectonic events. Three geological provinces dominate the basement geology of the Southern Margin basins. The Eyre, Ceduna, Duntroon and Polda Basins overlie basement of the Archean to Proterozoic Gawler-Antarctic Craton. The Otway and Sorell Basins overlie basement of the Neoproterozoic-early Palaeozoic Adelaide-Kanmantoo Fold Belt. The Bass and Gippsland Basins overlie basement of the Palaeozoic Lachlan Fold Belt. The contrasting basement terranes within the three basement provinces and the structures within and between them significantly influenced the evolution and architecture of the Southern Margin basins.

The present-day geometry was established during three Mesozoic extensional basin phases:

- Late Jurassic–Early Cretaceous NW–SE transtension forming deep rift basins to the west and linked pull-apart basins and oblique graben east of the Southwest Ceduna Accommodation Zone;
- Early–Mid Cretaceous NE–SW extension; and
- Late Cretaceous NNE–SSW extension leading to continental breakup. At least three, potentially trap forming, inversion events have variably influenced the Southern Margin basins; Mid Cretaceous, Eocene, and Miocene-Recent. Volcanism occurred along the margin during the Late Cretaceous and sporadically through the Tertiary.

First-order structural control on Mesozoic rifting and breakup were east–west trending basement structures of the southern Australian fracture zone. Second-order controls include:

- Proterozoic basement shear zones and/or terrane boundaries in the western Gawler Craton, which controlled basin evolution in the Eyre and Ceduna Sub-basins;
- Neoproterozoic structures, which significantly influenced basin evolution in the Ceduna sub-basin;
- Cambro-Ordovician basement shear zones and/or terrane boundaries, which were a primary control on basin evolution in the Otway and Sorell Basins; and
- Palaeozoic structures in the Lachlan Fold Belt, which controlled basin evolution in the Bass and Gippsland Basins.

A SEEBASE™ (Structurally Enhanced view of Economic Basement) model for the Southern Margin basins has been constructed to show basement topography. When used in combination with a rigorous interpretation of the structural evolution of the margin, it provides a foundation for basin phase and source rock distribution, hydrocarbon fluid focal points and trap type/distribution.

Linking basement and basin fill: Implications for the hydrocarbon prospectivity in the Otway Basin region

T. Bernecker and D. Moore

Presenter: Tom Bernecker
Department of Primary Industries

Session 4B: 2:25 pm, Bellarine rooms 1 and 2

Since the offshore discoveries of economic gas accumulations at Geographe and Thylacine, the Otway Basin has become the focus of an exploration resurgence. Its proximity to major markets ensures the discoveries will be commercially valuable. The latest successes in the basin are mainly due to modern 3D-seismic techniques. While the upper sedimentary succession has been imaged at high resolution, details of the deeper successions, however, remained obscure.

An integrated study of magnetic, gravimetric, bathymetric and deep seismic data-sets has outlined the way that pre-existing basement fractures controlled much of the later basin-evolution, the structural style and the distribution of hydrocarbon bearing structures.

The Otway Basin formed by the profound interaction between crustal fabric in the Proterozoic and Palaeozoic basement and the extensional stresses during Gondwana break-up. Overall, three different rift systems can be distinguished:

- Early ENE-trending Jurassic to Early Cretaceous rifts are an extension of the E-W rift system in Western Australia and South Australia,
- Early WNW Late Jurassic to Early Cretaceous rifts are connected to the ENE set and include the western Otway Basin east of the Robe Trough and the Torquay Sub-basin, and
- Early Cretaceous NNW transtensional rifts in the southern part of the Shipwreck Trough. These control the La Bella, Thylacine and Geographe discoveries, all of which overlie the Neoproterozoic to Cambrian Selwyn Block.

Within these rift systems, the Jurassic to Cretaceous rifts along the continental shelf break coincide with the northern edge of the Voluta Trough, whilst the mid-slope rifts are part of the deep Voluta Trough and were possibly generated during the Late Cretaceous.

Although the potential field data do not directly delineate hydrocarbon accumulations, when integrated with other data they provide powerful tools for exploration. For instance, it is possible to map the distribution of Paleocene channels that overlie the basement and represent likely reservoir facies, while data integration with palaeoenvironmental interpretations can highlight areas in which source rock facies developed.

Regionally, the way the rifts have formed with respect to the basement fabric suggests that the dominant extension direction in the basin was N to NNW. Integrating the interpretation with regional studies in the western Tasmanian region supports the proposition that the western part of the south Tasman Rise was once the outer part of the upper plate adjacent to the deepwater parts of the Otway Basin SW of Cape Otway.

Timing constraints on the structural history of the western Otway Basin and implications for hydrocarbon prospectivity around the Morum High, South Australia

I. Duddy, B. Erout, P. Green, P. Crowhurst and P. Boult

Presenter: Ian Duddy
Geotrack International

Session 4B: 2:50 pm, Bellarine rooms 1 and 2

Reconstructed thermal and structural histories derived from new AFTA Apatite Fission Track Analysis, vitrinite reflectance and (U-Th)/He apatite dating results from the Morum–1 well, Otway Basin, reveal that the Morum High is a mid-Tertiary inversion structure. Uplift and erosion commencing in the Late Paleocene to mid-Eocene (57–40 Ma) removed around 1,500 m of sedimentary section. The eroded section is attributed to the Paleocene-Eocene Wangerrip Group which is considered to have been deposited in a major depocentre in the vicinity of the present Morum High. This depocentre is interpreted to have been one of a number of transtensional basins developed at the margin of the Morum Sub-basin and adjacent to the Tartwaup Hinge Zone and Mussel Fault during the Early Tertiary. The Portland Trough in Victoria represents a similar depocentre in which over 1,500 m of Wangerrip Group section, mostly represented by deltaic sediments of the Early Eocene Dilwyn Formation, is still preserved.

Quantification of the maximum paleotemperature profile in Morum–1 immediately prior to Late Paleocene to mid-Eocene inversion shows that the paleo-geothemal gradient at the time was between 21 and 31°C/km, similar to the present-day level of 29°C/km, demonstrating that there has been little change in basal heat flow since the Early Tertiary.

Reconstruction of the thermal history at the Trumpet–1 location reveals no evidence for any periods of significant uplift and erosion, demonstrating the relative stability of this part of the Crayfish Platform since the Late Cretaceous.

The thermal and burial histories at Morum–1 and Trumpet–1 have been used to calibrate a Temis2D hydrocarbon generation and migration model along seismic line 85-13, encompassing the Crayfish Platform, Morum High and Morum Sub-basin. The model shows the cessation of active hydrocarbon generation from Eumeralla Formation source rocks around the Morum High due to cooling at 45 Ma (within the range 57–40 Ma) resulting from uplift and erosion of a Wangerrip Group basin. There has been almost no hydrocarbon generation from the Eumeralla Formation beneath the Crayfish Platform.

Migration of hydrocarbons generated from the Eumeralla Formation began in the Late Cretaceous in the Morum Sub-basin and is predicted to continue to the present day, with the potential for accumulations in suitably placed reservoirs within the Late Cretaceous package both within the Morum Sub-basin and at the southern margin of the Crayfish Platform.

SESSION 4C —COMMERCIALISING PETROLEUM—COMMUNITY AND STAKEHOLDER ISSUES

Ward and Wilson vs Anderson—Evolution or revolution in Native Title law?

D. Young and G. Scott

Presenter: Doug Young
Blake Dawson Waldron

Session 4C: 2:00 pm, Bellarine rooms 4 and 5

There is now a greater degree of certainty for the petroleum industry in Native Title law following the High Court's decisions in Ward v Western Australia[1] and Wilson v Anderson[2]. Both decisions were handed down on 8 August 2002. Ward in particular is the most significant Native Title decision in Australia since the High Court's decision in Wik v Queensland[3] in 1996. This paper presents an analysis of the issues dealt with in Ward and Wilson v Anderson with particular emphasis on the application for petroleum. The paper will also illustrate that while greater certainty flows from these decisions, it is still necessary for petroleum and resource companies to engage with Native Title groups (particularly by negotiating agreements) to enable the valid grant of titles and tenements to land subject to Native Title.

Towards an internationalisation of Native Title and community relations in the oil and gas industry

J. Cook

Presenter: John Cook
URS Brisbane

Session 4C: 2:25 pm, Bellarine rooms 4 and 5

The 20th Century has witnessed the consolidation of global industry and finance. It has also seen the growth of criticism of some developments associated with globalisation. This has been particularly the case with the resource extraction industries and their downstream counterparts. These industries now have to consider a range of factors as central to the management of risk and of reputation that would not have been necessary 30 years ago. One of these factors is the need for community consultation regarding the nature of specific resource development and often some form of compensation for the impacts of development.

Central to the Australian formulation of community consultation and development in the context of land use and natural resource development have been the Northern Territory Aboriginal Land Rights Act (ALRA) and the Native Title Act (NTA) as well as the setting up of Land Councils and representative bodies. These laws have been crucial, not just to the administration of land, but to the concept of aboriginality and citizenship as a whole. Like the ALRA, the Native Title Act has had a fundamental impact on the relationship between Aboriginal land interests and resource development. It has often, however, been mired in uncertainty, conflict, and amendments. This has contributed to a climate of legalism that has not necessary always been to the benefit of on-the-ground agreement processes.

In Indonesia there is no basis in law for native title issues and a high level of risk exists as a result of social and political transition. As a result some companies operating in Indonesia have begun to develop new approaches to issues of community relations and development. A new understanding of the necessity of carefully planned partnerships in the context of resource development has begun to emerge in Indonesia. The BP Tangguh project in the Bintuni Bay area of West Papua has set high standards for consultative practices relating to community consultation and community development practices. Whatever the commercial success of the Tangguh project, the processes and systems developed for that project indicate the likely future direction of other best-practice resource development projects in Indonesia and elsewhere.

In the past, development in Indonesia has been heavily influenced by rent capitalism, which has tended to emphasise the giving of permission over effective business and development practice. While the proponents of Native Title in Australia have often seen Australia as setting an international standard for development practice, this is belied by the actual results of Native Title and what is being undertaken in other international contexts. Native Title also often seems to act as a form of rent capitalism. As such it may be that Native Title does

not necessarily define best practice, and, in the international context, may be under-performing in terms of risk and reputation management.

Rather than assuming that emerging practices in either Indonesia or Australia are somehow occupying the higher ground in terms of best-practice development, it is suggested that Native Title and international practice can usefully be cross-fertilised in a critical manner. This process can be beneficial to companies and to stakeholders alike, particularly in the context of transparent consultation and negotiation practices that focus on the possibilities for cooperation in development, rather than conflict.

Can sustainable development thinking be applied to new oilfields? A case study of the early stages of the Enfield area development in an environmentally and socially sensitive area

F. Baronie, M. Fenton, G. Harman and M. Jury

Presenter: Francis Baronie
Woodside Energy

Session 4A: 2:50 pm, Bellarine rooms 4 and 5

Can development of a finite resource, such as oil, be consistent with sustainable development? Sustainable development involves meeting the needs of current and future generations through simultaneous consideration of environmental, social and economic aspects (referred to as the triple bottom line).

Since 1998, Woodside Energy Ltd (Woodside) has discovered three oil fields in the WA-271-P Permit area offshore North West Cape, northern Western Australia. The fields are some 20 km from the boundary of the Ningaloo Marine Park.

The first part of this paper presents a case study of the Enfield Area Development. It describes the approach taken to simultaneously manage environmental, social and economic considerations while planning for the development of oil fields in exploration permit WA-271-P.

A range of measures have been employed that are considered examples of best practice for the petroleum industry in Australia, including:

- early commitment to a range of responsible environmental management measures in design;
- a comprehensive community engagement program, with links to the development and environmental assessment processes; and
- pioneering environmental research.

Novel methods of establishing environmental and social issues as key priorities within the Woodside development team have been successfully implemented.

The case study provides by giving an overview of the most significant environmental risks associated with the proposed development, and concludes that the development does not represent a significant risk to the environment.

The second part of the paper then addresses the question of whether oilfields can be developed sustainably, looking at current views from the literature, and whether the approach outlined in the case study can be considered sustainable.

While the project is still in an early stage of development, it provides a strong indication that oil development can be consistent with current thinking on sustainability, provided that current needs, which include a dependence on fossil fuels, and future needs, such as preservation of the productive and social value of the environmental resource base, are balanced simultaneously. The paper concludes that oil development, even in an environmentally and socially sensitive area, can help facilitate the transition to a more sustainable future.

SESSION 5A —NORTH WEST SHELF—NEW IDEAS, NEW DISCOVERIES

The hydrocarbon potential of exploration permits WA-299-P and WA-300-P, Carnarvon Basin: A case study

M. Partington, K. Aurisch, W. Clark, I. Newlands, S. Phelps, P. Senycia, P. Siffleet, and T. Walker

Presenter: Mark Partington
Woodside Energy

Session 5A: 3:45 pm, John Batman theatre

Exploration permits WA-299-P and WA-300-P lie west of the North West Cape in a frontier part of the Carnarvon Basin where the largely Mesozoic Exmouth Sub-basin abuts against shallow Palaeozoic strata of the Gascoyne Platform. The only exploration well, within the permits, Pendock–1, penetrated a thin Valanginian Birdrong Sandstone unconformably overlying Carboniferous to Silurian units, so the Mesozoic hydrocarbon potential of the area is effectively untested.

The structure of the area comprises a complex mosaic of NNE–SSW trending Early Palaeozoic extensional, listric growth faults, dissected by NW–SE trending Permian extension relay zones. Subsequent phases of Callovian–Oxfordian and Valanginian uplift, together with Late Cretaceous and Miocene inversion along the main fault zone, further complicate the structure. Several seismic events, some of which correlate with magnetic anomalies, are discordant with the local stratigraphy indicating a probable igneous origin.

The primary targets are the Birdrong Sandstone and underlying Wogatti Formation, both of which host onshore oil accumulations at Rough Range and Parrot Hill–1. The retrogradational clastic shoreline facies of the Birdrong Sandstone is well known along the eastern edge of the Dampier–Barrow–Exmouth Sub-basins. The Wogatti Formation was deposited as a more restricted alluvial/fluvial sheet sand facies, so far identified only in the onshore Cape Range area. Where the Jurassic is preserved, fluvial/alluvial channel sand facies of the Middle Jurassic Learmonth Formation, known onshore at Sandy Point–1, and Callovian nearshore sands, as observed in Unknown Hill–l, are expected to be important secondary targets.

The most promising play types within the Southern Carnarvon Basin are dip and fault-dip closures at Birdrong/Wogatti level associated with Late Cretaceous reactivation of the main NE–SW listric faults, and accentuated by later Miocene compression. The most significant exploration risks are charge and the high risk of biodegradation of reservoired liquid hydrocarbons (critically linked to reservoir temperature).

Reservoir geometry of fluvial distributary channels—Implications for North West Shelf, Australia, deltaic successions

T. Payenberg and S. Lang

Presenter: Tobias Payenberg
NCPGG

Session 5A: 4:10 pm, John Batman theatre

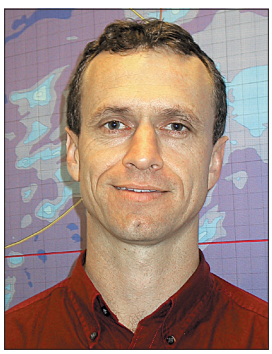
The exploration and development of stratigraphically trapped hydrocarbons requires detailed knowledge of the morphologies and reservoir characteristics of the stratigraphic body. Fluvial distributary channels are important exploration targets because they are typically isolated reservoirs, laterally and vertically sealed by delta plain and abandoned channel mudstone, and thus form excellent stratigraphic traps. The morphology and reservoir characteristics of fluvial distributary channels have been confused with fluvial channels in the past. Knowing the characteristics of fluvial distributary channels and their difference from fluvial channels is the key to the successful exploration and development of distributary channel reservoirs.

Fluvial distributary channels, formed by mixed-load systems, are commonly rectilinear channel segments found only on the delta plain between the head of passes and the depositional mouthbars. While fluvial channel reservoirs are mainly sandstone deposits of meander pointbars or braided sheets, fluvial distributary channel reservoirs are typically elongated sandy channel sidebars attached to morphologically rectilinear channel walls. The sidebars form by both lateral and downstream accretion resulting from flow in a confined, but low-sinuosity thalweg, which may be filled with organic mud following channel abandonment. On 3D seismic data the morphology of a fluvial distributary channel is often

slightly sinuous and can easily be mistaken for part of a meander channel belt.

Fluvial distributary channels are usually thinner and shallower compared to their updip fluvial channel belts. Width-thickness ratios for fluvial distributary channel reservoirs are on average 50:1 (range 15:1 to 100:1), while meandering fluvial channel reservoirs have width-thickness ratios typically >100:1, and braided river reservoirs show ratios of 500:1 or higher. Examples from the Mahakam Delta are used to illustrate these issues. Implications for exploration and development of deltaic deposits on the North West Shelf of Australia are discussed.

Overcoming historical bias: An integrated geological and engineering assessment of the Coniston Prospect, Exmouth Sub-basin



N. Smith, C. Dempsey, M. Jackson and J. Preston

Presenter: Neville Smith
BHP Billiton

Session 5A: 4:35 pm, John Batman theatre

The discovery of heavily biodegraded oil in Novara–1 in 1982 by Esso/BHP branded the Exmouth Sub-basin as a difficult exploration province for almost two decades. A total of 24 barrels of biodegraded, 16.7° API oil was recovered from a drill-stem test conducted over a 2 m interval, indicating an uneconomic flow rate of 33 BOPD. The perception that any future oil discoveries would be similarly biodegraded and therefore highly problematic, if not impossible, to produce economically, condemned the Exmouth Sub-basin in favour of its eastern cousins—the Barrow and Dampier sub-basins.

Despite an encouraging 550 BOPD flow of biodegraded oil from a poor quality reservoir in West Muiron–5 in 1993, it was not until late 1998/9 that flows of 4,300 and 4,800 BOPD from the nearby Woodside wells Vincent–1 and Enfield–1, respectively, demonstrated that biodegraded Exmouth oils could be produced at potentially commercial rates. Concurrent re-interpretation of the Novara–1/ST results, in an integrated geological and engineering assessment, promoted the Coniston prospect adjacent to the Novara fault block.

The Novara–1/ST test was demonstrated to have failed largely due to the test parameters, rather than the nature of the oil. Geochemically, the Novara oil is similar to West Muiron–5, so any oil discovered at Coniston had the potential to flow as well as Vincent–1 if a sufficiently thick oil column was encountered in the expected similarly high quality reservoir. Coniston–1 was drilled by BHP/Mobil in January/February 2000, and flowed biodegraded 15.6° API oil on DST at a rate of 2119 BOPD, restricted by rig and environmental constraints.

Historical bias has held back exploration of the Exmouth Sub-basin, leaving this one of the least explored of the Jurassic depocentres within the Carnarvon Basin. The Novara experience encourages explorers to challenge preconceptions and to ensure that the correct mix of technical skills is brought to bear in resolving prospectivity issues. Companies that maintain an active exploration position that allows them to respond rapidly to new concepts stand to gain most when historical biases are overturned.

SESSION 5B—UNRAVELLING OTWAY, BASS, GIPPSLAND—AND ENHANCING PROSPECTIVITY

Beating the odds at Casino!—A small Australian's example of risk management

D. Poynton

Presenter: Don Poynton
Strike Oil

Session 5B: 3:45 pm, Bellarine rooms 1 and 2

Strike Oil was a very small unlisted Australian company with a capitalisation of less than A$10 million when it decided to bid for block V98-4 (now VIC/P44) in the offshore Otway Basin in early 1999.

Block V98-4 met Strike Oil's gas strategy of pursuing opportunities in basins close to infrastructure and markets in the eastern states of Australia.

Prior to making the bid Strike Oil identified the geological, financial and operational risks associated with exploring the permit, especially with regard to conducting a 3D seismic survey in the environmentally sensitive and sometimes hostile Bass Strait. This led to the implementation of, and adherence to, a comprehensive risk management plan.

The geological risks were addressed by acquiring 3D seismic and conducting an analysis of the amplitudes and AVO responses associated with nearby gas discoveries and dry holes.

Management of the financial risk centred firstly around not overbidding and secondly finding a farmee who could add value to the permit during both the exploration and exploitation phases.

The operational risks were all associated with conducting the Casino 3D seismic survey. Local environmental considerations, particularly in relation to migratory whale species and the seasonal activities of local fishermen, meant there was only a six weeks' time window available for unhindered operations. This window also coincided with the spring gale season, when weather conditions can stop marine operations.

The use of experienced personnel, early stakeholder consultation, and the use of contingency plans, enabled Strike Oil to achieve its objectives under adverse conditions. The Casino 3D seismic survey, despite the odds, was completed on time, under budget, and with less than 7% infill, while still delivering high quality data.

The farmout, the acquisition and processing of the 3D seismic data, and the discovery and appraisal of the Casino gas field were all achieved within 14 months.

Fluvial architecture and the tectonic control on deposition of onshore Eumeralla Formation, Otway Ranges, Victoria: Implications for exploration in the Early Cretaceous Otway Basin

C. Noll and M. Hall

Presenter: Christian Noll
Monash University

Session 5B: 4:10 pm, Bellarine rooms 1 and 2

Spectacular outcrops of the terrestrial Aptian-Albian Eumeralla Formation are exposed in the Skenes Creek–Wongarra region, located on the eastern margin of the Otway Ranges, Victoria. The succession comprises mudstone-dominated floodplain and lacustrine successions and fluvially-derived sandstones. Lithofacies observed in the study area comprise intraformational and exotically derived conglomerate, massive and planar laminated sandstone, trough and tabular cross-bedded sandstone, ripple laminated sandstone, interbedded sandstone and mudstone, massive to laminated mudstone and thin coal seams. Architectural analysis of the fluvial system reveals these lithofacies are arranged into architectural elements that include channel elements, sandy bedforms, downstream and lateral accretion elements, laminated sand sheets and overbank fines elements.

The fluvial system is characterised by low-sinuousity, braided river channels with high width to depth ratios. Palaeocurrent data indicates that the generally westward palaeoflow is interpreted to have been diverted into local axial-through drainage patterns by active northeast trending normal faults. One of these, the Skenes Creek Fault, is also likely to have structurally isolated floodplain and lacustrine successions from the main channel belt, leading to the deposition of an anomalously thick coal measure sequence in the hanging wall of the fault. The local study therefore provides insight into regional lithofacies and potential source rock distributions, and the associated tectonostratigraphic evolution of the

Eumeralla Formation in the eastern Otway Basin. While the nature of the Eumeralla Formation sandstone does not lend itself to good reservoir properties, the geometry and internal structure of the sands provide an excellent model for other fluvial sandstone reservoir reconstructions.

Looking beyond the Warre: Alternative exploration targets in the Otway Basin

B. Lodwick

Presenter: B. Lodwick
Essential Petroleum

Session 5B: 4:35 pm, Bellarine rooms 1 and 2

Commercial onshore and offshore gas discoveries in the Late Cretaceous sands of the Waarre Formation of the Otway Basin have concentrated the recent surge of exploration on this reservoir. There are other proven, and potential, hydrocarbon-bearing reservoirs in the Otway Basin, however, that may lead to commercial successes in the future.

Despite the current lack of commercial successes, there are shows and flows in non-Waarre reservoirs ranging from Palaeozoic Basement to Tertiary sands. This should encourage continued exploration of them. Oil has flowed from the Heathfield Member of the Eumeralla Formation, onshore. Biodegraded oil has been discovered in the onshore Tertiary Pebble Point Formation. Offshore, Rock-Eval data suggests a low grade oil leg in submarine fan sands of the Belfast Mudstone. For oil explorers, these and other occurrences provide confidence that oil has migrated to reservoirs from the Late Cretaceous to the Tertiary. Gas prospects in the Waarre sands are regularly identified though amplitude versus offset (AVO) analysis of seismic data. Essential Petroleum's 2002 seismic survey in VIC/P46 has identified similar AVO anomalies in interpreted sands within the Belfast Mudstone. The Pretty Hill Formation is also providing AVO anomalies onshore.

With oil, gas and condensate being encountered through almost the entire sedimentary section, at various locations in the Otway Basin, exploration risks associated with hydrocarbon source and migration can be managed. The perception that non-Waarre plays are likely to be compromised (e.g. leaky faults, tight reservoirs, poor seals) has led, however, to downgrading, or dismissal, of many exploration targets. With more certain knowledge of hydrocarbons in the system, and with the increased activity in the area, it is only a matter of time before the mystery of the next commercial reservoir system in the Otway Basin is solved and a new phase of exploration begins.

This will be a presentation only.

SESSION 5C—DEVELOPMENTS IN THE MARINE ENVIRONMENT

Environmental management in the Bass Strait northern fields 3D seismic survey

S. Mustoe, M. Greenwood and J. Moore

Presenter: Michael Greenwood
Esso Australia

Session 5C: 3:45 pm, Bellarine rooms 4 and 5

The Northern Fields 3D seismic survey in Bass Strait was a large survey of 4,000 km^2, carried out between the months of October 2001 to July 2002. The program attracted interest from various groups regarding the possible impacts of the survey on fisheries and cetaceans (whales and dolphins).

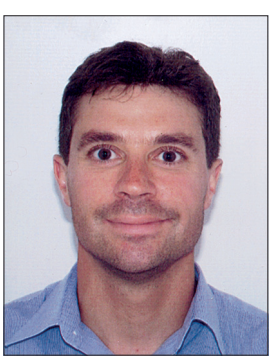
The survey was the first to operate in eastern Bass Strait after the Environment Australia Guidelines for Minimising Acoustic Disturbance to Whales, came into force, in September 2001.

The Northern Fields program was conducted in accordance with a method statement for the mitigation of impacts to cetaceans, developed by Esso to meet the requirements of Australian environmental legislation and acknowledge environmental best practice. The program utilised teams of three whale watchers who maintained a continuous rotational watch of two observers throughout the day. This proved to be a reliable element of the program and was one of several key learnings that may assist other companies in developing comprehensive and cost-effective mitigation strategies for future surveys.

Concerns raised by the fishing industry and some conservation groups about the potentially detrimental impact of seismic sources on commercial scallop larvae and fish populations were effectively addressed by avoiding commercial scallop areas during spawning periods. A controlled, in-situ study of scallops exposed to the acoustic source completed during the program conclusively demonstrated no significant variation in scallop mortality or muscle strength.

Observation data collected during this survey provided a sample of the cetacean population in Eastern Bass Strait during a large part of the annual migration cycle. These observations, which may be relevant to the planning and execution of future seismic surveys in the region, are discussed. The findings also provide valuable information for continued research into the distribution and conservation of whales and dolphins in Bass Strait.

Assessment and approval of petroleum activities under the Commonwealth Environment Protection and Biodiversity Conservation Act 1999—Lessons learned



K. Heiden (pictured)

Presenter: Malcolm Forbes
Environment Australia

Session 5C: 4:10 pm, Bellarine rooms 4 and 5

This paper provides a brief overview of the Environment Protection and Biodiversity Conservation Act 1999 (the Act) with respect to the upstream petroleum industry and focusses on the aspects of assessments and approvals under the Act.

The inception of the Act on 16 July 2000 has created a new environmental assessment and approval regime at the Commonwealth level. No longer are proposals referred for assessment on the basis of government decisions, but on the basis of the potential for a proposal to impact upon a matter of National Environmental Significance (NES). Examining the statistics of referrals made, controlled actions determined and approvals granted, provides a useful guide as to the types of activities that are captured by the Act. This exercise is particularly valuable for the oil and gas sector.

With more than 20 of the referrals received from the petroleum sector being determined to be controlled actions (that is, actions that are likely to have a significant impact upon matters of NES), a review of the assessment and approval processes under the Act provides some useful insights into what factors to consider when seeking approval under the Act. In particular, information on the timeframes involved, extent of information required, form and scope of approval conditions and synergies with other approval requirements provide valuable insights to proponents and can assist in planning future activities in a manner that is consistent with both the requirements of the Act and those of the proposed action.

This paper identifies key issues and lessons for proponents when seeking approval under the Act and also identifies areas where industry can work closely with the Commonwealth Government in ways to achieve a balance between environmental protection and the continued development of the oil and gas industry.

Australia's first regional marine plan

S. Sullivan

Presenter: Sean Sullivan
National Oceans Office

Session 5C: 4:35 pm, Bellarine rooms 4 and 5

Later this year, Australia will confirm its status as a world leader in marine resource management when the outcomes of the Commonwealth Government's planning process for the southeast marine region are made public.

The outcomes will not only be relevant for the industries and other users of Australia's ocean waters off South Australia, Victoria, NSW and Tasmania (including Macquarie Island). They will also inform the regional marine planning process throughout Australia's exclusive economic zone and will be watched closely around the world.

Within months, a strategy for the management of southeastern Australian waters will be released. It will enable better-informed ocean management decisions that will not only provide greater certainty for industries such as oil and gas, but avoid the type of costly mistakes that we have witnessed through many decades on the terrestrial environment.

The planning process has been long and complex because it required an understanding of all the interrelationships between users of our marine resources and their role in sustainable development.

Throughout this process, the National Oceans Office, the Commonwealth's lead agency for oceans policy, has worked closely with industry, community, indigenous and conservation groups to ensure the outcomes are owned by all stakeholders.

This will be a presentation only.

SESSION 6A—NORTH WEST SHELF—NEW IDEAS, NEW DISCOVERIES

Geological controls on sonic velocity in the Cenozoic Carbonates of the northern Carnarvon Basin, North West Shelf, Western Australia

M. Wallace, E. Condilis, A. Powell, J. Redfearn[2], K. Auld, M. Wiltshire, G. Holdgate and S. Gallagher

Presenter: Malcolm Wallace
University of Melbourne

Session 6A: 11:00 am, John Batman theatre

The Cenozoic carbonates of the Bounty-Talisman region can be divided into five major facies. From oldest to youngest, these are: Paleocene to Eocene basinal facies, Oligocene to Miocene slope-canyon facies, Oligocene to Miocene shelf facies, Oligocene to Miocene near-shore facies, and Pliocene-Quaternary shelf facies. This represents a shallowing-upwards cycle up to the late Miocene, followed by a significant transgression and a return to more open marine conditions in the Pliocene-Quaternary. The dominant geological processes controlling sonic velocity in the Cenozoic carbonates are physical compaction, burial calcite cementation, dolomitisation, and anhydrite/gypsum cementation. In the more open marine facies of the Cenozoic carbonates, compaction and burial calcite cementation have been the dominant geological processes that have controlled sonic velocity. Large-scale carbonate content variations associated with submarine canyon-fill sediments have also produced lateral sonic velocity variations. Dolomitisation and anhydrite cementation have produced localised high velocity zones within the near-shore facies of the carbonates.

Sub-surface uncertainty in oil fields: Learnings from early production of Legendre oil fields

R. Seggie, F. Jamal, A. Jones, M. Lennane, G. McFadzean and J. Rogers

Presenter: Alistair Jones
Woodside Energy

Session 6A: 11:25 am, John Batman theatre

The Legendre North and South Oil Fields (together referred to as the field) have been producing since May 2001 from high rate horizontal wells and had produced 18 MMBBL by end 2002. This represents about 45% of the proven and probable reserves for the field.

Many pre-drill uncertainties remain. The exploration and development wells are located primarily along the crest of the structure, leaving significant gross rock volume uncertainty on the flanks of the field. Qualitative use of amplitudes provides some insight into the Legendre North Field but not the Legendre South Field where the imaging is poor. The development wells were drilled horizontally and did not intersect any fluid contacts.

Early field life has brought some surprises, despite a rigorous assessment of uncertainty during the field development planning process. Higher than expected gas-oil ratios suggested a saturated oil with small primary gas caps, rather than the predicted under-saturated oil. Due to the larger than expected gas volumes, the gas re-injection system proved to have inadequate redundancy resulting in constrained production from the field. The pre-drill geological model has required significant changes to reflect the drilling and production results to date. The intra-field shales needed to be areally much smaller than predicted to explain well intersections and production performance. This is consistent with outcrop analogues.

Surprises are common when an oil field is first developed and often continue to arise during secondary development phases. Learnings, in the context of sub-surface uncertainty, from other oil fields in the greater North West Shelf are compared briefly to highlight the importance of managing uncertainty during field development planning. It is important to have design flexibility to enable facility adjustments to be made easily, early in field life.

Restoration of a deepwater profile from the Browse Basin: Structural-stratigraphic evolution and hydrocarbon prospectivity

N. Hoffman and K. Hill

Presenter: Nick Hoffman
University of Melbourne

Session 6A: 11:50 am, John Batman theatre

A Geoscience Australia interpretation of a 600 km long, deep-seismic reflection profile across the Browse Basin, has been structurally backstripped, decompacted, restored and adjusted to correct palaeobathymetry for 14 key horizons. The restorations suggest 45% local extension in the Middle Jurassic creating the deepwater Scott Plateau and Seringapatam Graben of the Browse Basin, adjacent to the Caswell Sub-basin which remained at shelfal depths. In the Upper Jurassic the 80 km wide, deepwater Seringapatam Graben was filled with up to 2 km of sediments. This probably included significant source rocks as well as a major influx of coarse clastic sediments in submarine fans derived from the adjacent Caswell shelf, allowing a favourable juxtaposition of hydrocarbon reservoir and source rocks. Valanginian to Aptian flooding resulted in a deeper water starved basin with condensed deposits whilst minor inversion in the Seringapatam Graben created potential hydrocarbon traps with several hundred metres of relief. A prograding shelf developed in the Upper Albian to Cenomanian and buried Callovian outcrops on the slope for the first time. Turbidites filled the Seringapatam Graben and passed across the Scott Plateau. A dramatic increase in subsidence rate and sedimentation occurred in the Late Oligocene and into the Miocene allowing deposition of a thick carbonate sequence with the shelf edge above the Caswell–Seringapatam transition and thick carbonate turbidites on the Scott Plateau. In the Seringapatam Graben the Upper Jurassic sequence was buried to depths of ~3 km, which may have been enough to generate and migrate oil.

This will be a presentation only.

SESSION 6B —UNRAVELLING OTWAY, BASS, GIPPSLAND—AND ENHANCING PROSPECTIVITY

Coal as a source of oil and gas: A case study from the Bass Basin, Australia

C. Boreham, J. Blevin, A. Radlinski and K. Trigg

Presenter: Chris Boreham
Geoscience Australia

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

Only a few published geochemical studies have demonstrated that coals have sourced significant volumes of oil, while none have clearly implicated coals in the Australian context. As part of a broader collaborative project with Mineral Resources Tasmania on the petroleum prospectivity of the Bass Basin, this geochemical study has yielded strong evidence that Paleocene–Eocene coals have sourced the oil and gas in the Yolla, Pelican and Cormorant accumulations in the Bass Basin.

Potential oil-prone source rocks in the Bass Basin have Hydrogen Indices (HIs) greater than 300 mg HC/g TOC. The coals within the Early–Middle Eocene succession commonly have HIs up to 500 mg HC/g TOC, and are associated with disseminated organic matter in claystones that are more gas-prone with HIs generally less than 300 mg HC/g TOC. Maturity of the coals is sufficient for oil and gas generation, with vitrinite reflectance (VR) up to 1.8 % at the base of Pelican–5. Igneous intrusions, mainly within Paleocene, Oligocene and Miocene sediments, produced locally elevated maturity levels with VR up to 5%.

The key events in the process of petroleum generation and migration from the effective coaly source rocks in the Bass Basin are:

- the onset of oil generation at a VR of 0.65% (e.g. 2,450 m in Pelican–5);
- the onset of oil expulsion (primary migration) at a VR of 0.75% (e.g. 2,700–3,200 m in the Bass Basin; 2,850 m in Pelican–5);
- the main oil window between VR of 0.75 and 0.95% (e.g. 2,850–3,300 m in Pelican–5); and;
- the main gas window at VR >1.2% (e.g. >3,650 m in Pelican–5).

Oils in the Bass Basin form a single oil population, although biodegradation of the Cormorant oil has resulted in its statistical placement in a separate oil family from that of the Pelican and Yolla crudes. Oil-to-source correlations show that the Paleocene–Early Eocene coals are effective source rocks in the Bass Basin, in contrast to previous work, which favoured disseminated organic matter in claystone as the sole potential source kerogen. This result represents the first demonstrated case of significant oil from coal in the Australian context. Natural gases at White Ibis–1 and Yolla–2 are associated with the liquid hydrocarbons in their respective fields, although the former gas is generated from a more mature source rock.

The application of the methodologies used in this study to other Australian sedimentary basins where commercial oil is thought to be sourced from coaly kerogens (e.g. Bowen, Cooper and Gippsland basins) may further implicate coal as an effective source rock for oil.

The Gippsland Basin Top Latrobe unconformity, and its expression in other SE Australia basins

G. Holdgate, C. Rodriquez, E. Johnstone, M. Wallace, and S. Gallagher

Presenter: Guy Holdgate
University of Melbourne

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

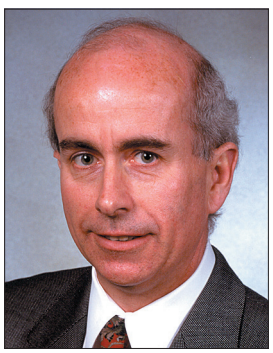
The Early/Middle Eocene was an important time for developing the present configuration of the Indo-Australian plate, with the onset of fast spreading beginning in the Southern Ocean, and the commencement of northwest directed compression in the Gippsland Basin. Significant unconformities developed during this time including the Top Latrobe Unconformity (Top Latrobe) within Gippsland, and similar unconformities in the Torquay and Otway Basins.

On seismic over uplifted highs, (and where close spaced well data exists), a low angular unconformity exists between interbedded sand/shale/coal facies of the Latrobe Group and the Seaspray Group. The Marlin and Flounder channels eroded up to 600 m into the earliest Eocene deformed surfaces, and their infill in turn has been eroded at a top-Latrobe group unconformity where tectonic deformation and the resultant variable tilting produced an angular unconformity up to 5°. Missing biostratigraphic zones occur below the unconformity and many faults terminate at the Top Latrobe. The Top Latrobe is also characterised by resistant sandstone

strike-ridges that created a varied topography. In areas of uplift where interbedded sandstone/shale units occur in the Top Latrobe subcrop, strike ridges are common. Where thick shale units occur at the Top Latrobe subcrop, topographic troughs or valleys are more common.

A study of 50 key offshore wells across the Gippsland Basin suggests that the best correlation between the seismic/synthetic Top Latrobe, and the litho-biostratigraphic Top Latrobe occurs in the upper part of the Middle Eocene. This date can be constrained between 40 and 44 Ma based on the ages of Marlin and Flounder channeling and infill and the Gurnard Formation. In the onshore part of the Gippsland Basin, the Top Latrobe can be located as a disconformity within coal measure units along the top of the Middle Eocene Traralgon–2 coal seam. In the Torquay Basin the only exposed example of this Eocene event is preserved in the Anglesea coal mine as a low angle unconformity between the A group coal seam and the overlying Boonah Formation. Low angular unconformities in seismic data are evident in the offshore Torquay and Otway basins at this time indicating the widespread nature of this unconformity in the southeastern Australian coastal basins.

Gippsland—A new potential from a mature basin



N. Heath

Presenter: Nick Heath
Esso Australia

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

It is now 39 years since the first gas was discovered in Bass Strait's Gippsland Basin. Advances in exploration and production technology mean that today Australia's longest producing offshore basin is also one of Australia's most prospective. Gippsland is now producing around 160,000 barrels of crude and 570 million cubic feet of gas per day. To date it has produced more than 3.5 billion barrels of oil and 5 trillion cubic feet of gas and the value of the infrastructure in place is estimated to be around A$16 billion.

Australia's evolving energy market means that gas demand continues to grow. Following the re-structuring of energy markets in southeastern Australia and the installation of new pipeline infrastructure, Gippsland gas now flows to Victoria, NSW, Tasmania and will supply into South Australia from 2004. To meet this growing demand the Esso/BHPBilliton joint venture partners are investing heavily and utilising a vast array of 3D exploration technology to unlock new opportunities. In 2002 they conducted the largest 3D survey ever undertaken in Bass Strait and expect to conduct another in early 2003. A program of exploration drilling is expected to commence in late 2003. With expanded market opportunities and a gas resource base of more than 5 trillion cubic feet, the future looks bright for Gippsland.

SESSION 6C —FUTURE GAS

Eastern Australia's gas supply and demand balance

A. Dickson and K. Noble

Presenter: Dr. Brian Fisher
ABARE

Session 6C: 11:00 am, Bellarine rooms 4 and 5

Concerns have been raised about the capacity for Australia's natural gas supplies to keep pace with growing demand, particularly in eastern Australia. Specifically, it has been suggested that unless significant infrastructure investment is undertaken now the demand/supply balance situation in eastern Australia will deteriorate quickly as natural gas resources are depleted in the face of strongly growing demand.

The purpose of this study is to examine whether and when supplies in eastern Australia are likely to fall short of growing demand and what alternative supply options present themselves.

A modelling framework was developed by ABARE to examine these issues at a regional level, building on ABARE's MARKAL model of the Australian energy system. The modelling framework includes representations of all potential sources of natural gas in Australia by basin and coal seam methane, all existing and proposed pipeline options as well as regional gas demands, by industry. Preliminary results for this study were released in August 2002. This paper provides a final revised and updated set of results for this study.

This paper will appear in Part 2 of the APPEA Journal 2003

The development of the Greater Gorgon area gas fields

P. Oen

Presenter: Paul Oen
ChevronTexaco

Session 6C: 11:25 am, Bellarine rooms 4 and 5

The gas fields of the Greater Gorgon area represent one of the largest discovered but undeveloped gas resources in Asia. The development of these resources will be a world scale undertaking requiring billions of dollars of investment spread over many years. The implications of these developments are far-reaching and will have a material impact on the energy market in Asia and beyond, and will bring significant benefits to Australia.

This paper will discuss the unique characteristics of the resources to be developed, the engineering and environmental work being carried out in support of the development, and the gas market opportunities being targetted. The paper will present ChevronTexaco's vision for the development of the Greater Gorgon fields and will discuss the economic, social and environmental effects of that development.

ChevronTexaco is the operator of the Gorgon gas field and holds participating interests varying from 50%–100% in the fields of the Greater Gorgon area.

This paper will appear in Part 2 of the APPEA Journal 2003

Bioenhancement of coal bed methane resources in the southern Sydney Basin

M. Faiz, L. Stalker, N. Sherwood, A. Saghafi, M. Wold, S. Barclay, J. Choudhury, W. Barker and I.Wang

Presenter: Mohinudeen Faiz
CSIRO

Session 6C: 11:50 am, Bellarine rooms 4 and 5

Coals in the Sydney Basin contain large amounts of gas ranging in composition from pure methane (CH_4) to pure carbon dioxide (CO_2). These gases are derived from thermogenic, magmatic and biogenic sources and their present-day distribution is mainly related to geological structure, depth and proximity to igneous intrusions.

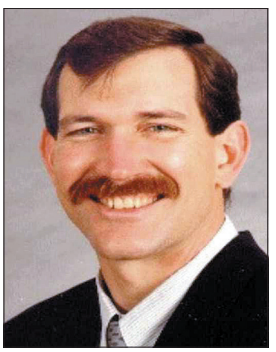
A coal bed methane (CBM) study of the Camden area of the Sydney Basin has been jointly conducted by Sydney Gas Company NL (SGC) and the Commonwealth Scientific and Industrial Research Organisation (CSIRO). The delineation of high production fairways is vital for any CBM project development to be commercially successful. An integrated research project employing various methods of reservoir characterisation, including geological, geochemical, geomechanical and gas storage analyses contribute to this delineation for the Camden area, where SGC is currently developing the 300-well Camden Gas Project.

In particular, accurate determinations of gas content, saturation levels, composition and origin, as well as interpretations about distribution, are essential for identifying sweet spots for CBM production optimisation. The extent of gas saturation is a function of numerous factors, including amounts of gas generated between the Permian and Late Cretaceous, amounts expelled from the system during Late Cretaceous-Tertiary uplift and amounts of subsequent secondary biogenic methane generated and absorbed in the coals. The extent of this secondary biogenic gas generation appears to be greatest in coals proximal to the basin margins, where meteoric waters carrying bacteria and nutrients had ready access. Significant enhancement of methane content also occurs, however, in deeper parts of the basin where permeable structures exist.

The integrated study shows that high production CBM wells drilled to date by SGC are located in zones of enhanced permeability. In these locations original thermogenic wet gases have been removed and additional secondary biogenic methane has been generated due to microbial alteration of coal, hydrocarbons and carbon dioxide. This process has replenished the coals by enhancing the methane contents of the respective seams and this phenomenon can be termed 'bio-enhancement' in the context of CBM production.

SESSION 7A—NEW PLAYS

Petroleum systems and exploration opportunities in the Officer Basin, Western Australia



G. Carlsen, A. Simeonova and S. Apak

Presenter: Greg Carlsen
DMPR

Session 7A: 2:30 pm, John Batman theatre

The Officer Basin in Western Australia contains a variety of hydrocarbon plays associated with compressional, halokinetic, unconformity and stratigraphic traps. Five distinct structural zones have been defined in the basin—a northeastern Marginal Overthrusted Zone, a northeastern Salt-ruptured Zone, a central Thrusted Zone, a Western Platform and a complex salt-dominated Minibasins Zone. These zones, together with salt-associated and sub-salt structure, are well delineated on about 2,900 km of reprocessed 1980s vintage seismic data, now publicly released.

Neoproterozoic rocks are marginally to fully mature for oil generation on the Western Platform and immature to overmature for different levels of the succession in the Salt-ruptured and Thrusted zones. Geochemical modelling indicates that the main phases of oil generation vary from different stratigraphic intervals and different parts of the Neoproterozoic basin with peaks during the latest Neoproterozoic, Cambrian, and Permian–Triassic. A variety of hydrocarbon shows have been recorded in each of the structural zones. The most recent, a gas show recorded in the stratigraphic well Vines–1 indicates the presence of potentially effective petroleum systems in the unexplored Waigen area of the Marginal Overthrusted Zone.

A wide variety of trap styles have been identified, associated with normal faults, thrust faults, thrust ramp folds, compressive folds, fault tip folds, sub-salt plays, unconformity truncations, pinchouts, lateral facies changes, erosive channels and valleys, fractured carbonates and halokinetic traps. Most of these trap styles are poorly tested or untested.

An integrated geological and geophysical interpretation of a portion of the offshore Sydney Basin, New South Wales

P. Arditto

Presenter: Peter Arditto
Sedstrat

Session 7A: 2:55 pm, John Batman theatre

The study area is within PEP 11, which is more than 200 km in length, covers an area over 8,200 km^2 and lies immediately offshore of Sydney, Australia's largest gas and petroleum market on the east coast of New South Wales. Permit water depths range from 40 m to 200 m. While the onshore Sydney Basin has received episodic interest in petroleum exploration drilling, no deep exploration wells have been drilled offshore.

A reappraisal of available data indicates the presence of suitable oil- and wet gas-prone source rocks of the Late Permian coal measure succession and gas-prone source rocks of the middle to early Permian marine outer shelf mudstone successions within PEP 11. Reservoir quality is an issue within the onshore Permian succession and, while adequate reservoir quality exists in the lower Triassic succession, this interval is inferred to be absent over much of PEP 11. Quartz-rich arenites of the Late Permian basal Sydney Subgroup are inferred to be present in the western part of PEP 11 and these may form suitable reservoirs. Seismic mapping indicates the presence of suitable structures for hydrocarbon accumulation within the Permian succession of PEP 11, but evidence points to significant structuring post-dating peak hydrocarbon generation. Uplift and erosion of the order of 4 km (based on onshore vitrinite reflectance studies and offshore seismic truncation geometries) is inferred to have taken place over the NE portion of the study area within PEP 11. Published burial history modelling indicates hydrocarbon generation from the Late Permian coal measures commenced by or before the mid-Triassic and terminated during a mid-Cretaceous compressional uplift prior to the opening of the Tasman Sea.

Structural plays identified in the western and southwestern portion of PEP 11 are well positioned to contain Late Permian clean, quartz-rich, fluvial to nearshore marine reservoir facies of the coal measures. These were sourced from the western Tasman Fold Belt. The reservoir facies are also well positioned to receive hydrocarbons expelled from adjacent coal and carbonaceous mudstone source rock facies, but must rely on early trap integrity or re-migrated hydrocarbons and,

being relatively shallow, have a risk of biodegradation. Structural closures along the main offshore uplift appear to have been stripped of the Late Permian coal measure succession and must rely on mid-Permian to Early Permian petroleum systems for hydrocarbon generation and accumulation.

Reservoir quality, diagenesis and sedimentology of the Pale and Subu sandstones: Re-visiting the eastern Papuan Basin, Papua New Guinea

S. Barclay, K. Liu and D. Holland

Presenter: Stuart Barclay
CSIRO Petroleum

Session 7A: 3:20 pm, John Batman theatre

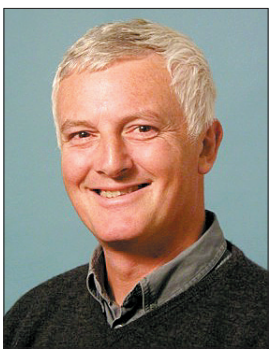
Two shallow diamond drill holes (Subu–1 and Subu–2) continuously cored in August and September 2001 by InterOil Australia represent the first sub-surface penetrations of reservoir quality sandstones in the Eastern Papuan Basin of Papua New Guinea. These wells intersected two sedimentologically distinct thick quartz sandstones (>100 m). The upper sandstone unit is Campanian in age and is correlated with the Pale Sandstone, whereas the lower sandstone is of Turonian age and has not been reported previously, and is tentatively named as the Subu Sandstone in this paper.

The core has been the subject of detailed reservoir quality and diagenetic study as part of a multi-disciplinary study conducted by CSIRO Petroleum. The results of the reservoir quality portion of this study form the basis of this report and demonstrate the following:

- There are two distinct depositional systems present with a lower sandy slope apron and basin floor fan system (Subu Sandstone) and a younger upper shoreface-shallow marine depositional system (Pale Sandstone).
- While the porosity and permeability data for subsurface samples (5 to 16% and 0.1 to 1000mD) are lower than previously reported by Boult and Carman (1990) for surface samples both the sandstone units demonstrate thick, good reservoir quality reservoir capable of holding significant volumes of hydrocarbons.
- Bitumen is present in the pore space through out the sandstones in both wells. The presence of biodegraded hydrocarbons demonstrates that liquid hydrocarbons have been generated in the basin and have either migrated through the Subu and Pale sandstone or have been reservoired in them.
- Associated with the bitumen is pyrite precipitated as an *in-situ* by-product of shallow biodegradation of the parent liquid hydrocarbon as indicated by sulphur isotope analysis.
- Diagenetic effects include compaction (the dominant control on reservoir quality), minor quartz cementation, minor secondary porosity generation, and in thin zones localised carbonate cementation.
- Despite their very different depositional settings and age difference the thin section petrology of the Pale and Subu sandstones are very similar. The subtle difference between them is textural (grain size, sorting) and detrital clay content. The Subu Sandstone is typically finer grained, displays a higher degree of sorting and has a higher detrital clay content than the Pale Sandstone.
- The character of these sandstones may have as much to do with provenance as with depositional environment and may indicate a separate quartz-rich depositional system sourcing sediment from the Australian craton independent of the Fly Platform Toro/Imburu systems.

SESSION 7B —UNRAVELLING OTWAY, BASS, GIPPSLAND—AND ENHANCING PRODUCTIVITY

Development of the Taranaki Basin and comparisons with the Gippsland Basin: Implications for deepwater exploration



C. Uruski, P. Baillie and V. Stagpoole

Presenter: Chris Uruski
Institute of Geological and Nuclear Science

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

Exploration of the Taranaki Basin entered a new phase in 2001 with Astrolabe, a 6,200 km high-quality 2D seismic survey acquired by TGS-NOPEC that has outlined a large depocentre containing up to 10 km of sedimentary fill. This new data has extended the previously-known Taranaki Basin into deeper water beyond the shelf edge. Subsequently, the New Zealand Government released an area of 42,000 km^2 for competitive bidding to close in September 2003.

Sequence analysis shows that a major deltaic system, comparable to the Golden Beach and Emperor subgroups of the Gippsland Basin, built into a restricted seaway during the Late Cretaceous and culminated with deposition of the Rakopi Formation coal measure succession. The Rakopi Formation covers an area of at least 15,000 km^2 of the study area and was followed by a transgression that continued until the Miocene.

Minor Eocene folding created broad structures with potential to trap large volumes of petroleum. Other potential trapping structures include drape across Cretaceous rift blocks and turbidite mounds of Miocene age.

Modelling shows that much of the Early Cretaceous delta is thermally mature and should be expelling petroleum today. Reservoir facies are present at many horizons, but the primary target is expected to be sandstones of the Rakopi Formation coal measures.

Many analogies can be drawn between the Taranaki and Gippsland basins. The deepwater Taranaki basin appears to be equivalent, however, to the offshore, oil-prone part of Gippsland while the nearshore Taranaki and Great South basins together form an analogy for the more gas-prone nearshore part of Gippsland.

Structural inheritance, stress rotation, overprinting and compressional reactivation in the Gippsland Basin—Tuna 3D seismic dataset

M. Power, K. Hill and N. Hoffman

Presenter: Mike Power
University of Melbourne

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

In the Tuna area, Turonian rifting between Australia and the Lord Howe Rise produced extensive irregular NE–SE to ENE–WSW trending Emperor Subgroup depocentres by oblique reactivation of inherited Early Cretaceous Strzelecki Group and Palaeozoic basement fault geometries. Santonian Tasman seafloor spreading rotated the stress vectors clockwise so that NE–SW Emperor Subgroup syn-rift depocentres were abandoned and more easterly trends were reactivated. This developed the Proto-Rosedale Fault across the northern margin as a complex series of branching fault splays with reactivated ENE–WSW trending segments and new east–west hard linkages. In the Late Cretaceous, extension vectors rotated a further 45° clockwise sympathetic to NW–SE trending Tasman Sea mid oceanic ridges. ENE–WSW trending splays of the Proto-Rosedale Fault became abandoned and overprinted by new Maastrichtian NW–SE trending segments perpendicular to the NE–SW stress field. By the Paleocene these segments had linked, displaying en echelon geometries above the obliquely reactivated Proto-Rosedale Fault. Tasman seafloor spreading and fault-controlled subsidence in Gippsland had finished by the Early Eocene. Extension was punctuated by Coniacian-Santonian, Eocene and Oligocene compressive pulses that inverted abandoned splays of the Proto-Rosedale Fault forming the Tuna faulted anticline oil and gas traps.

The Santonian-Campanian Proto-Rosedale Fault and other similarly oriented structures are promising fairways for deep exploration. Attractive reservoir targets include stacked braided fluvial channel sands of the Golden Beach Subgroup deposited along NE–SW to ENE–WSW trending segments of the Proto-Rosedale Fault. Anticlinal traps developed during multiple Cretaceous and Tertiary compressive phases. Campanian dykes, sills and flows are prevalent in the Golden Beach section and offer the potential for effective seal as seen in the Kipper field.

Improving recovery in a thin oil column reservoir—Tuna M–1 reservoir experience in the Gippsland Basin, southeast Australia

C. Santamaria and R. Fish

Presenters: Carla Santamaria
Esso Australia

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

The Tuna M–1 reservoir was developed in 1997 from both the new West Tuna platform and the existing Tuna A platform in the Gippsland Basin. The M–1 reservoir is contained within an anticlinal closure with an approximate gross hydrocarbon column of 85 metres. The oil column was originally 12 m thick and is supported by a large gas cap and a strong flank aquifer.

Performance from the M–1 reservoir has been good, due to excellent reservoir properties. The combination of conventional and geo-steered horizontal wells has performed well with recovery efficiencies of 70% observed in many parts of the field. Lower than expected performance from the northwestern edge of the oil rim was, however, a significant anomaly, with recovery efficiencies 10% lower than from comparable rock in the southern and eastern parts of the field. The underlying cause of this lower performance was believed to be the result of an anisotropic aquifer response allowing greater pressure support along the northwestern flank of the field

A re-entry well was drilled from a watered out horizontal well on the Tuna A platform in December 2000. This well was drilled as an oil production opportunity and as a key surveillance data point for the northwestern flank of the field. Results led to further surveillance including contact monitoring and production logging in horizontal wells. In addition to this, simulations were updated to reflect actual performance and surveillance data. Subsequent analysis supported development of a work program for new M–1 drainage points, including additional drill wells and the conversion of existing, watered out horizontal wells to conventional wells. The M–1 re-development work has been highly successful with production rates increasing by about 20,000 barrels per day in the first nine months of the program.

SESSION 7C —DEALING WITH CARBON DIOXIDE—THREAT OR OPPORTUNITY

Dealing with climatic change: Possible pathways forward

B. Fisher, G. Jakeman, K. Woffenden, V. Tulpulé and S. Hester

Presenter: Dr. Brian Fisher
ABARE

Session 7C: 2:30 pm, Bellarine rooms 4 and 5

Under the United Nations Framework Convention on Climate Change, the international community has sought to find a policy framework to address the threat of human induced climate change. The most significant action to date has been the adoption of the Kyoto Protocol in December 1997, which could enter into force in 2003. The protocol includes legally binding emission reductions for some countries over the period 2008–12.

It has yet not been possible, however, to find an approach that is truly global and that is aligned with the long-term environmental goal of reducing global greenhouse gas emissions to a safe level.

A framework for action that addresses these shortcomings is developed in this paper. The underlying tenets are environmental effectiveness, economic efficiency, and equity. The power of technology is drawn into the solution, the importance of an appropriate timeframe for action is acknowledged and involvement by all major emitting countries is facilitated. Importantly, this last point includes participation by developing countries in a way that accommodates their aspirations for economic growth. Together, these elements allow a response that minimises costs and maximises the environmental outcome while at the same time enhancing the growth prospects of developing countries.

The economics of geological storage of CO_2 in Australia

W. Allinson, D. Nguyen and J. Bradshaw

Presenter: Guy Allinson
University of New South Wales

Session 7C: 2:55 pm, Bellarine rooms 4 and 5

The economics of the storage of CO_2 in underground reservoirs in Australia have been analysed as part of the Australian Petroleum Cooperative Research Centre's GEODISC program. The economic analyses in the paper are based on cost estimates generated by a CO_2 storage technical/economic model developed at the beginning of the GEODISC project. The estimates rely on data concerning the characteristics of geological reservoirs in Australia. The uncertainties involved in estimating the costs of such projects are discussed and the economics of storing CO_2 for a range of CO_2 sources and potential storage sites across Australia are presented.

The key elements of the CO_2 storage process and the methods involved in estimating the costs of CO_2 storage are described and the CO_2 storage costs for a hypothetical, but representative storage project in Australia are derived. The effects of uncertainties inherent in estimating the costs of storing CO_2 are shown.

The analyses show that the costs are particularly sensitive to parameters such as the CO_2 flow rate, the distance between the source and the storage site, the physical properties of the reservoir and the market prices of equipment and services. Therefore, variations in any one of these inputs can lead to significant variation in the costs of CO_2 storage. Allowing for reasonable variations in all the inputs together in a Monte Carlo simulation of any particular site, then a large range of total CO_2 storage costs is possible. The effect of uncertainty for the hypothetical representative storage site is illustrated.

The impact of storing other gases together with CO_2 is analysed. These gases include methane, hydrogen sulphide, nitrogen, nitrous oxides and oxides of sulphur, all of which potentially could be captured together with CO_2. The effect on storage costs when varying quantities of other gases are injected with the CO_2 is shown.

Based on the CO_2 storage cost estimates and the published costs capturing CO_2 from industrial processes, the economics are shown of combined capture and storage (that is, the sequestration process as a whole) for the major CO_2 generation sites across Australia combined with potential compatible storage sites. Examples are shown of the volumes of CO_2 that could be sequestered economically depending on the level of the carbon credit in a hypothetical carbon credit trading regime. Purely as an illustration, assuming hypothetically that a real carbon credit of US$50 per tonne applied and that the cost of capture was US$40 per tonne across the board, then preliminary indications are that, ignoring tax considerations, it would be economic to store about 180 million tonnes per year of CO_2. This is equivalent to about 70% of the annual CO_2 emissions from stationary sources in Australia in 2000.

Onshore Otway Basin carbon dioxide accumulations: CO2-induced diagenesis in natural analogues for underground storage of greenhouse gas

M. Watson, N. Zwingmann, N. Lemon and P. Tingate

Presenter: Max Watson
NCPGG

Session 7C: 3:20 pm, Bellarine rooms 4 and 5

The study of natural carbon dioxide (CO_2) accumulations, such as those found in the onshore Otway Basin, is necessary for the validation of underground long-term storage technology as an option for decreasing greenhouse gas emissions.

The investigation of natural CO_2 occurrences is being investigated as part of the Geological Disposal of Carbon Dioxide (GEODISC) research program. This study identifies the effects of CO_2 on reservoir rock's mineralogy through time as well as its porosity and permeability. The Otway Basin CO_2 accumulations display variations in reservoir type, CO_2 concentration and time of injection. A range of typical reservoirs types for the CO_2 accumulations occurs in the Otway Basin, including feldspathic litharenites, subfeldsarenite and quartz arenite. CO_2 concentrations in the Otway Basin vary greatly in the accumulations studied, ranging from 10 mol% within the Port Campbell Field to 99 mol % in the Caroline Field. The source of the CO_2 is degassing of the deep-seated magmas of the Newer Volcanics, with CO_2 influx occurring between ~2 million to as recently as 5,000 years ago. This study investigated three areas of the Otway Basin;

- Penola Trough—Ladbroke Grove, Katnook (non-CO_2)
- Port Campbell Embayment—Boggy Creek, Langley, Port Campbell; and
- Gambier Sub-Basin—Caroline

Due to their close proximity and similar geological history prior to CO_2 influx, the Ladbroke Grove-Katnook gas accumulations are particularly useful for examining differences between a CO_2-rich (Ladbroke Grove) and a CO_2-absent field (Katnook) and for developing a post-CO_2 diagenetic history. Variation in grain size and CO_2 concentration affects the degree of reaction of CO_2 with the reservoir rock. Petrology and formation water chemistry of these fields indicate that CO_2 has modified the rock properties. In all CO_2-rich reservoirs examined (>10 mol % CO_2), dissolution and alteration of lithic and felsic framework grains has occurred (e.g. albite dissolution). Clays and cements throughout most of the Otway Basin CO_2 accumulations are modified to minerals more stable in the changed gas compositions (e.g. chlorite to kaolin). The change in mineralogy after the recent CO_2 influx shows that the Pretty Hill Formation with high amounts of reactive minerals and smaller grain size is an effective reservoir unit for mineral storage of CO_2. Long-term storage in the Waarre Sandstone quartz-rich reservoirs also displays the effectiveness of CO_2 storage in pore space.

This study of natural accumulations of CO_2 has demonstrated that geological storage of CO_2 is a viable option. Understanding of the mineral reactions involved with CO_2 in reservoir rock is vital for selection of storage sites and modelling the behaviour of CO_2 in the subsurface.