

The distribution of zircon, if present, in a powdered sample is an excellent indicator of sample homogeneity. Any major discrepancy in Zr results from the XRF and the ICP-MS will now suggest problems with the sample grinding rather than analytical problems. Results, particularly trace results, could be then treated with appropriate caution or the sample(s) reground and reanalysed.

The laboratory will be able to report both results for those elements that can now be equally well determined by XRF and ICP-MS. These elements will probably be Ba, V, Cr, Ni, Cu, Zn, Rb, Sr, Y, Zr and Pb because they are generally present in silicates at levels significantly above the detection limit of the less-sensitive XRF (see figures 1 to 9).

Although the effective sample weight in the final solution is smaller than presently used, the weight used to make the fused disc is approximately three times larger than at present. The end result is that laboratory staff is now using what should be a more representative aliquot of the sample.

Because discrete chips of glass are used, there are no problems with electrostatic charges that cause segregation in some sample powders. One chip digests as easily as a dozen smaller pieces.


Similar rock standards will routinely be run with each batch of both XRF and ICP-MS. Collection and storage of this data will continually monitor the performance of both techniques.

Disadvantage

Lithium and boron analyses will no longer be available from the Minerals Division laboratory because of the Li and B present in the flux and their memory effect within the spectrometer.

References

1. Jenner GA, Longerich HP, Jackson SE & Fryer BJ. 1990. ICP-MS—A powerful tool for high-precision trace-element analysis in earth sciences: Evidence from analysis of selected USGS reference samples. *Chemical Geology*; 83: 133-148.
2. Govindaraju K, ed. 1994. *Geostandards Newsletter*, special issue Jul; 18.

➤ John Pyke, Minerals Division, AGSO, phone +61 2 6249 9288 or e-mail john.pyke@agso.gov.au 

Bonaparte Basin

Geochemical characteristics of hydrocarbon families and petroleum systems

DS Edwards, JM Kennard, JC Preston, RE Summons, CJ Boreham & JE Zumberge

The Bonaparte Basin has been actively explored for more than 20 years, with oil production from several fields (Jabiru, Challis-Cassini, Laminaria-Corallina, Elang and the depleted Skua field) and proposed production from giant gas/condensate fields (Bayu-Undan, Sunrise-Loxton Shoals-Troubadour and Petrel-Tern). Despite this focused exploration and appraisal, to date geoscientists have had a relatively poor understanding of the region's petroleum systems.

To improve this understanding, isotopic and biomarker analyses of numerous oils, condensates and gases have been undertaken to geochemically characterise the hydrocarbon families in the Bonaparte Basin, and to correlate them with likely source rocks. Preliminary results of this study show that two Palaeozoic and seven Mesozoic oil families can be identified in the Bonaparte Basin. Details of the petroleum systems active in this basin were presented at the recent AAPG International Conference in Bali (October 15-18, 2000) by Dianne Edwards and John Kennard, and continue to be investigated by AGSO's North-north-west Regional Project.

The Bonaparte Basin lies between north-western Australia and the island of Timor (figure 1). It has a complex tectonic history involving two phases of Palaeozoic extension and Late Triassic compression prior to the onset of Mesozoic extension.

Initial rifting occurred in the Late Devonian to form the north-west-trending Petrel Sub-basin in the south-east. The resultant thick Late Devonian-Carboniferous rift and sag succession was orthogonally overprinted in the Late Carboniferous to Early Permian by north-east-trending rift basins to form a proto-Malita and possible proto-Vulcan Sub-basin. Late Jurassic extension resulted in a series of linked, north-west-trending (Vulcan Sub-basin and Malita Graben) and south-east-trending (Sahul and Flamingo Synclines) intracontinental grabens. Thick marine mudstones accumulated within these grabens, and passed laterally to fan delta sandstones on the adjacent horst blocks and terraces. These Mesozoic depocentres are surrounded by structural highs (Ashmore Platform, Londonderry High, Sahul Platform and Darwin Shelf; figure 1) which have relatively thin Jurassic-Cretaceous sediments across an uplifted and eroded Triassic-Palaeozoic section.

Most of the commercial and soon to be developed oil and gas accumulations are reservoired in Middle and Upper Jurassic sandstones (Plover and Montara/Elang Formation, respectively; figure 2). Commercial accumulations also occur in Upper Triassic and Upper Cretaceous sands in the Vulcan Sub-basin. In the Petrel Sub-basin, gas and gas/condensate accumulations occur in the Upper Permian Hyland Bay Formation (Petrel and Tern Fields, Fishburn-1 and Penguin-1), and gas discoveries on the Londonderry High (Prometheus-1, Ascalon-1A) and Sahul Platform (Kelp Deep-1) also occur within this unit (figure 2).

Hydrocarbon families

Oil-oil comparisons were made using cluster and principal component analysis—the results of which are displayed as a dendrogram in figure 3. The GeoMark protocol was adhered to which utilises 16 geochemical parameters (two bulk carbon isotopic values, 13 source-specific terpane

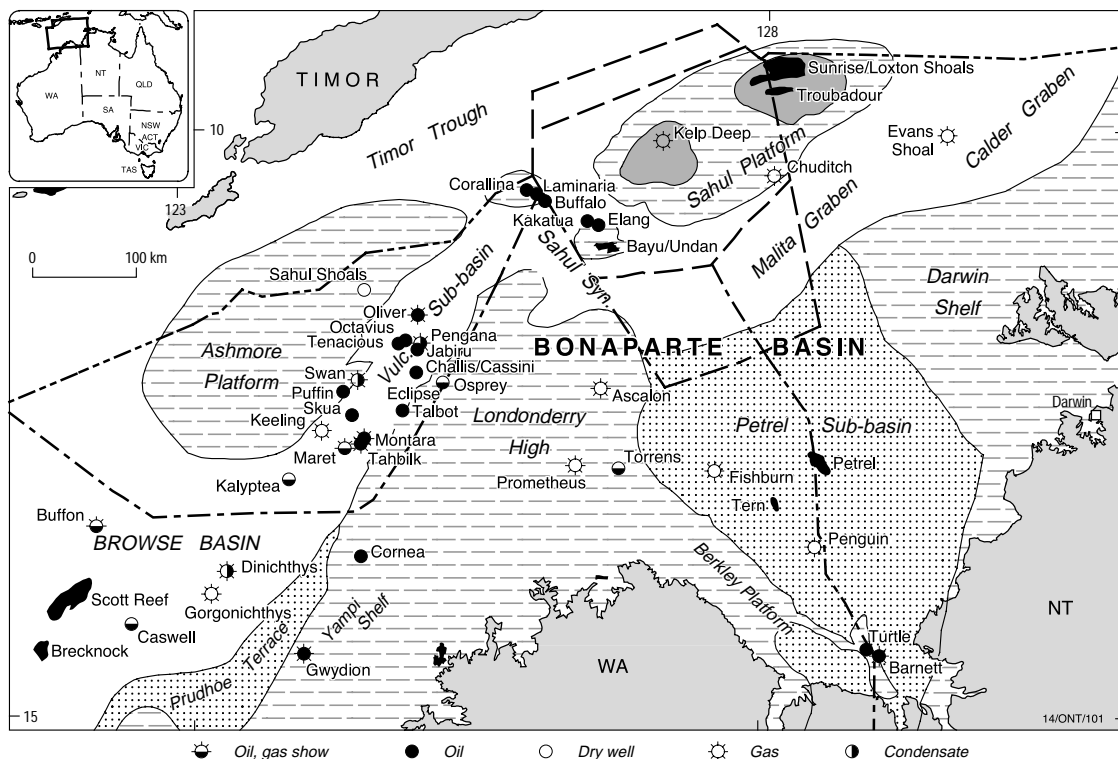


Figure 1. Location of petroleum exploration wells in the Bonaparte Basin

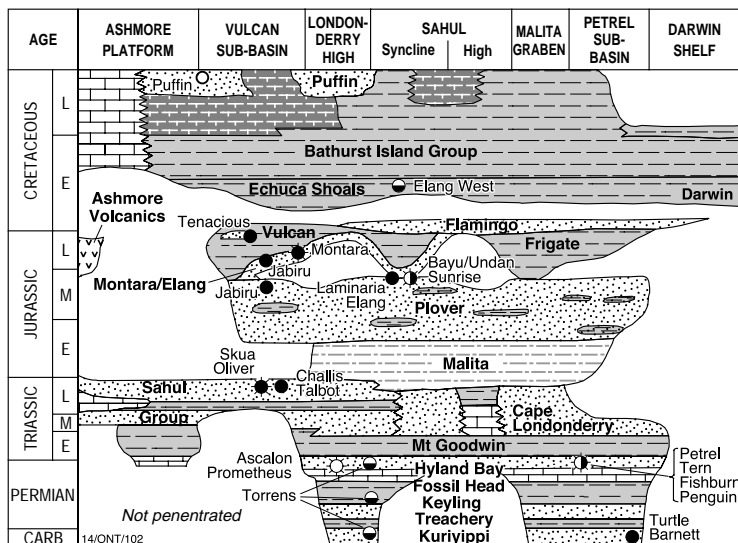


Figure 2. Generalised stratigraphy of the Bonaparte Basin

and sterane biomarker ratios, and pristane/phytane ratio).¹ Two Palaeozoic oil families are recognised in the Petrel Sub-basin, interpreted to be sourced by Carboniferous and Permian sediments. Seven Mesozoic oil families are currently recognised from the Bonaparte Basin, three of which are present in the Vulcan Sub-basin, and four in the northern part of the basin, in and adjacent to the Timor Gap Zone of Co-operation. The two oil families in the adjacent Browse Basin identified by Blevin et al. plot separately to those of the Bonaparte Basin.² It is apparent from the number of discrete oil families that there are many effective source units in the Bonaparte Basin.

Palaeozoic hydrocarbon families

Oils interpreted to be derived from the Lower Carboniferous Milligans Formation in the Petrel Sub-basin (Barnett, Turtle and Waggon Creek wells) are isotopically light ($\delta^{13}C$ values for the *n*-alkanes between -28 to -29 ‰) and have a slightly negative trend with increasing *n*-alkane number (figure 4). Their biomarker signatures are characterised by low pristane/phytane

ratios (Pr/Ph = 1.2), an abundance of rearranged hopane and steranes, and high sterane/hopane and tricyclic terpane/hopane ratios, which indicate generation from marine, anoxic, clay-rich source rocks.³

In contrast, the condensates from the Petrel and Tern Fields have heavy isotopic signatures ($\delta^{13}\text{C}_{\text{sat}} = -24\text{‰}$) and their *n*-alkane isotopic profiles exhibit a strong negative-slope. The *n*-alkane isotopic trends of the Tern-5 gases (C₁–C₅) are generally continuous with the *n*-alkane trends of the condensates, suggesting that the gases have the same source as the liquids. These heavy ¹³C enriched isotopic values of the gas/condensates are consistent with derivation from land-plant material, and this interpretation is supported by the high abundance of C₂₉ diasteranes. Geologically, the most likely source of these hydrocarbons are the Permian sediments of the Keyling and Hyland Bay Formations which are rich in land-plant remains and were deposited in coastal plain and deltaic environments, respectively.³

Dry gas from the Upper Permian Hyland Bay Formation in Kelp Deep-1 is extremely enriched in ¹³C, which is in keeping with generation from a land-plant-rich source rock that is now overmature. Its stratigraphic and structural position on the Sahul Platform also suggests a Permian origin.

The gas discoveries at Penguin-1 and Fishburn-1 in the Petrel Sub-basin, as well as Ascalon-1A and, most recently, Prometheus-1 on the Londonderry High (all reservoirised within the Upper Permian Hyland Bay Formation; figure 1), are also attributed to this Permian system.

Analysis of oil-bearing fluid inclusions in the Torrens-1 well on the Londonderry High indicates an interpreted 42-metre gross palaeo-oil column within the Permian Fossil Head Formation.⁴ Isotopic and biomarker profiles of a residual oil from this palaeo column (Core 2, Permian Fossil Head Formation) are comparable to the Petrel and Tern condensates (figure 4). This oil is thus also attributed to a Permian source.⁵⁻⁷ In contrast, the residual oil in Core 3 at Torrens-1 (Upper Carboniferous Kuriyippi Formation) has an isotopic signature similar to the Barnett and Turtle oils, and is interpreted to be derived from a Carboniferous source.

Oil-bearing fluid inclusions have also been interpreted to indicate a palaeo-oil column in the Upper Permian Hyland Bay Formation in Osprey-1 on the western margin of the Londonderry High.⁸ The strati-

graphic and structural setting of the Osprey-1 and Torrens-1 wells also supports the interpretation that these prior-oil accumulations were sourced from Permian sediments. This finding is significant because it indicates that a viable Permian oil play may be present across much of the Londonderry High.

Additional evidence of a viable Permian oil play in the Bonaparte Basin is suggested by the occurrence of clusters of interpreted oil slicks on Synthetic Aperture Radar (SAR) satellite scenes on the Ashmore Platform.⁹ These slicks overlie areas where Jurassic and Cretaceous source rock are known to be absent or immature. Based on the current state of knowledge of potential Triassic and Palaeozoic source rocks, these slicks most probably indicate an active, oil-prone Permian petroleum system.

New gas isotopic data indicate that the Permian system also extends into the eastern Browse Basin.¹⁰

Mesozoic hydrocarbon families in the Vulcan Sub-basin

In the Vulcan Sub-basin, two major oil families are recognised: one with a dominant marine source signature and the other with a dominant terrestrial source signature (figure 5). A third oil family comprises condensates with variable geochemical composition.

The Vulcan Sub-basin marine oil family comprises oils from the Puffin, Skua, Cassini, Challis, Talbot, Jabiru and Tenacious wells (figure 5). They have light isotopic signatures ($\delta^{13}\text{C}_{\text{sat}} = -27.5\text{‰}$) with the *n*-alkanes displaying a 'lazy-S' profile (figure 4). This type of isotopic profile is seen in many Upper Jurassic sourced oils on the North West Shelf and is characteristic of mixing low molecular weight *n*-alkanes of the oil fraction with the higher molecular weight components of a more mature gas.¹⁰ Whole oil chromatograms show that these oils have a unimodal *n*-alkane distribution with a maximum between C₁₀ and C₁₃ and intermediate Pr/Ph ratios (mean = 2.8), which are indicative of marine organic matter deposited in a sub oxic environment. Other source-dependent characteristics include a slight predominance of the C₂₉ homologue among the regular and rearranged steranes (C₂₉ > C₂₇ > C₂₈). A siliciclastic source lithology is indicated by the abundance of rearranged steranes and hopanes. Preliminary oil-source correlations indicate that these oils are derived from the Upper Jurassic Lower Vulcan Formation.

The Vulcan Sub-basin terrestrial-influenced oil family includes oils from Maret-1, Bilyara-1, Montara-1 and Oliver-1, all of which have relatively heavy isotopic signatures ($\delta^{13}\text{C}_{\text{sat}} = -25.5\text{‰}$). Whole oil chromatograms show that these oils have moderately high Pr/Ph ratios (2.4–6.2) and high wax contents, consistent with their derivation from land-plant organic matter. Diagnostic biomarker features include an abundance of C₂₉ sterane in comparison to the C₂₇ and C₂₈ homologues; diasteranes are more abundant than steranes. Rearranged hopanes are present, but in different relative amounts (e.g. C₂₉Ts/C₂₉ hopane ratio is lower) compared with the aforementioned marine oil family. The lower correlation co-efficient between the Oliver, Montara-Bilyara and Maret oils (figure 5) indicates derivation from several localised source units. The most likely source of these oils is the Lower–Middle Jurassic Plover Formation.

Condensates in the Vulcan Sub-basin—including those at Tahbilk-1, Eclipse-2 and Swan-1—show some variation in their geochemistry, and plot together as a separate family in figure 5. Data for these condensates were not used in the generation of the Bonaparte dendrogram (figure 3), because it is believed that their present composition is more reflective of reservoir alteration effects (such as leakage and gas flushing) rather than the type of organic matter in their source rocks.

Mesozoic hydrocarbon families in the northern Bonaparte Basin

The oils and condensates from the northern Bonaparte Basin fall into four families. The condensates from the Bayu–Undan Field and oils from the Elang and Kakatua Fields have a dominant marine signature, but plot as a separate family to the Vulcan Sub-basin marine oil family (figure 3). This is probably due to these oils originating from multiple marine-influenced source facies within the Middle Jurassic Plover Formation and Upper Jurassic Elang and Flamingo Formations.¹¹

The terrestrial-influenced oils from the Laminaria, Corallina, Buffalo and Jahal Fields make up a second oil family in the northern Bonaparte Basin. These oils probably also arise from several Jurassic source rocks, rich in land-plant remains.¹¹

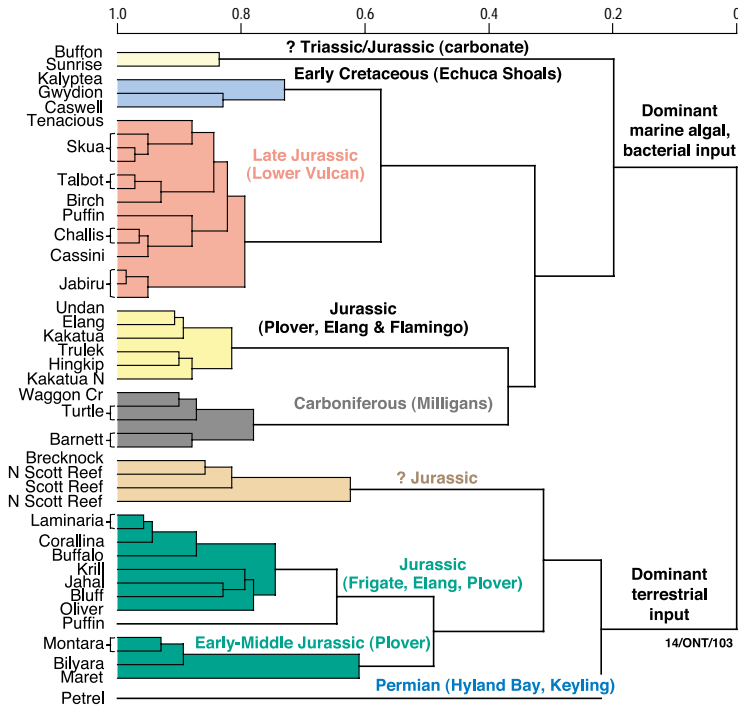


Figure 3. Oil family dendrogram showing the degree of compositional similarity between the oils/condensate of the Bonaparte and Browse Basins

The third oil family comprises condensate from the Sunrise Field. This condensate has a biomarker signature that is atypical of North West Shelf hydrocarbon accumulations in that it appears to have a marine carbonate origin, as demonstrated by the abundance of 30-norhopanes, with C₂₉ hopane being the dominant hopane. The only other known condensate in this region with similar composition is from Buffon-1 in the Browse Basin. These hydrocarbons are reservoirized within the Lower-Middle Jurassic Plover Formation, and may originate from pre-Jurassic source rocks. Alternatively, the carbonate signature in these condensates may originate from diesel contamination in the drilling muds; further work is required to resolve this issue of possible contamination.

A fourth oil family (not shown in figure 3), comprising the Elang West-1, Kakatua North-1 and Layang-1 oils (all reservoirized in the Lower Cretaceous

Darwin Formation), was recognised in the northern Bonaparte Basin by Preston and Edwards.¹¹ These oils have a marine clastic signature and have been correlated to the underlying Echuca Shoals Formation. Some similarity is seen between these oils and the Early Cretaceous oil family (Caswell-2 and Gwydion-1; figure 3) identified by Blevin and co-workers in the Browse Basin.²

Regional implications

These studies have identified numerous oil families and petroleum systems in the Bonaparte Basin, and highlight the fact that both Palaeozoic and Mesozoic source units are effective in the region.

The Permian system, previously known only as a gas/condensate system in the Petrel Sub-basin, has been shown to be more widespread and extends across the Londonderry High to the Sahul Platform and eastern Browse Basin. Fluid inclusion data indicates that this system has generated substantial palaeo-oil accumulations on the Londonderry High. Source rock data and

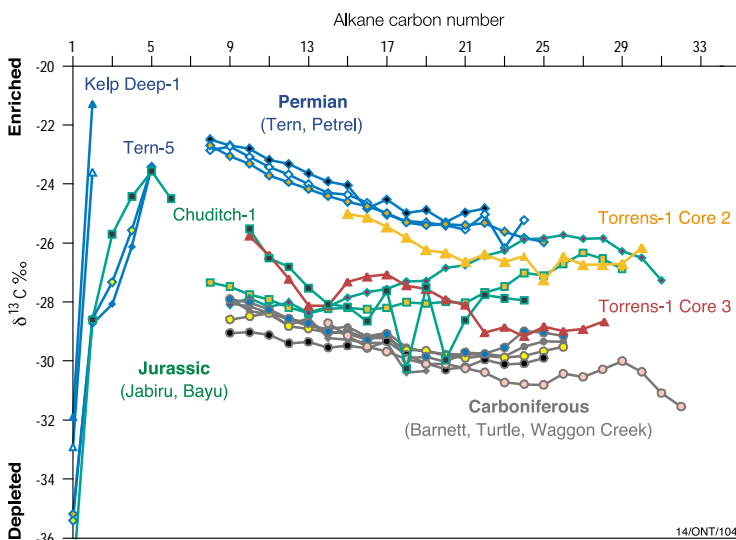
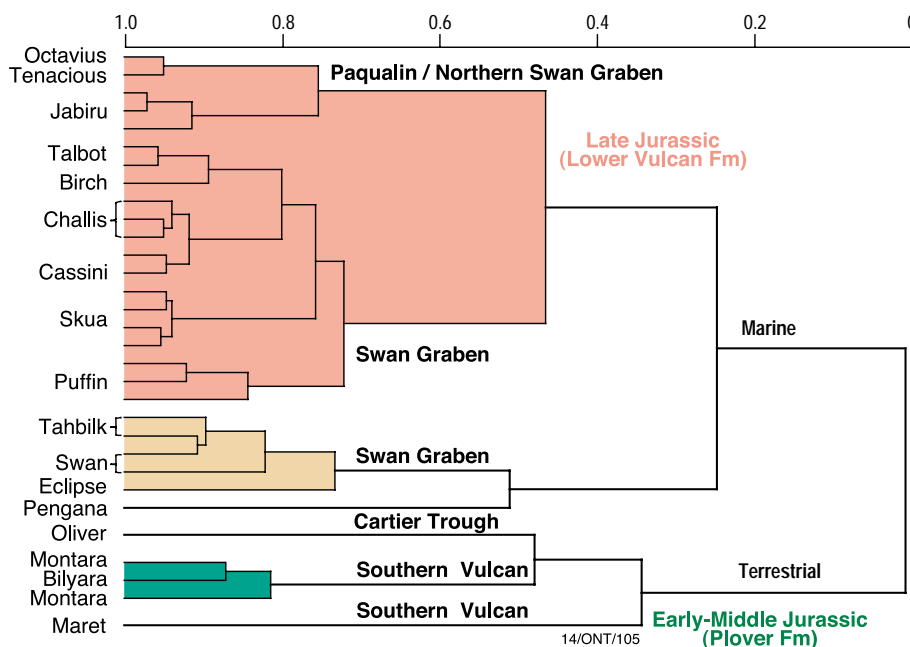


Figure 4. Plot of $\delta^{13}\text{C}$ versus carbon number for *n*-alkanes from selected Bonaparte gases, condensates and oils

Figure 5.
Dendrogram of
the Vulcan Sub-
basin oils and
condensates



palaeogeographic facies maps suggest that oil-prone coaly shales of the Lower Permian Keyling Formation probably extend across the Londonderry High and around the southern and north-eastern margin of the Petrel Sub-basin. The Permian system is untested on the Ashmore Platform, but oil potential here is suggested by the presence of interpreted SAR oil slicks.

Previous studies focusing on Mesozoic plays in the Bonaparte Basin have made the somewhat simplistic assumption that most hydrocarbon accumulations in the western and northern Bonaparte Basin have been charged from Upper Jurassic source rocks. Although this is true for the producing fields in the Vulcan Sub-basin, it is now apparent that there has been a significant contribution to hydrocarbon reserves in both the northern Bonaparte Basin and southernmost Vulcan Sub-basin from the Lower-Middle Jurassic Plover Formation. If plays can be identified where the timing of hydrocarbon generation and trap formation is more favourable to preserve Early-Middle Jurassic-derived liquids, then this system could add significant reserves to the region. Furthermore, non-Jurassic, oil-prone petroleum systems have now been identified in the Browse Basin (Gwydion-1, Caswell-2 and Cornea Field²) and northern Bonaparte Basin (Elang West-1),

both of which are sourced from Lower Cretaceous marine mudstones.

An additional (?) Early Mesozoic petroleum system may be indicated by the condensates at the Sunrise Field and Buffon-1 near the outer margins of the Australian plate. These condensates have a distinctive, marine carbonate biomarker signature, and may form part of the oil-prone Late Triassic–Early Jurassic carbonate system known in the Australian–Banda boundary complex to the north.¹² This carbonate system includes oils from the islands of Buton, Buru, Seram and Timor, and may also be prospective along the outer margin of the Bonaparte–Browse Basins.

In summary, the Bonaparte Basin has greater hydrocarbon potential than is currently recognised since several other source units besides the well-known Upper Jurassic marine mudstones are also capable of generating liquid hydrocarbons.

References

1. AGSO & GeoMark Research. 1996. The oils of Western Australia. Canberra & Houston; unpublished proprietary report.
2. Blevin JE, Boreham CJ, Summons RE, Struckmeyer HIM & Loutit TS. 1998. An effective Early Cretaceous petroleum system on the North West Shelf: Evidence from the Browse Basin. In: Purcell PG & RR, eds. The sedimentary basins of Western Australia 2: Proceedings of Petroleum Exploration Society of Australia Symposium, Perth; 397–420.
3. Edwards DS, Summons RE, Kennard JM, Nicoll RS, Bradshaw J, Bradshaw M, Foster CB, O'Brien GW & Zumberge JE. 1997. Geochemical characterisation of Palaeozoic petroleum systems in north-western Australia. APPEA Journal; 37(1): 351–79.
4. Lisk M & Brincat MP. 1998. Oil migration history of the west Bonaparte margin. Canberra: CSIRO confidential report 98-040; unpublished.
5. Summons RE, Bradshaw M, Crowley J, Edwards DS, George SC & Zumberge JE. 1998. Vagrant oils: Geochemical signposts to unrecognised petroleum systems. In: Purcell PG & RR, eds. The sedimentary basins of Western Australia 2: Proceedings of Petroleum Exploration Society of Australia Symposium, Perth; 169–184.
6. Passmore VL, Edwards DS & Kennard JM. 1999. [abstract]. Enhanced Permian-Triassic prospectivity in the Timor Sea provided by a new Paleozoic petroleum system. AAPG annual meeting, San Antonio, Texas, Apr 11–14; A105.

7. Ruble TE, Edwards DS, Lisk M, et al. 2000. Geochemical appraisal of palaeo-oil columns: implications for petroleum systems analysis in the Bonaparte Basin, Australia. AAPG Annual Meeting, New Orleans, Louisiana, Apr 16–19.
8. Lisk M, Brincat MP, Eadington PJ & O'Brien GOB. 1998. Hydrocarbon charge in the Vulcan Sub-basin. In: Purcell PG & RR, eds. The sedimentary basins of Western Australia 2: Proceedings of Petroleum Exploration Society of Australia Symposium, Perth; 287–302.
9. O'Brien GW, Lawrence G, Williams A, Webster M, Lee J & Burns S. 2000. Hydrocarbon migration and seepage in the Timor Sea and northern Browse Basin North West Shelf, Australia: an integrated SAR, geological and geochemical study. Canberra: AGSO, Nigel Press & Associates, RadarSat International, AUSLIG (Australian Centre for Remote Sensing).
10. Boreham CJ, Hope JM & Hartung-Kagi B. 2001. Understanding source, distribution and preservation of Australian natural gas: a geochemical perspective. APPEA Journal; 40 (1): in press.
11. Preston JC & Edwards DS. 2000. The petroleum geochemistry of oils and source rocks from the northern Bonaparte Basin, offshore northern Australia. APPEA Journal; 40 (1): 257–282.
12. Sykora JJ. 2000. The buried fold-thrust belt of offshore Seram. [abstract]. American Association of Petroleum Geologists International Conference and Exhibition, Bali, Oct 15–18.

- Dianne Edwards, Petroleum and Marine Division, AGSO, phone +61 2 6249 9782 or e-mail dianne.edwards@agso.gov.au
- John Kennard, Petroleum and Marine Division, AGSO, phone +61 2 6249 9204 or e-mail john.kennard@agso.gov.au
- Jim Preston, BHP Petroleum Pty Ltd, 600 Bourke Street, Melbourne, Victoria 3000
- Dr Roger Summons, Petroleum and Marine Division, AGSO, phone +61 2 6249 9515 or e-mail roger.summons@agso.gov.au
- Chris Boreham, Petroleum and Marine Division, AGSO, phone +61 2 6249 9488 or e-mail chris.boreham@agso.gov.au
- John Zumberge, GeoMark Research, 9748 Whithorn Drive, Houston, Texas 77095, USA 🌐

Hydrocarbon seepage in Carnarvon Basin subject of major study

AGSO and its partners, Signalworks Pty Ltd and Nigel Press & Associates are investigating hydrocarbon leakage and seepage in the Carnarvon Basin (figure 1). The study is using several independent remote-sensing technologies, namely:

- double-coverage RadarSat Synthetic Aperture Radar (SAR). SAR is effective for mapping oil-prone leakage and seepage;
- 20 000 kilometres of reprocessed Mark III Airborne Laser Fluorosensor (ALF) data. ALF effectively maps oil and condensate leakage and seepage. Interpretations from reprocessing BP regional legacy Mark II ALF data through the area are also being used, as are BP's original interpretations from the Mark II ALF surveys;
- more than 2000 kilometres of water column geochemical sniffer (WaSi) data, which detects oil, condensate and gas leakage and seepage; and
- Landsat data.

The interpretations derived from these technologies (i.e. SAR, WaSi, ALF and Landsat) are being compared and contrasted, and then integrated with regional seismic data, isopach maps of key reservoir, source and sealing units, and fault maps.

The goals of the study are to:

1. provide a soundly based understanding of the relative responses of these technologies to different types and rates of hydrocarbon seepage; and
2. determine the nature of, and principal controls on, hydrocarbon seepage within the Carnarvon Basin.

Lessons learnt in the Carnarvon Basin, and from a recently completed similar study in the Timor Sea, will be applied to evaluations of frontier exploration areas around Australia.

For more information about the study phone Dr Geoff O'Brien on +61 2 6249 9342 or e-mail geoff.obrien@agso.gov.au 🌐



Figure 1. Study area of seepage investigation, Carnarvon Basin, North West Shelf. Area covered by BP ALF data (now reprocessed) is shown in red; area covered by Fugro ALF survey (now reprocessed) is shown in blue. Water column geochemical sniffer data covers parts of the basin.