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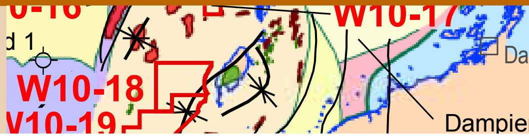
New opportunities for offshore petroleum exploration



2010 Acreage Release offers blocks in producing regions and in frontier areas

Thomas Bernecker

Each year, the Australian Government formally releases new offshore exploration areas at the annual Australian Petroleum Production and Exploration Association (APPEA) conference. The 2010 release of offshore petroleum exploration areas was announced on 17 May in Brisbane by The Hon. Martin Ferguson AM MP, Minister for Resources and Energy.

This year, 31 areas in five offshore basins were released for work program bidding. Closing dates for bid submissions are either six or twelve months from the release date, that is, 11 November 2010 or 12 May 2011 respectively, depending on the exploration status in these areas and the extent of available data. The 2010 Release Areas are located in Commonwealth waters off the Northern Territory, Western Australia and South Australia, and include intensively explored areas close to existing production as well as new frontier basins (figure 1). The Westralian Superbasin along the North West Shelf, comprising the Bonaparte, Browse, Roebuck and Carnarvon basins, continues to feature prominently in the 2010 Release. These areas are complemented by a new frontier area in offshore southwestern Australia (Mentelle Basin) and by two areas in the Ceduna/Duntroon sub-basins in the eastern part of the Bight Basin, off South Australia.

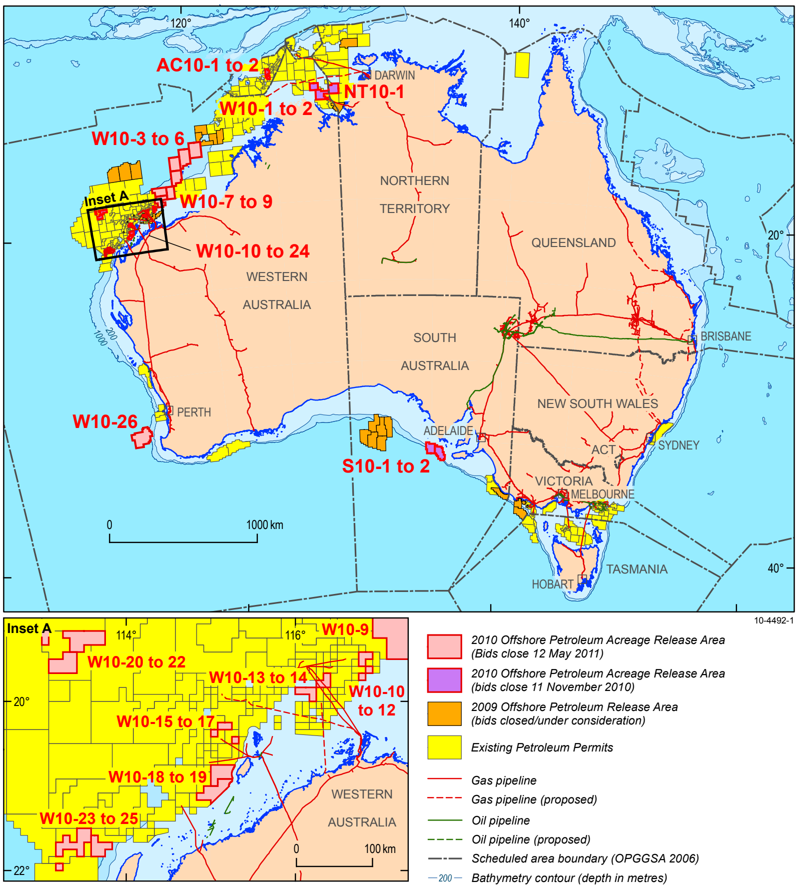


Figure 1. Location map showing the 2010 Offshore Petroleum Acreage Release Areas.

Bonaparte Basin

The Bonaparte Basin is predominantly offshore and covers an area of approximately 270 000 square kilometres on Australia's northwest continental margin. The basin contains up to 15 000 metres of Phanerozoic marine and fluvial sediments and is structurally subdivided into several Paleozoic and Mesozoic sub-basins and platform areas. Several proven petroleum systems for both oil and gas are known to exist in the basin (Barrett et al 2004). For 2010, three Release Areas have been gazetted within the Petrel Sub-basin and two areas within the Vulcan Sub-basin (figure 2).

Release Areas NT10-1, W10-1 and W10-2 are located in the Joseph Bonaparte Gulf, about 400 kilometres southwest of Darwin, in water depths ranging from 10 to 40 metres. The three areas are in the vicinity of the Petrel, Tern and Blacktip gas accumulations (figure 2). Gas from Blacktip is piped to Darwin via the onshore plant near Wadeye and the Bonaparte trans-territory pipeline. This pipeline connects to an existing pipeline, transporting gas from the Amadeus Basin to Darwin.

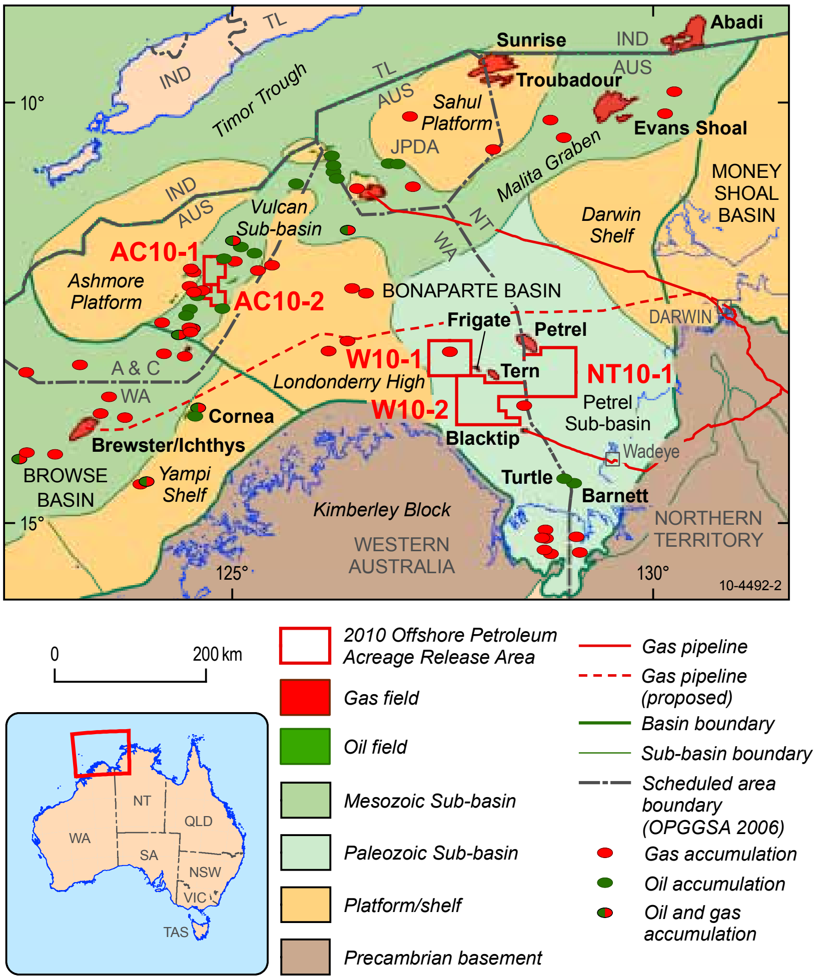


Figure 2. Structural elements map of the Bonaparte Basin showing location of the 2010 Release Areas and petroleum accumulations.

At least two Permian petroleum systems are considered viable in the central Petrel Sub-basin and it is the wide distribution of salt and related tectonism that dominates exploration play types. The key exploration uncertainties in the 2010 Release Areas appear to be the absence of a proven oil-prone system in the central Petrel Sub-basin, and the small number of suitably sized trap closures for economic gas accumulations. However, the overall prospectivity of the three Release Areas is highlighted by the distribution of commercial gas accumulations in Upper Permian and Lower Triassic sandstones, of which Blacktip has been put into production. Plans for future gas developments in the Petrel Sub-basin have been developed, and any new discovery could potentially be commercialised within a short timeframe.

Release Areas AC10-1 and AC10-2 are located approximately 650 kilometres west of Darwin in the Timor Sea, within Australia's Territory of Ashmore and Cartier Islands (figure 2). Both Release Areas lie in the central Vulcan Sub-basin on the continental shelf where water depths are generally less than 200 metres. The Vulcan Sub-basin is a proven hydrocarbon province containing producing and decommissioned oil fields in addition to oil and gas discoveries that are presently undeveloped. Recent discoveries in the area include Padthaway (2000), Audacious (2001), Katandra (2004) and Vesta (2005). Currently, oil is produced from the Jabiru, Challis-Cassini and Puffin fields, while the Montara, Skua and Swift-Swallow accumulations will have a linked development. Accumulations in the sub-basin generally range between 10 and 50 million barrels (MMbbl) or 1.6–7.9 million cubic metres (Mm^3) and are produced via subsea wellheads and tiebacks to Floating Production Storage and Offloading (FPSO) vessels.

The main exploration targets in the Vulcan Sub-basin are sandstones in the Upper Triassic Challis and Nome Formations, fluvio-deltaic sandstones of the Middle Jurassic Plover Formation, Oxfordian shoreface/barrier bar sandstones of the Montara Formation, Tithonian submarine fans of the upper Vulcan Formation and submarine fans of the Upper Cretaceous Puffin Formation. The Cretaceous and Tithonian sandstones generally have excellent to good reservoir qualities respectively, whereas reservoir quality is assessed as good to locally poor within the intersected Middle Jurassic and Triassic sections.

Rowley Sub-basin, Roebuck Basin

The Roebuck Basin, located between the Browse and Carnarvon basins, covers approximately 160 000 square kilometres on the central North West Shelf. It contains the Bedout and the Rowley sub-basins in which sediments disconformably overlie the Paleozoic intracratonic succession of the Oobagooma Sub-basin (figure 3), an offshore extension of the Fitzroy Trough. The four Release Areas (W10-3 to W10-6) extend across the central part of the Rowley Sub-basin which is a westward-thickening upper Paleozoic–Mesozoic depocentre (or area of thickest deposition).

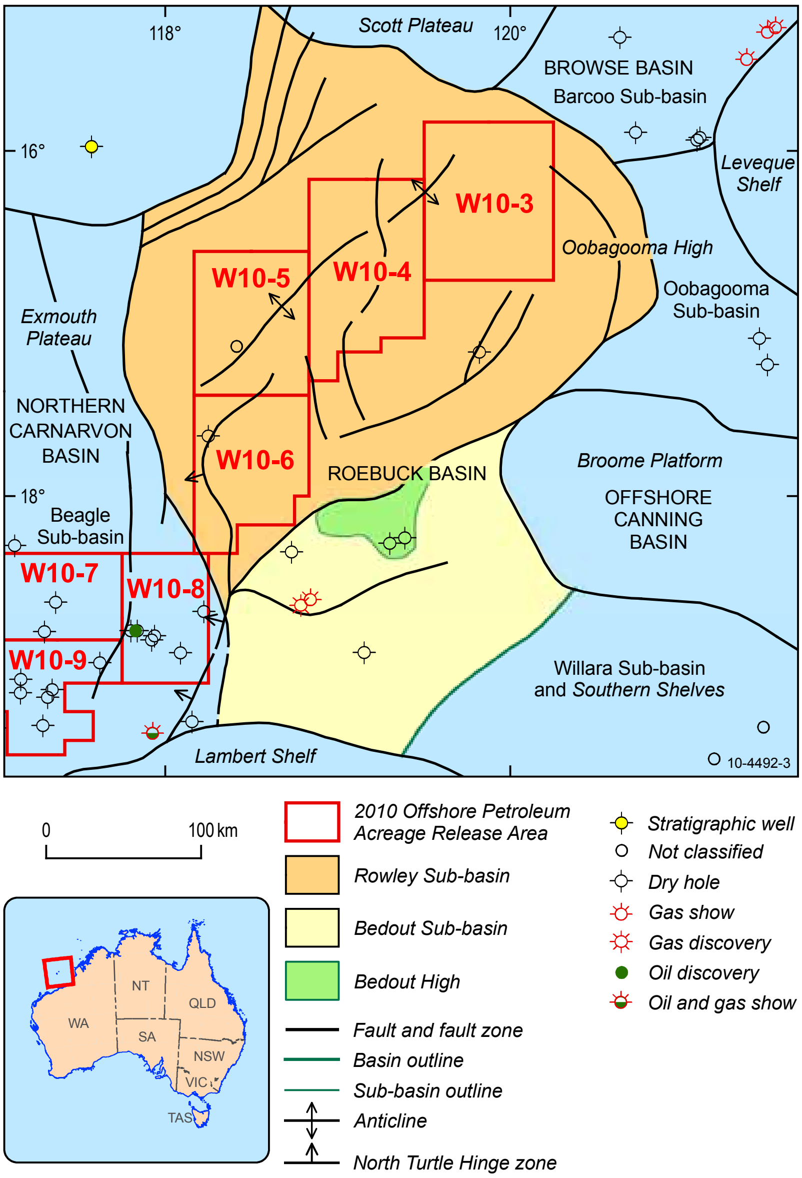


Figure 3. Structural elements of the Roebuck Basin (after Smith et al 1999).

Well control is limited to nine wells in the entire Roebuck Basin, none of which was commercially successful. The only significant hydrocarbon shows were recorded by Phoenix 1 and Phoenix 2 in the northern Bedout Sub-basin (figure 3). The coaly Triassic Locker Shale and parts of the Keraudren Formation are considered the source rock intervals for the gas occurrences in the Phoenix wells. Potential reservoirs occur at several stratigraphic levels including sandstones within the Permian Grant Group, shoreward facies of the Triassic Keraudren Formation and Locker Shale, as well as sandy deltaic facies in the Lower Cretaceous. The Keraudren Formation and the Locker Shale also provide intraformational seals.

Several stratigraphic plays have been proposed for exploration in the Rowley Sub-basin and encompass Triassic onlap and Jurassic fluvio-deltaic complex plays. For these, hydrocarbon charge is proposed to be derived from either intraformational or underlying source rocks (Smith et al 1999). In addition to stratigraphic plays, there is potential for various structural traps developed along several largely untested fault trends within the sub-basin.

The main exploration uncertainty appears to be effective hydrocarbon generation. However, widespread distribution of oil inclusions in the Roebuck Basin, including in East Mermaid 1, may be indicative of paleo-oil columns and evidence of petroleum generation within the Rowley Sub-basin. It is therefore possible that the application of new concepts to these Release Areas may translate to exploration success.

Northern Carnarvon Basin

The Carnarvon Basin is the southernmost province of the Late Paleozoic to Cenozoic Westralian Superbasin that underlies the northwestern continental margin of Australia from the Exmouth Plateau in the south to the Arafura Sea in the north. The northern offshore Carnarvon Basin contains about 15 000 metres of mainly Mesozoic sediments dominated by deltaic to marine siliciclastics and shelf carbonates. The basin is one of Australia's most explored and prospective and has ready access to established oil and gas exploration, production and support infrastructure (figure 4). The Australian Energy Resource Assessment (Geoscience Australia and ABARE 2010) shows that more than half of Australia's demonstrated resources of conventional gas (94 out of 164 trillion cubic feet or Tcf) are in the Carnarvon Basin as well as more than 40 per cent of the remaining oil (crude, condensate) and LPG. The 2010 Release Areas (figure 5) are located in the Beagle Sub-basin (three areas), Dampier Sub-basin (five areas), Barrow Sub-basin (five areas), Exmouth Plateau (three areas) and Exmouth Sub-basin (three areas).

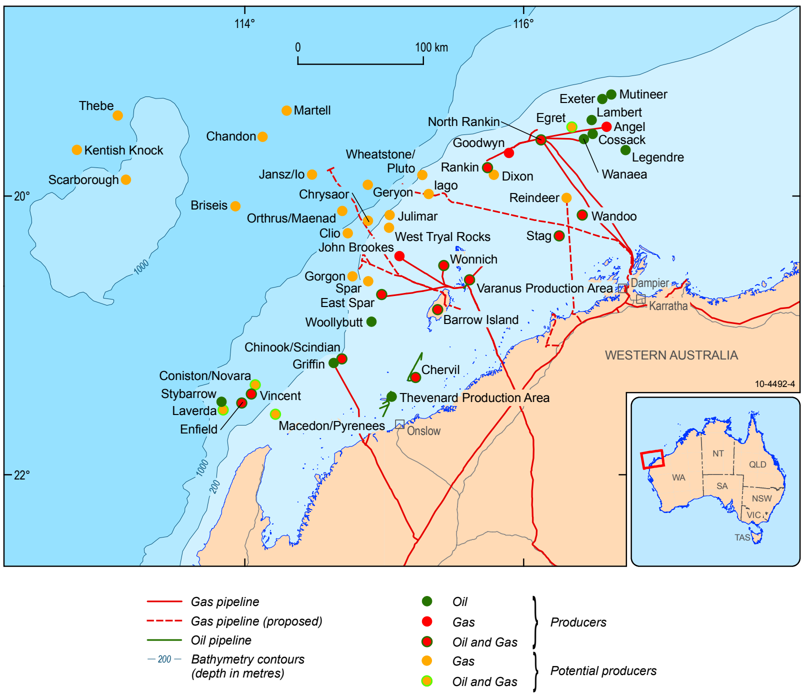


Figure 4. Oil and gas accumulations, production infrastructure and pipelines in the Northern Carnarvon Basin

Beagle Sub-basin

The Beagle Sub-basin is located between the Dampier Sub-basin to the southwest, and the Rowley and Bedout sub-basins of the Roebuck Basin, to the northeast and east, respectively (figure 5). Although previously considered as part of the offshore Canning Basin, close chronostratigraphic similarities with the Dampier Sub-basin sequences support its inclusion in the northern Carnarvon Basin framework.

Release Areas W10-7, W10-8 and W10-9 are located between 140 and 300 kilometres north-northeast of Dampier. Water depths across the areas deepen gradually from 50 metres in the southeast up to 1000 metres in the northwest. Exploration in the Beagle Sub-basin began in 1965 with regional seismic, gravity and magnetic surveys. Drilling started in 1971 and 25 wells have been drilled since then. No commercial accumulations of hydrocarbons have been encountered, and Nebo 1 (figure 5) drilled in 1993, is the only significant discovery.

The discovery of oil in Calypso Formation sandstones at Nebo 1 demonstrated the presence of an active petroleum system within the southern Thouin Graben of the Beagle Sub-basin. The dominant exploration play types for the Beagle Sub-basin are tilted fault-bounded sequences within, and along, the trans-tensional Triassic-Jurassic horsts. Basin floor sands developed after Late Jurassic break-up along the edges of elevated horsts may also represent valid plays. Structural highs hosting Upper Jurassic reservoir sandstones are also a proven play type developed within the troughs (Nebo 1 within the Thouin Graben). For these, the regionally extensive Lower Cretaceous Muderong Shale/Forestier Claystone would act as the main sealing facies. Although regional tectonic reactivation is likely to have impacted on fault-seal integrity and may have affected the configuration of migration pathways, the fact that a proven petroleum system is in operation, should encourage explorers to have a closer look the Beagle Sub-basin.

Dampier Sub-basin

The Dampier Sub-basin contains a late Paleozoic to Cenozoic sedimentary succession over 10 kilometres thick that is dominated by Triassic to Lower Cretaceous sediments. Thick successions of Jurassic oil-prone sediments underlain by faulted gas-prone Triassic sediments occur in the deeper depocentres. The five areas included in the 2010 Release lie in relatively shallow water (around 100 metres) and are located close to major oil and gas accumulations on the Rankin Platform (figure 5) and to the commercial Angel, Wanaea, Cossack and Legendre fields. To date, more than 200 exploration and development wells have been drilled in the Dampier Sub-basin with a technical success rate of 41 per cent. Three wells are located within the release areas: Patriot 1 and Pleiades 1 in Release Area W10-10, and Dampier 1 in Release Area W10-14.

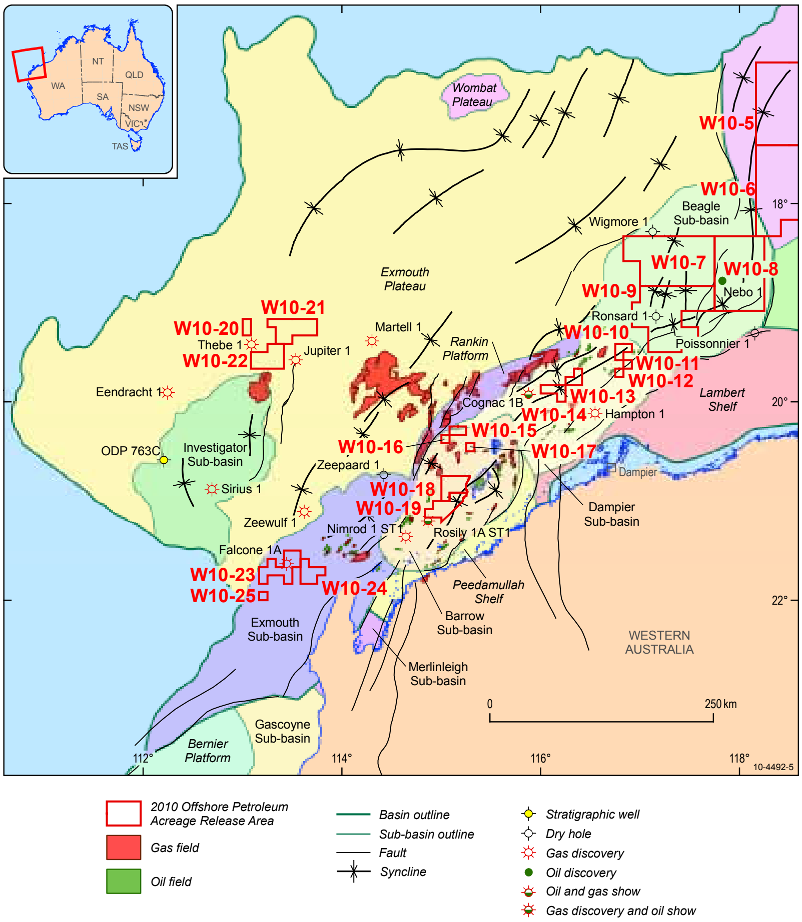


Figure 5. Structural elements of the Northern Carnarvon Basin and adjacent basins showing the 2010 Release Areas, oil and gas accumulations and selected wells.

Hydrocarbon accumulations in the Dampier Sub-basin occur at multiple stratigraphic levels from the Triassic to the Cretaceous, commonly as stacked pay sections. The main hydrocarbon source rocks occur within the Lewis and Kendrew troughs. Two proven petroleum systems are recognised on the basis of geochemical studies (Boreham et al 2001; Edwards et al 2007): a gas-prone system sourced from Triassic to Middle Jurassic fluvio-deltaic sediments and an oil-prone system sourced from Upper Jurassic marine sediments.

Exploration plays are quite diverse in the Dampier Sub-basin and mainly involve drape anticlines, such as Wandoo and Stag, and horst structures, such as Wanaea, Cossack, Mutineer and Egret. The potential for stratigraphic traps has long been recognised within the Dampier Sub-basin (Barber 1994) and related plays can now be tested with the application of improved 3D seismic technologies and third-order sequence stratigraphic analysis. Although the Dampier Sub-basin is a prolific hydrocarbon province, several exploration uncertainties need to be recognised. For instance, the entrapment and preservation of oil and gas accumulations varies across the sub-basin and diagenetic overprints in deeply seated reservoirs are known to affect permeabilities, as identified in Lynx 1A. However, the success rates in this part of the Carnarvon Basin highlight the Dampier Sub-basin as a prime exploration province.

Barrow Sub-Basin

The Barrow Sub-basin, located southwest of the Dampier Sub-basin (figure 5) has been actively and continuously explored since the 1960s. Oil was found in several zones in Cretaceous sediments in Barrow Island wells drilled in 1964, and production facilities have been established on Varanus Island. Release Areas W10-15 and W10-16 are located in the northeast-trending Tryal Rocks Terrace, which contains the John Brookes gas field, while Release Areas W10-17, W10-18 and W10-19 are located over the western edge of the Barrow depocentre.

The oil and gas fields that surround Release Areas W10-15 to W10-19 demonstrate that the area is highly prospective. There are proven plays at Triassic, Middle–Upper Jurassic, Lower Cretaceous and Paleocene levels. Within the Barrow Sub-basin, oil has accumulated primarily in the Barrow Group and the Windalia Sandstone Member of the Muderong Shale, within the post-breakup megasequence. The Lower Cretaceous Barrow Group has excellent reservoir characteristics, and Upper Cretaceous and middle Miocene faulted anticlines provide structural traps.

Gas charge appears to be pervasive throughout the region containing the Release Areas so that trap geometry, reservoir occurrence and quality are the main uncertainties. Overpressuring has been identified within the thick Jurassic section and within parts of the Cretaceous Barrow Group and is likely to be related to the presence of gas-generating organic matter at depth (He and Middleton 2002). Such zones of overpressure are an exploration uncertainty and a drilling hazard. Despite those uncertainties, the Barrow Sub-basin remains one of the most successful hydrocarbon provinces not only along the North West Shelf, but within Australia's offshore area.

Exmouth Plateau

The Exmouth Plateau is a deep-water marginal plateau that represents the western structural element of the Northern Carnarvon Basin. Most of the plateau is underlain by 10 to 15 kilometres of generally flat-lying or block faulted, tilted Lower Cretaceous, Jurassic, Triassic and older sedimentary section. These sediments were deposited during the periods of extension that preceded the break-up of Australia and Argo Land in the Middle Jurassic, and then Greater India in the Early Cretaceous.

Release Areas W10-20, W10-21 and W10-22 are located in deep water (900 to 1200 metres) about 300 kilometres off the coast of Western Australia, on the central portion of the Exmouth Plateau (figure 5). Gas production facilities are currently being developed for the nearby Chevron-operated Gorgon and Jansz–Io fields, and Woodside-operated Pluto field. ExxonMobil and BHP Billiton are currently examining development options for the Scarborough and Thebe fields. The super-giant Jansz–Io gas field, giant Scarborough gas field, and the Jupiter 1 and Eendracht 1 gas discoveries, together with the recent gas discoveries in the Chandon 1, Thebe 1 and 2, Martell 1, Glencoe 1, Nimblefoot 1, Briseis 1 and Kentish Knock 1 wells, demonstrate that the deep-water central Exmouth Plateau is prospective for large gas accumulations. All these discoveries are attributed to a widespread regional gas system sourced from the Triassic succession.

The main exploration play types involve rotated, high-relief Triassic fault blocks associated with drape features and deeper intra-Triassic cross-fault traps. Upper Triassic (Rhaetian) pinnacle and patch reefs, such as those intersected in the Ocean Drilling Program holes on the Wombat Plateau on the northern margin of the Exmouth Plateau, have also recently been identified on new 3D data across parts of the central Exmouth Plateau. They represent a potential new play in the region that has yet to be tested. Given that a proven hydrocarbon system has already been established across the central Exmouth Plateau, continued success relies on the identification of additional valid traps with access to charge from the gas-prone Mungaroo source. 3D seismic and AVO technology (see *AusGeo News* Issue 84) are thus key exploration tools that are likely to contribute to continued exploration success on the deep-water Exmouth Plateau.

Exmouth Sub-basin

Along with the Barrow, Dampier and Beagle sub-basins, the Exmouth Sub-basin formed as a series of northeast–southwest-trending, *en echelon* structural depressions during the Pliensbachian to Oxfordian. The pre-rift section in the Exmouth Sub-basin consists of a sequence of Permian and Lower to Middle Triassic sediments. The Locker Shale was deposited in shallow shelf environments during a widespread Early Triassic marine transgression which is recognised all along the western Australian margin from the Bonaparte Basin to the Perth Basin. Release Areas W10-23, W10-24 and W10-25 are located in the western Exmouth Sub-basin and Release Areas W10-23, W10-24 and W10-25 lie approximately 20 to 85 kilometres offshore from North West Cape on the Western Australian coastline (figure 5) where water depths rapidly increase to over 1000 metres.

Two petroleum systems are prospective in the Release Areas. The extensive Locker/Mungaroo–Mungaroo/Barrow petroleum system, which has sourced some of the giant gas fields in the Northern Carnarvon Basin, was proven with the discovery of gas in the Mungaroo Formation at Falcone 1A. Accumulations of the productive Dingo–Barrow petroleum system of the Exmouth Sub-basin lie about 20 to 30 kilometres to the northeast of the Release Areas. The Triassic sedimentary succession has proven potential for mature source facies, including possible organic-rich units in the Lower Triassic (marine Locker Shale equivalents) and Upper Triassic (deltaic Mungaroo Formation facies and marine equivalents). The Upper Jurassic Dingo Claystone is the principal source for oil in the Exmouth Sub-basin.

The proven traditional Triassic fault block play, which hosts most of the hydrocarbon reserves in the Northern Carnarvon Basin, extends into the Release Areas. Mungaroo Formation sandstones in fault-block traps are sealed by either the Dingo Claystone or intraformational seals. The gas accumulation at Falcone 1A, within Release Area W10-23, is an example of this play type. Barrow Group sandstones sealed by Muderong Shale or interbedded claystone units in stratigraphic and structural traps are the other targets. The oil and gas fields in the Exmouth Sub-basin are examples of these play types.

Mentelle Basin

The Mentelle Basin is a large (36 400 square kilometre) frontier basin on the southwest Australian margin located approximately 120 kilometres from Bunbury. It lies to the west of the Perth Basin which has shared tectonic and depositional histories. The 2010 Acreage Release comprises one large block in this offshore frontier (figure 1). As part of Geoscience Australia's Offshore Energy Security Program, new seismic data was acquired in 2008–09 to improve the understanding of the major sequences and structural elements. The results of the Mentelle Basin study, including the assessment of the hydrocarbon prospectivity, are described in the article by Borissova et al in this issue.

Bight Basin

The Jurassic–Cretaceous Bight Basin is a large, mainly offshore basin situated along the western and central parts of the continental margin of southern Australia, in water depths ranging from less than 200 metres to over 4000 metres. The basin contains five main depocentres—the Ceduna, Duntroon, Eyre, Bremer and Recherche sub-basins. The Release Areas S10-1 and S10-2 are located in the easternmost part of the Bight Basin, covering large parts of the Duntroon Sub-basin and minor parts of the Ceduna Sub-basin (figure 6).

In nearly 50 years of exploration in the offshore Bight

Basin, less than 100 000 line-kilometres of seismic data have been acquired and only 10 petroleum exploration wells have been drilled. The majority of these wells were drilled in water depths of less than 250 metres along the margins of the basin, where the source rock quality of mid- to Upper Cretaceous marine deposits has been reduced by the influx of terrigenous organic matter into proximal depositional facies. Prior to the drilling of Gnarlyknots 1A in 2003, most exploration drilling in the Bight Basin was focused around the inboard margin of the Ceduna Sub-basin or in the half-graben systems of the Eyre and Duntroon sub-basins. Seismic and sequence stratigraphic interpretation, as well as biostratigraphic and sedimentological studies, indicate that most wells penetrated the proximal parts of the Cretaceous depositional systems. Therefore, organic geochemical data from the wells provides information about the source rock potential of these proximal facies.

"This year's Acreage Release caters for the whole gamut of exploration companies…"

The thick Jurassic to Cretaceous succession in the Ceduna and Duntroon sub-basins contains a number of source intervals consisting of marine and non-marine carbonaceous shale, coal and oil shale. They were deposited in a variety of lacustrine, deltaic and marine environments and form good to excellent quality potential source rocks that have the potential to generate hydrocarbons (Totterdell et al 2008; Boreham 2009). Most data on reservoir rocks in the Bight Basin are from wells in the Duntroon Sub-basin and southeastern Ceduna Sub-basin. Reservoir quality across the basin varies from poor to excellent and is dependent on paleoenvironmental conditions and depth of burial.

One of the key risks identified prior to the most recent exploration phase was the possible lack of an effective source rock and thus adequate hydrocarbon charge. This risk has been significantly reduced by the sampling and identification of a high quality marine source rock of Cenomanian to Turonian age (Totterdell et al 2008) and the identification of a number of encouraging bright amplitude anomalies on seismic sections. Given the under-explored status of the Duntroon and Ceduna sub-basins, both 2010 Release Areas offer opportunities to pursue current exploration concepts.

In summary, the 2010 Offshore Acreage Release offers a wide variety of block sizes in shallow as well as deep water environments. Area selection has been undertaken in consultation with industry and the state and Northern Territory geoscience agencies. This year's Acreage Release caters for the whole gamut of exploration companies given that many areas are close to existing infrastructure while others are located in frontier offshore regions.

Figure 6. Structural elements of the eastern Bight Basin showing 2010 Release Areas and wells drilled.

For more information on the 2010 release areas

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To book into the 2010 Acreage Release Data Room visit

Offshore Petroleum Acreage Release Data Room
www.ga.gov.au/about-us/facilities/acreage-release-data-room.jsp

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Related articles/websites

2010 offshore petroleum exploration areas (Department of Resources, Energy and Tourism)

www.ret.gov.au/Documents/par/index.html

Data supporting the 2010 acreage release (Seismic data is available in GeoFrame™, Kingdom and Landmark™ formats)

ausgeodata@ga.gov.au

Associated well data

biu@ga.gov.au

AusGeo News 84: Reprocessing shows AVO potential for petroleum exploration

www.ga.gov.au/ausgeonews/ausgeonews200612/index.jsp

AusGeo News 98: First acreage release in frontier Mentelle Basin

www.ga.gov.au/ausgeonews/ausgeonews201006/mentelle.jsp