APRIL 2011

PETROLEUM IN WESTERN AUSTRALIA

WESTERN AUSTRALIA'S DIGEST OF PETROLEUM EXPLORATION, DEVELOPMENT AND PRODUCTION

Contents

Climbing the derrick, Rig 826, at Red Gully 1
(Photo courtesy of Karina Jonasson)

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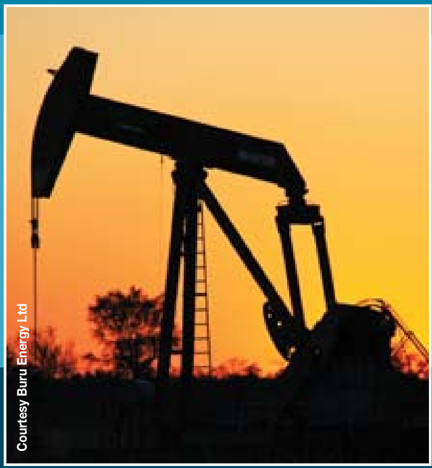
Cover Photo: Well testing on the *Jack Bates* at Glenloth 1 in WA-390-P by Hess Exploration Australia
(Photo courtesy of Kai Photography and Hess Exploration)

Government of **Western Australia**
Department of **Mines and Petroleum**

WESTERN AUSTRALIA

Opportunities to Explore

BIDS INVITED FOR ACREAGE



PETROLEUM ACREAGE

Northern Carnarvon Basin

There are two release areas in the highly prospective offshore Northern Carnarvon Basin. An area adjacent to the giant Barrow Island oilfield is 136 km^2 in size. A combined release area to the southwest is 1,128 km^2 in size.

Officer Basin

There are two release areas in the Blake Sub-basin of the Neoproterozoic Officer Basin. These are very large areas – 30,795 km^2 and 30,097 km^2. Oil fluorescence has been encountered in the Boondawari 1 and Mundadjini 1 stratigraphic coreholes. The Goldfields Gas Transmission Pipeline skirts the western edge of these release areas.

Canning Basin

A release area on the Lennard Shelf is 4,091 km^2 in size. Hydrocarbon shows are widespread on the Lennard Shelf, with economic accumulations of oil immediately southeast of the release area. These accumulations are found in a Devonian carbonate reef and in Permian-Carboniferous clastics.

Along the northeast margin of the basin there are two release areas, 7,787 km^2 and 5,809 km^2 in size. There are a variety of plays in these areas such as Ordovician, Devonian and Carboniferous reservoirs, most notably with a lower Carboniferous source.

A release area 50 km east of Broome is 2,033 km^2 in size. The Broome Platform has Ordovician sourced plays including migration into Permian reservoirs and has some shale gas potential. On the Mowla and Jurgurra Terraces there are plays involving thick Devonian and Carboniferous successions, with a lower Carboniferous source.

Perth Basin

There is one area in the coastal waters of the northern Perth Basin. The area is 1,331 km^2 in size. The northern Perth Basin has numerous seismic lines, wells, and oil and gas production from Permian reservoirs. Two gas pipelines occur to the east of the release area. A sealed highway to the east of the release area runs south to the State capital Perth and the Kwinana oil refinery.

Bids close 6 October 2011

GEOTHERMAL ACREAGE

Acreage is available for the whole of the State not covered by permits or applications. Application is by a Geothermal Prospecting Authority with Acreage Option (GSPA/AO).

- GSPA size is up to 160 x 5'x5'.
- GSPA is a 6 month title.
- There is no drilling in the GSPA period.
- There is a further 6 months in which to take up the Acreage Option – 30-50% of original GSPA area.

Companies interested in geothermal acreage are allowed to bid for multiple areas and are expected to drill at least one well to a depth of 400 m during the first two years of obtaining a geothermal title.

FURTHER INFORMATION

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Acreage release CD packages are available from DMP and a web version is also available: www.dmp.wa.gov.au/acreage_release

Acreage release packages contain relevant information about the release areas, land access and how to make a valid application for an Exploration Permit.

www.dmp.wa.gov.au

Hon. Norman Moore MLC
Minister for Mines and Petroleum

Minister's Message

A couple of key incidents highlighting the importance of safety and robust regulation will help ensure the petroleum industry remembers 2010 as a significant year of development.

The explosion on the *Deepwater Horizon* in the Gulf of Mexico, which resulted in 11 deaths, a major oil spill and economic, environmental and regulatory fall-out, will be felt for many years to come.

While the stark vision reminded many of the dangers of oil exploration, it must also be remembered that at the time of the incident the United States did not demand safety cases as a part of industry regulation.

In Australia, the obligation to establish a safety case has been a part of industry regulation since the late 1980s, following the *Piper Alpha* platform disaster in the North Sea where 167 lives were lost.

Australia's offshore safety record to date has been good. However, we can always improve.

Western Australia has a number of multi-billion dollar oil and gas projects due to come online in the next decade. Regulatory certainty and clarity will be vital to ensuring the timely and sound development of these projects.

The growing interest in petroleum exploration and development in Western Australia highlights the need for administration and regulation of petroleum titles to remain well coordinated across the projects, particularly where the infrastructure is in Western Australia.

In November last year the Federal Government received the Montara Report, which investigated the 2009 well incident which occurred in waters regulated by the Northern Territory near the Ashmore and Cartier Islands off the northern coast of Australia.

The Federal Government has proposed the introduction of a single national regulator for the administration of the offshore petroleum industry and used the report's findings to further strengthen its case.

However, the State Government is not persuaded that such a move would strengthen regulation or improve the safety standards of companies operating in Commonwealth waters in Western Australia.

The State Government has formerly requested Federal Resources and Energy Minister Martin Ferguson to reconsider his national offshore petroleum regulator model to reform offshore petroleum regulation in Australia.

The proposed national regulator is likely to increase the complexity of approval processes for the offshore industry, including environmental and native title issues.

Rather than simply opposing the Federal Government's proposal, I have suggested an alternative approach that would strengthen regulation without removing the role of the States and Territories.

Western Australia has proposed the introduction of a National Compliance Auditor, which would achieve improved regulation and maintain all key parts of the current regulatory system. This would also avoid any disruption to the environmental and safety regulation of projects offshore Western Australia.

This option would not only benefit projects in Western Australia, the largest Australian jurisdiction for offshore petroleum activity, but also strengthen the oversight role of the Federal Government.

Such a model would ensure that any delays, gaps or duplication in regulatory processes are quickly identified and resolved without disruption, while also maintaining the advantage of our existing extensive local knowledge and skills, and effective and timely processes.

This proposal also recognises the need to boost safety standards in the offshore petroleum industry and the regulatory role of Government, and supports the significant reform that is already taking place in Western Australia by the Department of Mines and Petroleum.

The current practice of mirroring Commonwealth and State petroleum legislation would continue to provide similar legislative frameworks across jurisdictions, and the current co-operative approach could continue to deliver more timely outcomes.

Western Australia's industry still has decades of lucrative years ahead of it and we need to play a major role in realising these benefits for the people of this State.

This is why the State Government does not support the introduction of a national offshore petroleum regulator, and maintains that the administration and regulation of petroleum titles in Western Australia should remain under the joint authority–delegated authority administrative process. ■

Bill Tinapple
Executive Director
Petroleum Division

Executive Director's Message: Will shale gas and tight gas be the basis for the next gas boom in WA?

Within the last fifty years Western Australia has experienced several petroleum booms. In 1966 the first commercial quantities of natural gas were discovered near Dongara 350 km north of Perth. Construction of the State's first gas pipeline (now known as the Parmelia Pipeline) to supply gas from Dongara to Perth, Kwinana and Pinjarra was completed in 1971.

In the 1980s the North West Shelf (NWS) Joint Venture developed what is claimed to have been the largest engineering project in the world at the time. The project was underpinned by the significant oil and gas resources of the Carnarvon Basin and support from the Western Australian Government and Alcoa. The State also underwrote the construction of the massive Dampier to Bunbury Natural Gas Pipeline to transport NWS gas to the domestic market across Western Australia.

It appears we are now starting the biggest boom of all with eight LNG projects developing in Western Australia which are at various stages of conceptual design and construction. These projects will support Western Australia's vision of increasingly strengthening its energy security role within the South East Asia region.

Conventional gas resources in Western Australia's offshore hydrocarbon province are still growing. In 2010, approximately 226 Gm^3 (8 Tcf) was discovered, bringing total resources to 3,680 Gm^3 (130 Tcf). Of the total, a little more than 28.3 Gm^3 (1 Tcf) was produced in 2010. With massive resources already having been identified, some would ask, will unconventional gas be able to compete?

Coal seam gas (CSG) and tight gas production was pioneered in the United States in the early 1980s when the US gas market was typically tight and therefore high priced.

The unconventional gas revolution occurring in the United States has been phenomenal. Since 2000, shale gas production has leapt from accounting for only one percent of US production to 20 per cent in 2009. Figures 1 and 2 provide an insight into the growth of unconventional gas in the United States.

A similar upturn in gas production from unconventional sources has also occurred closer to home in Queensland (Fig. 3). Australia is only the second country to become involved in CSG on a commercial front and, until recently, the technical and market factors have made the potential conversion of CSG to LNG too costly to justify.

Plans to convert CSG into LNG for export to the Asian market have led to the emergence of the CSG sector in Queensland as a potential rival to the offshore giant fields of Western Australia. Several LNG projects based around the Port of Gladstone are expected to be in operation by 2014, with a further project based at Abbot Point. This clearly shows that once the technology has been proven, development can occur very quickly.

As reported in an earlier issue of *Petroleum in Western Australia* there is a potential for serious shortfalls in our domestic gas supply, despite new domestic gas projects and the requirement for LNG producers to provide domestic gas. The cost of producing gas from deep offshore waters continues to rise. Despite new gas discoveries, if all LNG projects under consideration materialise, it will be unlikely that offshore gas will be able to keep all of the LNG facilities running at full capacity over the longer term. These factors, combined with high oil prices, have led to gas prices that will make unconventional gas developments economically viable.

The prospect for an unconventional gas revolution in WA is thought to be highly probable for tight gas and shale gas. Although there is some exploration

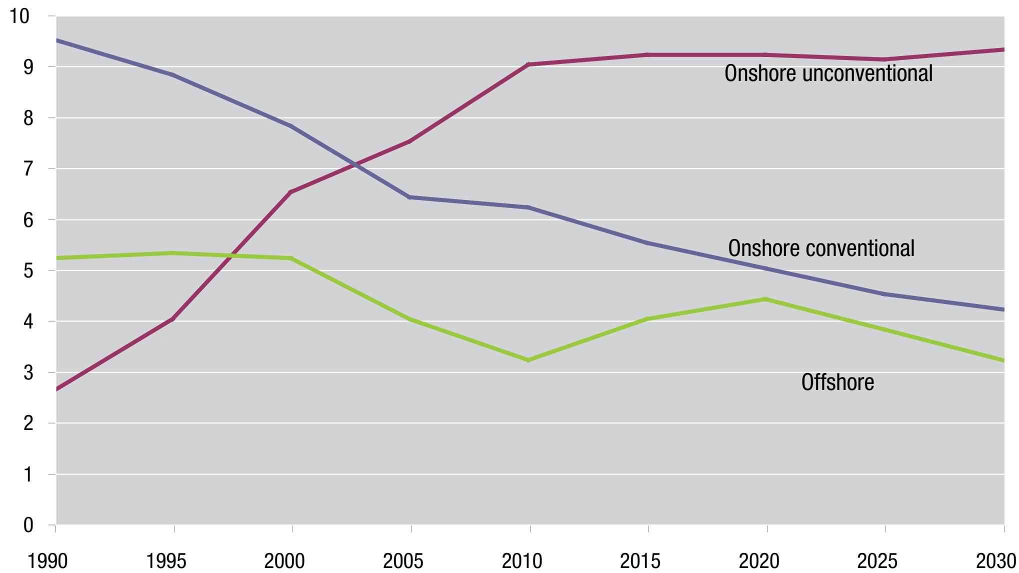


Figure 1 | **Growth of unconventional gas in the United States (Modified from EIA, 2008)** underway for CSG, indications are not as good as for tight gas and shale gas.

The Department of Mines and Petroleum estimates on the basis of previous drilling results, that there are between 255 and 340 Gm^3 (9 to 12 Tcf) of tight gas in the Perth Basin near to pipelines and gas markets. A number of companies are pursuing appraisal and development of these resources. The Corybas field is already in production in the Perth Basin.

Approximately 10 per cent of Western Australia is thought to be prospective for shale gas, which represents an area equivalent to 50 per cent of shale gas areas in the United States. Three basins are prospective for shale gas: the Perth, Carnarvon and Canning basins. Analysis has indicated shales with suitable maturity, total organic carbon (TOC), gas content and porosity, as well as huge resource potential.

Combined with the success of unconventional gas in the United States and strong indications of the potential for tight gas and shale gas, Western Australia could be on the cusp of another boom — this time onshore. It is an exciting time for the Western Australian unconventional gas industry. Markets, technology and geological knowledge are aligned so that all the components exist for unconventional gas to have a boom in Western Australia. ■

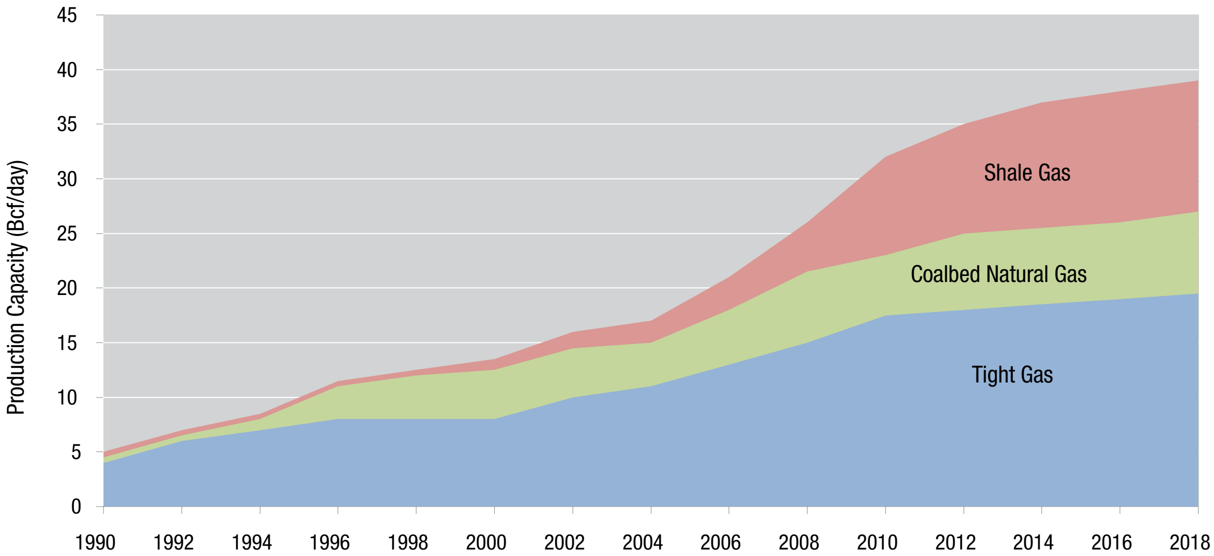


Figure 2 | **Unconventional gas production in the United States is predicted to increase from 42% of total gas production in 2007 to 64% in 2020 (Modified from American Clean Skies, Summer 2008)**

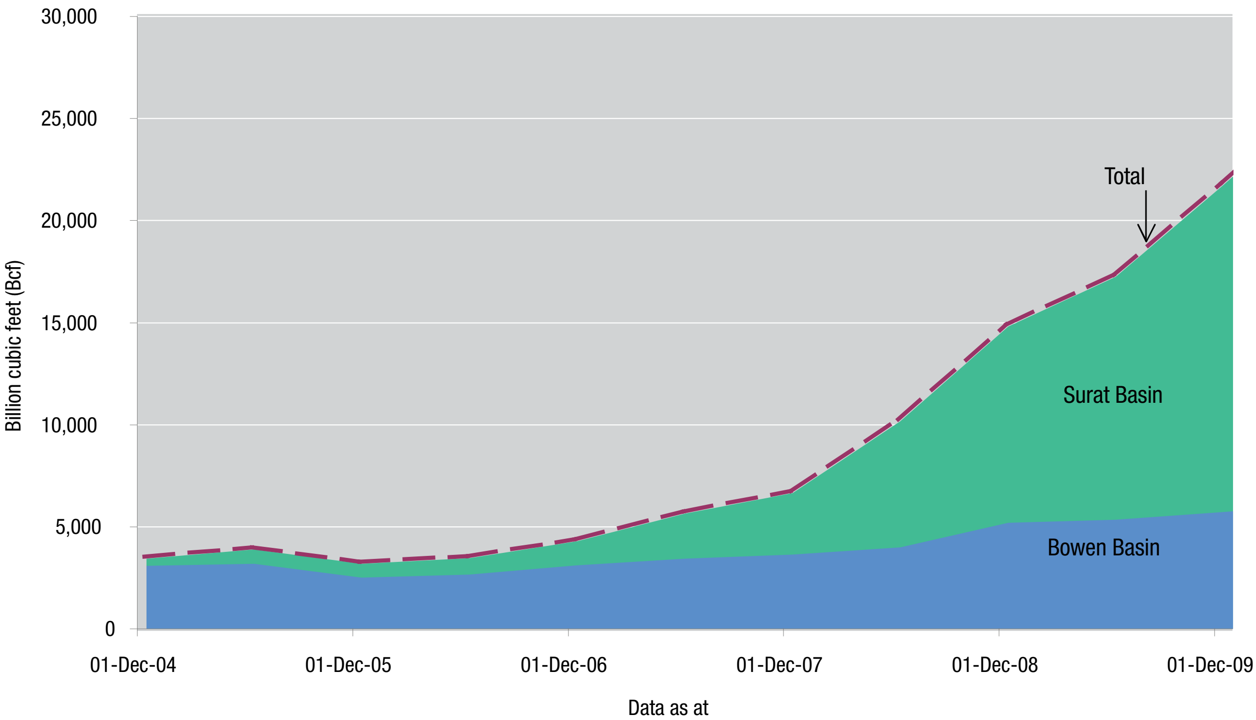


Figure 3 | **Growth in Queensland's CSG reserves for LNG expected to continue**

Petroleum Exploration, Production and Development Activity in Western Australia — 2010

Karina Jonasson
Petroleum Resource Geologist
Resources Branch

Gas flare at Glenloth 1
(Photo courtesy of Kai Photography and Hess Exploration)

Exploration highlights

In 2010 a total of 70 wells were drilled in Western Australia, down from 89 in 2009 and the lowest number of wells drilled in the State since 2002. There were 41 exploration wells (nine onshore and 32 offshore), 13 appraisal wells (one of which was onshore), and 16 development wells (of which three were onshore) drilled. Onshore drilling more than doubled the number of wells over the previous year.

While a considerable number of discoveries made from new field wildcats in 2010 may prove to be commercial, several discoveries are also considered significant (Figs 1–3):

The **Acme 1** exploration well is located in the WA-205-P permit area approximately 150 km offshore from Onslow. Drilled in 878 m of water to a depth of 4,715 m, the well encountered approximately 273 m of net gas pay. Acme 1 is the ninth and largest offshore discovery in Western Australia in the last 12 months. In terms of net gas pay, Acme 1 is one of Chevron's most significant natural gas discoveries in Australia. The discovery is likely to become feedstock for the Wheatstone project.

Woodside's **Alaric 1** exploration well in permit WA-434-P intersected approximately 185 m gross gas over several zones within the Triassic target. The Alaric 1 well is located in Woodside's Claudius hub and significantly extends the area of the known gas province in the Greater Carnarvon Basin.

The **Cimatti 1** exploration well, drilled by Woodside, intersected a gross oil column of 15 m, and sidetrack well **Cimatti 2** was completed to further appraise the field and speed up potential development. The sidetrack well intersected a 7-m thick oil bearing sand. The oil discovery is within close tie-back distance to Enfield.

ConocoPhillips and Karoon Gas drilled the **Kronos 1** well in WA-398-P which flowed gas at a rate of 736 km^3/d (26 MMscf/d). Kronos 1 is located near the Poseidon discovery which contains 85–42.5 Gm^3 (3–15 Tcf) of gas in the Browse Basin.

Larsen Deep 1, drilled by Woodside in permit WA-404-P, has intersected approximately 50 m gross gas over several zones within the Triassic target. Larsen Deep 1 is located within 9 km of Woodside's previous discoveries at Martell 1, Noblige 1 and Larsen 1.

Finally, the **Woodada Deep 1** well is significant for shale gas potential. AWE announced 368–566 Gm^3 (13–20 Tcf) gross gas in place in its Perth Basin shale gas acreage, following the analysis of Woodada Deep 1 core results. Targets for the gas are the Carynginia Formation, Kockatea Shale and the Irwin River Coal Measures.

Production highlights

In Western Australia two major offshore oil projects came online: Van Gogh (Operator Apache) and Pyrenees (Operator BHPBP). The Van Gogh development incorporates 10 production wells with produced oil processed and stored on the *Ningaloo Vision* FPSO. Oil production first started in February 2010 at the Van Gogh field 53 km north-northwest of Exmouth in the Exmouth Sub-basin.

First oil production commenced ahead of schedule from the BHP Billiton operated Pyrenees project. The project consists of the development of Crosby, Ravensworth, and Stickle oil- and gasfields which were discovered in 2003 at water depths ranging from 169 m to 250 m. The fields are developed with very long distance horizontal wells drilled from sea floor and then tied back to the *Pyrenees* FPSO via an extensive gathering system. Water injection is incorporated for enhanced oil recovery (EOR). The full project involves 13 wells, an extensive subsea gathering system, and an FPSO facility with production capacity of approximately 15,261 kL (96,000 bbl) of oil and gas reinjection capacity of 1.7 Mm^3 (60 MMcf) of gas per day. The wells were drilled and brought on in phases in 2010, with Crosby and Stickle ramping up from first oil and the Ravensworth field ramping up in August.

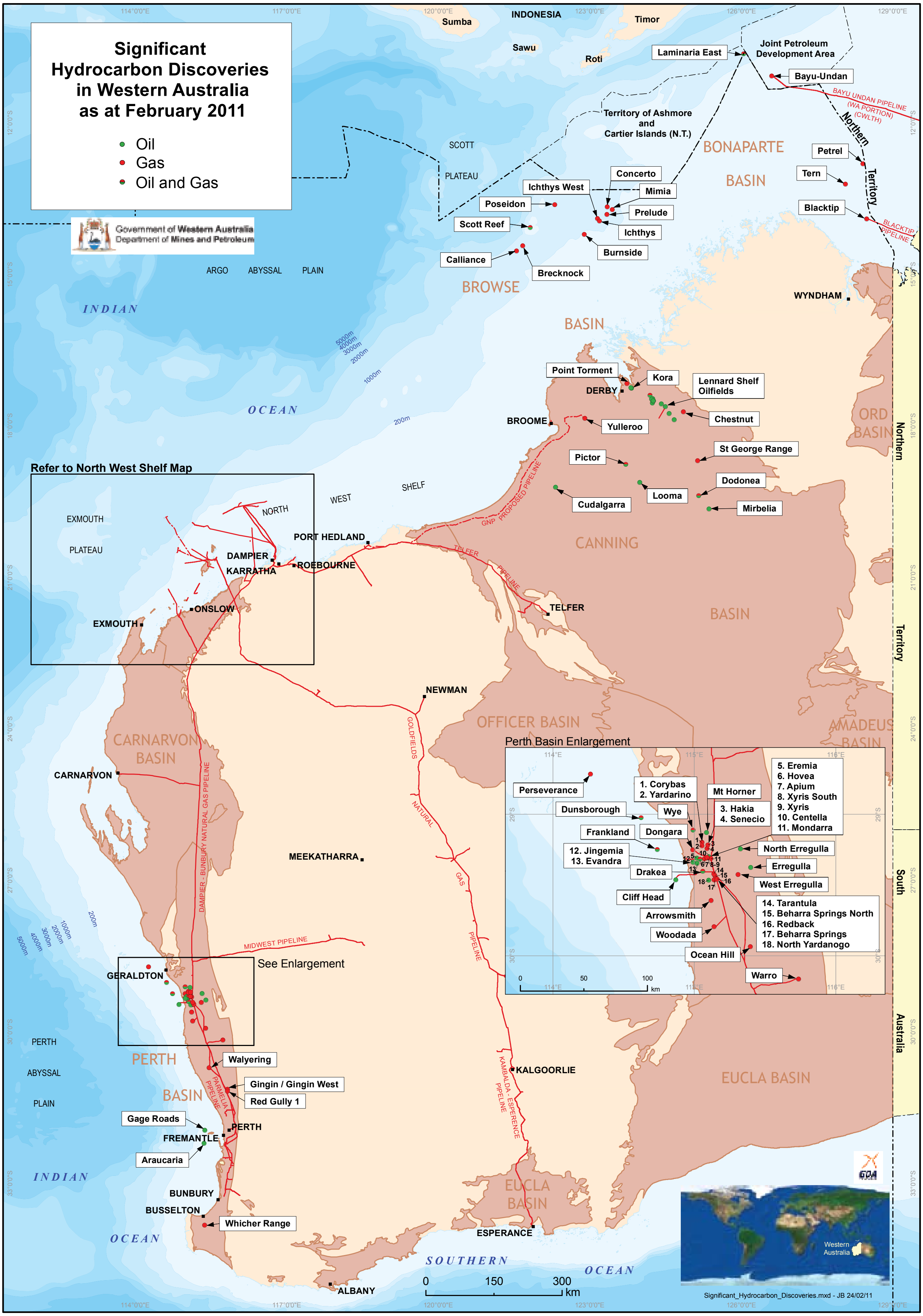


Figure 1 | **Significant hydrocarbon discoveries in Western Australia**

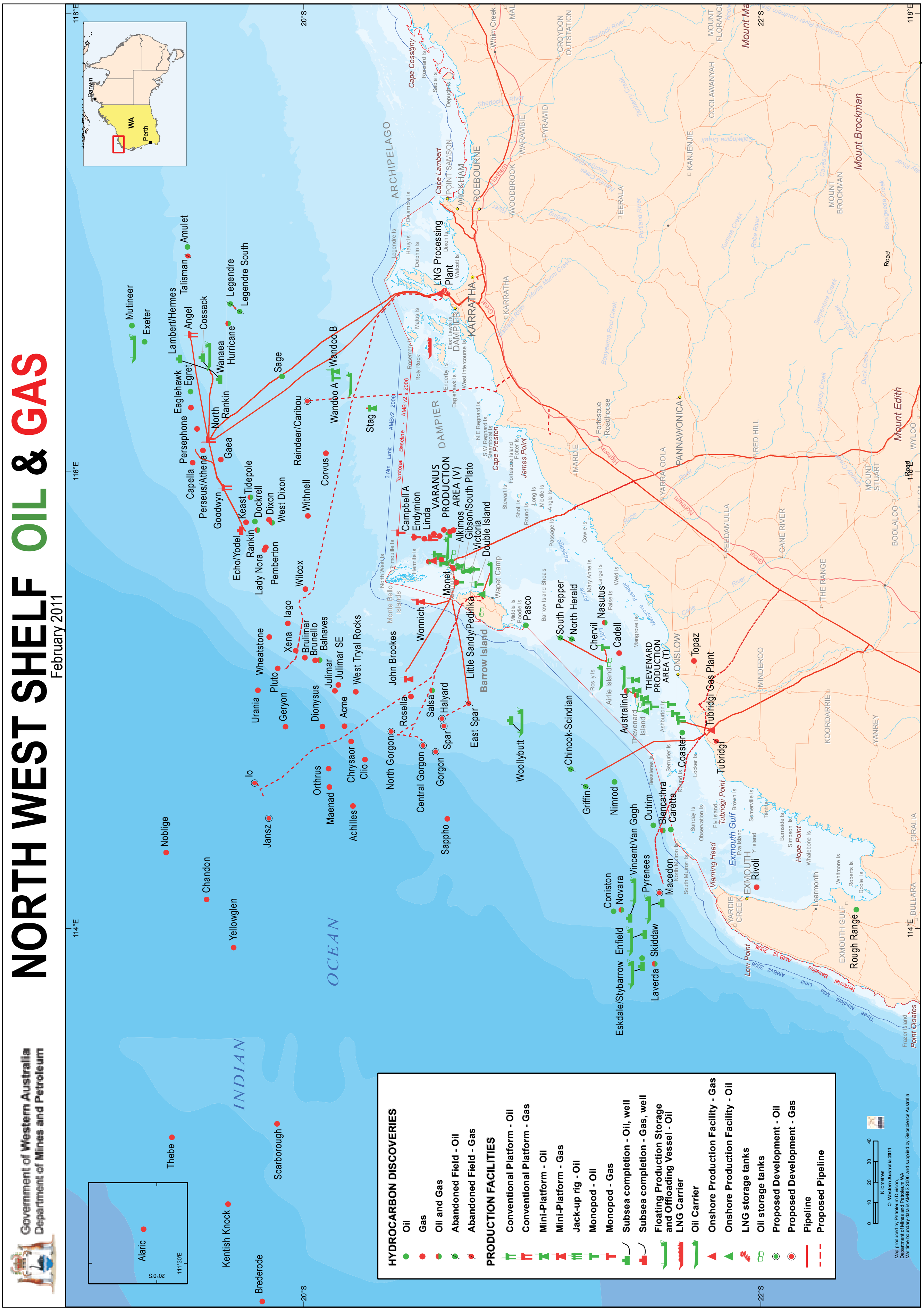


Figure 2 | **North West Shelf production facilities and significant hydrocarbon discoveries**

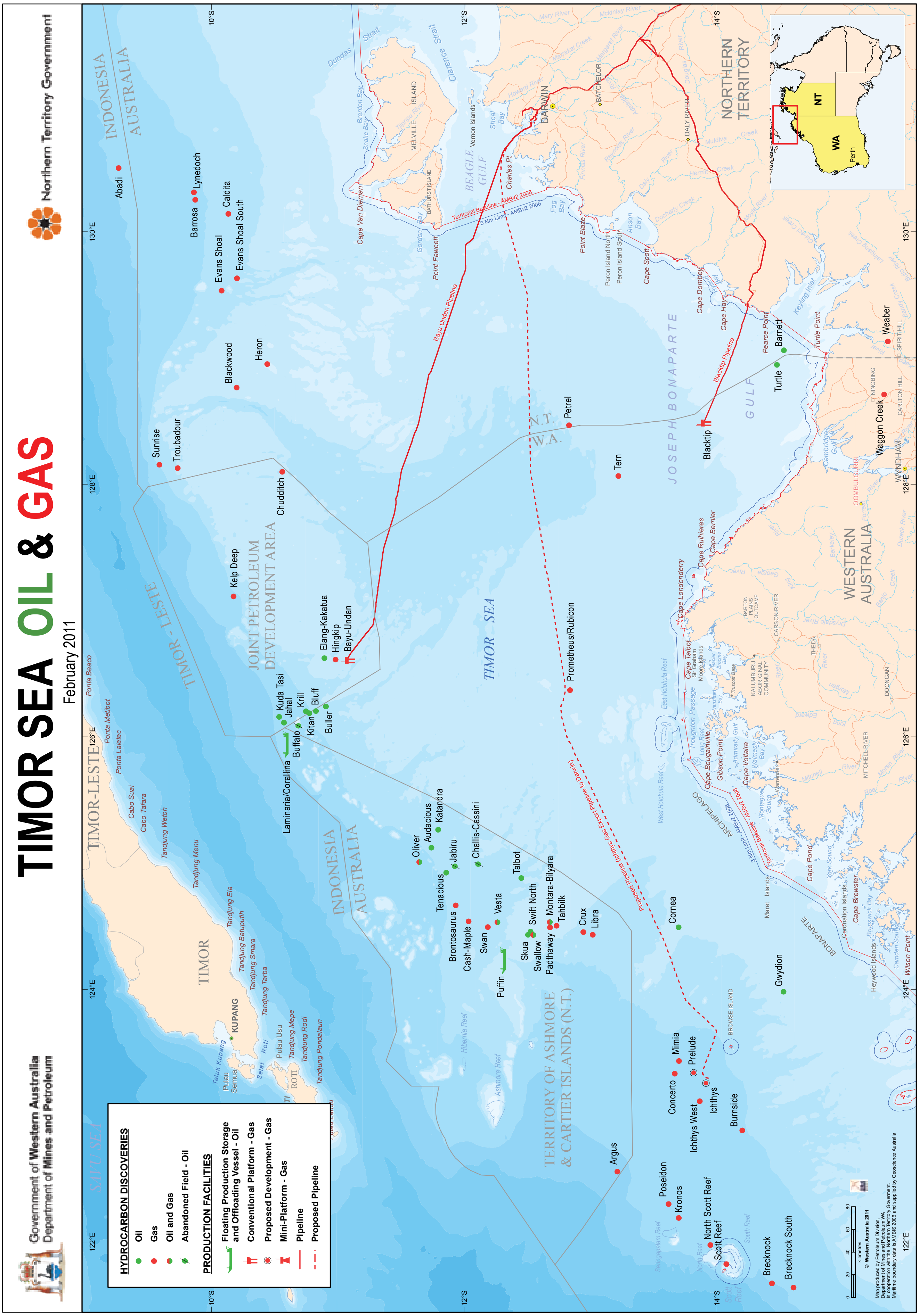


Figure 3 | **Timor Sea production facilities and significant hydrocarbon discoveries**

Tight Gas Highlight

The Corybas gasfield is the first tight gasfield in Western Australia to be put on line. This field was discovered by the Corybas 1 well in 2005. It is located onshore in the northern Perth Basin, about 14 km east of the town of Dongara. The reservoir formation is the Permian aged Irwin River Coal Measures, with an average porosity of 12.9% and an average permeability of 0.67 mD. Fracture stimulations were conducted to prove the commerciality of the field and the well produced 1.951 Mm^3 of gas and 52.5 kL of condensate in its first month of production for joint venture partners AWE and Origin Energy.

Western Australia continues to lead the country in oil and gas production. In 2010, hydrocarbon production was from 67 fields in 42 licences. Total liquids production was 21.2 GL – up from the previous year's output of 16.9 GL. LNG production continues to grow strongly at 36.4 Gm^3 increasing from 34.1 Gm^3 in the previous year.

Development highlights

There are 23 fields to be developed in the short-term and more than 70 fields to be developed in the medium to long-term, along with 30 fields held under Retention Leases with a further nine lodged and awaiting approval. In addition there are 21 discoveries with as yet unbooked resources.

The plans for the Browse liquefied natural gas hub at James Price Point in the Kimberley is a step closer. A draft strategic assessment report on the proposed project was released to the public in mid December recommending that the project go ahead. Both project Operator, Woodside Petroleum and the State Government have indicated that James Price Point is the preferred location for the multi-user LNG precinct. Environmental approval is still required.

Shell approved the development of the world's first floating LNG project for the Prelude gasfield in the Browse Basin, and Apache and Santos have committed to the joint development of the Halyard and Spar gasfields. Halyard is expected to come on stream in mid 2011 with Spar to follow in late 2012. The combined recoverable reserves are estimated at 8.9 Gm^3 (315 Bcf).

ACTIVITY BY BASIN

Bight Basin

No wells were drilled in the Bight Basin in 2010. The Bremer Basin 2D SS was completed in 2010 by Arcadia in the Southern Ocean with a total of 4,443.25 line km acquired.

Bonaparte Basin

No wells were drilled in the Western Australian portion of the Bonaparte Basin in 2010. Eni and Finder Exploration carried out two 2D surveys for a total of 603 line km and Reliance carried out a 3D seismic survey of 2,450 km^2 in the basin.

Browse Basin

Hawkestone Oil drilled the Braveheart 1 ST1 well in the Browse with disappointing results finding evidence of residual hydrocarbons at the top of the reservoir interval. ConocoPhillips was more successful with the Kronos 1 wildcat. Woodside, Total and INPEX carried out seismic surveying with two 2D and three 3D surveys completed. A mutliclient 2D survey of 2,507.4 line km by PGS finished and the Vampire non-exclusive 2D survey commenced in 2010.

Canning Basin

Buru Energy drilled four of the five wells in this underexplored basin. None of the wells were successful in discovering hydrocarbons. The fifth well was drilled by Oil Basins Ltd with a potential gross 77 m oil column between 917 mRT and 994 mRT within the Yellow Drum equivalent and Gumhole formations, with an implied potential net 40 m oil column with up to 25% porosity. The well was cased and suspended for further evaluation. Some 2D and aeromagnetic surveying was carried out in the basin.

DMP lifted the moratorium on Special Prospecting Authorities with Acreage Option (SPA/AO) in the Canning Basin in November 2010 allowing companies to explore vacant onshore acreage for unconventional gas plays as well as conventional petroleum prospects. An SPA/AO allows geophysical surveys to be undertaken in vacant acreage during a six month period but no drilling, and allows a further six months to evaluate the data prior to an application for an Exploration Permit.

Carnarvon Basin

Activity in the Carnarvon Basin remains steady with a total of 55 wells dilled in the basin, including the final five for Hess in their 16 well exploration program in WA-390-P. Several companies made discoveries as mentioned above; the majority of the discoveries this year were once again in the Carnarvon Basin. Drilling extended out into much deeper water with the Acme 1 exploration well drilled in over 4,000 m water depth. The discovery of gas there has significantly extended the area where hydrocarbons are encountered in the basin. Nine 3D seismic surveys were acquired in the basin in 2010, several of which were still in progress at the end of the year. Two 4D surveys, over Vincent and Enfield were in progress for Woodside.

Eucla Basin

A non-seismic electronic spin resonance (ESR) survey was carried out in this basin.

Perth Basin

Eight wells were drilled in the onshore Perth Basin, with three development wells at Mondarra. Three NFW wells spudded, with Dunnart 1 still in progress in early 2011. Origin's Redback 2 was a gas discovery and AWE's Woodada Deep 1 looks promising for shale gas. Origin's Wolf 1 was drilled to appraise the gas discovery at the Redback South 1 well drilled in 2009 and encountered gas. Two geological sampling surveys were carried out by Green Rock Energy in the Collie area for their geothermal exploration program.

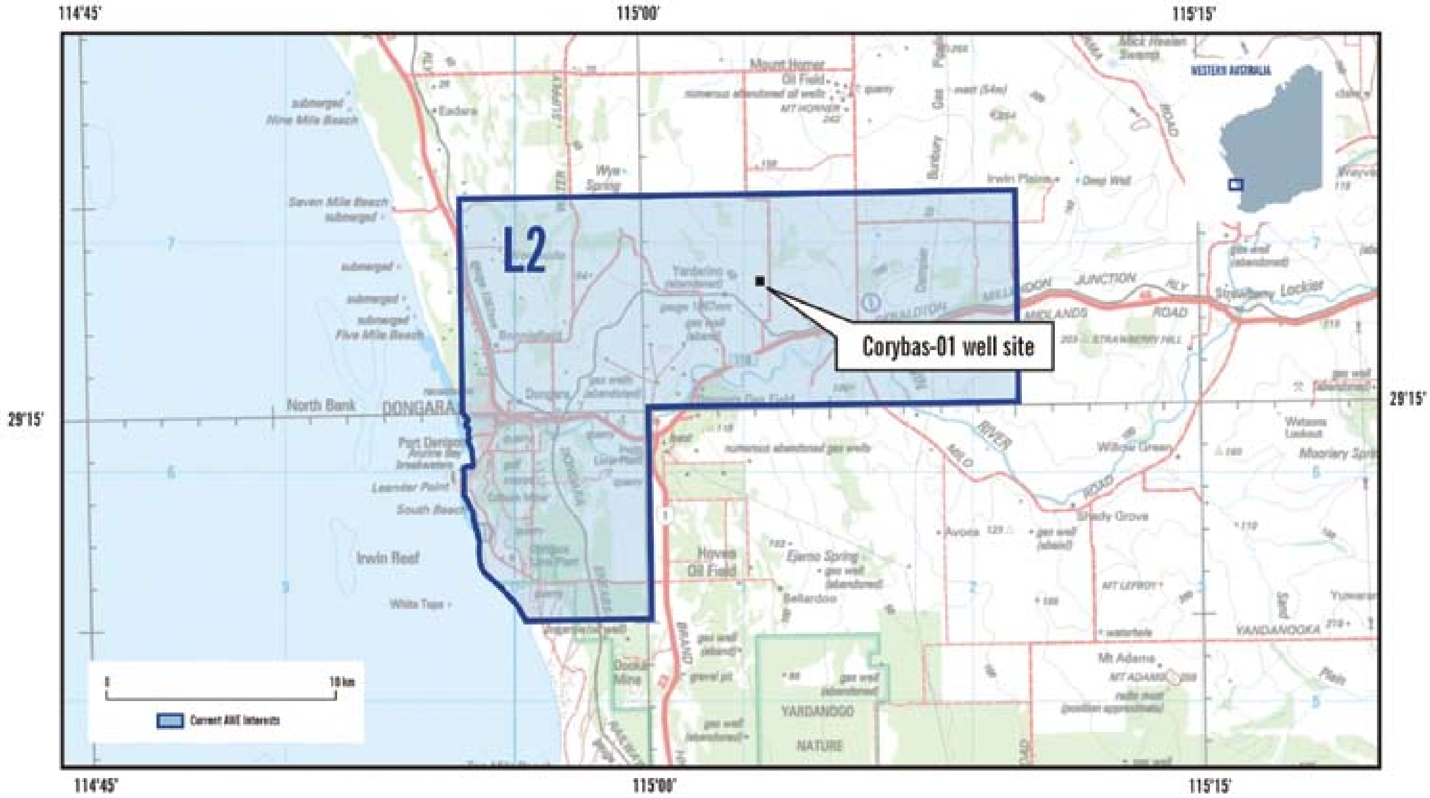
EXPLORATION ACTIVITY BY COMPANY

(Compiled from information provided by companies; where there is no report from a WA operating company, it is due to them not submitting one).

Australian Worldwide Exploration Ltd (AWE)

Corybas Tight Gasfield

The year 2010 marked a milestone for the Corybas tight gasfield. The Corybas 1 discovery well, drilled in February 2005 is situated just east of the township of Dongara, Western Australia. A modest domestic gas price and other conventional opportunities kept joint venture partners AWE and Origin Energy busy elsewhere for the following four years, until May 2009 when they decided to fracture stimulate the well.



Location of the Corybas tight gasfield near Dongara

The decision to begin appraising the gasfield was in no small part triggered by the substantial increase in the price of Western Australian domestic gas. The frac job was a success and subsequently the field began producing gas in April 2010 following the installation of a flowline to the Dongara Gas Production Facility. At present, the Corybas 1 well is being worked over to change out the frac string with a small diameter production string. The Corybas tight gasfield has qualified for relief under the state's tight gas royalty program.

Woodada Deep 1

AWE embarked on its shale gas initiative with the drilling of the Woodada Deep 1 exploration well. Four shale core samples were recovered and sent for detailed analysis in the US to assist in determining the gas production potential of these shales. The shale quality appears to be comparable with the successful gas shales of North America. While a robust evaluation will take some time, AWE is very encouraged by the initial results of this shale gas initiative. The Woodada Deep 1 well (AWE 100%) was designed to incorporate a potential testing program at the conclusion of drilling and was suspended after logging to enable future fracture stimulation in the vertical well.

The exploration well (a deepening of the Woodada 4 well) was drilled in March 2010 into the Carynginia and Irwin River Coal Measures for the purpose of obtaining shale core using the *Ensign*-5 rig. Four cores were successfully taken and 280 m of Carynginia shale was encountered. Gas was released from the core during the core recovery procedure, which may be viewed as a positive sign for the potential of the play. The core analysis was undertaken by TerraTek Laboratory in Salt Lake City, recognised experts in the field of Shales Gas analysis in the US. From this work the middle interval of the Carynginia Shale was high-graded as a target for further evaluation as it has ideal fracture stimulation parameters and a log signature analogous to some productive gas shales in the US. By correlating the core analysis with log data from existing wells AWE estimates that this middle interval of the Carynginia Shale may hold gas in place of 368–566 Gm^3 (13 to 20 Tcf) within AWE's acreage holdings, and based on a 20% recovery the contingent resource is potentially greater than 113 Gm^3 (4 Tcf).

The data collected to date is now being combined with a comprehensive geological and geophysical analysis for high-grading the prospective area within the Carynginia shale and to determine optimal locations for appraisal wells to be drilled in 2011.

Fracture stimulation equipment at the Corybas field
(Photo courtesy of AWE Ltd)

Looking Ahead

Shale Gas Initiative

The next phase of activity in AWE's shale gas program in the Perth Basin will involve the drilling and fracture stimulation of a well in EP 413 (AWE 44.25%) and the multistage fracture stimulation of the Woodada Deep 1 well (AWE 100%) which was drilled and cored in 2010. This activity will look to gain further technical data on the shales in the area and test the productive capacity of several potential reservoir zones at both locations. Advanced planning is underway and several lab tests are being organised by AWE to optimise the design of the fracture stimulations.

EP 455

Within EP 455, geological and geophysical investigations are underway to prepare for a future shale evaluation well in the permit.

Corybas Tight Gasfield

Follow up appraisal of the Corybas gasfield is planned for mid to late 2011.

Senecio Tight Gasfield

A workover and fracture stimulation program of the Senecio 2 well is under consideration. The un-stimulated well flowed at around 28,300 m^3/d (1 MMscf/d) on test. However, fracture stimulation may be required to achieve commercial production.

Denison 3D Seismic Reprocessing

Geological and geophysical studies, including pre-processing of sections of the Denison 3D survey, will be undertaken during 2011 to improve the imaging of prospects in the Drakea area and the area to the north of Beharra Springs (in L1/L2).

Chevron Australia Pty Ltd

Chevron is continuing to explore for and appraise Australia's world class natural gas resources with its largest drilling campaign underway offshore northwest Australia.

Chevron Australia participated in 13 exploration and appraisal wells in 2010. Operated exploration wells were successful with five discoveries at Brederode 1, Clio 3, Acme 1, Orthrus 2 and Sappho 1.

Greater Gorgon Area

In 2010, work continued to focus on the extensive exploration and appraisal drilling campaign with the *ENSCO 7500* and the *Atwood Eagle* rigs. The 2010 drilling program contained several appraisal wells within various permits in the Greater Gorgon Area. The work to prepare for this campaign has involved extensive seismic processing and interpretation, geological modelling and detailed well planning. Initial exploration well results have been positive with Chevron announcing two gas discoveries in 2010, Orthrus 2 and Sappho 1 in the Greater Gorgon Area. Chevron also conducted successful appraisal drilling at Chandon 2, Geryon 2, and Orthrus 2, with very encouraging drillstem tests (DST) at each.

Wheatstone

In 2010, there was continued focus on resource maturation of the Wheatstone and Iago fields; this included the drilling of Iago 5. The 2008–2009 appraisal program, which included seven wells and two well tests, successfully acquired data and information to firm up resource estimates to support the Wheatstone Project which entered FEED in late 2009 and continued throughout 2010.

Exploration and appraisal of the WA-205-P permit continued in 2010 with successful exploration/appraisal drilling and a DST at Clio 3. The Acme 1 exploration well discovered significant resources in northern WA-205-P with net gas pay in the well being a record for a Chevron operated well.

Exmouth Plateau

Chevron (as Operator) and Shell Development (Australia) Pty Ltd hold six frontier permits in the Exmouth Plateau region: WA-364-P, WA-365-P, WA-366-P, WA-367-P, WA-383-P and WA-439-P. The exploration targets on the Exmouth Plateau are Triassic Mungaroo Formation fault blocks and stratigraphic plays in the Cretaceous Barrow Group. During 2010 the focus of exploration activity was on the early drilling of an exploration wells in WA-364-P to satisfy the Year 6 work program commitment. The deviated Brederode 1 well was drilled in May 2010 using the Atwood *Eagle* semi submersible drilling rig and confirmed the presence of new gas field.

Preparations are underway for the WA-439-P Year 3 commitment well, Vos 1, scheduled to be drilled in 2011.

The acquisition and processing of the 1,867 km^2 Agrippina 3D MSS occurred in 2010 across WA-366-P and WA-439-P to satisfy the respective Year 5 and Year 2 commitment 3D seismic commitments. The acquisition of Eendracht MC3D program in WA-367-P was also completed in late 2010. Planning began for the acquisition of the Sovereign 3D marine seismic survey (MSS) in WA-383-P, which is scheduled to begin in 2011.

ConocoPhillips Australia Pty Ltd

ConocoPhillips' major producing assets in Australia are the Bayu-Undan gas condensate field in the Timor Sea and the Darwin LNG plant in the Northern Territory, which are linked by a 500 km subsea pipeline. ConocoPhillips operates the downstream component of Australia Pacific LNG — a 50:50 joint venture with Origin Energy, producing coal seam gas from the Bowen and Surat basins in Queensland. ConocoPhillips is also a participant in the Greater Sunrise LNG project. Exploration and development interests include exploration permits offshore Western Australia in the Browse Basin, and the Caldita/Barossa discoveries offshore Northern Territory.

2010 Activity

ConocoPhillips (Operator) and Karoon Gas are joint venture participants in Browse Basin Exploration Permits WA-314-P, WA-315-P and WA-398-P. During 2010 the focus of exploration activities included the completion of the first phase of exploration drilling and acquisition and processing of the Poseidon 3D seismic survey.

The exploration drilling campaign commenced in early 2009 with the Poseidon 1 well in WA-315-P, followed by the Kontiki 1 well in WA-314-P. Drilling activities in 2010 included the completion of drilling and drillstem testing of Poseidon 2, in permit WA-398-P. The well confirmed the presence of hydrocarbons. This was followed by Kronos 1, also in WA-398-P, which also encountered hydrocarbons and was successfully tested. The drilling campaign finished in June 2010.

Acquisition of the Poseidon 3D seismic survey was completed in March 2010. The survey comprises more than 2,800 km^2 full fold data, acquired over permits WA-315-P and WA-398-P.

Processing of the data will be completed in Q1 2011 and interpretation is in progress.

A second phase of drilling in the Browse Basin permits is planned for 2011/2012. Preparations are in progress for this campaign.

Empire Oil and Gas NL

Empire Oil & Gas NL is an independent Australian E & P company that was formed in 1994 and listed on the Australian Stock Exchange in 1998. The company's area of operations is onshore Western Australia and it has permits in the onshore Perth, Carnarvon and Canning basins. Empire is an experienced operator and has conducted numerous seismic surveys and drilled fifteen exploration wells in Western Australia.

Perth Basin

Empire is the major permit holder of Exploration Permits EP 368, EP 389, EP 416, EP 426, EP 430, EP 432, EP 440 and EP 454 in the onshore Perth Basin, and is the Operator of all these permits. It also has an interest in application areas L08-6 and L08-7 in the southern Perth Basin. These permits cover an area of almost 20,000 km^2 (5 million acres) which is approximately 50 per cent of the onshore part of the basin.

During 2010, the company tested the Gingin West 1 well in EP 389. The well flowed 217,000 m^3/d (7.66 MMcf/d) gas plus 47.5 kL/d (300 bbl/d) condensate from the interval 3,572-3,575 m at the top of Sand Member D in the Early Jurassic Cattamarra Coal Measures (see photo). The company mobilised Weatherford Rig 826 to drill Red Gully 1, located at Gingin West 1 but deviating into another prospect immediately northwest of Gingin West 1.

Gingin West 1 on test
(Photo courtesy of Empire Oil and Gas N.L.)

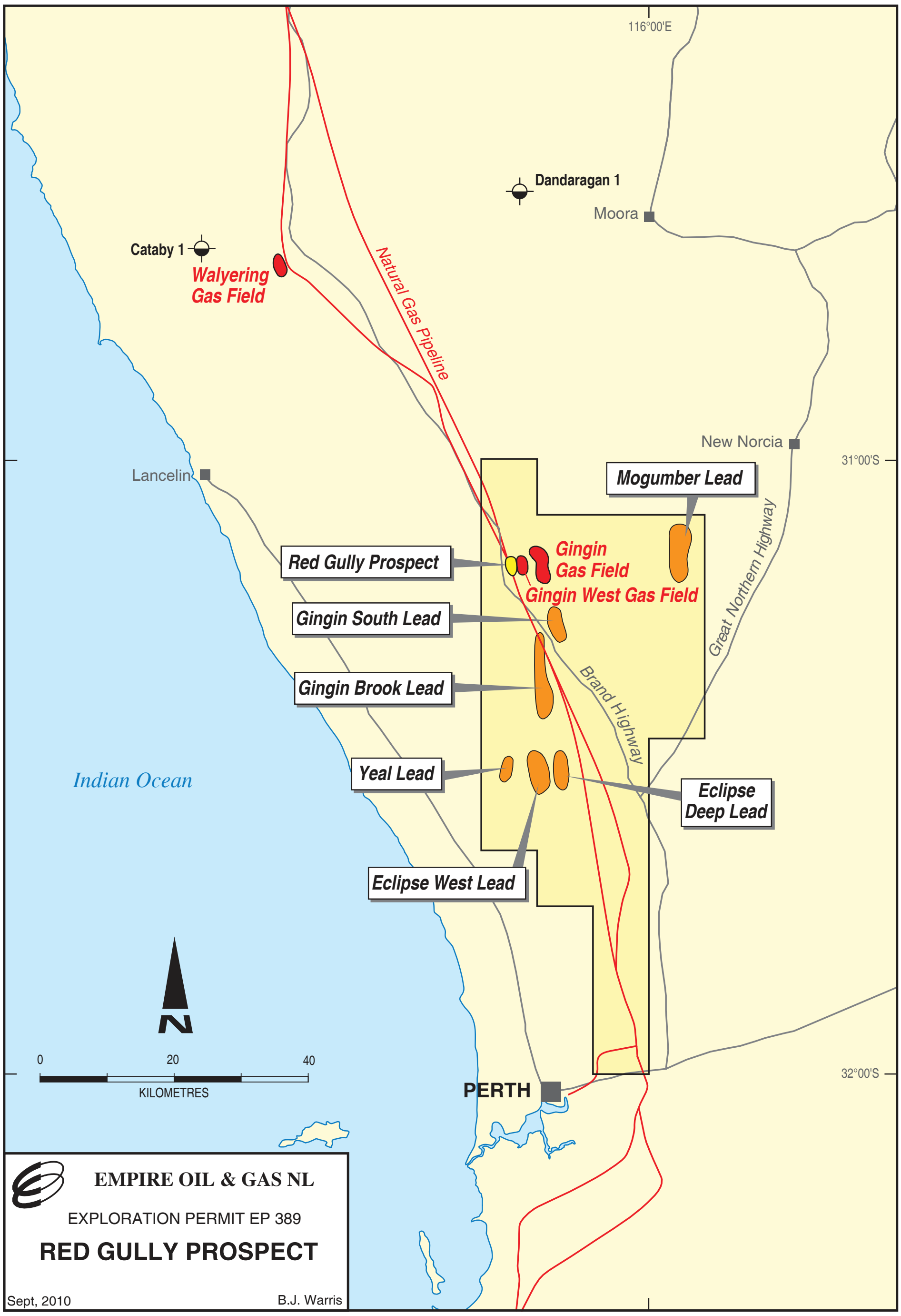
Carnarvon Basin

The Company is also a major player in the prospective Carnarvon Basin in Western Australia and has interests in and operates ten onshore exploration permits. These are EP 406, EP 434, EP 435, EP 359, EP 412, EP 439, EP 444, EP 460, EP 461 and EP 466. The company also has non-operated interests in EP 325 and EP 433, and an operating interest in Production Licence L14 over the Rough Range oilfield.

Canning Basin

The company is also a major player in the prospective Canning Basin in Western Australia and has interests in five large onshore exploration tenements. These are Exploration Permits EP 104, EP 438 and EP 448; Retention Lease R1; and Production Licence L15 over the West Kora oilfield.

The company participated in the testing of Stokes Bay 1 in Retention Lease R1, Canning Basin. This well flowed salt water from the Late Devonian Nullara Group.



Empire Oil's Exploration Permit EP 389 in the onshore Perth Basin

Planned Activity 2011

Empire plans to carry out the following exploration programs during 2011:

(i) Drill Red Gully 1 in EP 389, onshore Perth Basin (the well spudded on 6 January 2011). This prospect is a faulted anticline with Early Jurassic Cattamarra Coal Measures as the main objective;

(ii) Drill Bee-Eater 1 in EP 359, onshore Carnarvon Basin. The Bee-Eater Prospect is a seismically defined tilted fault block with the Birdrong Sandstone as the main objective;

(iii) Drill Chapter 1 in EP 439, onshore southern Carnarvon Basin. Chapter 1 has main objectives in the carbonates of the Late Devonian Gneudna Formation plus the Nannyarra Sandstone;

(iv) Drill one exploration well in EP 432, onshore Perth Basin. This well will be drilled on either the Cooljarloo Prospect updip from Cataby 1 well which encountered a 2.5 m oil bearing sand within the Cattamarra Coal Measures, or the Woolka Prospect with the same objectives or a Shale Gas well to evaluate the Permian marine shales of the Carynginia Formation;

(v) Drill Wellesley 1 in EP 416, southern Perth Basin. The Wellesley Prospect is an anticline with main objectives being the Permian Sue Coal Measures;

(vi) Participate in the drilling of Cyrene 1 in EP 438, Canning Basin. This prospect is an anticline with Ordovician carbonates of the Willara Formation as the main objective;

(vii) Conduct a 3D seismic survey over the North Erregulla Prospect in EP 368 and EP 426. The North Erregulla Prospect is a tilted fault block with the main objective being the Dongara Sandstone sealed and sourced by the Kockatea Shale;

(viii) Conduct a 2D seismic survey over the Garibaldi Prospect in EP 454. The Garibaldi Prospect is an anticline with the main objective being the Dongara Sandstone sealed and sourced by the Kockatea Shale; and

(ix) Conduct a 3D seismic survey over the Gingin Brook Prospect in EP 389. The Gingin Brook Prospect is an anticline with the main objective being the Early Jurassic Cattamarra Coal Measures.

Eni Australia Limited

In 2010, Eni was a participant in nine Exploration Permits in Western Australia and operated six of these.

The developments in the Bonaparte Basin and deep water Carnarvon Basin are consistent with Eni's growth strategy in the region.

In the Carnarvon Basin, as Joint Venture partner with then Operator OMV, Eni undertook about 4,000 km^2 of 3D seismic and in 2011 is committed to drill two exploration wells, one in permit WA-362-P and one in the permit WA-363-P. These exploration areas cover some 37,000 km^2 and are located in an unexplored area of the outer North West Shelf, north of the major gasfields of the North West Shelf and the Greater Gorgon area. Eni became Operator in December 2010 (40% equity) with OMV (40% equity) and Octanex NL (holding a 20% equity).

Finder Exploration Pty Ltd

Finder Exploration Pty Ltd was established in 2005 as a private oil and gas exploration company based in West Perth with a primary focus on capturing and de-risking prospective exploration acreage on the North West Shelf of Australia.

Finder is a fast growing and dynamic company with a track record of success in promoting exploration acreage, initially adding value through our regional knowledge and databases and sufficiently de-risking opportunities to attract investment from major oil and gas players.

Finder Exploration Business

Finder currently has a participating interest in the following 13 offshore Australian exploration permits (see Table 1 below) covering a total of ~46,000 km^2.

Table 1. Finder Exploration's interests in Western Australia

Carnarvon Basin Interests:	WA-418-P	35%
	WA-445-P	100%*
	WA-450-P	25%
Browse Basin Interests:	AC/P 36	~32%
	AC/P 44	60%*
	AC/P 45	67%*
	AC/P 52	55%*
Bedout Sub-basin Interests:	WA-435, 436, 437 & 438-P	50%*
Bonaparte Basin Interests:	NT/P 79	100%*
	WA-446-P	100%*

* Operator

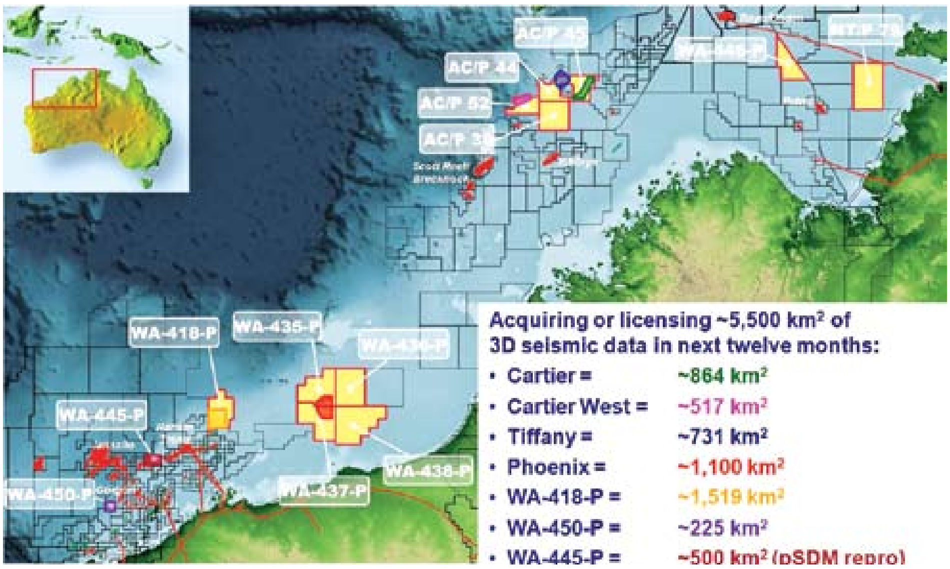
Finder also operate 5 exploration permits in the Walton Basin (offshore southern Jamaica).

Since the beginning of 2009 Finder has almost trebled its Australian net acreage holdings and has concluded farmout, acreage assignment and divestment of permit interests to:

Woodside and Hess	WA-401-P
Perenco (SE) Australia Pty Ltd	AC/P 44 and AC/P 45
Sasol Petroleum Australia Ltd	AC/P 52
Carnarvon Petroleum Limited	WA-435, 436, 437 and 438-P
Apache Northwest Pty Ltd	WA-450-P
Apache Northwest Pty Ltd	WA-418-P

Current Activity

In 2011 Finder is involved in the acquisition and interpretation of significant 3D seismic data volumes, with over 5,500 km^2 of new 3D seismic data across seven surveys over the majority of our Browse, Bedout and Carnarvon Basin permits.



Finder's Australian acreage and proposed seismic surveys for 2011

Hess Exploration Australia

WA-390-P

Hess Exploration Australia PTY Limited has entered into the next phase of evaluation in WA-390-P. Hess has successfully finished its exploration drilling campaign by completing its record 16 well Work Commitment with 13 discoveries on the block.

Hess immediately initiated an appraisal program with the Transocean *Jack Bates* MODU that will continue through mid 2011 and includes appraisal drilling and flow testing of several wells.

Commercial discussions with potential partners regarding WA-390-P are ongoing. No decisions or commitments have been made to any party, although Hess anticipates entering into relevant agreements with a chosen partner in the coming months.

INPEX conducted seismic surveys of the Ichthys field and surrounding areas in late 2010
(Photo courtesy of PGS)

INPEX Browse, Ltd

Browse Basin

INPEX actively pursued exploration activities in the Browse Basin through 2010, with four seismic surveys conducted over parts of Exploration Permits WA-343-P, WA-274-P, WA-344-P, WA-285-P and WA-281-P and Retention Lease WA-37-R. This included a 3D seismic survey over the Ichthys field, which covered an area of approximately 1,610 km^2.

Kingsway Oil Limited

Kingsway Oil has six permits and applications in the central and southern Canning Basin; EP 429, EP 449, AEP 01/08-9, AEP 13/07-8, AEP 02/08-9 and AEP 14/07-8. In the southern Canning Basin, AEP 01/08-9, AEP 13/07-8 (gazetted as L07-3), AEP 02/08-9 (gazetted as L07-4) and AEP 14/07-8 (gazetted as L07-5) have recently been offered to Kingsway subject to successful completion of Section 31 of the Commonwealth *Native Title Act (1993)*. Negotiations with the indigenous land owners are ongoing.

The Sally May 2 well was drilled during July-August 2009 in EP 429 and it recorded visual oil shows while drilling in the Nita – Goldwyer Transition, the Acacia Sandstone and also the lower Willara Formation. The Sally May 2 well failed to intersect well developed reservoirs at the primary objective Nita Formation and Acacia Sandstone levels. The well demonstrated that there is a hydrocarbon system in the area however the lack of reservoir quality has downgraded the prospectivity of EP 429.

EP 449 contains the Mirbelia 1 well drilled by WMC in 1985 to a total depth of 2,670 m in the Late Ordovician–Early Silurian Carribuddy Group. Due to poor hole conditions in Carribuddy Formation salt, the well did not reach its pre-salt objective. A test of the Mid-

Kingsway Oil's proposed 2D seismic coverage in EP 449

Late Devonian Mellinjerie Limestone yielded 1.5 litres of clean 22° API oil, with wireline log interpretation and test data indicating a 13 m gross oil column with porosities in the range 10% to

15%, confirming the presence of an active hydrocarbon system. Six leads have been identified in EP 449 and have been independently assessed to potentially contain cumulative un-risked mean probabilistic oil in place resource volume exceeding 31.8GL (200 MMbbl). Kingsway Oil has committed to the acquisition and interpretation of 120 line km of new 2D seismic data across the identified leads to elevate their status to drillable prospects. Terrex is scheduled to commence acquisition in September 2011.

Latent Petroleum Pty Ltd

Latent Petroleum is Operator of EP 321 and EP 407. During 2010 there were no field activities except for environmental surveys in preparation of the acquisition of the Warro 3D. During 2010 the Warro JV carried out a number of technical studies using tight sand expert based in the United States and determined the best approach for the drilling, stimulation and testing of Warro 4.

During 2011, the Warro JV will drill Warro 4 and acquire approximately 100 km^2 of 3D seismic data over the field area. Warro 4 will be fracture stimulated and undergo an extended testing program. If successful, we expect to carry out further drilling activities during late 2011, early 2012.

OMV Australia Pty Ltd

As at the end of 2010, OMV Australia Pty Ltd (OMV Australia) had interests in eight Exploration Permits and one Retention Lease located in the offshore Carnarvon Basin within the area administered by the Western Australian Department of Mines and Petroleum as detailed in Table 2 below.

Review of 2010 Exploration Activities

R 5

The R 5 Retention Lease was awarded over Nasutus oil pool (formerly within EP 409 Exploration Permit) for a five year term commencing 28 April 2010.

WA-290-P

A multi-survey reprocessing project of an 887 km^2 merged volume of 3D seismic data was completed in early 2010.

OMV Australia farmed-out a 20% interest and transferred the operatorship of WA-290-P to Apache Northwest with effect from 30 June 2010.

The Zola 1 exploration well commenced drilling on 1 December 2010 and operations were continuing at the end of the report period.

Table 2. OMV's Exploration Permit interests

Title	OMV Interest	Operator	Joint Venture Parties
R5	50%	Apache Oil Australia	Apache Oil Australia
WA-290-P	20%	Apache Northwest	Apache Northwest Nippon Oil Exploration (Dampier) Santos Offshore Tap (Shelfal)
WA-320-P	66.67%	OMV Australia	Tap (Shelfal)
WA-358-P	100%	OMV Australia	
WA-362-P	30%	Eni Australia *	Eni Australia Exmouth Exploration Octanex Strata Resources
WA-363-P	30%	Eni Australia *	Eni Australia Exmouth Exploration Octanex Strata Resources
WA-386-P	30%	OMV Australia	Eni Australia Exmouth Exploration
WA-387-P	30%	OMV Australia	Eni Australia Exmouth Exploration
WA-391-P	100%	OMV Australia	

* - OMV Operator to 1 December 2010

WA-320-P

A multi-survey reprocessing project of a 720 km^2 merged volume of 3D seismic data is being conducted.

WA-358-P

OMV Australia became the sole interest holder with effect from 20 April 2010. A multi-survey reprocessing project of a 730 km^2 merged volume of 3D seismic data is being conducted.

WA-362-P and WA-363-P

Acquisition and processing of the proprietary ~3,940 km^2 Schiele 3D Marine Seismic Survey over the central portion of these permits was completed during 2010. Seismic interpretation of the Schiele 3D volume was continuing at the end of the report period.

OMV Australia resigned as Operator and Eni Australia was appointed as Operator of these permits with effect from 1 December 2010.

WA-386-P and WA-387-P

Seismic interpretation of the proprietary Klimt 2D survey and vintage 2D seismic data and technical studies were continuing at the end of the report period.

WA-391-P

Pre-stack depth migration processing of multi-survey 3D seismic data over the permit was completed in early 2010. Seismic interpretation of the reprocessed 3D time and depth cubes and technical studies were continuing at the end of the report period.

Planned Exploration Activities for 2011

OMV's planned exploration activities for 2011 are as follows:

WA-290-P

Complete drilling of Zola 1 exploration well.

WA-320-P

Complete 3D reprocessing project, interpretation of the reprocessed seismic data and technical studies to determine and support work program for potential renewal of the permit.

WA-358-P

Complete 3D reprocessing project, interpretation of the reprocessed seismic data and technical studies to determine and support work program for potential renewal of the permit.

WA-362-P and WA-363-P

Drill an exploration well in each of the permits.

WA-386-P and WA-387-P

Complete interpretation of the proprietary Klimt 2D survey and vintage 2D seismic data and technical studies to determine and support forward exploration work program.

WA-391-P

Complete seismic interpretation of the reprocessed 3D time and depth cubes and technical studies to determine and support forward exploration work program.

Origin Energy

With a market capitalisation of over $15 billion, Origin is one of Australia's leading integrated energy companies focusing on oil and gas exploration and production, energy retailing and power generation. The company owns and operates exploration, production and generation throughout Australia and New Zealand, and provides gas and electricity to more than 3 million homes and businesses across Australasia and the Pacific.

In the Perth Basin, Origin continues to have an active and successful exploration and development program. Origin is the Operator of Production Licence L14 (49.189%) in which the Jingemia oilfield is located. Origin also operates Production Licence L11 (66.67%), which includes the Beharra Springs and Tarantula gasfields. Origin is also a 50% joint venture party with AWE in L1/L2, and holds a 15% interest in EP 368. (In 2010, Origin relinquished its interest in onshore Perth Basin block EP 413).

During 2010 Origin and its joint venture partners drilled two wells in the northern Perth Basin.

Redback 2 was drilled to test the hydrocarbon potential of the Wagina Sandstone north of the Redback South 1 discovery. The well encountered high-pressure gas in good quality sandstones.

Planned exploration activity for 2011

Origin intends to further appraise the extent of the gas resource on the Redback Terrace by drilling up to two wells. One of these wells, Trapdoor 1, will be drilled north of the Redback fault compartment to investigate the presence of reservoir quality sandstones and gas pay in the most northerly block on the terrace. A second well, Dugite 1, will be drilled close to the limit of the mapped closure south of Wolf 1 to evaluate the southern extent of the Redback South/Wolf gas accumulation.

Two additional exploration wells are also planned. Beharra Springs Deep 1 will test the reservoir potential of the High Cliff Sandstone west of the Beharra Springs Fault, beneath the Beharra Springs gasfield. Russ 1 will test the High Cliff Sandstone in the vicinity of Warradong 1 (drilled in 1981) and will provide a test of the Dongara Sandstone updip of Warradong 1.

A 3D seismic program of approximately 160 km^2 is also planned east of the Redback Terrace. This survey will merge with existing 3D coverage to provide full-fold imaging of the entire Redback Terrace as well as that portion of EP 320 east of the Redback Terrace.

Origin will also continue its ongoing geoscience studies with a view to maturing additional oil and gas exploration prospects and leads to drillable status.

ROC Oil Company Limited

In 2010, ROC-operated permits offshore Western Australia comprised one Production Licence (containing the producing Cliff Head oilfield), one Exploration Permit in the Abrolhos Sub-basin, and two Exploration Permits in the Vlaming Sub-basin (from which ROC withdrew in 2010). ROC also participated in a Production Licence onshore Perth Basin and an Exploration Permit in the Carnarvon Basin. This report includes 2010 activity in ROC-operated permits.

Abrolhos Sub-basin (Perth Basin) – WA-286-P and WA-31-L

Following the completion of prospectivity studies (including re-processing of 3D seismic data), the joint venture withdrew its application for renewal of WA-286-P and the permit expired on 30 November 2010.

In WA-31-L, the reprocessing of a 220 km 2D seismic survey and the interpretation of 3D seismic data was completed during the year. Additional reserves potential on the western flank of the Cliff Head field is being assessed based on revised seismic interpretation and depth mapping. West High has re-emerged as a possible in-field drilling candidate with an estimated mean reserve of 191 ML (1.2 MMbbl).

Vlaming Sub-basin (Perth Basin) – WA-381-P and WA-382-P

An application to withdraw from both WA-381-P and WA-382-P was made on 15 March 2010 and ROC's withdrawal from both permits was effective 27 April 2010.

Santos

Spar 2 (Carnarvon Basin, WA-4-R)

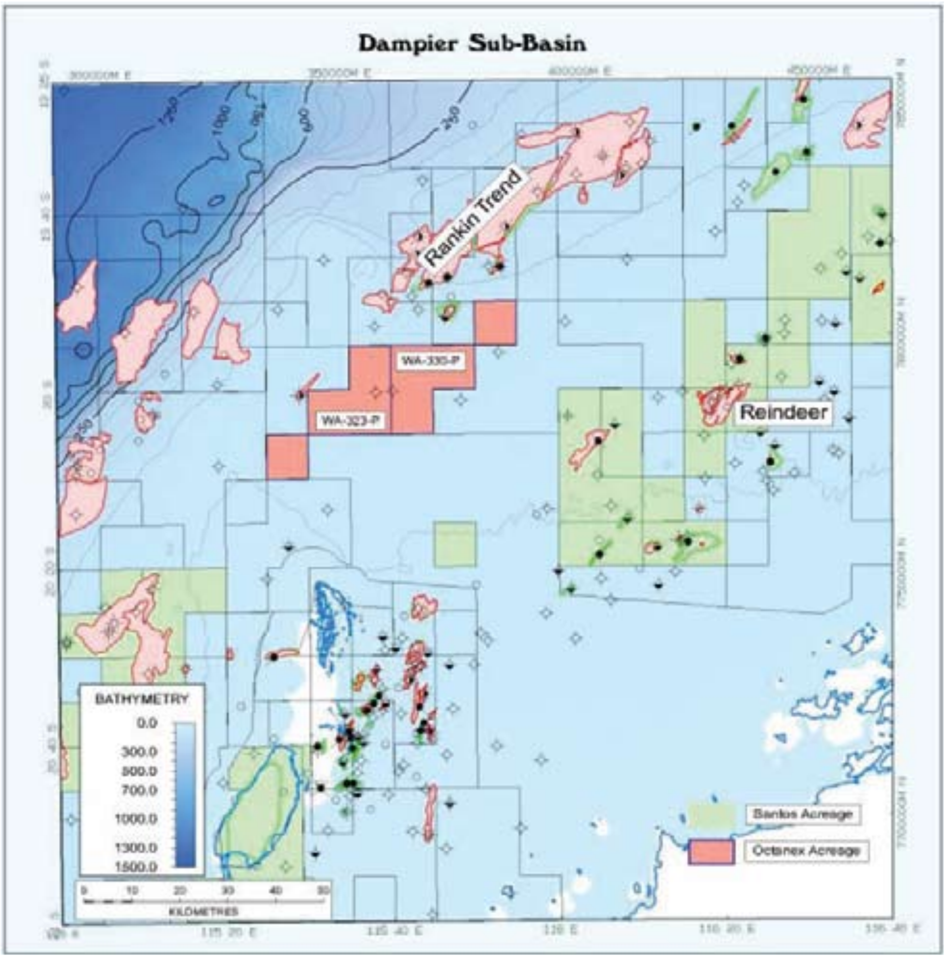
Santos drilled the Spar 2 well in WA-4-R and intersected 50+ m of net gas pay in the primary target Barrow reservoir. The target reservoir has exceptionally high productivity.

The previously stated expected recoverable resource in the Spar field was around 335 PJ gross, based on a pre-drill estimate of 26 m of net gas pay. With the Spar 2 net gas pay now confirmed, the recoverable resource (while still being assessed) will be significantly greater than previously stated.

The deeper secondary exploration target in the well has also intersected an approximate total of 40 m of net gas pay over several sands within the deeper B. *reticulatum* zone. A drillstem test was run over a 12 m section of this target and flowed at a gas rate of 141,584 m^3/d (5 MMscf/d), through a 25.4 mm (1 inch) choke. The current plan is to tie the Spar 2 well back to Varanus Island through the currently being developed Halyard 1 well. Spar 2 will be considered for recompletion over the deeper gas resource once the primary Barrow reservoir has been depleted.

Spar 2 is located approximately 70 km due west of Varanus Island, in the Carnarvon Basin, Western Australia and only 5 km from Halyard.

Santos holds 45% of WA-4-R. Apache owns the remainder and will become Operator of the permit.



Santos acreage – green permit areas

Farm-in to WA-323-P and WA-330-P (Carnarvon Basin)

Santos farmed into the prospective WA-323-P and WA-330-P permits. Santos was assigned 75% equity and operatorship of the permits based on acquiring a 3D seismic survey and drilling one well. The permits capture the very prospective Winchester gas prospect. If successful this opportunity can quickly be developed into the domestic gas market.

2011 Proposed Activities

Santos has a very active program planned for 2011 with the proposed drilling of four operated wells and two workovers.

Finucane South 1 (Carnarvon Basin, WA-191-P)

The program will commence with the drilling of a near field oil prospect Finucane South 1. The well is located on trend to the existing Fletcher 1/2 and Fletcher 3 oil discoveries. In the success case, these discoveries could potentially be tied back to the Mutineer/Exeter Production Facility located 15 km to the west.

Little Joe 1 (Carnarvon Basin, WA-208-P)

This proposed exploration oil well will test an anticlinal trap on trend from the Legendre oilfield. The well is scheduled to be drilled mid 2011. In the success case, there is a similar follow up oil opportunity in the vicinity.

Petrel 7 and Petrel 8 (Bonaparte Basin, WA-6-R & NT/RL1)

The Petrel Joint Venture is considering the drilling of two appraisal wells in the field. The wells will be located to confirm the field mapping and well productivity.

Mutineer 4 and Exeter 4 Workovers (Carnarvon Basin WA-26-L and WA-27-L)

Two workovers are planned for the Mutineer/Exeter fields. Both workovers will involve replacing the down-hole pumps.

Shell Development (Australia) Pty Ltd

Browse Basin

During 2010, Shell Development (Australia) Pty Ltd (SDA) submitted an application to drill for the Hippolyte prospect in Exploration Permit AC/P41 (Shell 75% and Operator, Mitsui E&P Australia 25%) and for the Concerto 2 appraisal well in Exploration Permit WA-371-P (Shell 100%). The Concerto 2 and Hippolyte 1 wells were spudded in 2010.

Carnarvon Basin

During 2010, SDA participated in five non-operated exploration wells (Keto 1, Acme 1, Brederode 1, Orthrus 2, Sappho 1) and one appraisal well (Clio 3).

In late 2010 and early 2011, SDA completed 3D seismic acquisition in permit WA-384-P in the Southern Exmouth Sub-basin (Shell 100%).

SDA, with partner Chevron, was successful in an application for gazettal block WA-444-P in the outer Exmouth Sub-basin.

In 2011, it is anticipated that SDA will participate in five exploration and appraisal wells in the Greater Carnarvon area.

Woodside Energy Ltd

Browse Basin

Drilling

No activity in 2010

Seismic

WA-415/416/417-P (Woodside 100%) acquired 4,100 line km of 2D seismic with the Koolama 2D MSS. The survey commenced on 25 May and was completed on 26 June 2010. The PGS vessel *Beaufort Explorer* was used to acquire the data.

Carnarvon Basin

Drilling

WA-404-P, Greater Pluto, Central Hub

Woodside 50 to 100% (Operator)

Drilling activity in WA-404-P in 2010 commenced with the successful discovery of hydrocarbons in Noblige 1. Including Noblige 1, seven wells were drilled in WA-404-P with four discoveries made, Noblige 1, Larsen 1, Larsen Deep 1, Remy 1. In addition, Martin 1 commenced drilling before the end of 2010. WA-404-P activity during 2011 is expected to focus on further exploration drilling and appraisal of discovered volumes.

WA-347-P, Greater Pluto, Cazadores South Hub

Woodside 90% (Operator)

Dalia South 1 was drilled but failed to intersect hydrocarbons; permits in the Cazadores Hub have been renewed.

WA-434-P, Greater Pluto, Claudius Hub

Woodside 100% (Operator)

Tiberius 1 was drilled to test a newly identified carbonate play and although the prognosis was successful the well failed to intersect hydrocarbons. Alaric 1 was then drilled and penetrated a gross gas bearing interval of approximately 185 m. During 2011, preparations will be made to drill two more Claudius hub wells following up on the success of Alaric 1.

WA-428-P, WA-430-P, WA-433-P, Greater Pluto, Ragnar Hub

Woodside 70% (Operator)

At least two Ragnar Hub gas prospects are proposed for drilling during 2011.

WA-28-L, Greater Enfield Area

Woodside 60% (Operator)

Cimatti 1 was drilled to test a 'near field' prospect within tieback distance to Enfield. Cimatti 1 successfully intersected a gross 15 m oil column in line with the pre-drill prognosis.

WA-255-P, Greater Enfield Area

Woodside 50% (non-Operator)

Furness 1 was drilled to evaluate the oil potential of a prospect in the southern portion of WA-255-P. The well failed to intersect hydrocarbons and was plugged and abandoned.

Seismic / CSEM

WA-428-P, WA-430-P, WA-433-P, Greater Pluto, Ragnar Hub

Woodside 70% (Operator)

A Controlled Source Electromagnetic Survey (CSEM) was acquired over the Ragnar Hub permits during December 2010. The survey commenced on 5 December and was completed on 22 December 2010. The FugroEMGS vessel *Boa Gallatea* was used to acquire the data. Data processing is underway and at least two Ragar Hub gas prospects are proposed for drilling during 2011.

PRODUCTION AND DEVELOPMENT ACTIVITY BY COMPANY

Chevron Australia Pty Ltd

2011 is set to be another landmark year for Chevron Australia which is leading the Gorgon and Wheatstone Gas Projects. The $43 billion Gorgon Project enters its second year of construction and a Final Investment Decision is expected for the Wheatstone Project near Onslow in the second half of 2011.

The Gorgon and Wheatstone Projects are set to position Chevron as a major LNG operator and will deliver energy, jobs and economic benefits to Australia, as well as assist in meeting long term demand growth for natural gas in Asia. They will provide opportunities and economic benefits on a scale never seen before in Australia. During peak construction, the Gorgon and Wheatstone Projects together, will create an estimated 16,500 direct and indirect jobs in Australia.

The two projects will generate almost $50 billion in expenditure on Australian goods and services and will bolster Government coffers by more than $60 billion through various tax revenue streams.

During 2011, Chevron will also continue to pursue its active exploration and appraisal program as part of its largest drilling campaign undertaken offshore Western Australia. Chevron will take delivery of a new rig, the Atwood *Osprey*, which will be involved in drilling development wells in the Greater Gorgon Area.

Chevron Australia operates Australia's largest onshore oilfield on Barrow Island together with the Thevenard oilfields; and is a foundation participant in the North West Shelf Venture and the Browse LNG development.

Barrow Island Facility, Carnarvon Basin

Barrow Island is located approximately 56 km from the Pilbara mainland, 1,300 km north of Perth. Since its discovery in 1964, the Barrow Island oilfield has produced more than 50 GL (316 MMbbl) of oil. Total oil production for Barrow Island (L1H) during 2010 was 311,510 kL. The total volume of water produced with oil during 2010 was 3,232,286 kL and the volume of gas was 18,615 km^3.

Since 1995, a total of 79 infill wells have been drilled in the Windalia reservoir on Barrow Island. The latest campaign took place in 2007–2008, comprising of 13 wells — eight water injectors and five producers. Nine of the 13 wells of this campaign were drilled proximal to the Barrow Fault targeting oil volumes unswept by the existing waterflood. Two of the remaining wells were drilled as production/appraisal wells in Production Blocks S and T on the northern flank of the Windalia oilfield. Preliminary analysis indicates that this campaign has been successful in targeting unswept oil, with results from the S and T Block wells stimulating further infill planning in the area.

The Atwood Osprey will drill development wells in the Greater Gorgon Area
(Photo courtesy of Chevron)

Construction in progress on Barrow Island for the Gorgon Project
(Photo courtesy of Chevron)

This work was complemented in 2009 with waterflood optimisation activities adopted in the Windalia field. The objective of this is to better allocate water and hence production returns. Water injection rates were also increased from less than 8 ML/d (50,000 bbl/d) to in excess of 9.9 ML/d (62,500 bbl/d).

Enhanced oil recovery (EOR) polymer injection is also being piloted in the Windalia F block to further target unswept oil in the reservoir, with results to determine whether the tertiary recovery technique is to be adopted field wide. These activities are all in line with strategies designed to increase the field life and enhance oil recovery from the reservoir.

Thevenard Island Facility, Carnarvon Basin

Thevenard Island is located about 25 km northwest of Onslow and has been the base for the processing and storage of hydrocarbons from the Saladin, Roller, Skate, Cowle and Crest fields.

Total oil production from the Thevenard production leases during 2010 was 112,793 kL. The volume of water produced during 2010 was 3,260,265 kL and the volume of gas was 14,936 km^3. The majority of water produced is re-injected back into the source reservoir.

Greater Gorgon Area Gasfields, Carnarvon Basin

The Gorgon Project plans to develop the Greater Gorgon Area gasfields, located between 130 and 200 km off the northwest coast of Western Australia. The Greater Gorgon Area gasfields are estimated to contain resources of about 113 Gm^3 (40 Tcf) of natural gas and are Australia's largest-known natural gas resource. Development of this substantial asset will secure Australia's position as a leading gas producer and generate a new source of wealth for Western Australia and Australia. The Gorgon Project has an expected economic life of at least 40 years.

The project includes:

- development of the Greater Gorgon Area gasfields involving subsea pipelines to Barrow Island;
- a gas processing facility on Barrow Island consisting of three, 5 mtpa LNG trains and a domestic gas phase with capacity of 300 TJ/d;
- LNG shipping facilities to transport products to international markets; and
- greenhouse gas management via injection of carbon dioxide into deep formations beneath Barrow Island.

A final investment decision (FID) on the Gorgon Project was taken in September 2009 and construction is progressing well. First gas is planned for 2014.

As of February 2011, the Project had generated more than 4,000 jobs in Australia and invested more the $10 billion into the Australian economy. It remains on track to deliver $20 billion in Australian Industry Participation expenditure during construction. This is the highest ever for an Australian resource project. Extensive economic modelling by an independent third party, ACIL Tasman, confirmed that the Gorgon Project will be Australia's largest resources project.

Other key economic findings based on the first 30 year operation of a 15 mtpa, three-train development include:

- peak construction employment in Western Australia of around 10,000 with more than 3,500 direct and indirect jobs sustained throughout the life of the Gorgon Project;
- an expected boost to Australia's Gross Domestic Product (GDP) of $64 billion net present value;
- locally purchased goods and services (local content) of $33 billion,
- expected Government revenue of around $40 billion in today's dollars.

The Gorgon Project received world recognition for its Carbon Dioxide Injection Project when it was formally recognised by the Carbon Sequestration Leadership Forum at its annual meeting in Poland in 2010.

The Chevron-operated Gorgon Project is a Joint Venture between the Australian subsidiaries of Chevron (approximately 47 per cent), ExxonMobil (25 per cent), Shell (25 per cent), Osaka Gas (1.25 percent), Tokyo Gas (1 per cent) and Chubu Electric Power (0.417 per cent).

Wheatstone and Iago Fields, Carnarvon Basin

The Wheatstone gasfield is located about 145 km off Western Australia's Pilbara coast, adjacent to another Chevron-operated field, Iago. To process the gas from these and other fields, Chevron plans to initially construct two LNG trains with a total capacity of 8.6 mtpa and a domestic gas plant at Ashburton North near Onslow. It eventually could have the capacity to produce up to 25 mtpa of LNG and associated domestic gas.

The Wheatstone Project is set to be one of Australia's largest resource projects, providing greater security of supply and offering significant economic benefits including employment, government revenue and local business opportunities for generations of Australians. The project is expected to create about 6,500 direct and indirect jobs during construction.

The project provides not only a foundation for commercialising the Wheatstone resource, but also future gas development opportunities in the western half of the Carnarvon Basin.

The Wheatstone Project moved into the front-end engineering and design (FEED) phase in 2009 and Final Investment Decision is expected in the second half of 2011.

During 2010, Chevron signed a binding Heads of Agreement with the Thalanyji Native Title holders for the Wheatstone Project.

In December 2010, Chevron finalised Joint Operating Agreements (JOAs) with announced Apache Julimar Pty Ltd, a subsidiary of the Apache Corporation, and KUFPEC Australia Pty Ltd, a subsidiary of the Kuwait Foreign Petroleum Exploration Company, as natural gas suppliers at the Wheatstone natural gas hub and equity participants in the project facilities.

Under the agreement, Apache and KUFPEC will provide natural gas from their Julimar and Brunello fields to supply Train 1 and 2 of the Wheatstone Project.

Eni Australia Limited

In WA Eni participates in three Production Licence areas and one Retention Lease, all of which it operates.

Woollybutt (WA-22-L and WA-25-L)

The Woollybutt oilfield is located in the WA-25-L Production Licence in the Carnarvon Basin and contains two separate lobes. The North Lobe has been in production since 2003 and its current production is around 668 kL/d (4,200 bbl/d).

In March 2010, production from the Woollybutt field was restarted after the re-certification of the FPSO *Four Vanguard* operating on the field.

The refit of the FPSO, now named *Four Rainbow*, has ensured the maximum exploitation of the field. Originally expected to have a field life of 3-4 years and total production of 2.9 GL (18 MMbbl), the Woollybutt field has produced over 5.4 GL (33.7 MMbbl) to date and has an expected field life of another 1-2 years. The FPSO *Four Rainbow* has a design production capacity of 6.4 ML/d (40,000 bbl/d).

Eni is Operator of the field with 65% equity on behalf of Joint Venture partners Mobil Australia Resources Co Pty Ltd (20%) and Tap West Pty Ltd (15%).

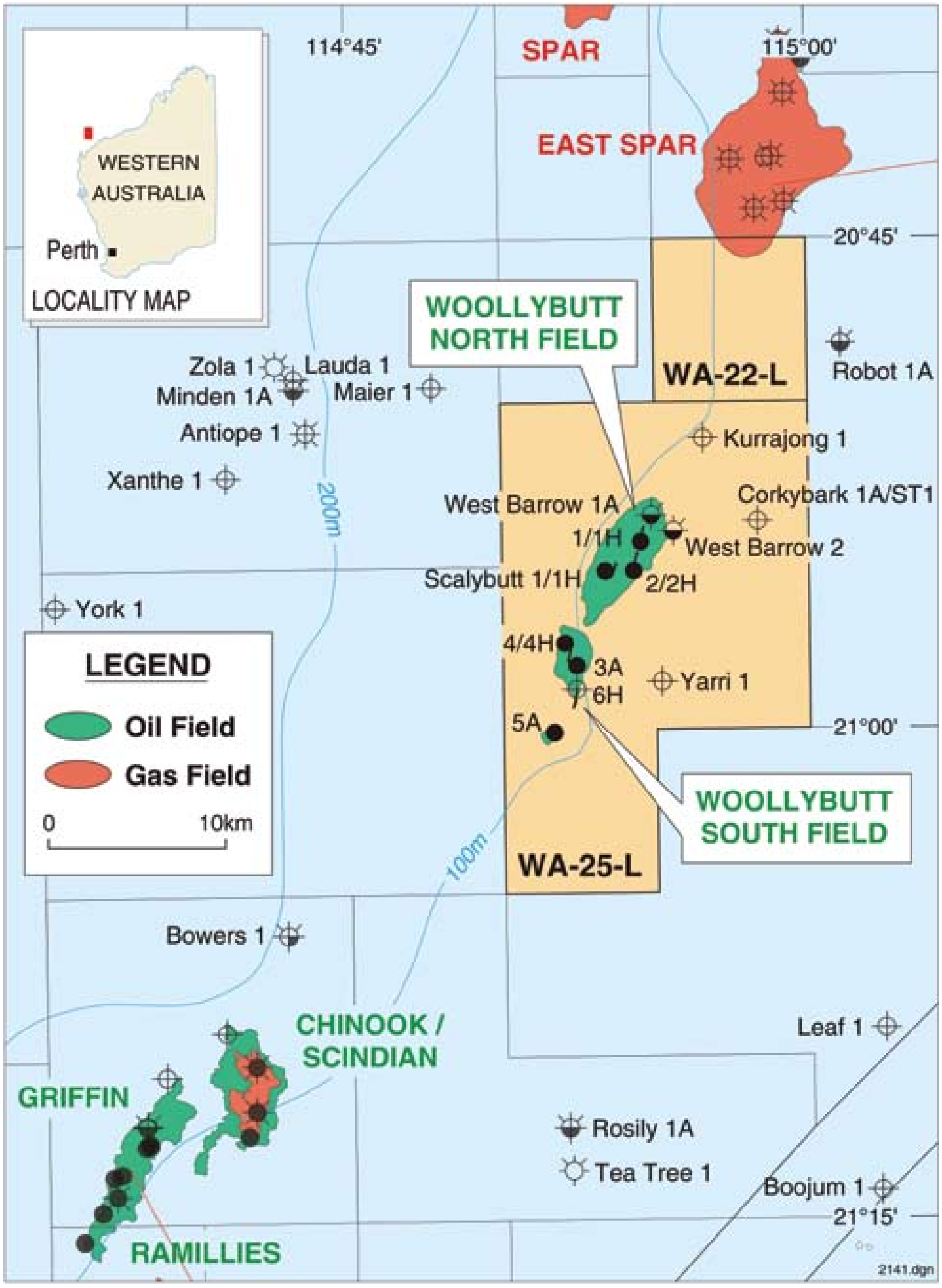
Blacktip (WA-33-L)

The Blacktip field is located in the Production Licence WA-33-L within the Exploration Permit WA-279-P.

In 2006, Eni began the development of the field based on the development concept of an unmanned well head platform (WHP) connected to an onshore gas plant (OGP) via a 110 km pipeline. The OGP is located at Yelcherr, near the town of Wadeye in the Northern Territory.

The Blacktip gasfield was developed to provide gas to the Northern Territory's Power Water Corporation (PWC) for power generation in the NT. The Gas Sale Agreement, concluded in 2006, is for the supply of gas over a 25 year period, commencing at 23 petajoules (PJ) per year rising to 38 PJ per year over the life of the contract.

Commissioning of the Blacktip Project commenced in mid 2009 with early gas supply starting in September. By mid December, dry sales gas was being provided to the PWC from the Blacktip Project. Production from the field during 2010 has been regulated by the buyer's gas demand, following a gas nomination of more than 22 PJ per year. The onshore gas plant has a design production capacity of 44 PJ per year.



Eni's Woollybutt oilfield in WA-25-L in the Carnarvon Basin

The Blacktip platform in WA-33-L
(Photo courtesy of ENI)

The Blacktip Project is 100% owned and operated by Eni.

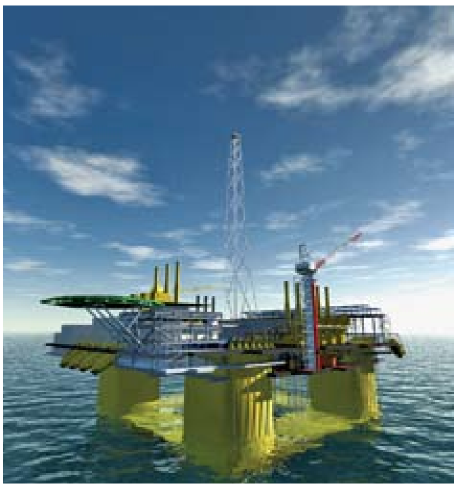
INPEX Browse, Ltd

Ichthys LNG Project

The Ichthys field is located in Retention Lease WA-37-R and Location 1SL/09-0 in the Browse Basin, approximately 200 km off the coast of Western Australia. The most likely resource estimates are 362 Gm^3 (12.8 Tcf) of gas and 83.8 GL (527 MMbbl) of condensate.

In early 2011, the Ichthys LNG Project was in the late stages of front-end engineering and design. Invitations to tender (ITTs) for construction of the offshore and onshore facilities were issued in late 2010, including for the floating central processing facility (CPF). The CPF would be one of the largest of its type ever built and the first time such a floating facility is utilised in Australian waters.

The Ichthys Project is a Joint Venture between INPEX Browse Ltd (76%, Operator) and Total E&P Australia (24%).



The Ichthys LNG Project's floating central processing facility would be one of the largest of its type ever built and the first time such a facility is utilised in Australian waters.

Origin Energy

Origin Energy is the Operator of the Jingemia oilfield (49.189%) and the Beharra Springs and Tarantula gasfields (66.67%) in the Perth Basin in WA. Origin is also a 50% joint venture partner with AWE in the Hovea/Eremia oilfields and Xyris Area Gas Gathering System (XAGGS).

The Redback 2 appraisal well was drilled from the same lease as the Redback South 1 exploration well. A 2.2-km production flowline was installed to tie-in the two Redback wells to the Beharra Springs gas plant. Redback 2 was brought online under a production test regime. Redback South 1 will be worked over to remediate completion integrity issues.

A workover on both Jingemia 4 and Jingemia 8, to repair well integrity and repair the artificial lift system, was successfully completed. An EOR chemical flood study was undertaken to review the feasibility of increasing oil recovery from the field. The Jingemia oilfield produced a total of 21.8 ML (137,000 bbl) of oil.

The Beharra Springs gas facility is located 35 km southeast of the township of Dongara and sold a total of 2.0 PJ (5.5 TJ/day) in 2010 from five production wells, the four Beharra Springs wells in natural field decline and Redback 2 at original discovery pressure.

The non-operated fields produced a total of 22.1 ML (139,000 bbl) and 0.45 PJ.

Planned development and production activity for 2011

Origin intends to workover Redback South 1 early in 2011 to repair the completion and bring the well into production.

Depending on further success in the exploration campaign, the gas plant may undergo de-bottlenecking or expansion to increase through-put.

ROC Oil Company Limited

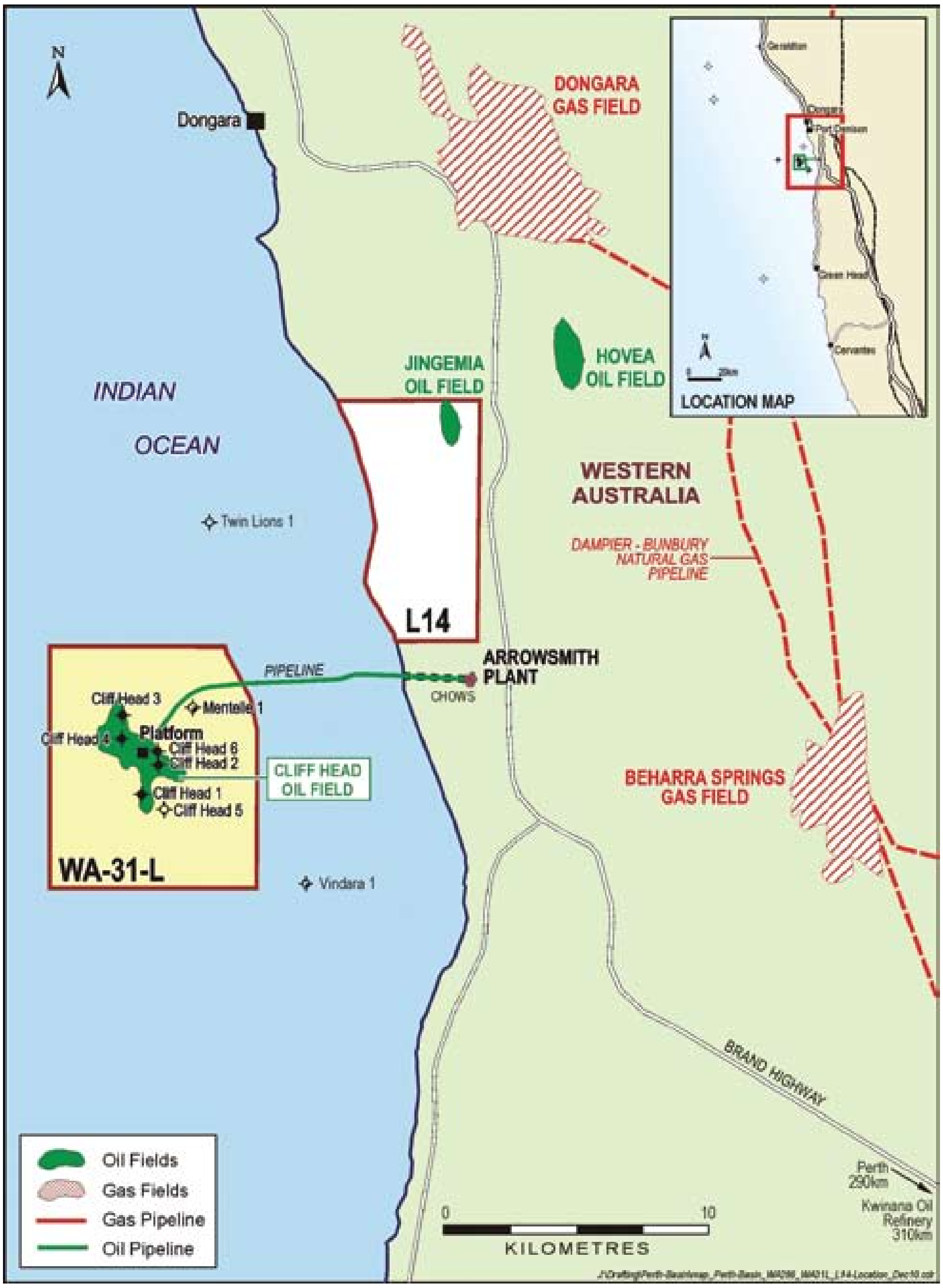
Cliff Head Oilfield — WA-31-L

Production operations at Cliff Head continued with good production performance and safety record in 2010. Total gross production in 2010 was 234,030 kL (1,476 Mbbl) or 643 kL/d (4,045 bbl/d). This is a four per cent increase compared to the previous year due to the successful completion of workovers in Q4 2009 and Q1 2010 that replaced electric submersible pumps (“ESP”) at the Cliff Head 6 and Cliff Head 10 production wells.

On 20 August 2010 cumulative Cliff Head oil production reached 1.6 GL (10 MMbbl). On 5 February 2011, the Cliff Head project celebrated five years operations without a Lost Time Injury.

During the year planning continued for another workover to install a higher-rate ESP at the Cliff Head 12 production well. Workover operations were initiated in early January 2011. A coiled tubing workover of Cliff Head 9 to investigate and remediate high water influx is also planned.

The field is in its mature phase of a slow, natural decline which is scheduled to last many years, during which time the focus will be on optimising well production performance and recovery.



ROC Oil’s Cliff head field in WA-31-L

Woodside Energy Ltd

Production

In 2010 Woodside produced 11.5 GL (72.7 MMbbl) of oil equivalent. This was lower than 2009 due to divestment of Woodside’s interest in the Otway Gas Project and oilfield natural decline.

The North West Shelf project achieved record LNG production following successful modification of Train 5’s main cryogenic heat exchangers in May 2010. Woodside’s share of LNG production in 2010 was 2.61 million tonnes up from 2.40 million tonnes in 2009. During the year Woodside, as Operator of the North West Shelf Venture, delivered a record 261 cargos of LNG. The 3,000th cargo of LNG since the North West Shelf commenced production in 1985 was loaded in August 2010.

Pluto

The foundation Pluto LNG Project was more than 95 per cent complete at the end of December 2010 with start-up targeted for August 2011.

The offshore pipelines were ready-for-use having been de-watered, vacuum dried and nitrogen purged. The fifth and final production well was completed and flow tested during the quarter. Onshore the transition from construction to commissioning will continue into 2011.

Work to expand beyond the initial Pluto foundation LNG train is ongoing. During the current Carnarvon Basin exploration campaign Woodside successfully drilled six discoveries from ten exploration wells in the Pluto inner and central hubs (including blocks WA-34-L, WA-350-P, WA-404-P). During fourth quarter 2010, Woodside purchased a 50% participating interest in Exploration Permit WA-404-P from Hess Exploration (Carnarvon) Pty Ltd, increasing its equity to 100%. Discussions continue with third parties in the Carnarvon Basin regarding the potential to process gas through additional trains at Pluto.

Browse

In 2010 Woodside completed Basis of Design (BOD) studies for the Browse LNG Development, on time and to budget. The first of the pre-FEED contracts, for the central processing facility was awarded in October. The subsea and pipelines, dry tree units and downstream pre-FEED packages were awarded in December to allow a seamless transition into FEED in early 2011.

The completion of BOD studies and other development activities met the requirements of the Retention Lease conditions issued by the Commonwealth and agreed to by the Browse Joint Venture participants in February 2010. During the year the Browse Joint Venture concluded a series of environmental and geotechnical studies to support the design of offshore installations, pipelines and port infrastructure for the Browse LNG Development and the Western Australian Government's Browse LNG Precinct. Discussions on a land access agreement for the Browse LNG Precinct continued between the Western Australian Government, Woodside and the Traditional Owners of James Price Point.

The Browse LNG Development plans to commercialise gas and condensate reserves in the Brecknock, Calliance and Torosa fields of the Browse Basin. The development concept is based on three infield tension leg platforms for hydrocarbons recovery; a central processing facility in shallower water; a 315-km, 42-inch trunkline to transport gas and liquids to shore; and a three-train, 12 mtpa LNG production facility with associated export infrastructure.

In 2011 Woodside plans to complete FEED and be in a position to take a FID by mid-2012.

North West Shelf

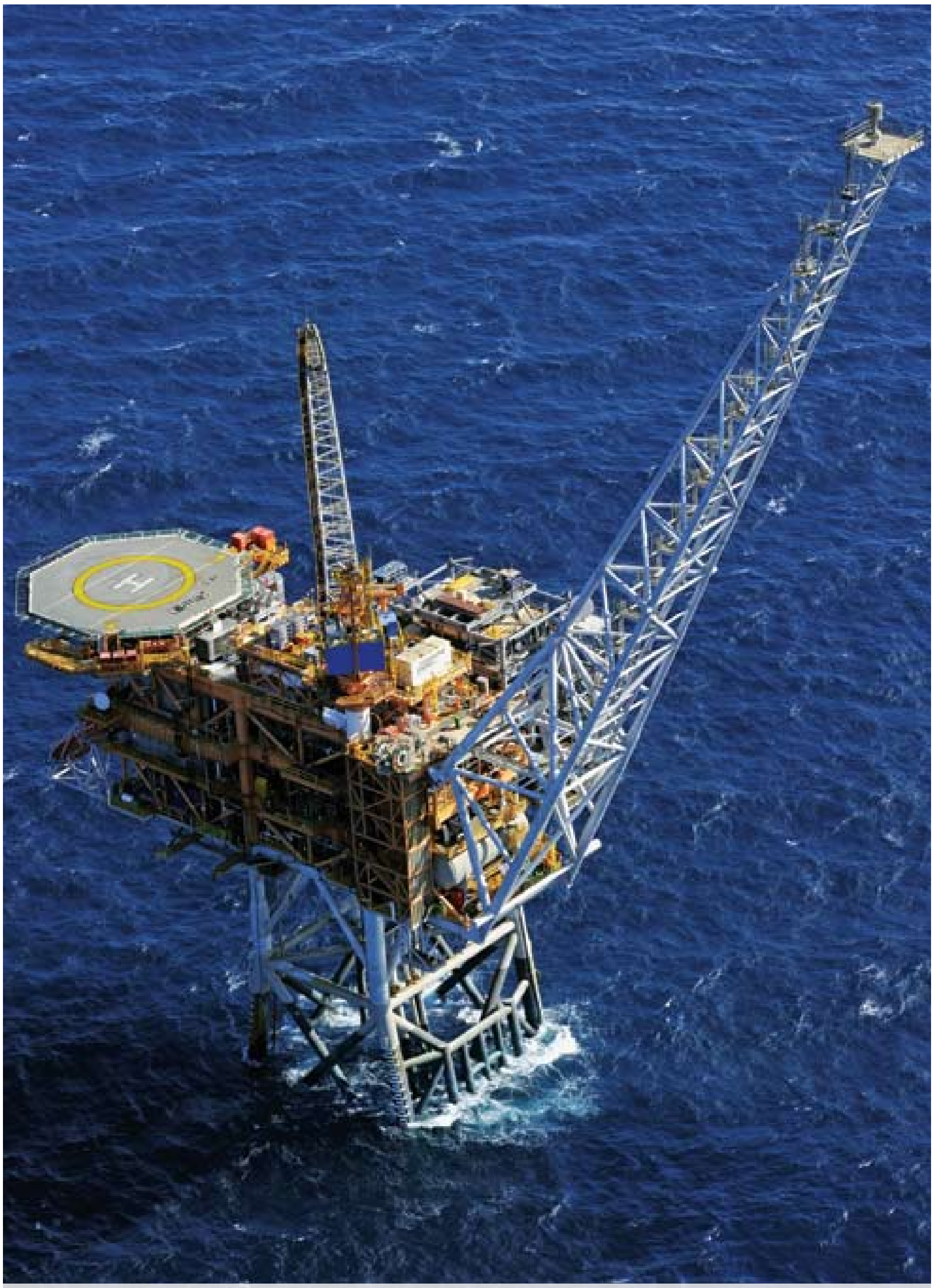
With improvements in capacity utilisation, the Woodside-operated, North West Shelf Venture achieved record production levels in 2010.

North Rankin Redevelopment

The project remains on cost and schedule with work continuing on the North Rankin B (NRB) jacket, piles and bridges fabrication in Indonesia and topsides fabrication in Korea. Installation of the support structure at NRA for the north bridge-link was completed ahead of schedule and the south bridge-link has commenced. At end of year the project was 63 per cent complete. The project is expected to cost approximately $5 billion ($840 million Woodside share) and is scheduled for completion in 2013.

North West Shelf Oil Redevelopment

Overall construction works are nearing completion for the *Okha* FPSO conversion and first production is scheduled for 2011 with the project at 86 per cent complete at the end of 2011. Commissioning works commenced as planned at the end of 2010, following completion of major construction works at Keppel Shipyard in Singapore.



The Pluto platform was installed in 2010 in WA-34-L
(Photo courtesy of Woodside Energy)

Greater Western Flank Development

The first phase of the Greater Western Flank (GWF) gas development is on track and is has moved into FEED. The GWF area is estimated to hold approximately 85 Gm^3 (3 Tcf) of recoverable gas and approximately 16 GL (100 MMbbl) of condensate from 14 fields to the southwest of Goodwyn A. The GWF together with other undeveloped gas reserves will maximise returns from existing infrastructure, maintain offshore supply to fill the Karratha Gas Plant capacity to beyond 2020 and support ongoing marketing.

Australia Business Unit

Vincent

While 2009 was a challenging year for Vincent, 2010 has seen increasing oil production throughout the year. This is due to higher facility uptime, the successful introduction of production from new infill wells adding over 1.6 ML (10,000 bbl) a day, and the use of the subsea multiphase pumps in Q3 2010 to provide artificial lift to the wells. Work is continuing to reinstate the gas compressors and current plans are to have them fully operational in the first half of 2011. The Vincent 4D seismic acquisition commenced in late 2010 providing valuable information on additional long term infill opportunities along with detailed performance data on existing wells.

The Vincent development currently comprises ten producing oil wells tied back to the *Ngujima-Yin* FPSO. At the end of the year the facility was producing 4 ML (25,000 bbl) of oil per day. In the first half of 2011 Woodside plan to drill two new infill wells which are expected to increase production as they target unswept parts of the reservoir. A third well is planned for late 2011 or early 2012 depending on drill rig availability.

Enfield

In 2010, ongoing activity at Enfield has focused on maintaining production and identifying new opportunities for development. Compared to 2009, Enfield achieved a significant increase in oil production following restoration of gas lift to all wells and a successful 2009 infill drilling campaign. Two new development wells were drilled in 2010; the “Main West” well came on stream in August and the “Horst” well in October. In November the Cimatti 1 exploration well successfully intersected a gross oil column of 15 m. The Cimatti 2 sidetrack well was also completed during the year to further appraise the field and speed up potential development. The Cimatti field may be tied back to Enfield with first oil from the field possibly as early as mid-2013. The Enfield development currently comprises eight oil-production wells, five water-injection wells and two gas injection wells tied back to the *Nganhurra* floating production storage and offloading vessel (FPSO). At the end of 2010 the facility was producing a total of 5 ML (31,000 bbl) of oil per day.

In 2011 a 4D seismic survey to evaluate further infill and near field exploration opportunities is planned. Past surveys have assisted in locating successful infill opportunities. This will be the fifth Enfield 4D survey.

Laminaria-Corallina

While natural field decline continued at Laminaria-Corallina during 2010, ongoing reservoir studies provided better understanding of the fields and will ensure production and recovery is maximised. Additional production capacity of approximately 80 kL (500 bbl) of oil per day was realised with the reinstatement of the production test riser.

The Laminaria-Corallina development currently comprises five production wells and one gas-injection well tied back to the *Northern Endeavour* FPSO. At the end of the year the facility was producing 1.5 ML (9,200 bbl) of oil per day, and provides the highest reliability of a Woodside manned and operated facility. A range of additional opportunities continue to be evaluated which could further increase short-term production levels. A strategic review of future opportunities for this asset is now underway.

Stybarrow

During 2010, Stybarrow production was supported by water injection and continued to be managed in line with natural field decline. It is expected that production will be slightly higher next year as 2010 production was impacted by significant off-station maintenance work on the FPSO swivel and a number of unplanned shutdowns in the second half of 2010 to perform critical maintenance activities. The Stybarrow North infill well, drilled in Q3 2010 and tied-in during December 2010, will contribute to production in 2011. The Stybarrow development comprises five oil-production and three water-injection wells tied back to the *Stybarrow Venture* FPSO. At the end of 2010 production was 4,276 kL (26,900 bbl) of oil per day. In order to identify further infill drilling opportunities a 4D seismic survey is planned for 2011.

Laverda

Appraisal drilling commenced in December 2010, continuing into the first half of 2011. Development concepts include possible stand-alone FPSO or tie-back to existing projects in the area. Engineering work is progressing, including subsea evaluation, potential topside requirements and optimised well locations. Concept narrowing is underway to reduce the number of development options and progress to the next stage of engineering.

The Opel 1 exploration well, located adjacent to Laverda, is scheduled to be drilled in early 2011 as part of the Laverda appraisal drilling program. ■

The *Jack Bates* drilling rig
(Photo courtesy of Kai Photography and Hess Exploration)

Richard Bruce
Exploration Geologist
Resources Branch

Awards of Petroleum Exploration Permits

Commonwealth Award of Petroleum Exploration Permits

These new permits result from the second round of the 2009 Acreage Release that closed on 29 April 2010.

Commonwealth award information was sourced from Western Australia's online Petroleum and Geothermal Register.

The total indicative value of work commitments for the following Commonwealth permits is A$43.43 million.

In November 2010 the permits granted were WA-451-P and WA-452-P.

WA-451-P (released as W09-18) in the Dampier Sub-basin has been awarded to *Woodside Energy Ltd*. The company proposed a guaranteed work program of geotechnical studies, 748 km^2 of 3D seismic reprocessing, 500 km of 2D seismic reprocessing and one exploration well to an estimated value of $19.44 million. The secondary work program consists of geotechnical studies, 500 km of 2D seismic reprocessing and one exploration well to an estimated value of $10.69 million. There was one other bid for this area.

WA-452-P (released as W09-13) in the Dampier Sub-basin has been awarded to *Riverina Energy Ltd*. The company proposed a guaranteed work program of geotechnical studies, 150 km of 2D seismic reprocessing and 105 km of 2D seismic survey to an estimated value of $3.15 million. The secondary work program consists of geotechnical studies and one exploration well to an estimated value of $10.15 million. There were no other bids for this area.

State Award of Petroleum Exploration Permits

The total indicative value of work commitments for the following State permits is A$105 million.

To the end of January 2011, petroleum Exploration Permits awarded in State areas were as follows:

In March 2010, **EP 468** (released as L04-6) in the Officer Basin was awarded to *Frontier Oil & Gas Pty Ltd*. The firm two year program consists of geological studies and 100 km of 2D seismic acquisition to an estimated value of $500,000. The remaining program consists of three exploration wells and 100 km of 2D seismic acquisition to a value of $2 million.

In April 2010, **EP 469** (released as L07-13) in the Perth Basin was awarded to *Warrego Energy Pty Ltd*. The firm two year program consists of geotechnical studies, engineering studies, 22 km of 2D seismic reprocessing and 250 km of 2D seismic acquisition to an estimated value of $3.9 million. The remaining program consists of engineering studies, four exploration wells, 250 km^2 of 3D seismic acquisition and field development to an estimated value of $40.6 million.

In April 2010, **EP 470** (released as L08-5) in the Northern Carnarvon Basin was awarded to *Energetica Resources Pty Ltd*. The firm two year program consists of geotechnical studies and 365 km of 2D seismic reprocessing to an estimated value of $500,000. The remaining program consists of 125 km of 2D seismic acquisition and interpretation, one exploration well and geotechnical studies to an estimated value of $8 million.

In October 2010, **EP 471** (released as L05-2) in the Canning Basin was awarded to *Arc Energy Ltd*. The firm two year program consists of geological studies, 2D seismic reprocessing, geophysical studies and 150 km of 2D seismic acquisition to an estimated value of $1.425 million. The remaining program consists of geological studies, geophysical studies and two exploration wells.

In October 2010, **EP 472** (released as L08-3) in the Canning Basin was awarded to *Buru Energy Ltd*. The firm two year program consists of 225 km of 2D seismic acquisition and two exploration wells to an estimated value of $11.25 million. The remaining program consists of geotechnical studies, 100 km of 2D seismic acquisition and one exploration well to an estimated value of $5.7 million.

In December 2010, **EP 473** (released as L05-1) in the Canning Basin was awarded to *Buru Energy Ltd*. The firm two year period program consists of geological and geophysical studies, 2D seismic reprocessing and 200 km of 2D seismic survey to an estimated value of $1.95 million. The remaining program consists of geological and geophysical studies and two exploration wells to an estimated value of $3.725 million.

In December 2010, **EP 474** (released as L07-9) in the Canning Basin was awarded to *Buru Energy Ltd*. The firm two year period program consists of geotechnical studies, 400 km of 2D seismic survey, 2D seismic reprocessing and two exploration wells to an estimated value of $11.25 million. The remaining program consists of geotechnical studies, 200 km of 2D seismic survey and one exploration well to an estimated value of $5.7 million.

In January 2011, **EP 475** (released as L08-4) in the Northern Carnarvon Basin was awarded to *Energetica Resources Pty Ltd*. The firm two year period program consists of geotechnical studies and 365 km of 2D seismic reprocessing to an estimated value of $500,000. The remaining program consists of a 125 km of 2D seismic survey, seismic interpretation, one exploration well and geotechnical studies to an estimated value of $8 million. ■

Company Focus: Whicher Range Energy Ltd

On site at the Whicher Range gasfield
(Photos courtesy of Whicher Range Energy)

Whicher Range Gasfield

The Whicher Range gasfield is a well-known field in the South West of Western Australia, and has challenged a number of operators over the years with its considerable in-place volumes and complex geology. Despite the best endeavours of earlier operators, commercial productivity has remained elusive. However, with the increasing success of the oil and gas industry to profitably develop unconventional gas reserves, and as external factors such as gas demand and infrastructure change, so too does the opportunity to produce from valuable resources that have been locked up over the years.

Whicher Range Energy is now poised to address the benefits of higher gas prices, high gas demand and "game changing" leaps forward in unconventional gas technology to unlock the Whicher Range gas resource. The significant gas volumes contained in the field have the potential to provide a hugely positive boost to gas supply in Western Australia.

Whicher Range Energy Pty Ltd (WRE) is a privately held oil and gas company located in Perth Australia. The company was established in 2007 to pursue oil and gas resources in Western Australia that may have been overlooked due to the technical challenges associated with the hydrocarbon resource.

The company is closely affiliated with leading drilling consultancy Advanced Well Technologies (AWT). This relationship enables the latest "state of the art" technologies that are being utilised on equally challenging resources globally to be developed and applied to the company's assets in Western Australia.

Whicher Range Energy holds a 100% interest and is the Operator (100%) of the Whicher Range gasfield and the surrounding Exploration Permits EP 408 and EP 381. These permits contain the discovered Whicher Range gasfield, the untested Wonnerup 1 gas discovery and the undrilled Whicher Range South structure, which are of a similar geological play type within the permits.

The Whicher Range field has a long history of attempts at addressing the technical challenges. The discovery well was drilled in 1968 by Union Oil, and after considerable attempts at testing, was considered non-commercial due to the limited productivity of the reservoir. The reservoir was classified as "tight" gas, and at the time, was considered to be of little interest in an area with limited infrastructure and demand. Over the next 42 years, four further wells were drilled. Each well intersected significant hydrocarbon columns, but economic productivity remained elusive. Whicher Range Energy believes that the significant developments in technology for unconventional gas, particularly in North America, will now unlock this large gas resource.

Access road to the Whicher Range field with the Whicher Range in the distance

The Whicher Range field is a large, well delineated gas resource with five well penetrations and seismic coverage, defining a gas-in-place resource potentially exceeding 141 Gm^3 (5 Tcf). The field is situated in the onshore southern Perth Basin, 280 km south of Perth, approximately 35 km from a tie-in point to the low pressure end of the Dampier to Bunbury natural gas pipeline (DBNGP). The field is proximal to existing industrial and commercial customers who require more gas than is currently available. It is forecast that demand for gas will increase in the short to medium term, and the shortfall is expected to increase significantly as further pressure is placed on the existing gas infrastructure.

A successful development of any large onshore gas project, such as the Whicher Range gasfield, has the potential to displace gas from offshore LNG projects, as LNG commands a higher price to its export customers than they achieve from domestic, piped gas sales. An arbitrage opportunity exists for potential LNG exporters to offset their domestic gas supply obligations, and maximising their LNG exports, by investing in onshore gas projects.

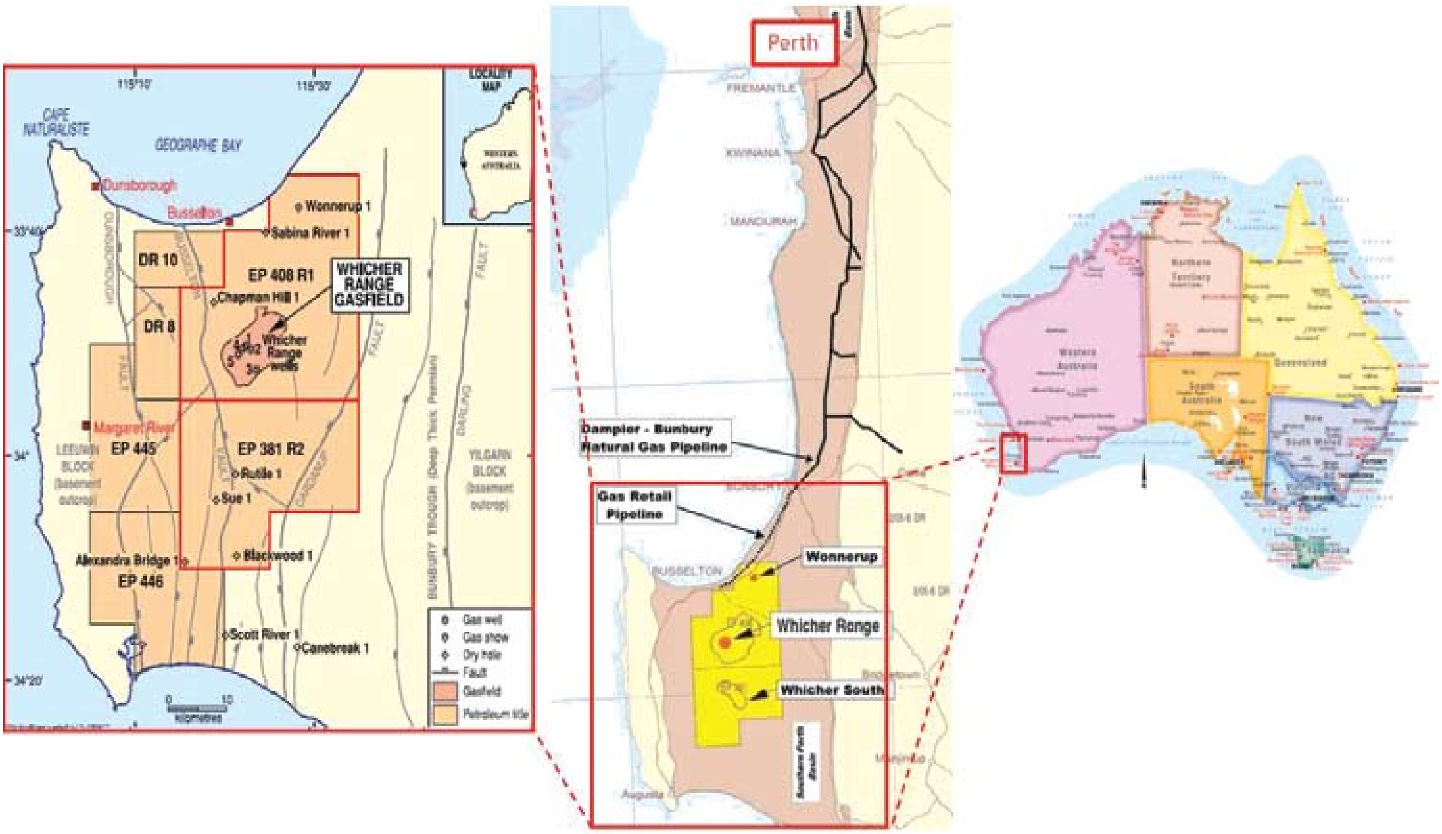
In particular the location south of Perth makes Whicher Range gas competitive against offshore North West Shelf supplies and the tariffs required to deliver gas 1,500 km via the DBNGP, to the market. It is also expected that in time, the DBNGP will be extended south to Albany thereby opening up further commercial demand.

Whicher Range Energy has undertaken extensive studies to better understand the complexities of the field, and in particular, why previous operators have not been successful in appraising and developing the field. In parallel, the company has reviewed best operator practices globally to develop a view on how best to apply the right technology to the field.

In adhering to these practices, Whicher Range Energy has been working with Curtin University, The University of Western Australia and the CSIRO (Commonwealth Scientific and Industrial Research Organisation) under direction from the Department of Mines and Petroleum, supported by a $750,000 Government funded study. This work is considered vital in getting the best academic skills and knowledge in the State applied to an extremely valuable resource in Western Australia. The study has focused on the structural and depositional geology of the field, and in particular, potential damage mechanisms that need to be carefully managed when drilling future wells. This work, under the auspices of WA:ERA (Western Australian Energy Research Alliance) is approximately half complete, and the results of the study in conjunction with best global drilling practices will enhance the prospects of the field considerably.

Whicher Range Energy intends to drill the next well on the field in 2011 to obtain valuable reservoir data including that identified in the Government funded studies. The well penetration will ideally be a new drill well, although a sidetrack of an existing well is also being explored as a more cost effective option. Key to the success of this new well will be to manage reservoir damage in order to fully assess undamaged reservoir potential. The next step will be to evaluate lateral reservoir connectivity.

A successful test will quickly lead to a first phase development designed to establish commercial production whilst further delineating the field. The current development concept is based



Location of the Whicher Range gasfield in the southern onshore Perth Basin

on modularised production facilities to enable “bolt on” expansion to further increase total production.

There are opportunities in the regional power generation markets, which are currently supplied by distant coal-fired generators. These provide a faster tracked, lower risk, lower capex, scalable commercialisation option based on the currently available gas volumes. These are currently being evaluated, as are other alternatives to the large scale capex required to install a 35 km gas pipeline.

WA’s road transport industry is currently moving towards LNG as a transport fuel. The nearest LNG supplier to the large South West market is based in Kwinana, almost 300 km to the north and a small scale LNG module on site would enjoy considerable cost, transport advantages and a regional monopoly.

A secondary activity will be to further appraise the Whicher Range South prospect and to further appraise the Wonnerup 1 discovery north of the Whicher Range field. Whicher Range South, located immediately south of Whicher Range gasfield in EP 381 is a significant potential extension of the Whicher Range field but is yet to be validated with the drill bit. It is a compelling high probability target which could add substantially, circa 28 Gm^3 (1 Tcf), to the gas-in-place volumes associated with Whicher Range.

The Wonnerup 1 discovery in EP 408, approximately 25 km north of the Whicher Range gasfield was drilled in 1972 by Union Oil. The well encountered similar sand units to that of the Whicher Range field, and had good gas shows and fluorescence throughout the reservoir interval. However, the well was not successfully tested due to a mechanical failure during testing and logging operations.

Given the potential significance of the Wonnerup discovery, Whicher Range Energy is investigating options to fast track the Wonnerup appraisal, possibly independent to the ongoing appraisal of Whicher Range gasfield. This may lead to the areas immediately surrounding Wonnerup being excised from the current permit to enable parallel activities to be undertaken on Wonnerup and Whicher Range gasfield.

Whicher Range Energy in conjunction with Advanced Well Technologies is working with local oil and gas industry to investigate ways to develop more cost effective operational practices, including cost sharing with other operators in the Perth Basin, and the use of innovative less conventional drilling rigs.

Both Whicher Range Energy and the WA Department of Mines and Petroleum consider the gas resource in the permits as significant and strategically important to the State, and significant in size in global terms. A successful development of the field has the potential to positively challenge the dynamics of the domestic gas market. It is hoped that the Whicher Range gasfield could be considered as an alternative domestic supply to the North West Shelf gas project, and in doing so, address security of supply to the State of Western Australia which will be good for all Western Australians.

The work that has been undertaken by Whicher Range Energy now provides a new insight into the complexities of the reservoir. The advancements in developing similar reservoirs throughout the world, and the increased demand for energy in the State give the company confidence that the time has now come for this valuable gas resource to be unlocked. ▪

Testing Whicher Range 4 in September 2008

State Areas Released for Petroleum Exploration April 2011

Richard Bruce
Exploration Geologist
Resources Branch

Vibroseis trucks from the Bunda 3D seismic survey in the Canning Basin in 2010
(Photo courtesy of Buru Energy Ltd)

DMP continues to promote the petroleum potential of Western Australia's vast sedimentary basins using a specific area release system.

A CD package accompanies the acreage release and contains information about the prospectivity of release areas, available data listings, land access and how to make a valid application for an Exploration Permit.

In April 2011, DMP released a total of nine blocks (Fig. 1). This release comprised four blocks in the Canning Basin, two blocks in the offshore Northern Carnarvon Basin, two blocks in the Blake Sub-basin of the Officer Basin, and one block in the Perth Basin's Coastal Waters.

Interest in the Canning Basin has increased in recent times particularly with ARC Energy and ARC's spinoff company Buru Energy taking up an extensive acreage holding, drilling wells and acquiring 2D and the basin's first 3D seismic. In addition, Mitsubishi Corporation has exercised its option to participate in Buru's 2011 exploration program in the Canning Basin. The size of the Canning Basin blocks ranges from 2,033 km^2 to 7,787 km^2.

Release area L10-1 is situated on the Lennard Shelf and is 4,091 km^2 in size. Hydrocarbon shows are widespread on the Lennard Shelf with economic accumulations of oil immediately southeast of L10-1. These accumulations are found in a Devonian carbonate reef and in Permian-Carboniferous clastics.

Release areas L11-1 and L11-3 are situated along the northeast margin of the Canning Basin. They are 7,787 km^2 and 5,809 km^2 in size. There are a variety of plays in these areas such as Ordovician, Devonian and Carboniferous reservoirs, with Lower Carboniferous source rocks.

Release area L11-2 is situated 50 km east of Broome and is 2,033 km^2 in size. The Broome Platform has Ordovician sourced plays including migration into Permian reservoirs, and has some shale gas potential. On the Mowla and Jurgurra Terraces there are plays involving thick Devonian and Carboniferous successions, with Lower Carboniferous source rocks.

The size of the Blake Sub-basin L10-4 and L10-5 blocks is very large (30,795 km^2 and 30,097 km^2 respectively), reflecting the very frontier nature of these release areas. These blocks are situated to the south and east of Newman in the Pilbara region. The Officer Basin is a Neoproterozoic basin. Oil fluorescence has been encountered in the Boondawari 1 and Mundadjini 1 stratigraphic coreholes. The two release areas were originally configured after interest was expressed by several companies.

Release area T10-1 is situated in the State Waters of the northern Perth Basin and covers 1,331 km^2. The region has a thick Lower Triassic source and seal interval as well as likely source intervals in the Lower Jurassic.

Work program bids for the release areas close at 4pm on Thursday 6 October 2011.

Should you require any further information or assistance, please contact Richard Bruce (08 9222 3314) of DMP's Petroleum Division or Jeff Haworth (08 9222 3214) of the Geological Survey of Western Australia. All enquiries will be dealt with in strictest confidence. ■

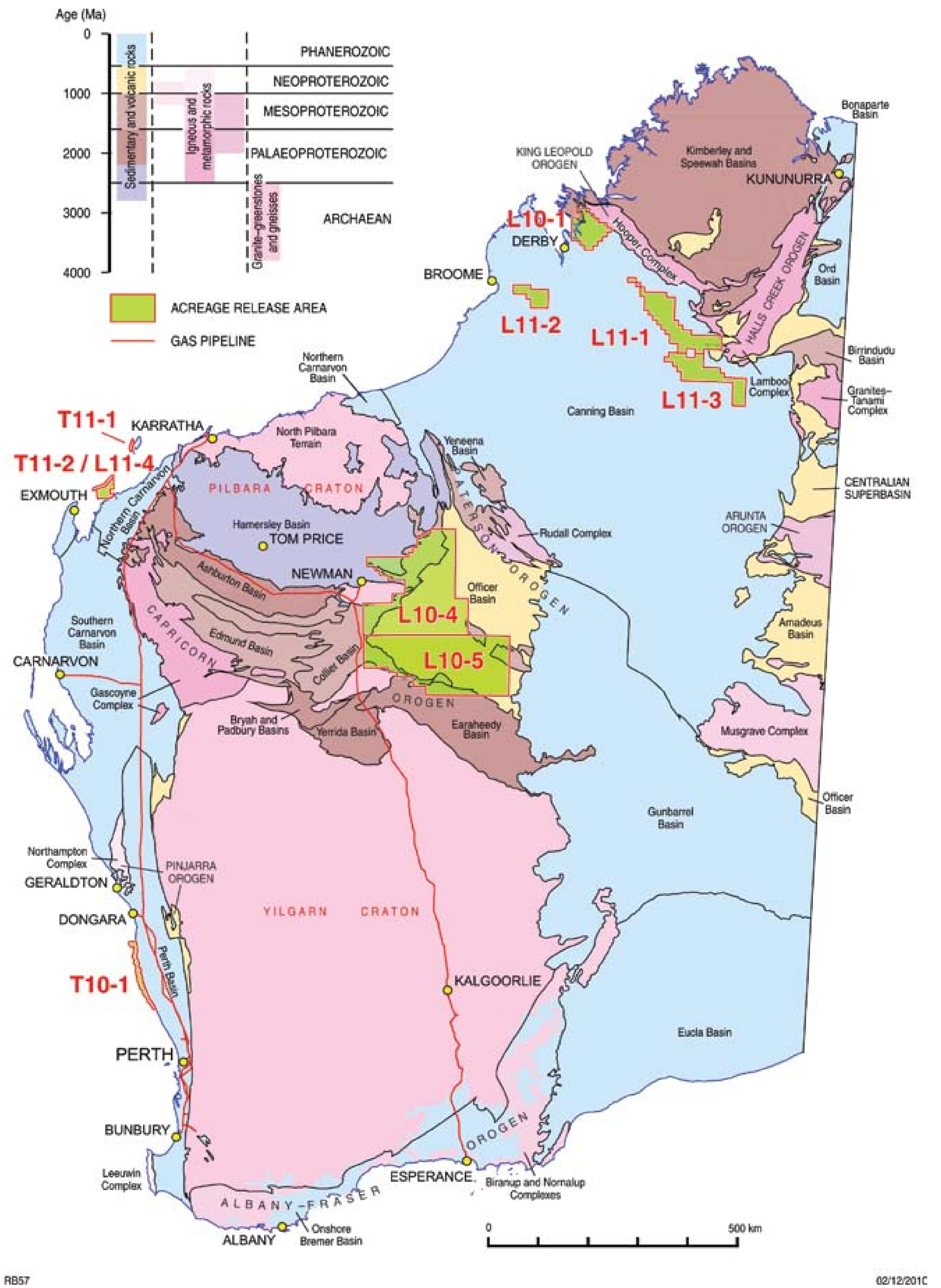


Figure 1 | **April 2011 State petroleum release areas**

Shale Gas in Western Australia

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Resources Branch


Coring at Woodada Deep 1 in 2010
(Photo courtesy of AWE Ltd)

Introduction

Shale is defined as an organic rich fine-grained, fissile, detrital sedimentary rock formed by the consolidation of clay and silt-sized particles into thin, relatively impermeable layers. Shale can include relatively large amounts of organic material compared with other rock types and thus has potential to become a rich hydrocarbon source rock.

In conventional petroleum fields, shale forms the geologic seal that retains the oil and gas within producing reservoirs, preventing hydrocarbons from escaping to the surface. However, in a handful of basins layers of shale, sometimes hundreds of metres thick and covering millions of square kilometres, are both the source and the reservoir for natural gas. Gas shows from such shales encountered during drilling have led to some of them being targeted as potential gas reservoirs. The gas is stored within the shale in three ways — adsorbed onto insoluble organic matter called kerogen; trapped in the pore spaces of the fine-grained sediments interbedded with shale; or confined in fractures within the shale (CEG, 2010).

In broad terms, economically viable shale gas plays are known to have the following properties: adequate porosity; suitable bounding layers such that fracture treatments are confined within intervals; brittle (as measured by low Poisson's Ratio and a high Young's Modulus); and moderate clay content (< 40%). The specific measures of typical shale gas plays are shown in Table 1.

Shale gas plays are considered area plays since shale gas, similar to coal bed methane, is often found over large contiguous areas. Most shales have low matrix permeabilities and require the presence of extensive natural fracture systems to sustain commercial gas production rates.

Overview of Shale Gas Resources in Western Australia

The economic success of shale gas in the United States (US) and the high conventional gas prices in Australia have driven the interest in unconventional gas resources, particularly shale gas resources in Western Australia (WA).

The Canning Basin has gathered a lot of interest in recent times and companies such as Buru Energy and New Standard Energy (NSE) are currently involved in an extensive exploration program focussed on this region's unconventional gas resource. The basin is one of WA's last frontier onshore provinces and it has the potential for major shale gas reserves that could be linked with the planned LNG hub at James Price Point north of Broome. Buru Energy has identified significant potential for unconventional resources in its Canning exploration permits and is currently undertaking a structured evaluation program of the area. In the wake of Buru Energy's exploration in the Canning Basin, NSE secured exploration acreage in nearby permits in the basin. The existing granted permits within the NSE portfolio form an integral part of the Goldwyer shale exploration area (Buru Energy, 2010; NSE, 2010a; NSE, 2010b).

The Carnarvon Basin is another region which is being looked into by NSE, with the focus on the Merlinleigh Sub-basin. Currently, analysis and studies are being carried out by NSE to estimate the gas resources in place and to lay out a program for development of this area. The Dampier to Bunbury pipeline infrastructure lies adjacent to the area. Potential domestic markets around this region include the Mid West and Pilbara developments (NSE, 2010c).

Table 1. Specific Measures (CEG 2010)

Characteristic	Measure	Target	Explanation
Maturity	Ro (%)	1.1 to 1.4	Vitrinite Reflectance
Thickness	ft / m	> 100 / 30.5	-
Total Organic Carbon	%	> 3%	-
Gas content	Scf / ton	> 50	preferably > 100
Porosity	%	> 3	preferably > 5

Despite these developments, the onshore Perth Basin remains the most likely commercial shale gas region in WA. Australian Worldwide Exploration (AWE), Norwest Energy and Westralian Gas and Power (WGP) are involved in exploration work within this region. AWE analysed a number of Perth Basin wells and the results have been sufficiently positive to encourage shale gas exploration in this region. AWE is presently evaluating several unconventional gas targets in the Carynginia Formation, the Kockatea Shale, and the Irwin River Coal Measures (IRCM). AWE is working with the Operator of EP 413 permit, Norwest Energy, to design a well to test the potential of the shales of the Arrowsmith area. In addition, AWE is working with WGP to evaluate the shale gas potential of the EP 455 permit, which is adjacent to the EP 413 permit. WGP also holds a drilling reservation, DR11, which is perceived to be highly prospective for gas within the Carynginia Formation (AWE, 2010; Norwest Energy, 2010; WGP, 2010).

Shale Gas Resources in the Onshore Perth Basin

The onshore Perth basin is located south of latitude 27°S and extends to the south coast, a distance of approximately 750 km (Fig. 1). The Yilgarn Craton forms the eastern edge of the basin which is bounded by the coast to the west. The majority of exploration activity has been concentrated in the onshore area, south of latitude 29°S. The basin is readily accessible and is close to petroleum industry infrastructure, including two major gas pipelines and trucking routes to an oil refinery 30 km south of Perth. The proximity of existing infrastructure and an expanding market allow the economic exploitation of small fields within this region (Owad-Jones and Ellis, 2000).

Figure 1 | **Potential shale gas basins in WA**

Three shale gas plays have been identified in the onshore Perth Basin: the Carynginia Formation, Kockatea Shale and the Irwin River Coal Measures (IRCM). Currently AWE, Norwest Energy and WGP are involved in shale gas development in the onshore Perth Basin. Together, they cover majority of this prospective shale gas area (Fig. 2) and will play an important role in the development of shale gas resources within this region.

Geology

The Perth Basin is a north–south elongate rift–trough, straddling the west coast of Australia. The tectonic framework of the onshore basin is dominated by the Darling Fault and a series of troughs bounded by transfer faults. The basin contains mainly continental clastic rocks, ranging in age from Permian to Recent, deposited in a developing rift system that culminated with the breakup of Gondwana in the Early Neocomian. The Dandaragan Trough in the north is a major depocentre up to 12,000 m thick. Two major tectonic phases are recognised: Permian extension in a southwesterly direction and Early Cretaceous transtension to the northwest during breakup. The main faults were rejuvenated by breakup tectonism, which caused horizontal displacements, wrench-induced anticlines, and further faults (Owad-Jones and Ellis, 2000). A cross-section of onshore Perth Basin depicting the Carynginia Formation, Kockatea Shale and the IRCM is shown in Figure 3.

Carynginia Formation

The Carynginia Formation is comprised of shales, clastics and limestones and it extends over large areas in the Perth Basin. AWE has identified the Carynginia shale as the primary shale gas play in the Perth Basin (Fig. 2). AWE has conducted significant studies to evaluate the shale gas potential of the Carynginia shale using their previous experience in shale gas development in the US and by studying information from previous wells in the Perth Basin (AWE, 2010).

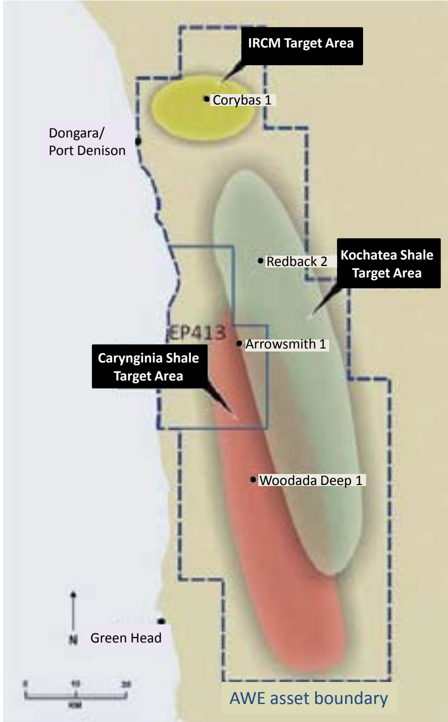

Figure 2 | **Distribution of shale gas plays in the northern Perth Basin (Norwest Energy, 2010)**

AWE completed the Woodada Deep 1 well in 2010 and undertook a coring and logging program across the Carynginia shale in three distinct intervals. The results highlighted the potential of the middle interval of the Carynginia shale. Significant quantities of gas were desorbed from the retrieved cores, which supported the view that it contained shale gas. The compositional analysis showed that it was dry gas, predominantly consisting of methane and small quantities of ethane, liquefied petroleum gas and carbon dioxide. The middle interval of the Carynginia shale has ideal fracture stimulation parameters and the log signatures were analogous to some productive shales in the US. AWE estimates that this middle interval of the Carynginia shale may hold gas in place (GIP) of 368.12 to 566.38 Gm^3 (within AWE's acreage) and in the event of successful flow testing, the recoverable reserve potential of this key area could be higher than 113.27 Gm^3 of gas (AWE, 2010). The key characteristics of the middle interval of the Carynginia shale are summarised in Table 2.

The gas potential of this region was supported by the positive results of the drillstem test in the Arrowsmith 1 well, drilled in EP 413 permit and located 25 km from Woodada Deep 1 well. It was estimated to produce gas at

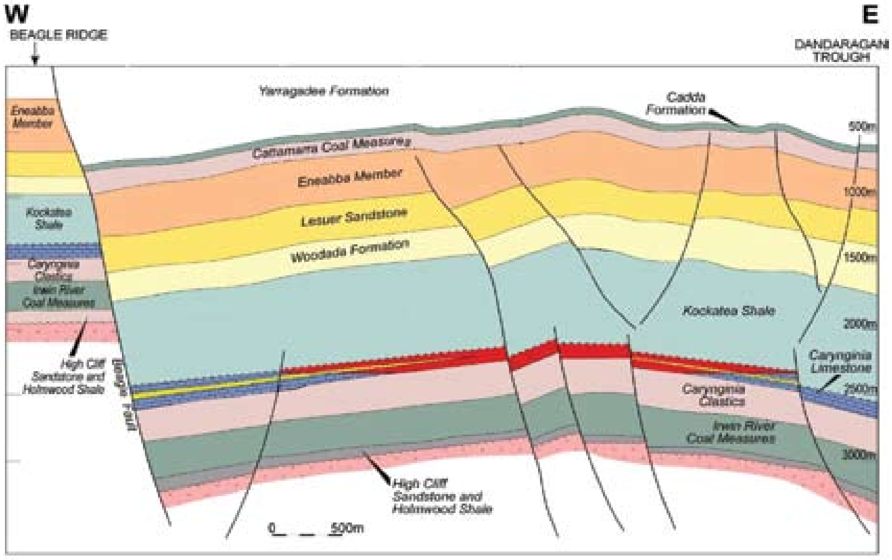

Figure 3 | **Stratigraphic cross-section of the onshore Perth Basin (Norwest Energy, 2010)**

rates as high as 113.27 Mm^3/d from the Caryinginia shale without fracture stimulation before it subsequently declined. AWE, along with Norwest Energy, is planning to further test the potential of shales of the Arrowsmith area. They are also planning for a test fracture stimulation of the middle Carynginia shale (AWE, 2010).

Kockatea Shale

The Kockatea Shale extends across a large area of the onshore Perth Basin (Fig. 2) and the shales within the formation are in places up to 600 m thick. These shales are proven source rocks for the petroleum fields in the Perth Basin. AWE drilled the Redback 2 well in 2010 and carried out a coring program over the lower section of the Kockatea Shale to further evaluate the potential of this play. Although gas was desorbed from the core, subsequent analysis appears to indicate that the high clay content in the cored Kockatea section may be detrimental to effective gas recovery. AWE is currently undertaking geological studies to determine the extent of the oil, wet gas and dry gas windows on the Kockatea Shale for high-grading more prospective areas within this region (AWE, 2010).

Irwin River Coal Measures (IRCM)

The IRCM is a formation that contains both shale gas and tight sandstone gas targets. The formation extends across the northern part of the onshore Perth Basin and has been recognised to generate gas. This formation had previously been disregarded as an unconventional target, as the formation was considered too tight to produce commercial quantities of gas.

In 2009, AWE decided to fracture stimulate the Corybas 1 well to test the IRCM. The results of the subsequent flow test were very encouraging and support the view that optimally designed fracture stimulation will liberate commercial gas flows. AWE believes that the implementation of best completion practices and the drilling of horizontal wells, which are multi-staged fracture stimulated, could achieve significantly higher production rates and recoveries (AWE, 2010).

Shale Gas Resources in the Onshore Canning Basin

The onshore Canning Basin lies in the Kimberley region of central northern WA and covers an area of 400,000 km^2 (Fig. 1). It is the largest onshore sedimentary basin in WA and it contains over 10,000 m of mainly Paleozoic sediments. The basin is located 2,300 km north of Perth and it has two main population centres, Broome and Derby. All-weather access roads run along the northern edge of the basin while the Telfer Gas Pipeline runs along the southern margin of the basin. Petroleum exploration in the Canning Basin began during the early 1920s and since then around 279 wells have been drilled onshore. The basin is largely underexplored with very few valid structural tests relative to the other basins in WA. The drilling density of the Canning Basin is only one-tenth that of the onshore Perth Basin.

Geology

The Canning Basin developed in the early Paleozoic as an intracratonic sag basin between the Precambrian Pilbara Craton and Kimberley Basin. Major structures strike northwest–southeast and divide the basin into sub-basins, platforms, grabens and terraces. The succession ranges in age from Ordovician to Cretaceous, but is predominantly Paleozoic. NSE has identified the Goldwyer Formation as the most prospective shale gas play within this region. The stratigraphy of the Broome Platform/Crossland Platform and the Goldwyer Formation is shown in Figure 4. The figure also shows the logs from the Missing 1 exploration well, drilled in 2001 and depicts four distinct intervals within the Goldwyer Formation. NSE suggests that the lowest interval, Unit 1 has the most potential for shale gas development (NSE, 2010b).

Goldwyer Formation

The Goldwyer Formation is a very rich and proven source rock and is present over large areas of the Canning Basin. The shales within the Goldwyer Formation are recognised as the major hydrocarbon source for the pre-salt section of the Canning Basin. This

Table 2. Characteristics of middle interval of the Carynginia shale (AWE 2010)

Characteristic	Value
Depth, Top (m)	1,600
Depth, Bottom (m)	3,200
Thickness (m)	60 – 90
TOC (%)	2 – 6
Maturity – Vitrinite Reflectance (%)	1 – 4 %
Total Porosity (%)	3 – 6 %
Young's Modulus (psi x 10^6)	3.0 – 5.0
Poisson's Ratio	0.13 – 0.23
Permeability & Gas Content	N / A

formation appears highly prospective for shale gas resources and has been penetrated by in excess of 50 petroleum exploration wells (NSE, 2010b). From these, 11 wells have intersected the Goldwyer shale with hydrocarbon shows. These wells are listed in Table 3 and their locations are shown in Figure 5.

The Goldwyer Formation has a potential shale gas resource stretching from the NW to SE portions of the Canning Basin and covering an area of 500 km by 150 km. Hence, potential exists for very large onshore shale gas resources in this region. The Goldwyer shale possesses appropriate maturity, TOC levels and free gas. It is a blanket marine shale of Ordovician age and contains black to dark grey shales and claystones with inter-bedded silty intervals. It has four distinct units with total thickness of between 200 m to 500 m with the most prospective shales present at depths of between 2,000 m and 3,500 m. The depths to top of the Goldwyer Formation range from 1,000 m to 4,000 m in the intersecting wells (NSE, 2010b).

Shale Gas Resources in the Onshore Carnarvon Basin

The Carnarvon Basin is a Palaeozoic to Cainozoic depocentre which encompasses over 1,000 km of the west and northwest coast of WA (Fig. 1). The basin is divided into the onshore Southern Carnarvon Basin and the mainly offshore Northern Carnarvon Basin (with some parts onshore). The basin covers about 115,000 km^2 onshore extending from just south of Kalbarri to Karratha. The basin is readily accessible from the North West Coastal Highway and the Dampier to Bunbury Natural Gas Pipeline (DBNGP) passes down the eastern side. Currently, NSE holds two Special Prospecting Authority (SPA) permits within this region in the Merlinleigh Sub-basin.

Geology

The Carnarvon Basin is an epicratonic, faulted and gently folded Phanerozoic basin located at the southern end of the North West Shelf of Australia. It is elongated north–south and contains mainly marine sediments of Ordovician–Silurian age to Recent. The Carnarvon Basin is transitional southwards into the Perth Basin and northeastwards into the offshore Canning and Roebuck basins. The Merlinleigh Sub-basin is located within the onshore part of the Carnarvon Basin and it has shown excellent gas source shales in the Lower Byro, Wooramel and Callytharra formations.

Merlinleigh Sub-basin

The Merlinleigh Sub-basin is believed to be highly prospective for large unconventional gas resources, particularly shale gas. Shales present across the Merlinleigh Sub-basin are of similar age and lithology to the northern Perth Basin Caryngina and IRCM shales. In addition, several faulted anticlines have been identified from previous work in this region.

The basal shale sequences (Wooramel Group and Callytharra) range from over-mature in the central basin areas to mature at the western margins. Two major target sequences (both conventional and unconventional) have been identified by NSE and they are within the Lower Permian Byro (Coyrie Formation) and the Wooramel (Billidee, Moogooloo, Cordalia formations). The Wooramel Group shales are situated in a mature gas window part of the basin with good gas generating signatures and there is a prevalence of type III Kerogen in much of the shale. These rocks have excellent characteristics to produce commercial quantities of gas such as high levels of TOC averaging 6–7% (up to 16%) (NSE, 2010c). A high proportion of the generated gas appears to be in-situ and non-migrated. The shales are up to 250 m thick and are present at depths between 200 m and 2,000 m (NSE, 2010c). The stratigraphic cross-section of the Merlinleigh Sub-basin with potential shale gas units is shown in Figure 6.

NSE has suggested that the shales in this area have the potential to hold up to 14.16 Gm^3 of gas in place within the conventional structural traps (NSE, 2010c).

Key Challenges and Considerations for Shale Gas Development

Exploration

Petroleum systems analysis plays an important role in shale gas exploration, as it identifies the type of source rock, TOC, and thermal maturity (Ro, Vitrinite Reflectance) of the shale. These properties show the potential of the shale gas play. In addition, the geological model addresses thickness, depth and structural complexity, and it provides critical information regarding target intervals. The interpretation of geophysical data is required prior to well planning and it improves the success rate for lateral placement, avoiding hazards such as faults (drill out of zone) or features that connect the shale to water-bearing formations (CEG, 2010).

Table 3. List of wells that have intersected the Goldwyer Formation

Wells	Year	Operator	Hydrocarbon shows
Blackstone 1	1967	WAPET	Gas
Wilson Cliffs 1	1968	Australian Aquitaine Petroleum Pty Ltd	Oil
McLarty 1	1968	Total Exploration Australia Pty Ltd	Minor HC shows
Matches Spring 1	1969	Total Exploration Australia Pty Ltd	Oil
Hedonia 1	1984	Gulf (Aust) Resources NL	Oil
Percival 1	1985	Western Mining Corporation Ltd	Oil
Crystal Creek 1	1988	Kufpec Australia Pty Ltd	Gas
Pegasus 1	1988	Amoco Australia Petroleum Company	Minor HC shows
Frankenstein 1	1988	Command Petroleum Holdings NL	Minor HC shows
Looma 1	1996	Shell Development (Aust) Pty Ltd	Oil and Gas
Missing 1	2001	Hughes & Hughes Australia Pty Ltd	Minor HC shows

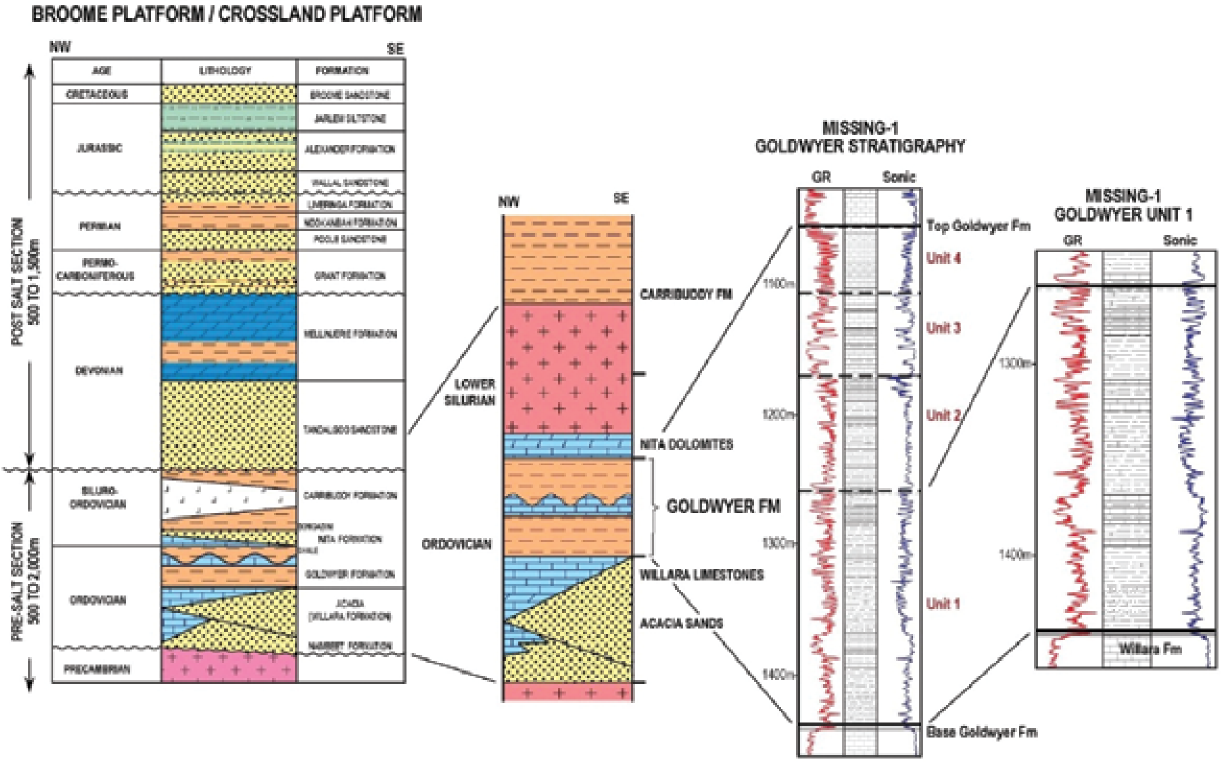

Figure 4 | **Stratigraphy of the Goldwyer Formation, Canning Basin (NSE, 2010b)**

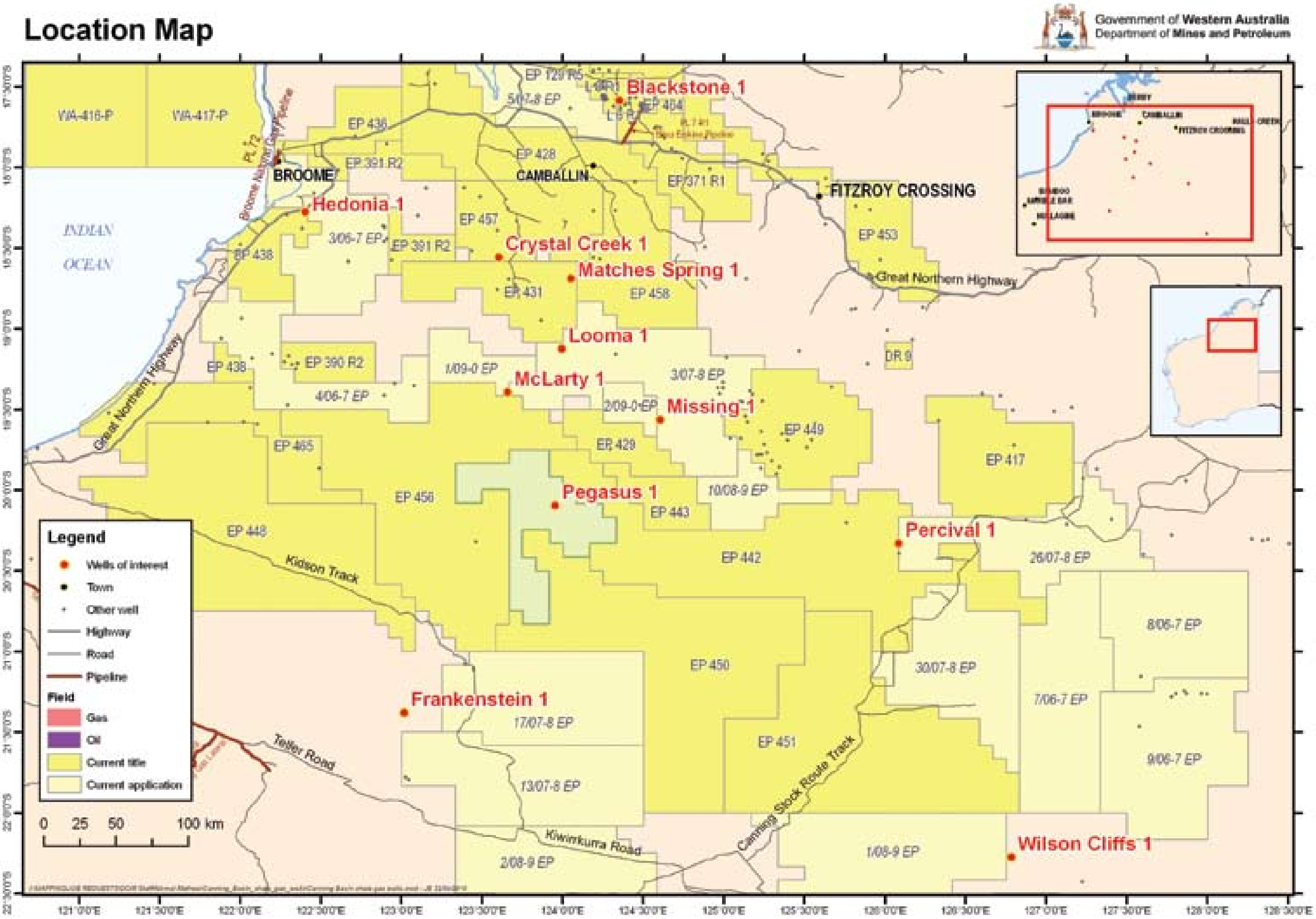

Figure 5 | **Wells with hydrocarbon shows that have intersected the Goldwyer Formation**

Development and Operation

Horizontal drilling and fracturing are significant technologies that have to be considered in shale gas development, to achieve maximum flow per well. The direction of a well is dependent on the natural fracturing nature of the shales and the well design changes accordingly. The effective use of horizontal wells is attributed to extended length of laterals (more reservoir access) and increased number of fracture stages to increase flow along the reservoir section.

In terms of completion design, engineers have to work on improving parameters such as optimal lateral length, distance between frac stages, preferred type of fluids and proppant. Gas rates from shale wells decline hyperbolically and this poses a significant challenge in the design of the wellbore for deliquification. Other surface engineering issues include water handling, compression, erosion and gas processing. Recent developments, such as microseismic monitoring, help to model the fracturing of shale gas reservoirs which result in better decision making and lower costs. This technology can be used to determine well spacing; optimal fracturing techniques, including the identification of wells suitable for re-fracturing; and development strategies (CEG, 2010).

Economics

Shale gas exploration and development involves a high level of recovery cost and hence, it is important for companies to identify markets (local and international), study the gas price volatility and understand the relative supply/demand scenario. The gas in place is also a critical factor for evaluating economics. Companies have to overcome high initial costs to prove economic viability and understand the economics to employ strategies to transition from appraisal to full field development.

Infrastructure

Infrastructure challenges include the accessibility to roads as the development involves transportation and logistics on a large scale. Other points include availability of water supply, availability of land for development and access to pipelines. Also, the proximity of existing gas treatment facilities and drilling/completion technologies are important parameters which have the potential to lower development costs. This is one of the biggest challenges in WA, as there is a lack of infrastructure and equipment capacity to supply the service as efficiently as in the US.

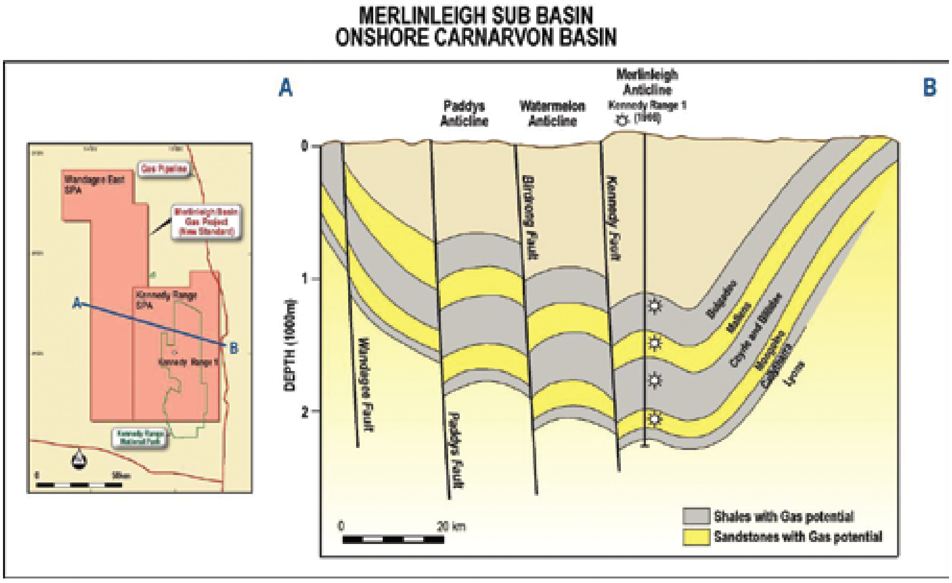

Figure 6 | **Potential shale gas units in the Merlinleigh Sub-basin (NSE, 2010c)**

Future Outlook for Shale Gas Development in Western Australia

There is huge potential for shale gas development in WA and the identified assets host a world class gas resource. There are important market drivers for development in WA including increasing demand, increasing price and presence of short term markets (local resource projects and infrastructure developments). Shale gas developments can make a medium term contribution to domestic gas supply through pipeline extensions as well as having a longer term potential to add to the gas reserves. There are large local companies which are seeking alternative sources of gas supply and it has the capacity to add to gas storage during low consumption seasons.

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The Hovea–Eremia–Jingemia Play Fairway

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Petroleum Geologist and
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Hovea production facility
(Photo courtesy of ARC Energy)

Introduction

The Hovea, Eremia and Jingemia oilfields lie along a structural trend in the northern part of the onshore Perth Basin (Fig. 1). Hovea and Eremia are located entirely within Production Licence L1 at 15 km and 14 km southeast of the Dongara town site respectively. L1 is currently operated by Australian Worldwide Energy Pty Ltd (AWE) on behalf of its joint venture partner Origin Energy Developments Pty Ltd (Origin). Jingemia is located within Production Licence L14 on the western coastal margin of the northern Perth Basin approximately 24 km from the township of Dongara and 90 km south-southeast of Geraldton. Origin is the current operator of the field for the L14 Joint Venture (AWE, Norwest Energy NL, ROC Oil (WA) Pty Ltd, Victoria Petroleum Offshore Pty Ltd, and John Kevin Geary).

The Hovea 1 well, the first discovery along the Hovea–Eremia–Jingemia fairway, was drilled by ARC Energy Limited in October 2001 and marked the first commercial oil discovery in the Perth Basin since 1966. The well encountered hydrocarbons in the Dongara/Wagina (Permian aged) section, the host of the majority of the commercial gas reserves in the northern Perth Basin. Jingemia 1 encountered oil pay within the same reservoir interval in October 2002. Subsequent drilling of the nearby Eremia 1 well in March 2003 by ARC Energy Ltd also encountered an

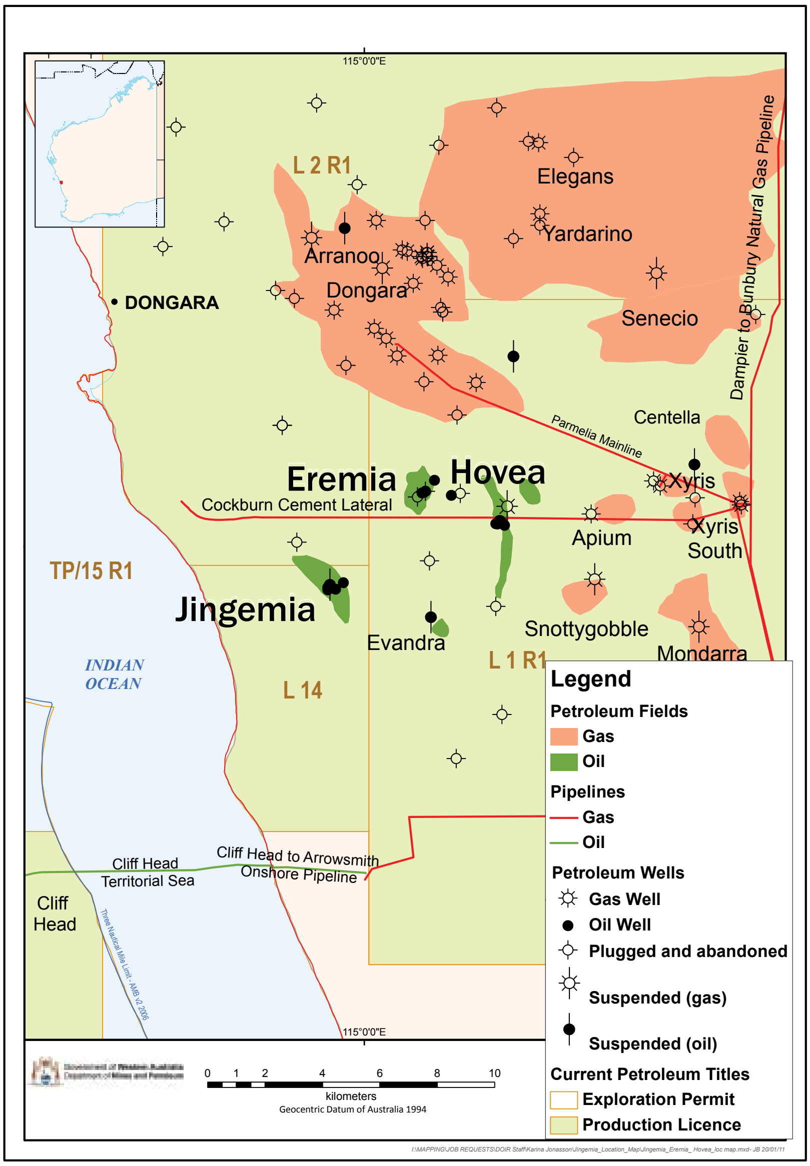

Figure 1 | **Location map, Hovea, Eremia and Jingemia oilfields** oil column in the Dongara Sandstone. Hovea also contains secondary gas reserves within the High Cliff Sandstone.

In 2003 oil production commenced from the Hovea and Eremia fields. Produced oil is separated on site at the respective production facilities and is trucked to Kwinana south of Perth for sale to BP. Field summaries can be found in Table 1.

Field Histories

Hovea field

Hovea 1 was spudded on 3 October 2001 by ARC Energy, 5 km north of the Dongara 7 well. The purpose of the well was to test the hydrocarbon potential of Wagina Formation sandstones within an interpreted fault closure. The two main targets within this formation were intersected, with the Dongara Sandstone showing good reservoir quality and oil shows in an 8 m gross oil column and the lower Wagina Formation sand indicating only poor to occasionally fair reservoir quality. No significant hydrocarbons were observed within the lower target and it was assumed to be uneconomic. A drillstem test of the Dongara Sandstone interval (1,995 to 2,002 m) recovered a total of 19 kL (122 bbl) of 41.6° API oil to the surface with no water. After logging and testing, the well was cased and suspended as a future oil producer.

Appraisal drilling commenced in June 2002 beginning with the Hovea 2 well located 930 m southwest of Hovea 1. Hovea 2 was drilled to test the Dongara Sandstone at a location up dip from the discovery well and to appraise the areal extent of the field. The Dongara Sandstone was intersected, but on the downthrown side of a parallel, down-to-the-east fault that had not been interpreted on seismic. This proved to be the bounding fault for the field and Hovea 2 was outside closure at the Dongara Sandstone level with the objective sandstones found to be water wet. Hovea 2 did, however, discover 15 m of net gas pay in a new pool of gas within the deeper High Cliff Formation. A drillstem test over the interval 2,370 to 2,419 m flowed 0.47 Mm^3/d (16.5 MMscf/d) through a 19.05 mm choke. The well was cased and suspended as a future gas producer.

Hovea 3 was drilled 40 m to the east of Hovea 1 to test the extent of the Hovea oilfield in this direction. The initial well required sidetracking and Hovea 3ST1 was kicked off from 1,507.5 m. The well intersected the Dongara Sandstone target with 22.6 m of oil pay in good reservoir quality sandstones in the upper part of the well and Hovea 3ST1 encountering 24.6 m of oil pay down to a field oil/water contact (OWC) of -1,932 mSS. Hovea 3ST1 also reached the secondary target, but the High Cliff Sandstone was water wet at this location.

In November 2002, Hovea 4 was drilled as an appraisal and development well for potential reserves within the northern section of the field. The closest wells are Hovea 1 and Hovea 3/3ST1, located 115 m to the north-northwest and north, respectively. The Hovea 4ST1 sidetrack well intersected a 44 m vertical oil column.

Hovea 5 was drilled at the southern end of the field, intersecting a gross oil column of 8.3 m. At the proposed target intersection the top Dongara Sandstone is located approximately 600 m south of Hovea 3ST1. Indications from dipmeter logs of updip potential to the southeast resulted in the sidetracking of Hovea 5 to Hovea 6 where a larger oil pay of 20.9 m was mapped. Despite the offset, still further updip potential was indicated to the southeast and the well was plugged and sidetracked to Hovea 7 to access the incremental reserves via the Hovea 5 and 6 wellbores. Drill cuttings from Hovea 7 showed fair to good quality reservoir sands and the well encountered 28.1 m of hydrocarbon pay above the field OWC. Indications of a gas cap where also recorded, despite engineering data predicting that gas should be higher in the structure. The well was completed as a future producer or for use as an injection well.

In July 2003, Hovea 8 was drilled within the central zone of the Hovea field with a 139 m horizontal section in the Dongara Sandstone. Drill cuttings indicated good gas and oil shows and a 21 m gross oil pay interval. The well was completed as a future oil producer.

Hovea 9, spudded 9 October 2003, was an appraisal well to test the oil potential for the southern portion of the field. After encountering a faulted section of the Dongara Sandstone the well was plugged and sidetracked to Hovea 9ST1, which intersected good reservoir quality sandstone with good oil shows. Log analysis indicated that the OWC had shifted up approximately 2.3 m as a result of field production. Hovea 9ST1 was plugged and sidetracked to Hovea 10.

Hovea 10, located approximately 360 m to the west of the Hovea 9 surface location, intersected the Dongara Sandstone 27.3 m below the field OWC. Subsequent to logging, analysis of which interpreted fair reservoir quality sands, the well was completed as a water injector to provide pressure support to the Hovea and Eremia fields.

Hovea 11, drilled proximal to the Hovea 1, 5 and 8 surface locations, encountered an oil column of 18.7 m in sands of good to fair reservoir quality in the southern section of the field and was completed for future appraisal.

Hovea 12 was drilled 19 September 2006 to drain potential crestal attic oil and unswept oil from the northern section of the field. The well intersected a reservoir zone of excellent quality with significant oil shows and an OWC 8 m lower than expected. The location of Hovea 12, north of Hovea 4ST1, was optimal to enhance efficient recovery of reserves in the field and the well was completed for future production.

Hovea 13, spudded 20 March 2009, targeted the Dongara Sandstone in a near-crestal location in a seismically mapped subculmination within the central portion of the field. Multiple problems encountered while drilling required sidetracking to Hovea 13ST1. The second sidetrack attempt was successful and encountered 5.6 to 6.8 m of unswept pay. The well was cased and completed as an oil well within the Dongara Sandstone. A schematic cross-section of the Hovea field is shown in Figure 2.

Eremia field

The discovery well, Eremia 1, was spudded on 6 March 2003 by ARC Energy to test a fault bounded four-way dip closure at the Dongara Sandstone level. Subsequently the well was deepened to reach secondary objectives in the lower Irwin River Coal Measures (IRCM) and the High Cliff Sandstone. Good gas and oil shows were encountered within the primary target with a 15 m oil column interpreted from wireline analysis. Wireline logs indicated that both of the lower zones were

Table 1. Fields summary

TITLE/LOCATION				
Permit/Licence	L1 & L14 (was EP 413)			
Basin	Northern Perth Basin			
Hovea Location	15 km onshore southeast of Dongara			
Eremia Location	14 km onshore southeast of Dongara			
Jingemia Location	5.5 km southwest of Hovea oilfield			
GEOLOGY				
Play type	tilted fault block, structural			
Reservoirs	Dongara Sandstone, High Cliff Sandstone			
Source	Kockatea Shale			
Seal	Kockatea Shale			
DISCOVERY WELLS				
	Hovea 1	**Hovea 2**	**Eremia 1**	**Jingemia 1**
Datum	GDA94	GDA94	GDA94	GDA 94
Latitude	29° 19' 05.05" S	29° 18' 48.88" S	29° 18' 33.60" S	29° 20' 22.15" S
Longitude	115° 02' 26.76" E	115° 02' 41.05" E	115° 01' 5.10" E	114° 59' 27.57" E
Permit	L1	L1	L1	L14
Spud Date	3 October 2001	23 June 2002	6 March 2003	6 October 2002
TD Date	13 October 2001	20 July 2002	26 March 2003	3 November 2002
RT elevation	68.1 m	80.8 m	35.0 m	16.3 m
Ground elevation	60.2 m	72.9 m	26.9 m	8.4 m
Total depth	2,134.0 mRT	2,687.0 mRT	2,550 mRT	2,950.0 mRT
Top reservoir	***Dongara SS***	***High Cliff SS***	***Dongara SS***	***Dongara SS***
	1,996.1 mRT	2,380.0 mRT	2,095.5 mRT	2,414.9 mRT
Gross pay	47.8 m (oil)	5 m (gas)	16.1m (oil)	34.3 m (oil)
Net pay	6.6 m (oil)	5 m (gas)	16.1m (oil)	29.7 m (oil)
PRODUCTION TESTS				
Hovea 1				
DST-1				
	Choke size	12.7 mm		
	Interval	1,995.0 to 2,002.0 mKB		
	Flow rate (oil)	150 kL/d (950 bbl/d)		
	Flow rate (gas)	3.2 km^3/d (129.8 kL/d)		
Hovea 2				
DST-1				
	Choke size	19.1 mm		
	Interval	2,370.0 to 2,419.0 mKB		
	Flow rate (gas)	467 km^3/d (16.5 MMscf/d)		
Eremia 1	not tested			
Jingemia 1				
DST-2				
	Choke size	19.1 mm		
	Interval	2,407.32 to 2,419.0 mRT		
	Flow rate (oil)	231 kL/d (2,000 bbl/d)		
WELL STATUS				
Hovea field				
No. of wells	13			
Producer	6 (Hovea 7,8,11,12,13)			
Suspended producer	1 (Hovea 2)			
P&A	3 (Hovea 5,6,9)			
Water injectors	3 (Hovea 1,3,10)			

Table 1. Fields summary

WELL STATUS (Continued)	
Original oil in place	3,020,759,kL (19 MMbbl)
Cumulative oil production	1,168,642 kL
Maximum daily rate (oil)	795 kL/d (5,000 bbl/d)
Remaining reserves as at 31/12/09	643,562 kL
Eremia field	
No. of wells	9 (4 sidetracked)
Producer	3 (Eremia 2HST1,6,7)
P&A	1 (Eremia 1)
Water injector	1 (Eremia 4)
Cumulative oil production	242,506 kL
Remaining reserves	too small to measure
Jingemia field	
No. of wells	12
Producer	5
P&A	3
Water injectors	4
Original oil in place	1,876,000 kL (11.8 MMbbl)
Cumulative oil production	715,013 kL (4.5 MMbbl)
Maximum daily rate (oil)	795 kL/d (5,000 bbl/d)
Present rate	79–95 kL/d (500–600 bbl/d)
Remaining reserves as at 30/04/2010	36,500 kL

water wet and the well was plugged back to 2,197 m and completed as a suspended oil producer.

In November 2003 Eremia 2/2H/2H ST1 was drilled 750 m to the east of Eremia 1 to determine the top of the Dongara Sandstone reservoir. The initial vertical well, Eremia 2, intersected the Dongara Sandstone at a similar level to Eremia 1. Eremia 2H ST1 was drilled after the initial horizontal well encountered technical difficulties at a lower angle of intersection. Good gas and oil shows were encountered within the well in a 17.2 m gross reservoir section down to an OWC at -2,078 mSS. The well was perforated and put into production through temporary facilities on 20 January 2004.

Eremia 3, spudded on 26 November 2004, was planned to appraise the southern extent of the field to confirm a possible upside in this area and for completion as a water injector for the Eremia oilfield. The intersection of the well with the reservoir sandstone was low to prognosis and too close to the field OWC to be successful and the well was plugged and sidetracked to Eremia 4 on 6 December 2004.

Eremia 4 was drilled from the Eremia 3 wellbore but also intersected the Dongara Sandstone close to the OWC with poor hydrocarbon shows recorded in the well. As a result Eremia 4 was completed as a water injector.

Eremia 5 was drilled on 19 October 2006 immediately adjacent to the Eremia production facility as a deviated oil appraisal and development well to drain the attic reserves in the north of the field. The well failed in this objective due to the faulting out of the well targets, the bounding fault location and the path having been misinterpreted on seismic data. As a result Eremia 5 was sidetracked to Eremia 6 from the original wellbore.

The Eremia 6 well, spudded 8 November 2006, was successful in encountering the Dongara Sandstone in the northern part of the field and logs run in the well indicated a 23 m oil column down to an OWC contact that matched the original field OWC. The location of the OWC in Eremia 6 shows that the northern part of the field had not been drained by existing production wells. The well was completed as an oil producer and was brought on stream in December 2006.

The wellhead at Eremia
(Photo courtesy of ARC Energy)

Eremia 7 was also drilled within the northern section of the field, to drain the attic and downdip oil, and spudded 3 November 2007. Shows were encountered within the Dongara Sandstone down to the original OWC but wireline logs indicate a present day contact at -2,060.1 mSS. Wireline analysis also indicated a significant swept zone within the reservoir. Eremia 7 was ultimately completed as an oil producer for the Eremia oilfield.

Jingemia field

The discovery well, Jingemia 1 was spudded on 6 October 2002 and was drilled to intersect the Dongara Sandstone and the High Cliff Sandstone within a three-way dip-closed structure

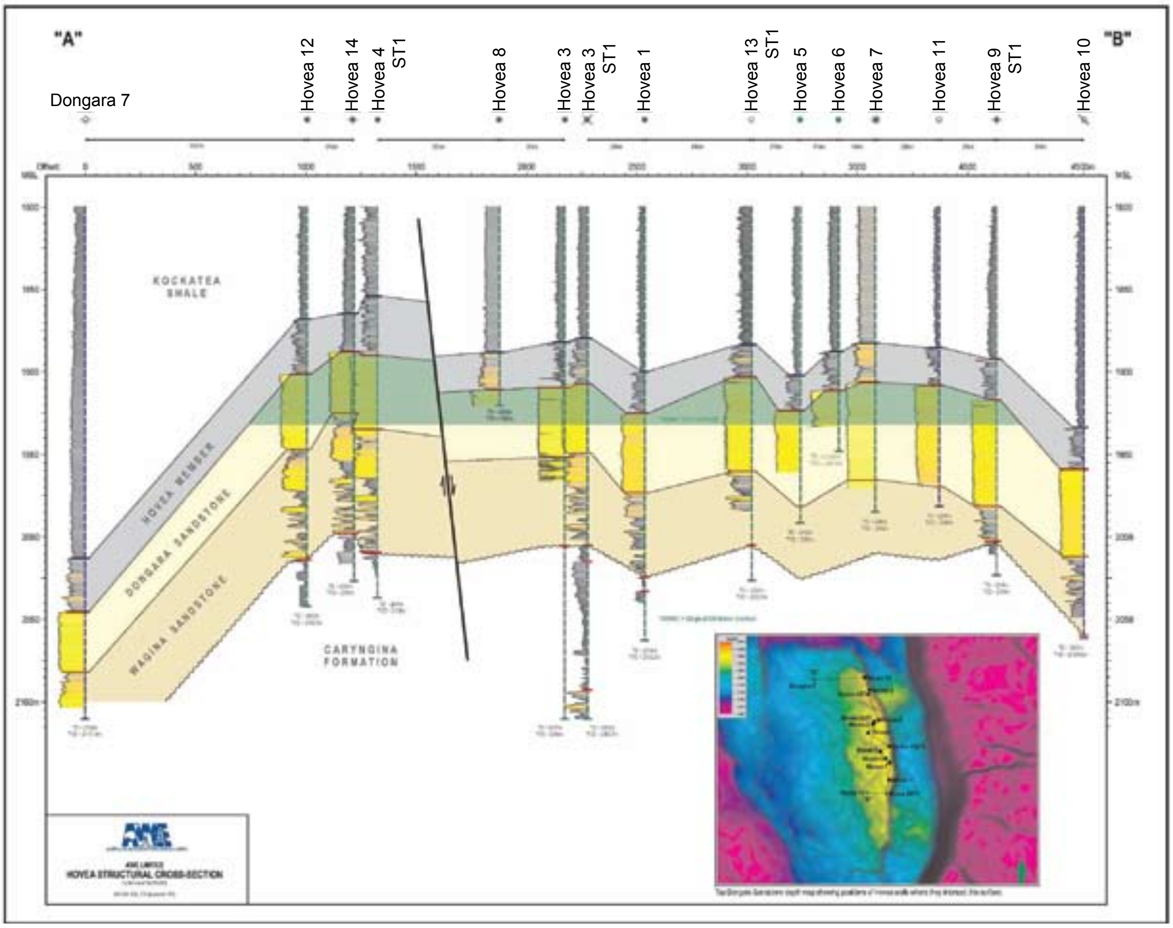

Figure 2 | **Geological cross-section of the Hovea field (courtesy of AWE)**

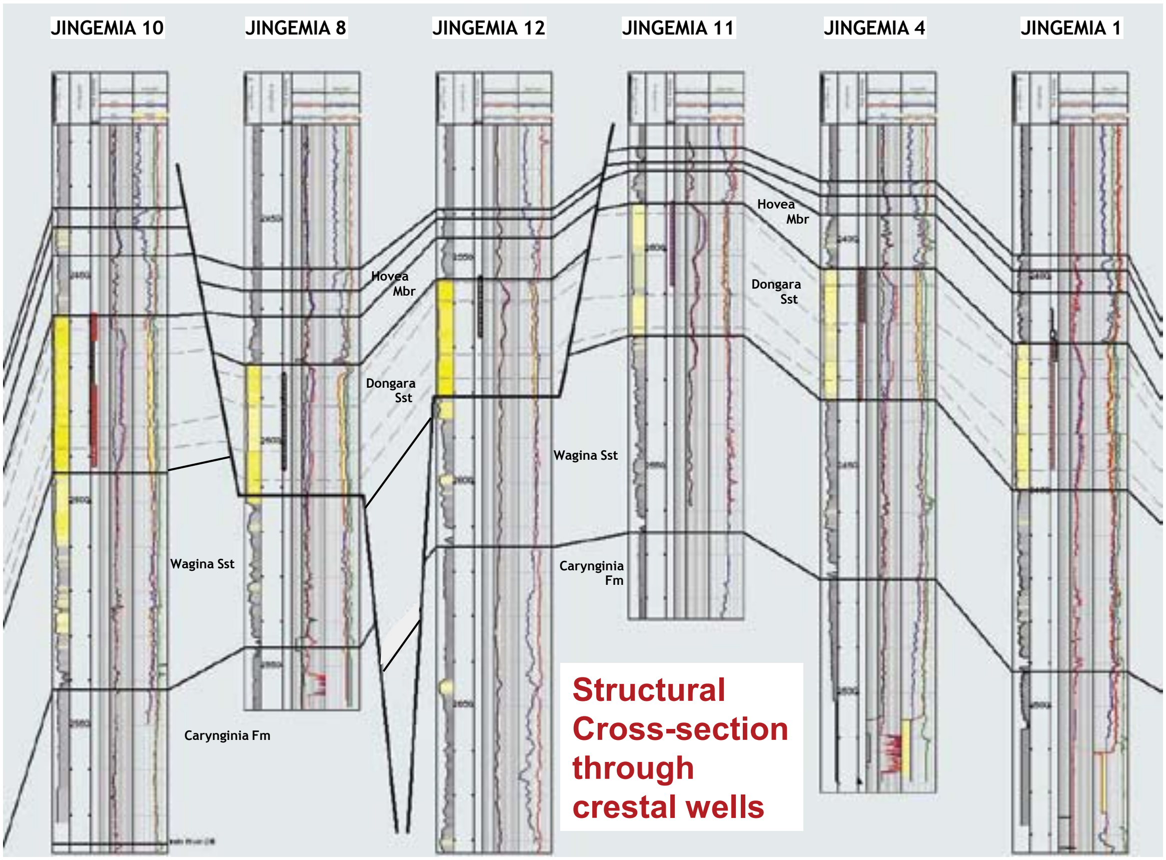

Figure 3 | **Geological cross-section of the Jingemia field (courtesy of Origin)** with fault closure to the east. Drillstem testing of the well in an interval of the Dongara Sandstone from 2,407.3 to 2,419.0 mRT flowed 36.6° API oil at a maximum rate of 231 m^3/d (2,000 bbl/d).

Jingemia 2 was drilled from the original Jingemia 1 pad and was intended as a directional well to intersect the Dongara Sandstone down dip. The purpose of the well was to accurately identify the OWC for the field and enable water injection to provide pressure support for oil recovery. Spudded on 24 August 2003, Jingemia 2 was successful in intersecting the target sandstone however log analysis indicated poor reservoir quality. The well was sidetracked up dip to intersect rock of better quality. As a result the well was plugged back and Jingemia 3 was sidetracked off the Jingemia 2 wellbore from 740.0 mMD September 2003. Log analysis proved the well successful; the reservoir quality was much higher at this location. The OWC was interpreted to be at 2,437.6 mRT (-2,414.9 mSS) and the well was suspended as a future water injector.

Jingemia 4 was spudded on 23 April 2004 and was drilled at a near crestal location to provide a second production offtake point at the Dongara Sandstone level and to appraise the reservoir potential of sandstones in the underlying Wagina Formation. Good hydrocarbon shows and reservoir quality were interpreted for the Dongara Sandstone but the Wagina sandstone was tight at this location. A conventional core was cut from 2,400.0 to 2,482.2 mRT in three coring runs. The cored interval was stratigraphically positioned from the Hovea Member of the lower Kockatea Shale to the upper Carynginia Formation. The subsequent well, Jingemia 5, was planned as an appraisal well but due to encountering only a minor gas show and no fluorescence it was completed as a water injector.

Jingemia 7 was spudded on 28 May 2005 to appraise the northern extent of the field. Fair to good quality reservoir sandstones were encountered but no significant hydrocarbon shows were recorded. Wireline logs were not acquired due to poor hole conditions. The well was plugged and suspended to be sidetracked to drill Jingemia 9. The sidetrack was designed to intersect the Dongara Sandstone at a crestal location approximately 630 m southeast of Jingemia 7. Jingemia 9 intersected the Dongara Sandstone 602.7 m southeast of Jingemia 7 and 33 m up dip. The well did not encounter any significant hydrocarbon shows either despite the fair to good quality sandstone. The well was completed as a water injection well for the Jingemia oilfield. Jingemia 6 in August 2005 and was also unsuccessful, intersecting the Dongara Sandstone on the eastern downthrown side of the Jingemia Fault. A kickoff plug was set for a potential sidetrack well, Jingemia 10, designed to intersect the reservoir at a near crestal location. The well was successful and completed as a future oil producer.

Jingemia 8 spudded on 13 August 2006 and was a directional well intended to intersect the Dongara Sandstone reservoir near the structural crest of the field and access oil up dip from the previously drilled Jingemia 4 well. MDT data showed that the reservoir pressure had not been depleted by production from nearby wells. This suggested that the well was not in communication and was most likely located in a fault block off the main bounding Jingemia Fault. The well was cased and completed after drilling and logging operations had been conducted.

Jingemia 11 is a similar directional well, drilled with the intention of accessing 28 ML (175,000 bbl) of oil up dip from Jingemia 10 and 11 that were interpreted to be inaccessible by the existing Dongara Sandstone producers.

Jingemia 12 spudded 18 July 2009 approximately 80 m south of the Jingemia 11 surface location. The well was designed to intersect the Dongara Sandstone near the structural crest of the Jingemia oilfield and to access oil up dip from the nearby Jingemia 8 and Jingemia 11 wells. Jingemia 12 is interpreted to have intersected the hanging wall of a sub-seismic fault; consequently it did not intersect the Dongara Sandstone at a crestal location. The well was cased and completed as an oil producer.

The Jingemia oilfield is at a late stage in its life. No further drilling opportunities have been identified, however, an Enhanced Oil Recovery (EOR) study has been conducted and it has been established that there is a potential application for a surfactant flood. The residual oil saturation in the Jingemia field is above 40 per cent, which is high when compared with the neighbouring Hovea and Eremia fields with residual oil saturations of less than 20 per cent. Further simulation and economic study will be performed before proceeding with the flood. A cross-section schematic of the Jingemia field is shown in Figure 3.

Reservoir

The main reservoir for all three fields is the late Permian Dongara Sandstone (Fig. 4). At Hovea and Eremia the depositional environment is interpreted as a delta front to shallow, storm dominated, marine environment. This produced sedimentary deposits comprised predominantly of coarse sands with minor fine- to silt-sized interbeds. The sands are moderately well sorted with angular to subrounded grains. At the Hovea field, the Wagina Formation provides additional reservoir potential in crestal positions. The Wagina sands are finer-grained with claystone interbeds, but are of much lower reservoir quality and thus only considered a secondary target. A secondary gas column was also encountered at Hovea in the High Cliff Sandstone, a marine sandstone with variable reservoir quality, consisting of fine- to medium-grained, moderately sorted sandstone with occasional coarse intervals. Additional reservoir targets for Eremia proved uneconomic with log analysis of both the IRCM and the High Cliff sandstone indicating that both objectives were water saturated. Furthermore no hydrocarbon shows were encountered within either interval during drilling.

At Jingemia the Dongara Sandstone is a highstand systems tract interval with upper shoreface (beach) to a potential dune system recognised as the dominant facies. Quartz arenites with rare horizons of subarkose to sublitharenites are the main rock types. The Dongara Sandstone thins and reservoir quality decreases to the south and west of Jingemia 1. This is interpreted to be the depositional edge of the Dongara Sandstone as no indications of structural cut off were apparent. The Wagina sandstone at the Jingemia field has low permeability. Consequently, this unit is interpreted as a basal seal for the Dongara Sandstone. In Jingemia 4, where the Wagina Formation occurs above the lowest known oil saturation for the field, no saturation was recorded within the

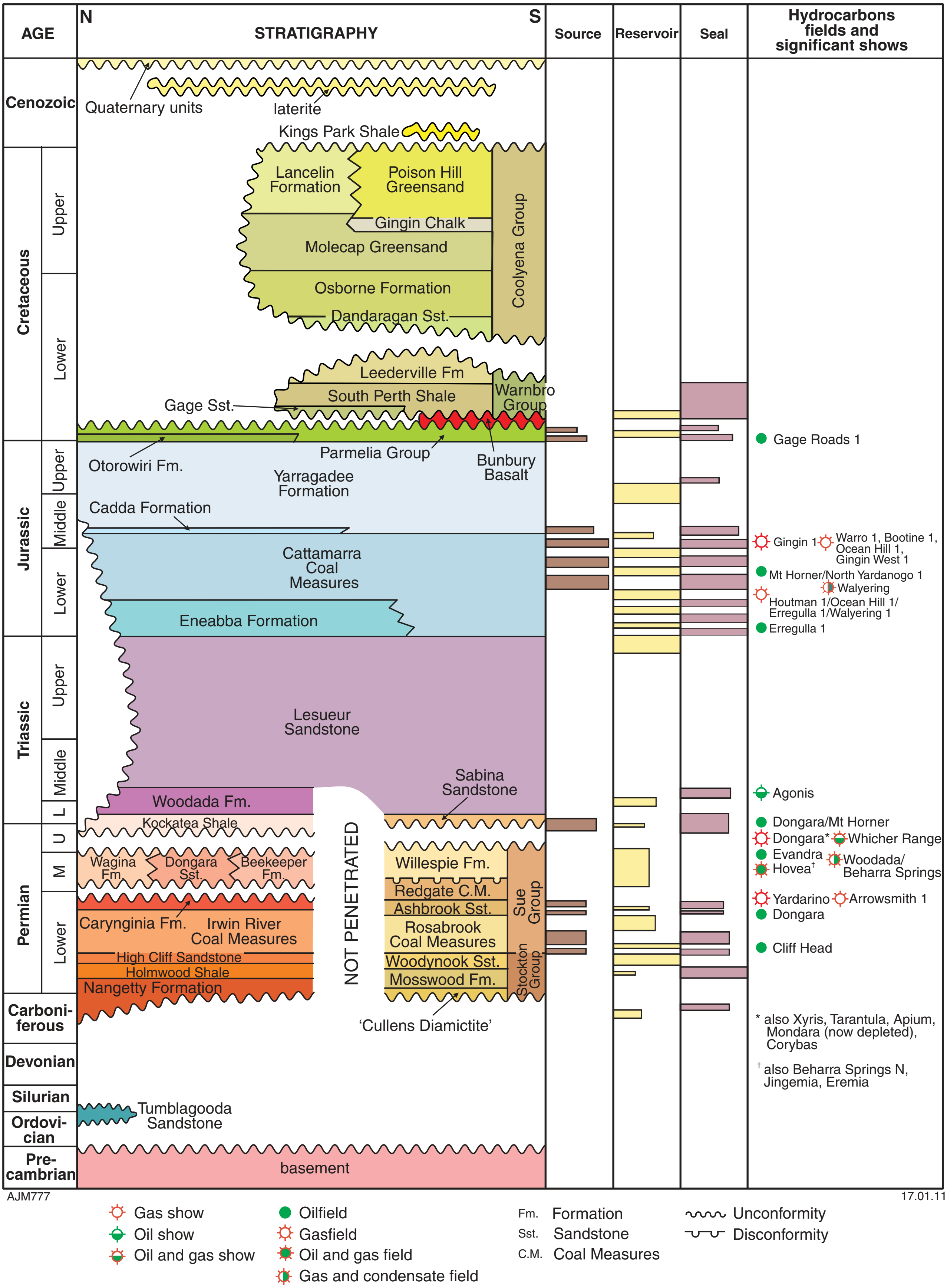

Figure 4 | **Stratigraphy of the onshore Perth Basin (GSWA 2011)** interval thus implying low permeability at the time of oil emplacement.

Reservoir Properties

The reservoir properties, consisting of log-interpreted porosity and water saturation, core porosity and permeability and net and gross gas pay, for the Dongara Sandstone in each well, are listed in Table 2.

Interpretation of the wireline logs in the Dongara Sandstone indicates average porosities of approximately 15.4% (Hovea); 16% (Eremia) and 11.4% (Jingemia) in the oil column. Core analysis confirms the log porosities and indicates a variable permeability between fields. Average permeability in the oil leg was measured at 518 mD at Hovea; 123 to 2,078 mD at Eremia and 154 to 362 mD at Jingemia. Jingemia also showed a vertical variability in permeability between the oil and water legs, with the water leg showing decreased permeability of 0.27 to 70 mD. Log analysis of the High Cliff Sandstone in Hovea 2 indicated a vertical porosity change within the unit from 10% at the base to 20% to the top of the unit. This variability is likely due to grain size changes with depth.

Results from core analysis indicate that permeability is highly variable ranging from 0.86 to 1,466 mD. Water saturation (Sw) in the Dongara Sandstone averages approximately 40.5% at Hovea, with 20% interpreted for Eremia and Jingemia.

Seal

The top seal for the Dongara Sandstone in all three fields is comprised of siltstones and shales of the Early Triassic Kockatea Shale (Fig. 4). This unit was formed in a major marine transgression and provides a regional seal for all Permian prospects across the northern

Table 2. Hydrocarbon reservoir thickness and quality

Well name	Oil column (m)		Porosity (%)		Permeability	Sw
	Gross	Net	Log	Core	(mD)	(%)
DONGARA SANDSTONE						
Hovea 1	47.8	45.6	13	–	–	40.5
Hovea 3	30.5	25	15.6	16	518	20.8
Hovea 4	52.4	44.5	16	–	–	21
Hovea 5	13.3	13.3	22.7	–	1,000–2,000	88.9
Hovea 6	3.2	3.2	–	–	up to 6,000	–
Hovea 7	–	28.1	–	–	–	–
Hovea 8	21	–	–	–	–	–
Hovea 9ST1	63.8	–	–	–	–	–
Hovea 10	52.9	–	10–20	–	–	–
Hovea 11	61	18.7	–	–	–	–
Hovea 12	–	22.2	15	–	20–27	13
Hovea 13ST1	69.8	5.6	18	–	–	30
Eremia 1	15	–	–	–	–	–
Eremia 2	17.2	16.1	22.5	–	1,000–2,000	74.7
Eremia 2HST1	16.6	–	–	–	–	–
Eremia 3	0.0	0.0	nd	–	–	–
Eremia 4	9.5	–	nd	–	–	–
Eremia 6	32.5	32.5	–	14	480	21
Eremia 7	42.4	12.3	–	15	–	26
Jingemia 1	32.7	32.3	11.5	–	163	28.9
Jingemia 2	11.2	0.40	–	–	–	46.9
Jingemia 3	22.6	0.0	12.8	–	51	48
Jingemia 4	29.0	28.5	12.1	18.9	364	20.1
Jingemia 5	31.0	–	–	–	–	–
Jingemia 6	–	–	–	–	–	–
Jingemia 7	40.0	0.0	nd	–	–	100
Jingemia 8	31.5	–	–	–	–	–
Jingemia 9	36.3	28.2	11.6	–	100– 600	–
Jingemia 10	34.5	34.5	14.1	–	662	17.6
Jingemia 11	30.5	28.0	11.6	–	20	26.1
Jingemia 12	26.9	15.7	12.2	–	80	31.5
HIGH CLIFF SANDSTONE						
Hovea 2	16.1	16.1	19	–	154–181	39

Note: Eremia 5 did not intersect the reservoir part of the Perth Basin. Lateral sealing for the fields is provided by juxtaposition of the reservoir sands against the Kockatea Shale along bounding faults. At Hovea and Jingemia fault sealing is present to the north and east with dip closure in other directions.

Source and Hydrocarbon Properties

The oil contained within the Dongara Sandstone in the Hovea, Eremia and Jingemia fields is sourced from the Early Triassic Hovea Member of the Kockatea Shale; a marine sequence of shale and siltstone. Geochemical analysis of the Hovea Member has indicated that the unit is an extremely rich oil prone source, in the order of 10 to 40 m thick. In particular the oil is generated from carbonaceous shales of mixed (including algal) organic matter, which form part of the Sapropelic Interval. This interval comprises laminated shales, thin limestone stringers and pyrite rich zones. Algal mats and bioherms within this interval are proven to be oil prone precursor organic matter. Deposition occurred in a restricted anoxic marine environment, which produced reducing conditions that facilitated the accumulation of organic matter required for oil formation. The peak maturity for oil generation in the northern Perth Basin occurred during the Late Jurassic, prior to the main Neocomian uplift, an event that would have caused a cease in the temperature and pressure parameters required for oil generation.

The Hovea–Eremia–Jingemia oil is of 41.5° API gravity, rich in saturate components (79.5%) and containing 14% aromatics and 6.4% NSO compounds. The fluid parameters of the hydrocarbons sourced from the Hovea field are outlined in Table 3.

The potential for gas is also recognised in the Kockatea Shale where the rock is over mature for oil generation. The IRCM has also been considered significant as a gas source for the region.

Structure

The dominant structural features in L1, interpreted from seismic, are the south-trending, east-dipping Mountain Bridge Fault and the subparallel Hovea Fault. A tilted horst block traps reserves at Hovea, having resulted from the interaction of north–south and northwest–southeast oriented fault systems. Entrapment of hydrocarbons within the reservoir results from fault juxtaposition to the east and north by the Hovea Fault, and an east–west trending north-dipping fault, respectively. The Hovea Fault intersects the field between Hovea 1 and Hovea 2. Dip closure is provided due to the strong southwest dip of the entire sedimentary section. The Eremia field is located within a fault dependent anticline with four-way dip closure provided by draping of the Dongara Sandstone over a paleohigh. There is some risk, due to the draping of sediments, of significant potential for thinning of the reservoir rock within the field.

The Jingemia structure is a three-way dip and fault closed structure within the Dongara Saddle, a region of limited burial between two major faults. The structure is recognised due to its structurally low lying nature between the Allanooka Terrace to the north and the Beagle Ridge to the south. Jingemia is located on the eastern updip side of a titled fault block between the major north–south trending Mountain Bridge Fault to the east and the northwest–southeast trending Beagle Fault to the west. Numerous generally NNW–SSE trending faults that throw down-to-the-east that have generated multiple rotated fault-blocks between these two major faults. The regional dip in the area is to the southwest providing dip closure of the field. The north closure is provided by a north moving change in strike along a northeast–southwest fault to the west-northwest, a bounding fault that has been recognised on five of the most recently acquired seismic lines. The majority of fault movement at Jingemia occurred during the Jurassic and indications of displacements dying out towards the surface have been observed.

Table 3. Hydrocarbon fluid and reservoir parameters (Dongara Sandstone)

	Hovea	Eremia	Jingemia
Oil/water contact	-1,835.1 m	-1,835.1 m	-2,414.0 m
Max gross pay	31.6 m	16.1 m	60 m
Area at oil/water contact	nd	1.25 km^2	nd
Net to gross	1.0	1.0	nd
Water saturation	40.5%	25.3%	17.6-48%
Porosity	15.4%	22%	16%
Formation volume factor	1.255 rbbl/STB	1.255 rbbl/STB	1.203 rbbl/STB
Solution gas/oil ratio	63.6 m^3/kL (360 scf/STB)	56.9 m^3/kL (322 scf/STB)	43.8 m^3/kL (248 scf/STB)
Oil gravity	41.5° API	43.4° API	38.8° API
Gas gravity	0.689	0.689	nd
Oil viscosity[1]	0.378 cp	0.378 cp	0.941 cp
Oil density[1]	0.703 gm/cc	0.703 gm/cc	0.723 gm/cc
Oil bubble point	8,811 kPa (1,278 psig)	8,811 kPa (1,278 psig)	8,998 kPa (1,305 psig)
Pour point	nd	nd	25°C
Permeability	518–910 mD	480 mD	20–662 mD
Temperature	190.5°C	190.5°C	nd
Initial pressure	18,071 kPa (2,621 psig)	16,489 kPa (2,393 psig)	20,815 kPa (3,019 psig)

[1] at reservoir conditions

Fluid migration, diagenesis and hydrocarbon entrapment

The predominant diagenetic change to the Dongara Sandstone reservoir at Hovea and Eremia is the formation of significant quartz overgrowth cement. Formation of these overgrowths early in the history of the rock has allowed for the preservation of primary porosity by providing support against compaction. Kaolin presence increases towards the top of graded cycles within the reservoir sandstone and can be assumed to relate to original deposition as energy decreased within the depositional environment. The minimal authigenic content of the Dongara Sandstone reservoir is directly related to the original depositional facies with high energy, significant reworking and fines by-pass accounting for the predominantly coarse and clean rock.

The shallowest samples of the Dongara Sandstone at Jingemia show illite and kaolinite, with two per cent grain replacement by illite and two to 15 per cent kaolinite. Silicification is variable, ranging from one to eight per cent (of much less significance than recognised in Hovea and Eremia), most likely due to the presence of detrital mineralogy and clays that prohibit quartz nucleation. Minor to trace glauconite and pyrite to the base of the reservoir section may indicate a greater marine influence during the formation of the basal interval. The impact of diagenetic events on the reservoir quality of the Dongara Sandstone is minimal however with primary intergranular pores abundant at Jingemia, resulting from the initial sorting of the rock and the depositional environment.

Migration of fluids to Hovea and Eremia was determined through maturity modelling with indications that the two potential source horizons are not mature for generation in the Hovea region. Mature rock was recognised to the southeast of the field but determination of migration pathways was difficult due to inadequate structural control. It is therefore assumed that charge to these fields was similar to that shown at the nearby Dongara oilfield where migration across the Mountain Bridge Fault occurred from the south and east of the field. At Jingemia the interpreted source interval, the Hovea Member, was mature for oil at the field location. The oil charge is thus interpreted to have occurred from the Jingemia oil kitchen and from

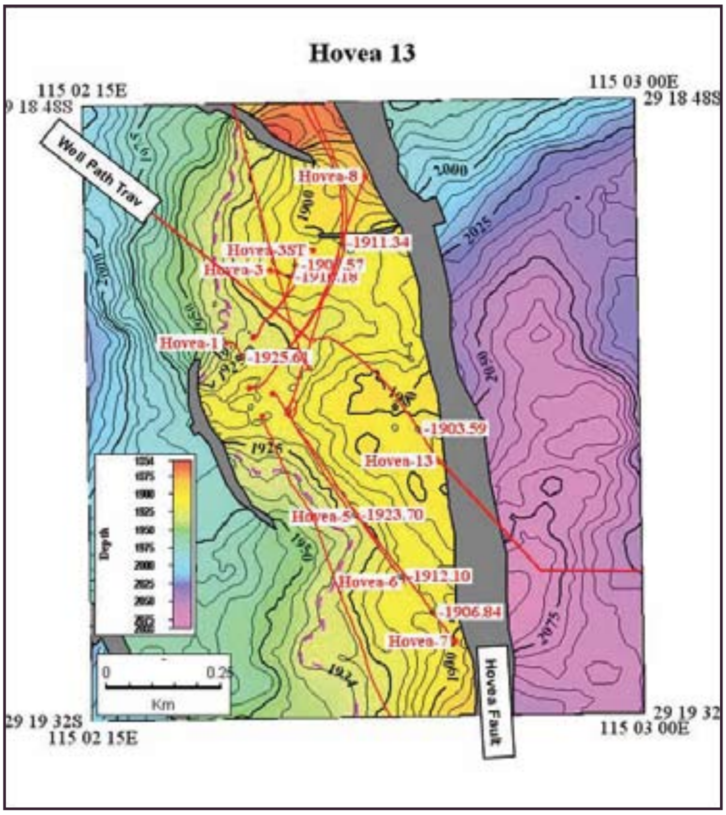

Figure 5 | **Depth structure map of the Hovea field, top Dongara Sandstone (courtesy of AWE)**

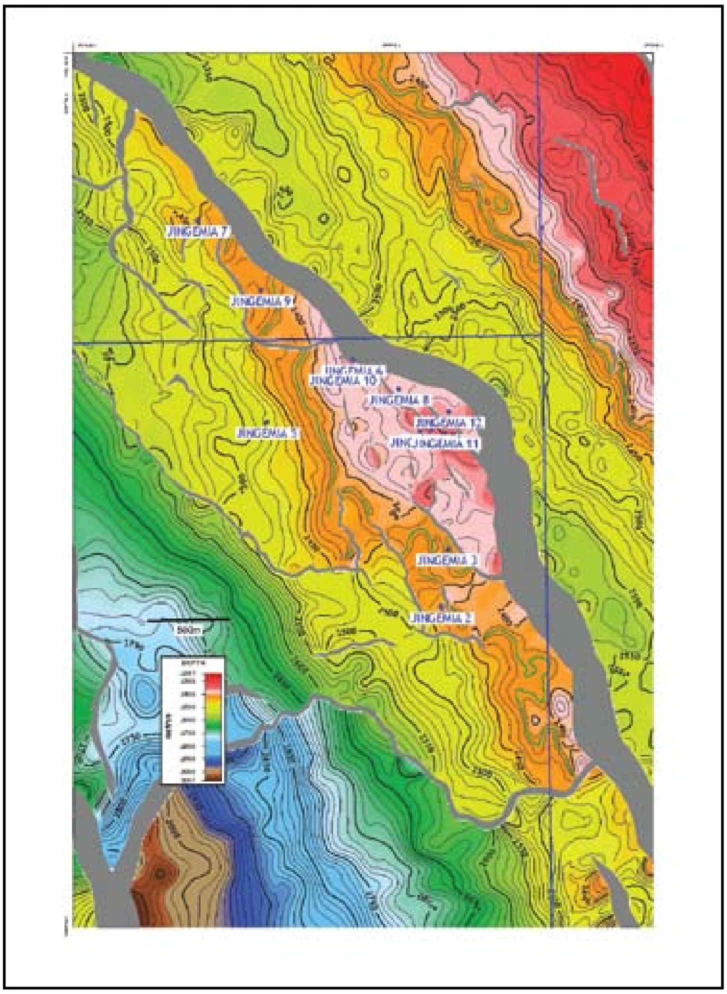

Figure 6 | **Depth structure map of the Jingemia field, Top Dongara Sandstone (courtesy of Origin)** the southwest of the field as the source rock is likely to continue into the oil window down dip at in this direction.

Reserves

The Hovea field is producing from a single oil column with a maximum gross oil column of 47.8 m down to an OWC at -1,930 mSS (Fig. 5). The Eremia field consists of a single oil column within the Dongara Sandstone. The field has a maximum gross oil column of 22.6 m down to the OWC at -2,078 mSS. The Jingemia field consists of a single oil pool, with additional reserves encountered with a fault splay intersected by Jingemia 8. A maximum gross oil column of 33.9 m was encountered down to an original OWC of -2,414 mSS. This contact has since moved with Jingemia 11 intersecting the OWC at -2,373 mSS (Fig. 6). The field has a maximum gross oil column of 29 m.

All three fields of the Hovea–Eremia–Jingemia fairway remain in production.

As at 31 December 2010 the Hovea field has produced 1,157,965 kL of oil and condensate and 100.5 Mm^3 of gas; Eremia has produced 242,506 kL of oil and 13.0 Mm^3 of gas and Jingemia has produced 715,013 kL of oil and 33.8 Mm^3 of gas. The remaining oil reserves at Hovea and Jingemia are 643,562 kL and 36,500 kL, respectively. Remaining reserves at Eremia are too small to measure. The production history for each of the three fields is shown in Figures 7 to 9. ▪

An aerial view of the Jingemia production facility with a drilling rig
(Photo courtesy of ARC Energy)

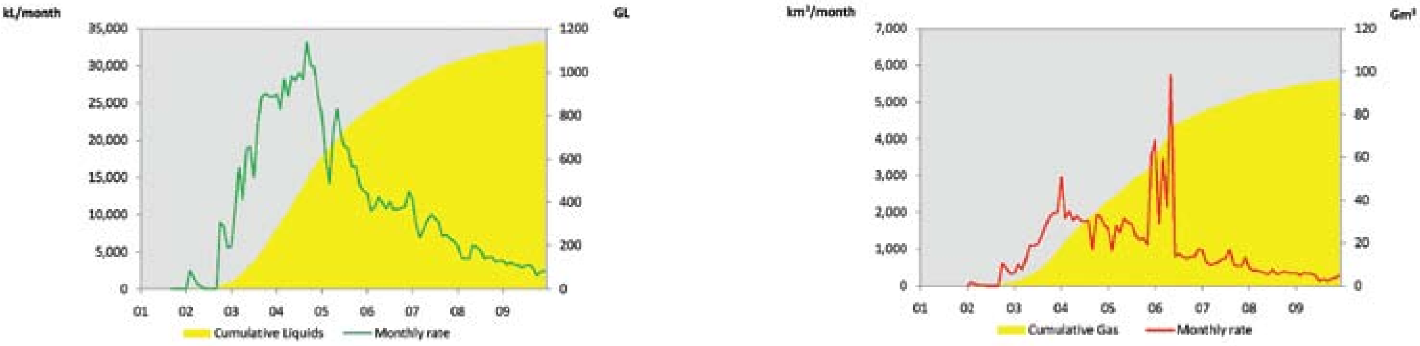

Figure 7 | **Production history, Hovea field**

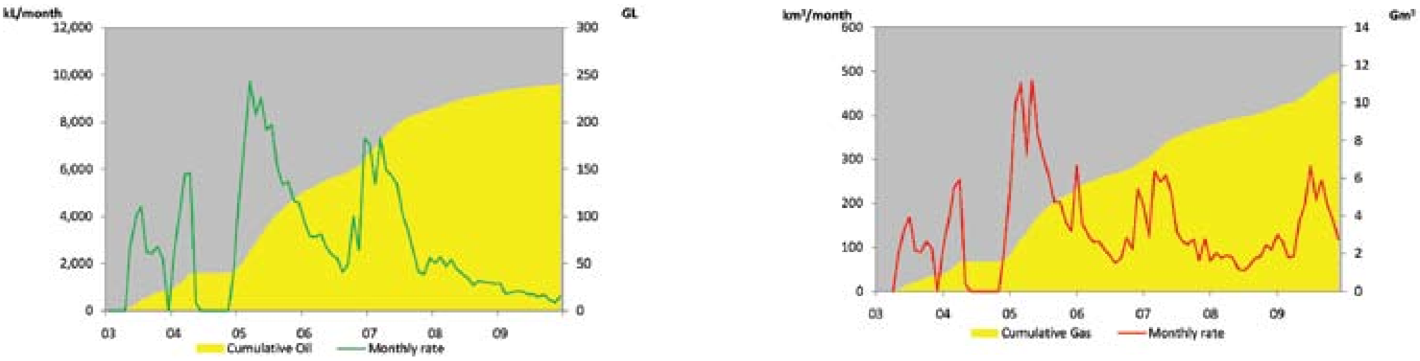

Figure 8 | **Production history, Eremia field**

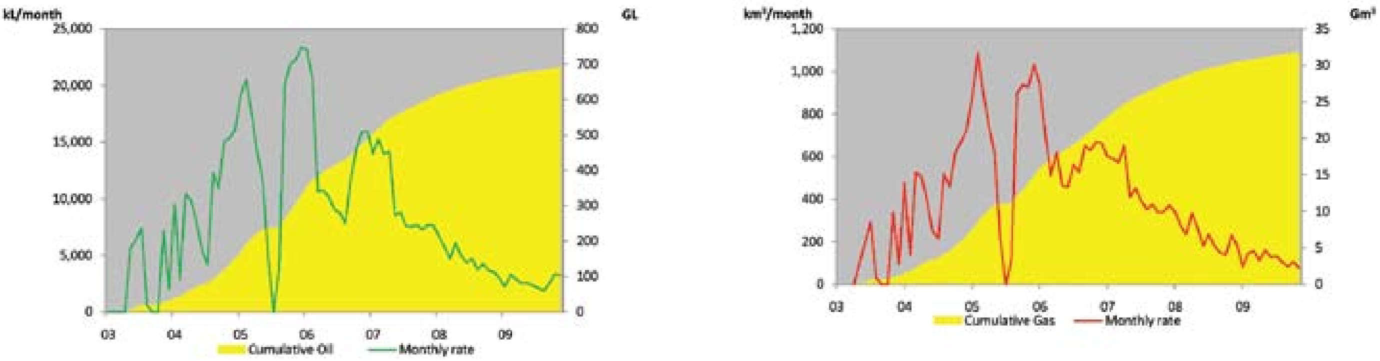

Figure 9 | **Production history, Jingemia field**

The Petroleum and Geothermal Register (PGR) – Bigger and Better

Hazel Harnwell
Manager Project Coordination and Information Management
Strategic Business Development Branch

The PGR Field Development Plan development team

In October 2010 the Petroleum Division achieved another major milestone with the release of the PGR Finance Module. Since then, further enhancements have been made to the system that benefit internal and industry users.

This milestone has provided authorised Petroleum Division staff with the ability to process financial related tasks within PGR. The processes and procedures for the receival of monies and banking have been improved and streamlined, enabling staff to perform tasks more accurately, effectively and efficiently. Greater transparency has been provided to detail how fees are calculated and adjusted.

The final stages in the development of the module required staff from the Petroleum Division, Finance Branch and Information Services Branch to participate in rigorous testing of the new system. Testing was conducted over a six week period in September and October in addition to normal daily duties.

A post-implementation review of the new PGR Finance Module has identified that industry has been quick to take advantage of the new EFT payments facility.

Also in 2010, DMP launched its Resource Project System. Petroleum and geothermal data is drawn from the PGR system giving internal users the ability to search for titles and applications by project name.

Future PGR releases will provide information on a wider range of technical and operational project specific data enabling external users to view comprehensive project details and allow:

- registered users to see a list of all projects relevant to their company;
- the ability to see all titles relating to a project;
- the ability to search by project name; and
- the ability to search for fields within a project.

Another significant addition to PGR is the ability to lodge an application for Change of Company Name online. This has replaced the eForms lodgement system and provides a user-friendly, seamless lodgement and approval process.

Online lodgement of applications to Drill a Well is scheduled for release in April 2011.

Work has also commenced on a Field Development Module which will allow industry to submit Field Development Plans online for approval by the Resource Management team.

Mark Gabrielson, General Manager Business Development Branch said that PGR was fast becoming a valuable tool for industry. “With each enhancement PGR is providing greater value to internal users but increasingly feedback from industry has shown that PGR Online has become a powerful source of information assisting them to manage their business”, he said. ■

Mineral Rig on Steroids – A New Paradigm in Geothermal Exploration

Mike Middleton and Karina Jonasson
Senior Energy Geotechnologist and Petroleum Resource Geologist
Resources Branch

Mobilising the GT3000
(Photos courtesy of Coretrack Limited)

Globe Drill Pty Ltd has designed and built a drilling rig expressly focussed on the geothermal and oil and gas energy sectors. Globe Drill is a fully owned subsidiary of the ASX listed company Coretrack Limited (ASX:CKK). The company's mission is encapsulated in the statement "Globe Drill is passionate about renewable energy and drilling for energy sources that will assist to create a sustainable future. As such the Company's initial focus is to provide drilling services to the geothermal industry with a secondary focus on the oil and gas industry. Globe Drill is committed to providing the world's best energy drilling service and turning previously nonviable energy projects into viable ones".

Coretrack Chief Executive Officer Nanne van 't Riet said that the new GT3000 drill rig was the brain-child of Warren Strange, who is a director of Coretrack and a technical consultant to Globe Drill with 34 years of experience in the drilling industry. He said that "Warren saw geothermal as the energy source of the future, and he wanted to build a rig specifically designed for the geothermal industry that was better suited and less expensive to operate than what was currently in the marketplace". The rig was manufactured in Western Australia and completed in 2010 after five years of research and development. Mr. van 't Riet was proud to announce that this rig was "unique worldwide", because of its mobility, small footprint, fuel efficiency and reduced manpower requirements. Moreover, the rig has an ability to drill using air hammer or mud rotary methods.

Mr. van 't Riet pointed out that the rig development was based on earlier mineral rig designs. Warren Strange is said to have described the rig as a "mineral rig on steroids". He pointed out that the rig's capability has several major ticks:

(1) a high torque (30,000 Nm @ 60 RPM),

(2) an excellent pullback capacity (154 ton),

(3) a high drill rate (in the vicinity of 35 m per hour through hard rock),

(4) a simpler and cheaper mobilisation ability, being track-mounted and requiring only five support trucks,

(5) a very small site footprint of 1,000 m^2, which is an order of magnitude less than most other rigs used in the geothermal and petroleum industries,

(6) a very good fuel efficiency (using about 15 litres per hour), and

(7) is designed to drill 20.3–25.4 cm (8–10 inch) holes past 3,000 m.

Further, Mr. van 't Riet indicated that, because the rig is track mounted with only five support trucks and requires an operating crew of only four people, mobilisation costs are substantially less than conventional oil and gas drilling rigs and drilling can begin within one day of the rig arriving on site. The increased mobility also improved accessibility to remote locations or sites in difficult terrain.

The GT3000 rig has a 3,500 m drilling depth capacity, and can drill holes at an angle of up to 60°. The rig has been primarily designed for drilling in "hard rock" conditions, and a test hole at Merredin was completed to a depth of 1,000 m in February 2011. In this test the specifications of the rig were verified, equipment commissioned and the crew put through its paces. Interestingly, the test hole encountered a fresh water aquifer at shallow depths, which was subsequently cased off. This highlights the rig's additional suitability for hydrogeological investigations.

Despite being primarily designed for hard rock conditions, the rig can also be configured to operate using a mud rotary system for sedimentary basin drilling. Thus, the company is able to participate in more traditional oil and gas drilling programs, as well as coal seam methane and shale gas projects. A cellar can be constructed under the rig to accommodate a blow out preventer (BOP) or diverter system. The company has just completed its first commercial job in December 2010, which was commissioned by Woodside.

The future outlook for Globe Drill includes the design and construction of a rig capable of drilling 5,000 m, which has been designated the GT5000. Mr. van 't Riet noted that the company takes about six months to construct a rig and anticipates being able to construct up to six rigs in a 12 month period if the demand arises. The cost of building a GT3000 rig is about $10 million, which includes both the construction and auxiliary equipment. ■

Western Australia's Potential Domestic Gas Demand and Supply Outlook

Andy Separovic and Derek Perez
Policy and Coordination Branch

The Karratha Gas Plant, May 2010
(Photo courtesy of Woodside Energy)

The September 2010 edition of Petroleum in Western Australia included an article titled, 'The Outlook for Domestic Gas in Western Australia'. The article featured a set of projections which highlighted some of the domestic gas supply issues and broader energy security challenges facing Western Australia. The projections generated a high level of interest from both upstream producers and consumers of the State's domestic gas.

The Department of Mines and Petroleum has undertaken further analytical work to refine its original domestic gas demand and supply outlook. The updated analysis is presented in this article and takes into account new data and feedback received.

Natural gas is vital to the Western Australian economy and accounts for half of the total primary energy consumed in this State. The volume of natural gas sold domestically in Western Australia in 2010 amounted to 9.3 billion cubic metres, or 961 terajoules per day (TJ/d). Most of this gas is consumed by the mining, manufacturing and electricity generation industries which collectively account for up to 90 per cent of the State's total domestic gas consumption.

Future demand growth will largely be driven by the State's minerals and energy sector. Forecasting this demand is difficult and depends on the extent to which new resource projects are developed and/or expanded. Significant increases in demand will be underpinned by a handful of large mineral processing or manufacturing projects. The lumpy nature of investment in these projects, changes to project status and timing can result in significantly different gas consumption forecasts.

The Department has estimated gas demand by aggregating the projected energy demands of known resource projects over time, with some adjustment for the probability they will proceed. A number of major resource projects under construction are scheduled to start-up in the near term. These include BHP Billiton's $8 billion Rapid Growth 5 and 6 iron ore expansion projects; CITIC Pacific's $5 billion iron ore magnetite project; and Worsley's $2.5 billion alumina refinery expansion. In addition, the emergence of new energy-intensive magnetite iron ore projects is likely to push up the demand for gas in the future.

As shown in Figure 1, estimated notional demand for gas in Western Australia is projected to increase from 961 TJ/d in 2010 to 1,912 TJ/d by 2030. This is consistent with the Western Australian domestic gas consumption growth rate of 3.5 per cent as measured over the last decade. The Department has included a demand outlook based on known major projects resulting in strong growth over the next five years as a number of mineral processing projects reach production stage. It is important to note that not all projects in this demand projection will proceed due to factors such as changes in international demand for the State's resources and global commodity prices.

Currently, nearly all of Western Australia's domestic gas is supplied by the North West Shelf joint venture and the Varanus Island hub. Over the next 20 years the fields supplying these facilities are expected to decline. Consequently, new sources of supply will need to be discovered to support future demand.

The Department has forecast the supply of domestic gas from existing and committed production facilities, and has projected the production rate and depletion rate of known gasfields. Low and high supply projections are provided using different assumptions. A key difference between the projections is based on the assumption that in the high supply case North West Shelf (NWS) domestic gas production is maintained at 600 TJ/d to 2030. In contrast, the low supply case assumes that production from the NWS is maintained at 600 TJ/d to 2020 before declining to 300 TJ/d by 2030.

The high supply case also assumes that approximately 2,350 petajoules of gas will be discovered and supplied domestically over the outlook period partially underpinning the continued

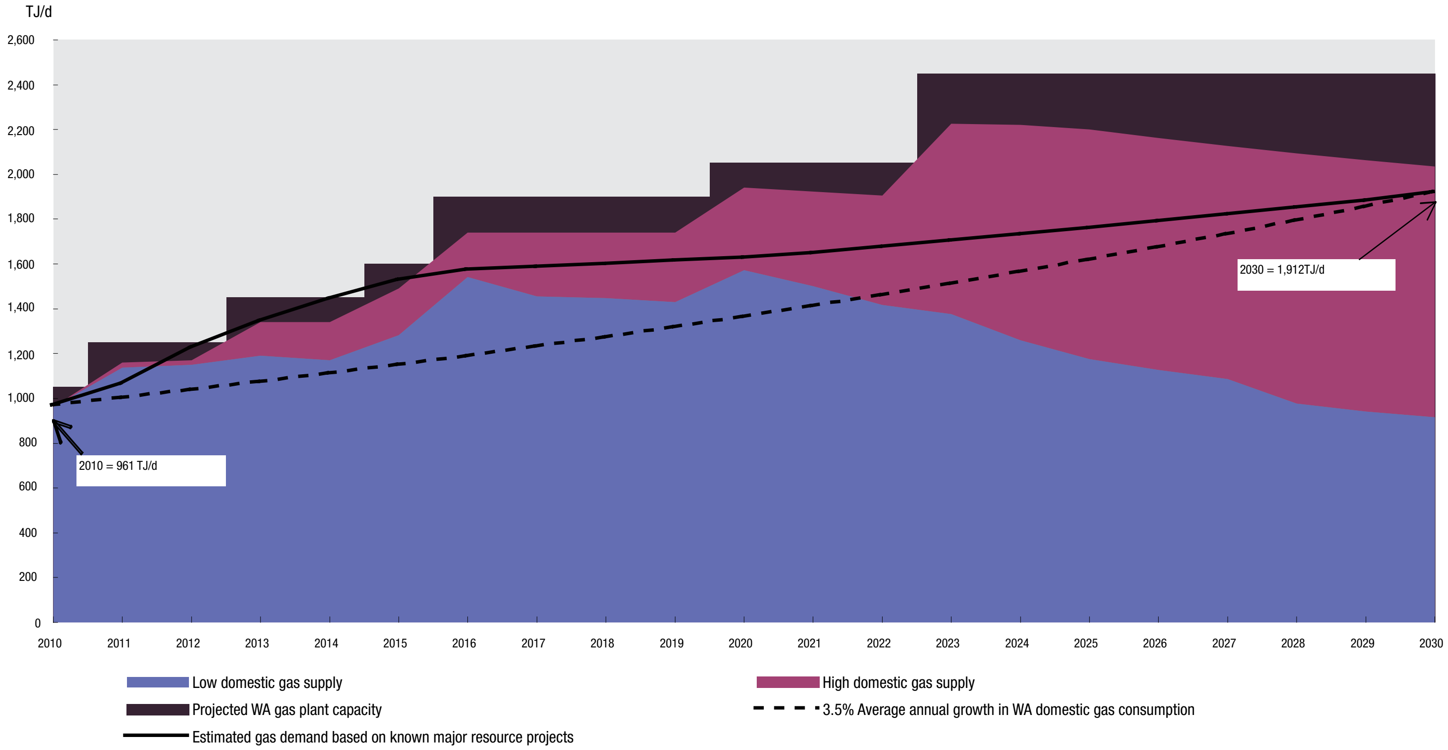

Figure 1 | **Western Australian potential domestic gas demand and supply from 2010 to 2030**

NOTES

(a) Estimated gas demand based on known major resource sector projects and excludes price effects. Not all projects in this demand projection will proceed due to factors such as international demand, supply and global commodity prices. From 1999-00 to 2009-10, WA gas sales have grown at an average rate of 3.5% per year. The model provides a 3.5% annual growth rate for domestic gas consumption over the next 20 years, rising from 961 TJ/d in 2010 to 1,912 TJ/d in 2030.

(b) A key difference between the supply projections is based on the assumption that in the high supply case NWS domestic gas production is maintained at 600 TJ/d to 2030. In contrast, the low supply case assumes that production from the NWS is maintained at 600 TJ/d to 2020 before declining to 300 TJ/d by 2030.

(c) The high supply case also assumes that approximately 2,350 PJ of gas will be discovered and supplied domestically over the outlook period partially underpinning the continued supply of gas from the Varanus Island, Devil Creek and Macedon gas processing facilities.

(d) Beyond 2020, the high supply case assumes domestic gas is supplied from new developments including Browse, Scarborough and from unconventional sources such as the Warro tight gas project.

Source: Department of Mines and Petroleum

Table 1. Assumptions underpinning potential gas supply

Project	Start-up	High supply	Low supply
North West Shelf (NWS)	operational	600 TJ/d maintained to 2030.	600 TJ/d maintained to 2020 declining to 300 TJ/d by 2030.
Varanus Island (includes gas supply from the Halyard/Spar fields)	operational	450 TJ/d maintained to 2020 declining to 300 TJ/d by 2030 assuming new fields are discovered to support this.	450 TJ/d in 2011 declining to less than 100 TJ/d by 2030.
Devil Creek gas plant	2011	110 TJ/d supplied for 13 years before declining to around 50 TJ/d by 2030 assuming new fields are discovered which extend supply to 2030.	110 TJ/d supplied for 13 years based on Reindeer development only.
Macedon processing facility	2013	170 TJ/d supplied for 12 years before declining to around 90 TJ/d by 2030 assuming new fields are discovered which extend supply to 2030.	145 TJ/d supplied for 12 years based on Macedon development only.
Gorgon	2015	150 TJ/d in 2015 followed by 300 TJ/d from 2020.	150 TJ/d in 2015 followed by 300 TJ/d from 2020.
Wheatstone	2016	200 TJ/d maintained to 2030.	200 TJ/d maintained to 2030.
Pluto	2016	100 TJ/d maintained to 2030.	100 TJ/d maintained to 2030.
Browse	2023	190 TJ/d maintained to 2030.	
Scarborough	2023	190 TJ/d maintained to 2030.	
Unconventional gas (includes Warro tight gas project)	2012	10 TJ/d maintained to 2030.	

supply of gas from the Varanus Island, Devil Creek and Macedon gas processing facilities. Beyond 2020, the high supply case also assumes that domestic gas is supplied from new developments including Browse, Scarborough and from unconventional sources such as the Warro tight gas project.

Table 1 provides details of projects supplying domestic gas which underpin both supply forecasts and lists those projects which are included in the high supply scenario. Figure 1 illustrates the notional outlook for gas demand supply and for Western Australia.

The improving outlook for the world economy along with strong growth in the State's resources sector points to a sharp increase in the demand for gas in the next five years before moderating over the outlook period. As indicated in Figure 1, this expected surge in gas demand will present challenges for the State in the short term. This suggests that projects unable to source gas will either defer, cancel or switch to an alternative energy source such as coal.

The updated outlook shows that domestic gas supply will increase to around 1,500 TJ/day in 2016, or higher if new supply from gasfields matches the full capacity of production facilities. Beyond this time, production from a number of known gasfields begins to decline, and the ability to meet future gas demand will depend on the rate at which new gasfields are discovered and developed.

As a strategic issue, it appears that Western Australia will have sufficient capacity in its domestic gas production facilities to meet the anticipated growth in demand over the next 20 years. The challenge will be finding and developing new gasfields to feed into those facilities, and the relationship between domestic gas supply and LNG exports. The anticipated supply of domestic gas from LNG projects such as Gorgon, Wheatstone, Scarborough and Browse will play a crucial role in securing future gas supply. Without new gasfields being brought to production, Western Australia is likely to face further increases in gas prices and/or unsatisfied demand.

Recognising the importance of addressing long-term domestic energy security, the Department has been working to promote and facilitate the exploration and development of alternative upstream energy sources including unconventional gas and geothermal energy, as a means of increasing and diversifying energy supply. ∎

An LNG tanker lit up at night
(Photo courtesy of Woodside Energy)

The Energy Security Mobilisation Scheme

Huoy Wei Tang and
Mark Gabrielson
Graduate Officer and General Manager Business Development
Petroleum Division

Drilling rig in the Perth Basin
(Photo courtesy of ARC Energy)

The Western Australian Government is encouraging the exploration and development of unconventional energy by contributing to the mobilisation costs of specialised equipment into the State from interstate and overseas. The Energy Security Mobilisation Scheme (ESMS) will be funded by the Royalties for Regions program and will provide explorers and developers access to drilling and fracturing equipment used in the development of unconventional resources.

Unconventional energy sources will be important in increasing and diversifying energy supply to ensure long-term energy security, particularly as gas currently supplies around 53 per cent of primary energy requirements to the State.

Although the development of unconventional energy is prevalent in some countries, there are significant entry cost barriers for industry in Western Australia. Currently, there is a lack of an economy of scale and competition amongst equipment contractors in the State. An unconventional gas well can be drilled and put on production in the United States at an average cost of over $3.75 million while comparable wells in Western Australia are in excess of $15 million.

Many companies are unable to afford the costs of the specialised equipment required to drill and fracture rocks beneath the earth's surface. A reduction of the high upfront costs associated with the drilling rigs and fracturing equipment would assist in the establishment of an unconventional gas industry in Western Australia.

Speaking to *PetroleumNews.net*, Department of Mines and Petroleum Executive Director, Bill Tinapple, said that an aim was to have a new drilling rig in the State by the end of the year.

"We want to facilitate this embryonic industry of unconventional gas and we've looked at ... the problems [and] ... the hurdles to get over to try and get exploration demonstration projects off the ground.

It seems like the gas prices are enough to make it worthwhile, but we don't have equipment. We're trying to get out and see what we can do about that as a government."

A specialist Project Manager has been appointed to facilitate the development of combined drilling work programs. The Project Manager will act as an honest broker in coordinating a 'drilling club' with companies and to assist with the mobilisation of drilling rigs once sufficient demand is demonstrated.

Under a combined work program, companies will be able to secure the use of drilling rigs at specific times for their exploration campaigns. If resource discoveries are found to be commercial, companies will be able to make their own arrangements to mobilise different rigs to develop the resource, thereby increasing the number of rigs available and creating more competition between drilling contractors.

The Energy Security Mobilisation Scheme has a significant role in developing the unconventional energy industry in Western Australia. In turn, this will increase and diversify the State's energy supplies and help ensure energy security for the future growth of Western Australia. ■

Table 1. 2010 Production by Field and Cumulative Production as at 31 December 2010

Field	Operator	2010 Production by Field			Cumulative Production			Permit
		Oil	Condensate	Gas	Oil	Condensate	Gas	
		kL	kL	10^3 m^3	kL	kL	10^3 m^3	
Albert	Apache	4,415	13	1,196	61,749	41	6,367	TL/6
Angel	Woodside	0	2,329,421	7,899,932	0	4,771,924	15,984,521	WA-3-L
Apium	AWE	0	63	4,349	0	355	30,603	L1
Artreus	Apache	9	0	37	32,836	14	3,850	TL/6
Bambra	Apache	67,974	30,030	323,677	309,109	114,650	846,715	TL/1
Barrow Island	Chevron	311,510	0	35,934	50,296,651	0	5,315,949	L1H
Beharra Springs N	Origin	0	341	41,804	0	24,211	2,279,971	L11
Beharra Springs S	Origin	0	11	1,112	0	2,012	206,230	L11
Blacktip	Eni	0	10,564	582,861	0	11,096	644,188	WA-33-L
Blina	Buru Energy	690	0	0	296,817	0	0	L6
Boundary	Buru Energy	292	0	0	20,743	0	0	L6
Cliff Head	ROC Oil	234,030	0	1,530	1,664,098	0	7,396	WA-31-L
Corybas	AWE	0	180	7,129	0	180	7,129	L2
Cossack	Woodside	263,643	0	7,042	12,848,307	0	384,977	WA-9-L
Cowle	Chevron	2,772	0	1,861	531,266	0	89,628	TL/4
Crest	Chevron	299	0	695	275,054	108	62,686	L12, L13
Crosby	BHP Billiton	1,908,621	0	72,190	1,908,621	0	72,190	WA-42-L
Dongara	AWE	1,217	4	19,079	193,094	49,681	12,889,122	L1, L2
Double Island	Apache	16,167	49	6,751	692,177	2,825	51,803	TL/9
Echo/Yodel	Woodside	0	176,313	200,844	0	10,747,852	13,567,553	WA-23/24-L
Enfield	Woodside	1,520,104	0	110,249	9,123,159	0	762,309	WA-28-L
Eremia	AWE	2,717	0	1,427	242,506	0	13,035	L1
Eskdale	BHP Billiton	87,614	0	86,268	398,900	0	268,310	WA-32-L
Exeter	Santos	27,873	0	149	2,513,130	0	4,997	WA-27-L
Gipsy	Apache	18	0	8	363,641	2,502	79,189	TL/1
Goodwyn	Woodside	0	1,487,995	7,533,371	0	44,299,453	128,855,757	WA-5-L
Gudrun	Apache	15	0	5	118,735	75	7,745	TL/1
Harriet	Apache	18,483	181	7,664	8,200,239	60,217	1,492,451	TL/1
Hermes	Woodside	1,261,095	0	89,767	12,681,481	0	844,868	WA-16-L
Hovea	AWE	19,264	0	4,263	1,157,714	251	100,471	L1
Jingemia	Origin	23,611	0	2,064	715,013	0	33,810	L14
John Brookes	Apache	0	167,451	2,838,976	0	745,329	11,955,870	WA-29-L
Laminaria East	Woodside	16,382	0	1,680	1,549,415	70,625	26,534	WA-18-L
Lee	Apache	0	14,907	122,315	0	107,492	707,522	TL/1
Legendre North	Apache	122,449	0	86,914	6,781,400	0	1,749,003	WA-20-L
Legendre South	Apache	35,531	0	224,003	884,778	0	1,222,452	WA-20-L
Little Sandy	Apache	4,083	12	1,593	92,230	455	13,301	TL/6
Lloyd	Buru Energy	160	0	0	30,284	0	0	L8
Macedon	BHP Billiton	0	0	16,761	0	0	16,761	WA-42-L
Mohave	Apache	13,457	123	8,472	155,052	231	26,830	TL/6
Mount Horner	AWE	1,663	0	0	298,094	0	0	L7
Mutineer	Santos	252,218	0	1,451	6,044,518	0	12,955	WA-26-L
North Alkimos	Apache	1,189	5	1,631	11,244	94	21,823	TL/6
North Rankin	Woodside	0	235,922	2,275,191	0	24,697,633	193,530,684	WA-1-L
Pedirka	Apache	12,378	50	6,563	326,938	1,254	37,201	TL/6
Perseus	Woodside	0	2,379,384	12,055,759	0	22,170,967	108,497,522	WA-1-L

Table 1. 2010 Production by Field and Cumulative Production as at 31 December 2010

Field	Operator	2010 Production by Field			Cumulative Production			Permit
		Oil	Condensate	Gas	Oil	Condensate	Gas	
		kL	kL	10^3 m^3	kL	kL	10^3 m^3	
Ravensworth	BHP Billiton	624,565	0	124,143	624,565	0	124,143	WA-42-L
Redback	Origin	0	15	11,175	0	15	11,175	L11
Roller	Chevron	39,616	0	12,818	7,117,562	0	755,893	TL/7
Rose	Apache	0	5,525	40,348	0	204,880	997,470	TL/1
Saladin	Chevron	66,007	0	22,638	15,468,324	0	1,741,051	TL/4
Searipple	Woodside	0	477,111	482,667	0	1,233,077	1,223,687	WA-1-L
Simpson	Apache	9,079	2,503	3,793	844,091	9,028	84,398	TL/1
Skate	Chevron	0	0	21,786	266,950	8,873	177,967	TL/7
South Plato	Apache	4,889	10	841	702,432	893	51,476	TL/6
Stag	Apache	342,022	0	4,267	8,560,191	0	398,721	WA-15-L
Stickle	BHP Billiton	1,543,454	0	104,632	1,543,454	0	104,632	WA-42-L
Stybarrow	BHP Billiton	586,147	0	35,459	6,408,459	1	388,182	WA-32-L
Sundown	Buru Energy	1,728	0	0	72,267	0	0	L8
Tarantula	Origin	0	69	7,386	0	3,927	315,450	L11
Van Gogh	Apache	1,878,286	0	157,015	1,878,286	0	157,015	WA-35-L
Victoria	Apache	2,844	8	594	52,422	375	8,435	TL/6
Vincent	Woodside	1,357,915	0	148,790	2,952,760	0	735,690	WA-28-L
Wanaea	Woodside	482,432	0	113,460	39,185,910	0	8,410,610	WA-11-L
Wandoo	Vermillion	426,541	0	38,535	12,623,493	0	1,006,511	WA-14-L
West Cycad	Apache	15,640	121	6,946	208,820	346	30,636	TL/9
West Terrace	Buru Energy	612	0	0	39,128	0	0	L8
Wonnich	Apache	0	36,374	419,020	0	438,937	4,345,206	TL/8
Woodada	AWE	0	0	583	0	10,603	1,496,908	L4, L5
Woollybutt	Eni	270,234	0	7,311	5,303,878	0	149,929	WA-25-L
Xyris	AWE	0	62	3,942	0	3,567	262,826	L1
Yammaderry	Chevron	395	0	9,001	857,756	0	107,726	TL/4
Yardarino	AWE	0	0	151	1,567	771	143,934	L2
Cumulative production for developed fields currently not producing					39,257,815	3,267,426	21,301,789	
Total		**13,884,349**	**7,354,817**	**36,461,868**	**264,789,123**	**113,064,246**	**547,263,738**	

Table 2a. Revised Petroleum Reserves Estimates by Basin as at 31 December 2009 (metric units)

Basin	Oil GL		Sales Gas Gm^3		Condensate GL	
Category 1	**P50**	**P90**	**P50**	**P90**	**P50**	**P90**
Bonaparte	0.00	0.00	23.53	11.06	0.00	0.00
Northern Carnarvon	56.59	24.94	493.98	401.01	66.29	48.53
Perth	1.58	1.04	0.33	0.13	0.00	0.00
Total	**58.17**	**25.98**	**517.84**	**412.20**	**66.29**	**48.53**
Category 2	**P50**	**P90**	**P50**	**P90**	**P50**	**P90**
Bonaparte	0.00	0.00	34.01	25.54	0.00	0.00
Browse	0.00	0.00	437.20	437.20	57.60	57.60
Northern Carnarvon	21.08	12.93	766.98	479.09	38.02	22.80
Total	**21.08**	**12.93**	**1,238.19**	**941.83**	**95.62**	**80.40**
Category 3	**P50**	**P90**	**P50**	**P90**	**P50**	**P90**
Browse	0.00	0.00	418.73	301.52	96.79	70.21
Northern Carnarvon	14.18	10.69	813.09	420.02	36.98	19.93
Total	**14.18**	**10.69**	**1,231.82**	**721.54**	**133.77**	**90.14**
Category 4	**P50**	**P90**	**P50**	**P90**	**P50**	**P90**
Bonaparte	0.00	0.00	16.87	1.56	0.00	0.00
Browse	0.00	0.00	5.64	5.64	0.55	0.55
Carnarvon	36.01	29.96	438.93	310.60	20.25	16.50
Perth	0.94	0.94	6.85	1.35	0.00*	0.00*
Total	**36.95**	**30.90**	**468.29**	**319.15**	**20.81**	**17.06**
GRAND TOTAL	**130.38**	**80.50**	**3,456.14**	**2,394.72**	**316.48**	**236.13**

* too small to measure

Table 2b. Revised Petroleum Reserves Estimates by Basin as at 31 December 2009 (field units)

Basin	Oil MMbbl		Sales Gas Tcf		Condensate MMbbl	
Category 1	**P50**	**P90**	**P50**	**P90**	**P50**	**P90**
Bonaparte	0.00	0.00	0.83	0.39	0.00	0.00
Northern Carnarvon	355.97	156.86	17.44	14.16	416.93	305.22
Perth	9.96	6.52	0.01	0.00	0.03	0.01
Total	**365.93**	**163.38**	**18.28**	**14.55**	**416.96**	**305.23**
Category 2	**P50**	**P90**	**P50**	**P90**	**P50**	**P90**
Bonaparte	0.00	0.00	1.20	0.90	0.00	0.00
Browse	0.00	0.00	15.44	15.44	362.29	362.29
Northern Carnarvon	132.61	81.32	27.09	16.92	239.16	143.38
Total	**132.61**	**81.32**	**43.73**	**33.26**	**601.45**	**505.67**
Category 3	**P50**	**P90**	**P50**	**P90**	**P50**	**P90**
Browse	0.00	0.00	14.79	10.68	608.79	441.61
Northern Carnarvon	89.19	67.24	28.71	14.83	232.60	125.35
Total	**89.19**	**67.24**	**43.50**	**25.51**	**841.39**	**566.96**
Category 4	**P50**	**P90**	**P50**	**P90**	**P50**	**P90**
Bonaparte	0.00	0.00	0.60	0.05	0.00	0.00
Browse	0.00	0.00	0.20	0.20	3.47	3.47
Carnarvon	226.52	188.47	15.50	10.97	127.39	103.81
Perth	5.91	5.91	0.24	0.05	0.00*	0.00*
Total	**232.43**	**194.38**	**16.54**	**11.27**	**130.86**	**107.28**
GRAND TOTAL	**820.16**	**506.32**	**122.05**	**84.59**	**1,990.66**	**1,485.14**

* too small to measure

NOTES

Category 1 comprises current reserves of those fields which are producing hydrocarbons or have been declared commercial (FFDP approved and FID).
Category 2 comprises estimates of recoverable reserves which are held under Retention Leases and have not yet been declared commercially viable.
Category 3 comprises estimates of contingent resources which are held in other licences and have been declared commercially viable but may or may not have a FFDP and have not yet reached FID.
Category 4 comprises estimates of contingent resources which are held in other licences and have not yet been declared commercially viable and are not held under a Retention Lease.
Reserves estimates for 2010 have not yet been submitted by industry to DMP.

Table 3. Seismic Surveys in Western Australia 2010 Calendar Year — Statistical Summary

		2D (line km)	3D (km²)
Bight Basin	Onshore		
	Offshore	1,539(a)	
Bonaparte Basin	Onshore		
	Offshore	603	2,450(b)
Browse Basin	Onshore		
	Offshore	12,184	2,911(c)
Canning Basin	Onshore	761	
	Offshore		
Carnarvon Basin	Onshore		
	Offshore		19,675(d)
Subtotal	Onshore	761	
	Offshore	14,326	25,036
Total		**15,087**	**25,036**

The above table lists the quantity of 2D seismic (line km) and 3D seismic (km²) acquired during the calendar year. For surveys that commenced before 1/1/2010 only acquisition after this date is included.
(a) Bremer Basin 2D M.S.S. commenced 2009
(b) RIL 3D 09/10 3D M.S.S. commenced 2009
(c) Includes Poseidon 3D M.S.S. commenced 2009
(d) Includes Claudius 2009 and Eendracht 3D M.S.S. commenced 2009
Non-seismic surveys for the year include Bedout Sub-basin aeromag, Ragnar Hub CSEM, Balladonia ESR and Collie sampling and gravity surveys.
The attached listing of surveys operating in the calendar year (Table 5) includes all data gathered prior to 31/12/2010.

Table 4. Petroleum Wells in Western Australia 2010 Calendar Year — Statistical Summary

		NFW		EXT		DEV		Subtotal		Total	
		Wells	Metres	Wells	Metres	Wells	Metres	Wells	Metres	Wells	Metres
Browse Basin	Onshore										
	Offshore	1	6,967(a)	1	6,470			2	13,437	**2**	**13,437**
Canning Basin	Onshore	5	9,453					5	9,453	**5**	**9,453**
	Offshore										
Carnarvon Basin	Onshore									**55**	**179,614**
	Offshore	31	95,766(b)	11	29,747(c)	13	54,101(d)	55	179,614		
Perth Basin	Onshore	4(e)	7,193	1	4,114	3	8,393	8	19,700	**8**	**19,700**
	Offshore										
Subtotal	Onshore	9	16,646	1	4,114	3	8,393	13	29,153	**70**	**222,204**
	Offshore	32	102,733	12	36,217	13	54,101	57	193,051		
Total		**41**	**119,379**	**13**	**40,331**	**16**	**62,494**	**70**	**222,204**		

The above table lists the number of wells spudded and metres drilled (subsurface) during the 2010 calendar year.
For wells spudded before 1/1/2010, only metres drilled during the calendar year are included.
(a) Includes Braveheart 1 spudded 2009
(b) Includes Balthazar 1 and Larsen 1 spudded 2009
(c) Includes Chandon 2 and lago 5 spudded 2009
(d) Includes six Pyrenees and two Vincent wells spudded 2009
(e) Includes Kaloorup Road 2 coal bed methane well

Table 5. Surveys in Western Australia Operating 2010 Calendar Year

Survey Name	Class	On Off	Title	Operator	Commenced	Completed	2D line km @ 31/12/2010	3D km² @ 31/12/2010	Non Seismic km
Bight Basin									
Bremer Basin 2D M.S.S.	2D	Off	WA-379-P, WA-380-P	Arcadia	9/12/2009	20/01/2010	4,443.25		
Bonaparte Basin									
Penguin 2010 2D M.S.S.	2D	Off	WA-313-P R1	Eni	19/03/2010	25/03/2010	393.85		
WA-446-P 2D M.S.S.	2D	Off	WA-446-P	Finder	25/10/2010	29/10/2010	209.28		
RIL 3D 09/10 M.S.S.	3D	Off	WA-405-P	Reliance	24/12/2009	16/01/2010		2,750.00	
Browse Basin									
Koolama 2D M.S.S.	2D	Off	WA-415-P, WA-416-P, WA-417-P	Woodside	24/05/2010	26/06/2010	4,101.00		
Vampire Non-Exclusive 2D M.S.S.	2D	Off	1SL/10-1	Searcher Seismic	1/11/2010		5,576.00		
Bassett 3D M.S.S.	3D	Off	WA-408-P	Total	23/09/2010	20/10/2010		855.82	
Ichthys 3D M.S.S.	3D	Off	WA-285-P R2, WA-37-R	Inpex	21/10/2010	23/12/2010		1,618.89	
Poseidon 3D M.S.S.	3D	Off	WA-314-P, WA-315-P, WA-389-P		11/10/2009	3/03/2010		3,141.01	
Golden Orb MultiClient 2D M.S.S.	2D	Off	12SL/09-0	PGS	28/06/2010	18/07/2010	2,507.40		
Canning Basin									
Pijalinga 2D S.S.	2D	On	EP 427, EP 442	Buru	2/10/2010	10/11/2010	414.86		
Yulleroo South 2D S.S.	2D	On	EP 391 R2, EP 428	Buru	27/08/2010	28/09/2010	346.30		
Bedout Sub-basin Aeromagnetic Survey	AEROMAG	Off	WA-435-P, WA-436-P, WA-437-P, WA-438-P	Finder	29/04/2010	19/05/2010			21,583
Carnarvon Basin									
Endeavour MC3D Multiclient M.S.S.	3D	Off	3SL/10-1	Western Geco	6/12/2010			160.00	
Phoenix MC3D M.S.S.	3D	Off	11SL/09-0	Fugro	9/12/2010			460.00	
Salsa 3D M.S.S.	3D	Off	WA-384-P	Shell	28/12/2010			89.00	
Zeebries MC3D M.S.S.	3D	Off	5SL/10-1	Fugro	3/12/2010			1,005.00	
Enfield M5 4D M.S.S.	4D	Off	WA-28-L	Woodside	28/12/2010			67.00	
Agrippina 3D M.S.S.	3D	Off	WA-366-P, WA-439-P	Chevron	27/01/2010	3/03/2010		1,729.00	
Claudius 2009 3D M.S.S.	3D	Off	WA-434-P	Woodside	22/10/2009	27/01/2010		3,771.00	
Eendracht 3D M.S.S.	3D	Off	6SL/08-9	Fugro	8/06/2009	27/10/2010		14,768.00	
Laverda 3D M.S.S.	3D	Off	WA-271-P R2, WA-28-L, WA-36-R	Woodside	17/05/2010	28/06/2010		144.00	
Schiele 3D M.S.S.	3D	Off	WA-362-P, WA-363-P	OMV Australia	21/04/2010	6/07/2010		3,943.00	
Vincent M1 4D M.S.S.	4D	Off	WA-28-L	Woodside	20/12/2010	27/12/2010		122.81	
Ragnar Hub 2D CSEM Survey	CSEM	Off	WA-428-P, WA-430-P, WA-433-P	Woodside	10/12/2010	23/12/2010			126
Eucla Basin									
Balladonia ESR Survey	ESR	On	4/09-1	Southern Sky	7/06/2010	30/06/2010			1,940
Perth Basin									
Collie Rock Chip & Soil Sampling Survey	GEOL	Off	GEP 10, GEP 11, GEP 12	Green Rock	5/07/2010	12/07/2010			
Collie Worsley Gravity Survey	GRAVITY	Off	GEP 10, GEP 11, GEP 12	Green Rock	28/05/2010	18/06/2010			

Class - Classification
2D - 2D Reflection, 3D - 3D Reflection, 4D - 4D Reflection, AEROMAG - Aeromagnetic Survey, GRAVITY - Airborne Gravity, CSEM - Controlled Source Electromagnetic Survey, ESR - Electron Spin Resonance, GEOL - Geological Sampling Survey

Table 6. Petroleum Wells in Western Australia Operating 2010 Calendar Year

Well Name	Class	On Off	Title	Operator	Latitude		
Browse Basin							
Concerto 2 ST1	EXT	OFF	WA-371-P	Shell	13	40	53.11
Braveheart 1 ST1	NFW	OFF	WA-333-P	Hawkestone Oil	13	51	42.99
Kronos 1	NFW	OFF	WA-398-P	Conoco Phillips	13	41	53.84
Canning Basin							
Backreef 1	NFW	ON	L 6 R1	Oil Basins Ltd	17	36	32.99
Fairwell 1	NFW	ON	L 8 R1	Buru	17	32	38.70
Leander 1 ST1	NFW	ON	L 8 R1	Buru	17	30	56.40
Nangu 1	NFW	ON	EP 471	Buru	19	10	30.20
Paradise 1	NFW	ON	EP 371 R1	Buru	18	0	-0.40
Carnarvon Basin							
ENE 02 RD1	DEV	OFF	WA-28-L	Woodside	21	28	53.96
ENE 03 RD1 ST1	DEV	OFF	WA-28-L	Woodside	21	28	52.84
Macedon 10	DEV	OFF	WA-42-L	BHPB	21	34	2.56
Macedon 7	DEV	OFF	WA-42-L	BHPB	21	33	50.80
Macedon 8A	DEV	OFF	WA-42-L	BHPB	21	34	17.47
Macedon 9	DEV	OFF	WA-42-L	BHPB	21	34	33.22
PLA 01 ST1	DEV	OFF	WA-34-L	Woodside	19	54	49.27
Ravensworth 3H	DEV	OFF	WA-12-R R1	BHPB	21	32	19.80
Ravensworth 4H	DEV	OFF	WA-155-P R4	BHPB	21	32	19.03
Ravensworth 5H	DEV	OFF	WA-155-P R4	BHPB	21	32	17.13
Ravensworth 6H	DEV	OFF	WA-155-P R4	BHPB	21	32	16.61
Stag 36H ST1	DEV	OFF	WA-15-L	Apache	20	17	43.86
Stag 37H ST2 BHC1	DEV	OFF	WA-15-L	Apache	20	17	23.91
Stybarrow 12H	DEV	OFF	WA-32-L	BHPB	21	28	11.32
VN-A 5H L1 ST1	DEV	OFF	WA-28-L	Woodside	21	26	22.00
VN-A 6H L1 ST1	DEV	OFF	WA-28-L	Woodside	21	26	23.21
Wandoo A6 H3	DEV	OFF	WA-14-L	Vermillion	20	8	14.61
Wandoo B12 ST3	DEV	OFF	WA-14-L	Vermillion	20	7	41.15
Wandoo B8 ST1	DEV	OFF	WA-14-L	Vermillion	20	7	41.15
Balnaves 3	EXT	OFF	WA-356-P	Apache	20	3	40.24
Balnaves 4	EXT	OFF	WA-356-P	Apache	20	3	40.24
Chandon 2	EXT	OFF	WA-268-P R1	Chevron	19	32	59.09
Clio 3	EXT	OFF	WA-205-P R3	Chevron	20	18	29.06
Geryon 2	EXT	OFF	WA-22-R R1	Chevron	19	57	12.44
Iago 5	EXT	OFF	WA-17-R R1	Chevron	19	50	45.63
Julimar SW 2	EXT	OFF	WA-356-P	Apache	20	9	15.99
Laverda North 1	EXT	OFF	WA-36-R	Woodside	21	30	44.72
Legendre South 3	EXT	OFF	WA-20-L	Apache	19	43	18.04
Orthrus 2	EXT	OFF	WA-24-R R1	Chevron	20	6	22.30

Longitude			Gnd Elev/ Water Depth	RT KB	Spud Date	TD Date	Rig Rel Date
123	21	31.31	268	25	4/04/2010	1/08/2010	17/08/2010
124	5	45.63	116	25	29/12/2009	13/01/2010	18/01/2010
122	11	29.96	512	22	19/02/2010	30/04/2010	3/06/2010
124	33	44.95	63	68	11/10/2010	27/10/2010	2/11/2010
124	18	58.20	44	49	18/05/2010	17/06/2010	19/06/2010
124	14	19.50	39	44	8/07/2010	4/09/2010	8/09/2010
122	3	50.80	73	77	28/11/2010	5/12/2010	7/12/2010
124	34	35.50	64	69	18/10/2010	28/11/2010	16/12/2010
113	59	17.69	521	23	6/05/2010	17/07/2010	5/08/2010
113	59	17.85	522	23	6/08/2010	15/09/2010	5/10/2010
114	10	8.64	180	22	14/08/2010	27/08/2010	14/12/2010
114	13	24.60	161	22	21/11/2010	1/12/2010	14/12/2010
114	11	46.99	169	22	17/10/2010	3/11/2010	14/12/2010
114	9	31.46	179	22	19/09/2010	23/09/2010	14/12/2010
115	7	54.53	829	22	4/10/2010	15/10/2010	14/11/2010
114	5	3.11	208	22	5/03/2009	8/05/2010	8/06/2010
114	5	3.47	209	22	21/03/2009	21/03/2010	8/06/2010
114	5	4.37	209	22	15/03/2009	27/02/2010	8/06/2010
114	5	4.39	231	22	11/03/2009	12/04/2010	8/06/2010
116	15	31.41	49	61	16/12/2010		
116	16	30.99	49	61	31/10/2010	7/12/2010	
113	50	47.36	801	22	31/07/2010	17/08/2010	22/09/2010
114	2	49.00	363	23	23/12/2009	8/03/2010	30/04/2010
114	2	47.28	363	23	28/12/2009	31/01/2010	30/04/2010
116	25	22.43	54	39	10/10/2010	12/10/2010	18/10/2010
116	26	4.04	54	42	31/08/2010	3/09/2010	18/10/2010
116	26	4.04	54	42	23/09/2010	27/09/2010	18/10/2010
115	11	7.03	162	25	27/07/2010	27/08/2010	30/09/2010
115	11	7.03	162	25	15/09/2010	26/09/2010	30/09/2010
114	7	47.79	1,168	22	27/11/2009	20/01/2010	3/02/2010
114	41	15.19	971	22	20/03/2010	16/04/2010	4/05/2010
114	52	43.64	1,219	22	5/02/2010	6/03/2010	18/03/2010
115	19	41.57	171	22	29/12/2009	25/01/2010	2/02/2010
115	2	19.04	175	25	13/02/2010	21/02/2010	25/02/2010
113	51	46.83	841	32	9/12/2010		
116	41	29.58	56	38	5/05/2010	14/05/2010	19/05/2010
114	4	4.00	1,194	22	16/08/2010	1/12/2010	

Table 6. Petroleum Wells in Western Australia Operating 2010 Calendar Year

Well Name	Class	On Off	Title	Operator	Latitude		
Carnarvon Basin cont.							
Spar 2	EXT	OFF	WA-4-R R2	Apache	20	36	31.98
Stag 34	EXT	OFF	WA-15-L	Apache	20	17	3.29
Stag 35	EXT	OFF	WA-15-L	Apache	20	17	3.29
Acme 1	NFW	OFF	WA-205-P R3	Chevron	20	12	27.10
Alaric 1	NFW	OFF	WA-434-P	Woodside	19	56	31.92
Balthazar 1	NFW	OFF	WA-356-P	Apache	20	5	26.28
Barberry 1	NFW	OFF	TL/2 R1	Apache	21	18	13.52
Bath 1	NFW	OFF	TL/2 R1	Apache	21	19	15.79
Black Pearl 1	NFW	OFF	WA-42-L	BHPB	21	34	7.35
Brederode 1	NFW	OFF	WA-364-P	Chevron	19	49	7.88
Camus 1	NFW	OFF	WA-404-P	Woodside	19	6	54.85
Chester 1 ST1	NFW	OFF	WA-390-P	Hess	20	28	44.22
Chutney 1	NFW	OFF	WA-426-P	Apache	20	29	39.28
Cimatti 1	NFW	OFF	WA-28-L	Woodside	21	26	43.60
Cimatti 2	NFW	OFF	WA-28-L	Woodside	21	26	43.60
Dalia South 1	NFW	OFF	WA-348-P	Woodside	18	57	36.31
Fullswing 1	NFW	OFF	WA-412-P	Japan Energy E&P	19	23	15.38
Furness 1	NFW	OFF	WA-255-P R2	BHPB	21	24	17.84
Glenloth 1	NFW	OFF	WA-390-P	Hess	20	4	23.90
Hine 1	NFW	OFF	WA-404-P	Woodside	19	1	34.70
Jeune 1	NFW	OFF	WA-390-P	Hess	20	6	32.18
Julimar SW 1	NFW	OFF	WA-356-P	Apache	20	9	15.99
Keto 1	NFW	OFF	WA-205-P R3	Chevron	20	35	8.36
Larsen 1	NFW	OFF	WA-404-P	Woodside	19	24	12.27
Larsen Deep 1	NFW	OFF	WA-404-P	Woodside	19	24	12.76
Laurel 1	NFW	OFF	TP/7 R3	Apache	21	12	50.70
Makybe Diva 1	NFW	OFF	WA-390-P	Hess	20	15	57.17
Martin 1	NFW	OFF	WA-404-P	Woodside	19	25	32.92
Moyet 1	NFW	OFF	WA-404-P	Woodside	19	14	57.32
Noblige 1	NFW	OFF	WA-404-P	Woodside	19	23	54.89
Opel 1	NFW	OFF	WA-36-R	Woodside	21	30	50.74
Remy 1A CH1	NFW	OFF	WA-404-P	Woodside	19	23	58.22
Sappho 1	NFW	OFF	WA-392-P	Chevron	20	37	41.83
The Grafter 1	NFW	OFF	WA-390-P	Hess	20	15	57.17
Tiberius 1	NFW	OFF	WA-434-P	Woodside	20	9	13.21
Zola 1	NFW	OFF	WA-290-P R1	Apache	20	48	40.83
Ravensworth 9WI	WIW	OFF	WA-12-R R1	BHPB	21	30	9.55
Stickle 7WI	WIW	OFF	WA-12-R R1	BHPB	21	30	9.28

Longitude			Gnd Elev/ Water Depth	RT KB	Spud Date	TD Date	Rig Rel Date
114	54	22.10	112	25	2/10/2010	1/11/2010	29/11/2010
116	15	24.77	49	37	31/07/2010	6/08/2010	17/08/2010
116	15	24.77	49	37	9/08/2010	12/08/2010	17/08/2010
114	49	8.94	877	22	18/06/2010	13/07/2010	26/07/2010
111	38	57.26	1,993	32	23/07/2010	17/08/2010	3/09/2010
115	9	45.76	134	25	31/12/2009	13/01/2010	20/01/2010
115	11	40.16	16	39	12/07/2010	23/07/2010	28/07/2010
115	7	46.18	17	39	23/05/2010	5/06/2010	9/06/2010
114	8	31.12	184	22	26/07/2010	3/08/2010	9/08/2010
112	22	14.96	1,387	22	17/05/2010	31/05/2010	14/06/2010
114	16	23.12	1,348	32	27/03/2010	25/09/2010	4/10/2010
113	55	39.32	1,121	29	20/06/2010	27/08/2010	7/09/2010
114	57	21.71	104	25	27/02/2010	12/03/2010	20/03/2010
113	58	15.44	547	23	1/11/2010	13/11/2010	30/11/2010
113	58	15.44	547	23	18/11/2010	21/11/2010	30/11/2010
113	41	3.00	1,314	32	30/04/2010	26/05/2010	9/06/2010
116	18	12.80	134	22	19/12/2010		
113	55	58.60	607	22	1/07/2010	13/07/2010	22/07/2010
113	46	46.26	1,117	29	20/02/2010	15/04/2010	8/05/2010
114	33	25.23	1,348	32	5/04/2010	19/04/2010	27/04/2010
113	43	29.42	1,114	29	13/05/2010	6/06/2010	17/06/2010
115	2	19.04	175	25	20/01/2010	7/02/2010	25/02/2010
114	36	36.44	715	22	15/02/2010	10/03/2010	23/03/2010
114	15	13.93	1,279	32	26/12/2009	1/02/2010	18/03/2010
114	14	59.41	1,243	26	19/03/2010	18/08/2010	13/09/2010
115	7	22.04	22	38	12/06/2010	2/07/2010	10/07/2010
113	41	20.69	1,117	29	28/09/2010	6/10/2010	16/10/2010
114	22	34.05	1,343	32	14/12/2010		
114	12	37.83	1,296	32	6/09/2010	27/11/2010	3/12/2010
114	19	58.65	1,312	29	5/01/2010	27/01/2010	18/02/2010
113	50	32.52	841	32	6/12/2010		
114	18	42.81	1,293	26	6/10/2010	18/11/2010	23/12/2010
114	28	48.78	819	22	25/03/2010	5/05/2010	11/05/2010
113	41	20.69	1,117	29	9/09/2010	24/09/2010	16/10/2010
111	35	41.47	1,658	32	16/06/2010	13/07/2010	21/07/2010
114	42	43.69	285	25	1/12/2010		
114	5	43.14	213	22	14/04/2009	3/02/2010	8/06/2010
114	8	41.59	191	22	19/04/2009	31/05/2010	8/06/2010

Table 6. Petroleum Wells in Western Australia Operating 2010 Calendar Year

Well Name	Class	On Off	Title	Operator	Latitude		
Perth Basin							
Kaloorup Road 2	CBM	ON	DR 10	Red Mountain Energy	33	42	13.00
Mondarra 6	DEV	ON	L 1 R1	APA	29	18	43.70
Mondarra 7	DEV	ON	L 1 R1	APA	29	18	43.72
Mondarra 8	DEV	ON	L 1 R1	APA	29	18	43.72
Wolf 1	EXT	ON	EP 320 R3	Origin	29	29	1.69
Dunnart 1	NFW	ON	EP 437	CalEnergy	29	9	24.10
Redback 2	NFW	ON	L 11	Origin	29	27	27.34
Woodada Deep 1	NFW	ON	L 5 R1	AWE	29	50	6.20

Classification

CBM Coal Bed Methane Well
DEV Development Well
EXT Extension Well
NFW New Field Wildcat
WIW Water Injector Well

Longitude			Gnd Elev/ Water Depth	RT KB	Spud Date	TD Date	Rig Rel Date
115	14	40.00	20	21	16/02/2010	9/03/2010	11/03/2010
115	7	8.37	79	87	13/09/2010	6/10/2010	14/10/2010
115	7	10.04	79	87	22/10/2010	12/11/2010	23/12/2010
115	7	10.04	79	86	18/11/2010	7/12/2010	23/12/2010
115	9	45.46	60	68	18/07/2010	18/08/2010	2/09/2010
114	56	15.60	42	45	5/12/2010		
115	9	41.77	65	73	23/04/2010	16/06/2010	11/07/2010
115	8	35.49	41	46	31/03/2010	18/04/2010	19/04/2010

Table 7. List of Petroleum and Geothermal Titles and Holders in Western Australia as at 21 January 2011

OFFSHORE PETROLEUM AND GREENHOUSE GAS STORAGE ACT 2006 **Exploration Permit**	
Title	Registered Holders (* denotes Nominee)
WA-1-P R7	Apache Northwest Pty Ltd
	Santos Limited
WA-18-P R6	Bonaparte Gas & Oil Pty Limited
	GDF SUEZ Bonaparte Pty Ltd
	Santos Limited
WA-28-P R7	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-155-P R5	Apache Permits Pty Ltd
	BHP Billiton Petroleum (Australia) Pty Ltd
	Inpex Alpha Ltd
WA-191-P R5	Kufpec Australia Pty Ltd
	Nippon Oil Exploration (Dampier) Pty Ltd
	Santos Limited
	Tap (Shelfal) Pty Ltd
WA-192-P R5	Apache Northwest Pty Ltd
WA-202-P R4	Apache Northwest Pty Ltd
WA-205-P R3	Chevron (TAPL) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Chevron Australia Pty Ltd
WA-208-P R3	Apache Northwest Pty Ltd
	Beach Energy Limited
	Eni Australia Limited
	Mosaic Oil NL
	Santos Limited
	Santos Offshore Pty Ltd
WA-209-P R3	Santos Offshore Pty Ltd
	* Apache Northwest Pty Ltd
WA-214-P R3	Santos (BOL) Pty Ltd
	* Apache Northwest Pty Ltd
WA-246-P R2	Kufpec Australia Pty Ltd
	Pan Pacific Petroleum (South Aust) Pty Ltd
	Santos Offshore Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
WA-253-P R2	Chevron (TAPL) Pty Ltd
	* Chevron Australia Pty Ltd
WA-254-P R2	Apache Northwest Pty Ltd
	First Australian Resources Limited
	Pan Pacific Petroleum NL
	Sun Resources NL
	Victoria Petroleum NL
WA-255-P R2	Woodside Energy Ltd
	* BHP Billiton Petroleum (Australia) Pty Ltd
WA-261-P R2	Apache Northwest Pty Ltd
	Bow Energy Ltd
	Strike Energy Limited
	Tap (Shelfal) Pty Ltd
WA-264-P R1	Beach Petroleum Limited
	Kufpec Australia Pty Ltd
	* Santos Offshore Pty Ltd
WA-268-P R2	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Shell Development (Australia) Proprietary Limited
WA-269-P R2	Japan Australia LNG (MIMI) Pty Ltd
	Total E&P Australia
	Woodside Energy Ltd
WA-271-P R2	Mitsui E&P Australia Pty Limited
	* Woodside Energy Ltd
WA-274-P R1	Chevron Australia (WA-274-P) Pty Ltd
	Inpex Browse Ltd
	* Coveyork Pty Limited
WA-275-P R2	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-279-P R1	Eni Australia B.V.
WA-281-P R1	Beach Energy Limited
	Chevron Australia (WA-281-P) Pty Ltd
	Inpex Browse Ltd
	* Santos Offshore Pty Ltd
WA-285-P R2	Inpex Browse Ltd
	Total E&P Australia
WA-290-P R1	Nippon Oil Exploration (Dampier) Pty Ltd
	OMV Australia Pty Ltd
	Santos Offshore Pty Ltd
	Tap (Shelfal) Pty Ltd
	* Apache Northwest Pty Ltd
WA-302-P R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
WA-313-P R1	Eni Australia B.V.
WA-314-P	ConocoPhillips (Browse Basin) Pty Ltd
	Karoon Gas Browse Basin Pty Ltd
WA-315-P	ConocoPhillips (Browse Basin) Pty Ltd
	Karoon Gas Browse Basin Pty Ltd
WA-320-P	Tap (Shelfal) Pty Ltd
	* OMV Australia Pty Ltd
WA-323-P	Strata Resources N.L.
	* Octanex N.L.
WA-329-P	United Oil & Gas Pty Ltd
WA-330-P	Strata Resources N.L.
	* Octanex N.L.
WA-333-P	Braveheart Energy Pty Ltd
	Braveheart Oil & Gas Pty Ltd
	Braveheart Petroleum Pty Ltd
	Braveheart Resources Pty Ltd
	Browse Petroleum Pty Ltd
	Moby Oil & Gas Limited
WA-334-P R1	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
WA-335-P	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	Kufpec Australia Pty Ltd
	* Apache Northwest Pty Ltd
WA-341-P	Inpex Browse Ltd
	Total E&P Australia
WA-342-P R1	Coldron Pty Ltd
	Cornea Energy Pty Ltd
	Cornea Oil & Gas Pty Ltd

Table 7. List of Petroleum and Geothermal Titles and Holders in Western Australia as at 21 January 2011

	Cornea Petroleum Pty Ltd
	Cornea Resources Pty Ltd
WA-343-P	Inpex Browse Ltd
	Total E&P Australia
WA-344-P R1	Inpex Browse Ltd
	Total E&P Australia
WA-346-P R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
WA-347-P R1	Kansai Electric Power Australia Pty Ltd
	Tokyo Gas Pluto Pty Ltd
	Woodside Burrup Pty Ltd
WA-348-P	Kansai Electric Power Australia Pty Ltd
	Tokyo Gas Pluto Pty Ltd
	* Woodside Burrup Pty Ltd
WA-350-P R1	Kansai Electric Power Australia Pty Ltd
	Tokyo Gas Pluto Pty Ltd
	Woodside Burrup Pty Ltd
WA-351-P R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	Roc Oil (WA) Pty Limited
	Tap (Shelfal) Pty Ltd
WA-353-P	Woodside Burrup Pty Ltd
WA-354-P	Apache Northwest Pty Ltd
WA-355-P	Apache Northwest Pty Ltd
WA-356-P	Apache Julimar Pty Ltd
	Kufpec Australia (Julimar) Pty Ltd
WA-357-P	Inpex Alpha Ltd
	* Apache Northwest Pty Ltd
WA-358-P	OMV Australia Pty Ltd
WA-359-P	Exoil Limited
	* Cue Exploration Pty Ltd
WA-360-P	Cue Exploration Pty Ltd
	North West Shelf Exploration Pty Ltd
	Petrobras International Braspetro BV - PIB BV
	Rankin Trend Pty Ltd
WA-361-P R1	Cue Exploration Pty Ltd
	Mineralogy Pty Ltd
	North West Shelf Exploration Pty Ltd
WA-362-P	Eni Australia Limited
	Exmouth Exploration Pty Ltd
	Octanex N.L.
	Strata Resources N.L.
	* OMV Australia Pty Ltd
WA-363-P	Eni Australia Limited
	Exmouth Exploration Pty Ltd
	Octanex N.L.
	Strata Resources N.L.
	* OMV Australia Pty Ltd
WA-364-P	Chevron Australia (WA-364-P) Pty Ltd
	Shell Development (Australia) Proprietary Limited
WA-365-P	Chevron Australia (WA-365-P) Pty Ltd
	Shell Development (Australia) Proprietary Limited
WA-366-P	Chevron Australia (WA-366-P) Pty Ltd
	Shell Development (Australia) Proprietary Limited
WA-367-P	Chevron Australia (WA-367-P) Pty Ltd
	Shell Development (Australia) Proprietary Limited
WA-368-P	ARC (Offshore PB) Limited
	Nexus Energy Australia NL
WA-371-P	Shell Development (Australia) Proprietary Limited
WA-374-P	Mobil Australia Resources Company Pty Limited

	Shell Development (Australia) Proprietary Limited
	* Chevron Australia (WA-374-P) Pty Ltd
WA-375-P	Goldsborough Energy Pty Ltd
	Torrens Oil & Gas Pty Ltd
WA-376-P	Goldsborough Energy Pty Ltd
	Torrens Oil & Gas Pty Ltd
WA-377-P	Nexus Energy WA377P Pty Ltd
WA-378-P	Mitsui E&P Australia Pty Limited
	PTTEP Australasia (Ashmore Cartier) Pty Ltd
	Toyota Tsusho Gas E&P Browse Pty Ltd
	Woodside Energy Ltd
WA-379-P	Arcadia Petroleum Limited
	Cathay Petroleum International Limited
WA-380-P	Arcadia Petroleum Limited
	Cathay Petroleum International Limited
WA-381-P	Emphazise Pty Ltd
	Lempika Pty Ltd
	Westralian Petroleum Pty Ltd
WA-382-P	Emphazise Pty Ltd
	Lempika Pty Ltd
	Westralian Petroleum Pty Ltd
WA-383-P	Shell Development (Australia) Proprietary Limited
	* Chevron Australia (WA-383-P) Pty Ltd
WA-384-P	Shell Development (Australia) Proprietary Limited
WA-385-P	Shell Development (Australia) Proprietary Limited
WA-386-P	Eni Australia Limited
	Exmouth Exploration Pty Ltd
	* OMV Australia Pty Ltd
WA-387-P	Eni Australia Limited
	Exmouth Exploration Pty Ltd
	* OMV Australia Pty Ltd
WA-388-P	Bharat PetroResources Limited
	Gujarat State Petroleum Corporation Limited
	Hindustan Petroleum Corporation Ltd
	Oilex Limited
	Sasol Petroleum Australia Ltd
	Videocon Industries Ltd
WA-389-P	Cue Exploration Pty Ltd
	Woodside Burrup Pty Ltd
WA-390-P	Hess Exploration Australia Pty Limited
WA-391-P	OMV Australia Pty Ltd
WA-392-P	Chevron Australia (WA-392-P) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Shell Development (Australia) Proprietary Limited
WA-394-P	Shell Development (Australia) Proprietary Limited
WA-396-P	Mitsui E&P Australia Pty Limited
	PTTEP Australasia (Ashmore Cartier) Pty Ltd
	Toyota Tsusho Gas E&P Browse Pty Ltd
	Woodside Energy Ltd
WA-397-P	Mitsui E&P Australia Pty Limited
	PTTEP Australasia (Ashmore Cartier) Pty Ltd
	Toyota Tsusho Gas E&P Browse Pty Ltd
	Woodside Energy Ltd
WA-398-P	ConocoPhillips (Browse Basin) Pty Ltd
	Karoon Gas Browse Basin Pty Ltd
WA-399-P	Apache Northwest Pty Ltd
	Carnarvon Petroleum Limited
	Jacka Resources Limited
	Rialto Energy Limited

Table 7. List of Petroleum and Geothermal Titles and Holders in Western Australia as at 21 January 2011

WA-401-P	Woodside Energy Ltd
WA-402-P	Petronas Carigali (Australia) Pty Ltd
	Total E&P Australia
WA-403-P	Petronas Carigali (Australia) Pty Ltd
	Total E&P Australia
WA-404-P	Hess Exploration (Carnarvon) Pty Limited
	* Woodside Energy Ltd
WA-405-P	Reliance Exploration & Production DMCC
WA-406-P	CNOOC Australia E&P Pty Ltd
WA-407-P	Goldsborough Energy Pty Ltd
WA-408-P	Total E&P Australia
WA-409-P	Cue Exploration Pty Ltd
	Rankin Trend Pty Ltd
WA-410-P	Chevron Australia (WA-410-P) Pty Ltd
	Inpex Browse Ltd
	Santos Offshore Pty Ltd
WA-411-P	Beach Energy Limited
	Inpex Browse Ltd
	Santos Offshore Pty Ltd
WA-412-P	Japan Energy E&P Australia Pty Ltd
WA-413-P	Hunt Oil Australia Permit 413 Holding Company Pty Ltd
WA-414-P	Hunt Oil Australia Permit 414 Holding Company Pty Ltd
	Mitsui E&P Australia Pty Limited
WA-415-P	Woodside Energy Ltd
WA-416-P	Woodside Energy Ltd
WA-417-P	Woodside Energy Ltd
WA-418-P	Finder Exploration Pty Ltd
WA-419-P	Emerald Gas Pty Ltd
WA-420-P	Goldsborough Energy Pty Ltd
WA-421-P	Goldsborough Energy Pty Ltd
WA-422-P	National Oil Corporation Pty Ltd
WA-423-P	Diamond Resources Australia Pty Ltd
	PTTEP Australia Offshore Pty Ltd
	* Murphy Australia Oil Pty Ltd
WA-424-P	IPM WA 424P Pty Ltd
WA-425-P	Hunt Oil Australia Permit 425 Holding Company Pty Ltd
	Mitsui E&P Australia Pty Limited
	SK Energy Co., Ltd
WA-426-P	Apache Northwest Pty Ltd
WA-427-P	Apache Northwest Pty Ltd
	Kufpec Australia Pty Ltd
WA-428-P	Mitsui E&P Australia Pty Limited
	Woodside Energy Ltd
WA-429-P	Mitsui E&P Australia Pty Limited
	Woodside Energy Ltd
WA-430-P	Mitsui E&P Australia Pty Limited
	Woodside Energy Ltd
WA-431-P	Hunt Oil Australia Permit 431 Holding Company Pty Ltd
	Mitsui E&P Australia Pty Limited
	SK Energy Co., Ltd
WA-432-P	Mitsui E&P Australia Pty Limited
	Woodside Energy Ltd
WA-433-P	Mitsui E&P Australia Pty Limited
	Woodside Energy Ltd
WA-434-P	Woodside Energy Ltd
WA-435-P	Carnarvon Petroleum Limited
	Finder Exploration Pty Ltd
WA-436-P	Carnarvon Petroleum Limited
	Finder Exploration Pty Ltd
WA-437-P	Carnarvon Petroleum Limited
	Finder Exploration Pty Ltd
WA-438-P	Carnarvon Petroleum Limited
	Finder Exploration Pty Ltd
WA-439-P	Chevron Australia (WA-439-P) Pty Ltd
	Shell Development (Australia) Proprietary Limited
WA-440-P	Goldsborough Energy Pty Ltd
WA-441-P	Goldsborough Energy Pty Ltd
WA-442-P	Ansbachall Pty Limited
	DVM International Limited
WA-443-P	Carnarvon Petroleum Limited
WA-444-P	Chevron Australia (WA-444-P) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Shell Development (Australia) Proprietary Limited
WA-445-P	Finder No 2 Pty Limited
WA-446-P	Finder No 1 Pty Limited
WA-447-P	Mitsui E&P Australia Pty Limited
	Woodside Energy Ltd
WA-448-P	Japan Australia LNG (MIMI) Pty Ltd
	Woodside Energy Ltd
WA-449-P	Mitsui E&P Australia Pty Limited
	Woodside Energy Ltd
WA-450-P	Finder No 4 Pty Limited
	* Apache Northwest Pty Ltd
WA-451-P	Woodside Energy Ltd
WA-452-P	Riverina Energy Ltd

OFFSHORE PETROLEUM AND GREENHOUSE GAS STORAGE ACT 2006
Infrastructure Licence

Title	Registered Holders (* denotes Nominee)
WA-1-IL	Kansai Electric Power Australia Pty Ltd
	Tokyo Gas Pluto Pty Ltd
	Woodside Burrup Pty Ltd

OFFSHORE PETROLEUM AND GREENHOUSE GAS STORAGE ACT 2006
Pipeline Licence

Title	Registered Holders (* denotes Nominee)
WA-1-PL	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
WA-2-PL	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
WA-3-PL	Inpex Alpha Ltd
	Mobil Exploration & Producing Australia Pty Ltd
	* BHP Billiton Petroleum (Australia) Pty Ltd
WA-4-PL	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd

Table 7. List of Petroleum and Geothermal Titles and Holders in Western Australia as at 21 January 2011

	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
WA-5-PL	Apache East Spar Pty Limited
	Apache Kersail Pty Limited
	Santos (BOL) Pty Ltd
	* Apache Oil Australia Pty Ltd
WA-6-PL	Apache Northwest Pty Ltd
	Santos (GLOBE) Pty Ltd
	Santos Offshore Pty Ltd
WA-7-PL	Apache Northwest Pty Ltd
	Santos Limited
WA-8-PL	ConocoPhillips Pipeline Australia Pty Ltd
	ENI GAS & POWER LNG AUSTRALIA B.V.
	Inpex DLNGPL Pty Ltd
	Santos Timor Sea Pipeline Pty Ltd
	TEPCO Darwin LNG Pty Ltd
	Tokyo Gas Darwin LNG Pty Ltd
WA-9-PL	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
WA-10-PL	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
WA-11-PL	Apache Northwest Pty Ltd
	Santos (BOL) Pty Ltd
WA-12-PL	ARC (Offshore PB) Limited
	AWE Oil (Western Australia) Pty Ltd
	Cieco Energy Australia Pty Ltd
	Roc Oil (WA) Pty Limited
WA-13-PL	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-14-PL	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Holdings Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-15-PL	Eni Australia B.V.
WA-16-PL	Kansai Electric Power Australia Pty Ltd
	Tokyo Gas Pluto Pty Ltd
	Woodside Burrup Pty Ltd
WA-17-PL	Kansai Electric Power Australia Pty Ltd
	Tokyo Gas Pluto Pty Ltd
	Woodside Burrup Pty Ltd
WA-18-PL	Apache Northwest Pty Ltd
	Santos Offshore Pty Ltd
WA-19-PL	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Shell Development (Australia) Proprietary Limited
WA-20-PL	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Shell Development (Australia) Proprietary Limited

OFFSHORE PETROLEUM AND GREENHOUSE GAS STORAGE ACT 2006
Production Licence

Title	Registered Holders (* denotes Nominee)
WA-1-L R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-2-L R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-3-L R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-4-L R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-5-L R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-6-L R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited

Table 7. List of Petroleum and Geothermal Titles and Holders in Western Australia as at 21 January 2011

	Woodside Energy Ltd
WA-8-L R1	Kufpec Australia Pty Ltd
	Tap (Shelfal) Pty Ltd
	* Santos Limited
WA-9-L	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-10-L	Inpex Alpha Ltd
	Mobil Exploration & Producing Australia Pty Ltd
	* BHP Billiton Petroleum (Australia) Pty Ltd
WA-11-L	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-12-L	Mobil Australia Resources Company Pty Limited
	* BHP Billiton Petroleum (Australia) Pty Ltd
WA-13-L	Apache East Spar Pty Limited
	Apache Kersail Pty Limited
	Santos (BOL) Pty Ltd
	* Apache Oil Australia Pty Ltd
WA-14-L	Vermilion Oil & Gas Australia Pty Ltd
WA-15-L	Santos Offshore Pty Ltd
	* Apache Northwest Pty Ltd
WA-16-L	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-17-L	ConocoPhillips Australia Gas Holdings Pty Ltd
	* Mobil Australia Resources Company Pty Limited
WA-18-L	Talisman Oil & Gas (Australia) Pty Ltd
WA-20-L	Apache Northwest Pty Ltd
	Santos Limited
WA-22-L	Mobil Australia Resources Company Pty Limited
	Tap West Pty Ltd
	* Eni Australia Limited
WA-23-L	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-24-L	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited

	Woodside Energy Ltd
WA-25-L	Mobil Australia Resources Company Pty Limited
	Tap West Pty Ltd
	* Eni Australia Limited
WA-26-L	Kufpec Australia Pty Ltd
	Nippon Oil Exploration (Dampier) Pty Ltd
	Woodside Energy Ltd
	* Santos Limited
WA-27-L	Kufpec Australia Pty Ltd
	Nippon Oil Exploration (Dampier) Pty Ltd
	Woodside Energy Ltd
	* Santos Limited
WA-28-L	Mitsui E&P Australia Pty Limited
	* Woodside Energy Ltd
WA-29-L	Apache Northwest Pty Ltd
	Santos (BOL) Pty Ltd
WA-30-L	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-31-L	ARC (Offshore PB) Limited
	AWE Oil (Western Australia) Pty Ltd
	Cieco Energy Australia Pty Ltd
	Roc Oil (WA) Pty Limited
WA-32-L	BHP Billiton Petroleum (Australia) Pty Ltd
	Woodside Energy Ltd
WA-33-L	Eni Australia B.V.
WA-34-L	Kansai Electric Power Australia Pty Ltd
	Tokyo Gas Pluto Pty Ltd
	Woodside Burrup Pty Ltd
WA-35-L	Apache Permits Pty Ltd
	Inpex Alpha Ltd
WA-36-L	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Chubu Electric Power Gorgon Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Osaka Gas Gorgon Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Tokyo Gas Gorgon Pty Ltd
WA-37-L	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Chubu Electric Power Gorgon Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Osaka Gas Gorgon Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Tokyo Gas Gorgon Pty Ltd
WA-38-L	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Chubu Electric Power Gorgon Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Osaka Gas Gorgon Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Tokyo Gas Gorgon Pty Ltd
WA-39-L	BP Exploration (Alpha) Ltd
	Chevron (TAPL) Pty Ltd

Table 7. List of Petroleum and Geothermal Titles and Holders in Western Australia as at 21 January 2011

	Chevron Australia Pty Ltd
	Chubu Electric Power Gorgon Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Osaka Gas Gorgon Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Tokyo Gas Gorgon Pty Ltd
WA-40-L	BP Exploration (Alpha) Ltd
	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Chubu Electric Power Gorgon Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Osaka Gas Gorgon Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Tokyo Gas Gorgon Pty Ltd
WA-41-L	Apache Northwest Pty Ltd
	Santos Offshore Pty Ltd
WA-42-L	Apache PVG Pty Ltd
	BHP Billiton Petroleum (Australia) Pty Ltd
WA-43-L	Apache PVG Pty Ltd
	Inpex Alpha Ltd
	* BHP Billiton Petroleum (Australia) Pty Ltd

OFFSHORE PETROLEUM AND GREENHOUSE GAS STORAGE ACT 2006
Retention Lease

Title	Registered Holders (* denotes Nominee)
WA-1-R R4	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	* Esso Australia Resources Pty Ltd
WA-4-R R2	Santos Offshore Pty Ltd
WA-5-R R3	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Chubu Electric Power Gorgon Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Osaka Gas Gorgon Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Tokyo Gas Gorgon Pty Ltd
WA-6-R R2	Bonaparte Gas & Oil Pty Limited
	GDF SUEZ Bonaparte Pty Ltd
	Origin Energy Bonaparte Pty Limited
	Santos Limited
WA-7-R R2	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
WA-9-R R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-10-R R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	CNOOC NWS Private Limited
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Woodside Energy Ltd
WA-14-R R1	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Chubu Electric Power Gorgon Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Osaka Gas Gorgon Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Tokyo Gas Gorgon Pty Ltd
WA-15-R R1	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Chubu Electric Power Gorgon Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Osaka Gas Gorgon Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Tokyo Gas Gorgon Pty Ltd
WA-16-R R1	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Shell Development (Australia) Proprietary Limited
WA-17-R R1	Chevron (TAPL) Pty Ltd
	* Chevron Australia Pty Ltd
WA-19-R R1	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Chubu Electric Power Gorgon Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Osaka Gas Gorgon Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Tokyo Gas Gorgon Pty Ltd
WA-20-R R1	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Chubu Electric Power Gorgon Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Osaka Gas Gorgon Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Tokyo Gas Gorgon Pty Ltd
WA-21-R R1	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Chubu Electric Power Gorgon Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Osaka Gas Gorgon Pty Ltd
	Shell Development (Australia) Proprietary Limited
	Tokyo Gas Gorgon Pty Ltd
WA-22-R R1	BP Exploration (Alpha) Ltd
	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Shell Development (Australia) Proprietary Limited
	* Chevron Australia Pty Ltd
WA-23-R R1	BP Exploration (Alpha) Ltd
	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Shell Development (Australia) Proprietary Limited

Table 7. List of Petroleum and Geothermal Titles and Holders in Western Australia as at 21 January 2011

	* Chevron Australia Pty Ltd
WA-24-R R1	BP Exploration (Alpha) Ltd
	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Shell Development (Australia) Proprietary Limited
	* Chevron Australia Pty Ltd
WA-27-R R1	Bonaparte Gas & Oil Pty Limited
	GDF SUEZ Bonaparte Pty Ltd
	Santos Limited
WA-28-R R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
WA-29-R R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
WA-30-R R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
WA-31-R R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
WA-32-R R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
WA-33-R R1	Apache Oil Australia Pty Ltd
	Pan Pacific Petroleum (South Aust) Pty Ltd
	Santos (BOL) Pty Ltd
	Tap (Shelfal) Pty Ltd
	WM Petroleum Limited
WA-34-R R1	Encana International (Australia) Pty Ltd
	Eni Australia B.V.
	SK Energy Co., Ltd
	Tap (Shelfal) Pty Ltd
WA-35-R	Japan Australia LNG (MIMI) Pty Ltd
	Woodside Energy Ltd
WA-36-R	Mitsui E&P Australia Pty Limited
	* Woodside Energy Ltd
WA-37-R	Inpex Browse Ltd
	Total E&P Australia
WA-38-R	Apache Northwest Pty Ltd
	Santos Offshore Pty Ltd

PETROLEUM (SUBMERGED LANDS) ACT 1982
Exploration Permit

Title	Registered Holders (* denotes Nominee)
TP/7 R3	Apache Oil Australia Pty Ltd
	Pan Pacific Petroleum (South Aust) Pty Ltd
	Santos (BOL) Pty Ltd
	Tap (Shelfal) Pty Ltd
TP/8 R3	Apache Northwest Pty Ltd
	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
TP/9 R3	* Apache Northwest Pty Ltd
TP/15 R1	Bharat PetroResources Limited
	Westranch Holdings Pty Ltd
TP/23	Apache Northwest Pty Ltd
TP/24	Emerald Gas Pty Ltd

PETROLEUM (SUBMERGED LANDS) ACT 1982
Pipeline Licence

Title	Registered Holders (* denotes Nominee)
TPL/1 R1	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
TPL/2 R1	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
TPL/3 R1	Apache Oil Australia Pty Ltd
	Pan Pacific Petroleum (South Aust) Pty Ltd
	Santos (BOL) Pty Ltd
	Tap (Shelfal) Pty Ltd
TPL/4 R1	Apache Oil Australia Pty Ltd
	Pan Pacific Petroleum (South Aust) Pty Ltd
	Santos (BOL) Pty Ltd
	Tap (Shelfal) Pty Ltd
TPL/5 R1	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
TPL/6	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd
TPL/7 R2	Apache Oil Australia Pty Ltd
	Pan Pacific Petroleum (South Aust) Pty Ltd
	Santos (BOL) Pty Ltd
	Tap (Shelfal) Pty Ltd
TPL/8	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
TPL/9 R1	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd
TPL/10	Inpex Alpha Ltd
	Mobil Exploration & Producing Australia Pty Ltd
	* BHP Billiton Petroleum (Australia) Pty Ltd
TPL/11	Chevron (TAPL) Pty Ltd

Table 7. List of Petroleum and Geothermal Titles and Holders in Western Australia as at 21 January 2011

	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd
TPL/12	Apache East Spar Pty Limited
	Apache Kersail Pty Limited
	Santos (BOL) Pty Ltd
	* Apache Oil Australia Pty Ltd
TPL/13	Apache East Spar Pty Limited
	Apache Kersail Pty Limited
	Apache Northwest Pty Ltd
	Apache Oil Australia Pty Ltd
	Kufpec Australia Pty Ltd
	Santos (BOL) Pty Ltd
	Tap (Harriet) Pty Ltd
TPL/14	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
TPL/15	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
TPL/16	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
TPL/17	Apache Northwest Pty Ltd
	Santos (BOL) Pty Ltd
TPL/18	ARC (Offshore PB) Limited
	AWE Oil (Western Australia) Pty Ltd
	Cieco Energy Australia Pty Ltd
	Roc Oil (WA) Pty Limited
TPL/19	Kansai Electric Power Australia Pty Ltd
	Tokyo Gas Pluto Pty Ltd
	Woodside Burrup Pty Ltd
TPL/20	Apache Northwest Pty Ltd
	Santos Offshore Pty Ltd
TPL/21	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Shell Development (Australia) Proprietary Limited
TPL/22	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Shell Development (Australia) Proprietary Limited

PETROLEUM (SUBMERGED LANDS) ACT 1982
Production Licence

Title	Registered Holders (* denotes Nominee)
TL/1 R1	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
TL/2 R1	Apache Oil Australia Pty Ltd
	Pan Pacific Petroleum (South Aust) Pty Ltd
	Santos (BOL) Pty Ltd
	Tap (Shelfal) Pty Ltd
TL/3 R1	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd
TL/4 R1	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd
TL/5	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
TL/6	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
TL/7	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd
TL/8	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
TL/9	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd

PETROLEUM (SUBMERGED LANDS) ACT 1982
Retention Lease

Title	Registered Holders (* denotes Nominee)
TR/1 R2	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
TR/2 R1	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
TR/3 R1	Apache Northwest Pty Ltd
TR/4 R1	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd
TR/5 R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
TR/6	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd

Table 7. List of Petroleum and Geothermal Titles and Holders in Western Australia as at 21 January 2011

PETROLEUM AND GEOTHERMAL ENERGY RESOURCES ACT 1967
Access Authority to Deviated Well

Title	Registered Holders (* denotes Nominee)
ADW 1/10-1	Arc Energy Limited
ADW 8/90-1	Chevron (TAPL) Pty Ltd
ADW 10/92-3	Kufpec Australia Pty Ltd
ADW 12/91-2	Kufpec Australia Pty Ltd
ADW 8/90-1	Mobil Australia Resources Company Pty Limited
ADW 1/10-1	Origin Energy Developments Pty Limited
ADW 8/90-1	Santos Offshore Pty Ltd
ADW 10/92-3	Tap (Harriet) Pty Ltd
ADW 12/91-2	Tap (Harriet) Pty Ltd
ADW 1/10-1	Westranch Holdings Pty Ltd
ADW 10/92-3	* Apache Northwest Pty Ltd
ADW 12/91-2	* Apache Northwest Pty Ltd
ADW 8/90-1	* Chevron Australia Pty Ltd

PETROLEUM AND GEOTHERMAL ENERGY RESOURCES ACT 1967
Drilling Reservation

Title	Registered Holders (* denotes Nominee)
DR 9	Backreef Oil Limited
DR 11	Westralian Gas and Power Limited
DR 12	Flamestar Corporation Pty Ltd
	Red Mountain Energy Pty Ltd
DR 13	Flamestar Corporation Pty Ltd
	Red Mountain Energy Pty Ltd

PETROLEUM AND GEOTHERMAL ENERGY RESOURCES ACT 1967
Exploration Permit

Title	Registered Holders (* denotes Nominee)
EP 61 R7	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd
EP 62 R7	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd
EP 104 R5	Arc Energy Limited
	First Australian Resources Limited
	Gulliver Productions Pty Ltd
	Indigo Oil Pty Ltd
	Pancontinental Oil & Gas NL
	Phoenix Resources PLC
EP 110 R4	Pancontinental Oil & Gas NL
	Strike Energy Limited
EP 129 R5	Buru Energy Limited
EP 307 R4	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
EP 320 R3	ARC (Beharra Springs) Pty Ltd
	* Origin Energy Developments Pty Limited
EP 321 R3	Latent Petroleum Pty Ltd
EP 325 R3	Advent Energy Ltd
	Bow Energy Ltd
	Rough Range Oil Pty Ltd
	Strike Energy Limited
EP 357 R3	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd
EP 358 R2	Apache Northwest Pty Ltd
	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
EP 359 R2	Lansvale Oil & Gas Pty Ltd
	Pace Petroleum Pty Ltd
	* Rough Range Oil Pty Ltd
EP 368 R3	Westranch Holdings Pty Ltd
EP 371 R1	Buru Energy Limited
EP 381 R2	Whicher Range Energy Pty Ltd
EP 386 R2	Advent Energy Ltd
EP 389 R1	ERM Gas Pty Ltd
	Empire Oil Company (WA) Limited
	Sunset Power Holdings Pty Ltd
	Wharf Resources PLC
EP 390 R2	Buru Energy Limited
EP 391 R2	Buru Energy Limited
EP 406	Euro Pacific Energy Pty Ltd
	* Victoria Diamond Exploration Pty Ltd
EP 407 R1	Latent Petroleum Pty Ltd
EP 408 R1	Whicher Range Energy Pty Ltd
EP 412 R1	Bounty Oil & Gas NL
	* Rough Range Oil Pty Ltd
EP 413 R2	Arc Energy Limited
	Bharat PetroResources Limited
	Geary, John Kevin
	Norwest Energy NL
EP 416 R1	Allied Oil & Gas Plc
	ERM Gas Pty Ltd
	Empire Oil Company (WA) Limited
EP 417 R1	Buru Energy Limited
	New Standard Onshore Pty Ltd
EP 419	Exoma Energy Limited
EP 424	Pancontinental Oil & Gas NL
	Strike Energy Limited
EP 426	Allied Oil & Gas Plc
	ERM Gas Pty Ltd
	Empire Oil Company (WA) Limited
EP 428	Buru Energy Limited
EP 429	Kingsway Oil Limited
EP 430	Empire Oil Company (WA) Limited
EP 431	Buru Energy Limited
EP 432	Allied Oil & Gas Plc
	ERM Gas Pty Ltd
	Empire Oil Company (WA) Limited
EP 433	Lansvale Oil & Gas Pty Ltd
	Pace Petroleum Pty Ltd
EP 434	Pace Petroleum Pty Ltd
	Rough Range Oil Pty Ltd
	* Lansvale Oil & Gas Pty Ltd
EP 435	Australian Oil Company No 3 Pty Limited

Table 7. List of Petroleum and Geothermal Titles and Holders in Western Australia as at 21 January 2011

	Bounty Oil & Gas NL
	Rough Range Oil Pty Ltd
EP 436	Buru Energy Limited
EP 437	CalEnergy Resources (Australia) Limited
	Key Petroleum (Australia) Pty Ltd
EP 438	Gulliver Productions Pty Ltd
	Indigo Oil Pty Ltd
	* Buru Energy Limited
EP 439	Falcore Pty Ltd
	Indigo Oil Pty Ltd
	Jurassica Oil & Gas Plc
	Longreach Oil Limited
	Vigilant Oil Pty Ltd
	* Rough Range Oil Pty Ltd
EP 440	Empire Oil Company (WA) Limited
EP 441	Apache Northwest Pty Ltd
EP 442	New Standard Exploration Pty Limited
	* Buru Energy Limited
EP 443	New Standard Onshore Pty Ltd
EP 444	Rough Range Oil Pty Ltd
EP 445	Red Mountain Energy Pty Ltd
EP 447	GCC Methane Pty Ltd
EP 448	Buru Energy Limited
	Gulliver Productions Pty Ltd
	Indigo Oil Pty Ltd
	United Orogen Limited
EP 449	Kingsway Oil Limited
EP 450	New Standard Onshore Pty Ltd
EP 451	New Standard Onshore Pty Ltd
EP 453	Budside Pty Limited
	Pobelo Pty Ltd
EP 454	Empire Oil Company (WA) Limited
EP 455	Westralian Gas and Power Limited
	* Arc Energy Limited
EP 456	New Standard Onshore Pty Ltd
EP 457	Rey Resources Ltd
EP 458	Rey Resources Ltd
EP 460	Falcore Pty Ltd
	Indigo Oil Pty Ltd
	Jurassica Oil & Gas Plc
	Longreach Oil Limited
	Vigilant Oil Pty Ltd
	* Rough Range Oil Pty Ltd
EP 461	Falcore Pty Ltd
	Indigo Oil Pty Ltd
	Jurassica Oil & Gas Plc
	Longreach Oil Limited
	Vigilant Oil Pty Ltd
	* Rough Range Oil Pty Ltd
EP 463	Emerald Gas Pty Ltd
EP 464	Exceed Energy (Australia) Pty Ltd
EP 465	Global International (Australia) Pty Ltd
EP 466	Rough Range Oil Pty Ltd
EP 467	ERM Gas Pty Ltd
EP 468	Frontier Oil & Gas Pty Ltd
EP 469	Warrego Energy Pty Ltd
EP 470	Energetica Resources Pty Ltd
EP 471	Arc Energy Limited
EP 472	Buru Energy (Acacia) Pty Ltd
	Buru Energy Limited
EP 473	Arc Energy Limited
EP 474	Arc Energy Limited
EP 475	Energetica Resources Pty Ltd

PETROLEUM AND GEOTHERMAL ENERGY RESOURCES ACT 1967
Geothermal Exploration Permit

Title	Registered Holders (* denotes Nominee)
GEP 1	The University of Western Australia
	* Green Rock Energy Limited
GEP 2	Green Rock Energy Limited
GEP 3	Green Rock Energy Limited
GEP 4	Green Rock Energy Limited
GEP 5	Granite Power Limited
GEP 6	Granite Power Limited
GEP 7	GT Power Pty Ltd
GEP 8	GT Power Pty Ltd
GEP 9	GT Power Pty Ltd
GEP 10	BHP Billiton Worsley Alumina Pty Ltd
	Green Rock Energy Limited
GEP 11	BHP Billiton Worsley Alumina Pty Ltd
	Green Rock Energy Limited
GEP 12	BHP Billiton Worsley Alumina Pty Ltd
	Green Rock Energy Limited
GEP 13	New World Energy Limited
GEP 14	New World Energy Limited
GEP 15	New World Energy Limited
GEP 16	New World Energy Limited
GEP 17	New World Energy Limited
GEP 18	New World Energy Limited
GEP 19	New World Energy Limited
GEP 20	New World Energy Limited
GEP 21	New World Energy Limited
GEP 22	AAA Energy Pty Ltd
GEP 23	Green Rock Energy Limited
GEP 24	Green Rock Energy Limited
GEP 25	Green Rock Energy Limited
GEP 26	Green Rock Energy Limited
GEP 27	Green Rock Energy Limited
GEP 28	Green Rock Energy Limited
GEP 29	Geothermal Energy Pty Ltd
GEP 30	New World Energy Limited
GEP 31	New World Energy Limited
GEP 32	New World Energy Limited
GEP 33	New World Energy Limited
GEP 34	New World Energy Limited
GEP 35	New World Energy Limited
GEP 36	New World Energy Limited
GEP 37	Greenpower Energy Limited
GEP 38	Greenpower Energy Limited
GEP 39	Green Rock Energy Limited
GEP 40	Green Rock Energy Limited
GEP 41	Green Rock Energy Limited

Table 7. List of Petroleum and Geothermal Titles and Holders in Western Australia as at 21 January 2011

PETROLEUM AND GEOTHERMAL ENERGY RESOURCES ACT 1967
Production Licence

Title	Registered Holders (* denotes Nominee)
L 1 R1	APT Parmelia Pty Ltd
	Arc Energy Limited
	Origin Energy Developments Pty Limited
L 2 R1	Origin Energy Developments Pty Limited
	* Arc Energy Limited
L 4 R1	Arc Energy Limited
L 5 R1	Arc Energy Limited
L 6 R1	Buru Energy Limited
L 7 R1	Arc Energy Limited
L 8 R1	Buru Energy Limited
L 9 R1	BHP Billiton Petroleum (Australia) Pty Ltd
L 10 R1	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd
L 11	ARC (Beharra Springs) Pty Ltd
	* Origin Energy Developments Pty Limited
L 12	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd
L 13	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd
L 14	Arc Energy Limited
	Geary, John Kevin
	Norwest Energy NL
	Origin Energy Developments Pty Limited
	Roc Oil (WA) Pty Limited
L 15	Buru Energy Limited
	First Australian Resources Limited
	Gulliver Productions Pty Ltd
	Indigo Oil Pty Ltd
	Pancontinental Oil & Gas NL
L 16	Rough Range Oil Pty Ltd
L 1H R2	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd

PETROLEUM AND GEOTHERMAL ENERGY RESOURCES ACT 1967
Retention Lease

Title	Registered Holders (* denotes Nominee)
R 1 R1	Arc Energy Limited
	First Australian Resources Limited
	Gulliver Productions Pty Ltd
	Indigo Oil Pty Ltd
	Pancontinental Oil & Gas NL
	Phoenix Resources PLC
R 2 R1	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
R 3	Oil Basins Ltd
	Tap (Shelfal) Pty Ltd
R 4	Chevron (TAPL) Pty Ltd
	Chevron Australia Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
R 5	Apache Oil Australia Pty Ltd
	OMV Australia Pty Ltd

PETROLEUM PIPELINES ACT 1969
Pipeline Licence

Title	Registered Holders (* denotes Nominee)
PL 1 R1	APT Parmelia Pty Ltd
PL 2 R1	APT Parmelia Pty Ltd
PL 3 R1	APT Parmelia Pty Ltd
PL 5 R1	APT Parmelia Pty Ltd
PL 6 R3	Arc Energy Limited
PL 7 R1	Buru Energy Limited
PL 8 R1	Mitsui Iron Ore Development Pty Ltd
	Nippon Steel Australia Pty Limited
	North Mining Limited
	Sumitomo Metal Australia Pty Ltd
	* Robe River Mining Co Pty Ltd
PL 12	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
PL 14	Apache Oil Australia Pty Ltd
	Pan Pacific Petroleum (South Aust) Pty Ltd
	Santos (BOL) Pty Ltd
	Tap (Shelfal) Pty Ltd
PL 15	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd
PL 16	BHP Petroleum (Ashmore Operations) Pty Ltd
PL 17	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
PL 18	ARC (Beharra Springs) Pty Ltd
	* Origin Energy Developments Pty Limited
PL 19	BHP Petroleum (Ashmore Operations) Pty Ltd
PL 20	Inpex Alpha Ltd
	Mobil Exploration & Producing Australia Pty Ltd
	* BHP Billiton Petroleum (Australia) Pty Ltd
PL 21	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Santos Offshore Pty Ltd
	* Chevron Australia Pty Ltd
PL 22	Epic Energy (Pilbara Pipeline) Pty Ltd

Table 7. List of Petroleum and Geothermal Titles and Holders in Western Australia as at 21 January 2011

PL 23	APT Parmelia Pty Ltd
PL 24	Alinta DEWAP Pty Ltd
	Southern Cross Pipelines (NPL) Australia Pty Ltd
	* Southern Cross Pipelines Australia Pty Limited
PL 25	Southern Cross Pipelines Australia Pty Limited
PL 26	Southern Cross Pipelines Australia Pty Limited
PL 27	Southern Cross Pipelines Australia Pty Limited
PL 28	Southern Cross Pipelines (NPL) Australia Pty Ltd
PL 29	Apache East Spar Pty Limited
	Apache Kersail Pty Limited
	Santos (BOL) Pty Ltd
	* Apache Oil Australia Pty Ltd
PL 30	Apache East Spar Pty Limited
	Apache Kersail Pty Limited
	Santos (BOL) Pty Ltd
	* Apache Oil Australia Pty Ltd
PL 31	Epic Energy (Pilbara Pipeline) Pty Ltd
PL 32	APT Pipelines (WA) Pty Limited
PL 33	APT Pipelines (WA) Pty Limited
PL 34	Newmont Yandal Operations Pty Ltd
PL 35	Plutonic Operations Limited
PL 36	Australian Pipeline Limited
PL 37	Norilsk Nickel Cawse Pty Ltd
PL 38	Epic Energy (Pilbara Pipeline) Pty Ltd
PL 39	Origin Energy Pipelines Pty Limited
PL 40	DBNGP (WA) Nominees Pty Limited
PL 41	DBNGP (WA) Transmission Pty Limited
PL 42	Apache East Spar Pty Limited
	Apache Kersail Pty Limited
	Apache Northwest Pty Ltd
	Apache Oil Australia Pty Ltd
	Kufpec Australia Pty Ltd
	Santos (BOL) Pty Ltd
	Tap (Harriet) Pty Ltd
PL 43	Western Power Corporation
	* APT Pipelines (WA) Pty Limited
PL 44	APT Parmelia Pty Ltd
PL 45	APT Parmelia Pty Ltd
PL 46	APT Parmelia Pty Ltd
PL 47	DBNGP (WA) Transmission Pty Limited
PL 48	Energy Generation Pty Ltd
PL 52	APT Parmelia Pty Ltd
PL 53	APT Parmelia Pty Ltd
PL 54	Western Power Corporation
	* APT Pipelines (WA) Pty Limited
PL 55	Talison Wodgina Pty Ltd
PL 56	Epic Energy (WA) One Pty Ltd
PL 57	Australian Gold Reagents Pty Ltd
PL 58	BHP Billiton Petroleum (North West Shelf) Pty Ltd
	BP Developments Australia Pty Ltd
	Chevron Australia Pty Ltd
	Japan Australia LNG (MIMI) Pty Ltd
	Shell Development (Australia) Proprietary Limited
	* Woodside Energy Ltd
PL 59	Esperance Pipeline Co. Pty Limited
PL 60	Gas Transmission Services WA (Operations) Pty Ltd
PL 61	APT Parmelia Pty Ltd
PL 62	Kufpec Australia Pty Ltd
	Tap (Harriet) Pty Ltd
	* Apache Northwest Pty Ltd
PL 63	Gas Transmission Services WA (Operations) Pty Ltd
PL 64	Arc Energy Limited
	Origin Energy Developments Pty Limited
PL 65	Dalrymple Resources NL
	LionOre Australia (Wildara) NL
PL 67	Hamersley Iron Pty Ltd
PL 68	Gas Transmission Services WA (Operations) Pty Ltd
PL 69	DBNGP (WA) Nominees Pty Limited
PL 70	ARC (Offshore PB) Limited
	AWE Oil (Western Australia) Pty Ltd
	Cieco Energy Australia Pty Ltd
	Roc Oil (WA) Pty Limited
PL 72	EDL NGD (WA) PTY LTD
PL 73	Redback Pipelines Pty Ltd
PL 74	EDL LNG (WA) PTY LTD
PL 75	EIT Neerabup Power Pty Ltd
	ERM Neerabup Pty Ltd
PL 76	APA Group
PL 77	Sino Iron Pty Ltd
PL 78	Hamersley Iron Pty Ltd
PL 80	Latent Petroleum Pty Ltd
PL 81	Apache Northwest Pty Ltd
PL 82	Epic Energy (Pilbara Pipeline) Pty Ltd
PL 83	WA Gas Networks Pty Ltd
PL 84	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Shell Development (Australia) Proprietary Limited
PL 85	Chevron (TAPL) Pty Ltd
	Mobil Australia Resources Company Pty Limited
	Shell Development (Australia) Proprietary Limited
PL 86	Apache Northwest Pty Ltd
	Santos Offshore Pty Ltd

Please consult DMP's online Petroleum and Geothermal Register for the most current information on Titles and Holdings.

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