Western Australian Oil and Gas Review

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Government of Western Australia

Department of
Industry and Resources

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Premier's Foreword

Welcome to the 2008 edition of the Department of Industry and Resources' *Western Australian Oil and Gas Review*.

Western Australia has a prosperous oil and gas sector, and this publication provides readers with details of current projects in the State, as well as information about the vast potential that still exists for the sector.

Western Australia continues to lead the way as Australia's number one resources investment destination, with more than $100 billion worth of projects either underway or planned over the next few years. These projects will create more than 38,000 construction jobs and more than 9000 permanent jobs. Oil and gas developments contribute a large portion of this.

The value of Western Australian petroleum sales for 2007 was $16.7 billion, an increase of around 8 per cent on the previous year.

China's phenomenal growth has resulted in an increasing demand for resources. As such, China has become the State's largest trading partner with petroleum exports to China accounting for a significant percentage of that trade. In September 2007, China's President Hu Jintao visited Perth, prompting a number of significant resource agreements to be finalised between Western Australian and Chinese companies.

Following President Hu's visit, three of China's principal petroleum companies have now invested in or have major business deals with Western Australian companies. This follows PetroChina signing an offtake agreement with Shell for the supply of liquefied natural gas (LNG) from the emerging Gorgon project. PetroChina is China's largest upstream petroleum company. This LNG supply deal with Shell builds on the success of Western Australia's current supply of LNG to Guangdong.

The North West Shelf project in Western Australia's Pilbara region began exporting LNG to Guangdong in May 2006, under a 25-year agreement. It still remains the largest international trade deal for either Australia or China.

I am confident there will be further interest from international investors not only in China but from around the world, and that foreign investment into WA will continue to increase.

In 2007, oil prices soared on global uncertainty, prices surpassed the symbolic milestone of US$100 a barrel and predictions for 2008 anticipate further increases.

Nations that are rich in oil and gas are enjoying extraordinary gains and opportunities, and are benefiting from the increased demand of importers such as China, Japan and India.

Western Australia is thriving in the current global industry climate and the State is experiencing unprecedented prosperity.

Western Australia not only has the natural resources to make it an attractive investment option in the oil and gas sector, it also has strong, complementing foundations of knowledge and expertise.

We have developed a strong service base for the industry, as well as significant research and technology capabilities.

The State Government is committed to establishing Western Australia as a centre of excellence in the provision of technology and services to the gas and subsea industry sectors.

The Australian Marine Complex (AMC), located in Henderson, is dedicated to strategic innovation and is currently developing a cluster for companies servicing marine and defence related industries, including the oil and gas sector and in particular sub-sea technologies.

In actively seeking and encouraging companies with core competencies in this area, the AMC aims to leverage off these specialist skills to further develop local technologies and capabilities in order to continue to provide excellent service to the oil and gas industry.

In addition, a Technology Precinct has been established at the AMC which focuses on technology-driven organisations within the marine, defence, oil and gas industry sectors.

Located within the Technology Precinct the new $11 Million Central Services Facility will be the core meeting and networking point for marine, defence, oil and gas organisations.

The Western Australian Government recognises that the oil and gas sector is a highly competitive global industry.

Developers and operators need to continually innovate and adopt new technology in order to remain competitive and to meet environmental and safety standards.

In Western Australia we place a high value on the environmental values of our State. We have firm, transparent environmental regulations in place to ensure we leave a sustainable legacy for the future.

Looking towards the future of our domestic gas market, the State Government has released for tender WA's first tight gas acreage block - the West Erregulla block. It is located east of Dongara in the Dandaragan Trough and is thought to contain more than 388 billion cubic feet (11 billion cubic metres) of gas - enough to power WA's entire domestic gas demand for more than one year.

In 2007 in State waters, production began on the Doric and Lee gas fields, and the West Cycad oil and gas field. Other fields to begin production included Stybarrow/Eskdale, Searipple and Apium.

Woodside's Pluto LNG project was one of the most significant to be given the go-ahead in 2007.

Environmental approval was also granted for the Gorgon gas project that will produce LNG on Barrow Island.

Other new fields actively under development in 2007 in Commonwealth waters included the Vincent oil field, the Angel gas field, the Van Gogh (Vincent) oil field, the Persephone gas field and the Blacktip gas field.

ARC Energy has also embarked on the largest frontier exploration program to be undertaken in Western Australia.

Western Australia currently boasts more than 130 trillion cubic feet of discovered reserves but much still remains under-explored.

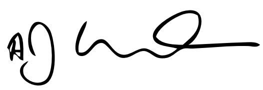
The State is rich in hydrocarbons, providing plenty of opportunities for further discoveries and developments in the years ahead.

Western Australia's petroleum exploration expenditure more than doubled in 2007 to reach a total of $1.9 billion, an increase of 102 per cent on 2006.

The Western Australia Government is already processing a record number of exploration and mining leases and the market shows few signs of slowing down.

The booming resource sector will continue to provide a foundation for strong economic growth in Western Australia.

I encourage you to find out more about our exciting petroleum sector in the *Western Australian Oil and Gas Review 2008*. ■



The Hon. Alan Carpenter MLA
Premier of Western Australia

Western Australian Oil and Gas 2008 — Year in Review

World Economic Review and Outlook

According to the IMF (October 2007), global economic growth remained above 5 per cent in the first half of 2007. For the first time, China, with growth of 11.5 per cent made the largest contribution to global growth measured at market and purchasing power- parity exchange rates. India and Russia continued to grow at more than 9 per cent and about 8 per cent respectively.

Together these three countries made up about one-half of world growth over the past year. In contrast, economic growth in the US in the first half of 2007 was about 2.25 per cent, while growth in the Euro area and Japan slowed in the June quarter, after experiencing two quarters of strong activity.

As a result, inflation has been subdued in these mature countries. In particular, prices in Japan were essentially flat. On the other hand, prices rose in China and India reflecting strong economic activity. (IMF October 2007).

Since its July 2007 World Economic Outlook Update, the IMF has maintained its global growth forecast for 2007 at 5.2 per cent, but downgraded growth for 2008 by about 0.5 percentage points to 4.8 per cent. The downgrade is due to financial problems in the US and uncertain prospects regarding its domestic demand (as well as in Europe).

Tight financial conditions in the US are affecting its already deteriorating housing sector, and may spread to other sectors of the economy – increasing the likelihood of a sharp slowdown in economic activity. This downturn is likely to affect the world economy, reinforced by uncertain conditions in the world credit market. Other risks impacting are potential inflation pressures arising from increasing oil and other commodity prices, and robust economic activities in China and India; and continued large global current account imbalances (ABARE September 2007 and IMF October 2007).

World Crude Oil

Despite reaching levels close to the inflation adjusted highs of 1980, current oil prices appear far from triggering widespread recession. From an average price slightly under US$55 per barrel in January 2007, the West Texas Intermediate (WTI) oil price has increased dramatically to reaching almost US$98 per barrel in early 2008.

While the Organisation of the Petroleum Exporting Countries (OPEC) announced they would increase production by 500,000 bbl/d at their September 2007 meeting, they are resisting calls for further increases, stating that the current market situation is not the result of a supply shortage, but due to market speculation and politics.

On the one hand it is less prudent to hold large inventories of oil given the high prices, but on the other the drop in inventories in the US as reported by the US Energy Information Administration (EIA) is helping to fuel speculation of high oil prices. In light of concerns over the current crude oil market balance, OPEC decided to convene an extraordinary meeting in December 2007 to reassess the situation.

The combination of the weaker US dollar, geopolitical instability, OPEC's reluctance to accelerate supply and relatively low spare crude production capacity levels, will result in another year of strong oil prices in 2008. EIA predicts the average WTI price to be US$73.5/bbl in 2008.

The West Australian Economy

Western Australia is currently experiencing its largest economic boom due to a thriving resources sector. Western Australia's gross State product grew by 6.3 per cent in 2006-07 (adjusted for inflation), significantly faster than the long-term average of 4.6 per cent per annum during the past 15 years.

Most indicators show more favourable economic conditions in Western Australia than nationally. The unemployment rate is lower and labour force participation higher, average earnings are higher and retail spending levels and growth are above the Australian average.

Western Australia has now become the largest State in terms of exports with more than a third of the nation's export products emanating from this State. The strong performance of the Western Australian economy has been based on strong investment in the State's minerals and energy sector over the past few years, which is now generating record production levels and export volumes.

Western Australian Oil & Gas 2006-07

Western Australia's petroleum exploration expenditure more than doubled to reach a total of $1.9 billion, an increase of 102 per cent on 2006. Earlier in 2007, an unprecedented $841 million was announced to be spent on new exploration work programs in the state's far north, including the largest single work commitment in Western Australia's petroleum exploration history. In July 2007, the results of a second bidding round were announced with exploration programs in new offshore permits worth more than $560 million.

Most petroleum exploration, investment and development is taking place offshore and Western Australia's onshore areas are under–explored and relatively untouched, despite the potential for huge resources to be found. High prices have increased the viability of exploration activity by moderating the increasing costs and scarcity of equipment, material and skilled labour. The viability of the service industries has also increased with the accompanied demand for infrastructure.

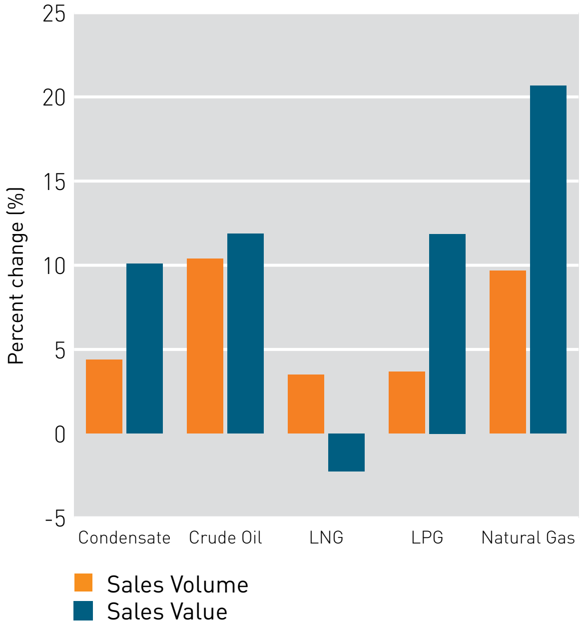
Petroleum is the largest resource sector by value and an increase of $1.2 billion saw it reach a record level of $16.7 billion. This was chiefly due to continued high world oil prices and a sharp increase in crude oil production.

In 2006-07 the amount of capital expenditure on mining in Western Australia alone amounted to $13.5 billion. This was a 26 per cent increase compared to the previous financial year, and it is expected that the strong demand for the states resources by Western Australian trading partners will continue in 2007- 2008, economic growth in Asia is increasing the global demand for oil and gas.

In 2007 the total value of Western Australian petroleum sales was $16.7 billion, a 7.85 per cent increase on 2006. This could be attributed to the continuing strength of oil prices and increasing LNG shipments, as sale quantities of crude oil and condensate continue to decline due to field maturity. Against a Western Australian landscape of general decline in output from mature oil fields, the boost in crude oil sales is due to significant output increases from new projects such as Roc Oil's Cliff Head operation and in particular, a boost in output of more than 12 million barrels from Woodside's new Enfield project.

Improved operational uptime and successful development drilling to offset natural decline also saw Wanaea's output increase significantly in 2006–07. Crude oil output in the near future should receive a boost with BHP Billiton's Stybarrow oilfield expected to start production in the first quarter of 2008. Later, production should also come from its Pyrenees oil development in the Exmouth Sub-basin.

Of the $16.7 billion value of petroleum sales earned in the 2007 calendar year, crude oil accounted for 44 per cent at $7.3 billion. This was followed by LNG (27 per cent) and condensate (19 per cent). The remaining petroleum sales value encompasses natural gas at 6 per cent and LPG propane and butane at 4 per cent.



Petroleum Sales in 2007 Source: DoIR

Crude Oil

Western Australia accounted for 71 per cent of Australia's national crude oil and condensate production in 2007, a small increase on 2006 of 1 per cent. The value of crude oil only increased 8.74 per cent from 2006, with the average price in 2007 at US$72 a barrel.

Crude oil sales from Western Australia in 2007 were valued at $7.3 billion a 9.4 per cent increase in sales volume to 13.19 MMbbl. Most of Western Australia's operating fields are mature and decreasing in annual production.

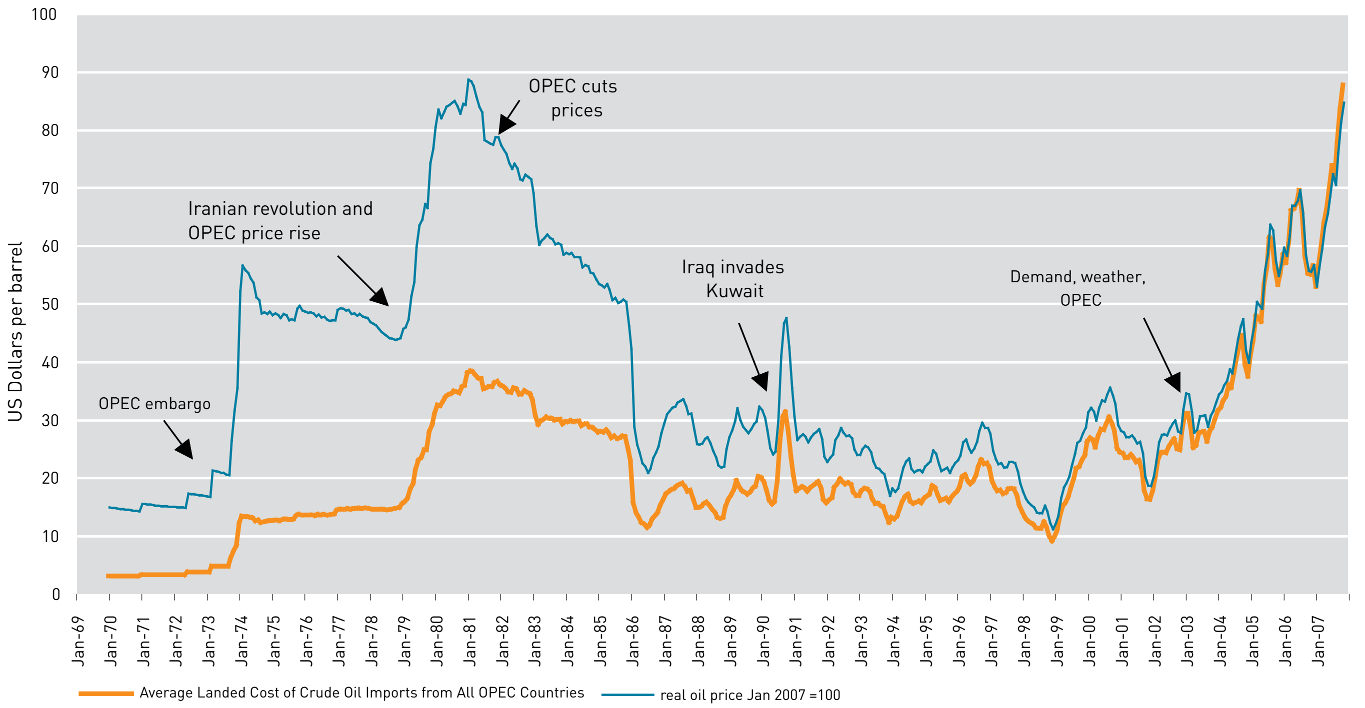
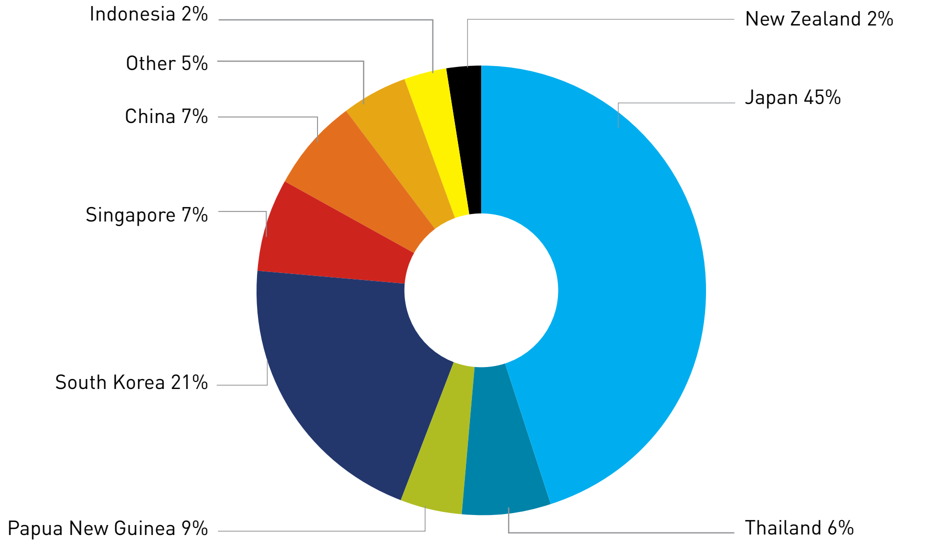
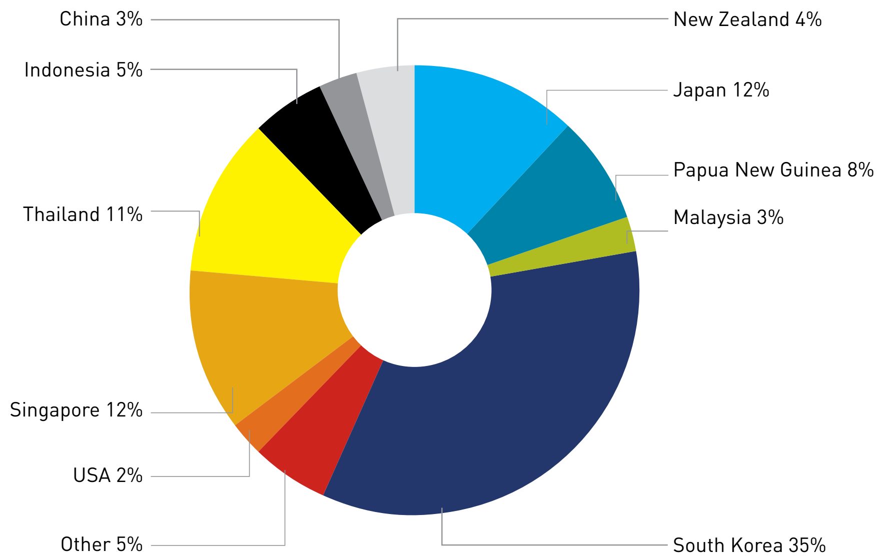


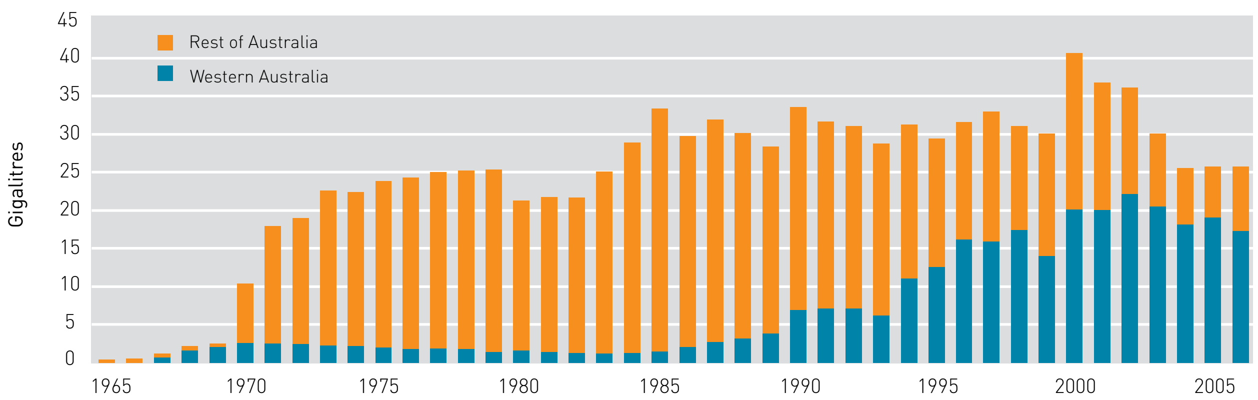
Figure 1 | **Historic Oil Prices** Source: Energy Information Administration, US Department of Energy; DoIR



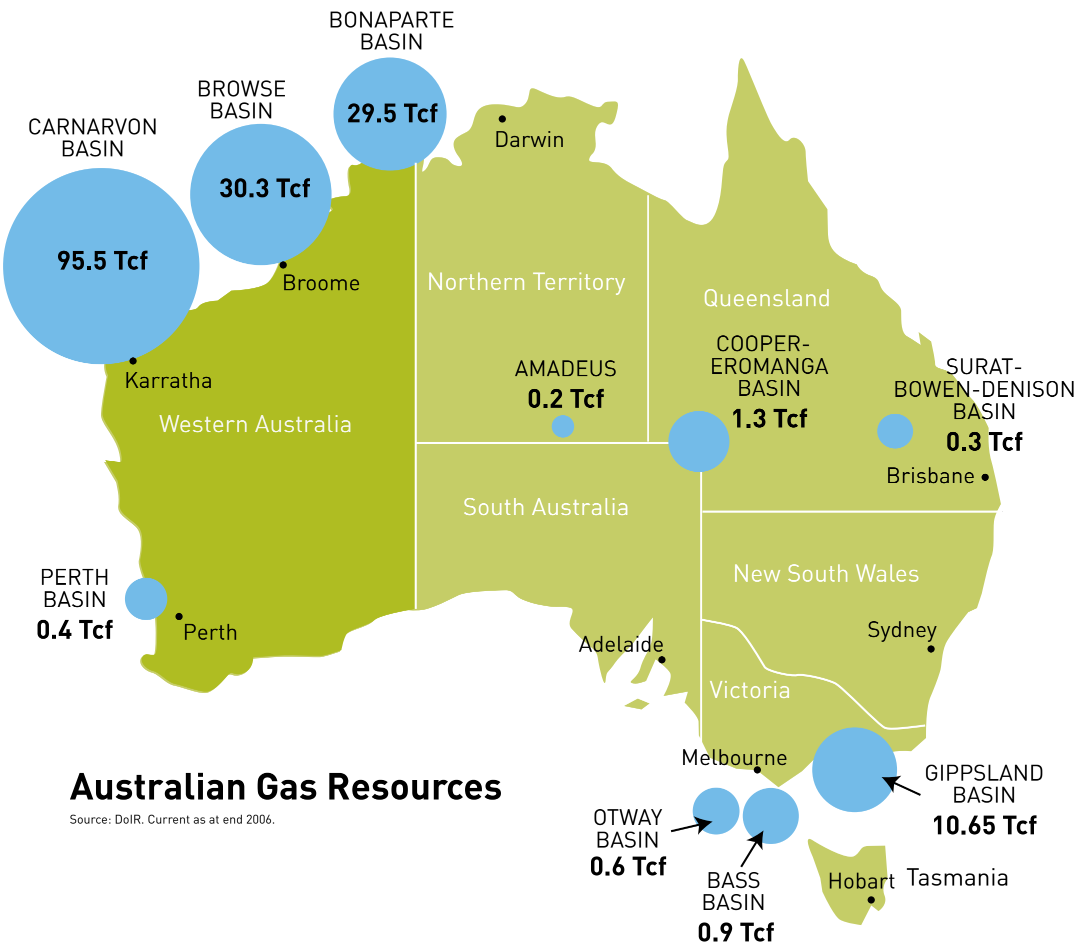
Petroleum Exports
Total Value $9.97 billion Source: DoIR



Crude Oil and Condensate Exports
Total Value $5.51 billion Source: DoIR



Crude Oil and Condensate Quantity Source: DoIR and ABARE



Australian Gas Resources

Source: DoIR. Current as at end 2006.

Condensate

There was 3.49 per cent increase in sales quantity for condensate in 2007, the value also increased from 2006 by 10.09 per cent to $3.2 billion. The largest producer of condensate in Western Australia is Woodside, operating the top four condensate fields for 2007 all out of the North West Shelf: Goodwyn at 10.3 MMbbl; Echo Yodel at 7.4 MMbbl; Perseus-Athena at 16.2 MMbbl; North Rankin at 1.9 MMbbl. This total of 36.0 MMbbl accounts for around 94 per cent of the total condensate production from Western Australia. Condensate is a by-product of offshore gas fields and used for petrochemicals.

The majority of Western Australia's condensate sales were exported, with the main customers being Singapore, South Korea, Japan and the USA.

Liquefied Natural Gas (LNG)

The value of LNG sales in 2007 decreased by 2.25 per cent from 2006 to $4.4 billion. During the March quarter of 2007, following adverse cyclonic weather conditions LNG suffered from a reduction in export volumes due to a disruptions in both production and port operations. Despite this LNG production still managed to grow 3.49 per cent from 2006 to 12.3 Mt.

All LNG from Western Australia emanates from the NWS joint venture project in Karratha which comprises four LNG production unit trains. Commissioned in August 2004, the 4.2 Mt/a fourth train is Australia's largest single LNG production unit.

Train 4 boosted NWS production to a total of 12.2 million tonnes in 2006-07 and its design is being replicated in Train 5, now under construction on the Burrup Peninsula. Completion is expected sometime during 2008, it will lift the projects capacity to about 16.3 Mt/a and make it one of the largest LNG plants in the world.

Other LNG projects possibly coming on line in the next few years include:

- Woodside Pluto LNG Project, expected to come on line 2010 at 4.3 Mt/a
- Woodside Browse Basin Development (Torosa, Brecknock, Calliance), combined these field hold 20Tcf, subject to FID to be producing 2014.
- Inpex's Browse Basin Ichthys LNG operation
- BHP Billiton and Exxon Mobil's Pilbara LNG project to be based on the Scarborough field

Western Australia, could therefore, potentially have several additional LNG projects operating within the next decade, depending on market conditions and progress on finalising the developments. There have also been major advances in liquefaction technology, making small-scale LNG an increasingly viable option.

Natural Gas

Some natural gas is used as feedstock to produce LNG, however the remainder of natural gas produced in Australia supplies domestic industrial and household demand. Western Australia accounts for 69% of national natural gas production. In 2007, the overall value of natural gas increased by $168 million to $985 million. Total production volume also increased by 9.68 per cent from 2006 values.

Liquefied Petroleum Gas (LPG)

The majority of Western Australia's LPG production is destined for export, with Japan being the main customer. LPG sales volume increased to $686 million, with an 11.86 per cent increase in value from 2006.

Movements in the Western Australian LNG sector in 2007

2007 was a successful year for securing project milestones for some of Western Australia's proposed liquefied natural gas (LNG) developments, the Pluto and Gorgon projects in particular. In addition, investigations continued during the year into a number of other proposed substantial LNG developments off the northwest coast.

Carnarvon Basin LNG developments

Pluto LNG

Woodside obtained conditional board approval for its Pluto LNG project on 27 July 2007 and obtained State and Commonwealth government environmental approvals in late 2007. The Commonwealth environmental approval was the last of the key environmental and heritage government approvals required for the project to proceed.

Woodside worked with both State and Commonwealth Government agencies to set realistic and achievable timelines and received internal company approval for the project and all required government approvals in less than 24 months.

The Pluto LNG project will use gas from the Pluto gas field, which is approximately 190 km northwest of Dampier. Pluto has a resource estimated at over 4 Tcf. The project includes offshore production wells, a supply pipe system to the Burrup Industrial Estate, an LNG processing plant and storage tanks, and port and shipping facilities.

The $11.2 billion project was formally launched by the Premier of Western Australia, Alan Carpenter, on 23 November 2007, and site preparation works were underway in early 2008.

Mr Don Voelte, CEO of Woodside, said at the official launch: "Pluto is on schedule to be the fastest LNG project in the world from discovery to first gas, and the start of construction of the project is a very exciting time for Woodside".

The initial development phase at Pluto will include a single LNG production train that is expected to operate initially at 4.3 Mt/a, and is forecast to increase to 4.8 Mt/a at full capacity. The first gas will be produced in late 2010. Feasibility work has already begun on an expansion of the Pluto project by addition of a second production train.

Woodside estimates that construction jobs will peak at 3000 during construction and that the project will generate 300 permanent jobs when operational. In addition, more than half of the estimated capital expenditure for the project will be spent in Australia and over the 30-year life of the project it is expected to inject more than $28 billion into the Western Australian economy. Woodside has also committed to supply domestic gas from the Pluto project.

In August 2007 Woodside formalised agreements with its LNG customers Tokyo Gas and Kansai Electric, for each to take 5 per cent equity in the Pluto project.

Gorgon LNG Development

The Gorgon Joint Venturers (GJV) (Chevron 50 per cent, Shell 25 per cent, and ExxonMobil 25 per cent) received State and Federal government environmental approvals in September and October 2007, respectively, for a 10 Mt/a LNG development on Barrow Island. Although an oilfield has operated there since 1967, Barrow Island is an A-class nature reserve and the environmental approvals have therefore imposed stringent conditions on the project. These include quarantine management, turtle protection, dredging management, and the requirement to construct a CO_2 injection system to dispose of reservoir CO_2 during operations.

In December 2007, the GJV announced their intention to upgrade the project specifications to increase production from the project to 15 Mt/a in order to improve project economics and address mounting industry cost pressures. The GJV expect the upgrade from two trains to three (5 Mt/a per train) will have minimal additional environmental impact to that of the already-approved two-train 10 Mt/a project. In mid March 2008, the Western Australian Environmental Protection Authority announced a Public Environmental Review level of environmental assessment for the proposed changes to the original proposal.

The Greater Gorgon gas fields contain some 40 Tcf of gas, the nation's largest undeveloped gas resource under the control of a single consortium. The GJV are proposing to develop the Gorgon and Jansz fields within the Greater Gorgon area first and to develop other fields within the Greater Gorgon area as the market dictates. The GJV estimate that the project has a nominal development life of around 60 years. The GJV cost estimate for the 10Mtpa development was $11 billion; the GJV has yet to release an updated cost estimate for the three-train project.

The project involves:

- subsea development of the Gorgon and Jansz gas fields with pipelines linked to an LNG plant on Barrow Island;
- LNG shipping facilities to transport products to international markets;
- a domestic gas plant and pipeline to deliver gas to the mainland; and
- greenhouse gas management by injection of CO_2 into deep formations beneath Barrow Island.

Chevron has LNG supply arrangements in place with Japanese and Korean buyers and Shell has arrangements with Indian buyers as well as access to regasification capacity at an LNG terminal under construction in Mexico. Exxon Mobil continues active marketing of Gorgon Gas in the Asia Pacific region.

Economic modelling completed by the GJV for the original 10 Mt/a development indicates that benefits to Australia from the project include $17 billion in taxes and royalties, additional export income of $2.5 billion a year, and approximately 6000 direct and indirect new jobs, 1700 of which will be in Western Australia. New economic modelling for the three train development concept will be completed by the GJV in 2008.

Once the GJV has obtained environmental approvals for the additional train and completed front-end engineering and design work for the project, it will consider a final investment decision on the project. Approvals are required under the *Barrow Island Act 2003* and its *Schedule 1* before the project can proceed. This legislation limits the impact of gas processing developments (including Gorgon) on Barrow Island to an area of 300 hectares of uncleared land, about 1.3 per cent of the island's area.

Pilbara LNG

The 50/50 Joint Venture between ExxonMobil and BHP Billiton is continuing to evaluate technical and commercial options to optimise the potential LNG development of the Scarborough gas field. The field is located 300 km offshore in 900 m of water and is estimated to contain in the region of 8 Tcf of gas. BHP Billiton has identified Onslow as a potential location for the LNG facility.

The North West Shelf Venture LNG Phase V Expansion Project
The fifth train expansion of the Woodside-operated North West Shelf Venture LNG development on the Burrup Peninsula is underway and will continue in 2008. The first LNG shipment is expected by the fourth quarter of 2008. The fifth train is expected to boost production capacity from the current 12.2 Mt/a to more than 16 Mt/a.

Browse Basin gas developments

The Browse Basin, which is estimated to contain more than 30 Tcf of gas, has seen considerable exploration activity in 2007 with drilling and seismic survey programs undertaken by a number of major groups including Shell, and the Inpex–Total, Woodside, and the Karoon–ConocoPhillips Joint Ventures (JVs).

In mid-2007, the State government established the Northern Development Taskforce, which incorporates the Burrup Taskforce. The creation of the West Kimberley subdivision of the Taskforce is to manage across-government planning processes and stakeholder consultation for selection and development of a suitable location (or locations) for processing of Browse Basin gas reserves.

The Taskforce is a cross-government initiative chaired by the Director General of the Department of Industry and Resources and includes representatives from the Department of Environment and Conservation, Department of Indigenous Affairs, Department for Planning and Infrastructure, the Office of Native Title, the Kimberley Development Commission, and Tourism WA. The Taskforce reports to a Ministerial Committee which is chaired by the Deputy Premier and Minister for State Development, the Hon. Eric Ripper MLA.

The purpose of the West Kimberley subdivision of the Taskforce is to ensure that development projects in the West Kimberley maximise strategic outcomes for the benefit of all West Australians in the northwest of the State. The Chair of the Ministerial Committee of the Taskforce stated in the foreword to the Taskforce Terms of Reference, released in late 2007, that it "*signifies a new stage in the management of Western Australia's resources. This Taskforce represents the government's commitment to the best possible outcomes for all who are affected by development in the northwest of our State — a region with outstandingly rich values across Indigenous culture, heritage, environment and tourism*".

The Taskforce intends to complete a site selection process that will identify a suitable location or locations by 01 July 2008.

On 4 February 2008 the Commonwealth Minister for the Environment, Heritage and the Arts, together with the Western Australian Ministers for State Development and the Environment and Climate Change, announced their intention to enter into a joint strategic assessment agreement for a common-user LNG hub precinct in the northwest to service Browse Basin gas developments. To ensure a sustainable and timely outcome, assessment of the plan for a common-user LNG hub precinct will be undertaken through a coordinated and collaborative process that will produce a set of reports to meet the requirements of both the *EPBC Act (Cwlth)* and *EP Act (WA)*.

Of companies with interests in the Browse Basin, the Woodside and Inpex–Total JVs are the most advanced in the appraisal of their petroleum permits and are continuing investigations into establishing LNG developments based on their current resource estimates.

Woodside Joint Venture: Browse LNG Development
The Woodside JV is investigating establishment of an LNG project to produce up to 15 Mt/a of LNG from the Torosa, Brecknock, and Calliance gas discoveries, which are located approximately 400 km north of Broome. These fields hold an estimated combined resource exceeding 20 Tcf of gas and 300 MMbbl of condensate.

The development will be operated by Woodside Energy Ltd in partnership with BP, BHP Billiton, Chevron, and Shell. The JV is considering several LNG development options, including both offshore and onshore processing plant alternatives.

The Woodside JV is aiming to start LNG production between 2013 and 2015, and in late 2007 Woodside as operator of the JV entered into two key terms agreements to supply up to 3 Mt/a of LNG from the Browse Basin to Petrochina Company Ltd and CPC Corporation Taiwan. Both agreements are subject to the Woodside JV making a final investment decision for the Browse development.

Inpex–Total JV: Ichthys LNG Development
The Inpex–Total JV (Inpex (operator) 76 per cent; Total, 24 per cent) is seeking to develop the offshore Ichthys gas and condensate field, which is located in 250 metres of water, approximately 440 km north of Broome. Reserve estimates for the Ichthys field are approximately 10 Tcf of gas and 312 million barrels of condensate and LPG.

The development is planned to include offshore semi-submersible facilities, and a subsea pipeline to onshore processing facilities to be located at Inpex's preferred location on the Maret Islands, off the Kimberley coast. Approximately 8 Mt/a of LNG will be produced for export to the Asia–Pacific market, with production scheduled to start by the end of 2012.

Inpex commenced both the State and Commonwealth environmental assessment processes for the Maret Islands in May 2006 and has received State and Commonwealth approval for its Environmental Scoping Document and Guidelines. The level of assessment requires an Environmental Review and Management Program and an Environmental Impact Statement.

WA Oil and Gas Industry Evolution — Structural Transformation of a Competitive Industry

Structural transformations in Western Australia's oil and gas sector in recent years have been truly significant, and are likely to provide a strong basis for future market development. There are five pillars that support the framework of the oil and gas sector: demand, supply, geopolitics, technology, and the environment. Notable transformations that have occurred within this framework include the Western Australian Government's introduction of a domestic gas policy, moves by some companies to consolidate their oil and gas assets in Australia, the establishment of a new presence in Western Australia by a number of major international companies, and the recent increase in Western Australian domestic gas prices to a level closer to those prevailing internationally.

Energy security to meet demand

A significant issue that has been gaining momentum worldwide is the preservation of energy security to ensure that future demand is met. The notion of energy security is complex, and includes not only physical protection of energy resources but also recognition from the global community of relevant issues, and the encouragement of cooperation for the preservation of supply security. Energy security has come to the forefront of many countries and regions, such as the United States and Europe,. An example of this is the Strategic Petroleum Reserve that the United States maintains to store supplies of oil, in order to ensure that demand can be met if there are serious disruptions to supply.

The Japan–Australia Free Trade Agreement is an important development. It is expected to be in effect by the end of 2008 and includes provisions for energy security. This agreement recognises the growing worldwide importance of energy security and, in particular, its importance to Australia's neighbours.

Supply insecurity has increased in Western Australia as the State becomes increasingly dependent on natural gas. This was highlighted in early 2008 when an electrical fault at the gas plant of the North West Shelf Venture pushed the State close to rolling power blackouts. One of the reasons Western Australia was able to avoid this outage was the State Government's ability to negotiate and re-prioritise the management of gas to meet demand.

Energy security is a combination of supply and demand management. With the introduction of carbon trading and increased environmental restrictions, the State's ability to use coal as a secondary fuel for power generation will face new challenges. Continuing economic growth and prosperity will see an increase in demand for natural gas.

Worldwide, and in India and China in particular, the demand and consumption of energy is growing at a pace that will require careful planning by governments globally. The importance of energy security can only increase as governments seek to diversify energy sources and ensure uninterrupted supplies to meet growing demand.

Oil and gas supply

There were two recent situations symbolic of the gas supply position in Western Australia.

The first was near the end of 2006, when the Harriet Joint Venture (Apache, Tap Oil, and KUFPEC) declared *force majeure* in relation to their ability to meet a 20-year gas supply contract with Burrup Fertilisers. The Western Australian Economic Regulation Authority (ERA) indicated that this declaration strongly contributed to the tightening of supply in the Western Australian gas market in 2007.

The second was in June 2007, when the ERA reported that the North West Shelf Venture (NWSV) had experienced technical difficulties upgrading domestic gas supply facilities for Western Australia. In November, media reporting supported initial statements by the ERA that the NWSV had chosen not to pursue expansion of domestic gas supply capacity. It was reported that compressor and turbine upgrading had failed and would be abandoned.

As mentioned earlier, two landmark projects that have the potential to significantly increase supply were given significant environmental approvals in the second half of 2007 — the Pluto and Gorgon projects. The assessment by State Government of Woodside's Pluto project proposal within a record time of only two years was heralded as a robust example of the government's ability to achieve timely and efficient assessment and approval.

Chevron, ExxonMobil, and Shell continued to work with government on the Gorgon approvals processes in 2007. In December 2007, the GJV announced their intention to upgrade the project specifications to increase production from the project to 15 Mt/a. The proposed upgrade will require ammendments to existing environmental approvals.

In 2007, Woodside further backed away from its 2000 policy of worldwide expansion of its oil interests in favour of concentrating assets in Australia. In July 2007 the company finalised the sale of assets in Papua New Guinea. A few months later, in September, Woodside sold oil assets in Mauritania to concentrate on LNG production and export from Australia. The company was reported to be in the process of finalising the sale of Kenyan oil assets as of late-2007 and thereby maintaining an Australian focus.

In September 2007, Woodside signed a $45 billion export contract with China for 2 to 3 Mt/a (over 15 years) of LNG from the Browse Project. This is likely to be the largest export contract in Australian history if it comes to pass, and will build significantly on Western Australia's initial LNG contract with China. In November, Woodside also signed a key terms agreement with CPC Taiwan that may result in sales of 2 to 3 Mt/a of LNG. This would be sourced from the Browse Project LNG development over a period of 15 to 20 years.

The approval of Pluto and Gorgon, and moves by Woodside to concentrate on environmental approval of Australian LNG operations, are representative of the large amount of investment growth Western Australia will see in 2008. With recent increases in gas prices, the market is beginning to see higher levels of portfolio rationalisation and the development of fields previously commercially unviable, thus significantly increasing gas supply. A good example of the changed economics was the announcement by Latent Petroleum in early 2008 that it will supply 20 million cubic feet of gas to the domestic market. Woodside's sales of international assets and Chevron's decision to sell its Thevenard oil and gas fields and pursue opportunities elsewhere in their Australasian operations are good examples of recent portfolio rationalisation of companies active in Western Australia.

Geopolitics and pricing

The Western Australian government policy on securing domestic gas supplies was released at the end of 2006. This policy reserves for domestic use up to the equivalent of 15 per cent of LNG production from new gas projects. The release of the policy stimulated considerable debate among gas producers as many consider that Western Australia has sufficient recoverable gas reserves to cover domestic needs.

In addition to the establishment of the State's domestic gas policy, the Western Australian State Premier approached the Commonwealth seeking an investigation into gas availability in Australia. In response, the Ministerial Council on Mineral and Petroleum Resources (MCMPR) and the Ministerial Council on Energy (MCE) formed the Joint Working Group on Natural Gas Supply (JWG). The JWG was established in recognition of the need to realise the twin goals of Australia becoming one of the world's major LNG exporters while also ensuring the long-term supply of gas for domestic use. The JWG concluded their deliberations in November 2007, with the public release of two reports.

In early to mid-2007, a number of papers on gas supply issues were released, most notably those of the Economic Regulation Authority of Western Australia (*Gas Issues in Western Australia*), the Western Australian Chamber of Commerce and Industry (*Meeting the Future Gas Needs of Western Australia*), and a report by McLennan Magasanik Associates commissioned by the JWG (*Report to the Joint Working Group on Natural Gas Supply: Natural Gas in Australia*). All of these papers examined, to some extent, the significant recent changes in the Western Australian gas market.

An issue of significance that was highlighted by several of these papers, and fuelled considerable discussion, was gas contract pricing. It became clear in 2007 that domestic gas contracts would become increasingly harder to secure at $2.50/GJ and with long-term timeframes. This was demonstrated by announcements in July that Santos had secured gas prices of more than $7/GJ in two separate contracts with Western Australian miners. Toward the end of 2007, some parties suggested that gas pricing should follow the example of Asia, where prices are tied to Tapis Crude Oil prices — this approach suggests contracts could be set at $14/GJ. It became clear in 2007 that gas is in short supply in Western Australia, and demand is increasingly driven by the ongoing mining boom. This transformed many previous perceptions of gas as a cheap and abundant fuel.

International crude oil markets experienced dramatic change in 2007 as oil prices hit record highs. Prices in late 2007 were higher by as much as 30 per cent than pre-August 2007 average prices of around US$70/bbl. In October, US light crude hit a record high of US$92.79/bbl. On 21 November, the price of light sweet crude reached US$99.29/bbl. Within the first few days of 2008, oil reached an all-time high of US$100/bbl (not adjusted for inflation), showing the continuation of the dramatic upward trend of oil prices. Continued increases in oil prices are likely to see alternative fuels, such as natural gas, gaining further popularity. The high price of oil also increases the cost of emergency situations where oil is used as a substitute for cheaper sources of energy for which supply is short or has been disrupted.

The environment

The growing awareness of the impact of human society on the environment and the inevitability of a carbon-constrained future has led to a global shift away from high-emission fuel sources such as coal. Within Western Australia, however, this has proved to be difficult to achieve as the demand for natural gas resources for export has increased and domestic gas prices have increased in response to high levels of demand. This has driven energy consumption back to coal as a cheaper and more readily available fuel source. This has required the development of new ways of using coal that reduce the amount of carbon dioxide released to the atmosphere. The process of carbon capture and storage (CCS), also known as geosequestration, is being used to capture, transport, inject, and store carbon dioxide in underground geological formations for the primary purpose of mitigating greenhouse gas emissions. Similarly, there has been much discussion of the concept of trading carbon offsets.

In addition to switching to cleaner sources of fuel and finding ways to reduce carbon emissions, companies are becoming increasingly concerned about (and bound to) reducing environmental impacts. This is only natural given the growth in recognition of the need for projects to be environmentally sustainable. A significant recent example is the Barrow Island turtle management program imposed on the Gorgon project proponents.

Most notable amongst environmental developments within the oil and gas industries will be the inevitable introduction of a carbon tax or carbon trading system — expected to be in place by the end of 2010. ■

The Future of Hydrocarbons: Implications for Western Australia in 2008 and Beyond

Over the past 50 years, oil has become the most important energy source for the world economy. On the economic front, 2008 started with a bang, with oil breaking through the significant psychological price barrier of US$100/bbl. **Figure 1**[1] shows the price of oil over the past 12 years and its spectacular rise since 2002. This sustained upward trend represents a quantum shift in the price of oil and culminated on 3 January 2008 when February crude oil futures contracts peaked at over US$100 per barrel.[2]

What is the importance of this event, and what are the implications for Western Australia?
This spike in the oil price is not the first of its kind and, in inflation-adjusted terms, it is arguably not a record price. Nevertheless, US$100 is a significant number.

Figure 2 shows the price of oil over the period 1970 to 2006. It illustrates the upward variation in price from a baseline price of around US$10 in response to international events. Over this period, the average price was US$22 per barrel, with perhaps the most significant events being the spike following the 1973 Arab oil embargo and the period of sustained high prices from 1980 to 1986 during the Iran–Iraq war.

It is also important to note that previous rapid increases in oil price have generally been the harbinger of economic recessions.

So, what is the probability of a global recession in the current economic climate?
The United States Government has taken action to avoid a potential US recession. In the current world climate, however, it is questionable whether a US recession induced by the sub-prime mortgage financial crisis, as some commentators are suggesting, would necessarily pull the world into a global recession. The US, although still the major consumer of oil, no longer consumes the major portion of global production.

If the US suffered a major recession, the rest of the world may not necessarily follow. It is possible that the major developing economies would shift their current industry focus of production for the export market to one of internal consumption, and perhaps continue on their upward growth curve.

It is also interesting to note that oil price increases over the past three years differ from previous spikes. Recent increases show more an upward ramp than a spike. No single event has been responsible for these increases, and while some economic commentators have blamed financial speculation, others argue that this is just the free market in action in an environment where demand is outstripping supply.

Possible causes of the increase in the price of oil are:

- increasing demand, especially from highly populated developing nations such as China and India;
- decreasing supply and the production decline of fields as they progress to depletion;
- an increasing proportion of supply coming from less secure geo-political regions;
- increasing domestic consumption by oil exporting nations;
- increasing nationalisation of oil companies and national control of oil assets; and
- the very rapid escalation of the costs of exploration and production.

It is not clear if the current price movement of oil and, more broadly energy and resources, is an indication that the world's 6.5 billion population is reaching a new and critical stage — a stage where its further development is limited by the availability of energy and/or other resources.

The "peak oil" theory recognises that oil is a finite natural resource subject to depletion. Eventually the rate of replacement of oil reserves through new discoveries becomes less than the rate of production and consumption. The term "peak oil" has entered the common vocabulary aided by film documentaries such as "A Crude Awakening: The Oil Crash"[3] but the idea was first presented by M King Hubbert[4] over 50 years ago. As suggested by his theory, oil production from most oil-producing nations is in decline and new resources discovered are not replacing current production. No new major oil provinces have been discovered since the Alaskan North Slope, or the North Sea. An Organisation of Petroleum Exporting Countries (OPEC) official recently intimated that OPEC producers may not be able to meet global demand for oil by 2024.

[1] Featured in the *Western Australian Oil and Gas 2008-Year in Review* article on page 4 of this publication.
[2] Oil prices exceeded US$111/bbl in March 2008

[3] Swiss Films, produced and directed by B Gelpke and R McCormack
[4] The peak oil theory was first presented by M K Hubbert in 1956 in *Techniques of Prediction as Applied to Production of Oil and Gas*, US Department of Commerce, NBS Special Publication 631.

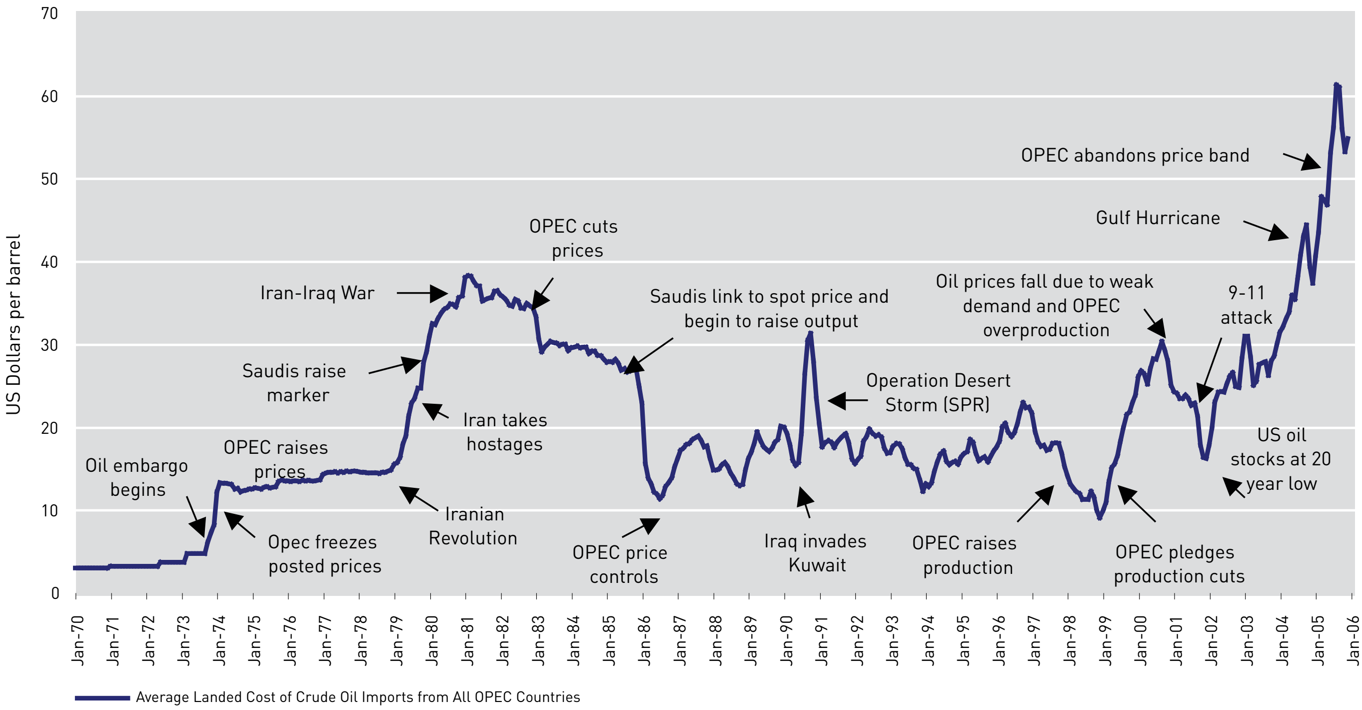


Figure 2 | **Historic Oil Prices** Source: Energy Information Administration, US Department of Energy; DoIR

Because of the recent quantum shift in the price of oil, significant known resources that have been considered sub-economic at lower oil process are now potentially economic. The growth of the available reserve base if these fields are exploited will potentially stave off the imminent onset of Hubbert's point of "peak oil" production.

A further concern is the greenhouse phenomenon and its contribution to global warming. This phenomenon is calling into question the wisdom of rampant use of fossil fuels by developed and developing nations.

As a consequence of both the escalation of the price of oil and concerns about the environment, there is a growing trend to rely less on oil and more on gas to satisfy energy needs. Not so long ago, natural gas was considered by many producers to be a waste product associated with oil production. This has changed and today gas is an important energy source, albeit one that is often more difficult and expensive to transport than oil. Gas reserves are growing and, because they provide a cleaner fuel than oil, successful exploration for gas is continuing and substantially adding to the energy reserve base that can be drawn upon.

Within this complex global context, where does Western Australia stand?

Western Australia stands reasonably well, and is better placed than most Australian States or other countries. Oil and gas have provided the impetus for the recent phenomenal economic growth in Western Australia. In 2006–07, oil and gas royalties contributed over $714 million to the State's coffers. Fortunately for Australia in the current market, the northwest energy arc is considered to be a gas-prone province, and is estimated to contain more than 105 Tcf of gas reserves. Australia is one of the few nations in the world to have an expanding hydrocarbon resource, predominantly in natural gas, without a national oil and gas company controlling its exploitation.

There are also a range of reasons for international companies to view Western Australia as an attractive place to pursue further energy resources. These include:

- an active exploration industry with a growing resource base;
- excellent infrastructure and a capable workforce;
- quality education systems;
- high-quality research institutions;
- an enviable lifestyle;
- low sovereign risk with open, transparent licensing arrangements for exploration and production; and
- a growing capability base, especially in the areas of LNG production, floating production storage and offloading facilities (FPSOs), and subsea well completions and pipeline construction.

However, in this context it is important to understand that gas developments differ fundamentally from oil production projects. For oil developments, the emphasis has traditionally been to maximise production in the first few years of development in order to recover costs as quickly as possible. Large natural gas developments commonly require much larger investments in initial development, possibly entailing the construction of LNG plants and/or facilities for transportation of gas to export markets or the domestic market. Consequently, the planned production life for natural gas developments may extend over three or more decades, and the economic viability of the projects depends critically on the initial development and construction costs.

On current indications, Western Australia can look forward to the development of a number of large natural gas projects over the coming decades, including the Pluto, Gorgon, and Ichthys projects. An energy-driven economic expansion that is likely to span the next three decades can therefore be envisaged for Western Australia. This has positive implications for future energy security. It provides a real opportunity to develop local industry by bringing both employment and business development opportunities to the State, and it also brings opportunities for significant international investment in Western Australia.

To build on these opportunities, the Western Australian government aims to develop Perth as a hub for the oil and gas sector, with particular focus on the subsea industry. The State government has already stimulated the growth of this industry sector by providing significant funding to:

- the Western Australian Energy Research Alliance (WA:ERA) — a joint venture between CSIRO, the University of Western Australia, and Curtin University whose aim is to consolidate a scientific foundation that will secure Western Australia's future as an enduring self-sufficient producer of clean natural energy;
- the Australian Centre for Energy and Process Training (ACEPT) — a provider of process operations training for the Australian oil and gas sector; and
- the Australian Marine Complex — developed to facilitate and enhance the opportunities created by clustering of industries servicing the marine, defence, mining, and petroleum industries.

Recently, the Western Australian Minister for Energy re-established the Oil and Gas Industry Coordinating Council to provide a forum for government and industry leaders to discuss strategic issues facing the sector in Western Australia. It also provides a mechanism for maximising Western Australian participation in the oil and gas sector, thereby increasing business, employment, and new inbound investment opportunities to further the economic development of the State.

The Western Australian government is well aware of the emergence of the oil and gas service industry in Perth and is keen to see it reach its full potential to service the Southeast Asian region as well as the local market. Recognising the challenge Australia faces in competing with differential labour costs in labour-intensive aspects of the resource industry, Western Australia aims to concentrate on the high-technology, high-value end of the service spectrum. To achieve this, Western Australia must focus on encouraging innovation, technological development, and the commercialisation or implementation of new developments.

But in the longer term, where will technology take us?
Recent examples of advanced technological development in the oil and gas industry include:

- increasingly sophisticated seismic exploration (3D and 4D) techniques to more readily find oil;
- the move of development into deeper water — subsea technology for cost-effective exploitation; and
- intelligent field design — more efficiently extracting the resource.

However, finding the oil and gas more efficiently and extracting it faster ultimately compounds the problem posed by the "peak oil" concept. There are two fundamental questions.

Do we maintain a portion of the natural resource for future security of domestic energy consumption, or do we capitalise the resource now, perhaps before another energy source renders it less valuable?

Do we use this resource now to build an enduring industrial base for Western Australia?

The State and its oil and gas sector face the challenge of optimising the use of energy resources for both current and future needs. This challenge presents excellent opportunities. For those with creativity, with competencies in the sector and with capital, we need creative and innovative solutions — solutions that can provide both commercial benefits for developers and prosperity for Western Australians. ■

Tight Gas to the Rescue

In 2007 a new chapter in the development of gas exploration in Western Australia began with Resources Minister Francis Logan announcing the release of the first "tight gas" acreage block over an area thought to contain more than 388 billion cubic feet of gas. Tight gas is considered unconventional.

So what exactly is unconventional gas? A precise answer to this question is hard to find. What was unconventional yesterday may, through some technological advance or dexterous new process, become conventional tomorrow. It is a broad term that has been coined to define gas that is more difficult and less economically sound to develop, usually because the technology to extract it has not been developed fully, or is too expensive.

Tight gas refers specifically to natural gas that is trapped in underground reservoirs from which it is difficult to extract; for example, in a sandstone (tight sand) or limestone formation of very low permeability and porosity. This makes it challenging to exploit the resource without the use of innovative extraction techniques. Tight gas is known to exist in Western Australia's South West and lower Mid West, but these occurrences have historically been thought to be uneconomic to exploit. Since the steep increases in global energy pricing, unconventional natural gas deposits may in future make up an increasingly large proportion of the supply picture.

In an era of declining production and increasing demand, economically producing oil and gas from unconventional sources is the next level in the fossil fuel recovery challenge. Tight gas has begun to attract more attention as current global and local market conditions create an environment in which its economic viability has improved. Higher gas prices, advances in geological knowledge, evolving drilling and well completion technology, along with domestic gas shortages, are providing niche opportunities for operators with core competencies in this specialised area.

There are several techniques, such as fracturing and acidizing, that allow natural gas to be extracted from tight formations. However, these techniques are very costly. Like all unconventional natural gas, the economic incentive must be there to encourage companies to extract tight gas instead of seeking more easily obtainable, conventional natural gas.

Tight gas presents opportunities for innovative small to medium size companies flexible enough to profit from exploiting smaller reserves, and to companies with core competencies in niche drilling techniques.

Latent Petroleum, an unlisted private company established to develop and produce gas for the Western Australian domestic market, has committed to drilling Warro, a tight, deep gas field 200 km north of Perth, with the aim of achieving first production in 2009 at an initial rate of 20 MMcfd (million cubic feet of gas a day) climbing to 100 MMcfd at peak production.

The Warro gas field is near the town of Moora and only 30 km east of the Parmelia and Dampier–Bunbury gas pipelines. The field contains high-quality gas suitable for domestic supply. According to Latent Petroleum, Warro is expected to provide a substantial, secure, and long-term supply of gas to Western Australia soon after development approval is granted.

Tight gas also provides an opportunity for Western Australian producers of large volumes of gas for export to meet some of their domestic gas responsibilities. Evaluating and exploiting unconventional gas resources close to the State's centres of demand can help them meet the requirements of the Western Australian State government's Domestic Gas Reservation Policy.

Tight gas makes up a significant portion of the United States' domestic natural gas resource base. The US Energy Information Administration estimated that on 1 January 2000 there was 253.83 trillion cubic feet of technically recoverable deep tight natural gas in the US. This represents over 21 per cent of the total recoverable natural gas in the country. Canada and Argentina are two countries that are already commercially producing tight gas.

Western Australia has been lucky enough to have large reserves of easy to access gas. Previously, there has been no incentive for explorers to pursue tight gas because exploration and development costs made it an unattractive proposition. Neither did the previous economic and policy environment foster exploration for and exploitation of unconventional gas reserves. Today, the environment has changed. Looking to the future, tight gas developments are expected to supplement gas supply and potentially alleviate supply shortfalls in the State, thus providing adept companies with interesting opportunities.

For further information about tight gas opportunities please contact Ali Sharif (08) 9222 3374. ■

Investor Buy-in — Customers See Opportunities in Local Oil and Gas Sector

Japan's resource profile — dependent on imported resources

Japan is WA's second largest export customer and enjoys a long trading and business relationship with the state. In 2006-2007 oil and gas exports from Western Australia to Japan comprised 47 per cent by value of Western Australia's total oil and gas exports. Japan is heavily dependent on imported oil and gas because of its lack of domestic oil and gas reserves. As a result, Japanese companies have proactively sought involvement in international upstream oil and natural gas projects. Japan is a major exporter of capital equipment for the energy sector, and Japanese companies have developed a solid reputation in the areas of engineering, construction, and project management services for energy projects.

Japan's participation in the development of the Western Australian LNG industry

Japanese participation in the Western Australian resources sector started more than 50 years ago. Initially interested in iron ore, Japan later turned its focus to securing a steady supply of LNG and contributed significantly to underwriting the cost of the early development of the State's LNG industry.

Eight Japanese foundation customers of the North West Shelf (NWS) project have benefited from the construction of world-class LNG production and export facilities on the Burrup Peninsula near Karratha in the State's North West. This provided a risk mitigation path for the developers and carriage of this risk provided a foundation for other project partners, Japan Australia LNG (MIMI), to become interested and invest.

Renewed interests in Western Australia's resources

In recent years, there has been a high level of renewed interest in Western Australia's oil and gas sector from Japan and other countries.

Building on the strengths of the NWS relationships, a number of Japanese groups have increased their participation in the State's oil and gas industry. This can be seen in the recent emergence of Japanese equity in several projects offshore from Western Australia.

In 2007, Tokyo Gas and Kansai Electric Power Co., both NWS foundation customers, each acquired a 5 per cent interest in Woodside's Pluto Project. The realisation of this project will have significant benefits for these two Japanese companies, and for Western Australia. The project is underpinned by an integrated package of LNG sale and purchase agreements as well as project equity and shipping arrangements, and is expected to create up to 3000 direct jobs during construction and 200 jobs during operation. More than half of project expenditure is expected to be in Australia.

During 2007 Osaka Gas, another NWS foundation customer, acquired a 15 per cent interest in the Crux project (Nexus Energy), which is in the offshore Browse Basin, off the north-west coast of Western Australia.

Foundation customers of the NWS Project		
Chubu Electric Power Co.	Supply from trains 1–3	Contract period 1989–2009 with plateau volume of 1.09 Mt/a LNG
Chugoku Electric Power Co.	Supply from trains 1–3	Contract period 1989–2009 with plateau volume of 1.11 Mt/a LNG
Kansai Electric Power Co.	Supply from trains 1–3	Contract period 1989–2009 with plateau volume of 1.13 Mt/a LNG
Kyushu Electric Power Co.	Supply from trains 1–3	Contract period 1989–2009 with plateau volume of 1.05 Mt/a LNG
Osako Gas Co.	Supply from trains 1–3	Original contract period 1989–2009 with plateau volume of 0.79 Mt/a LNG
Toho Gas Co.	Supply from trains 1–3	Contract period 1989–2009 plateau volume of 0.23 Mt/a LNG
Tokyo Electric Power Co.	Supply from trains 1–3	Contract period 1989–2009 with plateau volume of 1.18 Mt/a LNG
Tokyo Gas Co.	Supply from trains 1–3	Contract period 1989–2009 with plateau volume of 0.79 Mt/a LNG
Other important participants:		
Mitsui & Co. and Mitsubishi Corporation	These two companies each have half ownership of Japan Australia LNG (MIMI) Pty Ltd, which has $16^{2/3}$ per cent interest in the North West Shelf LNG Joint Venture	

Deregulation of the Western Australian gas industry

Strong historical economic growth in the State has resulted in an increase in total energy consumption flowing through to an increase in the use of natural gas as an energy source. Western Australia is the biggest consumer of natural gas in Australia. According to the Australian Bureau of Agricultural and Resource Economics, Western Australia is forecast to consume 632 PJ of energy in 2020 — at least 54 per cent more than each of the other Australian States.

On 31 May 2004, the Western Australian Government introduced reforms to the State's retail gas market that allow new gas companies to enter the marketplace, thereby providing gas purchasers in the State with choice of retail supplier. Importantly, the deregulated gas market enables natural gas sellers to compete and buyers to negotiate and thus secure competitive terms for natural gas sales.

The growth in gas demand in Western Australia will ultimately lead to the development of substantial further infrastructure to bring the State's gas reserves to its developing mineral provinces and industrial centres across the State.

Deregulation of the Japanese gas industry

Resources security concerns in East Asia have contributed to a heightened interest in the Western Australian oil and gas sector. Another key driver for Japanese companies entering into energy projects in Western Australia is increased competition in Japan's domestic gas market as a result of its deregulation.

The ongoing staged deregulation of Japan's domestic gas industry has allowed new participants to enter the gas market. The new entrants include gas pipeline companies, oil companies, electric power companies, general trading companies, and steel mills.

The revised Japanese Gas Industry Law became effective in April 2007. This change deregulates nearly 60 per cent of city gas demand in Japan. Further deregulation is expected in coming years.

The regulatory reform means that pre-existing gas utilities compete for market share with new entrants and, in some cases, with each other. These reforms are accelerating conventional competition within the electric power and oil sectors in Japan. The increased competition is one of the key factors that is encouraging Japanese oil and gas companies to explore new business in the global market.

Opportunities

The Western Australian government Policy to secure domestic gas supplies is designed to ensure that sufficient supplies of competitively priced gas are available to underpin Western Australia's long-term energy security and continued economic development. However, simply securing domestic gas does not in itself guarantee that the State will have access to that reserved gas.

There is an opportunity for Japanese and other international companies, particularly those who are already involved in Western Australia projects, to utilise their core competencies in the deregulated market in Western Australia.

There is a business opportunity to exploit the current economic and policy environment in Western Australia for commercial advantage while at the same time delivering broad strategic benefits to the Western Australian oil and gas sector and the State's economy in general. Japanese and other international operators can expand on their existing business relationships by bringing their expertise in pipeline construction, and their experience of aggregation of gas supply and demand in their domestic markets, to Western Australia, thus supporting the State's oil and gas industry, a sector in which they already have some experience.

In the current environment of high energy prices many nations that are net importers of energy resources are finding that their growth paths are foreshortened.

Worldwide LNG prices are high. LNG as a processed form of energy can incur many extra costs, particularly if there are large distances between source and supply locations. Liquefying gas to produce LNG, followed by shipping and then regasification before use (effectively converting the gas to its original form) incur significant, capital, operating, and carbon costs. From a life-cycle product-stewardship perspective, these processes involve cash costs, carbon emissions, and potential loss of resource during processing. Avoiding liquefaction, shipping, and regasification by using the resource in Western Australia, close to its source, can therefore provide many benefits. These include:

- less erosion of energy value in the processes of changing the resource from gas to liquid and then back to gas;
- cutting out "middle men" by using bilateral contracts on a take-or-pay basis;
- better negotiating positions for developers as ventures become less risky because shipping and regasification are no longer involved;
- confidence in a stable supply of gas for local industry, as required by the Western Australian government's domestic gas policy;
- access for gas consumers to energy resources at a more competitive and sustainable starting point from which to commence value-adding processes; and
- a positive contribution to intergenerational equity and the sustainability of Western Australia's future.

There are also significant environmental and social benefits for Western Australia if processing and manufacturing areas are close together. In the present environment, the State government is seeking to work with investors to define a strategy for the future, one that turns Western Australia's legacy assets into assets in perpetuity. This can be achieved by responsible investment and sustainable development, not simply taking resources out the ground for export.

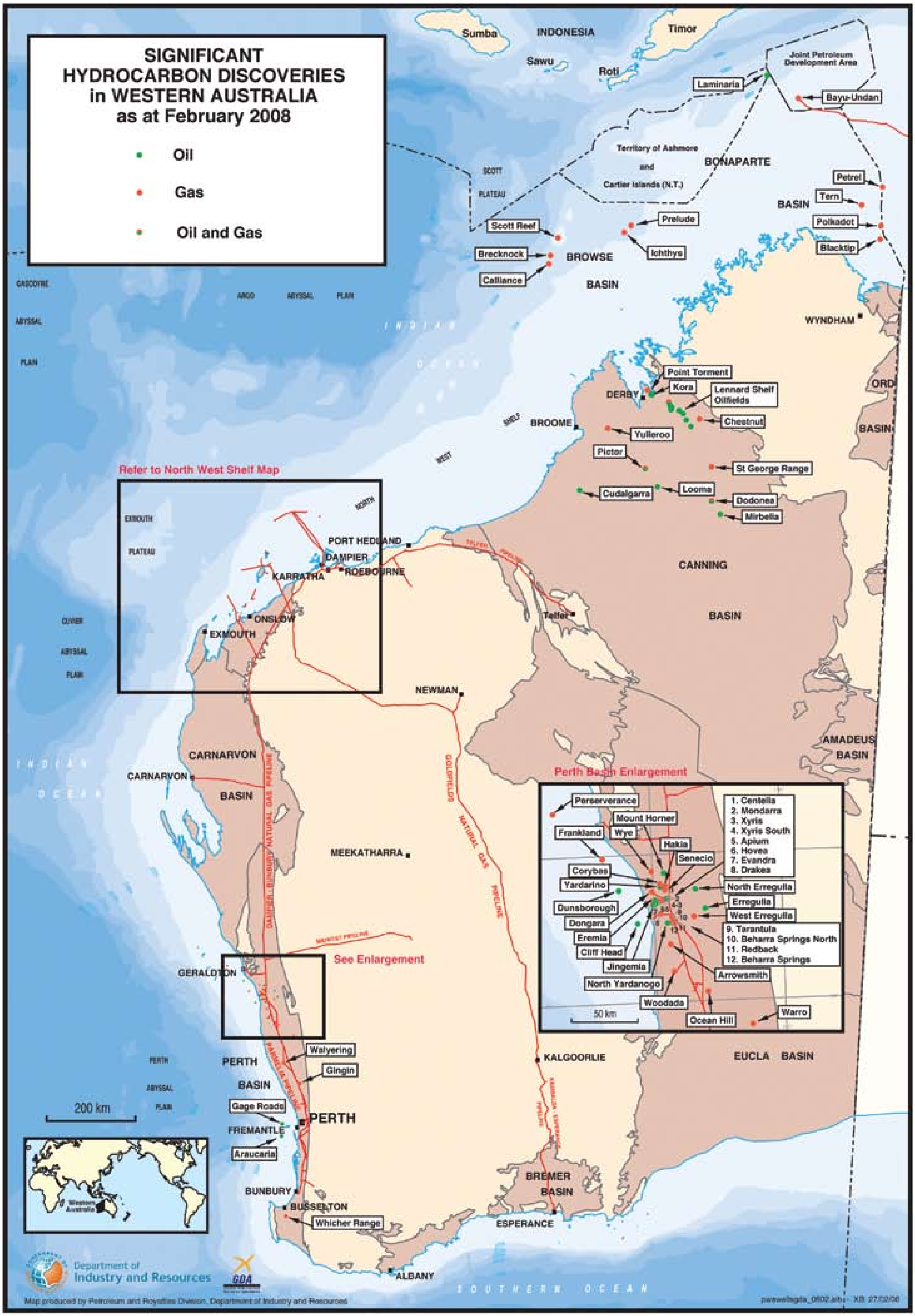
As Western Australia progresses towards a more carbon-constrained operating environment, the availability of vast natural resources, greenhouse-friendly natural gas in particular, offers the potential for Western Australia to achieve world's best practice in resource processing. For this to occur there must be a paradigm shift away from traditional processing methods. The traditional practice of extracting vast quantities of raw energy resources and developing mineral deposits in remote locations, and then transporting these for processing close to final overseas markets may not be an optimal practice. In a carbon-constrained world, post Kyoto agreement, this is increasingly being seen as adding considerably to carbon emissions and should be curtailed or eliminated.

Successful relationships with international stakeholders have laid the base for Western Australia's oil and gas industry, as shown by the foundation investments by Japanese companies in the NWS project. It is now time for Western Australia and international stakeholders to take these successful relationships to the next stage, and expand industry to strengthen Western Australia's economic base while also providing benefits for international stakeholders. Business, investment, manufacturing, and production are no longer constrained by international borders or remote locations — the world has become a global village.

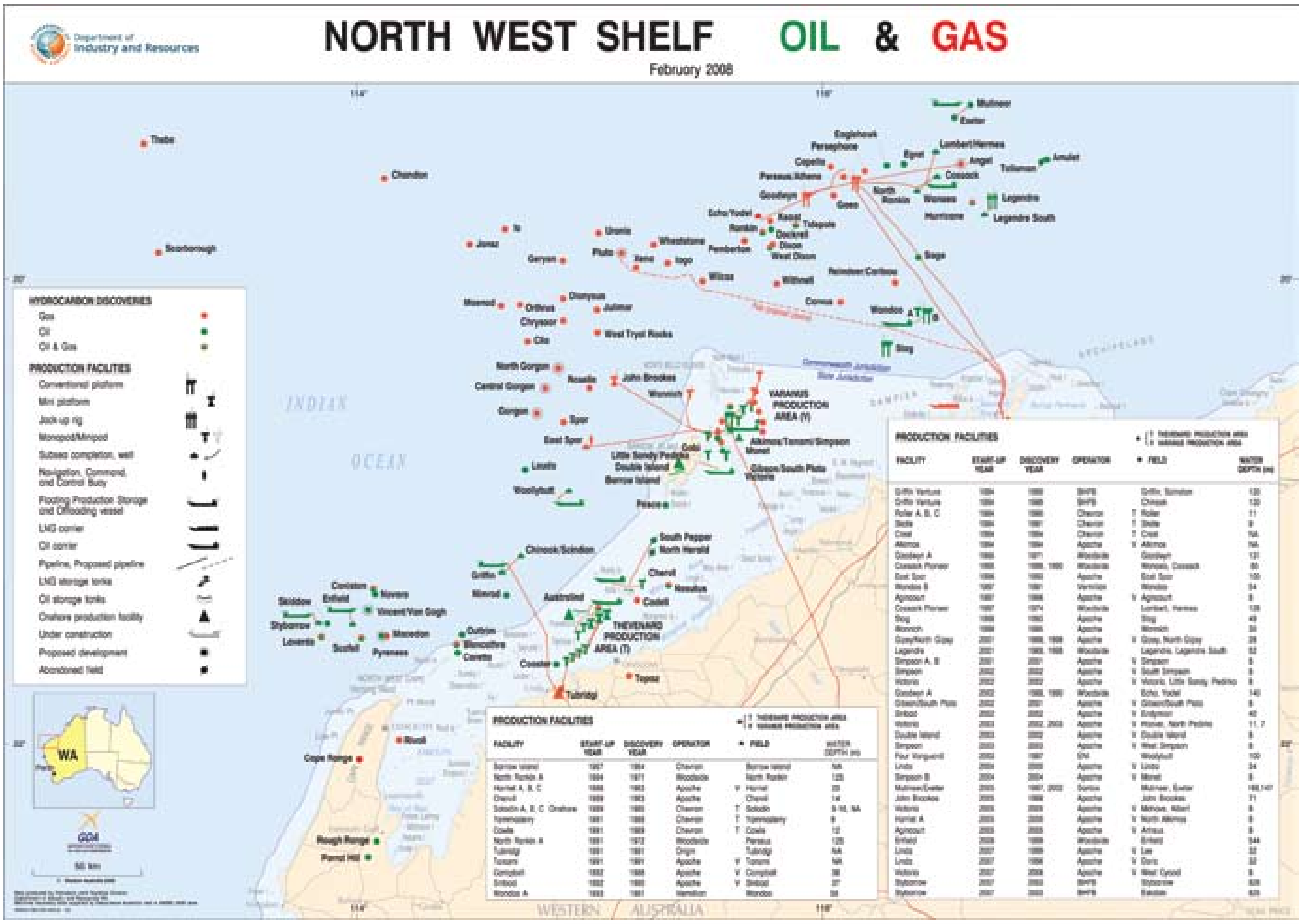
The deregulation of the Western Australian gas industry, coupled with the continuing strong demand for domestic gas, may create a positive environment for the participation of Japanese gas utilities and other international players in Western Australian industry. There is an opportunity for international utility companies to implement an alternative business model, one that allows them to profitably apply their expertise in Western Australia and thus support the growth and technological development of the already strong domestic industry.

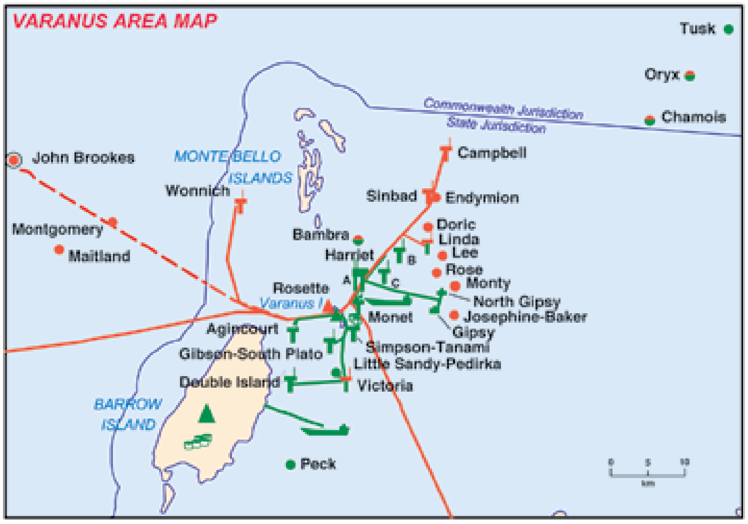
Costs and risks associated with the provision of domestic gas infrastructure could potentially be borne by new players whose core business expertise lies in the provision of infrastructure as a service to others. New alliances such as this would substantially reduce the disincentives for gas exporters to explore domestic market opportunities. This strategy would enhance the availability of significant volumes of domestic gas for existing and new users in the State while providing an alternative business model for organisations facing pressures such as deregulation in their own jurisdictions, whether they be in Japan, Europe, the USA, or other international locations. ■

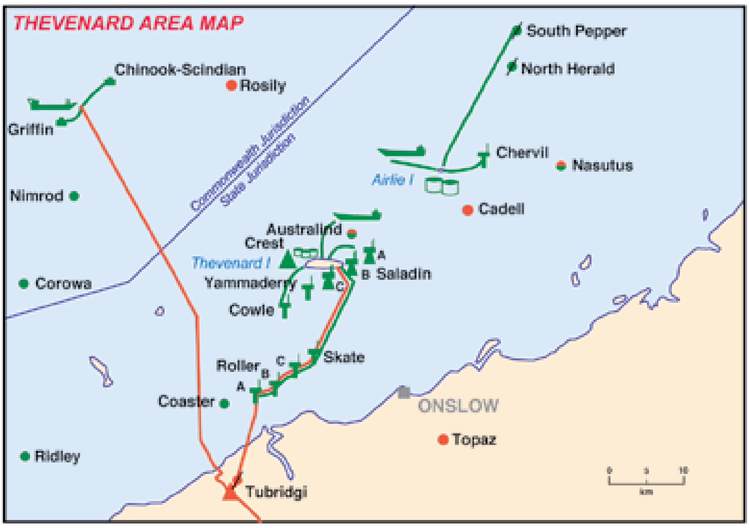
Map 1: Significant Hydrocarbon Discoveries In Western Australia



Map 2: North West Shelf Oil And Gas







HYDROCARBON DISCOVERIES

- Gas
- Oil
- Oil and Gas

PRODUCTION FACILITIES

- Conventional platform
- Mini-platform
- Jack-up rig
- Monopod/Minipod
- Subsea completion, well
- Navigation, Command, and Control Buoy
- Floating Production Storage and Offloading vessel
- LNG carrier
- Oil carrier
- Pipeline, possible pipeline route
- LNG storage tanks
- Oil storage tanks
- Onshore production facility
- Under construction
- Proposed development
- Abandoned field

Oil and Gas Projects 2008 (Index)

Blacktip Gas

Location
150 km north, northeast of Wyndham

Basin
Bonaparte

Permit/Licence
WA-279-P

Ownership	%
Eni Australia Limited (Operator)	100

Contact
Eni Australia Limited
Level 3, 40 Kings Park Road
WEST PERTH WA 6005
PO Box 1265
WEST PERTH WA 6872
Tel: +61 8 9320 1111
Fax: +61 8 9320 1100
Email: info@eniaustralia.com.au

Production

Production is expected to commence in first quarter 2009 through an Onshore Gas Plant near Wadeye in the Northern Territory. The Blacktip Project is being developed to supply the Northern Territory's Power Water Corporation with gas for power generation for the Northern Territory for a period of 25 years.

Exploration

Blacktip-1 was planned as a vertical exploration well to evaluate the hydrocarbon potential of the Blacktip structure in the offshore Southern Bonaparte Basin. The well tested a fault-independent anticline with amplitude support at intra Mount Goodwin Formation (Early Triassic) and Upper, Lower and Base Keyling Formation (Early Permian) levels. The well was spudded on 25 July 2001. Eight major gas-bearing reservoirs were encountered, one in the Mount Goodwin Formation, five within the Keyling Formation and two in the Treachery Formation. Total depth was reached in the Carboniferous Treachery Formation, at 3181 m, on 10 August 2001. The deeper Carboniferous Kuriyippi target was not reached. The rig was released on 3 September 2001.

Development

The Project was sanctioned in June 2006. Onshore civil works commenced in October 2006 with the clearing of the onshore gas plant site and access road from Wadeye. This work was 80 per cent complete at the end of 2007. Since sanction, a range of engineering, design and procurement activities have been undertaken in Perth and elsewhere, including the award of the major contract for the offshore fabrication and installation part of the project – this includes the fabrication and installation of the offshore Well Head Platform (WHP) and subsea pipeline from the Blacktip field. The WHP is being fabricated at Henderson in Western Australia.

The remaining major contract for the fabrication and installation of the Onshore Gas Plant was awarded in late 2007.

Barrow Island Oil

Location
88 km north of Onslow

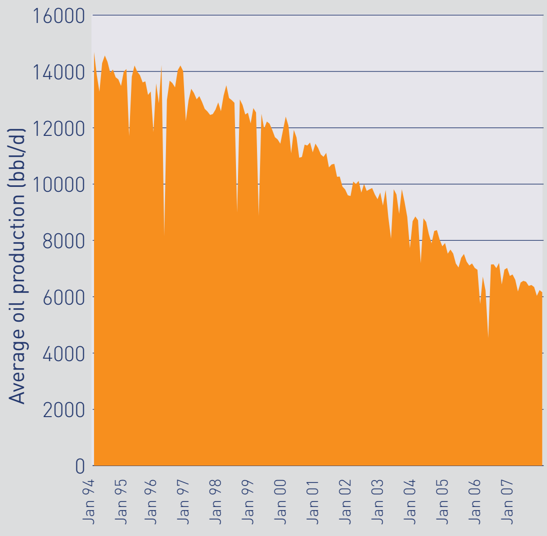
Basin
Carnarvon, onshore and offshore

Permit/Licence						
L1 H (R1)	WA-7-L	L10	TL/3	EP61	EP62	TP/2

Ownership	%
Chevron Australia Pty Ltd (Operator)	28.57
Chevron (TAPL) Pty Ltd	28.57
Santos Offshore Pty Ltd	28.57
Mobil Australia Resources Company Pty Ltd	14.29

Contact
Chevron Australia Pty Ltd
Level 24, QV1 Building
250 St George's Terrace
PERTH WA 6000
Tel: +61 8 9216 4000
Fax: +61 8 9216 4444
Web: www.chevrontexaco.com

Production	2006	2007
Oil (bbl)	2 399 987	2 334 030
Gas (kcm)	55 561	64 943



Barrow Island

The Barrow Island oil field was discovered in July 1964 beneath the 233 km² island and is the largest oil field discovered in Western Australia. Production commenced in April 1967 and peaked at 50 000 bbl/d in 1971. Barrow Island was originally envisaged to have a 30-year life, but as a result of careful management of the reservoirs using more than 800 oil production and water injection wells, the life of the field has been extended until 2031. The joint venture estimates that the field will have produced 343 MMstb of oil by 2031, approximately a third of the known oil-in-place.

In February 2000, Chevron Australia assumed the operatorship of Barrow Island from West Australian Petroleum Pty Ltd (WAPET) and in 2001, Shell Development (Australia) Pty Ltd completed the sale process of its Barrow exploration and production assets to Santos Offshore Pty Ltd.

In December 2003, Chevron celebrated the 50th anniversary of Australia's first significant oil discovery. On 4 December 1953, Standard Oil Company of California (SOCAL) announced Australia's first significant oil discovery by WAPET at Rough Range near Exmouth.

WAPET was owned 80 per cent by Caltex (itself jointly owned by Texaco and SOCAL, later to become Chevron) and 20 per cent by AMPOL Petroleum. The Rough Range discovery launched a major exploration campaign by WAPET across northern Western Australia, leading to the discovery of oil at Barrow Island in 1964.

In 2000, prior to its merger with Texaco in 2001, Chevron assumed responsibility for WAPET's operations in Australia.

In 2005, ChevronTexaco changed name to Chevron Australia.

Barrow Island Oil

Production Facilities

Barrow Island currently consists of 450 oil production wells (mostly in the Windalia reservoir), 250 water injection wells and a number of gas production and water disposal wells. In the majority of producing wells, oil is pumped to the surface using beam pumps (nodding donkeys). The remaining producing wells use gas-lift or are on natural flow.

The fluids produced from each well are piped to one of eight degasser stations, each capable of handling up to 80 wells (dependent upon fluid production). A typical degasser station has a test separator and a degasser tank and 2-phase pump. Produced fluids are pumped to the Central Processing Facilities (CPF) for separation and treatment. The CPF comprises of three separators, two water settling tanks and an oil storage tank. Clean oil is gravity fed to the Terminal Storage Tanks, comprising five 200 000 bbl oil tanks. At present, only three of the tanks are in service. The oil (37.7° API gravity) is then transported via a 508mm, 10.4 km submarine-pipeline to an offshore mooring system, where tankers are berthed for loading.

In February 1999, the joint venture announced that the facilities on Barrow Island could be utilised by third parties for processing oil and gas production from nearby operations.

Reservoirs

Barrow Island contains at least 30 different reservoirs of oil and gas. Currently there are 12 oil-producing formations, with the Windalia reservoir containing 95 per cent of known reserves. All producing reservoirs are continuously assessed as part of the Barrow Island Development Plan, a multi-disciplinary study aimed at optimising well production performance and increasing the mature field's reserves. The ongoing study includes re-completions, additional infill and extension drilling, workovers, refracture stimulation, artificial lift optimisation and facility expansion.

Production from the Windalia reservoir is by way of secondary recovery conditions known as "water-flooding". Water is injected into injection wells to displace oil towards producing wells. The joint venture estimates that there are significant amounts of oil remaining in the ground and, while some will be recovered with the existing water-flood technique, it presents a major challenge to develop innovative tertiary recovery techniques. Non-water-flood reserve potential is also under review and includes the Windalia extension areas around the flanks of the field, as well as the development potential in other reservoirs under Barrow Island.

Development and Exploration Drilling

Since 1995, a total of 79 infill wells have been drilled in the Windalia reservoir on Barrow Island, including 13 wells drilled during the 2007-2008 program. Water-injection volumes are being increased from less than 50 000 bbl/d to in excess of 90 000 bbl/d in line with strategies designed to increase the field life and enhance oil recovery from the reservoir.

Barrow Island in production.

Beharra Springs Gas and Condensate

Location
350 km north of Perth

Basin
Perth, onshore

Permit/Licence	
EP320	L11

Ownership	%
Origin Energy Developments Pty Ltd* (Operator)	67
ARC (Beharra Springs) Pty Ltd**	33

* a wholly owned subsidiary of Origin Energy Limited
** a wholly owned subsidiary of ARC Energy Limited

Contact
Origin Energy Developments Pty Ltd
34 Colin Street
WEST PERTH WA 6005
Tel: +61 8 9324 6111
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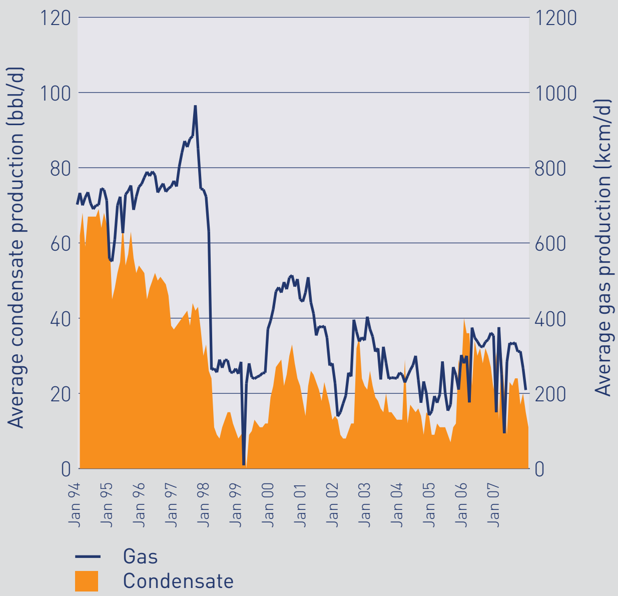
Web: www.originenergy.com.au

Production	2006	2007
Gas (kcm)	8 501	1 763
Condensate (kl)	723	94



Beharra Springs

Field History
The Beharra Springs gas field (which is the second-largest commercial gas field in the Perth Basin after the Dongara Field) and the Beharra Springs plant are located in production licence L11. Directly connected to the plant are the Beharra North and Tarantula discoveries. EP320 is a large exploration permit surrounding L11 and the eastern margin of L1/L2. It is primarily prospective for gas, with existing tight gas discoveries in the south plus numerous prospects defined by 3D seismic data.

Beharra Springs
The Beharra Springs field was discovered in April 1990 and commenced production in January 1991 using a temporary production facility. With three wells (Beharra Springs 1, 2 and 3) on the field, production peaked at 33 TJ/day in 1997 but has since declined. The discovery of Beharra Springs North in 2002 and Tarantula in 2004 on the basis of the 3D seismic surveys boosted reserves, increased production and prolonged the field life.

Beharra Springs North
A 3D seismic survey covering the L11 licence area and parts of the surrounding EP320 permit was completed in August 1999. On the basis of these data, Beharra Springs South-1 and North-1 were drilled in the second half of 2001. Beharra Springs South-1 intersected a water-wet reservoir and was plugged and abandoned. Beharra Springs North-1 intersected a gross gas-column of 28 metres. Subsequent testing of this well produced gas flow rates of up to 30 MMcf/d. Beharra Springs North-1 commenced production in August 2002.

Beharra Springs Gas and Condensate

Tarantula

The gas exploration well, Tarantula-1, commenced drilling in late May 2004. The well reached the primary target of the Wagina Formation in early June 2004. On penetration of the target, a significant increase in rate of penetration and a gas peak were observed. Preparation was then made to pull out of the hole to commence coring. During this procedure the well began to flow gas to surface and the well was not able to be secured. All personnel were evacuated and perimeters secured.

The well was brought under control in late June 2004 and operations to secure and suspend the well commenced. The Tarantula well was re-drilled in 2005 and subsequently tested at over 30 TJ/d, which is believed to be a record for an onshore Australia gas well. The well is currently producing around 9 TJ/d per day of sales gas through the Beharra Springs plant.

Beharra Springs 4

In March 2007 an appraisal well was commenced to test a separate fault compartment between the Beharra Springs 1/3 and Beharra Springs North compartments. Due to the possibility that this compartment of the field had been depleted, and hence the risk of entering an under-pressured reservoir, the well was initially drilled to a depth just short of the reservoir section. A coiled tubing unit was brought in later to complete drilling through the reservoir section to final total depth. This was the first time this drilling technique has been utilised on the Beharra Springs Field. This technique was used to avoid formation damage, with the consequence of reduced deliverability. Reservoir-quality sands were encountered which, when tested, flowed gas to surface at a stabilised flow rate of 35 MMcf/d.

Production facilities

A $9.4-million permanent gas-processing plant, with a capacity of 15 TJ/d, was commissioned in May 1992, replacing the temporary facility. Plant capacity was increased to 25 TJ/d following the completion of a $2.2-million expansion in November 1993. Compression facilities costing $8 million were commissioned in 1996. Production rates in excess of 30 TJ/d have been achieved through the more efficient use of existing equipment. Currently, the plant is processing gas from Beharra Springs North-1 and Tarantula-1, with Beharra Springs 4 expected to come into production by the beginning of 2008.

The plant has processed approximately 90PJ from the combined production of the Beharra Springs wells, Beharra Springs North-1 and Tarantula-1.

The gas-processing plant features low-temperature separation for the removal of condensate and water from the natural gas. In addition, semi-permeable membranes purify the gas for sale by removing carbon dioxide and hydrogen sulphide. Treated gas is pumped via a 168mm, 1.6km pipeline lateral into the Parmelia pipeline and is delivered to customers at that point. Condensate (62° API gravity) is stored in a 600-bbl tank and is then trucked to the BP refinery in Kwinana for processing.

Gas sales contract

Currently the field deliverability is fully contracted with supply to industrial customers in the Perth region and farther south.

Exploration drilling

This year will be an interesting year for exploration in EP320/L11 with the proposed Beharra Springs Deep-1. The Beharra Springs Deep prospect has been mapped beneath the existing Beharra Springs Field. This prospect is a gas prospect, with a High Cliff Sandstone reservoir objective. The High Cliff Sandstone has been proved to be a viable target, reservoiring a gas accumulation at Hovea-2, and an oil accumulation at Drakea-1 and -2. A gas discovery at Beharra Springs Deep-1 would hi-grade other High Cliff Sandstone prospects within the EP320/L11.

Blina–Boundary–Lloyd–Sundown–West Terrace Oil

Location
80 km east of Derby

Basin
Canning, onshore

Permit/Licence		
EP129	L6	L8

Ownership	%
ARC Energy Ltd (operator)	100

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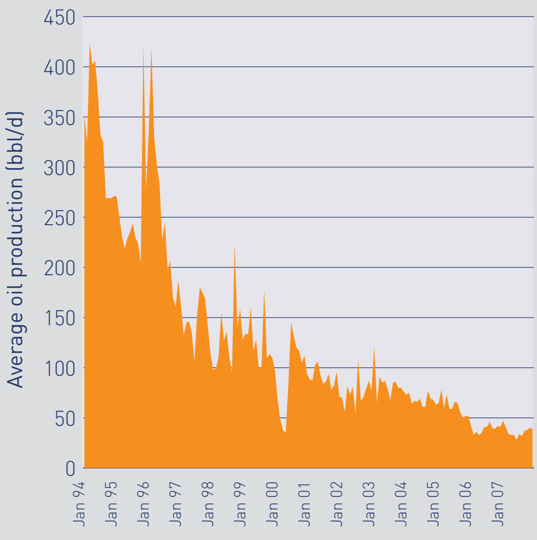
Production - Oil (bbl)		
Field	**2006**	**2007**
Blina	7 347	6 261
Boundary	767	-
Lloyd	151	-
Sundown	2 019	1 765
West Terrace	3 982	5 221



Blina, Boundary, Lloyd, Sundown and West Terrace

Ownership History
Kimberley Oil took over as operator of interests in the exploration and production licenses covering the Blina–Boundary–Lloyd–Sundown–West Terrace fields from Capital Energy in March 1999. Kimberley Oil also took over the direct management of the operations from Gearhart Australia Ltd in December 1999. In 2005, Kimberley Oil changed its name to European Gas Ltd to reflect growing interests in Western Europe.

Under its subsidiary company Terratek, European Gas Ltd exercised a joint venture farm in arrangement with Canadian company Golden Dynasty Resources Ltd in November 2005. By June 2006 Golden Dynasty had earned 80 per cent of assets through expenditure of $3 million on exploration and $500 000 on research and development activities. Terratek retained 20 per cent equity and a 2 per cent well head royalty until September 2006, when the remaining 20 per cent equity was sold to Golden Dynasty Resources Ltd. Terratek retained a 3 per cent well head royalty.

In 2006 the entire project, oilfields and associated permits, were purchased by ARC Energy Ltd. This move was to further diversify their operations in the Canning Basin. ARC now holds interests in permits and licences covering in excess of 140 000 km^2 in the Canning Basin.

Blina–Boundary–Lloyd–Sundown–West Terrace Oil

Production History

Blina

The Blina field, located 105 km southeast of Derby, was discovered in May 1981 and commenced production in September 1983. Eight wells have been drilled in the field, three of which are currently producing.

Sundown

The Sundown field, located 26 km northwest of Blina, was discovered in November 1982 and commenced production in July 1984. Sundown is currently producing from one well only, Sundown-3H.

West Terrace

Located 8 km north of Sundown, the West Terrace field commenced production in June 1985 from one well. A second well was drilled and produced oil for a short time in 1987 before being abandoned because of what was considered then to be excessive water cut. Successful workovers of both wells in June 2006 returned them to production.

Lloyd

The Lloyd field, located 30 km from Blina, was discovered in July 1987 and commenced production a month later from one well. A second well, Lloyd-3, was put on an extended test in August 1998 and significantly increased the output from the field. Lloyd-3 has now ceased production.

Boundary

Located 2.2 km south of Lloyd, the Boundary field was discovered in August 1990 and commenced production in December 1990 from one well. Boundary 1 has produced 115,000 bbl of 330 API oil from an intra-Grant sandstone bed at a depth of 1277-1281 m. Seismic data indicates that the well was drilled on the north western edge of an anticline and that the crest of the structure may lie to the south east.

In June 2006, as part of its required expenditure Golden Dynasty drilled Boundary SE-1 well to a depth of 1,710 m. The well did not encounter any commercial significance and as a consequence was plugged and abandoned. Unfortunately a similar result was achieved at Scrubby-1 within PL8 which was drilled to a depth of 1,250 m.

The ARC 2007 Reserves Review

ARC undertook a reserves review in 2007. The approach taken was to determine P90 reserves from current production and evaluate well performance on a well-by-well basis with a view to bringing wells back on line. The review also served to evaluate logs for missed horizons and zones and look to book these as reserves through planned workovers and completions. Evaluation of mapping for missed structures and areas in order to locate undrained volumes were also carried out.

Proposed 2008 Workovers

Up to nine well workovers are in various stages of planning, which includes wells in the Blina, Lloyd, West Terrace, Boundary and Sundown oil fields. This work principally includes either running new tubing or perforating new zones in order to increase production.

Cliff Head Oil

Location
20 km south of Dongara

Basin
Perth, offshore

Permit/Licence
WA-31-L

Ownership	%
Roc Oil (WA) Pty Limited (Operator)	37.5
AWE Oil (Western Australia) Pty Ltd	27.5
ARC (Offshore PB) Limited	30.0
CIECO Exploration and Production (Australia) Pty Ltd	5.0

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Roc Oil (WA) Pty Limited
Level 14, 1 Market Street
SYDNEY NSW 2000
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Fax: +61 2 9380 2066
Web: www.rocoil.com.au

Production	2006	2007
Oil (bbl)	2 009 353	3 157 454
Gas (kcm)	1 162	2 306

Exploration and Appraisal

Located 11km offshore in the Perth Basin in water depth of approximately 16m. The Cliff Head Oil Field ("Cliff Head") was discovered in December 2001 with the drilling of the Cliff Head-1 well which intersected a 5m oil-column and the Cliff Head-2 sidetrack appraisal well which intersected a 36m oil-column, both within the Irwin River Coal Measures. Production testing was not undertaken in either well and both wells were plugged and abandoned.

Further appraisal was undertaken with: a small 2D seismic survey in October 2002; the drilling of Cliff Head-3 (2.4 km northwest of Cliff Head-2) in January 2003; and the drilling of Cliff Head-4 (1 km south of Cliff Head-3) in March 2003. Appraisal confirmed that the oil–water contact encountered in Cliff Head-3 and Cliff Head-4 were the same as that for Cliff Head-1 and Cliff Head-2.

In January 2003, Cliff Head-3 was production tested over 27 metres of the reservoir for a three-day period and achieved a maximum flow rate of 3,000 bbl/d on a downhole pump through an 11 mm choke.

In November 2003, a 3D seismic survey was acquired, designed to support development planning and in particular, optimisation of development well design. In October 2004, Front End Engineering and Design, reservoir engineering work and geological modelling were completed and incorporated into a Cliff Head Pre-development Field Report and Field Development Plan.

In February 2005, Cliff Head-5 was drilled in the southeastern part of the field (about 1 km southeast of the Cliff Head-1 discovery well) as a dry hole, coming in low to prediction. In February-March 2005 the Cliff Head-6 deviated early development well was drilled on the main horst of the field (approximately 1.6 km north of the Cliff Head-1 discovery well), and was suspended as a future oil producer.

Development

Following the completion of appraisal drilling and assessment, a Final Investment Decision was made in March 2005 making Cliff Head the first oil field to be developed in the offshore Perth Basin. In July 2006, the field development, with 2P Reserves of 14 MMbbl, was completed at a total cost of $327 million.

The development design comprises: a remotely operated unmanned offshore platform with six production wells and two water injection wells; and two 14 km, 250 mm diameter pipelines connecting the offshore platform to the onshore crude stabilisation plant with a production capacity of 15,000 bbl/d.

Specifically, oil is produced from four horizontal and two deviated production wells using electric submersible pumps. The oil is then transported from the platform through one of the pipelines to the onshore plant where produced water is separated and the crude oil is stabilised and stored. Produced water, together with some additional make-up water is pumped from the onshore plant through the return second pipeline to the platform and re-injected into the reservoir through the two water injection wells.

Construction and commissioning of the facilities, including development drilling, was completed by July 2006.

Production commenced on 1 May 2006, less than 14 months after project sanction, at an initial controlled clean-up rate of approximately 1,000 bbl/d from one of the deviated wells. In August 2006, the field produced at a better than expected rate, with only four of the six production wells on stream averaging 12,500 bbl/d. The crude oil produced for the life of the field has been sold, and is transported by road tanker, to the BP Kwinana Refinery.

In September 2007, the field achieved a significant milestone when cumulative oil production exceeded four million barrels.

Dongara–Mondarra–Yardarino–Xyris–Apium–Elegans
Gas, Oil and Condensate

Field Histories
The Yardarino field was the first field discovered in the north Perth Basin in May 1964 and was followed by discoveries at Dongara in June 1966 and Mondarra in 1968. The first gas deliveries from the Dongara field commenced in October 1971 via the Parmelia Pipeline. The Mondarra field commenced deliveries in April 1972 and ceased production in July 1994. The Yardarino field came on-stream in October 1978 and ceased production in April 1989. Subsequently gas discoveries have been made at Xyris and Xyris South and Corybas (Elegans Pool).

The Dongara Field
Located 360 km north of Perth, the Dongara field is wholly owned by ARC and was discovered in 1966 by WAPET. It is a world-class field, with original reserves in excess of 480 PJ of recoverable gas and some 100 MMbbl of oil-in-place. Production from the Dongara Field for the 12 months ended 31 December 2007 was approximately 4 TJ/d.

Dongara Sandstone Pool
The Dongara Sandstone is the principal producing reservoir in the field, yielding the majority of reserves to date. Production has been optimised by installing wellhead compression workovers of existing wells to ensure the full recovery of remaining reserves.

Arranoo Pool
The Arranoo reservoir is a unit of thinly bedded sandstones and siltstones with an overall thickness of 80 m in the upper part of the Kockatea Shale. It has been recognised as an oil and gas reservoir since the early development of the Dongara field and Dongara wells-31, -32 and -33 were brought on production through the Dongara Processing Facility in 2005. The Dongara 36 well was brought on production via the Dongara Processing Facility in early 2007.

Permeabilities in the reservoir are generally low although further testing and exploration will continue in the CY2008 drilling program.

Location
360 km north of Perth

Basin
Perth, onshore

Permit/Licence			
L/1	L/2	PL/1	PL/2

Ownership	%
Dongara–Yardarino–Elegans ARC Energy Limited (Operator)	100
Xyris–Apium ARC Energy Limited (Operator)	50
Origin Energy Developments Pty Limited	50

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Web: www.arcenergy.com.au

Ownership/Contact	%
Pipeline Licences, Gas-processing Facilities, Mondarra Storage Facility Australian Pipeline Trust (Operator)	100

Contact
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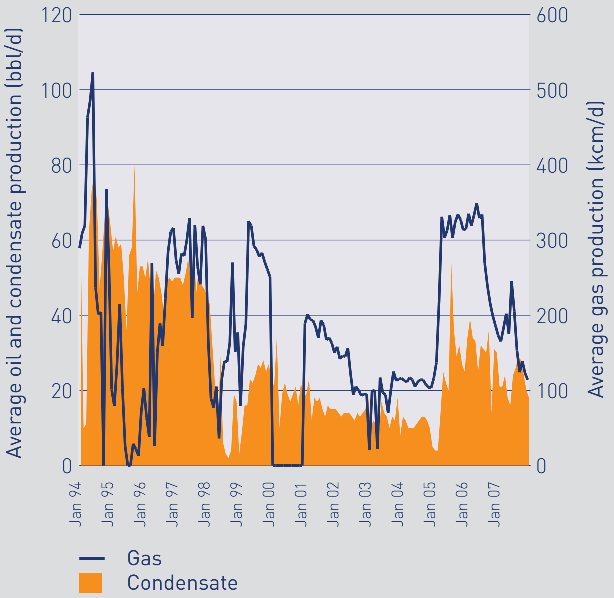
8 Marchesi Street
KEWDALE WA 6105
Tel: +61 8 9353 7500
Fax: +61 8 9353 2452
Email: acmswa@cmsenergy.com.au
Web: www.cmsenergy.com.au

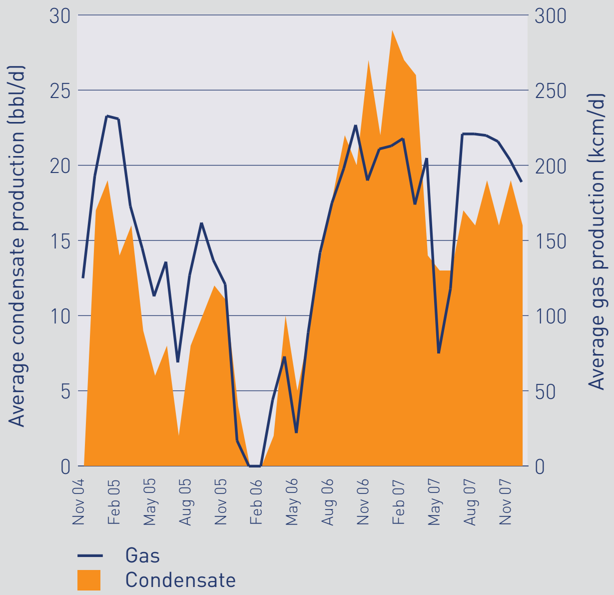
Production – Dongara	2006	2007
Oil (bbl)	9 448	6 413
Gas (kcm)	103 997	60 817
Condensate (bbl)	2 139	1 781

Dongara–Mondarra–Yardarino–Xyris–Apium–Elegans

Gas, Oil and Condensate



Dongara-Mondarra-Yardarino



Xyris

Dongara Oil Leg

The original in-place reserves of the Dongara field were estimated to be in excess of 60 MMbbl of oil and some 500 Bcf of gas.

However the existence of the oil leg was not discovered until after a commitment to produce the gas had been made and the production technique used to produce the field "smeared" the oil through the reservoir, making large amounts of it unrecoverable.

It is not currently economically or technically viable to extract this oil although the possibility of oil recovery from the leg continues to be reviewed, particularly given ARC's successful production at Hovea and Eremia.

Production and transportation facilities

To date 37 wells have been drilled on or near the Dongara field, of which seven are currently in production. Gas from these wells is transported by flow-lines to processing facilities and, after treatment to remove liquids, is compressed and transported down the Parmelia Pipeline.

In September 2005 ARC bought the Dongara Processing Facility (DPF) from APT Parmelia Pty Ltd (APT) and began operating the facility in mid 2007. APT still owns the Parmelia Pipeline. The DPF is a key upstream infrastructure asset in the northern Perth Basin and currently processes approximately 4 TJ/d of gas from the 100 per cent ARC-owned Dongara gas field.

The DPF was constructed in the early 1970s with the commissioning of production from the Dongara Field, and has previously produced at rates of up to 100 TJ/d. It is the largest gas processing facility in the Perth Basin and provides gas separation, dehydration, and compression via four,1000 hp, gas-turbine driven compressor units. It also has a central control facility and workshops, condensate storage and load-out facilities and a water treatment and disposal system. The plant is situated on approximately eight hectares of freehold land which was also included in the purchase.

The DPF is in excellent condition and an ideal central base for ARC's operations in the area. Together with the infrastructure assets already operated by ARC at Hovea–Eremia, Woodada, Xyris and Mount Horner and the non-operated interests in the Jingemia and Beharra Springs facilities, the Company now has interest in, or owns, all of the processing facilities in the Basin.

Dongara–Mondarra–Yardarino–Xyris–Apium–Elegans

Gas, Oil and Condensate

The DPF can assist in creating significant value for new gas developments encountered in the Dongara field area. Additionally, the DPF may be considered as playing an important role in the potential development of the Frankland gas discovery in the offshore Northern Perth Basin.

Parmelia Pipeline

APT is responsible for transportation of the processed gas to sales outlets via the 350-mm, 420-km high-pressure Parmelia Pipeline, which extends from Dongara to Pinjarra. The pipeline has a design gas capacity of around 124 TJ/d and currently transports around 25 TJ/d.

Gas Sales Contracts

The Dongara field principally supplies gas to industrial customers in Perth. Continued strong demand by gas consumers is pushing prices up on contract renewals as they roll-forward.

Yardarino Gas Field

The Yardarino gas field is a separate gas and oil accumulation lying to the northeast of Dongara. It has produced some 5 Bcf of gas and is currently shut-in pending an ongoing review of its structure and recoverability.

Elegans Gas Field

The Elegans gas field was discovered by the deepening of the existing Yardarino-1 well in 1999. The field contains over 400 Bcf of gas in relatively tight sandstones of the Caryinginia and Irwin River Coal Measures (IRCM) formations and demonstrates the highly petroliferous nature of the general area.

The commercialisation of the Elegans gas resource continues to be evaluated following the drilling of the Corybas-1 well, which was very encouraging with gas flows from the IRCM and also the subsequent Yardarino-6 and Hakia-2 wells.

Xyris–Xyris South and Apium Gas Fields and XAGGS Project (ARC per cent)

In March 2004, the Xyris-1 well was drilled and intersected a significant gas column, which subsequently flowed at rates of up to 15.5 MMcf/d. The following well, Apium-1, also intersected a gas column and tested at a rate of 1.9 MMcf/d. The Xyris plant was commissioned in November 2004 and other gas reserves in the area Xyris-South, Apium, Hovea-2 and Hovea were also developed into production, assisted by the completion in 2005 of XAGGS (Xyris Area Gas Gathering System) project link to the Parmelia Pipeline.

Production – Dongara	2006	2007
Oil (bbl)	9 448	6 413
Gas (kcm)	103 997	60 817
Condensate (bbl)	2 139	1 781

Production – Xyris	2006	2007
Gas (kcm)	41 925	69 069
Condensate (bbl)	4 497.35	6 800

Exploration drilling

ARC Energy undertook a vigorous exploration program over CY2007, operating an exploration well, two appraisal wells and a development well. In addition it participated in a further three exploration wells, an appraisal well, and two development wells in its non-operated acreage. Four-out-of-four exploration wells encountered hydrocarbon accumulations, including the Frankland-1 offshore gas discovery and the Beharra Springs-4 onshore gas discovery.

Table 1: List of ARC Energy Ltd operated wells for CY2007

Well	Permit	Classification	Status
Dongara-37	L2	Development	Gas producer
Eremia-7	L1	Appraisal	Oil producer
Drakea-1/2	L1	Exploration	Oil discovery
Apium-2	L1	Appraisal	Gas producer

Table 2: List of ARC Energy Ltd non-operated wells for CY2007

Well	Permit	Classification	Status
Jingemia-11	L14	Development	Oil producer
Beharra Springs-4	L11	Exploration	Gas discovery
Frankland-1	WA-286-P	Exploration	Gas discovery
Dunsborough-1	WA-286-P	Exploration	Oil discovery
Perseverance-1	WA-325-P	Exploration	Gas discovery

East Spar Gas and Condensate

Location
40 km west-northwest of Barrow Island

Basin
Carnarvon, offshore

Permit/Licence							
WA-214-P	WA-13-L	WA-5-PL	TPL/12	TPL/13	PL/29	PL/30	PL/42

Ownership	%
Apache Oil Australia Pty Ltd (Operator)	55
Santos (BOL) Pty Ltd	45

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PERTH WA 6000
Tel: +61 8 9422 7222
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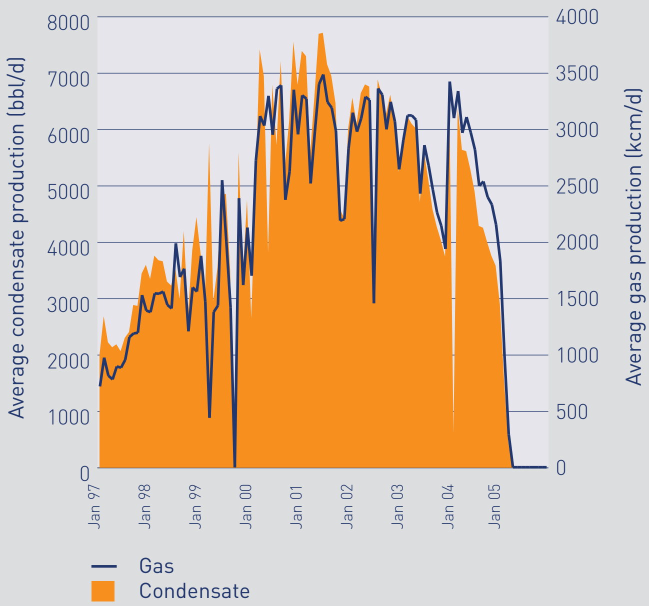

East Spar

The East Spar field was discovered in April 1993 and commenced production in November 1996. Total capital cost of the development was $250 million.

Production facilities
East Spar comprises Australia's first fully-automated all-subsea production and gathering system operated via an unmanned navigation control and communication (NCC) buoy. Controlling an entire subsea facility via an unmanned NCC buoy was a world first. Electro-hydraulic umbilicals connect the buoy to all control and monitoring devices on the subsea components. A telemetry communication system, with radio and satellite links, allows the remote control of the offshore facilities from a computerised master control system on Varanus Island. The buoy also includes chemical storage for corrosion and hydrate inhibitors, which are injected via umbilicals into the wellheads.

Production from the wells, which after cooling in heat exchangers, was conveyed to a manifold via 1.8-km, 150-mm flexible flowlines. The combined wet gas-production fluid was transported from the manifold via a 356-mm, 63-km carbon-steel pipeline to processing facilities on Varanus Island.

Water broke through in ES-01 during 2003 and the well ceased to produce. Several infill wells were drilled through 2003-04 with ES-06 being brought online as a subsea producer in late 2003. During 2005 production ceased with the watering out of the remaining producers ES-03 and ES-06.

Varanus Island processing facilities
In November 1996, two 120 TJ/d gas-processing trains were commissioned on Varanus Island adjacent to the two existing 60 TJ/d trains and the recently commissioned single 120 TJ/d train used by the Harriet Joint Venture.

In October 2005, two CO_2 (amine) removal plants were commissioned on Varanus Island designed to reduce the CO_2 content of the John Brookes gas from 5.8 mol% to below the pipeline specification of 3.6 mol%. The gas is then processed via the two existing 120 TJ/d East Spar gas-processing trains.

The processing trains remove condensate, water and other minor impurities from the gas, conditioning it to pipeline specifications. Sales gas is then transported to the mainland through either of two 100-km sales-gas pipelines (324 or 406 mm) connecting with the Dampier to Bunbury natural gas pipeline (DBNGP) and Goldfields gas transmission (GGT) pipeline at Compressor Station No.1. The 406-mm gas-pipeline, with a capacity in excess of 300 TJ/d, was commissioned by the East Spar (70 per cent) and Harriet (30 per cent) joint ventures in July 1999. Condensate (58° API gravity) is stored in existing tanks on Varanus Island and exported via tanker.

The East Spar and Harriet joint ventures entered into an infrastructure-sharing agreement in January 1997 whereby the Harriet gas transportation and liquids storage facilities on Varanus Island could be utilised by the East Spar joint venture. In addition, the two joint ventures agreed to share the cost of all operating resources and contract services such as supply boats and helicopters. This was the first infrastructure-sharing agreement made in the North West Shelf gas province.

Enfield Oil

Location
The Enfield FPSO is located about 37 km offshore, northwest of Australia's North West Cape

Basin
Carnarvon, offshore

Permit/Licence
Production Licence WA-28-L

Ownership	%
Woodside Energy Ltd. (Operator)	60
Mitsui E&P	40

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240 St George's Terrace
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Fax: +61 8 9214 2777
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Production	2006	2007
Oil (bbl)	7 359 841	17 095 660
Gas (kcm)	71 425	199 855

The Enfield oil project is situated within Production Licence Area, WA-28-L approximately 42 km offshore, north-west of Australia's North West Cape. Water depth across the licence area varies from 400 m in the east to over 550 m in the west.

Woodside was awarded exploration permit in 1997. The Enfield oil field is one of several oil fields discovered in the area. Vincent was discovered in December 1998, followed by Enfield in April 1999, and Laverda, in October 2000.

Enfield reserves are extracted using subsea wells with flowlines back to a double-hull type FPSO, the Nganhurra, with a disconnectable mooring, located about 2 km to the east of Enfield field in approximately 396 m water depth.

Water-injection wells are used for the disposal of produced water, supplemented by injection of seawater to provide reservoir pressure support. Excess gas is re-injected into the Enfield reservoir.

The Enfield FPSO is based on a Suezmax tanker design, of double-hulled construction, with a storage capacity of approximately 900 000 bbl. It is equipped with a disconnectable mooring and its own propulsion system to allow evasion of cyclones.

The Enfield reservoir contains medium crude, with an API gravity of approximately 22° (SG 0.92). The well-stream fluid is stabilised on the FPSO to produce export quality crude oil, which is stored in the FPSO's tanks and periodically exported through an offloading hose to tandem-moored offtake tankers.

The Final Investment Decision was made in March 2004 and first oil achieved in July 2006. Production is expected to extend over a period of about 12 years, however, the facility is designed for 20 years' operation. The FPSO has been designed to remain on-station for the entire design life without recourse to dry docking for maintenance or survey.

Griffin, Chinook–Scindian Oil and Gas

Location
68 km northwest of Onslow

Basin
Carnarvon, offshore

Permit/Licence				
WA-210-P	WA-10-L	WA-3-PL	TPL/10	PL/20

Ownership	%
BHP Billiton Petroleum Pty Ltd (Operator)	45
Mobil Exploration & Producing Australia Pty Ltd	35
Inpex Alpha Ltd	20

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Level 42, Central Park
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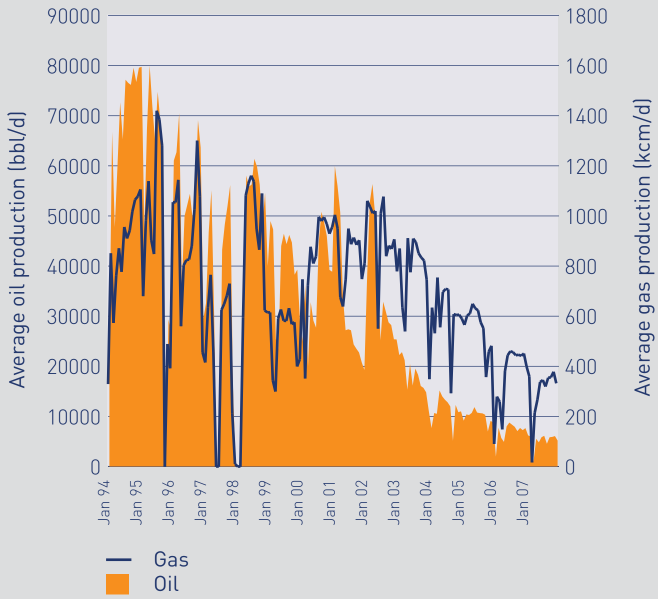
Production	Oil (bbl)		Gas (kcm)	
	2006	2007	2006	2007
Griffin	1 654 037	1 296 086	24 916	15 904
Chinook-Scindian	868 014	611 877	106 087	95 706



Griffin, Chinook-Scindian

The Griffin oil and associated gas development comprises the Griffin and Chinook–Scindian fields which were discovered in 1989–90. First oil production from Griffin commenced in January 1994, with production from Chinook–Scindian starting in March 1994.

Initial recoverable oil reserves were estimated at 115–130 MMbbl, however by 2007 production had exceeded 164 MMbbl (December 31, 2007).

Cargoes of the light Griffin crude are sold to markets in Australia, Singapore and Japan.

Production Facilities
The Griffin development utilises the 100 000 dwt double-hulled Griffin Venture Floating Production Storage and Offtake (FPSO) facility, which comprises a disconnectable mooring riser and production system. All production is from subsea-well completions linked back to the centrally located FPSO via flexible flowlines.

The vessel and its mooring riser system are configured to accommodate a total of 11 production wells. The FPSO stores up to 820 000 bbl of oil, which is pumped to stern-moored, offtake tankers through a floating hose system at a rate of 25 000 bbl/hr.

Harriet area fields Gas, Oil and Condensate

Varanus Island provides the base for the Harriet gas-gathering and oil export projects, which currently involve production from the Agincourt, Albert, Artreus, Bambra, Double Island, Endymion, Gipsy, Gudrun, Harriet, Linda, Little Sandy, Mohave, Monet, North Alkimos, Pedirka, Rose, Simpson, South Plato, Tanami, Victoria and Wonnich fields. The island infrastructure includes the following Harriet Joint Venture processing facilities:

- oil-processing plant comprising of 100 000 bcf/d 3-phase (gas/oil/water) separation facilities and two x 20 MMcf/d gas-lift compressors
- three 250 000-bbl oil tanks and tanker export facilities
- three-gas trains with a total 240 TJ/d processing,
- condensate stabilisation facilities
- water treatment and injection facilities
- two sales-gas pipelines and
- 7 MW power station.

The Varanus Island Hub is currently handling 2.94 ML (18 500bbl) of oil and 8.7 Mm^3 per day which is approximately 40 per cent of the gas produced and sold into the Western Australian domestic markets.

In January 1997, the Harriet joint venture entered into an infrastructure sharing agreement with the East Spar joint venture. Under the agreement, the Harriet joint venture will provide gas transportation and liquids storage services for the East Spar gas field utilising existing Harriet facilities on Varanus Island. In addition, the two joint ventures agreed to share the cost of all operating resources and contract services such as supply boats and helicopters.

In late 2006, the Harriet joint venture, which in 2001 contracted to supply gas to Burrup Fertilisers for 20 years, announced to the Australian Securities Exchange (ASX) the venturers had each declared *force majeure* (an unexpected and disruptive event that excuses a party from a contract) on that part of the sales agreement covering reserves to back the deal. The Harriet partners are currently supplying the 80 TJ contract quantity of gas and anticipate being able to do so for years to come, but the agreement requires the Harriet Joint Venture to have gas reserves for 20 years.

Location
120-km west of Dampier

Basin
Carnarvon, offshore

Permit/Licence						
TL/1	TL/5	TL/6	TL/8	TL/9	TP/8	TPL/1
TPL/2	TPL/5	TPL/8	TPL/13	PL/12	PL/17	PL/42

Ownership	%
Apache Northwest Pty Ltd (Operator)	68.5000
Kufpec Australia Pty Ltd	19.2771
Tap (Harriet) Pty Ltd	12.2229

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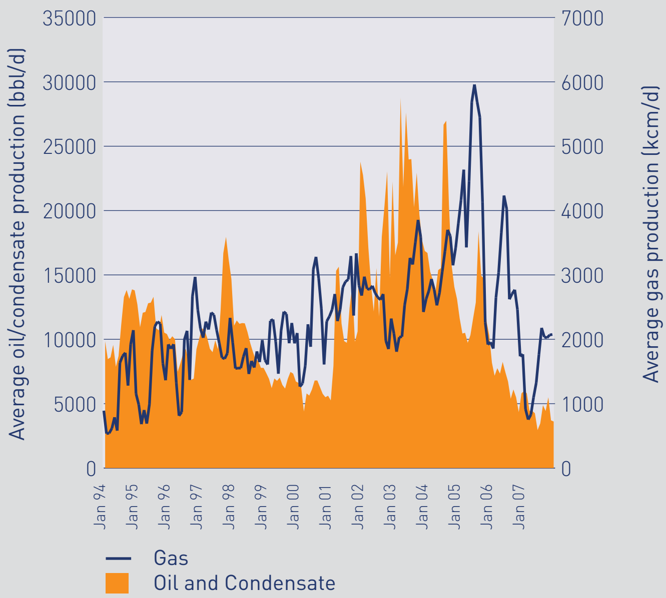


Harriet area fields

Harriet area fields Gas, Oil and Condensate

Harriet Area Production	Oil 2007 (bbl)	Gas 2007 (kcm)	Condensate 2007 (bbl)
Agincourt	-	-	-
Albert	74 927	768	40
Alkimos	-	-	-
Artreus	5	34	3
Bambra	436 389	49 160	188 255
Campbell	-	-	-
Double Island	108 055	4 198	174
Endymion	-	-	-
Gibson	-	-	-
Gipsy	6 499	2 633	405
Gudrun	48 736	1 044	60
Harriet	136 879	11 425	1 479
Linda	-	5 629	8 342
Little Sandy	33 605	1 851	52
Mohave	13 598	1 309	62
Monet	-	-	-
North Alkimos	-	105	-
North Gipsy	-	-	-
North Pedirka	-	-	-
Pedirka	108 930	4 679	184
Rose	-	149 883	197 544
Rosette	-	-	-
Simpson	2 361	7 828	433
Sinbad	-	-	-
South Plato	93 844	5 918	543
Tanami	1 035	2	-
Victoria	15 547	762	50
Wonnich	-	327 508	187 195
Total	1 080 410	574 736	584 821

Harriet area fields Gas, Oil and Condensate

Production operations

The oil project commenced in January 1986 and currently involves the transport of oil and condensate from the Agincourt, Albert, Artreus, Double Island, Gipsy, Gudrun, Harriet, Little Sandy, Mohave, Monet, North Alkimos, Pedirka, Simpson, South Plato, Tanami and Victoria, as well as condensate from the gas fields, to Varanus Island where it is processed and stored. A 762-mm, 3.5-km subsea pipeline then transfers the commingled crude to offshore tankers berthed at an eight-point spread mooring system. The crude (38–48° API gravity) is sold to refineries in Australia and overseas.

The $150 million Harriet gas-gathering project was commissioned in July 1992 and was Western Australia's first offshore gas project to tap associated gas, which is produced during the oil recovery process. The project currently involves the transport of gas from the Bambra, Endymion, Linda, Rose, Sinbad and Wonnich fields, as well as associated gas from the oil fields, to Varanus Island.

The separation gas plant removes water and natural gas liquids from the gathered gas, conditioning it to pipeline specifications. Separated liquids are then commingled with the crude oil. Sales gas is transported through either of two 100-km pipelines (324 or 406-mm) connecting with the DBNGP and Goldfields Gas Transmission pipeline at Compressor Station No. 1. The 406-mm gas pipeline, with a capacity in excess of 300 TJ/d, was commissioned by the Harriet (30 per cent) and East Spar (70 per cent) joint ventures in July 1999.

Agincourt

Agincourt was discovered in June 1996 and commenced production in August 1997 at a total cost of around $33 million. The joint venture estimates that the field contains around 3.7 MMbbl of recoverable oil reserves and is expected to have an operating life of around 10–15 years.

Current production is from one horizontal well linked to an unmanned offshore monopod. The platform has been designed to support up to three wells. A 150-mm, 6.5-km pipeline transports oil, condensate and gas to facilities on Varanus Island. Gas is compressed for access to the separation gas plant. It is also used for Agincourt lift gas, which is transported back to the monopod via a 100-mm, 6.5-km gas-lift pipeline. No flaring of the associated gas occurs unless required for an emergency.

In April 2006 Apache drilled the Zephyrus-1 exploration well in TL/1 from the Argincourt platform. The well started production at over 635 kl/d.

Albert

Albert was discovered in March 2005 and commenced production in the same month, as the deviated exploration/development well was drilled from the Victoria platform. The joint venture estimates that the field contains around 0.2 MMbbl of recoverable oil reserves.

Alkimos

The Alkimos-1 deviated well was drilled from Varanus Island in August 1994 and was completed as an oil producer a month later. In November 1995, Alkimos was re-completed as a gas producer and produced almost 120 000 kcm until being shut down in March 1997. The well is now used as a water disposal well.

Artreus

Artreus was discovered in September 2005 and commenced production in the same month, as the deviated exploration/development well was drilled from the Agincourt platform. The joint venture estimates that the field contains around 0.2 MMbbl of recoverable oil reserves.

Bambra

Discovered in 1983, the development of the Bambra oil/gas field was deferred early in the planning phase of the gas-gathering scheme because sufficient gas reserves were available from the Campbell, Sinbad, Rosette and Linda gas fields.

In December 1997, the Bambra-4 well successfully appraised the southern extension of the existing gas field. The well encountered a hydrocarbon column interpreted to comprise 9-m of gross gas and 5-m of net oil, overlaying a residual oil leg of approximately 2-m.

In July and August 2004, Bambra-5H development well was drilled as a dual horizontal well from a surface location some 2.3km from the Harriet Bravo platform. A second well, Bambra-6H was drilled in August–September 2004 as an interceptor well from the Harriet Bravo platform and although it was successful in locating the Bambra-5H wellbore, it was unable to successfully penetrate the wellbore and thus make a hydraulic connection.

In September and October 2005, Bambra-7H/L1 was drilled as an extended reach development well from the Harriet Bravo platform. The well intersected the Flag Sand in the northern area of the field adjacent to the suspended Bambra-5H well.

Bambra-7H/L1 commenced production in October 2005 and is currently undergoing gas cap blow-down at rates of between 22 and 30 MMscf/d. Future development will depend on the performance of Bambra-7H. The mean ultimate recovery from the Bambra field is estimated to be 8.1 MMbbl of oil, 13 Bcf of gas and 0.2 MMbbl of condensate.

In December 2006 Bambra-3 a sidetrack appraisal well was drilled. This was carried out to log the Bambra field reservoir and to better understand oil and gas movement as a result of production from the Bambra field. In 2007 Apache continued to drill a series of appraisal wells , Bambra East-1 and Bambra East-2 resulting in positive data, with hydrocarbon contact consistent with the original wells. In August 2007 the Bambra East-3 long-reach development well was drilled from the previously abandoned Bambra-6 well on the Harriet Bravo platform. The well was designed to exploit the gas column in the Bambra East Field and began production in late 2007.

Campbell

Located 25 km north-northeast of the Harriet-A platform, the Campbell gas field was discovered in 1979 and commenced production in October 1992. The field is linked to an offshore fixed monopod, situated in 40-m of water. The field ceased production in August 2004 after cumulative gas recovery of 86 Bcf of gas.

Harriet area fields Gas, Oil and Condensate

Doric

The Doric field was discovered in November 1992 by Ulidia-1, which encountered a 6.7-m gross gas-column in the Flag Sandstone Formation. Doric-1, drilled in 1996, confirmed the field to the southwest of Ulidia-1 with a common gas–water contact (GWC). The field has been remapped following the drilling of Dawn-1, which was drilled in December 2002 into a deeper Biggada target.

The field will be drained by one or two crestal wells drilled from the Linda gas platform. The Doric-2 natural gas well is located in Apache's Doric gasfield in Permit TL/1 and is on production at a rate of 1.84 MMm^3 per day. Both Doric-2 and Lee-3 (see below) gas wells were completed in Early January and flow through Apache's Varanus Island Hub. The gas will replace volumes from other Apache gas wells flowing into exisiting marketing contracts.

Double Island

The Double Island field was discovered in January 2002 by Double Island-1, which encountered a 16.9-m gross oil-column in sandstones informally referred to as the Double Island Sandstone Member of the Flag Sandstone Formation.

Reservoir properties within the Double Island Sandstone Member are excellent and similar to those of other Flag Sandstone discoveries to the north. The Double Island field is located about 8.8-km southwest of the South Plato and Gibson oil development and contains under-saturated oil similar to that found in the Gibson, Simpson and South Plato fields. The field came on production in February 2003 and is being drained by one horizontal well, Double Island-1H.

Endymion

The Endymion field was discovered in October 2002 by Endymion-1, which encountered a 20.6-m gross gas-column in the Flag Sandstone Formation with an average porosity of 20.7 per cent, a net-to-gross of 90.4 per cent and water saturation of 11.6 per cent. The Endymion gas field lies about 2 km to the south of the Sinbad platform. Production commenced in mid-November 2002 with an initial well deliverability of 35 MMcf/d.

Gibson

The Gibson field was discovered in March 2001 by Gibson-1, which encountered a 12.6-m gross oil-column. The field is located about 2 km south of the Tanami-4 well and contains under-saturated oil similar to that found in the Simpson field.

The field commenced production from Gibson-1 in June 2002 at a monthly average oil rate of 2500 bbl/d and water-cut of 40 per cent. An additional development well (Gibson-2H) was drilled in February 2003. The field ceased production in April 2003.

Gipsy–North Gipsy

The Gipsy oil and North Gipsy oil–gas fields are part of the Rose–Lee–Gipsy–North Gipsy group of fields. They have hydrocarbon reservoirs in up to four separate units — the North Rankin Formation, the Brigadier Formation and the Mungaroo A and B units. The reservoirs are highly faulted and the gas–water and oil–water contacts vary significantly between the fields. The fields were developed using subsea horizontal wells and they came on production in February 2001. North Gipsy field was abandoned in August 2003.

Gipsy-4 was drilled and completed as a deviated producer from the Mungaroo in November 2003, however, the well failed to flow. As a result the well was recompleted to the North Rankin Formation in December 2005 and commenced production in the same month. Initial rates were measured to be 250-300 bbl/d with latest test data showing the well was flowing 230 bbl/d on gas lift.

Gudrun

Gudrun-1, drilled in October 2001, discovered a 5.5-m gross (and net) oil-column in the Flag Sandstone. The field was developed by a single deviated well, Gudrun-2, drilled from the Harriet–Alpha platform and placed on production at an initial oil rate of approximately 1500 bbl/d.

Harriet

Harriet was discovered in November 1983 and became the first offshore oil development in Western Australia when production commenced in January 1986. The wells are linked to a fixed platform (Harriet A) and two offshore fixed monopods (Harriet B and C). Crude oil flows from the Harriet A platform through a 219-mm, 6.5-km subsea pipeline to Varanus Island while associated gas is transported via a 168-mm, 6.5-km subsea gas pipeline.

In July 1999, the North Harriet-1 well intersected an 8.7-m net hydrocarbon-column including 6-m of oil. The well confirmed the existence of oil in the northern area of the Harriet field. This oil is now being developed by the Harriet B-5H well which commenced production in September 1999.

Currently oil is being produced from the main central area by wells A-3, A-8H, A-9H, A-11H (drilled in May 2005) C-1, C-2 and C-4 and from the northern area by B-5H.

Hoover

The Hoover field was discovered in April 2002 by Hoover-1, which encountered a 6.0-m gross oil-column within the Flag Sandstone. The Hoover field is located about 2.8 km east of the Victoria oil development and contains under-saturated oil similar to that found in the Gibson, Simpson and South Plato fields.

The field was developed by a single development well, Hoover-2H, drilled from the Victoria platform in August 2003 and placed on production in September 2003. The field ceased production in June 2005 after cumulative production of 0.3 MMbbls.

Harriet area fields Gas, Oil and Condensate

Lee

Lee-1 was drilled in January 1999 to test a separate fault compartment to the north of the Rose structure. The well intersected a 112m gross hydrocarbon-column within the same three intervals intersected by the Rose wells and a deeper fourth interval containing oil. In May 1999, Lee-2 intersected hydrocarbons at the same four intervals as Lee-1, thereby proving the northern extent of the field.

The Lee field was developed by drilling an extended reach Lee-3 development well from the Linda platform. The Lee-3 deviated natural gas well located in Apache's Doric gasfield in Permit TL/1 is in production at a rate of 1.4 MMm^3 per day. The well was designed to produce gas and condensate from a field discovered by the Lee-1 exploration well. This gas well was completed in early January 2007 and started production following platform hook-up in early–mid 2007.

Linda

Linda was discovered in 2000 when the Linda-1 well encountered gas-saturated Biggada sand between 2629 m and 2720 m. On drillstem test Linda-1 flowed gas at rates up to 895 km3/d (31.6 MMcf/d) accompanied by 1457 bbl/d of condensate. An appraisal well, Linda-2 was drilled in April 2001 and confirmed a gas-column and established a gas–water contact at 2721 m.

The field was developed with a platform installation and tieback to Varanus Island through the existing Campbell–Sinbad pipeline. First gas flowed in April 2004.

Little Sandy

The Little Sandy field was discovered in March 2002 by Little Sandy-1, which encountered a 20.3m gross oil-column within the Flag Sandstone. The Little Sandy field is located about 5 km south of the South Plato and Gibson oil development and contains under-saturated oil, similar to that found in the Gibson, Simpson and South Plato fields. The lone development well, Little Sandy-1, commenced production in November 2002.

Mohave

The Mohave Oil Field was discovered in July 2005 with the drilling of Mohave-1 from the Victoria Platform. The well intersected a 13.3m gross (12.8m net) oil-column at the top Flag level. An oil-water contact was intersected in the well at 1771.5- TVD AHD.

Mohave-1 was sidetracked as a horizontal producer, Mohave-1H, and placed on production in July 2005 at an initial oil rate in excess of 10 000 bbl/d with no water-cut. The Mohave field covers an area of about 0.2 km^2.

Monet

The Monet Oil Field was discovered in April 2004 with the drilling of Monet-1 in Permit area TL/1 some 3.6 km northeast of the Simpson-B platform in 17 m water depth. The well intersected a 20m gross (18.2-m net) oil-column at the top Flag level. An oil–water contact was intersected in the well at 1851.7 m TVD.

The field was developed in June 2004 with the drilling of Monet-2H well from the Simpson-B platform and placed on production at an initial oil rate in excess of 10 000 bbl/d with no water-cut. Monet-2H has been shut-in since September 2005 having produced 0.9 MMbbls. The Monet field covers an area of about 0.2 km^2.

North Pedirka

The North Pedirka field was discovered in August 2003 by North Pedirka-1, which encountered a 7.4m gross oil-column within the Flag Sandstone.

The North Pedirka field is located about 4.6 km south of the South Plato – Gibson oil development and contains undersaturated oil, similar to that found in the Gibson, Simpson and South Plato fields. The field commenced production in September 2003 and ceased production in June 2005 having produced 0.1 MMbbls.

Pedirka

The Pedirka field was discovered in February 2002 by Pedirka-2, which encountered a 7.1m gross oil-column within the Valanginian Flag Sandstone. The Pedirka field is located about 4.6 km south of the South Plato and Gibson oil development and contains under-saturated oil, similar to that found in the Gibson, Simpson and South Plato fields. The field commenced production at the end of November 2002.

Rose

In July 1998, the Rose-1 well was drilled to a total depth of 2643 m and identified a gross hydrocarbon-column of up to 245 m. The well flow tested at a combined rate of 2520 kcm/d (89 MMcf/d) of gas and 3100 bbl/d of condensate over three separate intervals. The Rose-2 well was drilled in November 1998 but did not encounter hydrocarbons. Rose-3 was subsequently drilled and intersected the same three intervals as Rose-1.

The field was developed by drilling an extended reach well from the Linda platform in June 2005. The Rose-4 well was completed in the Brigadier and Mungaroo Formations with an initial well deliverability of over 100 MMcf/d which rapidly decreased to about 50 MMcf/d by mid-July 2005. At this point, perforations were added in the North Rankin Formation which increased deliverability to 65 MMcf/d. Further perforations were added in the North Rankin in August and September 2005 which lifted deliverability to 76 MMcf/d.

Rosette

The original Rosette well was directionally drilled to the west from Varanus Island in 1987. The field commenced a production test as an oil field in April 1988 but ceased production in September 1988 after producing 6900 bbl of oil. Rosette recommenced production as a gas field in July 1992. A workover was successfully conducted on the Rosette well during 1999 that substantially increased production from the field. The Rosette field watered out in November 2002. Rosette-1 has been converted into a water disposal well.

Harriet area fields Gas, Oil and Condensate

Simpson

The Simpson oil field was discovered in June 2000 by the Tanami-4 well, which was intended to be an exploration/ appraisal well of the nearby Tanami field. Tanami-4 encountered a 17.5m gross oil-column and is quite clearly located in a separate accumulation from the main Tanami field.

The Simpson-1 appraisal well was drilled in February 2001 and encountered a 33.5 m gross oil-column. Simpson-1 and Tanami-4 are located in the same oil accumulation, which has been named the Simpson field. Both wells have been completed as production wells. Simpson-2 appraisal well was drilled in March 2001 and encountered an oil–water contact similar to Simpson-1 well. The well increased the proven bulk rock value considerably from that established by Tanami-4 and Simpson-1 wells.

The Simpson field was developed in November 2001 utilising Tanami-4 and Simpson-1 plus one 500m-long horizontal well, Simpson-3H, located southwest of Simpson-1 with the toe of the well located near the Simpson-2 pilot hole location. Simpson-3H watered out in July 2002 and was followed by the drilling and completion of Simpson-4H and South Simpson-1 wells. Simpson-7 and West Simpson-1 wells were drilled and completed in April 2003.

Additional appraisal wells, Simpson-6, Simpson-8 and South Simpson-2 were drilled in November and December 2003. The successful Simpson-6 and South Simpson-2 wells were put on production.

Sinbad

The Sinbad gas field, located 16 km northeast of Harriet-A, was discovered in 1990 and commenced production in November 1992. Currently, the field only operates intermittently from Sinbad-1 well, which is linked to an offshore fixed monopod.

Gas and condensate from the Campbell and Sinbad fields are transported to Varanus Island via 324 mm, 30 km gas-gathering pipelines.

South Plato

Plato-1, located some 2.8 km north of South Plato-1 was drilled in 1986 and was dry. The South Plato field was discovered in February 2001 by South Plato-1 and encountered a 27.4m gross oil-column. The South Plato field is located 2 km southwest of Gibson-1 and 4 km southwest of the Tanami-4 well. The oil field contains under-saturated oil, similar to that found in the Simpson field. South Plato-2 appraisal well was drilled in October 2001 between South Plato-1 and Plato-1 and encountered a 3.8m net oil-column, thereby confirming the northern extent of the South Plato field. South Plato-3H well was drilled in February 2003.

Tanami

The Tanami-1 well was directionally drilled from Varanus Island in July 1991 and commenced production under an extended test in October 1991. Production facilities were installed in December 1993. Tanami-6 was drilled and completed in October 2002 as the second drainage point.

Victoria

The Victoria field was discovered in February 2002 by Victoria-1 which encountered a 33m gross oil-column primarily in sandstones, above the main massive Flag Sandstone, which are interpreted as being the feather edge of the younger, Double Island Sandstone Member. Victoria-2 was drilled in September 2002. Upside reserves were tested by Victoria-2 well in the second half of 2002 and have led to a downward revision in reserves. The Victoria field is located about 5 km south of the South Plato and Gibson oil development and contains slightly under-saturated oil. Victoria-1 commenced production in November 2002.

During 2006 the West Cyad-2 well, located in Permit TL/9, was drilled as a sidetrack from Apache's Victoria platform and was completed in early Febuary. The well is producing at a rate of 945 kl (6000bbl) of oil per day.

Wonnich

Wonnich was discovered in August 1995 and commenced production in July 1999 utilising one well linked to an unmanned monopod. The platform lies in 30 m of water and has been designed to support up to four wells. The field can produce gas at a rate of up to 80 TJ/d (73 MMscf/d). Gas and condensate are transported 33 km to the separation gas plant on Varanus Island via two 200mm pipelines. Total capital cost of the development was about $60 million.

The joint venture estimates proven and probable reserves to be 186 PJ of gas and 3.5 MMbbl of condensate, at year end 2006, which is expected to provide a field life of around 20 years.

In 2007 drilling of Wonnich Deep-1 exploration well from the Wonnich platform continued and intersected the secondary target Flag reservoir, with logs indicating an unswept 28.5m gas column overlying a 3.5m oil column. The Harriet JV has now started producing gas from the Flag Formation Wonnich Deep-1H well in TL/8.

After clean-up, the well was flowing at a stabilised rate of 50 MMcfd per day, however this has since increased to 65 MMcfd.

Production of gas from the Wonnich Deep-1 Flag sandstone intersection is from a previously unswept compartment of the Wonnich field and is anticipated to have a positive effect on the gas reserve estimates for the field.

Potential Developments and Dry Wells

The joint venture has made a number of oil and gas discoveries in close proximity to the existing facilities on Varanus Island. These discoveries may be developed in the future to maintain/ increase production and to secure new gas contracts.

Harriet area fields Gas, Oil and Condensate

Baker

The Baker-1 well was drilled to a total depth of 2512 m in January 2000. The well intersected a 31.5m gross hydrocarbon-column in three separate reservoirs in which both gas and condensate were recorded. Baker-1 was subsequently plugged and abandoned as a gas discovery.

Gibson - South Plato

In November 2006 a deviated well was drilled from the Gibson - South Plato Platform in production licence TL/6. South Gibson-1 intercepted a 2m oil-column which was considered not enough for commercial development and as such the well was plugged and abandoned.

Gipsy–Rose–Lee trend

In 1998, the joint venture confirmed a new hydrocarbon trend in the Gipsy–Rose–Lee series of complex fault blocks to the east of the Harriet field. It is the first major trend in the deeper and older Jurassic- and Triassic-aged reservoirs within the Carnarvon Basin, outside the deepwater Rankin trend. The majority of the Harriet area wells in the Carnarvon Basin only intersected the lower Cretaceous-age Formations.

Gipsy, North Gipsy and Rose have been developed with Lee awaiting pending gas deliverability requirements.

Gobi

In November 2006, exploration well Gobi-1 was drilled from the Gibson-South Plato platform in production licence TL/1. The well intersected a 5m oil-column but was deemed too small for commercial development and was subsequently plugged and abandoned.

Hector, Agamemnon and Priam

Hector-1 was the first of three deviated wells to be drilled in TL/6. After being drilled logging data showed prospects to be water-bearing with insufficient hydrocarbon implications. The well was plugged and drilling on the sidetrack of Agamemnon-1, the second well in the program, began and was plugged after reservoirs in the prospect were found to have 'minor' hydrocarbon implications. Sidetrack drilling of Priam-1 began, the third and final well to be drilled. Priam-1 proved to be dry and was subsequently plugged and abandoned.

Josephine

In January 2000, the Josephine-1 well was drilled to a total depth of 2678 m and intersected a 43.5m gross hydrocarbon-column in three separate reservoirs containing both gas and condensate. Josephine-1 was subsequently plugged and abandoned as a gas discovery.

Monty

Monty-1 was drilled to a total depth of 2492 m in December 1999 and intersected a 38.5m gross hydrocarbon-column in four separate reservoirs containing both gas and condensate. Monty-2 was subsequently drilled to evaluate the discovery but it did not encounter hydrocarbons. The well determined that the gas accumulation intersected in Monty-1 did not extend down to the Monty-2 location. Consequently, the joint venture has evaluated the Monty structure as containing a small volume of gas.

Narvik

Located 25 km southeast of the Harriet field in TP/8, the Narvik-1 well was drilled to a total depth of 820 m in November 1999. The well identified a 31m gross gas-column, of which 10.7 m is interpreted to be a productive reservoir. Narvik-1 was subsequently plugged and abandoned as a gas discovery. Reserves are yet to be established for the field.

Hovea–Eremia Oil

Located 6 km south of the Dongara field, the Hovea-1 well was drilled in October 2001 and oil discovered in the Dongara Sandstone formation. After acquiring a 3D seismic survey over the discovery in early 2002, the joint venture drilled a series of appraisal/development wells and the first exploration well on the trend, Eremia-1, was an oil discovery.

Field Reserves

At 30 June 2007 the Hovea-Eremia oil field had remaining recoverable reserves of 1.52 MMbbl.

Significance

The Hovea development represents a number of very significant milestones for both the joint venture and for Western Australia.Hovea was the first commercial oil discovery in the Perth Basin since 1966 and the first onshore oil field in Western Australia to be brought to commercial production in 20 years. The Hovea oil field, the Eremia field and the Jingemia oil discovery (in the permit adjacent to Hovea), as well as the offshore Cliff Head oil discovery, have opened up a large new oil fairway and rejuvenated exploration in the northern Perth Basin.

Hovea History

October 2001
Hovea-1 flows oil at 1 889 bbl/d

January 2002
Hovea 3D seismic survey acquired

June 2002
Hovea-2 finds High Cliff gas pool (16.5 MMcf/d)

August 2002
Hovea-3 well encounters 26-m oil-column

October 2002
Decision to develop the field taken

February 2003
Hovea-4 commences production

March 2003
HPF permanent facilities commissioned

March 2004
2 MMbbls produced

June 2005
5 MMbbls produced

January 2007
7 MMbbls produced from Hovea-Eremia

Hovea–Eremia Oil

Location
69 km south of Geraldton

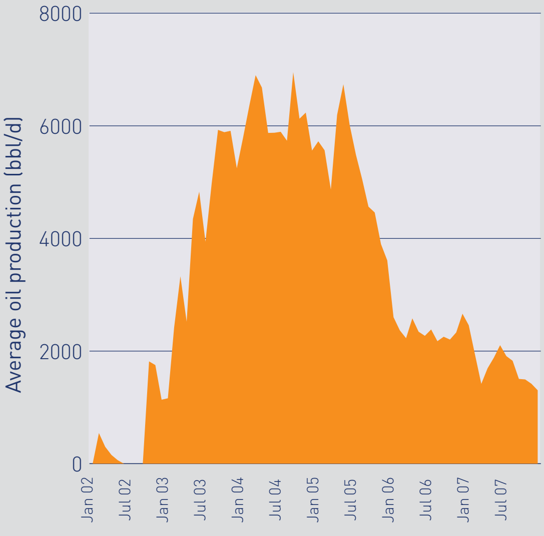
Basin
Perth, onshore

Permit/Licence
L/1

Ownership	%
ARC Energy Limited (Operator)	50
Origin Energy Developments Pty Ltd	50

Contact
ARC Energy Limited
Level 4, 679 Murray Street
WEST PERTH WA 6005
Tel: +61 8 9480 1300
Fax: +61 8 9480 1388
Email: arc@arcenergy.com.au
Web: www.arcenergy.com.au

Production	Oil (bbl)		Gas (kcm)		Condensate (bbl)	
	2006	2007	2006	2007	2006	2007
Hovea	864 215	637 182	22 797	8 333	1321	48
Eremia	240 127	329 605	1 557	1 989	-	-



Hovea-Eremia

Eremia Field (50 per cent)
The Eremia-1 exploration well was drilled in March 2003 and was completed as an oil discovery after encountering an oil column of up to 18m in thickness in excellent quality Dongara sandstone reservoir. The Eremia field is located 2.5 km to the west of the Hovea Production Facility (HPF).

The Eremia-1 well was placed on production through temporary facilities only six weeks after the rig was released. A second development well and a water injection well were subsequently completed and a flowline back to the HPF, together with a gas-lift-line from Hovea to Eremia, have been installed to maximise production.

The Eremia-2 development well was drilled in November 2003 and, after some initial issues with a stuck drill string, was plugged and sidetracked, then drilled as a high-angle production well that was completed in January 2004. The well intersected an oil-column of approximately 18 m in the Dongara Sandstone and was brought to production.

The Eremia-3 well was subsequently drilled to delineate the southern extent of the Eremia field. The well intersected the oil-water contact of the field and was plugged back and sidetracked (with the sidetrack designated Eremia-4) to a total depth of 2273 m, with a bottom hole location approximately 90 m to the north east of the original reservoir intersection.

Both well bores intersected the Dongara Sandstone reservoir at or just below the Eremia oil-water contact and Eremia-4 was completed as a water injector to provide pressure support to the main Eremia field pool.

In February 2007 the Eremia-7 appraisal well flowed at 1 553 bbl/d through a 40/64 inch choke while on test.

Jingemia Oil

Location
24 km south of Dongara

Basin
Perth, onshore

Contact
Origin Energy Developments Pty Ltd
34 Colin Street
WEST PERTH WA 6005
Tel: +61 8 9324 6111
Fax: +61 8 9321 5457
Web: www.originenergy.com.au

Ownership	%
Origin Energy Developments Pty Ltd* (Operator)	49.189
ARC Energy Limited	44.141
Victoria Petroleum Offshore Pty Ltd	5.000
Norwest Energy NL	1.278
Roc Oil (WA) Pty Ltd	0.250
J. K. Geary	0.142

* a wholly owned subsidiary of Origin Energy Limited

Production	2006	2007
Oil (bbl)	1 046 530	808 340
Gas (kcm)	7 772	5 729

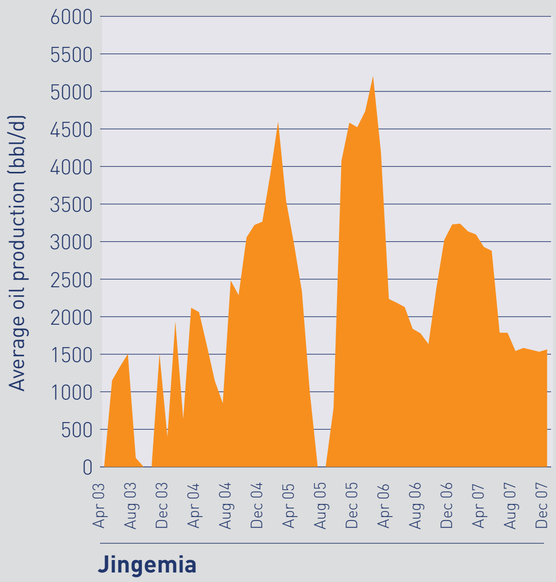
Field History

The Jingemia prospect was tested by the exploration well Jingemia-1 in October of 2002 and intersected up to 33m of net-oil pay in the Dongara Sandstone and Wagina Formation. Maximum free flow rates of up to 2000 bbl/d (317.8 kl/d) were recorded from the well on production test in May 2003, and the well was later completed for production. Jingemia-2 spudded in late August of 2003 to test the downdip extent of the field. Upon reaching the Dongara Sandstone reservoir, a thinned interval was encountered below the field oil–water contact. The well was plugged back and sidetracked. The sidetracked well, Jingemia-3, intersected good quality Dongara Sandstone updip from Jingemia-2, and was completed as a water-injection well.

Jingemia-4 was spudded in late April 2004 and intersected the Dongara Sandstone approximately 12 m updip of Jingemia-1; 28.3 m of net-oil-pay were encountered within excellent quality Dongara Sandstone. The underlying Wagina Formation was found to contain only minor fluorescence and low permeability. Three 27-m cores were cut through the Dongara Sandstone and Wagina Formation interval with 100 per cent recovery.

Jingemia-6 spudded on the 16th August 2005 and was drilled to a total depth of 2584 metres. This well failed to intersect the Dongara Sandstone reservoir section because the bounding fault was incorrectly located on the seismic. Jingemia-10 was drilled as a “kick off” from the Jingemia-6 wellbore, targeting the Dongara Sandstone 55 m to the west. The well reached a total depth of 2587 m. The Dongara Sandstone was intersected at 2458 m approximately 40 m above the presumed field oil-water contact. The Dongara Sandstone was found to be oil saturated.

Jingemia Oil



An additional production well, Jingemia-8 commenced drilling in August 2006 to increase oil production rates and access incremental reserves from the Dongara Sandstone. Jingemia-8 was drilled directionally, reaching a total depth of 2585 m measured depth within the Carynginia Formation. The top of the targeted Dongara Sandstone was intersected at 2482 m measured depth, at approximately 517 m north-northeast of the surface location and 30 m above the original oil-water contact of the Jingemia Field. Hydrocarbon indications recorded during drilling, and wireline logs indicated that the entire Dongara Sandstone reservoir section was oil-saturated in this well. Reservoir pressure data indicated that this reservoir was not in pressure communication with the rest of the Jingemia Field. Jingemia-8 was cased and completed in early September 2006 for connection to the Jingemia oil facility.

Jingemia-11 commenced drilling in February 2007. The well was drilled to a total depth of 2606 m measured depth. The well encountered the Dongara Sandstone reservoir 14 m updip from the previous highest point in the field. Wireline logs indicated the well had encountered 31 m of oil saturated sandstone. Although the lower 8 m appear to have been partially swept by existing producers.

Production facilities

Oil from the Jingemia -4,-8,-10 and -11 wellheads flows through a choke manifold and is processed via two horizontal 3-phase production separators where the gas and water are separated from the crude oil. The gas is flared via a smokeless vertical flare, and the water is transferred to the produced water treatment and re-injection system. The oil is transferred to a 940-bbl segregation tank and three 940-bbl oil-storage tanks. The oil is then pumped into road tankers via a fully automated tanker loadout facility, and then transported to BP in Kwinana for refining. Produced water is injected into the Jingemia -1, -3 and -5 wells via high-pressure pumps to maintain pressure support. Jingemia-9 is a remote injection well also used to maintain reservoir pressure.

Sales contracts

All oil production is currently trucked and sold to the BP refinery in Kwinana.

Exploration drilling

A number of other structures that potentially contain commercial quantities of hydrocarbons are present in L14 and EP413. The most prospective of these is the Freshwater Point structure, near the coast in EP413, approximately 18 km southwest of the Beharra Springs Gas Plant. It is expected the exploration drilling on the Freshwater Point structure will take place early in 2008. Mapping and analysis of additional leads and prospects forms part of the geologic and geophysical studies that will be undertaken in 2007-2008.

John Brookes Gas and Condensate

In November 1998, the John Brookes-1 well was drilled to a total depth of 3741 m in a water depth of 20 m and intersected an 80-m gross hydrocarbon-column. The well was tested over two separate zones and achieved a combined flow rate of 1510 kcm/d (53.4 MMcf/d) of gas and 460 bbl/d of 46º API condensate. A second well in the permit, Moon-1, was drilled to a total depth of 3035 m in October 1999, but was plugged and abandoned as a dry hole. Appraisal wells, Thomas Bright-1 drilled in March 2003, Thomas Bright-2 drilled in late 2004, Thomas Bright-3 drilled in July 2005, and Robert-Addams-1 drilled in November 2005 have confirmed the extent of the field.

It is estimated that the John Brookes field contains recoverable gas of more than 34 Bcm (1.2 Tcf).

In 2006 Newmont contracted 16 PJ of gas over three years from the John Brookes field. The contract which will supply gas to Newmont's Jundee gold mine and Parkestone power station, is expected to generate more than $90 million in revenue during its term.

The John Brookes field will also supply up to 37 PJ of gas over 10 years to Wesfarmers' new LNG plant at Kwinana, south of Perth, which is scheduled to come online in early 2008.

Production Facilities

Field development was completed in 2005 via an unmanned six-slot wellhead platform; 3 production wells (JB-02, JB-03 and JB-05); and a single three-phase 457- mm pipeline linking the wellhead platform to the Varanus Island gas treatment facilities. Debottlenecking of the East Spar gas plant and installation of CO_2 removal facilities is complete.

The first gas production from the field commenced in September 2005. The capacity of the facility is in the order of 350 TJ/d (321 MMcf/d) with JB-05 having a tested capacity in excess of 170 TJ/d (156 MMcf/d).

Location

60 km northwest of Varanus Island

Basin

Carnarvon, offshore

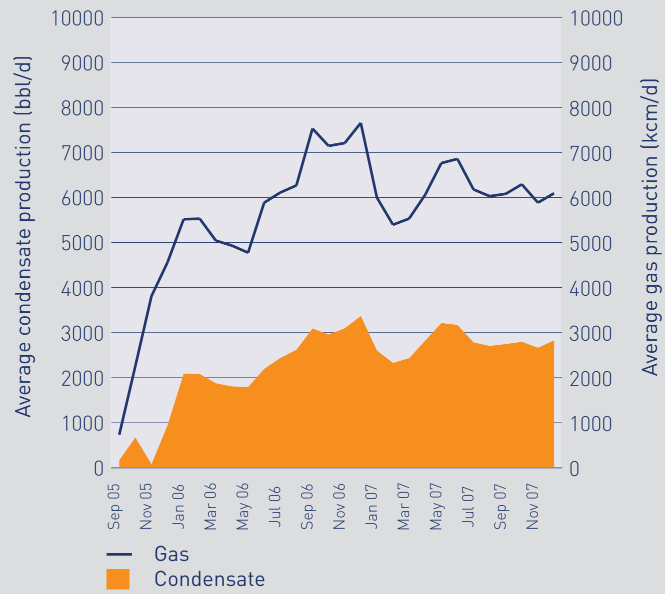
Permit/Licence
WA-214-P

Ownership	%
Apache Northwest Pty Ltd (Operator)	55.00
Santos (BOL) Pty Ltd	45.00

Contact

Apache Energy Limited
Level 3, 256 St George's Terrace
PERTH WA 6000
Tel: +61 8 9422 7222
Fax: +61 8 9422 7447
Web: www.apachecorp.com

Production	2006	2007
Gas (kcm)	2 242 120	2 229 814
Condensate (bbl)	895 740	1 007 940



John Brookes

Laminaria–Corallina Oil and Condensate

Location
550 km northwest of Darwin

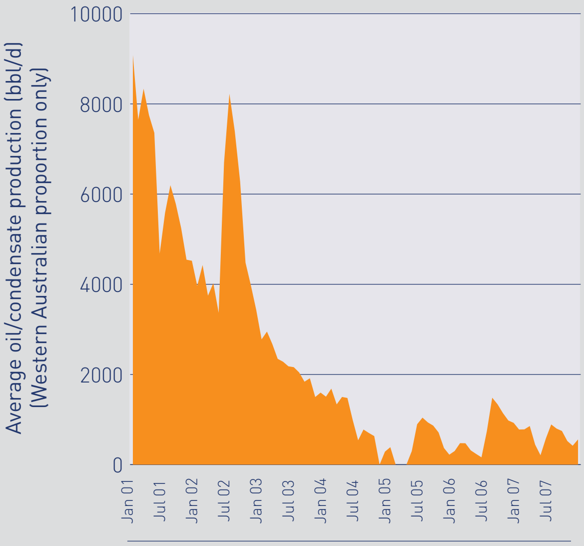
Basin
Bonaparte, offshore

Permit/Licence
AC/L5

Ownership	%
Woodside Energy Ltd. (Operator)	66.67
Talisman Oil & Gas (Australia) Pty Limited	33.33

Contact
Woodside Energy Ltd.
240 St George's Terrace
PERTH WA 6000
Tel: +61 8 9348 4000
Fax: +61 8 9214 2777
Web: www.woodside.com.au

Production	2006	2007
Oil (bbl)	262 048	230 971
Gas (kcm)	1 565	1 845



Laminaria-Corallina

The Laminaria field was discovered in October 1994. A separate field, Corallina, was discovered in December 1995. Laminaria and Corallina are administered by the Northern Territory Department of Mines and Energy on behalf of the Commonwealth of Australia.

Production in the Laminaria field commenced in November 1999 and was among the first developments in this part of the Timor Sea, following Elang–Kakatua located in the Joint Petroleum Development Area.

Production facilities
Development of the Laminaria and Corallina fields utilises the FPSO, the Northern Endeavour, which is permanently moored between the fields by means of an internal turret-mooring system. It is moored in a water depth of 390 m.

The Northern Endeavour comprises hydrocarbon separation, stabilisation and testing facilities which are designed to handle a maximum oil production rate of 170 000 bbl/d. Facilities have been provided for produced water treatment, gas compression, gas-lift, power generation, cooling water and fiscal metering. A stabilisation column reduces LPG content and improves crude value.

The two fields produce from subsea facilities consisting of eight production wells (six in Laminaria and two in Corallina), a network of manifold subsea flowlines and dynamic risers which are connected to the FPSO via an internal turret mooring system. Surplus gas is re-injected through a dedicated gas disposal well. The internal turret system includes provision for future risers and riser tubes, as well as future piping arrangements, thereby allowing the tie-in of additional Laminaria–Corallina wells and further discoveries in the area.

Stabilised oil (58° API gravity) is stored onboard the FPSO, which has a storage capacity of 1.4 MMbbl, and is then transferred via an offtake loading hose to an export tanker moored astern of the FPSO.

Legendre Oil and Gas

The Legendre North and Legendre South oil fields are located 35 km southeast of the Wanaea–Cossack fields in water depths of 45–60 m in Production Licence WA-20-L. Legendre North was discovered in 1968 with the drilling of Legendre-1, however, it was considered uneconomic to develop at that time. In 1997, Jaubert-1 confirmed the potential of the field. In April 1998, Legendre South-1 proved to be a separate accumulation with the intersection of a 21-m oil-column, 3.5 km southwest of Jaubert-1.

Field development

In October 1999, the joint venture formally approved the development of the Legendre oil fields at an estimated cost of $110 million. The initial development comprised four horizontal production wells (three in Legendre North and one in Legendre South) and one gas re-injection well. The development wells produce via the Ocean Legend Production Facility connected via a subsea pipeline and Catenary Anchored Loading Buoy to the Karratha Spirit Oil Storage and Offloading tanker. Both the Ocean Legend and Karratha Spirit are leased facilities and operate under service agreements.

First oil was achieved in mid-May 2001 after the completion of the first production well. In mid-June, the first cargo of approximately 630 000 bbl of Legendre crude oil was shipped. By early July 2001, four production wells and a single gas re-injection well had been completed and commissioning of the gas re-injection facilities commenced.

Legendre crude oil is a 43° API gravity, light, sweet crude oil. The attractive qualities of this crude have enabled the crude to be sold on a spot basis in markets in Australia, South Korea, China, Thailand, New Zealand and Indonesia.

In June 2003, the Legendre North-4H infill well was completed and came into production. This, coupled with gas compression optimisation work and a work over of the Legendre North-3H well, led to the achievement of record facility production rates. In June 2004, a sixth producer was added through realisation of the Legendre North-5H infill well.

In line with expectations, production from Legendre is now in natural decline. In 2007 Woodside sold its 45.94 per cent stake to Apache increasing Apache's ownership to 77.44 per cent.

Location

100 km north of Dampier

Basin

Carnarvon, offshore

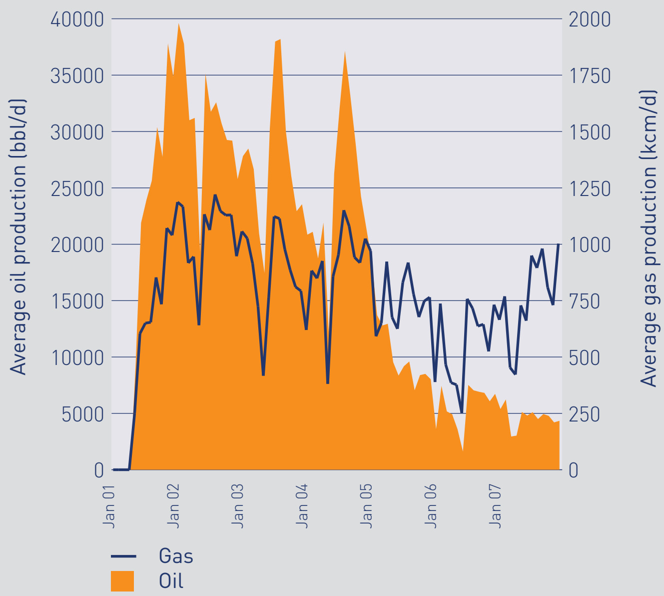
Permit/Licence	
WA-20-L	WA-1-P

Ownership	%
Apache Northwest Pty Ltd	77.44
Santos Limited	22.56

Contact

Apache Energy Limited
Level 3, 256 St George's Terrace
PERTH WA 6000
Tel: +61 8 9422 7222
Fax: +61 8 9422 7447
Web: www.apachecorp.com

Production	2006	2007
Oil (bbl)	2 048 559	1 681 146
Gas (kcm)	201 196	275 960



Legendre

Mount Horner Oil

Location
380 km north of Perth

Basin
Perth, onshore

Contact

Permit/Licence
L7

Ownership	%
ARC Energy Limited	100

ARC Energy Limited
Level 4, 679 Murray Street
WEST PERTH WA 6005
Tel: +61 8 9480 1300
Fax: +61 8 9480 1388
Email: arc@arcenergy.com.au
Web: www.arcenergy.com.au

Production	2006	2007
Oil (bbl)	-	23 263

The L7 permit lies immediately to the north of L1/L2, and contains significant exploration potential that will be further analysed as part of the next round of exploration. The permit also contains the Mt Horner oil field which was discovered in 1965 but did not commence production until May 1984. The field is now at a mature stage of its life.

ARC Energy acquired 100 per cent of the licence in February 2004 from the previous holder, Petroenergy Pty Ltd, to complement its other facilities in the area and assist in the further development of the field.

Production

Initial recommissioning work on the field was completed by ARC in December 2006 and oil production recommenced in early 2007. The potential for further recommissioning work is being assessed. Current oil production is approximately 70 bbl/d and onsite wells are on artificial lift by electrically driven beam pumps. The process facilities were installed in December 2000 and comply with stringent safety case requirements set by the Department of Industry and Resources. The crude oil (37.6° API gravity) is stored onsite in heated tanks and then trucked to the Kwinana refinery, south of Perth.

Mutineer–Exeter Oil

Mutineer

The Mutineer field is located in permit WA-26-L, in the northern part of the Carnarvon Basin, 150 km north of Dampier and 40 km north of the existing Wanaea–Cossack production facility (Cossack Pioneer FPSO). Water depth is 150 m.

The discovery well (Pitcairn-1), drilled in 1997 intersected 2.7 m of oil in the uppermost J40 sandstone of the Late Jurassic Angel Formation, with an oil–water contact of 3128 m subsea interpreted from wireline logs and pressure data. Mutineer-1B was drilled in August 1998 and encountered an 8-m oil-column with no OWC. Results from Mutineer-1B indicated a stratigraphic trap combining the Mutineer and Pitcairn oil discoveries.

Mutineer-2 and -3 were drilled in May and November 2002 respectively with the latter intersecting an 8-m oil-column and OWC at 3128 m subsea. Mutineer-3 was production tested, at rates up to 6600 bbl/d, flowing 43° API oil with a gas-to-oil ratio of 10 cf/bbl.

Three appraisal wells were drilled in the Mutineer field during 2004, Mutineer-7, -8 and -9. The results of these appraisal wells were used to better define the field and to plan and optimise the development well locations. The development drilling campaign for Mutineer commenced in 2004 with three horizontal production wells successfully drilled, tested and completed (Mutineer-4H, -5H and -9H).

An additional appraisal well (Mutineer-11) was drilled in the west of the field in 2005 and intersected a thicker than expected reservoir section and resulted in a development well (Mutineer-12H) being successfully drilled and placed on production in May, 2006.

In 2007, the Mutineer-13 appraisal well was drilled to test for a potential south westerly extension of the Mutineer field however the primary reservoir objective was intersected low to prognosis and water saturated.

Mutineer–Exeter Oil

Exeter

The Exeter field is located approximately 10 km south of Mutineer within permit WA-27-L. It was discovered in April 2002 when the Exeter-1 well encountered a 23-m oil-column with no OWC. Exeter-2 was drilled 40 m down-dip of Exeter-1, in May 2002, and encountered a 12-m oil-column with OWC at 3136 m subsea.

During 2004, Exeter-4AH horizontal development well was successfully drilled and tested at 10 220 bbl/d. An additional development well, Exeter-8HL1 was also successfully drilled and placed on production in 2006 to improve the drainage from the field.

Field Development

The fields are produced via subsea wells tied back, via a subsea manifold at each field, to an FPSO with an oil process capacity of 100 000 bbl/d and liquid process capacity of 140 000 bbl/d. Given the low GOR oil, the wells use dual electric submersible pumps, and each field uses a multiphase seabed booster pump located at a subsea manifold, all powered from the FPSO. There is provision for up to nine wells at Mutineer and five wells at Exeter. Field life is estimated at between 5 and 12 years, depending on reservoir performance.

First oil was delivered in March 2005, only 17 months after the final investment decision, from three wells at Mutineer and one at Exeter.

2005 and 2006 production was exceptional with facility uptime in excess of 98 per cent and excellent reservoir performance.

At Mutineer-Exeter there is currently a rig on site and anticipate if successful the appraisal and workover program during this quarter will increase gross oil production rates between 5000 and 10 000 bbl/d.

Location

150 km north of Dampier

Basin

Carnarvon, offshore, Dampier Sub-basin

Permit	
WA-26-L	WA-27-L

Ownership	%
Santos Ltd Group (Operator)	33.3977
Kufpec Australia Pty Ltd	33.4023
Nippon Oil Exploration (Dampier) Ltd	25.0000
Woodside Energy Ltd.	8.2000

Contact

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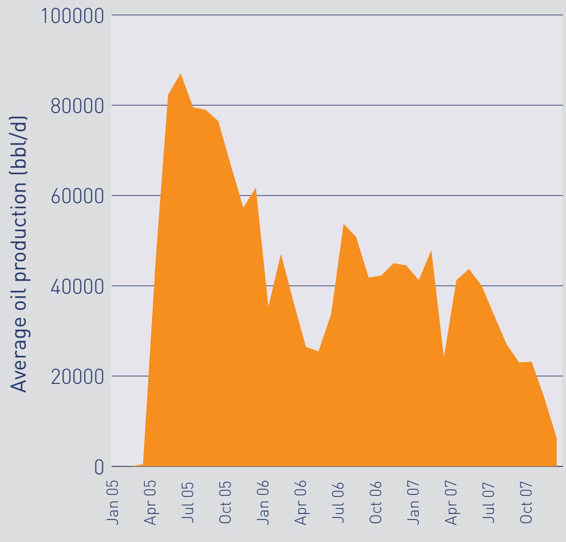
Level 28, Forrest Centre
221 St George's Terrace
PERTH WA 6000
Tel: +61 8 9460 8900
Fax: +61 8 9460 8971
Web: www.santos.com.au

Production	2006	2007
Oil (bbl)	10 136 826	8 710 325
Gas (kcm)	2 869	2 466



Mutineer-Exeter

North West Shelf Gas Project Gas, Oil and Condensate

Location
130 km northwest of Karratha

Basin
Carnarvon, offshore

Permit/Licence						
WA-28-P	WA-1-L to 6-L	WA-9-L	WA-11-L	WA-16-L	WA-1-PL	WA-2-PL

Ownership	%
Domestic gas	
Woodside Energy Ltd. (Operator)	50.00
BP Developments Australia Ltd	16.67
Chevron Australia Pty Ltd	16.67
BHP Billiton Petroleum (NWS) Pty Limited	8.33
Shell Development (Australia) Pty Ltd	8.33
LNG, Oil, LPG, Gas recycling	
Woodside Energy Ltd. (Operator)	16.67
BP Developments Australia Ltd	16.67
Chevron Australia Pty Ltd	16.67
BHP Billiton Petroleum (NWS) Pty Limited	16.67
Shell Development (Australia) Pty Ltd	16.67
Japan Australia LNG (MIMI) Pty Ltd	16.67

Contact
Woodside Energy Ltd.
240 St George's Terrace
PERTH WA 6000
Tel: +61 8 9348 4000
Fax: +61 8 9214 2777
Web: www.woodside.com.au

Oil Production (MMbbl)					
Field	2003	2004	2005	2006	2007
Wanaea	26.35	23.43	18.57	18.32	15.28
Cossack	5.17	3.62	3.76	2.89	3.27
Hermes	5.08	5.70	9.05	7.79	6.52
Lambert	2.70	0.97	-	-	3.18
TOTAL	39.30	33.72	31.98	29	28.25

Production	Gas (kcm)		Condensate (bbl)	
	2006	2007	2006	2007
Echo-Yodel	1 522 757	1 286 219	8 188 768	7 419 005
Goodwyn	7 267 250	7 128 850	10 871 057	10 304 184
Perseus	8 377 785	12 813 361	10 916 521	16 258 241
North Rankin	5 658 405	2 949 556	3 984 362	1 948 028
TOTAL	22 826 197	24 177 986	33 960 708	35 929 468

The North West Shelf Venture (NWSV) is Australia's largest natural resource development.

It produces gas for Western Australia's domestic market and gas, condensate and oil for export from its vast offshore gas and oil fields.

In June 2005 the Woodside-operated NWSV announced it would proceed with its A$2.6-billion Phase-V LNG expansion to increase production capacity to 16.3 Mt/a of liquefied natural gas (LNG) .

In December 2005 the NWSV also approved the A$1.6 billion Angel project which puts a remotely operated controlled platform over the Angel field from the North Rankin platform which will be tied in to the first trunkline to shore.

OFFSHORE GAS FIELDS
Gas and condensate are produced from the North Rankin, Goodwyn, Perseus and Echo–Yodel fields utilising the Goodwyn and North Rankin production platforms.

The gas is transported by two subsea pipelines to the NWSV onshore gas plant at Withnell Bay on the Burrup Peninsula 20 km north of Karratha. The plant currently produces LNG, natural gas, LPG and condensate.

North Rankin
Discovered in 1971, the North Rankin gas and condensate field is 130 km offshore from Karratha in approximately 125 m of water.

Production commenced in July 1984 following the installation and commissioning of the North Rankin platform, with the first deliveries of gas to the market one month later.

The North Rankin A (NRA) was originally designed to drill a maximum of 34 production wells up to a vertical depth of 3.4 km, deviated up to 60°. The drilling facilities were upgraded in 1990 to extend the rig's drilling capability to drill wells up to 70° deviation and up to 6.2 km along-hole depth.

In 2000, a rig refurbishment campaign enabled the drilling of production wells into the eastern flank of the Perseus field.

A proposed North Rankin Redevelopment Project (NR2) would extend the NRA platform's integrity and functionality.

North West Shelf Gas Project Gas, Oil and Condensate

Still subject to a final investment decision the project would include the installation of a second offshore platform with gas compression facilities adjacent to the existing North Rankin A platform. This would enable the recovery of additional low pressure gas from the North Rankin and Perseus gas fields.

Perseus

Discovered in 1996, the Perseus gas field is about 135 km northwest of Karratha in 131 m of water and started production in 2001.

Goodwyn

The Goodwyn gas field was discovered in 1972, 23 km southwest of the North Rankin field.

The Goodwyn platform was designed for 30 wells and started production in February 1995.

The initial drilling program of 13 wells included four horizontal, world-class, long-reach wells producing from up to 8.3 km from the platform. The second phase of drilling, included four long-reach, horizontal and deviated wells and was completed during 1999. The third phase of two wells was completed in 2001.

Echo–Yodel (gas and condensate)

The Echo field was discovered in 1988 and Yodel in 1990, 25 km southwest of the Goodwyn-A platform in 140 m of water.

In 2001, Production Licences were granted over the field and two subsea horizontal wells were completed and tied back to GWA.

Angel (gas and condensate)

In late 2005 approval was given for the $1.6-billion Angel project located 49 km east of the North Rankin Platform over permit WA-3-L which was discovered in 1971.

The remotely operated platform will be tied back to the North Rankin platform and have a capacity of up to 800 MMcf/d of gas a day and 50 000 barrels of condensate a day.

The 7500-t Angel jacket substructure and 7000-t topside are expected to produce first gas in Q3 2008.

PIPELINE GAS PRODUCTION

The onshore gas treatment plant on the Burrup Peninsula was commissioned in August 1984 to process gas and condensate piped from NRA.

The plant currently consists of two parallel processing trains with the main components of each train being the dehydration units, which separate water from the gas, and the extraction unit, which removes the heavier hydrocarbons.

After processing, the bulk of the gas is compressed and metered for delivery to customers in the Pilbara and the southwest of Western Australia.

Sales of pipeline gas are mostly under long-term take or pay contracts with the NWSV supplying about 60 per cent of Western Australia's annual pipeline gas requirements.

LNG PRODUCTION

The LNG plant was commissioned in July 1989 and currently consists of four liquefaction trains with a total capacity of 11.9 Mt/a of LNG, four 65 000-m^3 storage tanks and a jetty dedicated to the loading of LNG.

The LNG is stored before being piped to the LNG jetty for offloading onto purpose-built LNG ships for transport to Japan, South Korea and other international markets.

In 2005, construction of a fifth LNG train was approved, along with construction of a second LNG loading terminal. The expansion projects, which will cost up to A$2.6 billion, position the NWSV to satisfy growth in future contractual commitments.

The new train with a production capacity of 4.4 Mt/a is expected to deliver first gas by Q4 2008 and will take the total production capacity of the Karratha onshore gas plant to 16.3 Mt/a. This will make it one of largest single LNG production plants in the world.

As part of China's Guangdong LNG project, the NWSV participants and China National Offshore Oil Corporation (CNOOC) Limited finalised agreements in December 2004 that provide for CNOOC to acquire an approximate 5.3 per cent interest in the NWSV titles and to secure rights to use NWSV infrastructure to process gas and associated liquids.

LNG is sold to eight Japanese gas and electricity utilities under 20-year contracts, which started in 1989, as well as to the spot market when deliveries are available.

The first shipment to Japan left the Burrup Peninsula for Japan on 28 July 1989 on board the Northwest Sanderling.

In recent years, the NWSV has progressively signed further LNG supply contracts with eight existing and two new Japanese customers, as well as with customers in South Korea and China.

CONDENSATE PRODUCTION

Since 1984, the NWSV has produced condensate, light oil which is used as a feedstock to manufacture automotive and aviation fuels and for chemical plants.

The onshore gas-processing plant separates condensate from the dry gas via two slugcatchers, the second commissioned in February 2004.

LPG PRODUCTION

The onshore liquid petroleum gas plant on the Burrup Peninsula was commissioned in November 1995 and extracts propane and butane from the gas originating from the NWSV's offshore gas fields.

The facilities include a 52 000-m^3 liquid propane storage tank, a 65 000-m^3 liquid butane storage tank, a 450 m-long load-out jetty with berthing facilities for both LPG and condensate tankers and a chiller plant to reliquify boil-off gases. System capacity of the plant is 2500 terajoules a day.

The owners of the NWSV make sales arrangements of LPG on an individual basis.

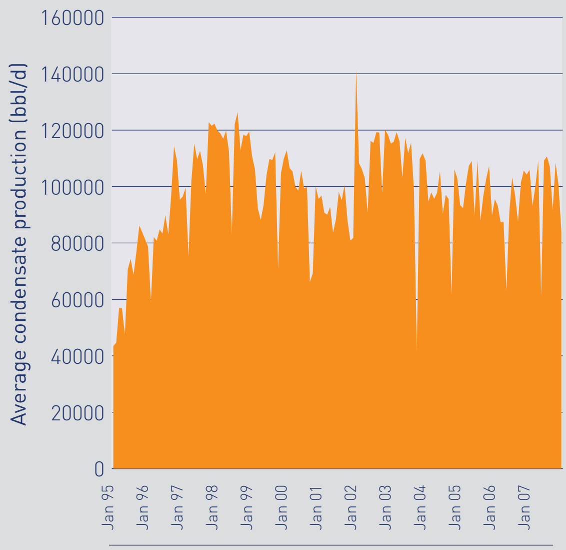
CRUDE OIL PRODUCTION

First oil production from the NWSV started in November 1995 and currently comprises production from the Wanaea, Cossack, Lambert and Hermes fields.

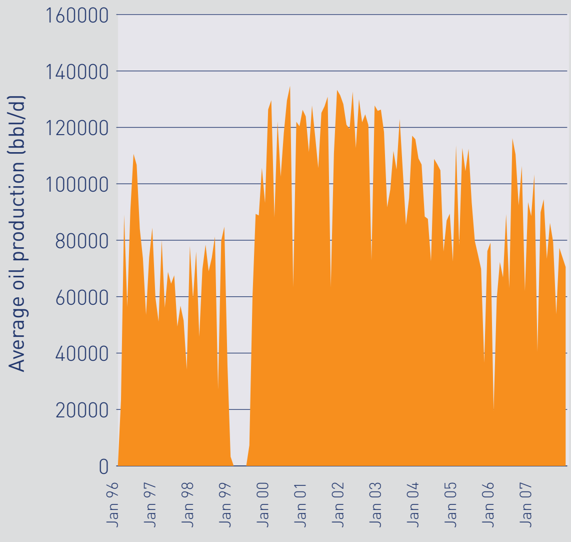
The oil development utilises an FPSO vessel, the Cossack Pioneer, which is moored by its bow to a disconnectable riser turret over the Wanaea field. It is capable of producing up to 140 000 bbl/d of oil.

The NWSV is currently evaluating various long-term options for producing from the Wanaea, Cossack, Lambert and Hermes fields.

North West Shelf Gas Project Gas, Oil and Condensate



NWS Condensate



NWS Oil

Rough Range Oil

Rough Range Oil Field

The Rough Range Oil Field is located in Exploration Permit EP-435 in the onshore Carnarvon Basin, some 65 km south of the town of Exmouth. The field was originally discovered in 1953 by Western Australian Petroleum Pty Ltd (Wapet) with the drilling of Rough Range-1 in the original Exploration Permit EP-41.

The oil is trapped in the Early Cretaceous Birdrong Sandstone which is 12 m thick and is sealed by 37 m of Muderong Shale. The source is believed to be the thick, Early Jurassic deltaic shales in the Paterson Trough to the northwest of the Rough Range Anticline. The Rough Range Anticline is a large, Miocene aged, compressional anticline trending northeast-southwest with the major Rough Range Fault on its south-eastern side.

Exploration History

Rough Range-1 intersected an 8.6-m gross oil column and a drill-stem-test produced a maximum stabilised flow of 550 bbl of 38.6º API oil per day through a 6.4 mm (1/4") choke. Wapet drilled four dry holes, Rough Range-4, -5, -6 and -10 within a radius of 600 m from the original discovery.

Ampol Exploration Limited took over the area in the early 1980's and drilled Rough Range-11. This well, located 170 m northeast of Rough Range-1, encountered the top of the Birdrong Sandstone 8 m low to prognosis and was plugged and abandoned.

Empire Oil and Gas NL became 100 per cent owner of Exploration Permit EP-41 (Part 3) and drilled Rough Range-1B and Central Rough Range-1 during 2000. Rough Range-1B was a re-drill of the original Rough Range-1A which had been plugged and abandoned by Ampol Exploration. Central Rough Range-1 encountered the top of the Birdrong Sandstone below the oil-water contact and was plugged and abandoned.

In 2006 Dune-1 exploration well was drilled and was discovered to be a duster and subsequently plugged. Environmental approval for Dune-2 and Dune-3 were received but never followed through as Dune-1 did not result in a commercial discovery.

In 2007 Parrot Hill-2 appraisal well was drilled. This well is a continuation of the undip test of the 1987 exploration well drilled by Ampolex which encountered a 6.2m gross oil column, Parot Hill-1 was subsequently completed as an oil well but never produced, and was later plugged and abandoned. Parrot Hill-2 suffered the same fate and wireline logs run in April 2007 resulted in no commercial hydrocarbon indications within the reservoir objectives. Parrot Hill-2 was also plugged.

Rough Range Oil

Production History

Rough Range-1 was drilled to a total depth of 4 452 m from September 1953 to May 1955. Due to formation damage, Wapet drilled Rough Range-1A in 1955. This well intersected a 7.3-m gross oil-column and was completed for production. A 48-day production test recovered 16 904 bbl.

During 1986, Ampol Exploration re-entered Rough Range-1A for a 36-day extended production test and a further 8 881 bbl was recovered.

In late 2000, Empire Oil conducted an extended production test and produced a further 18,888 bbl. Production was suspended due to the detection of minor amounts of hydrogen sulphide.

Facilities

With rising oil prices, Empire Oil provided the State with a Rough Range-1B Production Facility plan and a Safety Case to produce the Rough Range-1B oil well. The facilities are designed for a remote area and to handle the high paraffin, waxy crude and to minimise water coning. They include artificial lift, two heated storage tanks with a capacity of 1 000 bbl each, and insulated tankers for trucking the oil to the Kwinana Refinery. The facility is essentially mobile with all items skid-mounted and its size can be increased and duplicated should additional oil reserves be discovered in the area.

Recent Production

On 28th October, 2004, the Department of Industry and Resources granted Exploration Permit EP-435 over the old Exploration Permit EP-41 (Part 3). Following the grant of Exploration Permit EP-435, an Application for a Location 1/04-5 was made over graticular block number 7089, containing the Rough Range-1B oil discovery, on 30th November, 2004. This location was granted on 25th January, 2005 and an Application for a Production Licence 1/04-5L was made on 2nd February, 2005. This application has been offered subject to reaching a Native Title Agreement pursuant to the Native Title Act 1993.

An Application was made to conduct an Extended Production Test of the Rough Range-1B well. This application, together with the approval to construct the production facility, was granted on 12th April, 2005.

Production commenced on 17th July. Cumulative production from the field since discovery in 1953 has been over 96 800 bbl, of which a large quantity has been sold to the BP refinery in Kwinana.

Location

65 km south of Exmouth

Basin

Carnarvon, onshore

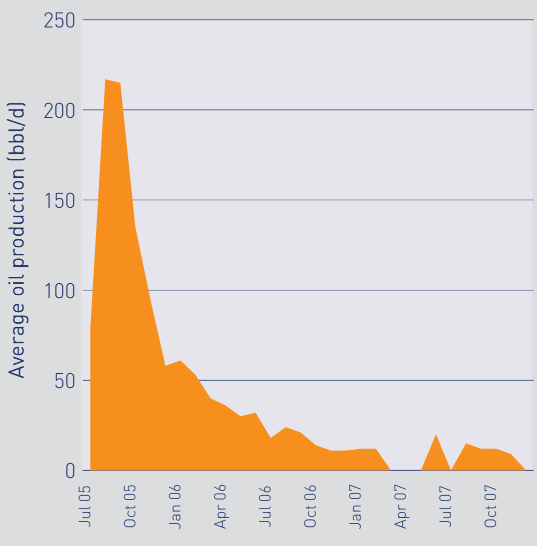
Permit/Licence
EP-435

Ownership	%
Empire Oil and Gas (Operator)	100

Contact

Empire Oil and Gas NL
9 O'Beirne Street
CLAREMONT WA 6010
Tel +61 8 9385 3810
Email: bwarris@empireoil.com.au
Web: www.empireoil.com.au

Production	2006	2007
Oil (bbl)	10 655	2 732



Rough Range

Stag Oil

Location
65 km northwest of Dampier

Basin
Carnarvon, offshore

Permit/Licence	
WA-209-P	WA-15-L

Ownership	%
WA-15-L	
Apache Northwest Pty Ltd (Operator)	33.3334
Santos Offshore Pty Ltd	66.6666
WA-209-P	
Apache Northwest Pty Ltd (Operator)	55
Santos Offshore Pty Ltd	45

Contact
Apache Energy Limited
Level 3, 256 St George's Terrace
PERTH WA 6000
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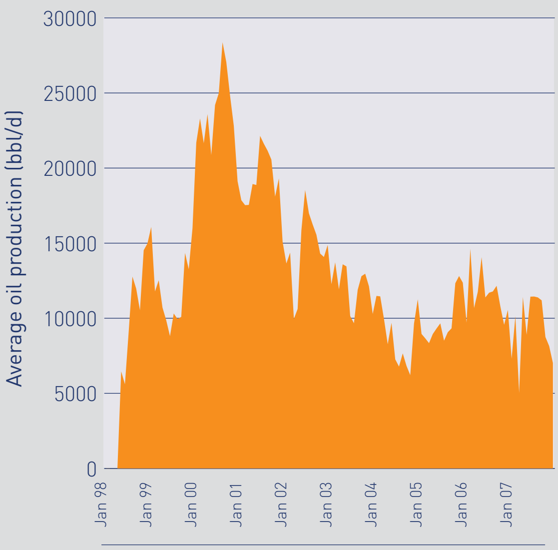
Fax: +61 8 9422 7447
Web: www.apachecorp.com

Production	2006	2007
Oil (bbl)	4 213 457	3 404 034
Gas (kcm)	31 579	22 729



Stag

The Stag field was discovered in June 1993 and commenced production in May 1998. The joint venture identified initial proven and probable oil reserves of around 44 MMbbl, giving the field a minimum life of 13 years. Total capital cost of the development was around $200 million.

Production facilities
The development utilises a central processing facility (CPF), which comprises a fixed production platform consisting of a six-leg piled substructure, topsides and processing facilities. The platform is able to accommodate up to 12 wells and has 50 000 bbl/d liquid processing capacity, including 40 000 bbl/d of water-injection.

Stag crude has an API gravity of 19° with low-wax and low-pour-point properties. Artificial lift with electric submersible pumps is therefore required to lift the oil to the surface at commercial rates. The oil is processed on the CPF and then exported through a 200-mm, 2 km subsea flowline to a CALM buoy. The buoy forms a mooring for a floating storage and offloading (FSO) facility, the Dampier Spirit, which has a storage capacity of 700 000 bbl.

In 2000, one new production well and one re-drilled well were placed on-stream. In 2001, Stag-23H was drilled and Stag-10H was sidetracked. Stag-24H was added in 2002, Stag-25H in June 2003 and Stag-26H, -27H and -28H in 2004. The field is now operating with 11 producing wells and three water-injection wells while producing at a rate of 12-14 000 bbl/d.

In 2006 Apache was active in the Stag field drilling to producers and one injection well. The two producers were Stag-9H and Stag-30H. The Stag-9H well tested at over 270 kl/d shortly after being drilled and the Stag-30H well is currently producing 213 kl/d. The Stag-29H injection well is a subsea injection well with a horizontal length exceeding 1200 m.

The Stag Water Injection project entailed the installation of a new 8 -inch water-injection flowline between the existing Stag central processing facility and the new 29H well to maintain and improve production by further sweeping the reservoir of oil accumulations. A new 8-inch steel riser and an 8-inch flexible flowline connect the Stag facility to the 29H wellhead located 3.2km west. Design commenced in September 2005 and water injection was successfully initiated in Early October 2006.

Reindeer
The Reindeer field, located 32 km north of Stag in permit WA-209-P, was discovered in October 1997 when the Reindeer-1 well encountered a 65-m gas-column in the Legendre Formation. Located 3.2 km south of Reindeer, the Caribou-1 well intersected a 19-m gas-column in April 1998 and confirmed the southern extension of the Reindeer field. Caribou-1 tested at a combined 51.9 MMcf/d gas rate and 850 bbl/d of condensate from two zones.

Stybarrow Oil

Reindeer (continued)

In 2006 exploration well Gnu-1 was drilled, located in the WA-209P, the well tested 26.3 MMcf/d of gas and 61 bbl/d of condensate from the North Rankin Formation. This well brought the expected gross recoverable reserves at Reindeer/Caribou to 0.5 Tcf.

In 2007 Rising West Australian gas prices have led Reindeer partners to begin front-end engineering and design (FEED) studies for the Reindeer gasfield. The FEED studies will focus on the preferred development option of an unmanned offshore platform with a pipeline to a new gas processing facility to be sited on the mainland.

Government expects the new onshore processing facility will possibly help increase the security of gas supply into the domestic West Australian market. The processing facility could possibly add incremental processing capacity other than those located at Varanus Island and North West Shelf.

The field is planned to be developed with the objective of first production in 2008.

Location

65 km northwest of Exmouth

Basin

Carnarvon, offshore

Permit/Licence	
WA-255-P(2)	WA-32-L

Ownership	%
BHP Billiton Petroleum Australia Pty Ltd	50
Woodside Energy Limited BHP Billiton Petroleum Pty Ltd (Operator)	50

Contact

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Stybarrow (Oil)

In 1994, exploration permit WA-255-P(2) was awarded to BHP Billiton. The permit is approximately 90 km southwest of the Griffin development.

BHP Billiton owns a 50 per cent interest and is the operator of WA-255-P(2) with the other 50 per cent held by Woodside Energy Limited (WEL).

From February 2003 to July 2004, BHP Billiton executed an exploration and appraisal program in WA-255-P(2) resulting in the Stybarrow and Eskdale discoveries. A total of nine wells were drilled over this period.

The Stybarrow oil discovery was made in February 2003, when the Stybarrow-1 well encountered a gross oil-column of 23 m with 18.6 m of net pay in the Macedon Member Sandstone reservoir.

The Stybarrow field is located in a water depth of approximately 825 m and is approximately 65 km from Exmouth, off the northwest Australian coast.

Stybarrow-1 was followed by further wells: Eskdale-1 (March 2003), Skiddaw-1 and Skiddaw-2 (May 2003), and Stybarrow-2 (June 2003). Two appraisal wells, Stybarrow-3 and Stybarrow-4 and two exploration wells, Eskdale-2 and Knott-1, were drilled in the permit from April to July 2004.

Stybarrow-3, located approximately 2 km northeast of Stybarrow-1, encountered a gross oil column of 6.5 m, with the sidetrack well Stybarrow-4 intersecting a 16 m gross oil column. The water depth was 792 m.

Eskdale-2 encountered a gross oil-column of 13 m and a gross gas-column of 24 m at a water depth of 830 m.

Knott-1 was drilled in June 2004, and then plugged and abandoned in July.

In November 2005 the Stybarrow development was approved for development. The project involves a subsea development and a Floating Production Storage and Offtake (FPSO) facility which will be used to process, store and offload oil to export tankers. The vessel is disconnectable, double-hulled and able to process approximately 80,000 bbl/d of oil.

On 19th February 2007 the Stybarrow joint venture participants were awarded Production Licence WA-32-L.

Stybarrow and the adjacent small oil rim of the Eskdale field have recoverable oil reserves estimated in a range from 60-90 MMbbl of oil. First oil was produced two months ahead of schedule in November 2007 and the operation reached full production the following month. The estimated economic field life is 10 years.

The Stybarrow Venture MVI6.

Thevenard Island Oil and Gas

Location
25 km northwest of Onslow

Basin
Carnarvon, onshore and offshore

Permit/Licence					
EP357	TL/7	TL/4	TR/4	L12	L13

Ownership	%
Chevron Australia Pty Ltd (Operator)	25.713
Chevron (TAPL) Pty Ltd	25.713
Santos Offshore Pty Ltd	35.713
Mobil Australia Resources Company Pty Ltd	12.861

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Fax: +61 08 9216 4444
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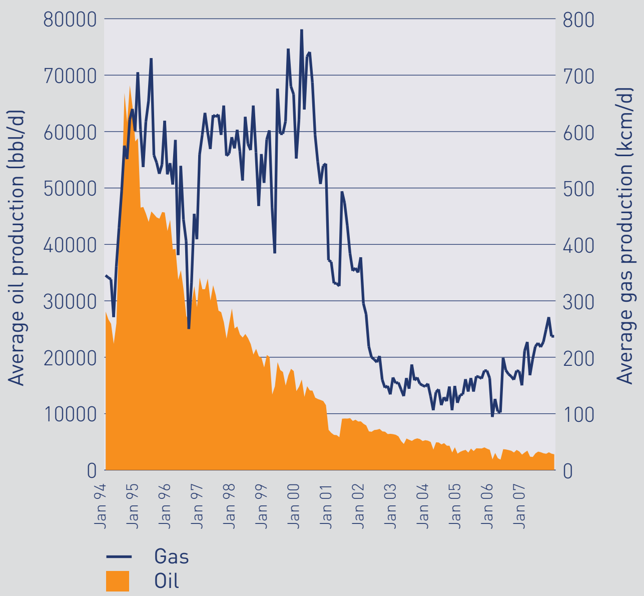
	Oil (bbl)	Gas (kcm)	Oil (bbl)	Gas (kcm)
	2006	2006	2007	2007
Cowle	26 839	2 346	13 825	1 169
Crest	7 517	5 298	6 686	4 641
Roller	468 894	15 805	415 360	18 110
Saladin	589 354	24 792	639 674	30 094
Skate	-	6 899	44	27 976
Yammaderry	937	16	-	-
Total	1 093 541	55 156	1 075 589	81 990



Thevenard

Thevenard Island provides the base for the processing and storage of hydrocarbons produced from the Saladin, Roller, Skate, Yammaderry, Crest and Cowle fields. The island infrastructure includes facilities capable of handling up to 120 000 bbl/d of mixed oil–water production, three 350 000-bbl oil tanks, water treatment and disposal facilities, pipelines, three gas-turbine generators, a gas-treatment plant, a 55 m^3 capacity slugcatcher/separator vessel and gas compression units. The joint venture announced in February 1999 that the facilities could be utilised by third parties for processing oil and gas production from nearby operations.

In February 2000, Chevron Australia Pty Ltd assumed the operatorship of Thevenard Island from WAPET and in 2001 Shell Development (Australia) Pty Ltd sold its interests in the Thevenard Island area production and exploration assets to Santos Offshore Pty Ltd.

Production Operations
Fluid produced from the six fields is piped to Thevenard Island where it is separated into oil, water and gas. The water is re-injected into the reservoirs while the oil is processed and blended together before being stored in tanks. It is then transported via a 610-mm, 7-km pipeline to offshore tankers berthed at a 10-point spread- mooring system. The crude (48o API gravity) is sold to refineries in Australia and overseas.

Saladin
The Saladin field was discovered in June 1985 and commenced production in November 1989. Eight wells are located offshore on three fixed mini-platforms and another eight wells are located on Thevenard Island.

Currently, one well is producing from the Barrow Group reservoir and eleven wells are producing from the Mardie Greensand reservoir. Fluid produced from each offshore platform and onshore well is transported through either 150 mm or 200 mm pipelines to separation facilities on Thevenard Island.

Gas injection through three wells is currently used to support pressure in the Mardie Greensand Formation. In addition, one horizontal producer has been converted to a water-injection service, following the installation of a water filtration system and a water-injection pump.

Thevenard Island Oil and Gas

The Mardie Greensand Formation is now the primary producing reservoir in the Saladin field with the original completions in the Flacourt Formation continuing to water-out. The joint venture estimates that the Mardie Greensand Formation contains oil-in-place of 55 MMbbl, with potential recoverable oil of 21 MMbbl.

Roller and Skate

The offshore Roller field was discovered in January 1990 and commenced production in May 1994. The field consists of four production wells and one gas-injection well which are linked to three unmanned monopods. Discovered in October 1991, the offshore Skate field commenced production in July 1994.

A 508-mm, 27-km three-phase production pipeline transports commingled oil from the two fields, together with associated gas and water, to separation facilities on Thevenard Island.

Total capital cost of the Roller and Skate development was $170 million.

Yammaderry and Cowle

Yammaderry and Cowle were each developed as single-well fields linked to separate offshore-unmanned monopods at a total capital cost of $30 million. Discovered in July 1988, the Yammaderry field commenced production in March 1991. After being shut-in throughout 1998, the field produced intermittently during 1999 following a workover of the Yammaderry-2 well. Production has continued from this well, at a very low rate. The well was shut-in for most of 2006.

Fluid is transported to Thevenard Island via a 150-mm, 2-km flowline that is connected to the Saladin C platform for processing with Saladin crude.

The Cowle field was discovered in December 1989 and commenced production in May 1991. The Cowle-4 well was completed in the Mardie Greensand as an oil producer in May 1999 and resulted in a four-fold increase in production for the year. Following the success of Cowle-4, Cowle-5 was also drilled into the Mardie Greensand, although with less encouraging results. A 200-mm, 10-km flowline transports fluid directly to Thevenard Island.

Crest

The onshore Crest field was discovered in February 1994 when the deviated Crest-1 well encountered hydrocarbons under Thevenard Island. The well was placed on an extended production test in June 1994.

In 1998, Crest-1 was abandoned and Crest-6 was drilled horizontally into the overlaying Mardie Greensand reservoir. Crest-6 produced at low oil rates and was shut-in in October 1998 pending the applications for a production licence. A production licence application over the Crest field (EP65) triggered the Native Title Act 1993 and the Right to Negotiate provisions. Extensive negotiations occurred with the Thalanyii people since November 1998. The matter ended in a determination in WAPET's favour. Legal discussions were finalised in 2002 and two production licences were granted over Thevenard Island (Production Licences L12 and L13). Production recommenced in December 2002 from the Mardie Greensand horizontal well Crest-6.

Potential Developments

The joint venture is continuing to evaluate potential developments within the permit areas that could be tied into existing production facilities on Thevenard Island.

Australind

Additional hydrocarbons were discovered in permit TP/3 (Pt 1) with the successful drilling of the offshore Australind-1 well in September 1993. Located about 5 km northeast of Thevenard Island, the well was drilled to a total depth of 1310 m in the Barrow Group Formation and encountered a 12-m gas-column associated with a minor oil-column. Australind-1 was abandoned. The development of this field remains marginal. The field is now covered by retention lease TR/4.

Coaster

In January 2000, the offshore Coaster-1 well intersected an 11-m net oil-column (30° API gravity) in the Barrow Group Formation after reaching a total depth of 1112 m. Located 5 km from Roller, the well was suspended as a potential oil producer.

Wandoo Oil

The Wandoo oil field was discovered in June 1991 in a water depth of 55 m. Production commenced in October 1993 under an extended production test using the Wandoo-A platform. First oil production from the Wandoo-B platform commenced in March 1997 and full field development was completed in June 1997. Total capital cost of the full development was $600 million.

There were three further horizontal wells drilled in late 2000, two on Wandoo-A and one on Wandoo-B.

In late 2006, Vermilion began the first phase of projects aimed at enhancing production and extending the reserve life. Vermilion significantly expanded our fluid handling facilities on the Wandoo B platform, installed a water-isolation plug in one well and ran production logs in several additional wells.

In early 2007, Vermilion successfully worked-over 2 wells for the recovery of bypassed oil zones. These are the first well interventions at Wandoo since the field was initially put on production in the mid-1990s. Production from these two wells increased by approximately 825 bbl/d.

On June 20, 2007, Vermilion closed the acquisition of an additional 40 per cent interest in the Wandoo field from Joint Venture Partner; Mitsui. This gave Vermilion 100 per cent ownership of the Wandoo field.

In 2008, activities will focus on the preparation to commence an attic oil infill drilling program in the second half of 2008. The drilling will target the interception of the oil column in the Wandoo field higher above the oil-water contact to improve the recovery of oil from this field. Preliminary estimates indicate potential well productivity of approximately 1,000 bbl/d per well, which would boost Vermilion's 2009 volumes.

Initial recoverable oil reserves were estimated at 75 MMbbl, giving the field a production life of around 20 years. The Wandoo crude has an API gravity of 19° with low-wax and low-pour-point properties, but high viscosity.

Wandoo Oil

Location
75 km northwest of Karratha

Basin
Carnarvon, offshore

Permit/Licence
WA-14-L

Ownership	%
Vermilion Oil & Gas Australia Pty Ltd	100

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Level 5, 30 The Esplanade
PERTH, WA 6000
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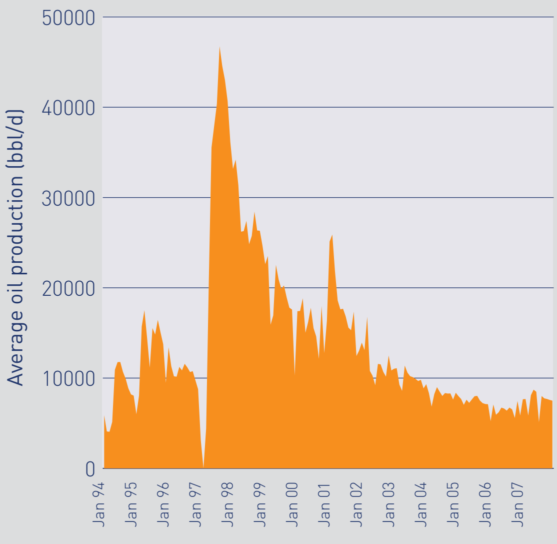
Fax: +61 8 9215 0333
Web: www.vermilionenergy.com

Production	2006	2007
Oil (bbl)	2 319 500	2 739 131
Gas (kcm)	46 370	37 475



Wandoo

Production facilities
Wandoo-A is a single column, monopod wellhead platform, which supports a deck and five production wells. Fluid produced from the wells is piped to the Wandoo-B platform, located to the northeast. Wandoo-B consists of a concrete gravity substructure (CGS) which supports steel topsides and provides storage capacity for 400 000 bbl of crude oil.

The 81 000-t CGS was constructed at a casting basin in the Port of Bunbury inner harbour. The completed CGS was floated out of Bunbury Harbour, towed 1760 km to the Wandoo field and then sunk into position on the seabed in October 1996. It was the first concrete seabed storage facility to be installed in Australia.

In January 1997, the topsides were installed on the CGS using the float-over method for the first time in Australian waters. The topsides support processing facilities, ten horizontal oil production wells, one gas injection well and an accommodation module.

The processing facilities were upgraded in 2006, to handle more than 157 000 bbl/d of total fluid and separate and process the fluids produced from both platforms. Typical production rates (2007) are 1200 kl/d of oil, 24 Ml/d of water and 160 kcm/d of gas. The water is treated and discharged into the ocean. Gas is used for reservoir gas-lift and fuel with excess gas re-injected into the reservoir.

Oil is stored in the CGS and then offloaded through two 348-mm flexible pipelines to a loading buoy located 1.2 km north of Wandoo-B. A floating hose is used to transfer the oil to export tankers at a mooring facility. Markets for the oil are mainly Japan.

Woodada Gas and Condensate

The Woodada gas field is located 275 km north of Perth and 13 km north west of the township of Eneabba. It was discovered in May 1980 and commenced production in May 1982.

Production Facilities

Processing facilities at Woodada include separation and compression units, a gas drying and sweetening unit, evaporation ponds and a condensate storage tank. The facilities had an early design-life capacity of 30 TJ/d.

A total of 18 wells have been drilled in the field, six of which are currently producing. Current field production is approximately 1.5 TJ/d.

Gas and condensate from the producing wells are collected by a 150 mm gas-gathering system. Following separation, dehydration and compression at the processing plant, the gas is transported via the Parmelia Pipeline, located 11 km north east of the field to Perth. Condensate (53.6° API gravity) is piped to a storage tank and then transported by truck to the BP refinery in Kwinana for processing.

Location

275 km north of Perth

Basin

Perth, onshore

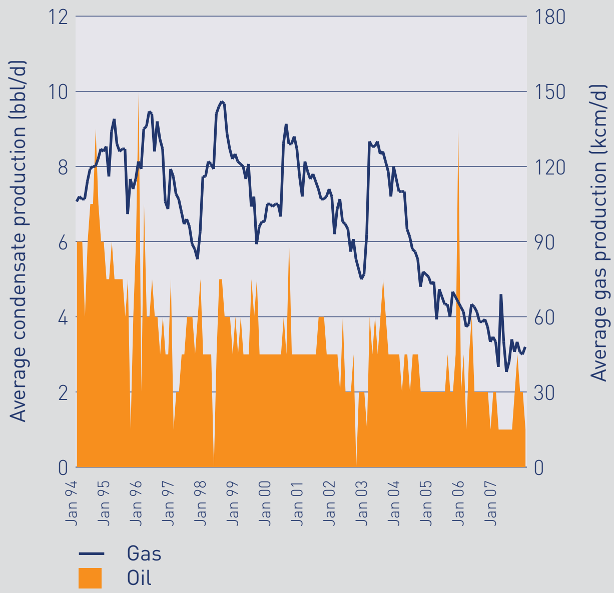
Permit/Licence		
L4	L5	PL/6

Ownership	%
ARC Energy Limited	100

Contact

ARC Energy Limited
Level 4, 679 Murray Street
WEST PERTH WA 6005
Tel: +61 8 9480 1300
Fax: +61 8 9480 1388
Email: arc@arcenergy.com.au
Web: www.arcenergy.com.au

Production	2006	2007
Oil (bbl)	-	-
Gas (kcm)	21 301	17 539
Condensate (bbl)	774	503



Woodada

Woollybutt Oil

Location
44 km west of Barrow Island

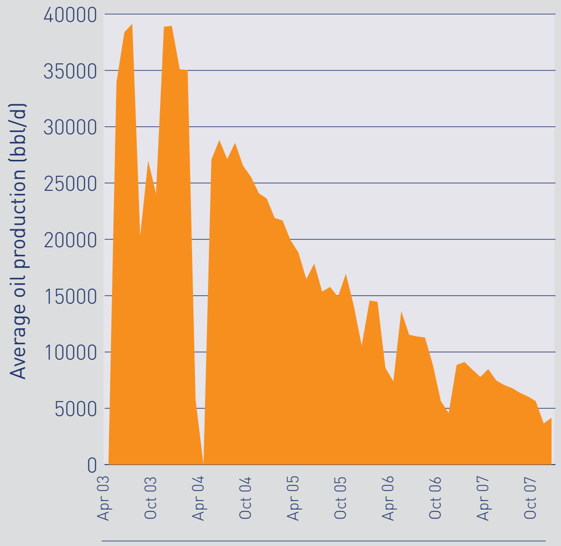
Basin
Carnarvon, offshore (Barrow Sub-basin)

Permit/Licence
WA-25-L

Ownership	%
Eni Australia Limited (Operator)	65
Mobil Exploration & Producing Australia Pty Ltd	20
Tap Oil NL	15

Contact
Eni Australia Limited
Level 3, 40 Kings Park Road
WEST PERTH WA 6005
PO Box 1265
WEST PERTH WA 6872
Tel: +61 8 9320 1111
Fax: +61 8 9320 1100
Email: info@eniaustralia.com.au

Production	2006	2007
Oil (bbl)	3 667 340	2 462 082
Gas (kcm)	17 388	12 498



Woollybutt

Exploration
The Woollybutt field was discovered in April 1997 by the well Woollybutt-1. This was followed by the drilling of a number of appraisal wells, which identified a separate accumulation to the south of the main field.

The exploration well Yarryi, drilled on a separate structure at the southeast of the field resulted in a dry hole.

Development
A development plan for the field was approved by the joint venture partners in the fourth quarter of 2001. The plan comprised tie-back of two subsea production wells to a leased FPSO facility. The Woollybutt-1 and Woollybutt-2 exploration and appraisal wells were re-entered in 2002 and sidetracked horizontally prior to completion as production wells. A contract with Vanguard SPC was executed in November 2001 for the provision and operation of the FPSO Four Vanguard. Production started on 29 April 2003 from the two initial horizontal wells. In 2005 the Scalybutt-1 exploratory well was sidetracked and completed as a horizontal producer, and later in the year it was tied-in to the existing production facilities. In October 2007 the Woollybutt-4 well was side-tracked and completed as a horizontal producer for the Woollybutt South lobe. The tie-in will take place in 2008.

The FPSO Four Vanguard is a double-hull converted tanker, with an internal mooring turret and a quick disconnectable mooring system. Design capacity of the production facilities is 40 000 bbl/d and the working storage capacity is about 580 000 bbls.

A total of 28.9 MMbbl, 49° API oil were produced to date (Nov 2007) and 76 offtake operations were successfully completed without accidents.

Project Details

Exmouth Plateau Gas

Location
250 km northwest of Onslow

Basin
Carnarvon, offshore

Permit/Licence
WA-364-P to WA-367-P

Ownership	
WA-364-P	
Chevron Australia Pty Ltd (Operator)	50%
Shell Development (Australia) Pty Ltd	50%
WA-365-P	
Chevron Australia (WA-365-P) Pty Ltd (Operator)	50%
Shell Development (Australia) Pty Ltd	50%
WA-366-P	
Chevron Australia (WA-366-P) Pty Ltd (Operator)	50%
Shell Development (Australia) Pty Ltd	50%
WA-367-P	
Chevron Australia (WA-367-P) Pty Ltd (Operator)	50%
Shell Development (Australia) Pty Ltd	50%
WA-383-P	
Chevron Australia (W05-13) Pty Ltd (Operator)	50%
Shell Development (Australia) Pty Ltd	50%

Contact
Chevron Australia Pty Ltd
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PERTH WA 6000
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Fax: +61 8 9216 4444
Web: www.chevron.com

Chevron, together with Shell was awarded four new exploration permits in June 2005 in the Exmouth Plateau (WA 364 P, WA 365 P, WA 366 P and WA 367 P) and a further block WA-383-P in August of 2006. Work is well advanced in these permits, including the acquisition of 5 833 km of 2D seismic data known as Leopard 2D MSS and the reprocessing of 20,206 km of legacy 2D data in 2006. The acquisition and processing of 4,144 km^2 of 3D seismic survey data, the Bonaventure MSS, in WA-364-P and WA-365-P was completed in the first half of 2007. Interpretation and analysis of the Bonaventure 3D will continue into 2008 in preparation for drilling 2 exploration wells in WA-365-P.

Greater Gorgon Area Gas

Location
200 km west of Dampier

Basin
Carnarvon, offshore

Permit/Licence			
WA-2-R	WA-3-R	WA-4-R	WA-5-R
WA-14-R	WA-15-R	WA-18-R	WA-19-R
WA-20-R	WA-21-R	WA-22-R	WA-23-R
WA-24-R	WA-25-R	WA-26-R	WA-205-P
WA-268-P	WA-374-P	WA-392-P	–

Ownership	
WA-2-R	
Chevron Australia Pty Ltd (Operator)	27.45%
Chevron (TAPL) Pty Ltd	22.55%
Shell Development (Australia) Pty Limited	25%
Mobil Australia Resources Company Pty Ltd	25%
WA-3-R, WA-4-R, WA-5-R, WA-14-R	
Chevron Australia Pty Ltd (Operator)	8/28
Chevron (TAPL) Pty Ltd	6/28
Shell Development (Australia) Pty Limited	25%
Mobil Australia Resources Company Pty Ltd	25%
WA-15-R	
Chevron (TAPL) Pty Ltd (Operator)	50%
Shell Development (Australia) Pty Limited	25%
Mobil Australia Resources Company Pty Ltd	25%
WA-18-R	
Mobil Exploration & Producing Australia Pty Ltd (Operator)	25%
Chevron (TAPL) Pty Ltd	50%
Shell Development (Australia) Pty Limited	25%
WA-19-R, WA-20-R, WA-21-R	
Chevron Australia Pty Ltd (Operator)	50%
Shell Development (Australia) Pty Limited	25%
Mobil Australia Resources Company Pty Ltd	25%

Project Details

Greater Gorgon Area Gas

WA-22-R, WA-23-R, WA-24-R, WA-25-R, WA-26-R	
Chevron Australia Pty Ltd (Operator)	25%
Chevron (TAPL) Pty Ltd	25%
Mobil Australia Resources Company Pty Ltd	25%
Shell Development (Australia) Pty Limited	12.5%
BP Exploration (Alpha) Ltd	12.5%
WA-205-P	
Chevron Australia Pty Ltd (Operator)	33.33%
Chevron (TAPL) Pty Ltd	33.33%
Shell Development (Australia) Pty Limited	33.33%
WA-268-P	
Chevron (TAPL) Pty Ltd (Operator)	100%
WA-374-P	
Chevron Australia Pty Ltd (Operator)	0%
Mobil Australia Resources Company Pty Ltd	25%
Shell Development (Australia) Pty Limited	25%
WA-392-P	
Chevron Australia (W06-12) Pty Ltd	50%
Shell Development (Australia) Pty Ltd	25%
Mobil Australia Resources Company Pty Ltd	25%

Contact

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Fax: +61 8 9216 4444
Web: www.chevron.com and www.gorgon.com.au

Greater Gorgon Area Fields

West Tryal Rocks was the first of the Greater Gorgon gas fields to be discovered in 1973 and this was followed by Spar in 1976. Up to 1999, a total of 14 exploration and appraisal wells had been drilled in the Greater Gorgon fields, comprising Gorgon (8), West Tryal Rocks (3), Chrysaor (1), Dionysus (1) and Spar (1). Guaranteed work commitments in exploration permits WA-205-P, WA-25-P and WA-267-P since 1999 have increased the number of wells in this area significantly. This recent exploration phase was extremely successful with six new gas discoveries in the Greater Gorgon area. These were Geryon, Orthrus, Maenad, Urania and Io in WA-267-P and Iago in WA 25 P–WA 253-P.

In 2002 and 2003, the Mobil-operated Jansz gas field has been further delineated with the drilling of Jansz-2 and -3. Jansz-2 was cored and Jansz-3 underwent production testing.

In 2004, a large 3D seismic program was acquired over the Io–Jansz gas field to further appraise the field in preparation of field development.

Chrysaor

Located immediately north of the Gorgon field in 806 m of water, the Chrysaor-1 exploration well was drilled to a total depth of 3597 m in December 1994. The well flowed gas at a maximum rate of 1798 kcm/d (63.5 MMcf/d) during production testing. Two retention leases were granted over the entire field, WA-14-R (from WA-205-P) and WA-15-R (from WA-253-P). These retention leases are currently pending renewal.

Dionysus

The Dionysus-1 well was spudded in 1100 m of water in June 1996 and was drilled to a total depth of 4417 m. The well flowed gas during two DSTs at a maximum rate of 1804 kcm/d (63.7 MMcf/d). Dionysus-1 intersected separate gas accumulations from those encountered in the Chrysaor field and established the presence of a second major gas field in permit WA-253-P. A retention lease (WA-15-R) was awarded over the Dionysus field on 20 April 2000 and is currently pending renewal.

Geryon, Orthrus-Maenad, Urania and Io

In August 1999, the joint venture commenced a significant deepwater drilling program involving six commitment wells in permit WA-267-P, located to the west of the Greater Gorgon fields. Drilling to date has resulted in five significant gas discoveries, Geryon-1, Orthrus-1, Urania-1, Maenad-1 and Io-1. The exploration success rate for this permit's drilling program was 83 per cent.

Geryon 1 was drilled in 1232 m of water and reached a total depth of 3515 m in September 1999. The well encountered a total net gas-pay of 113 m in three high-quality reservoir zones. Located 28 km southwest of Geryon in 1200 m of water, the Orthrus-well was drilled to a total depth of 3570 m in October 1999. The well encountered a total net gas-pay of 53 m in a high-quality reservoir zone.

In February 2000, 21 km northeast of Geryon, Urania-1 was drilled in 1200 m of water, reaching a total depth of 4010 m and encountering two high-quality reservoir zones with 54.5 m of total net gas-pay. Maenad-1, located 50 km southwest of Urania in 1220 m of water was drilled in March 2000. The well was drilled to a total depth of 2690 m and encountered two high-quality reservoir zones with a total net gas-pay of 20 m.

In January 2001, 2.5 km south-southeast of Geryon, Callirhoe-1 was drilled. While an unsuccessful exploration test of deeper reservoirs, it successfully appraised the Geryon gas accumulation.

The gas discovery, Io-1, was made in January 2001. Located 40 km northwest of Maenad in 1350 m of water, Io reached a total depth of 3020 m and encountered a single gas-bearing zone. Io-2 was spudded in May 2006.

Retention leases were awarded over all of the gas fields during 2003 and are named WA-19-R through to WA-26-R. Subsequent to the award of the gas retention leases, the remaining graticular blocks of WA-267-P were relinquished.

In 2006 the Duyfken 3D MSS was undertaken and a total of 3600 km2 of data was acquired, of which 71 km^2 was within WA-19-R and 80 km^2 was within WA-20-R.

Project Details

The Bollinger 2D seismic survey was acquired in January 2005 within WA 268 P. Acquisition totalled 3,728 km². This was followed by the Chandon well in June 2006, the Cygnet 3D survey (120 km²) in late 2006 and the The Centaur 3D survey in August 2007 (2629 km²).

In January 2006, Chevron, together with Shell and ExxonMobil were awarded a new exploration permit, WA 374 P, within the Greater Gorgon Area.

In mid-2006, the 3,600 km² Duyfken 3D survey was undertaken in WA-374-P. This survey also covered parts of WA-19-R, WA-20-R, WA-22-R, WA-24-R, WA-25-R and WA-26-R.

In July 2006, the Clio-1 exploration well was drilled in WA-205P, this was followed by the Draeck 3D survey , conducted in December/January 2007 and August 2007.

In February 2007, Chevron, together with Shell and ExxonMobil were awarded a new exploration permit, WA 392 P, within the Greater Gorgon Area. In August 2007, the 1682 km² Charon 3D survey was conducted in WA-392-P.

The Greater Gorgon Gas Resource Base

In January 1999, international petroleum consultants Netherland, Sewell and Associates, Inc. (NSAI) of Dallas Texas independently certified that proven hydrocarbon reserves for the Gorgon area fields were 360 Bcm (12.9 Tcf), including 270 Bcm (9.6 Tcf) for the Gorgon field itself. Proven and probable reserves exceed 500 Bcm (17.6 Tcf) and possible reserves extend the total to 608 Bcm (21.5 Tcf). The raw gas from these fields contains 12–15 per cent carbon dioxide.

In September 2003, NSAI independently certified additional proven hydrocarbon reserves of 3.2 Tcf for the Deepwater Fields of Geryon, Eurytion, Maenad, Orthrus and Urania. Proven and probable reserves for these fields are 4.4 Tcf and possible reserves extend the total to 6.1 Tcf of gas. The raw gas from these fields contains around 3 per cent inert gases, including carbon dioxide.

In addition to these significant reserves, other resources not independently certified, such as Janz and Io bring the total of the resource base up to 40 Tcf.

The Gorgon Project (oil, gas and condensate)

The Gorgon field was discovered in 1980 with the drilling of the Gorgon-1 well and was initially appraised with the drilling of North Gorgon 1 in 1982 and Central Gorgon-1 in 1983.

In July 1994, the North Gorgon-2 appraisal well was drilled to obtain a more accurate definition of the Gorgon reserves. The well flowed gas at a maximum rate of

1764 kcm/d (62 MMcf/d) during drillstem tests (DSTs). The North Gorgon-2 well confirmed the northern extension of the Gorgon field (within the main horst) and the existence of gas-bearing sands previously inferred from 3D seismic data.

To delineate further reserves and to aid in the selection of development options and sites within the North Gorgon field, two appraisal wells were drilled in 1995–96. The North Gorgon-3 vertical appraisal well was drilled to a total depth of 4628 m in December 1995 and intersected a gas-column. The well helped define the northern extension of the Gorgon field (further north of the main horst).

The North Gorgon 4 vertical appraisal well was drilled to a total depth of 4170 m in February 1996. The well flowed gas at a maximum rate of 1050 kcm/d (37 MMcf/d) during DSTs. The results of the tests indicated the presence of gas-bearing sands in a previously undrilled North Gorgon fault block (west of the main horst block).

In October 1998, the Gorgon 3 appraisal well was drilled to provide critical data on well productivity and fluid compositions. The well encountered over 398 m of permeable gas sands and flowed gas at a maximum rate of 1790 kcm/d (63.2 MMcf/d) during testing of two separate intervals. The high flow rates confirmed the enormous delivery of the Gorgon reservoirs.

North Gorgon-6, the final appraisal well in the Gorgon field, was drilled to a total depth of 4290 m in November 1998. The well encountered a total, net, gas-pay of 157 m and confirmed the continuity of the reservoir

The Triton 3D seismic survey was undertaken in 2006 and covered an area of 925 km².

Gorgon FEED progress

The Gorgon Project is globally significant with a resource base of more than 40 tcf and a development life of around 60 years. Chevron, ExxonMobil and Shell are committed to the Project and aligned on the way forward.

In 2005, the Gorgon Project - Chevron (50 per cent ownership), ExxonMobil (25 per cent) and Shell (25 per cent) - commenced front-end engineering and design (FEED) for the Gorgon Gas Project development.

The Gorgon Project entails the construction of a pipeline to transport natural gas from the Gorgon field to Barrow Island where a two train, 10 Mt/a-capacity liquefaction plant is to be constructed.

In late 2005 Chevron Australia entered into Heads of Agreement for the sale of Gorgon LNG with three major Japanese utilities:

Tokyo Gas for 1.2 Mt/a over 25 years

Chubu Electric for 1.5 Mt/a over 25 years

Osaka Gas for 1.5 Mt/a over 25 years.

In 2007 Chevron Australia entered into Heads of Agreement for the sale of 0.25 Mtpa of Gorgon LNG over 20 years to GSCaltex, a major energy producer and distributor in South Korea.

State and Commonwealth Government environmental approval was received in September and October 2007 and was the culmination of an extensive and collaborative process initiated in 2003.

Looking forward, it would be government's expectation that the project will have a continued focus on Gorgon's engineering and design work, completing the required environmental management plans and finalising risk mitigation studies and long-term resource planning.

Project Details

Ichthys Gas and Condensate

Location
440 km north of Broome

Basin
Browse, offshore

Permit/Licence
WA-285-P

Ownership	%
INPEX Browse Ltd (Operator)	76
Total	24

Contact
INPEX Browse Ltd
2 The Esplanade
PERTH WA 6000
Tel: +61 8 9223 8433
Fax: +61 8 9223 8455
Web: www.inpex.co.jp/english/

The Ichthys gas and condensate field was discovered in 1980 and is located in 250 metres of water.

After 2003 and 2004 drilling activities for Ichthys field exploration and appraisal in WA-285-P R1, INPEX conducted Ichthys Field development preparation work and remaining exploration potential evaluation.

The geological and geophysical studies focused primarily on identifying and evaluating leads and prospects for further drilling, utilising all data sources including the large amount of new information from the previous year's drilling campaign.

Development of the field is planned to include off-shore semi-submersible facilities and a sub-sea pipeline to a land-based liquefied natural gas plant and export facility. The company is also looking at new technologies associated with gas-to-liquids and di-methyl ether, as well as possibilities for domestic supply. Potentially, an LNG processing plant will be put onshore in the remote Kimberly area of WA.

Ichthys will produce an initial 6Mt/a of LNG, with scope for another train of 6 Mt/a. About 100 000 bbl/d of condensate and liquefied petroleum gas will be produced at peak. The project is expected to start up in about mid-2012.

An agreement was reached in 2006 for Total to acquire a 24% interest in the Ichthys gasfield.

Reserve estimates for the Ichthys field is approximately 9.5 Tcf of gas and 310 MMbbl of condensate.

Macedon Gas

Location
40 km north of Exmouth

Basin
Carnarvon, offshore

Permit/Licence
WA-12-R

Ownership	%
BHP Billiton Petroleum Australia Pty Ltd	71.43
Apache Energy Limited BHP Billiton Petroleum Pty Ltd (Operator)	28.57

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BHP Billiton Petroleum Pty Ltd
Level 42, Central Park
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The Macedon field was discovered in November 1992 by the West Muiron-3 well which encountered a gas column in excess of 81 m, but did not establish a hydrocarbon–water contact. The well was subsequently plugged and abandoned as a gas discovery after being drilled to a total depth of 1200 m. In May 1993, the West Muiron-4 well was drilled to a total depth of 1550 m and was suspended as a potential gas producer.

In November 1994, the joint venture successfully completed a five-well appraisal-drilling program in the Macedon field. The wells confirmed the structural interpretation, gas-water contact, reservoir distribution and production of the field. All the wells were plugged and abandoned, as programmed, with the exception of Macedon-4, which was suspended as a potential gas producer.

Gas marketing and development

The joint venture estimates that Macedon contains a gas resource of up to 0.7 Tcf. Gas recovered to date is dry containing no condensate or LPG. BHP Billiton has commissioned selection studies into the viability of a domestic gas project based on the Macedon field.

Based on preliminary plans, the project would incorporate subsea wells approximately 20 km offshore from North West Cape, the gas would come ashore at Tubridgi, south of Onslow and once processed enter the DBNGP.

Project Details

Julimar / Brunella Gas

Location
52 km northwest of Montebello Islands

Basin
Carnarvon Basin, offshore

Permit/Licence
WA-356-P

Ownership	%
Apache Energy Ltd	65
Kufpec Australia Pty Ltd	35

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Level 3, 256 St George's Terrace
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Fax: +61 8 9422 7447
Web: www.apache-energy.com.au

Julimar is just north of the West Tryal Rocks field and southwest of the Pluto field – both multi-Tcf discoveries in analogous reservoirs. Julimar is also northeast of Gorgon, which is part of a potential 40 Tcf of gas.

In 2007 Apache began appraising the Julimar complex. Julimar-1, a wildcat well drilled during the first half of 2007, discovered 40 m of net pay in the Mungaroo on-trend with other significant fields. A combined 85 MMcfd of gas flowed from zones surrounding two of the four gas-bearing fluvial channel sands encountered.

In the first half of 2007 Julimar East-1, an appraisal well, was drilled 5.8 km northeast of the Julimar-1 location. The well logged 224 feet of net gas pay and six sandstone reservoirs of the Triassic Mungaroo formation.

In the second half of 2007 Apache made its third consecutive gas find on the Northwest Shelf. Brunello-1 encountered 121 feet of net pay in the prolific Triassic Mungaroo formation. Estimated to contain 300 Bcf of recoverable resources, and flowing 72.5 MMcf of gas and 1230 bbl/d of condensate on test from a single pay zone, Brunello-1 will be suspended as a future production well.

In early 2008 Brulimar-1 a wildcat was drilled and encountered 113 feet of net pay in the Upper Triassic Mungaroo.

Apache estimates the Julimar complex to have a 2-4 Tcf potential. This year the company is planning to drill 52 wells, including 32 exploration wells. The schedule includes four additional exploration wells on the Julimar-Brunello trend.

Julimar/Brunella Gas.

Project Details

Outer Browse Basin Gas

Location
425 km north of Broome

Basin
Browse, offshore

Permits	
WA-301-P	WA-302-P
WA-303-P	WA-304-P
WA-305-P	WA-28-R
WA-29-R	WA-275-P
WA-30-R	WA-31-R
WA-32-R	TR5
R2	AC/RL8

Ownership	
WA-301-P	
BHP Billiton (Operator)	50%
CNOOC	25%
Total	25%
WA-302-P	
BHP Billiton (Operator)	100%
WA-303-P, WA-304-P, WA-305-P	
BHP Billiton (Operator)	25%
CNOOC	25%
Total	25%
Anadarko	25%
WA-28-R, WA-29R, WA-275-P	
BHP Billiton	20%
Woodside (Operator)	25%
BP	20%
Chevron	20%
Shell	15%
WA-30-R, WA-31-R, WA-32-R, TR5, R2	
BHP Billiton	8.33%
Woodside (Operator)	50.00%
BP	16.67%
Chevron	16.67%
Shell	8.33%
AC/RL8	
BHP Billiton (Operator)	100%

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Web: www.bhpbilliton.com

BHP Billiton is the operator of five permits in the deepwater Outer Browse Basin, located west of the Brecknock and Torosa discoveries. The Outer Browse is a relatively high-risk frontier basin with the potential to deliver large volumes of gas for LNG supply.

During 2006, acquisition of 3D seismic data over the Dacey prospect in our 100%-owned WA-302-P permit was undertaken and during 2007 the data was processed and interpreted.

In early 2007, BHP Billiton and its partner Anadarko farmed out equity to permits WA-301-P, WA-303-P, WA-304-P and WA-305-P to Total and CNOOC. The WA-303-P joint venture commenced drilling of the Warrabkook-1 exploration well in December 2007. The well is in approximately 1517 m of water and is located 410 kilometres northwest of Broome and 450 kilometres west of Derby. Drilling is scheduled to be completed in early 2008.

BHP Billiton is a joint venture partner in various Woodside-operated leases covering the Brecknock, Calliance and Torosa gas discoveries. A significant program of appraisal has been underway since 2005 to better define the commercial potential of these resources and to determine an optimum development strategy. Exploration drilling at the Snarf-1 exploration well in permit WA-275-P also commenced during 2007, but will not be completed until 2008 due to rig availability constraints.

Project Details

Pluto Gas and Condensate

Location
190 km northwest of Karratha

Basin
Carnarvon, offshore

Permit/Licence
WA-350-P

Equity Holding	%
Woodside Energy Ltd. (Operator)	90
Kansai Electric Co	5
Tokyo Gas Co	5

Contact
Woodside Energy Ltd.
240 St George's Terrace
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Tel: +61 8 9348 4000
Fax: +61 8 9214 2777
Toll-free: 1800 634 988
Web: www.woodside.com.au

The Pluto field was discovered in April 2005. The dry gas resource estimate for the Pluto field is 4.4 Tcf. A smaller field, Xena, with a dry gas estimate of 0.6 Tcf was also discovered in the WA-350-P permit and will be incorporated into the Pluto development.

The project includes an offshore production system, offshore platform in 85 m of water and a pipeline of approximately 180 km to shore where the new Burrup LNG Park is to be built. The Burrup LNG Park will include a single processing plant, with a forecast production capacity of 4.3 Mt/a, storage facilities and an export jetty.

Agreements were reached with Tokyo Gas and Kansai Electric in early 2006 for the supply of a combined 3.25 to 3.75 million tonnes of LNG a year from the Pluto gas field. The agreement included an option for the customers to each purchase a five per cent equity interest in the Pluto project.

Following the receipt of all relevant government approvals site works for the LNG tanks commenced in January 2007. In July 2007 Woodside approved funding of up to $11.2 billion for the initial phase of the project.

The Western Australian Government finalised project environmental approval in September 2007 followed by Commonwealth environmental approval in October 2007. Site preparation for the LNG plant commenced in October.

The first gas from the Pluto field is expected to be produced in late 2010.

Project Details

Pyrenees Oil

Location
45 km north of Exmouth

Basin
Carnarvon, offshore

Permit/Licence	
WA-155-P(1)	
Ownership	**%**
BHP Billiton Petroleum Australia Pty Ltd	39.999
Apache Energy Ltd	31.501
Inpex Alpha Ltd BHP Billiton Petroleum Pty Ltd (Operator)	28.500

Permit/Licence	
WA-12-R	
Ownership	**%**
BHP Billiton Petroleum Australia Pty Ltd	71.43
Apache Energy Limited BHP Billiton Petroleum Pty Ltd (Operator)	28.57

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Permits WA-12-R and WA-155-P(1) are located offshore in the Exmouth Sub-basin, approximately 70 km southwest of the Griffin development and approximately 20 km east of the Stybarrow development [WA-255-P(2)].

BHP Billiton owns a 71.43 per cent interest in, and is the Operator of, WA-12-R with 28.57 per cent held by Apache Energy Limited. BHP Billiton owns a 39.999 per cent interest in, and is Operator of, WA-155-P(1) with Apache Energy Ltd and Inpex holding 31.501 per cent and 28.5 per cent respectively.

In July 2003, the semi-submersible SEDCO 703 drilled Ravensworth-1 on the WA-155-P(1) and WA-12-R boundary, encountering a gross oil-column of 37 m and gross gas-column of 7 m with 43.5 m of net pay in the Lower Barrow Group sandstone reservoir. Crosby-1, located in WA-12–R, was drilled in October 2003 intersecting a 35-m gross oil-column in the target Pyrenees Member Sandstones.

Exploration activity during 2004 by BHP Billiton in WA-155-P(1) and WA-12-R focused on a drilling program to appraise the Ravensworth and Crosby oil discoveries and test adjacent fault blocks. The first well in this program, Stickle-1, intersected a 26.8-m gross oil-column while the second, Harrison-1, intersected 7-m of gross oil-pay, both within the Pyrenees Member Sandstones.

The Crosby-2 appraisal well, located 2.7 km northeast of Crosby-1, was drilled in May and June 2004, and encountered a 25-m gross oil-column in the Pyrenees Sandstone. Ravensworth-2, located 2.1 km northeast of Ravensworth-1, intersected a 29-m gross oil-column within the Pyrenees Sandstone. Both Crosby-2 and Ravensworth-2 were successful in defining the northern extension of each of the oil accumulations in these fields.

From July to August 2004, the Stickle-2 and Stickle-3 appraisal wells were drilled in WA-12-R using the Atwood Eagle, a deepwater, semi-submersible rig. Stickle-2, located approximately 2.5 km northeast of Stickle-1, intersected a gross oil-column of 23 m. The subsequent sidetrack well, Stickle-3, obtained further well engineering and drilling data.

The Stickle, Harrison, Crosby and Ravensworth oil discoveries occur over a series of adjacent faults known as the Pyrenees oil fields in a water depth of around 200 m.

The Pyrenees project was sanctioned in July 2007.

The project incorporates a Floating Production, Storage and Offtake (FPSO) facility and the development of 13 subsea wells tied back to this facility. The field is estimated to have an economic life of 25 years.

The Pyrenees fields of Crosby, Ravensworth and Stickle have estimated recoverable oil reserves in the range of 80-120 MMbbl. Water depth across the development area is between 170 to 250 m.

Pyrenees is BHP Billiton's second recent FPSO development in the region.

The FPSO vessel will be disconnectable, double-hulled and able to process approximately 96,000 barrels of oil a day. Oil export will be via shuttle tankers.

The Pyrenees WA-12-R project has been subjected to a comprehensive environmental impact assessment process that has involved extensive consultation with the local community and other key stakeholders.

Project Details

Scarborough Gas

Location
270 km northwest of Onslow

Basin
Carnarvon, offshore

Permit/Licence
WA-1-R

Ownership	%
Esso Australia Resources Pty Ltd (Operator)	50
BHP Billiton Petroleum (Australia) Pty Ltd	50

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Permit/Licence
WA-346-P

Ownership	%
BHP Billiton Petroleum (Australia) Pty Ltd (Operator)	100

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BHP Billiton Petroleum Pty Ltd
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The Scarborough gas field was discovered in 1979 by the drilling of Scarborough-1 well in more than 900 m of water. The gas field is a relatively simple anticlinal structure at a depth of about 1800 m. At the time of discovery, the lack of technology and undeveloped gas markets made the remote, deepwater gas field uneconomic to develop.

In early 1996, a 2440 km^2 seismic survey was completed over the field to define possible well locations for appraisal drilling. Based on this data, the Scarborough-2 appraisal well was spudded in June 1996 and drilled to a total depth of 2068 m measured depth.

In July 2003, BHP Billiton was awarded exploration permit WA-346-P, immediately to the north of Retention Lease WA-1-R, which BHP Billiton hold jointly with Esso Australia. These blocks are in water depths of 900 to 1500 m and contain the Scarborough gas field, discovered in 1979. WA-346-P also contains the smaller Jupiter gas discovery and has potential for further gas resources.

During 2004, BHP Billiton acquired a 912 km^2 3D seismic survey over the Scarborough field in both the permits. BHP Billiton operated the acquisition of the survey in WA-1-R with the agreement of Esso Australia. In December 2004, BHP Billiton commenced a three-well appraisal drilling program of the Scarborough gas field.

During 2006, drilling results from the 2004-2005 appraisal campaign at Scarborough were incorporated into resource modelling for the field.

In July 2007 the semi-submersible Atwood Eagle rig drilled the Thebe-1 well in Permit WA-346-P. Drilling reached a total depth of 2510 m after encountering a gross gas-column of between 96 and 108 m. The Thebe reservoir is approximately 50 km north of the Scarborough gas field in which BHP Billiton has a 50 per cent interest. In September 2007, BHP Billiton completed acquisition of the 1200 km^2 HEX07B seismic survey, which was designed to appraise the Thebe discovery and to improve understanding of adjacent exploration opportunities.

Gas Marketing and Development

The Scarborough gas field is under retention lease and the WA-1-R Joint Venture partners are examining a range of onshore and offshore options for commercialisation.

BHP Billiton holds exploration permit WA-346-P, immediately adjacent to the north of Retention Lease WA-1-R, which it holds jointly with Esso Australia. WA-1-R contains the Scarborough gas field, which was discovered in 1979. WA-346-P contains the Thebe-1 well ans smaller Jupiter gas discovery.

In late 2004 and early 2005 three appraisal wells in WA-1-R (Scarborough-3, Scarborough-4A and Scarborough-5) were completed to further delineate the field. BHP undertook this operation on a sole risk basis without contribution from Esso.

These three wells all encountered hydrocarbons and were plugged and abandoned. Significant and ongoing processing and interpretation of the drilling results and 3D seismic data acquired in 2004 was conducted during 2005.

Project Details

Tern–Petrel Gas

Location
250 km west of Darwin

Basin
Bonaparte, offshore

Permit/Licence		
WA-27-R	WA-6-R	NT/RL-1

Ownership	
Tern	%
Santos Ltd Group	100
Petrel	%
Santos Ltd Group	95
Origin Energy Bonaparte Pty Ltd	5

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Tern
The Tern field is located approximately 60 km from Petrel in Western Australian waters within permit WA-27-R. It was discovered in 1971 when the Tern-1 well encountered more than 36-m of gross-pay and flowed gas at a rate of 7 MMcf/d. In 1982, Tern-2 intersected over 28-m of gross-pay and flowed gas at rates of up to 14.8 MMcf/d. The Tern-3 well, drilled in 1988 on a satellite structure to the south, was dry.

Tern-4 was drilled to a total depth of 2633 m in October 1994 and confirmed the existence of gas in the southeast area of the field. Tern-4 was not completed as a production well as the hole was specifically designed to provide information on the reservoir.

In January 1998, the Tern-5 well flowed gas at a rate of 15.8 MMcf/d and indicated a gross gas-column of 35 m after reaching a total depth of 2702 m.

The joint venture estimates that the Tern and Petrel fields contain a contingent gas resource of 1.4 Tcf.

Petrel
The Petrel field is located on the Western Australian – Northern Territory seabed border in permits WA-6-R and NT/RL-1. Six wells have been drilled in the field, including the discovery well in May 1969 which blew out for a period of 14 months prior to drilling a relief well. The five subsequent wells were successful in delineating the field with recorded rates ranging from 14.5–28.7 MMcf/d.

Petrel-5 flowed gas at a rate of 34.6 MMcf/d and condensate at a rate of 16.6 bbl/d in October 1994. Located in the western side of the field within WA-6-R, the well was plugged and abandoned. In November 1995, Petrel-6 was drilled to a total depth of 3915 m but was plugged and abandoned after failing to intersect the reservoir sands that were targeted.

During September-October 2007 the 930 km^2 Petrel 3D Marine Seismic Survey was acquired and at time of writing was being processed.

Project Details

Torosa–Brecknock–Calliance
Gas and Condensate[1]

Location
425 km north of Broome

Basin
Browse, offshore

Permit/Licence		
WA-28-R to WA-32-R	TR/5	R2
Ownership		**%**
Woodside Energy Ltd. (Operator)		25
BP Developments Australia Ltd		20
Chevron Australia Pty Ltd		20
BHP Billiton Petroleum (NWS) Pty Ltd		20
Shell Development (Australia) Pty Ltd		15
WA-30-R to WA-32-R	TR/5	R/2
WA-30R to WA-32-R	*TR/5 R/2*	**%**
Woodside Energy Ltd. (Operator)		50.00
BP Developments Australia Ltd		16.67
Chevron Australia Pty Ltd		16.67
BHP Billiton Petroleum (NWS) Pty Ltd		8.33
Shell Development (Australia) Pty Ltd		8.33

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[1] The operator refers to this project as *their* Gas Browse Project. Reader not to confuse with geographic and geological location known as the *Browse Basin*, as this is held by a number of joint venture partners.

The Torosa gas discovery was made in 1971. The Brecknock gas discovery was made in 1979 with the Brecknock-1 well intersecting a net gas–condensate interval of some 72.5 m.

The Calliance gas discovery was made in 2000 and intersected a net gas-column of 119 m. With the exception of the Torosa field areas around Scott Reef, all fields are in water depths ranging from 400–800 m.

LNG Development
Woodside, as operator, has identified five potential development concepts for the commercialisation of the Browse gas fields. Detailed studies are under way on:

- Browse gas to Kimberley;
- Browse gas to Burrup;
- Browse gas to an Offshore LNG facility at Scott Reef.

Floating LNG and production in Darwin LNG are also being evaluated as potential alternatives. Technical, environmental and social impact studies are underway, including consultations with a broad range of stakeholders on the short-listed development concepts, with the aim of selecting a preferred location for the LNG processing facility in the second half of 2008.

Studies for all concepts are based on a two or three-train facility. Processing capacity will be firmed up with concept selection and is expected to be up to 15 Mt/a of LNG.

In parallel to the concept definition studies, field appraisal continued in 2007, with 3D seismic data acquired over the southern part of the Torosa gas field at Scott Reef (Maxima) and over the Calliance gas field. Three more appraisal wells were also drilled during the year, making a total of 13 wells on the three fields.

In 2007 Woodside secured Key Terms Agreements (KTAs) with PetroChina and CPC Corporation Taiwan for the supply of up to 6 Mt of LNG from its Browse LNG Development from 2013-2015. The KTAs are available to its Browse Joint Venture Participants.

Project Details

Van Gogh Oil

Location
53 km north-northwest of Exmouth

Basin
Exmouth sub-basin, offshore

Permit
WA-20L

Ownership	%
Apache Northwest Pty Ltd (Operator)	52.50
Inpex Corporation Ltd	47.50

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Apache's proposed Van Gogh oil field development is located off the coast of Exmouth. Van Gogh is part of the greater Vincent field and is located 53 km north-northwest of Exmouth and 30 km from the outer boundary of the Ningaloo Marine Park.

The development is expected to have a life of 12-15 years and, subject to obtaining all the necessary government approvals, the field installation of Van Gogh is expected to start in late 2008 and be in production by early to mid-2009. Apache is the operator of the $500-million Van Gogh development, which will utilise a floating production, storage and offloading vessel (FPSO) to tap fields discovered in 1999. The FPSO will have processing capacity of 63 000 bbl/d of oil and storage capacity of 620 000 bbl of oil.

The Vincent-1 discovery on the Vincent-Van Gogh structure, drilled in November 1999, encountered a 28-ft (8.5-m) gas column and a 62-ft (19-m) oil-column in the Lower Cretaceous Barrow Sandstones, and was quickly followed by the successful Vincent-2 appraisal well in February 2000. Apache participated in the first appraisal drilled by BHP Billiton in the WA-155-P (Part 1) concession – the Van Gogh-1/ST-1, in September 2003. The well encountered a 30-ft (9-m) oil- column with no gas-cap.

After the Van Gogh-1/ST-1, Apache and Inpex Corporation picked up BHP's share of the field and Apache became operator of the development. The final appraisal well prior to development, Theo-1, was drilled in April 2006 and encountered a 66-ft (20-m) gas-column and a 46-ft (14-m) oil-column. In June 2007, the Theo 3-H flowed 9 694 bbl/d of oil in a test of the first horizontal well at Van Gogh.

Wheatstone and Iago
In December 2000, the joint venture drilled Iago-1. Situated 6.4 km north of North Tryal-Rocks 1, Iago-1 was drilled in 118 m of water, reaching a total depth of 3354.5 m. A single reservoir with 20 m of net gaspay was encountered. Retention Leases WA-16-R (from WA-25-P) and WA-17-R (from WA-253-P) were granted in 2002 over the Iago field. The WA-25-P permit has since been relinquished.

Wheatstone and Iago Gas

Location
200 km west of Dampier

Basin
Carnarvon, offshore

Permit		
WA-253-P	WA-17-R	WA-16-R

Ownership	
WA-253-P	%
Chevron Australia Pty Ltd (Operator)	50
Chevron (TAPL) Pty Ltd	50
WA-17-R	%
Chevron Australia Pty Ltd (Operator)	50
Chevron (TAPL) Pty Ltd	50
WA-16-R	
Chevron Australia Pty Ltd (Operator)	42.86
Chevron (TAPL) Pty Ltd	23.81
Shell Development (Australia) Pty Limited	33.33

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In July 2004, Chevron, at 100 per cent equity, drilled the Wheatstone 1 wildcat targeting the Triassic AA sands of the Mungaroo Formation. Situated 12 km west of the Iago-1 discovery well, Wheatstone was drilled in 215 m water and reached a total depth of 3410 m. The well encountered 126 m of hydrocarbon column within the Tithonian and Triassic Mungaroo AA sands. A 50.5 m conventional core was cut and a DST was undertaken over the lower AA sands. Gas flowed at a rig-constrained rate of 54 MMcf/d.

In 2005 the Wheatstone 3D seismic survey was undertaken to improve field delineation. Acquisition took place in the first quarter of 2005, covering WA 253 P, WA 16 R and WA 17 R. Total acquisition was 766 km2.

Office studies continue with a focus on the Wheatstone geology, geophysics, reservoir and production engineering and facilities engineering for development alternatives. Meanwhile, Chevron continues to examine commercial options for the development of the fields.

To enhance knowledge of the resource, the Wheatstone-2 appraisal well was drilled in October 2007 to a target depth of 3520 m.

In early 2008 it was reported that Chevron had made a decision to promote the Wheatstone gas reservoir for export LNG opening a new window on Australia's offshore gas development.

Project Details

Whicher Range Gas

Location
21 km south of Busselton

Basin
Perth, onshore

Permit
EP 408

Ownership	%
Whicher Range Energy Pty Ltd. (Operator)	100

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Union Oil discovered the Whicher Range gas field in 1968 when the Whicher Range-1 well flowed a gas rate of 54 kcm/d (1.9 MMcf/d) from a 9-m sand. Several other sands were also tested, making a cumulative gas rate of 156 kcm/d (5.5 MMcf/d) from these individual sands. Because of the gas prices at the time, the field developed was rendered uneconomic.

Mesa Petroleum and British Petroleum drilled two subsequent appraisal wells in 1980 and 1982 respectively. These wells confirmed the significant size of the field, however, the flow rates from the tight sands were still not enough to justify the field development.

Hydraulic fracture stimulation

Amity Oil took over the rights to the Whicher Range permit in July 1997 with the intention of applying fracture stimulation technology. As a result, Amity farmed-in Pennzoil Exploration Australia and participated in the Whicher Range-4 drilling, Whicher Range-1 re-entry and fracture stimulation of these wells. The projects were completed in June 1998 and were operated by Pennzoil.

Whicher Range-4 was fracced in four zones and Whicher Range-1 in three zones. In spite of the fracs completion as planned, the well productivities were disappointing, the stabilised gas flows being 40 kcm/d (1.4 MMcf/d) from each well. Moreover, these gas flow rates were lower than pre-frac measurements.

The investigation conducted to explain this unusual behaviour concluded that the water-based filtrate of the fracturing fluid caused water blockage in the fracture walls, restricting severely the gas flow from the reservoir to the fracture. As a result, a remedial stimulation to remove the water-block was recommended.

Remedial stimulation – Whicher Range–4

Based on petrophysical work on a reservoir core sample, Stimlab Inc. recommended a high-pressure injection of liquid carbon dioxide into the Whicher Range-4 well. The injected carbon dioxide would dissolve into the water phase of the water-block, then the combined effect of Formation temperature and pressure reduction, caused by blowing down the well to atmosphere, would generate carbon dioxide expansion and rapid withdrawal from the sand face, removing in this way the water-block.

In late 1999, Amity (86 per cent) and GeoPetro Resources Company (14 per cent) undertook the remedial program, which resulted in the well flowing gas at a stabilised rate of 87 kcm/d (3.08 MMcf/d). Subsequent production logging indicated that only one sand was producing out of three zones; therefore, if these three zones were properly remedially stimulated, the total well flow rate would have been even higher.

Whicher Range-4 was suspended as a future commercial production well. The success of fracture stimulation and the remedial program, which more than doubled the gas flow rate from the well, indicated that fracture stimulation could generate commercial flow rates from the reservoir, provided minimum skin damage was achieved.

Whicher Range-5

Amity Oil drilled Whicher Range-5 from October 2003 to January 2004. The initial drilling design included the air drilling of the whole Sue Reservoir section to eliminate skin damage, but after the failure of three attempts to air drill this section the well was drilled using conventional KCL mud.

While air drilling moderate gas flows were noted, indicating the reservoir gas content.

Project Details

Whicher Range-5 Fracture Stimulation

To neutralise potential water blockage and eliminate skin damage the use of diesel base-fracturing fluid was recommended. The procedure entailed under-balanced, oriented perforations.

The reservoir is composed of 17 sand layers of 5 m to 30 m thickness, from which five prominent sands were chosen to be frac stimulated. It was expected that through vertical fracture growth, the adjacent sands would also be stimulated.

Unfortunately, a higher than expected fracture gradient complicated the fracture operation. The high rock stress caused injection pressure greater than the surface facilities pressure rating. In spite of these drawbacks, four fracs were conducted from July to October 2004, from which two were successfully completed.

At this stage it was clear that the area around Whicher Range-5 presented unusual high rock stress, complicating any fracture operation. Moreover, it was apparent that to achieve reasonable fracture geometry, higher-pressure-rated facilities and additional numbers of pumps would be required, making the project uneconomical. For these reasons it was decided to terminate the fracture campaign.

Whicher Range-5 Well testing after Fracture Stimulation

Following the termination of the fracturing campaign, the bridge plugs were drilled, the diesel unloaded and the well left to flow for clean-out. The total diesel injected during the campaign was 7450 bbl, from which a total of 3546 bbl were recovered after 36 days of production.

As a result of the poor well performance and the presence of water, it was decided to shut-in the well in preparation for it to be plugged and abandoned. With these results it was clear that the well would not be commercial, consequently it was plugged and abandoned on 11 February 2005. In December 2005, the wellsite was declared rehabilitated and the joint venture was released from its obligations.

Gas marketing

The joint venture estimates that the Whicher Range field contains in-place gas resources of 1–2 Tcf. The field is just 25 km from the end of the DBNGP and is close to the growing mineral-processing industry market in the southwest of Western Australia, as well as to the towns of Busselton, Margaret River and Dunsborough. Gas quality from Whicher Range is suited for domestic consumption as it contains less than 1.5 per cent inert gases and no sulphur.

Furthermore, the new technologies to monetise low deliverability gas reservoir are applicable to Whicher Range. This includes the generation of electricity at well site; thus eliminating the necessity of pipeline and plant treatment constructions. For this to be achievable, a low but sustainable long-term flow deliverability is required.

Production Testing

In 2007, Southern Amity Inc (operator) transferred its interests into the Australian-based Whicher Range Energy Pty Ltd. Since the completion of the site rehabilitation of Whicher Range-5, the new owners have been working towards a more comprehensive production test of the Whicher Range-4 and Whicher Range-1 wellheads in order to establish a long-term production flow rate. If the initial test establishes a base rate of 1 MMcf/d or more, the partners will probably put the field into an extended production test until permanent gas-processing facilities are commissioned.

Yulleroo and Pictor
Oil and Gas

Location
Broome and Derby surrounds

Basin
Canning, onshore

Permit				
EP 104	EP 129	EP 371	EP 390	EP 391
EP 428	EP 431	EP 436	EP 438	EP 448
EP 442	EP 443	EP450	EP 451	EP 456

Ownership	%
ARC Energy Developments Ltd (Operator)	Generally between 75-100*

* *Varies between permits*

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Project Details

The Blina-Fitzroy Trough area has seen the development of the only commercial fields in the Canning Basin to date. However, there are several other highly prospective areas in the ARC permits where there are numerous prospects and leads defined, to varying degrees by relatively good seismic data, and these will be the target of early drilling.

Yulleroo

The Yulleroo gas discovery was made in 1967 by German company Gewerkschaft Elwerath. Yulleroo occurs in permit EP391 at the crest of the Yulleroo anticline, 70 km east of Broome. Extensive coring in this well identified 700 m of excellent seal and 50 m of wet gas-pay in a fairly poor reservoir. Furthermore, a thick underlying source rock in the form of deep-water marine shales, with up to 4.5 per cent total organic carbon content and a large inferred areal extent was also identified. More recent seismic data has shown the Yulleroo-1 delta front sands to be a down-dip from the structural crest. In addition to the Yulleroo structure the new seismic data shows that there are numerous similar structures in the vicinity.

Pictor

The Pictor structure occurs in permit EP431 which was originally granted in December 2004 to Kimberley Oil (now European Gas Ltd). Pictor-1 is a large, faulted anticline clearly defined by seismic data. Pictor-1 discovered a gas-bearing zone between 905-944 m below surface, underlain by an oil-bearing zone between 944-1019 m in fractured, low-matrix permeability, dolomite and limestone of the Ordovician Nita Formation. The fractures are sub-vertical and only a limited number of these were accessed by the well. A production test, post acidising, produced 2.2 MMcf/d of gas and 200 bbl/d of liquid, mostly spent acid, diesel, light (45° API) crude oil and possibly formation water from a cased and perforated interval extending between 940-965 m. Pictor-2 was drilled in 1990 by Bridge Oil 230 m southwest of Pictor-1 and recorded a similar hydrocarbon column with an un-stimulated flow of 0.26 MMcf/d and 10.5 bbl/d.

Stokes Bay

The Stokes Bay-1 well was planned as a test of the extent and reservoir development of the gas accumulation intersected by the Point Torment-1 well. Point Torment-1 was drilled in 1992 and subsequently flowed gas at a rate of up to 4.3 MMcf/d of gas from the Carboniferous-aged Anderson Formation sandstones. Subsequent tests of these sands produced ambiguous information on potential volumes and reservoir quality and the Stokes Bay-1 well was designed to provide a definitive test of the reservoir quality and extent of the accumulation.

The Anderson Formation was encountered in both Valentine-1 and Stokes Bay-1 with good gas shows similar to Point Torment-1. Oil indications were also observed in the base of the Anderson Formation in these wells. Preliminary analysis of wireline log results indicates the presence of porous and permeable sandstones with modest levels of hydrocarbon saturation. Further testing of these oil and gas zones in Stokes Bay-1 will be required to determine if any commercial zones have been intersected.

After drilling through the Anderson Formation the Stokes Bay-1 well was deepened into the Devonian carbonates of the Nullara Formation. Significant loss of drilling fluid to the Nullara carbonates provided encouragement of the presence of both major porosity and significant permeability in the Nullara reef section. Development of vugular porosity in this section is a well recognised play, having previously been the target of exploration in the Basin (ie: host to oil production at Blina some 100 km to the southeast). The Stokes Bay-1 intersection is 80 m up-dip of the Pt Torment-1 intersection which did not have the vugular porosity developed, but nevertheless tested gas at low rates.

An initial production flow test to determine fluid type and flow characteristics commenced on 4 November 2007. The well flowed at relatively steady rates of some 3 000 to 4 000 bbl/d of fluid at a well-head pressure of some 30 psi. Fluids recovered to date appear from salinity and density measurements to be drilling mud and associated fluids. In excess of 12 000 barrels of drilling fluids were lost during drilling and completion and approximately a quarter of this volume has been recovered to date. The test will be re-commenced in the 2008 dry season until formation fluids are identified.

Valhalla

Valhalla-1 is located approximately 150 km southeast of Derby and 47 km north of the Noonkanbah community. Valhalla-1 is located just to the north of the Noonkanbah-determined land, in the same area as the recently completed 495 km Paradise 2D seismic survey, which did extend onto Noonkanbah lands. Noonkanbah is remembered for the dispute that began in 1982, when Fitzroy River-1 was drilled near the "goanna dreaming" site of Pea Hill. ARC announced on 25 July 2007 that ARC and the Noonkanbah people had signed a landmark heritage agreement that will ensure any activity by ARC is carried out in a socially and environmentally responsible manner.

Valhalla-1 is the second major play type to be tested in the ARC Energy regional drilling program. The well tested multiple, fault-independent structural-closures that could contain oil or gas or both. The primary reservoir objectives were sandstones in the Grant Group and Anderson and Laurel Formations similar to the sections in which gas and potentially oil were found in the recent Valentine and Stokes Bay wells. In this area it is recognised that there are significant upside volumes at each of these levels if fault- dependent closures are effective. The Valhalla trap is a series of rollovers on normal faults parallel to basin-bounding faults superimposed on a large plunging fold (Tullock Nose).

While drilling Valhalla-1 the presence of oil shows were observed from 110 m to 925 m in Permian sandstones and a small oil leg was intersected at the top of the Carboniferous Anderson Formation and up to 1300 m of gas shows were seen in interbedded limestones, claystones and sandstones of the Fairfield Group. Log analysis in the Permian sandstones suggests that these shows are residual, but the oil shows in the Anderson could be oil pay. These oil shows are very encouraging and confirms that hydrocarbons have migrated to the Valhalla structure and through the Tullock Nose. Further evaluation and drilling will be required to assess the commercial significance of the gas shows. After drilling to the final total depth of 3466 m the well was suspended at the 244 mm casing shoe due to a deterioration in well borehole conditions.

Airlie Island Oil

Location
35 km north of Onslow

Basin
Carnarvon, offshore

Permit/Licence	
TP/7	TL/2

Ownership	TL/2 (%)	TP/7(Pts 1–3)(%)	TP/7 (Pt 4) (%)
Apache Oil Australia Pty Ltd (Operator)	51.834	39.658	64.658
Pan Pacific Petroleum (South Australia) Pty Ltd	23.166	4.157	4.157
Santos (BOL) Pty Ltd	15.000	43.711	18.711
Tap (Shelfal) Pty Ltd	10.000	12.474	12.474

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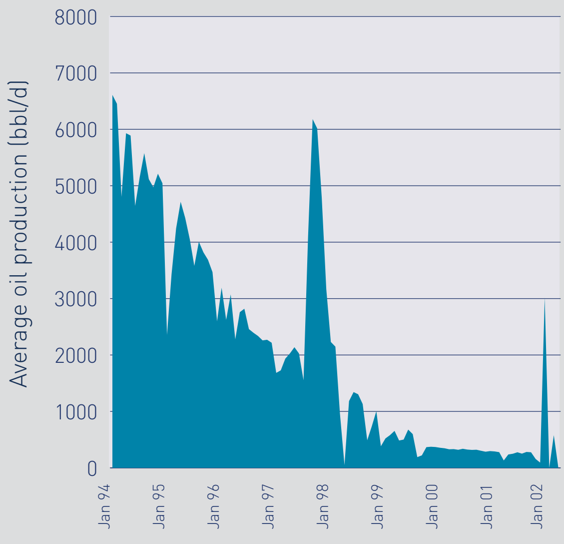

Chervil, North Herald and South Pepper

Airlie Island provided the base for the processing and storage of oil produced from the Chervil field. It also served as the base for production from the North Herald and South Pepper fields before they were decommissioned in December 1997. The island infrastructure includes oil-processing and water-separation facilities, two 150 000 bbl storage tanks, pipelines, a power generation plant and a flare tower.

Chervil
Chervil was discovered in August 1983 and commenced production in August 1989 using a two-well monopod platform. The field is currently shut-in but may be revived with a Chervil-7 well if new discoveries are tied into Airlie Island. It had one operating well, Chervil-6, which commenced production in August 1997. The oil (44° API gravity) was transported to processing facilities on Airlie Island through a 150-mm, 7-km pipeline. It was then pumped via a 508-mm, 2-km pipeline to an offshore tanker-loading facility and shipped to the BP refinery in Kwinana for processing.

Chervil-6 ceased production in March 2002. The joint venture may consider drilling Chervil-7 in the future to further improve the recovery from the field.

Potential Developments
The joint venture is continuing to examine potential developments within the permit area with the aim of extending production operations on Airlie Island. The Airlie facilities may also have an ongoing value as a storage facility for other oil and gas projects.

Cadell
The Cadell-1 well, located 7 km from Airlie Island in TP/7, intersected a 75-m gas-column in November 1999. The joint venture estimates that the field contains gas reserves of 0.5–1 Bcm (20–40 Bcf). Subject to further detailed analysis, Cadell is unlikely to be economic for a stand-alone development.

South Chervil
In November 1983, the South Chervil-1 well intersected a 3.5 m oil-column overlain by a 10-m gas-cap and tested a separate structure to Chervil. Around one-third of the field lies in TL/2 with the remainder in TP/7. South Chervil may be developed using a single well, similar to the approach undertaken with Chervil-6, and tied back to production facilities on Airlie Island.

Taunton
Taunton-2 was drilled in December 2002. It discovered 5.7-m and 1.4 m-gross oil-columns (4.9-m and 1.3-m net) within the P. burgeri (Birdrong Sandstone) and upper Barrow Group, respectively. Taunton-2 L1 horizontal sidetrack tested 49° API oil at rates up to 2783 bbl/d accompanied by 251 bbl/d of water and 2.05 TJ/d of gas. Taunton-3, drilled in August 2003, encountered 6.1-m gross (5.8-m net) oil-pay in the Birdrong Sandstone and sidetrack well, Taunton-3 L1, encountered 4.6-m gross and net oil-pay, also in the Birdrong Sandstone.

Taunton-4 was drilled in 2004 on the southwest flank of the field and found the shallowest part of the structure at both Top Birdrong Sandstone and Top Barrow Sandstone. The well established that the Barrow Sandstone and Birdrong sandstone reservoirs are separated by an effective sealing shale.

One further well, Blackthorn-1, was also drilled in 2004 on the southern flank of the field to test a potential extension of the field outside the mapped time closure. The well penetrated a thin section of Birdrong sandstone and identified for the first time an oil-water contact for the Birdrong reservoir. The Barrow Sandstone was water-saturated.

Economic and technical studies are being carried out to assess the viability of the field.

Tubridgi Gas

The Tubridgi gas field was discovered in June 1981 and commenced production in September 1991. The project incorporated gas production and transportation operations, as well as re-injection and storage facilities. In July 2004 BHP Billiton purchased the Tubridgi gas field from Origin Energy. Tubridgi production was shut-in during August 2004.

Tubridgi comprises a depleted gas reservoir, which has gas-storage potential and associated gas-facility infrastructure, including a strategic gas-transportation corridor and pipelines. The Tubridgi natural gas processing facility and associated onshore gas field is situated near Onslow, about 1400 km north of Perth.

Location
25 km southwest of Onslow

Basin
Carnarvon, onshore

Permit/Licence		
L9	PL/16	PL/19

Ownership	%
L9	
BHP Billiton Petroleum Pty Ltd	100
PL/16, PL/19	
BHP Petroleum (Ashmore Operations) Pty Ltd	

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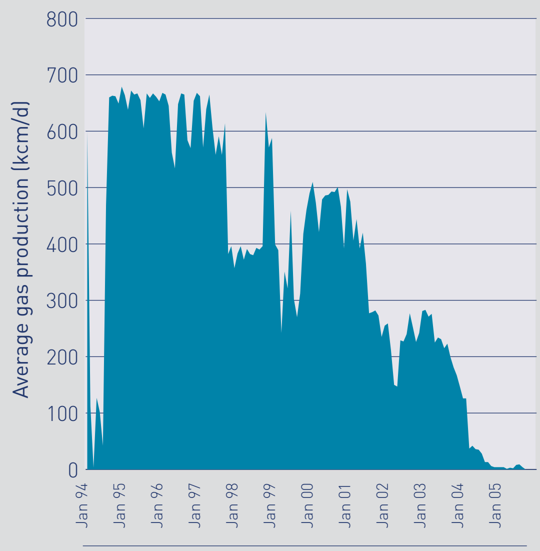

Tubridgi

WESTERN AUSTRALIAN PETROLEUM FACT SHEET

TABLE 1. 2007 PRODUCTION AND ADJUSTED RESERVES FOR DEVELOPED FIELDS

FIELD	OPERATOR	2007 PRODUCTION BY FIELD			CUMULATIVE PRODUCTION			2007 RESERVES*						PERMIT
		Oil (bbl)	Condensate (bbl)	Gas (kcm)	Oil (bbl)	Condensate (bbl)	Gas (kcm)	Oil		Condensate		Gas		
								MMbbl	MMbbl	MMbbl	MMbbl	(Gm^3)	(Gm^3)	
								90%	50%	90%	50%	90%	50%	
Agincourt	Apache	0	0	0	3,302,678	25,034	27,909	0.21	0.34	0.000	0.00	0.000	0.000	TL/1
Albert	Apache	74,927	38	768	297,020	132	3,465	0.00	0.00	0.00	0.00	0.000	0.000	TL/6
Apium	ARC Energy	0	604	7,170	0	604	7,170	0.00	0.00	0.01	0.01	0.057	0.082	L1
Artreus	Apache	6	0	34	205,142	88	3,707	0.01	0.05	0.00	0.00	0.000	0.000	TL/6
Bambra	Apache	436,388	188,253	49,160	465,825	368,273	247,593	5.99	7.54	0.00	0.00	0.054	0.157	TL/1
Barrow Island	Chevron	2,334,030	0	64,943	310,240,777	0	5,169,707	17.08	53.60	0.00	0.00	0.276	1.105	L1H
Beharra Springs	Origin	0	94	1,763	0	144,488	2,141,362	0.00	0.00	0.00	0.01	0.036	0.127	L11
Beharra Springs N	Origin	0	113	1,841	0	10,813	171,879	0.00	0.00	0.00	0.00	0.000	0.000	L11
Blina	European O&G	6,259	0	0	1,846,423	0	0	0.00	0.00	0.00	0.00	0.000	0.000	L6
Boundary	European O&G	0	0	0	127,530	0	0	0.00	0.00	0.00	0.00	0.000	0.000	L6
Chinook/ Scindian	BHP Billiton	611,879	0	95,706	29,517,869	0	1,763,251	1.31	2.84	0.00	0.00	0.114	0.280	WA-10-L
Cliff Head	Roc Oil	3,157,454	0	2,306	5,166,807	0	3,468	6.34	10.49	0.00	0.00	0.000	0.000	WA-31-L
Cossack	Woodside	3,277,103	0	12,679	73,880,925	0	356,378	11.19	25.66	0.00	0.00	0.000	0.057	WA-9-L
Cowle	Chevron	13,825	0	1,169	3,273,857	10,995	84,597	0.06	0.13	0.00	0.00	0.001	0.002	TL/4
Crest	Chevron	6,686	0	4,641	1,721,315	679	59,321	0.02	0.03	0.00	0.00	0.001	0.001	L12,L13
Dongara	ARC Energy	6,416	1,780	60,817	1,193,100	310,078	12,810,810	0.00	0.00	0.00	0.00	0.031	0.219	L1,L2
Doric	Apache	0	79,361	103,202	0	79,361	103,202	0.00	0.00	0.11	0.17	0.412	0.618	TL/1
Double Island	Apache	108,056	176	4,198	4,111,358	17,342	40,539	0.81	1.34	0.00	0.00	0.000	0.000	TP/8
East Spar	Apache	0	0	0	0	14,192,158	6,860,744	0.00	0.00	0.00	0.06	0.000	0.206	WA-13-L
Echo/Yodel	Woodside	0	7,419,005	1,286,219	0	61,137,372	12,411,836	0.00	0.00	0.00	0.00	0.044	0.584	WA-23/24-L
Endymion	Apache	0	0	0	0	448,565	592,597	0.00	0.00	0.04	0.04	0.000	0.060	TL/1, TL/5
Enfield	Woodside	17,095,660	0	199,855	24,455,501	0	271,280	28.19	56.50	0.00	0.00	0.000	0.000	WA-28-L
Eremia	ARC Energy	329,602	0	1,989	1,335,273	0	8,733	0.00	0.00	0.00	0.00	0.000	0.000	L1
Eskdale	BHP Billiton	158,005	0	11,961	158,005	0	11,961	5.03	8.18	1.26	1.89	0.000	0.000	WA-255-P
Evandra	ARC Energy	0	0	0	1,724	0	0	0.00	0.00	0.00	0.00	0.000	0.000	L1
Exeter	Santos	2,393,364	0	677	13,715,502	0	3,881	0.69	2.99	0.00	0.00	0.000	0.000	WA-27-L
Gipsy	Apache	6,498	403	2,633	2,287,189	15,738	79,180	0.06	0.23	0.00	0.00	0.000	0.000	TL/1
Goodwyn	Woodside	0	10,304,184	7,128,850	0	251,633,431	107,690,450	0.00	0.00	57.00	96.63	63.621	85.111	WA-5-L
Griffin	BHP Billiton	1,296,086	0	15,904	134,521,022	0	1,780,854	2.32	5.08	0.00	0.00	0.014	0.036	WA-10-L
Gudrun	Apache	48,735	63	1,044	736,905	472	7,656	0.00	0.01	0.00	0.00	0.000	0.000	TL/1
Harriet	Apache	136,877	1,478	11,425	51,366,285	377,614	1,479,093	0.25	0.97	0.43	0.00	0.000	0.000	TL/1
Hermes	Woodside	6,525,504	0	66,531	57,676,979	0	605,169	1.65	16.75	0.00	0.00	0.013	0.163	WA-16-L
Hovea	ARC Energy	637,183	50	8,333	6,589,303	1,554	88,655	0.00	0.00	0.00	0.00	0.000	0.000	L1
Jingemia	Origin	808,341	0	5,729	3,771,025	0	27,350	0.88	2.84	0.00	0.00	0.000	0.000	L14
John Brookes	Apache	0	1,007,941	2,229,814	0	1,961,574	4,820,644	0.00	0.00	10.44	12.20	30.050	35.128	WA-29-L
Lambert	Woodside	3,181,683	0	25,406	16,907,904	0	140,224	10.66	23.86	0.00	0.00	0.000	0.245	WA-16-L
Laminaria East	Woodside	230,969	0	1,845	9,399,657	444,231	22,423	0.00	0.58	0.00	0.00	0.000	0.000	WA-18-L
Lee	Apache	0	351,234	318,621	0	351,234	318,621	0.00	0.00	0.65	0.91	0.814	1.123	TL/1
Legendre North	Woodside	1,546,937	0	121,335	39,566,069	0	1,354,955	0.00	0.21	0.00	0.00	0.000	0.000	WA-20-L
Legendre South	Woodside	134,210	0	154,625	5,002,890	0	609,167	Reserves for Legendre North and Legendre South are now reported together						WA-20-L
Linda	Apache	0	8,341	5,629	0	1,793,059	1,110,907	0.00	0.00	0.25	0.37	0.200	0.303	TL/1
Little Sandy	Apache	33,608	50	1,851	518,026	2,736	10,380	0.03	0.06	0.00	0.00	0.000	0.000	TL/6

WESTERN AUSTRALIAN PETROLEUM FACT SHEET

TABLE 1. 2007 PRODUCTION AND ADJUSTED RESERVES FOR DEVELOPED FIELDS														
FIELD	OPERATOR	2007 PRODUCTION BY FIELD			CUMULATIVE PRODUCTION			2007 RESERVES*						PERMIT
		Oil (bbl)	Condensate (bbl)	Gas (kcm)	Oil (bbl)	Condensate (bbl)	Gas (kcm)	Oil		Condensate		Gas		
								MMbbl	MMbbl	MMbbl	MMbbl	(Gm³)	(Gm³)	
								90%	50%	90%	50%	90%	50%	
Lloyd	European O&G	0	0	0	187,631	0	0	0.00	0.00	0.00	0.00	0.000	0.000	L8
Mohave	Apache	13,599	63	1,309	885,940	667	17,995	0.02	0.04	0.00	0.00	0.000	0.000	TL/6
Mount Horner	ARC Energy	23,267	0	0	1,829,503	0	0	0.00	0.00	0.00	0.00	0.000	0.000	L7
Mutineer	Santos	8,710,323	0	2,466	31,507,226	0	8,919	0.71	11.51	0.00	0.00	0.000	0.000	WA-26-L
North Alkimos	Apache	0	0	105	42,388	560	12,931	0.00	0.13	0.00	0.00	0.000	0.000	TL/6
North Rankin	Woodside	0	1,948,038	2,949,556	0	150,712,130	186,478,757	0.00	0.00	33.27	52.14	146.310	161.320	WA-1-L
Pedirka	Apache	108,930	182	4,679	1,873,382	7,473	25,788	0.61	0.67	0.00	0.00	0.000	0.000	TL/6
Perseus	Woodside	0	16,258,241	12,813,361	0	90,022,405	70,932,604	0.00	0.00	161.75	193.20	197.667	232.497	WA-1-L
Roller	Chevron	415,360	0	18,110	43,755,020	0	708,413	0.62	1.70	0.00	0.00	0.008	0.034	TL/7
Rose	Apache	0	197,544	149,883	0	1,104,719	820,791	0.00	0.00	0.00	0.12	0.000	0.159	TL/1
Rough Range	Empire	2,730	0	0	96,879	0	0	0.00	0.00	0.00	0.00	0.000	0.000	EP 41
Saladin	Chevron	639,674	0	30,094	95,878,489	0	1,662,704	0.76	2.84	0.00	0.00	0.005	0.055	TL/4
Searipple	Woodside	0	347,629	54,282	0	347,629	54,282	0.00	0.00	2.80	4.06	0.706	0.936	WA-1-L
Simpson	Apache	14,851	434	7,828	5,166,059	39,187	76,085	0.07	0.13	0.00	0.00	0.000	0.000	TL/1
Skate	Chevron	44	0	27,976	1,678,883	55,811	120,852	0.00	0.00	0.00	0.00	0.000	0.000	TL/7
South Plato	Apache	93,847	541	5,918	4,327,973	5,353	46,187	0.05	0.14	0.00	0.00	0.000	0.000	TL/6
Stag	Apache	3,404,035	0	22,729	46,752,375	0	373,045	9.05	15.40	0.00	0.00	0.000	0.000	WA-15-L
Stybarrow	BHP Billiton	1,875,672	0	29,723	1,875,672	0	29,723	59.14	72.98	0.00	0.00	0.000	0.000	WA-255-P
Sundown	European O&G	1,768	0	0	408,309	0	0	0.00	0.00	0.00	0.00	0.000	0.000	L8
Tanami	Apache	1,038	0	2	3,089,988	82,651	86,479	0.04	0.07	0.00	0.00	0.000	0.000	TL/1
Tarantula	Origin	0	6,825	95,099	0	19,870	230,001	0.00	0.00	0.00	0.00	0.000	0.071	L11
Victoria	Apache	15,549	50	762	297,354	2,290	6,581	0.01	0.03	0.00	0.00	0.000	0.000	TL/6
Wanaea	Woodside	15,283,832	0	524,257	228,687,977	0	7,768,949	45.73	101.08	1.26	3.15	1.536	3.406	WA-11-L
Wandoo	Vermillion	2,739,132	0	37,475	71,395,073	0	893,257	16.57	22.42	0.00	0.00	0.000	0.000	WA-14-L
West Cycad	Apache	1,041,555	931	13,809	1,041,555	931	13,809	0.00	0.00	0.00	0.00	0.000	0.000	TL/9
West Terrace	European O&G	5,221	0	0	234,403	0	0	0.00	0.00	0.00	0.00	0.000	0.000	L8
Wonnich	Apache	0	187,197	327,508	0	2,162,257	3,278,596	0.00	0.00	0.00	0.00	0.000	0.000	TL/8
Woodada	ARC Energy	0	503	17,539	0	66,051	1,470,227	0.00	0.00	0.00	0.00	0.003	0.025	L4, L5
Woollybutt	Eni	2,462,082	0	12,498	29,042,433	0	131,448	5.78	29.05	0.00	0.00	0.000	0.000	WA-25-L
Xyris	ARC Energy	0	6,800	69,069	0	15,429	171,029	0.00	0.00	0.00	0.00	0.124	0.241	L1
Xyris South	ARC Energy	0	6	132	0	390	3,167	0.00	0.00	0.00	0.00	0.000	0.000	L1
Yammaderry	Chevron	0	0	0	5,392,801	0	97,413	0.00	0.00	0.00	0.00	0.000	0.000	TL/4
Zephyrus	Apache	119,284	63	716	320,960	107	2,481	0.00	0.00	0.00	0.00	0.000	0.000	TL/6
Other fields currently not producing**					56,063,594	3,902,480	55,026,335							
Total		81,568,078	38,318,215	29,227,558	1,435,191,747	581,876,012	493,849,966	231.96	478.47	269.273	364.96	442.01	524.35	

* 2006 reserves less 2007 production

**includes Alkimos, Buffalo, Campbell, Chervil, Gibson, Gingin, Hoover, Mondarra, Monet, North Gipsy, North Herald, North Pedirka, North Yardanogo, Rosette, Sinbad, South Pepper, Talisman, Tubridgi, Walyering, West Kora, and Yardarino.

WESTERN AUSTRALIAN PETROLEUM FACT SHEET

TABLE 2. RESERVES FOR UNDEVELOPED FIELDS AS AT JANUARY 2008								
Undeveloped Fields			Oil		Condensate		Gas	
			MMbbl	MMbbl	MMbbl	MMbbl	Gm^3	Gm^3
Field	Permit	Operator	90%	50%	90%	50%	90%	50%
Angel	WA-3-L	Woodside	0.000	0.000	59.126	84.286	38.790	52.390
Bambra East	TL/1	Apache	0.000	0.000	0.692	0.881	1.030	1.236
Blacktip	WA-279-P	ENI	0.000	0.000	0.000	0.000	10.800	32.500
Caribou	WA-209-P	Apache	0.000	0.000	0.377	0.566	0.762	1.102
Chamois	WA-261-P	Apache	1.321	2.327	0.000	0.000	0.000	0.103
Corvus	WA-246-P	Apache	0.000	0.000	0.189	0.503	1.442	3.523
Dixon	WA-9-R	Woodside	0.000	0.000	3.145	7.548	1.930	4.130
Dockrell	WA-5-L	Woodside	0.000	0.000	2.516	5.661	3.370	7.020
Gaea	WA-1-L	Woodside	0.000	0.000	1.887	3.145	1.950	3.260
Gorgon	WA-2/3-R	Chevron	0.000	0.000	93.004	121.001	359.521	475.586
Gungurru	WA-202-P	Apache	0.629	1.195	0.000	0.000	0.175	0.216
Ichthys Brewster	WA-285-P	Inpex	0.000	0.000	181.152	276.760	127.000	198.000
Ichthys Plover	WA-285-P	Inpex	0.000	0.000	15.725	35.224	34.000	71.000
Keast	WA-6-L	Woodside	0.000	0.000	0.629	1.887	0.740	3.790
Kultaar	WA-334-P	Apache	0.000	0.000	0.308	0.384	0.618	0.773
Lambert Deep	WA-16-L	Woodside	0.000	0.000	1.258	2.516	5.660	7.360
Narvik	TP/8	Apache	0.000	0.000	0.000	0.000	0.515	0.721
Nasutus	EP409	Apache	0.629	2.516	0.001	0.001	0.155	0.247
Oryx	WA-202-P	Apache	2.152	3.208	0.000	0.000	0.010	0.010
Pluto	WA-350-P	Woodside	0.000	0.000	0.025	0.034	68.300	92.310
Reindeer	WA-209-P	Apache	0.000	0.000	1.635	1.950	10.650	12.721
Sage	WA-254-P	Apache	3.208	4.655	0.000	0.000	0.000	0.000
South Chervil	TL/2	Apache	0.189	0.566	0.000	0.000	0.227	0.278
Taunton	TL/2	Apache	2.202	3.334	0.038	0.050	0.062	0.082
Tidepole	WA-5-L	Woodside	0.000	0.000	6.290	15.725	6.230	14.720
Tusk	WA-246-P	Apache	1.006	1.824	0.000	0.000	0.000	0.103
Van Gogh	WA-155-P	Apache	37.111	58.497	0.000	0.000	0.000	0.000
Vincent	WA-28-L	Woodside	40.256	72.964	0.000	0.000	0.000	0.000
Total			88.702	151.086	367.997	558.122	673.937	983.181
Total Reserves (Table 1 + Table 2)			320.662	629.556	637.270	923.082	1116.037	1507.531

WESTERN AUSTRALIAN PETROLEUM FACT SHEET

TABLE 3. Contingent Resources (Sub-commercial/Sub-economic)

			Contingent Resources					
			Oil		Condensate		Gas	
			MMbbl		MMbbl		Gm^3	
Field	Permit	Operator	90%	50%	90%	50%	90%	50%
Brecknock	WA-29/32-R	Woodside	0.000	0.000	54.723	109.446	104.770	150.080
Calliance (Brecknock S)	WA-28/31-R	Woodside	0.000	0.000	59.755	86.802	79.000	112.420
Chandon	WA-268-P	Chevron	0.000	0.000	6.441	11.014	45.865	78.401
Chrysaor	WA-14/15-R	Chevron	0.000	0.000	9.812	16.052	32.603	53.351
Clio	WA-205-P	Chevron	0.000	0.000	9.970	20.147	44.282	89.513
Crosby	WA-12-R	BHP	28.934	45.917	0.000	0.000	0.100	0.200
Dionysus	WA-14/15-R	Chevron	0.000	0.000	9.139	11.624	33.500	42.606
Dixon	WA-9-R	Woodside	0.000	0.000	3.145	7.548	1.160	2.040
Egret	WA-10-R	Woodside	6.290	15.096	0.000	0.629	0.310	0.930
Eurytion	WA-25-R	Chevron	0.000	0.000	0.547	1.403	8.625	15.454
Geryon/Callirhoe	WA-20/22-R	Chevron	0.000	0.000	3.950	8.812	72.675	93.871
Goodwyn S	WA-5-L	Woodside	0.629	2.516	3.145	9.435	1.990	5.840
Harrison	WA-12-R	BHP	1.887	4.403	0.000	0.000	0.000	0.000
Iago	WA-16/17-R	Chevron	0.000	0.000	0.944	10.882	2.797	30.359
Io	WA-25/26-R	Chevron	0.000	0.000	6.888	16.184	116.277	177.679
Jansz	WA-18-R	Mobil	0.000	0.000	0.000	0.000	279.000	392.000
Laverda	WA-271-P	Woodside	25.789	30.192	0.000	0.000	0.000	0.000
Macedon	WA-12-R	BHP	0.000	0.000	0.000	0.000	9.600	18.400
Maenad	WA-19-20/24-R	Chevron	0.000	0.000	0.201	0.855	2.263	9.146
Maitland	WA-33-R	Apache	0.000	0.000	0.598	1.648	1.700	4.666
Moondyne	WA-12-R	BHP	0.629	3.774	0.000	0.000	0.200	1.100
Orthrus	WA-19-20/24-R	Chevron	0.000	0.000	0.629	2.220	13.091	23.918
Pemberton	WA-24-28-L	Woodside	0.000	0.000	4.403	5.661	4.110	5.470
Persephone	WA-1-L	Woodside	0.000	0.000	11.951	15.725	16.990	22.650
Pluto	WA-350-P	Woodside	0.000	0.000	0.005	0.013	13.310	38.510
Pueblo	WA-28-P	Woodside	0.000	0.000	0.000	3.145	0.740	2.360
Rankin/Sculptor	WA-11-R	Woodside	0.000	0.000	0.000	3.145	0.000	2.610
Ravensworth	WA-155-P	BHP	28.305	45.288	0.000	0.000	0.200	0.300
Scarborough	WA-1-R	Mobil	0.000	0.000	0.000	0.000	125.000	147.000
Skiddaw	WA-255-P	BHP	1.887	3.774	0.000	0.000	0.000	0.000
Spar	WA-4-R	Chevron	0.000	0.000	1.503	6.504	1.699	7.362
Stickle	WA-12-R	BHP	16.983	33.966	0.000	0.000	0.100	0.200
Torosa (Scott Reef)	WA-30-R	Woodside	0.000	0.000	63.026	121.020	172.730	325.640
Urania	WA-21/23-R	Chevron	0.000	0.000	0.088	0.214	1.484	2.326
West Tryal Rocks	WA-5-R	Chevron	0.000	0.000	24.003	38.004	47.148	72.916
Wheatstone	WA-16-R	Chevron	0.000	0.000	16.002	26.003	78.761	112.432
Wilcox	WA-7-R	Woodside	0.000	0.000	13.209	19.499	6.180	9.340
Xena	WA-350-P	Woodside	0.000	0.000	2.516	5.032	6.600	13.820
Total			111.333	184.926	306.592	558.665	1324.860	2064.910

TABLE 4. Unbooked Resources and Total Resources

	Oil		Condensate		Gas	
	MMbbl		MMbbl		Gm3	
	90%	50%	90%	50%	90%	50%
Scope for recovery*	64.28	199.48	35.10	83.18	33.97	75.64
Total WA Resources**	496.26	1013.95	978.96	1564.93	2442.261	3648.197

*These resources constitute less than 1% of WA reserves. For the sake of consistency the above reserves are estimated by DoIR and are only indicative.

**Includes reserves, resources and scope for recovery

The petroleum production figures used in this publication are from the official returns as supplied by the companies to the Department and include all production from wells, including materials which may be reinjected, flared and used in the production process. For this reason, there may be differences between the figures in this report and final production figures as reported under obligations to the Australian Stock Exchange.

Abbreviations, permits and conversions

ABBREVIATIONS

API	standard method of measuring density of crude oils by the American Petroleum Institute
APPEA	Australian Petroleum Production and Exploration Association
bbl	barrels
bbl/d	barrels per day
bbl/MMcf	barrels per million cubic feet
Bcf	billion cubic feet
Bcm	billion cubic metres
Btu	British thermal unit
CALM	catenary anchor leg mooring
CGS	concrete gravity substructure
DBNGP	Dampier to Bunbury natural gas pipeline
DCQ	daily contract quantities
DST	drill stem test
dwt	dead weight tonnes
EOI	expression of interest
FPSO	floating production storage and offloading
FSO	floating storage and offloading
GGT	Goldfields gas transmission
GJ	gigajoules
Gl	gigalitres
Gm	gigametres
GWC	gas-water contact
HBI	hot briquetted iron
kcm	thousand cubic metres
kcm/d	thousand cubic metres per day
km	kilometres
km^2	square kilometres
l	litres
LNG	liquefied natural gas
LPG	liquefied petroleum gas
m	metres
m^3	cubic metres
m^3/bbl	cubic metres per barrel
m^3/d	cubic metres per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day
mm	millimetres
MMbbl	million barrels
MMm^2	million cubic metre
MOPU	mobile offshore production unit
Mt/a	million tonnes per annum
MW	megawatts
n/a	not available
NCC	navigation, control and communication
NWS	North West Shelf
NWSGP	North West Shelf Gas project
OWC	oil-to-water contact
PJ	petajoules
RTM	riser turret mooring
RT	rotary table
scf/bbl	standard cubic feet to barrels
t	tonnes
t/a	tonnes per annum
t/d	tonnes per day
Tcf	trillion cubic feet
TJ	terajoules
TJ/d	terajoules per day
TVDSS	total vertical distance subsea
UAE	United Arab Emirates
WA	Western Australia
2D	two-dimensional
3D	three-dimensional
$	Australian dollars unless otherwise noted

PERMITS/LICENCES

State Petroleum Act 1967	
EP1	Exploration Permit
L1	Production Licence
State Petroleum Act 1936 and 1967	
L1H	Petroleum Licence
State Petroleum Pipeline Licences Act 1969	
PL/1	Pipeline Licence
State Petroleum (Submerged Lands) Act 1982	
TP/1	Territorial Sea Exploration Permit
TL/1	Territorial Sea Production Licence
TPL/1	Territorial Sea Pipeline Licence
Commonwealth Petroleum (Submerged Lands) Act 1967	
WA-1-P	Exploration Permit
WA-1-L	Production Licence
WA-1-PL	Pipeline Licence
WA-1-R	Retention Licence
AC/P1	Ashmore–Cartier Production Licence
NTRL-1	Northern Territory Retention Licence

CONVERSIONS

1 barrel of oil	=	0.158987 kilolitres of oil
1 kilolitre of oil	=	6.28981 barrels of oil
1 standard cubic metre of natural gas	=	35.3147 cubic feet of natural gas
1 billion cubic metres of natural gas	=	730 000 tonnes of LNG
1 terajoule	=	26 300 cubic metres of natural gas
	=	0.929 million cubic feet of natural gas
1 metric tonne of LNG	=	1333 cubic metres of natural gas at 0°C
1 million tonnes of LNG per year	=	1.333 billion cubic metres per year
	=	3.65 million cubic metres of natural gas per day

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