EMERGING UNCONVENTIONAL SHALE PLAYS IN WESTERN AUSTRALIA

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ABSTRACT

Production of shale gas in the US has changed its position from a gas importer to a potential gas exporter. This has stimulated exploration for shale-gas resources in WA. The search started with Woodada Deep–1 (2010) and Arrowsmith–2 (2011) in the Perth Basin to evaluate the shale-gas potential of the Permian Carynginia Formation and the Triassic Kockatea Shale, and Nicolay–1 (2011) in the Canning Basin to evaluate the shale-gas potential of the Ordovician Goldwyer Formation. Estimated total shale-gas potential for these formations is about 288 trillion cubic feet (Tcf). Other petroleum source rocks include the Devonian Gogo and Lower Carboniferous Laurel formations of the Canning Basin, the Lower Permian Wooral and Byro groups of the onshore Carnarvon Basin, and the Neoproterozoic shales of the Officer Basin. The Canning and Perth basins are producing petroleum, whereas the onshore Carnarvon and Officer basins are not producing but have indications for petroleum source rocks, generation, and migration from geochemistry data. Exploration is at a very early stage, and more work is needed to estimate the shale-gas potential of all source rocks and to verify estimated resources.

Exploration for shale gas in WA will benefit from new drilling and production techniques and technologies developed during the past 15 years in the US, where more than 102,000 successful gas production wells have been drilled. WA shale-gas plays are stratigraphically and geochemically comparable to plays in the Upper Ordovician Utica Shale, Middle Devonian Marcellus Shale and Upper Devonian Bakken Formation, Upper Mississippian Barnett Shale, Upper Jurassic Haynesville-Bossier formations, and Upper Cretaceous Eagle Ford Shale of the US. WA is vastly under-explored and emerging self-sourcing shale plays have revived onshore exploration in the Canning, Carnarvon, and Perth basins.

KEYWORDS

Petroleum source rocks, shale plays, Canning Basin, Carnarvon Basin, Officer Basin, Perth Basin, Western Australia.

INTRODUCTION

The stratigraphy and vast geographic extent of onshore WA basins suggest high potential for unconventional shale petroleum resources. Basins rated with high to low potential include the Paleozoic Canning Basin, the Paleozoic–Mesozoic Perth Basin, the Paleozoic Southern Carnarvon Basin, and the Neoproterozoic Officer Basin, respectfully (Fig. 1). The Canning and Perth basins are producing conventional petroleum, whereas the Southern Carnarvon and Officer basins have indications for petroleum generative potential, supported by the petroleum geochemistry of source rocks and produced oil.

Conventional petroleum systems are buoyancy driven, occurring as discrete accumulations in structural and/or stratigraphic traps, whereas unconventional resources are generally not buoyancy driven. They are regionally pervasive accumulations, most commonly independent of structural and stratigraphic traps. In these petroleum systems, trapping mechanisms are typically subtle, independent of conventional trapping. They cover a large area of the basin, and the timing of charge versus trap formation is not critical as in a conventional petroleum system (Curtis, 2002; Law and Curtis, 2002).

Petroleum reservoirs exhibit a continuum (Fig. 2) from a pore-throat size greater than 2 μm in conventional reservoirs, to between 2–0.03 μm in tight-gas sandstones, and 0.1–0.005 μm in shale (Nelson, 2009). Shale source rocks typically retain a substantial quantity of petroleum even after expulsion to conventional reservoirs (Jarvie et al, 2007; Meyer, 2012). Moreover, these shales are texturally and mineralogically heterogeneous, and have different source rock characteristics (Durham, 2010; Aplin and Macquaker, 2011). Geochemical, geomechanical, and petrophysical properties of source rocks play a key role in unlocking retained petroleum, which is achieved mostly by a combination of horizontal drilling and hydraulic fracturing (Jaciob et al, 2008, 2009).

The quality of shale-gas resources depend on thickness of net pay (>100 m), adequate porosity (>2%), high reservoir pressure (ideally overpressure), high thermal maturity (>1.5% Ro), high organic richness (>2% TOC), low in clay (<50%), high in brittle minerals (quartz, carbonates, feldspars), and favourable in-situ stress.

During the past decade, unconventional shale and tight-sand gas plays have become an important supply of natural gas in the US, and now in shale oil as well. As a consequence, interest to assess and explore these plays is rapidly spreading worldwide. The high production potential of shale petroleum resources has contributed to a comparably favourable outlook for increased future petroleum supplies globally (Bishop et al, 2012). In 2012 the International Energy Agency (IEA) developed the Golden Rules for a Golden Age of Gas report to develop these vast gas resources profitably and in an environmentally acceptable matter, in particular to address issues related to hydraulic fracturing, water and chemical disposal, and well integrity.

In WA, technically recoverable shale-gas resources have been estimated for the Permian Carynginia Formation and the Triassic Kockatea Shale (Perth Basin) at about 29 and 30 trillion cubic feet (Tcf), respectively, and for the Ordovician Goldwyer Formation (Canning Basin) at about 229 Tcf (Fig. 3). These initial estimates were completed as a part of the World Shale Gas Resources study by Advance Resources International Inc. for the United States Energy Information Administration in 2011 (Kuusikraa et al, 2011), and studies are underway to verify these estimates. This paper briefly reviews the potential for unconventional petroleum plays in WA with reference to the development of these resources in the US. The assessments of basins presented are mainly based on petroleum geochemical studies undertaken by the Geological Survey of Western Australia (GSWA), predominantly for conventional petroleum resources.

APPEA Journal 2013—313

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Figure 1. Map of WA basins showing deep depocentres (highlighted in orange) in the Canning, Carnarvon, Officer, and Perth basins.
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Figure 2. Conventional and unconventional petroleum reservoirs and resources, modified from Nelson (2009).

Figure 3. Estimated recoverable shale-gas resources for Australian basins by Kuuskraa et al (2011).
DEVELOPMENTS IN THE US

In the US, federally funded research on unconventional gas systems began in the late 1970s. Since then, advancements in exploration techniques, and drilling and production technologies have improved the geological understanding of plays, and increased productivity. Tight-reservoir petroleum systems are now economically viable resources in the US. In addition, emerging shale plays are increasingly being explored and developed (Fig. 4), such as the Upper Ordovician Utica Shale, the Middle Devonian Marcellus Shale, the Upper Devonian to Lower Mississippian Bakken Formation, the Upper Mississippian Barnett Shale, the Upper Jurassic Haynesville-Bossier formations, and the Upper Cretaceous Eagle Ford Shale (Eoff, 2012). These shale formations contain vast gas resources that will allow the US to expand its gas supply and significantly reduce imports. Besides shale gas, the US is in the process of delineating the size of its shale-oil resources, which are expected to be in the order of billions of barrels and may replace its existing imports of nine million barrels per day across time (Bishop et al, 2012).

The IEA has estimated remaining gas resources in the top 15 countries (2012; Fig. 5). Russia has the highest total gas resource, whereas China has the highest estimated shale-gas resources, followed by the US and Australia. Since 1996, more than 102,000 productive unconventional gas wells have been drilled in the US, which accounts for about two-thirds of all successful natural gas wells. These wells increased production to more than 10 billion cubic feet (Bcf) per day, added more than 120 Tcf to the reserves, and identified new plays (Kuuuskraa, 2007). Since 2005, production from self-sourcing shale plays has increased to the extent that the US has moved from being a major importer to becoming a potential gas exporter (Fig. 6).

CANNING BASIN

The Canning Basin is the largest onshore basin in WA. The onshore part covers about 530,000 km² out of a total basin area of 640,000 km² (Fig. 7). The succession is mainly Ordovician-Lower Cretaceous (Fig. 8). The basin has been explored for petroleum since the 1920s (Fig. 9). It has been producing oil since 1983, but production is minor; in 2011, 2,833 kL (17,819 barrels) was produced.

The Canning Basin contains two major northwest-trending troughs separated by a mid-basin arch and marginal shelves (Fig. 10). In the north, the Fitzroy Trough and Gregory Sub-basin contain up to 15 km of predominantly Paleozoic rocks. In the middle, the Broome and Crossland platforms form a central arch. In the south, the Kidson and Willara sub-basins contain up to 5 km of predominantly Ordovician to Silurian and Permian aged sediments, with extensive Mesozoic cover. GSWA (Fig. 11; Ghori and Haines, 2006a; Ghori, 2011) and exploration data indicate three conventional and four potential self-sourcing petroleum systems in the onshore Canning Basin.

In the Ordovician-Silurian succession, the Goldwyer and Bongabinni formations contain the richest source rocks in the basin, particularly in wells drilled on the Barbwire Terrace and Admiral Bay Fault Zone. Organic-rich shales are oil-prone with TOC up to 60% in the Bongabinni Formation and greater than 5% in the Goldwyer Formation (Fig. 12). The Goldwyer Formation source rocks are correlated to significant oil and gas discovered at the Pictor and Dodonea areas, supported by GSWA oil and rock extract data (Fig. 13). GeoMark and the Australian Geological Survey Organisation (AGSO) performed detailed geochemical analyses of 13 oils from the Canning Basin and characterised petroleum systems as being sourced from the Ordovician, Devonian, Carboniferous, and vagrant (i.e., mixed) source rocks (1996; Fig. 14).

Figure 4. Map of North American shale plays identified up to May 2011.
Figure 5. Estimated recoverable gas resources of the top 15 countries by the International Energy Agency (2012).

Figure 6. Recoverable resources and production for the US since 2005 (International Energy Agency, 2012).
Figure 7. Canning Basin map showing tectonic units, exploration wells, and petroleum discoveries (from Hocking, 1994).
Figure 8. Canning Basin stratigraphic distribution of source and reservoir rocks, petroleum discoveries and systems, and apatite fission track analysis (AFTA) cooling events (timescale from International Commission on Stratigraphy, 2012).
These wells are located on the terraces at the northern border of the platform areas (Fig. 1). Reservoirs in the Nita and Willara formations are overlain by thick salts of the Carribuddy Group with excellent sealing capacities. The succession has been favourably affected by tectonics for trap development, Early Ordovician extension, and Permian–Triassic cooling events (Ghori and Haines, 2006b).

Kuuskraa et al estimated shale-gas resources of up to 229 Tcf for the Ordovician Goldwyer Formation (2011; Fig. 3). Foster et al estimated more than 61 billion barrels of generating capacity for the richest oil-prone source beds in the upper Goldwyer Formation on the Barbiwire Terrace (1986). For the eastern Canning Basin, Wulff estimated ultimate cumulative petroleum generative potential for the Goldwyer Formation at about 11,079 million barrels per cubic kilometre (MMbbl/km³; 1987). These estimates indicate that the petroleum generating potential of the Goldwyer Formation is higher than yet discovered in the Canning Basin. The Goldwyer Formation has an average thickness of about 400 m. The thickest estimated section is 739 m in Blackstone–1 on the Lennard Shelf, and 736 m is the complete intersection in Willara–1 in the Willara Sub-basin (Figs 15 and 16). The formation has been intersected in about 60 petroleum and 13 mineral exploration wells; most of these wells are located south of the Fitzroy Trough, except Blackstone–1, West Blackstone–1, Lovell's Pocke–1, and Tappers Inlet–1, which are north of the Fitzroy Trough. New Standard Nicolay–1 is the first well drilled to evaluate the shale-gas potential of the Goldwyer Formation, and is presently being evaluated. In the US, the Ordovician oil generated and preserved includes several giant oil fields, containing more than 100 MMbbl of oil, and the Ordovician Utica Shale contains productive shale plays (Carlsen and Ghori, 2005; Eoff, 2012).

The Bongabinni Formation is mainly developed in the southern Canning Basin. The formation is dominated by red-brown mudstone in most areas except the Admiral Fault Zone, where it has the most organic-rich oil-prone source rocks of the Canning Basin (Haines and Ghori, 2006). It is 208 m thick in Kidson–1, less than 100 m thick in the Willara Sub-basin and Broome Platform, and about 30 m thick on the terrace areas (Haines, 2004). Coal-like beds of up to about one metre thick are intersected in several fully core mineral boreholes on the Admiral Fault Zone, where its cumulative thickness exceeds three metres in DD86SS3 and DD86SS9 (McCracken, 1994; Edwards et al, 1997; Haines, 2004).

Haines correlates the Goldwyer and Bongabinni formations across the Canning Basin (2004). The Goldwyer Formation is mudstone-dominated in deeper basinal areas, and carbonate-dominated on platforms and terraces (Haines, 2004, 2009). The distribution of laminated mudstone source
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Facies and carbonate facies varies greatly across the basin and influences the petroleum source potential. Geochemical data indicate presence of the best source potential on the platform and terrace south of the Fitzroy Trough as opposed to the Willara and Kidson sub-basins.

In the Devonian-Lower Carboniferous succession, the lower reef complexes of the Laurel Formation and the inter-reef Gogo Formation were deposited during a major Frasnian transgression. Oil-prone organic-rich shales in the platform facies of the reef complexes contain up to 8% TOC, whereas shales in the Gogo Formation contain up to 3% TOC (Ellyard, 1984). Geochemical data available for the Lower Carboniferous Laurel Formation is very limited (Fig. 12) and sparsely distributed; however, the Laurel Formation source beds are correlated to oil discovered on both margins of the Fitzroy Trough.

Oil from the Blina Oilfield is correlated to the Devonian Gogo Formation, whereas oil from the Boundary, Lloyd, Sun-down, and West Terrace oil fields is correlated to the Lower Carboniferous Laurel Formation (Fig. 14). These oil fields

Figure 10. Canning Basin’s deep depocentre, modified from Yeates et al (1984).
are located on the Lennard Shelf at the northern margin of the Fitzroy Trough. On the southern margin of the Fitzroy Trough, significant oil and gas was discovered in the Yulleroo and Ungani areas in the Lower Carboniferous Laurel Formation (Fig. 7); the formation is both a source and a reservoir. Discoveries on both sides of the Fitzroy Trough indicate that it is a main oil- and gas-generating source pod. Reservoirs in the Devonian Reef complexes and Lower Carboniferous Fairfield Group, and Anderson Formation, are sealed by interbedded basinal shale and tight limestone in the Laurel and its equivalent formations. The Devonian extension and mid-Carboniferous Meda Transpression were responsible for deposition and structuring of the Devonian–Lower Carboniferous succession.

The Upper Carboniferous–Permian succession is producing oil at the Boundary, Sundown, and West Terrace oilfields on the Lennard Shelf. Producing reservoirs are present in the Grant Group, and seals in the shale units of the Poole Sandstone and Blina Shale. The petroleum system sourced by this succession is not known in the onshore Canning Basin. In the Permian succession, the organic-richness is up to 61% TOC, has 250 mg/g potential yield, and a hydrogen index of 400 in coaly beds, mainly sourced from tight-sand reservoirs. The Permian Noonkanbah Formation has the best source-rock potential in the succession; however, a low maturity in most parts of the Canning Basin may be a significant risk. Comparatively, the source rock’s richness and oil-proneness decreases from Ordovician to Permian. Organic-rich intervals in the Ordovician, Upper Devonian, Lower Carboniferous, and Lower Permian—identified from source rock and oil geochemistry data—may form self-sourcing shale plays, which are comparable to producing plays in the Ordovician Utica Shale, Lower Carboniferous (Mississippian) Barnett, Fayetteville and Woodford shales, and Devonian Marcellus shale of the US. Scott compares the Pennsylvanian carbonate-evaporite self-sourcing reservoir in the Cane Creek Shale of the Paradox Basin with the Goldwyer-Nita-Carribuddy system of the Canning Basin (1988). Exploration of these plays will benefit from new drilling and production techniques, mostly developed in the US. The Canning Basin remains vastly under-explored, as it is remotely located with little or no infrastructure, especially when compared with the Perth Basin, which has the best infrastructure in WA.

**CARNARVON BASIN**

The onshore Carnarvon Basin is predominantly Paleozoic and its tectonic units include the Peedamullah Shelf, Gascoyne Platform, and Merlinleigh and Byro sub-basins. The

<table>
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<th>Wells</th>
<th>Source rock</th>
<th>Correlation</th>
<th>Maturity</th>
<th>Reservoirs</th>
<th>Modelling</th>
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Figure 11. GSWA data generated since 2004 for the Canning Basin, WA.
Peedamullah Shelf is a part of the Northern Carnarvon Basin, and the rest are parts of the Southern Carnarvon Basin (Fig. 17). The Gascoyne Platform is the largest sub-basin of the Southern Carnarvon Basin, and contains mainly Silurian–Devonian succession unconformably overlain by a thin Cretaceous and Cenozoic section. In the Merlinleigh Sub-basin the Silurian–Devonian succession is overlain by a thick Permian–Carboniferous succession, except along the eastern margin. The Peedamullah Shelf contains mainly Mesozoic–Permian strata (Fig. 18). The Silurian Dirk Hartog Group, Upper Devonian Gneudna Formation, Lower Permian Wooramel and Byro groups, and the Upper Permian Kennedy Group contain source-rock intervals of excellent to fair quality (Fig. 19).

In the Silurian–Devonian succession, good-quality and mature—but thin—oil-prone source beds are present in the Dirk Hartog Group on the Gascoyne Platform in Coburn–1 and Pendock–1. The organic richness of these beds is up to 2.06% TOC, with the best potential yield ($S_1 + S_2$) of 6.29 mg/g from core in Coburn–1 (623.9 m). The effective source-rock potential of the Dirk Hartog Group is uncertain from the available data; however, geochemical analyses confirm the presence of source-rock beds in the Silurian, albeit locally. The Upper Devonian Gneudna Formation contains thin beds with the best oil-prone source-rock characteristics in the basin. In Barrabiddy–1A on the Gascoyne Platform, the organic richness of these beds is up to 13.6% TOC, with potential yields...
of up to 40 mg/g. These rich source beds are inside the oil window. On the eastern margin of the Merlinleigh Sub-basin, immature—but good-quality—source beds are recognised in Gneudna–1 and Uranerz CDH–8. On the western margin of the sub-basin in Quail–1, however, the formation is over-mature. The Gneudna source beds are very thin and their potential and maturity vary considerably, both vertically and laterally (Ghori, 1998a, 1999, 2002a).

In the Permian–Carboniferous succession, the best source-rock potential exists in the widespread Artinskian Wooramel Group of the Merlinleigh Sub-basin. The group is up to 380 m thick and contains interbedded organic-rich shales, with good to fair source potential, which are predominantly gas-prone. These organic-rich shales are identified through a 250 m interval in BHP Wandagee–1 and the adjacent Quail–1, and through a 115 m interval in Burna–1. These shales contain up...
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to 16% TOC, with an average of 7%, and their potential yield is up to 12 mg/g, with an average yield of 6 mg/g. The source-rock potential of the Wooramel Group decreases from the north (Burna–1, BHP Wandagee–1, and Quail–1) to the south (Gascoyne–1), and maturities range from immature to the early oil generative stage in all the studied wells except Kennedy–1. In Kennedy–1 the Wooramel Group is over-mature, probably as a result of local intrusion rather than a regional heating event. The Byro Group contains the next best source of the Lower Permian. Good to fair predominantly gas-prone source-rock intervals are present through a 700 m thick interval in Kennedy–1. Source beds are also recognised in BMR Kennedy Range–7 and CRAE GBH–4. The Byro Group is immature and incomplete in the studied wells except Kennedy Range–1, where it ranges from immature to over-mature (Ghori, 1996, 1997). Mature source beds are also present in

Figure 16. Map showing depth of the Goldwyer Formation within the Canning Basin, Western Australia.
the Upper Permian Kennedy Group on the Peedamullah Shelf. They have excellent oil- and gas-generating potential in Candace–1, whose source beds have an organic richness of up to 8.65% TOC, potential yields of up of 23.24 mg/g, and are inside the oil window.

Apatite fission track analysis, vitrinite reflectance measurements, and basin modelling indicate that the levels of maximum burial, palaeotemperatures, and maturation attained across the Carnarvon Basin vary greatly in the Silurian and Devonian successions (Fig. 20). Petroleum expulsion across the basin peaked during the Late Paleozoic for the Dirk Hartog Group and Gneudna Formation, and Early Mesozoic for the Permian source rocks (Ghori, 1998b; Ghori et al, 2005).

Presently, New Standard Energy is evaluating the shale-gas potential of the Merlinleigh Sub-basin for the Lower Permian Wooramel Group as primary resource play, and is expected to drill their first well in 2013. The basin has an estimated uncon-
ordial resource of up to 33 Tcf, and a mature source-rock area of about 1,100 km$^2$.

**OFFICER BASIN**

The Officer Basin is a part of the Centralian Superbasin, which includes the Neoproterozoic fill (840–545 Ma) of the Amadeus, Georgina, Ngalia and Officer basins, and developed as a single depositional system. Although there is no hydro-

carbon production from the Neoproterozoic succession of the superbasin, organic-rich rocks and significant oil and gas shows confirm the existence of the petroleum systems (Bradshaw et al., 1994). There is also a significant gas accumulation during the Petermann Ranges (540–600 Ma) and Alice Springs (320 Ma) orogenic events (Walter et al., 1995). Recent screening of 24 samples, to provide a preliminary insight into the gas-
shale potential of the Amadeus and Georgina basins, indicate that many samples have high potential for gas shale, but further studies are needed (Tiem et al, 2011).

The Officer Basin is elongate with a northwest–southeast trend, and contains more than 8,000 m of Neoproterozoic strata, overlain by the lower Paleozoic rocks of the Gunbarrel Basin (Figs 21 and 22). Minor oil shows and numerous bitumen occurrences have been reported in many of the petroleum exploration wells drilled in the basin (Ghori et al, 2009), confirming the existence of the Neoproterozoic petroleum systems. Given the sparse well control, however, the ultimate petroleum potential of this vast, under-explored basin remains unverified.

Yowalga–3 is the deepest well drilled in the WA part of the Officer Basin (Fig. 23). In the Yowalga area, fair to good oil source beds are identified in thin organic-rich shales of the Browne, Hussar, and Kanpa formations in Kanpa–1A, Yowalga–3 and Empress–1A, respectively. The Neoproterozoic succession is very thick and its maturity varies from immaturity to over-mature for different formations, depending on the maximum depth of burial (Ghori, 1998c). The Neoproterozoic succession may have the best potential for shale gas in the WA part of the basin.

Excellent oil source-beds are present in finely laminated shale and siltstone facies in an evaporitic succession penetrated in mineral corehole NJD–1 located on the Kingston Shelf, and are marginally mature for oil generation. Fair source beds have also been identified in mineral corehole LDDH–1 located on the Kingston Shelf, and are marginally mature for oil generation. Fair source beds have also been identified in mineral corehole LDDH–1 located on the Kingston Shelf, and are marginally mature for oil generation.

From a seismic-stratigraphy point of view, organic-rich source beds occur in the B2 and B4 parasequences of the Browne Formation, the H3 parasequence of the Hussar Formation, and the K1 parasequence of the Kanpa Formation. Modelling indicates the main phases of oil generation in the Neoproterozoic succession occurred during the latest Neoproterozoic, Cambrian and Permian–Triassic. These phases vary,
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both stratigraphically and geographically across the basin, depending on the depositional and structural history of the area (Ghori, 1998c, 2002b).

PERTH BASIN

The Perth Basin forms a north–south elongate rift-trough along the western coast of the Australian continent, extending south from the Southern Carnarvon Basin, and it covers an area of about 100,000 km², from the Yilgarn Craton in the east to the edge of the continental shelf in the west (Fig. 25). The tectonic framework of the basin is dominated by the Darling Fault and Dandaragan Trough in the east, and the offshore Abrolhos and Vlaming subbasins in the west. The Dandaragan Trough is a major depocentre up to 12 km thick. The basin contains mainly continental clastic rocks of Permian and younger ages (Fig. 26), deposited in a rift
system that culminated with the breakup of Gondwana in the Early Neocomian. Two major tectonic phases are recognised: Permian extension in a southwesterly direction, and Early Cretaceous transtension in a northwesterly direction during breakup.

The Perth Basin has been explored for petroleum since the early 1950s, and more than 309 onshore and 52 offshore wells have been drilled. About 20 commercial oil and gas fields and numerous other significant discoveries in tight-sand reservoirs have been discovered (Fig. 27). Geochemical analyses of 13 oils from these discoveries classify the oil as sourced from the Permian, Triassic, Jurassic, and vagrant (i.e., mixed) sources (Fig. 28). The petroleum systems are defined as Transitional and Gondwanan (Bradshaw et al, 1994; GeoMark and AGSO, 1996).

In the Gondwanan petroleum system, main oil-prone source beds are in the Triassic Kockatea Shale with a TOC of more than 2%, and gas-prone source beds in the Permian Carynginia Formation with a TOC of up to 11% (Thomas, 1984; Thomas and Barber, 1994). In the Transitional petroleum system, the main oil- and gas-prone source beds are inside the fluvial-lacustrine shale facies in the Jurassic Cattamarra Coal Measures with TOC up to 27%, and the Yarragadee Formation TOC up to 2% (Thomas, 1984). Source beds in the Permian, Triassic, and Jurassic have wide distribution and extend offshore into the Perth Basin (Crostella, 2001; Grosjean et al, 2012).

TOC and Rock-Eval pyrolysis analysis are available for more than 750 samples from about 55 wells. These data are from the shale and coaly-shale units in the Permian, Triassic, and Jurassic successions, indicating high organic richness, oil- and gas-generating organic facies, and a thermal maturity range from immature to over-mature (Fig. 29). The Hovea Member in the basal Kockatea Shale has the best oil-prone source rocks of the Perth Basin, which is widely distributed across the northern Perth Basin and marks the Permian-Triassic boundary extinction event associated with global source rock deposition (Thomas et al, 2004, Thomas and Barber, 2004).

Estimated total shale-gas resources for the Perth Basin are about 59 Tcf (Kuuskraa et al, 2011), reserovired in roughly equal proportions in the Permian Carynginia Formation and the Triassic Kockatea Shale. The Perth Basin is the most actively explored for unconventional petroleum resources in WA, and has the best infrastructure and a close market. Woodada Deep–1, drilled by Australian Worldwide Exploration (AWE) in 2010, is the first well in WA that was specifically drilled to evaluate shale-gas potential. The well targeted the Carynginia Formation, and the gas resource in place was estimated to be 13–20 Tcf. Arrowsmith–2 was drilled by Northwest Energy in 2011. Both wells were successfully fractured—and flowed gas—and viability for commercial gas production is presently being assessed. The Woodada gas field was originally discovered in 1980, and Arrowsmith–1 was drilled in 1965 and completed as a gas well, but due to rapid decline in gas production it was abandoned in 1981. These gas discoveries are located on the Cadda Terrace, which covers an area of more than 3,000 km² (Crostella, 1995), where high geothermal gradient and vitrinite reflectance values are measured, and the source of hydrocarbons are classified as vagrant (Fig. 28).

Besides shale gas, tight-sand gas resources are estimated at more than 12 Tcf for the Perth Basin (Manifold et al, 2009). Gas in the tight-sand reservoirs are in Corybas, Erregulla, Gingin, Ocean Hill, Warro, Walyering, Whicher Range, Senecio and Snottygobble. Corybas is the first gas field in WA to produce from a tight-sand reservoir, achieving flow in 2010, and the Warro gas field is being evaluated after successful fracturing and gas flow.
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Figure 24. Geochemical evaluation for the Officer Basin, WA: a) generating potential; b) Rock-Eval pyrolysis kerogen typing; and, c) pyrolysis gas-chromatography kerogen typing.

Figure 25. Map showing tectonic units, wells, oil and gas field of the Perth Basin, WA.
Figure 26. Perth Basin stratigraphic distribution of source and reservoir rocks, petroleum discoveries, and systems.

Figure 27. Perth Basin petroleum drilling and discovery history, WA.
CONCLUSIONS

Recent discoveries and estimates of shale-gas resource in the Perth and Canning basins have marked the start of shale exploration and development in WA, encouraged by the US’s success. The Canning Basin has the largest, presently estimated shale-gas resource in Australia, with about 229 Tcf in the Ordovician Goldwyer Formation. Further evaluation of the basin has started with the drilling of Nicolay–1 in 2011 by New Standard Energy. For the Perth Basin, estimated shale-gas resources are 29 Tcf for the Permian Carynginia Formation and 30 Tcf for the Triassic Kockatea Shale. Woodada Deep–1 in 2010 and Arrowsmith–2 in 2011 successfully produced gas from the Carynginia Formation, and their economic viability is presently being evaluated.

Geochemistry of produced oil and rock has also assisted in identifying petroleum source rocks in the Ordovician Bongabinni Formation, the Devonian Gogo Formation, the Lower Carboniferous Laurel Formation, the Lower Permian Noonkanbah Formation of the Canning Basin; the Lower Permian Wooram and Byro groups of the Merlinleigh Sub-basin in the Carnarvon Basin; and, the Neoproterozoic shale of the Officer Basin. These source rocks may also host shale-gas resources, in addition to the Goldwyer and Carynginia formations and the Kockatea Shale.

All these source rocks, however, are untested for petroleum richness as compared to the petroleum-rich shales of the US, which are mostly marine shale source rocks. The Ordovician Goldwyer Formation and the Triassic Kockatea Shale are marine source rocks, but they may have different petroleum richness and/or geological and fracturing characteristics to the US shales. In the US, where infrastructure is well developed with all the necessary facilities for geological evaluation, drilling, fracturing, and production, shale-plays have taken up to five years to convert to commercial plays. These facilities are, presently, lacking in WA and need to be developed. Four vertical shale-gas wells have been completed and successfully fractured, and are being geologically studied to understand how shale-petroleum is stored and how it can be effectively produced. These wells laid the foundation to expand facilities and expertise for shale-petroleum exploration and development in WA. Exploration is at a very early stage and much more work is needed to estimate and verify the shale-petroleum resources of the vastly under-explored onshore WA basins.

Figure 28. Oil characterisation based on multivariate analysis, Perth Basin, WA (GeoMark and AGSO, 1996).

Figure 29. TOC and Rock-Eval pyrolysis evaluation for generating potential and kerogen type for the Perth Basin, WA.
ACKNOWLEDGMENTS
This paper is published with the permission of the Director, Geological Survey of Western Australia.

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