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BONAPARTE BASIN

NORTHERN TERRITORY (NT)
WESTERN AUSTRALIA (WA)
TERRITORY OF ASHMORE & CARTIER ISLANDS ADJACENT AREA (AC)
JOINT PETROLEUM DEVELOPMENT AREA (JPDA)

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7. Browse Basin, Western Australia, 1991.
8. Carnarvon Basin, Western Australia, 1993.
9. Canning Basin, Western Australia, 1993.
10. Perth Basin, Western Australia, 1994.
11. Bowen and Surat Basins, Clarence-Moreton Basin, Sydney Basin, Gunnedah Basin and other minor onshore basins, Queensland, NSW and NT, 1998.

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56	Skua
57	Sunrise
58	Sunset
59	Swan
60	Tahbilk
61	Talbot
62	Tenacious
63	Tern
64	Troubadour
65	Turtle
66	Vienta
67	Waggon Creek
68	Weaber

ABBREVIATIONS

^{o}API	degrees American Petroleum Institute.
bbl(s)	barrel(s)
BCF	billion cubic feet
BCM	billion cubic metres
^{o}C	degrees centigrade
cc	cubic centimeters
DIR	Department of Industry and Resources, Western Australia
DRD	Department of Resources Development, Western Australia
DST	drill stem test
^{o}F	degrees fahrenheit
FPSO	floating production, storage and offloading facility
FSO	floating storage and offloading facility
ft	feet
ft^3	cubic feet
JPDA	Joint Petroleum Development Area
km	kilometres
km^2	square kilometers
kpa	kilopascals
LNG	liquefied natural gas
LPG	liquefied petroleum gas
m	metres
mm	millimetres
m^3	cubic metres
mD	millidarcies
MDT	modular dynamic tester
mKB	metres below kelly bushing
ml	millilitres
MMbbls	million barrels
MMscf	million standard cubic feet
mRT	metres below rotary table
MSCT	multiple sidewall core tool
mSS	metres sub-sea
NTBIRD	NorthernTerritory Department of Business, Industry and Resources
ppm	parts per million
psi	pounds per square inch (absolute)
psia	pounds per square inch absolute
psig	pounds per square inch gauge
RFT	repeat formation test
scf	standard cubic feet

ABBREVIATIONS CONTINUED

ST	sidetrack
stb	stock tank barrels
TCF	trillion cubic feet
TVDSS	true vertical depth sub-sea
TVDKB	true vertical depth below kelly bushing
TVT	true vertical thickness
ZOC	Zone of Cooperation

1. INTRODUCTION

This report contains data on the 68 petroleum accumulations discovered in the Bonaparte Basin to December 2002. It provides summaries of the regional setting, evolution and stratigraphy of the basin and discusses the hydrocarbon habitat and development of the producing accumulations.

For the purpose of this report, a discrete, measured recovery of petroleum on test from an exploration well qualifies as a ‘discovery’. Petroleum accumulations inferred from wireline log interpretations (and where petroleum has not been recovered on test) are referred to as ‘shows’. Small quantities of gas recovered on test in three wells included in this report may represent ‘solution gas’ - indicating these wells may not have intersected a petroleum pool.

In this report, a petroleum accumulation is classified as a ‘producer’ if, at time of writing, petroleum production is occurring; a ‘past producer’ if the accumulation has been depleted or is currently not producing; an ‘other discovery’ if the petroleum accumulation is unlikely to be produced within the next 15 years and; a ‘possible future producer’ if the accumulation is held under Retention Lease or where a development is under consideration.

Reserves data used in this report are publicly available from the West Australian Department of Minerals and Energy and Northern Territory Department of Business, Industry and Resource Development.

Non-confidential (‘open file’) test results from discovery wells drilled in the Bonaparte Basin are listed in **Appendix 1.**

2. REGIONAL SUMMARY

2.1 Introduction

The Bonaparte Basin is a large, predominantly offshore sedimentary basin that covers approximately 270,000 square kilometres of Australia's northwest continental margin. The basin contains up to 15 kilometres of Phanerozoic, marine and fluvial, siliciclastic and carbonate sediments.

The basin has undergone two phases of Palaeozoic extension, a Late Triassic compressional event and further extension in the Mesozoic. Convergence of the Australian and Eurasian plates in the Miocene to Pliocene resulted in flexural downwarp of the Timor Trough and widespread fault reactivation across the western Bonaparte Basin.

At date of writing, 68 petroleum accumulations had been identified within the Bonaparte Basin in reservoirs ranging from Carboniferous to Late Cretaceous in age (**Plate 1**, **Appendix 1**). Commercial production has occurred from 11 of these discoveries.

2.2 Basin Setting

The Bonaparte Basin is structurally complex and comprises a number of Palaeozoic and Mesozoic sub-basins and platform areas.

The Basin adjoins the Browse Basin to the south along the southwest margins of the Ashmore Block and the Vulcan Sub-basin **(Plate 1).** In the northeast, beyond the limits of the Darwin Shelf, the Bonaparte Basin adjoins the Arafura and Money Shoal Basins. The northern margin of the basin is taken as the Timor Trough, where water depths exceed 3,000 metres.

In the east, the northwest trending Petrel Sub-basin (referred to as the Bonaparte Basin by Gunn, 1988) underlies the Joseph Bonaparte Gulf **(Figures 10.1, Plate 1).** The sub-basin developed during rifting in the Late Devonian to Early Carboniferous and contains a thick evaporitic sequence, which was mobilised in a subsequent episode of salt tectonism (Gunn, 1988; Lee and Gunn, 1988).

Offshore, the Petrel Sub-basin is orthogonally overprinted by a northeast and east-northeast trending, Mesozoic structural grain that resulted from rifting and the ultimate break-up of Gondwanaland in the Middle Jurassic (O'Brien et al., 1993). The Malita Graben, a major Triassic depocentre which lies between the Petrel Sub-basin and the Sahul Platform, developed at this time **(Plate 1)**. The graben also contains a significant thickness of Cainozoic, Cretaceous and possibly, Late Jurassic sediments (Botten and Wulff, 1990; O'Brien et al., 1993)**(Figure 9.1, Plate 2)**.

The Sahul Platform, which underlies most of Joint Petroleum Development Area (JPDA), was a structural high throughout much of the Late Jurassic (Botten and Wulff, 1990). The southwest margin of both the Sahul Platform and the Malita Graben are delimited by the northwest trending, Sahul Syncline **(Figure 8.1, Plate 1)**.

Botten and Wulff, (1990) consider the Sahul Syncline formed in the Late Triassic to Middle Jurassic, whereas others (Durrant et al., 1990), believe it developed as part of the Bonaparte rift system in the Late Devonian.

The Vulcan Sub-basin, a major, northeast trending, Late Jurassic depocentre, lies southwest of the Sahul Syncline (Patillo and Nicholls, 1990). The Vulcan Sub-basin has been further sub-divided into a number of intra-sub-basin terraces and grabens **(Figures 5.1 and 5.2, Plate 1).**

The Vulcan Sub-basin is flanked both in the east and west by Permo-Triassic 'high' blocks - the Londonderry High and the Ashmore Platform, respectively.

2.3 Basin Evolution

The Bonaparte Basin has undergone a complex structural history. The Phanerozoic evolution of the Timor Sea area has been described by Veevers, (1971 and 1988); Gunn, (1988); Patillo and Nicholls, (1990); O'Brien et al., (1993); AGSO NW Shelf Study Group, (1994); Baillie et al., (1994); Whittam et al., (1996); O'Brien et al., (1996); Schuster et al., (1998); and Kennard et al., (2002 and 2003).

Neogene tectonism (and its implications for petroleum exploration in the basin) is described by Bowin et al., (1980); McCaffery, (1998); Richardson, (1993); and Keep et al., (2002).

Key tectonic events in the evolution of the Bonaparte Basin include:

- A northwest-trending, Late Devonian to Early Carboniferous rift formed the Petrel Sub-basin;
- Extension in the Late Carboniferous to Early Permian overprinted the older trend with a northeast oriented structural grain. The proto-Vulcan Sub-basin and Malita Graben developed at this time;
- A compressional event in the Late Triassic caused uplift and erosion on the Londonderry High, the Ashmore and Sahul Platforms and on the southern margins of the Petrel Sub-basin;
- In response to Mesozoic extension, the Vulcan Sub-basin, Malita Graben and Sahul Syncline became major, Jurassic depocentres;
- With the onset of thermal subsidence in the Valanginian, a thick wedge of fine grained, clastic and carbonate sediments prograded across the offshore Bonaparte Basin during the Cretaceous and Cainozoic;
- Regional compression associated with the collision of the Australian plate with the South East Asian microplates in the Miocene formed the Timor Trough and the strongly faulted northern margin of the adjacent, Sahul Platform.

2.4 Stratigraphy

The regional geology and stratigraphy of the Bonaparte basin has been described by many authors over the last half century. The first regional studies were largely of the onshore sequence (Traves, 1955; studies by the Bureau of Mineral Resources, Geology and Geophysics, Australia, from 1963-71; Veevers and Roberts, 1968; Guillaume, 1966; Brady et al., 1966; and Mory and Beere, 1988).

Many authors have since described the regional geology and stratigraphy of both the onshore and offshore Bonaparte Basin. The following description of the stratigraphy of the Bonaparte Basin is largely based on the work of Mory, (1991); Lavering and Ozimic, (1989); Whittam et al., (1996); Labutis et al., (1998); and Shuster et al., (1998).

Technical material accompanying the Commonwealth's annual release of offshore exploration acreage to the petroleum industry has also been used in the preparation of this report (Release of Offshore Petroleum Exploration Areas, 2001, 2002 and 2003).

The Bonaparte Basin has undergone a complex tectonic history. Consequently, the stratigraphy varies considerably across the basin (Messent et al., 1994) - Palaeozoic sediments are largely restricted to the onshore and inboard portions of the Petrel Sub-basin while Mesozoic and Cainozoic sequences are largely confined to the outboard portion of the Bonaparte Basin **(Plate 2)**.

Sedimentation in the Petrel Sub-basin commenced in the Cambrian **(Figure 10.2).** The pre-rift sequence comprises extensive evaporite deposits, but the precise age (Ordovician, Silurian or Devonian), lateral continuity and extent of these salt bodies is uncertain. Subsequent salt tectonics (flow, diapirism, and withdrawal) has controlled the development of numerous structural and stratigraphic traps within the sub-basin (Edgerley & Crist, 1974; Durrant et al., 1990; Miyazaki, 1997; Lemon & Barnes, 1997)**(Figure 10.6)**.

Northeast-southwest rifting was initiated in the Late Devonian, when clastic and carbonate sediments were deposited in shallow marine and non-marine environments across the Petrel Sub-basin. This was followed by a thick, Carboniferous succession of marine, fluvio-deltaic and finally glacial sediments which were deposited in response to post-rift subsidence and salt withdrawal **(Figure 10.5)**. Late Devonian to Late Carboniferous carbonate and clastic sequences are primary exploration objectives in the Petrel Sub-basin.

In the Late Carboniferous to Early Permian, the Late Devonian-Carboniferous rift-sag system was orthogonally overprinted by northeast-trending rifting. The proto-Malita Graben developed at this time (O'Brien, 1993; Baxter, 1996). A succession of northwest-thickening, shallow marine to fluvio-deltaic, Permian and Triassic sediments was then deposited across the Bonaparte Basin. Several petroleum accumulations have been identified both within the Permian section in the Petrel Sub-basin **(Figure 10.3)**, and the Triassic, fluvio-deltaic and marginal marine sandstones in the south and east of the Vulcan Sub-basin **(Figures 5.4 and 5.5)**.

Uplift in the Late Triassic caused widespread erosion on the Ashmore Platform, Londonderry High and on the southern margin of the Petrel Sub-basin. A thick succession of fluvial and fluvio-deltaic, Jurassic sediments (Plover Formation) were then deposited in the main depocentres within the basin (Vulcan Sub-basin, Sahul Syncline and Malita Graben) and across the Sahul Platform.

In the Northern Bonaparte Basin, a marine facies is developed at the top of the Plover Formation. This unit has been referred to as the Elang Formation, the Laminaria Formation or the 'Montara beds'. Many of the petroleum accumulations identified in the Vulcan Sub-basin and on the Sahul Platform are structurally trapped in Plover and Elang/Laminaria Formation sandstones **(Figure 8.4, 5.4 and 5.5, Plate 2).**

Plover Formation sediments are absent on the Ashmore Platform and on the crestal parts of the Londonderry High, but onlap the eastern flank of the Londonderry High from the Petrel Sub-basin. In areas south and east of the Malita Graben, however, the Plover Formation is not considered a primary exploration objective due to relatively shallow burial depths.

In the Late Jurassic, the rate of subsidence in the major grabens increased and fine grained sediments of the Flamingo Group were deposited over a basin-wide, Callovian unconformity. In the Vulcan Sub-basin, sediments of the Flamingo Group (Upper and Lower Vulcan Formations) have traditionally been considered good quality source rocks. A recent oil discovery in a Tithonian sandstone within the Upper Vulcan Formation (at **Tenacious-1**) indicates the unit also has reservoir potential. In the Sahul Syncline area, equivalent age sandstones within the Cleia Formation are also considered exploration targets. In the offshore Petrel Sub-basin, a sandstone of Late Jurassic age at the top of the Flamingo Group (Sandpiper sandstone) is considered a secondary exploration objective in the area **(Plate 2)**.

Mesozoic extension ended in the Valanginian when a marine transgression flooded the Australian continental margin. With the onset of thermal subsidence, fine grained, clastics and carbonates of the Bathurst Island Group were deposited across the Bonaparte Basin. At the base of the group, the Echuca Shoals Formation provides a regional seal to the underlying Upper Vulcan Formation in the Vulcan Sub-basin and to the Cleia Formation in the Sahul Syncline area. The unit thins on the platform areas in the west of the Bonaparte Basin, and in the Petrel Sub-basin to the east, is equivalent in age to sediments within the lowermost Darwin Formation **(Plate 2)**.

Late Cretaceous and Cainozoic sediments typically comprise thick, prograding, platform carbonates. Lowstands sands developed in the Maastrichtian (Puffin Formation) and Eocene (Grebe sandstone), however, are considered exploration targets in the Vulcan Sub-basin. Oil has been recovered on test from the channelled, fan sands within the Puffin Formation at **Puffin-1**.

Regional compression associated with the collision of the Australian plate with the South East Asian microplates reactivated Mesozoic faulting and breached many Middle to Late Jurassic, fault dependent structures on the Londonderry High, Sahul Platform and in the Vulcan Sub-basin - many exploration wells drilled in these areas have intersected residual oil columns within sands of the Plover and Laminaria/Elang Formations **(Tables 5.1, 6.1 and 8.1, Figures 5.6, 6.3 and 8.5)**.

A more detailed description of the Palaeozoic stratigraphy of the Bonaparte Basin can be found in **Section 10, Petrel Sub-basin**. Mesozoic and Cainozoic stratigraphy is more fully described in **Section 5, Vulcan Sub-basin** and **Section 8, Sahul Platform**.

2.5 Petroleum Systems

The Bonaparte Basin is a proven petroleum province. The basin contains all the prerequisites for additional discoveries with good quality reservoirs, mature source rocks and traps overlapping over a wide area of the basin. At date of writing, 68 petroleum accumulations had been identified in the Bonaparte Basin (**Plates 1 and 2**).

The petroleum potential of the Bonaparte Basin has been summarised by numerous authors over the last decade including McConachie et al, (1996); Colwell and Kennard, (1996); and Kennard et al., (2002 and 2003). These authors discuss the use of petroleum systems as an integrated approach to basin analysis, recognising existing proven petroleum plays and presenting them as a tool for identification of further hydrocarbon opportunities.

Magoon and Dow, (1991 and 1994) define a petroleum system as a mature source rock and all its generated hydrocarbon accumulations. Individual petroleum systems that share source rocks of similar age and facies can be grouped together into petroleum supersystems (Bradshaw et al., 1994). These can provide a basis for prediction of hydrocarbon occurrences in less well explored areas of a basin or basins with similar age rocks.

The key features of a petroleum play (source, maturity, reservoir, seal, trapping mechanism) are used to define a petroleum system. Petroleum systems identified in the Bonaparte Basin at date of writing are summarized below.

2.5.1 Palaeozoic Petroleum Systems

Colwell and Kennard, (1996) recognized three active Palaeozoic petroleum in the Petrel Sub-basin (elsewhere in the Bonaparte Basin, Palaeozoic sediments are not considered prospective for petroleum).

- A Late Devonian (Ningbing Limestone / Bonaparte Formation) Petroleum System. The gas accumulations identified within these units at Garimala and Vienta in the onshore, Petrel Sub-basin form part of this system and may have been sourced from either the Milligans Formation (Laws, 1981), or from the Bonaparte Formation (Kennard et al., 2002). Residual oil observed in a core cut in the Ningbing Limestone at Ningbing-1, may have been sourced locally from algal material within the limestone. This system appears to be restricted to the onshore and near offshore areas in the south of the Petrel Sub-basin;

- An Early Carboniferous (Milligans / Tanmurra / Kuriyippi Formations) Petroleum System. Thermally mature, marine mudstones within the Milligans Formation, have probably provided an oil and gas charge for the petroleum accumulations identified at Turtle, Barnett, Weaber and Waggon Creek **(Figure 2.1);**

- A Permian (Hyland Bay / Keyling Formations) Petroleum System. Gas (and possibly oil) sourced from either the Hyland Bay Formation or the Keeling Formation / Treachery Shale has charged the accumulations identified at Blacktip, Petrel, Tern and Fishburn **(Figure 2.2).**

2.5.2 Mesozoic Petroleum Systems

Mesozoic petroleum systems in the Timor Sea area are shown in **Figure 2.3** and include:

- A Middle Triassic to Middle Jurassic Petroleum System - oil and gas accumulations within the Challis, Nome and Plover Formations charged by Plover Formation source rocks (Challis, Cassini, Talbot, Maple, Crux, Pengana)(**Plate 2**);

- A Late Jurassic to Neocomian Petroleum System - source rocks within the Lower Vulcan Formation provide a hydrocarbon charge for Plover and Upper Vulcan Formation reservoirs (includes Jabiru, Skua, Audacious, Oliver, Tenacious). This system may also provide a petroleum charge for Late Cretaceous and Cainozoic reservoirs (Puffin Formation, Grebe and Oliver sandstones) via migration up faults;

- A Late Cretaceous Petroleum System. Although the Echuca Shoals and Upper Vulcan Formations are thermally immature for petroleum generation over much of the Bonaparte Basin, in the major depocentres in the Northern Bonaparte Basin (Sahul Syncline, Malita Graben), these units may provide a hydrocarbon charge for Upper Vulcan, Elang / Laminaria and Puffin Formation traps.

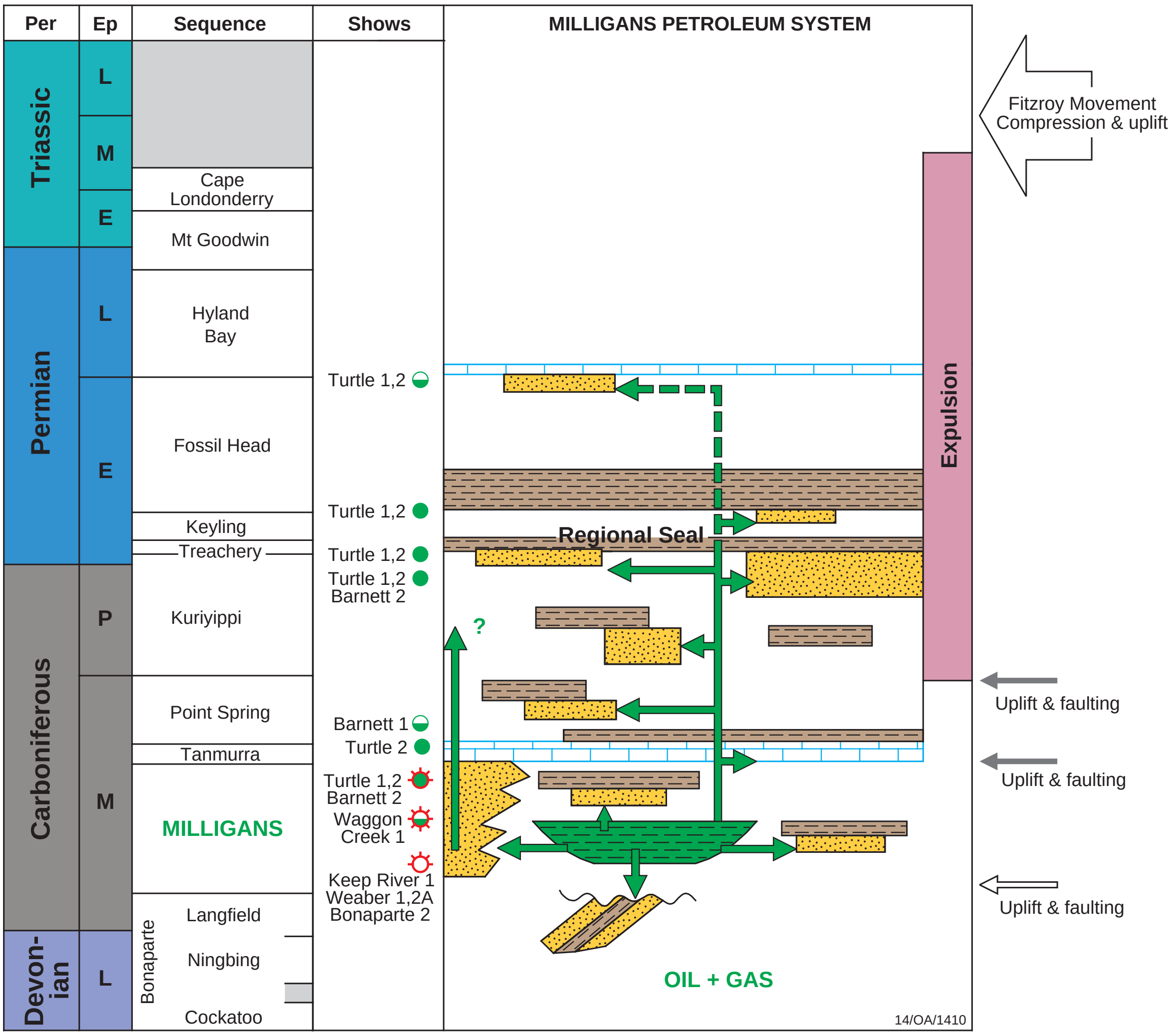

Figure 2.1 Schematic diagram of the early Carboniferous petroleum system (Kennard et al, 2002).

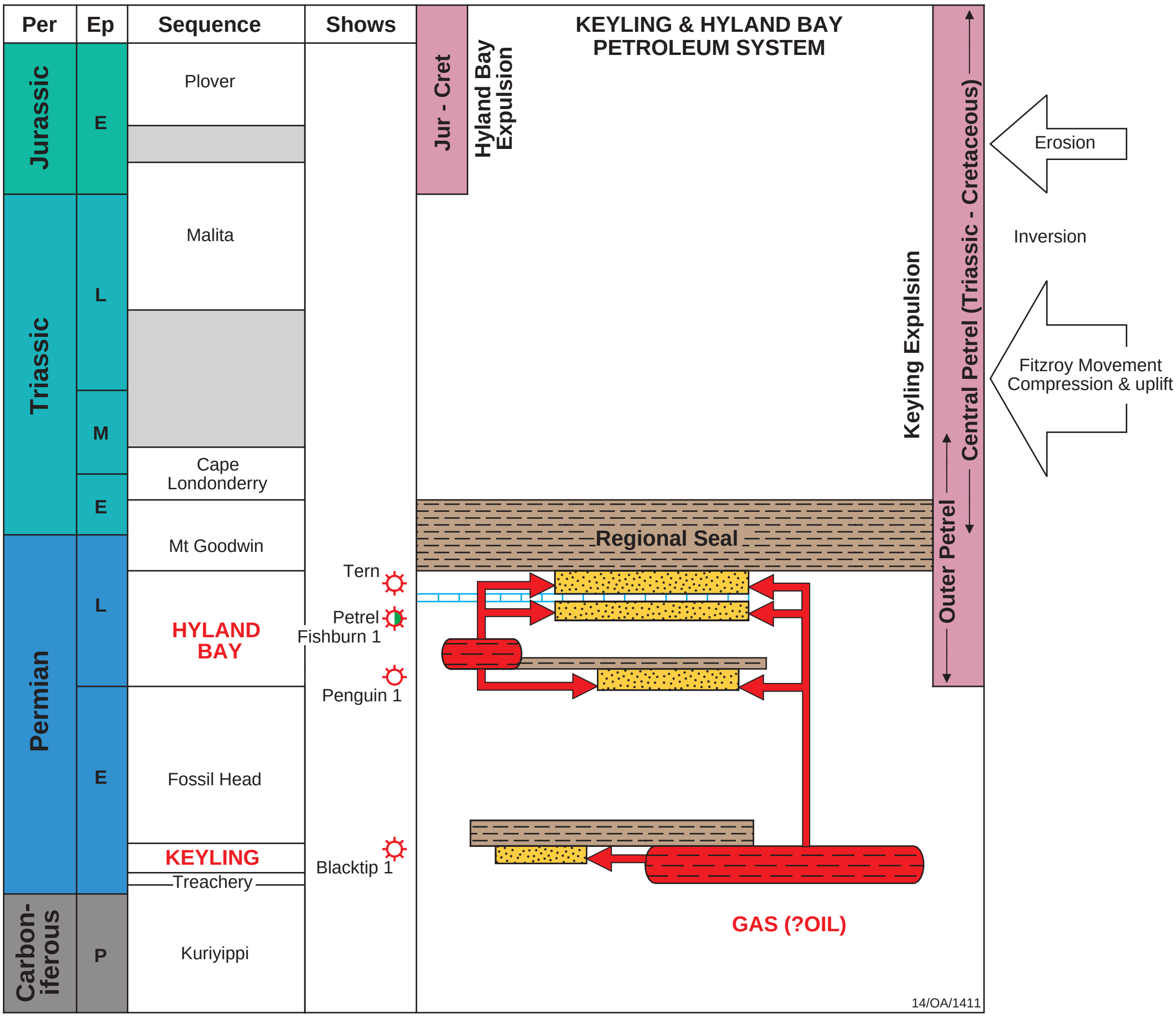

Figure 2.2 Schematic diagram of the Permian petroleum system (Kennard et al, 2002).

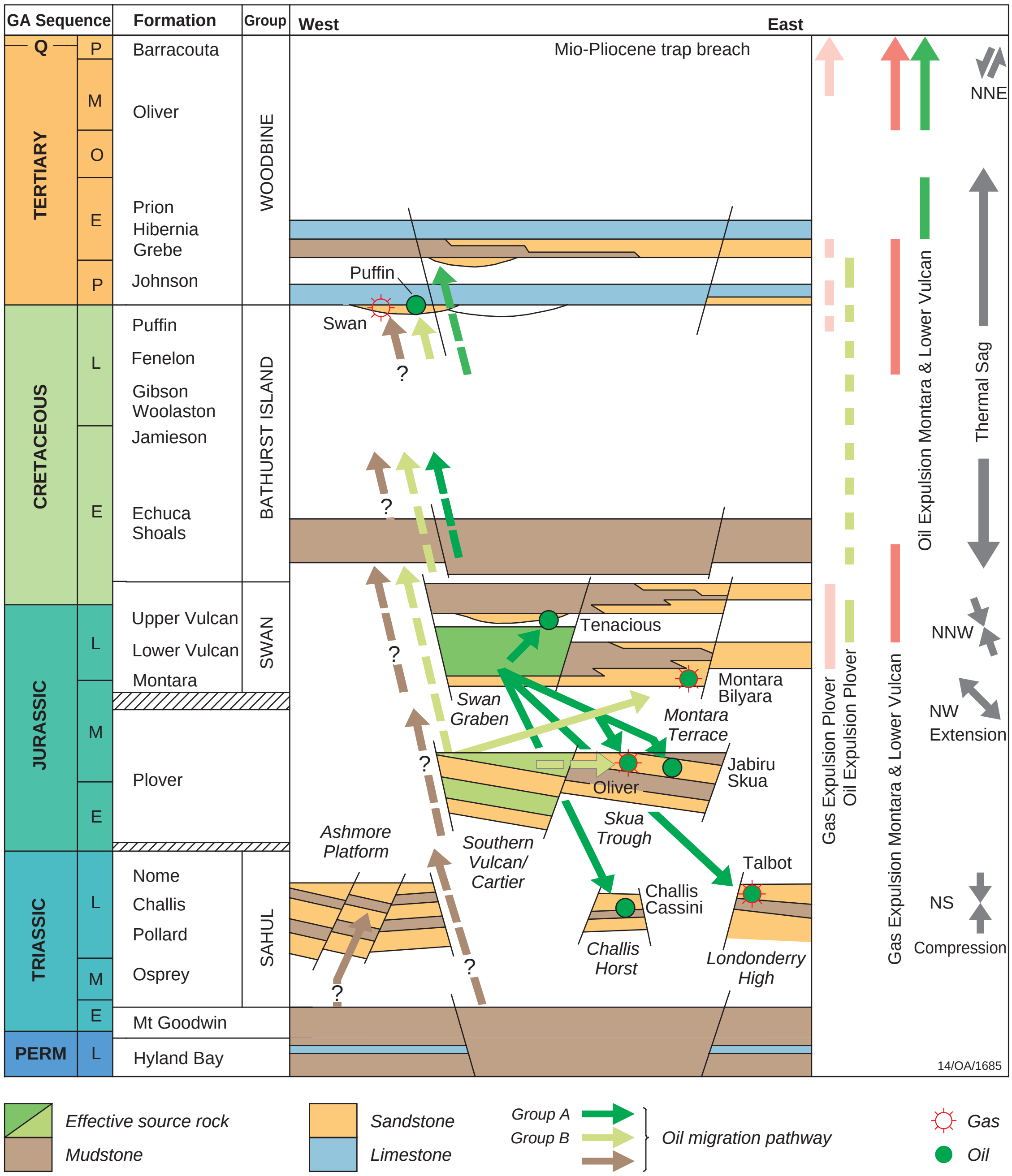

Figure 2.3 Schematic diagram of the Mesozoic petroleum system, Vulcan Sub-basin (Kennard et al., 2003).

3. EXPLORATION HISTORY

Initial exploration in the Bonaparte Basin commenced in the 1950's with regional studies of the southeastern, onshore portion of the basin (Petrel Sub-basin). The first exploration well (Spirit Hill-1) was drilled in the onshore Bonaparte Basin in 1959. Initially drilled as a water well, Spirit Hill-1 identified potential petroleum source rocks within the Early Carboniferous section. Further onshore drilling adjacent to the southeastern basin margin in the 1960's, (Bonaparte-1 and -2, Kulshill-1 and -2, Moyle-1 and Keep River-1) provided additional encouragement for petroleum exploration in the area **(Table 10.1, Figures 3.1)**.

Although several of these early wells did not test valid structural closures, gas flowed on drill stem test (DST) from the Early Carboniferous, Milligans Formation in **Bonaparte-2** (1964) and **Keep River-1** (1968). Oil shows were also recorded in the Late Carboniferous to Early Permian section at Kulshill-1 **(Table 10.2)**.

Onshore, the first significant discovery did not occur until 1982, when **Weaber-1** recovered gas on test from the Early Carboniferous, Enga Sandstone and Milligans Formation. Appraisal drilling on the Weaber feature continued over the next 16 years (Weaber-5 was drilled in 1998). Additional small, gas discoveries were made in the onshore, Petrel Sub-basin in 1995 (Gas was recovered from the Milligans Formation at **Waggon Creek-1**) and in 1998 (**Vienta-1** identified small gas accumulations in the Devonian to Early Carboniferous Langfield Group and Ningbing reef complex).

Exploration of the offshore Bonaparte Basin commenced in 1965 when regional aeromagnetic data was acquired over much of the basin. This was supplemented by regional seismic coverage between 1965 and 1974. The first offshore exploration wells were spudded by BOCAL/Woodside in the late 1960's. Located on the Ashmore Platform, Ashmore Reef-1 and Sahul Shoals-1 were drilled as stratigraphic tests. Although these wells failed to encounter hydrocarbons, they indicated the Jurassic section is either thin or absent and that Triassic sandstones form potential petroleum reservoirs over much of the Ashmore Platform.

Between 1969 and 1971, Arco Australia and Australian Aquitaine drilled seven wells in the offshore Petrel Sub-basin. This drilling campaign resulted in the discovery of the **Petrel** and **Tern** gas fields. Although several appraisal wells have since been drilled on the Petrel and Tern features, these gas accumulations have yet to be developed. The discoveries at Petrel and Tern identified the Late Permian Hyland Bay Formation as a primary exploration target in the Petrel Sub-basin.

In the early 1970's, exploration of the offshore Bonaparte Basin expanded beyond the limits of the Petrel Sub-basin and Ashmore Platform to include the Vulcan Sub-basin, Londonderry High and Sahul Platform. Between 1971 and 1975, twenty four wells were drilled - a further 9 in the Petrel Sub-basin, 4 on the Sahul Platform, 6 in the Vulcan Sub-basin, 2 on the Londonderry High and 2 on the Ashmore Platform. Several significant petroleum discoveries were made during this period including **Puffin**, **Troubadour** and **Sunrise**.

In 1972, **Puffin-1** was drilled to test the Mesozoic section within a horst block on the flanks of the Vulcan Sub-basin. Oil was found (interpreted from wireline logs) in vuggy, Eocene calcarenites trapped beneath the Eocene/Miocene unconformity and recovered on test from Maastrichtian age sands (Puffin Formation). The Puffin-1 well established the existence of an active petroleum system in the Vulcan Sub-basin. Recent appraisal drilling on the Puffin structure has yet to identify a commercial resource at Puffin.

In 1974, Woodside/BOCAL drilled **Troubadour-1** on the Troubadour High – a large culmination on the eastern Sahul Platform **(Figure 8.2)**. The well flowed gas on test from the Jurassic, Upper Plover Formation. In 1975, a second well (**Sunrise-1**) drilled approximately 20 kilometres to the north of Troubadour-1, flowed gas and condensate on test from the same reservoir.

Subsequent gas discoveries on the Troubadour High (**Loxton Shoals-1**, 1995; **Sunset-1**, 1997; Sunrise-2, 1998; **Sunset West-1**, 1998;) identified a complex of large, elongate, east-west oriented fault blocks with gas trapped in sandstones of the Plover Formation. This complex is referred to as the Greater Sunrise gas field (or Sunrise/Troubadour field). At date of writing, commercial development of the Greater Sunrise field is under consideration.

Between 1974 and 1991, a moratorium was placed on further appraisal drilling on the Sunrise/Troubadour structure until issues related to international jurisdiction and the boundary with Indonesia were resolved. A history of exploration permits in this area can be found in **Section 8.4, '**History of exploration permits in the Zone of Cooperation (ZOC) and the Joint Petroleum Development Area (JPDA)'. Elsewhere in the offshore Bonaparte Basin, relatively low levels of exploration drilling were recorded at this time **(**between 1975 and 1982, a total of 8 wells were drilled) **(Figure 3.1)**.

In 1983, BHP Petroleum drilled **Jabiru-1A** to test a fault dependent closure on an eroded and tilted Jurassic fault block, located on the Jabiru-Turnstone Horst in the Vulcan Sub-basin. The well flowed oil and gas on test from shallow marine sandstones of the Plover Formation and basal Flamingo Group. The Jabiru discovery was the first commercial oil discovery in the Bonaparte Basin. Production from the Jabiru oil field commenced in 1986.

The discovery of oil at Jabiru stimulated exploration in the Bonaparte Basin and over the next three years (1984 to 1986), 21 exploration wells were drilled in the offshore Bonaparte Basin. Of these, 12 were located in the Vulcan Sub-basin or on the western flank of the Londonderry High. This phase of exploration resulted in the discovery of a further two commercial oil accumulations in the Vulcan Sub-basin (**Challis** and **Skua** fields) and two non-commercial discoveries in the offshore Petrel Sub-basin (**Turtle** and **Barnett**).

After a brief downturn in 1987, levels of offshore exploration drilling in the Bonaparte Basin accelerated. Drilling activity peaked in 1990, when 22 exploration wells were drilled **(Figure 3.1)**.

Between 1988 and 1990, 31 exploration wells were drilled in the Vulcan Sub-basin. Drilling results from these wells proved disappointing. Although several small oil and gas discoveries were made (**Oliver-1**, **Montara-1**, **Bilyara-1**, **Talbot-1**, **Maple-1**, and **Tahbilk-1**), at date of writing, none of these are in commercial production.

Further to the north, on the terraced flanks of the Malita Graben, **Evans Shoal-1** (1988) identified a significant gas accumulation within the Jurassic, Plover Formation. An appraisal well (Evans Shoal-2) was drilled in 1998 and at date of writing, development options for the Evans Shoal accumulation are under consideration.

Resolution of the boundary between Indonesia and Australia in 1991 established the Zone of Cooperation (ZOC) and facilitated the further release of exploration acreage on the Sahul Platform. Between 1992 and 1998, the focus of exploration in the offshore Bonaparte Basin shifted to this area. Of the 73 exploration wells drilled in the offshore Bonaparte Basin during this period, 43 were located on or adjacent to the Sahul Platform. The first commercial petroleum success in the area resulting from this phase of exploration occurred in 1994 with the discovery of oil by **Elang-1**.

The Elang structure is the crestal culmination on the 'Elang Trend' (an east-west oriented structural high, located on the northwest flank of the Flamingo High). Oil at Elang is trapped in Late Callovian to Early Oxfordian sandstones beneath the Frigate Shale. These sands have previously been regarded as a marine facies at the top of the Plover Formation, or referred to as the 'Montara beds' (Young et al., 1995). This unit is now referred to as the Elang or Laminaria Formation.

In December 1994, **Kakatua-1** and **Kakatua North-1** were drilled to the west of Elang oil discovery. Both wells recovered oil on test from the Elang/Laminaria Formation. Commercial oil production from a joint Elang/Kakatua/Kakatua North development commenced in 1998 via sub-sea completions, tied back to an FPSO moored over the Elang field.

The discovery of oil at Elang identified a new oil play on the Sahul Platform. Further commercial success in the area quickly followed. In late 1994, immediately to the west of the ZOC, Woodside Petroleum drilled **Laminaria-1** on the Laminaria High, **(Figure 8.2)** The Laminaria-1 well tested a faulted horst complex and intersected a 102 metre gross oil column. As at Elang, the oil at Laminaria is trapped in transgressive, estuarine dominated delta sands of Callovian to Early Oxfordian age.

In late 1995, **Corallina -1** was drilled on a separate horst complex immediately to the north of the Laminaria discovery. Oil and gas were recovered from the same reservoir intersected by Laminaria-1. In 1999, commercial oil production commenced from a combined Laminaria/Corallina development via sub-sea completions tied back to an FPSO.

In early 1995, Phillips Petroleum drilled **Bayu-1** on a crestal culmination on the Flamingo High. The well intersected a 155 metre gross gas/condensate column in Late Oxfordian to Early Callovian sandstones. In mid-1995, a successful gas discovery well (Undan-1) was drilled on a separate culmination, on an extension of the same feature, in an adjacent exploration permit. Post-drill analysis and subsequent appraisal drilling indicate the Bayu-1 and Undan-1 gas/condensate discoveries comprise a single, large gas-condensate field with an areal extent of approximately

160 square kilometres (Brooks, et al., 1996). Commercial production from Bayu-Undan is expected to commence in 2004.

In 1996, BHP Petroleum drilled **Buffalo-1** to test the Callovian-Oxfordian section within a tilted fault block on the Laminaria High. The well flowed oil on test and commercial oil production from the Buffalo field commenced in December 1999. The field development comprises an unmanned wellhead platform, supporting three vertical wells, producing to a nearby FPSO. At date of writing, the Buffalo oil discovery remains the most recent commercial petroleum development in the Northern Bonaparte Basin.

Since the discovery at Buffalo, petroleum discoveries on the Sahul Platform have been small (**Bluff-1**, **Krill-1**, **Kuda Tasi-1**, **Jahal-1**, **Buller-1** and **Chuditch-1) (Figure 8.4)**. At date of writing, however, a joint development of the Kuda Tasi and Jahal oil discoveries is under consideration. Since the discovery of the Bayu-Undan gas/condensate accumulation in 1995, no commercial gas discoveries have been made in the Northern Bonaparte Basin. The discovery of gas within the Hyland Bay Formation at **Kelp Deep-1** in 1997, however, established the Permian section as a valid exploration objective on the platform, at least on the Kelp High.

To the south, results of exploration drilling in the Vulcan Sub-basin since the mid-1990s have been disappointing - small oil accumulations have been identified at **Tenacious-1** (1997) and **Audacious-1** (2001) and a gas accumulation at **Crux-1** (2000). At date of writing, commercial development of all three accumulations is under consideration.

Although the Tenacious oil discovery is small, the Tenacious-1ST1 well identified a new play in the Vulcan Sub-basin – the discovery is the first in the Vulcan Sub-basin to have oil both trapped and sealed within a Tithonian, submarine fan sand in the Upper Vulcan Formation (Woods and Maxwell, 2003).

In 1999, East Timor was granted independence by Indonesia. In that year, only one exploration well (Jura-1) was drilled in the former ZOC. Since that time, two wells (Coleraine-1, 2000; and **Kuda Tasi-1**, 2001), have been drilled within the now Joint Petroleum Development Area (JPDA).

Recent exploration drilling on the northeastern flanks of the Londonderry High identified a gas accumulation at **Prometheus/Rubicon** (2000). At time of writing, data is confidential and no other details on this discovery are available.

During 2001, two wells (Sandbar-1 and Blacktip-1), were drilled in the inshore portion of the Petrel Sub-basin. No hydrocarbons were encountered in Sandbar-1 but Blacktip-1 was completed as a gas discovery. **Blacktip-1** encountered a 20 metre gross gas column within the Triassic, Mount Goodwin Formation and a 339 metre gross gas column from several high quality, stacked reservoir zones within the Early Permian, Keyling Formation. Two deeper gas columns were also intersected within the Treachery Formation (Leonard et al., 2003). Although the Blacktip gas discovery has yet to be developed, the proposed construction of a gas pipeline from the Bayu-Undan gas field to Darwin and possible development of the Greater Sunrise gas field may provide an impetus to the development of small gas accumulations (such as Blacktip) in the southern Petrel Sub-basin.

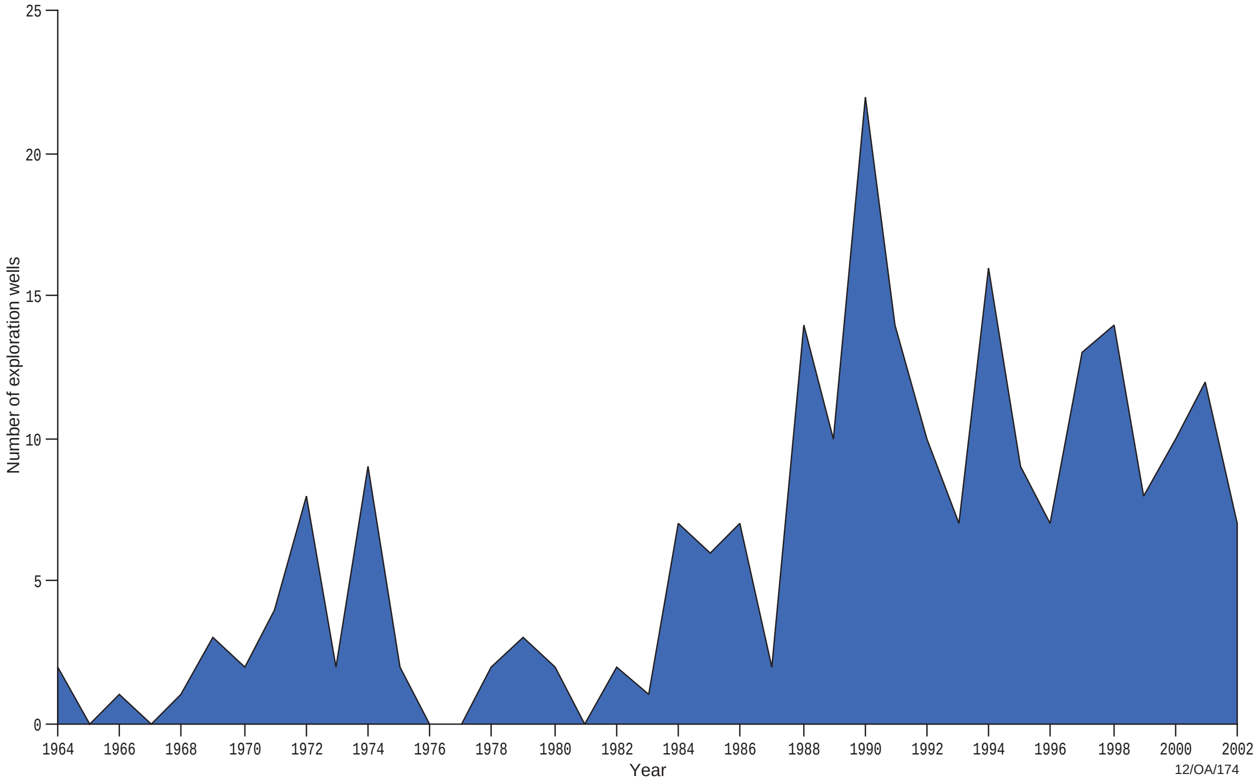

Figure 3.1 Exploration drilling, Bonaparte Basin, 1964 to 2002.

4. ASHMORE PLATFORM

4.1 Introduction

The Ashmore Platform is a large, elevated block that abuts the western margin of the Vulcan Sub-basin and the northern flank of the Browse Basin. An arcuate fault zone, concave to the west, divides the platform into two major segments - a western terrain with mainly west-dipping faults, and an eastern terrain with both east-dipping and west-dipping faults (Laws & Kraus, 1974) **(Figure 5.2).**

At date of writing, no petroleum accumulations had been identified on the Ashmore Platform.

4.2 Structural Evolution and Stratigraphy

The oldest unit intersected by drilling on the Ashmore Platform is the Triassic, Mount Goodwin Formation (Sahul Shoals-1). Undifferentiated Sahul Group sediments unconformably overly this unit over most of the platform.

Interbedded sandstones and shales of the Osprey Formation (a turbidite sequence) onlap Mount Goodwin Formation shales and siltstones on the eastern margin of the Ashmore Platform, while in the west of the platform, an oolitic limestone (Benalla Formation) developed within the Sahul Group **(Plate 2)**.

Seafloor spreading to the west of Ashmore Platform commenced in the Callovian when a basin-wide unconformity developed (Veevers, 1984). Jurassic sediments have not been intersected by drilling on the Ashmore Platform and are thought to have been largely removed by erosion in the Callovian. Late Jurassic volcanism associated with this spreading event resulted in the emplacement of the Ashmore Volcanics (a series of basaltic flows and acid volcanics) on the Ashmore Platform.

The basin-wide, Valanginian Unconformity (which marks the end on continental breakup and the commencement of thermal subsidence across the basin) is represented by a hiatus in the Vulcan Sub-basin. On the adjacent Ashmore Platform, however, considerable erosion took place, removing late Jurassic/Early Cretaceous sediments (Mory, 1988).

A thin, greensand was deposited over the Valanginian Unconformity on the eastern margin of the Ashmore Platform (Darwin or Echuca Shoals Formation equivalent) but is absent by non-deposition or erosion in the west.

The Late Cretaceous and Cainozoic succession deposited on the Ashmore Platform is typically a platform carbonate sequence punctuated by unconformities resulting from fluctuating sea levels. The Cartier Formation, an interbedded shale and sandstone sequence, was deposited during the Oligocene on the western Ashmore Platform during one of these regressions.

The geological evolution of the Ashmore Platform and its environs is described by O'Brien et al., (1993 & 1996); and Shuster et al., (1998).

4.3 Exploration Drilling and Hydrocarbon Occurrences

Wells drilled on the Ashmore Platform, to date, are shown on **Figures 5.1 and 5.2.**

Table 4.1 Results of exploration drilling, Ashmore Platform.

Exploration Well	Year	Operator	Well Classification	Comments
Ashmore Reef-1	1968	Burmah Oil	P&A (Dry)	Trap formation probably post-dated main phase of petroleum migration.
Sahul Shoals-1	1970	Burmah Oil	P&A (Dry)	Lack of access to mature source rocks.
Brown Gannet-1	1972	Arco	P&A (Dry)	Lack of access to mature source rocks.
North Hibernia-1	1974	Woodside / Burmah Oil	P&A (Dry)	Lack of access to mature source rocks.
Prion-1	1974	Arco	P&A (Dry)	Invalid structural test.
Grebe-1	1979	Arco	P&A (Dry)	Lack of reservoir at primary objective.
Mount Ashmore-1B	1980	Woodside / Burmah Oil	P&A (Dry)	Lack of access to mature source rocks / possible breached trap due to late faulting.
Pollard-1	1984	BHP	P&A (Dry)	Lack of competent top seal / lack of access to mature source rocks.
Rainbow-1	1985	BHP	P&A (Dry)	Invalid structural test – no cross-fault seal / lack of access to mature source rocks.
Delta-1	1988	Elf Aquitaine	P&A (Dry)	Lack of access to mature source rocks.
Cartier-1	1988	Santos	P&A (Dry)	Invalid structural test – no cross-fault seal.
Pascal-1	1990	BHP	P&A (Dry)	Lack of access to mature source rocks.
Lucas-1	1990	Santos	P&A (Dry)	Lack of access to mature source rocks.
Pokolbin-1	1990	TCPL	P&A (Dry)	Lack of access to mature source rocks.
Yarra-1	1990	TCPL	P&A (Dry)	Lack of access to mature source rocks.
Langhorne-1	1991	TCPL	P&A (Dry)	Invalid structural test – well probably drilled outside structural closure.
Warb-1A	1992	WMC	P&A (Oil show)	Invalid structural test – prognosed bounding fault to trap not present.

A dry hole analysis of wells drilled on the Ashmore Platform to December 2002 is shown in **Figure 4.1.**

Table 4.2 Hydrocarbon shows, Ashmore Platform.

Exploration Well	Show Type	Depth (mRT)	Formation	Show Description
Warb-1A	Oil	935-959	Oliver	Residual oil in cuttings and swc's.

4.4 Petroleum Potential

The thick, Jurassic pre-rift and syn-rift sediments identified in the Vulcan Sub-basin to the east are largely thin or absent on the Ashmore Platform. Here, intensely faulted Triassic sediments (up to 4,500 metres thick) form an extensive, tilted fault block terrain. Peneplanation in the Late Jurassic to Early Cretaceous led to the deposition of a thick succession of Early Cretaceous-Tertiary passive margin sediments on the unconformity surface.

4.4.1 Reservoirs and Seals

On the eastern flanks of the Ashmore Platform, good quality, Triassic sandstone reservoirs have been intersected at Woodbine-1 and Keeling-1. Further to the west, on the Ashmore Platform proper, Triassic fault blocks, either sealed by Early Cretaceous mudstones and shales (where present), or by Late Cretaceous and Cainozoic carbonates, may constitute exploration targets. On the Ashmore Platform, this play type has yet to be validated by a discovery of petroleum.

Good quality Maastrichtian (Puffin Fm) and Eocene (Grebe Sandstone Member) sandstones have been intersected in several wells drilled in the adjacent Vulcan Sub-basin. It is possible that Maastrichtian and Eocene sands, sealed by overlying carbonates, may form potential structural and stratigraphic traps on the eastern margin of the Ashmore Platform.

4.4.2 Source

Late Jurassic, oil-prone, marine source rocks and coaly fluvio-deltaic and shallow marine sediments of the Early-Middle Jurassic Plover Formation are known to constitute source rocks in the Vulcan Sub-basin to the east (Botten & Wulff, 1990; Kennard et al., 1999). However, Jurassic sediments are generally thin or absent on the Ashmore Platform **(Plate 2).**

Consequently, hydrocarbon charge for traps lying on the Ashmore Platform depends on either long range migration from source rocks within adjacent depocentres (Swan Graben and Caswell Sub-basin), or unproven source facies within the underlying Triassic Sahul Group. It is possible, however, that good quality Jurassic source rocks may be present in remnant Triassic grabens or half-grabens on the Ashmore Platform and provide a local source of hydrocarbons.

While the source potential of the Triassic section on the Ashmore Platform is unknown, elsewhere on the North West Shelf, the equivalent section is considered to have sourced several gas accumulations.

4.4.3 Traps

Tilted Triassic fault blocks and Maastrichtian to Palaeocene and Eocene lowstand sands on the eastern flanks of the Ashmore Platform constitute the primary exploration objectives in the area. The critical risk factors associated with these plays are:

- suitable migration pathways from adjacent/underlying mature source rocks;
- trap breach due to late faulting (failure of the Discorbis-1 well, in the Browse Basin to the south, is attributed to trap breach);
- lack of a competent top seal for Palaeocene and Eocene lowstand sands.

Gorter et al., (2002) postulated that the Early to Middle Miocene Oliver Formation (intersected by wells in the Vulcan Sub-basin), may be developed as patch reefs on the Ashmore Platform and have exploration potential.

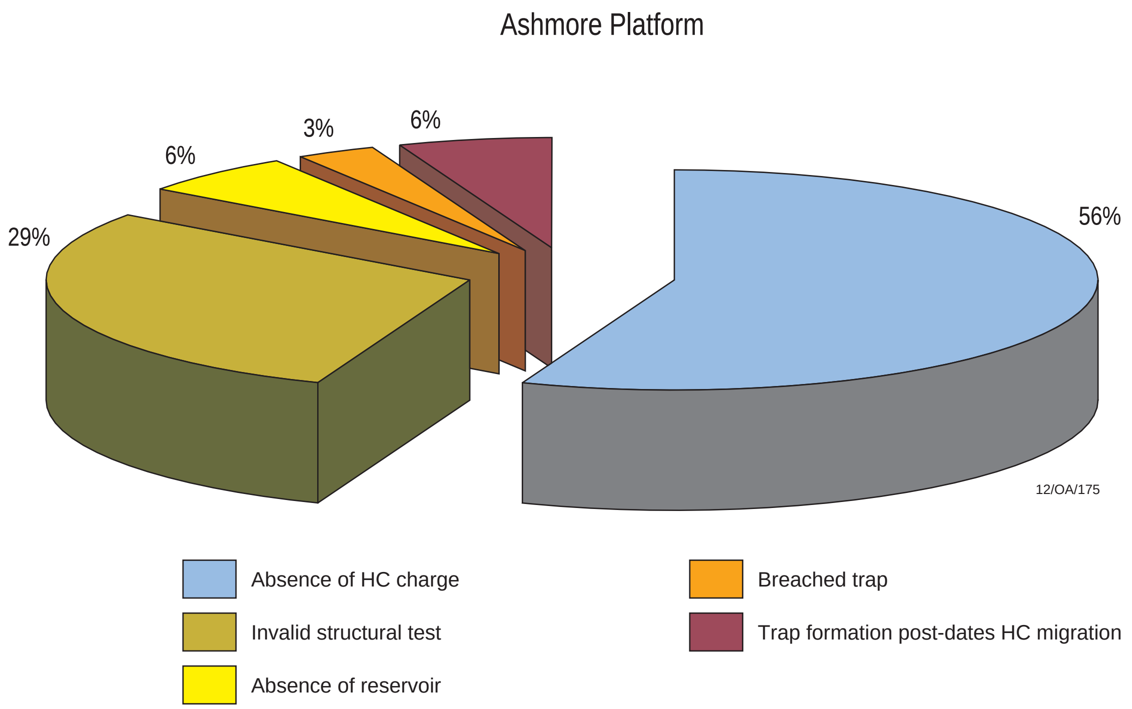

Figure 4.1 Dry hole analysis, Ashmore Platform.

5. VULCAN SUB-BASIN

5.1 Introduction

The Vulcan Sub-basin is a northeast-trending, Mesozoic, extensional depocentre located in the western Bonaparte Basin. The sub-basin comprises a complex series of horsts, grabens and basin margin terraces that abut the Londonderry High to the east-southeast and the Ashmore Platform to the west-northwest. Most exploration wells drilled within the Vulcan sub-basin are sited on narrow intra-basin horst blocks or on basin margin terraces **(Figure 5.2).**

A distinctive feature of the Ashmore-Cartier region is the presence of a thick Jurassic succession in major, graben-related sedimentary troughs such as the Vulcan Sub-basin. Thick Jurassic sequences in the Swan and Paqualin Grabens provide a petroleum charge for good quality, Jurassic age reservoirs in structural traps associated with intra-basin horst blocks and basin margin terraces.

The southern boundary of the Vulcan Sub-basin with the northern Browse Basin is somewhat arbitrary **(Plate 1).** O'Brien et al., (1999) consider that the boundary is marked by a major northwest trending Proterozoic fracture system.

At date of writing, 23 petroleum accumulations have been identified within the Vulcan Sub-basin. Commercial production has occurred from four of these discoveries (**Challis**, **Cassini**, **Jabiru**, **Skua**). At date of writing, development of a further 5 discoveries is under consideration (**Tenacious**, **Audacious**, **Montara/Bilyara** and **Crux**) **(Plate 1, Figures 5.3, 5.4 and 5.5).**

5.2 Structural Evolution

The geological history of the Vulcan Sub-basin and environs has been describeded by Veevers, 1988; Mory, 1988; MacDaniel, 1988; Patillo and Nicholls, 1990; O'Brien et al., 1993; O'Brien and Woods, 1995; and Woods, 1994. Woods, (1994) examines a salt-detachment model for the evolution of the Vulcan Sub-basin and discusses the geological evolution of the sub-basin in a number of tectonic 'phases' – similar to those of Patillo and Nicholls, (1990).

The regional geology of the Vulcan Sub-basin has been most recently described by Edwards et al., (2003). The key points to note from this review are:

- Prior to the onset of Mesozoic rifting, the region has had a complex structural history involving two phases of Palaeozoic extension and mild Late Triassic compression (Fitzroy Movement) (O'Brien et al., 1993; O'Brien et al., 1996; Shuster et al., 1998).

- An initial northwest-trending Late Devonian-Early Carboniferous rift system (Petrel Sub-basin, eastern Bonaparte Basin) was overprinted in the Late Carboniferous-Early Permian to form the northeast-trending, proto-Vulcan Sub-basin and Malita Graben.

- In the Late Triassic, mild compressional reactivation resulted in partial inversion of the Palaeozoic half-graben, and the formation of large-scale anticlinal and synclinal structures.

- Mesozoic extension in the Vulcan Sub-basin commenced in the Late Callovian, coincident with the onset of sea floor spreading in the Argo Abyssal Plain (Pattillo and Nicholls, 1990). Late Callovian-Tithonian faulting was focussed in the Swan and Paqualin Grabens, which contain up to 3 kilometres of marine, organic-rich, syn-rift sediments.

- Jurassic extension was followed by regional flooding of the northwestern Australian continental margin in the Valanginian when post-rift, thermal subsidence became dominant throughout the region. The passive margin ramp succession deposited in the Cretaceous is dominated by fine-grained clastic and carbonate facies. Cainozoic sediments are typically carbonates, deposited on a subtropical to tropical platform.

- In the Miocene to Pliocene, the convergence of the Australian plate and Southeast Asian microplates resulted in reactivation of the previous Jurassic extensional fault systems, and rapid subsidence of the Cartier Trough due to foreland loading. It appears this late faulting event has breached several petroleum accumulations in the Vulcan Sub-basin - many of the wells drilled in the area have intersected residual oil columns within fault dependent traps of Jurassic age **(Table 5.1)**.

An interpreted seismic line through the southern Vulcan Sub-basin is shown in **Figure 5.7**.

The presence of salt in the Vulcan Sub-basin was established in 1988 with the drilling of Paqualin-1. The well intersected a pre-Permian salt layer at considerable depth and indicated the Vulcan Sub-basin has an affinity with the Petrel Sub-basin to the east (Woods, 1994). Two salt diapirs have been recognised in the Vulcan Sub-basin. The Paqualin Diapir (named after Paqualin-1 well which penetrated a salt overhang within Cainozoic section) and the Swan Diapir (named after the **Swan-1** and-2 wells which were drilled adjacent to the Swan diapir).

The discovery of salt has implications not only for the structural evolution of the Vulcan Sub-basin but also for the hydrocarbon prospectivity of the area. Detailed structural analysis of the growth of both the Paqualin and Swan structures reveals that the salt began to move and form salt pillows in the Late Jurassic, while salt diapirism occurred towards the end of the Miocene. The timing of these two main phases of salt movement coincides with what are interpreted to be the two major tectonic events in the Timor Sea area - the breakup of the Australian Northwest continental margin and the collision between the Australian and South East Asian microplates, respectively.

5.3 Stratigraphy

The stratigraphy of the Vulcan Sub-basin is shown in **Figure 5.3 and Plate 2**.

In the Petrel Sub-basin to the east, the Permian Hyland Bay Group comprises a shallow marine carbonate and clastic sequence. Although this unit has not been intersected by wells in the Vulcan Sub-basin, it has been encountered in wells drilled on the adjacent Londonderry High and to the north, on the Sahul Platform. The top of this sequence is recognised on seismic data as a continuous high-amplitude reflector that can be mapped over much of the Bonaparte Basin. (The overlying Triassic Mount Goodwin Formation is a transgressive unit and provides a distinct lithological / impedance contrast to the underlying sequence).

A thick, Triassic section covers the Vulcan Sub-basin, the Londonderry High and the Ashmore Platform. The basal claystones of the Mount Goodwin Formation pass vertically into turbidites of the overlying Osprey Formation (Gorter et al., 1998). Succeeding the turbidites are pro-delta, delta front and delta plain sequences which may have some reservoir potential.

On the northern Londonderry High, the seismic character usually associated with the Triassic sequence changes. It has been suggested that the absence of the typical seismic pattern reflects a facies change within the Osprey Formation in this area. The Osprey Formation is overlain by the Pollard Formation - a shallow marine carbonate unit that exhibits prominent seismic reflectors.

Succeeding the Pollard Formation are the clastic and carbonate sediments of the Challis Formation. These are particularly well developed along the eastern margin of the Vulcan Sub-basin. The Challis Formation is a mixed carbonate and clastic shoreline sequence that exhibits complex lateral facies relationships and forms an important petroleum reservoir in the area.

Wells drilled in the Challis oil field show that at this location, the sequence was deposited on the margin of a protected macrotidal estuary or bay with marine conditions to the south and a major fluvial system to the northeast. The petroleum-bearing units of the Challis Formation in the Challis oil field comprise migratory channel sequences within a broad estuary or bay. Intercalated with the channels are tidal shoals and shoreline-oriented barrier island sands.

Succeeding the shoreline sequences of the Challis Formation are the major delta front to delta plain sequences of the Nome Formation (Gorter et al., 1998). This succession comprises a major prograding deltaic lobe that moved across the Vulcan Sub-basin during Norian and possibly Rhaetian times. The vertical and lateral facies changes within the sequence are consistent with a prograding delta front sequence which grades both vertically and laterally into lower delta plain deposits and a channelled upper delta plain sequence. The sandstone units within the Nome Formation comprise good quality petroleum reservoirs. The recent gas discovery at **Crux** was made in the Nome Formation.

Late Triassic to Late Jurassic faulting and extension resulted in a change in sediment distribution as well as the development of new 'smaller scale' structural elements (Struckmeyer et al., 1998). The Jurassic, Plover Formation rests unconformably on the Triassic sequence and was deposited in response to Mesozoic extension. The sequence is typically preserved beneath a major unconformity of Late Callovian age, referred to as the ‘breakup unconformity’.

The depositional environment of the Plover Formation has been given a threefold subdivision:

- Firstly, a basal sequence of braided and meandering channel fluvial systems with associated lateral deltaic units;
- secondly, a transgressive to deltaic sequence of Toarcian age;
- and finally, a thick sequence of accrectionary delta front sediments.

Sandstones of the Plover Formation provide some of the best quality reservoirs units in the Vulcan Sub-basin and host many of the petroleum discoveries identified within the Vulcan Sub-basin, to date **(Figures 5.4 and 5.5).**

Above the Callovian Unconformity, sediments of the Montara and Vulcan Formation were deposited both in the Vulcan Sub-basin and on the terraced areas on the western flank of the Londonderry High. The Vulcan Formation is sub-divided into an upper and lower unit, separated by an intra-Kimmeridgian unconformity. Source rock sequences within the Vulcan Formation are thought to have sourced a significant proportion of the petroleum accumulations found in the Vulcan Sub-basin.

The basal Montara Formation comprises prograding fan-delta systems which fringed the southeastern flanks of the Vulcan Sub-basin in the Oxfordian. Distal equivalents comprise low-energy, marine clays and siltstones which exhibit significant source rock potential. Elsewhere, such as on the Londonderry High, the sequence is either thin, or passes laterally into a shallow-water shoreline facies. In the southeastern Vulcan Sub-basin, the Montara Formation forms an important petroleum reservoir and hosts the accumulations identified at **Montara-1**, **Bilyara-1**, **Tahbilk-1** and **Padthaway-1**. Transgressive, Oxfordian age sands are also important exploration targets in the northern Browse Basin to the south.

Towards the end of the Oxfordian, marine conditions became widespread. As a result, fan-delta systems became inundated and replaced by marine shales and local submarine fan systems. In areas where little or no sedimentation took place (such as the Ashmore Platform, Londonderry High and intra-graben highs), exposure and local erosion shed coarse-grained clastics into adjacent lows, forming submarine fan systems. Within the grabens, a thick sequence of restricted marine sediments was deposited. Where sedimentation did cover horst and high blocks, condensed, glauconite-rich sequences were deposited.

Deposition of the Upper Vulcan Formation was terminated by an intra-Valanginian unconformity. This event marks the end of continental breakup and the onset of thermal subsidence on the northwest continental margin. Overlying the intra-Valanginian unconformity is a sequence of Late Valanginian to Early Aptian glauconitic claystone and sandstone (Echuca Shoals Formation). The basal part of this sequence grades vertically into radiolarian, glauconitic and calcareous claystone. Potential reservoir quality sandstones in the Echuca Shoals Formation have been intersected in the Asterias-1 well in the northern Browse Basin, to the south, and claystones within this unit form both competent seals and good quality source rocks.

Through the Aptian to Campanian, shelf to slope, fine grained, clastic and carbonate sedimentation dominated the Ashmore-Cartier region (Bathurst Island Group). Shelf sediments grade northwestwards into deeper water sequences. In the Late Campanian, a sea level lowstand led to the development of an extensive, channelled fan sand system (Puffin Formation) within the Vulcan Sub-basin and northern Browse Basin. Sands of the Puffin Formation form an important exploration target within the Vulcan Sub-basin. Oil has been recovered at **Puffin-1** and **Birch-1** and gas at **Swan-1** and East Swan-1 from this unit.

In the Cainozoic, a carbonate wedge prograded across the outer part of the Bonaparte Basin. Deposition of these carbonate cycles were interrupted in the Eocene and Oligocene by prograding, lowstand deltas, deposited in response to falling sea levels. The Grebe Sandstone Member was deposited at this time (Eocene) and forms a secondary, exploration objective in the area.

There is some evidence that the leakage and migration of hydrocarbons from traps since Pliocene times may have contributed to the nature and extent of the many, modern day, carbonate bioherm reef systems developed along the margins of the Ashmore Platform and Vulcan Sub-basin.

5.4 Exploration Drilling and Hydrocarbon Occurrences

Petroleum exploration in the Vulcan Sub-basin commenced in the late 1960s. Although the first oil discovery in the Vulcan Sub-basin was made at **Puffin-1** in 1972, the first commercial oil discovery was not made until 1983 (**Jabiru-1A)**. Since that time, further commercial discoveries of oil have been made at **Challis** (1984), **Skua** (1985) and **Cassini** (1988).

Table 5.1 Results of exploration drilling, Vulcan Sub-basin.

Exploration Well	Year	Operator	Well Classification	Comments
Puffin-1	1972	Arco	**Oil Discovery**	Oil recovered on test from the Late Cretaceous, Puffin Sandstone.
Swan-1	1973	Arco	**Gas Discovery**	Gas recovered on test from the Late Cretaceous, Puffin Sandstone.
Dillon Shoals-1	1974	Woodside / Burmah Oil	P&A (Oil show)	Residual oil in core cut in Triassic sandstone suggests trap breached by reactivation of bounding faults.
Turnstone-1	1974	Arco	P&A (Dry)	No access to mature source rocks. Possible lack of closure at primary objective level.
East Swan-1	1978	Arco	**Gas Discovery**	Gas recovered on test from the Plover Fm and Bathurst Island Gp.
Woodbine-1	1979	Woodside	P&A (Dry)	No access to mature source rocks.
Vulcan-1B	1982	Citco	P&A (Dry)	No reservoir development at primary objective level.
Jabiru-1A	1983	BHP	**Oil Discovery**	Oil recovered on test from the Plover Fm.
Challis-1	1984	BHP	**Oil Discovery**	Oil recovered on test from the Challis Fm.
Swift-1	1985	BHP	P&A (Oil and Gas shows)	Trap breached by late faulting.
Anderdon-1	1985	BHP	P&A (Dry)	No reservoir development at primary objective level (Hyland Bay Fm).
Skua-1	1985	BHP	P&A (Dry)	Drilled outside structural closure.

Skua-2	1985	BHP	**Oil & Gas Discovery**	Oil and gas recovered on test from the Plover Fm.
Nome-1	1986	BHP	P&A (Dry)	No reservoir development at primary objective level.
Eclipse-1	1986	BHP	P&A (Dry)	Did not test a valid closure (?)
Eclipse-2	1986	BHP	**Oil & Gas Discovery**	Recovered oil and gas on test from Flamingo Gp.
Snowmass-1	1987	BHP	P&A (Oil show)	Trap breached by late faulting.
Oliver-1	1988	BHP	**Oil & Gas Discovery**	Recovered oil and gas on test from the Plover Fm.
Rainier-1	1988	BHP	P&A (Dry)	Trap breached by reactivation of bounding faults.
Montara-1	1988	BHP	**Oil & Gas Discovery**	Recovered oil and gas on test from the Montara Fm.
Pengana-1	1988	BHP	**Gas Discovery**	Gas recovered on test from the Sahul Gp.
Cassini-1	1988	BHP	**Oil Discovery**	Oil recovered on test from the Challis Fm.
Tancred-1	1988	BHP	P&A (Oil show)	Trap breached by late faulting.
Bilyara-1	1988	BHP	**Oil & Gas Discovery**	Recovered oil and gas on test from the Montara Fm.
Allaru-1	1988	BHP	P&A (Oil and Gas shows)	Residual oil column indicates trap breached by late faulting.
Parry-1	1988	BHP	P&A (Dry)	May not have tested a valid closure.
Voltaire-1	1988	BP	P&A (Dry)	Possible lack of seal on bounding fault / no access to mature source rocks.
Cockell-1/ST1	1989	BHP	P&A (Dry)	Poor reservoir development at primary objective (U. Jurassic). May not have tested a valid closure.
Paqualin-1	1989	BHP	P&A (Dry)	No reservoir development at primary objective level.
Arunta-1	1989	BHP	P&A (Dry)	May not have tested a valid closure.
Taltarni-1	1989	BHP	P&A (Dry)	No reservoir development at primary objective level.
Talbot-1	1989	Santos	**Oil & Gas Discovery**	Recovered oil and gas on test from the Challis Fm.
Rowan-1/ST1	1989	BHP	P&A (Dry)	No reservoir development at primary objective level.
Keeling-1	1990	Norcen	P&A (Gas show)	May not have tested a valid closure.
Maple-1	1990	BHP	**Oil & Gas Discovery**	Recovered oil and gas on test from the Challis Fm.
Willeroo-1	1990	BHP	P&A (Oil show)	Trap formation post-dated oil emplacement.
Fagin-1	1990	BHP	P&A (Dry)	Did not test a valid closure.
Octavius-1	1990	WMC	P&A (Oil show)	Oil displaced by late gas migration or trap breached by late faulting.
Yering-1	1990	BHP	P&A (Dry)	Lack of seal on bounding fault.
Birch-1	1990	BHP	**Oil Discovery**	Recovered oil on test from the Puffin Fm.
Anson-1	1990	Santos	P&A (Oil show)	Residual oil in swc's indicates possible breached trap.
Delamere-1	1990	BHP	**Gas Discovery**	Recovered gas on test from the Flamingo Gp.
Casuarina-1	1990	BHP	P&A (Dry)	
Katers-1	1990	Santos	P&A (Dry)	No access to mature source rocks.
Champagny-1	1990	Norcen	P&A (Dry)	No access to mature source rocks.
Kimberley-1	1990	Norcen	P&A (Dry)	Lack of effective top seal.
Douglas-1	1990	WMC	P&A (Dry)	Trap breached by late faulting.
Tahbilk-1	1990	BHP	**Gas Discovery**	Recovered gas on test from the Gibson

				and Montara Fms.
Augustus-1	1991	WMC	P&A (Oil and Gas shows)	Residual oil column at the top of the Plover Fm. Trap breached by late faulting.
Longleat-1	1991	BHP	P&A (Dry)	Lack of effective top seal.
Cypress-1	1991	BHP	P&A (Dry)	No access to mature source rocks.
Hadrian-1	1991	WMC	P&A (Dry)	Drilled outside closure at primary objective (Plover Fm) level.
Conway-1	1991	Santos	P&A (Dry)	Invalid structural test - reservoir juxtaposed across sealing fault.
Rothbury-1	1991	TCPL	P&A (Dry)	No reservoir development at primary objective level.
Leeuwin-1	1991	BHP	**Gas Discovery**	Gas recovered on test from U. Vulcan Fm may be solution gas (?).
Octavius-2	1991	WMC	P&A (Oil and Gas shows)	Residual oil column in the Plover Fm. Oil displaced by late gas migration or trap breached by late faulting.
Great Eastern-1	1991	TCPL	P&A (Dry)	Invalid structural test - drilled outside structural closure.
Maret-1	1992	Norcen	**Gas Discovery**	Gas recovered on test from the Plover Fm.
Caversham-1	1992	TCPL	P&A (Dry)	No reservoir development at primary objective level.
Keppler-1	1993	BHP	P&A (Dry)	Trap breached by late faulting.
Elm-1	1993	BHP	P&A (Oil show)	Invalid structural test - drilled outside structural closure at Plover Fm level.
Pituri-1	1994	BHP	P&A (Oil show)	Invalid structural test - drilled outside structural closure.
Medusa-1	1994	BHP	P&A (Oil show)	Breached trap – non-sealing bounding faults.
Snipe-1	1995	MIM	P&A (Dry)	No access to mature source rocks.
Calytrix-1	1995	BHP	P&A (Dry)	Invalid structural test – no structural closure present.
Norquay-1	1995	BHP	P&A (Dry)	No access to mature source rocks.
Kym-1	1996	Cultus	P&A (Dry)	May not have tested a valid structural closure.
Tenacious-1	1997	Cultus	**Oil & Gas Discovery**	Recovered oil and gas on test from the Upper Vulcan Fm (Tithonian sst).
Fish River-1/ST1	1998	Santos	P&A (Dry)	No access to mature source rocks.
Mandorah-1	1998	Woodside	P&A (Dry)	No access to mature source rocks (?)
Columba-1A	1999	Nippon	P&A (Dry)	Invalid structural test – no structural closure present at primary objective.
Circinus-1	1999	Nippon	P&A (Dry)	Invalid structural test – no structural closure present at primary objective.
Brontosaurus-1	2000	Coastal Oil & Gas	P&A (Oil and Gas shows)	Data confidential at date of writing.
Padthaway-1	2000	BHPP	**Gas Discovery**	Recovered gas on test from the Montara Fm.
Crux-1	2000	Nippon	**Gas Discovery**	Recovered gas on test from the Nome Fm.
Elasmosaurus-1	2001	Coastal Oil & Gas	P&A (Oil and Gas shows)	Data confidential at date of writing.
Audacious-1	2001	OMV	**Oil Discovery**	Recovered oil on test from the Plover Fm.
Hadrosaurus-1	2001	Coastal Oil & Gas	P&A (Oil show)	Data confidential at date of writing.
Cromwell-1A	2001	OMV	P&A (Dry)	Data confidential at date of writing.
Capricious-1	2001	OMV	P&A (Dry)	Data confidential at date of writing.

Cash-1/ST1	2002	Coastal Oil & Gas	n.a.	Appraisal well on the Maple discovery.
Lantana-1	2002	OMV	P&A (Dry)	Data confidential at date of writing.

A dry hole analysis of wells drilled within the Vulcan Sub-basin to December 2002 is shown in **Figure 5.6.**

Table 5.2 Hydrocarbon shows, Vulcan Sub-basin.

Exploration Well	Show Type	Depth (mRT)	Formation	Show Description
Allaru-1	Oil & Gas	2342-2403	Upper Vulcan	15% total gas on hot-wire detector; 5% to 40% dull yellow-green fluorescence – interpreted as a residual hydrocarbon column.
Anson-1	Oil	1704-1718.5	Nome	Fluorescence in cuttings and swc's indicates possible residual oil column.
Augustus-1	Oil	3504.7-3508	Top Plover	Fluorescence in swc's indicates a 3 metre residual oil column.
Brontosaurus-1	Oil & Gas	Data confidential at date of writing		
Dillon Shoals-1	Oil	1820-1828	Nome (?)	Fluorescence in cuttings and 1.6% oil saturation in core #1 indicates a residual oil column.
Elasmosaurus-1	Oil & Gas	Data confidential at date of writing		
Elm-1	Oil	2748-2767	Lower Vulcan	Residual oil column (88% Sw) inferred from wireline logs and RFT pretest data.
Hadrosaurus-1	Oil	Data confidential at date of writing		
Keeling-1	Gas	3025-3059	Nome (?)	34 metre gross gas column inferred from wireline logs.
Medusa-1	Oil	1828-1832	Plover	Fluorescence in swc's and residual oil saturations interpreted from wireline logs (97% to 100% Sw).
Octavius-1	Oil	2715	Upper Vulcan	Oil observed on shakers – thought to have been swabbed from a fault plane intersected at 2715 metres.
Octavius-2	Oil & Gas	3193-3262	Plover	Fluorescence in swc's and wireline logs suggests a residual oil and gas column is present.
Pituri-1	Oil	1018-1019 1706-1710	Prion Grebe	Brownish-black residual oil staining in core. 1 metre net oil sand identified on wireline logs.
Snowmass-1	Oil	777-787	Johnson	Fluorescence in swc's and a residual oil column inferred from wireline logs (70% Sw).
Swift-1	Oil	2357-2401	Upper Vulcan	Residual oil in core. 44 metre residual oil column inferred from wireline logs.
Tancred-1	Oil	1366 1413-1424 1449-1462	Lower Vulcan Challis Challis	Fluorescence in swc's and residual oil columns inferred from wireline logs.
Willeroo-1	Oil	1961-1971	Jamieson	Fluorescence and oil staining in swc's suggest a residual oil column.

5.5 Petroleum Potential

The Vulcan Sub-basin is a proven oil and gas province. Both commercial and sub-commercial discoveries have been identified within Late Triassic (**Challis**), Early-Middle Jurassic and Late Jurassic (**Jabiru**), and Late Cretaceous (**Puffin**) reservoirs.

The primary play type in the sub-basin has traditionally been Triassic and Jurassic sands within tilted fault blocks, located either on narrow, intra-basin horsts or basin margin terraces.

5.5.1 Reservoirs

Clastic units within pre-extensional and rift sequences host the majority of the petroleum accumulations identified to date in the Vulcan Sub-basin (Woods, 1994). Reservoirs from which commercial petroleum production has taken place include the Triassic Challis Formation (at Challis and Cassini) and the Middle Jurassic Plover Formation (at Skua and Jabiru).

The main exploration targets in the Vulcan Sub-basin are fluvio-deltaic sands of Middle Jurassic Plover Formation, Upper Jurassic fan-deltas of the Montara Formation, submarine fans of the Vulcan Formation, Late Triassic Challis and Nome Formation sandstones and Upper Cretaceous, Puffin Formation sands.

5.5.2 Seal

Regional flooding of the northwest continental margin in the Valanginian led to the deposition of the Cretaceous Bathurst Island Group. The Lower Cretaceous shales of the Echuca Shoals Formation were deposited at this time and form a regional seal across the sub-basin.

Many Jurassic/Triassic reservoirs within tilted fault blocks in the Vulcan Sub-basin rely on competent, intra-formational and cross-fault seals for trap integrity. In structurally complex areas of the sub-basin, faulting is often difficult to image on seismic data. Recent developments in seismic acquisition and processing (3D seismic, Pre-Stack Depth Migration) are leading to more accurate predictions of trap geometries.

Higher in the stratigraphic succession, Puffin Formation reservoirs are sealed by Palaeocene carbonates of the Johnson Formation. The Puffin Formation is a channelled, fan sand deposit and many traps within this unit probably have a significant stratigraphic component.

5.5.3 Source

Late Jurassic, oil-prone, marine source rocks have been intersected by many wells drilled in the Vulcan Sub-basin (Vulcan Formation). Source rock facies within the Vulcan Formation appear to be sufficiently thermally mature to have sourced many of the petroleum accumulations identified in the area (Lowry, 1998). Kennard et al., (1999) indicate hydrocarbons have been generated from the Oxfordian-Kimmeridgian sequence (Lower Vulcan Formation) within the Swan and Paqualin Grabens, together with minor late gas from the deepest sequences within the Cartier Trough. Subsequent work by Edwards et al., (2001) confirms this interpretation - claystones of the Upper Jurassic, Lower Vulcan Formation have been geochemically ‘typed’ to many of the oils recovered from the Vulcan Sub-basin.

The Lower Cretaceous, Echuca Shoals Formation, which provides a regional seal to the underlying Upper Vulcan Formation reservoirs, also has significant source rock potential but is probably thermally immature to marginally mature for petroleum generation over much of the Vulcan Sub-basin. In major depocentres to the north, however, (Sahul Syncline and Malita Graben), the unit is thought to be thermally mature.

Thermally mature, coaly, fluvio-deltaic and shallow marine sediments of the Early-Middle Jurassic, Plover Formation also provide oil and gas source potential throughout much of the Vulcan Sub-basin (Botten and Wulff, 1990; Kennard et al., 1999).

Petroleum generation and expulsion in the Vulcan Sub-basin commenced in the Late Jurassic to Early Cretaceous. The main phase of gas expulsion did not occur until the Mid to Late Cainozoic and was associated with compaction and loss of pore space in the major source sequences. The model of petroleum generation outlined by Kennard et al., (1999) indicates that oil charge may be limited to areas proximal to the Swan and Paqualin Grabens **(Figure 5.2).**

Hydrocarbon generation in the Vulcan Sub-basin appears to have involved multiple charge events. Flushing of oil accumulations by late gas generation in the Cainozoic is a significant exploration risk in the Vulcan Sub-basin (Lisk et al., 1998).

5.5.4 Traps

Two major fault styles are recognised in the sub-basin. These are tilted horst blocks in the south, and hour-glass structures in the north (Woods, 1992).

Explorers in the Vulcan Sub-basin have traditionally targeted tilted fault blocks and horsts sealed by the Lower Cretaceous, Echuca Shoals Formation (regional seal). Many successful discoveries of petroleum have resulted – most of which are reservoired either in the Plover Formation (beneath the Callovian breakup unconformity), or in the Late Triassic, Nome and Challis Formations.

Higher in the stratigraphic succession, the Late Cretaceous (Maastrichtian) Puffin Formation hosts the Puffin, Swan, East Swan and Birch petroleum accumulations. Puffin Formation traps are usually subtle, four-way dip closures with a significant stratigraphic component.

A small gas accumulation has also been identified in the Late Cretaceous, Gibson Formation at **Tahbilk-1**. **(Figure 5.3 and Plate 2).**

The discovery of the Paqualin and Swan Salt Diapirs identified a new potential hydrocarbon play in the Vulcan Sub-basin (this is an established play in the Petrel

Sub-basin to the northeast). It is unlikely that salt distribution is limited to these two structures.

O'Brien et al., (1993) observed that all of the significant hydrocarbon discoveries in the Vulcan Sub-basin appear to be preferentially located either along, or at the intersection of, northwest and north-south trending fault sets with the northeast/east-northeast trending structural grain. They believe that this observation indicates a number of largely untested 'fairways' exist within the Vulcan Sub-basin.

Other largely untested Mesozoic plays in the Vulcan Sub-basin include rollovers into the downthrown side of faults, fans, mounds, scours and stratigraphic pinchouts.

Traditional challenges for explorers in the Vulcan Sub-basin have been the seismic definition of potential traps and the retention of hydrocarbons in tectonically reactivated structures (Woods, 2003). The identification of palaeo-oil columns in many wells drilled in the Vulcan Sub-basin highlights the risks associated with trap breach due to late faulting in this area **(Table 5.1)**. Explorers are addressing problems associated with trap integrity with the use of techniques such as fluid inclusion studies (GOI) and hydrocarbon seep indicators.

Post-drill interpretations of wells drilled in the Vulcan Sub-basin indicate many failed to test valid structural closures (**Table 5.1, Figure 5.6**). Modern seismic techniques, such as 3D seismic acquisition and the use of Pre-Stack Depth Migration (PSDM) are an aid to resolving the difficulties associated with fault definition in this area. Kym-1 (drilled in 1996) was believed to have tested the highest point on the Audacious horst block. The well was plugged and abandoned as a dry hole. Subsequent Pre-stack Depth Migration (PSDM) of seismic data acquired over the Audacious horst resulted in an improved image of the trapping geometries. In 2001, **Audacious-1** was successfully drilled on the horst, updip from the Kym-1 well location, and discovered oil.

It is likely that these new techniques will continue to play an important role in identifying exploration targets in structurally complex areas of the Bonaparte Basin such as the Vulcan Sub-basin.

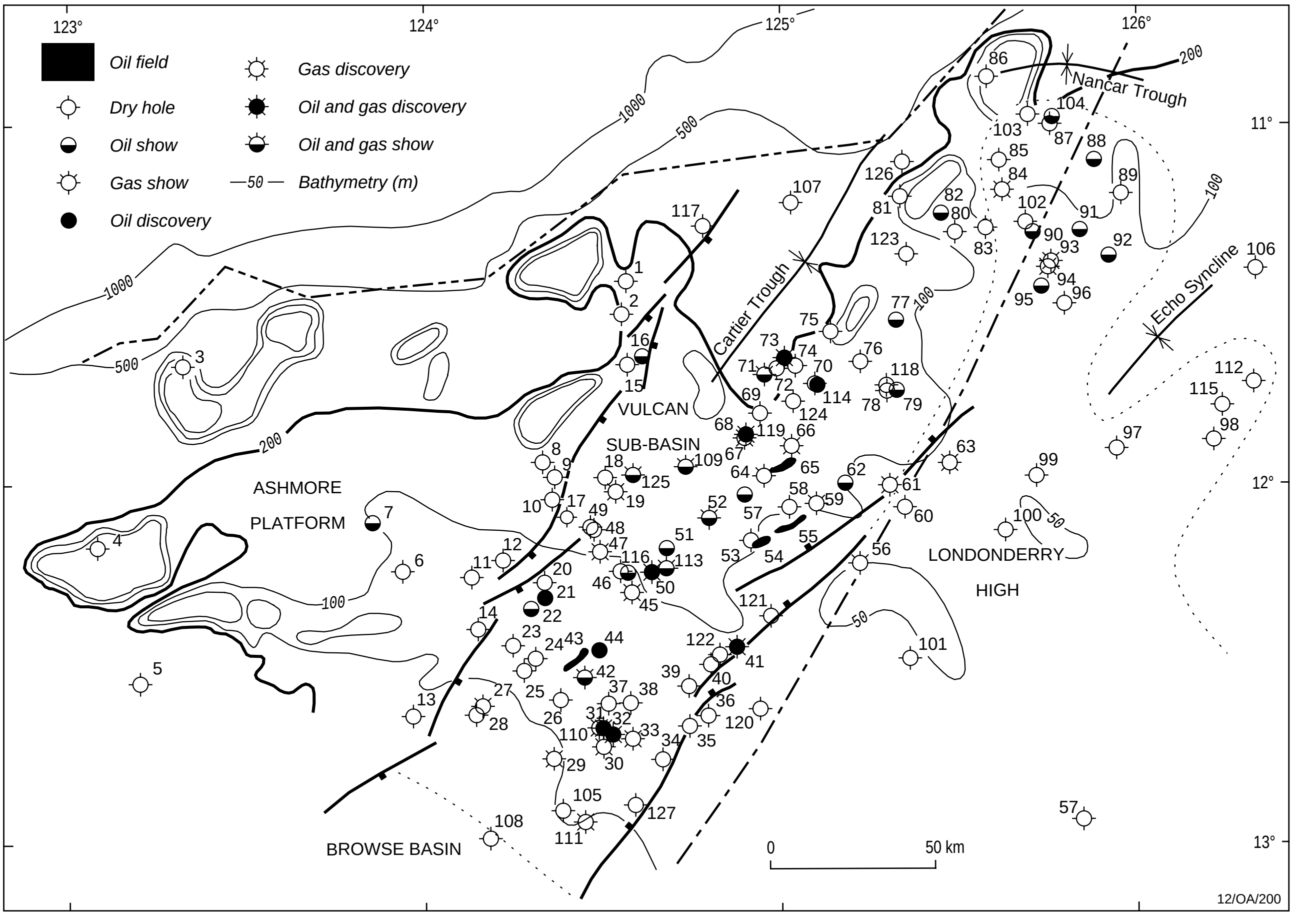

Figure 5.1 Vulcan Sub-basin/Ashmore Platform/Londonderry High - tectonic elements, bathymetry and exploration wells.

Vulcan Sub-basin, Ashmore Platform and Londonderry High - map key to **Figure 5.1**

Well Name	Drilling Results	Map No.
Sahul Shoals-1	P&A Dry	1
Pokolbin-1	P&A Dry	2
Hibernia North-1	P&A Dry	3
Ashmore Reef-1	P&A Dry	4
Mt Ashmore-1B	P&A Dry	5
Cartier-1	P&A Dry	6
Brown Gannet-1	Oil Show	7
Rainbow-1	P&A Dry	8
Langhorne-1	P&A Dry	9
Yarra-1	P&A Dry	10
Lucas-1	P&A Dry	11
Pascal-1	P&A Dry	12
Delta-1	P&A Dry	13
Prion-1	P&A Dry	14
Pollard-1	P&A Dry	15
Warb-1A	Oil Show	16
Great Eastern-1	P&A Dry	17
Paqualin-1	P&A Dry	18
Maple-1	**Gas Discovery**	19
Parry-1	P&A Dry	20
Puffin-1	**Oil Discovery**	21
Pituri-1	Oil Show	22
Grebe-1	P&A Dry	23
Champagney-1	P&A Dry	24
Snipe-1	P&A Dry	25
Kimberley-1	P&A Dry	26
Keeling-1	Gas Show	27
Woodbine-1	P&A Dry	28
Maret-1	**Gas Discovery**	29
Tahbilk-1	**Gas Discovery**	30
Bilyara-1	**Oil & Gas Discovery**	31
Montara-1	**Oil & Gas Discovery**	32
Leeuwin-1	**Gas Discovery**	33
Conway-1	P&A Dry	34
Katers-1	P&A Dry	35
Anderdon-1	P&A Dry	36
Yering-1	P&A Dry	37
Taltarni-1	P&A Dry	38
Longleat-1	P&A Dry	39
Anson-1	P&A Dry	40
Talbot-1	**Oil & Gas Discovery**	41
Swift-1	Oil & Gas Show	42
Skua-2	**Oil Discovery**	43
Birch-1	**Oil Discovery**	44
East Swan-1	**Gas Discovery**	45
Vulcan-1	P&A Dry	46
Swan-1	**Gas Discovery**	47
Rothbury-1	P&A Dry	48
Caversham-1	P&A Dry	49
Eclipse-2	**Oil & Gas Discovery**	50
Elm-1	Oil Show	51
Allaru-1	Oil & Gas Show	52
Calytrix-1	P&A Dry	53
Cassini-1	**Oil Discovery**	54
Challis	**Oil Discovery**	55
Osprey-1	Gas Show	56
Willeroo-1	Oil Show	57
Rainier-1	P&A Dry	58
Casuarina-1	Gas Show	59
Ibis-1	P&A Dry	60
Delamere-1	**Gas Discovery**	61
Snowmass-1	Oil Show	62
Halcyon-1	**Gas Discovery**	63
Arunta-1	Gas Show	64
Jabiru-1A	**Oil Discovery**	65

Well Name	Drilling Results	Map No.
Pengana-1	**Gas Discovery**	66
Octavius-2	Gas Show	67
Tenacious-1	**Oil & Gas Discovery**	68
Douglas-1	P&A Dry	69
Kym-1	P&A Dry	70
Augustus-1	Oil & Gas Show	71
Hadrian-1	P&A Dry	72
Oliver-1	**Oil & Gas Discovery**	73
Cockell-1	P&A Dry	74
Fagin-1	P&A Dry	75
Nome-1	P&A Dry	76
Medusa-1	Oil Show	77
Turnstone-1	P&A Dry	78
Tancred-1	Oil Show	79
Norquay-1	P&A Dry	80
Voltaire-1	P&A Dry	81
Dillon Shoals-1	Oil Show	82
Keppler-1	P&A Dry	83
Lorikeet-1	**Gas Discovery**	84
Mallee East-1	P&A Dry	85
Mandorah-1	P&A Dry	86
Nancar-1	P&A Dry	87
Fulica-1	Oil Show	88
Kittiwake-1	P&A Dry	89
Jarrah-1A	Oil Show	90
Drake-1	Oil Show	91
Garganey-1	Oil Show	92
Avocet-1A	**Gas Discovery**	93
Eider-1	**Gas Discovery**	94
Barita-1	Oil Show	95
Stork-1	P&A Dry	96
Cygnet-1	P&A Dry	97
Tamar-1	P&A Dry	98
Jacana-1	P&A Dry	99
Crane-1	P&A Dry	100
Whimbrel-1	P&A Dry	101
Marrakai-1	P&A Dry	102
Mindil-1	P&A Dry	103
Ludmilla-1	Oil Show	104
Circinus-1	P&A Dry	105
Franklin-1	P&A Dry	106
Fish River-1ST1	P&A Dry	107
Columba-1A	P&A Dry	108
Brontosaurus-1	P&A Dry	109
Padthaway-1	**Gas Discovery**	110
Crux-1	**Gas Discovery**	111
Wambenger-1	P&A Dry	112
Elasmosaurus-1	Oil & Gas Show	113
Audacious-1	**Oil Discovery**	114
Backpacker-1	P&A Dry	115
Hadrosaurus-1	Oil Show	116
Cromwell-1A	P&A Dry	117
Capricious-1	P&A Dry	118
Bodacious-1A	P&A Dry	119
Sleeper-1	P&A Dry	120
Sebring-1	P&A Dry	121
Anson North-1	P&A Dry	122
Mallonee-1	P&A Dry	123
Lantana-1	P&A Dry	124
Cash-1ST1A	Appraisal well	125
Banka Banka-1	P&A Dry	126
Saucepan-1	P&A Dry	127

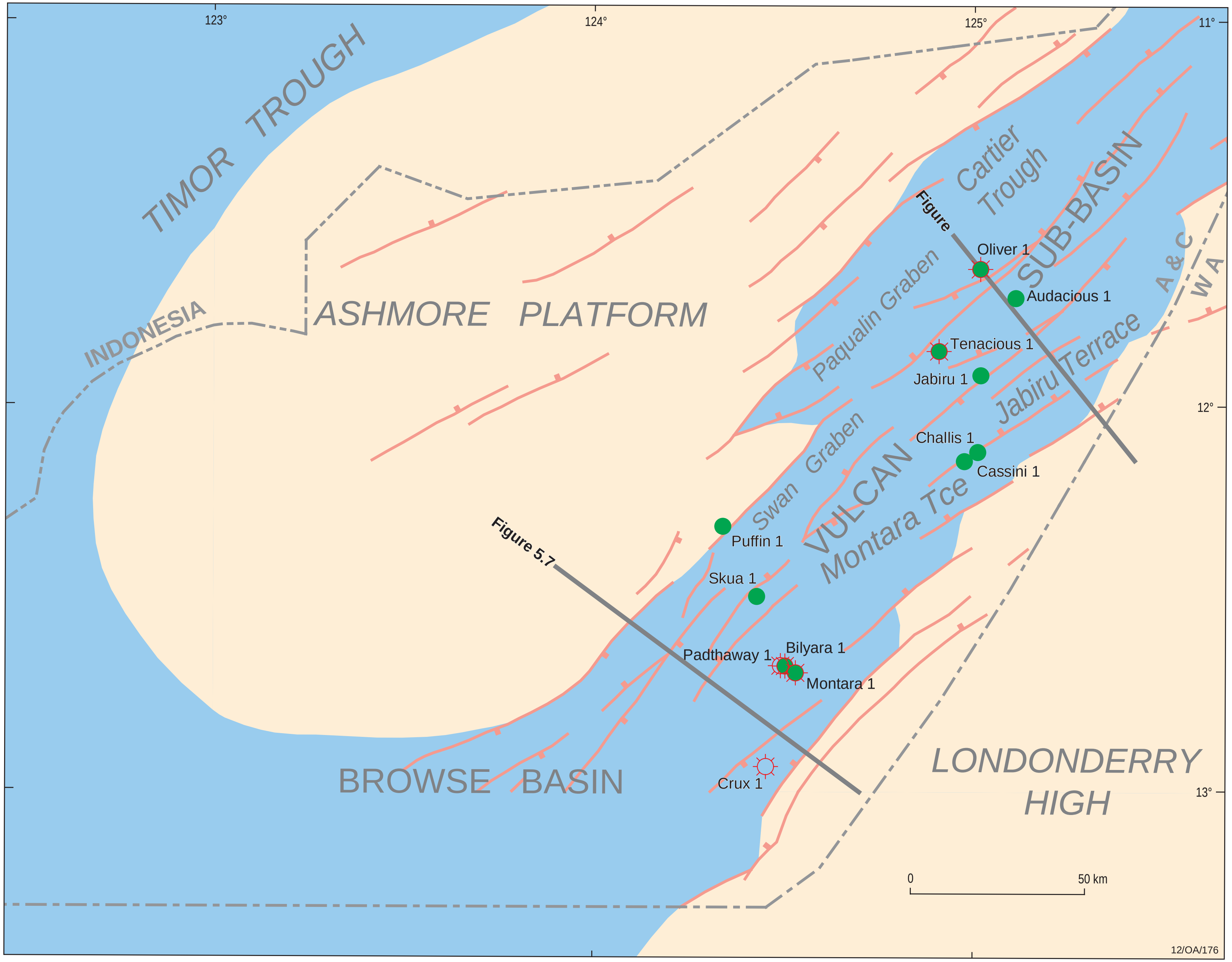

Figure 5.2 Structural elements and key petroleum discoveries of Vulcan Sub-basin, Ashmore Platform and Londonderry High (2003 Acreage Release CD-Rom).

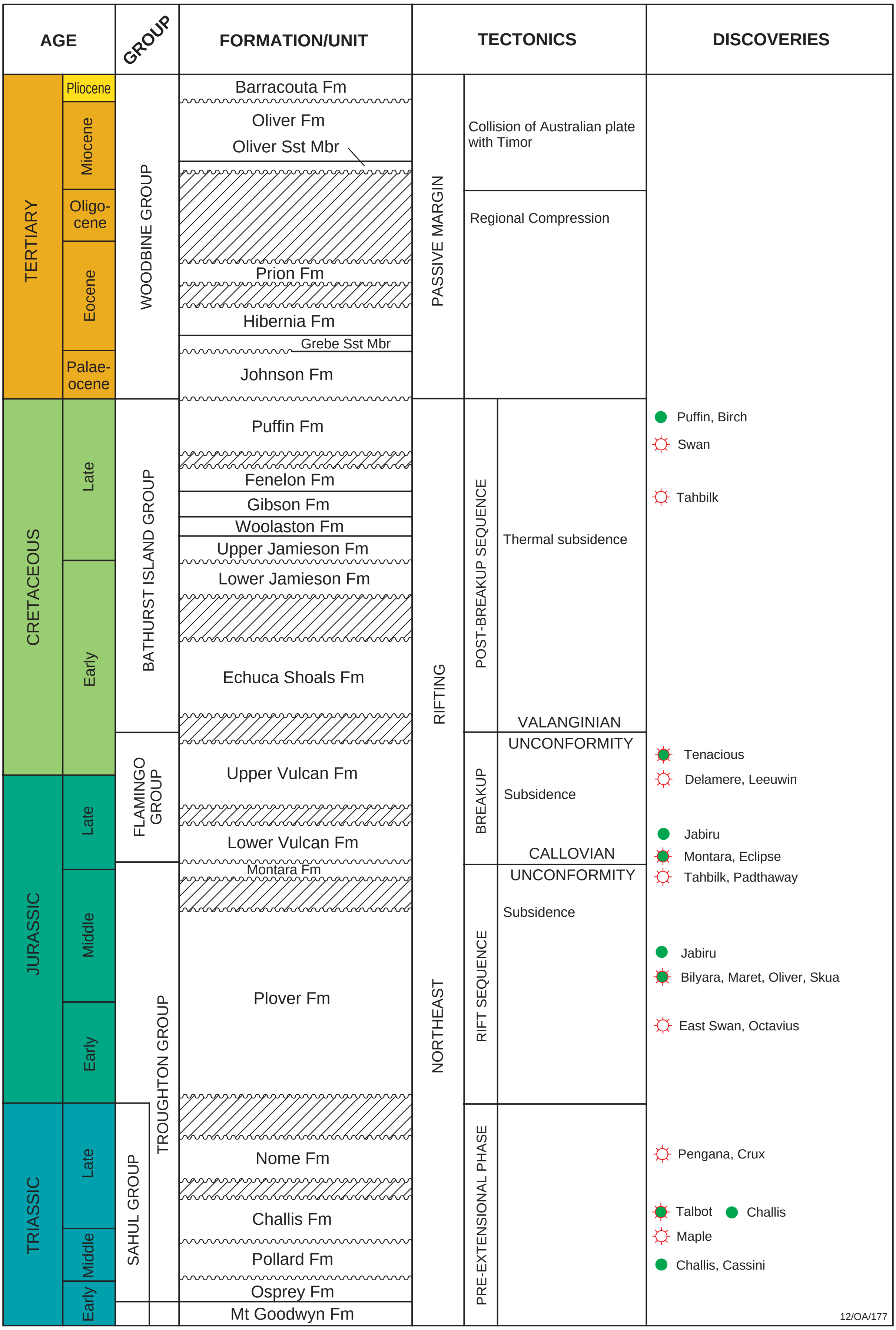

Figure 5.3 Vulcan Sub-basin - stratigraphy, tectonics and petroleum discoveries.

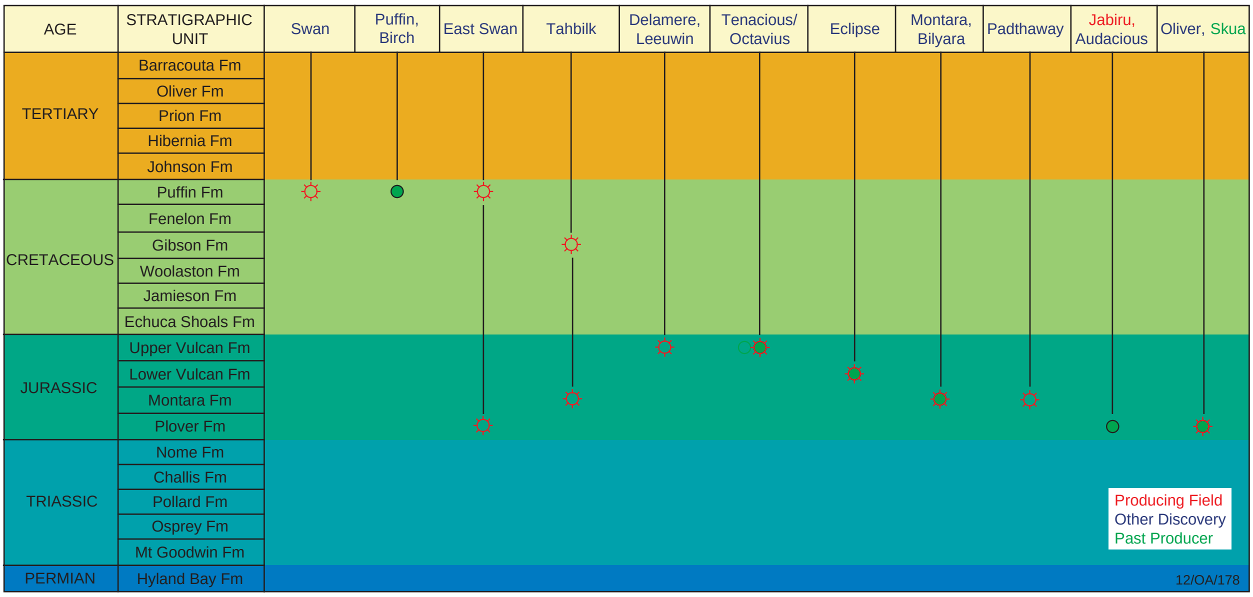

Figure 5.4 Petroleum discoveries, Vulcan Sub-basin (part 1).

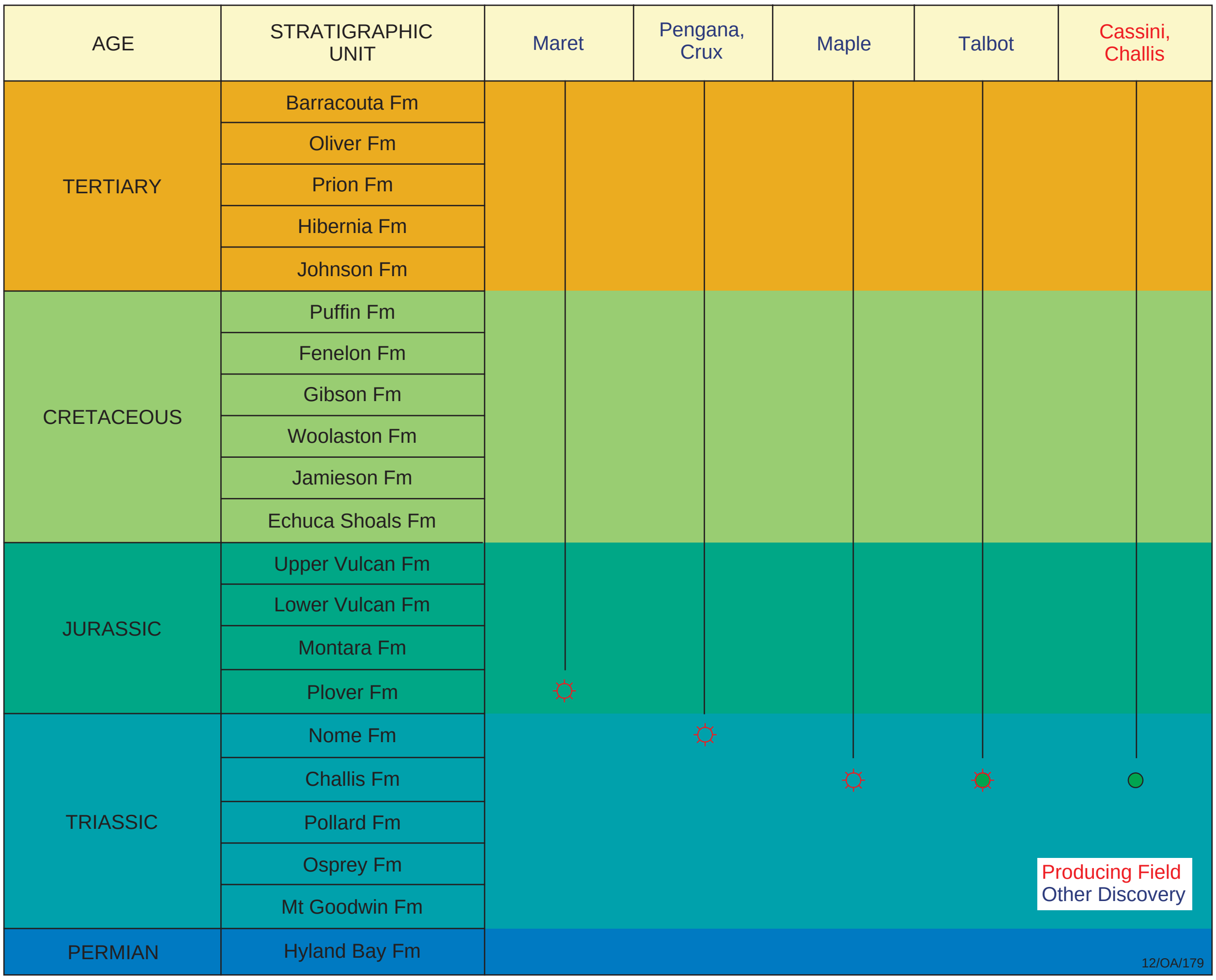

Figure 5.5 Petroleum discoveries, Vulcan Sub-basin (part 2).

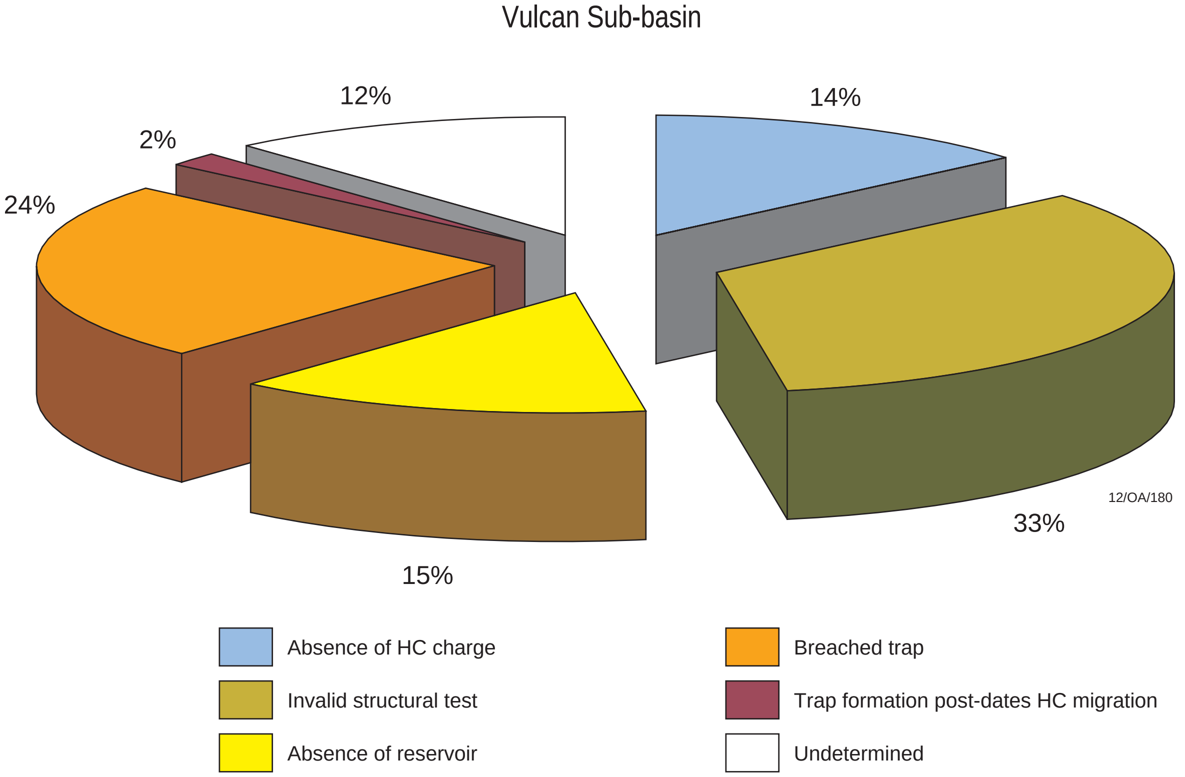

Figure 5.6 Dry hole analysis, Vulcan Sub-basin.

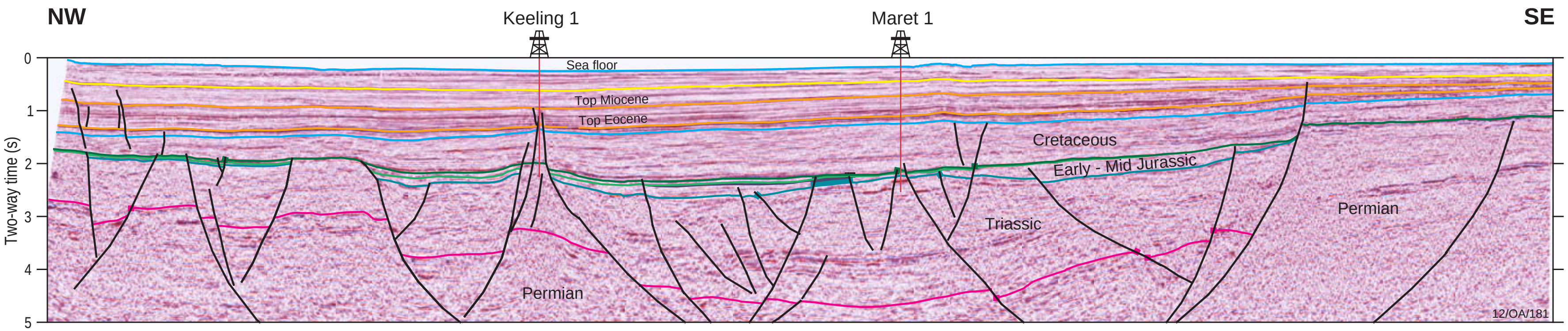

Figure 5.7 Interpretation of Geoscience Australia seismic line VTT-01 through the southern Vulcan Sub-basin (2003 Acreage Release CD-Rom).

6. LONDONDERRY HIGH

6.1 Introduction

The Londonderry High is a Permo-Triassic horst and graben complex which acted as a major source of sediment for adjacent depocentres during Late Jurassic rifting (Whibley and Jacobsen, 1990; De Ruig, 2000). It is bounded to the northeast and east by the Sahul Syncline and the Echo Syncline respectively. The Nancar Trough, a major depocentre containing up to 8 kilometres of Mesozoic-Cainozoic sediments, lies to the north (DeRuig et al., 2000). The Cartier Trough (a northeast-southwest trending extensional feature that subsided rapidly as a result of collision of the Australian plate with the South East Asian microplates in the Neogene), bounds the western side of the northern Londonderry High (Shuster et al., 1998; Whibley and Jacobsen, 1990)**. (Figure 5.1 and Plate 1**).

At date of writing, gas had been recovered on test from 6 wells drilled in the Londonderry High area (although at **Eider-1** and **Lorikeet-1** the gas recoveries could constitute solution gas) **(Figure 6.2)**. The most significant petroleum accumulation identified in the area is the **Prometheus/Rubicon** gas discovery, made in 2000, on the eastern flank of the Londonderry High.

6.2 Stratigraphy

The Londonderry High comprises a heavily faulted sequence of Palaeozoic and Triassic sediments, overlain unconformably by a relatively unfaulted, Late Jurassic and younger succession. Although most faulting terminates at the top of the Triassic sequence, some faults show evidence of Miocene reactivation (**Figure 6.4)**.

On the crestal parts of the Londonderry High, the Triassic section is deeply eroded. To the west, a series of basin margin faults and terraces truncate the Late Triassic and Jurassic sequences of the adjacent Vulcan Sub-basin. Uplift and erosion are less pronounced on the eastern and northern flanks of the Londonderry High. Here, the Triassic unconformity is progressively sub-cropped by a Permo-Triassic succession, more typical of the Petrel Sub-basin.

Although Plover Formation sediments are absent from the crest of the Londonderry High, sandstones within this unit constitute valid exploration objectives on basin margin terraces and tilted fault blocks that flank the western margin of the high. On the eastern flank, structural and stratigraphic traps both at Plover Formation level and within the Permo-Triassic succession are also exploration targets. Traps in this area rely on long distance migration of hydrocarbons from either the Sahul Syncline or Petrel Sub-basin for petroleum charge.

The Vulcan Formation is considered a potential source and reservoir in the Vulcan Sub-basin to the west. On the Londonderry High, however, the unit thins and is probably thermally immature for hydrocarbon generation. Gas has been recovered on test from the Upper Vulcan Formation in several wells drilled on the Londonderry High **(Table 6.1)**.

The Cretaceous to Cainozoic, siliclastic and carbonate succession encountered on the Londonderry High is similar to that intersected by wells in the adjacent Vulcan Sub-basin. Sea-level lowstands (particularly during the Aptian, Maastrichtian, Eocene and Oligocene), resulted in significant erosion on the Londonderry High.

The geological history and stratigraphy of the Londonderry High is further described in **Section 5, Vulcan Sub-basin** and **Section 2, Regional Summary**.

6.3 Exploration Drilling and Hydrocarbon Occurrences

Table 6.1 Results of exploration drilling, Londonderry High

Exploration Well	Year	Operator	Well Classification	Comments
Osprey-1	1972	Arco	P&A (Gas show)	Lack of reservoir development at primary objective.
Eider-1	1972	Arco	**Gas Discovery**	Gas recovered on test from the Plover Fm (possibly solution gas ?). Oil stained sidewall cores recovered over a 37 m interval in the Flamingo Gp.
Whimbrel-1	1974	Arco	P&A (Dry)	Upper Permian, pinnacle reef (primary objective) not present.
Plover-1	1974	Arco	P&A (Dry)	No access to mature source rocks.
Tamar-1	1979	Getty Oil	P&A (Dry)	No access to mature source rocks / Lack of top seal at primary objective.
Peewit-1	1984	WMC	P&A (Dry)	No access to mature source rocks / Possibly not a valid structural test.
Crane-1	1986	WMC	P&A (Dry)	Flamingo Gp objectives. No access to mature source rocks / Possibly not a valid structural test.
Ibis-1	1986	WMC	P&A (Dry)	Flamingo Gp objectives. No access to mature source rocks / Possibly not a valid structural test.
Avocet-1A	1986	Bond Corp	**Gas Discovery**	Gas recovered on test from the Upper Vulcan Fm. Residual oil columns in the Bathurst Island and Flamingo Gps. Trap possibly breached by late faulting or flushed by late gas charge.
Cygnet-1	1986	Bond Corp	P&A (Dry)	No access to mature source rocks.
Barita-1	1986	Bond Corp	P&A (Oil shows)	Oil shows in swc's from the Bathurst Island and Flamingo Gps. Possible breached trap.
Drake-1	1987	Bond Corp	P&A (Oil shows)	Residual oil columns in Bathurst Island and Flamingo Gps. Trap probably breached by late faulting.
Lorikeet-1	1988	BHP	**Gas Discovery**	Gas recovered on test from the Vulcan Fm (possibly solution gas ?). Residual oil columns in the Jamieson and Vulcan Fms. Trap possibly breached by late faulting or flushed by late gas charge.
Nancar-1	1989	BHP	P&A (Dry)	No access to mature source rocks.
Fulica-1	1989	Bond Corp	P&A (Oil shows)	Residual oil columns in the Bathurst Island and Flamingo Gps. Trap possibly breached by late faulting or lacked valid structural closure to the southwest.
Garganey-1	1989	Bond Corp	P&A (Oil shows)	Residual oil columns in the Bathurst

				Island and Flamingo Gps. Trap possibly breached by late faulting.
Jarrah-1A	1990	BHP	P&A (Oil shows)	Trap possibly breached by late faulting.
Stork-1	1990	Lasmo	P&A (Dry)	No access to mature source rocks.
Halcyon-1	1991	Lasmo	**Gas Discovery**	Gas recovered on test from the Flamingo Gp (17 m gas column identified on logs).
Jacana-1	1991	Lasmo	P&A (Dry)	No access to mature source rocks.
Torrens-1	1993	Kufpec	P&A (Oil shows)	Minor oil shows in the U. Carboniferous to U. Permian section.
Mallee East-1	1996	BHP	P&A (Dry)	
Ludmilla-1	1998	Woodside	P&A (Oil show)	Probable trap breach by late faulting.
Kittiwake-1	1998	Boral	P&A (Dry)	Interpretive data confidential at date of writing.
Wambenger-1	2000	Newfield	P&A (Dry)	Interpretive data confidential at date of writing.
Prometheus-1	2000	Kerr McGee	**Gas Discovery**	Gas recovered on test from the Permian (?). Forms one accumulation with adjacent Rubicon-1 discovery. Limited data available at date of writing.
Intrepid-1	2000	Kerr McGee	P&A (Dry)	Interpretive data confidential at date of writing.
Rubicon-1	2000	Kerr McGee	**Gas Discovery**	Gas recovered on test. Thought to be an extension of the adjacent Prometheus discovery.
Saratoga-1	2000	Kerr McGee	**Gas Discovery**	Gas is thought to have been recovered from the Flamingo Gp. Limited data available at date of writing.
Endeavour-1	2001	Kerr McGee	P&A (Dry)	Data confidential at date of writing.
Defiant-1	2001	Kerr McGee	P&A (Dry)	Data confidential at date of writing.
Backpacker-1	2001	Newfield	P&A (Dry)	Data confidential at date of writing.

A dry hole analysis of wells drilled on the Londonderry High to December 2002 is shown in **Figure 6.3**.

Table 6.2 Hydrocarbon shows, Londonderry High.

Exploration Well	Show Type	Depth (mRT)	Formation	Show Description
Barita-1	Oil	1781-1785	Basal Bathurst Island Gp	Fluorescence in cuttings and swc's.
		1828-1837	Upper Vulcan	Live oil and fluorescence in cuttings and swc's
Drake-1	Oil	1854-1877	Basal Bathurst Island Gp	Fluorescence in cuttings and swc's.
		1904-1935	Upper Vulcan	Live oil and fluorescence in cuttings and swc's
Fulica-1	Oil	2425-2447	Basal Bathurst Island Gp	Minor fluorescence in cuttings and swc's.
		2510-2515	Upper Vulcan	Strong fluorescence in cuttings and swc's.
Garganey-1	Oil	1359-1404	U. Bathurst Island Gp	Fluorescence in cuttings and swc's over all 3 intervals. Wireline logs indicate residual oil saturations in all 3 intervals.
		2029-2072	Basal Bathurst Island Gp	
		2097-2146	Upper Vulcan	
Jarrah-1A	Oil	1820-1850	Jamieson	Fluorescence in cuttings and swc's.

				Wireline logs indicate a residual oil column (Sw 80%).
Ludmilla-1	Oil	3289-3572	Plover (?)	Fluorescence in swc's and strong fluorescence in core (3305-3315 metres). Residual oil column inferred from wireline logs.
Osprey-1	Gas	1778-2539 2582-3185	Mt Goodwin Hyland Bay	Minor gas shows while drilling. Gas cut water recovered on DST.
Torrens-1	Oil	994-1000	Fossil Head	Residual oil saturations inferred from wireline logs.
		1517-1524	Hyland Bay	Residual oil saturations inferred from wireline logs.

6.4 Petroleum Potential

Petroleum plays identified on the Londonderry High include:

- Upper Vulcan Formation sandstones sealed by Bathurst Island Group claystones/shales within tilted, Triassic fault blocks;

- On the northern and eastern flanks of the Londonderry High, Malita and Plover Formation sandstones within structural or stratigraphic traps;

- On the eastern flanks of the Londonderry High, Hyland Bay Formation sandstones structurally or stratigraphically sealed by claystones of the Mount Goodwin Formation.

6.4.1 Reservoirs and Seals

Sandstones within the Flamingo Group and the underlying Plover Formation represent important petroleum reservoirs in the area. These units are sealed vertically and laterally by claystones of the Bathurst Island or Flamingo Groups.

On the eastern flanks of the Londonderry High, Permian and Carboniferous sequences onlap from the adjacent Petrel Sub-basin. Here, Permian and Carboniferous age sandstones constitute valid exploration objectives.

Trap integrity constitutes a critical exploration risk on the Londonderry High. Most of the wells drilled to date on the Londonderry High have targeted fault-dependant traps that formed during Mesozoic rifting and were reactivated during flexural extension associated with plate collision in the Neogene (Brincat et al., 2001). Residual hydrocarbon columns identified in a number of these wells indicate leakage of petroleum from traps after fault reactivation in the Miocene to Pliocene is a common occurrence in this area **(Table 6.1).**

Work by O'Brien and Woods, (1995), O'Brien et al., (1998) and Brincat et al., (2001) offers a model for more thoroughly evaluating the risk of trap breach on the Londonderry High.

6.4.2 Source

Most traps on the Londonderry High rely upon adjacent Sahul Syncline and Vulcan Sub-basin source kitchens for petroleum charge. On the eastern flanks of the high, however, mature source intervals within the Permo-Carboniferous succession provide a petroleum charge (via long distance migration) for accumulations in this area.

The Lower Vulcan Formation (a Late Jurassic sequence of graben-fill shales) is the principal source rock in the Vulcan Sub-basin. The shales reach thicknesses in excess of 1,000 metres in the Swan Graben and are thought to be the source for the Jabiru and Challis oil fields to the west **(Figure 5.2)**.

In the Sahul Syncline, the Lower to Middle Jurassic Plover Formation becomes more marine and thermally mature towards the axis of the syncline where it is thought to constitute a good quality, mature source rock.

6.4.3 Traps

Brincat et al., (2001) indicate that unbreached fault traps on the Londonderry High may be difficult to locate and conclude that stratigraphic traps may constitute an alternative play type on the northern and northeastern Londonderry High. These traps would not have inherent fault seal problems and have had, or are currently receiving, oil charge. They suggest that stratigraphic traps may be found in the Upper Jurassic turbidites of the Nancar Sandstone Member (as encountered in Ludmilla-1 and Nancar-1ST1). These sands pinch out towards the north where age-equivalent, *D. jusassicum* deposits, consist of a thin clay drape (Mandorah-1, Fannie Bay-1 and Lameroo-1).

Other potential plays on the Londonderry High include Maastrichtian sandstones within anticlinal closures (Brincat et al., 2001) and stratigraphic pinchouts and submarine fan sandstone plays within the basal Flamingo Group (Whibley and Jacobsen, 1990). Vertical migration of liquid hydrocarbons due to fault reactivation could have charged shallower reservoirs and produced valid exploration targets.

With the advent of modern 3D seismic surveys and sophisticated processing techniques, exploration for subtle four way dip closures within the Cretaceous section is now more feasible.

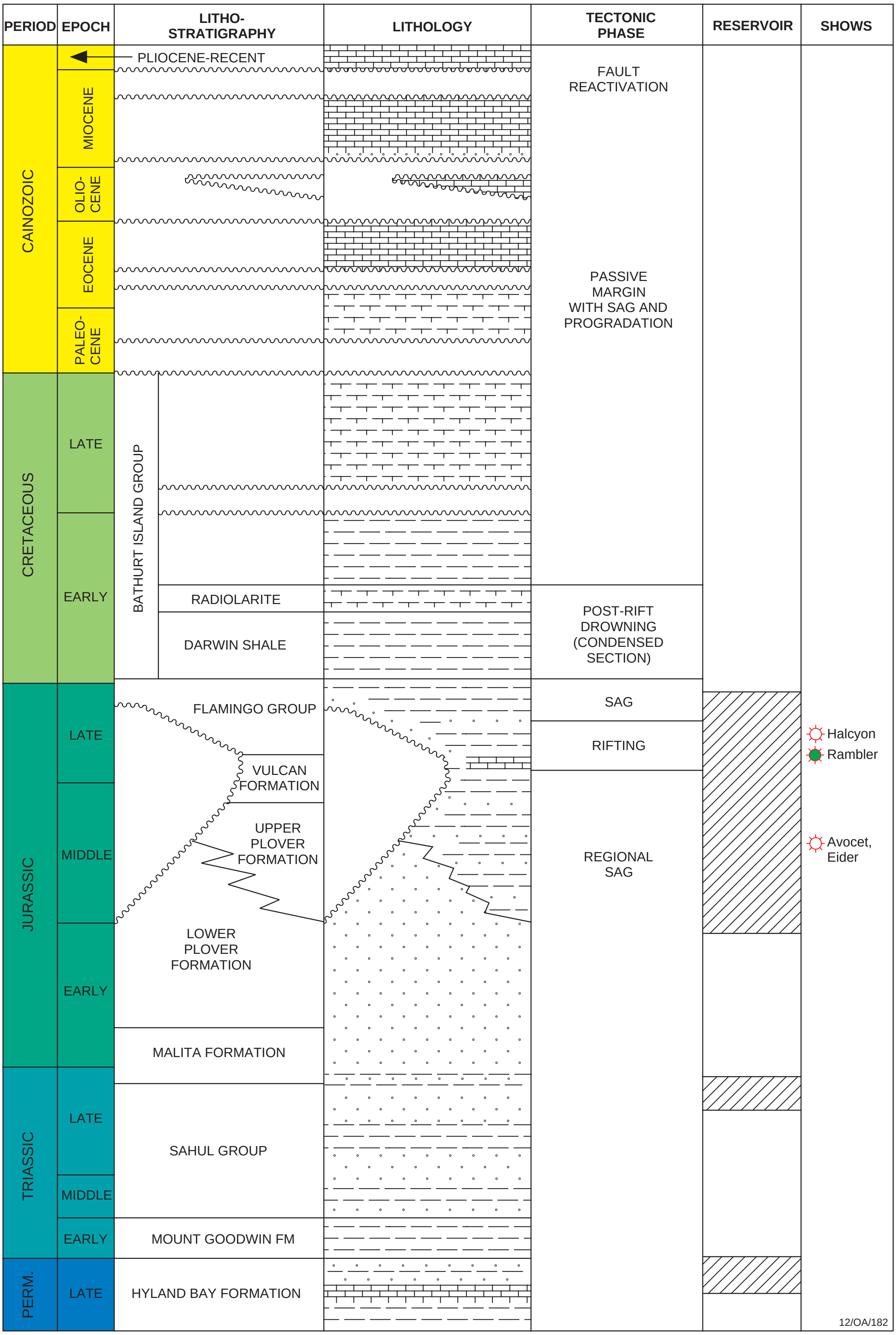

Figure 6.1 Stratigraphy, Londonderry High (2000 Acreage Release CD-Rom).

Figure 6.2 Petroleum discoveries, Londonderry High.

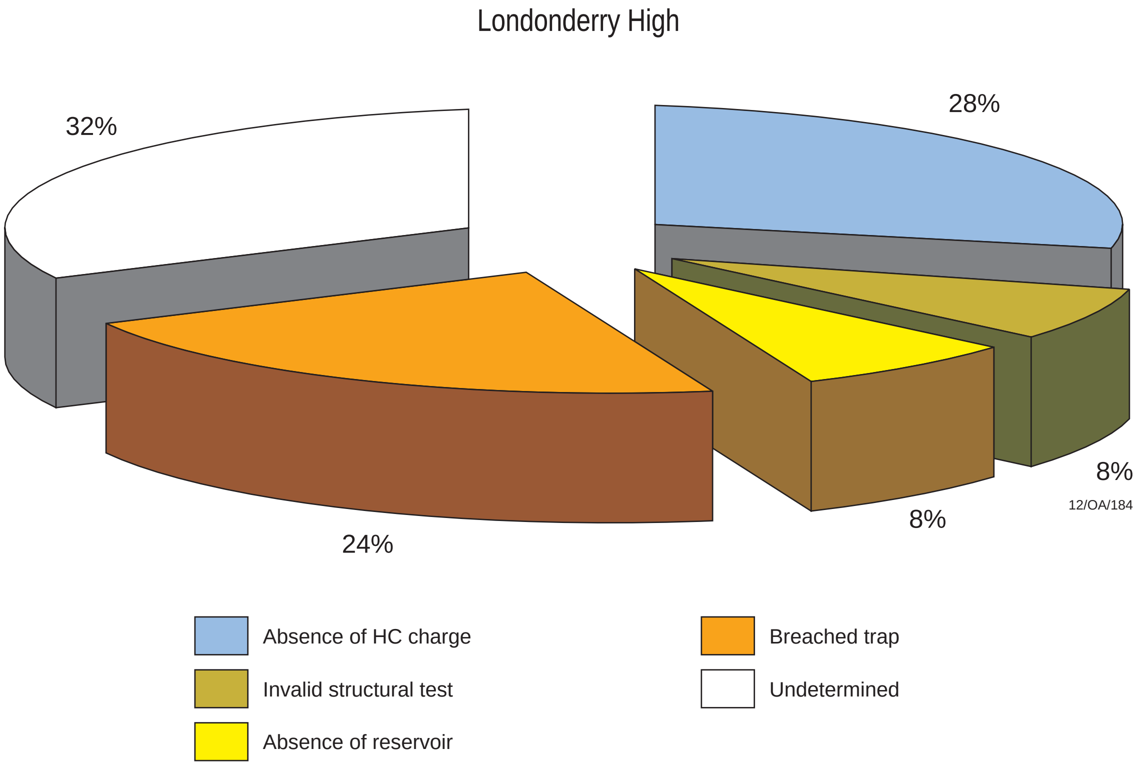

Figure 6.3 Dry hole analysis, Londonderry High.

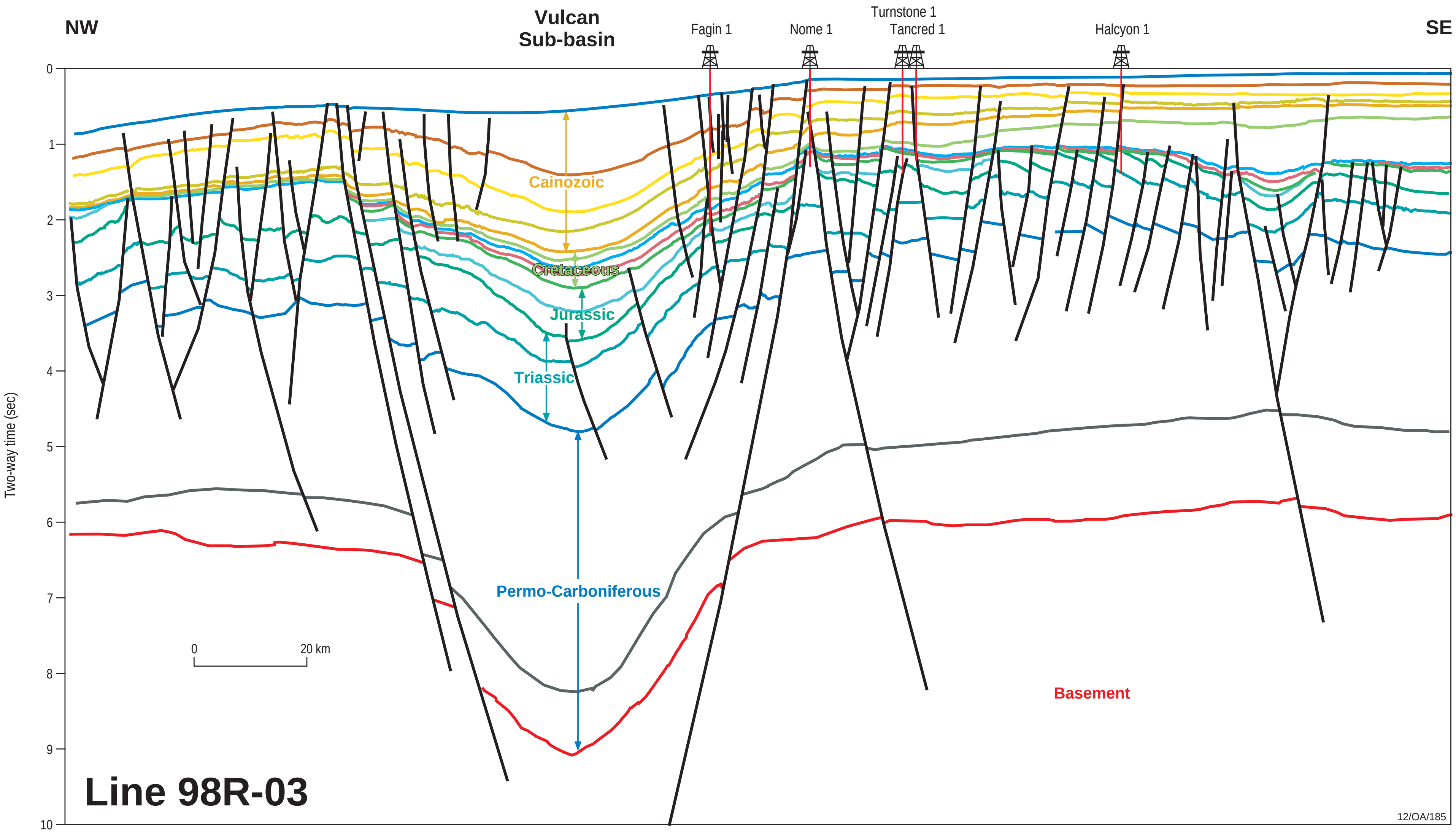

Figure 6.4 Interpreted seismic line N98R-03 through the Vulcan Sub-basin and Londonderry High (2000 Acreage Release CD-Rom).

7. SAHUL SYNCLINE

7.1 Introduction

The Sahul Syncline is a prominent Palaeozoic to Mesozoic northwest trending trough located in the northern Bonaparte basin **(Figure 8.2, Plate 1)**. The syncline is flanked to the north by the Sahul Platform and to the south by the northern Londonderry High.

Although only one petroleum accumulation has been identified within the Sahul Syncline (Rambler-1), the syncline is considered a source kitchen for a number of petroleum accumulations identified on the adjacent Laminaria and Flamingo Highs **(Plate 1, Figures 8.2 and 8.4)**.

7.2 Structural Evolution and Stratigraphy

Botten and Wulff, (1990) consider the Sahul Syncline formed in the Late Triassic to Middle Jurassic, whereas others (Durrant et al., 1990) believe it formed as part of the Bonaparte rift system in the Devonian.

The Sahul Syncline has been described as a ‘sag’ feature overlying an extension of the Bonaparte Basin margin (O’Brien et al., 1993; Robinson et al., 1994). These authors consider that Late Carboniferous to Early Permian extension reactivated pre-existing, northwest trending fault zones (such as the Sahul Syncline) as transfer faults.

Subsidence in the Late Permian to Late Triassic led to the deposition of a thick, sedimentary sequence in the Sahul Syncline. Tectonic compression in the Late Triassic resulted in uplift and erosion of the adjacent structural highs and the deposition of a thick red bed sequence (Malita Formation) in the Petrel Sub-basin to the east. The Malita Formation has not been intersected by wells drilled in the Sahul Syncline, but may be present at depth.

Further subsidence resulting from Mesozoic extension led to the deposition of a thick, Late Jurassic to Early Cretaceous clastic sequence (Plover Formation and Flamingo Group) in the Sahul Syncline. In axial areas of the syncline, the Plover Formation and sandstones within the Flamingo Group probably lie too deep to constitute valid exploration objectives. These units, however, form viable exploration targets on the flanks of the Sahul Syncline (in **Rambler-1**, oil was recovered from the Flamingo Group and a gas column was identified on wireline logs within the Plover Formation).

At the conclusion of continental breakup in the Valanginian, Cretaceous and Cainozoic sediments were deposited across the Sahul Syncline. This sedimentary sequence is similar to the succession encountered in the Vulcan Sub-basin to the southwest.

Further details of the stratigraphy and structural evolution of the Sahul Syncline can be found in **Section 5, Vulcan Sub-basin** and **Section 2, Regional Summary**.

7.3 Exploration Drilling and Hydrocarbon Occurrences

Table 7.1 Results of exploration drilling, Sahul Syncline.

Exploration Well	Year	Operator	Well Classification	Comments
Cleia-1	1992	Phillips	P&A (Dry)	No reservoir development at primary objective level.
Iris-1	1993	Phillips	P&A (Oil show)	Non-sealing bounding fault.
Rambler-1	1993	SAGASCO	**Oil & Gas Discovery**	Oil and gas recovered on test from the Plover Fm.
Heifer-1	1999	BHPP	P&A (Dry)	Data confidential at date of writing.
Franklin-1	1999	BHPP	P&A (Dry)	Data confidential at date of writing.

7.4 Petroleum potential

7.4.1 Source

The Sahul Syncline is an important source kitchen in the Northern Bonaparte Basin. The Lower Vulcan Formation, which comprises a Late Jurassic sequence of graben-fill shales, is the principal source rock in the Vulcan Sub-basin to the southwest. Here, the shales exceed a thickness of 1000 metres in the Swan Graben and are believed to be the source for the oil produced at Jabiru and Challis.

Lateral equivalents in the Sahul Syncline (Frigate Formation), together with the overlying Cleia Formation, are considered excellent seal and source facies.

The Lower to Middle Jurassic Plover Formation becomes more marine, thermally mature and thickens towards the axis of the Sahul Syncline, where it may provide good source potential.

7.4.2 Reservoirs and Seals

Although the Sahul Syncline is primarily viewed as a source kitchen, a number of wells have been drilled on the western flanks of the syncline to test Plover Formation sandstones within tilted, Mesozoic fault blocks. Towards the axis of the syncline, however, Triassic and Jurassic reservoirs, which are primary exploration targets elsewhere in the Bonaparte Basin, are probably buried too deep to constitute viable exploration targets.

Multiple, stacked turbidite ramp and canyon-fed submarine fan sands within the Flamingo Group (Cleia Formation) sealed by either thick Cretaceous Bathurst Island Group shales (Echuca Shoals Formation) or intraformational shales, may also constitute valid exploration objectives on the flanks of the Sahul Syncline.

8. SAHUL PLATFORM (NORTHERN BONAPARTE BASIN)

8.1 Introduction

The Northern Bonaparte Basin, or Sahul Platform *sensu lato*, is bounded by the Sahul Syncline in the west, the Malita Graben to the southeast and the Timor Trough to the north. **(Figures 8.1 and 8.2).** Hocking et al., (1994) defined the Northern Bonaparte Basin as an area to the northwest of the Petrel Sub-basin, containing a thick Mesozoic and Cainozoic succession.

The Sahul Platform is a large northeast trending basement high comprised of tilted fault blocks and horsts. The platform plunges to the southwest. Permian, Triassic and Jurassic sediments thin over the platform to the northeast (**Plate 2**). The platform probably formed during Palaeozoic rifting, with later rejuvenation and uplift occurring during continental breakup in the Mesozoic and collision of the Australian plate with the South East Asian microplates in the late Cainozoic.

Two major Upper Jurassic to Lower Cretaceous, depocentres are recognised in the Northern Bonaparte Basin – the Malita Graben and the Sahul Syncline (including its western extension, the Nancar Trough) (Whittam et al., 1996) **(Figure 8.2, Plate 1).**

The Sahul Platform has been sub-divided into the following elements:

- the Troubadour High - a culmination located on the east of the Sahul Platform where depth to basement is approximately 3,000 metres;
- the Kelp High - located further to the west, where basement is interpreted to be significantly deeper;
- the Flamingo High - a major pre-Jurassic domal feature which lies between the Sahul Platform and the Londonderry High;
- the Laminaria High - a small, east-west orientated, drowned platform-remnant between the Sahul and Flamingo Synclines (Smith et al., 1996).

The Flamingo Syncline is a shallow southeast-trending, Upper Jurassic to Lower Cretaceous trough that separates the Sahul Platform from the Laminaria and Flamingo Highs.

Although the Flamingo and Laminaria Highs are not *sensu-stricto* part of the Sahul Platform, because of similarities in their tectonostratigrapy and hydrocarbon potential they are included in this section of report.

At date of writing, 20 oil, gas, and oil and gas discoveries made in the Northern Bonaparte Basin **(Plates 1 and 2, Figure 8.4).** Commercial production has occurred from 7 of these discoveries (**Elang**, **Kakatua**, **Kakatua North**, **Laminaria**, **Corallina**, **Buffalo** and **Bayu-Undan**). At date of writing, development of the Greater Sunrise gas field (which includes the **Troubadour**, **Sunrise**, **Loxton Shoals** and **Sunset** discoveries) and a joint development of the **Kuda Tasi** and **Jahal** oil discoveries are under consideration.

8.2 Structural Evolution

The Phanerozoic history of the Northern Bonaparte Basin has been summarised by Veevers, (1971, 1988); Gunn, (1988); Pattillo and Nicholls, (1990); O'Brien et al., (1993); AGSO NW Shelf Study Group, (1994); Baillie et al., (1994); Whittam et al., (1996); O'Brien et al., (1996); Shuster et al., (1998); and Labutis et al., (1998). The following description draws on this work.

The present day configuration of the Northern Bonaparte Basin has resulted from the intersection of two major structural trends – a Palaeozoic to Middle Jurassic northwest-southeast structural grain on which is superimposed on a northeast orientated, Late Jurassic to Holocene trend.

The pre-existing Palaeozoic structural grain had considerable influence on the distribution and thickness of the Mesozoic and Cainozoic succession on the western part of the Sahul Platform (particularly during the Triassic), and is expressed in the southeast orientation of both the Sahul and Flamingo Synclines (Whittam et al., 1996).

This structural grain is cross-cut by a series of Jurassic faults, the strike of which varies from northeast-southwest in the area adjacent to the Londonderry High, through north northeast-south southwest at the western end of the Malita Graben, to east-west in the area of the Flamingo and Laminaria Highs. Woods, (1992) attributes this latter east-west trend to Tithonian tectonism.

Whittam et al., (1996) concluded that although the geological history of the Northern Bonaparte Basin and Vulcan Sub-basin are broadly similar (refer to **Section 5, Vulcan Sub-basin**), there are significant differences in the Northern Bonaparte Basin which have implications for petroleum exploration in the area.

Variations in the subsidence history and timing of tectonic events between the two areas, influences the distribution and preservation of potential reservoir and source rocks. For example, it is considered unlikely that deposition of the Elang / Laminaria Formation reservoir sands would be widespread on the Sahul Platform if the Callovian extension that occurred in the Vulcan Sub-basin to the south had occurred on the western part of the Sahul Platform.

Similarly, the differences in subsidence history, and in thickness of the mid-Cretaceous to Cainozoic succession had a major impact on the timing of hydrocarbon generation and on the extent to which later episodes of faulting affected the integrity of Jurassic traps.

8.3 Stratigraphy

The overall stratigraphy of this area has been described by MacDaniel, (1988); Lavering and Ozimic, (1989); Mory, (1988); Patillo and Nicholls, (1990); O'Brien et al., (1993); Hocking et al., (1994); Baillie et al., (1994); AGSO, (1994); Whittam et al., (1996); Labutis et al., (1998); Shuster et al., (1998); and Seggie et al., (2000). The following description draws on the work of these authors.

The generalised stratigraphy, tectonic elements and petroleum discoveries in the Sahul Platform area are shown in **Figures 8.1, 8.2, 8.3 and 8.4, Plates 1and 2.** The stratigraphy of the Sahul Platform is further discussed in **Sections 8.3.1, Laminaria High; 8.3.2, Troubadour High; 8.3.3. Flamingo High; and 8.3.4, Kelp High**.

The Permian, Hyland Bay Formation is the oldest unit intersected by drilling on the Sahul Platform to date. During the initial phase of exploration in the area, the Permo-Carboniferous succession was generally considered by explorers to be unprospective for hydrocarbons. The discovery of gas in the Hyland Bay Formation at **Kelp Deep-1** in 1997, however, changed these perceptions (at least on the Kelp High).

A marine transgression in the Early Triassic led to the deposition of marine claystones (Mt Goodwin Formation) over the Sahul Platform. This was followed in the Middle and Late Triassic by a regressive sequence of shallow marine to fluvio-deltaic sandstones, claystones and minor carbonates (Sahul Group). In the Late Triassic to Early Jurassic, a red bed sequence (Malita Formation) was deposited. Few exploration wells have penetrated the Triassic sequence on the Sahul Platform (the most complete Triassic sections have been encountered by the Kelp-1, Kelp Deep-1 and Troubadour-1 wells).

Early to Middle Jurassic sediments (Plover Formation) were deposited in a broad, northeast-southwest trending ‘sag’ basin in non-marine to marginal marine, depositional environments. At the top of the Plover Formation, a shallow marine sandstone (Elang / Laminaria Formation) forms an important petroleum reservoir in the area. The Elang/Laminaria Formation comprises two depositional sequences and represents the youngest unit deposited below the breakup unconformity. This unit was originally considered to be a marine facies within the uppermost Plover Formation.

Continental breakup in the Late Jurassic initiated the formation of the Sahul Syncline, the Malita Graben and a series of east-west trending troughs. The Sahul Platform and the Londonderry High flank these depocentres. The Flamingo Syncline is a younger feature developed in the Albian.

Late Jurassic and Early Cretaceous sediments of the Flamingo Group are mainly confined to the Malita Graben and Sahul Syncline and are absent or represented by very thin condensed sequences on the flanking ‘highs’. Tithonian to Berriasian age Flamingo Group sediments are interpreted to occur within east-west trending troughs on the Sahul Platform and may constitute potential reservoirs.

Wells distant from the Malita Graben and Sahul Syncline have encountered hydrocarbons, indicating that source rocks on the Sahul Platform are thermally mature and have generated and expelled significant quantities of petroleum **(Figure 8.1)**.

Labutis et al., (1998) note that the stratigraphic nomenclature on the Sahul Platform is often misleading as it is commonly based on lithostratigraphy, with some formation names unique to an area or well and others extrapolated from nearby wells. The formations are usually based on facies and rarely on biostratigraphy and are thus difficult to identify or tie with seismic data at any distance from the well or area where the lithostratigraphic unit was first defined.

Consequently, units of different ages have been assigned to the same formation. For example, the Montara Formation was first defined in the Vulcan Sub-basin to the south, in the Montara-1 well, based on the predominantly marine sandstones of the uppermost Callovian and Oxfordian age (*R. aemula* to *W. spectabilis* dinoflagellate palynozones). This same formation name is applied to the section now called the Laminaria or Elang Formation or 'Montara Beds' in many of the wells drilled on the Sahul Platform.

The tectonostratigraphy of the Sahul Platform is further discussed in the following sections.

8.3.1 Laminaria High

The Laminaria High is a small, east-west orientated, drowned platform-remnant lying between the Sahul and Flamingo Synclines (Smith et al., 1996) **(Figure 8.2)**. On the high, Palaeozoic basement is relatively shallow and is overlain by thick Triassic to Lower Jurassic 'sag' phase sediments which have known equivalents in other parts of the Bonaparte Basin.

The stratigraphic succession on the Laminaria High is well known from drilling on the **Laminaria**, **Corallina** and **Buffalo** oil fields, which are located on the high.

The Laminaria and Frigate Formations were deposited in half-grabens which developed over the Laminaria High in the late Callovian to early Tithonian. Fault movement ended in the Late Kimmeridgian and faulting largely terminates near the top of the Frigate (Shale) Formation, where a significant unconformity occurs (Patillo and Nicholls, 1990; Gorter and Kirk, 1995). The upper part of the Frigate Shale is preserved on the flanks of the Laminaria High while over 20 metres of section has been removed on the crest of the feature. Flamingo Group shales rest disconformably on this surface. The crest of the Laminaria High was not covered until Late Tithonian (*P. iehiense zone*) times.

The overlying Cretaceous and Cainozoic sequences are similar to those found elsewhere in the Bonaparte Basin. However, the Cretaceous sediments are thin compared to adjacent synclinal areas and substantial erosion / non-deposition occurred over the Laminaria High near the Cretaceous/Cainozoic boundary.

In contrast, the overlying Cainozoic section is very thick, resulting from substantial flexure, rapid subsidence and extensive prograding of shelfal carbonates over the drowned Laminaria High, as the Australian Plate converged on the South East Asian microplates in the Cainozoic. The rapid deposition of a thick, Cainozoic section has resulted in rapid, thermal maturation of underlying source rock sequences that have provided the petroleum charge for accumulations on the Laminaria High.

8.3.2 Troubadour High

The Troubadour High (referred to as the Sunrise High by Seggie et al., 2000), is a large culmination on the eastern Sahul Platform. The Troubadour High was a prominent feature from Permo-Triassic through to Recent times. The high is bounded to the south by the Malita Graben, to the east by the Calder Graben, to the southwest by the Sikitan Syncline **(Figure 8.2, Plate 1).**

The Sunrise/Troubadour/Loxton Shoals/Sunset gas field (commonly referred to as the Sunrise/Troubadour field or the Greater Sunrise field) lies on the Troubadour High. The Greater Sunrise structure is a complex of large, east-west elongated fault blocks. The main phase of structural development at Greater Sunrise occurred during the Pleistocene as a consequence of rapid subsidence of the Timor Trough (Seggie et al., 2000).

The stratigraphy of the Troubadour High has been well documented from wells drilled on the Greater Sunrise field. Fuller accounts of the regional geology and stratigraphy are available in Schuster et al., (1998) and Whittam et al., (1996).

Troubadour-1, drilled on the northern margin of the Sahul Platform in 1974, encountered recrystallised, Late Permian carbonates of the Hyland Bay Formation overlying granitic basement (**Figure 8.6**). Late Permian to Early Triassic, marine siltstones and shales of the Mount Goodwin Formation overlie the Hyland Bay Formation. Deposition of the Triassic Sahul Group (a mixed clastic-carbonate succession), followed. A Late Triassic marine regression, induced in part by regional uplift associated with the Fitzroy compressional movement, culminated in the deposition of fluvio-deltaic redbeds (Nome and Malita Formations) across the region **(Figure 8.3)**.

A transgression in the Early to Mid Jurassic deposited a thick fluvio-deltaic to marine succession (Plover Formation) over the area. These units form the petroleum reservoirs in the Greater Sunrise gas field. Marine influence within the Plover Formation increases from the southwest to the northwest across the Sahul Platform. The Plover Formation reservoir in the Greater Sunrise field is interpreted to be Bathonian in age and the most marine section encountered on the Sahul Platform to date.

On the Troubadour High, the Plover Formation is para-conformably overlain by marine sandstone/shale sequences of late Callovian to early Oxfordian age (Laminaria or Elang Formation). This unit constitutes both a reservoir and source rock interval at Greater Sunrise.

In other areas of the Bonaparte Basin, a period of block faulting and uplift during the Callovian resulted in an unconformity between the Plover Formation and the Laminaria / Elang Formation / Frigate Shale. On the Troubadour High, however, the main episode of faulting occurred during the Latest Jurassic. This led to the development of east-west trending horsts and grabens and a major Late Jurassic unconformity.

Deposition of marine claystones and siltstones of the overlying Flamingo Group (Tithonian to Berriasian in age) is widespread in the Malita Graben. This unit onlaps the flanks of the Troubadour High. The areal distribution of the Flamingo Group and its potential as an exploration target on this part of the Sahul Platform remains uncertain as a number of hiatuses associated with continental breakup are evident in the Flamingo Group succession on the Troubadour High.

Following the onset of sea-floor spreading in the mid-Valanginian, subsidence of the Australian continental margin resulted in the widespread deposition of a condensed section of glauconitic, marine claystone (Valanginian to Early Aptian, Echuca Shoals Formation). The peak of this transgression is represented by a condensed, radiolarian chert, claystone and calcilutite (Darwin Formation, Whittam et al., 1996). The top of the radiolarite (Aptian) is a prominent seismic marker over the Troubadour High and is used to map the top of the reservoir (phantomed downwards) over the Greater Sunrise field.

A thick Aptian to Maastrichtian progradational section of claystone, calcilutite and marl (Jamieson and Wangarlu Formations) overlies this condensed section and fills the accommodation space created by the rapid subsidence of the Australian margin after break-up.

The Cainozoic section on the Troubadour High is similar to the succession encountered elsewhere on the northwest margin, where a thick succession of prograding, marine, shelf/slope carbonate dominated sediments was deposited.

8.3.3 Flamingo High

The Flamingo High is a major pre-Jurassic domal structure lying between the adjacent Sahul Platform and the Londonderry High **(Figure 8.2)**.

The Flamingo High has long been recognised as a potential hydrocarbon objective (Brooks et al, 1996). Palinspastic reconstructions of the Permian and Triassic intervals show that prior to Late Triassic, the Flamingo High had no structural expression – the area from Sahul to Flamingo Synclines constituted one broad depocentre (McIntyre, 1995).

Following the formation of the Flamingo High in the Late Triassic/Early Jurassic, localised, north-south oriented faulting occurred on the Flamingo High and western Sahul Platform. Extensional faulting initiated during the Oxfordian-Valanginian resulted in the development of east-west trending tilted fault blocks, horst and grabens across the Sahul Platform (including the Flamingo High). Contemporaneously, the Londonderry High and Sahul Platform were uplifted and sub-aerially eroded.

Tilting of the Flamingo High occurred during the Aptian-Turonian, extending the areal extent of the high to the west (at the level of the Aptian Disconformity).

The collision of the Australian continental plate with the South East Asian microplates in the Neogene led to increased water depths over the northern half of the Sahul Platform. Flexuring caused by thrust loading during the Late Miocene-Pliocene resulted in east-northeast trending normal faulting, erosion, and extensive channelling (Bradley and Kidd, 1991; McIntyre, 1995).

The stratigraphy of the Flamingo High is well documented from the results of drilling on the **Bayu-Undan** gas field and the **Elang / Kakatua / Kakatua North** oil discoveries. A detailed stratigraphy of the Flamingo High has been compiled by Brooks et al., (1996) and Young et al., (1995).

The first well to be drilled on the Flamingo High was **Flamingo-1** (1971). Since that time, three commercial oil discoveries (Elang, Kakatua and Kakatua North) and one commercial gas discovery (Bayu-Undan) have been made on the high.

8.3.4 Kelp High

The Kelp High is a large culmination on the western Sahul Platform. This 'domal' feature was identified on regional 'sparker' seismic surveys acquired in the late1960s and early 1970s. The Kelp High remained a 'geological anomaly' for a further 25 years (partly due to the moratorium on petroleum exploration in this area between 1976 and 1992).

The Sahul Platform has been a structural high since Late Jurassic times. Analysis of isochores suggests that significant structural closure did not exist on the Kelp High feature prior to the Pliocene and that the Upper Cretaceous section is thin at this locality.

The Kelp High consists of a crestal, east-west trending horst block with the flanks of the feature composed of numerous tilted fault blocks. Kelp-1 was drilled in 1994 to test Jurassic and Triassic sediments in a crestal position on the Kelp High. The well encountered a stratigraphic section ranging in age from Cainozoic (Miocene or younger) to Middle to Late Triassic. No hydrocarbons were encountered.

The well confirmed the presence of good quality reservoir sands in the Plover and Flamingo Formations. The secondary objective (Triassic, Sahul Group sands) exhibited poor reservoir quality at this location.

In 1997, **Kelp Deep-1** was drilled approximately 15 kilometres southwest of Kelp-1 on a separate fault block on the Kelp High. The well was designed to test the limestones and fluvio-deltaic sandstones of the Late Permian Hyland Bay Formation (together with sandstones of the Lower Cretaceous/Upper Jurassic Flamingo Group and Plover Formation).

In Kelp Deep-1, no hydrocarbons were encountered within the Flamingo Group and Plover Formation, but gas was recovered on test from the deeper, Permian Hyland Bay Formation.

Although to date, exploration drilling on the Kelp High has proved disappointing (Kelp-1, Kelp Deep-1, Hydra-1, Mandar-1 and Naga-1), the wells have established both the presence of excellent reservoirs within the Flamingo Group and Plover Formation and a new petroleum play within the Permian sequence **(Table 8.1).**

8.4 History of Exploration Permits in the Zone of Cooperation (ZOC) and Joint Petroleum Development Area (JPDA)

Much of the Sahul Platform and environs lies in an area of the Timor Sea over which sovereignty has been disputed - initially by Indonesia and more recently by the independent nation of East Timor. Since exploration permits were first awarded over the region in the late 1960s and early 1970s, exploration has undergone a complex history.

Australian offshore permits in the Timor Sea adjacent to the, then, non-agreed seabed boundary between Australia and East Timor were suspended in the middle of 1976 (shortly after Indonesia claimed sovereignty over Portugese East Timor). The moratorium on exploration in the area was lifted in 1991 when agreement was reached between Australia and Indonesia to explore in the Zone of Cooperation (ZOC).

Three zones were agreed to in a treaty signed by both parties:

- ZOCC - the northern zone close to East Timor. All legal rights and administration by Indonesia.
- ZOCB - the southern zone close to Australia. All legal rights and administration by Australia
- ZOCA - a zone between ZOCC and ZOCB jointly administered and shared legal rights between Australia and Indonesia. Administered from Jakarta with an office in Darwin.

The Joint Authority, which administered Area 'A' gazetted exploration areas within ZOCA in late 1991. The first permits within ZOCA were awarded in February 1992. In recognition of their expertise in exploring the area, prior holders of permits (Australian) within the boundaries of Area 'A' were given rights of special consideration on these permits. The terms of special consideration gave prior permit holders a right to match bids on permits of their choice. These permits, together with subsequent renewals and new permits, remained in force until East Timor was granted independence in 2002.

On 20 May 2002, the date of East Timor's independence, Australia and East Timor signed the Timor Sea Treaty. This treaty was officially ratified between the governments on 2 April 2003 for a period of 30 years.

The key elements of the treaty include:

- The creation of the Joint Petroleum Develoment Area (JPDA) from the former ZOC.
- A revenue split of 90% for east Timor and 10% for Australia from petroleum activities in the JPDA;
- Deferral of permanent delimitation of the seabed boundary without prejudice to Australia's and East Timor's rights and entitlements;
- Maintenance of contractual terms of the existing petroleum projects (Bayu-Undan, Greater Sunrise and Elang-Kakatua);
- Australian jurisdiction over pipelines from the JDPA to Australia;
- Unitisation of the Greater Sunrise field (which straddles the JDPA and an area under Australian jurisdiction) on the basis that 20.1% of the field lies within JDPA and 79.9% within Australian jurisdiction.

8.5 Exploration Drilling and Hydrocarbon Occurrences

Table 8.1 Results of exploration drilling, Northern Bonaparte Basin.

Exploration Well	Year	Operator	Well Classification	Comments
Flamingo-1	1971	Arco	**Gas Discovery**	Gas recovered on test from the Plover Fm (possibly solution gas ?).
Troubadour-1	1974	Woodside	**Gas Discovery**	Gas recovered on test from the Plover Fm.
Sunrise-1	1975	Woodside	**Gas Discovery**	Gas recovered on test from the Plover Fm.
Hydra-1	1992	Marathon	P&A (Dry)	
Basilisk-1A	1993	Marathon	P&A (Oil show)	Residual oil column in Plover Fm. Trap breached by late faulting.
Naga-1	1993	Marathon	P&A (Oil show)	Fluorescence in cuttings and swc's from the Plover Fm.
Kelp-1	1994	Woodside	P&A (Dry)	Lacks adequate cross-fault seal.
Mandar-1	1994	Petroz	P&A (Oil show)	Residual oil column identified on logs (187 metres). Trap breached by late faulting.
Sikatan-1	1994	SAGASCO	P&A (Dry)	Invalid structural closure or lack of access to mature source rocks.
Elang-1	1994	BHP	**Oil Discovery**	Oil recovered on test from the Elang / Laminaria Fm.
Mistral-1	1994	Phillips	P&A (Gas show)	No reservoir development at primary objective (Sandpiper Sst).
Squilla-1	1994	BHP	P&A (Oil show)	Trap breached by late faulting (?)
Kakatua-1	1994	BHP	**Oil Discovery**	Oil recovered from Elang / Laminaria Fm
Nabarlek-1	1994	Enterprise	P&A (Dry)	
Minotaur-1	1994	Marathon	P&A (Oil show)	Residual oil saturations in the Plover Fm. Trap breached by late faulting.
Laminaria-1	1994	Woodside	**Oil Discovery**	Oil recovered on test from the Elang / Laminaria Fm.
Fohn-1	1994	Phillips	**Gas Discovery**	Gas recovered on test from the Plover Fm.
Loxton Shoal-1	1995	Woodside	**Gas Discovery**	Gas recovered on test from the Plover Fm.
Bayu-1	1995	Phillips	**Gas Discovery**	Gas recovered on test from the Elang / Laminaria and Plover Fms.
Sandang-1	1995	BHP	P&A (Oil show)	
Barnacle-1	1995	BHP	P&A (Dry)	Incompetent seal or lack of access to mature source rocks.
Corallina-1	1995	Woodside	**Oil Discovery**	Oil recovered on test from the Elang / Laminaria Fm.
Buller-1	1996	BHP	**Oil Discovery**	Oil recovered on test from the Elang / Laminaria Fm.
Jahal-1	1996	BHP	**Oil Discovery**	Oil recovered on test from the Elang / Laminaria Fm.
Buffalo-1	1996	BHP	**Oil Discovery**	Oil recovered on test from the Elang / Laminaria Fm.
Wallaroo-1	1996	Enterprise	P&A (Oil show)	Residual oil saturations in the Plover Fm. Trap breached by late faulting.
Thornton-1	1997	Shell	P&A (Dry)	Invalid structural test.
Kelp Deep-1	1997	Mobil	**Gas Discovery**	Gas recovered on test from the Hyland Bay Fm.
Sunset-1	1997	Shell	**Gas Discovery**	Gas recovered on test from the Plover

				Fm.
Kakatua North-1	1997	BHP	**Oil Discovery**	Oil recovered on test from the Elang / Laminaria Fm.
Krill-1	1997	BHP	**Oil & Gas Discovery**	Oil and Gas recovered on test from the Elang / Laminaria Fm.
Layang-1	1997	BHP	P&A (Oil show)	Trap breached by late faulting (?)
Bogong-1	1997	BHP	P&A (Oil show)	Trap breached by late faulting (?)
Alaria-1	1997	Woodside	P&A (Dry)	Drilled outside structural closure at primary objective level.
Buang-1	1997	BHP	P&A (Oil show)	Trap breached by late faulting (?)
Vidalia-1	1997	Woodside	P&A (Dry)	Lacks adequate cross-fault seal or lacks access to mature source rocks.
Capung-1A	1998	BHP	P&A (Oil and show)	Trap breached by late faulting (?)
Bluff-1	1998	BHP	**Oil Discovery**	Oil recovered on test from the Elang / Laminaria Fm.
Fannie Bay-1	1998	Woodside	P&A (Oil show)	Data confidential at date of writing.
Tanjil-1	1998	BHP	P&A (Dry)	Data confidential at date of writing.
Lameroo-1	1998	Woodside	P&A (Oil show)	Data confidential at date of writing.
Conch-1	1998	Woodside	P&A (Dry)	Invalid structural test (drilled outside closure at primary objective level).
Bard-1	1998	Woodside	P&A (Dry)	Invalid structural test (well did not reach primary objective).
Chuditch-1	1998	Shell	**Gas Discovery**	Gas recovered on test from the Plover Fm.
Wowo Wiwi-1	1998	BHP	P&A (Dry)	Data confidential at date of writing.
Claudea-1	1999	Woodside	P&A (Dry)	Data confidential at date of writing.
Mindil-1	1999	Woodside	P&A (Dry)	Data confidential at date of writing.
Marrakai-1	1999	Woodside	P&A (Dry)	Data confidential at date of writing.
Jura-1	1999	Woodside	P&A (Dry)	Data confidential at date of writing.
Coleraine-1	2000	Phillips	P&A (Oil show)	Data confidential at date of writing.
Kuda Tasi-1	2001	Woodside	**Oil Discovery**	Oil recovered on test from the Elang / Laminaria Fm.
Pandorina-1	2001	Woodside	P&A (Dry)	Data confidential at date of writing.

A dry hole analysis of wells drilled in the Northern Bonaparte Basin to December 2002 is shown in **Figure 8.5.**

Table 8.2 Hydrocarbon shows, Northern Bonaparte Basin.

Exploration Well	**Show Type**	**Depth (mRT)**	**Formation**	**Show Description**
Basilisk-1A	Oil	2860-2880	Plover	Fluorescence in cuttings and core. Residual oil column inferred.
Bogong-1	Oil	3532.5-3596	Elang/Laminaria	63.5 metre residual oil column inferred from logs.
Buang-1	Oil		Elang/Laminaria	45 metre palaeo oil column inferred from GOI studies.
Capung-1A	Oil & Gas		Elang/Laminaria	10 metre palaeo oil column and 80 metre palaeo gas column inferred from GOI studies.
Coleraine-1	Oil	Data confidential at date of writing		
Fannie Bay-1	Oil	Data confidential at date of writing.		
Lameroo-1	Oil	Data confidential at date of writing.		
Layang-1	Oil	3204-3232	Elang/Laminaria	Fluorescence in cuttings and core indicates a residual oil column.

Mandar-1	Oil	2938-3125	Plover	187 metre residual oil column identified on wireline logs.
Minotaur-1	Oil	3317-3365	Plover	Residual oil column identified on wireline logs.
Mistral-1	Gas	~3088	Plover	Gas accumulation inferred from wireline logs at top of Plover Fm (10.4 metres net pay; 50% Sw).
Naga-1	Oil	3002-3033	Plover	Fluorescence in cuttings and swc's.
Sandang-1	Oil	2905-2915	Jamieson	Fluorescence in cuttings.
Squilla-1	Oil	3348-3384	Plover (?)	Fluorescence in cuttings, core and swc's. Possible residual oil column.
Wallaroo-1	Oil	2968-2999	Plover	Good oil shows (residual oil) in core cut at top of Plover Fm.

8.6 Petroleum Potential

The discovery of several commercial petroleum accumulations on the Sahul Platform (**Bayu-Undan**, **Greater Sunrise**, **Laminaria / Corallina**, **Elang / Kakatua / Kakatua North**, **Buffalo**) has verified the presence of an active petroleum system in the area. Construction of the Bayu-Undan gas pipeline (to Darwin) and the possible future development of the Greater Sunrise gas-condensate discovery may provide further impetus for exploration and development both on the Sahul Platform and in the Petrel Sub-basin to the southeast.

8.6.1 Reservoirs

The Plover and Elang / Laminaria Formations are the primary exploration objectives on the Sahul Platform. These units are widely distributed, show little variation and are dominated by fluvial to open marine sandstones. They are absent over the Londonderry High, but are present in wells on the southwestern flank of the Sahul Syncline and thin to the north towards the Kelp High. They may either be absent or very thin in the central areas of the Sahul Platform.

The porosity within the Elang and Plover Formations is fair to good (5% - 20%). Calcraft, (1997) has shown that on the southern Sahul Platform, reservoir porosities of over 15% are maintained to depths of around 3,300 metres, but are severely degraded below 3,400 metres. (Gas bearing sands intersected at **Fohn-1** below 3,400 metres rarely attain porosities above 10%; reservoir porosity within the Elang / Laminaria Formation intersected by Minotaur-1 is around 10-15% between 3,300 and 3,400 metres).

Gorter and Kirk, (1995) report porosities of between 17% and 20% in Elang Formation equivalent sands in **Flamingo-1** at depths of around 3,400 metres. In addition, Plover Formation reservoirs have retained porosities in excess of 25% on the Kelp High at depths of between 2,000 and 3,000 metres (**Kelp Deep-1**). Labutis et al., (1998) has attributed this variation in porosity with depth to differences in depositional environments.

Occlusion of primary porosity within the Elang / Laminaria and Plover Formations is thought to be due to development of interstitial clays in marine sandstone reservoirs and silica overgrowths in both marine and non-marine sands. Labutis et al., (1998) consider that high heat flows may have also contributed to porosity degradation and cites data from the **Elang-1** well, where logging tools failed due to high temperatures.

Over most of the Sahul Platform, the Triassic to Early Jurassic section is considered too deeply buried to constitute a valid exploration target. Although this succession is within drillable depths on the Kelp High, the Triassic section intersected by Kelp-1 (and in wells drilled on the Londonderry High) comprised a low net to gross section of shales and sandstones with minor carbonates.

Although gas flowed on test from the Permian, Hyland Bay Formation at Kelp Deep-1, at date of writing no information is available on the reservoir properties of the Hyland Bay Formation at this location.

8.6.2 Source

Source rock intervals have been identified within the Elang / Laminaria Formation, Plover Formation, Frigate Shale and Flamingo Group (Preston and Edwards, 2000). The thickest succession of Late Jurassic to Early Cretaceous source rocks is found in the adjacent Malita Graben and Sahul Syncline. (**Figure 8.2).**

To date, most exploration wells have either been drilled on highs adjacent to or on the flanks of these source kitchens, where source rock quality is poor to fair (**Figure 8.1**). No wells have been drilled in the kitchen areas, but maturation modelling indicates these units are probably mature for gas generation in the Malita Graben and Sahul Syncline.

It is likely, however, that local source pods on the northern flank of the Malita Graben are oil-mature and could provide an oil charge for traps that lie within migration shadows, shielded from the main gas charge from the deeper portions of the Malita Graben. There may also be some potential for oil charge from the Sikitan Syncline to the southwest. At Troubadour-1, the Plover, Elang / Laminaria Formations and the Flamingo Group are at optimum thermal maturity for oil generation, whilst the Permian Hyland Bay Formation is gas mature.

Isotopic and biomarker analysis of condensates recovered from the Greater Sunrise field suggest these accumulations represent a separate hydrocarbon family to other oils and condensates recovered from the Bonaparte Basin. A definitive condensate-source correlation has yet to be established for the Greater Sunrise field (Edwards et al., 2000).

A condensed Oxfordian section is present over most of the Sahul Platform and comprises nearshore sediments with poor source potential. In the Sahul Syncline, however, Oxfordian shales (underlying the Kimmeridgian marl) are expected to be thick and organic rich. Gorter and Kirk, (1995) indicate that TOC values in the Oxfordian shales in wells on the flank of the Sahul Syncline reach 1.5% to 2%.

Shales within the Darwin Formation and Flamingo Group are potential source rocks, although TOC values are generally less than 2% in these units.

Tithonian to Aptian sediments in wells on the southern Sahul Platform currently lie within the oil window at depths of around 3,600 metres.

8.6.3 Seals

Late Jurassic and Cretaceous sediments overlying the Bajocian to Callovian reservoir section usually constitute excellent sealing facies on the Sahul Platform.

Competent claystone seals are also found both above and below the Bathurst Island Radiolarite. These sealing facies thicken towards the Sahul Syncline and Malita Graben but thin northwards towards the Kelp High.

8.6.4 Traps

To date, most wells drilled on the Sahul Platform have targeted Plover and Elang / Laminaria Formation sandstones within east-northeast trending horst blocks. Although several of these wells have discovered commercial petroleum accumulations, fault trap integrity is perceived as one of the key risks on the Sahul Platform - a number of wells have intersected palaeo-hydrocarbon columns (**Table 8.1**).

Young et al., (1995) suggest that the risk relating to fault seal integrity could be minimised on a prospect basis by a detailed analysis of growth history, fault geometry and fault seal. A recent study in the Timor Sea (Mildren et al., 1994) suggests that fault trap orientation may also be an important consideration in seal prediction. Fault seal integrity, hydrocarbon charge history and the implications for trap integrity on the North West Shelf have also been the subject of recent research by Otto et al., (2001) and Brincat et al., (2001).

It is possible that Early Cretaceous sandstones may form stratigraphic traps in Late Jurassic, east-west oriented troughs on the Sahul Platform. Some petroleum potential may also be associated with Late Cretaceous and Cainozoic sands deposited in incised valleys, charged by hydrocarbons from deeper, breached accumulations.

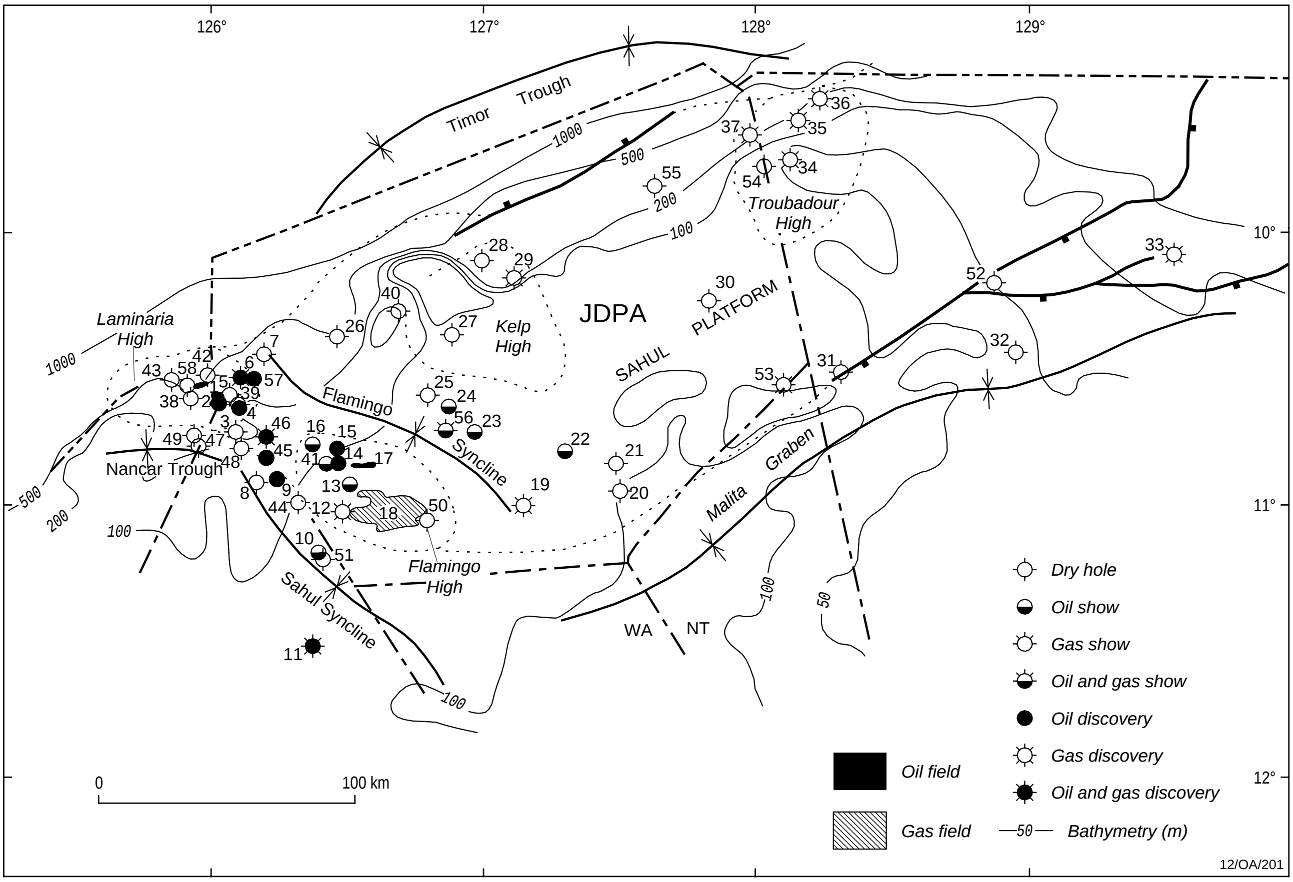

Figure 8.1 Sahul Platform - tectonic elements, bathymetry and exploration wells.

Sahul Platform - map key to **Figure 8.1**

Well Name	Drilling Results	Key No.
Corallina	**Oil Discovery**	1
Laminaria	**Oil Discovery**	2
Bogong-1	P&A Dry	3
Buffalo	**Oil Discovery**	4
Buang-1	P&A Dry	5
Jahal-1	**Oil & Gas Discovery**	6
Barnacle-1	P&A Dry	7
Cleia-1	P&A Dry	8
Buller-1	**Oil Discovery**	9
Iris-1	Oil Show	10
Rambler-1	**Oil & Gas Discovery**	11
Flamingo-1	**Gas Discovery**	12
Sandang-1	Oil Show	13
Kakatua	**Oil Discovery**	14
Kakatua North	**Oil Discovery**	15
Squilla-1	Oil Show	16
Elang	**Oil Discovery**	17
Bayu-Undan	**Gas Discovery**	18
Fohn-1	**Gas Discovery**	19
Narbarlek-1	P&A Dry	20
Wallaroo-1	P&A Dry	21
Basilisk-1A	Oil Show	22
Minotaur-1	Oil Show	23
Naga-1	Oil Show	24
Mandar-1	P&A Dry	25
Thornton-1	P&A Dry	26
Hydra-1	P&A Dry	27
Kelp-1	P&A Dry	28
Kelp Deep-1	**Gas Discovery**	29
Sikatan-1	P&A Dry	30
Shearwater-1	P&A Dry	31
Heron-1	P&A Dry	32
Evans Shoal-1	**Gas Discovery**	33
Troubadour-1	**Gas Discovery**	34
Sunrise-1	**Gas Discovery**	35
Loxton Shoals-1	**Gas Discovery**	36
Sunset-1	**Gas Discovery**	37
Alaria-1	P&A Dry	38
Capung-1A	P&A Dry	39
Conch-1	P&A Dry	40
Layang-1	Oil Show	41
Claudea-1	P&A Dry	42
Vidalia-1	P&A Dry	43
Wowo Wiwi-1	P&A Dry	44
Bluff-1	**Oil Discovery**	45
Krill-1	**Oil & Gas Discovery**	46
Lameroo-1	P&A Dry	47
Tanjil-1	Oil Show	48
Fannie Bay-1	P&A Dry	49
Mistral-1	P&A Dry	50
Heifer-1	P&A Dry	51
Wonorah-1	P&A Dry	52
Chuditch-1	**Gas Discovery**	53
Bard-1	P&A Dry	54
Jura-1	P&A Dry	55
Coleraine-1	Oil Shows	56
Kuda Tasi-1	**Oil Discovery**	57
Pandorina-1	P&A Dry	58

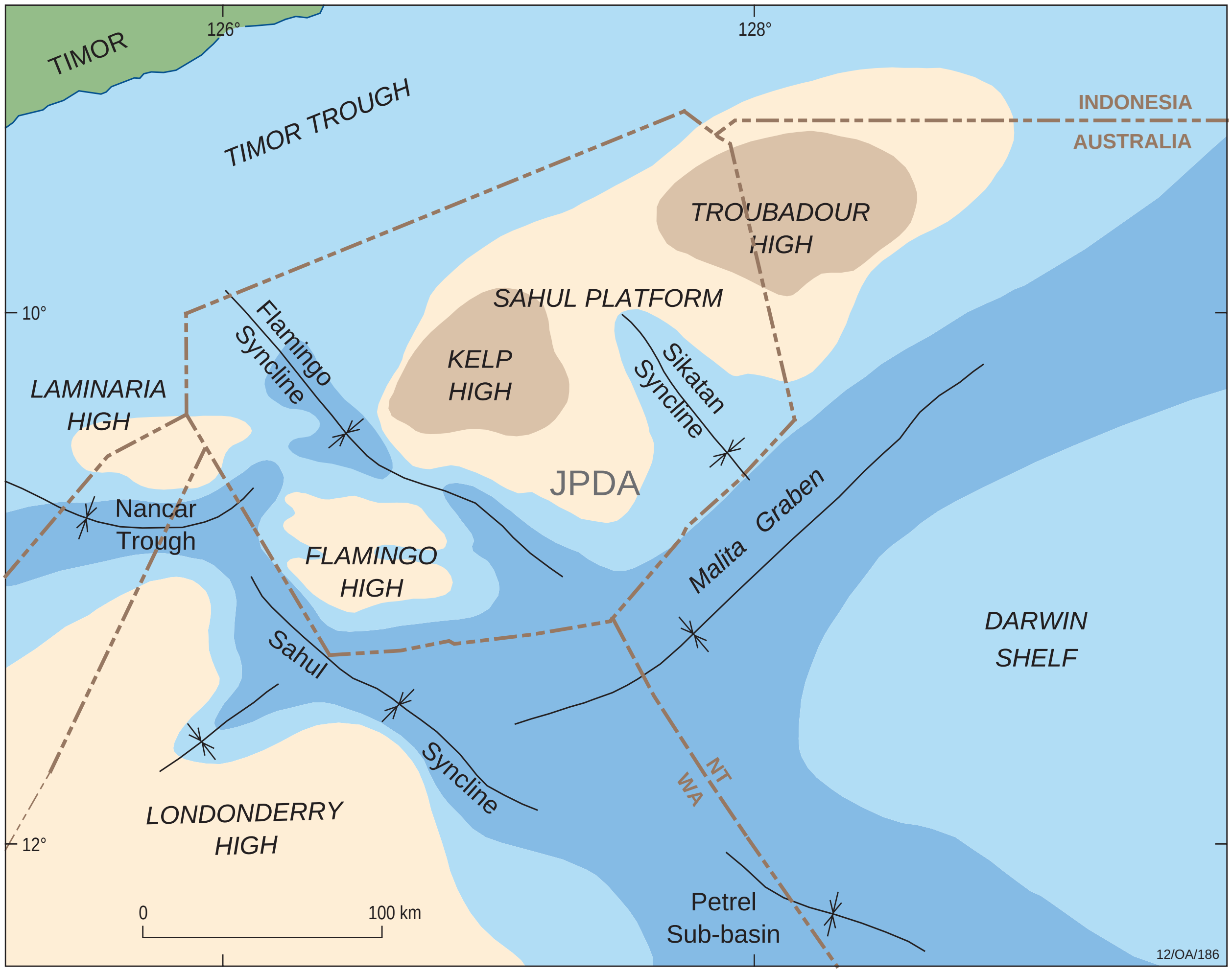

Figure 8.2 Structural elements, northern Bonaparte Basin (2002 Acreage Release CD- Rom).

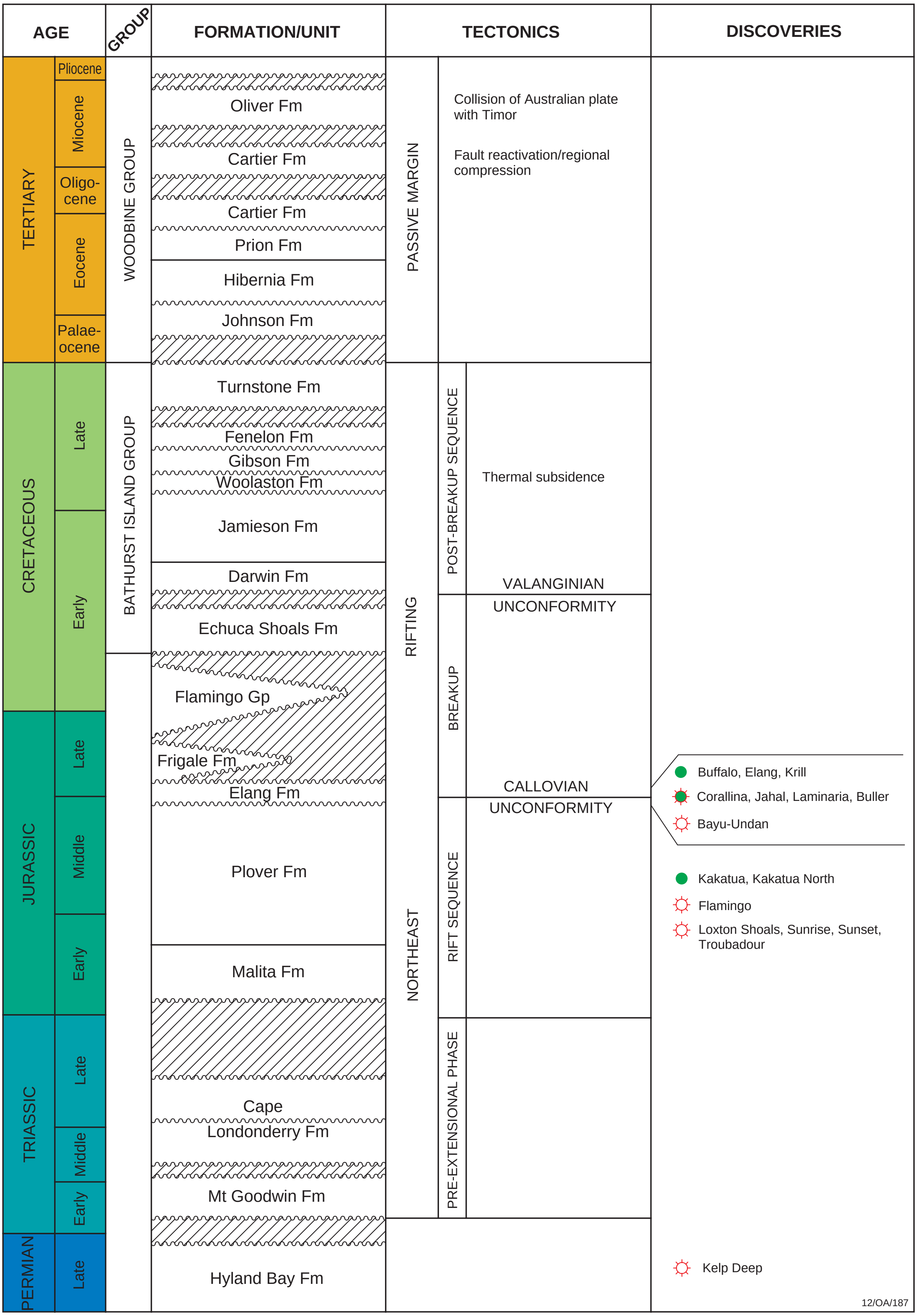

Figure 8.3 Sahul Platform - stratigraphy, tectonics and petroleum discoveries.

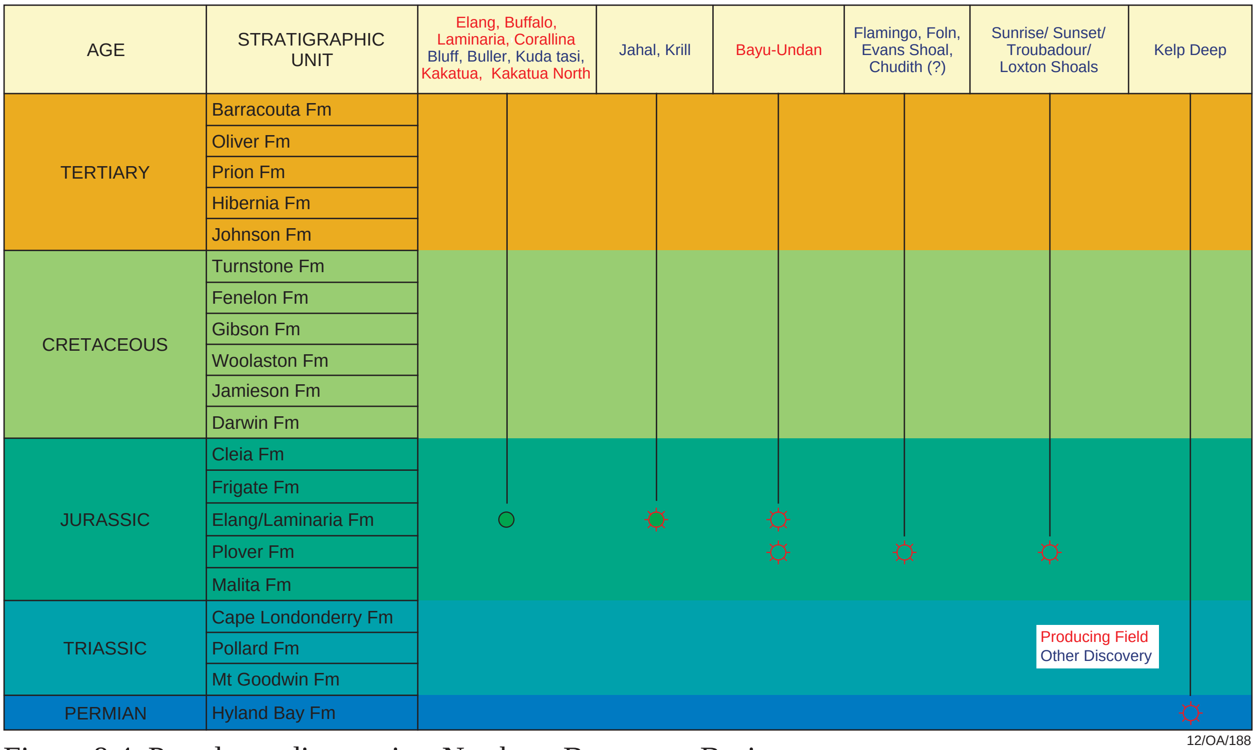

Figure 8.4 Petroleum discoveries, Northern Bonaparte Basin.

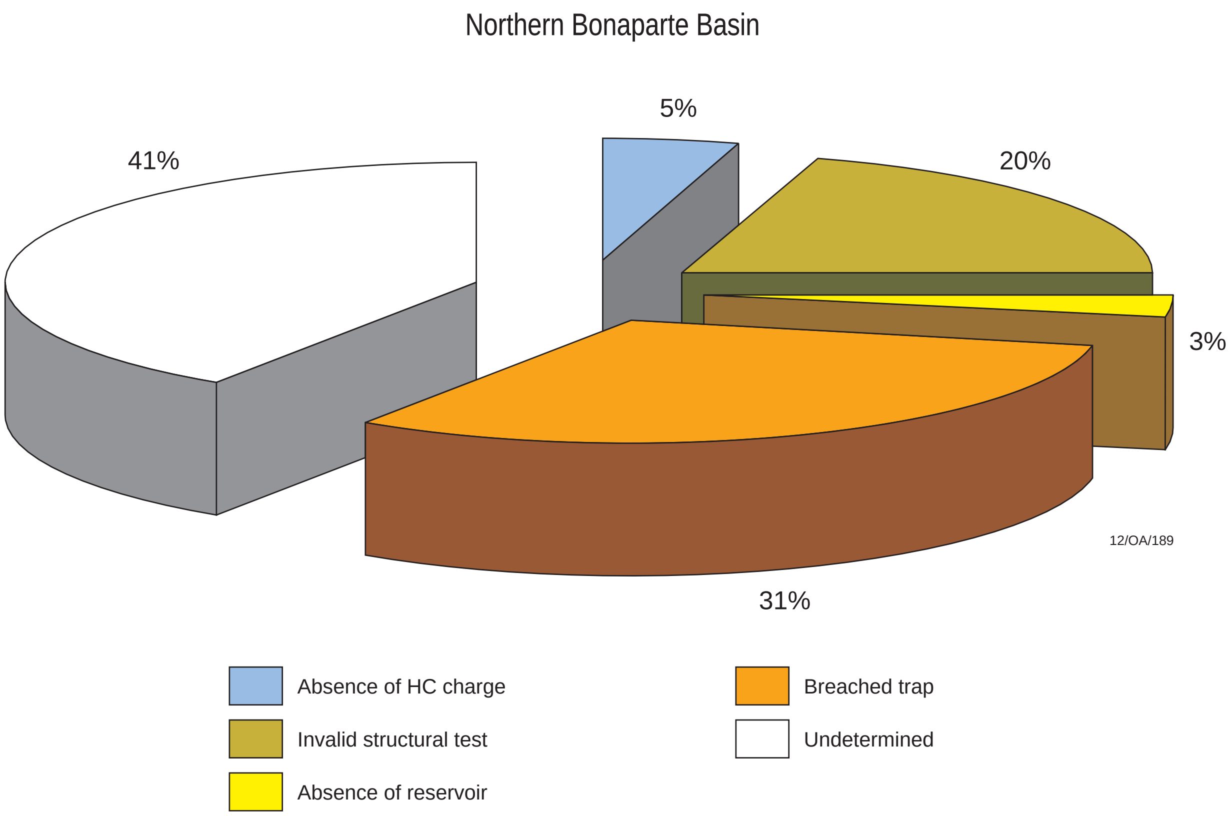

Figure 8.5 Dry hole analysis, Northern Bonaparte Basin.

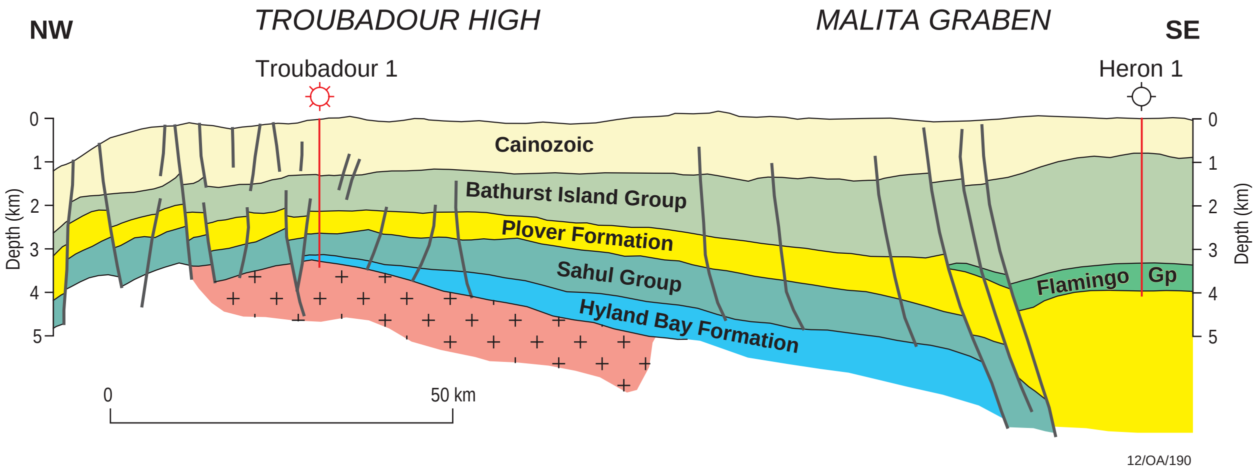

Figure 8.6 Cross-section, Troubadour 1 to Heron 1 (2002 Acreage Release CD-Rom).

9. MALITA GRABEN

9.1 Introduction

The Malita Graben is a Triassic depocentre, bordered by the Sahul Platform to the northwest and the Darwin Shelf to the southeast. The graben is bounded by large displacement, east-northeast trending faults (**Figure 9.1**). An exploration well has not been drilled in the central graben but Mory, (1988) suggests a Mesozoic and Cainozoic sediment pile exceeding 10 kilometres in thickness, underlain by Precambrian basement, may be present.

Of the 8 exploration wells drilled either in or on the flanks of the Malita Graben to date, only one (Evans Shoal-1) has recovered gas on test **(Plate 1, Figure 8.4)**

9.2 Structural Evolution and Stratigraphy

The structural evolution and stratigraphy of the Malita Graben is referred to in other sections of this report (Sahul Platform and Petrel Sub-basin) and are shown in **Plate 2**. Key features of the stratigraphic succession deposited in the Malita Graben are:

- Plover Formation sediments are expected to thicken into the graben, and probably include good quality, Early Jurassic source rocks.
- Thick, organic-rich shales of the Flamingo Group provide additional source potential in the area.
- Tithonian turbidite sands (which were intersected in Heron-1) may provide valid exploration targets in the graben.
- The Cretaceous Bathurst Island Group exceeds a thickness of 2,000 metres in the Malita Graben.
- The Echuca Shoals Formation is also thought to be relatively thick and to provide additional source potential in the area.

9.3 Exploration Drilling and Hydrocarbon Occurrences

Table 9.1 Results of exploration drilling, Malita Graben.

Exploration Well	Year	Operator	Well Classification	Comments
Heron-1	1972	Arco	P&A (Dry)	Lack of reservoir development at primary objective level.
Lynedoch-1	1973	Shell	P&A (Gas show)	Lack of reservoir development at primary objective level.
Shearwater-1	1974	Arco	P&A (Dry)	Lack of reservoir development at primary objective level.
Jacaranda-1	1984	Tricentrol	P&A (Gas show)	Lack of reservoir development at primary objective level.
Darwinia-1A	1985	Tricentrol	P&A (Dry)	Lack of access to mature source rocks / trap breached by late faulting.
Evans Shoal-1	1988	BHP	**Gas Discovery**	Gas recovered on test from the Plover Fm.
Beluga-1	1991	BHP	P&A (Oil and gas shows)	Lack of reservoir development at primary objective level / incompetent

				seal.
Wonarah-1	1998	Shell	P&A (Dry)	Lack of reservoir development at primary objective level.

A dry hole analysis of wells drilled within the Malita Graben to December 2002 is shown in **Figure 9.4.**

Table 9.2 Hydrocarbon shows, Malita Graben.

Exploration Well	Show Type	Depth (mRT)	Formation	Show Description
Beluga-1	Oil & Gas	2571-2582 2774-2789 2933-2972	Flamingo Gp Flamingo Gp Flamingo Gp	Fluorescence in cuttings. Fluorescence in cuttings. Gas column inferred from wireline logs (Sw 70%).
Jacaranda-1	Gas	3525-3550	Flamingo Gp	Gas in tight reservoir inferred from wireline logs (Sw 60%)
Lynedoch-1	Gas	3674-3715	Bathurst Island Gp	Gas column in Early Cretaceous carbonates inferred from wireline logs (Sw 50% to 80%).

9.4 Petroleum Potential

Sediments in the Malita Graben have traditionally been regarded by explorers as gas-prone (tight gas in the Upper Vulcan Formation / Flamingo Group at Jacaranda-1; gas shows in the Flamingo Group at Heron-1; gas recovered on test from the Plover Formation at Evans Shoal-1).

Elsewhere in the Bonaparte Basin, however, the Echuca Shoals Formation contains good quality, oil-prone source rocks. It is possible that the equivalent unit in this area (Darwin Formation) has provided an oil charge for traps in the vicinity of the Malita Graben. Flushing of oil accumulations by late gas generation, however, is a potential exploration risk in this area.

9.4.1 Reservoirs

Several potential sandstone reservoirs have been identified either in or on the flanks of the Malita Graben. These include the Jurassic Plover Formation, the Laminaria / Elang Formation and sands within the Flamingo and Bathurst Island Groups (Wangarlu Formation) **(Figure 10.2, Plate 2).**

Due to increased diagenetic alteration of sandstone reservoirs with depth, over much of the Malita Graben, the Plover Formation may lie too deep to constitute a valid exploration target **-** in the axial parts of the Malita Graben, it is expected to be found at depths below 5,000 metres **(Figure 9.2)**. At these depths, it is a possible that fractures within the Plover Formation sandstones are the primary source of porosity. At some locations, however, the early emplacement of hydrocarbons into Plover Formation sands may have inhibited diagenesis and subsequent porosity occlusion.

Jurassic turbidite sandstones within the Flamingo Group (shed from the Sahul Platform in the north and the Darwin Shelf in the east) and Late Cretaceous, lowstand sands both within the Bathurst Island Group and in the overlying Palaeocene section may also provide valid exploration targets in the Malita Graben. (Where Late Cretaceous sands were intersected in the Darwinia-1/1A well, porosities ranged from 20% to 28% over a 150 metre interval).

9.4.2 Seals

A massive claystone and siltstone interval at the base of the Bathurst Island Group (referred to as the Darwin Formation in the Petrel Sub-basin or, elsewhere in the Bonaparte Basin, as the Echuca Shoals Formation) forms the regional seal in the area. Several petroleum accumulations identified in the Vulcan Sub-basin and on the flanks of the Londonderry High occur immediately below this regional seal.

Intra-formational shales and claystones are also form competent seals within the Flamingo Group, Plover and Wangarlu Formations.

Where present in the Malita Graben, Late Cretaceous and Eocene lowstand sands are probably sealed by Cainozoic carbonate sequences.

9.4.3 Source

Three potential oil prone source rock intervals exist within Malita Graben area.

In the vicinity of the Malita Graben, where the Flamingo Group has been intersected by wells, shales and siltstones exhibit good to excellent source potential. At Heron-1, an average TOC value of 2.5% was recorded within the Flamingo Group (78 samples). At Jacaranda-1, TOC values average around 0.7% over both the Flamingo Group and Laminaria / Elang Formation. At Curlew-1, average TOC values within the Flamingo Group exceed 1%.

The Mid to Late Cretaceous Bathurst Island Group (Wangarlu Formation) also exhibits moderately good source potential, with TOC values as high as 1.3% recorded in the Flamingo-1 well, 3.4% in the Lynedoch-1 well and 1.8% in the Heron-1 well.

Poor well control in the vicinity of the Malita Graben makes thermal maturation trends difficult to establish. However, it is expected that most potential Late Jurassic / Cretaceous source rocks in the area have attained at least marginal maturity for oil generation. A possible exception is the Plover Formation, which may currently be over-mature **(Figure 9.3).**

Maturation modelling indicates that oil explusion from the Darwin Formation probably occurred in the Late Cretaceous, with late gas generation commencing in the Early Cainozoic. Source intervals within the Laminaria / Elang and Plover Formations probably expelled oil in the Middle Cretaceous, with the onset of late gas generation from these units occurring in the Early Cainozoic **(Figure 9.3)**.

9.4.4 Traps

The predominant trap style identified to date in the Malita Graben is the Jurassic/Triassic tilted fault block, sealed either by intra-formational claystones, or by claystones or shales of the overlying Flamingo or basal Bathurst Island Group. Hanging wall, fault dependent closures on the downthrown, faulted margins of the Malita Graben are also considered to be valid exploration objectives.

Late Cretaceous (Puffin Formation equivalents) and Eocene drape closures, are secondary exploration targets in the area. These features are likely to comprise subtle, four-way dip closures with a significant stratigraphic component. Turbidite sands within the Flamingo Group may also form stratigraphic traps on the margins of the Malita Graben.

On the southern flank of the Malita Graben, where the northwest trending Petrel Sub-basin intersects the northeast trending Malita Graben **(Figure 10.1),** structuring related to salt diapirism (Gull and Curlew diapirs) may have resulted in the formation of a number of structural and stratigraphic traps.

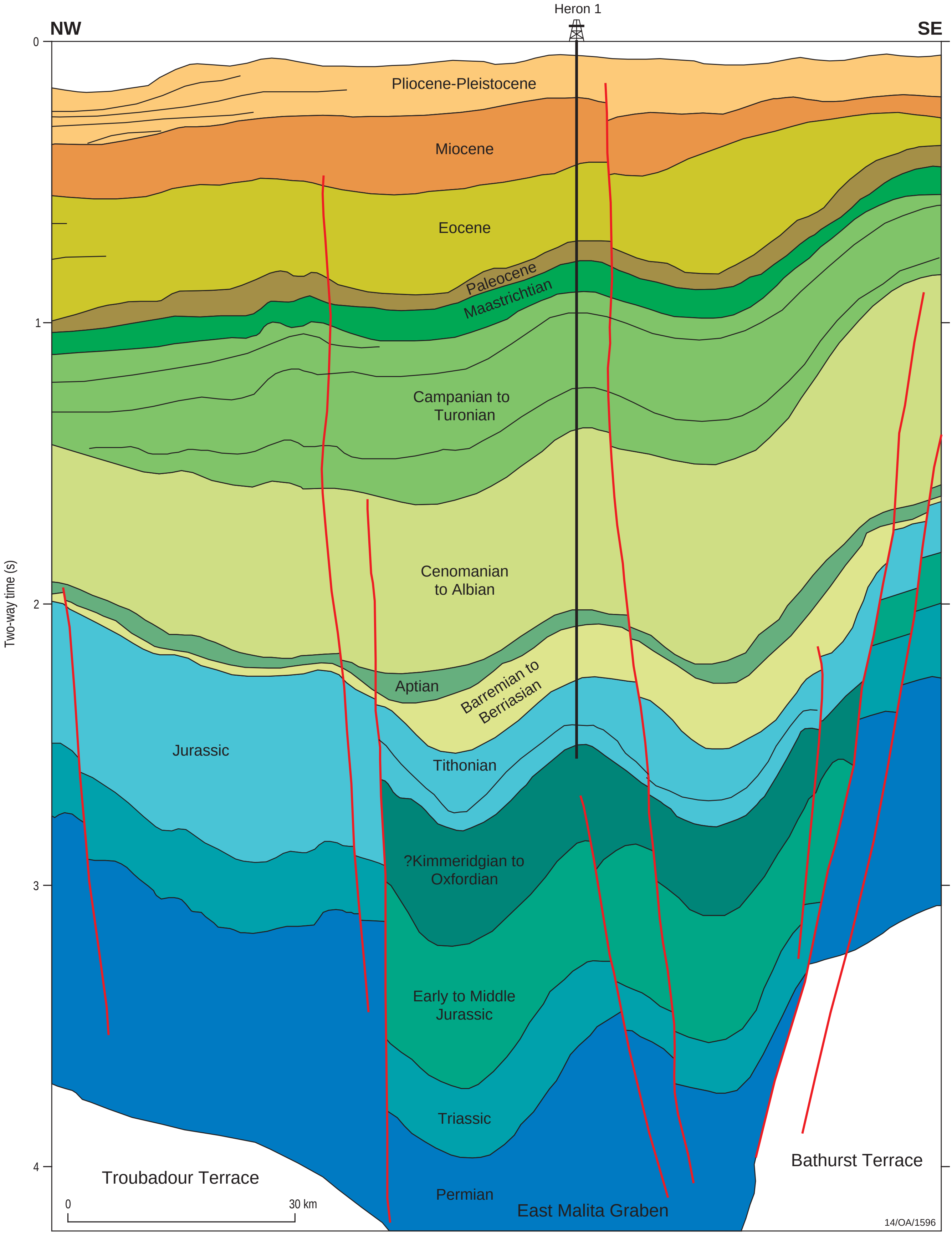

Figure 9.1 Structure and stratigraphy of the Malita Graben and adjacent terraces (2003 Acreage Release CD-Rom).

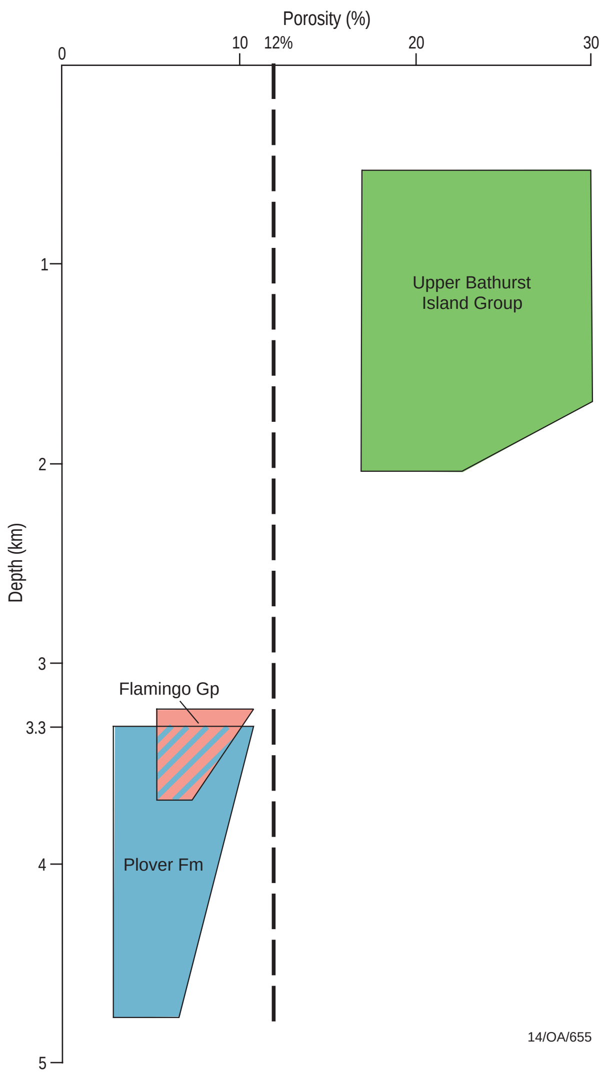

Figure 9.2 Porosity plot for wells in the Malita Graben (1999 Acreage Release CD-Rom).

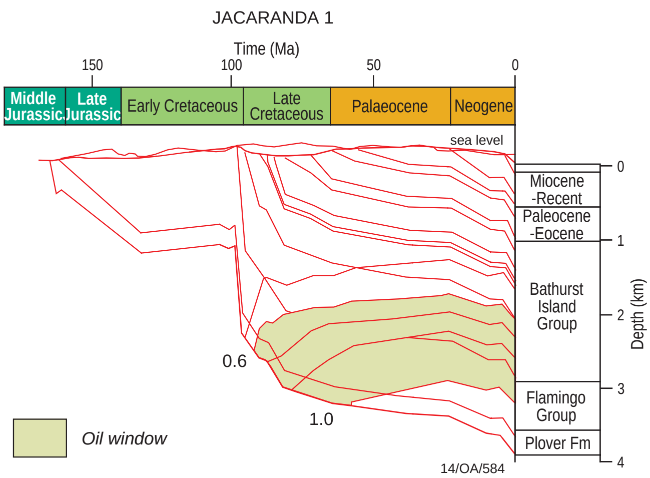

Figure 9.3 Jacaranda 1 geohistory (1999 Acreage Release CD-Rom).

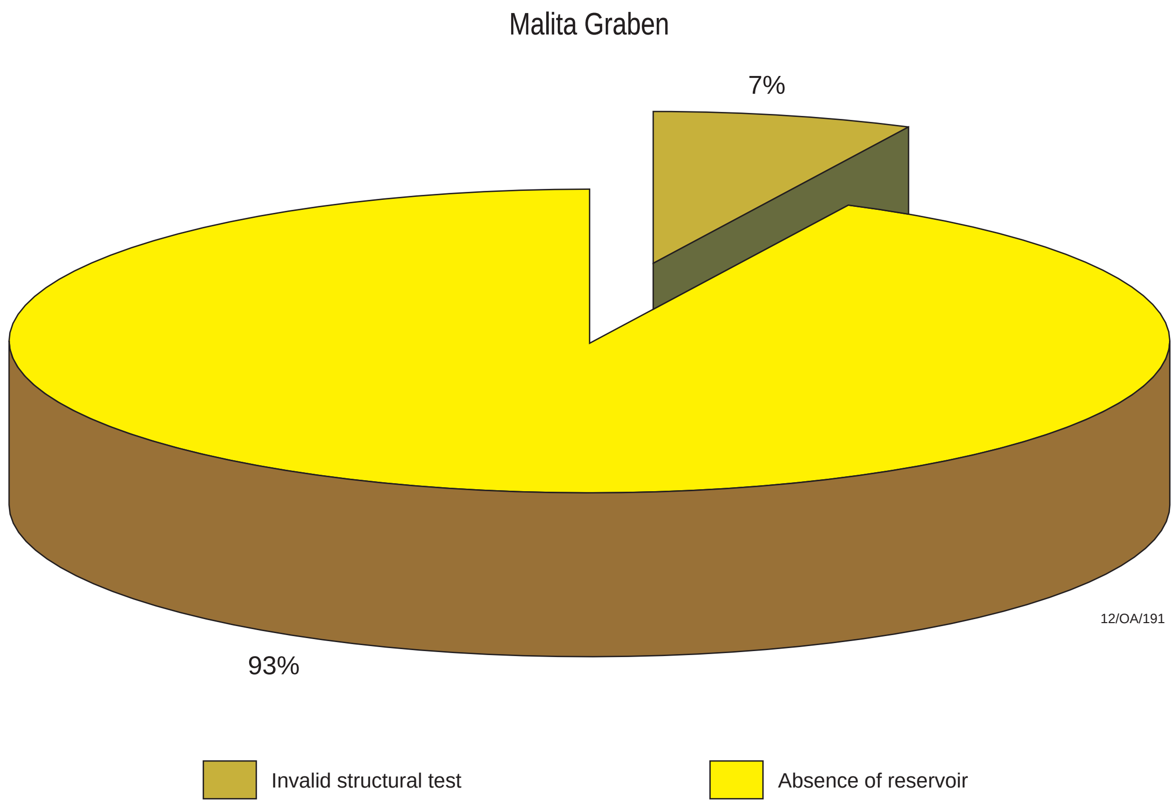

Figure 9.4 Dry hole analysis, Malita Graben.

10. PETREL SUB-BASIN

10.1 Introduction

The Petrel Sub-basin is an asymmetric, northwest–southeast trending Palaeozoic rift located in the southeast portion of the Bonaparte Basin. The sub-basin underlies the Bonaparte Gulf, extends onshore to the south and contains a succession of Palaeozoic and Mesozoic sediments **(Figures 10.1 and 10.2, Plates 1 and 2).**

The eastern and western faulted margins of the sub-basin converge onshore to form the southern boundary of the sub-basin. To the south and east of the Petrel Sub-basin, extensions of the Halls Creek-Fitzmaurice Mobile Zone separate the sub-basin from the Precambrian Victoria Basin and Pine Creek Geosyncline.

Extensive basement shelves overlain by a thin cover of Phanerozoic sediments lie on the eastern, western and southern margins of the Petrel Sub-basin. To the east, the Darwin Shelf extends to the south-southwest into the Moyle Platform and Kulshill Terrace. In the south, the Berkley Platform has been sub-divided into several, smaller southeast-trending horst (Lacrosse Terrace and Turtle-Barnett High) and graben (Cambridge Trough) structures.

Since petroleum exploration began in the onshore part of the sub-basin the late 1950's, a total of 19 accumulations have been discovered. **(Plate 1, Figure 10.3)**. While none of these are commercial at date of writing, several are held under Retention Lease. At time of writing, the development of a recent gas discovery made on the southern margin of the Petrel Sub-basin (**Blacktip-1**) is under consideration.

10.2 Structural Evolution and Stratigraphy

The generalised stratigraphy of the Petrel Sub-basin is shown in **Figures 10.2 and 10.5** and **Plate 2.**

The structural and stratigraphic setting of the Petrel Sub-basin are most recently summarised in Kennard et al., (2002). The regional geology of the sub-basin is discussed in detail by Mory, (1988 & 1991); Lee & Gunn, (1988); Gunn & Ly, (1989); McConachie et al., (1996); and Colwell & Kennard, (1996). The following description draws on the work of these authors.

The Petrel Sub-basin is underlain by Proterozoic crystalline basement and sediments of the Proterozoic Kimberley Basin. The sub-basin contains a rift-dominated succession of Palaeozoic and Mesozoic sediments which dip regionally to the northwest about a northwest-plunging synclinal axis (Colwell & Kennard, 1996). Sediment thickness within the Petrel Sub-basin is estimated to be greater than 15 kilometres.

The Palaeozoic succession is known from outcrop and well intersections onshore and in the inboard portion of the Petrel Sub-basin (Laws & Kraus, 1974; Laws & Brown, 1976). Here, Cambrian sediments unconformably overly Precambrian basement which comprises a sub-aerial, volcanic sequence (Antrim Plateau Volcanics) (Veevers and Roberts, 1968). A shallow marine, clastic and carbonate succession of Cambrian to Early Ordovician age (Tarrara Formation and Carlton Group) was then deposited over the Cambrian unconformity surface.

Seismic data and exploration drilling indicate that an evaporitic sequence was deposited in the Bonaparte Basin during Late Silurian and Early Devonian times, and that subsequent salt movement has formed a number of salt-induced features (Edgerley and Crist, 1974). Several wells drilled within the Petrel Sub-basin have encountered salt and in the Vulcan Sub-basin to the southwest, two salt diapers (Swan and Paqualin) have been identified.

In the Petrel Sub-basin, Middle Devonian to Early Carboniferous sediments comprise:

- a basinal marine sequence of shale and siltstone (Bonaparte Beds);
- a clastic sequence developed on the eastern margin of the Petrel Sub-basin (Cockatoo Formation) and;
- a shelfal carbonate sequence comprising a massive algal reef with horizontally-bedded back reef deposits (Ningbing Limestone or reef complex).

Gas has been recovered on test from all three of these units in wells drilled in the onshore portion of the Petrel Sub-basin (**Figure 10.3**, **Plate 2**).

During the Tournasian, a carbonate / siltstone / shale sequence (Langfield Group) was deposited along the southwestern margin of the Petrel Sub-basin. The Langfield Group conformably overlies the Ningbing reef complex and passes offshore into clastic sediments of the Bonaparte Formation.

Onshore, the Early Carboniferous, Milligans Formation (a sequence of marine shales, siltstones and sandstones of Visean age), unconformably overlies the Langfield Group. Offshore, the unit rests unconformably on the Bonaparte Formation. Offshore, oil has been recovered from the Milligans Formation at **Turtle** and **Barnett**, while onshore, gas has flowed on test from this unit at **Waggon Creek** and **Weaber**.

The Tanmurra Formation is a transgressive unit comprising near-shore sandstones and carbonates. The unit disconformably overlies the Milligans Formation. The top of the Tanmurra Formation is a prominent seismic reflector in the southern part of the Petrel Sub-basin and is Late Visean to Late Carboniferous in age (Veevers and Roberts, 1968).

After deposition of the Tanmurra Formation, uplift and erosion on the flanks of the Petrel Sub-basin provided the sediment supply for a deltaic sequence deposited in the Late Carboniferous within the southern Petrel Sub-basin (Point Spring Sandstone and Kuriyippi Formation). These units form part of an overall regressive sequence. The regression reached a maximum in the Late Carboniferous to Early Permian when the Treachery Shale was deposited over large areas of the Petrel Sub-basin.

The Treachery Shale is a lacustrine unit, has good source potential and forms a competent top seal for the underlying Kuriyippi Formation reservoirs. In the offshore Petrel Sub-basin, oil has been recovered from the Kuriyippi Formation at Turtle and Barnett.

A marine transgression in the Early Permian led to the deposition of an interbedded sandstone / shale sequence (Keyling Formation) over the Treachery Shale. The Keyling Formation is considered a fair to moderately good quality petroleum reservoir. Oil has been recovered on test from the Keyling Formation at **Turtle**. More recently, on the southern margin of the Petrel Sub-basin, gas flowed on test from this unit at **Blacktip-1**.

The Fossil Head Formation is a transgressive sequence of marine siltstone and shale and conformably overlies the Keyling Formation (Laws and Brown, 1976). The unit is Early to Late Permian in age (Sakmarian to Kungurian), comprises estuarine to tidal shelf sediments and forms a competent top seal for underlying Keyling Formation reservoirs.

In the Late Permian (Kazanian to Tartarian), a sandstones, shale, and carbonate sequence (Hyland Bay Formation) was conformably deposited over the Fossil Head Formation**.** The formation has been subdivided into three main lithological elements:

- a basal sequence of limestone and shales;
- a middle, tidal clastic sequence and;
- an upper sequence of mudstones and sandstones, deposited as a coarsening-upwards deltaic sequence.

The Hyland Bay Formation is a primary exploration target in the Petrel Sub-basin and hosts the gas accumulations identified at **Petrel** and **Tern**.

In the Early Triassic, a sequence of marine shales and siltstones (Mount Goodwin Formation) transgressed across the Bonaparte Basin. The Mount Goodwin Formation thickens towards the centre of the Petrel Sub-basin and forms a regional seal for the underlying Hyland Bay Formation. A regressive sequence of fluvial sandstones of Middle Triassic age was then deposited.

Late Triassic compressional inversion related to the Fitzroy Movement produced extensive uplift and erosion along the southern margin of the Petrel Sub-basin, together with numerous fault-related inversion structures and anticlines (O'Brien et al., 1996). Erosion and collapse of these uplifted areas led to the widespread deposition of Lower to Middle Jurassic fluvio-deltaic clastics and 'redbeds' (Malita Formation).

Crustal extension in the Late Jurassic resulted in a series of linked, northeast and southeast-trending intercontinental grabens northwest of the Petrel Sub-basin (Malita Graben, Sahul Syncline and Vulcan Sub-basin) (Patillo & Nicholls, 1990; Woods, 1992). Thick, organic-rich marine sediments accumulated within restricted marine environments in these Late Jurassic grabens. Although these facies extend into the Petrel Sub-basin, they lack sufficient thermal maturation to have sourced significant quantities of petroleum (Messent et al., 1994).

Post-rift regional thermal subsidence of the northwest Australian margin commenced in the Valanginian (Baxter, 1996; Baxter et al., 1997). This resulted in the deposition of a thick Cretaceous-Cainozoic passive margin wedge, deposited in a northwest-plunging syncline across the Petrel Sub-basin. These units are absent in the southern part of the sub-basin but thicken to the northwest toward the Malita Graben. The Cretaceous succession is dominated by fine-grained clastic facies, while the Cainozoic succession comprises shallow marine sands that grade offshore to a subtropical to tropical carbonate platform sequence.

Apart from minor downwarp in the outboard and central portions of the sub-basin, the convergence of the Australian continental plate with the South East Asian microplates in the Neogene had little effect on the Petrel Sub-basin.

Salt diapirism has been an important control on the occurrence of petroleum in the Petrel Sub-basin. Sourced from pre-Devonian evaporitic sediments, salt movement occurred as early as the Carboniferous and, in most instances (including the Petrel and Tern structures), was continuous until the Late Cretaceous (Lemon & Barnes, 1997). Many petroleum plays associated with salt diapirism remain untested in the Petrel Sub-basin.

The Mesozoic stratigraphy of the Bonaparte Basin is further described in **Section 5, Vulcan Sub-basin** and **Section 8, Sahul Platform**.

10.3 Exploration Drilling and Hydrocarbon Occurrences

In 1839, the crew of HMS *Beagle* found bitumen in water wells sunk on banks of the Victoria River in the southern Petrel Sub-basin. This is one of the earliest oil shows documented in Australia. Initial offshore exploration in the Petrel Sub-basin commenced in the early 1960s with extensive aeromagnetic and gravity surveys. During this period, the Bureau of Mineral Resources (BMR) conducted regional 'sparker' surveys in the Bonaparte Gulf. Industry commenced conventional regional marine seismic surveys in the 1960s.

Since the late 1950's when petroleum exploration began in the onshore part of the sub-basin, a total of 19 oil or gas accumulations have been discovered **(Figure 10.3)**.

Table 10.1 Results of exploration drilling, Petrel Sub-basin.

Exploration Well	Year	Operator	Well Classification	Comments
Spirit Hill-1	1960	Oil Dev. Co.	P&A (Dry)	Drilled outside structural closure.
Bonaparte-1	1964	Alliance Oil	**Gas Discovery**	Gas recovered on test from the Milligans Fm.
Kulshill-1	1966	Australian Aquitaine	P&A (Oil and gas shows)	Breached trap (?)
Moyle-1	1966	Australian Aquitaine	P&A (Dry)	Invalid structural test.
Keep River-1	1969	Australian Aquitaine	**Gas Discovery**	Gas recovered on test from the Milligans Fm.
Lacrosse-1	1969	Arco	P&A (Oil show)	Poor reservoir development at primary objective, or breached trap, or invalid structural closure.
Newby-1	1969	Australian Aquitaine	P&A (Dry)	Invalid structural test.
Petrel-1A	1969	Arco	**Gas Discovery**	Gas blowout to surface from the Hyland Bay Fm.
Flat Top-1	1970	Australian	**Gas Discovery**	Gas recovered on test from the Hyland

		Aquitaine		Bay Fm (possibly solution gas).
Gull-1	1971	Arco	P&A (Dry)	Lack of reservoir development at primary objective level.
Sandpiper-1	1971	Arco	P&A (Dry)	Lack of reservoir at primary objective level (intersected a salt diaper).
Tern-1	1971	Arco	**Gas Discovery**	Gas recovered on test from the Hyland Bay Fm.
Bougainville-1	1972	Australian Aquitaine	P&A (Dry)	Lack of access to mature source rocks and poor reservoir development at primary objective level.
Pelican Island-1	1972	Arco	P&A (Oil show)	Lack of reservoir development at primary objective and possible breached trap due to late faulting.
Penguin-1	1972	Arco	**Gas Discovery**	Gas recovered on test from the Hyland Bay Fm.
Kinmore-1	1974	Australian Aquitaine	P&A (Dry)	Lack of access to mature source rocks.
Curlew-1	1975	Arco	**Gas Discovery**	Gas recovered on test from the Bathurst Island and Flamingo Gps (possibly solution gas).
Frigate-1	1978	Arco	P&A (Dry)	Lack of access to mature source rocks.
Lesueur-1	1980	Australian Aquitaine	**Gas Discovery**	Gas recovered on test from the Tanmurra and Milligans Fms.
Berkley-1	1982	Magnet Minerals	P&A (Dry)	Lack of access to mature source rocks.
Ningbing-1	1982	Australian Aquitaine	P&A (Oil and gas shows)	Poor reservoir development at primary objective (fracture porosity within algal mound).
Cambridge-1	1984	WMC	P&A (Oil shows)	Breached trap. Lack of competent seal on bounding fault.
Skull-1	1984	Australian Aquitaine	P&A (Dry)	Lack of reservoir development at primary objective level.
Turtle-1	1984	WMC	**Oil Discovery**	Oil recovered on test from the Keyling, Kuriyippi, Tanmurra and Milligans Fms.
Barnett-1	1985	Elf Aquitaine	P&A (Oil shows)	Lack of reservoir development in Tanmurra and Milligans Fms.
Matilda-1	1985	WMC	P&A (Dry)	Lack of competent seal on bounding fault.
Garimala-1	1988	Santos	**Gas Discovery**	Gas recovered on test from the Bonaparte Fm.
Barnett-2	1989	Elf Aquitaine	**Oil and Gas Discovery**	Oil recovered on test from the Kuriyppi Fm. Oil and gas recovered on test from the U. Milligans Fm.
Kite-1	1990	WMC	P&A (Dry)	Lack of access to mature source rocks.
Harbinger-1	1991	Kufpec	P&A (Dry)	Lack of access to mature source rocks.
Billabong-1	1992	BHP	P&A (Dry)	Lack of access to mature source rocks.
Billawock-1	1992	BHP	P&A (Dry)	Lack of access to mature source rocks.
Fishburn-1	1992	BHP	**Gas Discovery**	Gas recovered on test from the Hyland Bay Fm.
Oberon-1	1992	Kufpec	P&A (Dry)	Lack of access to mature source rocks.
Shalimar-1	1992	Kufpec	P&A (Dry)	Lack of access to mature source rocks and/or trap leakage on bounding fault.
Helvetius-1	1994	MIM	P&A (Dry)	Lack of access to mature source rocks.
Kingfisher-1	1994	Teikoku	P&A (Dry)	Lack of access to mature source rocks (?)
Sunbird-1	1994	Teikoku	P&A (Dry)	Lack of access to mature source rocks (?)
Ascalon-1A	1995		**Gas Discovery**	Gas recovered on test from the Hyland

				Bay Fm.
Waggon Creek-1	1995	Amity Oil	**Gas Discovery**	Gas recovered on test from the Milligans Fm.
Marsi-1	1996	MIM	P&A (Dry)	
Ningbing-2	1996	Amity Oil	P&A (Gas show)	Poor reservoir development at primary objective
Pincombe-1	1996	Amity Oil	P&A (Dry)	Poor reservoir development and reservoir flushed by meteoric waters.
Cape Ford-1	1997	Cultus	P&A (Oil show)	
Schilling-1	1997	Petroz	P&A (Dry)	
Vienta-1	1998	Amity Oil	**Gas Discovery**	Gas recovered on test from the Langfield Gp.
Blacktip-1	2001	Woodside	**Gas Discovery**	Gas recovered on test from the Keyling and Mt Goodwin Fms.
Sandbar-1	2001	Woodside	P&A (Dry)	Data confidential at date of writing.

A dry hole analysis of wells drilled in the Petrel Sub-basin to December 2002 is shown in **Figure 10.4**.

Table 10.2 Hydrocarbon shows, Petrel Sub-basin.

Exploration Well	Show Type	Depth (mRT)	Formation	Show Description
Barnett-1	Oil	834-852	Keyling	Oil staining in core.
		1550-1555	Kuriyippi	Oil staining in core.
		2028-2035	Tanmurra	Trace of residual oil recovered on RFT / DST.
Cambridge-1	Oil	568-650	Kulshill Gp	Trace of residual oil in swc's.
Cape Ford-1	Oil	2490-2603	Milligans	Fluorescence in cuttings and swc's.
		2768-2803	Milligans	Fluorescence in cuttings and swc's
Kulshill-1	Oil & Gas	1180-1455	Keyling	Oil staining and fluorescence in cuttings.
		1692-1710	Kuriyippi	Oil staining and fluorescence in cuttings.
		2109-2114	Milligans	Residual oil in core.
Lacrosse-1	Oil	1742-1759	Kulshill Gp	Residual oil in core.
Ningbing-1	Oil & Gas	~286	Bonaparte	Gas cut mud recovered on DST.
		1019-1034	Ningbing Lst	Residual oil in core.
Ningbing-2	Gas	410-412	Ningbing Lst	Gas to surface at a RTSTM on DST.
		535-598	Ningbing Lst	Gas to surface at a RTSTM on DST.
Pelican Island-1	Oil	162-390	Kuriyippi (?)	Residual oil in cuttings and swc's.

10.4 Petroleum potential

Unlike the North West Shelf, the petroleum prospectivity of the Petrel Sub-basin is largely restricted to the Palaeozoic succession - Mesozoic and Cainozoic sediments only constitute viable exploration targets in the north of the Petrel Sub-basin, on the flanks of the Malita Graben.

Several authors have discussed petroleum systems active in the Petrel Sub-basin. These include Colwell and Kennard, 1996; Edwards and Summons, 1996; McConachie et al., 1996; Edwards et al., 1997 & 2000; and Kennard et al., 1999, 2002 & 2003.

McConachie et al., (1996) described three petroleum systems operating in the Petrel Sub-basin:

- a Late Devonian gas and oil system (Late Devonian-Ningbing-Bonaparte Petroleum System)
- a Carboniferous sourced oil and gas system reservoired in Carboniferous and Permian rocks (Early Carboniferous-Milligans-Kuryippi/Milligans Petroleum System) **(Figure 2.1).**
- a Permian gas and condensate system (Permian-Hyland Bay /Keyling Petroleum System) **(Figure 2.2)**.

They also speculated on the existence of petroleum systems of Cambro-Ordovician and Mesozoic age.

For a more detailed discussion on petroleum systems active in the Bonaparte Basin refer to Kennard et al., (2002).

10.4.1 Reservoirs

The Carboniferous Weaber Group exhibits good reservoir properties towards the basin margin (around 25% porosity and 500 md permeability). Onshore, turbidite sands within the Milligans Formation host an oil and gas accumulation at **Waggon Creek-1**, but the correlative shallow marine sandstones in the offshore (around the Turtle and Barnett oil accumulations) appear to have more limited reservoir potential. The overlying Tanmurra Formation and Point Spring Sandstone also have reservoir potential, but these units may only be at drillable depths in the extreme southern part of the offshore Petrel Sub-basin.

In the overlying Late Carboniferous/Early Permian Kulshill Group, fluvio-glacial sands of the Kuriyippi Formation exhibit excellent reservoir potential - the first recorded recovery of oil in the Petrel Sub-basin was from Kuriyippi Formation sands at **Turtle-1**. Petroleum trapped within Kuriyippi Formation reservoirs has probably been sourced from the Milligans Formation and sealed by the Treachery Shale.

Keyling Formation sandstones (sealed by the overlying Fossil Head Formation) also form petroleum reservoirs at **Turtle** and **Blacktip**.

The Permian Hyland Bay Formation constitutes the main petroleum reservoir for accumulations identified in the central, (offshore) part of the Petrel sub-basin to date (**Petrel** and **Tern, Figure 10.3**). This unit, however, is eroded and absent in the southern inshore area (Lee & Gunn, 1988). Porosities of up to 20% have been recorded within the Hyland Bay Formation in the offshore, Petrel Sub-basin and gas has flowed on test at rates of up to 9.2 million cubic feet/day from this unit at Petrel-2.

The fluvio-deltaic, Jurassic, Plover Formation is well known for its good reservoir properties elsewhere in the Bonaparte Basin - it is the main reservoir for many of the petroleum accumulations identified in the Northern Bonaparte Basin and in the Vulcan Sub-basin. At **Petrel-1A**, the Plover Formation exhibits porosities in excess of 20% and permeabilities of up to 600 md (at a depth of 1,970 metres).

10.4.2 Seals

The Permian Fossil Head Formation and Treachery Shale provide regional seals for the underlying Keyling Formation and Kuriyippi Formation, respectively. However, shaley members within these units can also form effective, local, intraformational seals. Competent, intraformational seals are also present within the Permian Hyland Bay Formation (intraformational carbonates), the Point Spring Sandstone and the Milligans Formation. Although Hyland Bay Formation reservoirs can be sealed by intraformational carbonates, regional seal for the unit is provided by the thick, marine shales of the overlying Mount Goodwin Formation.

Although the Plover Formation is probably present throughout most of the northern and western parts of the Petrel Sub-basin, the unit is probably not at sufficient depths of burial to constitute a valid exploration objective. The Plover Formation is sealed regionally by shales of the overlying Flamingo Group.

Salt (associated with diapirism) is also likely to provide an effective seal to structural and stratigraphic traps in the Petrel Sub-basin.

10.4.3 Source

Since Kraus and Parker's work on the geochemical evaluation of the Bonaparte Basin in 1979, several workers have re-examined the source rock potential of the Petrel Sub-basin (Jefferies, 1988; Gunn & Ly, 1989; Durrant et al., 1990; Colwell & Kennard, 1996; Edwards & Summons, 1996; McConachie et al., 1996; Edwards et al., 1997 & 2000; Kennard et al., 1999 & 2002). These studies have resulted in the general consensus that mature and moderate-quality source rocks are present at multiple stratigraphic levels in Carboniferous and Permian Formations in the sub-basin.

It is thought that the Late Devonian Ningbing-Bonaparte Petroleum System may have sourced the gas accumulations at **Garimala**, **Vienta** and Ningbing in the onshore Petrel Sub-basin. Alternatively, these accumulations may have been sourced from the Milligan's Formation (Laws, 1981) or from underlying Bonaparte Formation sediments (Kennard et al., 2002). No offshore occurrences of petroleum can be attributed to this petroleum system (although Ningbing-Bonaparte Petroleum System is expected to extend into the inshore area of the Petrel Sub-basin).

The Early Carboniferous Milligans Formation is also considered to have significant source potential. Oil/source correlations have been established between the anoxic marine shales of the Milligans Formation and the oil recovered at **Barnett-1**, **Turtle-1** and **Waggon Creek-1** (McKirdy, 1987; Edwards and Summons, 1996; Edwards et al., 1997). Maturation modeling by Kennard (1996) suggests peak generation and expulsion of hydrocarbons from the Milligans Formation in this area occurred during the Late Carboniferous.

The Early Permian Keyling Formation contains delta-plain coals and marginal marine shales that have a high organic content and fair to good liquid and gas generative potential. Source rocks within this unit have been intersected in Flat Top-1 (1970) and in Kinmore-1 (1974). Burial and thermal history modeling suggests that peak expulsion from these source rocks probably occurred either in the Early Jurassic or

Middle to Late Triassic (around the time of the Fitzroy Movement phase of basin inversion).

Pro-delta front shales within the Hyland Bay Formation are organic rich but are mainly gas prone. Based on isotopic and biomarker analyses, gas and condensate recovered from the Petrel and Tern accumulations are thought to have been sourced from Permian rocks, probably within the Keyling and/or Hyland Bay Formations (Colwell & Kennard, 1996; Kennard et al., 1999 & 2002). Gas recovered from the **Fishburn-1** and **Penguin-1** wells is also attributed to the Keyling/Hyland Bay Petroleum System.

In parts of the Petrel sub-basin, Keyling Formation sediments include delta-plain coals and organic-rich marginal marine shales which exhibit moderate to very good oil and gas potential. Geohistory modelling suggests that expulsion of hydrocarbons from the Keyling Formation in the central sub-basin commenced in the Early Triassic and continued to the mid-Cretaceous (Kennard et al., 2002). On the flanks of the sub-basin, however, expulsion did not occur until the Late Cretaceous or Cainozoic.

The early Permian system is prospective for gas throughout a large portion of the Petrel Sub-basin, and the occurrence of interpreted SAR oil slicks east and southeast of the Petrel gas field (Nigel Press & Associates Group, 2001) may indicate oil migration pathways/seeps sourced from local oil-prone coaly facies within this system.

10.4.4 Traps

Structural and stratigraphic traps (containing both sandstone and carbonate reservoirs) have been identified at several stratigraphic levels in the southern Petrel Sub-basin **(Figure 10.6).** These include:

- Kulshill Group rollovers on fault blocks down-thrown against the Lacrosse Terrace;
- stratigraphic plays within the Milligans Formation (lowstand basin-floor fans and stratigraphic pinchouts against the Turtle-Barnett high);
- salt diapir flank plays;
- erosional truncation of uplifted Langfield Group sediments;
- Tanmurra Formation carbonate mounds and associated drape plays.

Salt tectonics (flow, diapirism and withdrawal) has also formed structural and stratigraphic traps within the Palaeozoic section **(Figure 10.6).** These features are thought to be present across most of the Petrel Sub-basin (Edgerley & Crist, 1974; Durrant et al., 1990). Salt movement may have triggered petroleum migration and influenced migration pathways throughout the development of the Petrel sub-basin. Many of the wells drilled in the Petrel Sub-basin have unsuccessfully tested traps associated with diapiric structures. Several anticlinal drape features associated with diapirs have been found to be highly faulted (Gull-1, Curlew-1 and Bougainville-1).

In the offshore Petrel Sub-basin, there is evidence on seismic data for the presence of turbidites, basin-floor sands, slope-fan sands and coastal onlap of sand bodies within local depocentres over laterally migrating, salt bodies (Lemon & Barnes, 1997;

Miyazaki, 1997). These sandstones constitute primary exploration objectives when found in favourable trap geometries. The reefal facies of the Carboniferous Tanmurra Formation appears to have formed on salt-induced seafloor mounds.

Leonard et al., (2003) stress that a major challenge to explorers in the Petrel Sub-basin, is the successful application of quantitative geophysical analysis (DHI, AVO analysis). Pre-drill predictions of pore fill were made at Blacktip-1 following horizon-based AVO analysis, which revealed structurally conformable anomalies at several levels. AVO modelling was conducted post-drill using fluid-substituted versions of the Blacktip-1 well logs and achieved excellent ties to the updip/downdip anomalies at several levels.

The well has proved that seismic attribute analysis (a technique traditionally associated with shallow, Cainozoic reservoirs) can be successful in Palaeozoic rocks provided that reservoir quality is adequately preserved. In the Palaeozoic southern Bonaparte Basin porosity is preserved to depths of at least 3,100 metres.

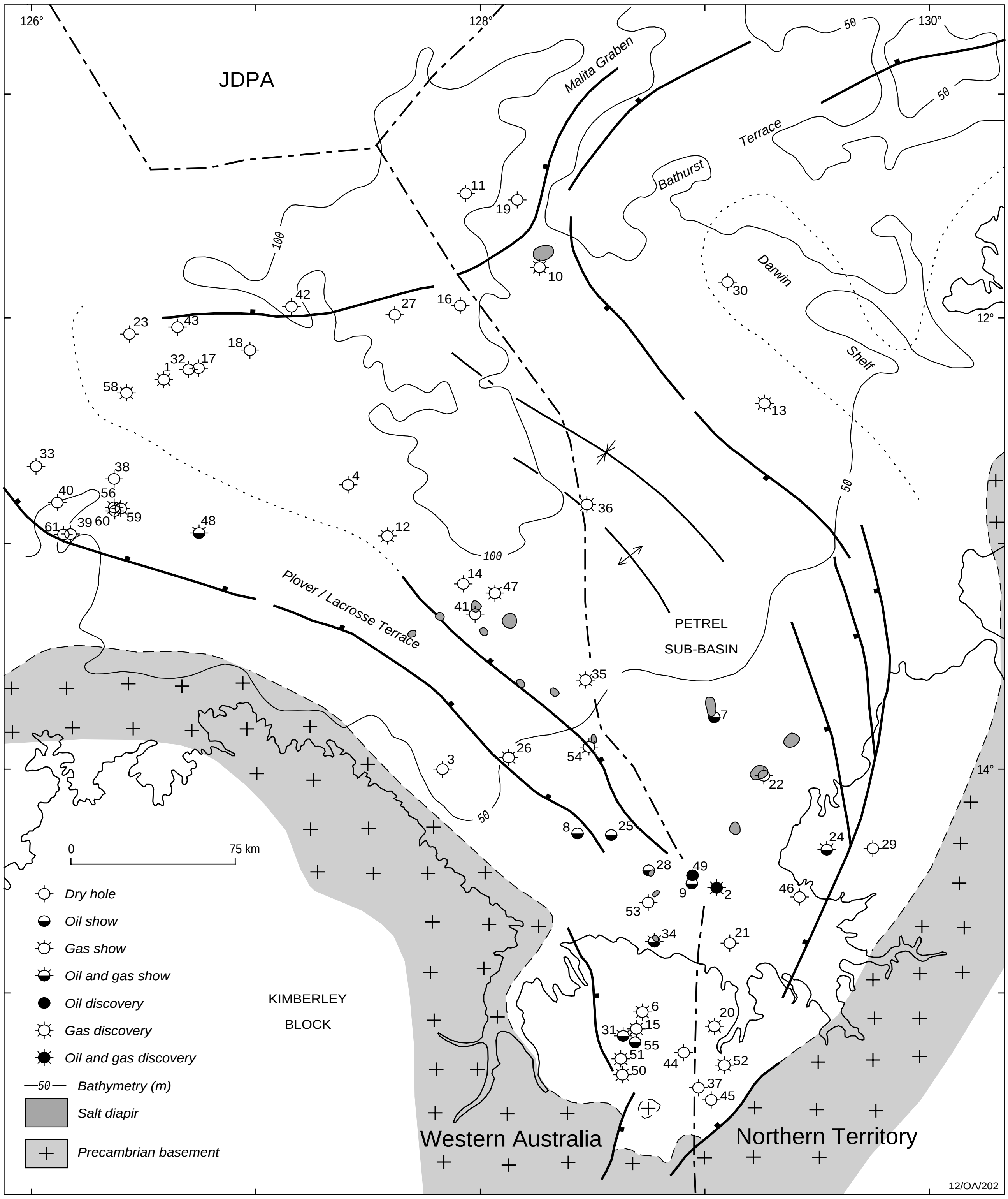

Figure 10.1 Petrel Sub-basin - tectonic elements, exploration wells and bathymetry.

Petrel Sub-basin - map key to **Figure 10.1**

Well Name	Drilling Results	Map No.
Ascalon-1A	**Gas Discovery**	1
Barnett-2	**Oil & Gas Discovery**	2
Berkley-1	P&A Dry	3
Billabong-1	P&A Dry	4
Billawock-1	P&A Dry	5
Bonaparte-2	**Gas Discovery**	6
Bougainville-1	Oil Show	7
Cambridge-1	Oil Show	8
Cape Ford-1	Oil Show	9
Curlew-1	**Gas Discovery**	10
Darwinia-1A	P&A Dry	11
Fishburn-1	**Gas Discovery**	12
Flat Top-1	**Gas Discovery**	13
Frigate-1	P&A Dry	14
Garimala-1	**Gas Discovery**	15
Gull-1	P&A Dry	16
Harbinger-1	P&A Dry	17
Helvetius-1	P&A Dry	18
Jacaranda-1	P&A Dry	19
Keep River-1	**Gas Discovery**	20
Kingfisher-1	P&A Dry	21
Kinmore-1	P&A Dry	22
Kite-1	P&A Dry	23
Kulshill-1	Oil & Gas Show	24
Lacrosse-1	Oil Show	25
Lesueur-1	**Gas Discovery**	26
Marsi-1	P&A Dry	27
Matilda-1	Oil Show	28
Moyle-1	P&A Dry	29
Newby-1	P&A Dry	30
Ningbing-1	Oil & Gas Show	31
Oberon-1	P&A Dry	32
Peewit-1	P&A Dry	33
Pelican Island-1	Oil & Gas Show	34
Penguin-1	**Gas Discovery**	35
Petrel-1A	**Gas Discovery**	36
Pincombe-1	P&A Dry	37
Plover-1	P&A Dry	38
Plover-2	P&A Dry	39
Plover-3	P&A Dry	40
Sandpiper-1	P&A Dry	41
Schilling-1	P&A Dry	42
Shalimar-1	P&A Dry	43
Skull-1	P&A Dry	44
Spirit Hill-1	P&A Dry	45
Sunbird-1	P&A Dry	46
Tern-1	**Gas Discovery**	47
Torrens-1	Oil & Gas Show	48
Turtle-1,-2	**Oil Discovery**	49
Vienta-1	**Gas Discovery**	50
Waggon Creek-1	**Gas Discovery**	51
Weaber-1,-2A	**Gas Discovery**	52
Sandbar-1	P&A Dry	53
Blacktip-1	**Gas Discovery**	54
Ningbing-2	Oil Show	55
Prometheus-1	**Gas Discovery**	56
Intrepid-1	P&A Dry	57
Saratoga-1	**Gas Discovery**	58
Rubicon-1	**Gas Discovery**	59
Endeavour-1	P&A Dry	60
Defiant-1	P&A Dry	61

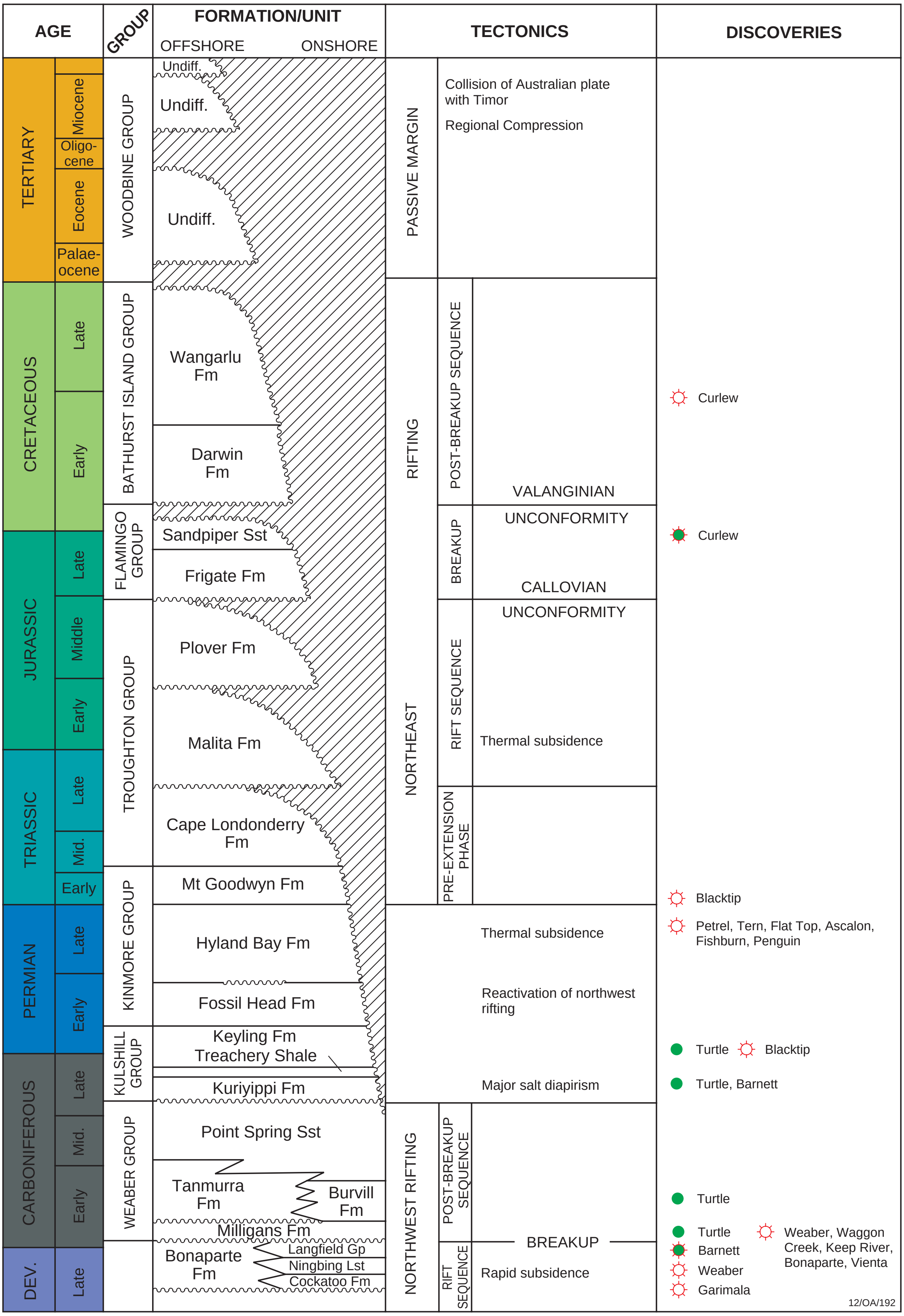

Figure 10.2 Petrel Sub-basin - stratigraphy, tectonics and petroleum discoveries.

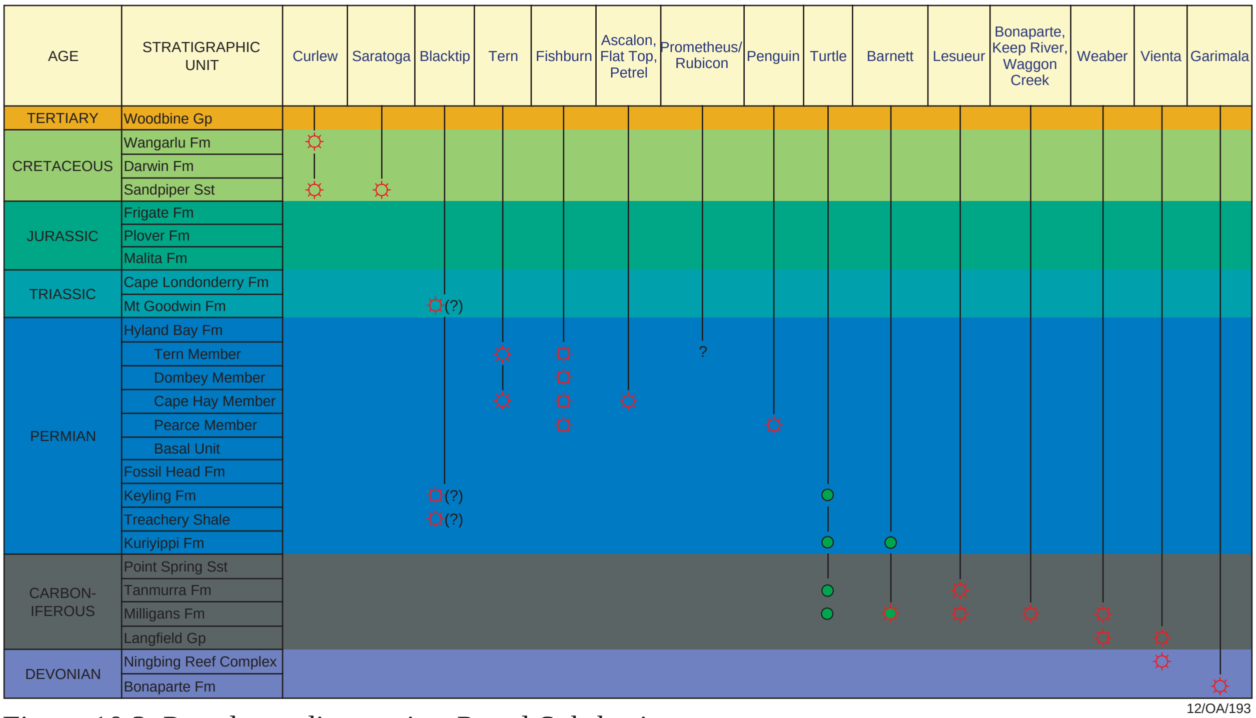

Figure 10.3 Petroleum discoveries, Petrel Sub-basin.

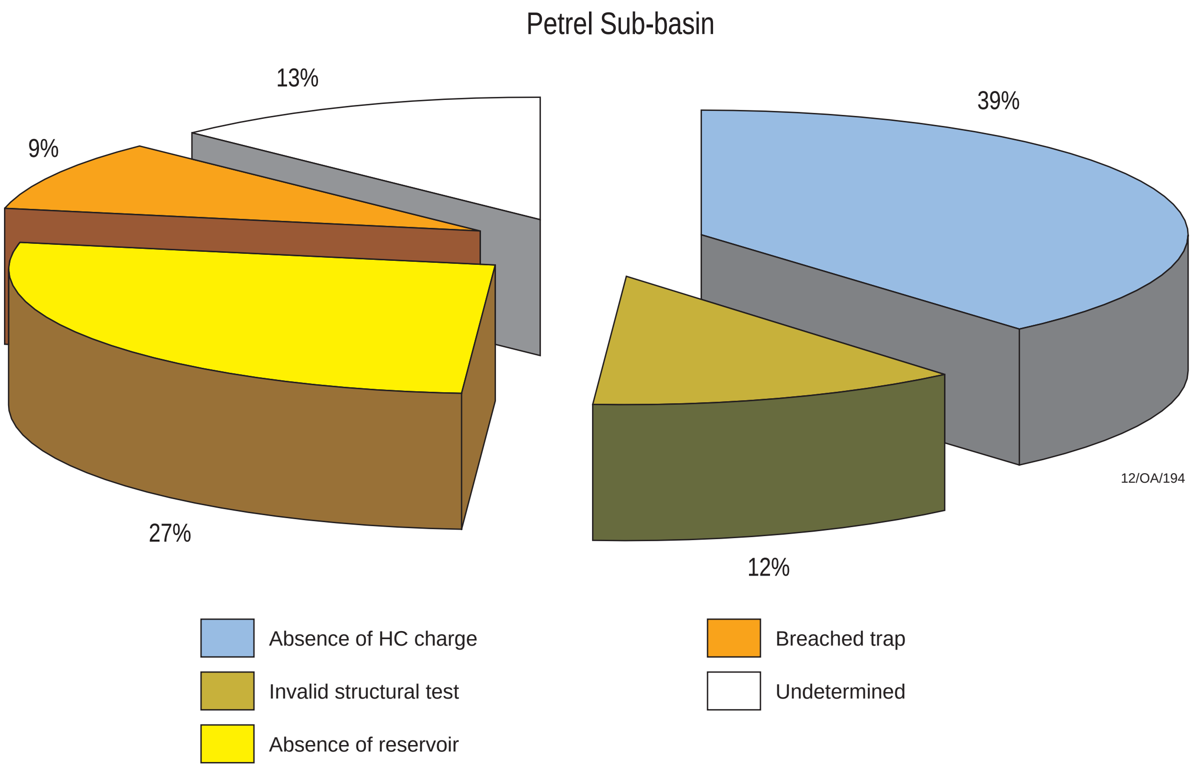

Figure 10.4 Dry hole analysis, Petrel Sub-basin.

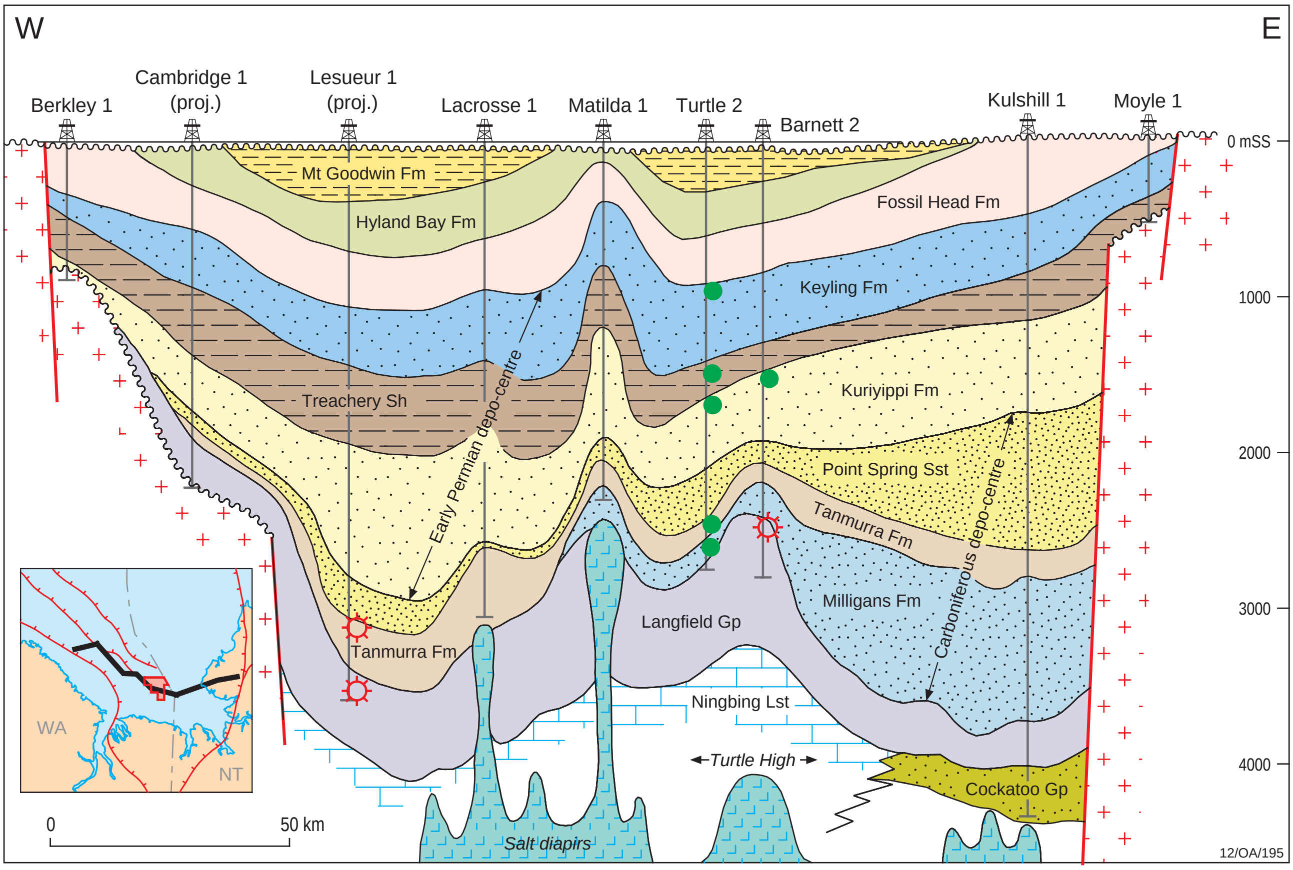

Figure 10.5 Geological cross-section of the Southern Petrel Sub-basin (modified after Miyazaki, 1997).

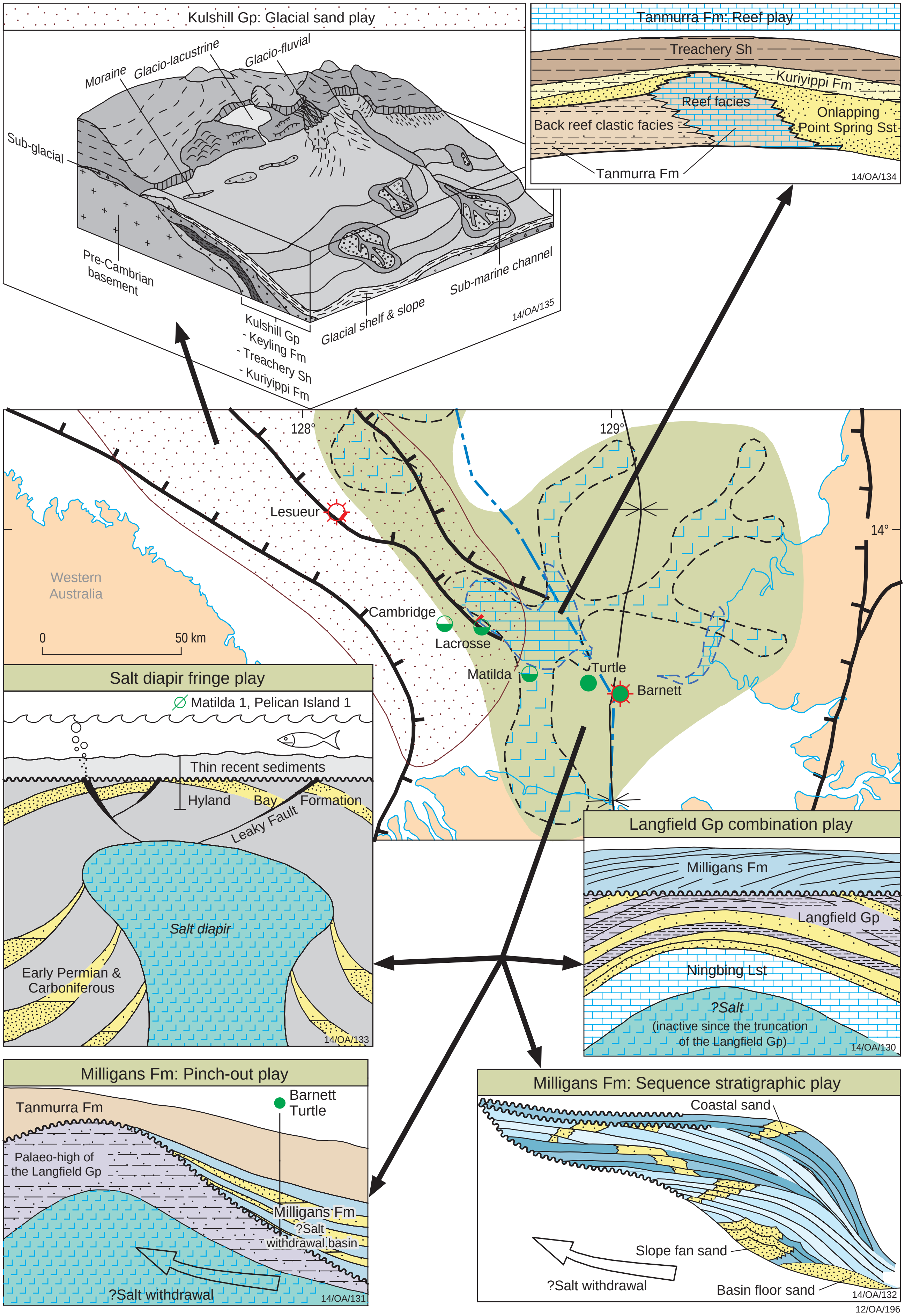

Figure 10.6 Play types in the southern Petrel Sub-basin (modified after Miyazaki, 1997).

11. PRODUCTION FACILITIES

11.1 Bayu-Undan

The Bayu-Undan gas accumulation was identified in 1995 when Bayu-1 was drilled approximately 500 kilometres northwest of Darwin on the Sahul Platform (Flamingo High). Located within the Joint Petroleum Development Area (JPDA) in 72 metres of water, the well encountered a 155 metre gross gas column within sands of the Elang / Laminaria and Plover Formations.

Later in 1995, Undan-1 was drilled 10 kilometres west-northwest of Bayu-1, in the adjacent exploration permit, on a separate culmination on the Bayu feature. The well confirmed the existence of a single, gas/condensate accumulation covering an area of at least 160 square kilometres (Brooks et al., 1996).

At date of writing, a further 9 appraisal wells had been drilled on the Bayu-Undan feature (including Trulek-1 and Hingkip-1) (**Appendix 1**).

The first phase of development comprises a gas recycling project, in which condensate, propane and butane will be stripped from the wet gas and dry, natural gas reinjected into the reservoir. The Central Production and Processing complex (CPP) will comprise two, separate platforms – one supporting drilling, production and processing equipment and the other supporting gas compression, utilities and accommodation facilities.

Other surface facilities at Bayu-Undan will comprise an unmanned, wellhead platform and a purpose-built Floating Storage and Offloading Facility (FSO). The FSO will be permanently moored two kilometres from the CPP, connected by pipelines and will have the capacity to store up to 820,000 barrels of condensate , 300,000 barrels of propane and 300,000 barrels of butane. First production from Bayu-Undan is scheduled for 2004.

In the second phase of the development, a 500 kilometre gas pipeline to Darwin is planned. The gas from Bayu-Undan will supply an LNG facility at Wickham Point near Darwin which will utilise ConocoPhillips proprietary Optimised Cascade LNG technology. Originally planned as single train LNG plant with a capacity of 3 million tonnes per year, approval has recently been granted expand the facility to a capacity of 10 million tonnes per year. The first export shipment of LNG is scheduled for 2006.

Bayu-Undan reserves are estimated at 400 million barrels of condensate and 3.4 trillion cubic feet of gas (Northern Territory Department of Business Industry and Resource Development).

11.2 Buffalo

In 1996, Buffalo-1 was drilled 15 kilometres southeast of the Laminaria oil field, on the flank of the Laminaria High, in the Northern Bonaparte Basin. The well flowed oil and gas on DST from the Elang / Laminaria Formation. An appraisal well (Buffalo-2) was drilled in 1997 and cased and suspended as a future oil producer.

The Buffalo oil field lies in 27 metres of water beneath a high relief (approximately 300 metres) carbonate bank (Big Bank) which is approximately 12 kilometres long by 4 kilometres wide. The field development comprises a five-slot, unmanned wellhead platform connected to 2 production wells via sub-sea completions. The wellhead platform is remotely controlled from a Floating Production, Storage and Offloading facility (FPSO), the *Buffalo Venture*, which is permanently moored 2 kilometres away, in water depths or around 300 metres.

Oil production from Buffalo commenced in December 1999. In 2001, Nexen Petroleum Australia Pty Ltd became the operator of the field and embarked on a development drilling program using the jackup drilling rig, the 'Ocean Bounty'. Currently, there are 4 producing wells on the Buffalo field. Production rates from the field are expected to peak at between 40,000 and 50,000 barrels/day over a three year field life.

Initial reserves at Buffalo field are estimated at 25 million barrels (Department of Resources Development, WA, 1998).

11.3 Challis / Cassini

The Challis oil field was discovered in 1984 when Challis-1, drilled on a Triassic horst block on the Jabiru Terrace (Vulcan Sub-basin), intersected a 29 metre gross oil column within the Challis Formation. The Triassic, reservoir sands at Challis sub-crop the Valanginian unconformity and are sealed by basal claystones, marls and carbonates of the Bathurst Island Group (Wormald, 1988; Gorman, 1990).

In 1988, Cassini-1 tested a separate culmination on the same structural trend five kilometres to the southwest of Challis-1. The well flowed oil and associated gas from the same reservoirs intersected by Challis-1. The oil pool intersected by Cassini-1 is separated from the Challis accumulation by a low relief saddle. The oil-water contact at Cassini is 7 metres lower than at Challis.

The Challis and Cassini oil fields are located in 106 metres of water, approximately 600 kilometres west of Darwin. Following early appraisal drilling on Challis (Challis-2 through 6) and the discovery of the Cassini oil pool in 1988, the field development plan was amended and the joint development of Challis and Cassini commenced. At date of writing, 13 appraisal/development wells had been drilled on Challis and one appraisal well on Cassini.

Production from Challis / Cassini commenced in December 1989. Production facilities comprise an FPSO vessel moored to a single anchor leg, rigid arm, mooring system (consisting of a mooring base on the sea floor and a mooring column connected to the FPSO by a steel yoke). A total of 80 kilometres of flow line and control umbilicals connect eleven sub-sea wells to the FPSO. The FPSO is a purpose-built, moored barge designed as a production storage and offloading facility.

Initial oil reserves at Challis / Cassini have been estimated at 56.6 million barrels and, at end 2001, remaining reserves at 2.6 million barrels. (Northern Territory Department of Business, Industry and Resource Development, 2003).

11.4 Elang / Kakatua / Kakatua North

The discovery of the Elang oil accumulation on the flanks of the Flamingo High in 1994 identified a new petroleum play in the Northern Bonaparte Basin. The Elang structure is an east-west oriented fault dependent closure on the Elang Trend – a prominent structural high in the area. Elang-1, drilled in 82 metres of water, intersected a 76 metre gross hydrocarbon column within the Elang / Laminaria Formation.

In December 1994, Kakatua-1 tested a nearby fault dependent closure on the same structural trend and intersected a 29 metre gross oil column within the same formation. In the year approval for a joint Elang / Kakatua development was granted (1997), Kakatua North-1 recovered oil from the Elang / Laminaria Formation in a separate fault dependent structure, immediately to the north of Kakatua.

Production from joint Elang/Kakatua development commenced in July 1998. Three sub-sea completions (Elang-1, Elang-2 and Kakatua-1) connect to an FPSO (the *Modec Venture 1* - formerly the *Skua Venture*), moored over the Elang field. Export of oil is via shuttle tankers.

The Kakatua North accumulation was tied in to the Elang / Kakatua development via a sub-sea completion at Kakatua North-1 and a 12 kilometre pipeline. Production from Kakatua North commenced in December 1998.

Initial reserves at Kakatua North and Elang / Kakatua have are estimated at 12.2 million barrels and 17 million barrels, respectively (Department of Resources Development, WA, 1998).

11.5 Jabiru

The discovery of oil in the Vulcan Sub-basin at Jabiru, was the first commercial oil discovery in the Bonaparte Basin. Drilled in 1983, Jabiru-1A intersected at 57 metre gross oil column within sands of the Upper Plover Formation and basal Flamingo Group. The Jabiru structure is an eroded, Jurassic fault block, sealed by claystones and marls of both the Flamingo and Bathurst Island Groups.

At date of writing, a further 12 appraisal / development wells had been drilled, several of which were sidetracked. Five of these wells are currently producing.

Located in water depths of around 119 metres, the Jabiru development consists of sub-sea completions connected via flow lines to an FPSO vessel, the *Jabiru Venture* - a converted oil tanker. Oil is transferred from the FPSO to a shuttle tanker moored in tandem. Commercial oil production from Jabiru commenced in 1986.

Initial oil reserves at Jabiru are estimated at 107.2 million barrels. Cumulative production from Jabiru to the end of 2002 was estimated at 104.5 million barrels. Due to natural depletion, production has declined from its peak of 51,600 barrels/day at the end of 1989 to 5,200 barrels/day (Northern Territory Department of Business, Industry and Resource Development, 2003).

11.6 Laminaria / Corallina

In October 1994, Laminaria-1 was drilled in exploration permit AC/P8 (subsequently converted to production license AC/L5) to test a tilted block on the Laminaria High. The well intersected a 102 metre gross oil column within the Elang / Laminaria Formation. At date of writing, a further 9 appraisal / development wells had been drilled on the Laminaria structure, including one deviated well. The Laminaria oil field was found to extend into adjacent exploration permit WA-260-P (production license WA-18-L) and a unitisation agreement was finalised between the permittees of AC/P8 and WA-260-P in 1998.

In December 1995, Corallina-1 was drilled on a complex fault block, 10 kilometres northwest of Laminaria-1. The well flowed oil on test from the Elang / Laminaria Formation. Water depths increase from 300-400 metres over Laminaria, to 400-450 metres over Corallina.

A joint development of the Laminaria and Corallina oil discoveries was approved and in the initial development phase, 4 subsea completions at Laminaria and 2 production wells at Corallina were tied back to an FPSO (the *Northern Endeavour*) via flowlines. One well has been dedicated to gas re-injection. The *Northern Endeavour* is permanently moored to an internal turret mooring system in a water depth of 385 metres, making it Australia's deepest offshore oil production facility.

Production from Laminaria and Corallina commenced in November 1999. Phase two of the development was designed to accelerate production and access incremental reserves in the two fields. Laminaria-7 and Laminaria-8 were drilled during this phase and the wells flowed oil on test at 20,000 barrels/day and 50,000 barrels/day, respectively. (Laminaria-7 and Laminaria-8 were originally planned as horizontal wells but after encountering drilling difficulties, the wells were re-designed as vertical producers). Production from Laminaria-7and Laminaria-8 commenced in June 2002.

Initial, combined reserves of the Laminaria and Corallina oil fields have been estimated at 137.1 million barrels. The production life of the development has been estimated at 14 years (Northern Territory Department of Business, Industry and Resource Development, 2003).

11.7 Skua

In 1985, Skua-1 was drilled to test a tilted horst block within the Vulcan Sub-basin. The well was drilled within structural closure, but was plugged and abandoned with minor oil shows. (Subsequent appraisal and development drilling showed Skua-1 intersected the primary objective (Plover Formation) down-dip from the oil/water contact).

A follow up well (Skua-2) intersected the western bounding fault of the structure and did not penetrate a complete reservoir section. Oil was recovered on test from a Santonian age sand. This sand is juxtaposed against the Plover Formation reservoir across the western bounding fault of the Skua structure. The unit is thought to be draining oil across the fault from the Plover Formation but due to poor reservoir quality, the Santonian sand acts as a natural choke to flow. The well was subsequently plugged and abandoned due to poor flow rates (Osborne, 1990).

A further 8 appraisal / development wells were drilled on Skua. Seven reservoir units are recognized in the field - all are Early to Middle Jurassic, Plover Formation sands. These units sub-crop the Callovian Unconformity and are sealed by basal claystones and marls of the Bathurst Island Group.

The Skua field covers an area of approximately 4.5 square kilometers and is interpreted to have a 28 metre gas cap and a 46.5 metre oil leg (Osborne, 1990). The Skua development consisted of three producing wells (sub-sea completions) linked to an FPSO (the *Skua Venture*). Oil production commenced in December 1991 and continued for a little over five years. 20.2 million barrels of oil have been produced from Skua.

On 30 January 1997, the Skua field was decommissioned. At that time, oil was being produced at a rate of 1,900 barrels/day. (The maximum oil production rate of 15,000 barrels/day was achieved in August 1992; in 1996, the average oil production rate was 3,702 barrels/day. The Northern Territory Department of Business, Industry and Resource Development (2003) estimates there are approximately 2.5 million barrels of recoverable oil remaining in the Skua field.

12. RESERVES

Initial reserves (at the P50 confidence level) for petroleum accumulations in the Bonaparte Basin are shown in Table 12.1. The data presented in this table, together with further information on these accumulations, are available from the Western Australian and Northern Territory State and Territory websites:

Western Australia: http://www.mpr.wa.gov.au

Northern Territory: http://www.dme.nt.gov.au

Discovery of oil/condensate and gas reserves in the Bonaparte Basin from 1968 to date of writing (December 2002) is shown in **Figures 12.1** and **12.2**, while API oil gravities of selected oils recovered from the basin are presented in **Figure 12.3**.

A recent, medium term forecast by Geoscience Australia of undiscovered hydrocarbon resources for the Mesozoic and Palaeozoic petroleum systems of the Bonaparte Basin concludes that there is a mean expectation that 350 million barrels (56 gigalitres) of oil, 2.9 trillion cubic feet (82 billion cubic metres) of gas and 115 million barrels (18 gigalitres) of condensate are likely to be discovered in the next ten to fifteen years (Barrett et al., in press).

Table 12.1 Reserves data, Bonaparte Basin oil and gas accumulations.

Accumulation	**Year of Discovery**	**Initial Oil / Condensate Reserves** (millions of barrels)	**Initial Gas Reserves** (billions of cubic feet)	**Source of Data**
Petrel	1969	-	535.0	NTBIRD, February 1997.
Tern	1971	5.7	415.0	DIR, WA, June 2002.
Puffin	1972	42.0	-	NTBIRD, September 2000
Swan	1973	5.0	70.0	NTBIRD, February 1997.
Greater Sunrise	1974	321.0	9560.0	NTBIRD, February 2000.
Jabiru	1983	107.2	-	NTBIRD, March 2002.
Challis and Cassini	1984	56.6	-	NTBIRD, March 2002.
Turtle	1984	7.7	-	DIR, WA, June 2002.
Skua	1985	20.5	-	NTBIRD, May 1998.
Weaber	1985	-	11.0	NTBIRD, May 1998.
Barnett	1985	9.6	-	NTBIRD, December 1999.
Oliver	1988	21.4	310.0	NTBIRD, April 1999.
Evans Shoal	1988	28.8	8000.0	NTBIRD, June 1988.
Montara, Bilyara and Tahbilk	1988	23.0	105.0	NTBIRD, March 1999.
Talbot	1989	2 to 5	-	NTBIRD, September 1999.
Maple	1990	10.0	345.0	NTBIRD, February 1997.
Elang / Kakatua	1994	17.0	-	DRD, WA, 1998
Laminaria	1994	119.5	-	NTBIRD, March 2002.
Corallina	1995	97.6	-	NTBIRD, March 2002.
Bayu-Undan	1995	400.0	3400.0	NTBIRD, July 1998.
Buffalo	1996	25.0	-	DRD, WA, 1998.
Kakatua North	1997	12.2	-	DRD, WA, 1998.
Tenacious	1997	5.9	-	NTBIRD, April 1999.
Crux	2000	-	1365.0	NTBIRD, August 2000.

Prometheus / Rubicon	2000	-	370	DIR, WA, June 2002.
Blacktip	2001	1.9	1139.0	DIR, WA, June 2002.

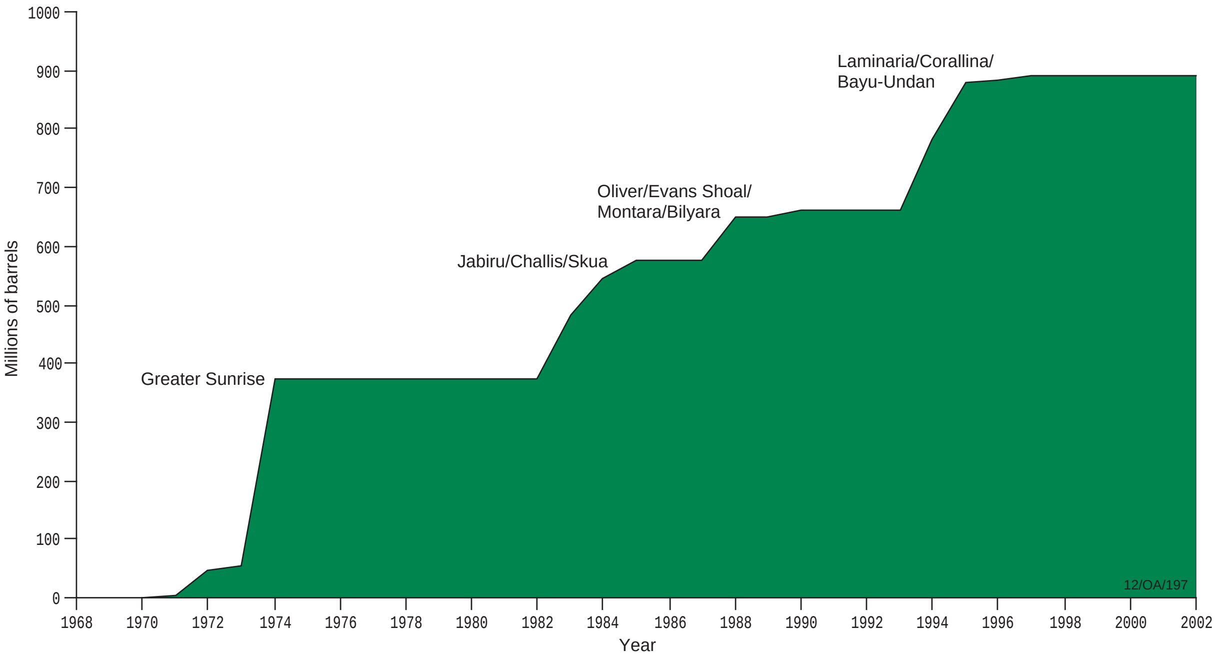

Figure 12.1 Initial oil and condensate reserves (cumulative), Bonaparte Basin, 1968 to 2002.

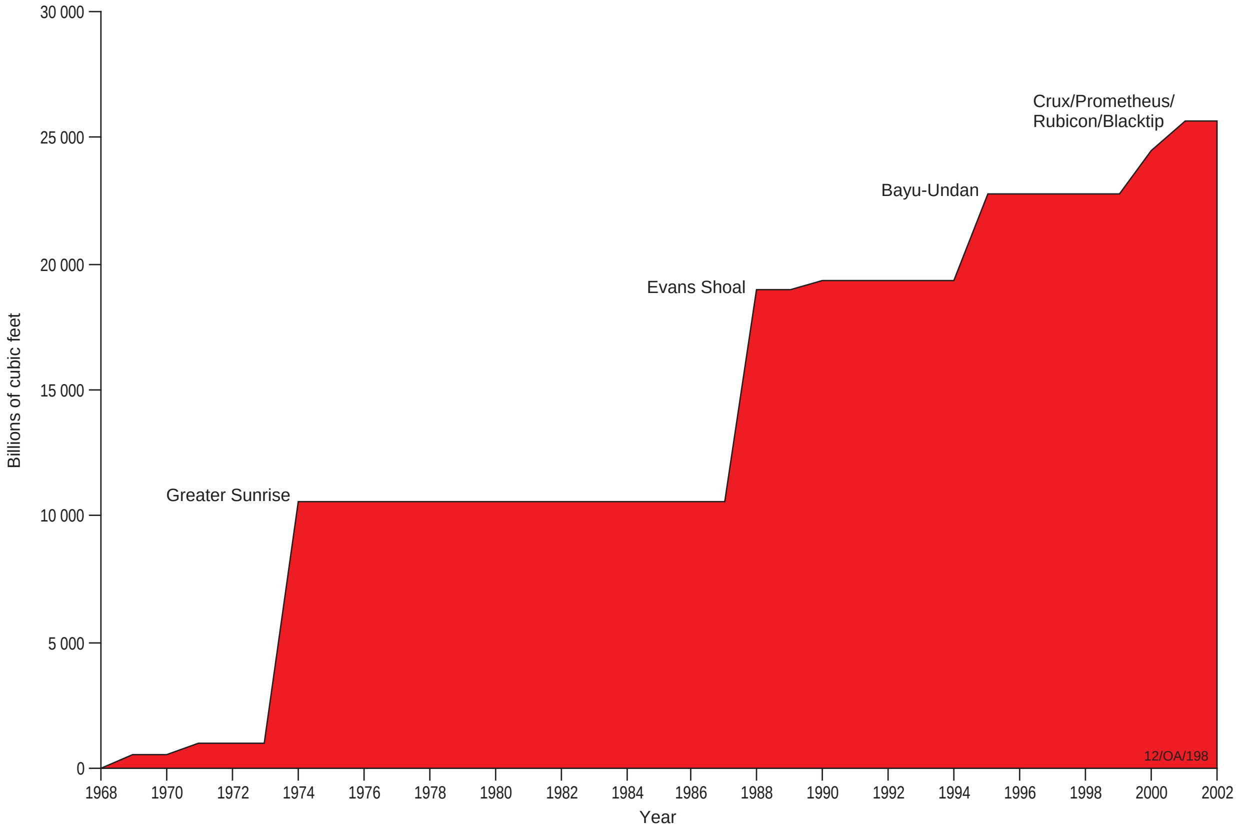

Figure 12.2 Initial gas reserves (cumulative), Bonaparte Basin, 1968 to 2002.

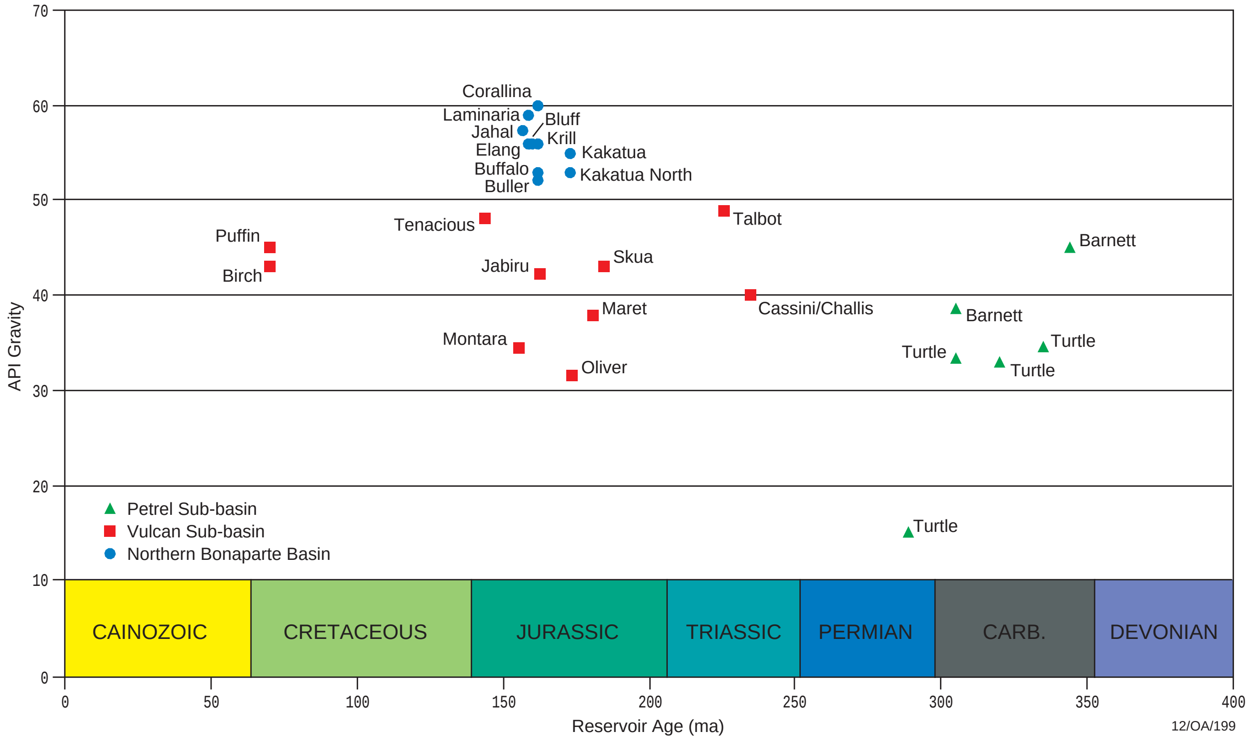

Figure 12.3 API oil gravities, Bonaparte Basin.

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APPENDIX 1

ACCUMULATION SUMMARIES

BONAPARTE BASIN

Accumulation Number: 1

ASCALON

ORIGINAL OPERATOR:	Mobil Oil Australia Ltd
TYPE:	Gas
STATUS:	Other discovery
LOCATION:	465 km west of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	WA-217-P
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Ascalon-1A
Longitude (E):	126.5883
Latitude (S):	-12.2722
Date total depth reached:	01 SEP 95
Water Depth:	68 m
Kelly bushing:	22 m
Operator:	Mobil Oil Australia Ltd
Total Depth:	4,688 mKB
NUMBER OF WELLS DRILLED:	2
STRUCTURE/TRAP:	Fault dependent closure.
AREAL CLOSURE:	665 km^2
VERTICAL CLOSURE:	455 m

PETROLEUM BEARING UNIT No.1:	Cape Hay Member (6 gas bearing sands)
CONTENTS:	Gas
FORMATION:	Hyland Bay Formation
AGE:	Late Permian
DEPOSITIONAL ENVIRONMENT:	Transgressive delta plain to delta front sequence.
GROSS HYDROCARBON COLUMN:	130 m (4,480 – 4,610 mRT)
NET PAY:	6.1 m
NET TO GROSS RATIO:	4.7%
GAS/WATER CONTACT:	4,561 mRT
POROSITY:	11.4% (average log porosity)
PERMEABILITY:	0.06 - 0.13 mD (DST 1, test values)
HYDROCARBON SATURATION:	44.2%

TEST DATA FROM THE DISCOVERY WELL (Ascalon-1A)**:**

DST 1, 4,557-4,559.5m, 4,573-4,617m, Flowed gas at 29,490 m^3/day and water at 188 m^3/day through a 3/4” choke (averaged over 16 hours). Maximum gas flow of 70,800 m^3/day.	Hyland Bay Formation

REMARKS:

Ascalon-1 was drilled to the first casing point, plugged and abandoned and respudded 50 metres away as Ascalon-1A.

The Cape Hay Member of the Hyland Bay Formation was found to be overpressured. DST 1 recorded formation pressures of 10,585 psia.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	**Ascalon-1A, DST-1 (mole %)**
Methane	90.14
Ethane	1.34
Propane	0.15
Isobutane	0.05
N-butane	0.02
Isopentane	0.01
N-pentane	0.00
Hexanes	0.02
Heptanes	0.03
Octanes +	0.02
Nitrogen	0.47
CO_2	7.75
H_2S	10-40 ppm

STRATIGRAPHY (Ascalon-1A) **:**

AGE	**UNIT**		**FORMATION TOP (mTVDSS)**
TERTIARY	WOODBINE GROUP	Undifferentiated	68.0
		Hibernia Formation	390.0
CRETACEOUS	BATHURST ISLAND GROUP	Puffin Formation	607.0
		Wangarlu Formation	656.0
		Darwin Formation	1772.0
	FLAMINGO GROUP	Sandpiper Sandstone	1814.0
JURASSIC		Frigate Shale equiv.	1949.0
	TROUGHTON GROUP	Plover Formation	2113.0
		Malita Formation	2589.5
TRIASSIC		Cape Londonderry Fm	3239.0
	KINMORE GROUP	Mt Goodwin Fm	3856.0
PERMIAN		Hyland Bay Formation	4328.0
		Tern Member	4328.0
		Dombey Member	4408.0
		Cape Hay Member	4432.0

Accumulation Number: 2

AUDACIOUS

ORIGINAL OPERATOR:	OMV Australia Pty Ltd
TYPE:	Oil
STATUS:	Possible Future Producer
LOCATION:	650 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/P17
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Audacious-1
Longitude (E):	125.1012
Latitude (S):	-11.7206
Date total depth reached:	31 JAN 01
Water Depth:	170 m
Operator:	OMV Australia Pty Ltd
Total Depth:	2,055 mRT
NUMBER OF WELLS DRILLED:	2

REMARKS:

Audacious-1 was drilled down-dip from Kym-1 on the Audacious horst. The well flowed oil on production test from the Plover Formation.

Audacious-2 appraisal well was drilled 2.3 km to the southwest of Audacious-l.

Commercial development of the Audacious oil discovery is currently under consideration.
No further information on Audacious is available at date of publication.

Accumulation Number: 3

AVOCET

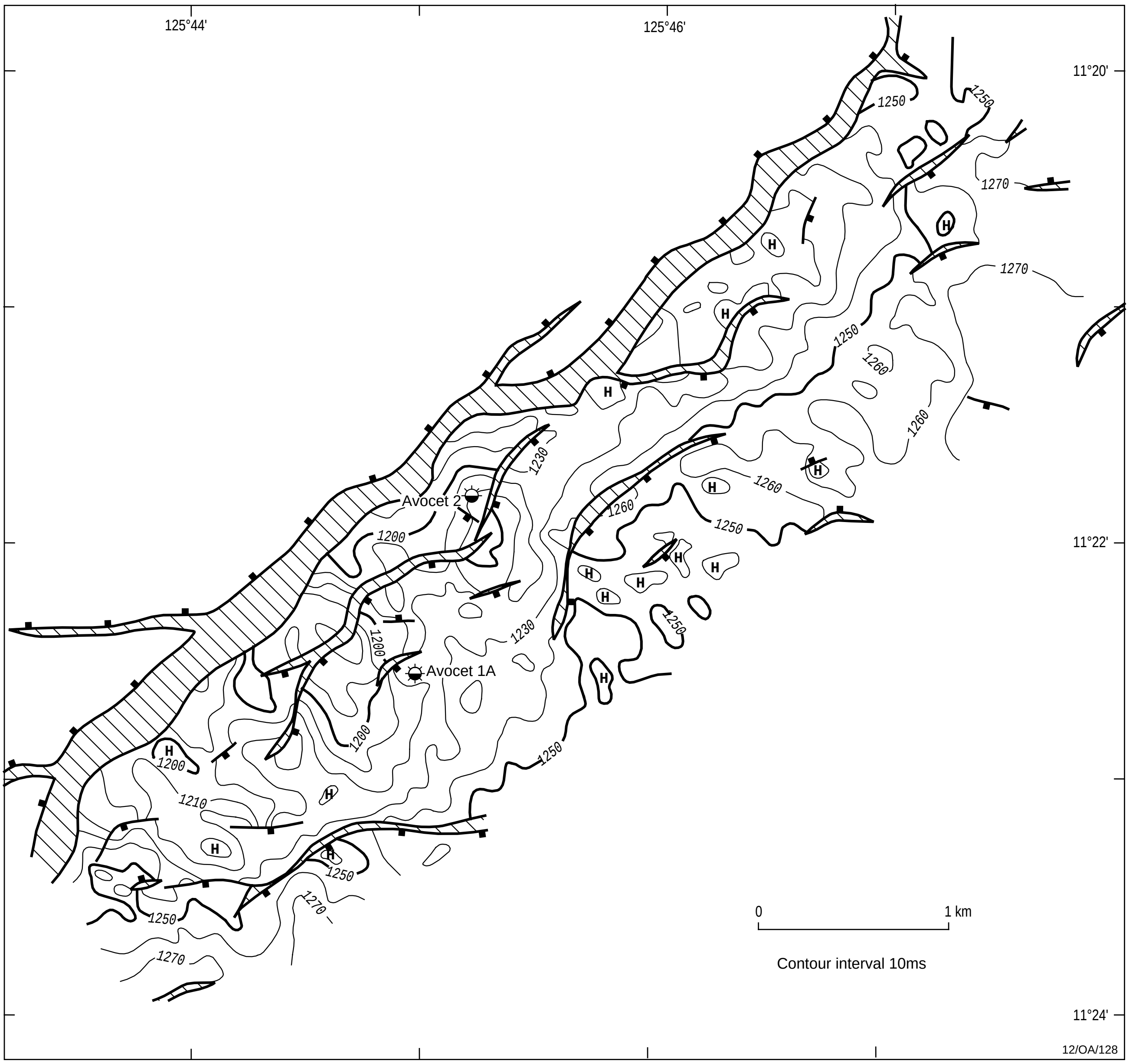
ORIGINAL OPERATOR:	Bond Corporation Holdings Ltd
TYPE:	Gas
STATUS:	Other discovery
LOCATION:	570 km west-northwest of Darwin, 15 m northeast of Avocet-1
STATE:	Western Australia
ORIGINAL TITLE(S):	WA-199-P
BASIN:	Bonaparte
SUB-BASIN:	Londonderry High
DISCOVERY WELL:	Avocet-1A
Longitude (E):	125.7550
Latitude (S):	-11.3731
Date total depth reached:	27 AUG 86
Water Depth:	105 m
Kelly bushing:	12 m
Operator:	Bond Corporation Holdings Ltd
Total Depth:	2,217 mKB
NUMBER OF WELLS DRILLED:	3
STRUCTURE/TRAP:	Tilted fault block
AREAL CLOSURE:	18 km^2
RESERVOIR UNITS:	2

PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Gas
FORMATION:	Flamingo Group
AGE:	Late Jurassic
LITHOLOGY:	Sandstone, very fine grained and argillaceous with interbedded claystone
DEPOSITIONAL ENVIRONMENT:	Shallow marine
FORMATION TOP (mKB):	1,752 m
PERMEABILITY:	0.19-2.9 mD

PETROLEUM BEARING UNIT No.2:	Troughton Group
CONTENTS:	Gas
FORMATION:	Plover Formation
AGE:	Early Jurassic
LITHOLOGY:	Sandstone, medium to coarse grained with interbedded siltstone and claystone
DEPOSITIONAL ENVIRONMENT:	Fluvio-deltaic to marginal marine
FORMATION TOP (mKB):	1,781 m
PERMEABILITY:	9.5-1255 mD

TEST DATA FROM THE DISCOVERY WELL (Avocet-1A)**:**

RFT 1, 1,755.5 m, Recovered 0.15 cubic feet of gas and 8 litres of mud filtrate with an oil scum.	Flamingo Group



Avocet, Near Base Cretaceous, TWT map

RFT 2, 1,800.0 m, Recovered 0.27 cubic feet of gas and 10 litres of mud filtrate.	Plover Formation

APPRAISAL AND DEVELOPMENT DRILLING:

Avocet-1 was abandoned at 346 mKB due to mechanical difficulties.

Avocet-2, designed to test the updip potential of the Avocet structure, encountered the same residual oil zones intersected by Avocet-1A. No formation tests were undertaken in this well.

REMARKS:

Log analysis of Avocet-1A indicates oil saturation in low permeability sandstones between 1,701-1,722 m and 1,752-1,770 m, with a residual oil/water contact at 1,813 mKB. This suggests a palaeo-oil accumulation at Avocet may have been breached by faulting or displaced by late gas migration.

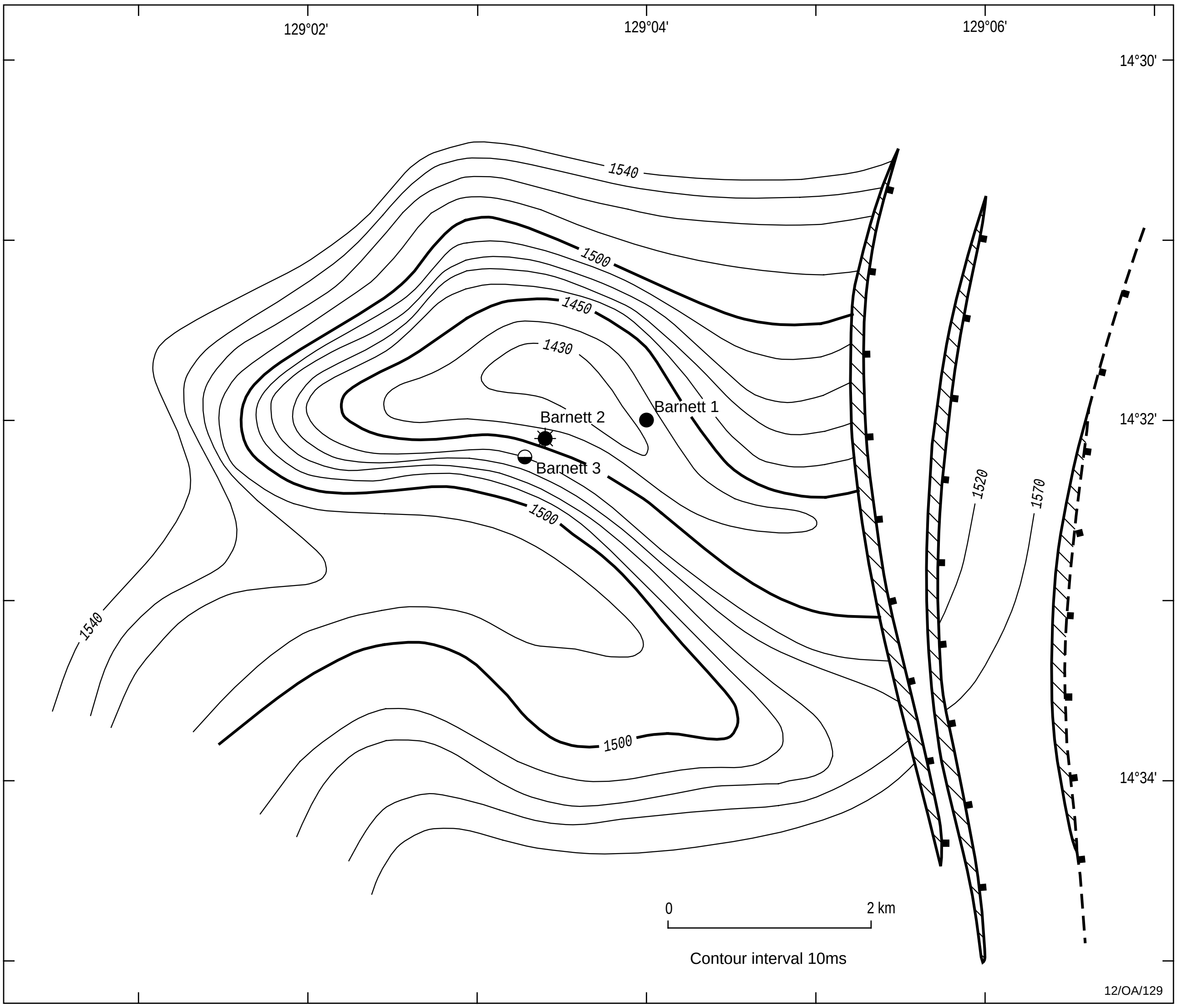
STRATIGRAPHY (Avocet-1A) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	117.5
		Hibernia Formation	500.0
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	1133.0
JURASSIC	FLAMINGO GROUP	Undifferentiated	1752.0
	TROUGHTON GROUP	Plover Formation	1781.0

Accumulation Number: 4

BARNETT

ORIGINAL OPERATOR:	Elf Aquitaine
TYPE:	Oil and Gas
STATUS:	Possible Future Producer
LOCATION:	300 km southwest of Darwin
STATE:	Northern Territory
ORIGINAL TITLE(S):	NT/P28
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Barnett-2
Longitude (E):	129.0522
Latitude (S):	-14.5323
Date total depth reached:	11 OCT 89
Water Depth:	24 m
Kelly bushing:	33 m
Operator:	Elf Aquitaine
Total Depth:	2,818 mKB
NUMBER OF WELLS DRILLED:	3
STRUCTURE/TRAP:	Anticlinal closure at Upper Milligans Formation level. Fault dependent closure at Lower Milligans Formation level.
AREAL CLOSURE:	45 km^2
VERTICAL CLOSURE:	115 m
RESERVOIR UNITS:	2
OIL GRAVITY:	38.6^o API (Kuriyippi Formation)
	44-47^o API (Upper Milligans Formation)
BOTTOM HOLE TEMPERATURE:	100^{o}C (after 34 hrs 10 mins)
PETROLEUM BEARING UNIT No.1:	Kulshill Group
CONTENTS:	Oil
FORMATION:	Upper Kuriyippi Formation
AGE:	Upper Carboniferous
DEPOSITIONAL ENVIRONMENT:	Shallow marine channel sands
FORMATION TOP (mKB):	1,479 m
GROSS HYDROCARBON COLUMN:	30.6 m (1,491.4 - 1,522 mKB)
NET PAY:	18.7 m
NET TO GROSS RATIO:	61%
POROSITY:	17-27%
WATER SATURATION:	30-45%
FORMATION PRESSURE:`	2,105.4 psia (at 1,493.7 mKB)



Barnett, Top Tanmurra Formation, TWT map

PETROLEUM BEARING UNIT No.2: Weaber Group
CONTENTS: Oil and Gas
FORMATION: Upper Milligans Formation
AGE: Lower Carboniferous
LITHOLOGY: Sandstone, tight, argillaceous, fine grained with some evidence of fracturing in cores.
DEPOSITIONAL ENVIRONMENT: Moderately deepwater with possible pro-delta progrades or submarine fans
FORMATION TOP (mKB): 2,190 m
GROSS HYDROCARBON COLUMN: 41.2 m (2,387-2,428.2 mKB)
NET PAY: 10.7 m
NET TO GROSS RATIO: 26%
POROSITY: 8-14% plus fracture porosity
PERMEABILITY: 0.02-0.29 mD (from core)
WATER SATURATION: 30-50%

TEST DATA FROM THE DISCOVERY WELL (Barnett-2)**:**

DST 3, 1,491-1,497 m, Flowed 38.6^o API oil on jet pump at 752 bbls/day.	Upper Kuriyippi Formation
DST 4, 1,491-1497 m and 1,500.5-1,506.5 m, Flowed 38.6^o API oil on jet pump at 921 bbls/day over a 3 hour period.	Upper Kuriyippi Formation
RFT, 1,493.7 m, Recovered 22.6 litres of filtrate with a trace of oil and 4 litres of filtrate with abundant oil.	Upper Kuriyippi Formation
DST 2, 1,929-1,935 m, Recovered 262 bbls of formation water on jet pump.	Upper Kuriyippi Formation
DST 1, 2,393-2,408 m, 2,415-2,421 m and 2413.5-2419.5 m, Flowed gas at 2,549 m^3/day and recovered 7 litres of 44-47^o API oil in the bottom hole sampler.	Upper Milligans Formation

APPRAISAL AND DEVELOPMENT DRILLING:

Barnett-1, drilled approximately 1 km to the east of Barnett-2, encountered traces of residual, non-biodegraded, 24^{o}API oil in the Kulshill Formation. However the Kulshill reservoir proved tight and oil saturations were low (around 20%) and the well was plugged and abandoned. Tanmurra and Milligans Formation reservoirs proved tight in Barnett-1.

Barnett-3, drilled 300 m to the southwest of Barnett-2, was plugged and abandoned as a dry hole. Kuriyippi Formation sands exhibited poor reservoir quality in this well and only traces of residual, brown oil were encountered in the Keyling Formation.

RESERVES:

Oil: 9.6 MMbbls
Source: Northern Territory Department of Business Industry and Resource Development, 1999.

REMARKS:

3 hydrocarbon bearing intervals were identified on logs and by drilling in Barnett-2 : 1,491.4-1,522 m, (Kuriyippi Formation); 2,153.6-2,156.6 m (Tanmurra Formation); and 2,387-2,428.2 m (Upper Milligans Formation). Hydrocarbons were only recovered from the Upper Kuriyippi Formation and the Upper Milligans Formation.

At date of publication, the Barnett oil and gas accumulation is held under Retention Lease NT/RL3 by a Joint Venture led by Frontier Bonaparte Pty Ltd.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	**Gas Upper Milligans Fm Barnett-2, DST-1**
Methane	84.23
Ethane	6.99
Propane	3.55
Isobutane	0.42
N-butane	1.02
Isopentane	0.35
N-pentane	0.42
Hexanes +	1.08
Nitrogen	1.87
CO_2	0.07
H_2S	0.00
Specific Gravity	0.6960
BTU/ft^3 (gross)	1203

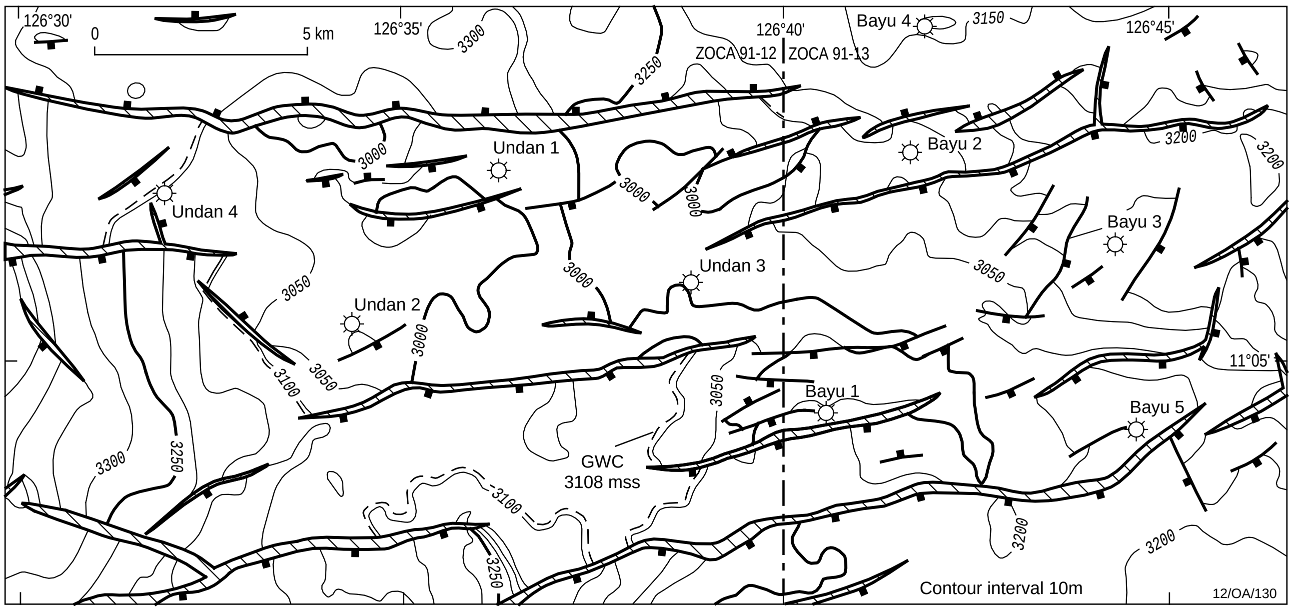
STRATIGRAPHY (Barnett-2) **:**

AGE	**UNIT**		**FORMATION TOP (mKB)**
TERTIARY	WOODBINE GROUP	Undifferentiated Tertiary	57.0
PERMIAN	KINMORE GROUP	Hyland Bay Formation	235.0
		Fossil Head Formation	518.5
	KULSHILL GROUP	Keyling Formation	839.5
		Treachery Shale Formation	1326.5
CARBONIFEROUS		Kuriyippi Formation	1479.0
	WEABER GROUP	Tanmurra Formation	2084.5
		Upper Milligans Formation	2190.0

Accumulation Number: 5

BAYU-UNDAN

ORIGINAL OPERATOR(S):	Phillips Petroleum Company ZOC Ltd BHP Petroleum (ZOCA-91-12) Pty Ltd
TYPE:	Gas
STATUS:	Future Producer
LOCATION:	450 km northwest of Darwin
STATE:	Joint Petroleum Development Area (JPDA)
ORIGINAL TITLE(S):	ZOCA 91-13 and ZOCA 91-12
BASIN:	Bonaparte
SUB-BASIN:	Flamingo High.
DISCOVERY WELL:	Bayu-1
Longitude (E):	126.6755
Latitude (S):	-11.0951
Date total depth reached:	03 FEB 95
Water Depth:	71 m
Kelly bushing:	22 m
Operator:	Phillips Petroleum Company ZOC Ltd
Total Depth:	3,205 m
NUMBER OF WELLS DRILLED:	11 (Bayu-1 to 5, Undan-1 to 4, Hingkip-1 and Trulek-1)
STRUCTURE/TRAP:	Tilted fault block. Fault dependent with some internal four-way-dip closure.
AREAL CLOSURE:	> 160 km^2
RESERVOIR UNITS:	1
GAS/WATER CONTACT:	3,128.5 mKB
RESERVOIR TEMPERATURE:	$130^{o}C$
GROSS HYDROCARBON COLUMN:	155 m (Bayu-1)
NET PAY:	86.1 m (Bayu-1)
NET TO GROSS RATIO:	55%
HYDROCARBON SATURATION:	74% (Elang Formation) 81% (Plover Formation)
CONDENSATE/GAS RATIO (CGR):	60 bbl/MMscf
CONDENSATE GRAVITY:	62^{o} API
PETROLEUM BEARING UNIT No.1:	Elang Formation (marine facies of the Upper Plover Fm and Plover Formation).
CONTENTS:	Gas and Condensate
FORMATION:	Elang and Plover Formations
AGE:	Middle to Upper Jurassic
LITHOLOGY:	A coarsening upwards sequence of silty, clay-rich sandstones which grade upwards to clean, well sorted, medium grained sandstones at the top of the unit.
DEPOSITIONAL ENVIRONMENT:	Transgressive sequence, ranging from fluvial and estuarine channel sands at the base, through lower shoreface and delta slope deposits, to distributary channel and upper shoreface environments at the top of the unit.
FORMATION TOP (mKB):	2,954.5 m (Elang Formation)
POROSITY:	1-17% (10% average)
PERMEABILITY:	0.02-2,500 mD (10 mD average)



(after Brooks et al, 1996)

Bayu-Undan, Top Callovian, depth map

TEST DATA FROM THE DISCOVERY WELL (Bayu-1)**:**

DST 4, 2,980-2,999 m, Elang Formation
Flowed gas at 453,070 m3/day and
62^o API condensate at 960 bbls/day
through a 1" choke at a wellhead pressure
of 1,119 psig.

DST 3, 3,017-3,029 m, Plover Formation
Flowed gas at 679,604 m^3/day and
62^o API condensate at 1,510 bbls/day
through a 1" choke at a wellhead pressure
of 1,320 psig.

DST 2, 3,072-3,092 m, Plover Formation
Flowed gas at 736,238 m^3/day and
62^o API condensate at 1,426 bbls/day
through a 1" choke at a wellhead pressure
of 1,322 psig.

DST 1, 3,101-3,120 m, Plover Formation
Flowed gas at 651,287 m^3/day and
62^o API condensate at 1,376 bbls/day
through a 1" choke at a wellhead pressure
of 1,250 psig.

APPRAISAL AND DEVELOPMENT DRILLING:

Bayu-2, drilled 6 km north-northeast of Bayu-1 recorded a maximum flow rate of 962,733 m^3/day of gas and 325 m^3/day of condensate from an open hole DST taken between 3,052 mKB and 3,064 mKB in the Plover Formation.

Bayu-3, spudded 8 km northeast of Bayu-1 towards the eastern edge of the field, encountered a gas/condensate column as prognosed but was plugged and abandoned without testing.

Bayu-4, located 9.5 km north-northeast of Bayu-1, encountered an 80 – 90 m hydrocarbon column in the Plover Formation with a hydrocarbon/water contact at 3,132 mKB. The well flowed gas at a maximum rate of 396,436 m^3/day from the Plover Formation through a 22.4 mm choke. The well was plugged and abandoned.

Bayu-5 was drilled 5 km south-southeast of Bayu-1 on the southern edge of the structure mapped at Bayu-Undan. The well intersected a 56 m gross gas/condensate column. The well was plugged and abandoned without testing.

Undan-1, spudded 10 km northwest of Bayu-1, was designed to evaluate the lateral extent of the accumulation identified by Bayu-1. A cased hole DST taken over the interval 3,016.5 3,021.5 mKB in the Plover Formation, flowed gas at 1,189,307 m^3/day and 63^{o}API condensate at 353 m^3/day through a 1" choke. Undan-1 was suspended as a possible future gas producer.

Undan-2, located 11.5 km west of Bayu-1, was cased and suspended as a future possible gas producer. The well flowed gas on test from the Plover Formation at 1,005,248 m^3/day and 63^{o}API condensate at 328 m^3/day through a 22 mm choke over the interval 3,101 – 3,122 mKB.

Undan-3 was drilled 5 km from Undan-1, midway between Undan-1 and Bayu-1. The well was cased and suspended as a possible future gas producer after intersecting a 136 m gross gas column between 2,996 mKB and 3,132 mKB in the Plover Formation.

Undan-4, drilled 4.25 km north-northwest of of Undan-2, was plugged and abandoned after intersecting a 43 m gross hydrocarbon column. The well flowed gas on test at 243,525 m^3/day through a 1" choke.

Hingkip-1, drilled 6.6 km north of Undan-1 in June 1997, intersected an 85 m gas column between 3,044 mKB and 3,129 mKB . The gas at Hingkip is thought to be a northerly extension of the Bayu-Undan gas/condensate field. Hingkip-1 has been suspended as a future gas producer.

Trulek-1, drilled 5.2 km southeast of Undan-2 in November 1996, intersected a 63 m gross gas column. As with the Hingkip well, the gas encountered at Trulek is thought to be an extension of the Bayu-Undan gas/condensate field. Trulek-1 has been cased and suspended as a future gas producer.

RESERVES :

Gas : 3.4 TCF
Condensate : 400 MMbbls
Source: Northern Territory Department of Business Industry and Resource Development, 1998.

REMARKS:

Commercial production of petroleum from Bayu-Undan is scheduled for 2004. Initial development of the resource will involve a gas recycling project (the stripping of gas-liquids and reinjection of gas into the reservoir). A gas pipeline from Bayu-Undan to a LNG facility in Darwin is planned.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Gas Plover Fm, DST-1	Gas Elang Fm, DST-4
Methane	75.39	76.30
Ethane	7.61	7.39
Propane	4.15	3.90
Isobutane	0.89	0.84
N-butane	1.10	1.06
Isopentane	0.40	0.39
N-pentane	0.25	0.24
Hexanes +	0.49	0.46
Nitrogen	3.67	3.51
CO_2	6.05	5.91
H_2S	0.00	0.00
Specific Gravity	0.759	0.751
BTU/ft^3 (gross)	1119	1112

STRATIGRAPHY (Bayu-1) **:**

AGE	**UNIT**		**FORMATION TOP (mKB)**
TERTIARY	WOODBINE GROUP	No Returns	93.0
		Oliver Formation	727.0
		Hibernia Formation	754.0
		Grebe Sandstone	1256.0
		Johnson Formation	1356.0
CRETACEOUS	BATHURST ISLAND GROUP	Vee Formation	1842.0
		Wangarlu Formation	2366.0
		Jamison Fm Radiolarite	2776.0
		Darwin Formation	2861.0
JURASSIC	FLAMINGO GROUP	Undifferentiated	2875.0
	TROUGHTON GROUP	Plover Formation	2954.0

Accumulation Number: 6

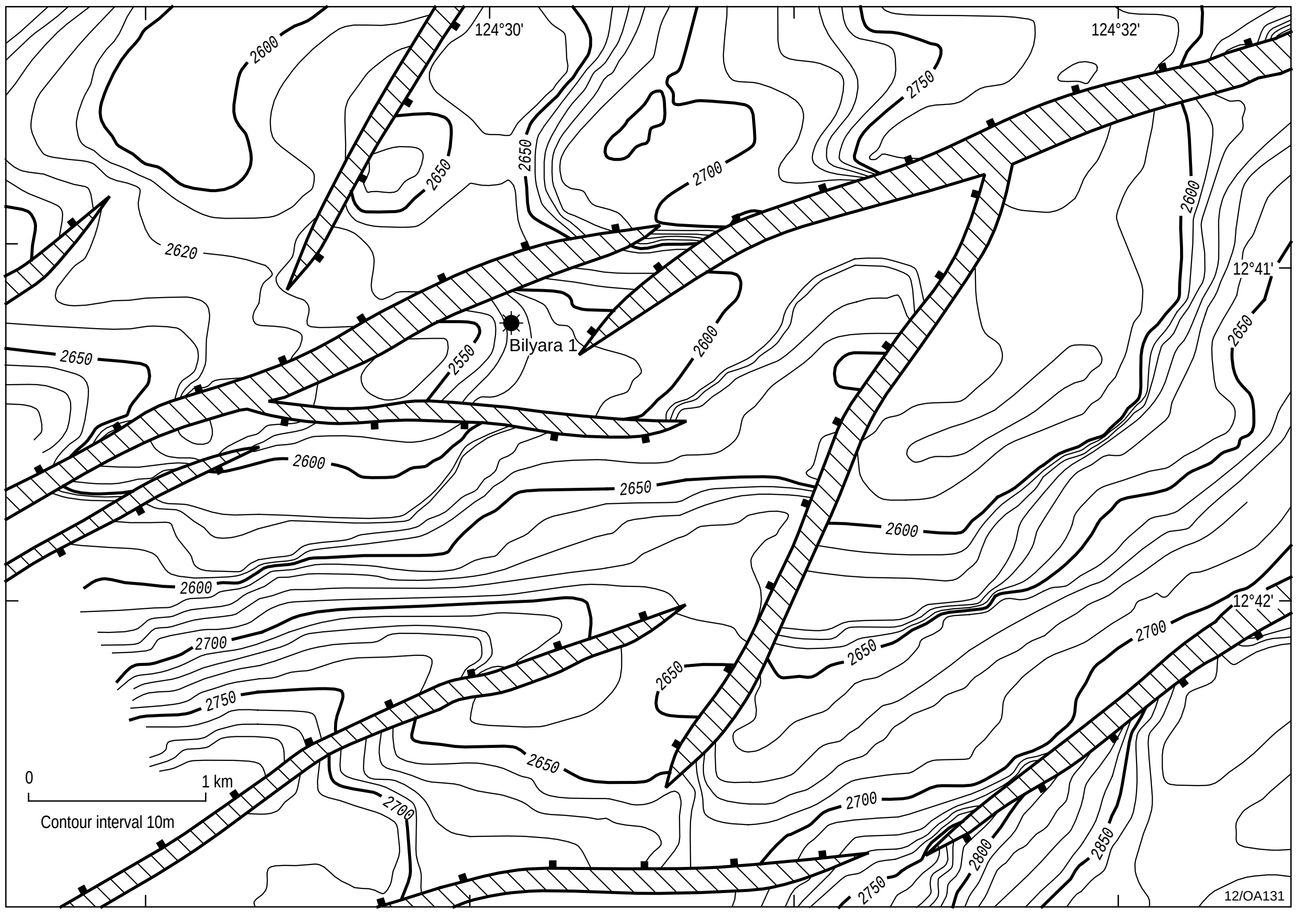
BILYARA

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Oil and Gas
STATUS:	Possible Future Producer
LOCATION:	680 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/P17
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Bilyara-1
Longitude (E):	124.5059
Latitude (S):	-12.6847
Date total depth reached:	13 SEP 88
Water Depth:	82 m
Kelly bushing:	27 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	2,754 mKB
NUMBER OF WELLS DRILLED:	2 (one sidetrack)
STRUCTURE/TRAP:	Designed to test a separate culmination on the Montara Anticline, 2.9 km to the west of Montara-1.
RESERVOIR UNITS:	1
GAS/OIL CONTACT:	2,611.5 mSS
OIL/WATER CONTACT:	2,614.5 mSS
GROSS GAS COLUMN:	46.5 m (2,565-2,611.5 mSS)
GROSS OIL COLUMN:	3 m (2,611.5-2,614.5 mSS)
RESIDUAL OIL COLUMN:	14.5 m (2,614.5-2,629 mSS)
OIL SATURATION:	16% (average, 2,611.5-2,614.5 mSS)

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Oil and Gas
FORMATION:	Montara Formation
AGE:	Early to Middle Jurassic
LITHOLOGY:	Sandstone, transparent to translucent, grey to buff, predominantly medium to fine grained, angular to subangular, occasionally subrounded, poorly sorted, hard, minor quartz cement, traces of pyrite.
DEPOSITIONAL ENVIRONMENT:	Upper shoreface/barrier bar
POROSITY:	14.2-23.3% (core data)
PERMEABILITY:	4 – 2,874 mD (horizontal perm, core data) 0.21 – 1,233 mD (vertical perm, core data)

TEST DATA FROM THE DISCOVERY WELL (Bilyara-1)**:**

RFT, 2,601 m, Recovered 2.1 m^3 of gas and 2.7 litres of condensate and gas.	Montara Formation
RFT, 2,641.6 m, Recovered formation water with an oil film.	Montara Formation



Bilyara, Top Montara Formation, depth map

RFT, 2,708 m, Recovered 3.1 litres of oil, 0.49 m^3 of gas and 5.65 litres of filtrate.	Montara Formation
RFT, 2,718 m, Recovered 0.45 litres of oil, 0.086 m^3 of gas and 20.85 litres of filtrate.	Montara Formation
DST 2, 2,715-2,720 m, Recovered formation water.	Montara Formation
DST 1, 2,720-2,730 m, Recovered formation water.	Montara Formation

RESERVES:

Oil: 23 MMbbls (includes Montara and Tahbilk)
Gas: 105 BCF (includes Montara and Tahbilk)
Source: Northern Territory Department of Business Industry and Resource Development, 1999.

REMARKS :

Difficulties were experienced in accurately determining the oil/water contact in Bilyara-1 due to the argillaceous nature of the reservoir at that depth and and the presence of a residual oil column beneath the main accumulation. For these reasons, the Bilyara-1ST well was deviated 300 m downdip to the southeast to intersect the oil/water contact in a clean reservoir section. The oil/water contact was determined at 2,614.5 mSS.

At date of publication, Bilyara is held under Retention Lease AC/RL3 by a Joint Venture led by Newfield Australia (Ashmore Cartier) Pty Ltd.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Plover Fm RFT, 2601 m
Methane	78.87
Ethane	5.26
Propane	2.78
Isobutane	0.67
N-butane	1.47
Isopentane	0.80
N-pentane	0.76
Hexanes	0.78
Heptanes +	1.58
Nitrogen	0.61
CO_2	6.42
H_2S	-
Specific Gravity	0.798
BTU/ft^3 (gross)	1218

Accumulation Number: 7

BIRCH

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Oil
STATUS:	Other Discovery
LOCATION:	650 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/P2
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Birch-1
Longitude (E):	124.4954
Latitude (S):	-12.4607
Date total depth reached:	01 AUG 90
Water Depth:	87 m
Kelly bushing:	22 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	2,822 mKB
NUMBER OF WELLS DRILLED:	1 (sidetracked due to mechanical difficulties)
STRUCTURE/TRAP:	Tilted fault block
RESERVOIR UNITS:	1
OIL GRAVITY:	43^{o} API
HYDROCARBON SATURATION:	46.1%
GAS/OIL RATIO:	222 scf/stb
GROSS HYDROCARBON COLUMN:	2.5 m (2039-2041.5 mKB)

PETROLEUM BEARING UNIT No.1:	Bathurst Island Group
CONTENTS:	Oil
FORMATION:	Puffin Formation
AGE:	Late Cretaceous
LITHOLOGY:	Sandstone, very pale orange, medium to coarse grained, well sorted, subangular to rounded, moderately calcareous with traces of pyrite and glauconite.
FORMATION TOP (mKB):	1,977 m
POROSITY:	18.4% (average log porosity)
PERMEABILITY:	75 – 1,500 mD

TEST DATA FROM THE DISCOVERY WELL (Birch-1)**:**

RFT 1, 2,040.5 m, Recovered 6 litres of 43^{o} API oil, 3.3 litres of formation water and 0.237 m^3 of gas.	Puffin Formation

REMARKS:

Birch-1 was plugged back and sidetracked at 1,765 mKB due to mechanical problems.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	**Puffin Fm RFT 1, 2040.5 m**
Methane	64.24
Ethane	14.58
Propane	8.41
Isobutane	0.96
N-butane	2.21
C_5+	1.10
CO_2	8.48

STRATIGRAPHY (Birch-1) **:**

AGE	**UNIT**		**FORMATION TOP (mKB)**
TERTIARY	WOODBINE GROUP	Barracouta/Oliver Fms	109.0
		Prion Formation	796.0
		Grebe Sandstone	1171.0
		Johnson Formation	1417.0
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	1977.0
JURASSIC	FLAMINGO GROUP	Undifferentiated	2380.0
	TROUGHTON GROUP	Plover Formation	2639.0

Accumulation Number: 8

BLACKTIP

ORIGINAL OPERATOR:	Woodside Energy Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	300 km southwest of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	WA-279-P
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Blacktip-1
Longitude (E):	128.4847
Latitude (S):	-13.9041
Date total depth reached:	10 AUG 01
Water Depth:	55.2 m
Operator:	Woodside Energy Ltd
Total Depth:	3,181 mRT
NUMBER OF WELLS DRILLED:	1
RESERVOIR UNITS:	3 (multiple reservoir sands)
GROSS HYDROCARBON COLUMN:	339 m (Keyling Formation) 20 m (Mt Goodwin Formation)
PETROLEUM BEARING UNIT No.1:	Kinmore Group
CONTENTS:	Gas
FORMATION:	Mt Goodwin Formation
PETROLEUM BEARING UNIT No.2:	Kulshill Group
CONTENTS:	Gas
FORMATION:	Keyling Formation (multiple reservoirs)
PETROLEUM BEARING UNIT No.3:	Kulshill Group
CONTENTS:	Gas
FORMATION:	Treachery Formation

RESERVES:

Gas: 1.139 TCF
Condensate: 1.9 MMbbls
Source: Department of Industry and Resources, Western Australia, 2002.

REMARKS:

No further information on the Blacktip discovery is available at date of publication.

Accumulation Number: 9

BLUFF

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Oil
STATUS:	Other Discovery
LOCATION:	520 km west-northwest of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	WA-260-P
BASIN:	Bonaparte
SUB-BASIN:	Sahul Platform
DISCOVERY WELL:	Bluff-1
Longitude (E):	126.2025
Latitude (S):	-10.8280
Date total depth reached:	21 JUL 98
Water Depth:	115.5 m
Kelly bushing:	25 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	3,534 mTVDSS
NUMBER OF WELLS DRILLED:	1
RESERVOIR UNITS:	1

PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Oil
FORMATION:	Elang Formation

TEST DATA FROM THE DISCOVERY WELL (Bluff-1)**:**

MDT, Run 3, 3,388 m, Recovered 15 litres of dark brown oil, 17.1 ft^3 of gas and 3.9 litres of filtrate/water in the 6 gallon chamber.	Elang Formation

Accumulation Number: 10

BONAPARTE

ORIGINAL OPERATOR:	Alliance Oil Development Australia
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	375 km southwest of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	PE 127 H
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Bonaparte-2
Longitude (E):	128.7211
Latitude (S):	-15.0853
Date total depth reached:	09 OCT 64
Ground level:	117 m
Kelly bushing:	5 m
Operator:	Alliance Oil Development Australia.
Total Depth:	2,136 mKB
NUMBER OF WELLS DRILLED:	2
STRUCTURE/TRAP:	Northwest-southeast trending anticline
AREAL CLOSURE:	> 50 km^2
VERTICAL CLOSURE:	> 75 m
RESERVOIR UNITS:	1

PETROLEUM BEARING UNIT No.1:	Weaber Group
CONTENTS:	Gas
FORMATION:	Milligans Formation
AGE:	Early Carboniferous
LITHOLOGY:	Argillaceous sandstone interbedded with carbonaceous siltstone and shale.
DEPOSITIONAL ENVIRONMENT:	Moderately deepwater marine
FORMATION TOP (mKB):	480.7 mKB (top Milligans Fm) 1,437.4 mKB (top reservoir)
POROSITY:	Up to 16%

TEST DATA FROM THE DISCOVERY WELL (Bonaparte-2)**:**

DST 1, 460-523 m, Recovered 55 m of slightly water cut drilling mud and 289 m of fresh water.	Tanmurra Formation
DST 2, 524-586.9 m, Recovered 6 m of watery drilling mud and 120 m of fresh water.	Milligans Formation
DST 3, 1,001-1,024.9 m, Recovered 1.5 m of drilling mud.	Milligans Formation
DST 4, 1,067.9-1,088.9 m, Recovered 58 m of drilling mud.	Milligans Formation
DST 5, 1,379.9-1,389.1 m, Recovered 76 m of water cut drilling mud and 870 m of salt water.	Milligans Formation

DST 14, 1,431.1-1,451.1 m, Milligans Formation
Flowed gas at 29,000 m^3/day and recovered 41 m of drilling mud.

DST 6, 1,436-1,469.2 m, Milligans Formation
Flowed gas at 43,500 m^3/day and recovered 3 m of gassy drilling mud.

DST 7, 1,451.1-1,490.2 m, Milligans Formation
Recovered 244 m of watery drilling mud and 829 m of slightly mud cut salty water.

DST 12, 1,738.8-1,746.1 m, Milligans Formation
Misrun.

DST 13, 1,741.1-1,748 m, Milligans Formation
Recovered 131 m of salty water.

DST 11, 1,846.1-1,883.9 m, Milligans Formation
Recovered 122 m of watery drilling mud and 223 m of salt water.

DST 8, 1,962.9-1,988.8 m, Milligans Formation
Recovered 199 m of drilling mud.

DST 9, 2,044.9-2,074.1 m, Bonaparte Formation
Misrun.

DST 10, 2,049.9-2,087.9 m, Bonaparte Formation
Recovered 46 m of drilling mud.

APPRAISAL AND DEVELOPMENT DRILLING:

Bonaparte-1, located 8 km to the north-northeast of Bonaparte-2, was drilled as a stratigraphic test. A DST taken over the interval 1,715 – 1,736 mKB in the Milligans Formation recovered a quantity of gas-cut, salty water.

REMARKS:

The gas bearing sandstones encountered in the Milligans Formation in Bonaparte-2 were retested after the well reached total depth. A maximum stabilised flow rate of 32,500 m^3/day was attained. Bonaparte-2 was plugged and abandoned as the gas discovery was thought to be uneconomic.

STRATIGRAPHY (Bonaparte-2) **:**

AGE	UNIT		FORMATION TOP (mKB)
CARBONIFEROUS	WEABER GROUP	Point Springs Sandstone	5.2
		Tanmurra Formation	185.3
		Milligans Formation	480.7
DEVONIAN	COCKATOO GP	Bonaparte Formation	2034.5

Accumulation Number: 11

BUFFALO

ORIGINAL OPERATOR:	BHP Petroleum (Northwest Shelf) Pty Ltd
TYPE:	Oil
STATUS:	Producer
LOCATION:	550 km west-northwest of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	WA-260-P
BASIN:	Bonaparte
SUB-BASIN:	Laminaria High, Sahul Platform
DISCOVERY WELL:	Buffalo-1
Longitude (E):	126.0974
Latitude (S):	-10.6728
Date total depth reached:	27 SEP 96
Water Depth:	27.3 m
Kelly bushing:	28.3 m
Operator:	BHP Petroleum (Northwest Shelf) Pty Ltd
Total Depth:	3,473 mKB
NUMBER OF WELLS DRILLED:	2
STRUCTURE/TRAP:	Faulted horst block with some internal four-way-dip closure.
RESERVOIR UNITS:	1
OIL GRAVITY:	53^{o} API
GAS TO OIL RATIO:	126 scf/stb

PETROLEUM BEARING UNIT No.1:	Elang Formation
CONTENTS:	Oil
FORMATION:	Elang Formation
AGE:	Middle Jurassic (Callovian)
LITHOLOGY:	Stacked sandstones, interbedded with minor argillaceous siltstones, silty claystones and claystone. Sandstone: very light grey to yellowish grey to light olive grey, very fine to fine, medium to carse grained, well sorted, commonly unconsolidated, friable with minor pyritic matrix and weak siliceous cement.
DEPOSITIONAL ENVIRONMENT::	Stacked distributary channels deposited in an estuarine environment superposed upon a sequence of stacked mouth and transverse bars.
GROSS HYDROCARBON COLUMN:	45.1 m (3,301 – 3,346.1 mRT)
NET PAY:	32 m
NET TO GROSS RATIO:	72%
HYDROCARBON SATURATION:	77%
OIL/WATER CONTACT:	3,323.4 mTVDSS (free water level from MDT data)
POROSITY:	12% (average log porosity)
PERMEABILITY:	378 mD (average from core)

TEST DATA FROM THE DISCOVERY WELL (Buffalo-1)**:**

DST (CASED) 1, 3,307-3,335 m, Flowed 53^{o} API oil at 11,800 bbls/day and gas at 328,500 m^{3}/day through a 20.6 mm choke.	Elang Formation

APPRAISAL AND DEVELOPMENT DRILLING:

Buffalo-2 was drilled in April 1997 and was suspended as future oil producer after encountering hydrocarbons in the Elang Formation.

RESERVES :

Oil : 25 MMbbls
Source: Department of Resources Development, Western Australia, 1998.

REMARKS:

Commercial production of oil from Buffalo commenced in December 1999. Two production wells are connected to to an unmanned wellhead platform which is linked to a permanently moored FPSO (the Buffalo Venture).

The Buffalo oil discovery lies in Production Licenses WA-19-L and WA-21-L.

Accumulation Number: 12

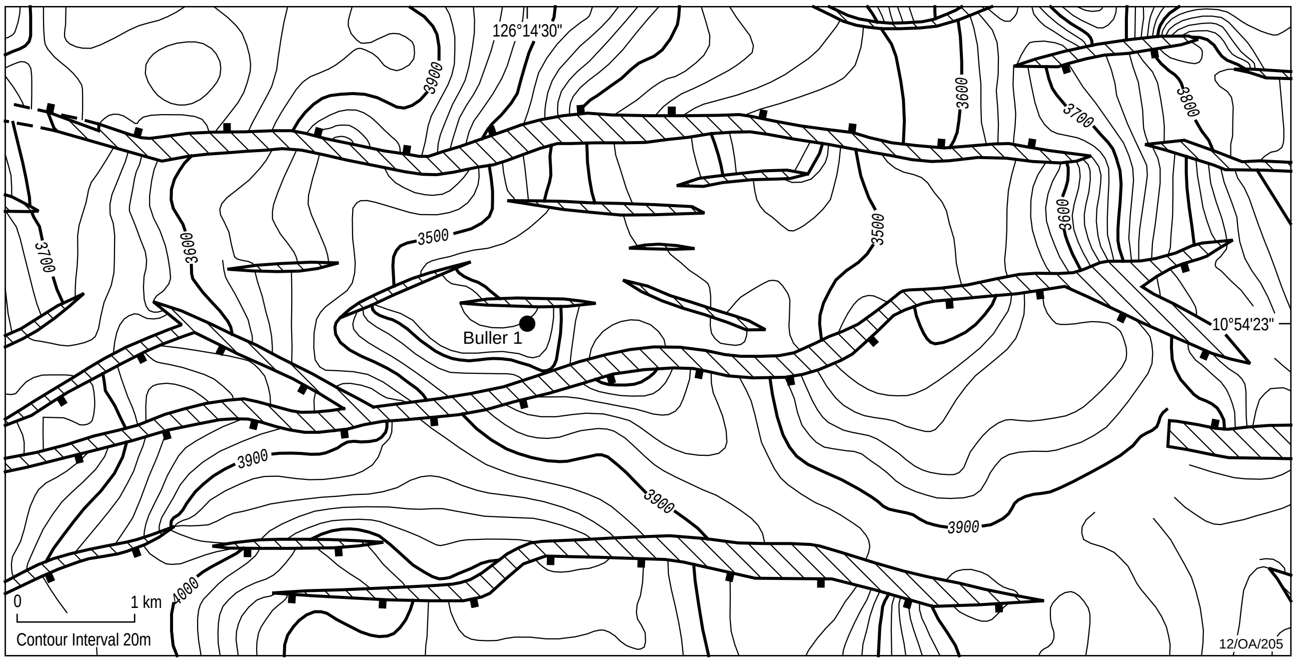
BULLER

ORIGINAL OPERATOR:	BHP Petroleum (Northwest Shelf) Pty Ltd
TYPE:	Oil
STATUS:	Other Discovery
LOCATION:	530 km west-northwest of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	WA-260-P
BASIN:	Bonaparte
SUB-BASIN:	Flamingo High
DISCOVERY WELL:	Buller-1
Longitude (E):	126.2403
Latitude (S):	-10.9077
Date total depth reached:	13 DEC 96
Water Depth:	109 m
Kelly bushing:	25 m
Operator:	BHP Petroleum (Northwest Shelf) Pty Ltd
Total Depth:	3,609 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Tilted fault block.
AREAL CLOSURE:	1 km^2
VERTICAL CLOSURE:	180 m
OIL GRAVITY:	52^o API
GAS/OIL RATIO:	114 scf/stb

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Oil
FORMATION:	Elang Formation
FORMATION TOP:	3,421.5 mTVDSS
AGE:	Callovian
LITHOLOGY:	Stacked sandstone sequence, interbedded with silty claystones and claystones. Sandstone: light greyish brown, very light grey to mid grey, light olive grey, rare brownish black, very fine to fine, medium to coarse grained, predominantly medium, poor to moderately well sorted, unconsolidated in part but mainly friable to firm. Common to abundant weak quartz overgrowths with traces of carbonate cement and argillaceous matrix.
DEPOSITIONAL ENVIRONMENT:	Transgressive delta, comprising stacked distributory channels and upper shoreface sands.
GROSS HYDROCARBON COLUMN:	26.5 m (3,446.5 – 3,473 mRT)
NET PAY:	8.56 m
NET TO GROSS RATIO:	32.3%
HYDROCARBON SATURATION:	83.4%
OIL/WATER CONTACT:	3,448 mTVDSS (free water level)
POROSITY:	11.9% (core data) 10.7% (average log)
PERMEABILITY:	369.7 mD (average from core)

TEST DATA FROM THE DISCOVERY WELL (Buller-1)**:**

MDT 1, 3,440.7 mTVDSS, Recovered 16 litres of 52^o API oil and 0.15 m^3 of gas.	Elang Formation



Buller, Top Elang Formation, depth map

REMARKS:

Fluorescence recorded below the oil/water contact indicates the possible presence of a residual oil column.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Gas Elang Fm (mole %)
Methane	6.47
Ethane	0.79
Propane/Butane	6.28
Pentane	6.17
Hexane	14.07
Heptane	15.46
Octane	10.63
Nonane	7.09
Decane	4.82
C_{11}+	24.86
N_2	0.45
CO_2	2.91

STRATIGRAPHY (Buller-1) **:**

<table>
<tr><th>AGE</th><th colspan="2">UNIT</th><th>FORMATION TOP (mTVDSS)</th></tr>
<tr><td rowspan="5">TERTIARY</td><td rowspan="5">WOODBINE GROUP</td><td>Undifferentiated</td><td>109.0</td></tr>
<tr><td>Oliver Formation</td><td>650.5</td></tr>
<tr><td>Cartier Formation</td><td>1218.0</td></tr>
<tr><td>Prion Formation</td><td>1267.5</td></tr>
<tr><td>Hibernia Formation</td><td>1647.5</td></tr>
<tr><td rowspan="5">CRETACEOUS</td><td rowspan="5">BATHURST ISLAND GROUP</td><td>Grebe Sandstone</td><td>1950.0</td></tr>
<tr><td>Johnson Formation</td><td>2021.0</td></tr>
<tr><td>Wangarlu Formation</td><td>2346.0</td></tr>
<tr><td>Jamieson Formation</td><td>2731.0</td></tr>
<tr><td>Darwin Formation</td><td>2968.0</td></tr>
<tr><td rowspan="5">JURASSIC</td><td rowspan="4">FLAMINGO GROUP</td><td>Echuca Shoals Formation</td><td>3064.5</td></tr>
<tr><td>Flamingo Formation</td><td>3109.0</td></tr>
<tr><td>Frigate Formation</td><td>3403.5</td></tr>
<tr><td>Elang Formation</td><td>3421.5</td></tr>
<tr><td>TROUGHTON GP</td><td>Plover Formation</td><td>3550.0</td></tr>
</table>

Accumulation Number: 13

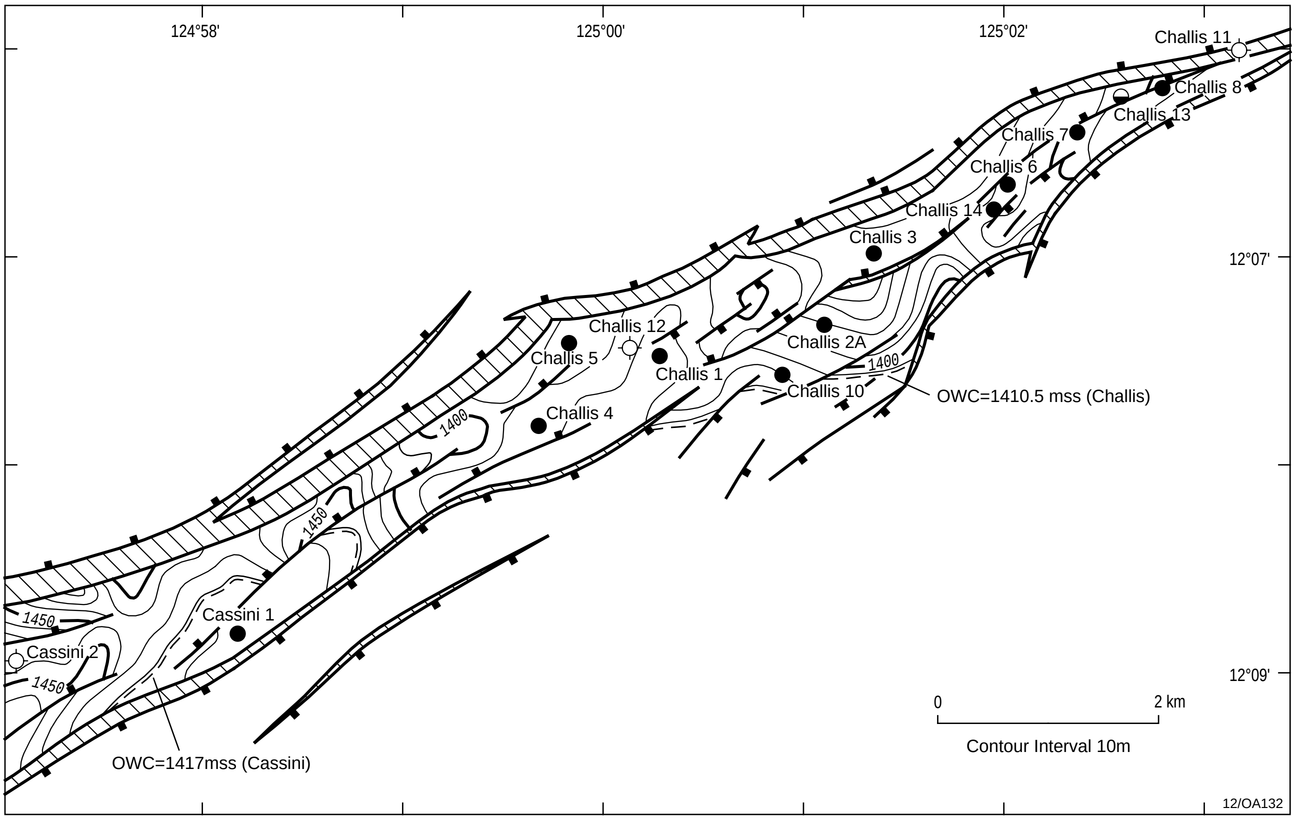
CASSINI

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Oil
STATUS:	Producer
LOCATION:	650 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/L3
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Cassini-1 (sidetracked)
Longitude (E):	124.9681
Latitude (S):	-12.1465
Date total depth reached:	18 JUL 88
Water Depth:	116 m
Kelly bushing:	26 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	1,724 mKB
NUMBER OF WELLS DRILLED:	2
STRUCTURE/TRAP:	Fault dependent closure on the southern extremity of the Cleghorn Horst, separated from the adjacent Challis accumulation by a saddle area.
AREAL CLOSURE:	1.2 km^2
VERTICAL CLOSURE:	15 m
RESERVOIR UNITS:	Multiple reservoir sands.
GAS/OIL RATIO:	250 scf/stb
OIL GRAVITY:	40^o API
DRIVE:	Water drive
BOTTOM HOLE TEMPERATURE:	71^oC

PETROLEUM BEARING UNIT No.1:	Sahul Group
CONTENTS:	Oil
FORMATION:	Challis Formation
AGE:	Middle to Late Triassic
LITHOLOGY:	Quartzose and commonly feldspathic sandstones, typically 10-20 m thick, separated by 25-50 m thick claystone, siltstone and carbonate sequences with occasional thin sandstone interbeds.
DEPOSITIONAL ENVIRONMENT:	Upper deltaic regressive sequence at base, grading upwards to a sequence of barrier/shoreline sands which transgress lagoonal and tidal flat sediments.
FORMATION TOP (mKB):	1,405 mKB
POROSITY:	24-30%
PERMEABILITY:	Up to 10 darcies

TEST DATA FROM THE DISCOVERY WELL (Cassini-1)**:**

DST 1, 1,435.3-1,437.1 m, Flowed 40^o API oil at 7,590 bbls/day and gas at 37,520 m^3/day through a 2 inch choke.	Challis Formation



(modified after Gorman, I.G.D., 1990)

Cassini, Base Cretaceous Unconformity, depth map

APPRAISAL AND DEVELOPMENT DRILLING :

Cassini-2 was drilled below the oil/water contact and outside structural closure due to inaccurate velocity modeling. Minor residual hydrocarbons were noted over the interval 1,462 – 1,527 mKB within the Triassic in Cassini-2.

RESERVES:

Initial Oil: 56.6 MMbbls (includes Challis)
Remaining Oil: 2.6 MMbbls (at end 2001)
Source: Northern Territory Department of Business Industry and Resource Development, 2002.

REMARKS:

At date of publication, the Cassini accumulation was held under Production License AC/L3.

Cassini forms part of a joint development with the nearby Challis oil field. Production is via sub-sea completions connected to an FPSO.

STRATIGRAPHY (Cassini-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	116.0
		Hibernia Formation	422.0
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	1070.5
TRIASSIC	SAHUL GROUP	Undifferentiated	1405.0

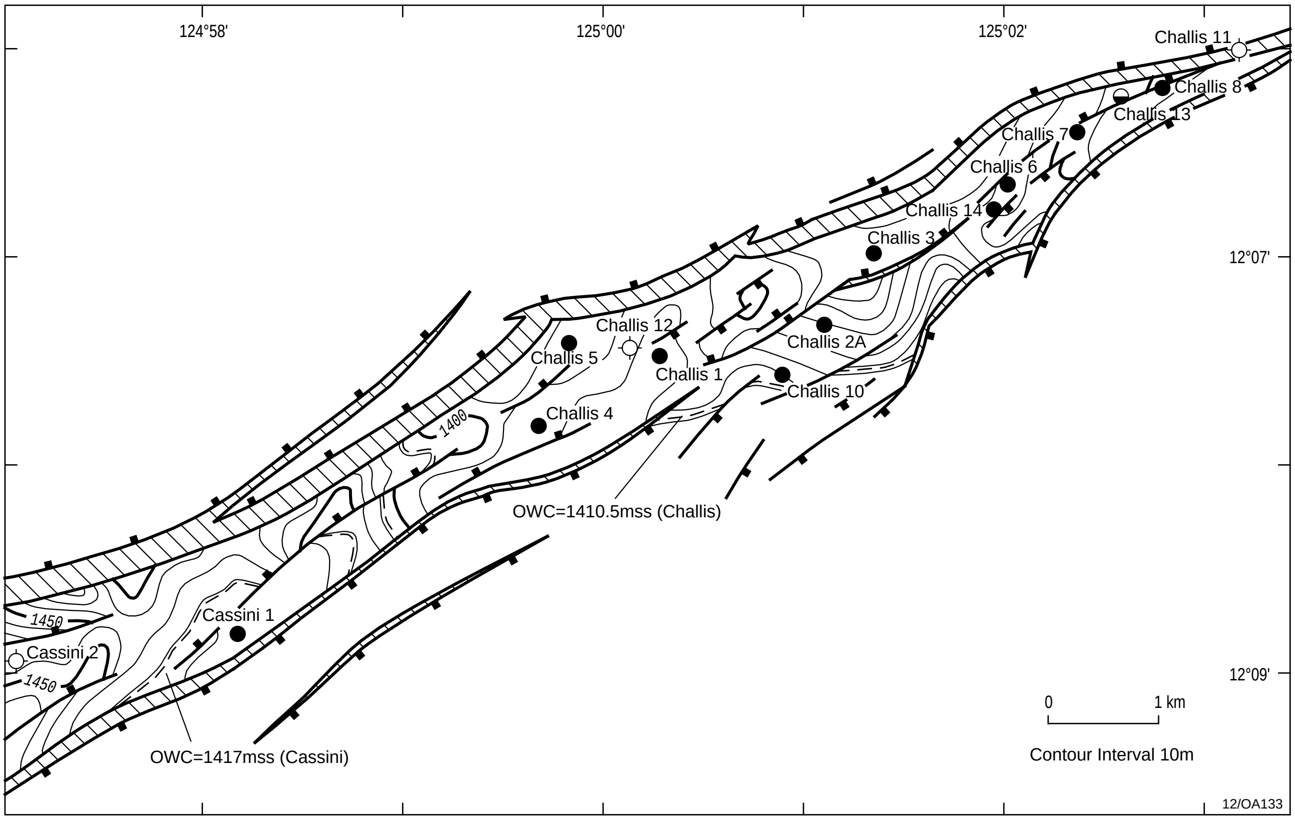
Accumulation Number: 14

CHALLIS

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Oil
STATUS:	Producer
LOCATION:	650 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	NT/P26
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Challis-1
Longitude (E):	125.0045
Latitude (S):	-12.1238
Date total depth reached:	23 OCT 84
Water Depth:	106.2 m
Kelly bushing:	8 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	1,960 mKB
NUMBER OF WELLS DRILLED:	14 wells plus 2 sidetracks
STRUCTURE/TRAP:	Fault dependent closure on the Cleghorn Horst, separated by a saddle from the Cassini accumulation to the southwest.
AREAL CLOSURE:	7 km^2
VERTICAL CLOSURE:	55 m
RESERVOIR UNITS:	Multiple reservoir sands
GROSS HYDROCARBON COLUMN:	29 m
NET TO GROSS RATIO:	72%
GAS/OIL RATIO:	326 scf/stb
OIL/WATER CONTACT:	1,410.5 mSS
OIL GRAVITY:	40^o API
DRIVE:	Water Drive
PETROLEUM BEARING UNIT No.1:	Sahul Group
CONTENTS:	Oil
FORMATION:	Challis Formation
AGE:	Middle to Late Triassic
LITHOLOGY:	Very fine to fine grained, moderately well to well sorted, subround to angular quartz grains with abundant potassium feldspar and minor lithic fragments, carbonates, micas and clays.
DEPOSITIONAL ENVIRONMENT:	Channel sand system which transgressed estuarine and lagoonal sediments forming laterally extensive sheet sands interbedded with claystones, siltstones and minor carbonates.
FORMATION TOP (mKB):	1,387 m
POROSITY:	Up to 36% (29% average)
PERMEABILITY:	Up to 6,500 mD (1,320 mD average)

TEST DATA FROM THE DISCOVERY WELL (Challis-1)**:**

Production Test, 1,390.5-1,403.5 m,Challis Formation
Flowed 40^o API oil at 6,730 bbls/day.



(modified after Gorman, I.G.D., 1990)

Challis, Base Cretaceous Unconformity, depth map

RFT 4, 1,392 m, Recovered 6.5 litres of oil, 500 cc of water and 0.4 m^3 of gas.	Challis Formation
RFT 2, 1,407.5 m, Recovered 6 litres of oil, 3 litres of water and 0.6 m^3 of gas.	Challis Formation
RFT 1, 1,417.8 m, Recovered 1.2 litres of oil, 12.3 litres of water and 0.04 m^3 of gas.	Challis Formation

APPRAISAL AND DEVELOPMENT DRILLING :

Challis-2 was abandoned due to mechanical difficulties.

Challis-2A intersected good quality oil saturated sandstones between 1,371.8 mSS and 1,409.8 mSS. The 25 m of net pay is divided into two intervals , separated by a 13 m shale break.

Challis-3 intersected two sands within a 36 m gross oil column (1,333.5 mSS to 1,379 mSS and 1,408 mSS to 1,416 mSS). Residual oil fluorescence was noted down to 1,420 mSS.

Challis-4 intersected a 22.7 m gross oil column (19 m net pay) between 1,384.8 mSS and 1,407.7 mSS.

Challis-5 was plugged and abandoned. The prognosed structural high at the Challis-5 location was not present. The time pull-up observed around Challis-5 is thought to have resulted from fast Palaeocene interval velocities.

Challis-6 intersected a 47.5 m gross oil column (18 m net pay) between 1,363 mSS and 1,410.5 mSS.

Challis-7 intersected a 64.5 m gross oil column (29 m net pay) between 1,346 mSS and 1,410.5 mSS.

Challis-8 intersected a 77.5 m gross oil column (36 m net pay) between 1,335 mSS and 1,412.5 mSS and was completed as a Pollard Formation oil producer. The well was plugged and abandoned in 1991 after the drilling of Challis-9, which was drilled in the same fault compartment and updip of Challis-8.

Challis-9 intersected a 44.7 m gross oil column between 1,363 mSS and 1,407.7 mSS and was completed as Pollard Formation oil producer.

Challis-10 was planned as a water injector. However a sealing fault between the Challis-2A and Challis-10 locations precluded this. Challis-10 was cased and suspended as an oil producer after intersecting a 28.1 m gross vertical oil column (10.2 m net pay).

Challis-11 was plugged and abandoned after intersecting the reservoir below the oil/water contact. Two sidetracks were drilled to the southeast and northwest to determine the lateral extent of the Challis Horst, but both were plugged and abandoned dry.

Challis-12 was plugged and abandoned dry.

Challis-13 was plugged and abandoned dry after recovering non-commercial quantities of oil.

Challis-14 was designed as a new drainage location for the northeastern portion of the Challis Horst.

RESERVES:

Initial Oil: 56.6 MMbbls (includes Cassini)
Remaining Oil: 2.6 MMbbls (at end 2001)
Source: Northern Territory Department of Business Industry and Resource Development, 2002.

REMARKS:

A residual oil column has been interpreted below the oil/water contact in all the Challis wells. Maximum residual oil column of 57 m is present in Challis-5.

Challis-8 and Challis-9 were completed as Pollard Formation oil producers.

Commercial production of oil from the joint development of the Challis and Cassini oil fields commenced in 1989. Eleven sub-sea completions are connected to an FPSO. The FPSO is a purpose-built moored barge designed as a floating oil production storage and offloading facility.

At date of publication, The Challis and Cassini oil fields were held under Production Licenses AC/L2 and AC/L3.

STRATIGRAPHY (Challis-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	116.2
		Hibernia Formation	478.0
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	984.0
TRIASSIC	SAHUL GROUP	Undifferentiated	1387.0

STRATIGRAPHY (Challis-14) **:**

AGE	UNIT		FORMATION TOP (mSS)
TERTIARY	WOODBINE GROUP	Barracouta/Oliver Fms	72.5
		Hibernia Formation	451.5
		Grebe Sandstone	689.5
		Johnson Formation	779.5
CRETACEOUS	BATHURST ISLAND GROUP	Borde Formation	975.5
		Fenelon Formation	1091.5
		Gibson Formation	1167.5
		Woolaston Formation	1238.5
		Jamieson Formation	1239.5
JURASSIC	FLAMINGO GROUP	Echuca Shoals Fm	1348.5
TRIASSIC	SAHUL GROUP	Challis Formation	1363.0
		Pollard Formation	1545.5

Accumulation Number: 15

CHUDITCH

ORIGINAL OPERATOR:	Shell Development (PSC 9) Pty Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	380 km northwest of Darwin
STATE:	Zone of Cooperation, Part A
ORIGINAL TITLE(S):	ZOCA 91-09
BASIN:	Bonaparte
SUB-BASIN:	Sahul Platform
DISCOVERY WELL:	Chuditch-1
Longitude (E):	128.0985
Latitude (S):	-10.5616
Date total depth reached:	1 NOV 98
Water Depth:	64 m
Kelly bushing:	25 m
Operator:	Shell Development (PSC 9) Pty Ltd
Total Depth:	3,035 mRT
NUMBER OF WELLS DRILLED:	1
VERTICAL CLOSURE:	26 m (at Top Plover Formation)
NET PAY:	19.6 m
NET TO GROSS RATIO:	78%
GAS/CONDENSATE RATIO:	0.7 bbls/MMscf

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Gas
FORMATION:	Plover Formation
AGE:	Middle Jurassic (Bathonian to Bajocian)
LITHOLOGY:	Sandstone with minor interbedded claystone and a trace of coal. Sandstone: light brownish grey to dark olive grey, clear to translucent, rare grayish yellow, very hard, massive, fine to medium grained, sub-angular, rare sub-rounded, sub-spherical, very well to moderately sorted with minor to common quartz overgrowths, common to abundant siliceous cement, rare lithics, trace of nodular pyrite, poor to fair intergranular porosity.
DEPOSITIONAL ENVIRONMENT:	Deltaic to shallow marine.
FORMATION TOP (mTVDSS):	2,894 mTVDSS
POROSITY:	6% to 18% (12.5% average), (core data).

TEST DATA FROM THE DISCOVERY WELL (Chuditch-1):

MDT 1, Run 3, 2,934 m Recovered 6.9 m^3 of gas, 1.2 litres of mud filtrate from the 6 gallon chamber. Recovered 54 litres of gas from the 1 gallon chamber.	Plover Formation
MDT 2, Run 3, 3,004 m Recovered 6.1 litres of oily mud filtrate and mud and 2.5 litres of water from the 2.75 gallon chamber.	Plover Formation

STRATIGRAPHY (Chuditch-1) **:**

AGE	**UNIT**		**FORMATION TOP (mTVDSS)**
TERTIARY	WOODBINE GROUP	Barracouta Formation	64.0
		Oliver Formation	293.0
		Hibernia Formation	688.0
		Johnson Formation	1103.0
CRETACEOUS	BATHURST ISLAND GROUP	Turnstone Formation	1573.0
		Vee Formation	1741.0
		Wangarlu Formation	1947.0
		Darwin Formation	2869.0
	FLAMINGO GROUP	Echuca Shoals Fm	2880.5
JURASSIC		Flamingo Formation	2885.0
	TROUGHTON GROUP	Plover Formation	2894.0

Accumulation Number: 16

CORALLINA

ORIGINAL OPERATOR:	Woodside Petroleum Development Pty Ltd
TYPE:	Oil
STATUS:	Producer
LOCATION:	570 km northwest of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/P8
BASIN:	Bonaparte
SUB-BASIN:	Laminaria High, Sahul Platform
DISCOVERY WELL:	Corallina-1
Longitude (E):	125.9560
Latitude (S):	-10.5917
Date total depth reached:	21 DEC 95
Water Depth:	411 m
Kelly bushing:	22 m
Operator:	Woodside Petroleum Development Pty Ltd
Total Depth:	3,340 mKB
NUMBER OF WELLS DRILLED:	2
STRUCTURE/TRAP:	Fault dependent closure on the Corallina Horst.
AREAL CLOSURE:	11 km^2
VERTICAL CLOSURE:	140 m
RESERVOIR UNITS:	1
GROSS HYDROCARBON COLUMN:	77 m
NET TO GROSS RATIO:	90%
HYDROCARBON SATURATION:	79%
GAS/OIL RATIO:	239 scf/stb
BUBBLE POINT:	350 psig at 84^{o}F
OIL GRAVITY:	60^o API
BOTTOM HOLE TEMPERATURE:	120^{o}C

PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Oil
FORMATION:	Laminaria/Elang Formation (basal sand unit of the Flamingo Group)
AGE:	Middle Jurassic (Callovian)
LITHOLOGY:	Sandstone: fine to medium grained, partly pyritic with silica cement at the top, grading to interbedded sandstone, siltstone and claystone towards the base of the unit. The uppermost 12 m of reservoir comprises siltstone and and very fine grained, argillaceous sandstone of poor reservoir quality.
DEPOSITIONAL ENVIRONMENT:	Transgressive, estuarine dominated delta.
FORMATION TOP:	3,154 mKB
POROSITY:	15.2% (average log porosity) 15.7% (average core porosity)
PERMEABILITY:	597 mD (average from core)

TEST DATA FROM THE DISCOVERY WELL (Corallina-1)**:**

Production Test, 3,186-3,196 m, Flowed 60^o API oil 7,800 bbls/day and gas at 10,477 m^3/day through a 16 mm choke at 870 psi and 136^{o}F.	Laminaria/Elang Formation

APPRAISAL AND DEVELOPMENT DRILLING :

Corallina-2 was completed as a future oil producer in April 1998.

RESERVES :

Initial Oil : 97.6 MMbbls
Remaining Oil: 55.9 MMbbls (at end 2001)
Source: Northern Territory Department of Business Industry and Resource Development, 2002.

REMARKS:

Commercial oil production from a combined Corallina/Laminaria development commenced in November 1999. Two production wells on Corallina and a further four on Laminaria are connected via sub-sea completions and flowlines to an FPSO (the Northern Endeavour) moored between the two fields in 390 metres of water. Surplus gas is reinjected into the reservoir via a single, dedicated gas disposal well.

At date of publication, the Corallina/Laminaria oil fields were held under Production License AC/L5.

STRATIGRAPHY (Corallina-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	433.0
		Oliver Formation	897.0
		Cartier Formation	1763.0
		Upper Hibernia Fm	1811.0
		Lower Hibernia Fm	2374.0
		Grebe Fm equivalent	2583.0
		Johnson Formation	2788.0
CRETACEOUS	BATHURST ISLAND GROUP	Undifferentiated	2793.0
		Wangarlu Formation	2824.0
		Darwin Formation	2924.0
JURASSIC	FLAMINGO GROUP	Upper Flamingo Gp	2950.0
		Lower Flamingo Gp	3122.0
		Laminaria Formation	3154.0
	TROUGHTON GP	Plover Formation	3284.0

Accumulation Number: 17

CRUX

ORIGINAL OPERATOR:	Nippon Oil Exploration (Vulcan) Pty Ltd
TYPE:	Gas
STATUS:	Possible Future Producer
LOCATION:	700 km west of Darwin.
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/P23
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Crux-1
Longitude (E):	124.4526
Latitude (S):	-12.9441
Date total depth reached:	04 MAY 2000
Water Depth:	168.0 m
Kelly bushing:	26.5 m
Operator:	Nippon Oil Exploration (Vulcan) Pty Ltd
Total Depth:	3,955 mRT
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Fault dependent closure with internal four-way dip closure.

PETROLEUM BEARING UNIT No.1:	Sahul Group
CONTENTS:	Gas
FORMATION:	Nome Formation
AGE:	Triassic
GROSS HYDROCARBON COLUMN:	244 m (3,640 – 3,884 mRT)
GAS/CONDENSATE RATIO:	36.8 bbls/MMscf (DST 1) 22.4 bbls/MMscf (DST 2)
POROSITY:	14% (average log porosity)
PERMEABILITY:	up to 5,500 mD

TEST DATA FROM THE DISCOVERY WELL (Crux-1):

DST 1, 3,816 – 3,853 m, Flowed gas at a maximum rate of 890 m^3/day and condensate at 1160 bbls/day on a 96/64" choke.	Nome Formation
DST 2, 3,642 – 3,660 m, Flowed gas at a maximum rate of 960 m^3/day and condensate at 761 bbls/day on a 80/64" choke.	Nome Formation

RESERVES:

Gas: 1.365 TCF
Source: Northern Territory Department of Business Industry and Resource Development, 2000.

REMARKS:

Post well analyses indicate the Crux structure contains a palaeo oil column that has been breached in the Miocene. The structure has subsequently been charged with gas in the Pliocene to Pleistocene.

STRATIGRAPHY (Crux-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Barracouta Formation	194.5
		Hibernia Formation	745.0
		Grebe Sandstone	903.9
		Johnson Formation	1204.0
CRETACEOUS	BATHURST ISLAND GROUP	Puffin Formation	1509.0
		Fenelon Formation	2043.0
		Gibson Formation	2277.7
		Woolaston Formation	2337.0
		Jamieson Formation	2388.0
		Echuca Shoals Formation	2591.5
JURASSIC	SWAN GROUP	Upper Vulcan Formation	2690.0
		Lower Vulcan Formation	3154.5
		Montara Formation	3515.0
		Malita Formation	3591.0
TRIASSIC	SAHUL GROUP	Nome Formation	3640.0

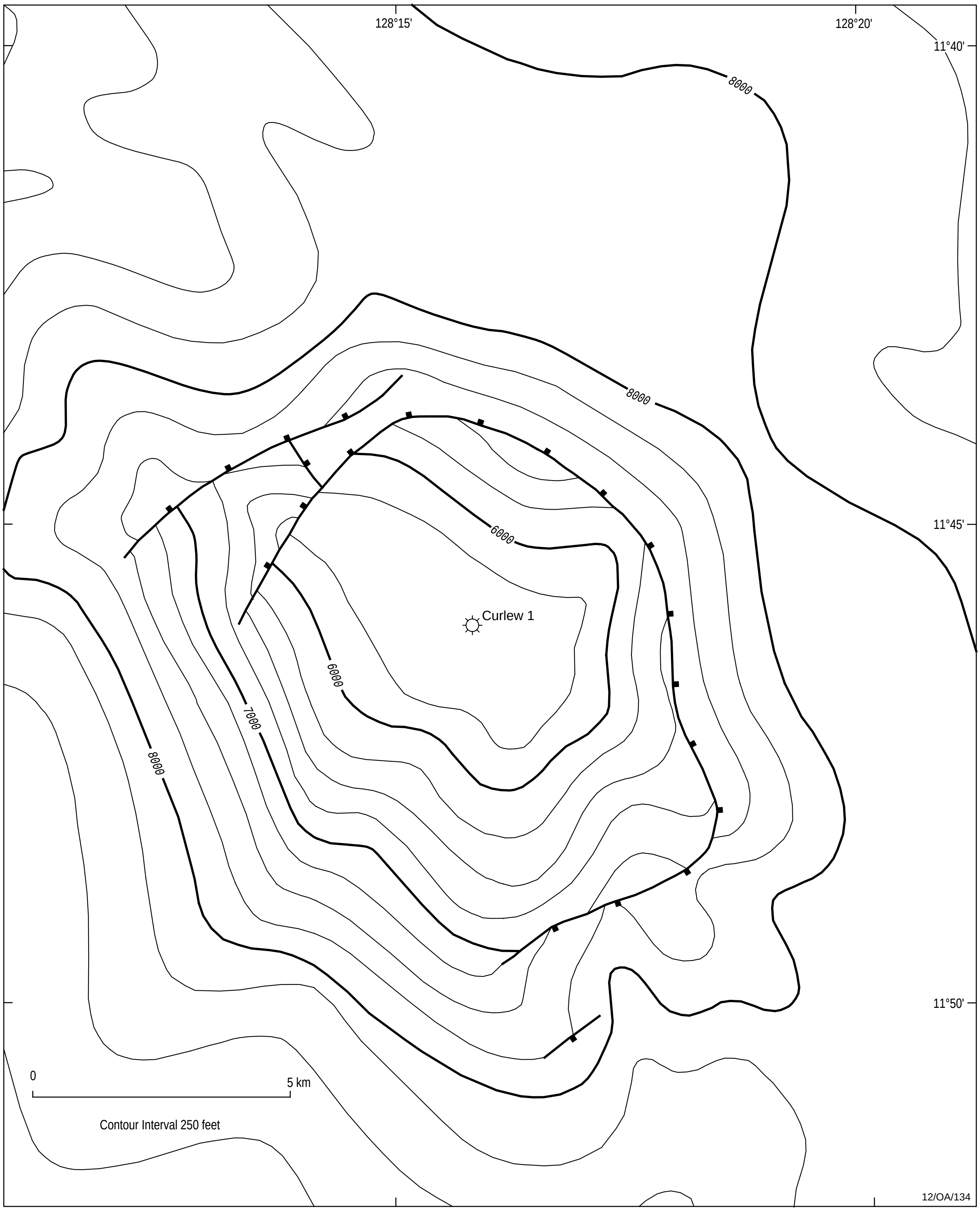
Accumulation Number: 18

CURLEW

ORIGINAL OPERATOR:	Arco Australia Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	290 km west-northwest of Darwin
STATE:	Northern Territory/Commonwealth Government
ORIGINAL TITLE(S):	NT/P3
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Curlew-1
Longitude (E):	128.2639
Latitude (S):	-11.7706
Date total depth reached:	13 JAN 75
Water Depth:	77 m
Kelly bushing:	25 m
Operator:	Arco Australia Ltd
Total Depth:	2,035 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Domal feature structurally controlled by a deep seated piercement salt dome.
AREAL CLOSURE:	100 km^2
VERTICAL CLOSURE:	Up to 400 m
RESERVOIR UNITS:	2
BOTTOM HOLE TEMPERATURE:	88^{o}C

PETROLEUM BEARING UNIT No.1:	Bathurst Island Group
CONTENTS:	Gas
FORMATION:	Bathurst Island Group
AGE:	Cretaceous
LITHOLOGY:	Sandstone, very fine grained, dolomitic, occasionally argillaceous with common pyrite and occasional glauconite.
FORMATION TOP (mKB):	338.9 m
POROSITY:	Up to 38% (log porosity)

PETROLEUM BEARING UNIT No.2:	Flamingo Group
CONTENTS:	Gas
FORMATION:	Flamingo Group
AGE:	Late Jurassic
LITHOLOGY:	Sandstone, medium grained, subrounded to rounded, partially cemented by silica overgrowths, occasional argillaceous matrix, interbedded with siltstone and shale
FORMATION TOP (mKB):	1,725.1 m
POROSITY:	13% to 19% (log porosity)



Curlew, Near Base Cretaceous, depth map

TEST DATA FROM THE DISCOVERY WELL (Curlew-1)**:**

FIT 1, 595.6 m, Recovered 18.5 litres of water and 0.014 m^3 of gas.	Bathurst Island Formation
FIT 3, 1,729.8 m, Recovered 17.4 litres of filtrate and 0.009 m^3 of gas.	Flamingo Group
FIT 2, 1,735.8 m, Recovered 0.014 m^3 of gas and 20.25 litres of filtrate.	Flamingo Group
DST 3, 1,731-1,740 m, Recovered 113 m of water and mud and 1,559 m of salt water.	Flamingo Group
DST 2, 1,731-1,740 m, Recovered 122 m of water and mud and 1,560 m of salt water.	Flamingo Group
FIT 4, 1,746.5 m, Recovered 300 cc of oil, 0.015 m^3 of gas and 20.7 litres of filtrate.	Flamingo Group
FIT 6, 1,770.9 m, Recovered 1 litre of mud.	Flamingo Group
FIT 5, 1,772.7 m, Recovered 400 cc of mud.	Flamingo Group
DST 1, 1,774-1,782 m, Recovered 91 m of water and mud and 1,501 m of salt water.	Flamingo Group

REMARKS :

Analysis of the 300 cc of 'oil' recovered in FIT 4 indicates that this sample is probably diesel oil contamination.

It is possible that the gas recovered from the Bathurst Island and Flamingo Groups at Curlew is solution gas.

STRATIGRAPHY (Curlew-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	102.7
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	338.9
JURASSIC	FLAMINGO GROUP	Undifferentiated	1725.1

Accumulation Number: 19

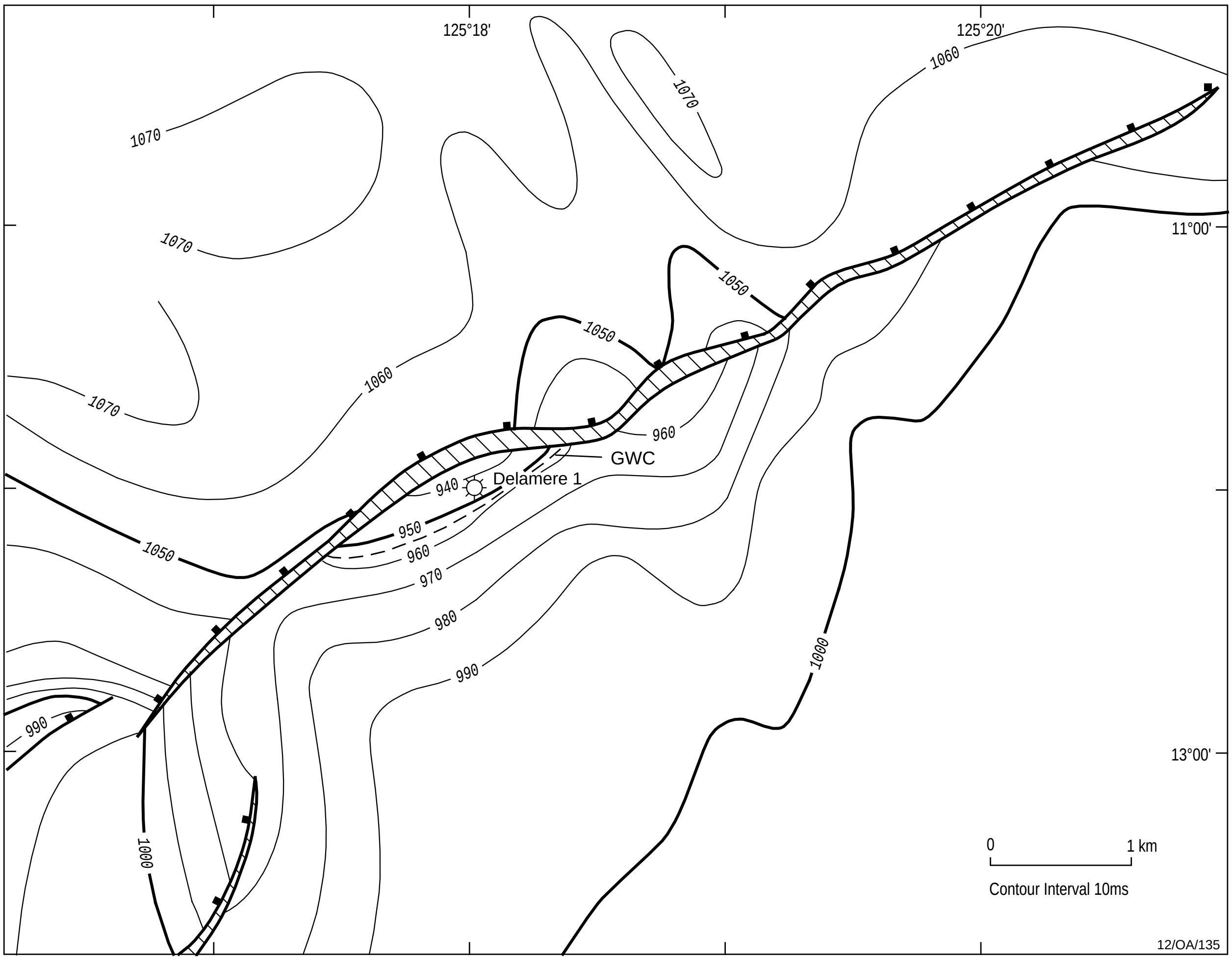
DELAMERE

ORIGINAL OPERATOR:	BHP Petroleum Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	600 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/P4
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Delamere-1
Longitude (E):	125.3042
Latitude (S):	-12.0005
Date total depth reached:	20 AUG 90
Water Depth:	101 m
Kelly bushing:	22 m
Operator:	BHP Petroleum Ltd
Total Depth:	1,530 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Fault dependent closure (tilted fault block)
AREAL CLOSURE:	1 km^2
VERTICAL CLOSURE:	10 m
RESERVOIR UNITS:	1
GROSS GAS PAY:	9 m (1,267.5 – 1,276.6 mKB)
GAS/WATER CONTACT:	1,276.6 mKB (from RFT data)
NET TO GROSS RATIO:	95%
HYDROCARBON SATURATION:	69%
RESERVOIR PRESSURE:	1,848 psia
FORMATION TEMPERATURE:	61^{o}C (at 1,508.9 mKB, after 0.83 hours circulation, 11.33 hours post circulation)

PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Gas
FORMATION:	Flamingo Group
AGE:	Late Jurassic to Early Cretaceous
LITHOLOGY:	Sandstone, very coarse grained, subrounded to well rounded, well sorted, moderate to high sphericity, glauconitic in part, quartzose.
DEPOSITIONAL ENVIRONMENT:	Lower shoreface environment at base of reservoir section to a coastal plain environment at the top (high stand systems tract).
FORMATION TOP (mKB):	1,267 m
POROSITY:	26.6% (average log porosity)
PERMEABILITY:	8.5-184 mD (core analysis) 1,700 mD (average from RFT data)

TEST DATA FROM THE DISCOVERY WELL (Delamere-1)**:**

RFT 1, 1,276.9 m Recovered 0.0014 m^3 of gas and 3.6 litres of filtrate and water.	Flamingo Group
RFT 2, 1,274 m, Recovered 8.9 m^3 of gas and 1.8 litres of filtrate and water with a trace of oil.	Flamingo Group



Delamere, Intra Valanginian, TWT map

REMARKS :

Wireline logs indicated 46.6 m of net pay sand occurs below 1,288 mKB in the Triassic Pollard Formation. Although average log porosity for this interval was around 21.6%, the Pollard Formation was entirely water-wet.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Gas Flamingo Gp
Methane	80.64
Ethane	3.24
Propane	0.29
Isobutane	1.83
N-butane	0.10
Isopentane	0.97
N-pentane	0.03
Hexanes +	0.17
$N_2 + O_2$	11.14
CO_2	1.59

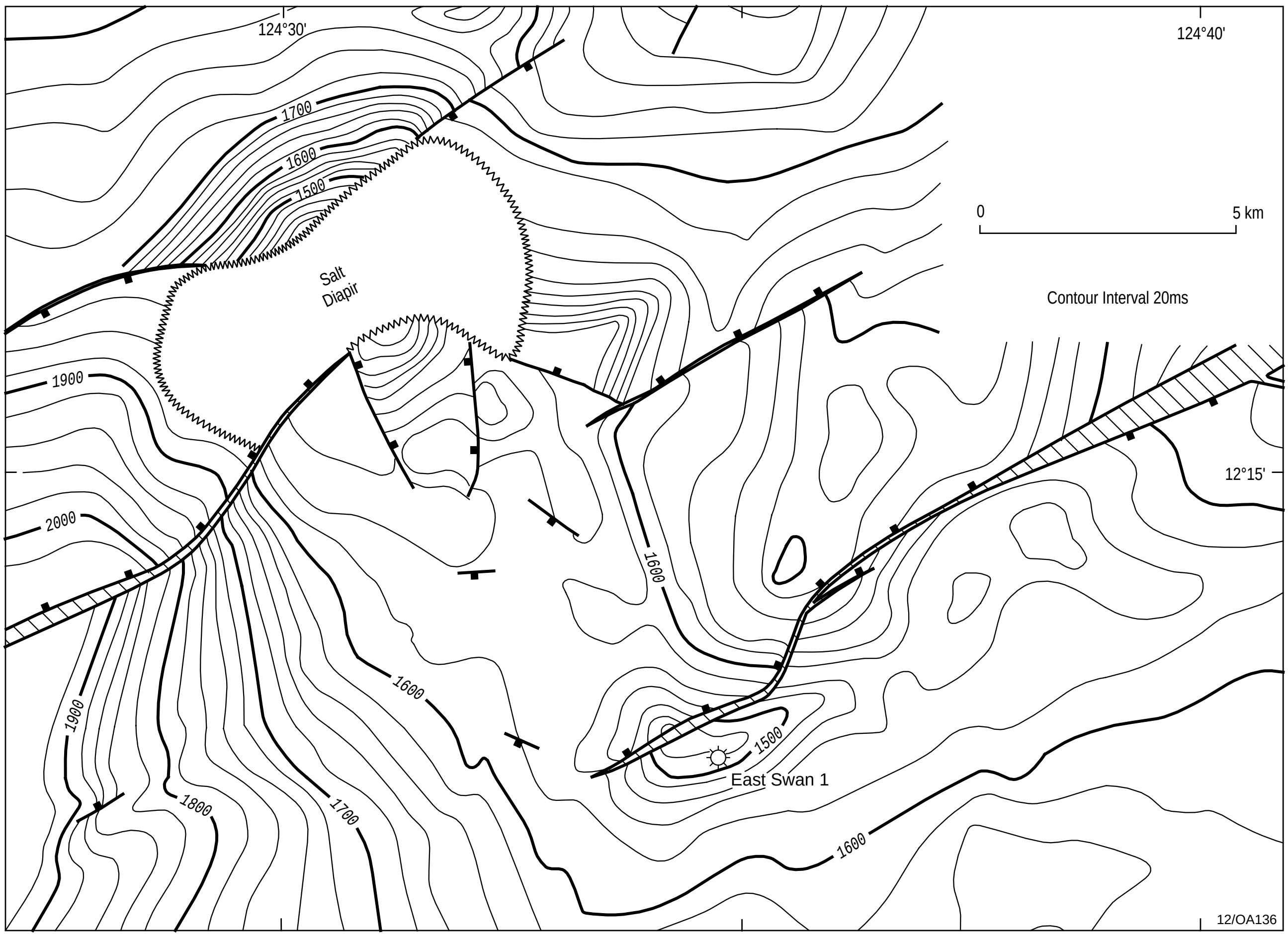
STRATIGRAPHY (Delamere-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Oliver/Barracouta Formations	123.0
		Hibernia Formation	408.0
		Johnson Formation	648.0
CRETACEOUS	BATHURST ISLAND GROUP	Borde Formation	795.0
		Fenelon Formation	913.0
		Gibson Formation	963.0
		Woolaston Formation	1016.0
		Echuca Shoals Formation	1240.0
LATE JURASSIC	FLAMINGO GROUP	Undifferentiated	1267.0
TRIASSIC	SAHUL GROUP	Pollard Formation	1288.0

Accumulation Number: 20

EAST SWAN

ORIGINAL OPERATOR:	Arco Australia Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	690 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	NT/P2
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	East Swan-1
Longitude (E):	124.5822
Latitude (S):	-12.3020
Date total depth reached:	19 MAR 78
Water Depth:	103 m
Kelly bushing:	21 m
Operator:	Arco Australia Ltd
Total Depth:	3,038 mKB
NUMBER OF WELLS DRILLED:	2
STRUCTURE/TRAP:	Tilted fault block
RESERVOIR UNITS:	3
BOTTOM HOLE TEMPERATURE:	247^{o}F (pseudo-Horner plot method)
PETROLEUM BEARING UNIT No.1:	Bathurst Island Group
CONTENTS:	Gas
FORMATION:	Bathurst Island Group
AGE:	Cretaceous
LITHOLOGY:	Sandstone, fine to medium, occasionally coarse, subround, moderately well sorted, common sparite cement, trace of glauconite, rare foraminifera.
FORMATION TOP (mKB):	1,824.2 m
POROSITY:	25% (average log porosity)
PETROLEUM BEARING UNIT No.2:	Troughton Group
CONTENTS:	Gas
FORMATION:	Plover Formation (2 discrete reservoirs)
AGE:	Jurassic
LITHOLOGY:	Sandstone, very fine to coarse, predominantly medium grained, subangular to subround, fair to good sorting (bimodal grainsize distribution), kaolinitic matrix with common sparite cement, abundant quartz overgrowths and pyrite.
DEPOSITIONAL ENVIRONMENT:	Fluvio-deltaic to marginal marine
FORMATION TOP (mKB):	2,330.2 m
GROSS GAS COLUMNS:	20.2 m (2,695 – 2,715.2 mKB) 18.3 m (2,792 – 2,810.3 mKB)
NET TO GROSS RATIOS:	50% (2,695 – 2,715.2 mKB) 55% (2,792 – 2,810.3 mKB)
POROSITY:	7.4 - 17.9% (log porosity, 2,695 – 2,715.2 mKB) 15.2 - 22.2% (log porosity, 2,792 – 2,810.3 mKB)



East Swan, Base Cretaceous, TWT map

GAS SATURATION:	33% (average, 2,695 – 2,715.2 mKB) 36.5% (average, 2,792 – 2,810.3 mKB)

TEST DATA FROM THE DISCOVERY WELL (East Swan-1)**:**

FIT 1, 2,035 m, Recovered 0.74 m^3 of gas, 18 litres of water and 500 cc of mud.	Bathurst Island Group
FIT 4, 2,698 m, Recovered 0.008 m^3 of gas and 9.7 litres of filtrate.	Plover Formation
FIT 3, 2,710 m, Tight test.	Plover Formation
FIT 2, 2,793 m, Recovered 0.014 m^3 of gas and 9.25 litres of filtrate with an oil scum.	Plover Formation
FIT 6, 2,793 m, Recovered 0.011 m^3 of gas and 2 litres of filtrate and formation water with a trace of oil.	Plover Formation
FIT 5, 2,806 m, Recovered 0.014 m^3 of gas, 2 litres of formation water with an oil scum and a quantity of oil stained sand.	Plover Formation

APPRAISAL AND DEVELOPMENT DRILLING :

East Swan-2, drilled 1 km north of East Swan-1, was plugged and abandoned dry.

REMARKS :

Fluid inclusion studies undertaken by O'Brien & others (1996) identified a residual oil column of around 91 m (2,630 – 2,721 mKB) in East Swan-2. The data also suggest a palaeo-gas cap may have originally been present between 2,606 mKB and 2,630 mKB in this well.

STRATIGRAPHY (East Swan-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	124.4
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	1824.2
JURASSIC	FLAMINGO GROUP	Flamingo Gp/Plover Fm	2330.2

Accumulation Number: 21

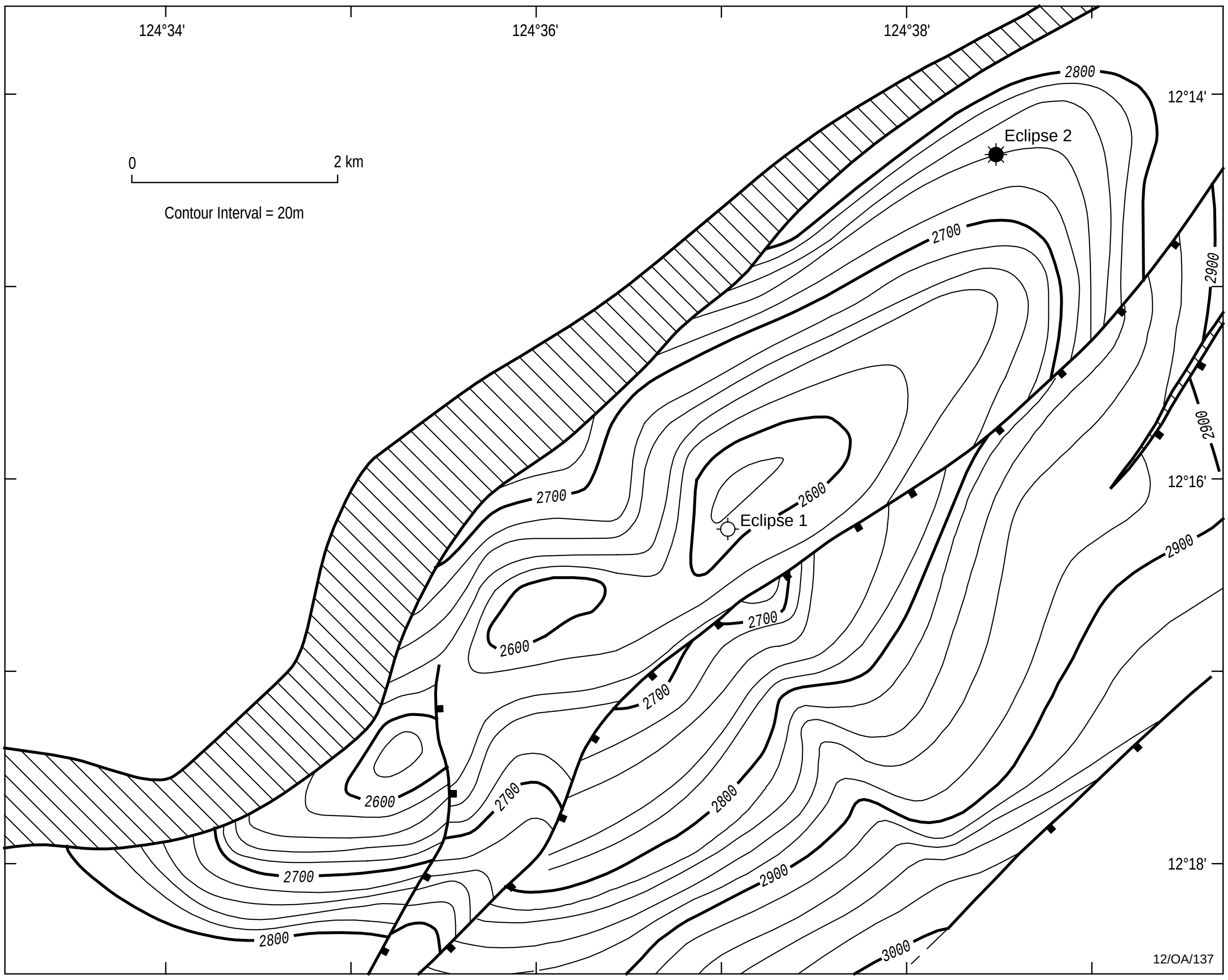
ECLIPSE

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Oil and Gas
STATUS:	Other Discovery
LOCATION:	685 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/P2
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Eclipse-2
Longitude (E):	124.6436
Latitude (S):	-12.2384
Date total depth reached:	03 JUL 86
Water Depth:	117 m
Kelly bushing:	8.3 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	2,930 mKB
NUMBER OF WELLS DRILLED:	2
STRUCTURE/TRAP:	Northeast/southwest trending anticline on the Eclipse-Skua Horst.
RESERVOIR UNITS:	1
BOTTOM HOLE TEMPERATURE:	95°C
GAS/OIL CONTACT:	2,459.7 mKB
OIL/WATER CONTACT:	2,460.2 mKB

PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Oil and Gas
FORMATION:	Flamingo Group
AGE:	Late Jurassic (Oxfordian)
LITHOLOGY:	Hydrocarbons are reservoired in a thin sandstone encountered between 2,458.5 mKB and 2,461 mKB sealed by intraformational claystone and siltstone.
FORMATION TOP (mKB):	2,438 mKB (Flamingo Group)
POROSITY:	10.9% to 21.8% (17% average from core)
PERMEABILITY:	516 to 746 mD (622 mD average from core)

TEST DATA FROM THE DISCOVERY WELL (Eclipse-2)**:**

RFT, 2,457.5 m, Recovered 1.6 m^3 of gas, 550 cc of filtrate and 50 cc of oil.	Flamingo Group
RFT, 2,460.7 m, Recovered mud filtrate, formation water and a minor quantity of oil.	Flamingo Group



Eclipse, Intra Flamingo Group, TWT map

APPRAISAL AND DEVELOPMENT DRILLING :

Eclipse-1, (planned as an updip test of the sandstones which exhibited oil shows in East Swan-1), was plugged and abandoned as a dry hole after only minor fluorescence was observed while drilling the Jurassic section.

REMARKS :

In Eclipse-2, residual oil staining was noted between 2,787 mKB and 2,799 mKB.

Post-drill analysis of Eclipse-2 indicated that complex faulting and poor seismic resolution had caused the well to be drilled into a 'stair-step' fault adjacent to the main bounding fault.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Gas (%) Flamingo Gp
Methane	90.9
Ethane	4.3
Propane	2.7
Isobutane	0.4
N-butane	0.7

STRATIGRAPHY (Eclipse-2) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	117.0
		Hibernia Formation	889.0
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	1935.0
JURASSIC	FLAMINGO GROUP	Undifferentiated	2438.0
	TROUGHTON GROUP	Plover Formation	2930.0

Accumulation Number: 22

EIDER

ORIGINAL OPERATOR:	Arco Australia Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	570 km west-northwest of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	WA-15-P
BASIN:	Bonaparte
SUB-BASIN:	Londonderry High
DISCOVERY WELL:	Eider-1
Longitude (E):	125.7464
Latitude (S):	-11.3892
Date total depth reached:	16 SEP 72
Water Depth:	100 m
Kelly bushing:	34 m
Operator:	Arco Australia Ltd
Total Depth:	2,835 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Extensively faulted anticlinal feature.
AREAL CLOSURE:	5 km^2
VERTICAL CLOSURE:	114 m
RESERVOIR UNITS:	1
BOTTOM HOLE TEMPERATURE:	92°C

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Gas
FORMATION:	Plover Formation
AGE:	Jurassic
LITHOLOGY:	Sandstone, fine to coarse grained, subangular to subrounded, poorly cemented and slightly glauconitic, commonly interbedded with light grey to dark grey-brown, silty to sandy, firm, fissile shale.
DEPOSITIONAL ENVIRONMENT:	Fluvio-deltaic to marginal marine
FORMATION TOP (mKB):	1,801 mKB
POROSITY:	11% to 25% (log porosity)
PERMEABILITY:	No quantitative permeability data available. DST data indicate that permeability between 1,848 m and 1,852 m is probably very high.

TEST DATA FROM THE DISCOVERY WELL (Eider-1):

DST 2, 1,785-1,837 m, Recovered 582 m of water cushion and 395 m of muddy water.	Bathurst Island Group/Flamingo Group
DST 1, 1,848-1,852 m, Recovered 494 m of water cushion and 113 m of muddy water.	Plover Formation
RFT 3, 1,850 m, Seal failure. Recovered drilling mud.	Plover Formation
RFT 6, 1,850 m, Seal failure. Recovered drilling mud.	Plover Formation

Eider, Near Base Cretaceous, OWT map

RFT 4, 1,852 m, Seal failure. Recovered drilling mud.	Plover Formation
RFT 1, 1,853 m, Recovered 0.03 m3 of gas, 2.1 litres of water and 20 cc of sand.	Plover Formation
RFT 2, 1,864 m, Recovered 2.2 litres of formation water with a trace of gas.	Plover Formation
RFT 5, 1,870 m, Recovered 2.2 litres of formation water.	Plover Formation

REMARKS:

Oil stained, sandstone sidewall cores were recovered over a 37 m interval spanning the Flamingo Group and upper Plover Formation in this well.

Gas recovered on RFT from the Plover Formation may be solution gas.

STRATIGRAPHY (Eider-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	134.0
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	1177.0
JURASSIC	FLAMINGO GROUP	Undifferentiated	1801.0
	TROUGHTON GROUP	Plover Formation	1848.0
		Malita Formation	2332.0
TRIASSIC	SAHUL GROUP	Undifferentiated	2661.0

Accumulation Number: 23

ELANG

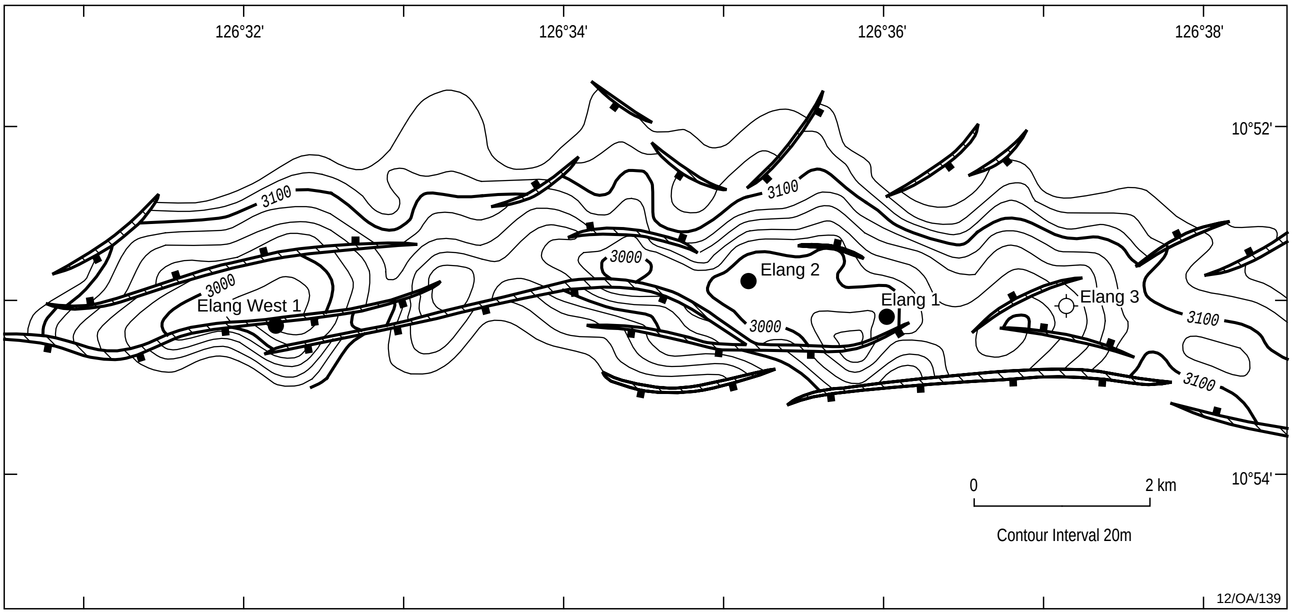
ORIGINAL OPERATOR:	BHP Petroleum (ZOCA 91-12) Pty Ltd
TYPE:	Oil
STATUS:	Producer
LOCATION:	500 km west-northwest of Darwin
STATE:	Zone of Cooperation, Part A
ORIGINAL TITLE(S):	ZOCA 91-12
BASIN:	Bonaparte
SUB-BASIN:	Flamingo High, Sahul Platform
DISCOVERY WELL:	Elang-1
Longitude (E):	126.6004
Latitude (S):	-10.8843
Date total depth reached:	10 FEB 94
Water Depth:	82 m
Kelly bushing:	22 m
Operator:	BHP Petroleum (ZOCA 91-12) Pty Ltd
Total Depth:	3,192 mKB
NUMBER OF WELLS DRILLED:	4 (including Elang West-1)
STRUCTURE/TRAP:	Elongate, east-west oriented, faulted four-way-dip closure on the Elang Trend.
AREAL CLOSURE:	16 km^2
VERTICAL CLOSURE:	120 m
RESERVOIR UNITS:	1
GROSS HYDROCARBON COLUMN:	76.5 m (3,006 – 3,083 mRT)
HYDROCARBON SATURATION:	64% (average)
NET TO GROSS RATIO:	38%
GAS/OIL RATIO:	216 scf/stb
OIL/WATER CONTACT:	3,083 mRT (3061 mSS)
OIL GRAVITY:	59.5^o API

PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Oil
FORMATION:	Elang Formation
AGE:	Middle to Late Jurassic (Late Callovian to Early Oxfordian)
LITHOLOGY:	Sandstone, very fine to very coarse grained, moderately well sorted, mineralogically mature with occasional thin clay stringers and laminae. Common authigenic quartz and kaolin with traces of pyrite, carbonate and glauconite. Five sandstone bodies between 3,006.5 mKB and 3,083 mKB, separated by interbedded claystones have been identified on logs.
DEPOSITIONAL ENVIRONMENT:	A nearshore to shelfal marine facies which transgressed the underlying fluvio-deltaic sediments of the Plover Formation.
FORMATION TOP:	3,006.5 mRT
POROSITY:	11% (average)
PERMEABILITY:	Up to 524 mD (core analysis)

TEST DATA FROM THE DISCOVERY WELL (Elang-1)**:**

MDT, 1 gallon chamber, 3,010 m, Recovered 130 cc of oil with mud filtrate.	Elang Formation

MDT, first 2.75 gallon chamber, 3,060 m, Recovered 2.6 litres of oil, 6.9 litres of Filtrate and 1,443 litres of gas	Elang Formation
DST (CASED) 1, 3,006.5-3,015.5 m, Flowed 56^o API oil at 830 bbls/day through a 6 mm choke at 1,280 psi.	Elang Formation
Production Test, 3,006 – 3,115.5 m, Flowed 57^o API oil at 5,013 bbls/day.	Elang Formation



(modified after Young et al, 1995)

Elang, Near 'Breakup Unconformity', depth map

DST (CASED), 3,006.5-3,068 m, Flowed oil at 5,800 bbls/day through a 21 mm choke. — Elang Formation

APPRAISAL AND DEVELOPMENT DRILLING :

Elang-2 was drilled 1.7 km west of Elang-1 to further appraise the Elang discovery. A production test over the intervals 3,054 – 3,059 mKB and 3,062 – 3,067 mKB flow oil at a maximum stabilised rate of 6,080 bbls/day from the Elang Formation through a 16 mm choke. The oil had an API gravity of 57^o and a gas/oil ratio of 400 cubic feet per barrel. The well was suspended as a possible future oil producer.

Elang-3 was spudded 2 km east of Elang-1 in 1995 to appraise the northeast flank of the Elang structure. The well was plugged and abandoned after failing to encounter significant hydrocarbons in the primary objective.

Elang West-1 was drilled 7 km to the west of Elang-1 in early 1995. The well flowed 40^o API oil at 1,640 bbls/day through a 19 mm choke from the interval 2,822-2,983 mKB. The zone tested by Elang West-1 was stratigraphically higher than the producing zones encountered in Elang-1 and Elang-2. Elang West-1 was cased and suspended as a future oil producer.

RESERVES :

Oil : 17 MMbbls (includes Kakatua)
Source: Department of Resources Develoment, WA, 1998.

REMARKS:

The Elang/Kakatua oil development commenced production in 1998. Sub-sea completions at Kakatua-1, Elang-1 and Elang-2 are connected to an FPSO (the Modec Venture 1) moored over the Elang field.

STRATIGRAPHY (Elang-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	104.0
		Oliver Formation	476.0
		Hibernia Formation	923.5
		Johnson Formation	1740.5
CRETACEOUS	BATHURST ISLAND GROUP	Upper Wangarlu Formation	2088.0
		Lower Wangarlu Formation	2488.5
		‘Radiolarite’	2850.0
		Darwin Formation	2881.5
JURASSIC	FLAMINGO GROUP	Flamingo Group	2915.o
		Montara Formation	3006.5
	TROUGHTON GROUP	Plover Formation	3099.0

Accumulation Number: 24

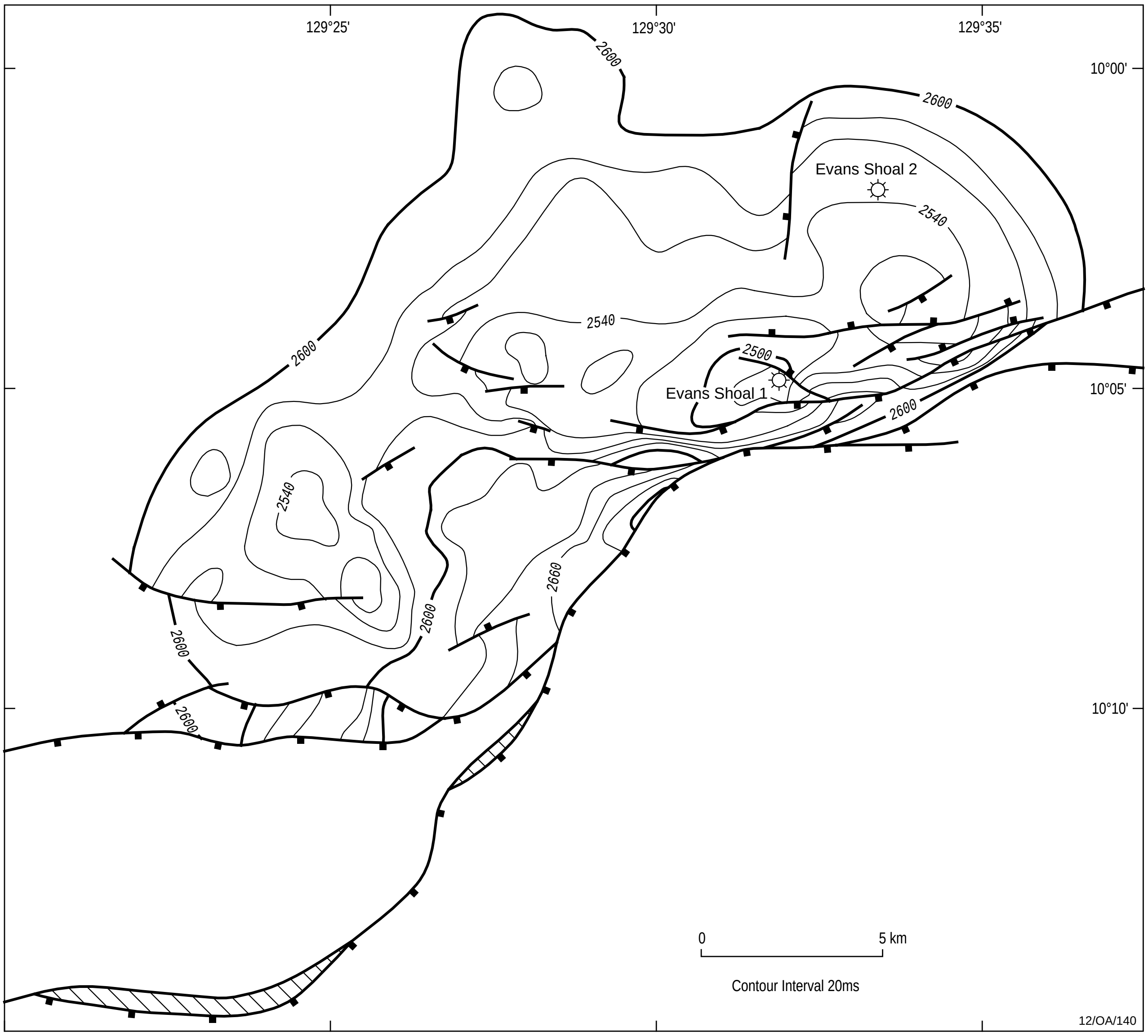
EVANS SHOAL

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	300 km north-northwest of Darwin
STATE:	Northern Territory
ORIGINAL TITLE(S):	NT/P40
BASIN:	Bonaparte
SUB-BASIN:	Sahul Platform/Malita Graben
DISCOVERY WELL:	Evans Shoal-1
Longitude (E):	129.5320
Latitude (S):	-10.0815
Date total depth reached:	18 AUG 88
Water depth:	110 m
Kelly bushing:	17.7 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	3,712 mKB
NUMBER OF WELLS DRILLED:	2
STRUCTURE/TRAP:	Broad, faulted anticlinal feature. Eastern flank of the structure is fault dependent.
VERTICAL CLOSURE:	260 m (at top of middle Jurassic horizon)
RESERVOIR UNITS:	1
BOTTOM HOLE TEMPERATURE:	170^{o}C @ 3,700 mKB

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Gas
FORMATION:	Plover Formation
AGE:	Middle Jurassic (Bathonian to Callovian)
LITHOLOGY:	Sandstone, clear to pale grey or fawn, friable to hard, very fine to occasionally coarse grained, quartzose, common carbonaceous material and pyrite, rare glauconite, abundant quartz overgrowths, interbedded with minor dark grey to black claystone and silty claystone.
DEPOSITIONAL ENVIRONMENT:	Delta plain to marginal marine.
FORMATION TOP (mKB):	3,453 mKB
GROSS HYDROCARBON COLUMN:	169.5 m + (complete reservoir section not penetrated)
NET PAY:	33.7 m
NET TO GROSS RATIO:	20%
GAS SATURATION:	88%
POROSITY:	Up to 12% (8.3% average log porosity) 1.7-2.5% from core (3,709-3,712 mKB)
PERMEABILITY:	0.01-1.0 mD from core (3,709-3,712 mKB)

TEST DATA FROM THE DISCOVERY WELL (Evans Shoal-1)**:**

RFT 1, 3,554 m, Recovered 12.9 m^3 of gas and a quantity of mud filtrate with a black oil scum.	Plover Formation
RFT 7, 3,613.8 m, Recovered 0.07 m^3 of gas and a quantity of mud filtrate with a black oil scum.	Plover Formation



Evans Shoal, Top Plover Formation, TWT map

RFT 13, 3,678 m, Plover Formation
Recovered 2.23 m^3 of gas and a quantity
of mud filtrate with a black oil scum.

APPRAISAL AND DEVELOPMENT DRILLING :

Evans Shoal-2, spudded on 12 February 1998, intersected a 216 m gross gas column in the Plover Formation. A production test taken in the Plover Formation flowed gas at 722,000 m^3/day.

RESERVES:

Condensate: 28.8 MMbbls
Gas: 8.0 TCF
Source: Northern Territory Department of Business Industry and Resource Development, 1998.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	**Plover Fm RFT 1, 3554 m**	**Plover Fm RFT 7, 3613.8 m**
Methane	77.61	78.67
Ethane	2.07	2.32
Propane	0.54	0.64
iso-Butane	0.16	0.19
n-Butane	0.16	0.19
iso-Pentane	0.10	0.14
n-Pentane	0.06	0.07
Hexanes	0.09	0.11
Heptanes	0.06	0.08
Octanes	0.03	0.05
Nonanes	0.01	0.02
Decanes	0.00	0.02
Undecanes	0.00	0.01
Dodecanes +	0.00	0.01
Nitrogen	0.67	0.72
CO_2	18.44	16.76
H_2S (ppm)	0.00	0.00

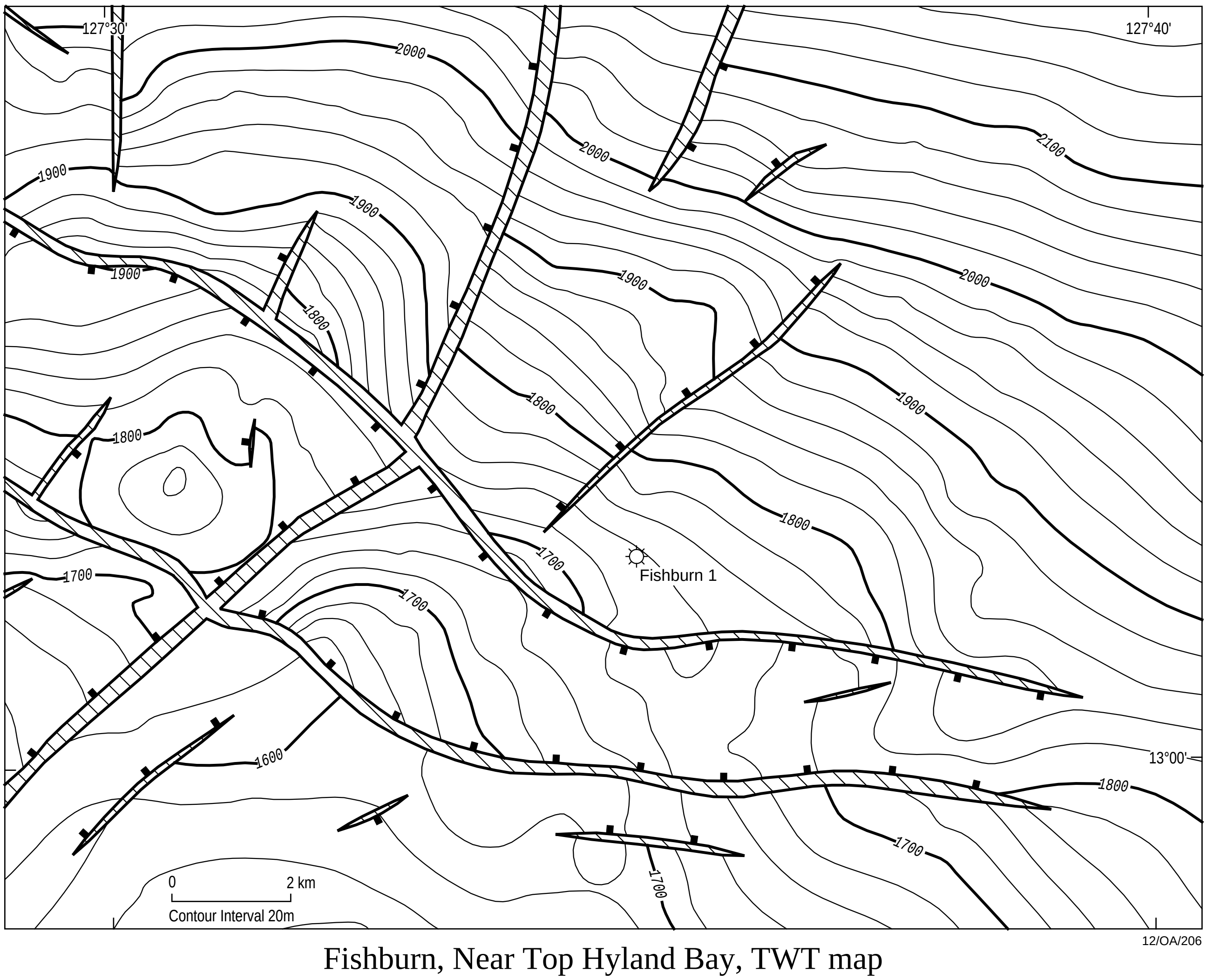
STRATIGRAPHY (Evans Shoal-1) **:**

AGE	**UNIT**		**FORMATION TOP (mKB)**
TERTIARY	WOODBINE GROUP	Undifferentiated	451.0
		Hibernia Formation	700.5
CRETACEOUS	BATHURST ISLAND GP	Wangarlu Formation	1697.0
JURASSIC	TROUGHTON GROUP	Plover Formation	3453.0

Accumulation Number: 25

FISHBURN

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	360 km west-southwest of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	WA-218-P
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Fishburn-1
Longitude (E):	127.5843
Latitude (S):	-12.9680
Date total depth reached:	22 OCT 92
Water Depth:	63.6 m
Kelly bushing:	30.4 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	2,870 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Tilted fault block with three-way dip closure.
RESERVOIR UNITS:	1
BOTTOM HOLE TEMPERATURE:	104^{o}C (after 1.2 hours circulation, 7.9 hours post circulation)
RESERVOIR PRESSURE:	23,240 kpa (at 2,370 mKB)
GROSS HYDROCARBON COLUMN:	51 m (2,319-2,370 mKB)
NETT HYDROCARBON COLUMN:	27.7 m
NETT TO GROSS RATIO:	54%
HYDROCARBON SATURATION:	27% (average)
GAS/WATER CONTACT:	2,370 mKB (from logs)
PETROLEUM BEARING UNIT No.1:	Tern/Dombey/Cape Hay and Pearce Members
CONTENTS:	Gas
FORMATION:	Hyland Bay Formation
AGE:	Late Permian (Kazanian)
LITHOLOGY:	*Tern Member*: Sandstone, off-white to pale brown, very fine, subangular, poorly sorted, argillaceous, minor siliceous cement, trace of carbonaceous material, feldspar and mica, grading to tan to dark grey silty claystone towards top of unit. *Dombey Member*: Calcarenite, off-white, firm to hard, brittle, commonly recrystallised (crypto- to microcrystalline), fine to medium to coarse grained, angular to subangular, elongate to slightly spherical, poorly to moderately well sorted, common off-white, micritic and argillaceous matrix, fossiliferous. *Cape Hay Member:* Interbedded silty and arenaceous claystone, sandstone and siltstone. Sandstone is off-white to light grey, clear to translucent quartz grains, very fine to medium, subangular to subrounded, moderately well sorted, common calcareous cement and white, argillaceous matrix, trace of glauconite and carbonaceous material.



Fishburn, Near Top Hyland Bay, TWT map

	Pearce Member: Calcilutite/Calcarenite, white to off-white, fine to medium, angular to subangular, recrystallised in part, patchy off-white argillaceous matrix, trace of bryozoan and spinose fragments.
DEPOSITIONAL ENVIRONMENT:	*Tern Member*: lower to upper shoreface. Possibly a distributary mouth bar, channel or intradistributary bay deposit. *Dombey Member*: deltaic to shallow marine with restricted sediment supply. *Cape Hay Member*: regressive phase with environment of deposition shallowing from lower to upper delta plain.
FORMATION TOP (mKB):	2,293.5 mKB (Tern Member)
POROSITY:	15% (average log porosity)
PERMEABILITY:	8.8 - 27.9 mD (MSCT data) 10.4 mD (average log permeability)

TEST DATA FROM THE DISCOVERY WELL (Fishburn-1)**:**

RFT 1, 2,323 m, Recovered 2.7 m^3 of gas, 5.2 litres of filtrate with a trace of oil/condensate.	Hyland Bay Formation (Tern Member)
RFT 2, 2,373 m, Recovered 0.09 m^3 of gas and 46.5 litres of filtrate.	Hyland Bay Formation (Pearce Member)

REMARKS:

The low hydrocarbon saturations observed in the reservoir are thought to be due to a combination of deep filtrate invasion and the presence of pyrite (seen in cuttings) making log interpretation difficult.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	**Hyland Bay Fm (Tern Mbr) RFT 1, 2323 mKB**
Methane	93.05
Ethane	2.09
Propane	0.52
Isobutane	0.07
N-butane	0.13
Isopentane	0.04
N-pentane	0.04
Hexanes	0.07
Heptanes	0.15
Octanes	0.09
Nonanes	0.08
C_{10}+	0.07
Nitrogen	0.66
CO_2	2.94
O_2	0.00
Specific Gravity	0.621

STRATIGRAPHY (Fishburn-1) **:**

<table>
<tr><th>AGE</th><th colspan="2">UNIT</th><th>FORMATION TOP (mKB)</th></tr>
<tr><td rowspan="2">TERTIARY</td><td rowspan="2">WOODBINE GROUP</td><td>Recent</td><td>94.0</td></tr>
<tr><td>Undifferentiated</td><td>140.0</td></tr>
<tr><td rowspan="2">CRETACEOUS</td><td rowspan="2">BATHURST ISLAND GROUP</td><td>Wangarlu Formation</td><td>391.0</td></tr>
<tr><td>Darwin Formation</td><td>1186.6</td></tr>
<tr><td rowspan="2">JURASSIC</td><td rowspan="2">FLAMINGO GROUP</td><td>Sandpiper Sandstone</td><td>1193.0</td></tr>
<tr><td>Frigate Shale</td><td>1428.5</td></tr>
<tr><td rowspan="3">TRIASSIC</td><td rowspan="2">TROUGHTON GROUP</td><td>Plover Formation</td><td>1566.7</td></tr>
<tr><td>Malita Formation</td><td>1860.8</td></tr>
<tr><td rowspan="7">KINMORE GROUP</td><td>Mt Goodwin Formation</td><td>1904.5</td></tr>
<tr><td rowspan="6">PERMIAN</td><td>Hyland Bay Formation
Tern Member</td><td>2293.5</td></tr>
<tr><td>Dombey Member</td><td>2331.0</td></tr>
<tr><td>Cape Hay Member</td><td>2332.6</td></tr>
<tr><td>Pearce Member</td><td>2562.0</td></tr>
<tr><td>Basal Member</td><td>2574.0</td></tr>
<tr><td>Fossil Head Formation</td><td>2603.2</td></tr>
</table>

AccumulationNumber: 26

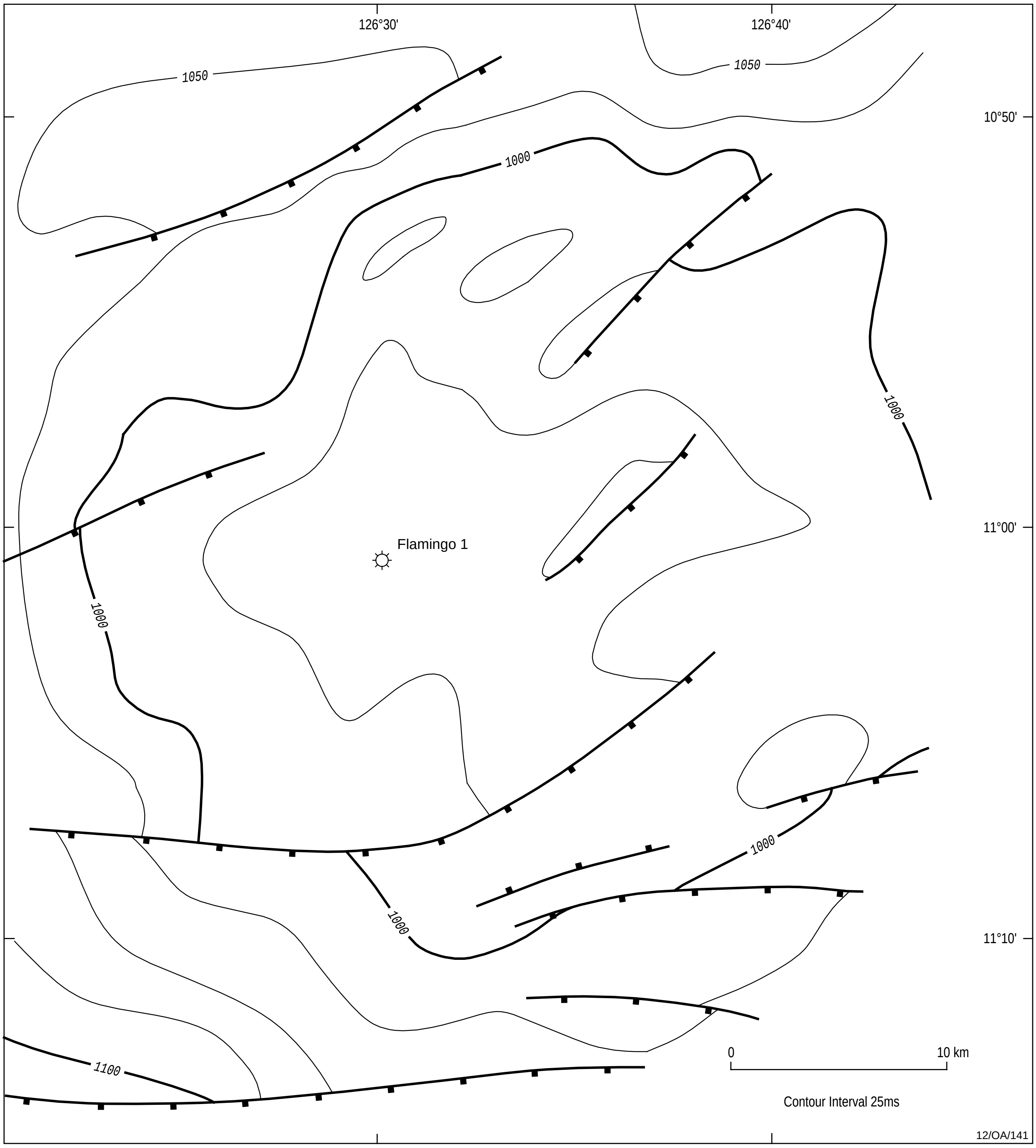
FLAMINGO

ORIGINAL OPERATOR:	Arco Australia Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	500 km northwest of Darwin
STATE:	Zone of Cooperation, Part A
ORIGINAL TITLE(S):	WA-16-P
BASIN:	Bonaparte
SUB-BASIN:	Flamingo High, Sahul Platform
DISCOVERY WELL:	Flamingo-1
Longitude (E):	126.4819
Latitude (S):	-11.0261
Date total depth reached:	30 NOV 71
Water Depth:	96 m
Kelly bushing:	34 m
Operator:	Arco Australia Ltd
Total Depth:	3,700 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Faulted four-way-dip closure
AREAL CLOSURE:	Up to 780 km^2
VERTICAL CLOSURE:	Up to 220 m
RESERVOIR UNITS:	Multiple (6) gas sands within the Plover Formation
GROSS HYDROCARBON COLUMN:	217 m (3,250-3,467 mKB)
NET PAY:	71.6 m
NET TO GROSS RATIO:	33%
HYDROCARBON SATURATION:	45% (average)
BOTTOM HOLE TEMPERATURE:	124^{o}C

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Gas
FORMATION:	Plover Formation
AGE:	Jurassic
LITHOLOGY:	Sandstone, calcareous and glauconitic in part, interbedded with micaceous siltstone.
DEPOSITIONAL ENVIRONMENT:	Fluvio-deltaic to marginal marine
FORMATION TOP (mKB):	3,048 m
POROSITY:	13.9% (average)
PERMEABILITY:	Up to 21 mD

TEST DATA FROM THE DISCOVERY WELL (Flamingo-1)**:**

RFT 4, 3,271 m, Recovered 10.5 litres of muddy water.	Plover Formation
RFT 11, 3,276 m, Recovered 2.2 litres of formation water.	Plover Formation
RFT 10, 3,315 m, Recovered 0.13 m^3 of gas and 2.1 litres of formation water.	Plover Formation
RFT 3, 3,317 m, Recovered 0.04 m^3 of gas and 18.5 litres of muddy water.	Plover Formation



Flamingo, Near Base Cretaceous, OWT map

RFT 2, 3,376 m, Plover Formation
Recovered 2.2 litres of muddy water.

RFT 5, 3,376 m, Plover Formation
Misrun.

RFT 9, 3,432 m, Plover Formation
Recovered 2.6 litres of formation water.

RFT 1, 3,445 m, Plover Formation
Recovered 245 cc of formation water.

RFT 8, 3,511 m, Plover Formation
Recovered 17.5 litres of water.

RFT 7, 3,549 m, Plover Formation
Recovered 200 cc of drilling mud.

RFT 12, 3,625 m, Plover Formation
Recovered 2.1 litres of formation water.

RFT 6, 3,633 m, Plover Formation
Recovered 2.2 litres of muddy water.

REMARKS:

Live oil shows were observed in core-6 (3,623.46-3,634.44 mKB, Plover Formation).

It is possible that the gas recovered on RFT from the Plover Formation constitutes solution gas.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Gas Plover Fm (3315 mKB)	Gas Plover Fm (3317 mKB)
Methane	33.9	59.4
Ethane	2.8	4.3
Propane	0.7	1.4
Isobutane	0.1	0.2
N-butane	0.2	0.3
Isopentane	0.1	0.2
N-pentane	0.1	0.1
Nitrogen	9.7	26.0
CO_2	0.1	5.3
H_2	2.4	2.8
Air	50.0	00.0

STRATIGRAPHY (Flamingo-1) **:**

AGE	**UNIT**		**FORMATION TOP (mKB)**
TERTIARY	WOODBINE GROUP	Undifferentiated	277.0
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	2006.0
JURASSIC	FLAMINGO GROUP	Undifferentiated	2925.0
	TROUGHTON GROUP	Plover Formation	3048.0

Accumulation Number: 27

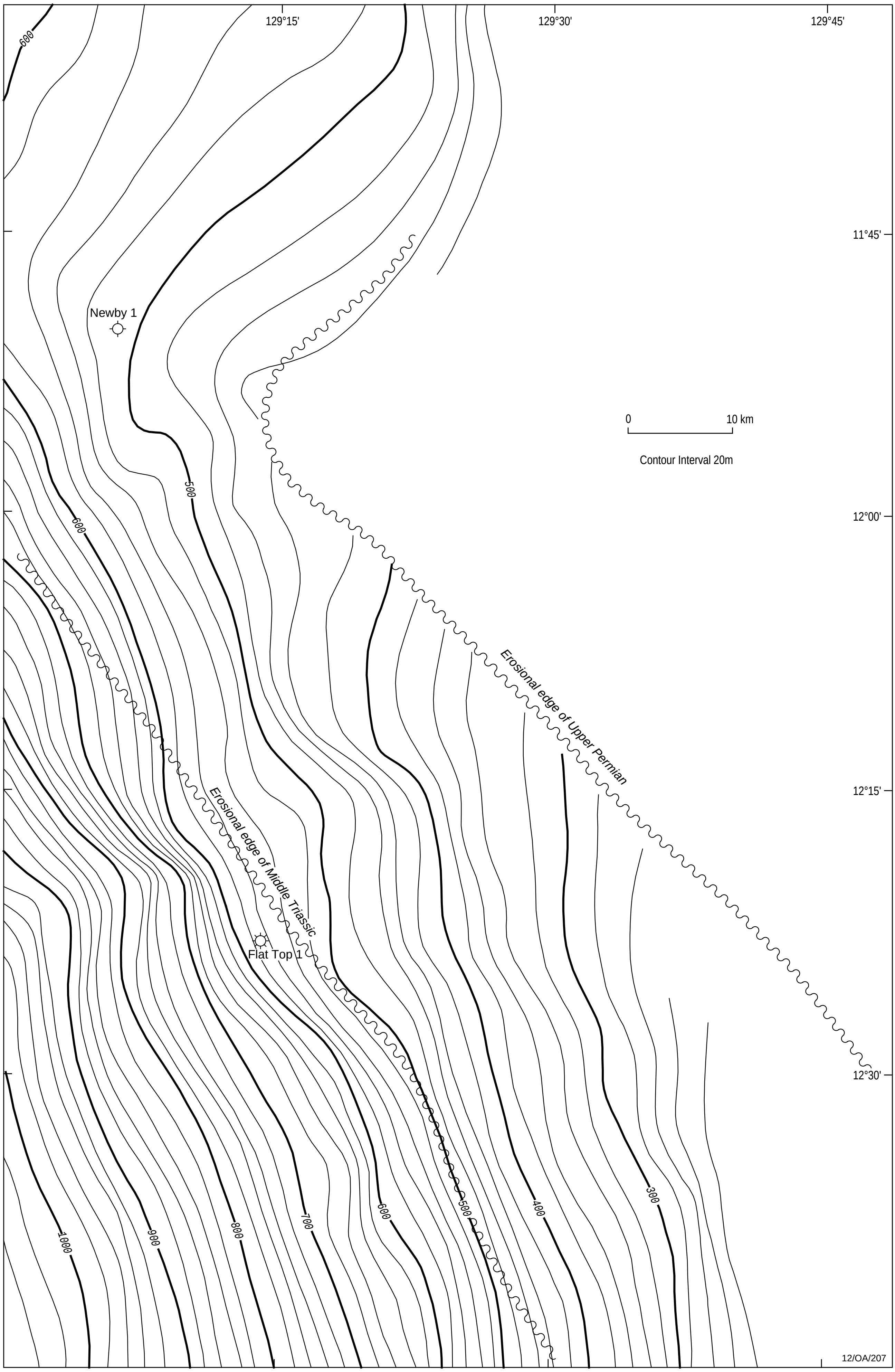
FLAT TOP

ORIGINAL OPERATOR:	Australia Aquitaine Petroleum Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	170 km west of Darwin
STATE:	Northern Territory
ORIGINAL TITLE(S):	NT/P17
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Flat Top-1
Longitude (E):	129.2655
Latitude (S):	-12.3765
Date total depth reached:	26 JAN 70
Water Depth:	41 m
Kelly bushing:	12.2 m
Operator:	Australia Aquitaine Petroleum Ltd
Total Depth:	2,174 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Drilled to test for the presence of stratigraphic pinchouts and erosional wedges on the northern edge of the Petrel Sub-basin.
RESERVOIR UNITS:	1
BOTTOM HOLE TEMPERATURE:	105°C

PETROLEUM BEARING UNIT No.1:	Hyland Bay Formation
CONTENTS:	Gas
FORMATION:	Cape Hay Member ?
AGE:	Permian
LITHOLOGY:	Sandstone, very fine to coarse, friable, interbedded with tight, micritic and bioclastic limestone and dark grey to black, pyritic and lignitic shale. Limestone forms three massive beds (1,304-1326 m, 1,417-1,453 m and 1,553-1,578 m)
DEPOSITIONAL ENVIRONMENT:	Deltaic to marginal marine
FORMATION TOP (mKB):	1,277 mKB (Cape Hay Member ?)
POROSITY:	22-30% (log porosity)
PERMEABILITY:	around 160 mD

TEST DATA FROM THE DISCOVERY WELL (Flat Top-1)**:**

RFT 3, 1,082 m, Recovered 19 litres of formation water and 750 cc of drilling mud.	Hyland Bay Formation
RFT 1, 1,473 m, Recovered 0.001 m^3 of gas and 20 litres of drilling mud.	Hyland Bay Formation
RFT 4, 1,473 m, Recovered 0.01 m^3 of gas, 16.5 litres of formation water and 3.5 litres of drilling mud.	Hyland Bay Formation



Flat Top, Near Top Permian, OWT map

RFT 2, 1,588 m, Recovered 13.5 litres of formation water and 1.2 litres of drilling mud.	Hyland Bay Formation

REMARKS:

It is possible that the gas recovered from the Hyland Bay Formation by RFT constitutes solution gas.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Hyland Bay Fm RFT 4, 1473 m
Methane	10.50
Ethane	0.15
Oxygen	18.60
Nitrogen	70.30
CO_2	0.45

STRATIGRAPHY (Flat Top-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	55.0
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	189.0
JURASSIC to TRIASSIC	FLAMINGO & TROUGHTON GROUPS	Undifferentiated	730.0
PERMIAN	KINMORE GROUP	Hyland Bay Formation	978.0
		Cape Hay Member ?	1277.0
		Fossil Head Formation ?	1579.0
PROTEROZOIC	BASEMENT	Undifferentiated	2166.0

Accumulation Number: 28

FOHN

ORIGINAL OPERATOR:	Phillips Australia Oil Company Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	430 km northwest of Darwin
STATE:	Zone of Cooperation, Part A
ORIGINAL TITLE(S):	ZOCA 91-13
BASIN:	Bonaparte
SUB-BASIN:	Flamingo Syncline
DISCOVERY WELL:	Fohn-1
Longitude (E):	127.1455
Latitude (S):	-11.0033
Date total depth reached:	06 AUG 94
Water Depth:	83 m
Kelly bushing:	22 m
Operator:	Phillips Australia Oil Company Ltd
Total Depth:	1,440 mKB (main well) 3,814 mKB (sidetrack. Kick-off at 1,359 mKB)
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Tilted fault block with some internal 4-way-dip closure.
AREAL CLOSURE:	12 km^2
VERTICAL CLOSURE:	160 m (At Base Valanginian)
RESERVOIR UNITS:	1
GROSS HYDROCARBON COLUMN:	218 m (3,565 – 3,783 mKB)
NET PAY:	82 m
NET TO GROSS RATIO:	38%
HYDROCARBON SATURATION:	50%

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Gas
FORMATION:	Plover Formation
AGE:	Jurassic
LITHOLOGY:	Sandstone, very light grey, very fine to medium grained, well sorted, subangular to subrounded, 5 – 20% silica cement, interbedded with claystone and siltstone.
DEPOSITIONAL ENVIRONMENT:	Fluvio-deltaic to marginal marine
FORMATION TOP (mKB):	3,512.0 m
POROSITY:	8% (average log porosity)
PERMEABILITY:	0.01 – 0.13 mD (core data)

TEST DATA FROM THE DISCOVERY WELL (Fohn-1)**:**

MDT, 3,579.5 m Unspecified quantity of gas recovered using MDT tool.	Plover Formation

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Plover Fm MDT sample 3579.5 m
Methane	79.44
Ethane	7.20
Propane	4.29
Isobutane	0.69
N-butane	0.86
Isopentane	0.27
N-pentane	0.16
Hexanes +	0.18
Nitrogen	6.73
CO_2	0.18
Specific Gravity	0.6960
BTU/cubic ft	1115

STRATIGRAPHY (Fohn-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Hibernia Formation	706.0
		Johnson Formation	1340.0
CRETACEOUS	BATHURST ISLAND GROUP	Vee Formation	2002.0
		Wangarlu Formation	2522.0
		Radiolarite Equivalent	3347.0
		Darwin Formation	3404.0
	FLAMINGO GROUP	Undifferentiated	3469.0
JURASSIC	TROUGHTON GROUP	Plover Formation	3512.0

Accumulation Number: 29

GARIMALA

ORIGINAL OPERATOR:	Santos Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	380 km southwest of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	EP 126
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Garimala-1
Longitude (E):	128.7263
Latitude (S):	-15.1879
Date total depth reached:	03 NOV 88
Ground level:	21.1 m
Kelly bushing:	22.9 m
Operator:	Santos Ltd
Total Depth:	2,553 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	North trending anticline on the western flank of the Petrel Sub-basin

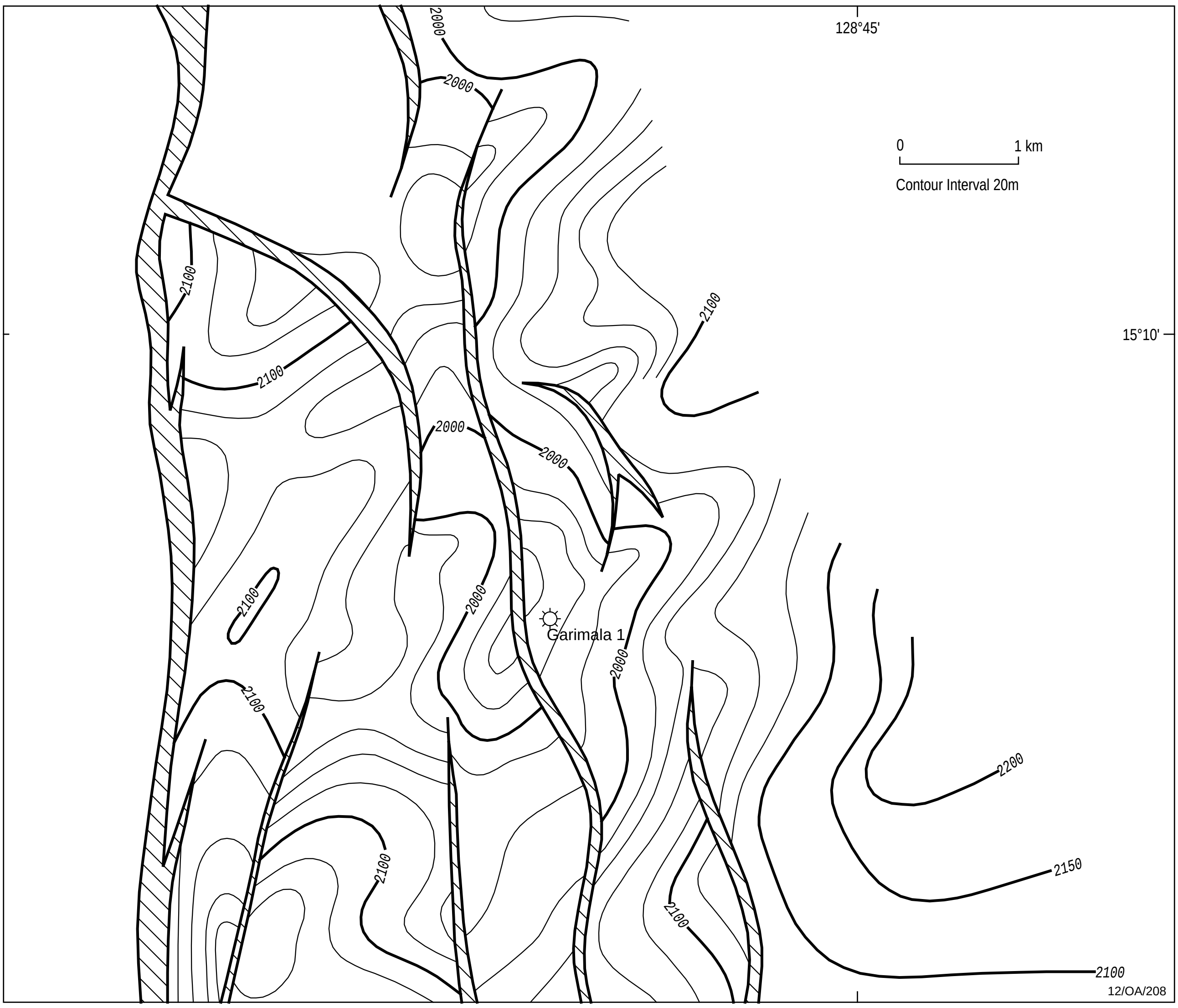
PETROLEUM BEARING UNIT No.1:	Bonaparte Formation
CONTENTS:	Gas
FORMATION:	Bonaparte Formation
AGE:	Devonian

TEST DATA FROM THE DISCOVERY WELL (Garimala-1)**:**

DST 1, 995-1,040 m, No flow to surface. Recovered 79.5 m^3 of mud and mud filtrate.	Upper Milligans Formation
DST 2, 2,381-2,401 m, Flowed gas at 21,240 m^3/day through a 25.4 mm choke.	Bonaparte Formation

REMARKS:

Non-mobile oil (fluorescence) was noted in the Milligans Formation



Garimala, Intra Bonaparte Formation, depth map (pre-drill)

Accumulation Number: 30

HALCYON

ORIGINAL OPERATOR:	Lasmo Oil Company Australia Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	590 km west of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	WA-199-P
BASIN:	Bonaparte
SUB-BASIN:	Northeast Londonderry High
DISCOVERY WELL:	Halcyon-1
Longitude (E):	125.4717
Latitude (S):	-11.9378
Date total depth reached:	29 JUL 91
Water Depth:	98 m
Kelly bushing:	18 m
Operator:	Lasmo Oil Company Australia Ltd
Total Depth:	2,090 mKB 1,853 mTVD
Deviation Angle:	38^o
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Fault dependent closure
RESERVOIR UNITS:	1
GROSS HYDROCARBON COLUMN:	15.6 mTVT (1,336 – 1,353 mKB)
GAS/WATER CONTACT:	1,353 mKB (1,340 mTVD KB)
HYDROCARBON SATURATION:	40 - 75%
NET TO GROSS RATIO:	70% (10% porosity cut-off)
BOTTOM HOLE TEMPERATURE:	67^oC (13.45 hours post circulation)

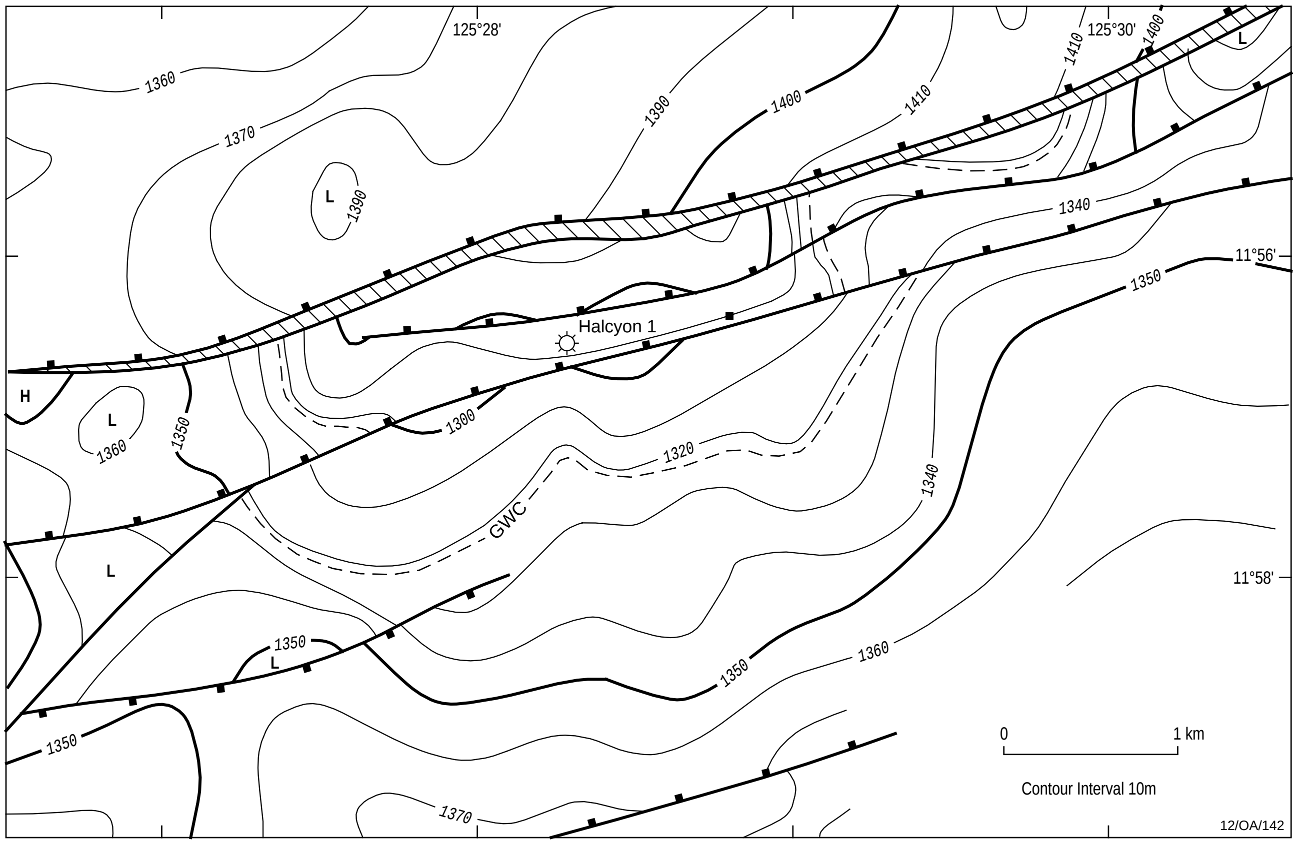
PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Gas
FORMATION:	Flamingo Group
AGE:	Late Jurassic to Early Cretaceous
LITHOLOGY:	Fine to coarse grained quartz arenite, clay matrix, common glauconite, slightly cemented with siderite, calcite and silica, interbedded with thin siltstones and shales.
FORMATION TOP (mKB):	1,336 m
POROSITY:	17% (average log porosity)
PERMEABILITY:	23 - 86 mD (RFT data)

TEST DATA FROM THE DISCOVERY WELL (Halcyon-1)**:**

RFT, 1,343.5 m Recovered 1.46 m^3 of gas and 90 cc of water.	Flamingo Group

REMARKS:

Halcyon-1 was deviated at an average angle of 40^o NNW below the $13^3/_8$" casing point.



Halcyon, Near Base Cretaceous, depth map

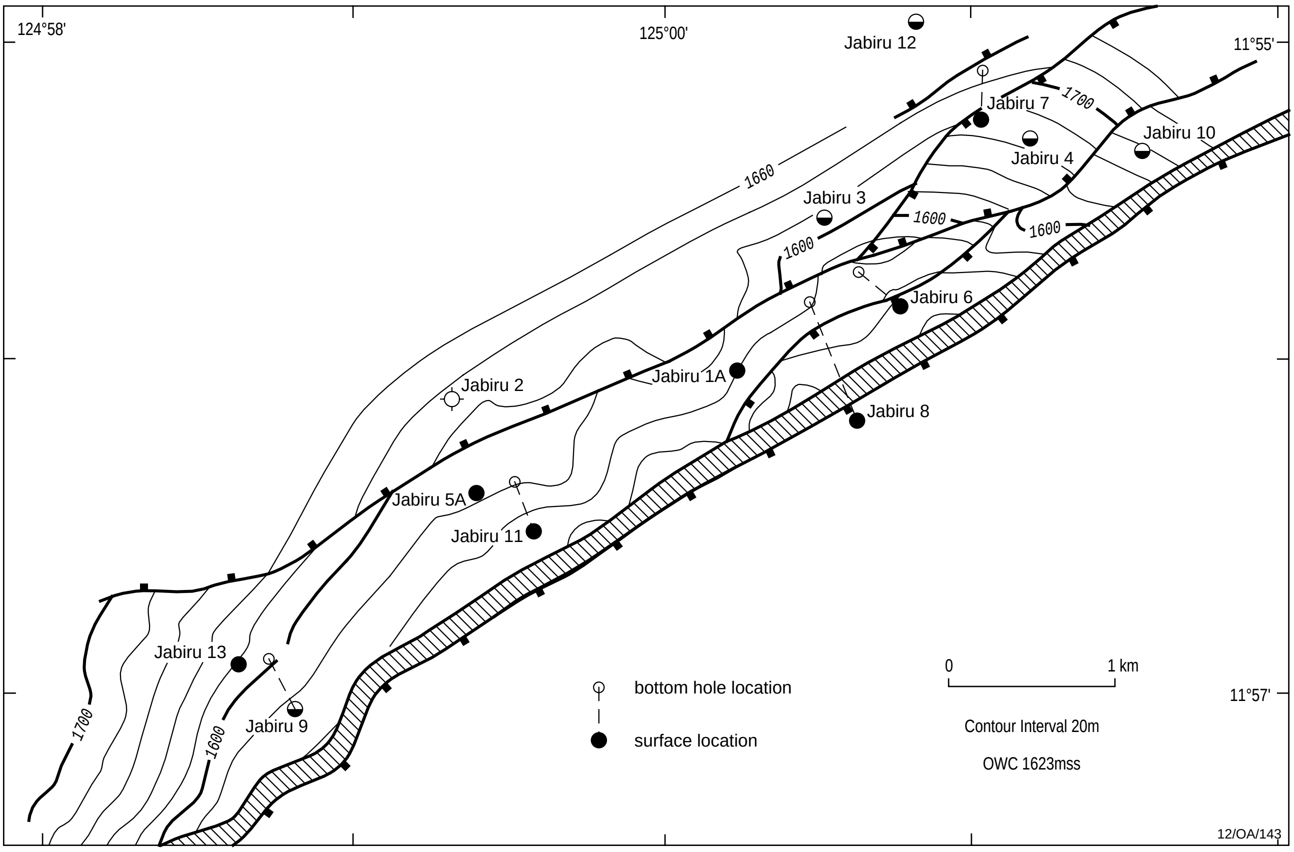
STRATIGRAPHY (Halcyon-1) **:**

AGE	**UNIT**		**FORMATION TOP (mKB)**
TERTIARY	WOODBINE GROUP	Undifferentiated	118.0
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	680.5
	FLAMINGO GROUP	Undifferentiated	1336.0
TRIASSIC	SAHUL GROUP	Undifferentiated	1374.5

Accumualtion Number: 31

JABIRU

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Oil
STATUS:	Producer
LOCATION:	640 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	NT/P26
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Jabiru-1A
Longitude (E):	125.0041
Latitude (S):	-11.9336
Date total depth reached:	29 SEP 83
Water Depth:	120 m
Kelly bushing:	30 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	3,225 mKB
NUMBER OF WELLS DRILLED:	23 (includes 3 redrills, 7 sidetracks and 1 deviated well)
STRUCTURE/TRAP:	Fault dependent. Eroded and tilted Jurassic fault block on the Jabiru-Turnstone Horst.
AREAL CLOSURE:	30 km^2
VERTICAL CLOSURE:	35 m
RESERVOIR UNITS:	1
OIL/WATER CONTACT:	1,623 mSS
GAS/OIL RATIO:	449 scf/stb
GROSS HYDROCARBON COLUMN:	103 m
NET TO GROSS RATIO:	95%
HYDROCARBON SATURATION:	85% (Flamingo Group) 91% (Plover Formation)
OIL GRAVITY:	42.5^{o} API
BUBBLE POINT PRESSURE:	2,106 psig @ 72^{o}C
RESERVOIR PRESSURE:	2,382.2 psia (Jabiru-1A, prior to production)
BOTTOM HOLE TEMPERATURE:	102^{o}C (Jabiru-1A)
PETROLEUM BEARING UNIT No.1:	Flamingo Group/Troughton Group
CONTENTS:	Oil
FORMATION:	Flamingo Group/Plover Formation
AGE:	Middle to Late Jurassic
LITHOLOGY:	Flamingo Gp: very fine to fine grained, argillaceous sandstone. Plover Fm: medium to coarse grained, moderately to well sorted quartz arenite.
DEPOSITIONAL ENVIRONMENT:	Flamingo Gp: shallow marine to upper shoreface or strandline deposits Plover Fm: crossbedded coastal sand body deposited in a beach or barrier island environment.
FORMATION TOP (mKB):	1,594 m (Flamingo Gp)
POROSITY:	Flamingo Gp: 12% to 23% Plover Fm: 21% (average)
PERMEABILITY:	Flamingo Gp: 30-2,000 mD Plover Fm: 600-10,000 mD



Jabiru, Top Reservoir, depth map

TEST DATA FROM THE DISCOVERY WELL (Jabiru-1A)**:**

RFT 26, 1,595 m, Flamingo Group
Recovered 4 litres of oil, 0.032 m^3 of gas and 5.5 litres of water.

RFT 6, 1,602 m, Flamingo Group
Recovered 5.2 litres of oil, 0.34 m^3 of gas and 4.5 litres of water.

DST (CASED) 3, 1595-1,602 m, Flamingo Group
Flowed oil at 2,450 – 7,120 bbls/day and gas at 24,600 – 59,900 m^3/day through a 5/8” choke.

DST (CASED) 1, 1608-1615 m, Plover Formation
Flowed oil at 1,600 – 7,040 bbls/day and gas at 13,000 – 44,000 m^3/day.

DST (CASED) 2, 1,608-1,628 m, Plover Formation
Flowed oil at 590 – 6,900 bbls/day and gas at 5,800 – 54,800 m^3/day through a 1” choke.

RFT 27, 1,610 m, Plover Formation
Recovered 6.5 litres of oil, 0.2 m^3 of gas and 2.2 litres of water.

RFT 1, 1,639 m, Plover Formation
Recovered 2 litres of oil, 0.11 m^3 of gas and 8.1 litres of water.

RFT 2, 1,647 m, Plover Formation
Recovered 6.25 litres of oil, 0.28 m^3 of gas and 3.5 litres of water.

RFT 28, 1,661 m, Plover Formation
Recovered 22 litres of water with an oil scum.

RFT 29, 1,710 m, Plover Formation
Recovered 22.2 litres of water.

APPRAISAL AND DEVELOPMENT DRILLING :

Jabiru-1 was abandoned at 1,160 m due to mechanical difficulties.

Jabiru-2, drilled 1.7 km to the southwest of Jabiru-1A on the southwestern flank of the structure, intersected the reservoir below the oil/water contact and was plugged and abandoned without recording significant hydrocarbon shows.

Jabiru-3, drilled 1 km to the northeast of Jabiru-1A on the northeastern flank of the structure, was plugged and abandoned after encountering uneconomic quantities of hydrocarbons.

Jabiru-4 intersected a 32.5 m gross oil column (22.5 m net pay). However production testing resulted in an oil flow of only 90 bbls/day and the well was plugged and abandoned.

Jabiru-5A was sidetracked from Jabiru-5 and intersected a 37.3 m gross oil column within the Jurassic. Oil shows were noted between 1,206 mKB and 1,220 mKB towards the base of the Palaeocene and may be evidence of oil leaked from the Jabiru structure as a result of Mio-Pliocene fault reactivation.

Jabiru-6 was drilled to produce oil updip of Jabiru-3. The well intersected 60 m TVT of net oil sand and was cased and suspended as an oil producer.

Jabiru-7 intersected the base of the Cretaceous on the downthrown side of the major bounding fault. The well penetrated 6.9 m of net oil sand and was sidetracked (Jabiru-7ST-1)

Jabiru-7ST-1 was sidetracked 130 m to the north at an angle of 53.7^{o} from the main vertical well (Jabiru-7). The sidetrack intersected 13.2 m TVT of net oil sand and was cased and suspended as an oil producer.

Jabiru-8 was plugged and abandoned after losing the bottom hole assembly.

Jabiru-8A, (planned as a redrill of Jabiru-8), was sidetracked after encountering the Cretaceous and Jurassic sections on the downthrown side of the main bounding fault.

Jabiru-8AST-1 intersected a 45 m TVT net oil column after Jabiru-8 was plugged back and kicked off at 1,060 mKB. The sidetrack was subsequently cased and suspended as an oil producer.

Jabiru-9 was plugged and abandoned after a fish became stuck in the hole.

Jabiru-9ST-1 was sidetracked around the fish but was interpreted as having been drilled on the downthrown side of the main bounding fault. The well was plugged back to 1,369 mKB and kicked off as Jabiru-9ST-2.

Jabiru-9ST-2 was plugged back to 1,423 mKB and kicked off as Jabiru-9ST-3.

Jabiru-9ST-3 intersected a 24 mTVT gross oil column (22 mTVT net pay) but was plugged and abandoned.

Jabiru-10 was plugged and abandoned after intersecting a 21 m gross oil column in poor quality reservoir. A residual oil/water contact was noted at 1,644 mSS.

Jabiru-11 was designed as a directional hole to drain oil updip of Jabiru-5. An inability to build up the deviation angle caused the well to be plugged back 1,210 mKB and kicked off as Jabiru-11ST-1.

Jabiru-11ST-1 was cased and suspended as an oil producer.

Jabiru-12 was plugged and abandoned after intersecting an 11 m gross oil column (10.3 m net pay).

Jabiru-13 was plugged and abandoned dry but a deviated well (Jabiru-13DW-1) drilled from the same location was cased and suspended as an oil producer.

RESERVES:

Initial Oil: 107.2 MMbbls
Remaining Oil: 5.3 MMbbls (at end 2001)
Source: Northern Territory Depatment of Business Industry and Resource Development, 2002.

REMARKS:

Fluid inclusion studies by O'Brien & others (1996) have identified a residual oil zone below the present day OWC. This suggests that the Jabiru structure originally contained considerably more oil than it holds at present and that this oil has subsequently been leaked as a result of Mio-Pliocene fault reactivation.

Commercial production of oil from Jabiru commenced in 1986. The development at Jabiru comprises sub-sea completions connected via flowlines to an FPSO vessel (the Jabiru Venture).

At date of publication, the Jabiru oil field was held under Production License AC/L2.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Associated Gas (Separator Sample)
Methane	82.21
Ethane	6.96
Propane	3.39
Isobutane	0.65
N-butane	1.01
Isopentane	0.28
N-pentane	0.24
Hexanes +	0.35
Nitrogen	2.11
CO_2	2.80
H_2S	0.00
Specific Gravity	0.700
BTU/ft^3 (gross)	1132

STRATIGRAPHY (Jabiru-1A) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	150.0
		Hibernia Formation	555.0
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	920.0
JURASSIC	FLAMINGO GROUP	Undifferentiated	1594.0
	TROUGHTON GROUP	Plover Formation	1605.0

STRATIGRAPHY (Jabiru-12) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Oliver/Barracouta Fm	118.0
		Hibernia Formation	470.0
		Grebe Sandstone	754.0
		Johnson Formation	890.5
CRETACEOUS	BATHURST ISLAND GROUP	Borde Formation	1224.0
		Fenelon Formation	1403.0
		Gibson Formation	1483.0
		Woolaston Formation	1535.0
		Jamieson Formation	1574.0
JURASSIC	FLAMINGO GROUP	Lower Vulcan Fm	1638.5
	TROUGHTON GROUP	Plover Formation	1711.0

Accumulation Number: 32

JAHAL

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Oil
STATUS:	Other Discovery
LOCATION:	560 km northwest of Darwin
STATE:	Zone of Cooperation, Part A
ORIGINAL TITLE(S):	ZOCA 91-01
BASIN:	Bonaparte
SUB-BASIN:	Laminaria High
DISCOVERY WELL:	Jahal-1
Longitude (E):	126.1025
Latitude (S):	-10.5676
Date total depth reached:	06 MAY 96
Water Depth:	402.3 m
Kelly bushing:	25 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	3,445 mKB
NUMBER OF WELLS DRILLED:	1 (plus 1 sidetrack)
STRUCTURE/TRAP:	Tilted fault block

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Oil
FORMATION:	Elang Formation
AGE:	Late Jurassic (Callovian)
LITHOLOGY:	Sandstone with interbedded claystone. Sandstone: very fine to medium, predominantly fine grained, subangular to subrounded, well sorted, quartzose.
DEPOSITIONAL ENVIRONMENT:	Deltaic highstand and transgressive systems tracts.
GROSS HYDROCARBON COLUMN:	33 m (Jahal-1ST1) 10 m (Jahal-1)
NET PAY:	7.56 m (Jahal-1) 13.69 m (Jahal-1ST1)
HYDROCARBON SATURATION:	65.2%
OIL/WATER CONTACT:	3,308 mRT (3,283 mTVDSS)
OIL GRAVITY:	55^{o} API
POROSITY:	10.7% (average log porosity)
PERMEABILITY:	less than 10 mD

TEST DATA FROM THE DISCOVERY WELL (Jahal-1 and Jahal-1/ST1)**:**

RFT, 3,306.5 m, Recovered 20.5 litres of oil and 0.5 m^3 of gas.	Elang Formation
DST 1, 3,300-3,315 m, Flowed oil at 1,422 bbls/day and gas at 2,548 m^3/day through a 9.5 mm choke.	Elang Formation

REMARKS:

Jahal-1 was drilled to 3,303 m before being plugged back to 2,780 m, sidetracked and drilled to 3,445 m.

Water saturations in the Elang Formation are considered pessimistic due to the large percentage of pyrite (up to 27%) present throughout the reservoir interval.

STRATIGRAPHY (Jahal-1) **:**

<table>
<tr><th>AGE</th><th colspan="2">UNIT</th><th>FORMATION TOP (mRT)</th></tr>
<tr><td rowspan="7">TERTIARY</td><td rowspan="7">WOODBINE GROUP</td><td>Undifferentiated</td><td>427.0</td></tr>
<tr><td>Oliver Formation</td><td>1139.0</td></tr>
<tr><td>Cartier Formation</td><td>1845.0</td></tr>
<tr><td>Prion Formation</td><td>2032.0</td></tr>
<tr><td>Hibernia Formation</td><td>2517.0</td></tr>
<tr><td>Grebe Sandstone</td><td>2674.0</td></tr>
<tr><td>Johnson Formation</td><td>2741.0</td></tr>
<tr><td rowspan="6">CRETACEOUS</td><td rowspan="6">BATHURST ISLAND GROUP</td><td>Wangarlu Formation</td><td>2803.0</td></tr>
<tr><td>U. Jamison Formation</td><td>2873.0</td></tr>
<tr><td>L. Jamison Formation</td><td>2945.0</td></tr>
<tr><td>Darwin Formation</td><td>2995.0</td></tr>
<tr><td>Echuca Shoals Formation</td><td>3002.0</td></tr>
<tr><td>Flamingo Formation</td><td>3056.0</td></tr>
<tr><td rowspan="3">JURASSIC</td><td rowspan="2">FLAMINGO GROUP</td><td>Frigate Formation</td><td>3289.0</td></tr>
<tr><td>Elang Formation</td><td>3298.0</td></tr>
<tr><td>TROUGHTON GROUP</td><td>Plover Formation</td><td>3378.0</td></tr>
</table>

Accumulation Number: 33

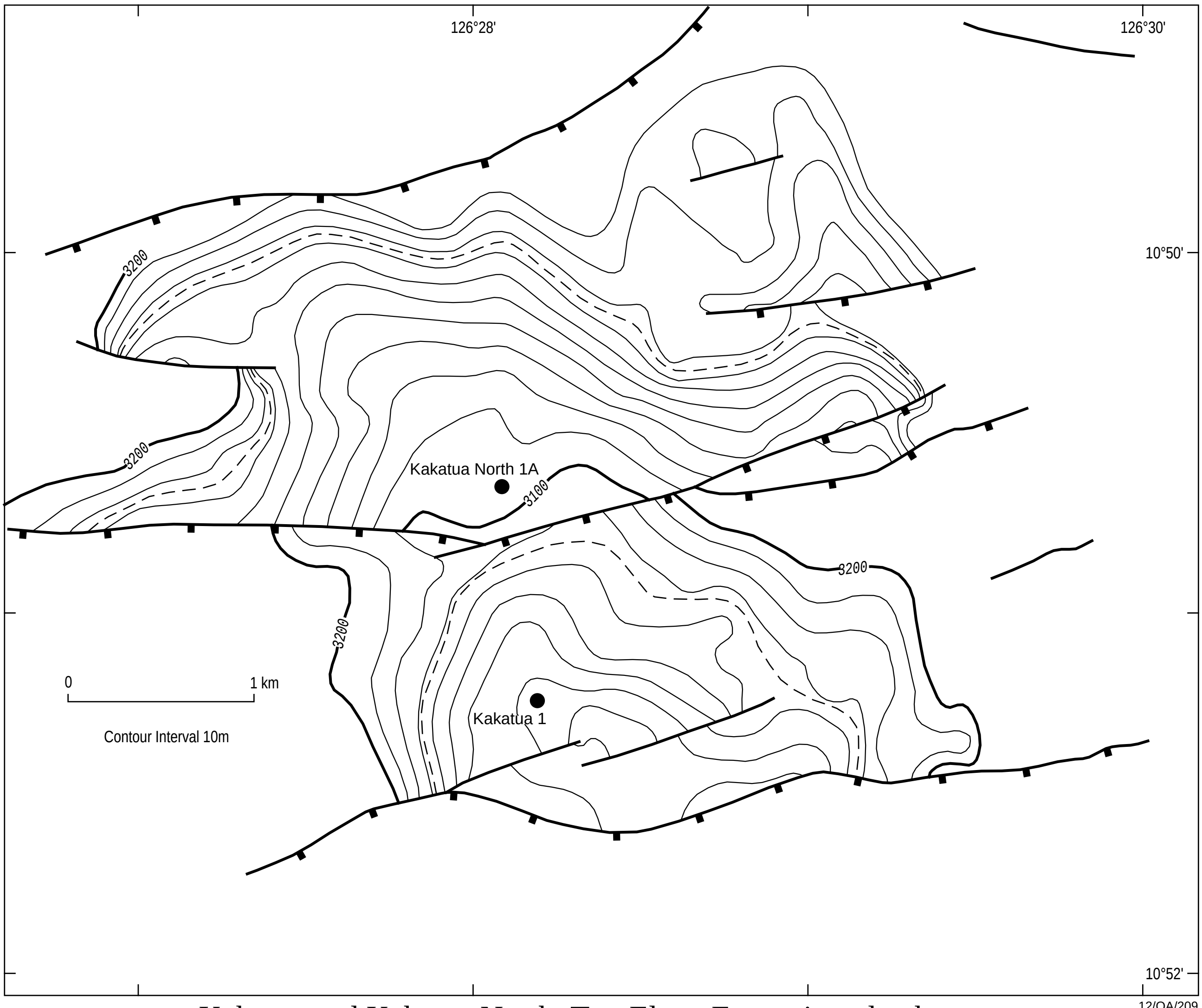
KAKATUA

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Oil
STATUS:	Producer
LOCATION:	510 km northwest of Darwin
STATE:	Zone of Cooperation, Part A
ORIGINAL TITLE(S):	ZOCA 91-12
BASIN:	Bonaparte
SUB-BASIN:	Flamingo High
DISCOVERY WELL:	Kakatua-1
Longitude (E):	126.4699
Latitude (S):	-10.8542
Date total depth reached:	08 DEC 94
Water Depth:	94 m
Kelly bushing:	22 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	3,290 mKB
NUMBER OF WELLS DRILLED:	1 (not including Kakatua North-1 and 1A)
STRUCTURE/TRAP:	Fault dependent closure.
VERTICAL CLOSURE:	87 m
RESERVOIR UNITS:	Multiple sands.
OIL GRAVITY:	53^{o} API

PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Oil
FORMATION:	Elang Formation
AGE:	Middle Jurassic
GROSS HYDROCARBON COLUMN:	29 m (3,160 – 3,189 mRT)
NET PAY:	23.2 m
NET TO GROSS RATIO:	80%
HYDROCARBON SATURATION:	79.3%
GAS TO OIL RATIO:	220 scf/stb (MDT, 3,177.8 mRT) 150 scf/stb (MDT, 3,162 mRT) 178 scf/stb (Cased DST, 3,160 -3,184 mRT)
OIL/WATER CONTACT:	3,167 mSS (MDT data)
POROSITY:	11.9% (average log porosity)
PERMEABILITY:	200 mD (MSCT cores) 4 - 15 mD (drawdown mobility)

TEST DATA FROM THE DISCOVERY WELL (Kakatua-1)**:**

MDT, 3,162 m, Recovered 3.5 litres of brown, 53.5^{o} API Oil, 3.2 ft^3 of gas and 0.2 litres of filtrate/ water from the 2.75 gallon chamber.	Elang Formation
MDT, 3,177.8 m, Recovered 1.6 litres of 52.7^{o} API, brown oil, 2.2 ft^3 of gas and 1.7 litres of filtrate/ water from the 1 gallon chamber.	Elang Formation
DST (CASED), 3,160-3,184 m, Flowed 53^{o} API oil at 8,100 bbls/day through a 23 mm choke. Perforated over the intervals 3,160-3,163 m and 3,169-3,184 m.	Elang Formation



Kakatua and Kakatua North, Top Elang Formation, depth map

REMARKS:

A residual oil column was interpreted from logs over the interval 3,189 – 3,230 mRT.

The Elang/Kakatua oil development commenced production in 1998. Sub-sea completions at Kakatua-1, Elang-1 and Elang-2 are connected to an FPSO (the Modec Venture 1) moored over the Elang field.

RESERVES :

Oil : 17 MMbbls (includes Elang)
Source: Department of Resources Development, WA, 1998.

STRATIGRAPHY (Kakatua-1) **:**

AGE	UNIT		FORMATION TOP (mTVDSS)
TERTIARY	WOODBINE GROUP	Oliver Formation	423.0
		Prion Formation	1030.0
		Hibernia Formation	1283.0
		Grebe Sandstone	1884.0
		Johnson Formation	1950.0
CRETACEOUS	BATHURST ISLAND GROUP	Borde Formation	2210.0
		Fenelon Formation	2363.0
		Gibson Formation	2453.0
		Woolaston Formation	2573.0
		Jamison Formation	2617.5
		Darwin Formation	2923.0
		Echuca Shoals Formation	2953.0
JURASSIC	FLAMINGO GROUP	U. Flamingo Formation	3000.0
		Lwr Flamingo Formation	3125.0
		Elang Formation	3128.0
	TROUGHTON GROUP	Plover Formation	3214.0

Accumulation Number: 34

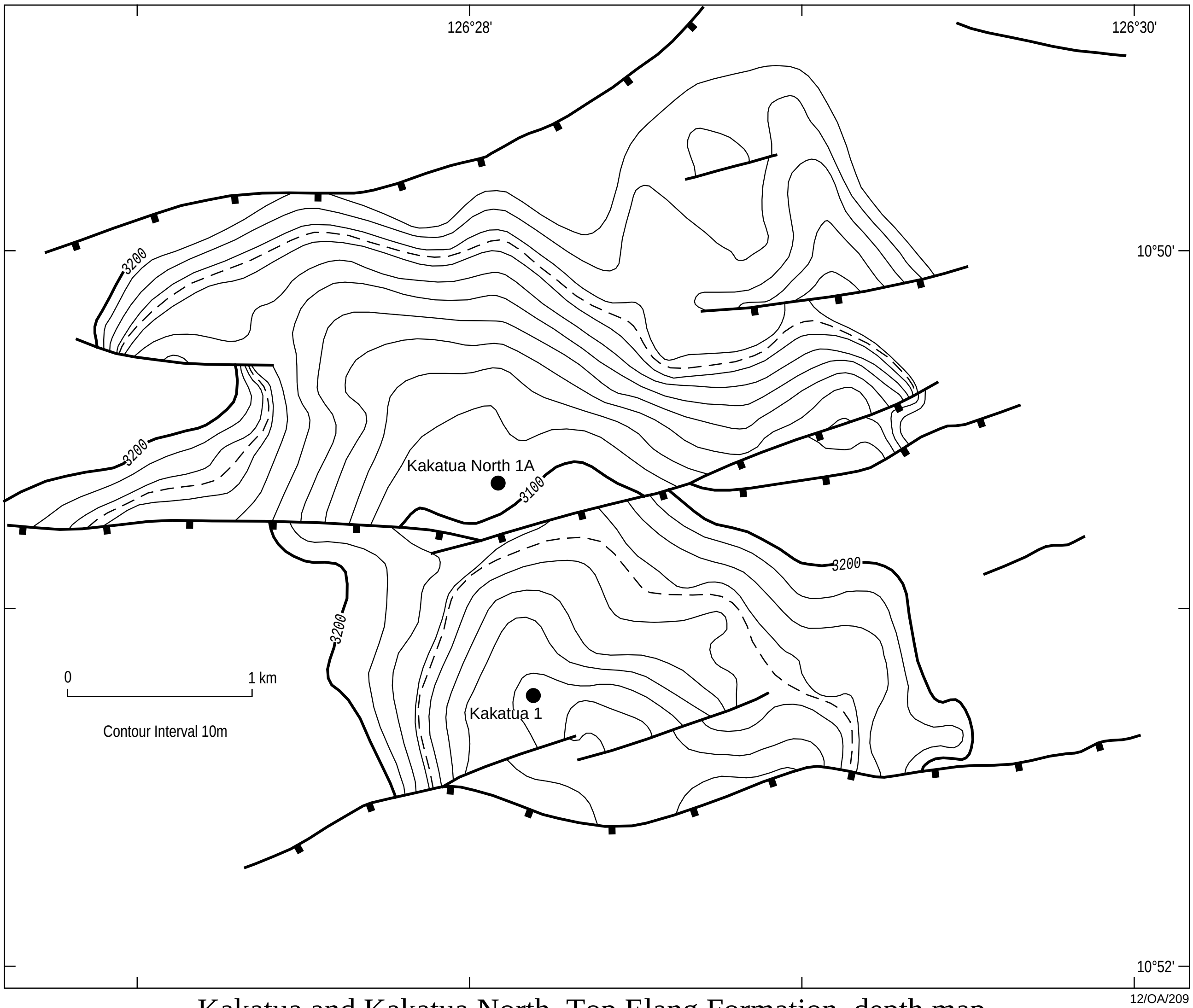
KAKATUA NORTH

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Oil
STATUS:	Producer
LOCATION:	512 km northwest of Darwin
STATE:	Zone of Cooperation, Part A.
ORIGINAL TITLE(S):	ZOCA 91-12
BASIN:	Bonaparte
SUB-BASIN:	Flamingo High
DISCOVERY WELL:	Kakatua North-1A
Longitude (E):	126.4682
Latitude (S):	-10.8444
Date total depth reached:	12 FEB 97
Water Depth:	94 m
Kelly bushing:	25 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	3,300 mKB
NUMBER OF WELLS DRILLED:	2 (includes 1 redrill)
STRUCTURE/TRAP:	Separate fault dependent closure 2 km north of the Kakatua oil discovery.
OIL GRAVITY:	55^o API
GROSS HYDROCARBON COLUMN:	69.4 m (3,131.6 – 3,201 mRT)
NET PAY:	26.4 m
HYDROCARBON SATURATION:	75.4%
OIL/WATER CONTACT:	3,176 mSS (free-water level)

PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Oil
FORMATION:	Elang Formation
AGE:	Jurassic
LITHOLOGY:	Interbedded sandstone, siltstone and claystone. Sandstone: fine to very fine, occasionally medium to coarse, variable siliceous cement, common quartz overgrowths, laminated and cross-bedded in part, coarsening upwards.
DEPOSITIONAL ENVIRONMENT:	Interdeltaic barrier beach complex.
FORMATION TOP:	3,106.5 mTVDSS
POROSITY:	12.6% (average log porosity)

TEST DATA FROM THE DISCOVERY WELL (Kakatua North-1A)**:**

RFT, 3,158.5 m, Recovered 12.9 litres of 55^o API oil and 60.8 ft^3 of gas.	Elang Formation



Kakatua and Kakatua North, Top Elang Formation, depth map

REMARKS:

Kakatua North-1 was abandoned due to mechanical difficulties. Kakatua North-1A was spudded 13 m to the northeast of Kakatua North-1.

Flow testing of the Kakatua North-1 well was not deemed necessary due to similarities with the previously tested Kakatua-1 reservoir.

The Kakatua North development comprises a sub-sea completion at Kakatua North-1, tied back to the Elang/Kakatua development via a 12 km pipeline.

RESERVES :

Oil : 12.2 MMbbls
Source: Department of Resources Development, WA, 1998.

STRATIGRAPHY (Kakatua North-1) **:**

AGE	UNIT		FORMATION TOP (mTVDSS)
TERTIARY	WOODBINE GROUP	Oliver Formation	94.0
		Prion Formation	1025.0
		Hibernia Formation	1473.5
		Grebe Sandstone	1883.0
		Johnson Formation	1982.5
CRETACEOUS	BATHURST ISLAND GROUP	Turnstone Formation	2211.5
		Fenelon Formation	2345.0
		Gibson Formation	2472.0
		Woolaston Formation	2591.0
		Jamison Formation	2634.0
		Darwin Formation	2865.0
		Echuca Shoals Formation	2948.0
JURASSIC	FLAMINGO GROUP	U. Flamingo Formation	2988.0
		Elang Formation	3106.5
	TROUGHTON GROUP	Plover Formation	3219.2

Accumulation Number: 35

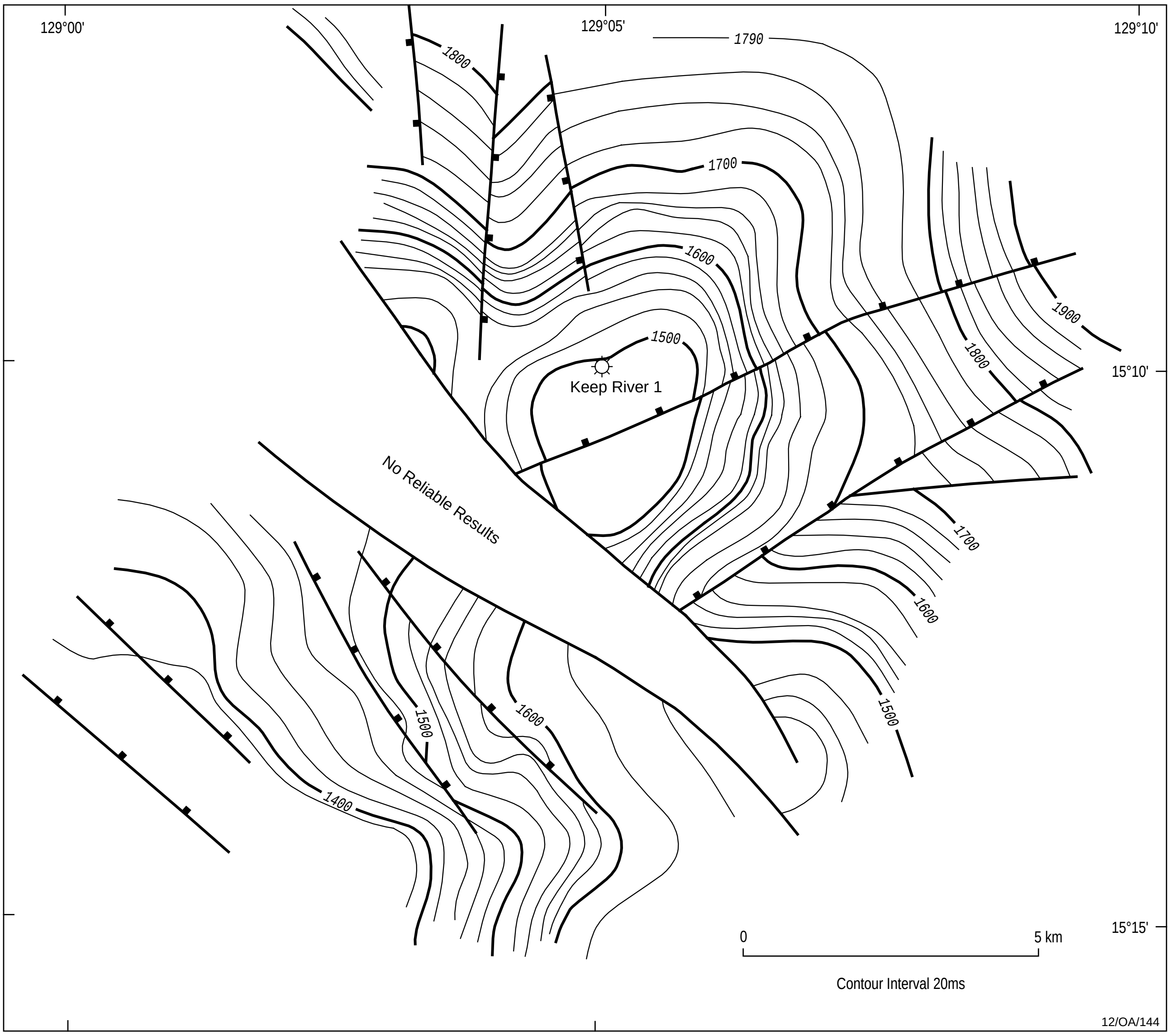
KEEP RIVER

ORIGINAL OPERATOR:	Australia Aquitaine Petroleum
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	355 km south-southwest of Darwin
STATE:	Northern Territory
ORIGINAL TITLE(S):	OP 162
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Keep River-1
Longitude (E):	129.0894
Latitude (S):	-15.1680
Date total depth reached:	23 FEB 69
Ground Level:	23 m
Kelly bushing:	27.7 m
Operator:	Australia Aquitaine Petroleum
Total Depth:	4,762 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Faulted four-way-dip closure
RESERVOIR UNITS:	1 (multiple reservoirs)

PETROLEUM BEARING UNIT No.1:	Weaber Group
CONTENTS:	Gas
FORMATION:	Lower Milligans Formation
AGE:	Early Carboniferous
LITHOLOGY:	Sandstone, white, fine to medium grained, abundant calcareous cement and fossiliferous in part (echinoderms, brachiopods and foraminifera) interbedded with silty brown and dark to medium grey, non-calcareous shale.
DEPOSITIONAL ENVIRONMENT:	Pro-delta to moderately deep water.
FORMATION TOP (mKB):	756.2 m
POROSITY:	Less than 5% (core data)
PERMEABILITY:	Less than 0.1 mD (core data)

TEST DATA FROM THE DISCOVERY WELL (Keep River-1)**:**

DST(CASED) 8, 1,881.8-1,889.8 m, Recovered 137 m of salt water.	Milligans Formation
DST(CASED) 7, 1,963.8-1,974.8 m, Recovered 1,372 m of salt water.	Milligans Formation
DST 1, 2,101.1-2,122.3 m, Recovered 1804 m of salt water.	Milligans Formation
DST(CASED) 6, 2,187.6-2,205.2 m, Recovered 107 m of gas cut mud and 1,356 m of salt water accompanied by a small unmeasured gas flow.	Milligans Formation
DST(CASED) 5, 2,289-2,316.5 m, Recovered 57 m of mud.	Milligans Formation



Keep River, Top Langfield Group, TWT map

DST 4, 2,583.2-3,352.8 m, Milligans Formation Flowed gas at 85,000 m^3/day decreasing to 5,600 m^3/day over 8 hours and recovered 2,050 m of gas cut mud. DST 3, 3,871.6-3,889.3 m, 'Ningbing Limestone' Recovered 45.7 m of mud and salt water. DST 2, 4,039.2-4,056.9 m, 'Ningbing Limestone' Recovered 111.6 m of mud and salt water.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Keep River-1 DST-4 Milligans Fm	Keep River-1 DST-6 Milligans Fm
Methane	93.8	97.4
Ethane	0.5	1.3
Propane	trace	0.2
Nitrogen	2.7	0.7
CO_2	2.9	0.3
Helium	0.1	0.1

STRATIGRAPHY (Keep River-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
PERMIAN	KULSHILL GP	Undifferentiated	0.0
CARBONIFEROUS	WEABER GROUP	Tanmurra Formation	480.1
		Milligans Formation	756.2
	LANGFIELD GROUP	Septimus Formation	2898.7
		Enga Formation	3221.8
		Burt Range Formation	3445.8
DEVONIAN	NINGBING GROUP	'Ningbing Limestone'	3712.5
	COCKATOO GP	Undifferentiated	4736.6

Accumulation Number: 36

KELP DEEP

ORIGINAL OPERATOR:	Mobil Exploration and Production Australia Pty Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	490 km northwest of Darwin
STATE:	Zone of Cooperation, Part A
ORIGINAL TITLE(S):	ZOCA 95-18
BASIN:	Bonaparte
SUB-BASIN:	Sahul Platform
DISCOVERY WELL:	Kelp Deep-1
Longitude (E):	127.1112
Latitude (S):	-10.1682
Date total depth reached:	29 JUL 97
Water Depth:	223 m
Operator:	Mobil Exploration and Production Australia Pty Ltd
Total Depth:	5,122 mKB
NUMBER OF WELLS DRILLED:	1

PETROLEUM BEARING UNIT No.1:	Pearce Member
CONTENTS:	Gas
FORMATION:	Hyland Bay Formation
AGE:	Late Permian

TEST DATA FROM THE DISCOVERY WELL (Kelp Deep-1)**:**

DST 5, Hyland Bay Formation (Dombey Member)
No fluids to surface.

DST 4, 4,393.5-4,406.5 m, Hyland Bay Formation (Dombey Member)
No fluids to surface.

DST 3, 4,593.9-4,581.1 m; Hyland Bay Formation (Cape Hay Member)
4,624.9-4,613 m; 4,606-4,598 m ;
4,577.5-4,569 m ; 4,550.5-4,548.5 m,
No gas to surface.

DST 2, Hyland Bay Formation (Pearce Member)
Flowed gas at 147,250 m^3/day and water at 1,503 bbls/day.

DST 1, 5,088-5,100 m, Hyland Bay Formation (Pearce Member)
Flowed gas at 339,800 m^3/day and water at 1,500 bbls/day.

REMARKS:

Kelp Deep-1 was plugged back to 3,582 mRT and sidetracked (Kelp Deep-1/ST-1) to a total depth of 4,323 mRT to test the productivity of the Dombey Limestone Member.

Accumulation Number: 37

KRILL

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Oil and Gas
STATUS:	Other Discovery
LOCATION:	540 km northwest of Darwin
STATE:	Zone of Cooperation, Part A
ORIGINAL TITLE(S):	ZOCA 91-01
BASIN:	Bonaparte
SUB-BASIN:	Flamingo High
DISCOVERY WELL:	Krill-1
Longitude (E):	126.2022
Latitude (S):	-10.7513
Date total depth reached:	19 JUL 97
Water Depth:	268 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	3,640 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Tilted fault block
RESERVOIR UNITS:	1
OIL GRAVITY:	56^{o} API
GAS/OIL RATIO:	229 scf/stb
FREE WATER LEVEL:	3,388 mTVDSS
BOTTOM HOLE TEMPERATURE:	140.5^{o}C at 3,646 mRT (3,568 mTVDSS)

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Oil and Gas
FORMATION:	Elang Formation
SEAL:	Flamingo Fm silstones and claystones
AGE:	Late Jurassic
LITHOLOGY:	Sandstone with interbedded claystones. Sandstone: fine to medium grained, angular to subrounded, well sorted, quartzose with abundant siliceous cement and quartz overgrowths. Claystone: brownish-grey, hard and blocky.
DEPOSITIONAL ENVIRONMENT:	Storm and wave influenced proximal delta front sandstones.
GROSS HYDROCARBON COLUMN:	17.2 m (3,476.5 – 3,493.7 mRT)
NET PAY:	4.27 m
POROSITY:	9.1%
PERMEABILITY:	< 300 mD
HYDROCARBON SATURATION:	50.6%

TEST DATA FROM THE DISCOVERY WELL (Krill-1)**:**

MDT, 3,485 m, Recovered 18 litres of 56^{o} API oil and 25.9 cubic feet of gas.	Elang Formation
MDT, 3,539 m, Recovered 1.17 cubic feet of gas and 9.2 litres of filtrate/water.	Elang Formation

STRATIGRAPHY (Krill-1) **:**

AGE	**UNIT**		**FORMATION TOP (mTVDSS)**
TERTIARY	WOODBINE GROUP	Undifferentiated	268
		Oliver Formation	1599
		Cartier Formation	1628
		Prion Formation	1663
		Hibernia Formation	2127
CRETACEOUS	BATHURST ISLAND GROUP	Grebe Sandstone	2291
		Johnson Formation	2385
		Wangarlu Formation	2613
		Jamieson Formation	2927.5
		Darwin Formation	3116
JURASSIC	FLAMINGO GROUP	Echuca Shoals Formation	3144
		Flamingo Formation	3167
		Frigate Formation	3349
		Elang Formation	3373
	TROUGHTON GP	Plover Formation	3496

Accumulation Number: 38

KUDA TASI

ORIGINAL OPERATOR:	Woodside Petroleum (Timor Sea) Pty Ltd
TYPE:	Oil
STATUS:	Other Discovery
LOCATION:	560 km northwest of Darwin
STATE:	Zone of Cooperation, Part A
ORIGINAL TITLE(S):	ZOCA 91-01
BASIN:	Bonaparte
SUB-BASIN:	Sahul Platform
DISCOVERY WELL:	Kuda Tasi-1
Longitude (E):	126.1572
Latitude (S):	-10.5381
Date total depth reached:	16 MAR 01
Water Depth:	430 m
Operator:	Woodside Petroleum (Timor Sea) Pty Ltd
Total Depth:	3,535 mRT
NUMBER OF WELLS DRILLED:	1

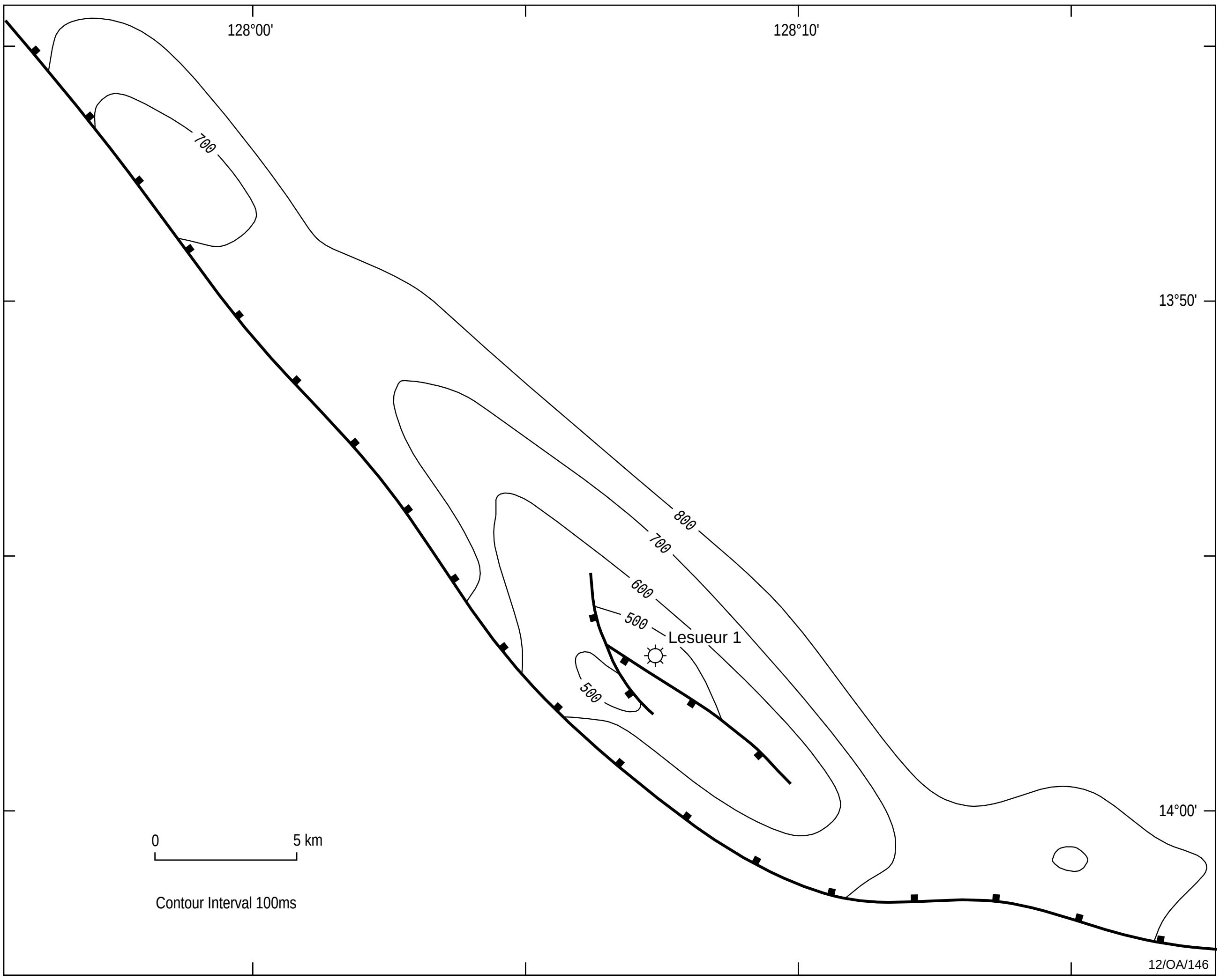
REMARKS:

Reports indicate oil was recovered on test from the Elang Formation.
No further information on Kuda Tasi-1 is available at date of publication.

Accumulation Number: 40

LESUEUR

ORIGINAL OPERATOR:	Australian Aquitaine Petroleum
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	340 km southwest of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	WA-18-P
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Lesueur-1
Longitude (E):	128.1256
Latitude (S):	-13.9526
Date total depth reached:	22 AUG 80
Water Depth:	58 m
Kelly bushing:	25.5 m
Operator:	Australian Aquitaine Petroleum
Total Depth:	3,589 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Large anticlinal closure associated with a basin margin fault.
AREAL CLOSURE:	135 km^2
VERTICAL CLOSURE:	770 m
RESERVOIR UNITS:	2
PETROLEUM BEARING UNIT No.1:	Weaber Group
CONTENTS:	Gas
FORMATION:	Tanmurra Formation
AGE:	Carboniferous (Visean to Namurian)
LITHOLOGY:	Sandstone, fine to medium grained, medium brown, hard, calcareous and tight, interbedded with medium brown, finely crystalline, dolomitic, moderately hard limestone.
DEPOSITIONAL ENVIRONMENT:	Prograding shelf sequence.
FORMATION TOP (mKB):	3,057 m
GROSS HYDROCARBON COLUMN:	95 m (3,095-3,190 m) 60 m (3,324-3,384)
HYDROCARBON SATURATION:	60% (3,095-3,190 m) 50% (3,324-3,384)
POROSITY:	Less than 5%
PERMEABILITY:	Up to 105 mD
PETROLEUM BEARING UNIT No.2:	Weaber Group
CONTENTS:	Gas
FORMATION:	Milligans Formation
AGE:	Carboniferous (Visean to Namurian)
LITHOLOGY:	Sandstone, light grey to pink-brown, medium grained, poorly sorted, hard and friable, interbedded with silty shale and calcareous siltstone.
DEPOSITIONAL ENVIRONMENT:	Pro-delta to moderately deep water.
FORMATION TOP (mKB):	3,384 m
RESERVOIR PRESSURE:	5000 psi (extrapolated pressure at 3,385 mKB)
POROSITY:	19% (average log porosity)
PERMEABILITY:	Up to 3 mD



Lesueur, Top Permian, TWT map

TEST DATA FROM THE DISCOVERY WELL (Lesueur-1)**:**

FIT 6, 3,100.5 m, Recovered 1.99 m^3 of gas, contaminated mud and 20 cc of ‘gasoline’.	Tanmurra Formation
FIT 8, 3,104 m, Recovered 8.3 litres of formation fluid with a trace of free gas.	Tanmurra Formation
FIT 7, 3,108.5 m, Recovered 0.028 m^3 of gas and 10.2 lires of mud with a trace of an oil film (dull orange-brown fluorescence).	Tanmurra Formation
FIT 9, 3,108.8 m, Recovered 8.25 litres of contaminated mud with a trace of free gas.	Tanmurra Formation
FIT 5, 3,178 m, Recovered 0.057 m^3 of gas and 8.5 litres of formation fluid.	Tanmurra Formation
FIT 4, 3,325 m, Recovered 0.011 m^3 of gas, 6.55 litres of mud and 3.75 litres of dark brown opaque fluid showing blue-white surface fluorescence.	Tanmurra Formation
DST 3, 3,383.5-3,386 m, Recovered 940 m of formation water, 1,500 m of water cushion with minor gas.	Milligans Formation
DST 2, 3,384.5-3,385.5 m, Misrun.	Milligans Formation
FIT 3, 3,385 m, Recovered 0.125 m^3 of gas, 2.0 litres of mud and 5.4 litres of dark brown water with a thin layer of oil.	Milligans Formation
FIT 2, 3,533 m, Recovered 0.088 m^3 of gas and 6.3 litres of dark brown water with a thin layer of black oil in globule form.	Milligans Formation
FIT 1, 3,542.5 m, Recovered 0.034 m^3 of gas, 2.5 litres of mud and 7.5 litres of dark brown water with a thin oil film.	Milligans Formation
DST 1, 3,551.5-3,589 m, Tight.	Milligans Formation

REMARKS :

Log analysis and test results indicate the presence of two oil columns within the Tanmurra Formation (3,324-3,384 m ; Sw = 50% and 3,095-3,190 m ; Sw = 40%) and a gas column in the Milligans Formation (3,384-3,386.5 m. Oil may also be present below 3,479 m in the Milligans Formation where better porosity is developed.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Milligans Fm FIT 3, 3385 m	Tanmurra Fm FIT 4, 3325 m	Tanmurra Fm FIT 5, 3178 m
Methane	92.24	94.40	92.40
Ethane	4.84	3.80	5.50
Propane	2.00	1.20	1.40
Isobutane	0.13	0.12	0.10
N-butane	0.17	0.22	0.40
Pentane	0.05	-	-
Incombustible Gas	0.57	0.30	0.20

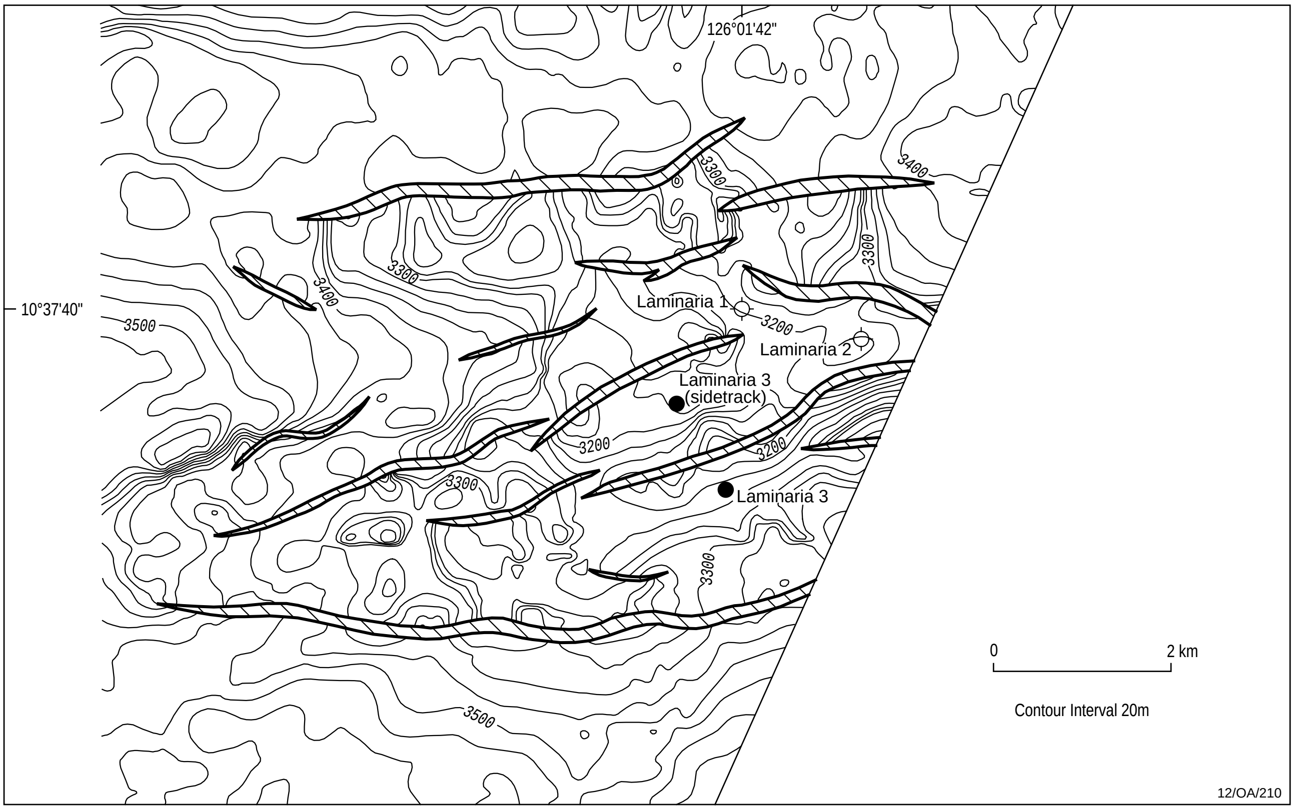
STRATIGRAPHY (Lesueur-1) **:**

<table>
<tr><th>AGE</th><th colspan="2">UNIT</th><th>FORMATION TOP (mKB)</th></tr>
<tr><td rowspan="3">PERMIAN</td><td rowspan="2">KINMORE GROUP</td><td>Hyland Bay Formation</td><td>372.0</td></tr>
<tr><td>Fossil Head Formation</td><td>685.0</td></tr>
<tr><td rowspan="3">KULSHILL GROUP</td><td>Keyling Formation</td><td>1044.0</td></tr>
<tr><td rowspan="4">CARBONIFEROUS</td><td>Treachery Shale</td><td>1290.0</td></tr>
<tr><td>Kuriyippi Formation</td><td>1814.0</td></tr>
<tr><td rowspan="2">WEABER GROUP</td><td>Tanmurra Formation</td><td>3057.0</td></tr>
<tr><td>Milligans Formation</td><td>3384.0</td></tr>
</table>

Accumulation Number: 39

LAMINARIA

ORIGINAL OPERATOR:	Woodside Offshore Petroleum Ltd
TYPE:	Oil
STATUS:	Producer
LOCATION:	560 km northwest of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory) and Western Australia.
ORIGINAL TITLE(S):	AC/P8
BASIN:	Bonaparte
SUB-BASIN:	Laminaria High
DISCOVERY WELL:	Laminaria-1
Longitude (E):	126.0283
Latitude (S):	-10.6279
Date total depth reached:	09 OCT 94
Water Depth:	361 m
Kelly bushing:	22 m
Operator:	Woodside Offshore Petroleum Ltd
Total Depth:	3,400 mKB
NUMBER OF WELLS DRILLED:	6 (includes Laminaria East-1 and Laminaria-3 Sidetrack)
STRUCTURE/TRAP:	A series of east-northeast to west-southwest oriented tilted fault blocks which form the Laminaria Horst
AREAL CLOSURE:	Over 17 km^2
VERTICAL CLOSURE:	Over 120 m
RESERVOIR UNITS:	1
GROSS HYDROCARBON COLUMN:	102 m (Laminaria-1)
OIL/WATER CONTACT:	3,288 mTVDSS
GAS/OIL RATIO:	175 scf/stb
OIL GRAVITY:	59^o API
BUBBLE POINT:	538 psig @ 230^oF
INITIAL RESERVOIR PRESSURE:	4,680 psia (at 3,200 mTVDSS)
BOTTOM HOLE TEMPERATURE:	118^oC (after 0.9 hours circulation, 62.95 hours post circulation)
PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Oil
FORMATION:	Laminaria Formation (basal sand unit of the Flamingo Group)(also referred to as Elang Formation)
AGE:	Middle to Late Jurassic (Callovian to Oxfordian)
LITHOLOGY:	Varies from poorly sorted, sandy mudstones (bay and estuarine channel facies) through moderately well sorted, subrounded to rounded, quartzose sandstones with minor clay, silt, siderite, carbonate and kaolinite (distributary channel facies) to well sorted, subrounded to rounded quartzose sandstones with common carbonate, siderite or pyrite cement (stream mouth bar facies).
DEPOSITIONAL ENVIRONMENT:	Transgressive, estuarine dominated delta.
FORMATION TOP (mKB):	3,201 m
POROSITY:	Variable. 5-12% (bay facies), 8-16% (estuarine channel facies), 13-16% (distributary channel facies) and 12-20% (stream mouth bar facies).
PERMEABILITY:	Variable. 0.5-10 md (bay facies), 10-500 md (estuarine channel facies), 100-1,000 md (distributary channel facies) and 100-1,200 md (stream mouth bar facies).



Laminaria, Top Reservoir, depth map

TEST DATA FROM THE DISCOVERY WELL (Laminaria-1)**:**

RFT 1, 3,213 m, Laminaria/Elang Formation
Recovered 750 cc fo 59^o API oil, 9 cc of water and 0.45 cubic feet ofgas.

Production Test 1, 3,292-3,302 m, Laminaria/Elang Formation
Flowed oil at 6,085 bbls/day and gas at 253,000 m^3/day through a 32/64" choke.

Production Test 2, 3,213-3,240 m, Laminaria/Elang Formation
Flowed oil at 5,826 bbls/day and gas at 165,000 m^3/day through a 32/64" choke.

Production Test 3, 3,259.8-3,264.5 m, Laminaria/Elang Formation
Flowed oil at 7,542 bbls/day and gas at 106,000 m^3/day through a 40/64" choke.

APPRAISAL AND DEVELOPMENT DRILLING :

Laminaria-2, drilled 1.5 km east of Laminaria-1, intersected a 102 m oil column in the Elang/Plover Formation. A cased DST over the interval 3,285 – 3,300 mKB flowed oil at 6,650 bbls/day and gas at 7,079 m^3/day. The well was suspended as a potential oil producer in May 1995.

Laminaria-3 was drilled 2 km south of Laminaria-1 to evaluate the most southerly fault block in the Laminaria structure. The well was deviated as Laminaria-3DW-1.

Laminaria-3DW-1 was drilled to achieve a displacement of the bottom hole location of 1,000 m to 330^o in order to further evaluate the Laminaria reservoir. The deviated well intersected a 23 m gross oil column.

Laminaria-4 was located 200 m away from Laminaria-1. The well was cased and suspended as a future oil producer after intersecting a 99 m gross oil column.

Laminaria-5 was spudded in February 1998 and was sidetracked due to mechanical difficulties. The well was cased and suspended as a future oil producer after intersecting a 150 m gross oil column.

Laminaria East-1 was drilled 3 km east of Laminaria-1 to test the eastern extension of the Laminaria structure within the adjacent permit (AC/P8). A DST over the interval 3,292.75 – 3,312.75 mKB flowed oil at 11,100 bbls/day and gas at 61,164 m^3/day through a 20.6 mm choke.

Laminaria-6 was spudded in January 1999 and completed as a future oil producer.

Laminaria-7 and 8 were originally planned as horizontal wells to accelerate production and access incremental reserves, but were redesigned as vertical producers after encountering drilling difficulties.

RESERVES :

Initial Oil : 119.5 MMbbls
Remaining Oil: 64.6 MMbbls (at end 2001)
Source: Northern Territory Department of Business Industry and Resource Development, 2002.

REMARKS:

Oil production from a combined Corallina/Laminaria development commenced in November 1999. Two production wells on Corallina and a further four on Laminaria are connected via sub-sea completions and flowlines to an FPSO (the Northern Endeavour) moored between the two fields in 390 metres of water. Surplus gas is reinjected into the reservoir via a single, dedicated gas disposal well.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Gas Laminaria Fm (Separator gas)
Methane	67.41
Ethane	1.26
Propane	2.81
Isobutane	2.05
N-butane	2.47
Isopentane	1.21
N-pentane	0.86
Hexanes +	1.19
Nitrogen	10.19
CO_2	10.55
H_2S	-
Specific Gravity	0.8680
BTU/ft^3 (gross)	1066

STRATIGRAPHY (Laminaria-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	383.0
		Oliver Formation	918.0
		Cartier Formation	1661.0
		Hibernia Formation	1702.0
CRETACEOUS	BATHURST ISLAND GROUP	Bathurst Island Group	2743.0
		Wangarlu Formation	2838.0
		'Radiolarian Unit'	2920.0
		Darwin Formation	2937.0
JURASSIC	FLAMINGO GROUP	Upper Flamingo Group	2956.5
		Lower Flamingo Group	3143.0
		Laminaria Formation	3201.0
	TROUGHTON GP	Plover Formation	3316.0

Accumulation Number: 41

LEEUWIN

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	680 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/P7
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Leeuwin-1
Longitude (E):	124.5851
Latitude (S):	-12.7112
Date total depth reached:	02 DEC 91
Water Depth:	85 m
Kelly bushing:	26 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	3,376 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Fault dependent closure on the eastern flank of the 'Greater Montara' Horst Block
AREAL CLOSURE:	6.5 km2
VERTICAL CLOSURE:	75 m (at the intra-Oxfordian unconformity)
RESERVOIR UNITS:	1
RESERVOIR PRESSURE:	3,568.6 psia
RESERVOIR TEMPERATURE:	95^{o}C
BOTTOM HOLE TEMPERATURE:	116^{o}C (22.6 hours post circulation)

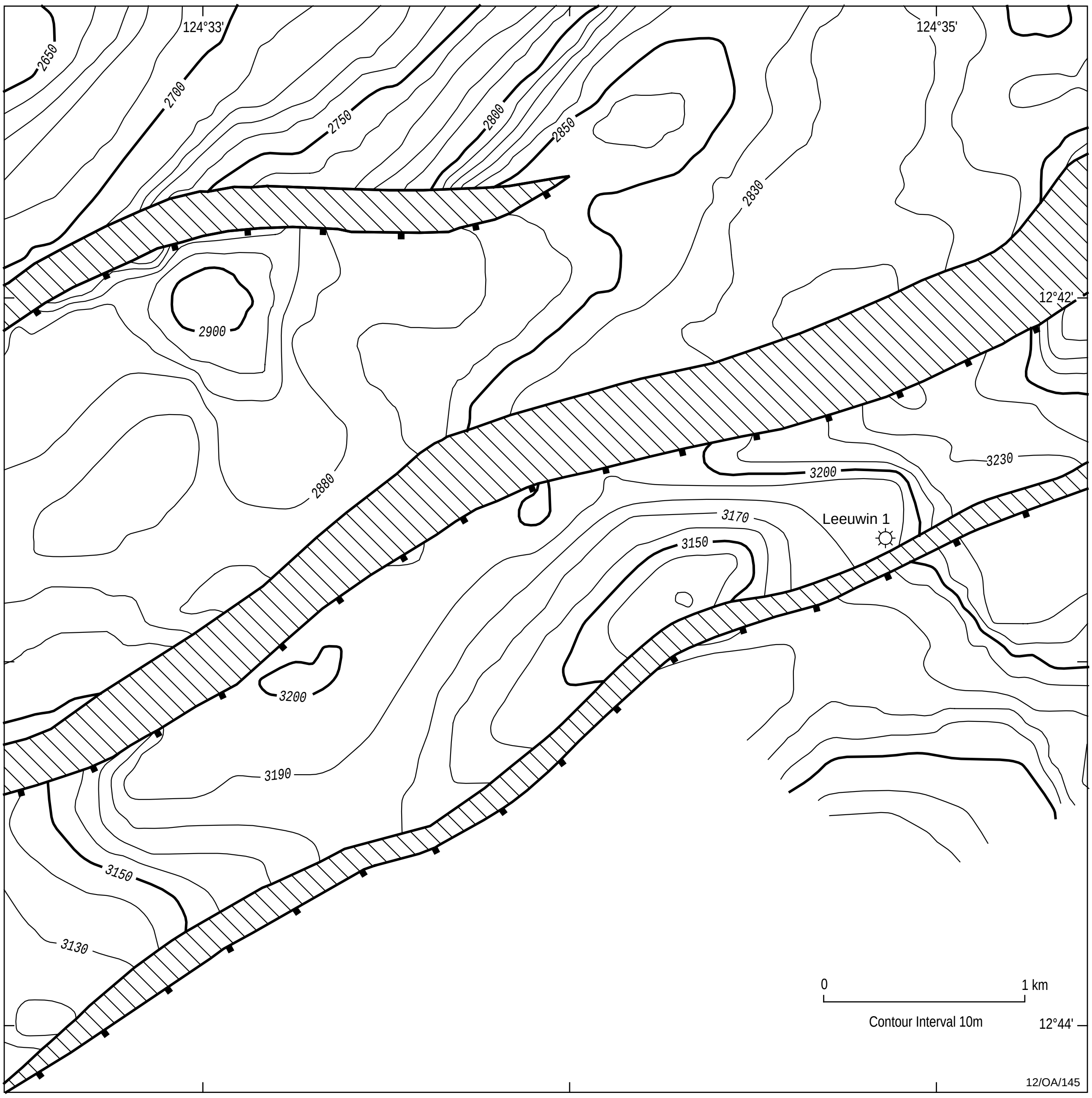
PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Gas
FORMATION:	Upper Vulcan Formation
AGE:	Upper Jurassic
LITHOLOGY:	Sandstone, glaucontic and argillaceous, off white to light green to green-grey, fine to medium grained, well sorted,angular to subrounded with up to 50% white argillaceous matrix with common, very fine to fine, glauconite pellets.
DEPOSITIONAL ENVIRONMENT:	Distal portion of a prograding submarine fan.
FORMATION TOP (mKB):	2,460 m
POROSITY:	18% average (from logs)
PERMEABILITY:	160-570 mD

TEST DATA FROM THE DISCOVERY WELL (Leeuwin-1)**:**

RFT, 2,476 m, Recovered 0.003 m^3 of gas and 21.5 litres of filtrate and formation water.	Upper Vulcan Formation

REMARKS:

Gas recovered at Leeuwin may be solution gas and an indication of a hydrocarbon accumulation updip of Leeuwin-1.



Leeuwin, Top Montara Formation, depth map

STRATIGRAPHY (Leeuwin-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Barracouta Formation	111.0
		Prion Formation	702.0
		Hibernia Formation	900.0
		Grebe Sandstone	1052.0
		Johnson Formation	1221.0
CRETACEOUS	BATHURST ISLAND GROUP	Puffin Formation	1635.0
		Fenelon Formation	2010.0
		Gibson Formation	2114.0
		Woolaston Formation	2209.0
		Jamieson Formation	2323.0
JURASSIC	FLAMINGO GROUP	Upper Vulcan Formation	2460.0
		Lower Vulcan Formation	2604.0
		Montara Formation	3237.0

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	**Leeuwin-1 Upper Vulcan Fm 2476 mKB**
Methane	83.84
Ethane	3.13
Propane	0.44
Isobutane	0.03
N-butane	0.05
CO_2	0.48
H_2S	2.68

Accumulation Number: 42

LORIKEET

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	585 km west-northwest of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/P4
BASIN:	Bonaparte
SUB-BASIN:	Londonderry High
DISCOVERY WELL:	Lorikeet-1
Longitude (E):	125.6180
Latitude (S):	-11.1737
Date total depth reached:	28 AUG 88
Water Depth:	108 m
Kelly bushing:	26 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	1,900 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Fault dependent closure
RESERVOIR UNITS:	1
HYDROCARBON SATURATION:	12%
BOTTOM HOLE TEMPERATURE:	87^{o}C

PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Gas
FORMATION:	Vulcan Formation
AGE:	Upper Jurassic (Tithonian)
LITHOLOGY:	Sandstone, fine grained, argillaceous and glauconitic.
FORMATION TOP (mKB):	1752 m (Vulcan Formation)
POROSITY:	12.8 - 27.6% (core data)
HORIZONTAL PERMEABILITY:	0.13 – 3,094 mD (core data)
VERTICAL PERMEABILITY:	0.02 - 822 mD (core data)

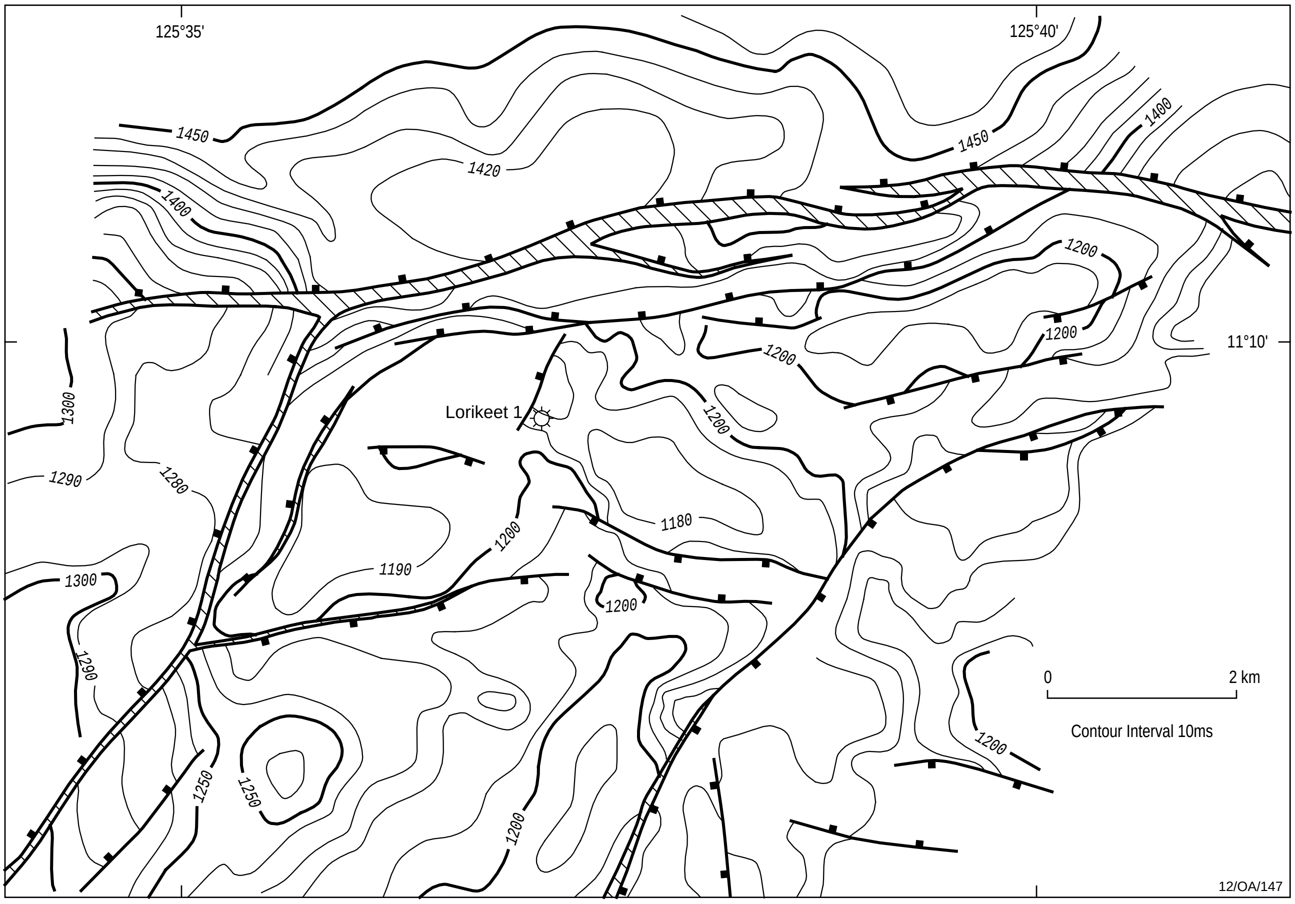
TEST DATA FROM THE DISCOVERY WELL (Lorikeet-1)**:**

RFT 1, 1,764.3 m, Recovered 0.025 m^3 of gas and 21.5 litres of water with a thin oil film.	Vulcan Formation

REMARKS:

Log analysis indicates residual oil saturations of up to 45% in the Jamieson Radiolarite. This, in conjunction with the residual hydrocarbons encountered in the Vulcan Formation suggest that the Lorikeet structure has been breached.

It is possible that the gas recovered from the Vulcan Formation by RFT is solution gas.



Lorikeet, Intra Valanginian Unconformity, TWT map

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Vulcan Fm RFT 1, 1764.3 mKB (%)
Methane	10.3530
Ethane	0.2850
Propane	0.0934
Isobutane	0.0273
N-butane	0.0246

STRATIGRAPHY (Lorikeet-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Barracouta Formation	134.0
		Oliver Formation	405.0
		Hibernia Formation	635.0
		Johnson Formation	995.0
CRETACEOUS	BATHURST ISLAND GROUP	Borde Formation	1425.0
		Fenelon Formation	1453.0
		Gibson Formation	1533.5
		Woolaston Formation	1630.0
		Jamieson Radiolarite	1663.5
		Echuca Shoals Formation	1742.7
JURASSIC	FLAMINGO GROUP	Vulcan Formation	1752.0
	TROUGHTON GROUP	Plover Formation	1765.0

Accumulation Number: 43

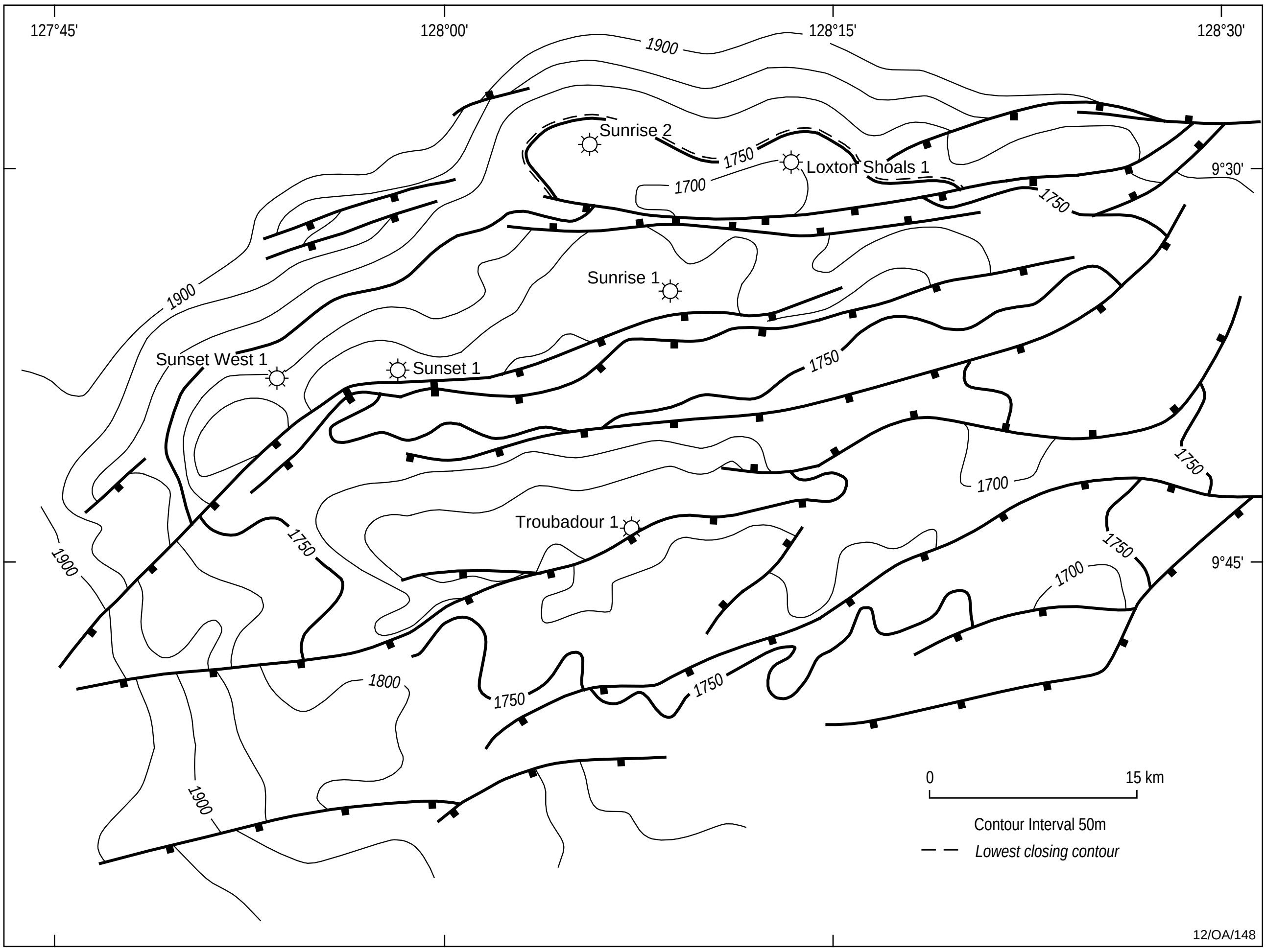
LOXTON SHOALS

ORIGINAL OPERATOR:	Woodside Offshore Petroleum Pty Ltd
TYPE:	Gas
STATUS:	Possible Future Producer
LOCATION:	430 km northwest of Darwin
STATE:	Northern Territory
ORIGINAL TITLE(S):	NT/P12
BASIN:	Bonaparte
SUB-BASIN:	Sahul Platform
DISCOVERY WELL:	Loxton Shoals-1
Longitude (E):	128.2327
Latitude (S):	-9.5106
Date total depth reached:	17 AUG 95
Water Depth:	290 m
Kelly bushing:	22 m
Operator:	Woodside Offshore Petroleum Pty Ltd
Total Depth:	2,330 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Tilted fault block.
AREAL CLOSURE:	81 km^2
VERTICAL CLOSURE:	80 m
RESERVOIR UNITS:	1
GROSS HYDROCARBON COLUMN:	64 m
NET PAY:	27.7 m
NET TO GROSS RATIO:	43%
CONDENSATE TO GAS RATIO:	50-60 bbl/MMscf
HYDROCARBON SATURATION:	78%
GAS/WATER CONTACT:	2,205 mTVDSS (free water level)

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Gas
FORMATION:	Plover Formation
AGE:	Jurassic (Callovian to Aalenian)
LITHOLOGY:	Sandstone, clear to dark grey, fine to medium grained, occasionally coarse grained, occasionally silty and argillaceous, common silica cement. Sequence coarsens upwards at the top of the section.
DEPOSITIONAL ENVIRONMENT:	Fluvio-deltaic to marginal marine
FORMATION TOP (mKB):	2,114.5 m
POROSITY:	15.1% (average log porosity)

TEST DATA FROM THE DISCOVERY WELL (Loxton Shoals-1)**:**

RFT, 2,139.1 m, Recovered 1.356 m^3 of gas and 7.7 litres of mud filtrate.	Plover Formation
MDT, 2,139 m, Recovered 1.345 m^3 of gas, 4.25 litres of mud filtrate and 250 cc of condensate.	Plover Formation



Loxton Shoals, Near Base Cretaceous, depth map

RESERVES:

Gas: 9.56 TCF (includes Sunrise/Troubadour/Sunset/Sunset West)
Condensate: 321 MMbbls (includes Sunrise/Troubadour/Sunset/Sunset West)
Source: Northern Territory Department of Business Industry and Resource Development, 2000.

REMARKS:

Loxton Shoals-1, Troubadour-1, Sunset-1, Sunset West-1, Sunrise-1 and Sunrise-2 all recovered gas on test from the Plover Formation from what are thought to be adjacent fault compartments on the greater Sunrise/Troubadour structure. Development of the Sunrise/Troubadour resource is currently under consideration.

At date of publication, Loxton Shoals was held under Retention Lease NT/RL2.

STRATIGRAPHY (Loxton Shoals-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Not sampled	315.0
		Hibernia Formation	1305.0
		Johnson Formation	1435.0
CRETACEOUS	BATHURST ISLAND GROUP	Undifferentiated	1556.0
		Wangarlu Formation	1736.5
		Jamieson Radiolarite	2074.0
JURASSIC	FLAMINGO GROUP	Darwin Fm/Flamingo Gp	2096.0
	TROUGHTON GROUP	Laminaria Fm Equivalent	2100.0
		Plover Formation	2114.5

Accumulation Number: 44

MAPLE

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Oil and Gas
STATUS:	Other Discovery
LOCATION:	690 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/P2
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Maple-1
Longitude (E):	124.5387
Latitude (S):	-12.0199
Date total depth reached:	11 JAN 90
Water Depth:	125 m
Kelly bushing:	22 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	4,230 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Tilted fault block adjacent to the Paqualin Graben on the northeastern extension of the Puffin Horst.
RESERVOIR UNITS:	1 (multiple reservoir sands)
GROSS HYDROCARBON COLUMN:	500 m + (complete reservoir section not penetrated)
HYDROCARBON SATURATION:	69% (average, 3,650-3,805 mKB)
NET TO GROSS RATIO:	16% (average, 3,650-3,805 mKB)
BOTTOM HOLE TEMPERATURE:	130.5^{o}C (after 3 hours circulation and 15 hours post circulation)

PETROLEUM BEARING UNIT No.1:	Sahul Group
CONTENTS:	Oil and Gas
FORMATION:	Challis Formation
AGE:	Upper Triassic (Norian to Carnian)
LITHOLOGY:	Sandstone, greenish-white, fine to medium grained, moderately well sorted, subangular to subround, extensively cemented with carbonate cement, thinly interbedded with light to dark grey claystones and minor oolitic limestones.
DEPOSITIONAL ENVIRONMENT:	Estuarine and tidal channel sand sequence.
FORMATION TOP (mKB):	3,686 m
POROSITY:	8.4 -16.4% (log porosity, 3,650-3,805 mKB) 13.6% average
PERMEABILITY:	0.5 – 1,400 mD (RFT data)

TEST DATA FROM THE DISCOVERY WELL (Maple-1)**:**

RFT 1, 3,718.3 m, Recovered 0.29 m^3 of gas and 12.7 litres of filtrate and water with a thin oil film.	Challis Formation
RFT 6, 3,718.5 m, Recovered 2.66 m^3 of gas, 0.3 litres of oil/condensate and 11 litres of water.	Challis Formation

RFT 8, 3,724.9 m, Recovered 0.03 m^3 of gas and 25 litres of water with a trace of oil.	Challis Formation
RFT 2, 3,993 m, Recovered 0.15 m^3 of gas and 12.6 litres of water with a trace of oil.	Challis Formation
RFT 5, 4,094.9 m, Recovered 0.02 m^3 of gas and 12.1 litres of water.	Challis Formation

RESERVES:

Oil: 10 MMbbls
Gas: 345 BCF
Source: Northern Territory Department of Business Industry and Resource Development, 1997.

REMARKS:

Log analysis indicates a number of discreet 1–2 m thick gas bearing sandstones over a 546 m sequence of interbedded, tightly cemented, Triassic sandstone, limestone and claystone (Challis Formation). The well was plugged and abandoned.

In 2002, Cash-1/ST-1 was drilled as an exploration well, approximately 8 km northwest of Maple-1. At date of publication, limited information is available on the Cash-1/ST-1 well. However, Cash-1/ST-1 is thought to have successfully tested a separate culmination on the Maple feature.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Challis Fm RFT, 3718.5 m
Methane	78.80
Ethane	4.86
Propane	1.78
Isobutane	0.22
N-butane	0.35
Isopentane	0.08
N-pentane	0.04
Hexanes +	0.01
Nitrogen	0.52
CO_2	13.34

STRATIGRAPHY (Maple-1) **:**

AGE	**UNIT**		**FORMATION TOP (mKB)**
TERTIARY	WOODBINE GROUP	Oliver Formation	148.0
		Hibernia Formation	1109.0
		Grebe Sandstone	1608.0
		Johnston Formation	2008.0
CRETACEOUS	BATHURST ISLAND GROUP	Puffin Formation	2546.0
		Fenelon Formation	2622.0
		Gibson Formation	2748.0
		Woolaston Formation	2791.0
		Jamieson Formation	2826.0
		Echuca Shoals Formation	2835.0
JURASSIC	FLAMINGO GROUP	Upper Vulcan Formation	2844.0
		Lower Vulcan Formation	3084.0
TRIASSIC	SAHUL GROUP	Challis Formation	3688.0

Accumulation Number: 45

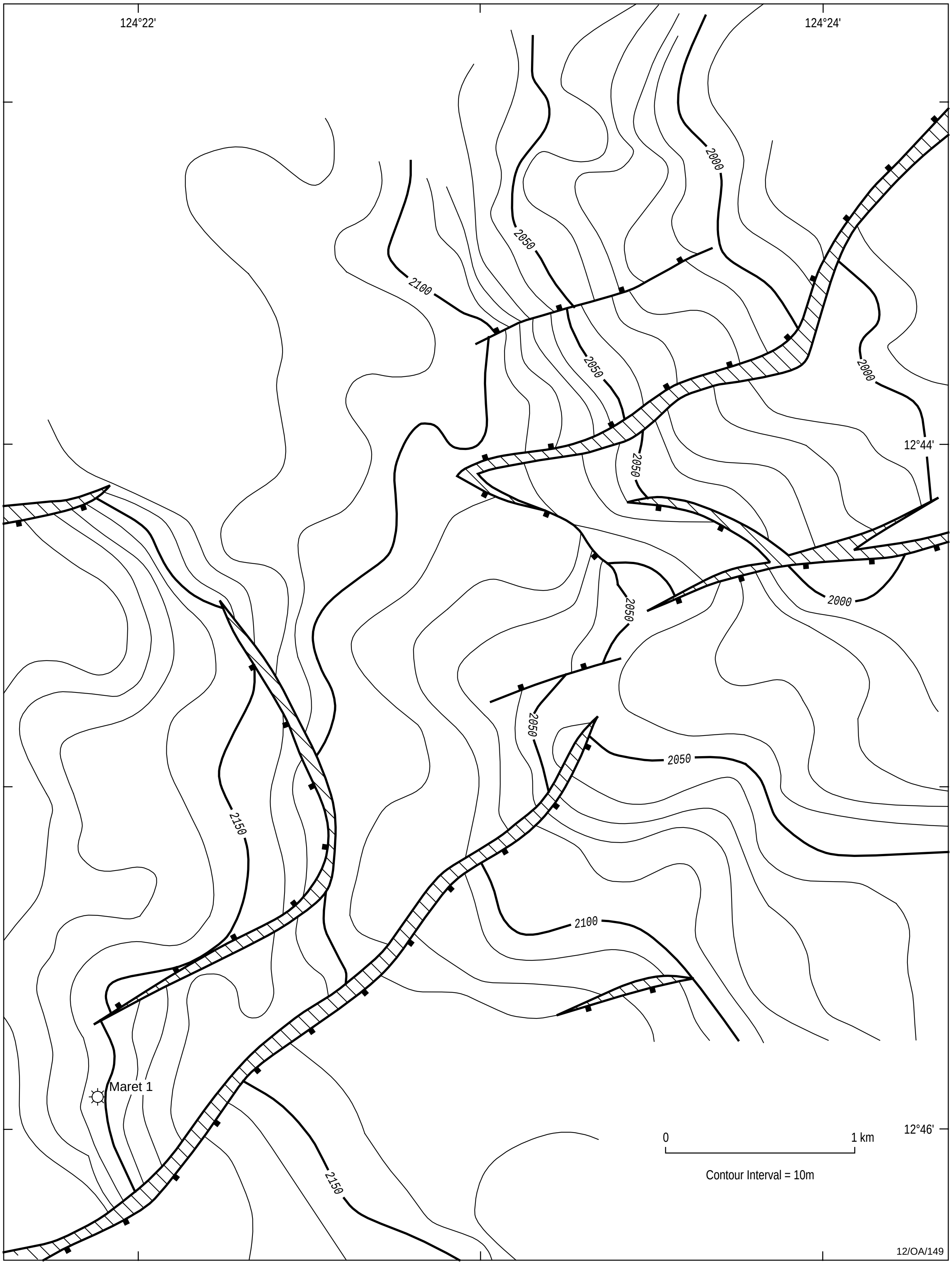
MARET

ORIGINAL OPERATOR:	Norcen International Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	705 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/P10
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Maret-1
Longitude (E):	124.3656
Latitude (S):	-12.7651
Date total depth reached:	23 JAN 92
Water Depth:	131 m
Kelly bushing:	22 m
Operator:	Norcen International Ltd
Total Depth:	3,560 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Subcrop play situated on a northeast-southwest trending horst block. The discovery well was designed to test dipping Oxfordian sandstones truncated by a Kimmeridgian unconformity.
RESERVOIR UNITS:	1
GROSS HYDROCARBON COLUMN:	3.5 m
NET PAY:	1.8 m
NET TO GROSS RATIO:	51%
CONDENSATE GRAVITY:	38^{o} API
CONDENSATE/GAS RATIO:	30.8 bbl/MMscf
DEW POINT:	5,202 psig
RESERVOIR PRESSURE:	4,912.1 psia (at 3,409.5 mKB)

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Gas
FORMATION:	Plover Formation
AGE:	Early Jurassic (Toarcian to Bathonian)
LITHOLOGY:	Sandstone, light to medium grey, fine to very coarse, translucent quartz grains, poorly to moderately well sorted, interbedded with thin (up to 3 m thick) siltstones, claystones and coals.
DEPOSITIONAL ENVIRONMENT:	Delta plain environment comprising distributary channel/bar and interdistributary bay/marsh deposits.
FORMATION TOP (mKB):	3,385 m
POROSITY:	9 - 13% (log analysis)

TEST DATA FROM THE DISCOVERY WELL (Maret-1)**:**

RFT 24, 3,409.5 m, Recovered 1.24 m^3 of gas, 0.4 litres of condensate and 8.3 litres of filtrate.	Plover Formation



Maret, Intra Valanginian Unconformity, TWT map

REMARKS:

A 3.5 m gross hydrocarbon column was identified on logs between 3,407.5 mKB and 3,411 mKB. The pay sand is interbedded with siltstones, claystones and water-wet sandstones suggesting the hydrocarbons are probably trapped stratigraphically in an isolated pocket. Oil shows were recorded between 3,375 mKB and 3,420 mKB.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Plover Fm RFT 24, 3409.5 m
Methane	72.04
Ethane	9.10
Propane	5.20
Isobutane	0.86
N-butane	1.84
Isopentane	0.60
N-pentane	0.74
Hexanes	0.82
Heptanes	1.14
Octanes	1.18
Nonanes	0.51
Decanes	0.32
Undecanes	0.19
Dodecanes +	0.89
Nitrogen	0.34
CO_2	4.23
H_2S	0.00

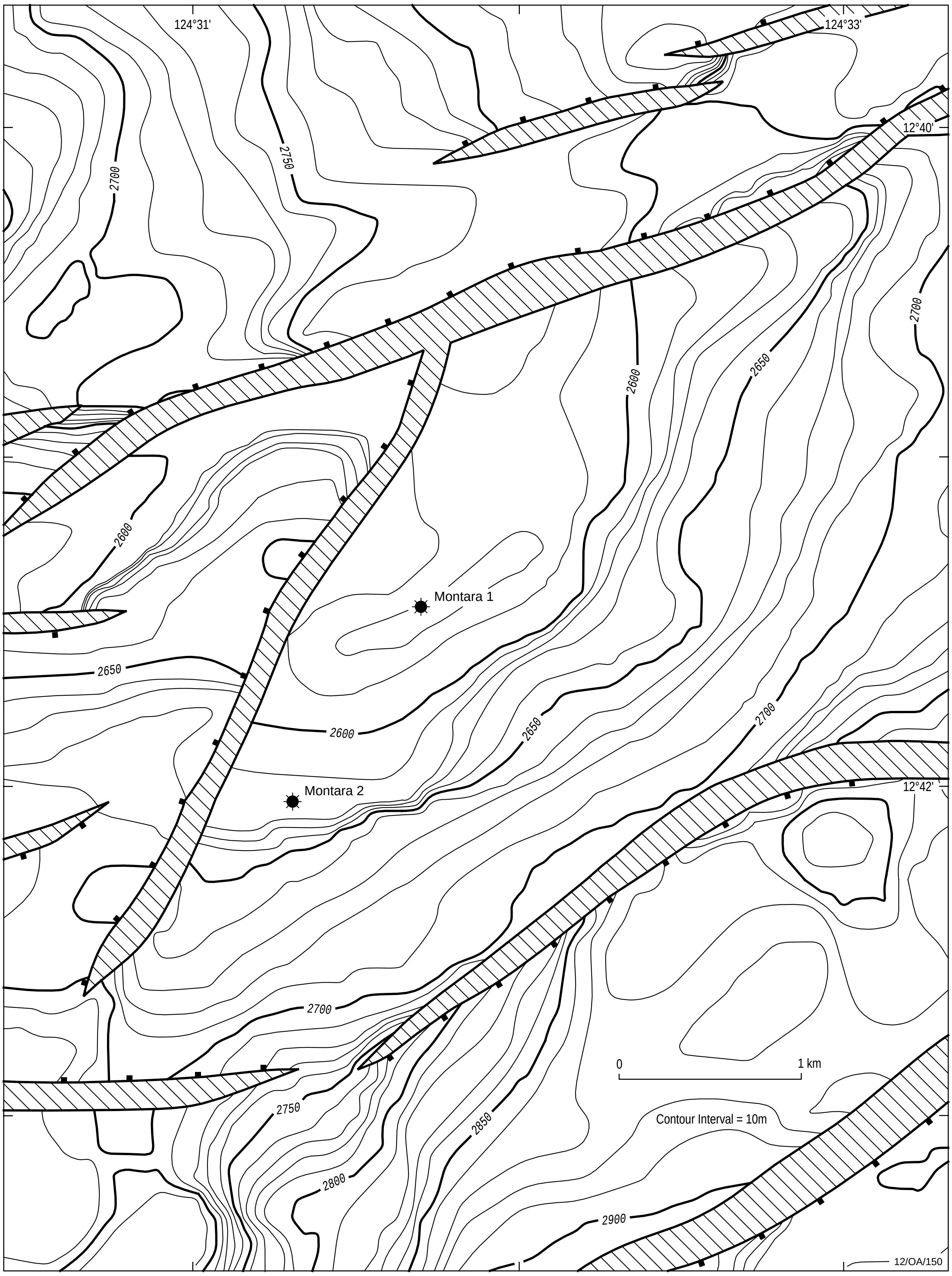
STRATIGRAPHY (Maret-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Barracouta Formation	153.0
		Oliver Formation	448.0
		Hibernia Formation	814.0
		Johnston Formation	1426.0
CRETACEOUS	BATHURST ISLAND GROUP	Puffin Formation	1726.0
		Fenelon Formation	2505.0
		Gibson Formation	2717.0
		Woolaston Formation	2775.0
		Jamieson Formation	2833.0
		Echuca Shoals Formation	3118.0
JURASSIC	FLAMINGO GROUP	Upper Vulcan Formation	3257.0
		Lower Vulcan Formation	3276.0
	TROUGHTON GROUP	Plover Formation	3385.0

Accumulation Number: 46

MONTARA

ORIGINAL OPERATOR:`	BHP Petroleum Pty Ltd
TYPE:	Oil and Gas
STATUS:	Possible Future Producer
LOCATION:	670 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/P7
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Montara-1
Longitude (E):	124.5317
Latitude (S):	-12.6893
Date total depth reached:	26 APR 88
Water Depth:	85.1 m
Kelly bushing:	17.7 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	3,444 mKB
NUMBER OF WELLS DRILLED:	2
STRUCTURE/TRAP:	Fault dependent closure on northeast-southwest trending horst block.
RESERVOIR UNITS:	1
GAS/OIL CONTACT:	2,606 mSS (Montara-1)
OIL/WATER CONTACT:	2,621.5 mSS (Montara-2)
NET GAS PAY:	24.8 m (2,599-2,624 mKB, Montara-1)
NET OIL PAY:	9.4 m (2,624-2,633 mKB, Montara-1)
WATER SATURATION (S_w):	40% (average, 2,599-2,624 mKB, Montara-1)
GAS/OIL RATIO:	3,613 scf/stb (DST-2)
OIL GRAVITY:	34.6^o API
SOLUTION GAS/OIL RATIO:	739 scf/bbl (at 107^{o}C)
OIL VOLUME FACTOR:	1.417 bbl/std bbl
RESERVOIR PRESSURE:	3,777 psig
RESERVOIR TEMPERATURE:	107^{o}C
BOTTOM HOLE TEMPERATURE:	119^{o}C
PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Oil and Gas
FORMATION:	Montara Formation
AGE:	Late Jurassic (Oxfordian)
LITHOLOGY:	Sandstone, generally massive, becoming graded and cross-bedded with depth with individual laminae fining upwards. Generally medium to coarse grained, subrounded to subangular, well sorted, quartzose, minor kaolin with traces of carbonate cement and with minor development of secondary porosity by dissolution of feldspars.
DEPOSITIONAL ENVIRONMENT:	Upper shoreface barrier bar.
FORMATION TOP (mKB):	2,388 m
POROSITY:	19.6 - 24.5% (core data, 2,604-2,610.5 m)
PERMEABILITY:	759 – 5,967 mD (core data, 2,604-2,610.5 m) (around 4,000 mD average)



Montara, Top Montara Formation, depth map

TEST DATA FROM THE DISCOVERY WELL (Montara-1)**:**

DST 1, 2,641.6-2,648.6 m, Montara Formation
Flowed 35.5^o API oil at 496 bbls/day and gas at 6,654 m^3/day at 250 psig.

DST 2, 2,628-2,633 m, Montara Formation
Flowed 36.2^o API oil at 4,285 bbls/day and gas at 438,373 m^3/day at 321 psig through a 2” choke.

APPRAISAL AND DEVELOPMENT DRILLING :

Montara-2 was drilled 1.3 km southwest of Montara-1. A 15 m gross oil column was intersected between 2,614.5 mSS and 2,629.5 mSS. The upper 7 m of the column is thought to be moveable oil while the lower 8 m is considered to be a residual oil column. The residual oil zone has an average porosity of 23% and an average water saturation (S_w) of 63%. In Montara-2, the oil/water contact was placed at 2,621.5 mSS.

RESERVES:

Oil: 23 MMbbls (includes Bilyara and Tahbilk)
Gas: 105 BCF (includes Bilyara and Tahbilk)
Source: Northern Territory Department of Business Industry and Resource Development, 1999.

REMARKS:

At date of publication, the Montara discovery was held under Retention Lease AC/RL3.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Lower Vulcan Fm DST 2, 2628-2633 m
Methane	82.60
Ethane	6.60
Propane	2.26
Isobutane	0.29
N-butane	0.45
Isopentane	0.11
N-pentane	0.08
Hexanes	0.06
Heptanes +	0.12
Nitrogen	0.07
CO_2	7.36
H_2S	0.00
Specific Gravity	0.698

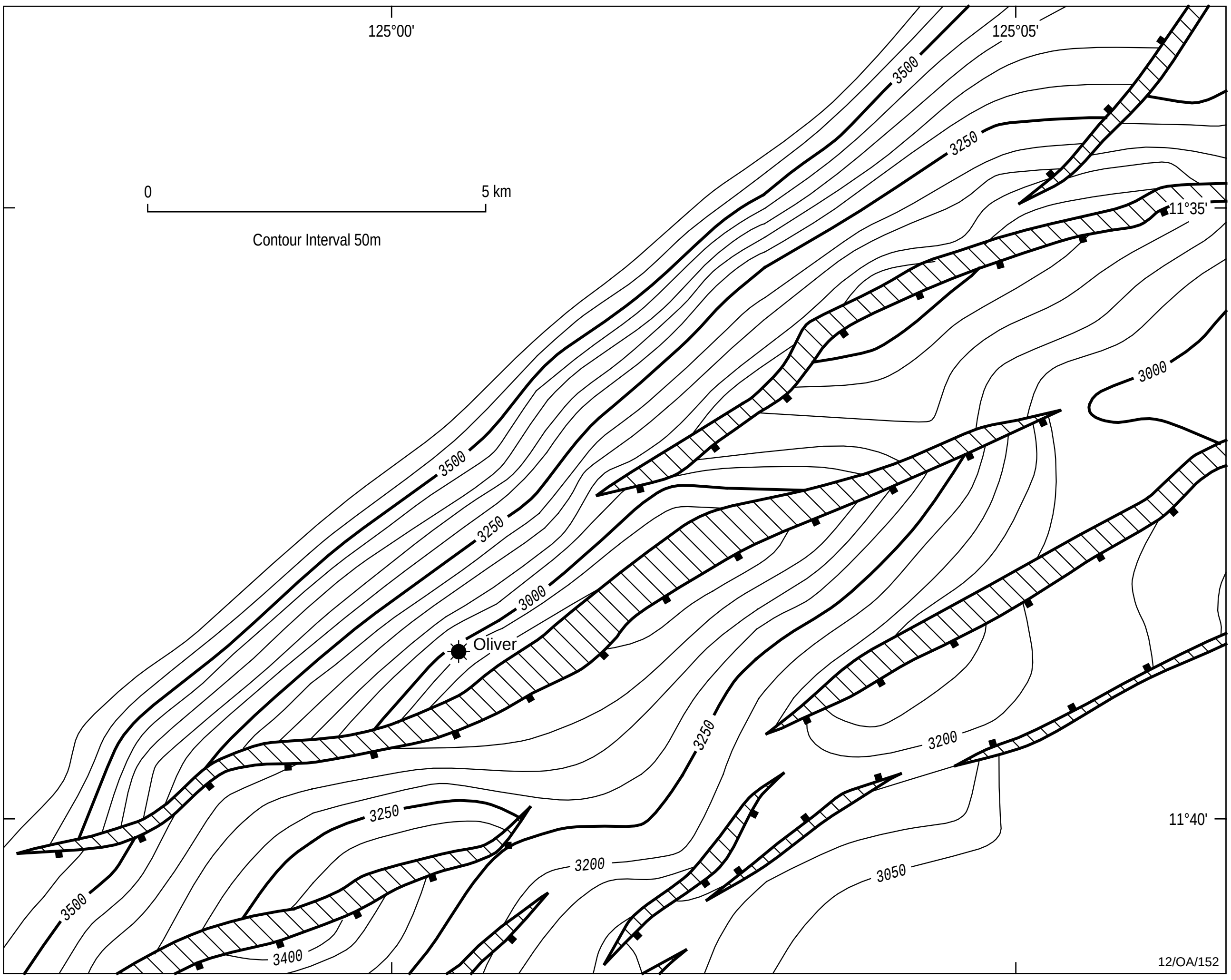
STRATIGRAPHY (Montara-1) **:**

AGE	**UNIT**		**FORMATION TOP (mKB)**
TERTIARY	WOODBINE GROUP	Barracouta Formation	85.1
		Prion Formation	712.0
		Grebe Sandstone	1078.0
		Johnson Formation	1252.0
CRETACEOUS	BATHURST ISLAND GROUP	Puffin Formation	1654.0
		Fenelon Formation	2118.0
		Gibson Formation	2229.0
		Woolaston Formation	2274.0
		Jamieson Formation	2327.0
JURASSIC	FLAMINGO GROUP	Lower Vulcan Formation	2388.0
		Montara Formation	2580.0

Accumulation Number: 47

OLIVER

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Oil and Gas
STATUS:	Other Discovery
LOCATION:	645 km west-northwest of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/P6
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Oliver-1
Longitude (E):	125.0088
Latitude (S):	-11.6448
Date total depth reached:	02 FEB 88
Water Depth:	305 m
Kelly bushing:	17.7 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	3,500 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Northeast-southwest oriented tilted fault block located on the eastern flank of the Cartier Trough.
AREAL CLOSURE:	9.9 km^2 (on the Callovian unconformity)
VERTICAL CLOSURE:	280 m
RESERVOIR UNITS:	1
GROSS GAS COLUMN:	162.7 m TVT (2,929 – 3,091.7 mTVDSS)
GROSS OIL COLUMN:	13 to 16 mTVT (3,091.7 – 3,104.3 or 3,108.1 mTVDSS)
OIL/WATER CONTACT:	3,104 mTVDSS
OIL GRAVITY:	31.8 ^{o} API
GAS/OIL RATIO:	628 scf/bbl
BOTTOM HOLE TEMPERATURE:	121^{o}C
PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Oil and Gas
FORMATION:	Plover Formation
AGE:	Early Jurassic (Bathonian to Hettangian)
LITHOLOGY:	Sandstone, clear to light grey, generally unconsolidated, fine to coarse grained (predominantly medium), subangular to subrounded, moderately well sorted with occassional white kaolinitic matrix and siliceous cement, interbedded with claystones and minor shales and siltstones with rare coal laminae.
DEPOSITIONAL ENVIRONMENT:	Marginal marine to lower deltaic. Predominantly infilling of a wide, distributary channel system but also includes mouth bars/delta fronts (reworked in places) and crevasse splay facies.
FORMATION TOP (mKB):	2,948 m
POROSITY:	10.4 - 21.3% (average 16.3%, log analysis) 12 - 15.4% (average 14.1%, core data, 2,972 – 2,980.8 mKB)
HORIZONTAL PERMEABILITY:	319 - 984 mD, 707 mD average (full diameter core samples). 650 mD (average from RFT data).
VERTICAL PERMEABILITY:	37 - 799 mD (388 mD average)



(after Evans et al, 1995)

Oliver, Callovian Unconformity, depth map

TEST DATA FROM THE DISCOVERY WELL (Oliver-1)**:**

RFT, 3,051 m, Plover Formation
Recovered 44.9 ft^3 of gas and 250 ml of oil.

RFT, 3,116 m, Plover Formation
Recovered a quantity of oil.

RESERVES:

Oil: 21.4 MMbbls
Gas: 310 BCF
Source: Northern Territory Department of Business Industry and Resource Development, 1999.

REMARKS:

Determination of the oil/water contact at Oliver is difficult as it lies within a very shaley section. Fluid inclusion studies by O'Brien & others (1996) have indicated that the Oliver structure was originally filled to spill point with oil. However most of this oil was subsequently displaced by late gas migration.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Plover Fm RFT, 3051 m
Methane	78.38
Ethane	5.72
Propane	2.19
Isobutane	0.50
N-butane	0.76
Isopentane	0.41
N-pentane	0.33
Hexanes	0.50
Heptanes	0.56
Octanes	0.41
Nonanes	0.20
Decanes	0.19
Undecanes	0.14
Dodecanes +	0.41
Nitrogen	1.46
CO_2	7.84
H_2S	0.00
Specific Gravity	0.810

STRATIGRAPHY (Oliver-1) **:**

AGE	**UNIT**		**FORMATION TOP (mKB)**
TERTIARY	WOODBINE GROUP	Undifferentiated	590.0
		Hibernia Formation	1577.0
		Woodbine Formation	2002.0
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	2392.5
JURASSIC	FLAMINGO GROUP	Undifferentiated	2698.0
	TROUGHTON GROUP	Plover Formation	2948.0
TRIASSIC	SAHUL GROUP	Undifferentiated	3365.0

Accumulation Number: 48

PADTHAWAY

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	680 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/RL3
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Padthaway-1
Longitude (E):	124.5017
Latitude (S):	-12.6807
Date total depth reached:	09 APRIL 00
Water Depth:	88 m
Kelly bushing:	25 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	2,875 mRT
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Tilted fault block
RESERVOIR UNITS:	1
GROSS HYDROCARBON COLUMN:	9 m (2,585-2,594 mRT)
GAS/WATER CONTACT:	2,569 mSS
GAS/CONDENSATE RATIO:	30.1 bbl/MMscf
HYDROCARBON SATURATION:	96% (average)

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Gas
FORMATION:	Montara Formation
AGE:	Oxfordian
LITHOLOGY:	Sandstone: medium grey to olive grey, firm, friable, fine to coarse grained with angular to sub-rounded, moderately spherical, poorly sorted. Minor to locally abundant silty argillaceous matrix, trace of silicieous cement, trace lithic fragments, trace of glauconite with poor to fair visual porosity.
DEPOSITIONAL ENVIRONMENT:	Fluvial dominated deltaic deposit.
FORMATION TOP (mKB):	2,585 m
POROSITY:	25% (average log porosity)
PERMEABILITY:	8,000 mD (average from logs)

TEST DATA FROM THE DISCOVERY WELL (Padthaway-1)**:**

MDT, Run1, 2,609 m Recovered 10.5 litres of formation water and filtrate from the 2.75 gallon chamber.	Montara Formation

MDT, Run 1, 2,600.5 m Recovered 21 litres of formation water and mud filtrate with an oil scum from the 6 gallon chamber. Recovered 10 litres of formation water and mud filtrate from the 2.75 gallon chamber.	Montara Formation
MDT, Run 1, 2,589 m Recovered gas from the 1 gallon Chamber.	Montara Formation

REMARKS:

A 9.5m residual oil column between 2,569 mSS and 2,578.5 mSS is inferred from wireline logs.

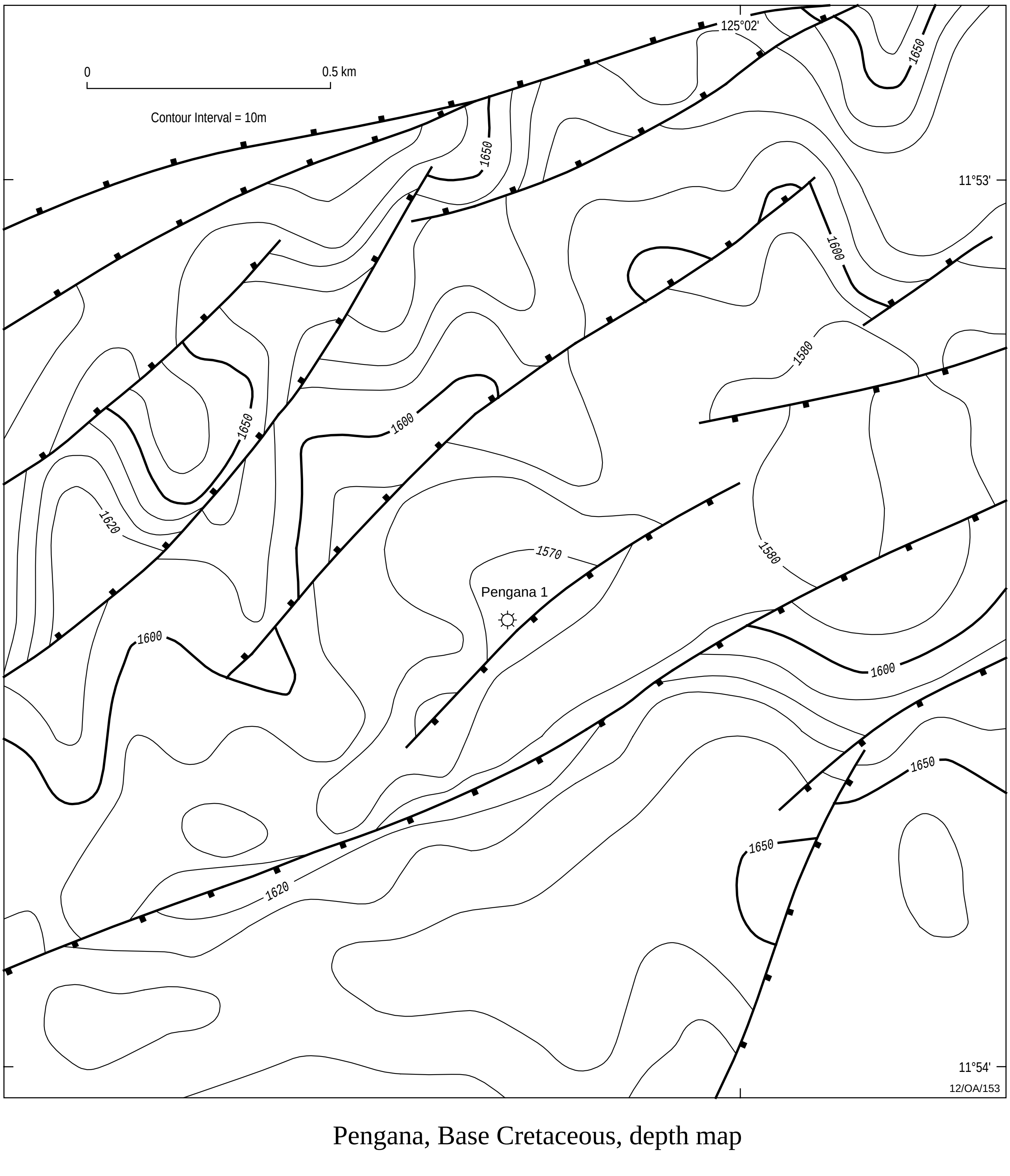
STRATIGRAPHY (Padthaway-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Oliver Formation	412.5
		Prion Formation	736.0
		Hibernia Formation	993.0
		Grebe Sandstone	1095.5
		Johnson Formation	1297.5
CRETACEOUS	BATHURST ISLAND GROUP	Puffin Formation	1697.0
		Fenelon Formation	2166.4
		Gibson Formation	2313.8
		Woolaston Formation	2367.3
		Jamieson Formation	2305.3
JURASSIC	FLAMINGO GROUP	Lower Vulcan Formation	2457.8
		Montara Formation	2585.2

Accumulation Number: 49

PENGANA

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	640 km west-northwest of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/L1
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Pengana-1
Longitude (E):	125.02904
Latitude (S):	-11.8914
Date total depth reached:	06 MAY 88
Water Depth:	117 m
Kelly bushing:	26 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	2,095 m
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	East-northeast/west-southwest oriented fault block on the Jabiru Horst.
RESERVOIR UNITS:	1
GROSS HYDROCARBON COLUMN:	5 m (1,639 – 1,644 mKB)
GAS/WATER CONTACT:	1,644 – 1,647 mKB (log derived) 1,618 – 1,621 mTVDSS (log derived)
GAS/CONDENSATE RATIO:	22.8 bbl/MMscf (DST-1) 52.7 bbl/MMscf (DST-2)
RESERVOIR PRESSURE:	2,374.3 psia (at 1,642 mKB)
RESERVOIR TEMPERATURE:	63°C
HYDROCARBON SATURATION:	50%
BOTTOM HOLE TEMPERATURE:	83°C
PETROLEUM BEARING UNIT No.1:	Sahul Group
CONTENTS:	Gas
FORMATION:	Sahul Group
AGE:	Triassic
LITHOLOGY:	Sandstone. Several fining upwards cycles observed in core. Coarse to fine grained, occasionally grading upwards to silt size, angular to subrounded, poorly sorted, quartzose, crossbedded, occasional bimodal grainsize distribution, common pyrite and carbonaceous material, interbedded with minor siltstone, claystone and coals. No evidence of reworking.
DEPOSITIONAL ENVIRONMENT:	Fluvial, meandering stream environment.
FORMATION TOP (mKB):	1,621 m
POROSITY:	22.1% (average)
PERMEABILITY:	2 – 11,768 mD (RFT data)



Pengana, Base Cretaceous, depth map

TEST DATA FROM THE DISCOVERY WELL (Pengana-1)**:**

RFT 1, 1,642 m, Recovered 3.9 m^3 of gas, 495 ml of condensate and 505 ml of water.	Sahul Group
RFT 2, 1,643.5 m, Recovered 1.6 m^3 of gas, 471 ml of condensate and 1.36 litres of water.	Sahul Group

REMARKS:

A 5 m gas sand was encountered in the Triassic section in Pengana-1. Determination of the hydrocarbon /water contact was difficult as log analysis indicates that it it lies within a thin shaley interval. RFT data indicated a hydrocarbon/water contact at 1,645 mKB.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Sahul Group RFT 1, 1642 m
Methane	76.98
Ethane	10.99
Propane	4.82
Isobutane	0.72
N-butane	1.08
Isopentane	0.26
N-pentane	0.18
Hexanes +	<0.01
Nitrogen	2.63
O_2	0.09
CO_2	2.25

STRATIGRAPHY (Pengana-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	142.0
		Hibernia Formation	468.0
		Undifferentiated	864.0
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	1218.5
TRIASSIC	SAHUL GROUP	Undifferentiated	1621.0

Accumulation Number: 50

PENGUIN

ORIGINAL OPERATOR:	Arco Australia Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	290 km southwest of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	WA-17-P
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Penguin-1
Longitude (E):	128.4683
Latitude (S):	-13.6078
Date total depth reached:	29 JUL 72
Water Depth:	69 m
Kelly bushing:	34.4 m
Operator:	Arco Australia Ltd
Total Depth:	2,757 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	North-northwest/south-southeast trending asymmetrical anticline.
AREAL CLOSURE:	26 km^2
VERTICAL CLOSURE:	88 m (near base of Upper Permian)
RESERVOIR UNITS:	1
GROSS HYDROCARBON COLUMN:	9.8 m (2,534.1-2,543.9 m)
NET PAY:	8.5 m
NET TO GROSS RATIO:	87%
BOTTOM HOLE TEMPERATURE:	93^{o}C

PETROLEUM BEARING UNIT No.1:	Kinmore Group
CONTENTS:	Gas
FORMATION:	Hyland Bay Formation
AGE:	Late Permian
LITHOLOGY:	Sandstone, quartzose, light grey, fine to medium grained, subangular to subrounded, moderately well sorted, friable, very calcareous, micaceous, lignitic and pyritic in part, interbedded with silty shales and siltstones.
FORMATION TOP (mKB):	2,098 m
POROSITY:	11% to 23% (core data)
PERMEABILITY:	Less than 0.1 to 18 mD (core data)

TEST DATA FROM THE DISCOVERY WELL (Penguin-1)**:**

RFT 1, 2,101.6 m, Hyland Bay Formation
Seal failure. Recovered 22 litres of mud.

RFT 2, 2,107 m, Hyland Bay Formation
Recovered 8.2 litres of watery mud.

RFT 3, 2,535 m, Hyland Bay Formation
Seal failure.

Penguin, Near Base of Upper Permian, TWT map

RFT 5, 2,535 m, Recovered 3.6 m^3 of gas, 2.5 litres of water with a trace of condensate.	Hyland Bay Formation
RFT 4, 2,540 m, Recovered 3.65 m^3 of gas and 2.5 litres of water.	Hyland Bay Formation

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Penguin-1 FIT-4 Hyland Bay Fm	Penguin-1 FIT-5 Hyland Bay Fm
Methane	58.50	62.90
Ethane	3.00	2.10
Propane	2.10	0.89
Isobutane	0.18	0.14
N-butane	0.23	0.11
Isopentane	0.09	0.03
N-pentane	0.05	trace
Hexanes +	trace	-
Nitrogen	31.3	30.3
O_2	3.4	3.2
CO_2	1.1	0.29

STRATIGRAPHY (Penguin-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	256.0
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	378.0
JURASSIC	FLAMINGO GROUP	Undifferentiated	803.0
	TROUGHTON GROUP	Plover Formation	861.0
		Malita Formation	1131.0
TRIASSIC		Undifferentiated	1278.6
	KINMORE GROUP	Mt Goodwin Formation	1611.5
PERMIAN		Hyland Bay Formation	2098.0
		Undifferentiated	2544.0

Accumulation Number: 51

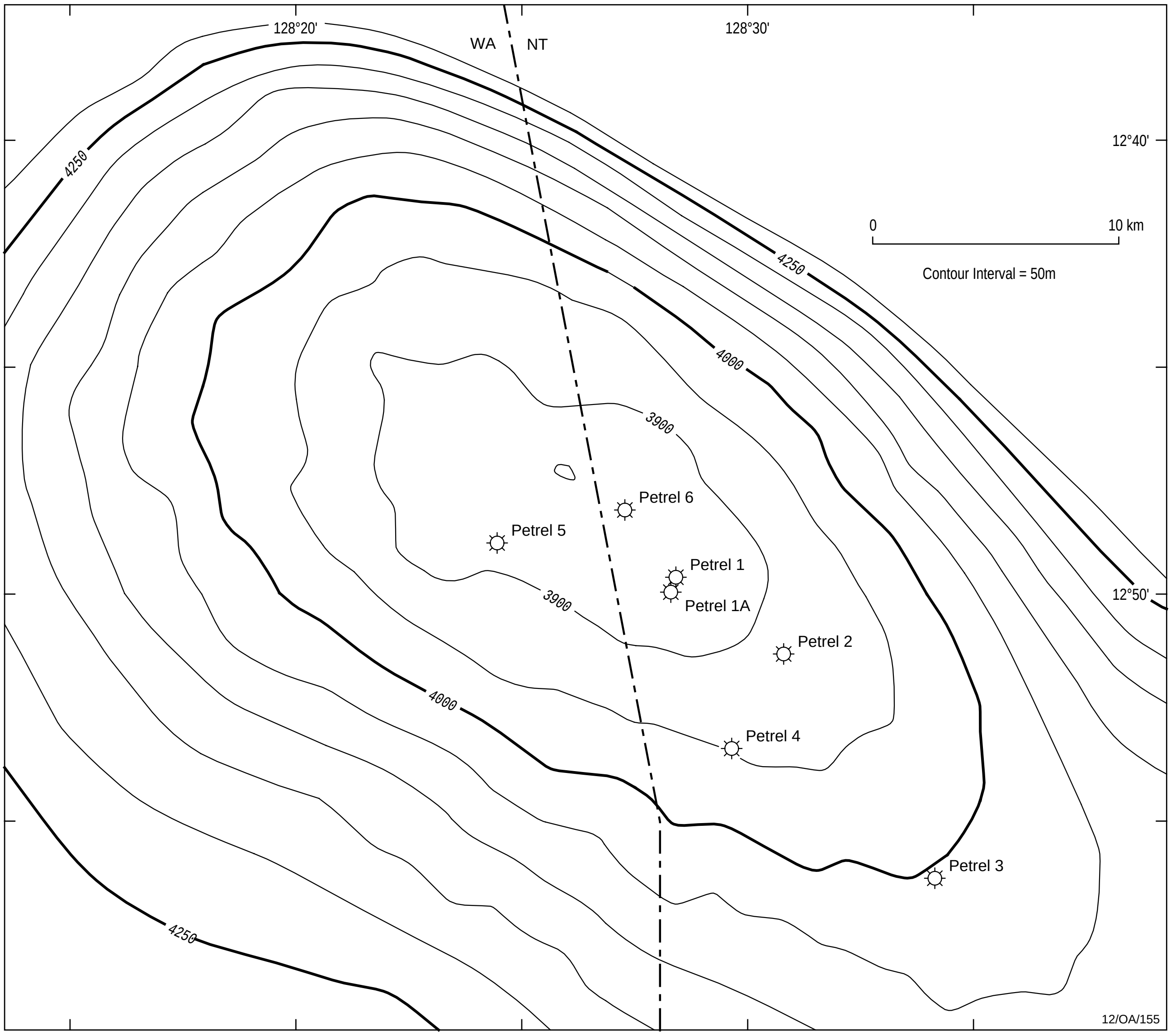
PETREL

ORIGINAL OPERATOR:	Arco Australia Ltd
TYPE:	Gas
STATUS:	Possible Future Producer
LOCATION:	260 km west-southwest of Darwin
STATE:	Western Australia and the Northern Territory
ORIGINAL TITLE(S):	NT/P3
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Petrel-1
Longitude (E):	128.4742
Latitude (S):	-12.8264
Date total depth reached:	06 AUG 69
Water Depth:	98 m
Kelly bushing:	34.4 m
Operator:	Arco Australia Ltd
Total Depth:	3,980 mKB
NUMBER OF WELLS DRILLED:	7 (includes 1 relief well)
STRUCTURE/TRAP:	Elongate, northwest-southeast oriented anticline. Some of the gas pools may have a major stratigraphic component due to lateral changes in reservoir quality.
AREAL CLOSURE:	124 km^2 (at base Jurassic level) 570 km^2 (at the top of the Lower Permian)
VERTICAL CLOSURE:	198 m (from the top of the Lower Permian)
RESERVOIR UNITS:	3 sands within the Cape Hay Member ('Lower', 'Middle' and 'Upper' Sands)
HYDROCARBON SATURATION:	66% ('Upper' Sand, Petrel-5) 77% ('Middle' Sand, Petrel-5)
BOTTOM HOLE TEMPERATURE:	137^{o}C (at 3,933 mKB, Petrel-5)

PETROLEUM BEARING UNIT No.1:	Cape Hay Member
CONTENTS:	Gas
FORMATION:	Hyland Bay Formation
AGE:	Late Permian
LITHOLOGY:	Sandstone, very fine to medium grained, occassionally coarse grained, usually well sorted, clean, quartzose, subangular to rounded with patchily developed calcite cement and quartz overgrowths. Interbedded with siltstones and shales.
DEPOSITIONAL ENVIRONMENT:	Shallow, tidally dominated, estuarine conditions
FORMATION TOP (mKB):	3,974.6 m (Cape Hay Member)
POROSITY:	9-11% (average)
PERMEABILITY:	Up to 1,500 mD (core analysis 'Upper Sandstone Zone', Petrel-5)

TEST DATA FROM THE DISCOVERY WELL (Petrel-1)**:**

Well not tested.



Petrel,Intra Hyland Bay Formation, depth map

APPRAISAL AND DEVELOPMENT DRILLING :

Petrel-1A was drilled as a directional relief well to control the gas blowout that occurred while drilling Petrel-1.

Petrel-2 was drilled 5.2 km to the southeast of Petrel-1A. The first measured gas flow from the Petrel accumulation occured in this well. Here, DST 6 taken at around 3,658 mKB, flowed gas at 263,350 m^3/day from the 'Middle Sandstone Zone' of the Cape Hay Member.

Petrel-3, drilled 15.6 km to the southeast of Petrel-1A on the southern nose of the Petrel anticline was cased and suspended as a possible future gas producer.

Petrel-4 drilled 6.8 km south-southeast of Petrel-1A, structurally updip from Petrel-3, was cased and suspended as a possible future gas producer.

Petrel-5 recorded the highest gas flow on test from the Petrel accumulation. In this well, gas flowed at 979,760 m^3/day and condensate at 19 bbls/day through a 25.4 mm choke from a sandstone near the top of the Cape Hay Member. The well was plugged and abandoned as it was not considered to be in an optimal position for field development.

Petrel-6, drilled 3.8 km northwest of Petrel-1A in a crestal position was plugged and abandoned after failing to encounter reservoir quality sandstones above the highest known water.

RESERVES:

Gas: 535 BCF
Source: Northern Territory Department of Business Industry and Resource Development, 1997.

REMARKS:

In Petrel-1, gas from a drilling break encountered between 3,978.2 mKB and 3,979.8 mKB in the Hyland Bay Formation blew out. The gas blowout burned at a slowly diminishing rate over a 16 month period until a directional relief well (Petrel-1A) was drilled.

At date of publication, the Petrel accumulation was held under Retention Lease NT/RL1 and Retention Lease WA-6-R.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Petrel Field Cape Hay Mbr (‘Upper’ Sand)
Methane	91.47
Ethane	1.70
Propane	0.35
Isobutane	0.07
N-butane	0.09
Isopentane	0.03
N-pentane	0.03
Hexanes +	0.26
Nitrogen	0.85
CO_2	5.15
H_2S	0.00
Specific Gravity	0.7599
BTU/ft^3 (gross)	991

STRATIGRAPHY (Petrel-1) **:**

<table>
<tr><th>AGE</th><th colspan="2">UNIT</th><th>FORMATION TOP (mKB)</th></tr>
<tr><td>TERTIARY</td><td>WOODBINE GROUP</td><td>Undifferentiated</td><td>34.4</td></tr>
<tr><td>CRETACEOUS</td><td>BATHURST ISLAND GP</td><td>Undifferentiated</td><td>412.7</td></tr>
<tr><td rowspan="2">JURASSIC</td><td>FLAMINGO GROUP</td><td>Undifferentiated</td><td>1571.2</td></tr>
<tr><td rowspan="2">TROUGHTON GROUP</td><td>Malita Formation</td><td>2229.3</td></tr>
<tr><td rowspan="2">TRIASSIC</td><td>Cape Londondery Fm</td><td>2471.3</td></tr>
<tr><td rowspan="4">KINMORE GROUP</td><td>Mt Goodwin Fm</td><td>2887.1</td></tr>
<tr><td rowspan="3">PERMIAN</td><td>Hyland Bay Formation</td><td>3464.4</td></tr>
<tr><td>Tern Member</td><td>3464.4</td></tr>
<tr><td>Cape Hay Member</td><td>3974.6</td></tr>
</table>

Accumulation Number: 52

PROMETHEUS / RUBICON

ORIGINAL OPERATOR:	Kerr McGee NW Shelf Energy Australia Pty Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	450 km west of Darwin
STATE:	Western Australia
CURRENT TITLE(S):	WA-278-P
BASIN:	Bonaparte
SUB-BASIN:	Petrel
DISCOVERY WELL:	Prometheus-1
Longitude (E):	126.3688
Latitude (S):	-12.8392
Date total depth reached:	07 JUN 00
Water Depth:	69 m
Operator:	Kerr McGee NW Shelf Energy Australia Pty Ltd
Total Depth:	2,360 mRT
NUMBER OF WELLS DRILLED:	2

RESERVES:

Gas: 370 BCF
Source: Department of Industry and Resources, Western Australia, 2002.

REMARKS:

In December 2000, Rubicon-1 was drilled approximately 3 km to the east of Prometheus-1 in an adjacent fault block.

Limited data is available at date of publication but the two wells are thought to have recovered gas on test from the Permian section in adjacent fault compartments on the one structure.

Accumulation Number: 53

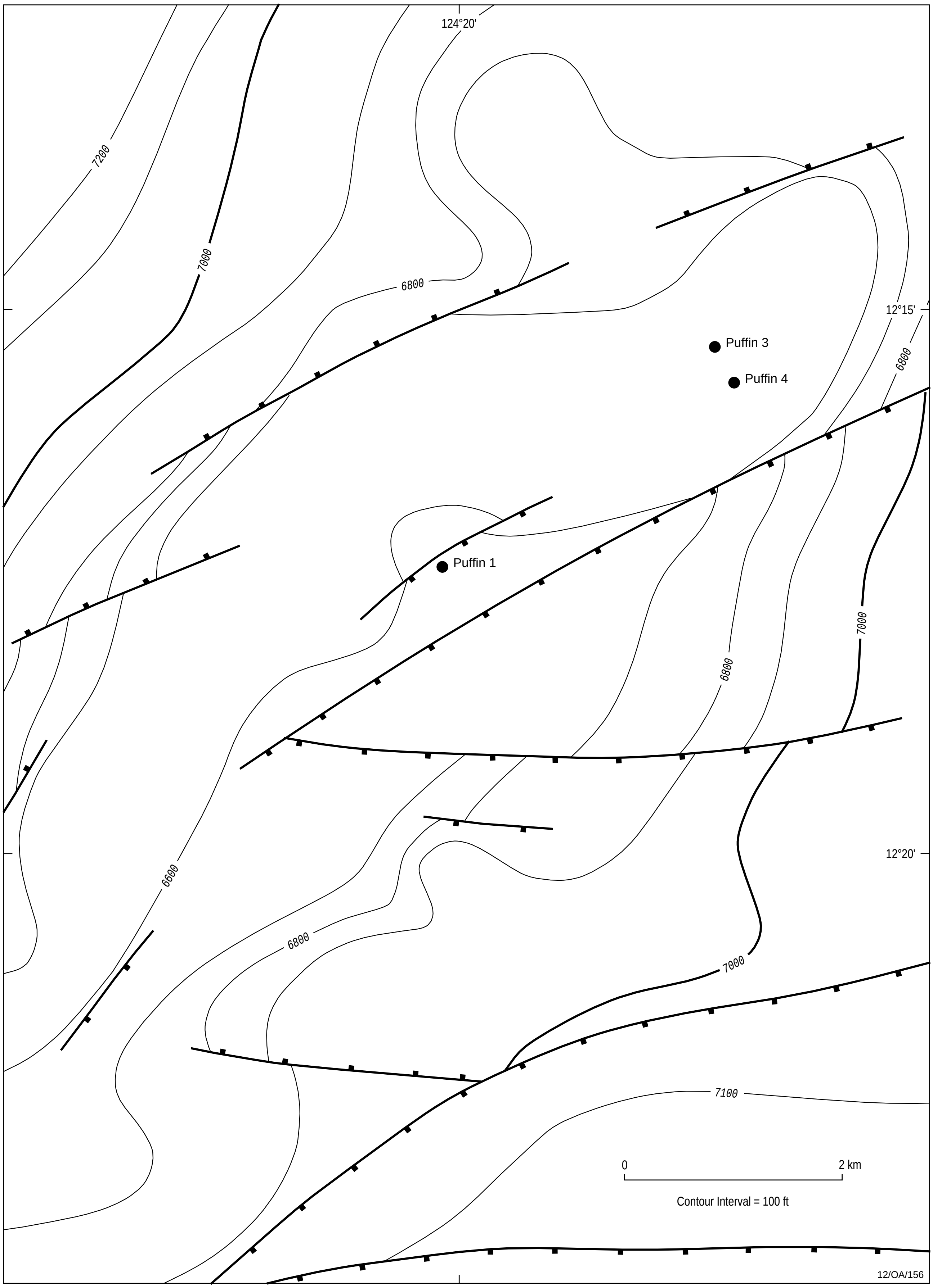
PUFFIN

ORIGINAL OPERATOR:	Arco Australia Ltd
TYPE:	Oil
STATUS:	Other Discovery
LOCATION:	710 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	NT/P2
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Puffin-1
Longitude (E):	124.3336
Latitude (S):	-12.3083
Date total depth reached:	08 JUN 72
Water Depth:	102 m
Kelly bushing:	34 m
Operator:	Arco Australia Ltd
Total Depth:	2,961 mKB
NUMBER OF WELLS DRILLED:	4
STRUCTURE/TRAP:	Northeast-southwest trending horst block.
VERTICAL CLOSURE:	183 m (near base Tertiary) 366 m (near base Cretaceous)
RESERVOIR UNITS:	1
GROSS HYDROCARBON COLUMN:	1.5 m (2,066 – 2,067.5 mKB)
OIL/WATER CONTACT:	2,075 mSS (Puffin-4); 2,077 mSS (Puffin-3)
OIL GRAVITY:	45^{o} API
BOTTOM HOLE TEMPERATURE:	90^{o}C

PETROLEUM BEARING UNIT No.1:	Bathurst Island Group
CONTENTS:	Oil
FORMATION:	Puffin Formation
AGE:	Late Cretaceous
LITHOLOGY:	Sandstone, light grey, fine to coarse grained, quartzose, slightly glauconitic and friable, occasionally calcareous and argillaceous.
FORMATION TOP (mKB):	1,999.5 m
POROSITY:	16 - 30% (log porosity))
PERMEABILITY:	21 – 3,870 mD (RFT data, Puffin-4)

TEST DATA FROM THE DISCOVERY WELL (Puffin-1)**:**

RFT 1, 2,067 m, Recovered 20.15 litres of 45^{o} API oil, 0.69 m^3 of gas and 25 cc of sand.	Puffin Formation
RFT 2, 2,071 m, Recovered 22 litres of formation water.	Puffin Formation
RFT 4, 2,162 m, Recovered 22 litres of formation water.	Puffin Formation
RFT 3, 2,214 m, Recovered 21.5 litres of formation water.	Puffin Formation



Puffin, Near Top Puffin Formation, depth map

APPRAISAL AND DEVELOPMENT DRILLING :

Puffin-2, located 9 km southwest of Puffin-1, flowed oil at 4,608 bbls/day on DST over the interval 2,028-2,036 mKB in the Bathurst Island Group.

Puffin-3, located 3 km northeast of Puffin-1, recovered oil on RFT from the same oil bearing interval (3 m gross pay) in the Late Cretaceous section.

Puffin-4, drilled 450 m southeast of Puffin-3, intersected the same Upper Cretaceous sandstone, but wireline logs showed that only the upper 0.7 m of the reservoir (2,099.8 – 2,100.5 mKB) had significant hydrocarbon saturations (20%).

RESERVES:

Oil: 42 MMbbls
Source: Northern Territory Department of Business Industry and Resource Development, 2000.

REMARKS:

Log analysis in Puffin-1 indicated a heavy, sour crude oil is trapped in vuggy calcarenites and argillaceous calcilutites of Eocene age between 1,021 mKB and 1,029 mKB. The oil is trapped at the Eocene - Miocene unconformity.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Bathurst Island Gp RFT 1, 2067 m
Methane	73.40
Ethane	4.40
Propane	1.40
Isobutane	0.26
N-butane	0.04
Isopentane	trace
N-pentane	trace
Hexanes +	0.03
Nitrogen	14.10
CO_2	0.12

STRATIGRAPHY (Puffin-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	136.9
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	1999.5
TRIASSIC	SAHUL GROUP	Undifferentiated	2362.2

STRATIGRAPHY (Puffin-4) **:**

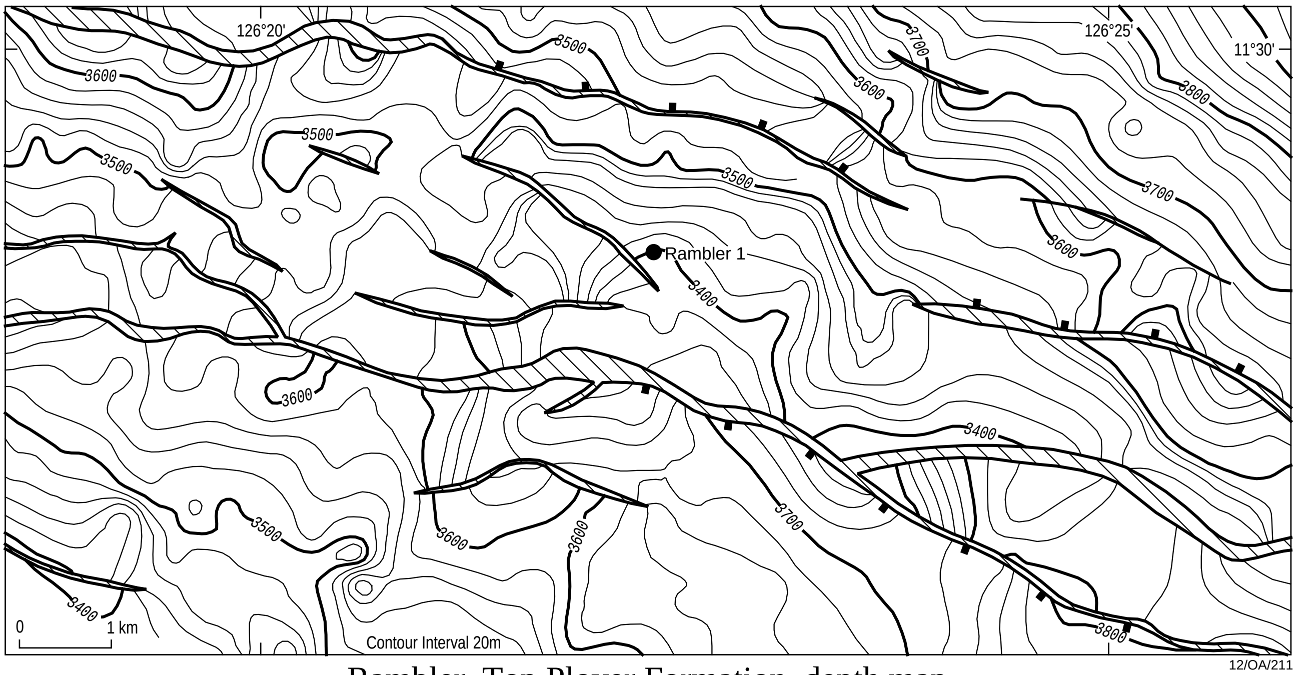
Kelly Bushing = 26 m; Total Depth = 2456 m

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Barracouta Formation	370.0
		Oliver Formation	580.0
		Hibernia Formation	1031.0
		Johnson Formation	1788.0
CRETACEOUS	BATHURST ISLAND GROUP	Puffin Formation	2008.0
		Fenelon Formation	2295.0
TRIASSIC	SAHUL GROUP	Challis Formation	2314.5

Accumulation Number: 54

RAMBLER

ORIGINAL OPERATOR:	SAGASCO Resources
TYPE:	Oil and Gas
STATUS:	Other Discovery
LOCATION:	500 km west-northwest of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	WA-224-P
BASIN:	Bonaparte
SUB-BASIN:	Londonderry High
DISCOVERY WELL:	Rambler-1
Longitude (E):	126.3716
Latitude (S):	-11.5205
Date total depth reached:	30 DEC 93
Water Depth:	112 m
Kelly bushing:	23 m
Operator:	SAGASCO Resources
Total Depth:	3,709 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Tilted, Mesozoic fault block on the western flank of the Sahul Syncline.
RESERVOIR UNITS:	2
BOTTOM HOLE TEMPERATURE:	152^{o}C (after 3 hours circulation)
PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Oil and Gas
FORMATION:	Flamingo Group
AGE:	Early Jurassic
LITHOLOGY:	Grey to olive-grey, calcareous claystone, very silty to sandy in part, interbedded with grey and brown clayey siltstone.
DEPOSITIONAL ENVIRONMENT:	Moderately deep water, marine.
FORMATION TOP (mKB):	2,774 m
POROSITY:	Low permeability fracture porosity.
PETROLEUM BEARING UNIT No.2:	Troughton Group
CONTENTS:	Gas (inferred from logs only)
FORMATION:	Plover Formation
AGE:	Jurassic
DEPOSITIONAL ENVIRONMENT:	Fluvio-deltaic to marginal marine.
FORMATION TOP (mKB):	3,595 m
POROSITY:	10.6% (average log porosity)
GROSS HYDROCARBON COLUMN:	85 m (3,597-3,682 mKB, inferred from logs)
NET PAY:	6.2 m
NET TO GROSS RATIO:	7.3%
HYDROCARBON SATURATION:	66%
GAS/WATER CONTACT:	3,682 mKB (from logs)



Rambler, Top Plover Formation, depth map

TEST DATA FROM THE DISCOVERY WELL (Rambler-1)**:**

DST 3 (CASED HOLE), 2,842-2,926 m, Flamingo Group
Recovered 17 bbls of water with an oil scum.

DST 2 (CASED HOLE), 3,000-3,027 m, Flamingo Group
Recovered 0.5 bbls of water.

RFT 1 (CASED HOLE), 3,018.5 m, Flamingo Group
Recovered 300 cc of medium green brown 43^o API oil and 1.1 ft^3 of gas.

DST (CASED HOLE) 1, 3,074-3,093 m, Flamingo Group
Tight. No recovery.

RFT 2 (CASED HOLE), 3,082 m, Flamingo Group
Recovered 390 cc of medium green brown 37^o API oil and 4.7 ft^3 of gas.

REMARKS:

A fracture intersected at 3,448 m within the lower Flamingo Group appears to have bled oil and gas into the wellbore. However, the fracture is thought to be of limited extent or relatively impermeable, as the well stabilised after kicking 50 bbls of mud.

Geochemical analysis indicates that the oil bleeding from the fracture at 3,448 m is identical to the oil recovered at 3,018.5 m and 3,082 m by RFT. It is thought that that gassy oil bleeding from the fracture at 3,448 m mixed with cement during the setting of casing and that the RFT tools subsequently recovered oil from the oil impregnated cement.

Log analysis indicates the presence of an 86 m gas column in low porosity and permeability sandstones of the Upper Plover Formation. RFTs run near the top of the Plover Formation were either dry or recorded very slow pressure buildups.

STRATIGRAPHY (Rambler-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	134.0
CRETACEOUS	BATHURST ISLAND GROUP	Vee Formation	1354.0
		Wangarlu Formation	1581.0
		Radiolarite	2646.0
		Darwin Formation	2742.0
JURASSIC	FLAMINGO GROUP	Undifferentiated	2774.0
		Cleia Shale	3504.0
	TROUGHTON GROUP	Plover Formation	3595.0

Accumulation Number: 55

SARATOGA

ORIGINAL OPERATOR:	Kerr-McGee NW Shelf Australia Energy Pty Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	475 km west of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	WA-276-P
BASIN:	Bonaparte
SUB-BASIN:	Petrel
DISCOVERY WELL:	Saratoga-1
Longitude (E):	126.4237
Latitude (S):	-12.3296
Date total depth reached:	17 DEC 00
Water Depth:	94.6 m
Kelly bushing:	25 m
Operator:	Kerr-McGee NW Shelf Australia Energy Pty Ltd
Total Depth:	2,139 mRT
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Westnorthwest – eastsoutheast trending anticline with independent fault closure at Elang/Plover formation level.
AREAL CLOSURE:	11 km^2
VERTICAL CLOSURE:	55 m
BOTTOM HOLE TEMPERATURE:	115.6^{o}C (at 2,102 m, by Shell method)

PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Gas
FORMATION:	Upper Flamingo Formation
AGE:	Late Jurassic
LITHOLOGY:	Sandstone: fine, well to moderately well sorted, subarkosic, well cemented with quartz overgrowths, minor feldspar, glauconite and authigenic kaolinite. Poor to occasionally fair visual porosity, some secondary porosity development.
FORMATION TOP (mKB):	1,757 m
POROSITY:	18.2% (average log porosity)
PERMEABILITY:	84.3 mD (average from logs)
GROSS HYDROCARBON COLUMN:	8.5 m
NET PAY:	4.3 m
NET TO GROSS RATIO:	51%
HYDROCARBON SATURATION:	57.3% (average)
GAS/WATER CONTACT:	1,768.7 m (logs and pressure data)

TEST DATA FROM THE DISCOVERY WELL (Saratoga-1)**:**

RCI Bottomhole sample, 1,761.5 m Upper Flamingo Formation
Recovered 840 cc of gas.

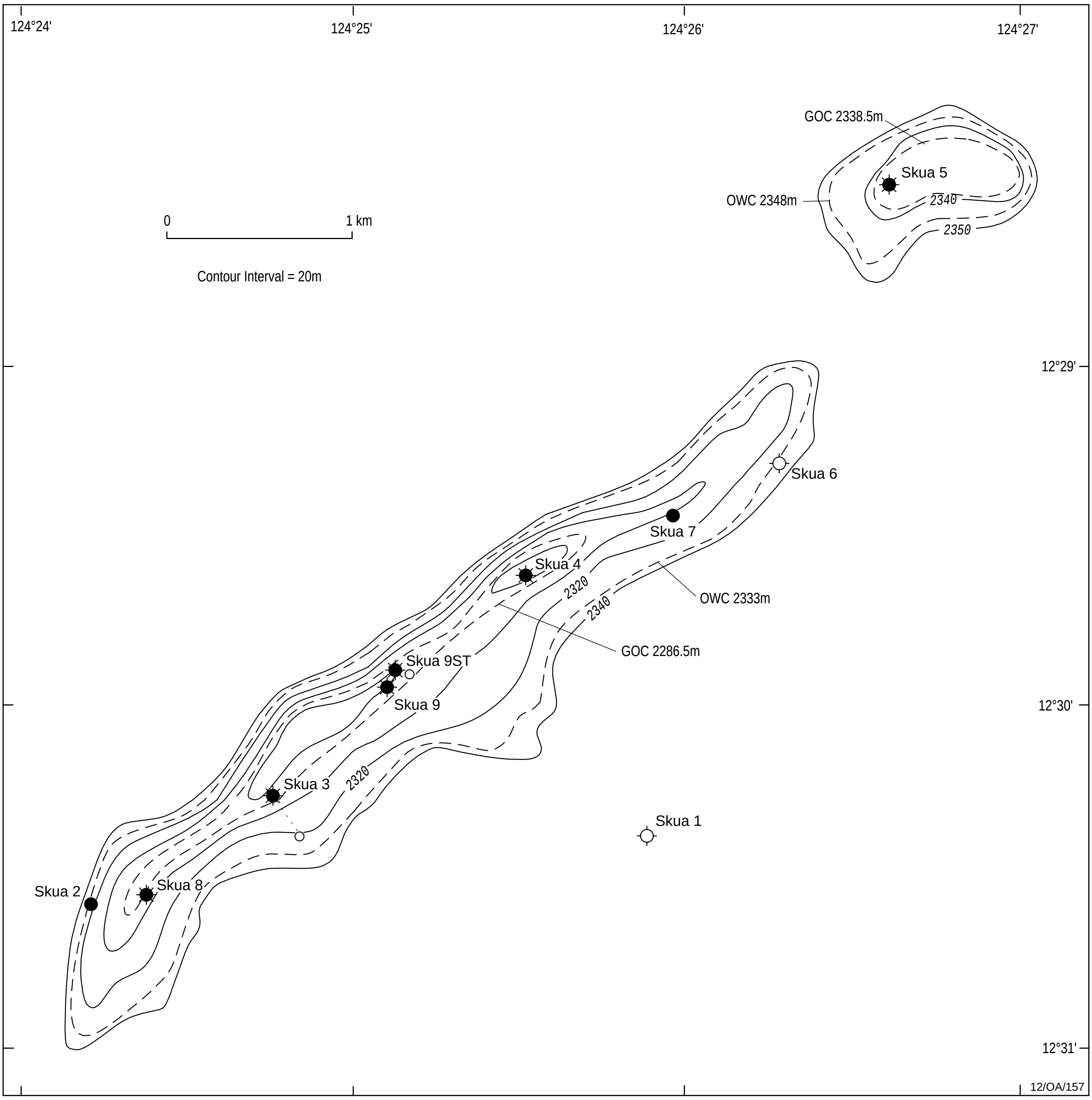
STRATIGRAPHY (Saratoga-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Barracouta/Oliver Fms	119.6
		Oliver Sandstone	366.0
		Hibernia Formation	371.5
		Johnson Formation	444.0
CRETACEOUS	BATHURST ISLAND GROUP	Puffin Formation	630.0
		Jamieson Formation	683.0
		Darwin Radiolarite	1711.0
		Echuca Shoals Formation	1727.0
JURASSIC	FLAMINGO GROUP	Upper Flamingo Fm	1757.0
		Lower Flamingo Fm	1992.2
		Elang Formation	2037.4

Accumulation Number: 56

SKUA

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Oil and Gas
STATUS:	Past Producer
LOCATION:	700 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	NT/P2
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Skua-2
Longitude (E):	124.4043
Latitude (S):	-12.5095
Date total depth reached:	26 DEC 85
Water Depth:	81.7 m
Kelly bushing:	8 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	2,600 mKB
NUMBER OF WELLS DRILLED:	10 (including one redrill)
STRUCTURE/TRAP:	Fault dependent. Tilted horst block.
AREAL CLOSURE:	4.5 km^2
VERTICAL CLOSURE:	74.5 m (above oil/water contact)
RESERVOIR UNITS:	1 (7 correlatable flow units)
GROSS HYDROCARBON COLUMN:	74.5 m
NET TO GROSS RATIO:	50%
GAS COLUMN:	28 m
OIL COLUMN:	46.5 m
GAS/OIL CONTACT:	2,286.5 mSS
OIL/WATER CONTACT:	2,333 mSS
GAS TO OIL RATIO:	900 scf/stb
WATER SATURATION:	12-25% (most likely value of 18%)
INITIAL RESERVOIR PRESSURE:	3,315 psia at the gas/oil contact 3,356 psia at the oil/water contact
RESERVOIR TEMPERATURE:	96^{o}C (at the gas/oil contact)
FORMATION VOLUME FACTOR:	1.48
DRIVE:	Water drive
PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Oil and Gas
FORMATION:	Plover Formation
AGE:	Early to Middle Jurassic
LITHOLOGY:	Sandstone, fine to medium grained, subangular to subrounded, well sorted, minor silica and calcite cement, occassionally argillaceous, interbedded and interlaminated with dark brown/ black claystone, silty claystone and common coal laminae.
DEPOSITIONAL ENVIRONMENT:	Fluvial, braided stream environment at the base of the reservoir sequence, grading upwards into deltaic and marginal marine units.
FORMATION TOP (mKB):	2,338 m
POROSITY:	21-22% (average)
PERMEABILITY:	360-1,700 mD



(modified after Chapman G.J., 1993)

Skua, Intra Valanginian Unconformity, depth map

TEST DATA FROM THE DISCOVERY WELL (Skua-2)**:**

DST 2, 1,852-1,855 m, Bathurst Island Group (Late Maastrichtian)
Recovered 30 bbls of formation water.

DST 1, 2,332-2,336.5 m, Bathurst Island Group (Santonian)
Flowed 43.3^{o} API oil at 450 bbls/day
through a 6.4 mm choke at 630 psi.

APPRAISAL AND DEVELOPMENT DRILLING :

Skua-1 was drilled inside structural closure but intersected the reservoir below the oil/water contact and was plugged and abandoned. Minor oil shows were recorded in swc's shot at the Miocene/Eocene unconformity and in tight Palaeocene limestones.

Skua-2 intersected the western bounding fault of the structure at 2,338 mKB and did not penetrate a complete reservoir section. The well was subsequently plugged and abandoned due to poor flow rates. A residual oil column was identified between 1,853 mKB and 1,859 mKB in a Late Maastrichtian sand in Skua-2. Testing (DST 2) indicated the sand was water saturated. The Santonian oil saturated sand tested by DST 1 in the Skua-2 well is juxtaposed against the Plover Formation reservoir across the western bounding fault. The unit is thought to be draining oil across the fault from the Plover Formation but due to poor reservoir quality, the Santonian sand acts as a natural choke to flow.

Skua-3 was initially drilled vertically to test a series of shallow, stacked closures. Below 1,488 mKB, the well was drilled directionally to intersect deeper closures in an optimal position. The well intersected a 44.4 mTVT hydrocarbon column between 2,286.3 mTVDSS and 2,330.7 mTVDSS (35.8 mTVT of net pay) and was suspended as a potential oil producer. Skua-3, drilled in a crestal position, was the first well to test the Plover Formation reservoir proper. DST 2, taken over the interval 2,376-2,381 m, flowed oil at 5,477 bbls/day and gas at 240,665 m^3/day.

Skua-4, located 1.8 km northeast of Skua-3, was cased and suspended as a future oil producer.

Skua-5 was an appraisal well designed to test the northeasterly extent of the field. The well tested a small, deeper and separate oil and gas accumulation which was not thought to economically producible. The well was plugged and abandoned.

Skua-6 was drilled as a flank appraisal well. The well was plugged and abandoned after encountering a residual oil column down to 2,368 mSS in the Early Jurassic section.

Skua-7 was plugged and abandoned after the Operator was unable to run 30" surface casing. The well was redrilled as Skua-7A.

Skua-7A was drilled as production well on the northern culmination of the field. The well intersected a 29 m oil column (12.9 m net pay) but the oil/water contact was obscured by a shaley interval. Oil was recorded down to 2,333 mSS. Skua-7A also intersected a 1 m oil column overlain by gas in a thin sand within the Puffin Formation (1,930 – 1,932.5 mKB).

Skua-8 was completed as a future producer after intersecting a 51 m gross hydrocarbon column (4 m gas column, 47 m oil column).

Skua-9 intersected a 50 mTVT gross hydrocarbon column (41.9 mTVT net pay) before the drill string became irretrievably stuck at 2,534 mKB. The well was plugged back and kicked off at 2,074 mKB as Skua-9ST-1.

Skua-9ST-1 was completed as a future producer after intersecting a 53 mTVT hydrocarbon column (46.5 m oil column, 6.5 m gas column) between 2,280 mTVDSS and 2,333 mTVDSS.

RESERVES:

Initial Oil: 20.5 MMbbls
Source: Northern Territory Department of Business Industry and Resource Development, 1998.

REMARKS:

Fluid inclusion studies by O'Brien & others (1996) indicates a 10 m residual oil column below the present day OWC. This suggests appreciable quantities of oil (~ 20 million barrels) have leaked from the Skua structure, probably during the reactivation of bounding faults in the Tertiary.

Production from the Skua oil field commenced 1991 via sub-sea completions connected to an FPSO. The field was producing oil at a rate of 1,900 bbls/day when production was shut in and the field decommissioned in January 1997.

STRATIGRAPHY (Skua-2) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Undifferentiated	89.0
		Hibernia Formation	852.0
		Woodbine Beds	1393.0
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	1844.0
JURASSIC	TROUGHTON GROUP	Plover Formation	2338.0

STRATIGRAPHY (Skua-9) **:**

AGE	UNIT		FORMATION TOP (mSS)
TERTIARY	WOODBINE GROUP	Barracouta/Oliver Fms	83.0
		Prion/Hibernia Fms	838.5
		Grebe Sandstone	1224.0
		Johnson Formation	1430.0
CRETACEOUS	BATHURST ISLAND GP	Puffin/Fenelon Fms	1848.0
JURASSIC	TROUGHTON GROUP	Plover Formation	2283.0

Accumulation Number: 57

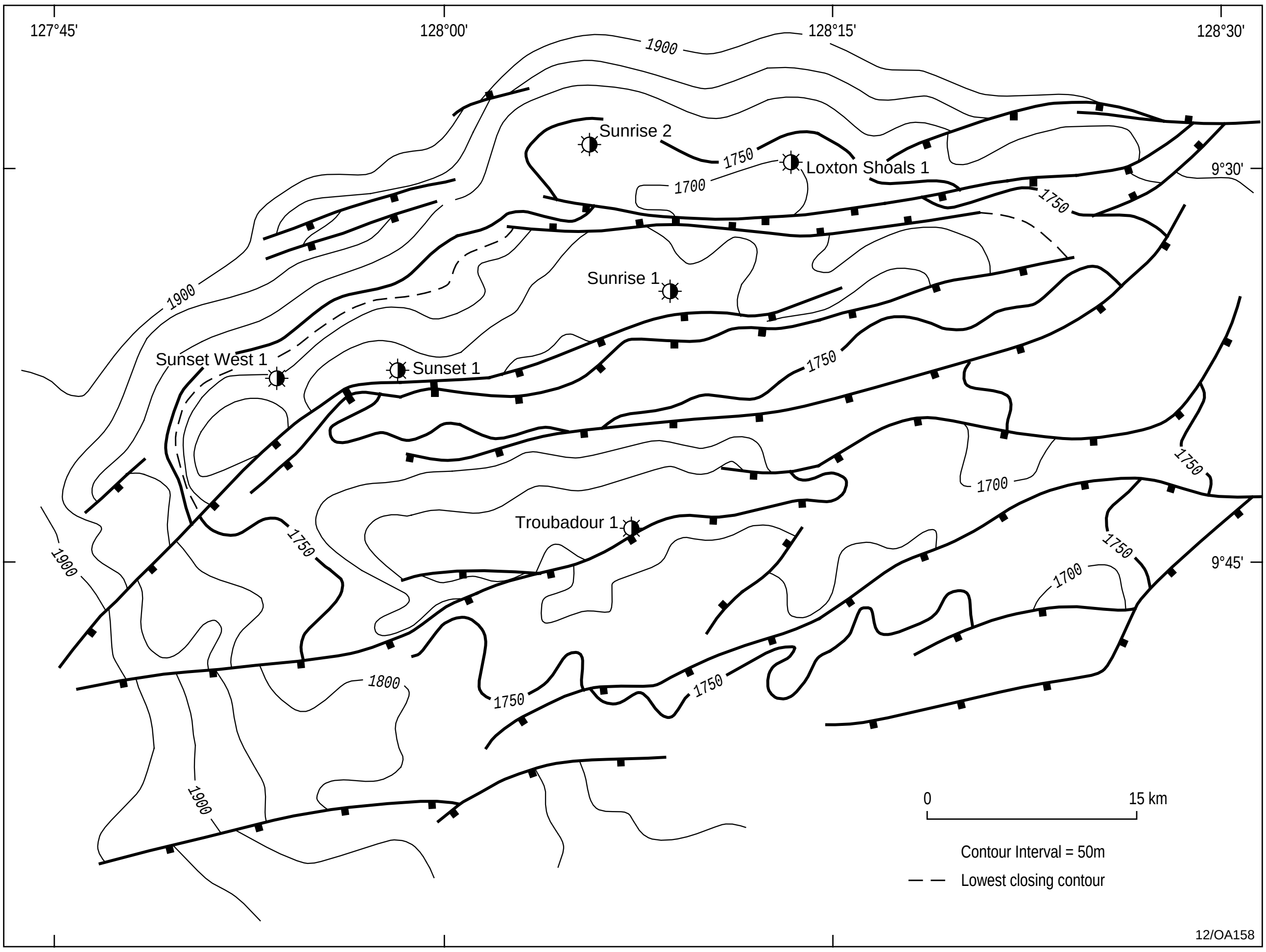
SUNRISE

ORIGINAL OPERATOR:	Woodside/Burmah Oil NL
TYPE:	Gas
STATUS:	Possible Future Producer
LOCATION:	440 km northwest of Darwin
STATE:	Northern Territory
ORIGINAL TITLE(S):	NT/P12
BASIN:	Bonaparte
SUB-BASIN:	Sahul Platform
DISCOVERY WELL:	Sunrise-1
Longitude (E):	128.1538
Latitude (S):	-9.5901
Date total depth reached:	28 JAN 75
Water Depth:	159 m
Kelly bushing:	30 m
Operator:	Woodside/Burmah Oil NL
Total Depth:	2,341 mKB
NUMBER OF WELLS DRILLED:	2
STRUCTURE/TRAP:	Faulted anticline
AREAL CLOSURE:	44 km^2
VERTICAL CLOSURE:	66 m
RESERVOIR UNITS:	2
BOTTOM HOLE TEMPERATURE:	103^{o}C

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Gas
FORMATION:	Plover Formation
AGE:	Late Jurassic
LITHOLOGY:	Claystone with interbedded sandstone and siltstone.
DEPOSITIONAL ENVIRONMENT:	Fluvio-deltaic to marginal marine.
FORMATION TOP (mKB):	2,096.5 m
GROSS HYDROCARBON COLUMN:	25 m (2,142-2,156 mKB; 2,195-2,206 mKB)
HYDROCARBON SATURATION:	75% (2,142-2,156 mKB) 65% (2,195-2,206 mKB)
POROSITY:	Up to 14% (2,142-2,156 mKB) Up to 18% (2,195-2,206 mKB)
PERMEABILITY:	Less than 5 mD

TEST DATA FROM THE DISCOVERY WELL (Sunrise-1)**:**

RFT 4, 2,144 m, Recovered 4.15 m^3 of gas , 800 cc of condensate and 800 cc of mud.	Plover Formation
RFT 3, 2,154 m, Recovered 0.03 m^3 of gas and 12 litres of water.	Plover Formation
RFT 2, 2,203 m, Recovered 2.56 m^3 of gas, 546 cc of condensate and 365 cc of mud and condensate emulsion.	Plover Formation



Sunrise, Near Base Cretaceous, depth map

RFT 1, 2,301 m, Recovered 12.25 litres of water with a trace of mud.	Plover Formation

APPRAISAL AND DEVELOPMENT DRILLING :

Sunrise-2, located 15 km north-northwest of Sunrise-1, was drilled in May 1998 to appraise the northern limit of the Sunrise gas/condensate accumulation. A 151 m gross gas column was identified on logs and a DST taken over the interval 2,112-2,124 mKB achieved a maximum flow rate of 849,500 m^3/day through a 2" choke.

RESERVES:

Gas: 9.56 TCF (includes Loxton Shoals/Troubadour/Sunset/Sunset West)
Condensate: 321 MMbbls (includes Loxton Shoals/Troubadour/Sunset/Sunset West)
Source: Northern Territory Department of Business Industry and Resource Development, 2000.

REMARKS:

Two hydrocarbon bearing zones were identified on logs. The upper sand, (2,142-2,156 mKB) recorded water saturations of around 25% while the lower zone, (2,195-2,206 mKB) averaged 35% water saturation.

Loxton Shoals-1, Troubadour-1, Sunset-1, Sunset West-1, Sunrise-1 and Sunrise-2 all recovered gas on test from the Plover Formation from what are thought to be adjacent fault compartments on the greater Sunrise/Troubadour structure. Development of the Sunrise/Troubadour resource is currently under consideration.

STRATIGRAPHY (Sunrise-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
QUATERNARY	WOODBINE GROUP	Undifferentiated	189.0
TERTIARY		Undifferentiated	492.5
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	1472.0
JURASSIC	TROUGHTON GROUP	Plover Formation	2096.5

Accumulation Number: 58

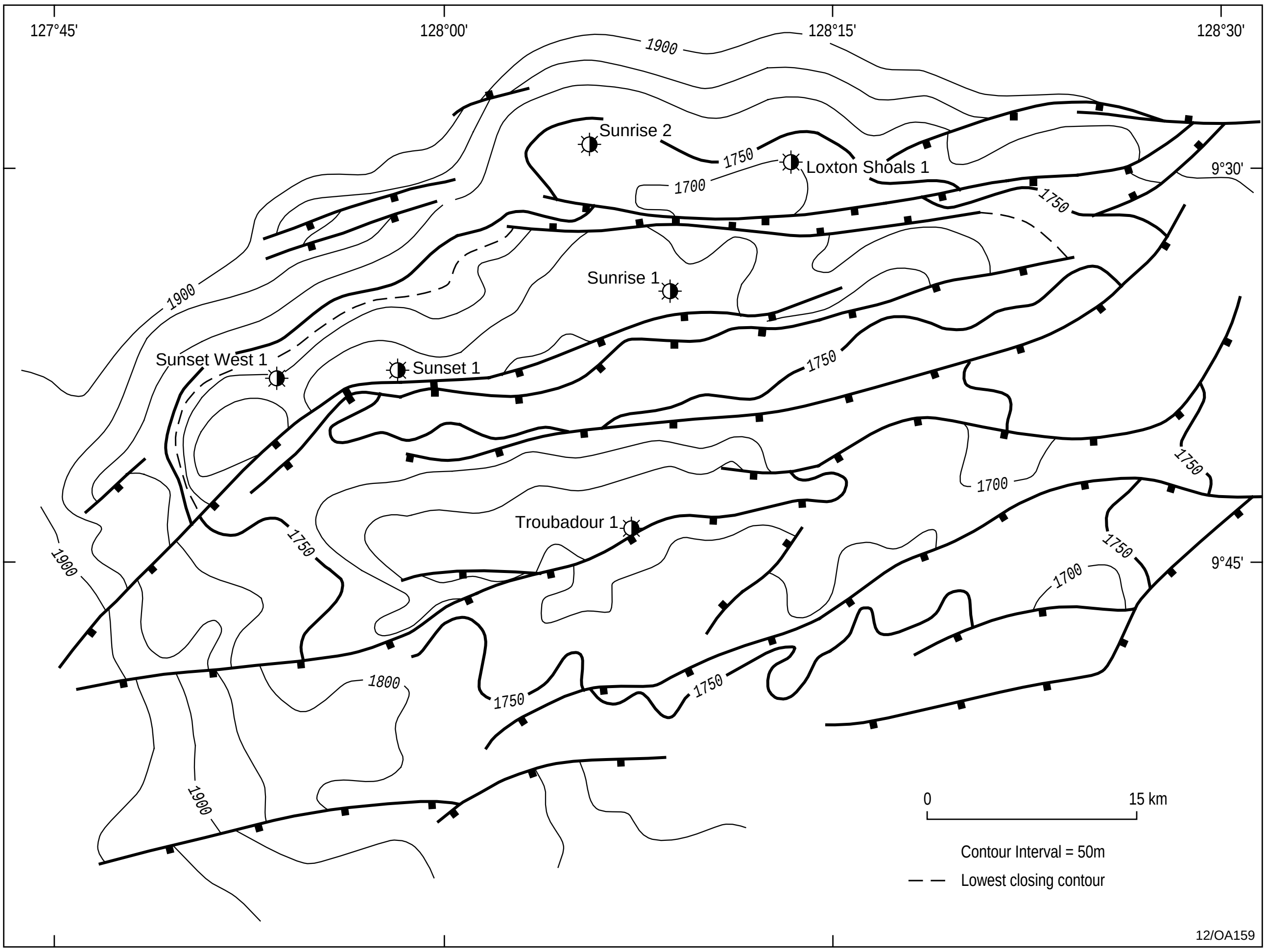
SUNSET

ORIGINAL OPERATOR:	Shell Development (PSC 19) Pty Ltd
TYPE:	Gas
STATUS:	Possible Future Producer
LOCATION:	440 km northwest of Darwin
STATE:	Zone of Cooperation, Part A
ORIGINAL TITLE(S):	ZOCA 95-19
BASIN:	Bonaparte
SUB-BASIN:	Sahul Platform
DISCOVERY WELL:	Sunset-1
Longitude (E):	127.9763
Latitude (S):	-9.6434
Date total depth reached:	13 OCT 97
Water Depth:	238.5 m
Kelly bushing:	25 m
Operator:	Shell Development (PSC 19) Pty Ltd
Total Depth:	2,420 mKB
NUMBER OF WELLS DRILLED:	2
STRUCTURE/TRAP:	Fault dependent closure on the same horst block as the Sunrise accumulation to the east.
RESERVOIR UNITS:	1

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Gas
FORMATION:	Plover Formation
AGE:	Pliensbachian to Callovian
LITHOLOGY:	Sandstone interbedded with shales and argillaceous sandstones.
DEPOSITIONAL ENVIRONMENT:	Marginal marine to fluvio deltaic.
GROSS HYDROCARBON COLUMN:	96 m
NET PAY:	34.7 m
NET TO GROSS RATIO:	36%
HYDROCARBON SATURATION:	71%
GAS/WATER CONTACT:	2,251 mRT (free water level from pressure data)
POROSITY:	16-17% (average log porosity)
PERMEABILITY:	variable (2-207 mD)

TEST DATA FROM THE DISCOVERY WELL (Sunset-1)**:**

DST, Flowed gas at 673,900 m^3/day and condensate at 750 bbls/day through a 15.9 mm choke.	Plover Formation
DST 2, 2,195.5-2,155 m, Flowed gas at 906,100 m^3/day and condensate at 28 bbls/day through a 28.5 mm choke.	Plover Formation
DST 1, 2,223-2,241 m, Flowed gas at 124,940 m^3/day and condensate at 1,500 bbls/day through a 31.8 mm choke.	Plover Formation



Sunset, Near Base Cretaceous, depth map

APPRAISAL AND DEVELOPMENT DRILLING :

Sunset West-1, drilled approximately 8 km to the west of Sunset-1 in April 1998, intersected a 64 m gross gas column. A maximum flow rate of 555,000 m^3/day of gas was achieved by DST 2, over the interval 2,189-2,231 mKB in the Plover Formation.

RESERVES:

Gas: 9.56 TCF (includes Loxton Shoals/Troubadour/Sunrise/Sunset West)
Condensate: 321 MMbbls (includes Loxton Shoals/Troubadour/Sunrise/Sunset West)
Source: Northern Territory Department of Business Industry and Resource Development, 2000.

REMARKS:

Loxton Shoals-1, Troubadour-1, Sunset-1, Sunset West-1, Sunrise-1 and Sunrise-2 all recovered gas on test from the Plover Formation from what are thought to be adjacent fault compartments on the greater Sunrise/Troubadour structure. Development of the Sunrise/Troubadour resource is currently under consideration.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Plover Formation (Mole %)
Methane	79.41
Ethane	4.76
Propane	2.26
Isobutane	0.63
N-butane	0.95
Isopentane	0.57
N-pentane	0.52
Hexanes	0.98
Heptanes	1.60
Octanes +	1.23
Nitrogen	2.97
CO_2	4.12

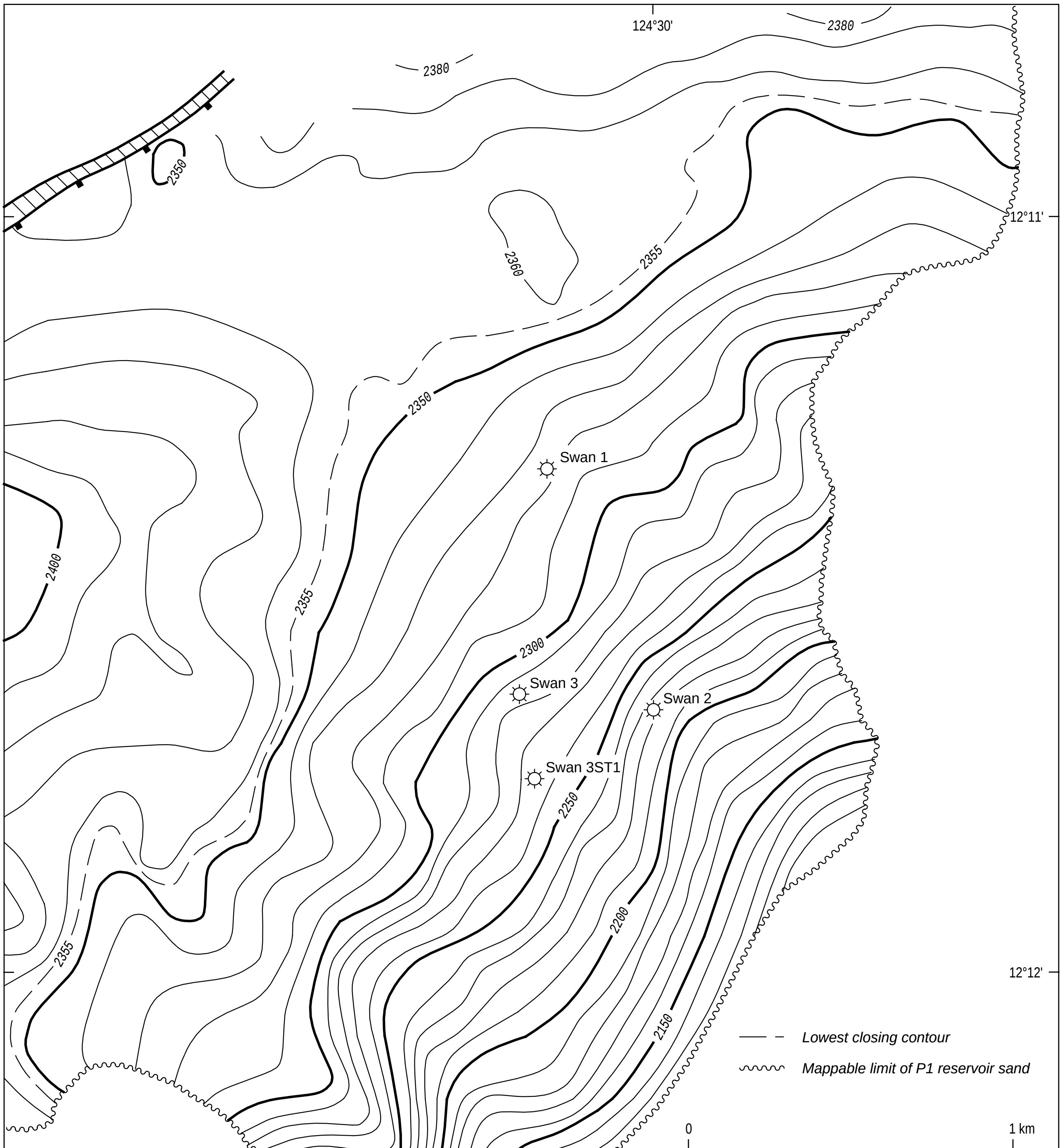
STRATIGRAPHY (Sunset-1) :

AGE	UNIT		FORMATION TOP (mTVDSS)
TERTIARY	WOODBINE GROUP	Oliver Formation	498.0
		Cartier Formation	992.0
		Hibernia Formation	1119.0
		Johnson Formation	1418.0
CRETACEOUS	BATHURST ISLAND GROUP	Vee Formation	1496.0
		Wangarlu Formation	1731.0
		Darwin Formation	2066.0
		Echuca Shoals Formation	2097.0
JURASSIC	FLAMINGO GROUP	Elang Formation	2105.0
	TROUGHTON GROUP	Plover Formation	2130.0

Accumulation Number: 59

SWAN

ORIGINAL OPERATOR:	Arco Australia Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	700 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	NT/P2
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Swan-1
Longitude (E):	124.4928
Latitude (S):	-12.1882
Date total depth reached:	30 JAN 73
Water Depth:	109 m
Kelly bushing:	34 m
Operator:	Arco Australia Ltd
Total Depth:	3,284 mKB
NUMBER OF WELLS DRILLED:	4 (including 1 sidetrack)
STRUCTURE/TRAP:	Northeast-southwest trending horst block with updip closure dependent on fault seal against a salt diapir.
AREAL CLOSURE:	6 km^2
VERTICAL CLOSURE:	270 m
RESERVOIR UNITS:	Several, thin gas bearing sands identified on logs in the Late Cretaceous section (informally named the P1, P2, P3 and P4 reservoir sands).
NET PAY:	11.25 m (Swan-1, P1 and P2 sands) 22.1 m (Swan-2, P1, P2 and P3 sands) 19.4 m (Swan-3, P1 and P2 sands) 32.7 m (Swan-3/ST1, P1, P2 and P3 sands)
NET TO GROSS RATIO:	75% (Swan-3, 2,306-2,332 mKB, P1 and P2 sands) 55% (Swan-3/ST1, 2,342-2,375 mKB, P1 and P2 sands) 93% (Swan-3/ST1, 2,445-2,461 mKB, P3 sand).
HYDROCARBON SATURATION:	57% (Swan-1, P1 and P2 sands) 82% (Swan-2, P1, P2 and P3 sands) 32% (Swan-3, P1 and P2 sands) 75% (Swan-3/ST1, P1, P2 and P3 sands)
BOTTOM HOLE TEMPERATURE:	100°C
PETROLEUM BEARING UNIT No.1:	Bathurst Island Group
CONTENTS:	Gas
FORMATION:	Puffin Formation
AGE:	Late Cretaceous
LITHOLOGY:	Sandstone, clean, fine to medium grained, subangular, well sorted, excellent visual porosity. Fluid escape structures, dish structures, flame structures and water escape pipes are observed in cores.
DEPOSITIONAL ENVIRONMENT:	Stacked, submarine fan sandstone sequence.
FORMATION TOP (mKB):	2,152.8 m (Bathurst Island Group)
POROSITY:	18.9% (average log porosity, Swan-1, P1 and P2 sands) 23% (average log porosity, Swan-3, P1 and P2 sands) 20% (average log porosity, Swan-3/ST1, P1, P2 and P3 sands).



Swan, Intra Puffin Formation, depth map

TEST DATA FROM THE DISCOVERY WELL (Swan-1)**:**

RFT, 2,364 m, Recovered 2.06 m^3 of gas, 625 cc of condensate and 3.175 litres of muddy water.	Puffin Formation
RFT, 2,398 m, Recovered 0.017 m^3 of gas and 21.5 litres of muddy water.	Puffin Formation
RFT, 3,231 m, Recovered 22 litres of mud.	Plover Formation
RFT, 3,258 m, Recovered 22 litres of mud.	Plover Formation

APPRAISAL AND DEVELOPMENT DRILLING :

Swan-2 encountered wet gas shows between 2,248 mKB and 2,335 mKB (P3 sand) within the Upper Cretaceous. Gas shows were also recorded in thin sands or fractures around 3,341 mKB in the Upper Jurassic to Oxfordian section. The well was plugged and abandoned at 4,064 mKB in overpressured Oxfordian shales.

Swan-3 was drilled to test the reservoir potential of the P3 reservoir intersected in Swan-2. The P3 sand was not encountered in this well. Instead, a shaley, water saturated sandstone (P4 sand) was intersected at the base of the Puffin Formation and a 26 m gross gas column was encountered in the P1 and P2 sands between 2,306 mKB and 2,332 mKB (19.4 m net pay). The well was plugged back and kicked off at 1,824 mKB as Swan-3ST-1 in an endeavour to intersect the P3 reservoir.

Swan-3ST-1 intersected a 33 m gross gas column (18.2 m net gas pay) between 2,342 mKB and 2,375 mKB in the P1 and P2 reservoirs. 14.3 m of net gas sand was identified in the P3 reservoir. No gas/oil or gas/water contacts were identified and the well was plugged and abandoned.

RESERVES:

Oil: 5 MMbbls
Gas: 70 BCF
Source: Northern Territory Department of Business Industry and Resource Development, 1997.

REMARKS:

In Swan-1, thin, possibly gas bearing sandstones were identified on logs in the Late Jurassic section. RFT testing showed these sandstones were tight.

The drilling of the Swan-3 well indicates that the accumulation at Swan is probably a single accumulation of stacked sands, although no proven gas/oil or gas/water contacts have been identified.

Whole extract analysis on sidewall cores taken in the Swan-3 well indicates residual oil is present in all the gas bearing sandstones encountered at Swan. It is thought that an initial oil accumulation at Swan has been displaced by gas, resulting in residual oil in a gas/condensate accumulation. RFT pressure data from the Swan-3 well suggest the possibility of an oil leg downdip from Swan-3.

STRATIGRAPHY (Swan-1) **:**

AGE	**UNIT**		**FORMATION TOP (mKB)**
TERTIARY	WOODBINE GROUP	Undifferentiated	296.6
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	2152.8
JURASSIC	FLAMINGO GROUP	Undifferentiated	2630.3
	TROUGHTON GROUP	Plover Formation	2696.3

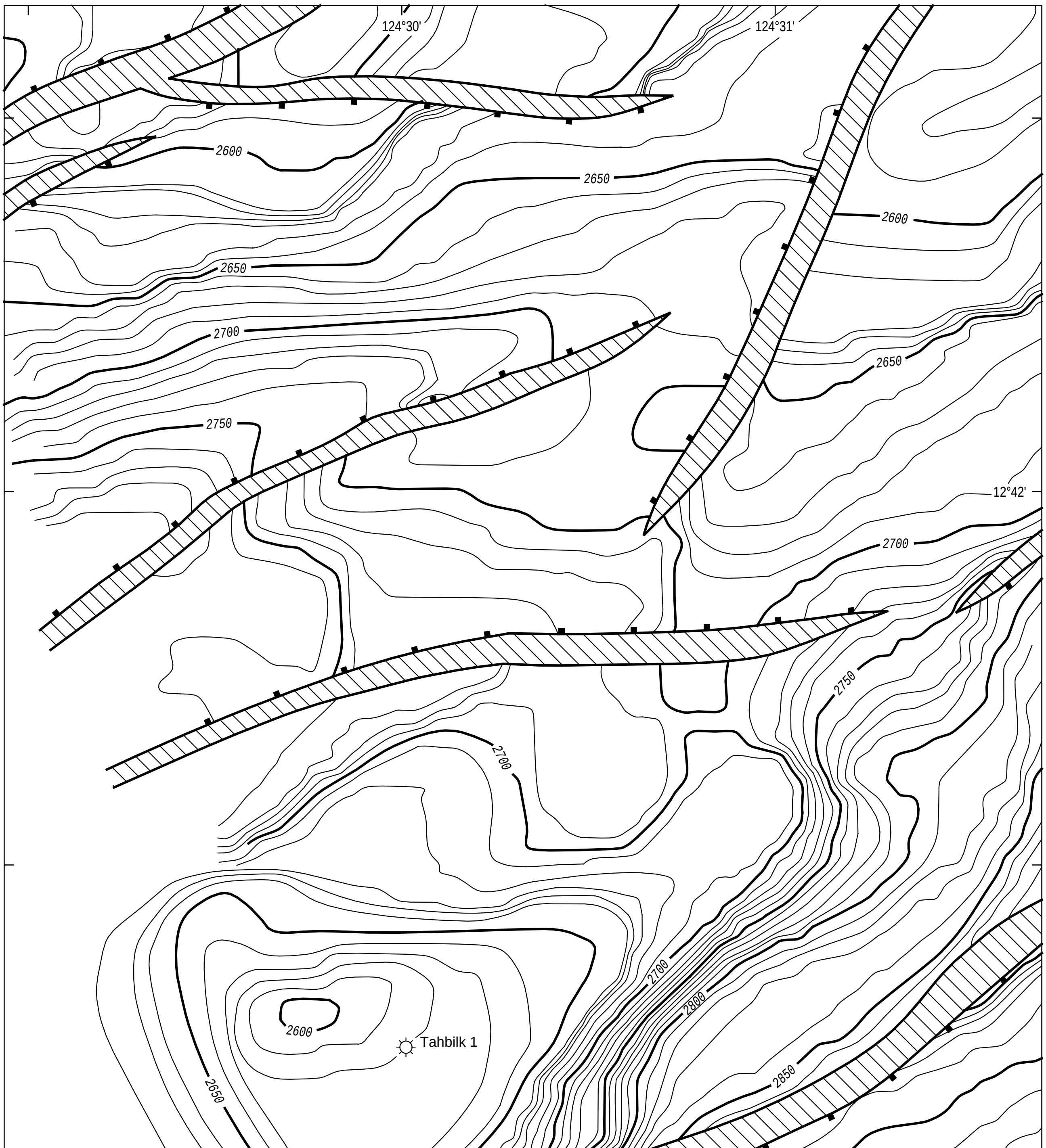
STRATIGRAPHY (Swan-3) **:**

AGE	**UNIT**		**FORMATION TOP (mKB)**
TERTIARY	WOODBINE GROUP	Barracouta/Oliver Fms	133.5
		Prion/Hibernia/Grebe Fms	833.0
		Johnson Formation	1624.0
CRETACEOUS	BATHURST ISLAND GP	Puffin Formation	2121.0
		Fenelon Formation	2417.0

Accumulation Number: 60

TAHBILK

ORIGINAL OPERATOR:	BHP Petroleum Pty Ltd
TYPE:	Gas
STATUS:	Possible Future Producer
LOCATION:	700 km west of Darwin
STATE:	Territory of the Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/P7
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Tahbilk-1
Longitude (E):	124.5040
Latitude (S):	-12.7328
Date total depth reached:	01 DEC 90
Water Depth:	89 m
Kelly bushing:	26 m
Operator:	BHP Petroleum Pty Ltd
Total Depth:	3,226 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Northeast-southwest trending tilted fault block
AREAL CLOSURE:	4.1 km^2 (at Intra-Oxfordian level) 23 km^2 of drape closure at Top Cretaceous level
VERTICAL CLOSURE:	130 m
RESERVOIR UNITS:	2
BOTTOM HOLE TEMPERATURE:	114^{o}C (at 3,223 m)
PETROLEUM BEARING UNIT No.1:	Bathurst Island Group
CONTENTS:	Gas
FORMATION:	Gibson Formation
AGE:	Santonian
LITHOLOGY:	Sandstone, fine grained, glauconitic, subangular to subrounded, well sorted and well cemented with calcareous cement. Coarsening upwards profile.
DEPOSITIONAL ENVIRONMENT:	Distal turbidite sands.
FORMATION TOP (mKB):	2,260 m
GROSS HYDROCARBON COLUMN:	34 m (2,273-2,307 mKB)
NET PAY:	32.3 m
NET TO GROSS RATIO:	95%
HYDROCARBON SATURATION:	69%
CONDENSATE TO GAS RATIO:	40 bbls/MMscf
POROSITY:	21% (average log porosity)
PERMEABILITY:	100-400 mD
PETROLEUM BEARING UNIT No.2:	Flamingo Group
CONTENTS:	Gas (2 separate sands)
FORMATION:	Montara Formation
AGE:	Late Callovian to Oxfordian
LITHOLOGY:	Sandstone, clear, medium grained, moderately well sorted, subangular to subround interbedded with bioturbated, lower shoreface siltstones and shales.
DEPOSITIONAL ENVIRONMENT:	Northeast-southwest oriented barrier bar/strandline deposits.
FORMATION TOP (mKB):	2,624 m
GROSS HYDROCARBON COLUMN:	69.6 m



Tahbilk, Top Montara Formation, depth map

NET PAY: 60.7 m
NET TO GROSS RATIO: 87%
HYDROCARBON SATURATION: 89%
GAS/WATER CONTACT: 2,691 mKB
POROSITY: 22% (average log porosity)
PERMEABILITY: 175-4,460 mD (2,353 mD average)

TEST DATA FROM THE DISCOVERY WELL (Tahbilk-1)**:**

RFT 3, 2,305 m, Recovered 3.369 m^3 of gas, 750 ml of olive-yellow condensate and 4 litres of water. — Gibson Formation

RFT 2, 2,314.3 m, Recovered 0.191 m^3 of gas and 21 litres of water. — Gibson Formation

RFT 1, 2,631.8 m, Recovered 1.081 m^3 of gas, 215 ml of olive-yellow condensate and 280 ml of water. — Montara Formation

RESERVES:

Oil: 23 MMbbls (includes Montara and Bilyara)
Gas: 105 BCF (includes Montara and Bilyara)
Source: Northern Territory Department of Business Industry Development, 1999.

REMARKS:

Tahbilk-1 was suspended for possible future evaluation.

At date of publication, the Tahbilk discovery was held under Retention Lease AC/RL3.

STRATIGRAPHY (Tahbilk-1) **:**

AGE	UNIT		FORMATION TOP (mKB)
TERTIARY	WOODBINE GROUP	Oliver/Barracouta Fms	87.0
		Prion Formation	731.0
		Hibernia Formation	938.0
		Grebe Sandstone	1081.0
		Johnson Formation	1263.0
CRETACEOUS	BATHURST ISLAND GROUP	Puffin Formation	1608.0
		Fenelon Formation	2167.0
		Gibson Formation	2260.0
		Woolaston Formation	2315.0
		Jamieson Formation	2347.0
JURASSIC	FLAMINGO GROUP	Lower Vulcan Formation	2463.0
		Montara Formation	2600.0
	TROUGHTON GROUP	Plover Formation	3080.0

Accumulation Number: 61

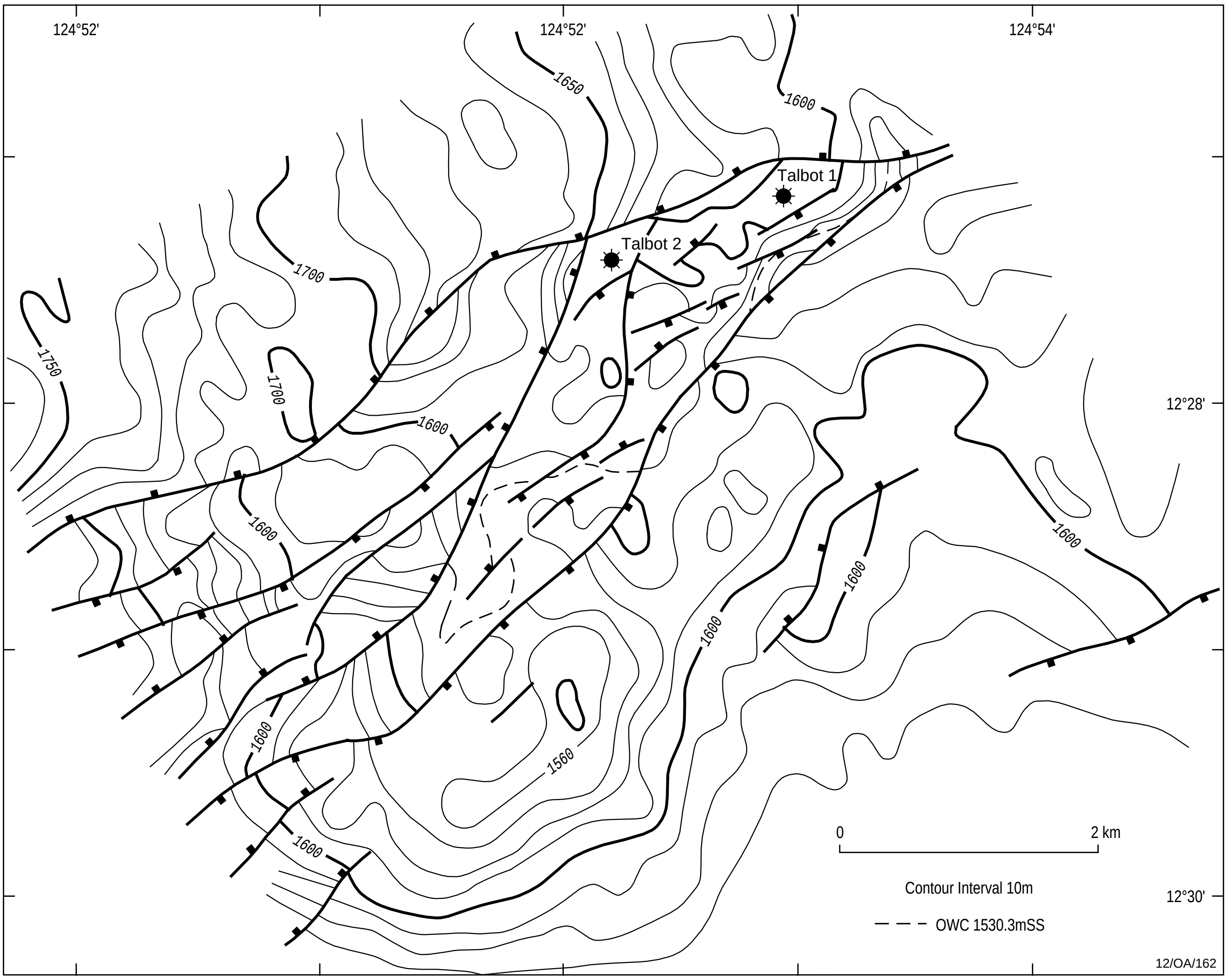
TALBOT

ORIGINAL OPERATOR:	Santos Ltd
TYPE:	Oil and Gas
STATUS:	Possible Future Producer
LOCATION:	650 km west of Darwin
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area (Northern Territory)
ORIGINAL TITLE(S):	AC/P12
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Talbot-1
Longitude (E):	124.8816
Latitude (S):	-12.4532
Date total depth reached:	28 NOV 89
Water Depth:	104 m
Kelly bushing:	11 m
Operator:	Santos Ltd
Total Depth:	1,784 mKB
NUMBER OF WELLS DRILLED:	2
STRUCTURE/TRAP:	Northeast-southwest trending horst block
AREAL CLOSURE:	3.5 km^2 (at oil/water contact)
VERTICAL CLOSURE:	80 m
RESERVOIR UNITS:	1
OIL/WATER CONTACT:	1,530.7 mSS
GAS/OIL CONTACT:	1,497.5 mSS
GROSS HYDROCARBON COLUMN:	34 m (1,508-1,542 mKB)
NET PAY:	15.7 m
NET TO GROSS RATIO:	46%
OIL GRAVITY:	49^o API
WATER SATURATION:	30% (average)
GAS TO OIL RATIO:	742 scf/stb
FVF (B_o):	1.448
BOTTOM HOLE TEMPERATURE:	80^oC @ 1,780 m

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Oil and Gas
FORMATION:	Challis Formation
AGE:	Late Triassic (Carnian)
LITHOLOGY:	Sandstone, silty, fine grained with interbedded ferroan dolomites, dolomitic siltstones and minor thin, fine grained, clean sandstones.
DEPOSITIONAL ENVIRONMENT:	Estuarine and tidal channel sands.
FORMATION TOP (mKB):	1,507 m
POROSITY:	18.7% (average)

TEST DATA FROM THE DISCOVERY WELL (Talbot-1)**:**

DST 1, 1,505-1,540 m, Flowed oil at 5,000 bbls/day and gas at 104,200 m^3/day through a 25.4 mm choke.	Challis Formation



(after Bourne and Faehrmann, 1991)

Talbot, Base Cretaceous, depth map

Production Test, Perforated between 1,506-1,530 m and 1,533-1,540 m. Flowed oil at maximum rate of 4,981 bbls/day and gas at 104,770 m^3/day, declining to 4,123 bbls/day and 108,170 m^3/day, respectively, at 560 psig.	Challis Formation
RFT 1, 1,522.5 m, Recovered 7.8 litres of gassy, 51.2^o API oil, 0.93 m^3 of gas and 11.7 litres of water.	Challis Formation
RFT 2, 1,539 m, Recovered 13.5 litres of oil, 0.77 m^3 of gas and 5 litres of water.	Challis Formation

APPRAISAL AND DEVELOPMENT DRILLING :

Talbot-2, located 1.3 km west-southwest of Talbot-1, was drilled to determine reservoir quality, delineate reserves and provide a possible drainage point for the field. A 39.5 m gross hydrocarbon column (16.9 m net pay) was intersected at the top of the Challis Formation. This zone flowed oil on test at rates of up to 4,992 bbls/day. The well was cased and suspended as a possible future producer.

RESERVES:

Oil: 2 to 5 MMbbls
Source: Northern Territory Department of Business Industry and Resource Development, 1999.

REMARKS :

Geochemical analysis indicates that the hydrocarbons reservoired at Talbot have probably not been sourced in situ but have migrated from the Skua Trough over distances of up to 20 km.

At date of publication, the Talbot discovery was held under Retention Lease AC/RL1.

COMPOSITIONAL DATA :

OIL :

FLUID PROPERTIES	Oil Challis Fm RFT-1
API Gravity @ 60°F	49.0
Asphaltenes (wt%)	0.02
Wax content (wt%)	0.00
Pour Point (^{o}C)	-9
Cloud Point (^{o}C)	-16
Flash Point (^{o}C)	-18
Specific Gravity	0.7477
Viscosity (cp@100°F)	0.975

COMPOSITIONAL DATA CONTD :

GAS :

GAS PROPERTIES	**Gas Challis Fm**
Methane	83.90
Ethane	6.55
Propane	3.84
Isobutane	0.71
N-butane	0.98
Isopentane	0.30
N-pentane	0.22
Hexanes +	0.48
$N_2 + O_2$	2.40
CO_2	0.62
H_2S	0.00
Specific Gravity	0.688

STRATIGRAPHY (Talbot-1) **:**

AGE	**UNIT**		**FORMATION TOP (mKB)**
TERTIARY	WOODBINE GROUP	Undifferentiated	115.0
		Hibernia Formation	498.0
		Undifferentiated	832.0
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	1098.0
TRIASSIC	TROUGHTON GROUP	Challis Formation	1507.0

Accumulation Number: 62

TENACIOUS

ORIGINAL OPERATOR:	Cultus Timor Sea Ltd
TYPE:	Oil and Gas
STATUS:	Possible Future Producer
LOCATION:	650 km west-northwest of Darwin, 560 m northwest of Octavius-2.
STATE:	Territory of Ashmore and Cartier Islands Adjacent Area
ORIGINAL TITLE(S):	AC/P17
BASIN:	Bonaparte
SUB-BASIN:	Vulcan Sub-basin
DISCOVERY WELL:	Tenacious-1
Longitude (E):	124.9012
Latitude (S):	-11.8595
Date total depth reached:	21 JUN 97
Water Depth:	157 m
Operator:	Cultus Timor Sea Ltd
Total Depth:	3,205 mKB
NUMBER OF WELLS DRILLED:	2 (includes 1 deviated well, Tenacious-1 ST1)
STRUCTURE/TRAP:	Tilted fault block
PETROLEUM BEARING UNIT No.1:	Flamingo Group
CONTENTS:	Oil and Gas
FORMATION:	Upper Vulcan Formation (Tithonian Sandstone Member)
AGE:	Jurassic (Tithonian)
LITHOLOGY:	Sandstone with interbedded shales. Sandstone: fine grained to pebbly, clean, quarzose, poorly sorted with minor detrital feldspar and traces of clay.
DEPOSITIONAL ENVIRONMENT:	Low stand slope fan deposited as proximal submarine facies adjacent to newly emergent fault blocks.
GROSS HYDROCARBON COLUMN:	28.7 m (Tenacious-1 ST1)
NET PAY:	22.9 m (Tenacious-1 ST1) 5.4 m (Tenacious-1)
NET TO GROSS RATIO:	57% (2,798.2 – 2,937 mRT, Tenacious-1)
HYDROCARBON SATURATION:	44% (Tenacious-1) 67.6% (Tenacious-1 ST1)
OIL/WATER CONTACT:	2,764.8 mSS to 2,775.2 mSS
OIL GRAVITY:	48 - 49^{o} API
GAS TO OIL RATIO:	520 scf/stb
BUBBLE POINT:	2,000 psia
RESERVOIR PRESSURE:	>4,000 psia
POROSITY:	18% (average log porosity, 2,798.2 – 2,803.6 mRT)
PERMEABILITY:	798 - 861 mD (DST data, Tenacious-1 ST1)

TEST DATA FROM THE DISCOVERY WELL (Tenacious-1)**:**

RFT 1, 2,799.5 m, Recovered 6.1 litres of 50.8^{o} API oil and 0.977 m^3 of gas.	Upper Vulcan Formation (Tithonian Sandstone Member)
RFT 2, 2,802 m, Recovered 1.9 litres of oil, 0.26 m^3 of gas and 17.3 litres of mud filtrate.	Upper Vulcan Formation (Tithonian Sandstone Member)

APPRAISAL AND DEVELOPMENT DRILLING :

Octavius-1. 37.5^{o} API oil was detected over the shale shakers while drilling the interval 2,715 – 2,825 mKB. Tight hole problems encountered at this time suggested the oil was being swabbed from a fault plane intersected at 2,715 mKB. Octavius-1 was plugged back and sidetracked at 2,150 mKB (Octavius-1ST-1).

Octavius-1ST-1. The drill string became stuck at 3,015 mKB and the well was plugged back and sidetracked at 2,778 mKB (Octavius-1ST-2).

Octavius-1ST-2. The drill string became stuck at 3,151 mKB and the well was plugged back and sidetracked at 3,013 mKB (Octavius-1ST-3).

Octavius-1ST-3. The drill string became stuck at 3,204 mKB and the well was plugged back and sidetracked at 3,100 mKB (Octavius-1ST-4).

Octavius-1ST-4 was abandoned at 3,142 mKB due to a stuck drill string.

Octavius-2 was drilled 2 km southwest of Octavius-1. Oil was detected in the drilling mud at the shale shakers at 2,933 mKB and 3,040 mKB and was associated with gas peaks of 253 and 159 units respectively. A residual oil column was interpreted to be present in the Plover Formation (white, streaming cut fluorescence and brown oil staining in sidewall cores over the interval 3,193 – 3,262 mKB). The oil is thought to have been subsequently displaced by late gas migration. Octavius-2 was plugged and abandoned due to poor reservoir quality in the Plover Formation.

In 1998, **Tenacious West-1** was drilled in adjacent exploration permit AC/P4(R1) to appraise the southwestern extension of the Tenacious/Octavius discovery. Tenacious West-1 was plugged back to 1,958 mRT from 2,150 mRT and sidetracked. **Tenacious West-1/ST-1** kicked off at 2,102 mRT and was drilled to a measured depth of 3,030 mRT (2,913 mTVDRT).

RESERVES:

Oil: 5.9 MMbbls
Source: Northern Territory Department of Business Industry and Resource Development, 1999.

REMARKS:

A deviated well, Tenacious-1 ST1, was kicked off at 2,030 mKB and drilled to a depth of 3,020 mKB to test the updip potential of the Tenacious feature. A DST over the intervals 2,806-2,817 m and 2,822-2,834 m flowed oil at 7,667 bbls/day and gas at 113,834 m^3/day.

In 1990, Western Mining Corporation Ltd drilled Octavius-1 (including four sidetracks) and encountered oil shows in the Plover Formation. In the following year, an appraisal well (Octavius-2, drilled 560 m southeast of Tenacious-1) recovered gas on RFT from the Plover Formation.

It is thought that Octavius-2 intersected the same hydrocarbon accumulation tested by Tenacious-1.

STRATIGRAPHY (Tenacious-1) **:**

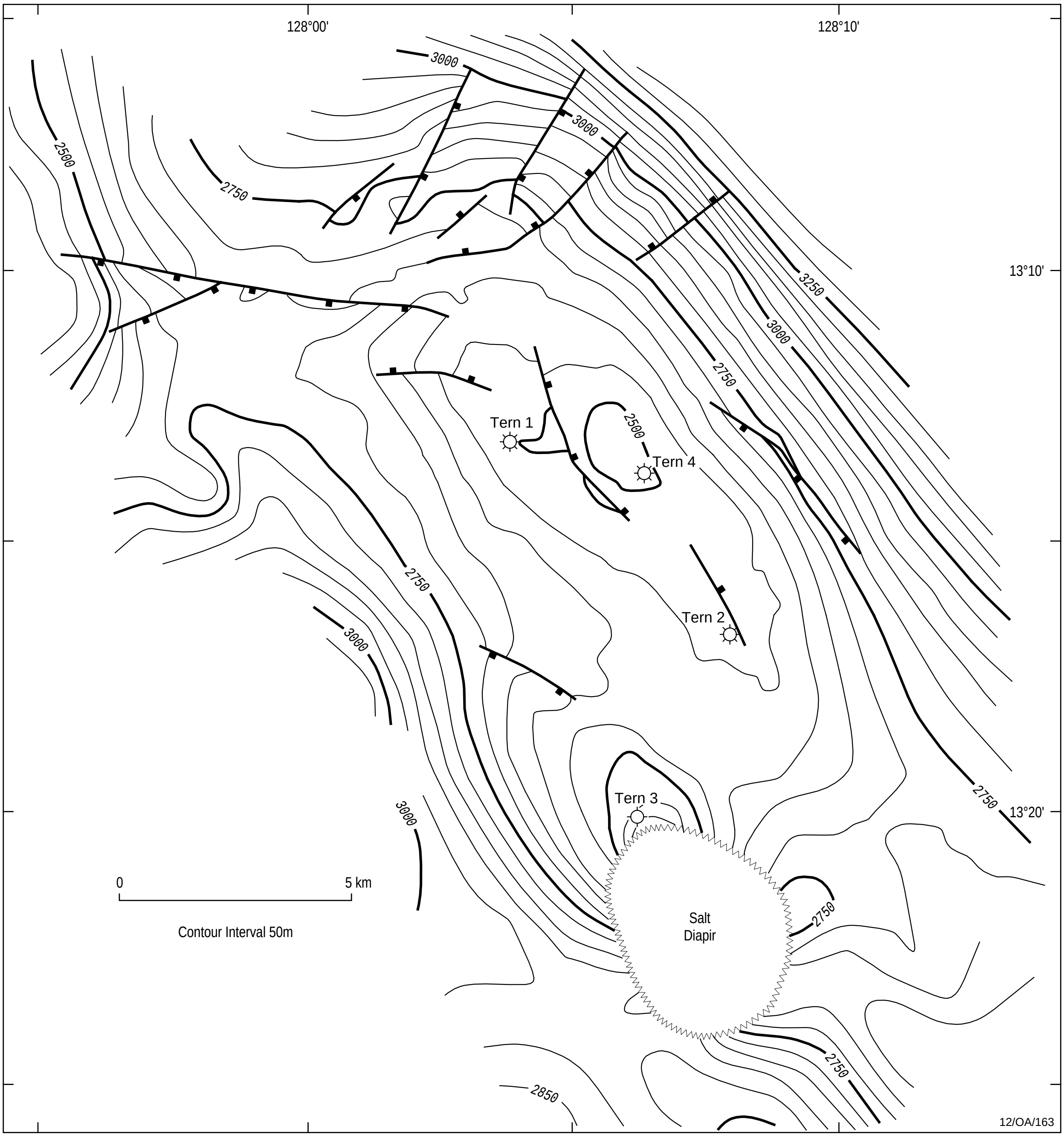
AGE	**UNIT**		**FORMATION TOP (mTVDSS)**
TERTIARY	WOODBINE GROUP	Barracouta Formation	153.0
		Hibernia Formation	937.0
		Grebe Sandstone	1140.0
		Johnson Formation	1306.0
CRETACEOUS	BATHURST ISLAND GROUP	Borde Formation	1816.0
		Fenelon Formation	1921.0
		Gibson Formation	1961.5
		Woolaston Formation	2134.0
		Jamieson Formation	2188.0
		Echuca Shoals Formation	2412.0
JURASSIC	FLAMINGO GROUP	Upper Vulcan Formation	2481.5
		‘Tithonian Sandstone’ Mbr	2769.7
		Basal Claystone	2908.0
		Lower Vulcan Formation	2958.5
		Lwr Vulcan Claystone	2972.0

Accumulation Number: 63

TERN

ORIGINAL OPERATOR:	Arco Australia Ltd
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	310 km west-southwest of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	WA-18-P
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Tern-1 (Tern Member gas pool)
Longitude (E):	128.0647
Latitude (S):	-13.2208
Date total depth reached:	04 JUL 71
Water Depth:	92 m
Kelly bushing:	11.9 m
Operator:	Arco Australia Ltd
Total Depth:	4,352 mKB
DISCOVERY WELL:	Tern-4 (Cape Hay Member gas pool)
Longitude (E):	128.1059
Latitude (S):	-13.2298
Date total depth reached:	13 NOV 94
Water Depth:	91.8 m
Kelly bushing:	22.5 m
Operator:	Santos Ltd
Total Depth:	2,700 mKB
NUMBER OF WELLS DRILLED:	5
STRUCTURE/TRAP:	Northwest-southeast oriented anticline resulting from salt withdrawal from the flanks of the structure.
AREAL CLOSURE:	54 km^2 (near top of the Late Permian)
VERTICAL CLOSURE:	76 m (at Late Permian level)
RESERVOIR UNITS:	2
CONDENSATE GRAVITY:	50.5^o API
LOWEST KNOWN GAS:	2,567.8 mSS (Tern Member Pool, Tern-2)

PETROLEUM BEARING UNIT No.1:	Tern Member (Tern-1)
CONTENTS:	Gas
FORMATION:	Hyland Bay Formation
AGE:	Late Permian
LITHOLOGY:	Coarsening upwards sequence. Fine to medium grained, bioturbated sandstone at the base, overlain by ‘shelly’ coarse grained sandstones.
DEPOSITIONAL ENVIRONMENT:	Barrier bar.
FORMATION TOP (mKB):	2,542 m (Tern-4)
GROSS HYDROCARBON COLUMN:	31.5 m (2,543.5-2,575 mKB, Tern-4)
NET PAY:	5.9 m (Tern-4)
NET TO GROSS RATIO:	19%
HYDROCARBON SATURATION:	51%
RESERVOIR PRESSURE:	3,668 psia (2,573 mKB, Tern-4)
RESERVOIR TEMPERATURE:	95^{o}C (2,573 mKB, Tern-4)
POROSITY:	Up to 26%. The best porosity is preserved in the basal sandstone where silicification of the reservoir is less extensive.



Tern, Near Top Hyland Bay Formation, depth map

PERMEABILITY:	Up to 17 mD between 2,542-2,544 m (core analysis, Tern-4). Up to 47 mD between 2,567-2,570 m (core analysis, Tern-4)
PETROLEUM BEARING UNIT No.2:	Cape Hay Member (Tern-4)
CONTENTS:	Gas
FORMATION:	Hyland Bay Formation
AGE:	Late Permian
LITHOLOGY:	Sandstone, off white to pale grey/brown, fine to coarse, poorly to moderately well sorted, subangular to subrounded, occassional to moderate amounts of calcareous and siliceous cement. Interbedded with dark grey/black to brown carbonaceous siltstone with a trace of pyrite.
DEPOSITIONAL ENVIRONMENT:	Shallow, tidal, estuarine environment
FORMATION TOP (mKB):	2,619 mKB (Cape Hay Member, Tern-4)
GROSS HYDROCARBON COLUMN:	1.5 m (2,642-2,643.5 mKB, Tern-4)
RESERVOIR PRESSURE:	3,738 psig (2,643 mKB, Tern-4)
RESERVOIR TEMPERATURE:	100.6^{o}C (2,643 mKB, Tern-4)

TEST DATA FROM THE DISCOVERY WELL (Tern-1)**:**

DST 2, 2,525.3-2,550.3 m, Flowed gas at 195,400 m^3/day through a 15.8 mm choke.	Hyland Bay Formation (Tern Member)

TEST DATA FROM THE DISCOVERY WELL (Tern-4)**:**

DST, 2,542-2,545 m, Flowed gas at 152,100 m^3/day.	Hyland Bay Formation (Tern Member)
DST (CASED) 1, 2,542-2,573 m, Flowed gas at 141,000 m^3/day, water at 6.3 bbls/day and 50.5^{o} API condensate at 13 bbls/day.	Hyland Bay Formation (Tern Member)
RFT 2, 2,643 m, Recovered 1.444 m^3 of gas and 12 litres of water.	Hyland Bay Formation (Cape Hay Member)

APPRAISAL AND DEVELOPMENT DRILLING :

Tern-2 was drilled 9.8 km southeast of Tern-1 on the southern nose of the Tern anticline. A DST taken over the interval 2,545.5 – 2,569.5 mKB in the Tern Member flowed gas at 420,000 m^3/day. Tern-2 was suspended as a possible future gas producer.

Tern-3, drilled 7 km south-southwest of Tern-2, unsuccessfully tested an adjacent but separate culmination to the south of the Tern field. The well was plugged and abandoned without encountering significant hydrocarbons.

Tern-4 was an appraisal well designed to delineate the Tern structure, prove-up reserves and to fully core the Tern Member reservoir. Gas flows of up to 152,100 m^3/day were recorded from the Tern Member and gas was also recovered from the Cape Hay Member on RFT. The well was plugged and abandoned as it was not considered to be in an optimal position for any future field development.

APPRAISAL AND DEVELOPMENT DRILLING CONTD :

Tern-5 was drilled 4 km northeast of Tern-1 to appraise the northeastern flank of the Tern structure. The well encountered a 35 m gross gas column and flowed gas at 447,000 m^3/day from the Tern Member between 2,545 and 2,580 m. Tern-5 was plugged and abandoned in February 1998.

RESERVES :

Gas: 415 BCF
Condensate: 5.7 MMbbls
Source: Department of Industry and Resources, Western Australia, 2002.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	**Gas Cape Hay Mbr Tern-4**	**Gas Tern Mbr Tern-4**
Methane	85.66	87.67
Ethane	3.62	3.69
Propane	1.84	1.17
Isobutane	0.31	0.18
N-butane	0.58	0.25
Isopentane	0.20	0.10
N-pentane	0.20	0.09
Hexanes +	1.29	0.58
Nitrogen	4.21	4.11
CO_2	2.09	2.16
H_2S	0.00	0.00
Specific Gravity	0.689	0.653
BTU/ft^3 (gross)	1100	1039

STRATIGRAPHY (Tern-4) **:**

AGE	**UNIT**		**FORMATION TOP (mKB)**
		No Returns	114.3
CRETACEOUS	BATHURST ISLAND GP	Undifferentiated	304.0
JURASSIC	FLAMINGO GROUP	Sandpiper Sandstone	1134.0
		Frigate Shale	1230.0
		Frigate Sandstone	1321.0
TRIASSIC	TROUGHTON GROUP	Malita Formation	1646.0
		Cape Londonderry Formation	1702.0
	KINMORE GROUP	Mount Goodwin Formation	2038.0
PERMIAN		Hyland Bay Formation	2542.0
		Tern Member	2542.0
		Dombey Member	2607.0
		Cape Hay Member	2619.0

Accumulation Number: 64

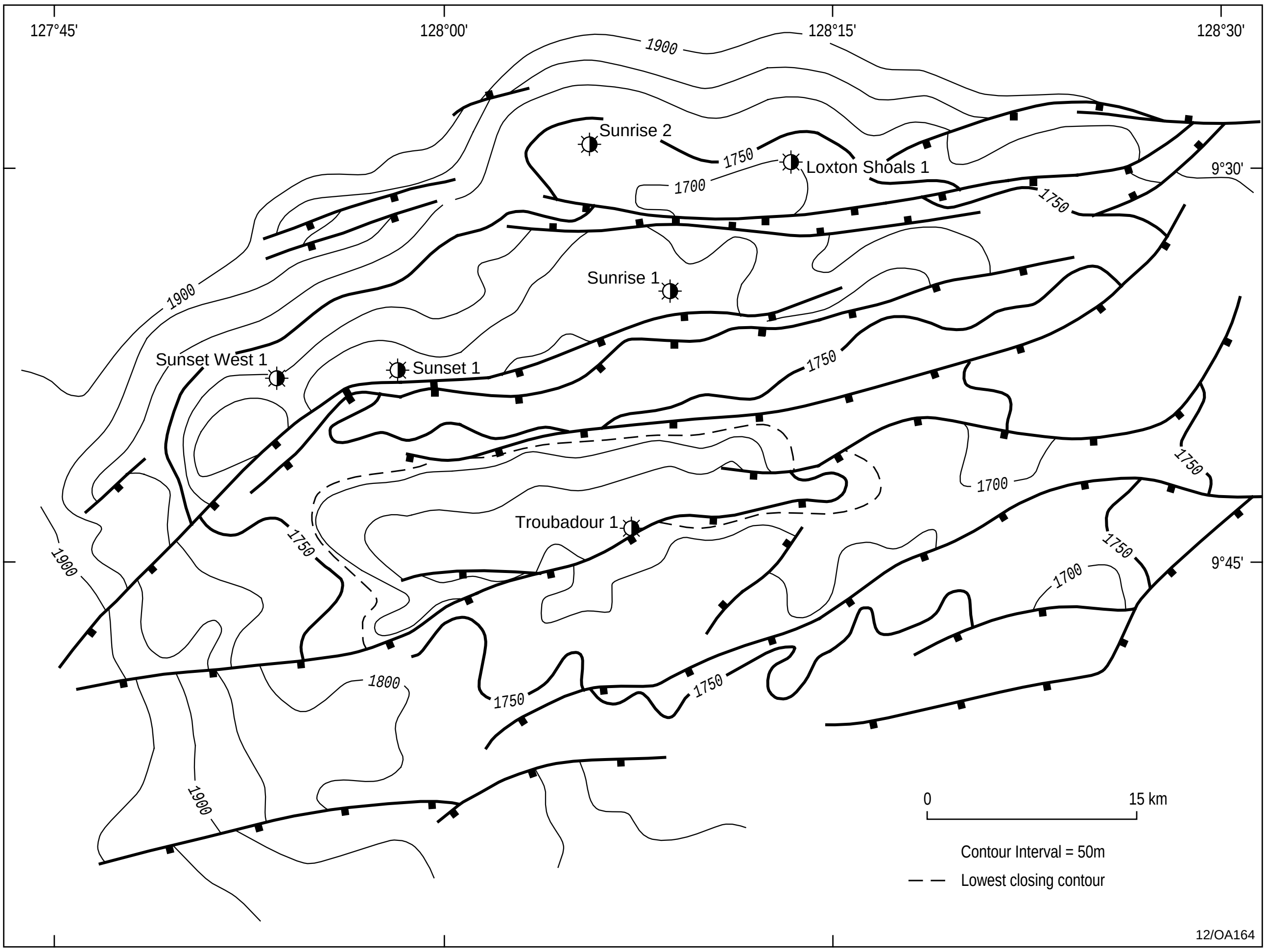
TROUBADOUR

ORIGINAL OPERATOR:	Woodside/Burmah Oil NL
TYPE:	Gas
STATUS:	Possible Future Producer
LOCATION:	430 km northwest of Darwin
STATE:	Northern Territory
ORIGINAL TITLE(S):	NT/P12
BASIN:	Bonaparte
SUB-BASIN:	Sahul Platform
DISCOVERY WELL:	Troubadour-1
Longitude (E):	128.1237
Latitude (S):	-9.7344
Date total depth reached:	15 AUG 74
Water Depth:	96 m
Kelly bushing:	12 m
Operator:	Woodside/Burmah Oil NL
Total Depth:	3,459 mKB
NUMBER OF WELLS DRILLED:	1
STRUCTURE/TRAP:	Faulted drape anticline
AREAL CLOSURE:	17.5 km^2
VERTICAL CLOSURE:	41 m
RESERVOIR UNITS:	1 (‘Upper’ and ‘Lower’ unit differentiated)
BOTTOM HOLE TEMPERATURE:	151^{o}C

PETROLEUM BEARING UNIT No.1:	Troughton Group
CONTENTS:	Gas
FORMATION:	Plover Formation
AGE:	Jurassic
LITHOLOGY:	Interbedded sandstones, siltstones and claystones. Sandstones are commonly well cemented with silica.
DEPOSITIONAL ENVIRONMENT:	Intermediate marine environment.
FORMATION TOP (mKB):	2,159.5 mKB
POROSITY:	9.5 - 14.9% (core data, ‘Upper’ unit)
PERMEABILITY:	<0.01 - 1.2 mD (core data, ‘Upper’ unit)
GROSS HYDROCARBON COLUMN:	25 m (2,201.5-2,226.5 mKB) (‘Upper’ unit) 20.5 m (2,226.5-2,247 mKB)(‘Lower’ unit)
HYDROCARBON SATURATION:	50% (‘Upper’ unit, log data) 55% (‘Lower’ unit, log data)
GAS / WATER CONTACT:	2,285 mKB (?) (The interval 2,247-2,295 mKB is considered to be predominantly gas saturated but of very low porosity)

TEST DATA FROM THE DISCOVERY WELL (Troubadour-1)**:**

DST 3, 2,206-2,211 m, Flowed gas at 41,500 m^3/day, condensate at 13 bbls/day and water at 17.6 bbls/day.	Plover Formation
DST 2, 2,228-2,244 m, 2,238-2,244 m, Flowed gas at 279,000 m^3/day and condensate at 245 bbls/day.	Plover Formation



Troubadour, Near Base Cretaceous, depth map

FIT 3, 2,286 m, Recovered 0.45 m^3 of gas, 13.65 litres of water and 2.85 litres of mud with a trace of condensate.	Plover Formation
DST 1, 2,389-2,393 m, Misrun.	Plover Formation
FIT 2, 2,389 m, Recovered 0.011 m^3 of gas and 15.25 litres of water. Gas is thought to be shaped charge gas.	Plover Formation
FIT 1, 2,598 m, Seal failure.	Plover Formation

RESERVES:

Gas:	9.56 TCF (includes Loxton Shoals/Troubadour/Sunrise/Sunset West)
Condensate:	321 MMbbls (includes Loxton Shoals/Troubadour/Sunrise/Sunset West) Source: Northern Territory Department of Business Industry and Resource Development, 2000.

REMARKS:

Sandstones encountered between 2,206 m and 2,739 mKB are thought to contain 10-20% immovable oil, suggesting a breached palaeo-oil column. Sediments below 2,739 mKB are 100% water -wet.

Loxton Shoals-1, Troubadour-1, Sunset-1, Sunset West-1, Sunrise-1 and Sunrise-2 all recovered gas on test from the Plover Formation from what are thought to be adjacent fault compartments on the greater Sunrise/Troubadour structure. Development of the Sunrise/Troubadour resource is currently under consideration.

At date of publication, the Troubadour discovery was held under Retention Lease NT/RL2.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	**Plover Fm DST 2, 2228-2233, 2238-2244 mKB**	**Plover Fm DST 3, 2206-2211 mKB**
Methane	84.30	84.19
Ethane	4.95	4.81
Propane	1.97	1.98
Isobutane	0.49	0.47
N-butane	0.63	0.68
Isopentane	0.32	0.36
N-pentane	0.26	0.32
Hexanes +	0.49	0.96
Nitrogen	2.40	2.39
CO_2	4.18	3.83
H_2S	-	-
Specific Gravity	0.6866	0.6963
BTU/ft^3 (gross)	1072	1101

COMPOSITIONAL DATA CONTD :

CONDENSATE :

CONDENSATE PROPERTIES	**Plover Fm DST 2, 2228-2233, 2238-2244 mKB**
API Gravity	57.4
Specific Gravity	0.7491
Sulphur (wt%)	0.005
Pour Point	< -30^{o}F
Salt Content (lb/1000 bbls)	< 4
Reid Vapour Pressure (psi)	6.9
Viscosity (@ 70^{o}F) (cs)	1.12
Gross BTU/lb	20200
Nett BTU/lb	18860

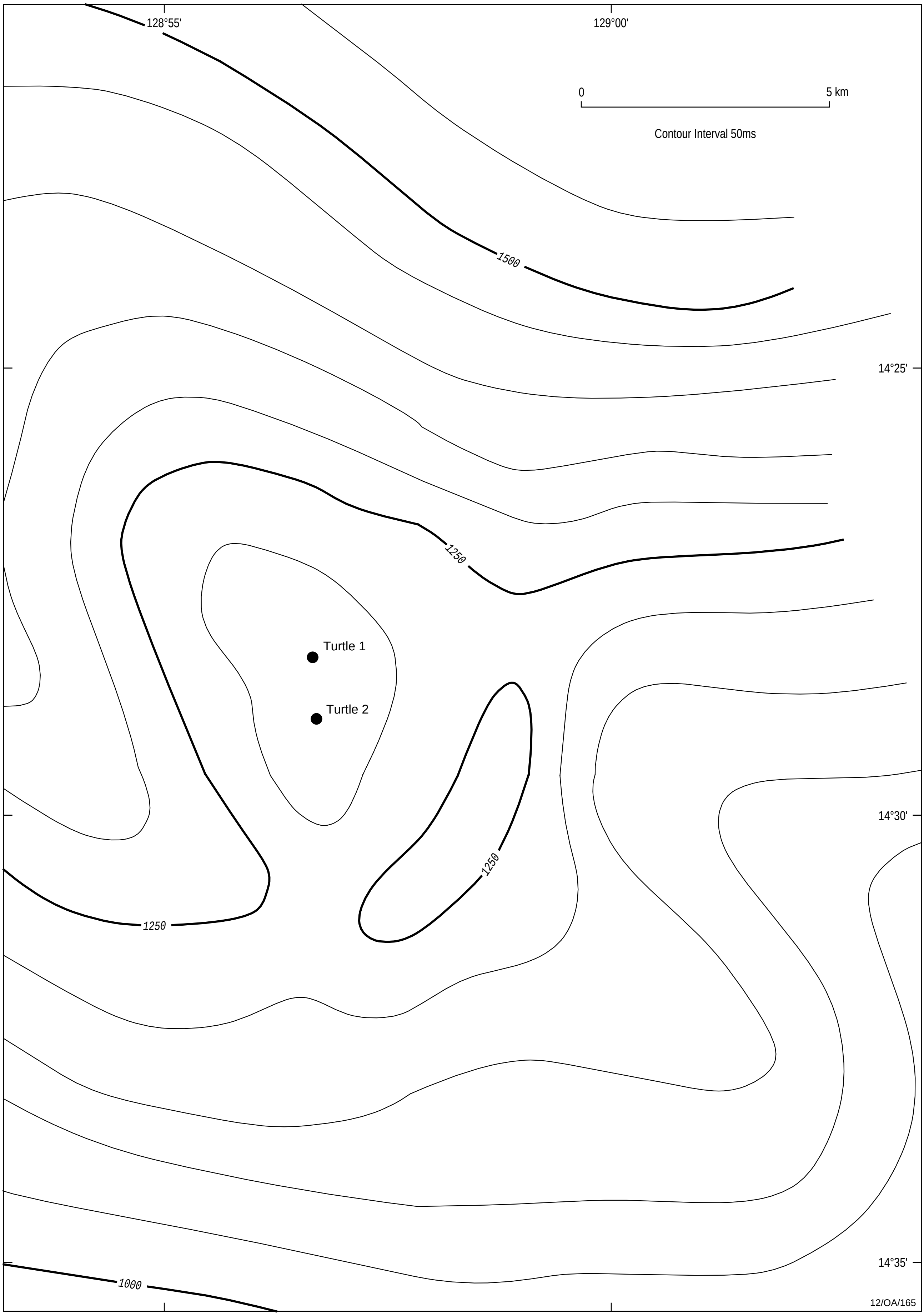
STRATIGRAPHY (Troubadour-1) **:**

<table>
<tr><th>AGE</th><th colspan="2">UNIT</th><th>FORMATION TOP (mKB)</th></tr>
<tr><td>TERTIARY</td><td>WOODBINE GROUP</td><td>Undifferentiated</td><td>109.0</td></tr>
<tr><td>CRETACEOUS</td><td>BATHURST ISLAND GP</td><td>Undifferentiated</td><td>1402.0</td></tr>
<tr><td>JURASSIC</td><td rowspan="4">TROUGHTON GROUP</td><td>Plover Formation</td><td>2159.5</td></tr>
<tr><td rowspan="3">TRIASSIC</td><td>Cape Londonderry Fm</td><td>2764.0</td></tr>
<tr><td>Pollard Formation</td><td>2796.0</td></tr>
<tr><td>Mount Goodwin Fm</td><td>3003.0</td></tr>
<tr><td>PERMIAN</td><td>KINMORE GROUP</td><td>Hyland Bay Formation ?</td><td>3294.0</td></tr>
<tr><td>?</td><td>BASEMENT</td><td>Undifferentiated</td><td>3315.5</td></tr>
</table>

Accumulation Number: 65

TURTLE

ORIGINAL OPERATOR:	Western Mining Corporation Ltd
TYPE:	Oil
STATUS:	Possible Future Producer
LOCATION:	300 km southwest of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	WA-128-P
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Turtle-1 (Kuriyippi Formation oil pool)
Longitude (E):	128.9448
Latitude (S):	-14.4766
Date total depth reached:	10 FEB 84
Water Depth:	24 m
Kelly bushing:	33 m
Operator:	Western Mining Corporation Ltd
Total Depth:	2,700 mKB
DISCOVERY WELL:	Turtle-2 (Keyling, Tanmurra and Milligans Fm oil pools)
Longitude (E):	128.9458
Latitude (S):	-14.5059
Date total depth reached:	30 APR 89
Water Depth:	24.6 m
Kelly bushing:	35.8 m
Operator:	Western Mining Corporation Ltd
Total Depth:	2,760 mKB
NUMBER OF WELLS DRILLED:	2
STRUCTURE/TRAP:	Northwest-southeast trending drape anticline.
AREAL CLOSURE:	12 km^2
VERTICAL CLOSURE:	40 milliseconds twt
RESERVOIR UNITS:	4
OIL GRAVITY:	15^o API (Keyling Formation) 33.4^o API (Kuriyippi Formation) 33^o API (Tanmurra Formation) 34.5^o API (Milligans Formation)
BOTTOM HOLE TEMPERATURE:	97^oC
PETROLEUM BEARING UNIT No.1:	Kulshill Group
CONTENTS:	Oil
FORMATION:	Keyling Formation (Turtle-2)
AGE:	Early Permian (Sakmarian)
LITHOLOGY:	Sandstone, white to light grey, fine to medium grained (rarely coarse grained), moderately to well sorted, up to 10% kaolinitic cement, up to 30% calcite cement in some thin beds. Interbedded with minor, medium grey siltstone and rare dark grey claystone.
DEPOSITIONAL ENVIRONMENT:	Delta plain/fluvial environment
FORMATION TOP (mKB):	915 m (Turtle-2)
GROSS OIL COLUMN:	13.3 m (915-928.3 m, Turtle-2)
OIL/WATER CONTACT:	928.3 mKB (Turtle-2)
POROSITY:	12.2-30.9% (core data, Turtle-2)
PERMEABILITY:	22-3,053 mD (core data, Turtle-2)



Turtle, Intra Kulshill Formation, TWT map

PETROLEUM BEARING UNIT No.2:	Kulshill Group
CONTENTS:	Oil
FORMATION:	Kuriyippi Formation (Turtle-1)
AGE:	Late Carboniferous
LITHOLOGY:	Sandstone, white to light grey, rarely pink-orange, massive, very fine to very coarse grained, poorly cemented with calcite and silica, common lithic fragments. General fining upwards within sandstone units. Interbedded with occassional, light to medium grey, thin, fining upwards siltstones.
DEPOSITIONAL ENVIRONMENT:	Delta plain/fluvial environment. Glacial influences towards the top of the unit.
FORMATION TOP (mKB):	1,592 m (Turtle-2)
POSSIBLE OIL/WATER CONTACT:	1,691.2 mKB (Turtle-2)
POROSITY:	3.6-25.2% (core data, Turtle-2)
PERMEABILITY:	0.01-116 mD (core data, Turtle-2)
PETROLEUM BEARING UNIT No.3:	Weaber Group
CONTENTS:	Oil
FORMATION:	Tanmurra Formation (Turtle-2)
AGE:	Early Carboniferous
LITHOLOGY:	Sandstone, clear-white to light grey, massive, predominantly fine grained, slightly argillaceous with common calcite cement and minor silica cement. Overlain by a massive limestone containing minor siltstones and sandstones.
DEPOSITIONAL ENVIRONMENT:	Prograding shelf sequence with deepwater clays overlain by shelfal sandstones which are superceded by oolitic sand shoals.
FORMATION TOP (mKB):	2,452 m (Turtle-2)
GROSS OIL COLUMN:	30 m+ (2,585-2,615 mKB, Turtle-2)
POSSIBLE GROSS GAS COLUMN:	14 m (2,571-2,585 mKB, Turtle-2)
RESERVOIR PRESSURE:	3,557 psia (depleted 200 psi by test)
POROSITY:	0.9-8.1% (core data, Turtle-2)
PERMEABILITY:	0.01-1.9 mD (core data, Turtle-2)
PETROLEUM BEARING UNIT No.4:	Weaber Group
CONTENTS:	Oil
FORMATION:	Milligans Formation (Turtle-2)
AGE:	Early Carboniferous (Visean)
LITHOLOGY:	Sandstone, clear-white to light grey to light brown, fine to very fine grained, occassionally argillaceous, with common pyrite, calcite and dolomite cement. Interbedded with white to off-white, hard, fine grained limestone.
DEPOSITIONAL ENVIRONMENT:	Probably moderately deepwater, marine environment. Coarsening upwards cycles may represent pro-delta progrades or submarine fan deposits.
FORMATION TOP (mKB):	2,637 m (Turtle-2)
RESERVOIR PRESSURE:	4,040 psia
POROSITY:	Around 10%
PERMEABILITY:	Less than 0.5 mD

TEST DATA FROM THE DISCOVERY WELL (Turtle-1)**:**

DST 8, 952-955 m, Reversed out 12.5 bbls of water with a trace of oil and gas and 3 bbls of rathole mud.	Keyling Formation
DST 7, 1,466-1,468 m, Misrun.	Kuriyippi Formation
DST 7A, 1,466-1,468 m, Recovered 5 bbls of oil, 2.5 bbls of water and 15.5 bbls of muddy water with a trace of gas.	Kuriyippi Formation
DST 6, 1,615.7-1,624 m, Flowed a mixture of oil, gas and acid in varying quantities and rates.	Kuriyippi Formation
DST 5, 1,618.8-1,621 m, Reversed out 32.7 bbls of 33.4^{o} API oil and 3 bbls of packer fluid.	Kuriyippi Formation
DST 4, 1,622-1,624 m, Reversed out 26 bbl of 32.5^{o} API oil and 5.5 bbls of water.	Kuriyippi Formation
DST 3, 1626.5-1628 m, Reversed out 7 bbls of muddy water, 21 bbls of water and 4 bbls of filtrate.	Kuriyippi Formation
DST 2, 2,233.5-2,239 m, Reversed out 2 bbls of muddy water and 48 bbls of formation water.	Point Spring Sandstone
DST 1, 2,242-2,247 m, Reversed out 7 bbls of muddy water and 51 bbls of formation water.	Point Spring Sandstone

TEST DATA FROM THE DISCOVERY WELL (Turtle-2)**:**

RFT 1, 923.2 m Recovered 10 cc of oil and 10.25 litres of mud filtrate.	Keyling Formation
RFT 7 (CASED HOLE), 927.1 m, Recovered 15 litres of 15^{o} API oil.	Keyling Formation
RFT 3, 1,489 m, Recovered 2.5 cc of oil and 8.5 litres of mud filtrate.	Treachery Shale
DST 4A, 1,607-1,615 m, No flow or recovery.	Treachery Shale

RFT 4, 1,624.6 m, Recovered 1-2 cc of oil and 400 cc of mud filtrate and formation water.	Treachery Shale
RFT 2, 1,673 m, Recovered 5 cc of oil and 70 cc of mud filtrate.	Kuriyippi Formation
RFT 5, 1,690 m, Recovered 5 cc of oil and 9.9 litres of mud filtrate.	Kuriyippi Formation
DST 3, 2,420-2,447 m, Recovered 23 bbls of formation water on jet pump after acid washing. Tight formation.	Kuriyppi Formation (Point Spring Sandstone)
DST 2, 2,571-2,632 m, Recovered 25 bbls of 33^{o} API oil and 1,320 bbls of formation water on jet pump.	Tanmurra Formation
DST 1A, 2,632-2,721 m, Recovered 22 bbls of 34.5^{o} API oil and 658 bbls of formation water on jet pump after acid washing.	Milligans Formation

APPRAISAL AND DEVELOPMENT DRILLING :

Turtle-2 was drilled as an updip test of Turtle-1, 3.5 km to the south. A 5 m oil column (1,450-1,444 mKB, Turtle-2) was identified near the top of theTreachery Shale, but this interval was not tested.

RESERVES:

Oil: 7.7 MMbbls
Source: Department of Industry and Resources, Western Australia, 2002.

REMARKS:

At date of publication, the Turtle discovery was held under Retention Lease WA-13-R.

STRATIGRAPHY (Turtle-1) **:**

AGE	**UNIT**		**FORMATION TOP (mKB)**
TRIASSIC	SAHUL GROUP	Undifferentiated	57.0
PERMIAN	KINMORE GROUP	Mount Goodwin Formation	226.0
		Hyland Bay Formation	266.0
		Tern Member	266.0
		Dombey Member	334.0
		Cape Hay Member	338.0
		Basal Member	607.0
		Fossil Head Formation	617.0
CARBONIFEROUS	KULSHILL GROUP	Undifferentiated	937.0
	WEABER GROUP	Tanmurra Formation	2388.0
		Milligans Formation	2486.0

STRATIGRAPHY (Turtle-2) **:**

AGE	**UNIT**		**FORMATION TOP (mKB)**
TRIASSIC	SAHUL GROUP	Undifferentiated	61.0
PERMIAN	KINMORE GROUP	Hyland Bay Formation	257.0
		Fossil Head Formation	592.0
CARBONIFEROUS	KULSHILL GROUP	Keyling Formation	915.0
		Treachery Shale	1428.0
		Kuriyippi Formation	1592.0
	WEABER GROUP	Point Spring Sandstone	2225.0
		Tanmurra Formation	2452.0
		Milligans Formation	2637.0
		Bonaparte Formation	2737.0

Accumulation Number: 66

VIENTA

ORIGINAL OPERATOR:	Amity Oil NL
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	10 km south of Waggon Creek-1, 345 km southwest of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	EP 386
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Vienta-1
Longitude (E):	128.78547
Latitude (S):	-15.37068
Date total depth reached:	7 SEP 98
Ground Level:	34 m
Kelly bushing:	4.5 m
Operator:	Amity Oil NL
Total Depth:	1,536 m
NUMBER OF WELLS DRILLED:	1
RESERVOIR UNITS:	1

PETROLEUM BEARING UNIT No.1:	Langfield Gp/Ningbing reef complex
CONTENTS:	Gas
FORMATION:	Langfield Gp/Ningbing reef complex
AGE:	Late Devonian to Early Carboniferous
DEPOSITIONAL ENVIRONMENT:	Shallow marine

TEST DATA FROM THE DISCOVERY WELL (Vienta-1)**:**

DST 1, 345-452 m, Flowed gas to surface at a rate too small to measure.	Milligans Formation
DST 2, 1,314-1,381 m, Flowed gas at 4,786 m^3/day.	Langfield Gp/Ningbing reef complex

Accumulation Number: 67

WAGGON CREEK

ORIGINAL OPERATOR:	Amity Oil NL
TYPE:	Gas
STATUS:	Other Discovery
LOCATION:	400 km southwest of Darwin
STATE:	Western Australia
ORIGINAL TITLE(S):	EP 386
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Waggon Creek-1
Longitude (E):	128.7105
Latitude (S):	-15.3238
Date total depth reached:	14 NOV 95
Ground Level:	45 m
Kelly bushing:	47 m
Operator:	Amity Oil NL
Total Depth:	700 m
NUMBER OF WELLS DRILLED:	2
STRUCTURE/TRAP:	Large structural/stratigraphic trap on the western basin margin.
RESERVOIR UNITS:	1 (multiple sands)

PETROLEUM BEARING UNIT No.1:	Weaber Group
CONTENTS:	Gas
FORMATION:	Milligans Formation
AGE:	Early Carboniferous

TEST DATA FROM THE DISCOVERY WELL (Waggon Creek-1)**:**

DST 1, 352.6-415 m, Flowed gas at 36,800 m^3/day with condensate through a 12.7 mm choke.	Milligans Formation
Flow Test, 386.3 m, Flowed gas at 37,950 m^3/day through a 13 mm choke at a flowing pressure of 260 psi.	Milligans Formation
DST 3, 586-601.2 m, Flowed gas at 28,300 m^3/day at 280 psi through a 9.5 mm choke with an estimated 3% condensate and salt water.	Milligans Formation

APPRAISAL AND DEVELOPMENT DRILLING :

Waggon Creek-1A was designed to cope with the shallow gas encountered in Waggon Creek-1 and to test the deeper Lower Milligans Formation targets not penetrated by Waggon Creek-1. The well encountered oil shows at a similar stratigraphic level to the discovery well (104–120 mKB) and oil and gas shows between 474 mKB and 510 mKB. Log analysis indicates that sandstones and limestones intersected between 971 mKB and 1,180 mKB are gas saturated but tight (a DST taken over the interval 960-1,095 mKB flowed gas at a rate too small to measure, with no water recovery). Below 1,180 mKB the section is water saturated. Waggon Creek-1A was plugged back to the cased section and suspended.

Ningbing-2 was drilled in August 1996, 10km north of Waggon Creek-1 as an appraisal well on the Waggon Creek structure. Although oil and gas shows were noted, the Milligans sands at Ningbing-2 proved to be tight and unconnected to the gas-bearing sands intersected by Waggon Creek-1. (Ningbing-1, drilled in 1982, 5 km north of Ningbing-2, flowed gas from the Milligans Formation at a rate too small to measure).

REMARKS :

In Waggon Creek-1, oil shows were noted between 117 mKB and 125 mKB. Small quantities of non-biodegraded, 31.4^{o} API oil were recovered from DST 3.

In November 1995, (at the beginning of the wet season), the well was cased and suspended. Drilling resumed in June 1996 with the spudding of Waggon Creek-1A, adjacent to the Waggon Creek-1 location.

RESERVES :

The Joint Venture has indicated that gas reserves at Waggon Creek are probably less than the 100 billion cubic feet required to commence commercial production. Further successful exploration drilling on adjacent structures will probably be necessary toensure the commercial viability of any development at Waggon Creek.

Accumulation Number: 68

WEABER

ORIGINAL OPERATOR:	Australian Aquitaine Petroleum
TYPE:	Gas
STATUS:	Possible Future Producer
LOCATION:	370 km southwest of Darwin
STATE:	Northern Territory
ORIGINAL TITLE(S):	OP 186
BASIN:	Bonaparte
SUB-BASIN:	Petrel Sub-basin
DISCOVERY WELL:	Weaber-1 (‘Enga Sandstone’ gas pool)
Longitude (E):	129.1296
Latitude (S):	-15.3539
Date total depth reached:	16 OCT 82
Kelly bushing:	6 m
Operator:	Australian Aquitaine Petroleum
Total Depth:	1950 mKB
DISCOVERY WELL:	Weaber-2A (Milligans Formation gas pool)
Longitude (E):	129.1082
Latitude (S):	-15.3476
Date total depth reached:	05 SEP 88
Ground Level:	12 m
Kelly bushing:	17.7 m
Operator:	Santos Ltd
Total Depth:	1,657 mKB
NUMBER OF WELLS DRILLED:	5 (including Weaber-2A)
STRUCTURE/TRAP:	Anticlinal structure formed by drape and compaction of Early Carboniferous Upper Burt Range Formation and Weaber Group sediments over a pre-existing palaeotopographic high (Ningbing Group and Lower Burt Range Formation).
RESERVOIR UNITS:	2
BOTTOM HOLE TEMPERATURE:	91^{o}C (Weaber-2A)
PETROLEUM BEARING UNIT No.1:	Weaber Group (Weaber-2A)
CONTENTS:	Gas
FORMATION:	Milligans Formation
AGE:	Early Carboniferous (Late Tournasian)
LITHOLOGY:	Sandstone, off-white to white, very fine grained, moderately well to well sorted, subangular to subround, common calcareous or dolomitic cement with occasional argillaceous or silty matrix. Poor visual porosity. Interbedded with siltstones and shales.
FORMATION TOP (mSS):	506 m

PETROLEUM BEARING UNIT No.2:	Langfield Group (Weaber-1)
CONTENTS:	Gas
FORMATION:	Enga Sandstone
AGE:	Early Carboniferous (Mid Tournasian)
LITHOLOGY:	‘13.0 Sand’ : Off-white to pale yellow-brown, very fine grained, subangular to subrounded with calcareous cement. Poor visual porosity. ‘14.0 Sand’ : Sandstone, predominantly off-white to white, very fine to medium grained, angular to subrounded, poorly sorted with dolomitic and calcareous cement and occasional silty matrix, interbedded with siltstone.
DEPOSITIONAL ENVIRONMENT:	Shallow marine, shoreface environment.
NET PAY:	‘13.0 Sand’ : 1.5 m ‘14.0 Sand’ : 15 m
GROSS PAY:	‘14.0 Sand’ : 18 m
NET TO GROSS RATIO:	‘14.0 Sand’ : 83%
WATER SATURATION:	‘13.0 Sand’ : 35.6% (average from logs) ‘14.0 Sand’ : 23.6% (average from logs)
POROSITY:	‘13.0 Sand’ : 9.9% (average from logs) ‘14.0 Sand’ : 10.3% (average from logs)

TEST DATA FROM THE DISCOVERY WELL (Weaber-1)**:**

DST 1, 1,281-1,313 m, Flowed gas at 56,600 m^3/day through a 12.7 mm choke.	Enga Sandstone’(‘13.0 Sand’)
DST 4, 1,273-1,421 m, Flowed gas at 127,420 m^3/day through a 12.7 mm choke.	Enga Sandstone (‘13.0’ and ‘14.0 Sands’)

TEST DATA FROM THE DISCOVERY WELL (Weaber-2A)**:**

DST 1, 1,016-1,044 m, Gas to surface at a rate too small to measure in 76 minutes. Recovered 17.7 m of rathole mud.	Milligans Formation
DST 2, 1,020-1,037 m, Flowed gas to surface in 14 minutes at 3,790 m^3/day through a 12.7 mm choke. Recovered 1.4 bbls of slightly gas cut mud.	Milligans Formation

APPRAISAL AND DEVELOPMENT DRILLING :

Weaber-2 was plugged and abandoned at 445 mKB due to severe hole problems. The well was redrilled as Weaber-2A.

Weaber-2A flowed gas from the Milligans Formation. This gas sand is not developed in the nearby Weaber-1 well. The Enga Sandstone reservoir encountered in Weaber-1 proved to be water wet in Weaber-2A

Weaber-3, drilled 1.5 km north of Weaber-1, was suspended pending further evaluation.

Weaber-4 flowed gas at 116,100 m^3/day on production test and completed as a future gas producer.

RESERVES:

Gas: 11 BCF
Source: Northern Territory Department of Business Industry and Resource Development, 1998.

REMARKS:

Weaber-1 was originally plugged and abandoned without testing. The well was later found to be leaking gas at the surface and was subsequently re-entered and tested. Test results suggested formation damage had occurred and that flow rates of up to 480,000 m^3/day may be possible from the Enga Sandstone.

The Weaber gas discovery is currently held under Retention Lease RL 1.

COMPOSITIONAL DATA :

GAS :

GAS PROPERTIES	Gas Milligans Fm Weaber-2A (DST-1)
Methane	89.09
Ethane	5.45
Propane	1.16
Isobutane	0.10
N-butane	0.15
Isopentane	0.03
N-pentane	0.01
Hexanes +	0.20
Nitrogen	3.42
CO_2	0.51
H_2S	-
Specific Gravity	0.617
BTU/ft^3 (gross)	1042

STRATIGRAPHY (Weaber-2A) **:**

AGE	UNIT		FORMATION TOP (mKB)
EARLY CARBONIFEROUS	WEABER GROUP	Tanmurra Formation	227.0
		Milligans Formation	525.0
	LANGFIELD GROUP	Enga Sandstone	1372.0
		13-0 Sand	1372.0
		14-0 Sand	1468.0
		Burt Range Formation	1489.0

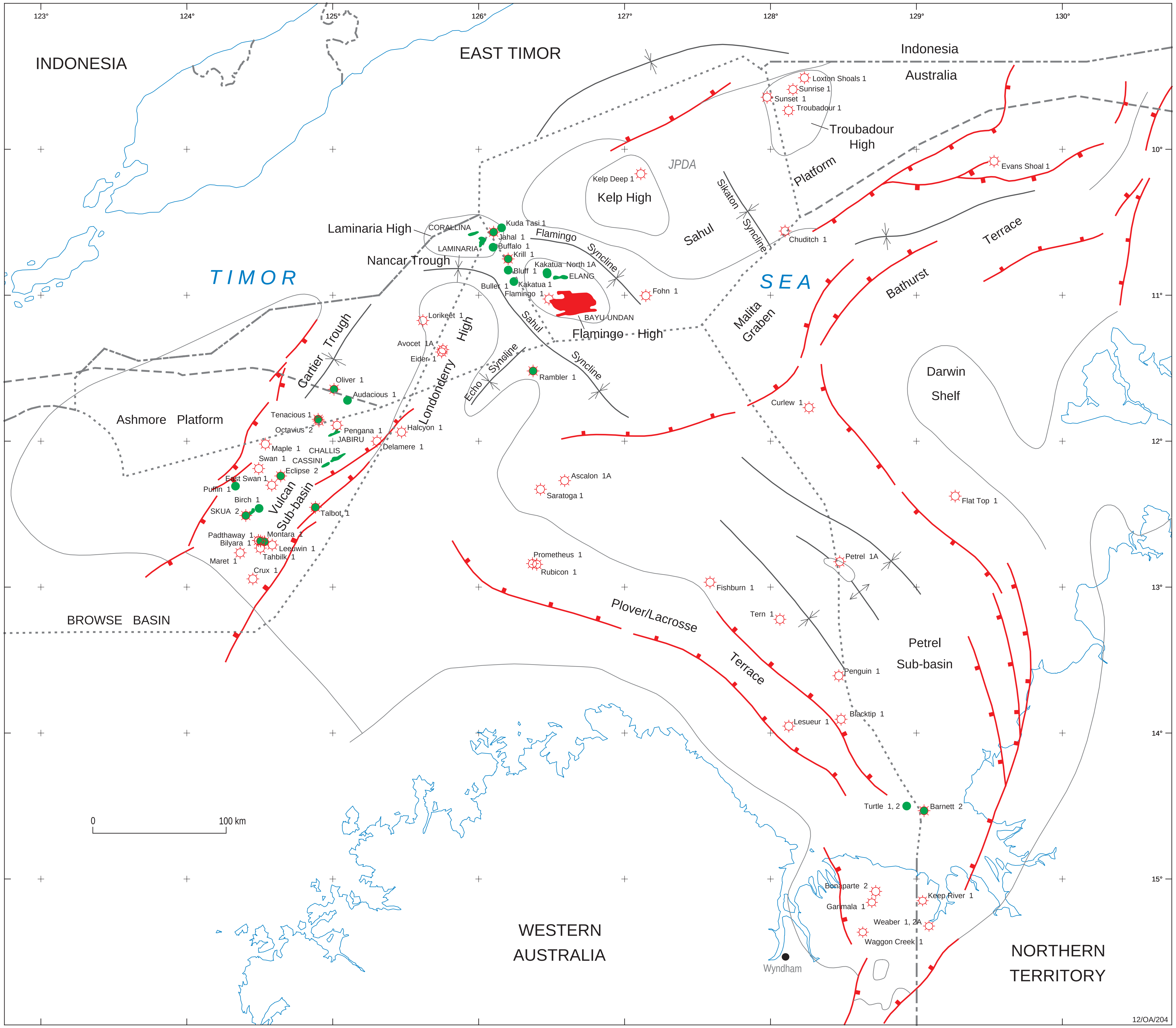

123°
124°
125°
126°
127°
128°
129°
130°
10°
11°
12°
13°
14°
15°
INDONESIA
EAST TIMOR
Indonesia
Australia
TIMOR
SEA
Loxton Shoals 1
Sunrise 1
Sunset 1
Troubadour 1
Troubadour High
Platform
JPDA
Kelp Deep 1
Kelp High
Sikaton
Syncline
Sahul
Chuditch 1
Evans Shoal 1
Terrace
Bathurst
Laminaria High
CORALLINA
LAMINARIA
Kuda Tasi 1
Jahal 1
Buffalo 1
Krill 1
Flamingo
Syncline
Nancar Trough
Kakatua North 1A
Bluff 1
ELANG
Kakatua 1
Buller 1
Flamingo 1
Fohn 1
BAYU-UNDAN
Flamingo High
Malita
Graben
Lorikeet 1
Avocet 1A
Eider 1
Londonderry
High
Sahul
Syncline
Echo
Syncline
Rambler 1
Cartier Trough
Oliver 1
Audacious 1
Ashmore Platform
Tenacious 1
Octavius 2
Pengana 1
JABIRU
Halcyon 1
Delamere 1
Maple 1
CHALLIS
Swan 1
CASSINI
Eclipse 2
East Swan 1
Puffin 1
Birch 1
SKUA 2
Vulcan
Sub-basin
Talbot 1
Padthaway 1
Bilyara 1
Montara 1
Leeuwin 1
Tahbilk 1
Maret 1
Crux 1
BROWSE BASIN
Curlew 1
Darwin
Shelf
Ascalon 1A
Saratoga 1
Flat Top 1
Prometheus 1
Rubicon 1
Petrel 1A
Fishburn 1
Tern 1
Plover/Lacrosse
Terrace
Petrel
Sub-basin
Penguin 1
Blacktip 1
Lesueur 1
Turtle 1, 2
Barnett 2
0
100 km
Bonaparte 2
Garimala 1
Keep River 1
Weaber 1, 2A
Waggon Creek 1
Wyndham
WESTERN
AUSTRALIA
NORTHERN
TERRITORY
12/OA/204

PLATE 1


AGE
Ma
ASHMORE PLATFORM
VULCAN SUB-BASIN
LONDONDERRY HIGH
SAHUL SYNCLINE
SAHUL PLATFORM
MALITA GRABEN
PETREL SUB_BASIN
OFFSHORE
ONSHORE
GROUP
TECTONICS
TERTIARY
CRETACEOUS
JURASSIC
TRIASSIC
PERMIAN
CARBONIFEROUS
DEVONIAN
BARRACOUTA FORMATION
OLIVER FORMATION
OLIVER SANDSTONE MEMBER
UNDIFFERENTIATED
CARTIER FORMATION
PRION FORMATION
HIBERNIA FORMATION
GREBE SANDSTONE MEMBER
GREBE SANDSTONE MBR
JOHNSON FORMATION
PUFFIN FORMATION
TURNSTONE FORMATION
BROWN GANNET LIMESTONE
FENELON FORMATION
GIBSON FORMATION
WOOLASTON FORMATION
UPPER JAMIESON FORMATION
LOWER JAMIESON FORMATION
JAMIESON FORMATION
WANGARLU FORMATION
DARWIN FORMATION
ECHUCA SHOALS FORMATION
UPPER VULCAN FORMATION
CLEIA FORMATION
ASHMORE VOLCANICS
LOWER VULCAN FORMATION
FRIGATE FORMATION
FLAMINGO GROUP
SANDPIPER SANDSTONE
ELANG FORMATION
MONTARA FORMATION
PLOVER FORMATION
MALITA FORMATION
ASHMORE PLATFORM MARGINAL FAULT SYSTEM
BASIN MARGIN FAULT SYSTEM
NOME FORMATION
CHALLIS FORMATION
BENALLA FORMATION
CAPE LONDONDERRY FORMATION
POLLARD FORMATION
OSPREY FORMATION
MT GOODWIN FORMATION
TERN MEMBER
HYLAND BAY FORMATION
DOMBEY MEMBER
CAPE HAY MEMBER
PEARCE MEMBER
FOSSIL HEAD FORMATION
KEYLING FORMATION
TREACHERY SHALE
KURIYIPPI FORMATION
POINT SPRING SANDSTONE
TANMURRA FORMATION
BURVILL FM
MILLIGANS FORMATION
LANGFIELD GROUP
BONAPARTE FORMATION
NINGBING REEF COMPLEX
COCKATOO FORMATION
WOODBINE GROUP
BATHURST ISLAND GROUP
FLAMINGO GROUP/ SWAN GROUP
TROUGHTON GROUP
SAHUL GROUP
KINMORE GROUP
KULSHILL GROUP
WEABER GROUP
Collision of Australian Plate with Timor
Fault reactivation
Regional compression
PASSIVE MARGIN
POST-BREAKUP SEQUENCE
Thermal subsidence
India rifts from Western Australia
VALANGINIAN UNCONFORMITY
Regional Transpressional Event
BREAKUP
CALLOVIAN UNCONFORMITY
Major subsidence in Vulcan Sub-basin, Sahul Syncline and Malita Graben
RIFT SEQUENCE
Thermal subsidence in Petrel Sub-basin
NORTHEAST RIFTING
North-South compression causes wrench reactivation of existing structures
PRE-EXTENSIONAL PHASE
Continued thermal subsidence in Petrel Sub-basin
REACTIVATION OF NORTHWEST RIFTING
Major phase of salt diapirism in Petrel Sub-basin
POST-BREAKUP SEQUENCE
BREAKUP
RIFT SEQUENCE
Rapid subsidence in Petrel Sub-basin
INITIATION OF MAJOR RIFTING IN PETREL SUB-BASIN
NORTHWEST RIFTING

PLATE 2