Australian Government
Department of Resources, Energy and Tourism

Release Areas S09-1, S09-2, S09-3, S09-4, S09-5 and S09-6, Ceduna Sub-basin, Bight Basin, South Australia

Location

Release Areas S09-1 to S09-6 (**Figure 1**) are situated in the central Great Australian Bight off southern Australia , approximately 415 to 655 km west of Port Lincoln, and 250 to 530 km southwest of Ceduna. The areas are located within the Ceduna Sub-basin, in the eastern part of the Bight Basin. At present, no permits are held in this part of the basin. The Release Areas lie approximately 750 km to the east of two current petroleum exploration permits (WA-279-P and WA-280-P) in the Bremer Sub-basin of the Bight Basin.

Release Area S09-1 comprises 86 full graticular blocks and covers a total area of approximately 6125 km^2. It lies in water depths ranging from approximately 140 m to 1550 m.

Release Area S09-2 comprises 90 full graticular blocks and covers a total area of approximately 6395 km^2. It lies in water depths ranging from approximately 280 m to 1600 m.

Release Area S09-3 comprises 88 full graticular blocks and covers a total area of approximately 6255 km^2. It lies in water depths ranging from approximately 130 m to 1400 m.

Release Area S09-4 comprises 85 full graticular blocks and covers a total area of approximately 6000 km^2. It lies in water depths ranging from approximately 1500 m to 4500 m.

Release Area S09-5 comprises 90 full graticular blocks and covers a total area of approximately 6335 km^2. It lies in water depths ranging from approximately 1200 m to 4600 m.

Release Area S09-6 comprises 87 full graticular blocks and covers a total area of approximately 6110 km^2. It lies in water depths ranging from approximately 1300 m to 4500 m.

Release Area Geology

Local Tectonic Setting

The 2009 Release Areas are located almost entirely within the Ceduna Sub-basin of the Bight Basin (**Figure 1**). The east-southeast trending Ceduna Sub-basin is the major depocentre in the Bight Basin, extending over an area of 126300 km^2 and containing at least 15000 m of syn-rift and post-rift Middle Jurassic-Late Cretaceous sediments (**Figure 2** and **Figure 3**). The deepwater Recherche Sub-basin adjoins the Ceduna Sub-basin and extends west along the southern margin. The Ceduna Sub-basin is flanked to the northwest by the half-graben systems of the Eyre Sub-basin. The Duntroon Sub-basin adjoins the Ceduna Sub-basin to the southeast, and consists of a series of oblique extensional depocentres. Thin platform cover areas-the Madura and Couedic shelves-are located to the north and east of the Ceduna Sub-basin respectively (refer to Figure 1 Regional Geology of the Bight Basin).

The northern and eastern margins of the Ceduna Sub-basin have a steep ramp-like geometry and are characterised by a series of fault-bounded half graben containing an interpreted Middle Jurassic-Early Cretaceous syn-rift and post-rift succession (**Figure 2** and **Figure 4**). Landward of these structures, the basin-fill thins abruptly and onlaps basement of the Gawler Craton. The basin thickens rapidly seaward so the distribution of the early extensional structures beneath much of the Ceduna Sub-basin cannot be determined (**Figure 4** and **Figure 5**). The sub-basin fill is dominated by a thick late Early Cretaceous to Late Cretaceous marine-deltaic succession (**Figure 4**, **Figure 5** and **Figure 6**). The structural architecture of the sub-basin is controlled by a series of generally northwest-southeast oriented, listric normal faults that formed as a result of gravity sliding and gravity spreading processes during deposition of a major delta system in the Cenomanian. Dominantly southwest-dipping regional faults detach onto a décollement formed in Albian-Cenomanian shales (**Figure 5**). Further outboard and down-dip in the Recherche Sub-basin, this extension is compensated by contractional faulting, folding and diapirism (**Figure 6**). A transitional zone of complex deformation lies between the growth fault dominated region and the zone of down-dip contraction. This region forms an outer high at the seaward edge of the Ceduna Sub-basin (**Figure 6**). Compaction-related faulting and/or reactivation of the listric extensional faults occurred during the Turonian-Santonian prior to the initiation of sea-floor spreading in the latest Santonian (**Figure 4**, **Figure 5** and **Figure 6**). Some reactivation occurred on selected faults in the Campanian-Maastrichtian, particularly in the more outboard parts of the sub-basin. During this period, new gravity-slide structures also formed at the outer edge of the sub-basin as a result of collapse of the gravitationally unstable, palaeoshelf margin. Structurally, the sub-basin can be divided into the following domains:

> An inboard steeply-dipping hinge zone containing transtensional Middle Jurassic-Early Cretaceous half-graben systems (Figure 4)

> A broad central depocentre characterised by detached extensional faulting and fault reactivation, forming a complex series of rotated fault blocks (Figure 6)

> An outer basin high underlain by a zone of complex, mainly contractional, Cenomanian deformation, which was the focus of subsequent extensional faulting (Figure 6) and shelf-margin instability.

Structural and stratigraphic evolution of the sub-basin

The Ceduna Sub-basin developed in response to repeated periods of extension (upper crustal and lithospheric) and thermal subsidence leading up to, and following, the commencement of seafloor spreading between Australia and Antarctica (Totterdell & Bradshaw, 2004).

A tectonostratigraphic framework for the eastern part of the Bight Basin was compiled by Totterdell et al (2000) and Totterdell and Bradshaw (2004), based on the sequence stratigraphic and structural interpretation of an extensive grid of seismic data, tied, where possible, to 9 petroleum exploration wells in the offshore Bight Basin (**Figure 2** and **Figure 3**; see also Figure 7 in Regional Geology of the Bight Basin, this CD). Data from the 2003 Gnarlyknots 1A well were not available for those studies. Stratigraphic control on the Madura Shelf and in the northern Ceduna Sub-basin is provided by the Apollo 1 and Potoroo 1 wells, which intersect thin mid-Late Cretaceous successions at the edge of the sub-basin. Gnarlyknots 1A was drilled further basinward (**Figure 2**). In the Eyre Sub-basin to the northwest, Jerboa 1 penetrated the latest Jurassic-Early Cretaceous section. Further south, in the southern Ceduna and Duntroon sub-basins, Platypus 1, Greenly 1, Duntroon 1, Borda 1, Echidna 1 and Vivonne 1 provide information on the Early-Late Cretaceous succession (see Figure 7 in Regional Geology of the Bight Basin, this CD). The correlation between the depositional sequences of Totterdell et al (2000) and the previously defined lithostratigraphy (e.g. Hill, 1991) is shown in **Figure 3**.

Stratigraphy

The tectonostratigraphic development of the Ceduna Sub-basin can be described in terms of four basin phases (**Figure 3**; Totterdell et al, 2000). Basin Phase 1 (BP1) records the initiation of sedimentation during the Middle-Late Jurassic to earliest Cretaceous phase of northwest-southeast to north-northwest to south-southeast intracontinental extension. This resulted in the formation of a series of oblique extensional and transtensional half graben along the northern and eastern margins of the Ceduna Sub-basin (**Figure 4**), as well as in the Bremer, Eyre and Duntroon sub-basins. This section has not been intersected by wells drilled in the Ceduna Sub-basin, but the fill of the basal half graben imaged on seismic data is assigned to the Sea Lion and Minke supersequences by analogy with the Eyre Sub-basin. In Jerboa 1 well in the Eyre Sub-basin, the rift-fill comprises a fluvial-lacustrine sandstone, siltstone and mudstone succession.

The extensional phase was followed by a period of slow thermal subsidence that lasted throughout most of the Early Cretaceous (BP2; **Figure 3**). This phase is represented by the Berriasian Southern Right Supersequence and the Valanginian to mid-Albian Bronze

Whaler Supersequence. Deposition during Basin Phase 2 was largely non-marine, although some marine influence is evident late in the phase. The Southern Right Supersequence has not been drilled in the Ceduna Sub-basin, but is inferred to be present based on seismic interpretation and correlation with the Eyre and Duntroon Sub-basins. The Bronze Whaler Supersequence generally consists of an aggradational succession of fluvial and lacustrine sediments. Where interpreted in the Ceduna Sub-basin, the succession has an onlapping, sag-fill geometry.

An abrupt increase in subsidence rate in the mid-Albian signalled the start of the third basin phase (BP3; **Figure 3**), during which up to 10000 m of deltaic and marine, predominantly fine-grained sediments were deposited in the central Ceduna Sub-basin. This period of accelerated subsidence, which continued until the commencement of sea-floor spreading between Australia and Antarctica in the Late Santonian, coincided with a period of rising global sea level (**Figure 3**). This combination of factors resulted in a high rate of creation of accommodation, the first major marine flooding event in the basin and the widespread deposition of marine silt and shale of the Albian-Cenomanian Blue Whale Supersequence. The present-day distribution of the supersequence indicates that the seaway at that time extended along the southern margin from the open sea in the west towards the Otway Basin in the east. Progradation of deltaic sediments into this seaway (White Pointer Supersequence) commenced in the Cenomanian, following uplift and erosion along the eastern margin of the continent. Deposition was rapid, resulting in the development of overpressure in the underlying marine shales, and a short-lived period of shale mobilisation and growth faulting throughout the northern half of the Ceduna Sub-basin (**Figure 5**). Interpretation of seismic facies suggests that a broad band of coaly sediments is present within the White Pointer Supersequence in the inner part of Ceduna Sub-basin. The Blue Whale Supersequence, which was considerably deformed by the shale tectonics, is interpreted to have had a pre-deformation thickness of about 1500-2000 m (Totterdell & Krassay, 2003b). The thickness of the unit is now highly variable, reaching a maximum of about 4000 m adjacent to some growth faults. The White Pointer Supersequence has a maximum thickness of approximately 5000 m within growth fault bounded-depocentres.

The Cenomanian deltaic sediments are overlain by the marginal marine, deltaic and open marine sediments of the Turonian-Santonian Tiger Supersequence. In wells, the supersequence is dominated by mudstone and a few thick sandstone units. On seismic data, this supersequence has an overall flat-lying aggradational character, with some progradational seismic facies evident in its upper part. The Tiger Supersequence has a maximum thickness of approximately 2500 m in the Release Areas.

Continental break-up in the late Santonian was followed by a period of thermal subsidence and the establishment of the southern Australian passive margin (BP4; **Figure 3**). It was during this phase that the second large deltaic system developed, represented by the latest Santonian-Maastrichtian Hammerhead Supersequence (**Figure 4**, **Figure 5** and **Figure 6**). In contrast with the earlier deltaic system, this sand-rich delta is characterised by strongly prograding stratal geometries and shows no evidence of widespread shale tectonics. The base of the Hammerhead Supersequence is markedly erosional in places and the updip portion of the basal sequence boundary is characterised by widespread incision and the presence of large incised valleys (**Figure 5** and **Figure 6**). Seismic data reveals that the Hammerhead Supersequence has an overall progradational-aggradational character defined by three sequence sets (**Figure 4**, **Figure 5** and **Figure 6**). The first two sequence sets are strongly progradational in character, reflecting a consistently high rate of sediment supply from the Late Santonian through the Campanian. The thick, stacked deltaic sequences of the upper sequence set were deposited during a period of balance between the rates of creation of accommodation space and sediment supply. In the Release Areas the Hammerhead Supersequence reaches a maximum thickness of about 3500 m.

A dramatic reduction in sediment supply at the end of the Cretaceous saw the abandonment of deltaic deposition. There is some seismic evidence of regional uplift at this time. On the Madura Shelf, there is an angular unconformity between the Bight and Eucla basin successions, with Cretaceous units progressively eroded across the shelf (**Figure 6**). From the Late Paleocene to present, the largely cool-water carbonates of the Eucla Basin accumulated on a sediment-starved passive margin. A short phase of magmatism in the Middle Eocene, coinciding with the onset of rapid spreading, affected the central Ceduna Sub-basin. This magmatic phase was characterised by both extrusive volcanism (volcanoes, flows, volcanic build-ups) and the intrusion of sills, dykes and deeper igneous bodies (Schofield and Totterdell, 2008).

Exploration History

Petroleum exploration in the Ceduna Sub-basin occurred in four major cycles - the late 1960s to early 1970s, the early 1980s, the early 1990s and, most recently, from 2000-2007. In nearly 50 years of exploration in the offshore Bight Basin, less than 100000 line-km of seismic data have been acquired and only 10 petroleum exploration wells have been drilled (see Figure 7 Regional Geology of the Bight Basin, this CD). The majority of these wells were drilled in water depths of less than 250 m along the margins of the basin, where the source rock quality of mid to Late Cretaceous marine deposits has been reduced by the influx of terrigenous organic matter into proximal depositional facies. More distal facies are found in the Ceduna Sub-basin (**Figure 2**), the thickest depocentre, which covers an area of 126300 km^2. Five wells have been drilled in the sub-basin - Platypus 1, Potoroo 1, Borda 1, Greenly 1 and Gnarlyknots 1/1A. Three of these wells (Platypus 1, Greenly 1 and Borda 1) were originally assigned to the 'Duntroon Basin', however, reinterpretation of the basin boundaries by Bradshaw et al (2003), shows they were drilled in the Ceduna Sub-basin. With the exception of Gnarlyknots 1/1A, the wells were drilled in relatively shallow water near the basin margin and the deeper part of the sub-basin remains untested (**Figure 1** and **Figure 2**).

The first petroleum exploration permits held over the current Release Areas were granted to Shell Development (Australia) Ltd (Shell) in 1966. OEL 38 covering most of the Bight Basin and was converted to a number of exploration petroleum permits (EPP) between 1968 and 1969, with the current Release Areas covered in part by EPPs 5, 6, 10 and 11. Between 1966 and 1976 Shell carried out seven seismic surveys (R4 to R10) over these areas, acquiring over 14500 line-km of 2D seismic reflection data. Magnetic data was also recorded along most of the deep water lines. In 1966, Shell, in conjunction with Outback Oil Co. NL (Outback), recorded 16000 km of regional aeromagnetic data over OELs 33 and 38. Several prospects were developed from these activities and three exploration wells were drilled, Echidna 1 and Platypus 1 in 1972 and Potoroo 1 in 1975. Potoroo 1 is located in the northernmost part of the Release Area S09-1 (**Figure 1** and **Figure 2**). By 1977, Shell had surrendered all of its Bight Basin exploration petroleum permits.

The early 1980s was a period of relatively lacklustre exploration in the central Ceduna Sub-basin. During this period EPPs 16, 17 and 19, covering the current Release Areas, were held by BP Petroleum Development Pty Ltd (BP) and Hematite Petroleum Pty Ltd, a consortium headed by Sterling Petroleum NL and by Outback Oil Co. NL respectively. In 1982, Outback acquired 539 line-km of seismic in EPP 19, with the contractor Geophysical Service Inc. recording an additional 827 line-km of data in adjacent permits on a non-exclusive basis (O'Neil, 2003). However, interest in the area was so low that most of the data was left unprocessed and by 1984 all the permits had been surrendered (Stagg et al, 1990).

In 1982, EPP 21, which was located to the east of the current Release Areas overlying the central Duntroon Sub-basin, was granted to a joint venture, ultimately operated by BP after a farm-in in 1985. In 1983, the joint venture acquired 2102 line-km of reflection seismic data in conjunction with a geochemical hydrocarbon seepage sniffer survey, with a further 1017 line-km of seismic data acquired in 1984 (Stagg et al, 1990; O'Neil, 2003).

These surveys defined several large prospects in the Duntroon and Ceduna Sub-basins, and led to the drilling of Duntroon 1 in early 1986 (see Figure 7 Regional Geology of the Bight Basin, this CD). The well was dry and subsequent mapping indicated that it had been drilled off-structure on the flank of a large faulted closure (O'Neil, 2003).

After an exploration hiatus through the late 1980s, BP flew an Airborne Laser Fluorosensor (ALF) survey in early 1990, under the auspices of a Scientific Investigation Authorisation. The survey covered the entire inboard Bight Basin and was conducted as part of a regional evaluation prior to an expected release round. A total of 27624 line-km of data were recorded at a line spacing of 5 km over an area of approximately 108508 km^2 (Mackintosh and Williams, 1990). The initial results were poor with only two definite, but weak fluors detected. However, reprocessing and reinterpretation of the data recorded a total of 941 confident fluors (Cowley, 2001). The fluors are concentrated in three regions in the Ceduna Sub-basin, one in the vicinity of Greenly 1 and two other dense, but less confidently interpreted areas approximately 50 km south and approximately 100 km southwest of Potoroo 1.

A new phase of exploration began in 1991, when BHP Petroleum (Australia) Pty Ltd (BHP) was awarded EPPs 25 and 26 covering the eastern Ceduna and Duntroon sub-basins, east of the current Release Areas. In 1991, 1046 line-km of seismic data acquired by the EPP 21 joint venture was reprocessed and three new seismic surveys (DH91, DH92 and HD95) acquired high quality 2D seismic data from 1991 to 1995. These new data indicated that all prior drilling had been sited on invalid structures (O'Neil, 2003). BHP drilled three wells in 1993; Borda 1 and Greenly 1 lie within the remapped boundaries of the Ceduna Sub-basin (Bradshaw et al, 2003), while Vivonne 1 was drilled in the Duntroon Sub-basin (see Figure 7 Regional Geology of the Bight Basin, this CD). Although all were plugged and abandoned, their results are encouraging and emphasise the highly unpredictable stratigraphy and complex structural history of the basin. Borda 1 was designed to test a Late Cretaceous to Cenozoic play sealed by Cenozoic marls, similar in style to the highly productive Gippsland Basin play. The most likely cause of failure was the presence of thick Late Cretaceous claystones, which inhibited vertical migration from the Bronze Whaler Supersequence to reservoirs in the Wobbegong Supersequence (Messent, 1998). Greenly 1 tested a basal Late Cretaceous play, reaching a total depth of 4860 mRT. Oil and gas were recovered at 4209 mRT during testing (RFT) and numerous oil indications were recorded from 3430-4524 mRT and 4770-4818 mRT (Messent, 1998). These results represent the first major indication of hydrocarbons in the sub-basin, identifying the presence of a valid source rock and thus considerably upgrading the prospectivity of the Ceduna Sub-basin. Vivonne 1 tested a Late Cretaceous play and reached a total depth of 3000 mRT. The lack of a suitable migration pathway from the Bronze Whaler Supersequence is thought to have contributed to the failure of this well (Messent, 1998).

The latest phase of petroleum exploration commenced in 1999, with the release by the Commonwealth Government of eleven areas for petroleum exploration. Three petroleum exploration permits were awarded in 2000 to a joint venture comprising Woodside Energy Ltd (operator), Anadarko Australia Co. Ltd and PanCanadian Petroleum Corp. (now EnCana Corp.). The permits, EPP 28, EPP 29 and EPP 30 covered the majority of the current Release Areas. The joint venture acquired a large quantity of 2D seismic data and drilled an exploration well, Gnarlyknots 1/1A (**Figure 7**). The Flinders 2D Seismic Survey, completed in May 2001, recorded a total of 15636 line-km of closely spaced, full fold data across the three permits. The seismic grid ranges from 4 x 4 km in the west to 4 x 8 km in the northern and eastern portions of the survey area and recording parameters were optimised to capture any potential AVO effects (Bruins et al, 2001). In early 2006, 1250 km^2 of 3D seismic data (Trim 3D Seismic Survey) was acquired over EPP 29. This survey overlies the northern portions of the current Release Areas S09-4 and S09-5. The Gnarlyknots 1A well was plagued by mechanical problems and abandoned prematurely due to bad weather (1500 m above the prognosed total depth). Although Gnarlyknots 1A failed to recover hydrocarbons, several encouraging results were recorded. These include excellent quality sandstone reservoirs, marine shale top seals and thermogenic hydrocarbon shows, which indicate the presence of a mature source rock down-dip (Tapley et al, 2005). Although the joint venture identified numerous leads (**Figure 7**), some with amplitude support, all three permits were surrendered in 2007.

Geoscience Australia (GA) and its predecessor agencies have a long history of research in the Bight Basin, conducting several gravity and magnetic surveys and acquiring over 28000 line-km of regional 2D seismic data. More recently, GA carried out an integrated basin study of the eastern Bight Basin (1998-2003) using regional seismic and well data. Resulting petroleum system and play models predict numerous potential petroleum systems in Jurassic and Cretaceous age depocentres from the Eyre, Duntroon and Ceduna sub-basins (Blevin et al, 2000; Totterdell et al, 2000, Struckmeyer et al, 2001). These studies were followed by a marine survey (Bight Basin Geological and Sampling Survey) in 2007 (Totterdell, in press), which targeted and recovered potential source rocks of late Cenomanian to early Turonian age (Totterdell et al, 2008) from the northwestern edge of the Ceduna Sub-basin (**Figure 2**).

Well Control

Ten wells have been drilled in the offshore Bight Basin; six of these are located in the Ceduna Sub-basin. Of these, Potoroo 1 and Gnarlyknots 1/1A are located within the current Release Areas, while Jerboa 1 and Greenly 1 are key wells drilled adjacent to the Release Areas (**Figure 1** and **Figure 2**). Most of the wells have been drilled close to the margins of the basin where the sedimentary section is relatively thin. Oil and gas shows were recorded in Greenly 1, while other wells have recorded oil and gas indications. To date no commercial hydrocarbons have been discovered in the Ceduna Sub-basin.

Potoroo 1 (1975)

Potoroo 1 was drilled on the northern edge of the Ceduna Sub-basin by Shell Development (Australia) Pty. Ltd in 1975 and is located in the northernmost part of the current Release Area S09-1 (**Figure 1** and **Figure 2**). The well was drilled to test a structure within the Platypus Formation (White Pointer Supersequence) with dip closure against a major basement fault. The target interval was characterised by strong seismic reflections, similar to the'Platypus' sands encountered in Platypus 1, drilled in the adjacent Duntroon Sub-basin (Messent, 1998).

Potoroo 1 intersected an Early Cretaceous to Holocene, lacustrine to marine sedimentary succession characterised by interbedded siltstone and claystone; Precambrian basement was intersected at 2815 mRT. Reservoir sandstones were not encountered in the target interval (Messent, 1998). The well intersected a major fault that marks the present-day northern edge of the Early Cretaceous units. Occasional high gas peaks (methane with traces of ethane up to 6000 ppm) were recorded from below the top of the Wigunda Formation (Tiger Supersequence) to a total depth (TD) of 2924 mRT (Messent, 1998). Gas recorded in the Platypus Formation (White Pointer Supersequence) was associated with coal (Messent, 1998). The primary cause of failure was attributed to the lack of reservoirs within the target horizon, together with the lack of hydrocarbon migration into the structure (Messent, 1998). There is also considerable doubt as to whether the well was drilled'on structure'.

Jerboa 1 (1980)

Jerboa 1 was drilled approximately 200 km east-northeast of the current Release Areas in the Eyre Sub-basin (**Figure 1** and **Figure 2**). The well was drilled by Esso Australia Ltd in 1980 on the footwall of a major half-graben bounding fault. The well targeted Late Jurassic to Early Cretaceous sandstone reservoirs in the Sea Lion-Bronze Whaler supersequences. Closure on the prospective section was provided by drape over the Precambrian basement fault block (Messent, 1998). Jerboa 1 penetrated a small, localised hanging wall section close to the bounding fault, intersecting Late Jurassic to Recent, lacustrine to marine sedimentary successions with multiple reservoir-seal pairs. Recent work on the fluid history of the well (Liu and Eadington, 1998; Ruble et al, 2001) documented the presence of a 15 m net palaeo-oil zone extending over the gross interval 2470-2495 mRT in sandstone of the Sea Lion Supersequence. Geochemical studies of the oil clearly point to a lacustrine source (Ruble et al, 2001). Source rocks penetrated in the well are immature to marginally mature. Deeper parts of the adjacent half graben may contain mature, lacustrine source rocks deposited during rift development.

Greenly 1 (1993)

Greenly 1 was drilled by BHP Petroleum Pty Ltd in 1993 approximately 275 km southeast of the current Release Areas (**Figure 1** and **Figure 2**). The well was drilled within the previously defined Duntroon Basin, however, re-mapped basin margins by Bradshaw et al (2003) place it within the Ceduna Sub-basin. The well was designed to test a simple anticlinal structure, targeting Late Cretaceous sandstone reservoirs at the base of the Wigunda Formation (Tiger Supersequence). However, structural misinterpretation resulted in the well drilling the hanging wall of a tilted fault block (Messent, 1998).

Oil and gas were recovered from the Wigunda Formation (Tiger Supersequence) during testing (RFT). The oil was recovered as a surface scum and as a water/oil mixture (Messent, 1998). Numerous oil indications were also reported from the Wigunda and Platypus formations (Tiger and White Pointer supersequences). The most likely source of the hydrocarbons is the upper Borda Formation (Bronze Whaler Supersequence) (Smith and Donaldson, 1995; Messent, 1998). Vitrinite reflectance data and Bottom Hole

Temperature measurements indicate the top of the oil window is at approximately 3600 mRT and the well is still within the oil window at TD (4860 mRT) (Wong, 1994; Messent, 1998).

The absence of significant hydrocarbons at Greenly 1 is most likely due to a combination of poor reservoir quality and the lack of closure at the target horizon (Messent, 1998). There was also an error in the structural interpretation. Due to significant horizon mis-picks during seismic interpretation, the target horizon was in excess of 2000 m deeper than predicted (Messent, 1998).

Gnarlyknots 1/1A (2003)

Woodside Energy Ltd and its joint venture partners drilled Gnarlyknots 1/1A in April 2003. The wells lie in the central portion of Release Area S09-2 (**Figure 1** and **Figure 2**). Gnarlyknots 1 was abandoned at 1824 mRT due to mechanical difficulties and Gnarlyknots 1A was spudded approximately 50 m to the southwest. The well was designed to test the petroleum systems within the more distal Late Cretaceous depositional systems of the Ceduna Sub-basin where oil-prone, marine source rocks are more likely (Tapley et al, 2005). The well was drilled to test as much of the prospective basin stratigraphy as possible by penetrating four stratigraphic horizons with fault-dependent closure within a tilted fault block, targeting reservoir seal pairs predicted in the intra-Santonian and top-Coniacian intervals (Woodside, 2004). However, due to adverse weather conditions the well was abandoned at 4736 mRT near the top of the Tiger Supersequence, some 1500 m above the predicted total depth, with several key targets remaining untested. Although Gnarlyknots 1A failed to recover hydrocarbons, several encouraging indications were observed. Tapley et al (2005) reported the following hydrocarbon indications:

- fluorescence and cut in side wall cores and cuttings from 4383 mRT;
- methane-depleted wet gas to gas-condensate response in the primary objective (intra-Santonian) - observed using Fluid Inclusion Stratigraphy analysis - consistent with a highly mature palaeo-charge;
- strong proximity to pay indicators within local shale seals below 4600 mRT, possibly indicating proximity to an oil column below the TD of the well; and
- indications that thermogenic gas has migrated into the structure from mud gas isotope analysis in the primary objective.

The failure of Gnarlyknots 1A to discover significant hydrocarbons is attributed to the well being drilled outside of any independent fault closure, and the absence of valid cross-fault seals within the sand-prone coastal plain deposits (Tapley et al, 2005). Due to technical problems, causing early abandonment, the well failed to test several key targets.

Table 1: Key wells listing

Well	Operator	Year	Total Depth	Hydrocarbons
Apollo 1	Outback Oil Company NL.	1975	876 mKB	No tests
Borda 1	BHP Petroleum Pty Ltd	1993	2800 mRT	No tests
Duntroon 1	BP Petroleum Development Limited	1986	3510 mRT	No tests
Echidna 1	Shell Development (Australia) Pt Ltd	1972	3832 mRT	No tests
Gnarlyknots 1	Woodside Energy Ltd	2003	1824 mRT	No tests
Gnarlyknots 1A	Woodside Energy Ltd	2003	4736 mRT	No tests
Greenly 1	BHP Petroleum Pty Ltd	1993	4860 mRT	Minor gas
Jerboa 1	Esso Australia Limited	1980	2537.5 mRT	No tests
Platypus 1	Shell Development (Australia) Pty Ltd	1972	3892.9 mRT	No tests
Potoroo 1	Shell Development (Australia) Pty Ltd	1975	2924 mRT	No tests
Vivonne 1	BHP Petroleum Pty Ltd	1993	3000 mRT	No tests

Rig Release Year shown. Data accurate as at 31 March 2009

Seismic Coverage

Seismic coverage over the Release Areas (**Figure 7**) ranges from excellent to poor, and comprises a mixture of vintages ranging from the 1970s through to recently acquired data. Between 1967 and 1977, Shell Development Australia Pty Ltd acquired over 14500 km line-km of seismic data across the Ceduna Sub-basin, while at about the same time the Bureau of Mineral Resources (BMR, now GA) acquired approximately 15000 line-km of 2D data across the Bight Basin. Most of these older surveys have line spacings of between 5 and 25 km. Two deep seismic (16 seconds TWT) transects across the Great Australian Bight, together with deep seismic data across the South Australian Abyssal Plain and Recherche Sub-basin, were acquired by the Australian Geological Survey Organisation (AGSO, now GA) in 1997. Seismic Australia (now Fugro Multi Client Services), in joint venture with AGSO, acquired 8500 line-km of regional seismic data across the Ceduna Sub-basin during 1998-99 (HRGAB and DWGAB surveys). Line spacings for these seismic surveys range from approximately 10 to 40 km. More recently, Woodside Energy Ltd acquired the Flinders 2D Seismic Survey (2001) and Trim 3D Seismic Survey (2006). The Flinders 2D Seismic Survey comprises 15636 line-km of closely spaced 2D seismic data with magnetics and gravity data recorded concurrently. The seismic grid ranges from 4 x 4 km in the west to 4 x 8 km in the northern and eastern portions of the survey area. The Trim 3D Seismic Survey acquired 1250 km^2 of seismic data in the former permit EPP 29. This survey overlies the northern portions of Release Areas S09-4 and S09-5 (**Figure 7**).

Many of the earlier seismic datasets were reprocessed by Fugro Multi Client Services in 1999 and 2004 and a new data product comprising reprocessed seismic, new potential field data and satellite SAR seep data over the Ceduna Sub-basin is also currently available.

A full listing of the seismic is available in the **Ceduna Sub-basin Data Listing**.

Other data

Additional publications, reports and data covering the Release Areas and broader Bight Basin are available from GA and Primary Industries and Resources SA (PIRSA). Data and analyses include gravity, magnetics and bathymetry grids, depth-time functions, results of SAR and ALF seepage surveys, company reports and related publications.

For more information:

> www.ga.gov.au/oceans/sa_bght_pubs.jsp

> www.petroleum.pir.sa.gov.au/home

Hydrocarbon Potential

Petroleum Systems

Prior to the drilling of Gnarlyknots 1A in 2003, most exploration drilling in the Bight Basin was focused around the inboard margin of the Ceduna Sub-basin or in the half-graben systems of the Eyre and Duntroon sub-basins (**Figure 1** and **Figure 2**). Seismic and sequence stratigraphic interpretation (Totterdell et al, 2000), as well as biostratigraphic and sedimentological studies (Hill, 1991; Smith and Donaldson 1995; Morgan 1999), indicate that most wells penetrated the proximal parts of the Early-Late Cretaceous depositional systems. Therefore, organic geochemical data from the wells only provide information about the source rock potential of these proximal facies. The data (**Figure 8** and **Figure 9**) suggest the presence of high-quality, dominantly non-marine source rocks with oil and gas generative potential (Totterdell et al, 2000; Struckmeyer et al, 2001; Boreham et al, 2001). The open file data are available from Geoscience Australia's database (**http://dbforms.ga.gov.au/www/npm.well.search**).

In addition, geochemical data provide evidence of a breached hydrocarbon accumulation at Jerboa 1 in the Eyre Sub-basin, most likely sourced from lacustrine facies within the adjacent Middle-Late Jurassic half graben (Ruble et al, 2001). Totterdell et al (2000) and Struckmeyer et al (2001) emphasised that, although all the available data are considered to be representative of the organic character and generative potential (**Figure 8** and **Figure 9**) of facies along the margins of the Bight Basin, they are not necessarily indicative of the quality of organic-rich facies that are expected to lie in a more basinal environment. Based on these considerations, they predicted the presence of at least one, but probably several petroleum systems in the Ceduna Sub-basin, with the older systems located along the shallower water, northern and eastern margins of the basin and younger systems located increasingly basinward in deeper water. Evidence for the presence of an active petroleum system was summarised in hydrocarbon seep studies using Synthectic Aperture Radar (SAR), Airborne Laser Fluorosensor (ALF), seismic and well data (Struckmeyer et al, 2002), and geochemical studies of asphaltite strandings along the southern margin (Edwards et al, 1998; Boreham et al, 2001). However, as the distal parts of the depositional system had not been sampled by drilling, the presence of high quality marine source rocks in the basin could only be theorised.

The first order transgressive-regressive cycle (**Figure 3**) reached its transgressive maximum in the mid-Cretaceous just prior to the commencement of seafloor spreading in the central Bight Basin. Therefore, an increasing marine influence from the Aptian to the eustatic sea-level peak in the Late Albian-mid-Turonian, would have led to a basinward improvement in source rock quality for the uppermost Bronze Whaler, Blue Whale, White Pointer and Tiger supersequences. Source rock quality may also have been enhanced by the palaeogeography of the margin. By the mid-Cretaceous, open ocean lay to the west and a narrow, possibly restricted, seaway would have existed along the southern margin, at least as far east as the western Otway Basin. Accelerated subsidence prior to the commencement of seafloor spreading led to increased marine accommodation in the Bight Basin, with an enhanced potential for the deposition and accumulation of organic-rich rocks.

Another factor potentially influencing source rock quality is that deposition during the mid-Late Cretaceous coincided with several global marine organic carbon burial events or Oceanic Anoxic Events (OAE) (Schlanger and Jenkyns, 1976; Jenkyns, 1980; Schlanger et al, 1987; Arthur et al, 1987, 1990).

Results of a 2007 GA sampling survey in the Great Australian Bight are summarised by Totterdell et al (in press). The primary objective of the survey was to recover samples from distal parts of the Jurassic-Cretaceous Bight Basin in order to address petroleum exploration industry concerns regarding the presence of viable source rocks in the basin. The survey successfully recovered a suite of mid-basin to distal rocks of Cenomanian-Maastrichtian age, including several samples of Late Cenomanian to Early Turonian age with excellent source potential (**Figure 8** and **Figure 9**), thus supporting the earlier predictions based on the sequence stratigraphic model for the basin.

Source Rocks

Based on the studies outlined above, a number of potential source intervals consisting of carbonaceous shales, coals and oil shales deposited in a variety of lacustrine, deltaic and marine environments are predicted to occur in the Ceduna Sub-basin.

These include:

- lacustrine shales and coaly deposits of the Middle-Late Jurassic Sea Lion and Minke supersequences and Early Cretaceous Bronze Whaler Supersequence along the inboard margin of the basin;
- coaly facies of the Early Cretaceous Southern Right Supersequence;
- marginal marine to coastal plain mudstone and coal of the upper Bronze Whaler Supersequence;
- marine shales of the Albian-Cenomanian Blue Whale and Turonian-Santonian Tiger supersequences;
- deltaic and shallow marine shale and coal of the Cenomanian White Pointer Supersequence; and
- prodelta shale of the latest Santonian-Maastrichtian Hammerhead Supersequence.

The Jurassic *Sea Lion and Minke* supersequences typically contain Type I and III kerogen (**Figure 9**). In the Bight Basin, these two units were intersected in only one well (Jerboa 1), where TOC values are typically below 2%. Samples from wells in the nearby Polda Basin have TOC values up to 22% and HI values of up to 500 mg HC/g TOC. Here, the organic matter occurs as both coaly fragments and as dispersed organic matter in mudstone. The source potential of the Jurassic Sea Lion and Minke supersequences was discussed in more detail by Ruble et al (2001) based on the geochemistry of an interpreted palaeo-oil column at Jerboa 1. Biomarkers indicate that the inclusion oil was derived from a carbonate-rich rock containing algal and bacterial organic material deposited in lacustrine environments. Ruble et al (2001) concluded that deposition occurred in non-marine, fluvio-lacustrine environments in a series of half graben associated with initial extension in the Bight Basin. These half graben are typically restricted to the Eyre and Duntroon sub-basins and the inner margins of the Ceduna Sub-basin. Maturity data from Jerboa 1 and regional petroleum systems modelling (**Figure 10a**; Totterdell et al, 2008) suggests that these potential source rocks are marginally mature to overmature at present, depending on their depth of burial. They are predicted to lie within the oil window where the overburden is approximately 3000-4000 m thick.

The Berriasian *Southern Right* Supersequence comprises interbedded sandstones, mudstones and coals deposited in fluvial and lacustrine environments. Based on available RockEval data from 13 well samples, this unit appears to have low potential for generating hydrocarbons (**Figure 8** and **Figure 9**). However, the low number of samples is probably not representative of this succession. It is likely that organic-rich rocks deposited in fluvial and lacustrine environments are locally present. This unit probably has minor potential for the generation of waxy oils, but could have significant potential for gas generation.

The Valanginian to mid-Albian *Bronze Whaler* Supersequence comprises interbedded sandstones, mudstones and coals deposited in mostly fluvio-lacustrine environments. Organic matter is abundant, with TOC values ranging from 0.5 to 57% (**Figure 8**), and typically comprises Type II/III kerogen (**Figure 9**). The higher TOC values are largely due to the presence of coals in the upper part of the succession. However, some of these may represent cavings from the White Pointer Supersequence. The presence of an Aptian oil shale with 10% TOC in Gambanga 1 in onshore equivalents (Totterdell and Krassay, 2003a; Boreham et al, 2001) also suggests that very good to excellent oil source rocks are present within the younger part of this succession. The oil shale is characterised by land-plant dominated organic facies and was deposited in a lacustrine environment. Similar organic-rich rocks are likely to occur offshore. An intermittent marine influence in the upper part of the supersequence is indicated by the presence of dinoflagellates and spinose acritarchs in Duntroon 1 (Morgan 1986) and a thin marine age-equivalent succession onshore, in Mallabie 1 (Morgan 1999). The presence of marine sediments near the inner depositional edge of the basin suggests the presence of fully marine late Aptian to middle Albian intervals in the main depocentre of the Ceduna Sub-basin. Struckmeyer et al (2001) concluded that the upper part of the Bronze Whaler Supersequence has good to excellent potential for both oil and gas generation, whereas the lower Bronze Whaler Supersequence has moderate potential only and is probably gas-prone. Similar to the underlying units, the maturation levels are highly variable, ranging between immature to overmature for oil generation, depending on the thickness of the overburden. In some parts of the inboard Ceduna Sub-basin, the Bronze Whaler Supersequence is currently within the main oil generation window, at depths between 3 and 5000 m (Totterdell et al, 2008). It is gas mature to overmature in the remainder of the basin (**Figure 10b**).

The Albian-Early Cenomanian *Blue Whale Supersequence* records the first major marine flooding event in the Ceduna Sub-basin and was deposited at the start of an accelerated tectonic subsidence phase (Totterdell et al, 2000). Organic matter content is high (Struckmeyer et al, 2001), with TOC values ranging from 0.5 to 62 % (**Figure 8**), and typically comprises Type II/III kerogen (**Figure 9**). The higher values represent mostly coals. HI values for the shales are generally lower than those of the coals, but reach values of up to 230 mg HC/g TOC. RockEval and TOC data show that, overall, the Blue Whale Supersequence has good potential for the generation of both oil and gas. In Platypus 1, both the coaly and shaly lithologies contain excellent source rocks for oil. Most of the samples analysed from the Blue Whale Supersequence are from the Duntroon Basin, where the environment of deposition is generally shallow marine. The coaly facies is probably restricted to the inner Duntroon Basin and areas basinward of Potoroo 1. The presence of organic-rich, shallow marine mudstone in the onshore Eyre 1 well (Boreham et al, 2001) supports the interpretation of widespread marine environments. Boreham et al (2001) and Struckmeyer et al (2001) suggested that deeper water, restricted marine environments that could have resulted in the deposition of rich marine source rocks, were present in the central Ceduna Sub-basin during this time. **Figure 10** shows that, at present, the Blue Whale Supersequence lies within the oil window in the inner and outermost parts of the Ceduna Sub-basin, but is gas mature to overmature across the greater part of the sub-basin.

A considerable proportion of the organic matter analysed from the Cenomanian *White Pointer* Supersequence consists of coal (Struckmeyer et al, 2001). These are typically rich in vitrinite and liptinite and have HI values ranging up to 338 mg HC/g TOC (**Figure 8** and **Figure 9**). TOC values obtained from shales and siltstones are consistently above 1.0% and most are above 2%. Although a considerable proportion of the organic matter comprises Type III kerogen, over 50% of the analysed samples contain Type II/III kerogen. These data indicate that this succession contains rocks with good to excellent source potential for both oil and gas. The lower part of this thick succession is typically gas mature throughout the basin, except for the basin margins, but the upper White Pointer Supersequence lies within the oil window and wet gas window in the greater part of the basin (**Figure 10**; Totterdell et al, 2008).

Based on data from exploration wells only, the Turonian-Late Santonian *Tiger* Supersequence appears to have overall poor to fair source potential (**Figure 8** and **Figure 9**). Considering that it was deposited during a time of high global sea levels, coincident with the global'Turonian anoxic event' (Arthur et al, 1990) during a period of accelerated subsidence, Totterdell et al (2000) and Struckmeyer et al (2001) postulated that the unit could contain good quality marine source rocks. This has since been tested with the dredging of a number of samples (**Figure 11**) from Tiger Supersequence rocks outcropping on the seafloor (Totterdell et al, 2008). These samples and their locations (**Figure 2** and **Figure 11**) were described in detail by Totterdell et al (2008) and constitute the best potential source rocks found in the Bight Basin to date. In eleven samples dated as latest Cenomanian to Turonian, TOC contents range from >2% to 6.9% and HI values range from 274 to 479 mg HC/g TOC, with the highest HI values corresponding to the highest TOC values (**Figure 8** and **Figure 9**). These data suggest good to excellent generative potential for oil. The high hydrocarbon potential of these samples is further supported by a dominance of the hydrogen-rich liptinite maceral group and its main component lamalginite (Keiraville Konsultants, 2008). Molecular composition of the extractable organic matter shows that the organic matter was deposited in a marine environment under reducing conditions. These are similar conditions to the proposed depositional system for the marine asphaltites found stranded along the southern Australian coastline (Edwards et al, 1998; Boreham et al, 2001). Totterdell et al (2008) concluded that these organic-rich rocks as well as the asphaltites are likely to be a local expression in the Bight Basin of the global oceanic anoxic event (OAE2) in the Late Cretaceous. Regional petroleum systems modelling (Totterdell et al, 2008) suggests that the basal Tiger Supersequence is currently mature for oil and gas generation across the greater part of the depocentre and immature along the basin margins (**Figure 10** and **Figure 12**). In the thickest part of the basin, where the overburden is between about 5000 and 5500 m thick, the basal Tiger Supersequence is gas mature.

The Late Santonian-Maastrichtian *Hammerhead* Supersequence has not been sufficiently sampled to fully assess its source potential, particularly considering the wide range of source facies possible within a deltaic environment. TOC values for 42 samples from the proximal part of the delta system range from 0.6 to 2.5 % (**Figure 8**) and the average HI index is 147 mg HC/g TOC (Struckmeyer et al, 2001). This indicates that the succession has poor to fair potential for the generation of oil and gas. However, several HI values over 200 mg HC/g TOC and two values above 400 mg HC/g TOC suggest that potential oil source rocks are present locally. Across most of the basin, these potential source rocks would be immature, but regional modelling suggests that the basal Hammerhead Supersequence may reach the oil window in the growth fault controlled depocentres at the palaeoshelf margin in the southeastern part of the Ceduna Sub-basin (Totterdell et al, 2000; Krassay and Totterdell, 2003).

Expulsion and Migration

Generation and expulsion from potential Jurassic source rocks of the Sea Lion and Minke supersequences occurred during the Early Cretaceous in most of the Ceduna Sub-basin (**Figure 13**). However, where the overburden is less than about 3000-4000 m, expulsion is likely to have occurred during the mid to Late Cretaceous. Regional petroleum systems modelling suggests that expulsion from the Southern Right Supersequence occurred mainly in the Albian to Turonian, and from the Bronze Whaler Supersequence during the Cenomanian to Turonian. Most of these early generated and expelled hydrocarbons are likely to have been lost during major structuring related to breakup. However, in the inboard parts of the basin, where this structuring was less pronounced, some accumulations within reservoir units of the Bronze Whaler Supersequence may be preserved as dry gas.

Recent 2D petroleum systems modelling along two transects across the Ceduna Sub-basin (**Figure 2**, **Figure 10** and **Figure 14**), using source-specific multi-component kinetics (Totterdell et al, 2008), focussed on three main potential source rocks - marine Blue Whale and Tiger supersequence source rocks comprising mainly Type II kerogen, and deltaic, upper White Pointer Supersequence source rocks comprising mainly Type II/III kerogen. Along the northern transect, present-day kerogen transformation ratios for a basal Tiger Supersequence source unit are generally below 50% (**Figure 14a**), whereas ratios for the White Pointer Supersequence source unit reach up to 90% and the Blue Whale Supersequence up to 100% for most of the basin. This suggests that kerogen transformation is complete for the two older source units. Along the central section, where it is buried to its greatest depth, the basal Tiger Supersequence source unit also has present-day transformation ratios between 90 and 100% (**Figure 14b**). Overall, modelling results (Tapley et al, 2005; Totterdell et al, 2008) suggest that generation and expulsion from the Tiger Supersequence occurred continuously from about the mid-Campanian, following deposition of the Hammerhead 1 sequence, until the present day (**Figure 13**). Generation and expulsion from potential upper White Pointer Supersequence source rocks occurred from the Early Campanian. Generation and expulsion from potential source rocks of the Blue Whale Supersequence occurred from the Turonian onwards and continues to the present-day near the basin margins. Expulsion from potential deltaic source rocks of the Hammerhead Supersequence probably commenced in the Maastrichtian.

The major regional structural gradients in the basin during the Late Cretaceous include shallowing towards the northwest and north and the southeast and east. Some fault reactivation at the time of breakup (late Santonian) may have facilitated the vertical movement of fluids along faults, many of which terminate at the Hammerhead Supersequence boundary. Another period of minor reactivation has been dated as Early to mid-Paleocene, and may relate to changes in the rates of sea floor spreading (Totterdell et al, 2000; Sayers et al, 2001) or sedimentary load induced flexure. Steep, planar normal faults associated with this event terminate at the Wobbegong Supersequence boundary, and may have facilitated migration of hydrocarbons from pre-existing traps. Based on 2D petroleum systems modelling, Totterdell et al (2008) concluded that hydrocarbon volumes expelled and available for accumulation may range up to several billion barrels of liquids and several trillion cubic feet of vapour along the two transects.

Apart from oil and gas indications in wells of the Duntroon Basin and a palaeo-oil accumulation in the Eyre Sub-basin in Jerboa 1 well, evidence for hydrocarbons is provided by numerous indirect indicators on seismic and remote sensing data (Struckmeyer et al, 2002). Although Gnarlyknots 1A was unsuccessful, a number of secondary indications of charge such as fluorescent hydrocarbon-bearing inclusions, monazite grains with hydrocarbon rims and a shallow biogenic gas signal from fluid inclusion stratigraphy have been described from analyses of well samples (King and Mee, 2004). Hydrocarbon indications on seismic sections include amplitude anomalies within the Hammerhead and Tiger supersequences (King and Mee, 2004; Tapley et al, 2005).

Reservoirs

The primary reservoir units in the Ceduna Sub-basin are the deltaic sandstones of the Late Santonian to Maastrichtian Hammerhead Supersequence delta (**Figure 13**). Data from Potoroo 1 and Gnarlyknots 1A (King and Mee, 2004) and wells in the Duntroon Sub-basin show that sandstones from this succession are quartzose and medium to very coarse grained with porosities between 10 and 35%. King and Mee, (2004) reported preservation of porosities >20% at depths up to about 3000 m based on petrophysical models, and regional petroleum systems modelling suggests porosities of 15% to depths of about 4000 m (Totterdell et al, 2008). Seismic facies studies of the Hammerhead

Supersequence delta (Krassay and Totterdell, 2003; King and Mee, 2004) indicate that coarse-grained facies deposited in alluvial and coastal plain settings occur in the inner to central basin, and shelf deposits and turbiditic slope and basin floor sands are likely to occur in the central to outer basin.

Potential reservoir rocks also occur in the Early Cretaceous Bronze Whaler Supersequence, the Cenomanian White Pointer Supersequence and the Turonian to Santonian Tiger Supersequence (**Figure 13**). Porosities in the Bronze Whaler Supersequence are likely to be too low in the Release Areas to provide an effective reservoir, but the White Pointer Supersequence is likely to have porosities of up to15% to depths of about 3000 m and of up to 20% to depths of about 2000 m. In the inboard parts of the basin, where coarse-grained facies are likely to be more abundant, this unit could be a viable reservoir interval. Results from Gnarlyknots 1A and seismic facies mapping show that the Tiger Supersequence is characterised by coarser grained shallow marine facies in the inboard Ceduna Sub-basin. Sandy units in the middle of the Tiger Supersequence are also indicated by the presence of a clear impedance contrast at this stratigraphic level on seismic data across the basin (Totterdell et al, 2008). Predicted porosities for this unit range from 10-20% at depths of 3000-4500 m and 15-25% at depths of 2000-3500 m respectively.

Seals

Seals in the Ceduna Sub-basin include both regional and intraformational seals (**Figure 13**). Moderate to excellent intraformational seals are probably present throughout the Cretaceous succession, with quality and thickness dependent on depositional facies. The Blue Whale Supersequence may provide a good regional seal for potential accumulations in Early Cretaceous reservoirs in the inboard part of the basin. Marine shales of the Tiger Supersequence are likely to form an excellent regional seal for reservoir rocks of the White Pointer and Tiger supersequences (Somerville, 2001). For example, a potential mid-Tiger Supersequence reservoir unit is likely to be sealed by a regional upper Tiger Supersequence seal in the central and outer basin, whereas seal quality of this unit is reduced in the inboard parts of the basin due to a higher sand content, as suggested by the results of Gnarlyknots 1A.

Seals within the Hammerhead Supersequence are probably mostly intraformational, although the presence of more widespread, thin, transgressive marine shales within the shallow marine to nearshore facies is also likely (King and Mee, 2004). Downlapping marine shales deposited in outer shelf to slope environments in the central to outer basin are probably the best potential seals within this unit (Krassay and Totterdell, 2003; King and Mee, 2004). Given the present-day depths of burial of regionally extensive potential sealing units such as the Tiger Supersequence, the presence of intraformational seals within the Hammerhead Supersequence, particularly in the upper aggradational parts of the section, will probably be crucial to exploration success in this part of the basin.

Marl and limestone of the middle Eocene to Recent Dugong Supersequence may provide a regional seal for reservoirs in the upper Hammerhead Supersequence. This unit is of varying thickness and probably varying quality (Messent et al, 1996). Beyond the present-day shelf break, the Dugong Supersequence is typically less than 500 m thick and is likely to have improved sealing properties.

Play Types

The Ceduna Sub-basin contains a wide range of possible plays at various stratigraphic levels, but the main plays are associated with faults in the post- Albian section. They include both hanging wall and footwall traps with either rollovers or dip closures. During their 2000-2007 exploration phase, Woodside Energy Ltd identified a number of plays and prospects (King and Mee, 2004; Tapley et al, 2005) along two major trends (**Figure 7**); an inner basin trend (Gnarlyknots Trend) and an outer basin trend (Springboard Trend). The Gnarlyknots Trend was described as fault related traps with targets in Cenomanian to Santonian reservoirs (White Pointer and Tiger supersequences), charged laterally and vertically from Turonian to Santonian (Tiger Supersequence) source rocks. The Springboard Trend is characterised by fault related traps, both lowside and highside, with targets in Campanian deltaic reservoirs (Hammerhead Supersequence), charged by either marine shales of the Tiger Supersequence or prodeltaic shales of the basal Hammerhead Supersequence.

Figure 15 illustrates structural plays in the inboard part of the basin at a regional scale. Possible targets within reservoirs of the White Pointer and Tiger supersequences are typically at depths of 3.5 to 4.5 seconds two-way time. They would be charged laterally from a mature Tiger Supersequence source to the west or vertically and laterally from mature marine shales of the Blue Whale Supersequence and coaly source rocks of the White Pointer Supersequence. A more detailed example of this play type in the inboard part of the basin is given in **Figure 16**, showing changes in amplitude at this level across three fault blocks. Other play types in the inboard part of the basin include stratigraphic plays in the basal Hammerhead Supersequence (**Figure 16**), basement onlap and drape stratigraphic plays, and structural plays associated with half-graben bounding faults. Some of these may be charged by mature source rocks of the syn-rift succession (Sea Lion and Minke supersequences).

In the outer basin, in Release Areas S09-4, S09-5 and S09-6, the main structural plays are within the mid-Tiger Supersequence and the Hammerhead Supersequence. **Figure 17** shows a seismic line across Release Area S09-4 illustrating a series of fault-dependent plays in the Hammerhead Supersequence delta, including the Springboard Prospect (King and Mee, 2004). Potential reservoirs are provided by shallow water sandy facies sealed by interbedded transgressive shales. Cross-fault seal could be provided by finer grained, outer shelf facies. Hydrocarbon charge to these traps is likely to originate from the Turonian-Cenomanian marine shales of the Tiger Supersequence and/or Cenomanian coaly shales and coals from the White Pointer Supersequence. Contributions from the Albian to Cenomanian marine shales of the Blue Whale Supersequence are also possible. Combination stratigraphic/structural plays within the basal Hammerhead Supersequence include distal fan and turbidite plays with seals provided by prodelta shales (**Figure 17**). Evidence for hydrocarbon charge in this area is provided by a number of seismic amplitude anomalies (**Figure 17** and **Figure 18**), some of which display AVO responses (King and Mee, 2004; Tapley et al, 2005).

Critical Risks

One of the key risks identified prior to the most recent exploration phase was the possible lack of an effective source rock and thus adequate hydrocarbon charge. This risk has been significantly reduced by the sampling and identification of a high quality marine source rock of Cenomanian to Turonian age (Totterdell et al, 2008) and the identification of a number of encouraging bright amplitude anomalies (King and Mee, 2004; Tapley et al, 2005). Burial depth and thermal maturity calibrated by data from the Potoroo 1 and Gnarlyknots 1A wells suggest that this potential source rock is thermally mature for oil and gas generation across much of the basin depocentre.

Another risk is the presence of an effective seal, as evidenced by the high net to gross ratio encountered in Gnarlyknots 1A. However, seismic facies mapping suggests that prodelta shales are likely to exist at various levels within the Cenomanian-Turonian section. The majority of plays are structural and, as such, are dependent on cross fault seal. In the outboard basin this is probably less of a risk, because of the very likely presence of thick basinal shales in the Tiger Supersequence, and outer shelf to slope fine-grained sediments within the lower part of the Hammerhead Supersequence (Krassay and Totterdell, 2003; King and Mee, 2004). These could provide excellent cross fault seals for hydrocarbons in intra-Tiger Supersequence reservoirs and basal Hammerhead Supersequence turbidite reservoirs. Tapley et al (2005) suggested that net to gross ratios are probably lower in the middle to lower Tiger Supersequence (i.e. below TD of the Gnarlyknots 1A well) and cross fault seals are likely to be present.

Figures

Figure 1:	Location of Release Areas S09-1 to S09-6, Bight Basin.
Figure 2:	Structural elements of the eastern Bight Basin showing 2009 Release Areas and wells. Locations of seismic lines used in Figures are shown.
Figure 3:	Bight Basin stratigraphic correlation chart showing basin phases and predicted source rock intervals (modified from Blevin et al, 2000 and Totterdell et al, 2000). The sea-level curve (Haq et al, 1988) is modified to the time scale of Gradstein et al (2004).
Figure 4:	Seismic line (DWGAB-10) across the Ceduna Sub-basin. Supersequences are labelled. Refer to Figure 2 for location of seismic line.
Figure 5:	Portion of seismic line (DWGAB-04) across the Ceduna Sub-basin. Supersequences are labelled. Refer to Figure 2 for location of seismic line.
Figure 6:	Composite seismic line (GA199-05 - DWGAB-06 - HRGAB-119) across the Ceduna Sub-basin. Supersequences are labelled. Refer to Figure 2 for location of composite seismic line.
Figure 7:	Map of the 2009 Release Areas showing seismic lines, and play areas and leads mapped at a Santonian horizon by Woodside Energy Ltd (after Tapley et al, 2005).

Figure 8:	Source rock character (TOC vs HI) based on samples from the Bight Basin and Polda Basin (Sea Lion Supersequence only). Data with TOC values less than 0.5% are not included.
Figure 9:	Tmax vs HI based on samples from the Bight Basin and Polda Basin (Sea Lion Supersequence only).
Figure 10:	Modelled present-day maturity zones (% Ro) for two 2D maturity profiles through Potoroo 1 and Gnarlyknots 1A. Supersequences are labelled. Refer to Figure 2 for location of profiles (after Totterdell et al, 2008).
Figure 11:	Location of dredge sample (25DR17) along canyon edge in the northeastern Ceduna Sub-basin and example of recovered Cenomanian-Turonian organic-rich rock (after Totterdell et al, 2008). Refer to Figure 2 for location of dredge sample.
Figure 12:	Present-day maturity map for Cenomanian-Turonian marine shale at the base of the Tiger Supersequence.
Figure 13:	Petroleum systems diagram for the Ceduna Sub-basin.
Figure 14:	Modelled present-day transformation ratios (%) of three Cretaceous potential source rock units along two profiles through Potoroo 1 and Gnarlyknots 1A. Supersequences are labelled. Refer to Figure 2 for location of profiles (after Totterdell et al, 2008).

Figure 15:	Seismic line (DWGAB-10) across Release Areas S09-2 and 3 (portion of seismic line shown in Figure 2 for location of seismic line) showing typical structural plays such as lowside and highside fault traps at multiple stratigraphic levels (arrowed). Key supersequence boundaries are labelled.
Figure 16:	Seismic lines from Release Area S09-1 showing multiple structural plays at mid-Tiger Supersequence level (Santonian) on a) a SW-NE oriented dip line, and b) a NW-SE oriented strike line (refer to Figure 2 for location of seismic lines). The dotted line represents the intersection of the two lines. The strike line also shows a possible onlap play within a basal Hammerhead Supersequence channel. Key supersequence boundaries are labelled.
Figure 17:	Portion of a seismic line in Release Area S09-4 showing the Springboard Prospect (King and Mee, 2004) and other fault-dependent plays in the Hammerhead and Tiger supersequences, including combination structural/stratigraphic plays at the base of the Hammerhead Supersequence. Key supersequence boundaries are labelled (refer to Figure 2 for location of seismic line).
Figure 18:	Seismic line from Release Area S09-5 showing example of bright amplitudes (Trapline prospect; King and Mee, 2004) within Campanian sandstones of the mid-Hammerhead Supersequence (refer to Figure 2 for location of seismic line).

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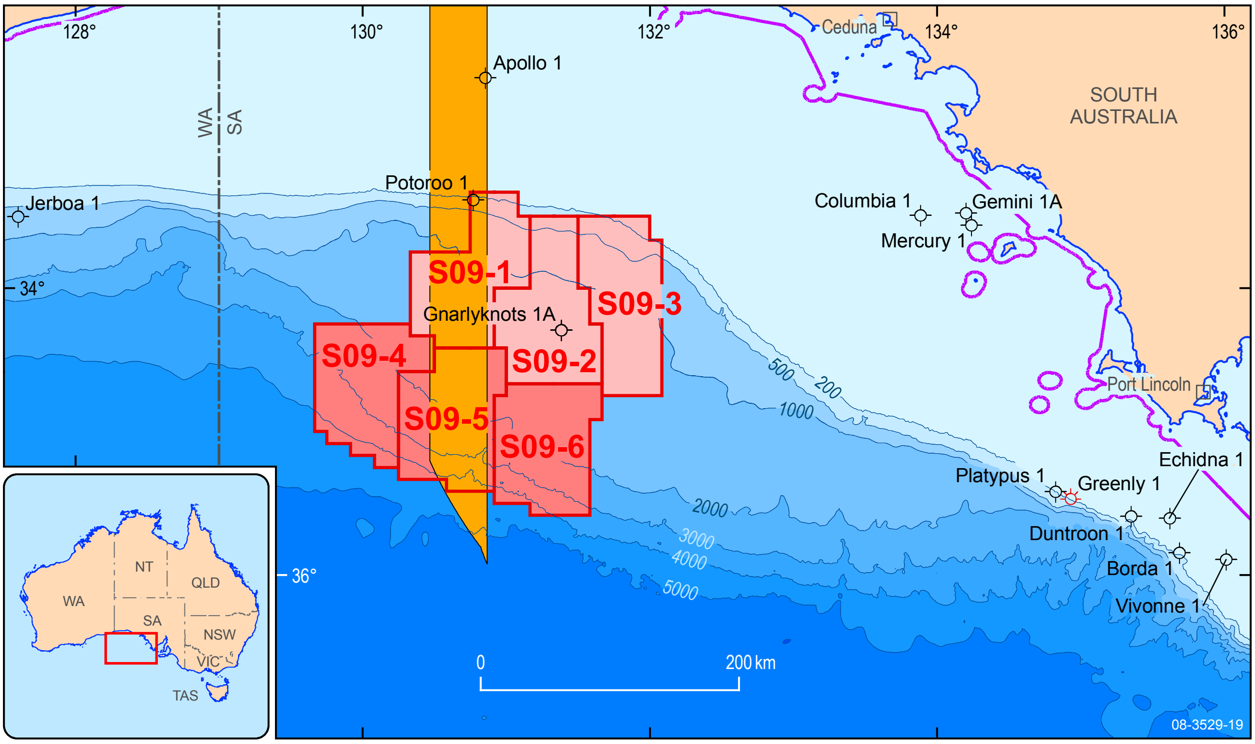


Where well symbol information is sourced from publicly available "open file" data, it has been provided by Geoscience Australia from Well Completion Reports. These symbols were generated from open file data as at 31 March 2009. Where well symbol information is not publicly available from titleholders' data, the information has been extracted from other public sources.

2009 Designated Frontier Area
2009 Offshore Petroleum Acreage Release Area
Great Australian Bight Marine Park
Scheduled area boundary (OPGGSA 2006)
Limit of Coastal Waters
200 *Bathymetry contour (depth in metres)*
Petroleum exploration well - Dry hole
Petroleum exploration well - Gas show

Figure 1. Location of the Release Areas S09-1 to S09-6, Bight Basin.

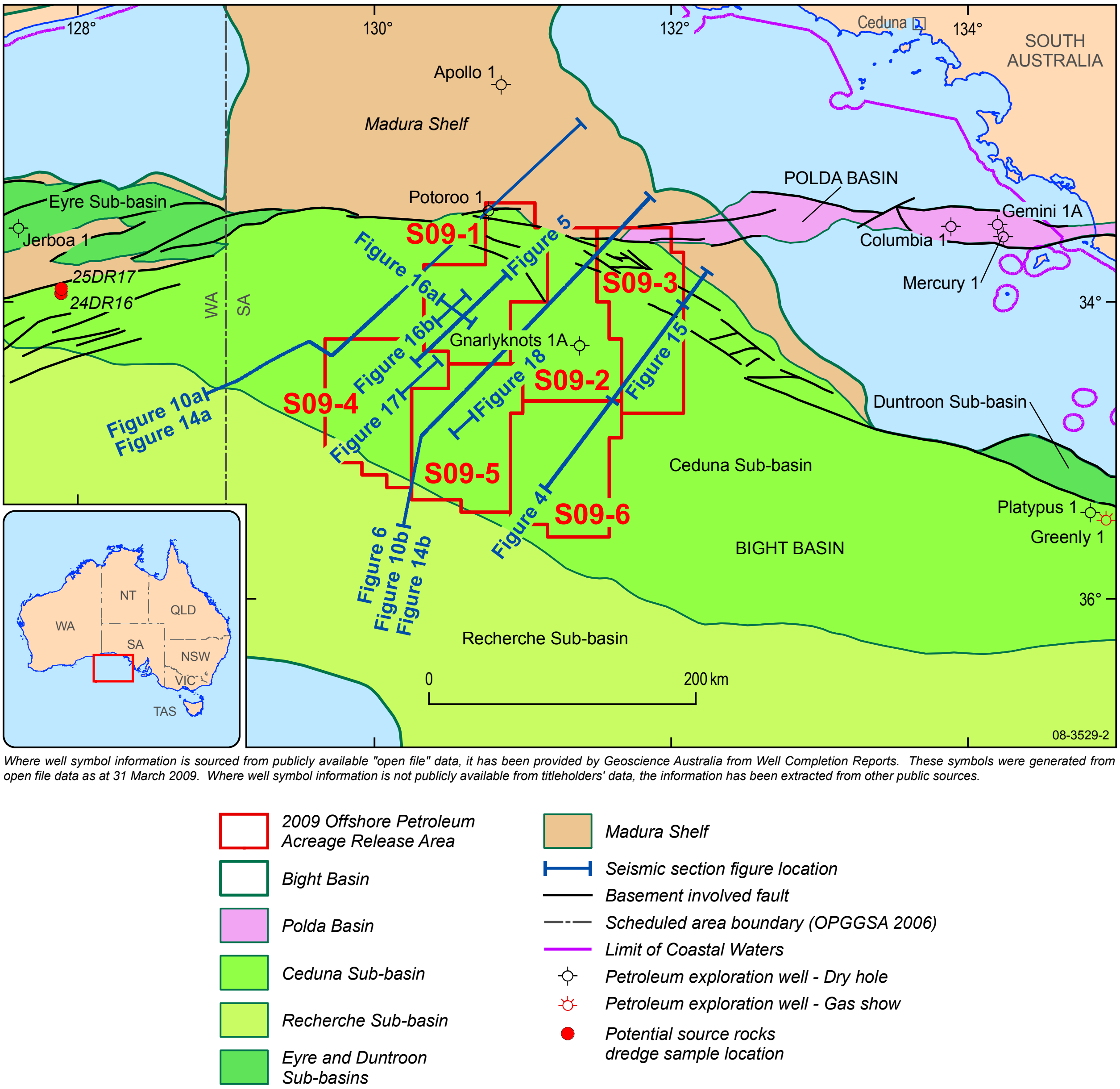


Figure 2. Structural elements of the eastern Bight Basin showing 2009 Release Areas and wells. Locations of seismic lines used in figures are shown.

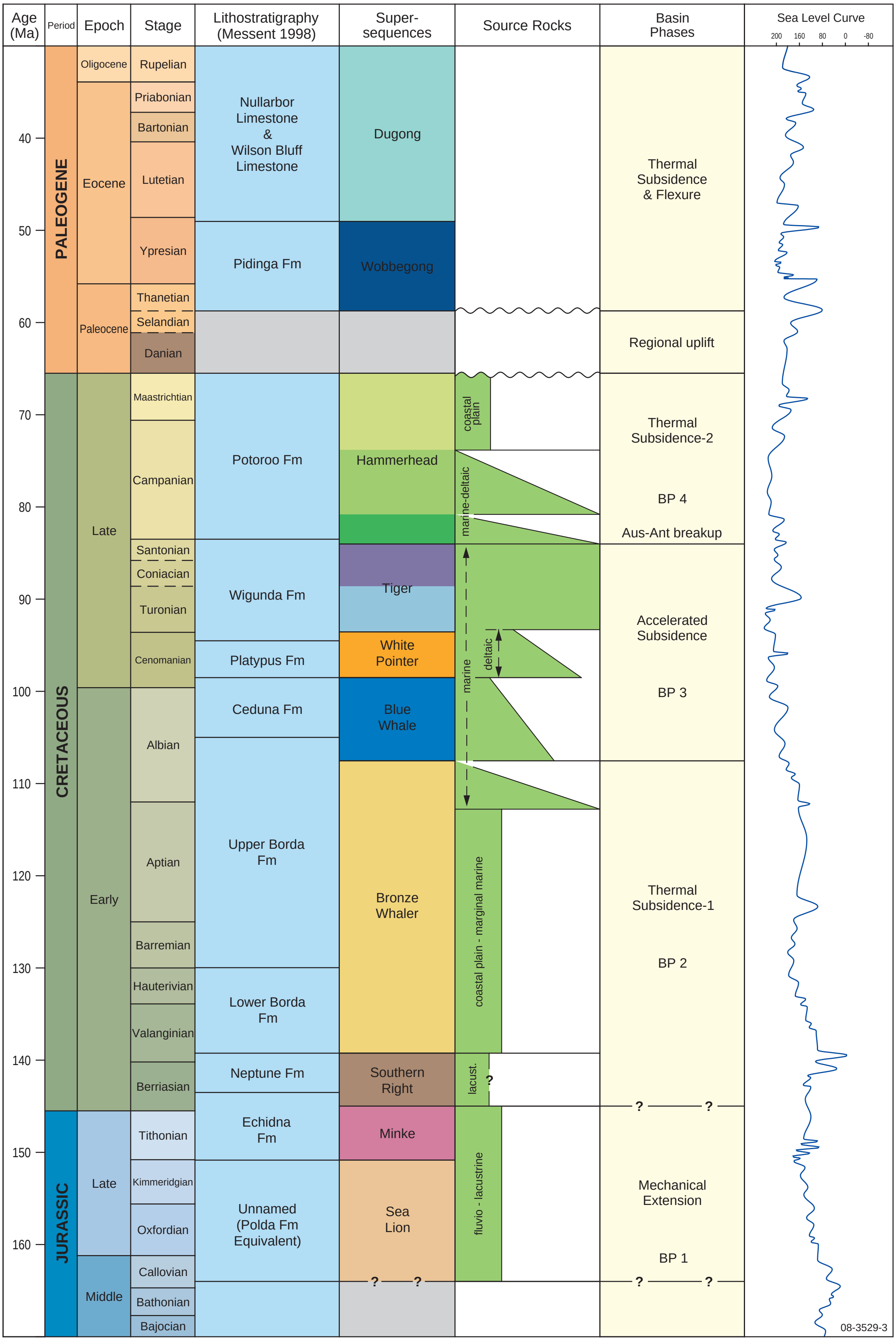


Figure 3. Bight Basin stratigraphic correlation chart showing basin phases and predicted source rock intervals (modified from Blevin et al, 2000 and Totterdell et al, 2000). The sea-level curve (Haq et al, 1988) is modified to the time scale of Gradstein et al (2004).

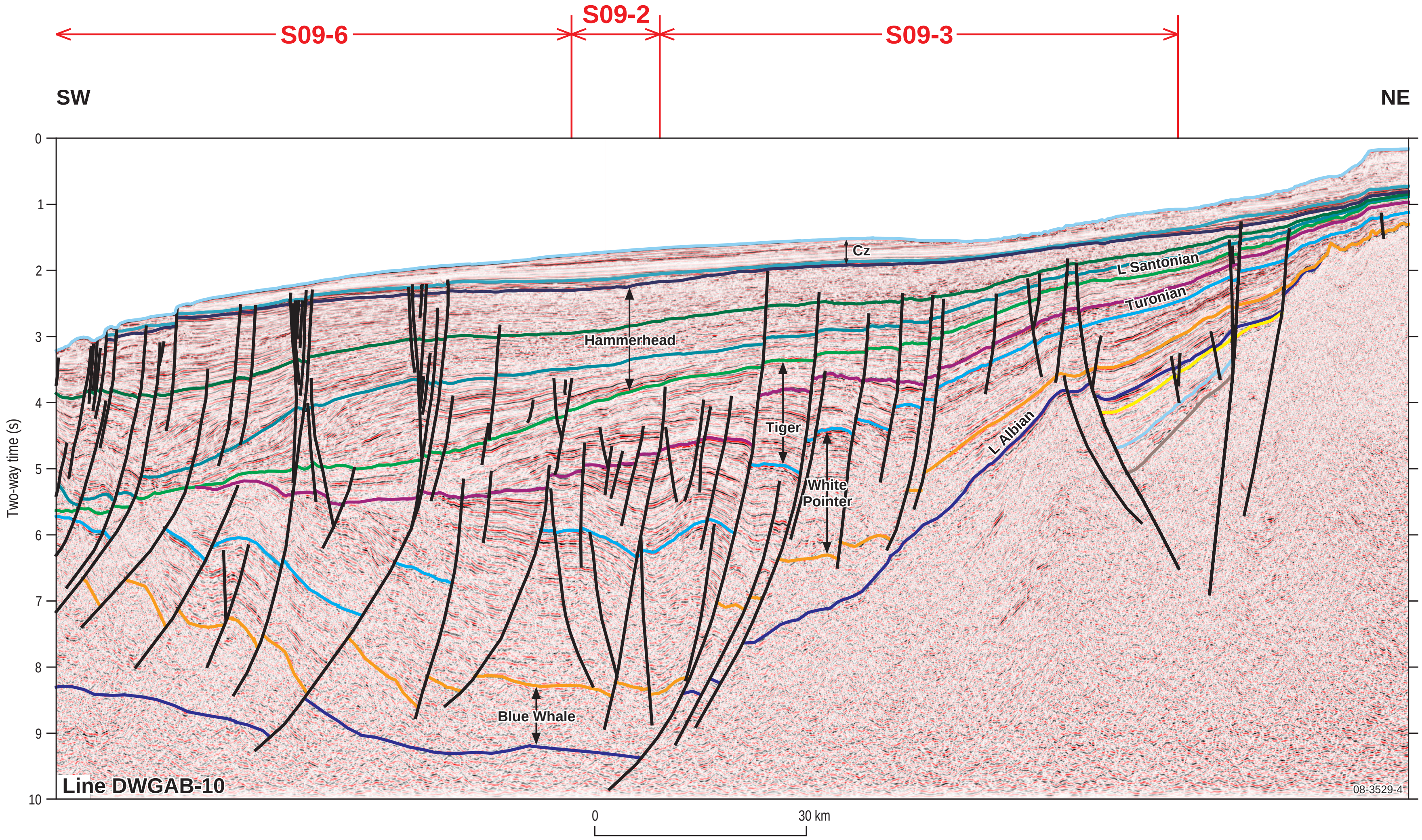


Figure 4. Seismic line (DWGAB-10) across the Ceduna Sub-basin. Supersequences are labelled. Refer to Figure 2 for location of seismic line.

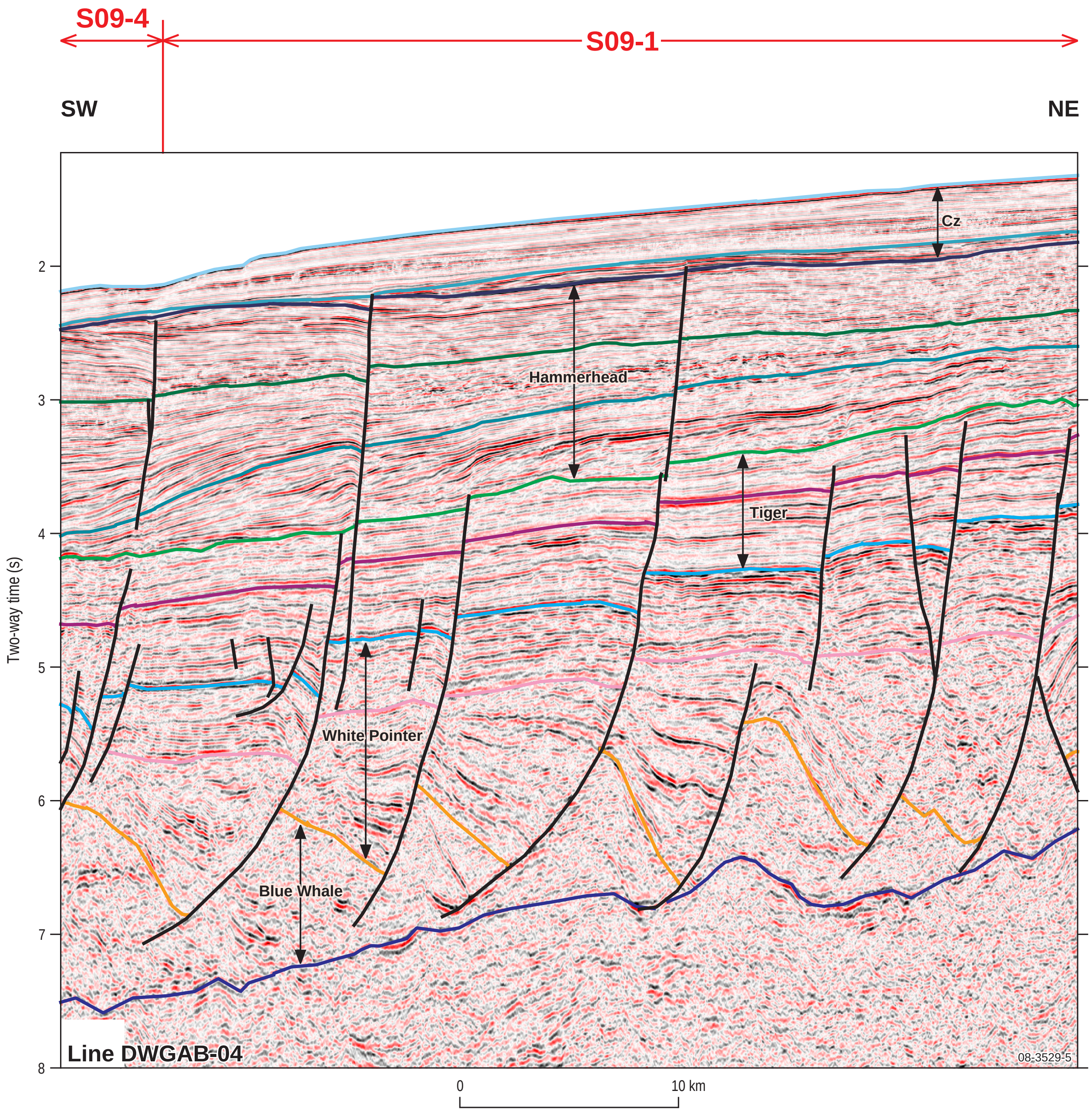


Figure 5. Portion of seismic line (DWGAB-04) across the Ceduna Sub-basin. Supersequences are labelled. Refer to Figure 2 for location of seismic line.

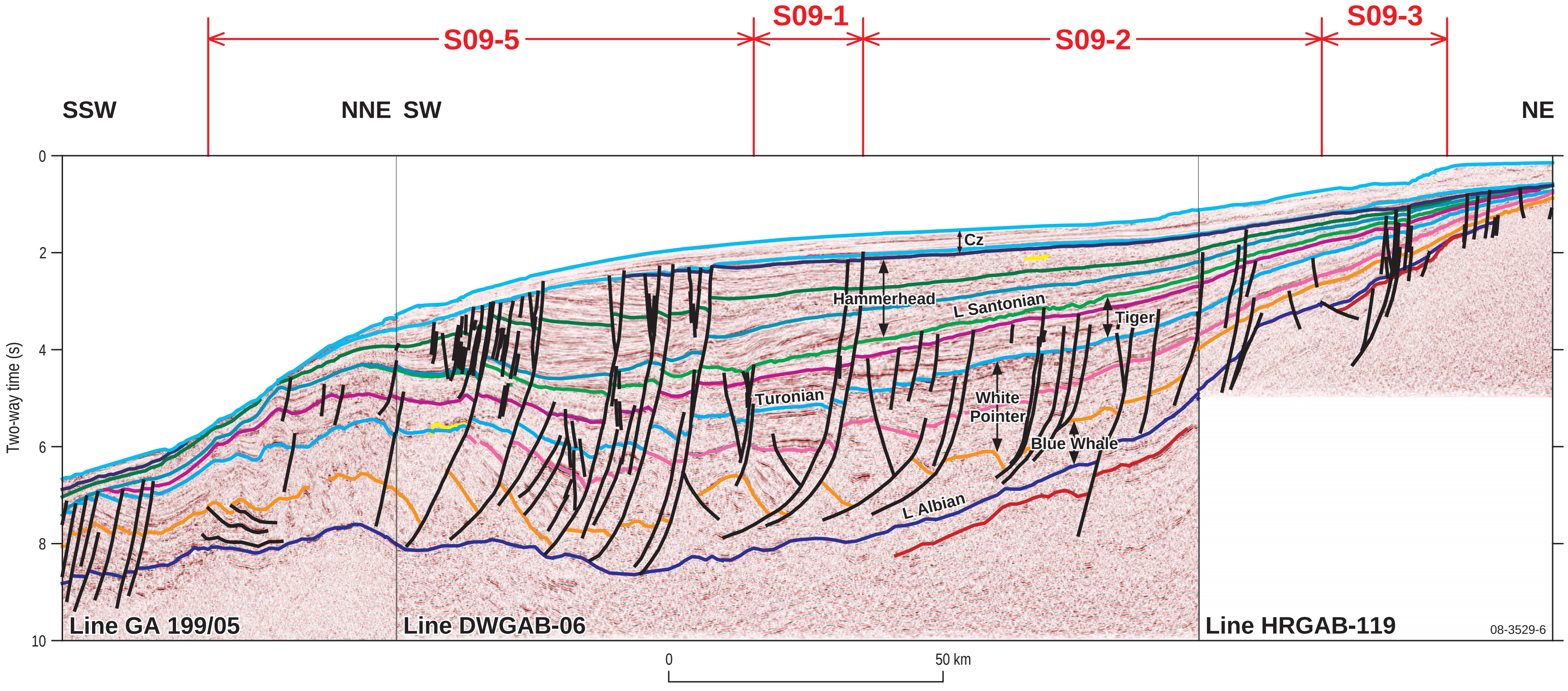


Figure 6. Composite seismic line (GA199-05 - DWGAB-06 - HRGAB-119) across the Ceduna Sub-basin. Supersequences are labelled. Refer to Figure 2 for location of composite seismic line.

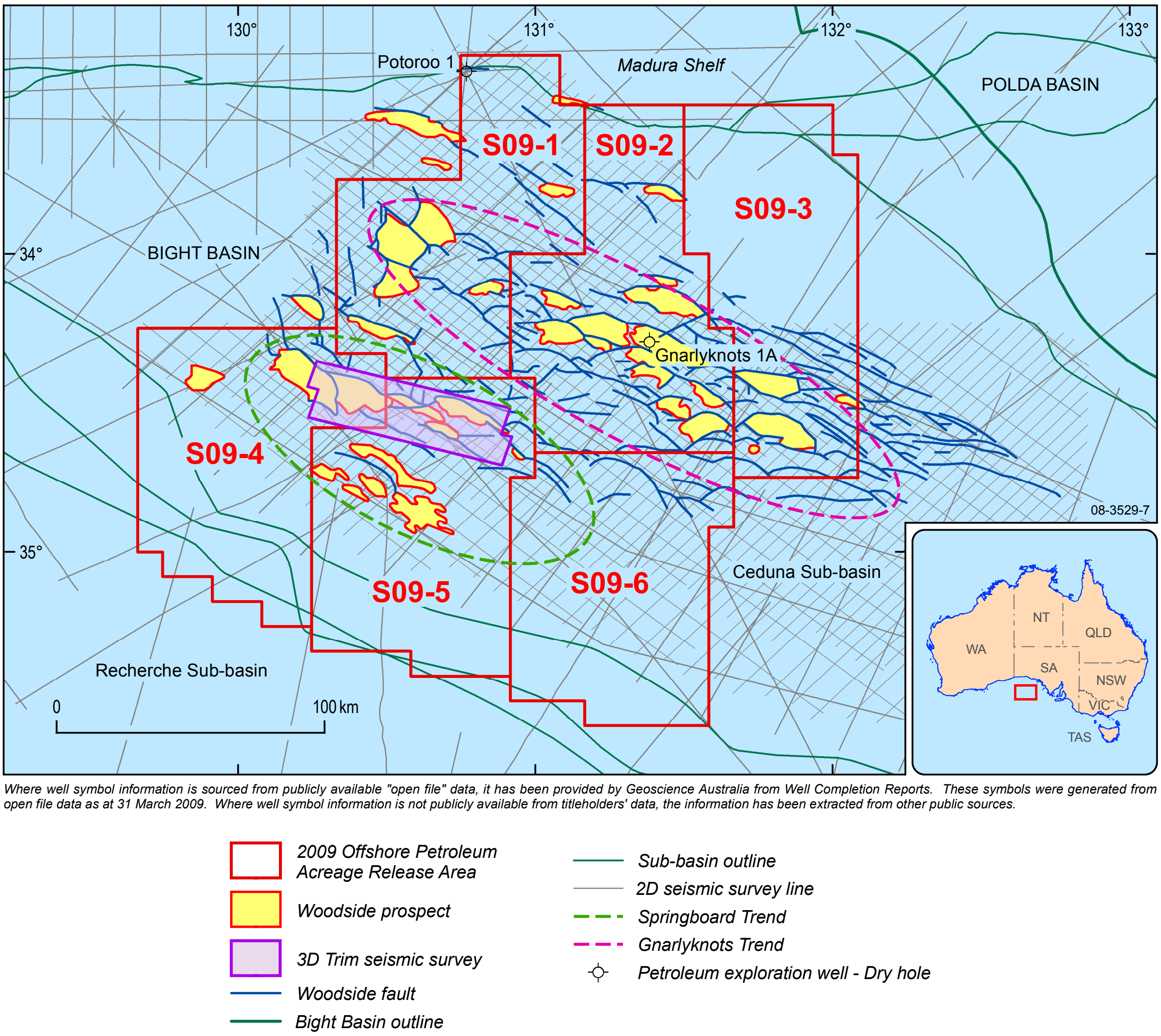


Figure 7. Map of the 2009 Release Areas showing seismic lines, and play areas and leads mapped at a Santonian horizon by Woodside Energy Ltd (after Tapley et al, 2005).

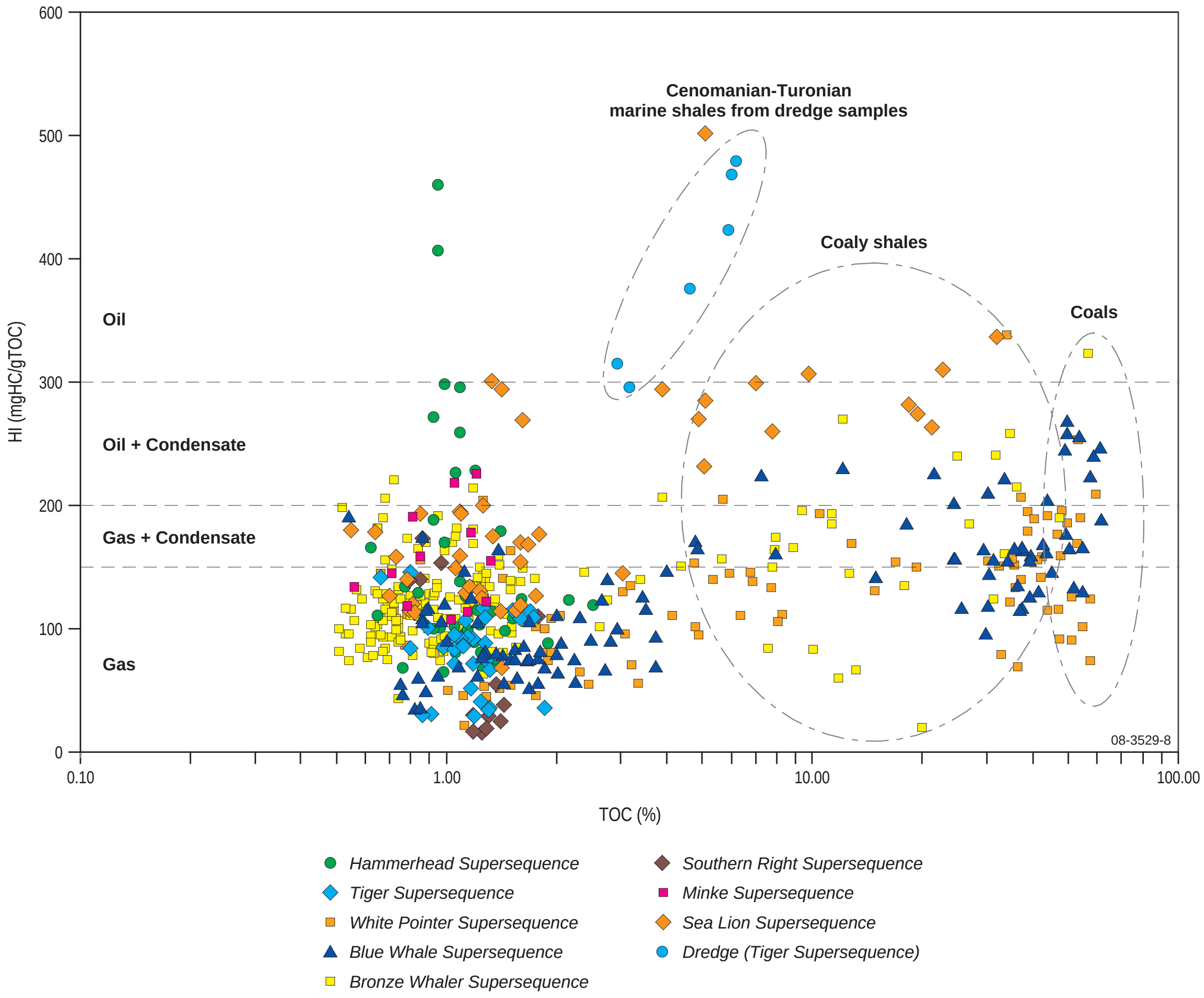


Figure 8. Source rock character (TOC vs HI) based on samples from the Bight Basin and Polda Basin (Sea Lion Supersequence only). Data with TOC values less than 0.5% are not included.

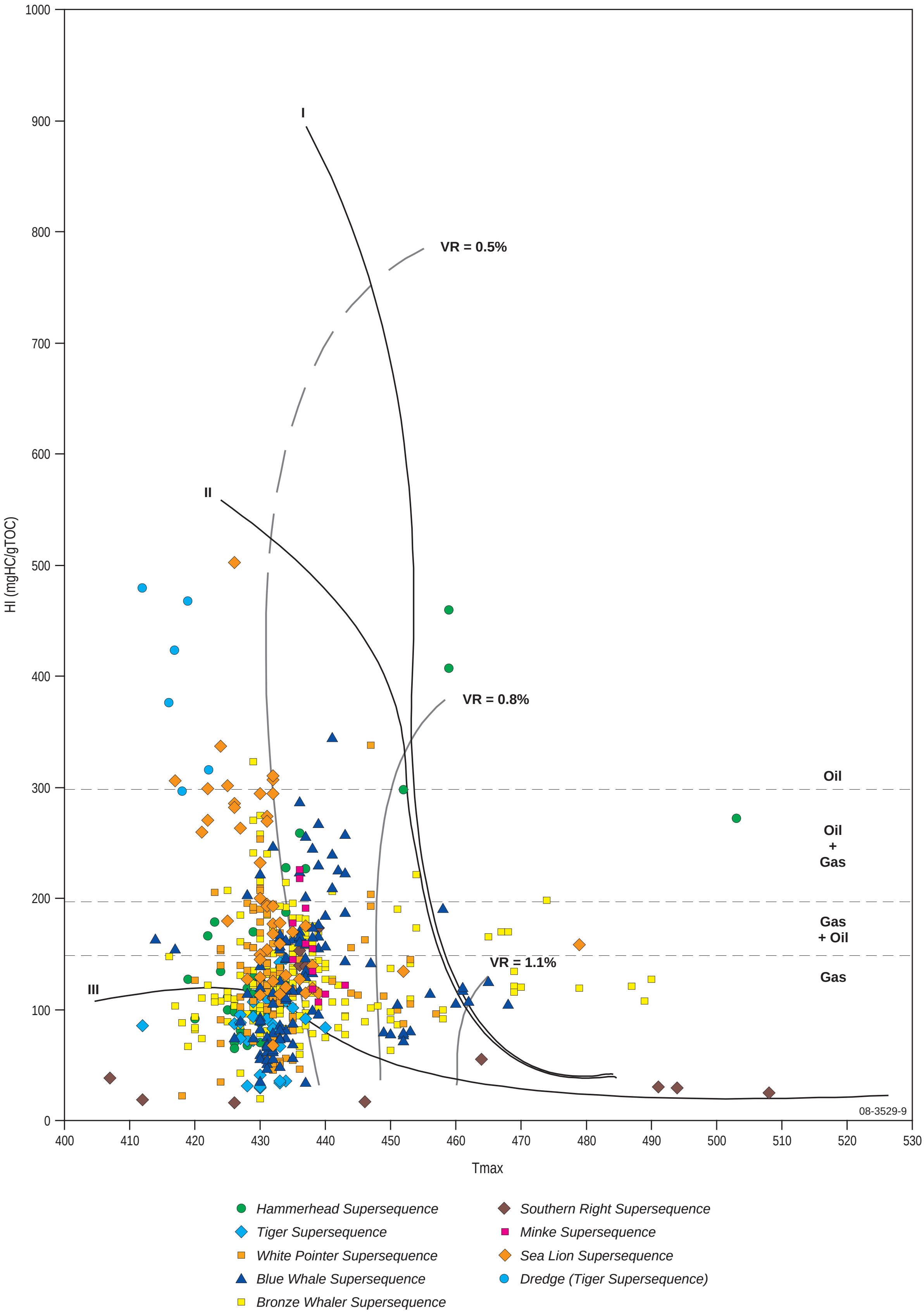


Figure 9. Tmax vs HI based on samples from the Bight Basin and Polda Basin (Sea Lion Supersequence only).

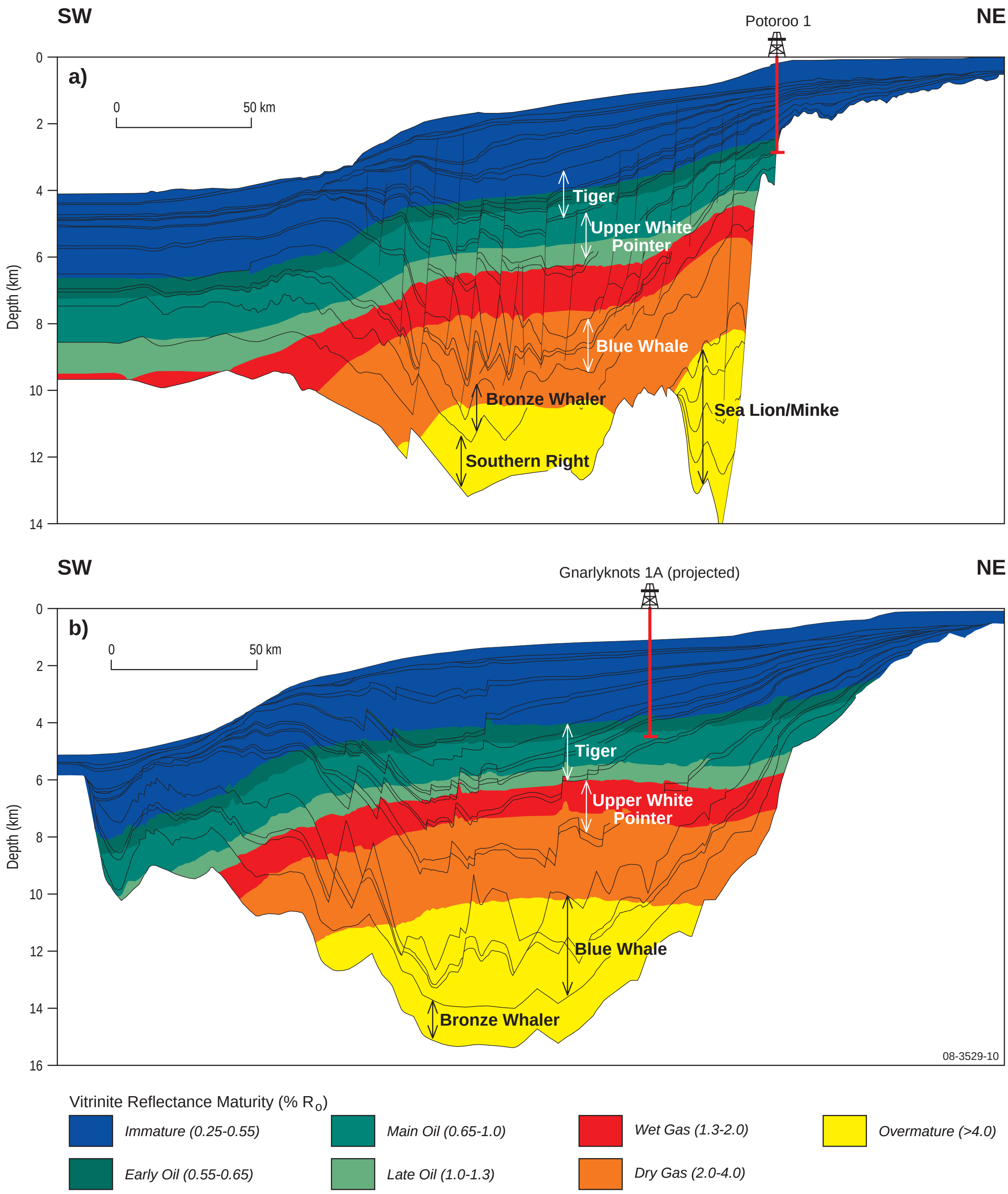


Figure 10. Modelled present-day maturity zones (% R_o) for two 2D maturity profiles through Potoroo 1 and Gnarlyknots 1A. Supersequences are labelled. Refer to Figure 2 for location of profiles (after Totterdell et al, 2008).

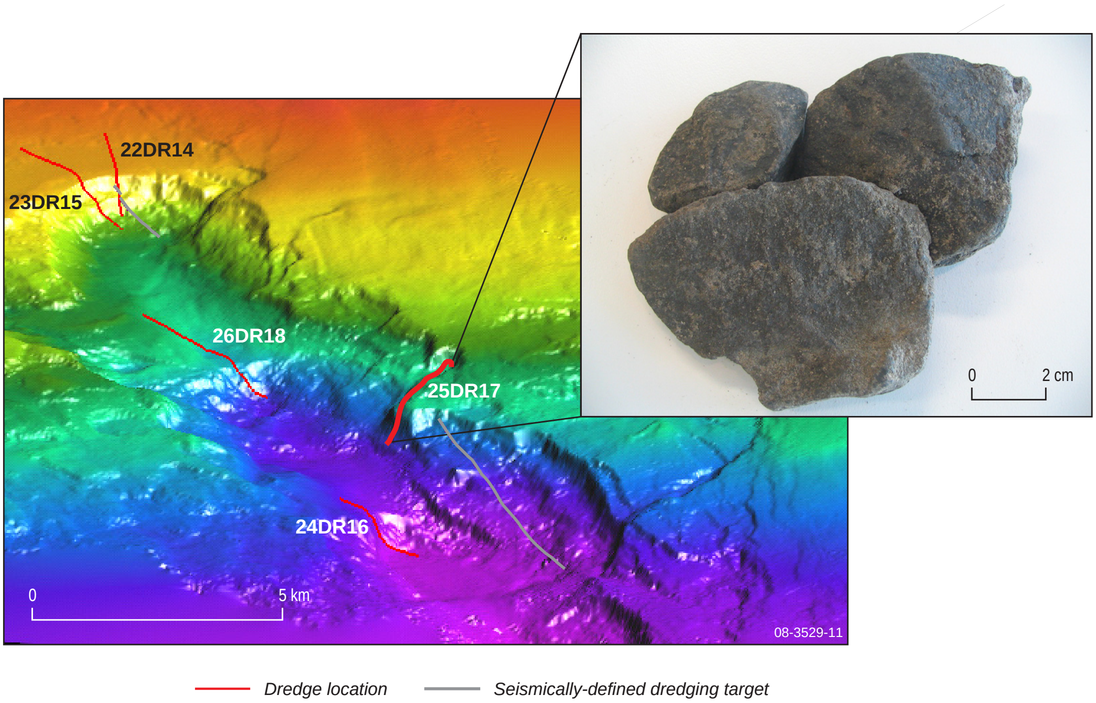
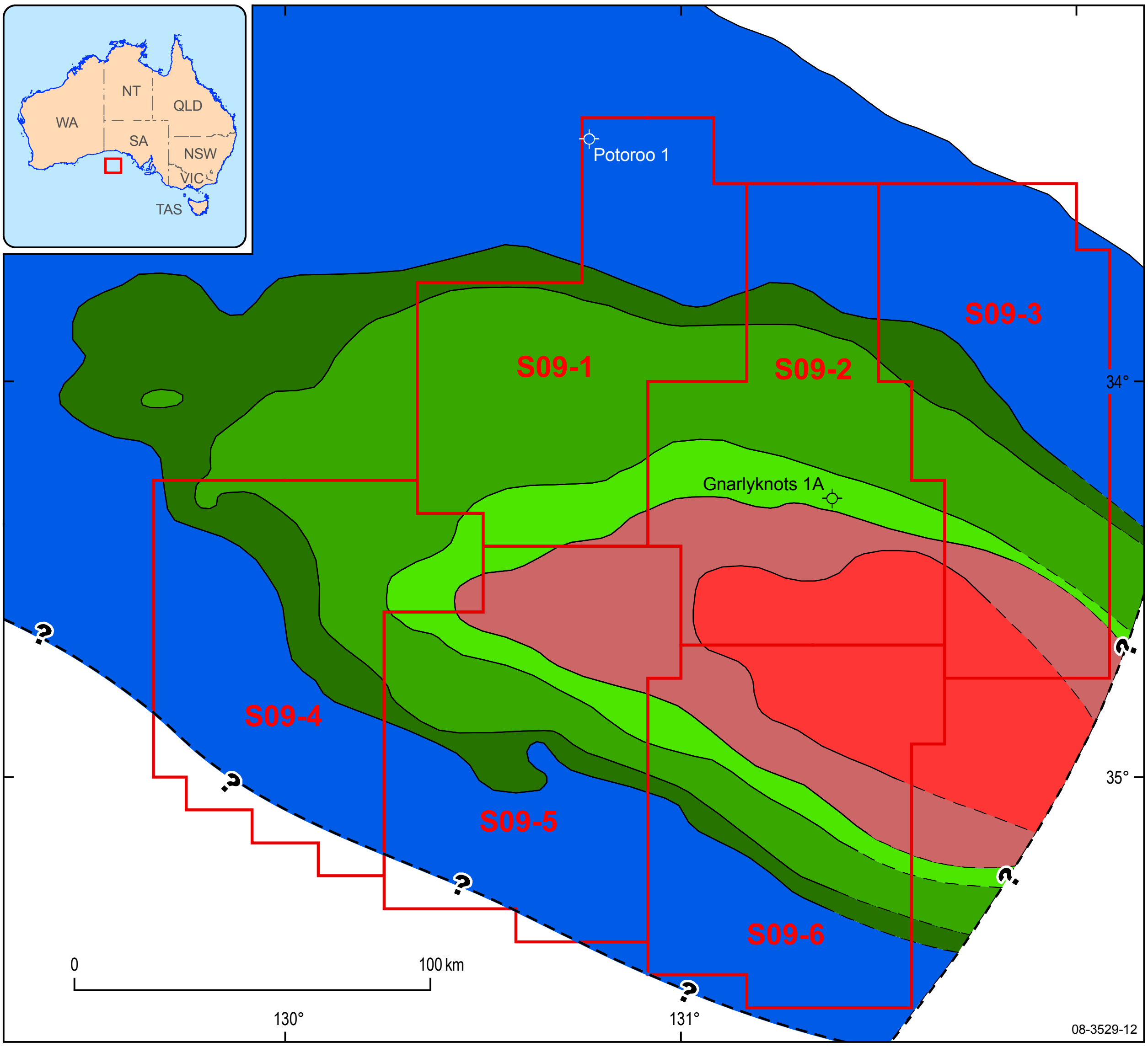


Figure 11. Location of dredge sample (25DR17) along canyon edge in the northwestern Ceduna Sub-basin and example of recovered Cenomanian-Turonian organic-rich rock (after Totterdell et al, 2008). Refer to Figure 2 for location of dredge sample.



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2009 Offshore Petroleum Acreage Release Area
Immature
Early Oil
Main Oil
Late Oil
Wet Gas
Dry Gas
Petroleum exploration well - Dry hole

Figure 12. Present-day maturity map for Cenomanian-Turonian marine shale at the base of the Tiger Supersequence.

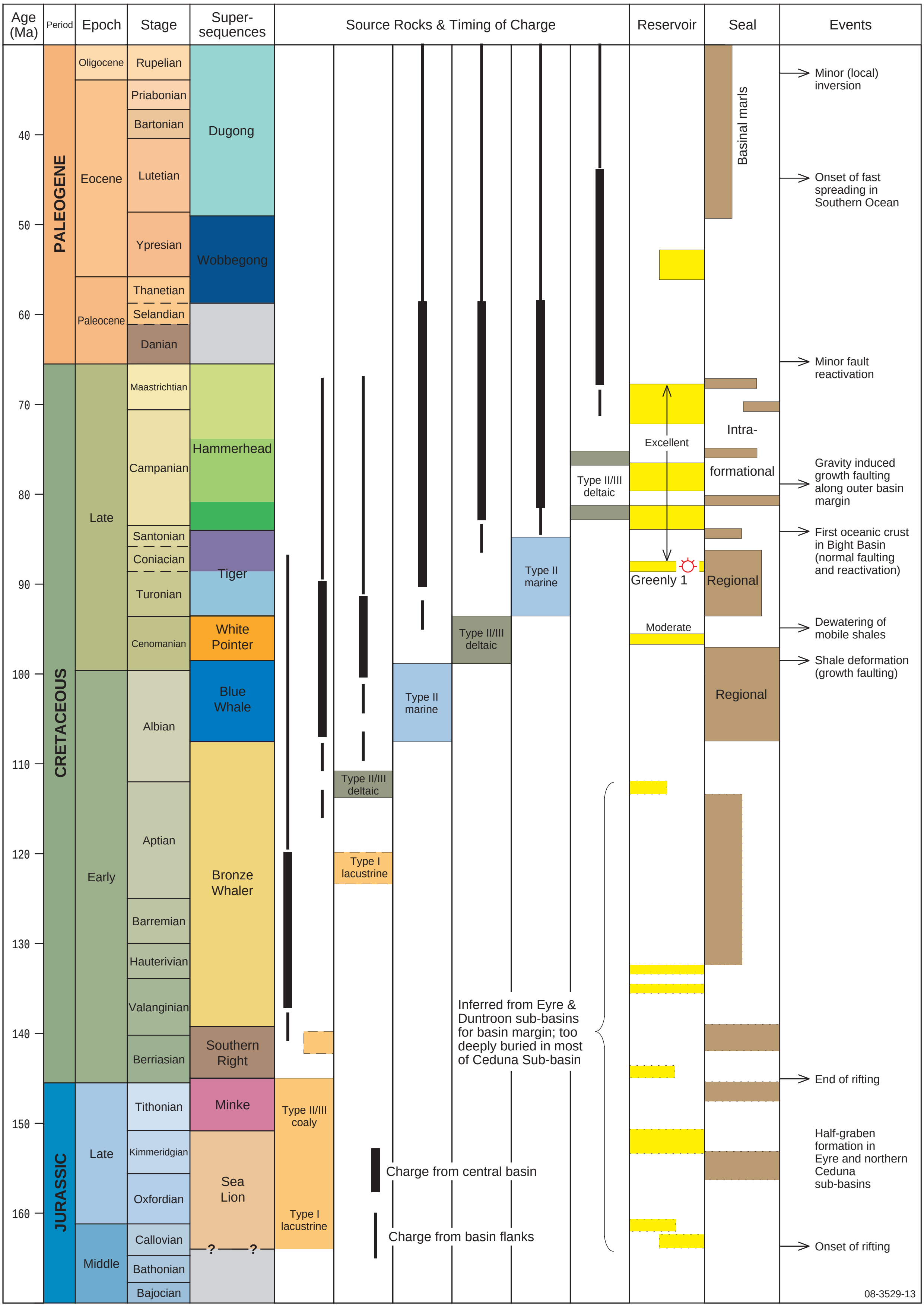

Figure 13. Petroleum systems diagram for the Ceduna Sub-basin.

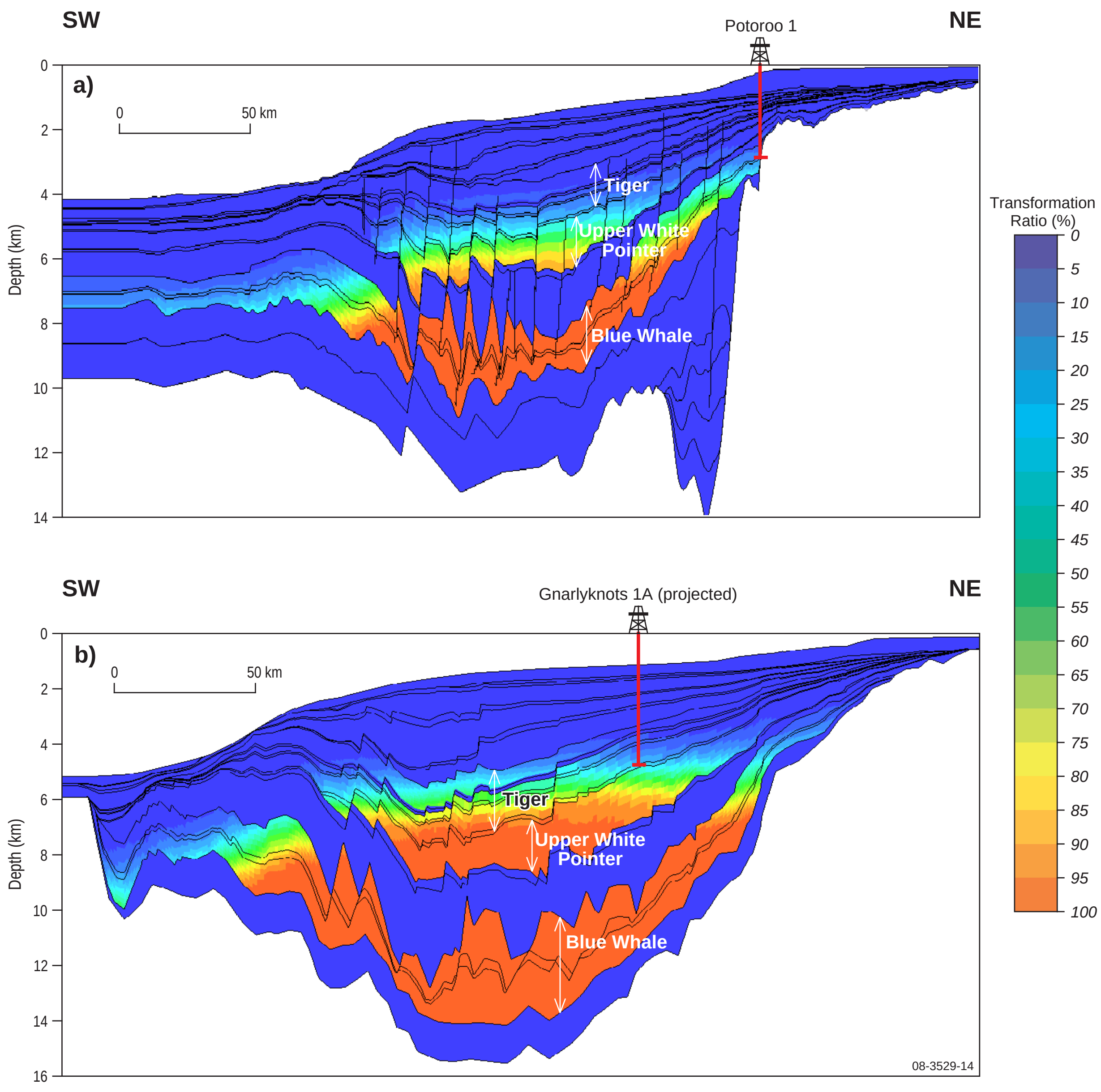

Figure 14. Modelled present-day transformation ratios (%) of three Cretaceous potential source rock units along two profiles through Potoroo 1 and Gnarlyknots 1A. Supersequences are labelled. Refer to Figure 2 for location of profiles (after Totterdell et al, 2008).

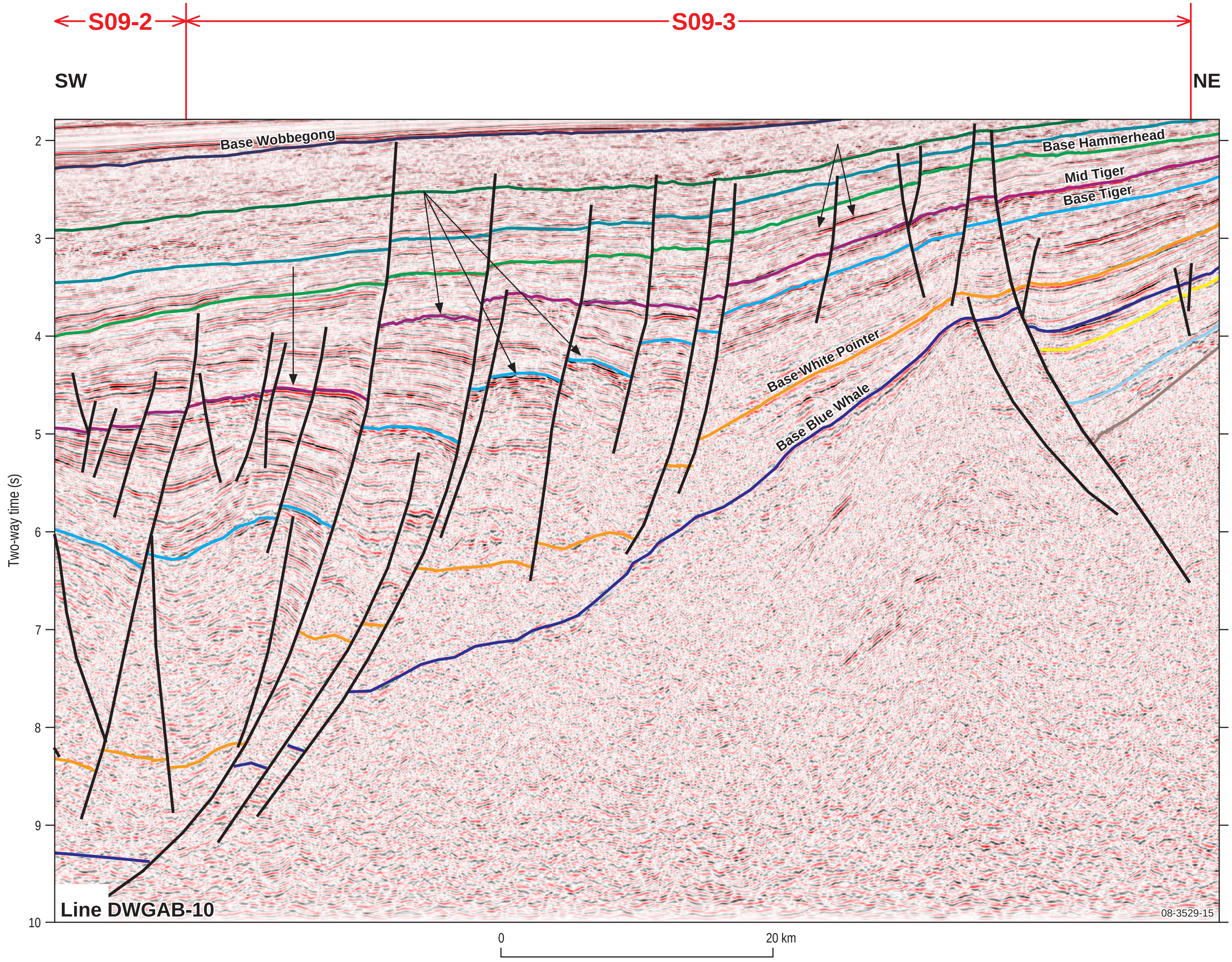

Figure 15. Seismic line (DWGAB-10) across Release Areas S09-2 and 3 (portion of seismic line shown in Figure 4; refer to Figure 2 for location of seismic line) showing typical structural plays such as lowside and highside fault traps at multiple stratigraphic levels (arrowed). Key supersequence boundaries are labelled.

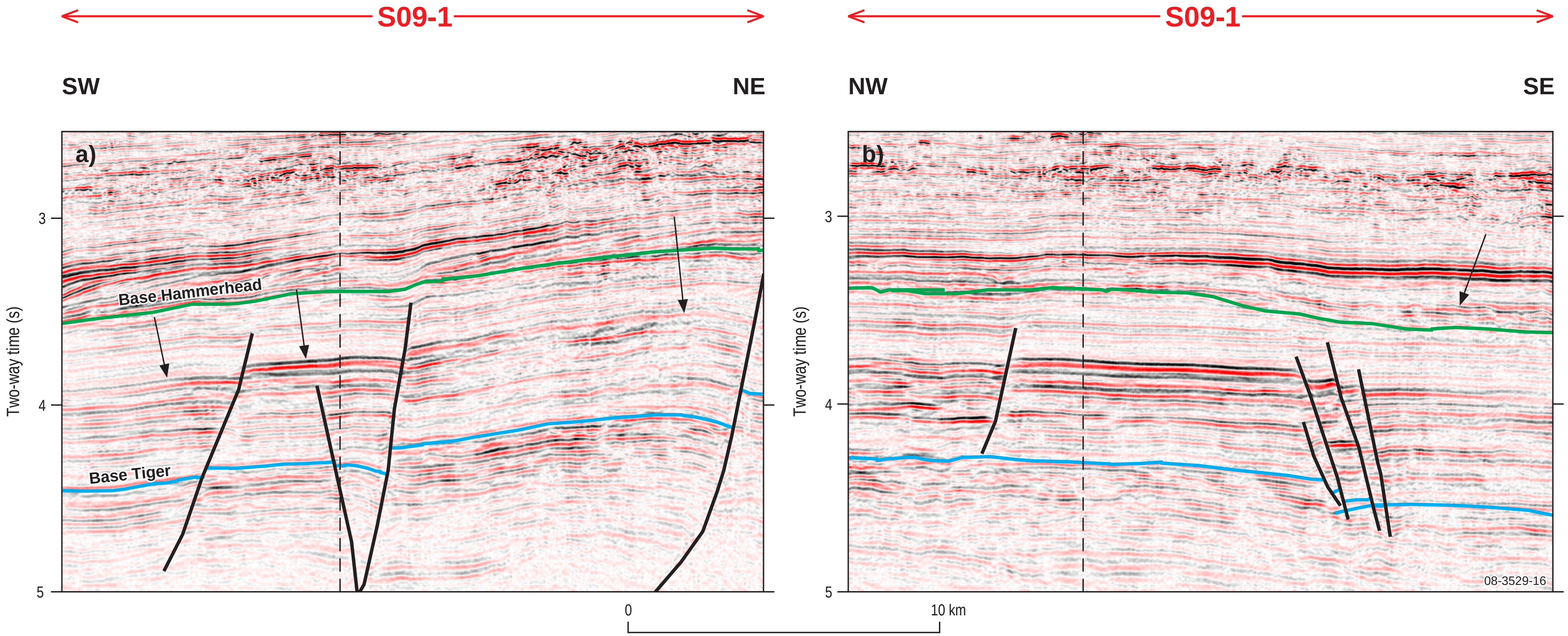

Figure 16. Seismic lines from Release Area S09-1 showing multiple structural plays at mid-Tiger Supersequence level (Santonian) on a) a SW-NE oriented dip line, and b) a NW-SE oriented strike line (refer to Figure 2 for location of seismic lines). The dottedline represents the intersection of the two lines. The strike line also shows a possible onlap play within a basal Hammerhead Supersequence channel. Key supersequence boundaries are labelled.

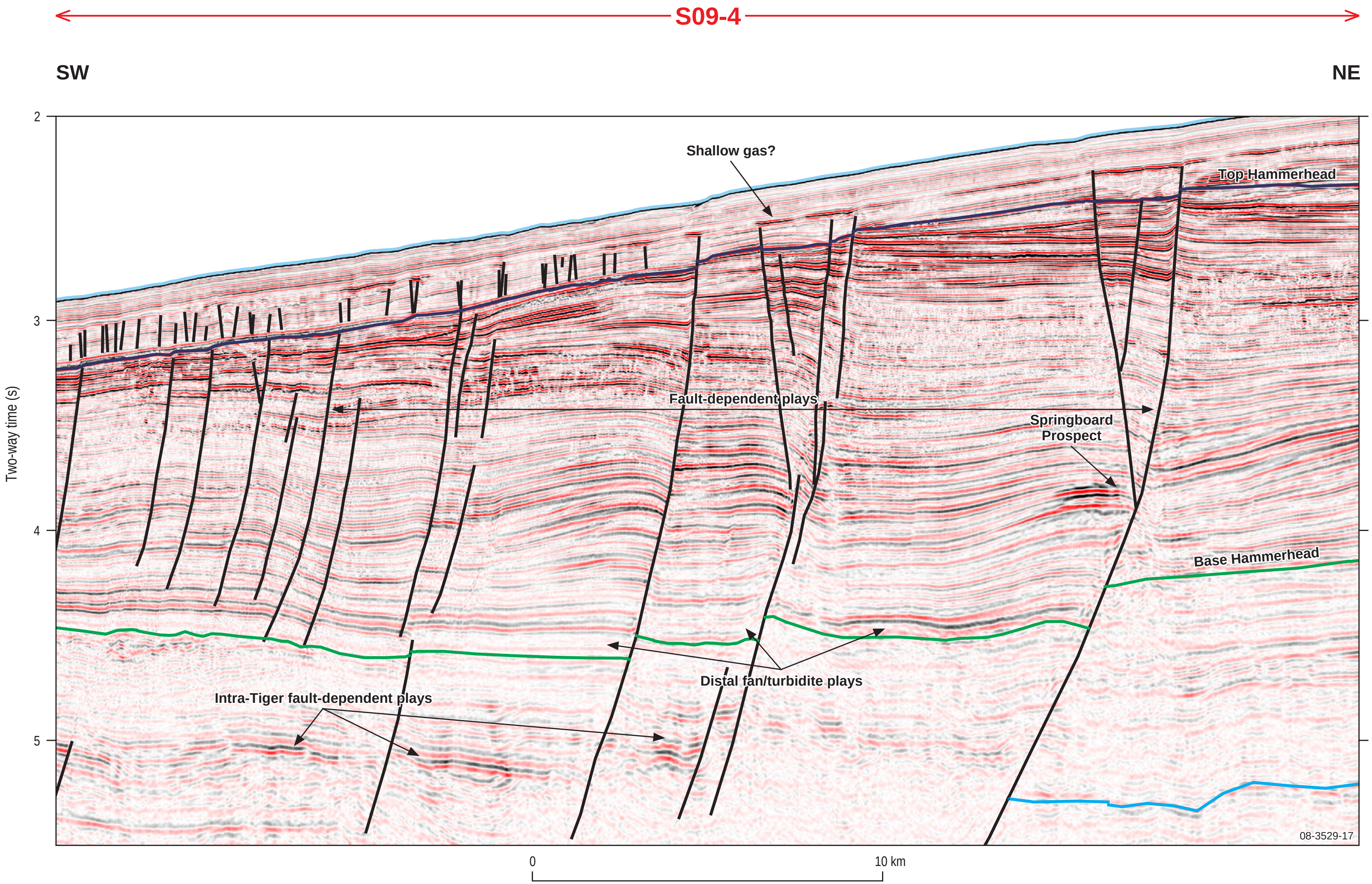

Figure 17. Portion of a seismic line in Release Area S09-4 showing the Springboard Prospect (King and Mee, 2004) and other fault-dependent plays in the Hammerhead and Tiger supersequences, including combination structural/stratigraphic plays at the base of the Hammerhead Supersequence. Key supersequence boundaries are labelled (refer to Figure 2 for location of seismic line).

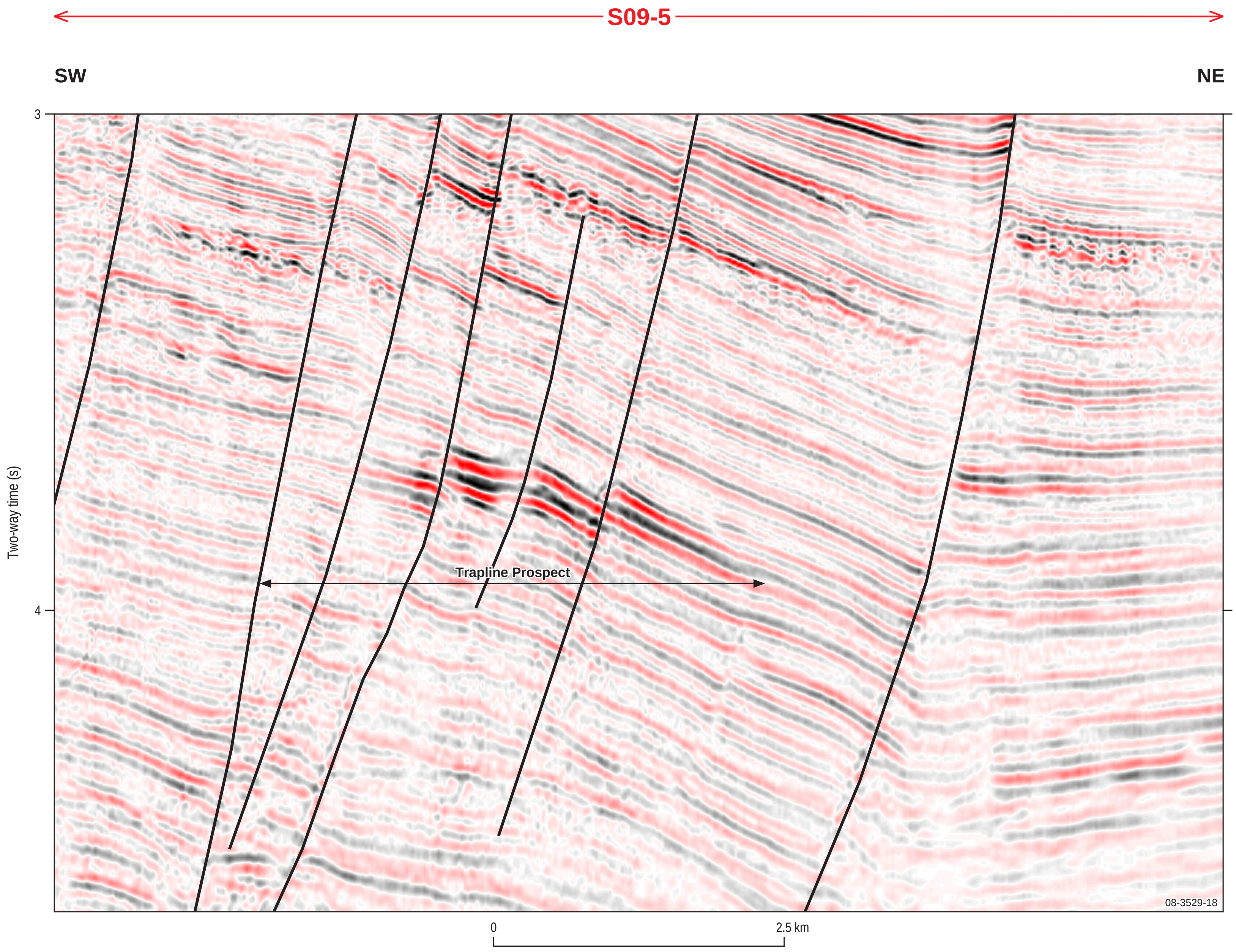

Figure 18. Seismic line from Release area S09-5 showing example of bright amplitudes (Trapline prospect; King and Mee, 2004) within Campanian sandstones of the mid-Hammerhead Supersequence. Refer to Figure 2 for location of seismic line.