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The structural-stratigraphic framework and petroleum systems of the Sandakan Basin, offshore East Sabah, Malaysia

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Abstract: Decades of exploration activities in the Sandakan Basin offshore eastern Sabah, Malaysia, since the 1970s have yet to yield commercial hydrocarbon discoveries. Of the nineteen wells that have been drilled in the basin up to 2015, only five are classified as discoveries, all made between 1970 and 1995. There are essentially two main proven play types: (1) Early to Middle Miocene "Segama play", in which the reservoir targets are the Tanjong Formation equivalents within the Segama Group, which were deposited as part of the synrift sequence. (2) Middle to Late Miocene "Sebahat play" in which the reservoirs belong to the Sebahat Formation, characterised by prograding deltaic shoreface and shelf sequences, advancing eastwards and southwards from an uplifting hinterland in central and northern Sabah. The best reservoir facies are shoreface sands, which have porosities greater than 20%, particularly at depths shallower than ~2000 m. Although the generative source rocks have not been penetrated, geochemical data indicate that they are present at depths greater than 3200 m. The source rocks are characterised by predominantly Type III and Types II/III organic matter, which are typical of deltaic settings. The data indicate that hydrocarbons were generated by source rocks with a maturity range of 0.7 – 0.8% vitrinite reflectance (Ro). The Sandakan Basin was affected by several compressional deformation events which are expressed as major erosional unconformities; most significantly, the Middle Miocene ("D2 event", 13.0 Ma) and Late Miocene ("D3 event", 8.6 Ma). The unconformities were the result of compression and faulting which, while being responsible for trap formation, may also pose significant risk to trap integrity and preservation. Modelling results indicate that hydrocarbon generation and migration took place during Late Miocene–Early Pliocene and continues today. The basin's prospectivity, therefore, critically depends on the delicate interplay between the timing of trap formation and hydrocarbon migration. Understanding these processes requires detailed understanding of the structural evolution and petroleum systems of the basin.

Keywords: Sandakan Basin, East Sabah, structure, stratigraphy, hydrocarbons, petroleum systems

INTRODUCTION

Eastern Sabah is one of the few regions in Malaysia that have yet to produce commercial hydrocarbons despite decades of exploration. Sub-commercial discoveries made during the 1970s and 1990s demonstrate the presence of a generative petroleum system in the offshore area between the Sandakan and Dent peninsulas, known as the Sandakan Basin[1] (Figure 1). These occurrences complement the numerous oil and gas seeps that are commonly associated with mud volcanoes and salt springs, reported especially from Dent Peninsula (Haile & Wong, 1965; Leong & Azlina, 1999) (Figure 2).

A review of the geology and hydrocarbon potential of this area is long overdue. The last review was conducted by Leong & Azlina (1999). There had not been any published studies on the area since 1999. A comprehensive internal study was carried out by ISIS (2005) but the results were not published. The present study draws partly from the key findings of the ISIS (2005) study and provides our interpretation of the available data. It is hoped that this review would generate interest among researchers and industry players to carry out further work to realise the exploration potential of Sandakan Basin.

GEOLOGY AND TECTONIC SETTING

Leong & Azlina (1999) considered the Sandakan Basin as a sub-basin of the NE Sabah Basin, which extends over central/eastern Sabah and the adjacent Sulu Sea margin. The basin is bounded to the northwest by the Cagayan Ridge and to the southeast by the NE-SW trending Sulu volcanic arc which stretches from Zamboanga to southern

[1] The term "Sandakan sub-basin" was used by PETRONAS to denote this part of the NE Sabah Basin (Leong & Azlina, 1999). For simplicity, we refer to it in this paper as the Sandakan Basin.

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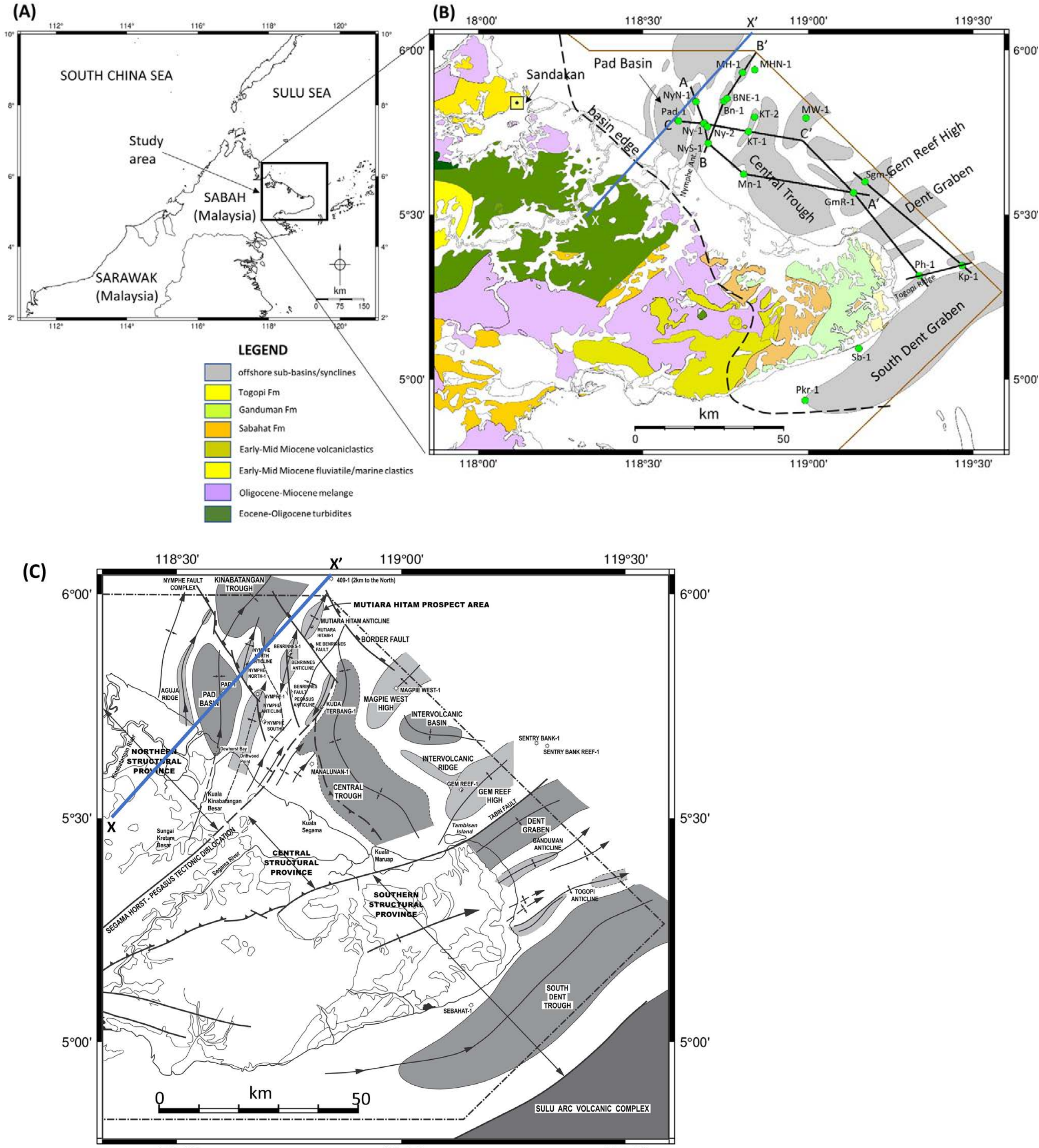

Figure 1: (A) Location map of study area in eastern Sabah. (B) Geological map of eastern Sabah and the adjacent offshore Sandakan Basin. The approximate landward edge of the basin is marked by the dash line. It includes a portion of Dent Peninsula where Middle Miocene to Pliocene strata crop out successively eastwards and extend offshore northwards beneath the coastline where they are deformed into synclinal sub-basins (grey shaded areas). Four profiles discussed in the paper are marked by XX', AA', BB', and CC'. Green dots are exploration wells. (C) Main structural elements of the Sandakan Basin, which can be subdivided into Northern, Central and Southern provinces. The most structurally complex region, and the most explored, is the Northern Province, where oil/gas have been discovered. The Central Trough is filled with a thick Late Miocene-Pliocene section. Figure modified after Weeden (1993). Blue line XX' represents profile shown in Figure 7.

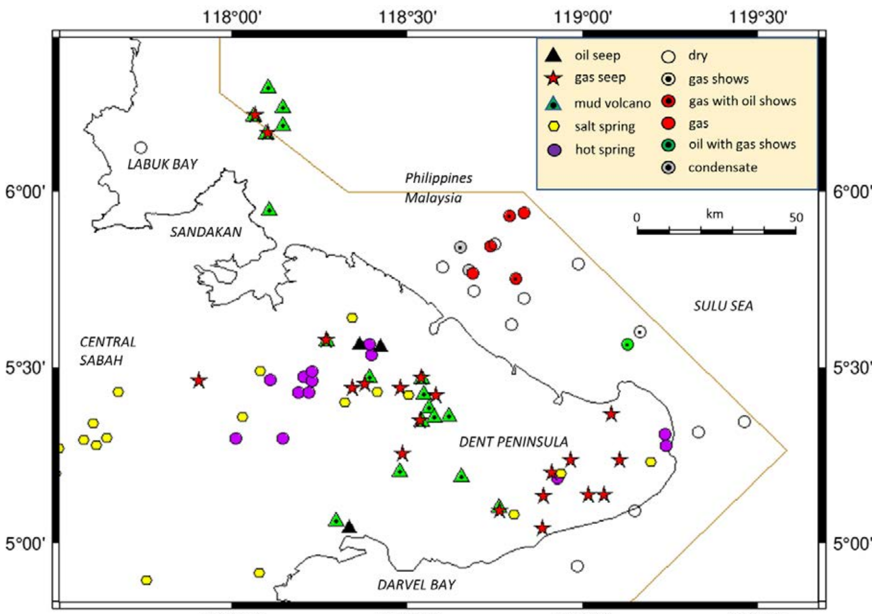

Figure 2: Hydrocarbon occurrences on Dent Peninsula and adjacent offshore areas (Sandakan Basin). Onshore occurrences of seeps, springs and mud volcanoes are from WMC (1995) and Leong (1999). Offshore occurrences are based on well results compiled for this study, including dry wells (open circles).

Sabah (Figure 3). Across the Malaysia-Philippines maritime boundary the basin extends beneath the outer shelf and abyssal plain of the southwestern Sulu Sea marginal basin (e.g., Scibiorski *et al*., 2009; Jong & Futalan, 2015). The basin is subdivided into Northern, Central and Southern structural provinces which are bounded by major NE-SW structural highs (ridges) and intervening synclines (Figure 1C). Some of these structural features, such as the Aguja Ridge, Kinabatangan Trough, Pegasus Ridge, Pad Basin, and Central Trough, are controlled by major fault zones.

An Early Miocene (~20-18 Ma) tectonic reconstruction (Figure 3) shows the central Sabah region being bounded to the north by a southward-dipping subduction zone related to the closure of the proto-South China Sea. The cessation of subduction during late Early Miocene resulted in the uplift and emergence of the Crocker accretionary prism which stretches from Central Sabah into Palawan (Liu *et al*., 2019; Zhu *et al*., 2022). This uplifted region provided the sediment supply to the two major rift basin systems that subsequently developed in central Sabah; a NE-trending Sulu Sea rift and a SE-trending North Tarakan Basin (Figure 4A). These rift systems remained active throughout the Early Miocene and had acted as conduits for fluvio-deltaic sediment supply to the deep marine

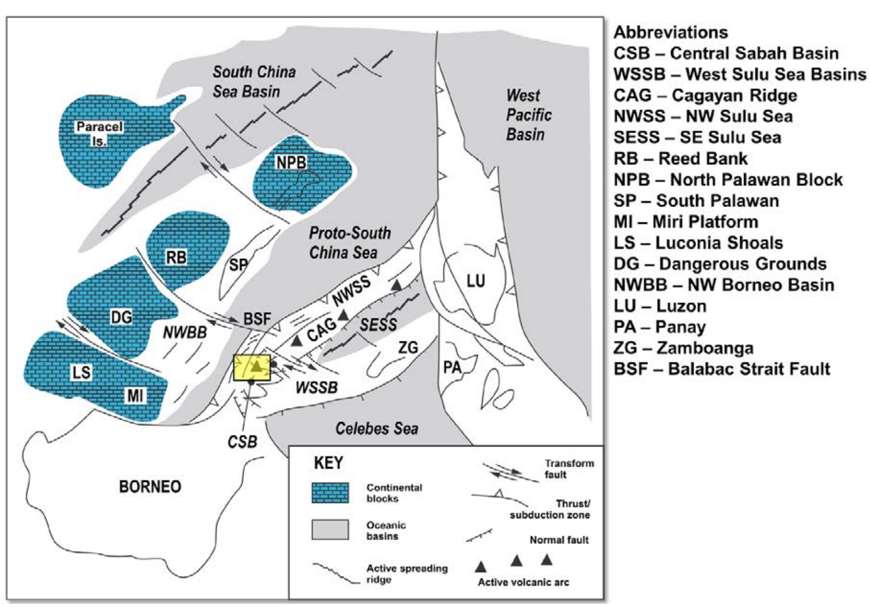

Figure 3: Early Miocene (18 Ma) reconstruction of the tectonic elements in the Borneo-Sulu Sea and surrounding region (after Clennell, 1996), showing the incipient rifting of the SE Sulu Sea (SESS) that extends onshore into the Central Sabah Basin (CSB, yellow shaded box). This region was initially an emergent, compressional terrane bounded by the North and South by subduction zones and spreading centres, namely the Proto-South China Sea and the Celebes Sea.

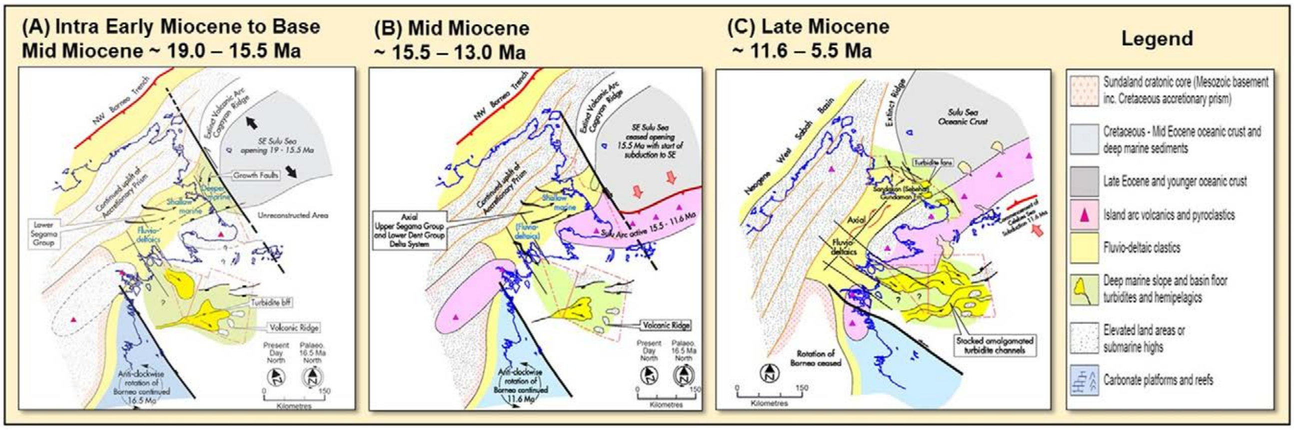

Figure 4: Palinspastic reconstructions of eastern Sabah and surrounding region, after ISIS (2005). (A) Intra-Early Miocene – Base Mid-Miocene, (B) Mid-Miocene, and (C) Late Miocene.

turbidite basins to the northeast and southeast. During the late Early Miocene (~19–15.5 Ma), extension of the Sulu Sea rift continued to form a deep ocean basin in which a major volcanic arc developed. The Sulu volcanic arc extended westwards into the Dent and Semporna peninsulas in eastern and southern Sabah (Figure 4B) and separates the Sulu Sea from the Celebes Sea to the south (Figure 3). During the Late Miocene, a northward-dipping subduction zone was initiated at the Celebes Sea margin, causing slab roll-back and crustal extension in the overlying volcanic arc and later rifting of the Sulu Sea marginal basin (Lai *et al*., 2021; Figure 4C). Rapid subsidence of the volcanic arc and marginal basin starting at around 15-14 Ma continued to the present-day to reach water depths of greater than 4500 m.

According to some authors the NE Sabah Basin originated as a rift system associated with the opening of the Sulu Sea marginal basin (Hutchison, 1988, 1992, 2005; Tjia *et al.*, 1990; Hall, 2013). In this rift model, the Oligocene-Early Miocene melange and deep marine clastics such as Labang Formation and its equivalents could be considered as part of the pre-rift sequence. The synrift succession is represented by the deltaic to shallow marine Tanjong Formation and the co-eval volcaniclastic-rich formations of the Segama Group, which crop out in the onshore circular basins and derived the sediment supply from the uplifted Crocker accretionary prism (Figure 4A). The post-rift succession extends offshore on the southwestern passive margin of the Sulu Sea as the Sandakan Basin. The synrift and post-rift successions are separated by the late Early Miocene (Top Segama) Unconformity, which has been observed on seismic lines across the "Pad Basin" (Clennell, 1991; Leong & Azlina, 1999; see Figures 1B and C for the location of Pad Basin). Following an Early Miocene uplift and erosional episode, there was rapid subsidence and progradation of the delta and shelf towards the east and southeast during Middle to Late Miocene (Figures 4B, 4C).

STRATIGRAPHY

Stratigraphic subdivision of the offshore Sandakan Basin is based on seismic sequence stratigraphy which is correlated with onshore lithostratigraphy (Wong, 1993; Leong & Azlina, 1999). Although the offshore seismic units are poorly constrained by biostratigraphic data they have been assigned formation names (e.g., Wong, 1993). Due to the low microfossil content and significant reworking, biostratigraphic analysis had been problematic (ISIS, 2005). Despite the shortcomings, a working stratigraphic scheme has been established and applied in the basin since the early 1970s. Figure 5 shows an updated scheme that incorporates the results of ISIS (2005). In this scheme, seismic-derived sequence boundaries (SB) are assigned ages from 28.5 to 5.5 Ma while the intervening sequences are correlated with the onshore formations.

The most prospective interval in the basin is the Middle–Late Miocene Sebahat Formation, which is bounded by the 8.6 and 13.0 Ma SBs (Figure 5). On seismic, the Sebahat is a strongly progradational package with south-dipping clinoforms deposited by the Sandakan delta system (Figure 6). The 13.0 Ma SB marks the synrift–post-rift unconformity and may be correlated with the Deep Regional Unconformity (DRU) in offshore West Sabah (Figure 5). The toesets in the lower Sebahat downlap onto this surface (Figure 6) which likely contains a condensed sequence of bathyal mudstones deposited in the prodelta/basinal setting. On seismic, there appears to have been a reduction in the rate of progradation, which resulted in a slightly aggradational sequence above the 11.6 Ma SB. This is indicated by the presence of eastward-climbing clinoforms (Figure 6). Since this aggradational package is truncated by a major regional unconformity (the 8.6 Ma SB), we interpreted it as belonging to the upper part of the Sebahat Formation. The Sebahat is analogous and probably coeval with the Stage IVC unit in offshore West Sabah (van Vliet & Schwander, 1987; Wong, 1997). Sebahat and the overlying Ganduman and Togopi formations are part of the post-rift succession that range in

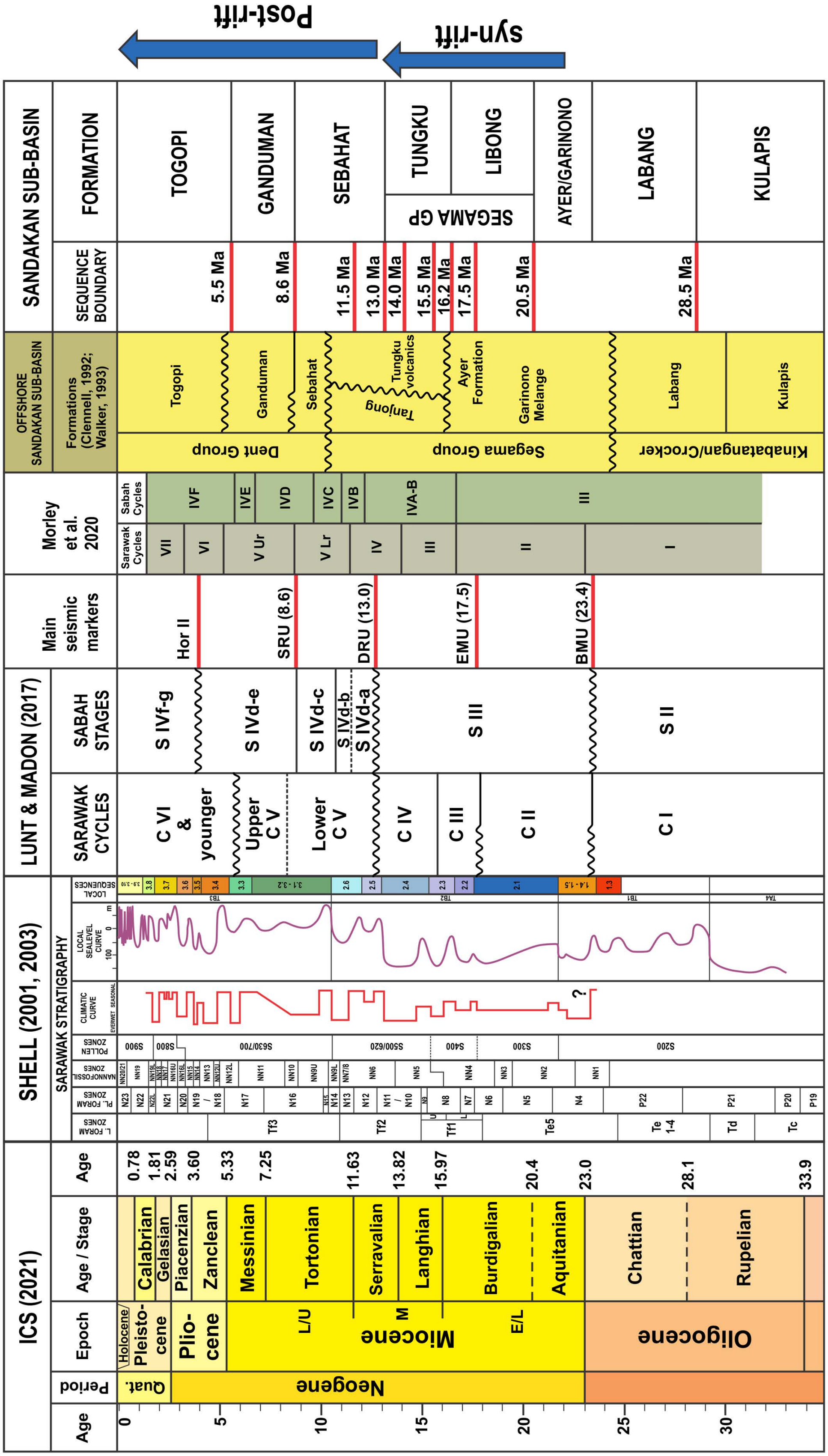

Figure 5: Stratigraphic nomenclature for Sandakan Basin based on the sequence stratigraphic framework of ISIS (2005), shown in the two columns on the extreme right, and its approximate correlation with offshore Sarawak and western Sabah (middle columns, from Lunt & Madon, 2017), as well as the previous Sandakan nomenclature (Clennell, 1991; Walker, 1993). Geological time scale on the left is from ICS (2021) and the Sarawak stratigraphic information is from Shell (Jong & Ho, 2001; Shell, 2003).

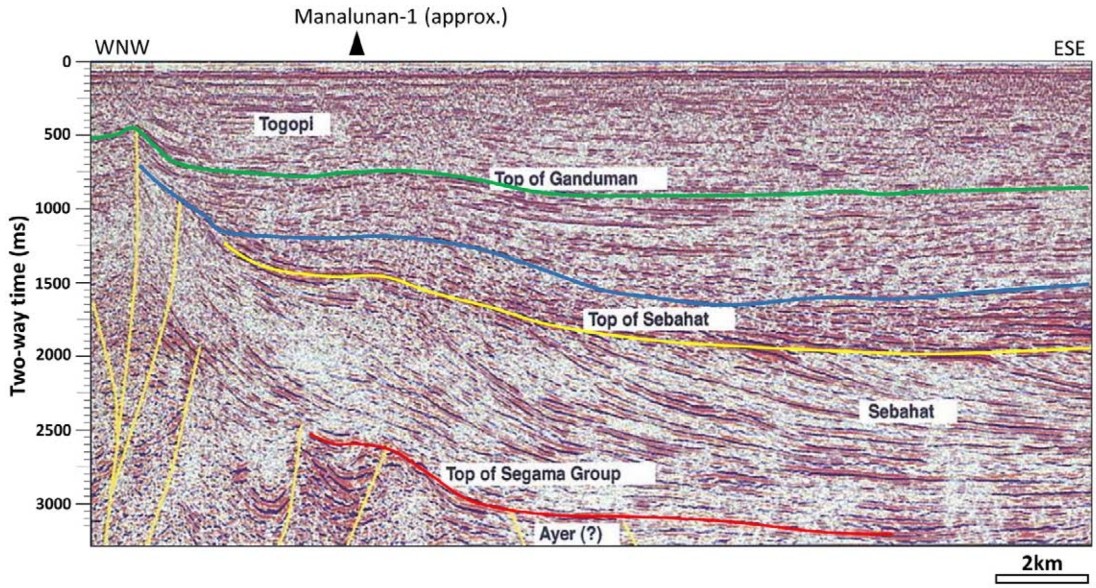

Figure 6: Seismic profile across the Sandakan Basin, modified from Leong & Azlina (1999), with the major seismic markers identified. The profile is similar to the one published by Wong (1993) and crosses Manalunan-1 well in an approximately NW-SE orientation. According to the previous authors, the top of Sebahat Formation is represented by the topset facies of the prograding clinoforms (yellow horizon). Based on the sequence stratigraphic interpretation by ISIS (2005), the top of Sebahat is some 400 ms above the top of the prograding clinoforms (indicated by the blue horizon) and includes some aggradational topset/foreset facies prograding towards the basin (eastwards).

age from Middle Miocene to Quaternary (Figure 5). The unconformable boundary between Ganduman and Togopi is marked by the 5.5 Ma SB.

Sequences below the base of Sebahat Formation (13.0 Ma SB) is considered to represent the synrift succession that belongs to the Segama Group (Figure 5). This includes the age-equivalents of the Tanjong Formation that fill the circular basins, as well as the Tungku, Libong, Ayer and Garinono formations, which form the melange formations in Central Sabah (Clennell, 1991). The melange formations (Ayer, Garinono and equivalents) were deposited during the early synrift phase, the base of which is marked by the 20.5 Ma (Early Miocene) SB. This is tentatively correlated with the base of Stage IVA unit in offshore West Sabah. The top of the deepwater Labang Formation, which is marked by the 23.4 Ma SB, is tentatively correlated with the Base-Miocene Unconformity (BMU) in offshore West Sabah where it is also considered equivalent to the Top-Crocker Unconformity (van Hattum *et al.*, 2006; Hall *et al.*, 2008).

STRUCTURAL AND STRATIGRAPHIC EVOLUTION

The main stratigraphic units are shown schematically in a regional cross-section (XX') from onshore to offshore Sandakan area (Figure 7). In this profile, a pre-Middle Miocene synrift succession can be distinguished from an overlying post-rift succession (Sandakan Basin) by a late Early Miocene unconformity (age ~16.2 or 15.5 Ma) at the top of the Segama Group. This unconformity cuts deeper stratigraphically into the Tanjong Formation landwards, while the overlying formations onlap onto the basin flank which dips eastwards into the Sulu Sea. Uplifted pre-rift

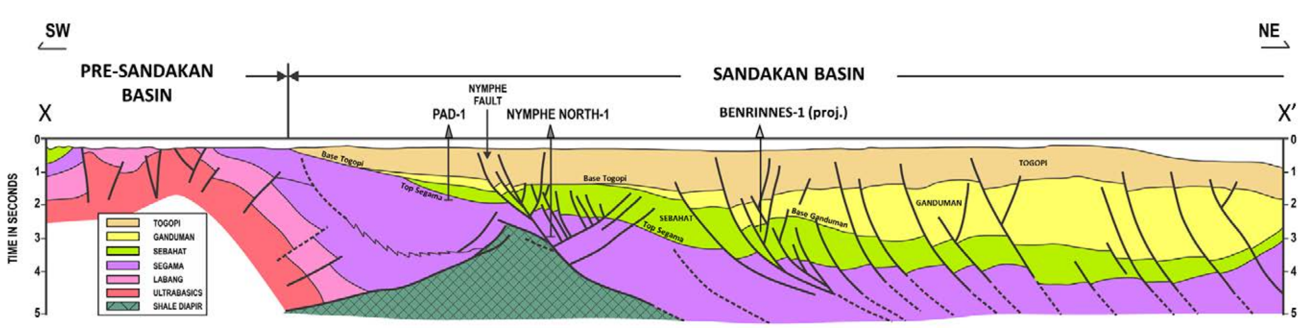

Figure 7: Regional SW-NE geological section across the Kinabatangan area, central eastern Sabah to the offshore Sandakan Basin (from Madon, 1999, based on the unpublished report by WMC, 1994). Profile location (XX') is shown in Figure 1B.

rocks in central Sabah therefore provided part of the sediment supply for the prograding delta and shelf, which were dissected by numerous down-to-the-basin growth faults.

The structure and stratigraphic evolution of the basin can be examined further in the geoseismic profiles shown in Figure 8, which are based on the sequence stratigraphic interpretation by ISIS (2005). Profile AA' in Figure 8A starts in the west at the Nymphe North anticlinal structure and crosses the main Nymphe anticlinorium southeastwards through well Manalunan-1 towards Gem Reef-1. The different structural culminations have been penetrated by wells Nymphe-1, Nymphe North-1 and Nymphe South-1. The Central Trough, between Manalunan-1 and Gem Reef-1, is a broad synclinal area bounded by a west-dipping, north-trending reverse/thrust fault in the pre-Middle Miocene section below the base of Sebahat (13.0 SB). Eastwards of this thrust fault, the pre-Middle Miocene interval gradually thins towards and onlaps onto the Gem Reef High, indicating that thrust-front loading may have had a role in the subsidence of the Central Trough. The NE-SW trending Gem Reef High is parallel to several other structural highs that are aligned with the Dent Peninsula in the southern part of the Sandakan Basin. The intervals between the 28.5 to 11.5 Ma SBs onlap towards the southeast at Gem Reef, which is draped by younger strata. It is also noted that the progradational lower Sebahat sequence above the 13.0 Ma SB is generally less affected by faulting.

Profile BB' (Figure 8B) is oriented in a SW-NE direction and cuts across Nymphe North, Benrinnes and Mutiara Hitam structures. Nymphe South-1 and Mutiara Hitam-1 were drilled on the hangingwall of major normal faults, targeting the Segama Group and Sebahat Formation, respectively. Benrinnes-1 was drilled on an anticlinal structure between the two. In map view, these structures appear as NE-SW trending *en echelon* anticlines associated with NW-trending transfer faults (Figure 1C). Similar anticlinal features along the E-W Profile CC' are penetrated by wells Pad-1, Nymphe-1, and Kuda Terbang-1 (Figure 8C). The anticlines were probably developed by compressional reactivation of major normal faults during the Late Miocene to Pliocene times. Well Pad-1 is an exception as it targeted reservoirs in the Segama Group (Tanjong Formation) in a synclinal area ("circular basin") and was considered an invalid test.

Two major erosional unconformities are easily identifiable on the profiles. In Profile AA' (Figure 8A) the Base Sebahat and Base Ganduman unconformities are identified by the 13.0 and 8.6 Ma SBs, respectively. The Base Sebahat is a downlap surface for the prograding Sebahat delta, whereas the Base Ganduman is a major truncational unconformity that truncates the crests of anticlinal structures. The Base Ganduman (8.6 Ma SB) is the most pronounced unconformity and represents a major period of structural deformation in the Sandakan Basin. The less distinct Base Togopi unconformity (5.5 Ma SB), caused by an inversion event during the Early Pliocene, appears conformable upon the Ganduman Formation except on major structural crests, such as at Gem Reef High.

The major erosional unconformities exerted a strong influence on the stratigraphic architecture of the basin. The most significant of these is the Base Ganduman unconformity (8.6 Ma SB) which was caused by compressional uplift during the Late Miocene. The unconformity eroded the crest of Nymphe anticline down to the 14 Ma SB, resulting in a missing section the equivalent of up to *ca.* 5.5 Myr duration (Figure 9). At Nymphe, the unconformity resulted in the removal of much of Sebahat Formation, which is preserved only to the east of Nymphe South-1. We named the deformation event associated with the Base Ganduman unconformity the D3 event (Figure 9B). The uplift related to D3 increased in magnitude westwards, resulting in stratigraphically deeper erosion landwards. Based on its age, D3 may be correlated with the Shallow Regional Unconformity (SRU) in offshore West Sabah (Levell, 1987) and is likely to be tectonically related to the Kinabalu granitoid emplacement (Cottam *et al.*, 2010).

The Sebahat Formation was also affected by an erosional unconformity, D2, which is associated with a missing section between the 17.5 and 14.0 Ma SBs (Figure 9B). The D2 event cuts down into the Segama Group (beneath the 17.5 Ma SB) and marked the initiation of the progradation of the Sebahat delta during the Middle Miocene. To the east and south, between Nymphe South-1 and Gem Reef-1, the unconformity passes basinward into fine-grained basinal deposits of distal turbidites and hemipelagites deposited at the distal end of the deltaic system. An unconformity D1, marked by the 16.2 Ma SB, is equivalent to the regional Early-Middle Miocene event in offshore West Sabah, considered by some authors as being related to the cessation of sea-floor spreading in the South China Sea (e.g., Cullen *et al.*, 2010; Hall, 2013; Li *et al.*, 2015; Sun, 2016). D1 is also probably equivalent to the Deep Regional Unconformity (DRU) in offshore West Sabah (Levell, 1987). In the Sandakan Basin, however, D1 does not show significant erosion, with is observed in only a relatively small part of the core of the anticlinal structure (Figure 9B).

The broad anticlinal structure at Gem Reef-1 (Figure 8A) suggests that the Gem Reef High is a relatively young inversion structure that grew during Pliocene times. Basin inversion is indicated by a thicker stratigraphic interval between the 8.6 and 11.0 Ma SBs in the crestal region compared to that on the flanks. The uniform thickness of the 5.5-8.6 Ma interval and thinning of the overlying strata towards the structural crest suggest uplift during Late Pliocene to Quaternary, post-5.5 Ma. Shallowing due to the uplift may have initiated the development of a carbonate build-up on the structure.

The spatial and temporal relationships between the deformation events D1 to D3 are shown in Figure 9B. Sediments eroded off the anticlinal crests (e.g., at Nymphe-1)

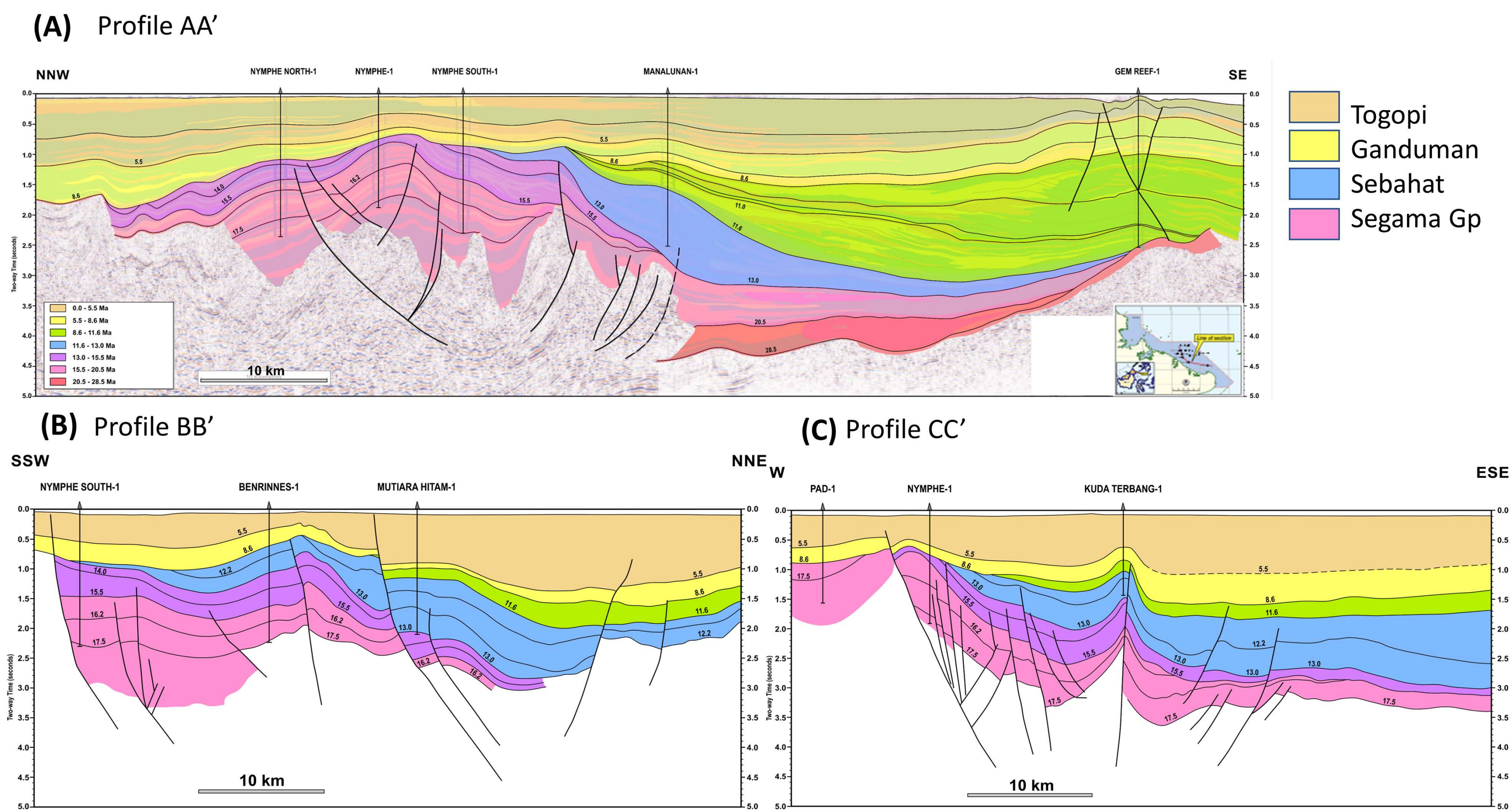

Figure 8: Geoseismic profiles interpreted based on time sections (modified from ISIS, 2005). All profiles are plotted on the same horizontal and vertical scales. Major sequence boundaries identified with assigned ages in Ma. Profile locations are shown in Figure 1B. (A) Profile AA', NW-SE oriented margin-parallel profile crossing the Nymphe anticlinorium through the Central Trough to the Gem Reef structure overlayed on seismic line with facies interpretation as shown in Figure 9A. (B) Profile BB', SSW-NNE margin-normal "dip" profile across the Nymphe-Benrinnes-Mutiara Hitam anticlinal trend. (C) Profile CC' shows increasing depth of erosion landwards across the Pad Basin, in which several unconformities are compounded within the top Segama (D3) event, such that the Togopi Formation sits directly on deformed Early Miocene Tanjong Formation (Clennell, 1996; Leong & Azlina, 1999).

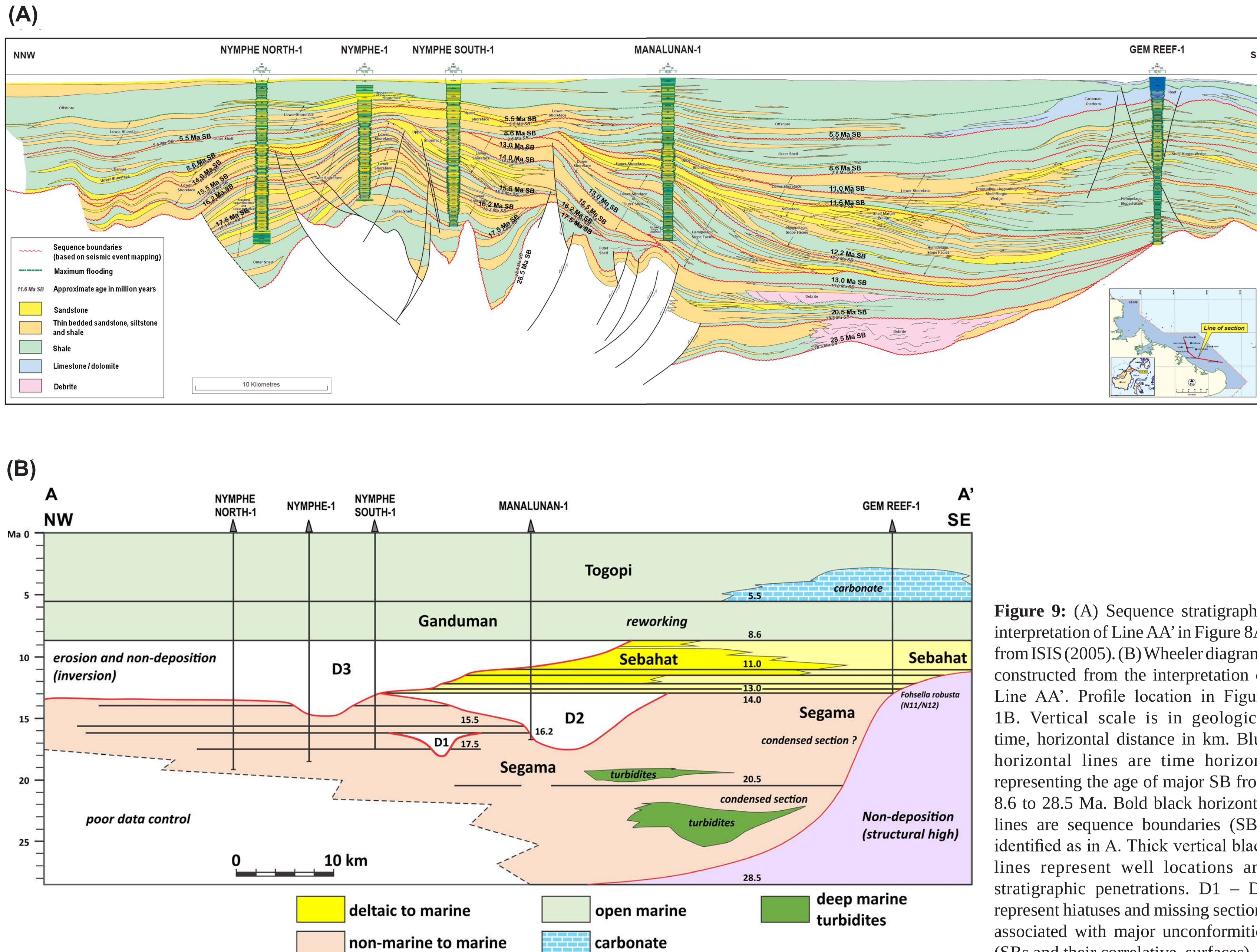

Figure 9: (A) Sequence stratigraphic interpretation of Line AA' in Figure 8A, from ISIS (2005). (B) Wheeler diagrams constructed from the interpretation of Line AA'. Profile location in Figure 1B. Vertical scale is in geological time, horizontal distance in km. Blue horizontal lines are time horizons representing the age of major SB from 8.6 to 28.5 Ma. Bold black horizontal lines are sequence boundaries (SBs) identified as in A. Thick vertical black lines represent well locations and stratigraphic penetrations. D1 – D3 represent hiatuses and missing sections associated with major unconformities (SBs and their correlative surfaces).

by both the D2 and D3 events may have been reworked downdip into the thick Ganduman Formation, which accumulated in the low area (Central Trough) between Nymphe South-1 and Gem Reef High.

PETROLEUM SYSTEMS

Exploration history

Wells drilled by Aquitaine between 1970 and 1975 had some hydrocarbon shows, with small amounts (estimates ranging from 28–43 MMboe) of gas at Nymphe-1, Nymphe North-1 and Benrinnes-1. By 1995, a total of eleven wells had been drilled, giving an overall success ratio of 45%. In contrast, eight wells drilled since 2005 had only minor shows. Tables 1 and 2 summarise the well results and relevant information from the 19 exploration wells drilled in the basin to date. Five wells are classified as oil and gas discoveries; they are Benrinnes-1, Nymphe-1 North, Nymphe-1, Mutiara Hitam-1 and Kuda Terbang-1; all discovered before 1995. Condensates were also recovered from Nymphe-1, Nymphe North-1 and Benrinnes-1. Figure 10 shows the structural maps of the main discoveries. Kuda Terbang-1 and Mutiara Hitam-1 were drilled by WMC Petroleum Ltd. in 1994 after a two-decade exploration hiatus. The hydrocarbons were encountered mainly in deltaic sandstones of the Sebahat Formation. The recoverable resource at Kuda Terbang-1 was estimated to be *ca.* 90 MMboe.

Besides the discoveries, there were numerous oil and gas shows recorded in other wells. WMC's post-mortem study (Walker, 1993) had indicated that wells Manalunan-1, Magpie West-1, Gem Reef-1, Nymphe South-1, Sebahat-1 and Pad-1 were invalid tests for various reasons, e.g., absence of structural closure or misidentified carbonate reef. Lower quality seismic data available at the time, as well as poor biostratigraphic control, may have also contributed to uncertainties in interpretation.

Figure 11 summarises the stratigraphic penetration of the wells drilled to date. As indicated by the drilling results (Tables 1 and 2), the most prospective sedimentary section in the Sandakan Basin is mainly within the Middle to Upper Miocene interval, which includes the Upper Segama Group (Libong and Tungku formations) and Sebahat Formation. From 2005 to 2008, PCSB drilled four appraisal wells: Mutiara NE-1, Benrinnes NE-1, Kuda Terbang-2, and Nymphe-2-ST1, with generally poor results. Mutiara Hitam NE-1, drilled downdip of Mutiara Hitam-1 to the east, found only minor hydrocarbons in the Segama Group. Kuda Terbang-2 appraised the down-dip (north-eastward) continuation of the hydrocarbon-bearing reservoirs at Kuda Terbang-1 and found only 8 m of net gas sands. In 2008, the deviated well Nymphe-2 appraised the gas-bearing sands down-dip of Nymphe-1 and found 88 m of gas and condensate in Segama Group.

The last three wells drilled by PETRONAS, namely Pahu-1, Kerupang-1 in 2012 and Pendekar-1 in 2015, are located on the northern and southern margins of the South Dent Graben, respectively (Figure 1B). Examples of seismic profiles across the wells are shown in Figure 12. Pahu-1 was drilled to test the hydrocarbon potential

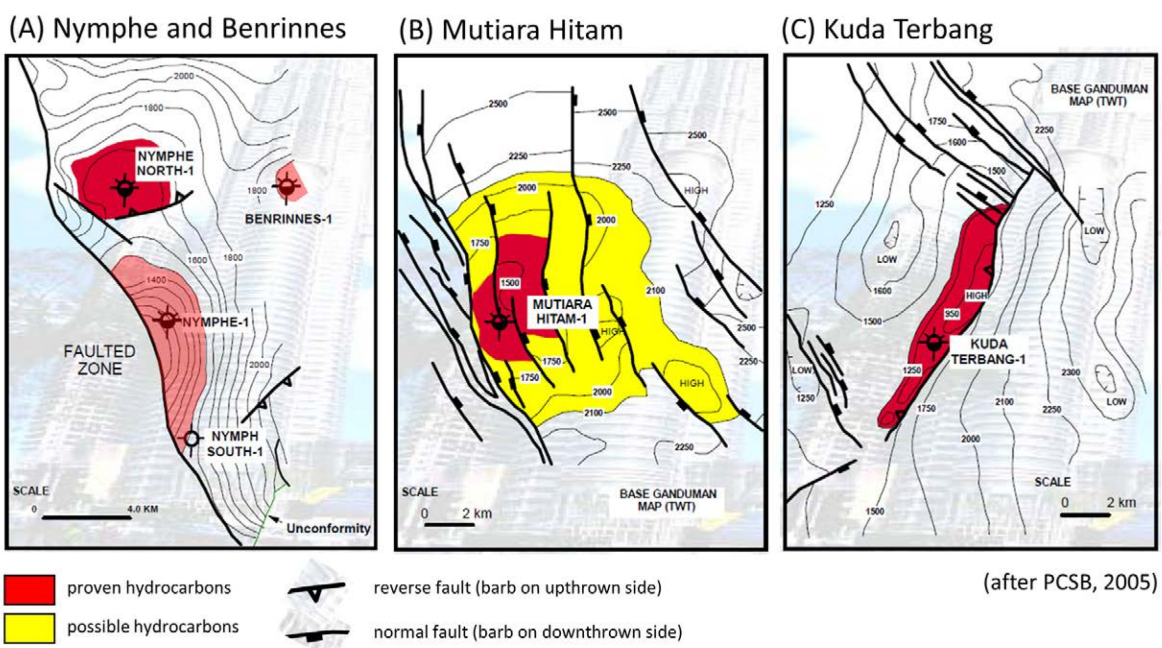

Figure 10: Structural maps of the key discoveries in the Sandakan Basin. (A) Benrinnes, Nymphe and Nymphe North fault-dip closures. (B) Mutiara Hitam fault bounded closure. (C) Kuda Terbang structure. Modified after PCSB (2005).

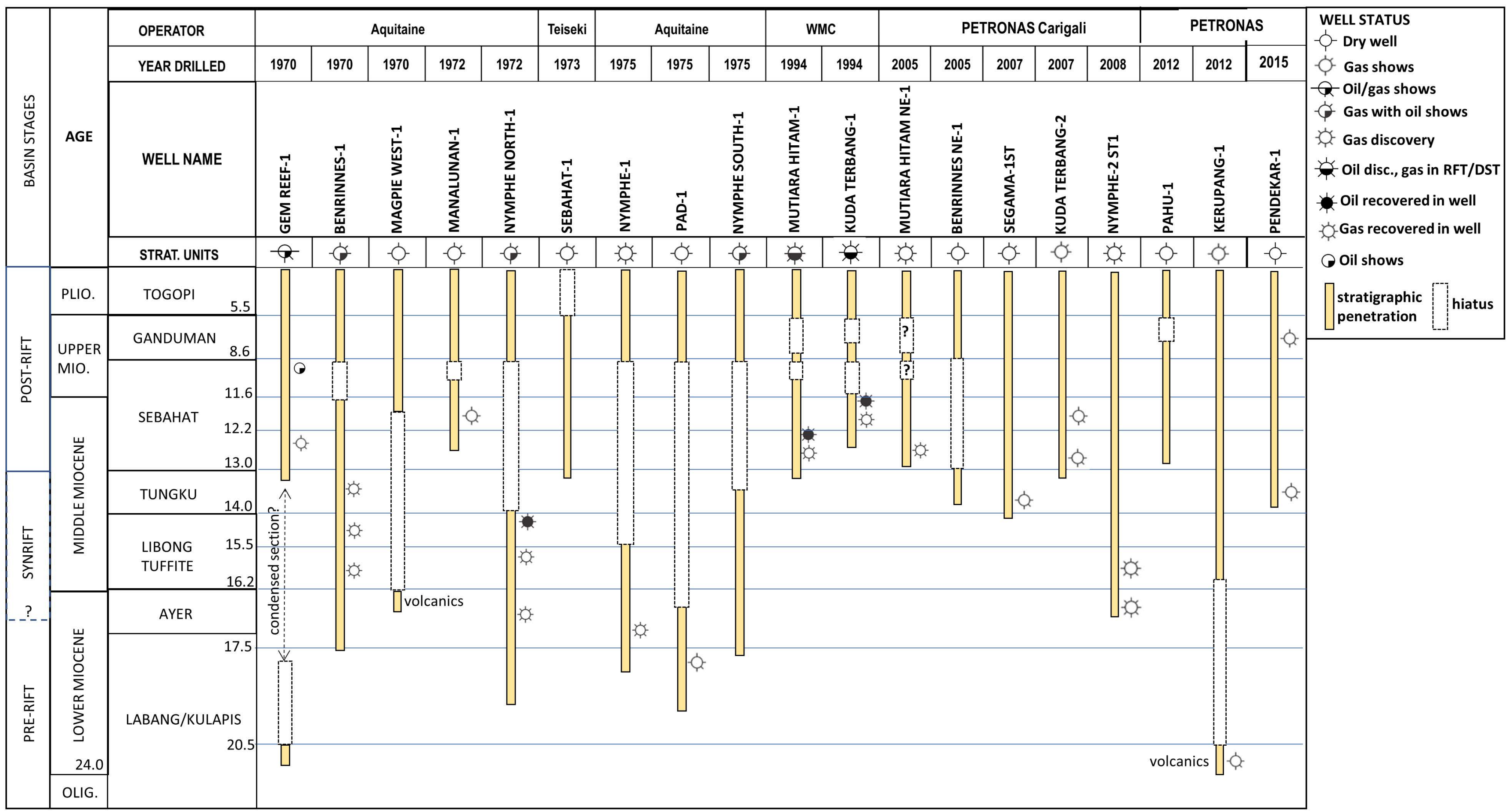

Figure 11: Stratigraphy and well penetration history in the Sandakan Basin arranged in chronological order from left to right. Stratigraphic units assigned to the well column is based on a revised choronostratigraphic framework resulting from the current study. Note that the age on the vertical scale with the major timelines indicated in blue horizontal lines (representing sequence boundaries identified in seismic) is not linear and is for illustrative purposes only. Magpie West–1 penetrated 193 m of volcanic sediments and extrusives of the Segama Group; recovered core samples were identified as volcanic breccia/agglomerate overlain by tuffite.

Table 1: Oil and gas occurrences in the Sandakan Basin. RFT: Repeat formation test; FIT: Formation interval test; DST: Drill stem test; NGS = Net gas sand; NOS = Net oil sand. Compiled from unpublished company reports, including Petronas Carigali.

Well	Year	Operator	Water depth (m)	TD (m)	Status	Drilling objective/ Reservoir formation penetrated	Post-mortem and diagnosis (Walker, 1993 and Petronas well reports)	Hydrocarbon indicators (see more details in Table 2)	Reservoir properties
Gem Reef-1	1970	Aquitaine	45	3378	dry hole with gas shows.	Sebahat	Invalid structural test; apparent anticline is a volcanic structure; the well was off-target due to velocity pull-up caused by shallow reefs	Gas from FIT	
Benrinnes-1	1970	Aquitaine	55.5	3120	untested gas discovery	Segama/Tanjong/Sebahat	Valid test	Gas/condensate from FIT; NGS = 20.1 m	Ave por=16%, Sw 54%, 3 cores taken
Magpie West-1	1970	Aquitaine	91	1543	dry	Dent Group	Invalid structural test; apparent anticline is a volcanic structure	Minor gas shows (C1 only) from carbonaceous siltstones of Ganduman Fm.	
Manalunan-1	1972	Aquitaine	40	3027	dry	Sebahat/Dent Group	Invalid stratigraphic test; no closure, or pinch-out; unclosed deltaic topsets	Gas shows in cuttings; Gas shows (C1 with trace of C2, C3 and iC4) in Sebahat Fm.	
Nymphe North-1	1972	Aquitaine	55	3440	tested gas discovery	Segama/Tanjong/Sebahat	Valid test	Gas, heavy condensate and light oil from DST; NGS = 123 m	Ave por=25%, K=1000mD, 4 cores
Sebahat-1	1973	Teiseki	131	3700	dry	Dent Group	Invalid structural test, Lack of structural closure	Gas shows in cuttings	
Nymphe-1	1975	Aquitaine	47	2403	tested gas discovery	Segama/Tanjong	Valid test	Gas/condensate from DST; NGS = 137.4 m.	Por=16-22%, Sw 45-55%, K=50-300 mD, 2 cores
Pad-1	1975	Aquitaine	44	1833	dry	To test stratigraphic play in Segama /Tanjong	Top seal absent; too far downdip from pinch-out	Gas shows in cuttings	
Nymphe South-1	1975	Aquitaine	39	2957	dry	Segama/Tanjong	Invalid structural test; outside of closure	Gas shows and fluoresence in cuttings	
Labuk Bay-1	1977	Esso	5	1266	dry	Bongaya Formation	No reservoir	None	
Mutiara Hitam-1	1994	WMC	77.3	2745	tested oil & gas discovery	Segama/Tanjong	Valid test; discrepancy between pre-drill seismic correlation and post-drilled biostratigraphic results	Oil/gas from RFT; gas/ condensate from DST; NGS = 29.7 m; NOS = 4.1 m	Oil and Gas 0= 16-22% Sw= 45-55% 5 HC zones

Continued.

Table 1: *continued.*

Well	Year	Operator	Water depth (m)	TD (m)	Status	Drilling objective/ Reservoir formation penetrated	Post-mortem and diagnosis (Walker, 1993 and Petronas well reports)	Hydrocarbon indicators (see more details in Table 2)	Reservoir properties
Kuda Terbang-1	1994	WMC	55.4	1590	untested oil & gas discovery	Segama/Tanjong Eq.	Valid test; faulted compressional anticline; discrepancy between pre-drill seismic correlation and post-drilled biostratigraphic results	Oil/gas from RFT; NGS = 84.9 m; NOS = 30.4 m.	Gas and Oil 0= 17-29% Sw= 43-il4% K= 1410 mD 2 cores
Mutiara Hitam NE-1	2005	PCSB	85	3500	gas shows	Segama/Tanjong	Fault seal failure	Minor gas shows	Gas 0= 18 -26 % Sw= 43 -67%
Benrinnes NE-1	2005	PCSB	57	3120	dry	Deltaic sands between 14.0-16.2 Ma SBs	Charge/migration failure	Minor gas shows	
Segama-1ST	2007	PCSB	130	2321	gas shows	To test carbonate build-up (Gem Reef) within 14.0-16.2 Ma SBs	Well was sidetracked twice due to kicks and losses at the top of carbonate	37 m of carbonate at TD; gas detected from logs, possible small gas column	Reservoir present but thin hydrocarbon column suggests limited charge
Kuda Terbang-2	2007	PCSB	26	1496	dry	To appraise the extension of reservoirs found at Kuda Terbang-1	Drilled too far downdip; possible fault barriers between Kuda Terbang-1 and Kuda Terbang-2	NGS = 8 m	Por = 26-35%, Sw=81-85% 3 cores
Nymphe-2ST1	2008	PCSB	48	3208	gas discovery	To appraise down-dip gas reservoirs found at Nymphe-1 in Tungku/ Libung Fm (16.2-17.5 Ma SB)	Valid structural test One of the reservoirs may be underfilled	Wet gas, NGS = 88 m Gas, condensate from DST in Tungku and Libong intervals	
Kerupang-1	2012	PETRONAS	200	2538	dry	Carbonate reef in Sebahat	3 sidetracks due to hole pack-offs, absence of carbonate (misidentified target)	No shows at TD but gas shows in upper section (Ganduman)	
Pahu-1	2012	PETRONAS	200	1154	suspended	To test Lower Tungku and Upper Sebahat reservoirs	Well plugged and abandoned before reaching target due to operational issues (hole pack-off at 1154 m)	No shows	
Pendekar-1/1ST1	2015	PETRONAS	83.7	2076	dry	To test the Tungku and Ganduman reservoirs	Penetrated Ganduman Formation and terminated in Tungku Formation conglomerates	No shows	

Table 2: Detailed on hydrocarbon occurrences in the 5 discovery wells, based on post-mortem analysis (Velosi, 2008).

Well	Year	Operator	Water Depth (m)	TD (m)	Status	Test results: Post-mortem report
Benrinnes-1	1970	Aquitaine	55.5	3120	Untested Gas Discovery	Five gas zones identified in Ganduman and Sebahat Fms. FIT : Zone 1 (1,580.08m): 54 cu.ft. gas (C1-C6) & condensate Zone ll (1,733.4 m): 13cu.ft. gas (C1-C6) & trace of condensate
Nymphe North-1	1972	Aquitaine	55	3440	Tested Gas Discovery	Five reservoir zones under hydrostatic pressure and three high pressure reservoirs. Zone lllB (1,656.28 - 1,704.44m) represents the most attractive reservoir. FIT 4 (1,660.86m) & 5 (2,300.02 m) recovered gas (C1-C8+) TC 2 (1,657.81 - 1,662.38m) flowed heavy condensate or light oil (API 46.5°)
Nymphe-1	1975	Aquitaine	47	2403	Tested Gas Discovery	Three zones with gas kicks in Sebahat Fm. DSTs flowed gas (C1-C4) and condensate (50° and 51° API): DST 1 (2,184.20 - 2,227.48 m), 15.25 mmcfd, 94 bcfd condensate DST 2 (2,047.04 - 2,113.79 m), 14.525 mmcfd, 14 bcfd condensate
Mutiara Hitam-1	1994	WMC	77.3	2745	Tested Oil & Gas Discovery	Oil shows in drill cutting and SWC DST 1A (2,639.5 - 2,689.5 m) flowed gas (C1-nC5) and condensate (API 41.5°) RFT (2,089.2 m, 2,024 m & 2,222.8 m) gas (C1-C5) & black oil (API 38.6°)
Kuda Terbang-1	1994	WMC	55.4	1590	Untested Oil & Gas Discovery	Good quality reservoir 824 - 1,076 m. RFT (953.1 - 1,107.5 m) in Segama Group found gas (C1-C5) & black oil (31.7° & 32.3° API)

of Lower Tungku and Upper Sebahat sand reservoirs, but was plugged and abandoned before reaching the target depth due to operational problems. The structure therefore remains untested. Kerupang-1 was drilled to test a carbonate reef structure along strike from Pahu-1 on the Togopi Ridge. The well, however, did not find carbonate but siliciclastics and volcanics. Clearly an invalid test, this structural high that had been misidentified as a "reef" was actually a pre-rift paleo-high (probably formed of the Libung tuffite or Tungku Formation) below an angular unconformity. Based on the Kerupang-1 results, the unpenetrated structure at Pahu-1 could also be a volcanic high. The seismic interpretation of this prospect needs to be reviewed.

Pendekar prospect, at the southern edge of South Dent Graben, was mapped as a 4-way structural dip closure at the top of Tungku Formation which is onlapped by the prograding Sebahat Formation. Well Pendekar-1 penetrated a predominantly conglomeratic interval in the upper Tungku consisting mostly of quartzite and slate with minor occurrence of breccia, andesite, and chert. No hydrocarbon shows were observed either in the upper Tungku Formation or the overlying Ganduman Formation.

Trap styles

The traps that bear hydrocarbons are mainly fault and/or dip-closed structures along anticlinal trends, the main ones being Nymphe-Benrinnes-Mutiara Hitam and Kuda Terbang (Figure 10). These faulted anticlinal structures were formed by basin inversion and the consequent reactivation of growth fault-related structures by wrench and strike-slip faulting during Late Miocene to Pliocene. The first structure to be drilled, Benrinnes, was the largest four-way dip closure in the Northern Province, and is similar to other structures nearby that were drilled subsequently, e.g., Nymphe and Nymphe North (Figures 13A-C). The discovery well Mutiara Hitam-1 was drilled on a fault-associated fold structure which is on trend with Benrinnes-1 to the southwest (Figure 13D). The structure is essentially a growth-fault anticline that had been modified by the Late Miocene-Early Pliocene compression. Kuda Terbang-1, located on a similar SW-NE trend parallel to that of Benrinnes-Mutiara Hitam trend, is a tight compressional anticline with a major reverse fault on its southeastern side and was probably produced by the same deformation event (Figure 13E).

Besides the proven structural traps, potential stratigraphic traps have also been tested by wells such as Manalunan-1

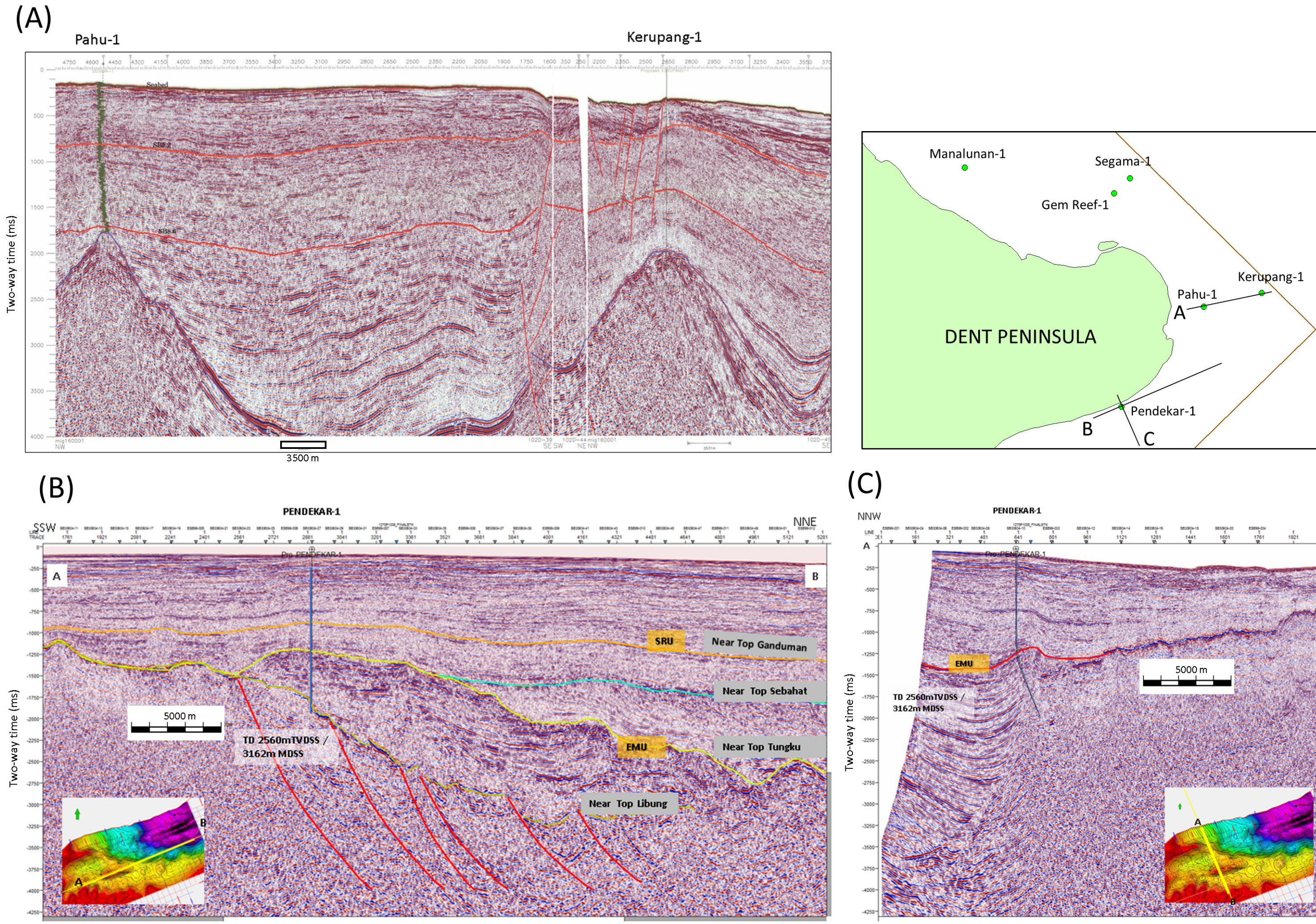

Figure 12: Seismic profile through the latest wells in Sandakan Basin. (A) Pahu-1 and Kerupang-1 prospects (line location shown on map to the right). Both are located above structural highs that are likely to volcanic ridge associated with the southern Sulu Sea margin. Note the relatively young age of faulting at Kerupang-1. (B) Seismic profile through well Pendekar-1 in the South Dent Graben. This strike profile shows the geometry of the Pendekar prospect, which is defined at the top of Tungku Formation, coinciding with the late Early Miocene Unconformity (16.2 Ma SB). At Pendekar-1 the overlying Upper Sebahat is thin, and the 8.6 Ma SB (top Sebahat unconformity) probably eroded parts of the Sebahat and merged with the EMU. The marked difference in seismic facies above and below the EMU is clearly seen. (C) Dip profile across the Pendekar structure which appears to have formed as a hangingwall anticline above a major north-hading normal fault at the southern boundary of the South Dent Graben. Pendekar-1 penetrated conglomerate near the top of Tungku Formation within the footwall (basin margin) (profiles from PETRONAS, 2015).

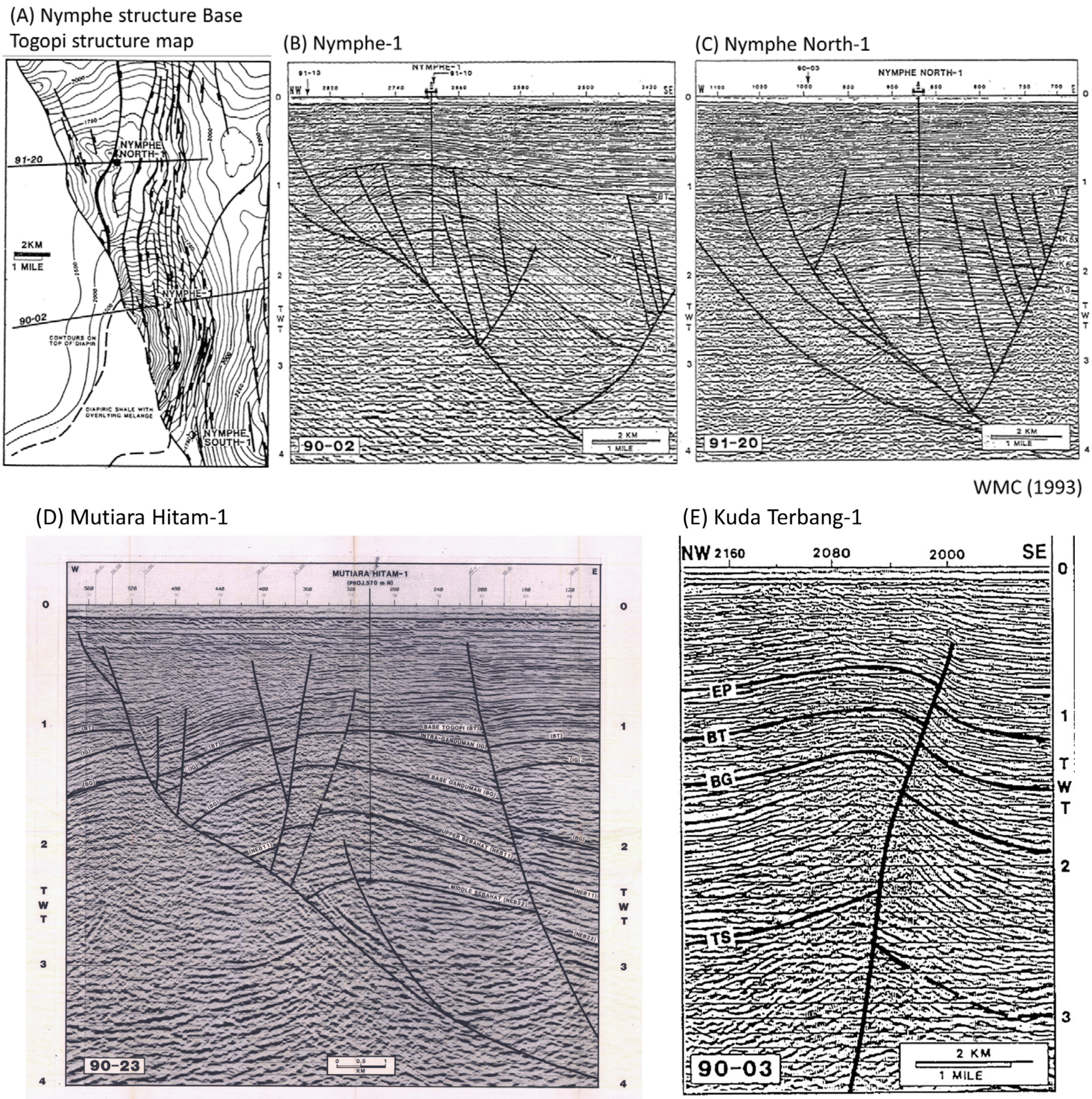

Figure 13: Vintage seismic cross-sections of the hydrocarbon-bearing structures. (A) Structural map of Nymphe structure with two profiles across Nymphe North and Nymphe. (B) Aquitaine well – Nymphe North-1. (C) Aquitaine well – Nymphe-1. (D) WMC well - Mutiara Hitam-1. (E) WMC well - Kuda Terbang-1. Map and profiles A to C are from Weeden (1993). Profiles D and E are from WMC (1995).

and Pad-1. As mentioned above, however, these wells were considered invalid tests. In addition, wells Gem Reef-1 and Segama-1 tested the carbonate play in the Southern Province. While Gem Reef-1 was considered an invalid test, Segama-1 successfully penetrated 37 m of carbonates at the terminal depth (TD) but did not find hydrocarbons.

Reservoirs

Well results indicate that the hydrocarbon-bearing sands in the Sandakan Basin were deposited in a deltaic to shallow marine setting. Various types of the lower coastal plain to offshore prodelta deposits were recognised, representing distributary channels, mouth-bars, and shallow subtidal offshore bars. The reservoirs at Mutiara Hitam-1 and Kuda Terbang-1 are interpreted as lower shoreface sands belonging to the Sebahat Formation. Some hydrocarbons also occur in the Segama Group, which in part also contains volcaniclastic sediments. Palaeogeographic reconstructions of the Northern and Central provinces based on available well data (ISIS,

2005) indicate an east to northeast-facing shoreline that prograded across the southwestern margin of the Sulu Sea (Figure 14). During Lower Sebahat times, eastward deltaic progradation resulted in the clinoform package seen in seismic, with lower coastal plain and deltaic topset facies in a N-S trending belt from Mutiara Hitam-1 to Manalunan-1 (Figure 14A). As the sediment supply gradually kept pace with subsidence, the rate of progradation increased and the shoreline stabilised with the deposition of thick delta topsets (Figure 14B). Throughout Sebahat times, turbidite fans are believed to have been deposited seawards in the regions to the east and southeast. During Ganduman times the shoreline assumed a NW-SE orientation, similar to the present-day coastline (Figure 14C). The progradation of shelf-slope facies across the basin can be observed by facies changes in the wells, as shown in Figure 15. Lower to upper shoreface facies in the wells are characterised by upward coarsening log shapes from slope facies to shoreface facies. Within the Sebahat, the sand content also deteriorates basinward as the facies changed from upper shoreface to outer shelf to slope facies from north to south.

Core samples from Benrinnes-1, Nymphe North-1, Gem Reef-1, and Kuda Terbang-1 provide some direct information on the reservoir quality (Figure 16). The best developed high-quality sands are at Nymphe-1 and Nymphe North-1, comprising medium- to coarse-grained, planar cross-bedded sandstones, interpreted as channel and mouth-bar deposits. Fine- to very fine-grained sands in the distal mouth-bar or offshore bar settings are more widespread facies but of relatively lower quality. These are faintly laminated sandstones and siltstones, with occasional bioturbation, and some burrows of *Ophiomorpha* sp. Heterolithic thinly bedded sandstone-mudstone facies were seen in the cores from Manalunan-1. They are typically argillaceous, organic rich, with carbonaceous and coaly layers, probably deposited in crevasse splays or interdistributary bays. Sebahat Formation reservoirs are of good quality, comprising fine- to medium-grained sandstones with high visual porosity. At Kuda Terbang-1 good quality sandstones (4-26 m thick) were found in cores at 993-1005 m depth, with an average porosity of 30% and an average permeability of 1410 mD.

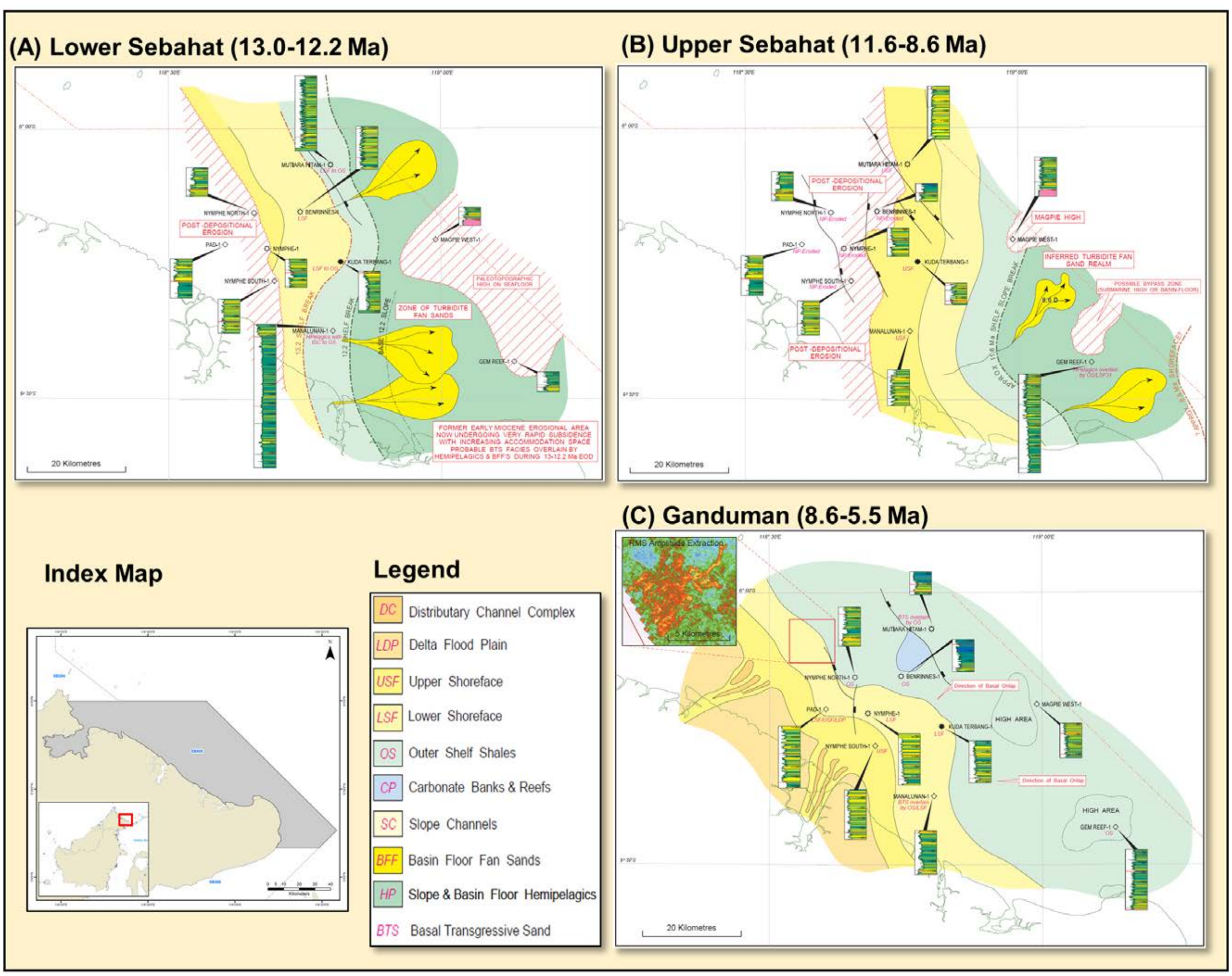

Figure 14: Paleogeographic reconstructions from 13 Ma to 5.5 Ma, representing (A) Lower Sebahat, (B) Upper Sebahat (C) Ganduman.

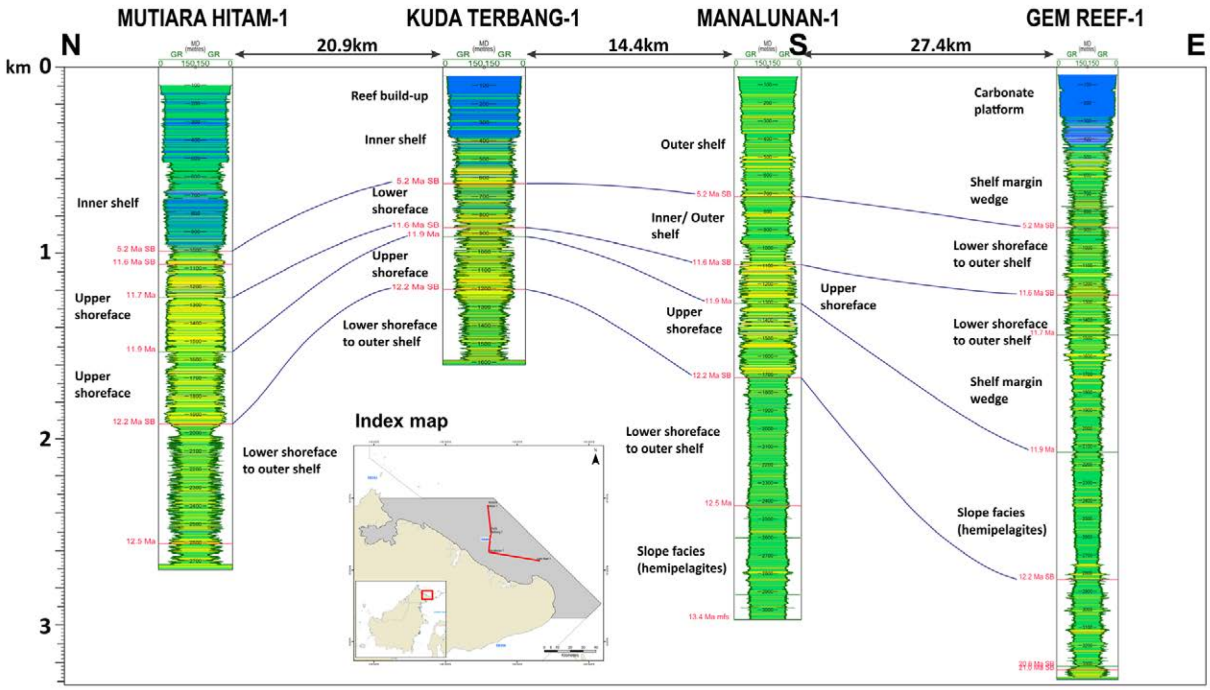

Figure 15: Well correlation from Mutiara Hitam-1 to Gem Reef-1, showing the overall basinward facies changes from upper shoreface to shelf-margin and slope facies from north to south with the prograding clinoforms in the Sebahat Formation. The curve for each well is the Gamma Ray curve plotted in opposite scales. Horizontally not to scale.

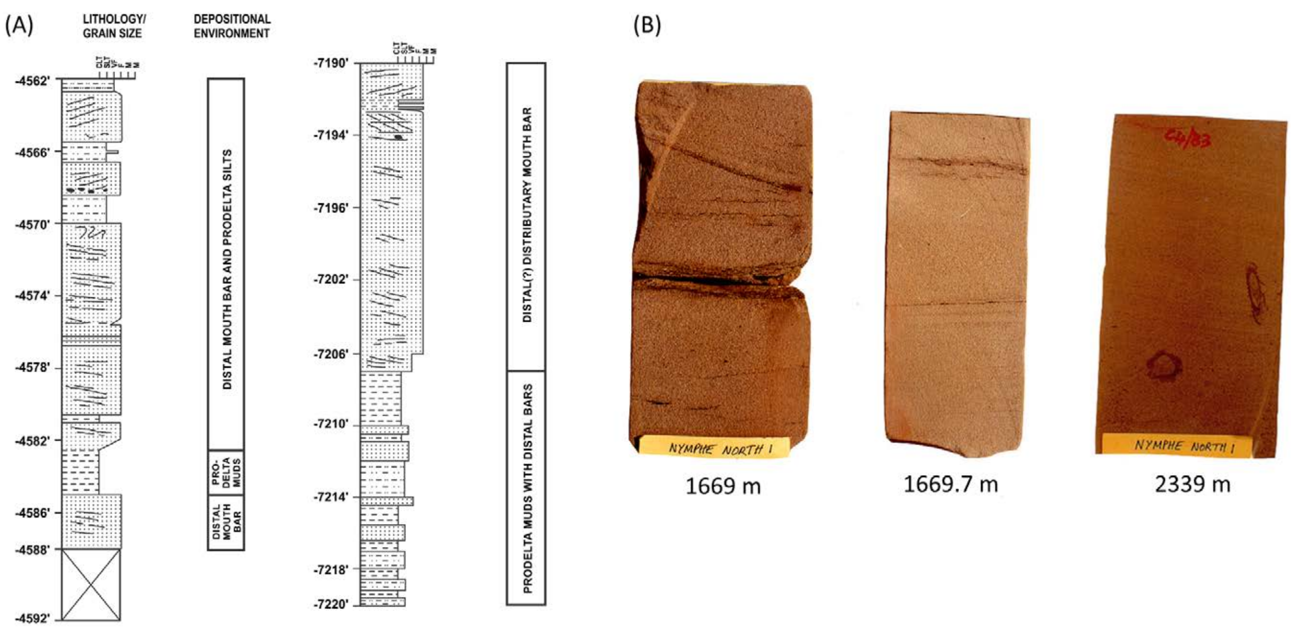

Figure 16: Core logs and examples of lithofacies in cores from Nymphe-1 North well (Barr, 1991). (A) Core logs of distal mouthbar and prodelta facies. Vertical scale in feet. (B) Examples of reservoir facies comprising medium and fine-grained sandstones.

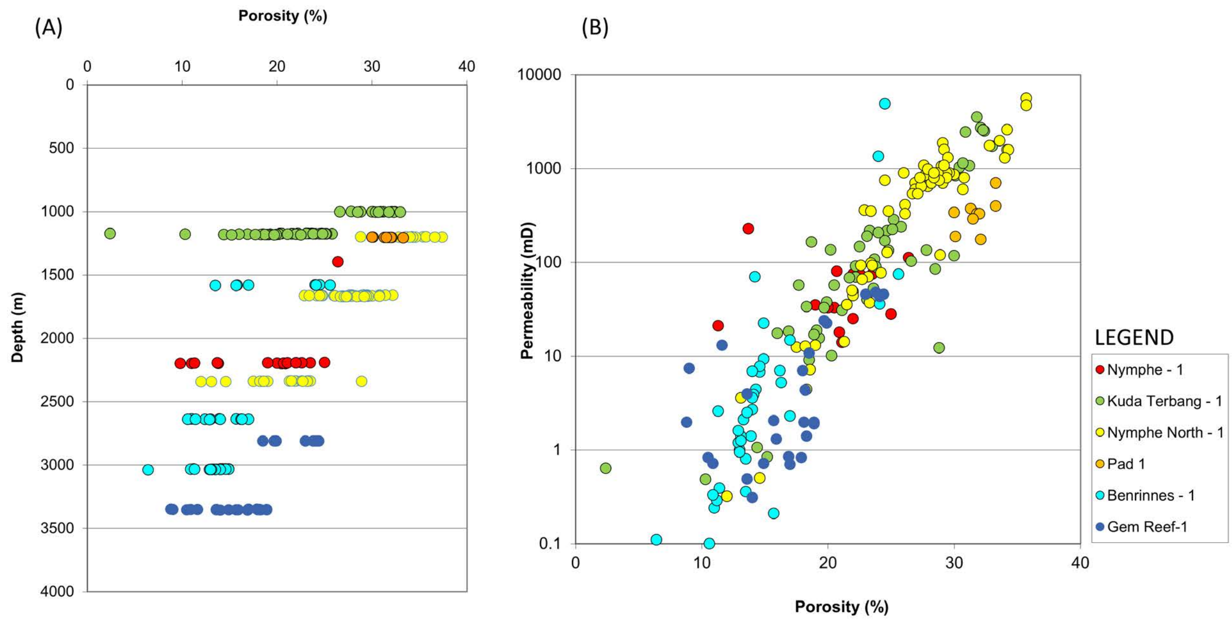

Figure 17: Porosity and permeability measured in cores from the Sandakan Basin. (A) Porosity and depth plot. Based on this dataset the porosity is expected to be less than 20% at ~3000 m, (B) Porosity-permeability relationship. At 3000 m, the permeability would generally be less than 10 mD.

Figure 17 shows the porosity and permeability data compiled from the available core samples (Barr, 1991). The best reservoirs for oil are upper shoreface sands with greater than 20% porosity. Lower shoreface sands are poor quality reservoirs deeper than about 2000 m. The porosity floor for these shoreface sands is around 3000 m. Lower porosities may occur at shallower depths in some areas as a result of basin inversion and uplift.

Source rocks

Source rock data from the Sandakan Basin have been previously reviewed by Leong & Azlina (1999). Although the main reservoirs targets are in the Sebahat Formation, potentially generative source rock intervals are mainly within the underlying Segama Group. However, the total organic carbon content (TOC) is generally less than 1%, with a maximum of 3%. Higher TOCs were recorded from coals found at Pad-1 and Gem Reef-1. The organic matter in the source rocks is dominated by higher-plant derived, Type III and Types II/III kerogen, as is typical of deltaic settings (ISIS, 2005; Velosi, 2008).

Direct correlation of the potential source rocks to the hydrocarbons could not be made due to the lack of biomarker data. Hydrocarbon samples from Mutiara Hitam-1 and Kuda Terbang-1, however, indicate two distinct source rock types: a marine influenced terrestrial source, shown by oils from Mutiara Hitam-1, and a deltaic/terrestrial source, shown by condensates and extracts from Mutiara Hitam-1 and oils and associated gases from Kuda Terbang-1. Based on the physical properties and petroleum system analysis, the gases and condensates at Nymphe-1, Nymphe North-1 (including the oil) and Benrinnes-1 probably belong to the latter group of source rock.

Thus, as in the Baram and Mahakam deltas, the hydrocarbons in the Sandakan Basin, ranging from light oil to condensate and gas, were mainly derived from dispersed terrestrial organic matter in the Miocene-Pliocene sequences (e.g., Tan *et al.*, 1999; Peters *et al.*, 2000; Jong *et al.*, 2017). The oils are generally classified as non-marine, paraffinic, liquid hydrocarbons, which are mature products of organic matter deposited in a fairly oxic, deltaic or lower coastal plain environments, and associated swamps and brackish water marine embayments. This interpretation is consistent with the general depositional environment of the Early-Middle Miocene succession in the basin, whereby fluvio-deltaic successions contain coals and coaly shales with abundant terrestrial derived organic matter.

Rock-Eval data (ISIS, 2005) indicate that the potential source rocks within the generative sequence are dominantly gas-prone, with minor oil-prone facies containing vegetal waxes and resins. The geochemical data also indicate that the generative source rock maturity was at ~0.74 – 0.80% equivalent vitrinite reflectance (VRo). Since no mature source rocks have been penetrated, the generative source rock is interpreted to lie at depths of more than 3200 m below the sea floor (Figure 18A). These are most probably mature coals and coaly shales, as well as shales with abundant dispersed terrestrial organic matter, occurring within the Lower Miocene (pre-Sebahat) interval.

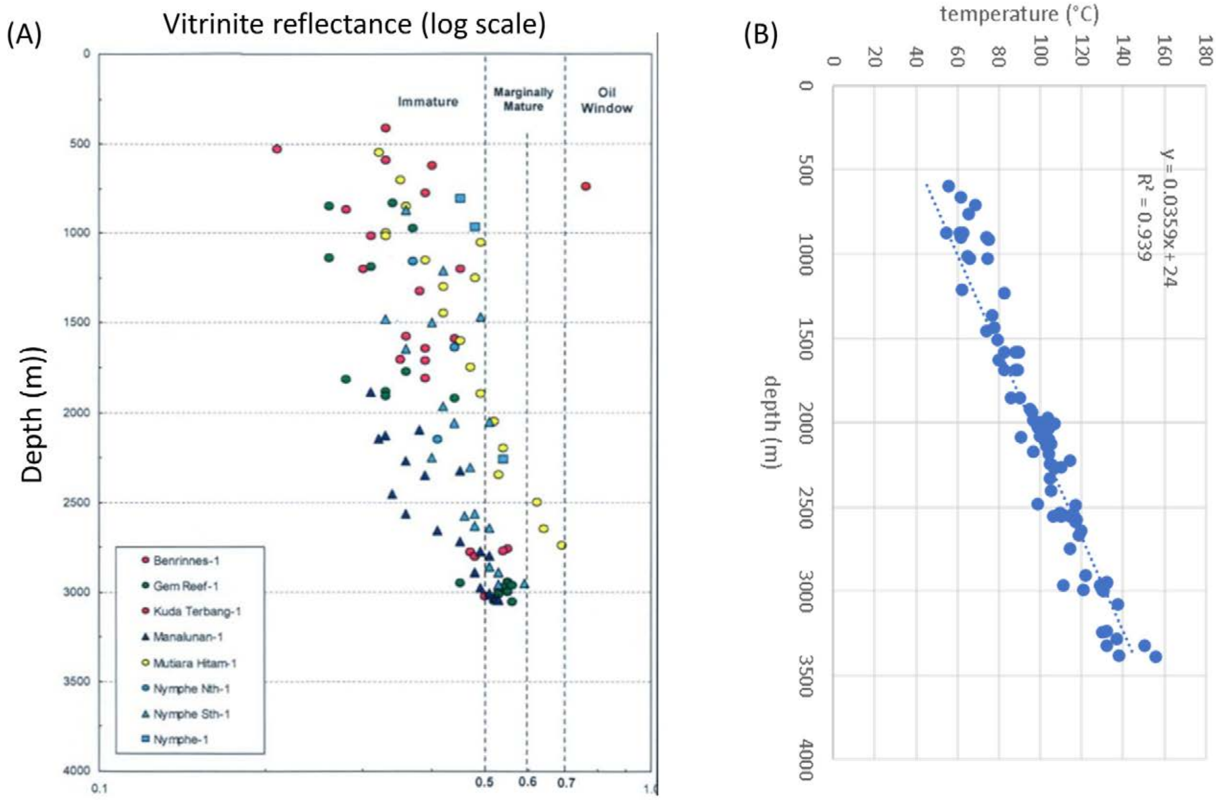

Figure 18: (A) Mean vitrinite reflectance (Ro) vs depth in wells of Sandakan Basin. The data indicate that the penetrated section is currently in the early mature stage. (B) Corrected bottom-hole temperature (BHT) data, with regression line indicating average temperature gradient of 35.9 °C/km, assuming temperature at seabed of 24 °C.

Hydrocarbon expulsion and migration

Due to the generally poor quality of the source rocks, it is thought that only small volumes of hydrocarbons have been expelled and trapped in the structures, as indicated by the drilling results. Hydrocarbons expelled from the source rocks, generally at depths greater than 3200-3300 m, may have migrated vertically through the major deep-seated faults that cut across the structures. It is worth noting, however, that the numerous occurrences of seeps in the area (Figure 2) could also indicate potentially high risk of seal breach. Thus, a detailed understanding of the migration and trapping histories would be critical in assessing the remaining potential.

Based on the seismic data (Figure 8), there had been several periods of structural growth associated with compressional stresses and erosional unconformities that put seal risk as a major concern for hydrocarbon trapping and preservation. Also considered a critical risk factor is the late timing of structural trap formation (Late Miocene-Pliocene, marked by the Base Ganduman Unconformity or 8.6 Ma SB) relative to hydrocarbon generation, especially for the shallower traps within the compressional structures. For instance, folding of the Base Togopi Unconformity (5.5 Ma SB) suggests relatively late structural growth of the Kuda Terbang anticline (Figures 8C, 13E). The same can be said of the Nymphe structures (Figure 8B).

Table 3: Calculated geothermal gradients from corrected bottom-hole temperatures in the wells. Average geothermal gradient is 35.3 °C/km.

Well Name	Longitude (°E)	Latitude (°N)	Gradient (°C/km)
Mutiara Hitam-1	118.8001	5.931793	36.4
Kuda Terbang-1	118.8182	5.752582	40.1
Benrinnes-1	118.7438	5.84489	34.4
Nymphe South-1	118.6963	5.717382	33.4
Manalunan-1	118.8036	5.623521	34.4
Nymphe-1	118.6829	5.77707	36.8
Nymphe North-1	118.6594	5.84313	37
Gem Reef-1	119.1363	5.567138	33.5
Magpie West-1	118.9924	5.793729	37.2
Segama-1	119.1713	5.600507	34.8
Kerupang-1	119.4654	5.346107	30.4

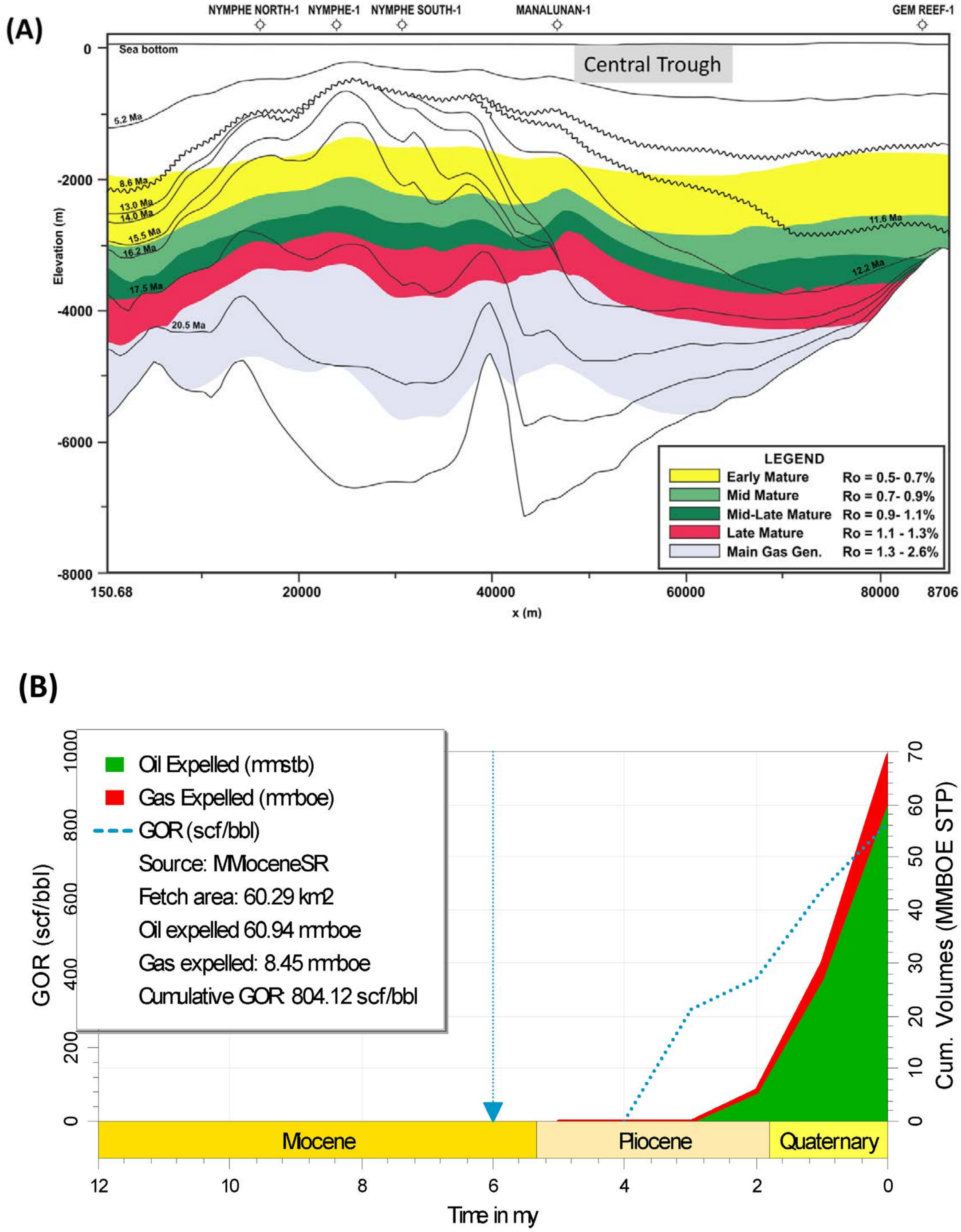

Figure 19: (A) Present-day maturity profile across the Sandakan Basin, along the Profile AA' (location in Figure 1). (B) Hydrocarbon expulsion model for the Sandakan Basin suggests that expulsion occurs mainly within the last 3 Myr (Mid-Pliocene) to present-day.

Due to the relatively low geothermal gradients of 30-40 °C/km (average 35.3 °C/km) (Table 3), the depth to the top of the oil window ranges from 2500 to 3500 m subsea and hydrocarbon expulsion probably occurred during Late Miocene to Quaternary (Figure 19A). Modelling results (ISIS, 2005) indicate that migration of hydrocarbons into the structures began during Late Miocene times. Source rock maturation and expulsion study (Jong & Futalan, 2015) suggests that the source rocks have been generating hyrocarbons since the Late Miocene to Pliocene (post-6 Ma) to the present-day and are currently within the peak oil generation window (Figure 19B). Thus, traps that were formed during the Pliocene would have received an oil charge. The study also suggests that gas-charged source rocks may exist within the deeper Lower Miocene section of the basin but further mapping and investigation are required.

The petroleum systems in the Sandakan Basin are summarised in Figure 20. The source rocks are mature coals and coaly shales, and dispersed terrestrial organic matter in the Middle to Late Miocene section of the Tungku and Sebahat formations, represented by the interval 8.6 – 16.2 Ma SB (Figure 11). The main target reservoirs are fluviomarine sediments (and some volcaniclastics) within the Segama Group (i.e., the Tanjong-equivalent Tungku Formation), mainly in the Northern Province, and the shallow marine sandstones in the Sebahat and possibly Ganduman formations in the Central Province, east of the Mutiara Hitam fault. Besides the siliciclastic reservoir targets, commonly observed on seismic are coeval shallow water carbonate build-ups within the Togopi Formation. These reefal stuctures are potential drilling targets in the Central and Southern provinces.

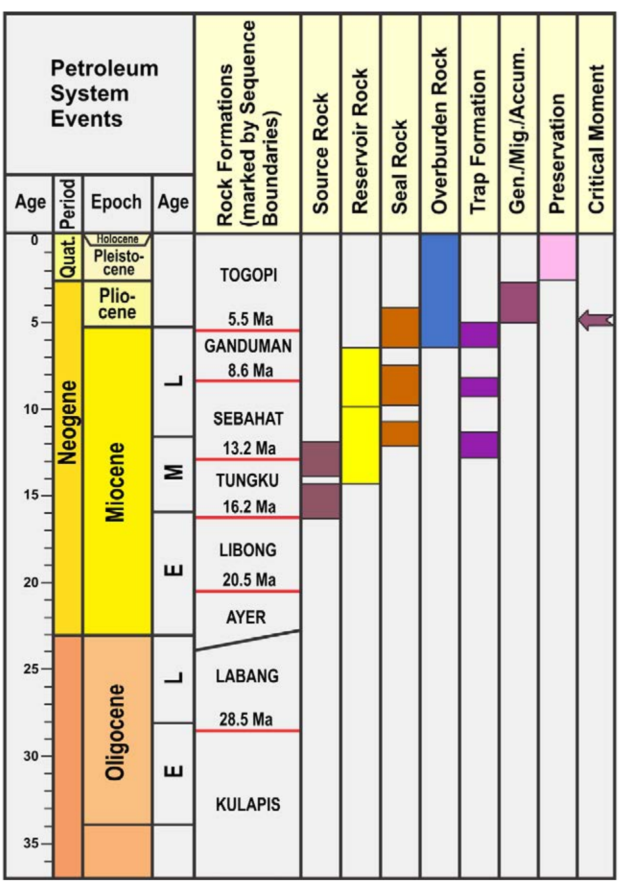

Figure 20: Petroleum system events chart for Sandakan Basin. The stratigraphic column is based on the revised scheme shown in Figure 5. The timing of hydrocarbon generation and migration ("critical moment") is based on modelling results in Figure 19.

Intraformational shales form the top seals to the fault-dip closures. In sand-rich areas, some seals may have been breached and resulted in short hydrocarbon columns. Nonetheless, an overburden of greater than about 800 m could still generally form an effective cap rock for traps that formed during the Pliocene uplift event. It is unclear, however, if the mudstones above the 8.6 Ma SB (Base Ganduman Unconformity) acted as an effective regional seal for the structures.

POST-WELL PLAY ANALYSIS

With the petroleum systems of the Sandakan Basin defined, we carried out a post-well analysis to identify the key risk elements of the petroleum systems that contributed to the success or failure of the drilled prospects. The post-well analysis also provides an understanding of the hydrocarbon potential and risks by comparison with historic analogues. We reviewed the exploration well results along with the available data, including composite logs, seismic and well completion reports, using Player® (www.gis-pax.com). This is a play-based exploration tool used to investigate which intervals (formations) in the wells may contain hydrocarbons based on the well results. For each prospective interval, either primary or secondary targets, the analysis considers all the critical risk elements: reservoir presence and quality, top seal and fault/side seal effectiveness, trap presence, and hydrocarbon charge.

The post-well analysis results are shown in the play summary in Figure 21. As the well results in Figure 11 and Table 2 show, the discoveries at Nymphe-1, Nymphe North-1 and Benrinnes-1 are mainly in the Segama play, while Mutiara Hitam-1 and Kuda Terbang-1 are in the Sebahat play. There is no discovery yet in the Togopi Formation, except for a gas show only in Benrinnes-1. The other wells are devoid of hydrocarbon accumulations, although the formations were tested and failed. This is likely due to the lack of charge and/or ineffective top seal at shallow depth in certain areas, probably compromised by the Pliocene uplift event. In the Ganduman Formation, which is not a primary drilling target, it is noted that hydrocarbon shows are present in Gem Reef-1, Benrinnes-1 and Kerupang-1, indicating insufficient charge at these well locations. The other wells were dry due to the lack of charge, poor reservoir quality or invalid trap definition.

The Sebahat Formation is a successful key objective, with oil and gas discoveries made at Mutiara Hitam-1 and

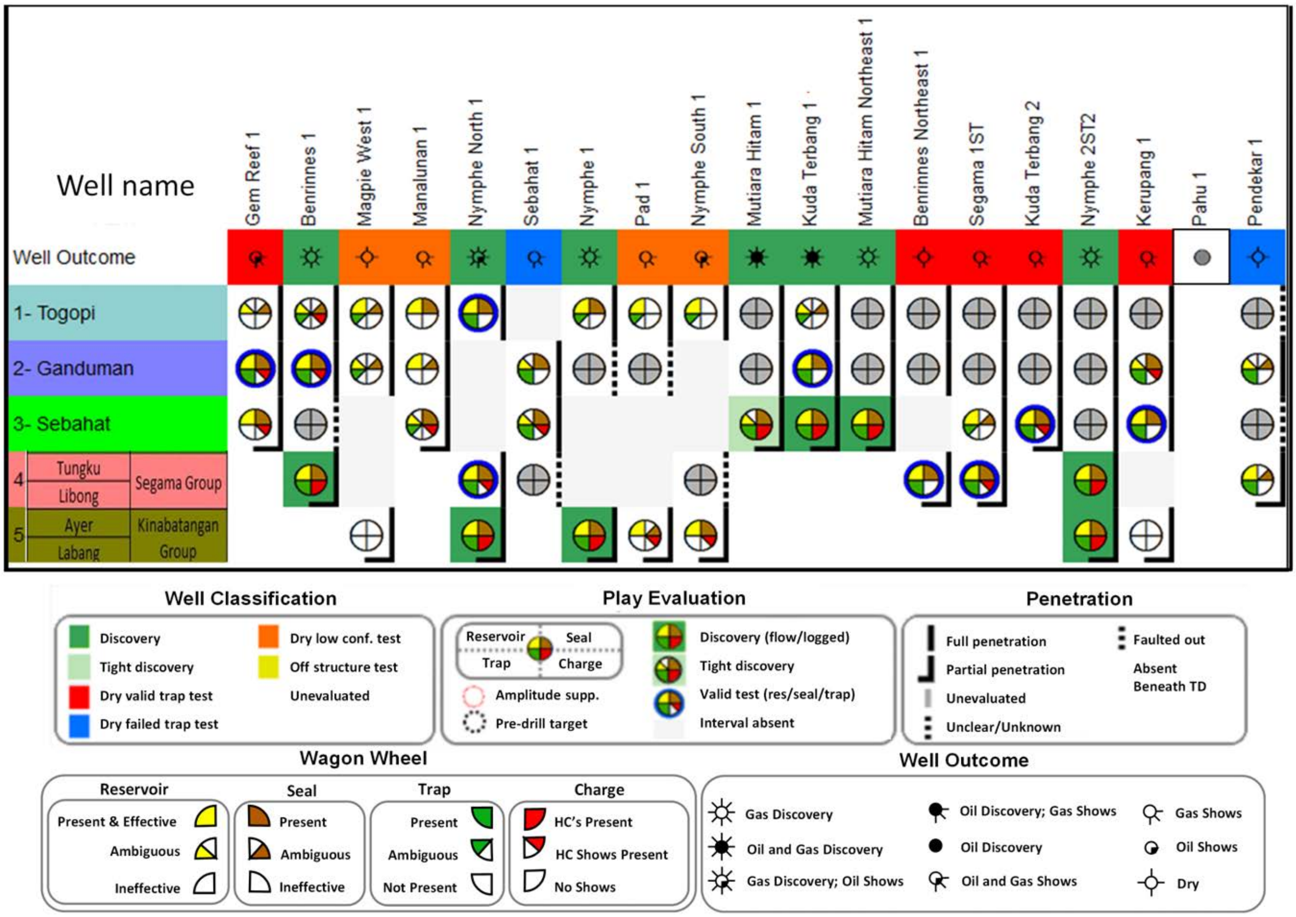

Figure 21: Play analysis summary of Sandakan Basin. Play classification according to Formation (left column); the most prospective are the Sebahat and Segama plays.

Kuda Terbang-1, and a gas discovery at Mutiara Hitam NE-1. Well Gem Reef-1 failed due to the lack of trapping configuration, while at other well locations failure was attributed to the lack of charge (Figure 21). The Segama Group (Tungku/Libong/Ayer formations) and Kinabatangan Group (Labang/Kulapis formations) are possible deeper targets for exploration in the Sandakan Basin. In the Segama Group, gas was found in Benrinnes-1 and Nymphe-2 wells. Failure in other well was attributed to the lack of charge. In the Kinabatangan Group, gas was discovered in Nymphe North-2, Nymphe-1 and Nymphe-2, while there were no valid traps at the Pad-1 and Nymphe South-1 locations. Volcanic rocks were penetrated at Magpie West-1 and Kerupang-1 (Figures 11 and 12). For the younger Togopi and Ganduman formations, where top seal and the lack of charge are major concerns, the targets would have to be buried at a depth of at least around 800 m below the mudline, based on data from offshore NW Sabah, to be an effective top seal (e.g., Jong *et al.*, 2016).

Uncertainties in 2D seismic interpretation may have contributed to invalid tests during the early exploration phase. Modern 3D seismic and processing technologies are critical for maturing the remaining structural traps, as well as the more subtle stratigraphic-related traps for future exploration. Currently, only the Northern Province is covered by 3D seismic. For successful exploration, the Sandakan Basin will need to be covered by modern, deep imaging 3D seismic for better trapping definition. This would help prevent the drilling of invalid structural tests such as Nymphe South-1 and Magpie West-1. Besides seismic, the recently acquired full tensor gradiometry (FTG) gravity data covering the Sandakan and Dent Peninsula areas (Haris, 2015) would certainly aid the interpretation of basin structure and the differentiation of intrusive igneous bodies and other basement highs from carbonate build-ups.

The various trap configurations in the Sandakan Basin are schematically illustrated in Figure 22 based on the actual hydrocarbon occurrences as well as potential traps that have yet to be de-risked. As mentioned, the primary drilling objectives are in the Sebahat Formation, the deeper Segama and Kinabatangan groups, and the Miocene carbonate build-ups. While the major trap styles associated with structural culminations have been tested by the drill to some extent, there are several other more subtle trap

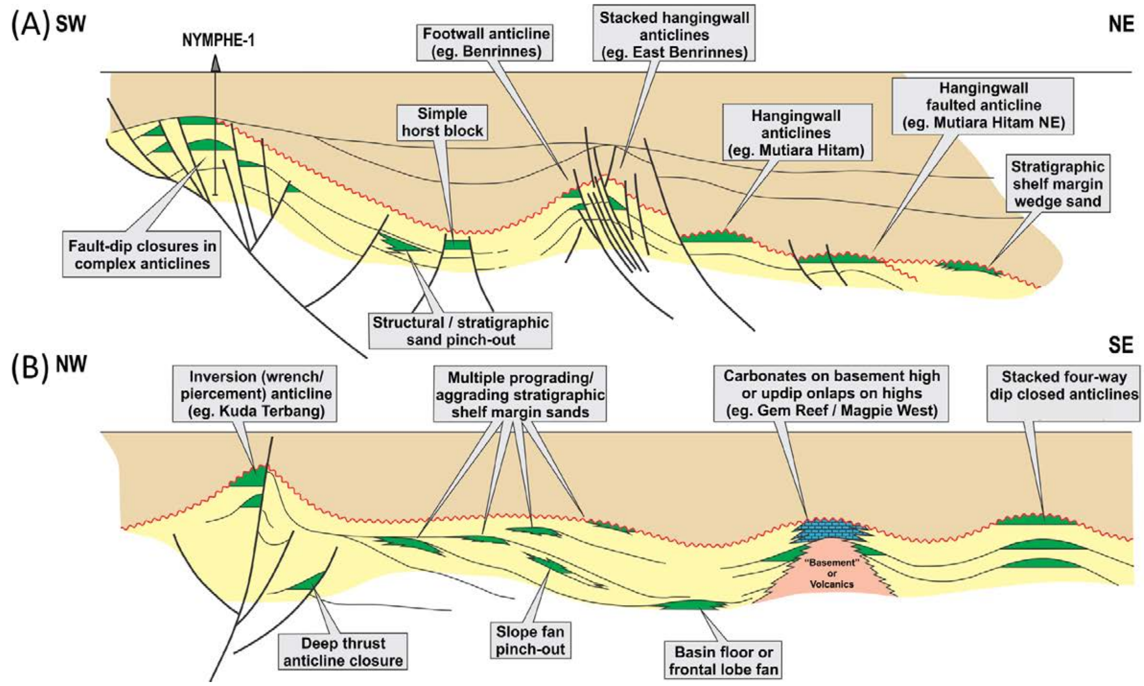

Figure 22: Schematic diagram of potential hydrocarbon trap styles in Sandakan Basin, based on the discoveries to date as well as future play concepts (modified after ISIS, 2005). (A) SW-NE profile from shallow to deep water with basinward hading growth faults modified by compressional wrench faults, especially in the inboard areas (e.g., at Nymphe-1). Approximately based on profile BB' in Figure 1B. Structural traps are mostly fault-dip closures in compressional anticlinal structures (inboard) and gravitational related rollovers (outboard). Onlapping shelf-margin sands may form stratigraphic traps. (B) NW-SE profile, approximately based on profile CC' (Figure 1B) depicting compressional anticlines at Kuda Terbang-1 passing into the synclinal Central Trough where shelf-margin sands may form stratigraphic and combination traps within the prograding clinoform package (Sebahat). Southeastwards, reservoirs can be found as basin floor fans in the deep troughs, as well as on the flanks of the basement/volcanic ridges capped by carbonate reefs, which are also potential drilling targets.

types, such as those associated with stratigraphic pinchouts against structural highs and unconformities. Quantitative interpretation and fluid substitution study would potentially help to predict the presence of hydrocarbons in these new plays, thereby further reducing the exploration risk in this relatively under-explored basin.

CONCLUSION REMARKS

Exploration in the Sandakan Basin has been going on for over 50 years since 1970. The first exploration period (1970-1995) during the Aquitaine and WMC era resulted in 5 oil and gas discoveries but all were sub-commercial. After a ten-year gap, the second exploration period (2005-2015) during the PETRONAS era also did not find significant amounts of hydrocarbons. The last well drilled was in 2015.

Most of the hydrocarbons encountered are in the late synrift (Segama Group) system of central Sabah and the succeeding post-rift (Sebahat Formation) sequences of Middle Miocene to Pliocene age that were formed as part of the southeastward prograding delta system. Due to major structural movements during Late Miocene and Pliocene (principally the 8.6 Ma SB), the timing of trap formation was relatively late compared to the probable timing of hydrocarbon migration.

In addition to the high sand contents as observed in some well locations, a major erosion event in Late Miocene (8.6 Ma), coupled with faulting associated with compressional tectonics pose significant risk to trap integrity and hydrocarbon preservation. Well data suggest that the generative source rocks are probably in early mature stage and occur at depths below the well penetration. Thus, hydrocarbon generation and migration, as indicated by basin modelling results, took place within the last 4–5 Myr and are probably ongoing. This, coupled with the low geothermal gradient, and the late maturation and generation of hydrocarbons relative to structural trap formation, pose another major geological risk for hydrocarbon exploration.

Sparse 2D seismic coverage in the basin during the early phase of exploration may have contributed to the invalid tests. Thus, further acquisition of 3D seismic using the latest processing technologies will be critical for maturing the new plays especially in the Central and Southern provinces, and could help to differentiate carbonate build-ups from volcanics and paleo-highs to reduce exploration risk. New data and techniques such as full-tensor gradiometry should be utilised in conjunction with quantitative interpretation, thermal history and migration modelling, and other geochemical prospecting tools to increase the chances of success in the relatively under-explored of the basin.

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AUTHORS CONTRIBUTION

MM - paper conceptualization, literature review, data analysis and interpretation, writing and editing, figure drafting; JJ - data analysis and interpretation, writing and editing, figure drafting.

CONFLICT OF INTEREST

The authors have no conflicts of interest to declare in connection with this article.

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