STATUS OF THESIS

Title of thesis	Updated Sequence Stratigraphy of Blocks A & B, Song Hong Basin, Vietnam.

I HAMZAH BIN HARUN hereby allow my thesis to be placed at the Information Resources Center (IRC) of Universiti Teknologi PETRONAS (UTP) with the following conditions:

1. The thesis becomes the property of UTP
2. The IRC of UTP may make copies of the thesis for academic purposes only.
3. This thesis is classified as

[√] Confidential

[ ] Non-confidential

Reason:

As instructed by Petronas Carigali Sdn Bhd (PCSB)

Endorsed by

Petronas Carigali Sdn Bhd, Level 16, Tower 2, Petronas Twin Tower, Kuala Lumpur City Centre, 50088, Kuala Lumpur.	Petronas Carigali Sdn Bhd, Level 16, Tower 2, Petronas Twin Tower, Kuala Lumpur City Centre, 50088, Kuala Lumpur.
Date: 18th February 2008	Date: 18th February 2008

APPROVAL

UNIVERSITI TEKNOLOGY PETRONAS

Approval by supervisor (s)

The undersigned certify that they have read, and recommend to The Postgraduate Studies Programme for acceptance, a thesis entitled "**Updated Sequence Stratigraphy of Blocks A & B, Song Hong Basin, Vietnam**" submitted by **Hamzah bin Harun** for the fulfillment of the requirements for the degree of MSc Petroleum Geoscience.

Date : 18th February 2008

Signature :

Main Supervisor : Othman Ali B Mahmud

Date : 18th February 2008

UNIVERSITI TEKNOLOGI PETRONAS

Updated Sequence Stratigraphy of Blocks A & B, Song Hong Basin, Vietnam

By

Hamzah bin Harun

A THESIS

SUBMITTED TO THE POSTGRADUATE STUDIES PROGRAMME

AS A REQUIREMENT FOR THE

DEGREE OF MSC. PETROLEUM GEOSCIENCE

IN PETROLEUM GEOSCIENCE

BANDAR SERI ISKANDAR

PERAK

FEBRUARY, 2008

DECLARATION

I hereby declare that the thesis is based on my original work except for quotations and citations which have been duly acknowledged. I also declare that it has not been previously or currently submitted for any other degree at UTP or other institutions.

Signature: ____________________

Name : Hamzah bin Harun

Date : 18th February 2008

ACKNOWLEDGEMENTS

First and foremost, my deepest gratitude to Petroliam Nasional Berhad (PETRONAS) for giving me the opportunity and sponsor my MSc programme in Petroleum Geoscience at UTP, and for granting the permission to use their data needed for this report. I would also like to thank to my supervisor, Mr. Othman Ali Mahmud for his guidance and encouragement during accomplishment of this projcct. To Puan Rashidah Karim and expert members at Level 16, thank you so much. Thank to Vietnam team and G&G support staff at Level 14 Tower 2 for being patient and helpful in accommodating my queries. My fellow classmates, you are the best and supportive. Last but not least, to my lovely wife, daughter and my family members for their moral support and prayers.

ABSTRACT

Blocks A & B are located in the Song Hong Basin, offshore, Northern Vietnam in a water depth of 25 to 30 meters. Company C is the operator with a 50% of interest. In 2004, Company C drilled the first commitment well (Well 6) and discovered minor oil and gas in the Middle Miocene sand. The subsequent well (Well 7) was drilled in middle 2006 which is turned out to be a dry well. The third exploration well drilled in end 2006 encountered significant amount of gas in the Middle to Late Miocene sands.

Plate tectonic reconstruction and geodynamic evolution showed that the Song Hong basin is a rift basin that was formed in the late Eocene/ Oligocene time. The basin formation and evolution is very closely related to the strike slip movements of the Red River Fault Zone following the collision between the Indian Plate and Eurasia Plate in the Oligocene time. The basin had undergone a series of extensional and compressional events that provided the main structural framework for hydrocarbon trapping mechanism in the area.

Four key seismic lines have been selected to identify sequence boundaries and to produce geoseismic sections. The study has identified six sequence boundaries that separated the depositional package into seven sequences. Two horizons namely, Lower Miocene and Base Pliocene were interpreted. Three paleogeographic maps and illustrated 3D models were produced. Based on the paleogeographic maps, Composite Common Risk Segment (CCRS) maps were produced and the results from the risk mapping suggest that these two blocks are in the medium to high risk zone in terms of petroleum exploration.

A working petroleum system is believed to be present in the basin based on a couple of discoveries have been made in Blocks A & B and the adjacent blocks. The first package in the early Oligocene sequence are believed to be deposited in the lacustrine setting that provided the main potential source rock in the area. The peak of the hydrocarbon generation and migration is believed to be in the middle Miocene time, which post-dated most of the structure formation. The main reservoir is the karstified and fractured pre-Tertiary carbonate rock. Other potential reservoirs are from the fluvial to deltaic in the Oligocene section and coastal, deltaic to shallow marine sands of Miocene sections. The seal is provided by intraformational shale and reinforced by a thick layer of regional Middle Miocene shallow marine shale. The traps are associated with the formation of syn-rift, horst and grabens and a latter series of inversion events that took place during the evolution of the Song Hong basin. Potential stratigraphic traps such as onlapping shallow marine sands and basin floor fan may also present. The area to the south of Block B warrant further investigation to delineate the potential of possible deposition of basin floor fan during sea level drops in the middle Miocene time. Nine play types were identified based on previous study and of the nine plays; five had been tested by previous wells while the four new plays will be investigated in the ongoing explorations programmed.

TABLE OF CONTENT

LIST OF TABLES

LIST OF FIGURES

LIST OF ENCLOSURES

CHAPTER 1
INTRODUCTION

1.1 INTRODUCTION

Block A and Block B are located in the northern part of offshore Vietnam (Figure 1.1) in a water depth of 25 to 30 meters. The total area of the two blocks is about 14 000 sq. km.

The two blocks are located in the Song Hong Basin (SHB) which is also known as the Yinggehai Basin in the China side (Figure 1.2a). The basin is located in the valley of Bac Bo between Hainan Island and mainland of Northern Vietnam. SHB is a rift basin oriented in a NW-SE direction where it covers an area of more than 60 000 sq. km. The basin is about 650 km long and 150 km wide and it is the largest Tertiary basin in the continental shelf of Vietnam. The onshore part of the SHB is known as the Hanoi Trough.

Based on several literatures, the central part estimated more than 10 km. deep. Using conventional seismic input, the basin is about 8 sec TWT, which corresponds to a depth of more than 15 km (Nielsen et al., 1999). Using gravity inversion and isostatic models, Vu & Rabitnowitz, 1996, suggest that the SHB has a maximum depth around 14 km. However, other estimates suggest a deeper depth about 15-20 km (Hirayama, 1991; Dinh & Troung, 1995; Hao et al., 1998).

Structurally, SHB is a valley-shaped depression bounded by two main NW to SE trending faults, called Song Chay and Song Lo Faults (Figure 1.2b). These faults are believed to be the seaward extension of the very prominent strike slip faults in the region, The Red River Fault Zone (RRFZ) (Zhen Sun et al., 2003).

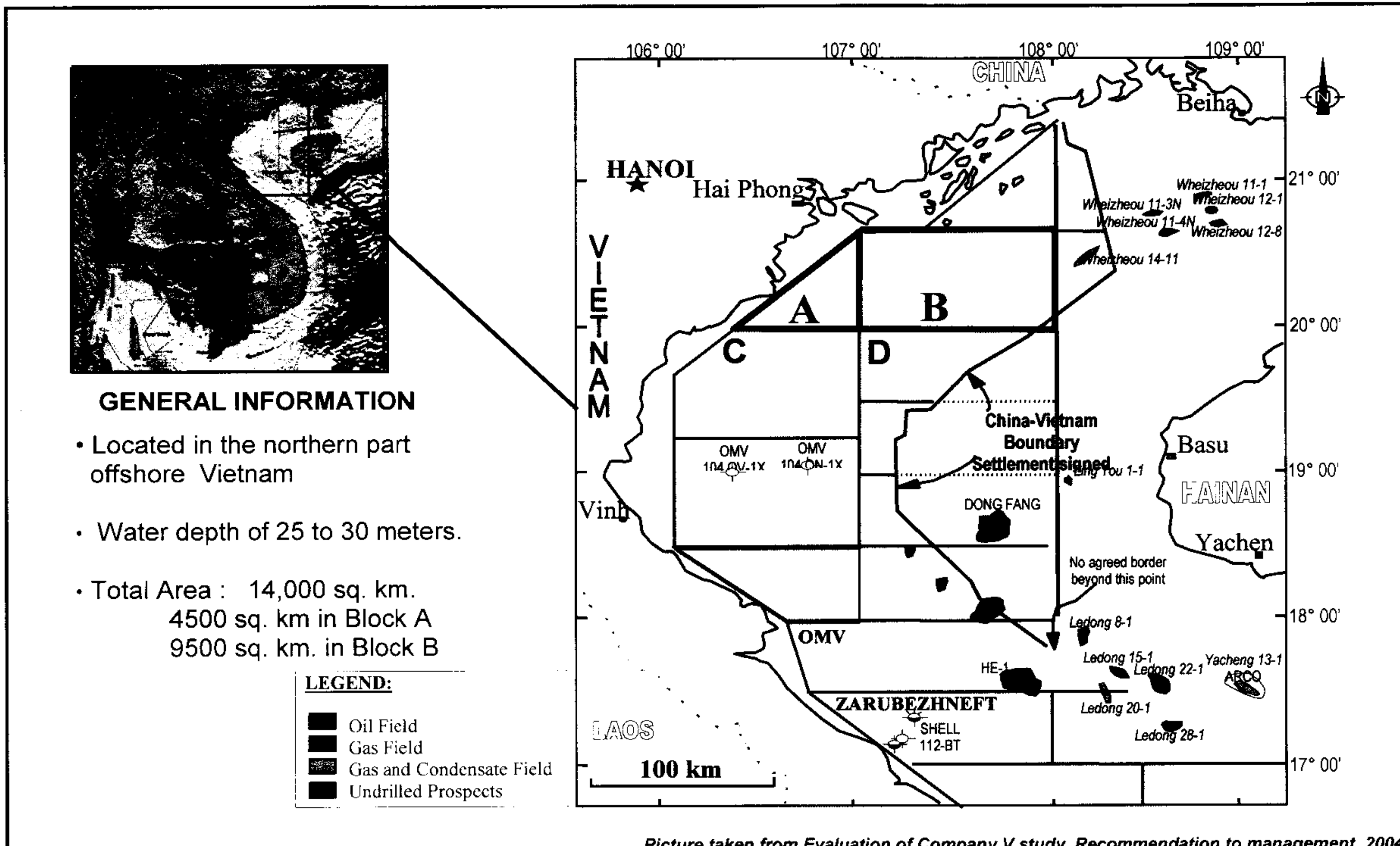


Figure 1.1 : Location Map of the Blocks A & B, Song Hong Basin Vietnam

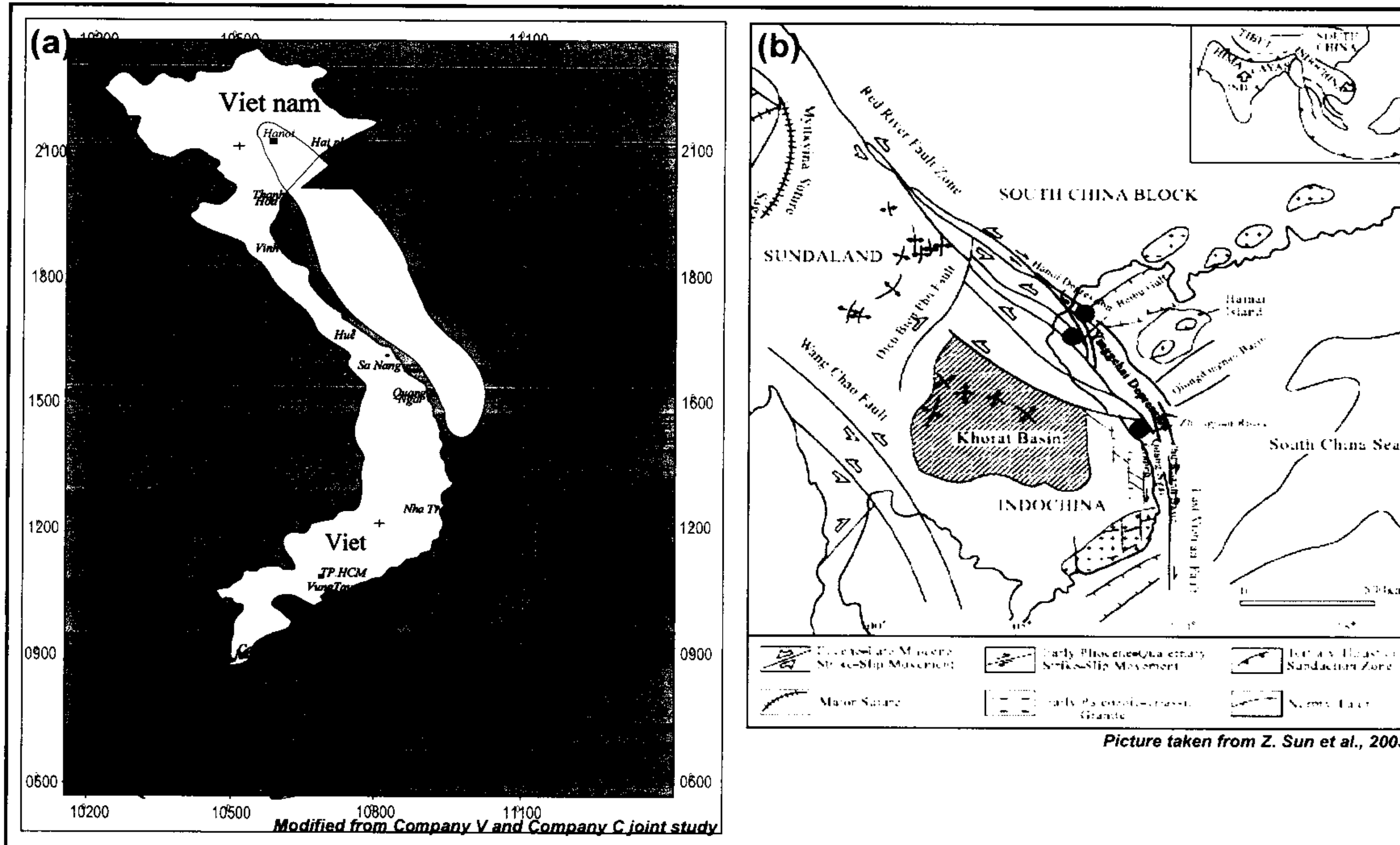


Figure 1.2 : Outline of Song Hong Basin (a) and major fault system related to Song Hong basin (b)

Several papers have been published to discuss and debate the types and direction of the strike slip movements of these faults where they are believed to have played a major role in the formation and evolution of the SHB. Ru (1988) believed that SHB developed along the NW Riedel shear plane under NWW-SEE transtensional stress field. Other authors proposed that the SHB was a dextral pull-apart basin along NW and NS faults (Gong & Li, 1997). However, Guo et al., (2001) suggested a sinistral oblique pull-apart model related to the Southeast extrusion and clockwise rotation of the Indochina block along RRFZ. Based on outcrops in northern Vietnam, the data indicates that RRFZ experienced a sinistral strike slip from 35 to 20 Ma (Leloup et al., 1995) and a shift to dextral movement after 5 Ma (Allen et al., 1984; Leloup et al., 1995).

SHB is surrounded by four other basins namely, (Figure 1.2); (1) Beibu Wan basin in the NE, (2) Qiongdongnan basin to the East, (3) Hoang Sa basin in the SE and (4) Phu Khanh basin to the South.

1.2 EXPLORATION HISTORY

In 1988, Company A signed the Petroleum Sharing Contract (PSC) over the area covered by Block B and parts of Blocks A, C and D. During the exploration stage, Company A acquired 9 200 km of 2D seismic lines with 60 fold full coverage (Figure 1.3). The grid spacing for the seismic coverage ranged from 4 x 4 km in the NE part to 2 x 2 km in the central and southern part of the Block B.

The objective of drilling these three wells was to test inversion structures in Blocks C and D in the northern part of the basin. Well 4 was drilled to a depth of 3 413m in March 1990 to test an inverted Miocene structure. The well penetrated several gas and condensate horizons from the Miocene sandstones with an estimated gas volume of 6 MMSCFG. However, Company A considers this small discovery as non-commercial.

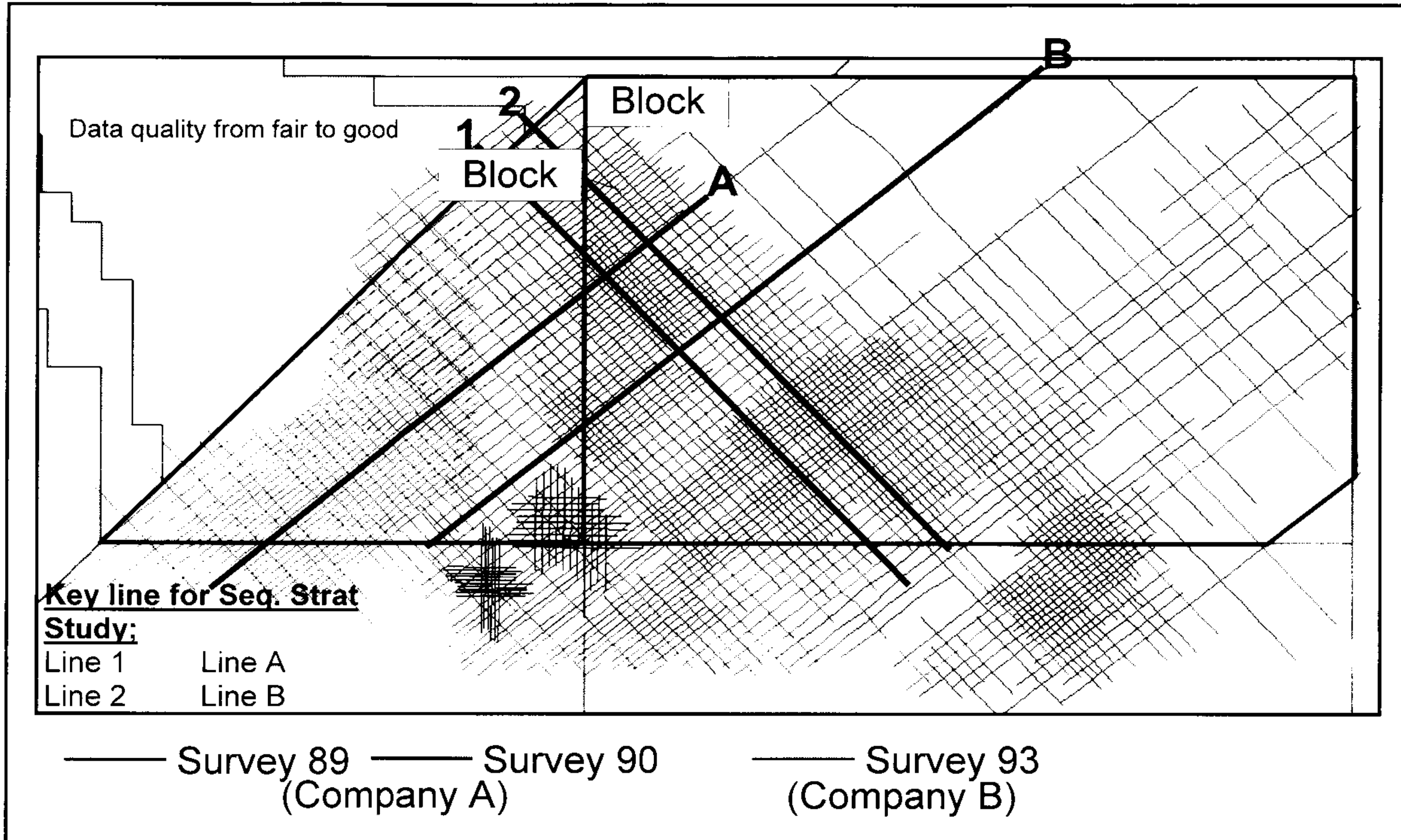


Figure 1.3 : 2D seismic data acquired from 1989 to 1993 by Company A & B

The second well, Well 5, was drilled in May 1990 to test fault dependent closures in the Oligocene section. The total depth (TD) of the well was 3 503m and was plugged and abandoned as a dry well.

Well 8 penetrated Eocene-Oligocene syn-rift sediments in a major inversion structure east of the Song Lo fault zone. However, the well only encountered traces of gas. Company A relinquished this whole area in 1991 without even drilling a well in Blocks A and B.

Company B signed the PSC on Block A in June 1992. They shot 2 270 km of 2D seismic lines in 1993 with 80 fold full coverage (Figure 1.3). The grid spacing for the seismic coverage in the center part of the Block A was about 1 km x 2 km. In the SW part of the block, the gridline, varied from 1 km x 4 km to 2 km x 8km and in the NE part, the gridlines were about 1 km x 2 km to 2 km x 4 km. In 1994 they drilled two wells, Well 2 and Well 3. Both wells were dry and they relinquished the PSC in September 1995.

In February 2003, Company C farmed-in into Block A and B and subsequently acquired some 450 sq. km. of 3D seismic data. Based on this new data, Well 6 was drilled on September 2004. The objective to drill this well was to test pre-Tertiary fractured karstified carbonate rock and Miocene/ Oligocene stratigraphic play. The result was very encouraging where 2.9 m net Middle Miocene oil sand with an average porosity of 18% and average water saturation (Sw) of 57% were encountered. Well 6 was the first oil discovery in offshore northern Vietnam and had proven the existence of petroleum systems inside the blocks. Production test (DST#1) carried out in the carbonate basement, the presence of gas was revealed, but the result was inconclusive with regards to hydrocarbon properties due to an immature test. The test was prematurely abandoned due to the high level of H_2S to surface during lifting.

In 2005, Company C conducted two additional new 3D seismic surveys, with 320 sq. km. in Block A and 284 sq. km. in Block B. The survey was completed in June 2005. In June 2006, a second exploration well, Well 7 was drilled. This well reached a final total depth of 1 930m. The objective of this well was to test pre-Tertiary fractured karstified carbonate rock and Miocene/ Oligocene stratigraphic play. The well was plug and abounded with oil and gas shows in both objectives. One production test (DST#1) in the Pre-Tertiary Carbonate basement was carried out. However the result for this production test only produced water with a flow rate of 516.5 stb/d. Another discouraging result from this well was that the Middle Miocene section was interpreted to be a sandy layer, however the formation turned out to be shaly.

In September 2006, Company C drilled discovery well, which is Well 1. A total of 70 meters net hydrocarbon zones were encountered in seven layers of Lower to Middle Miocene sands intervals. Two production tests were conducted with the flows of 23 MMscf/d and 24 MMscf/d.

CHAPTER 2
OBJECTIVES

2.1 STUDY OBJECTIVES

The objective of this study is to update the sequence stratigraphy of Blocks A and B in SHB carried out by Othman and Jaafar in 2006 with the incorporation of new well data. The latest well data included in the study are Wells No. 1 and No. 7 that had been drilled in 2006.

The results from this study will provide regional Geological and Geophysical (G&G) understanding of both blocks and the surrounding areas in terms of tectonic and basin evolution, paleo-depositional environment, sediment supply and the working petroleum system in the area using well information and sequence stratigraphic approach as evidence. This study also will show the result of play concept in the area as a follow up from the previous study.

The second objective of this study is to produce Common Risk Segment (CRS) maps and Composite Common Risk Segment (CCRS) maps. The result from CRS map will provide the subsurface distribution of potential reservoir, seal and source rock that constitute the main elements for a petroleum system in Blocks A, B and surroundings.

CHAPTER 3
DATABASE AND METHODOLOGY

3.1 DATABASE

An active exploration activity inside this block started back in 1988, where two companies (Companies A & B) had acquired a total of 11 470 km of 2D seismic data (Figure 1.3) with three vintage lines namely, 1989, 1990 and 1993. The data generally varied from fair to good quality at the zones of interest especially in the clastics and fractured carbonate rock. In addition, Company C acquired a total of 1 125 sq. km. of 3D data before drilling Wells 1, 6 and 7. The data quality was very good.

Data from eight wells (Figure 3.1) have been integrated into this study where four of the wells are located within the blocks and the remaining four wells from outside the study area. Out of the eight wells, only three wells (Wells 1, 6 and 7) have a complete well data set with the Mud Log, Wireline Log, Post-drilling Review and Petrographic analysis. The remaining wells data provided for this study are incomplete with only the Gamma Ray results and resistivity curves.

3.2 METHODOLOGY

The approach adopted in this study was based on Exxon's techniques (Van Wagoner et al., 1990), which defined sequence boundary as a product of relative falls in sea level.

Seismic data and well data (logs, lithology & biostratigraphy (if available)) were used to identify major bounding surfaces in order to establish a framework in which genetically related facies can be studied and a realistic depositional model can be constructed.

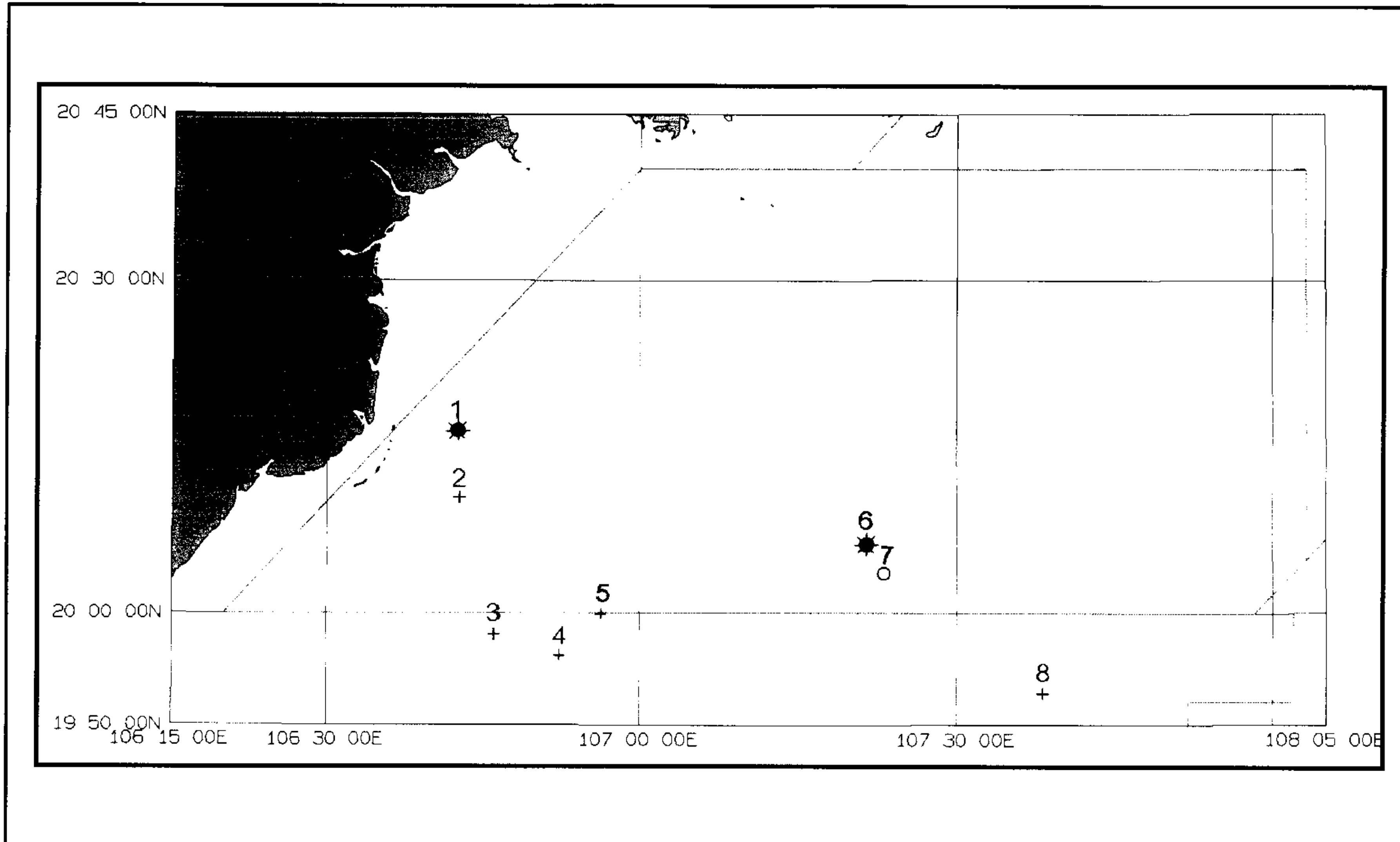


Figure 3.1 : Previous exploration wells drilled in Blocks A & B

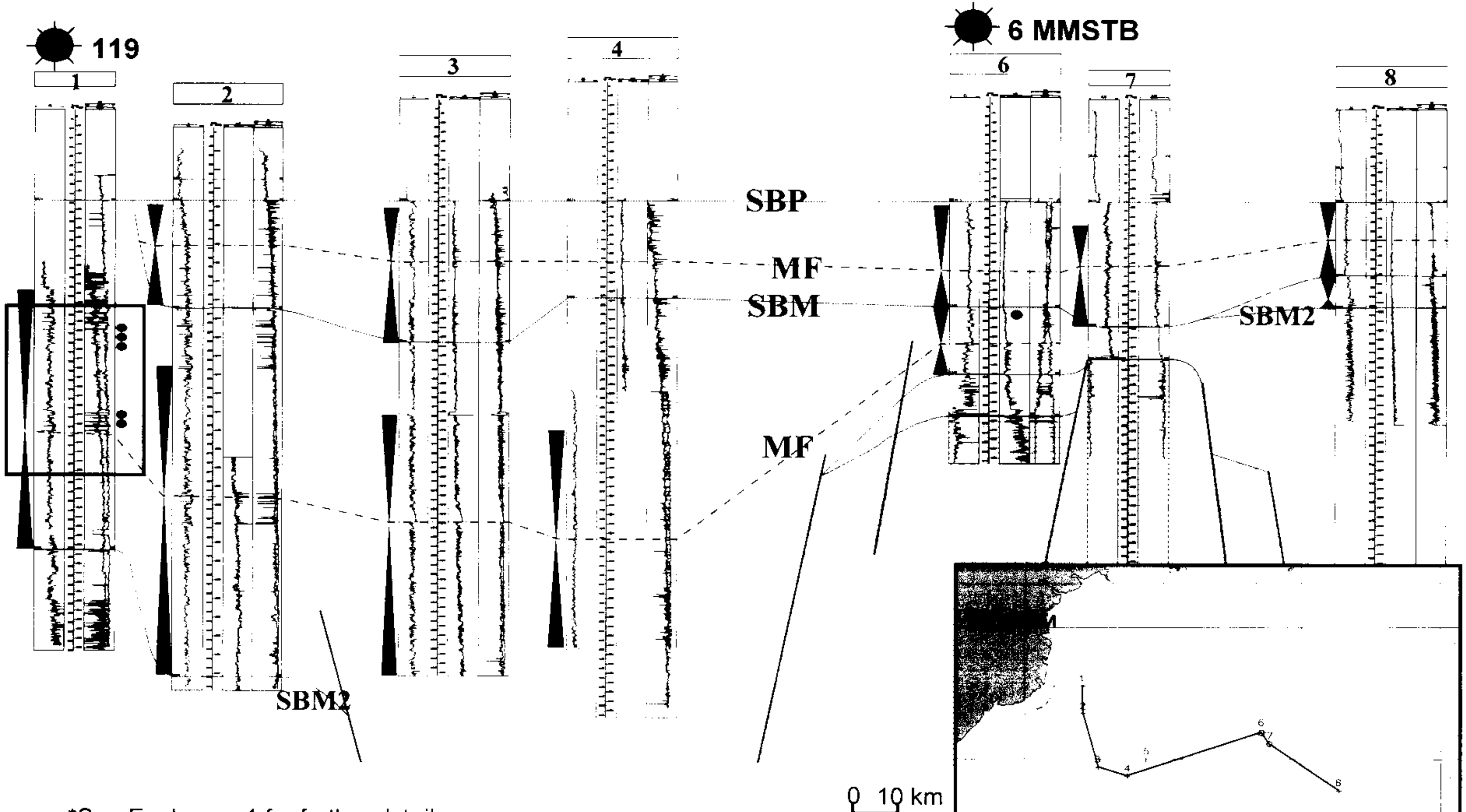
The key surfaces, which divide stratigraphy into its component parts, are sequence boundaries, transgressive surfaces, maximum flooding surfaces and marine onlap/ downlap surfaces.

The identified sequence boundary is the third order sequence boundary. Its derivation was based on potential time gap identified from seismic data as indicated by major bounding surfaces and reflector termination above and below the surfaces (strong reflector, truncation, toplap and onlap features) and comprised sets of components tracts (LST, TST, HST). These bounding surfaces were later validated with the well data and come out with well logs correlation (Figure 3.2). Well to well correlation was carried out mainly using Stratworks software in Linux machines. Normally, seismic data was extensively used in finding good well-to-well correlation. However, this method was not applicable in this study case.

Based on the available 2D seismic data, six major bounding surfaces dividing seven sequences were identified in the basin. The six bounding surfaces were named as Top Basement, SBO1, SBM2, SBM3, SBP4 and SBQ5. The six sequences divided by the seven identified surfaces in the basin ranged in age from Eocene to Quaternary.

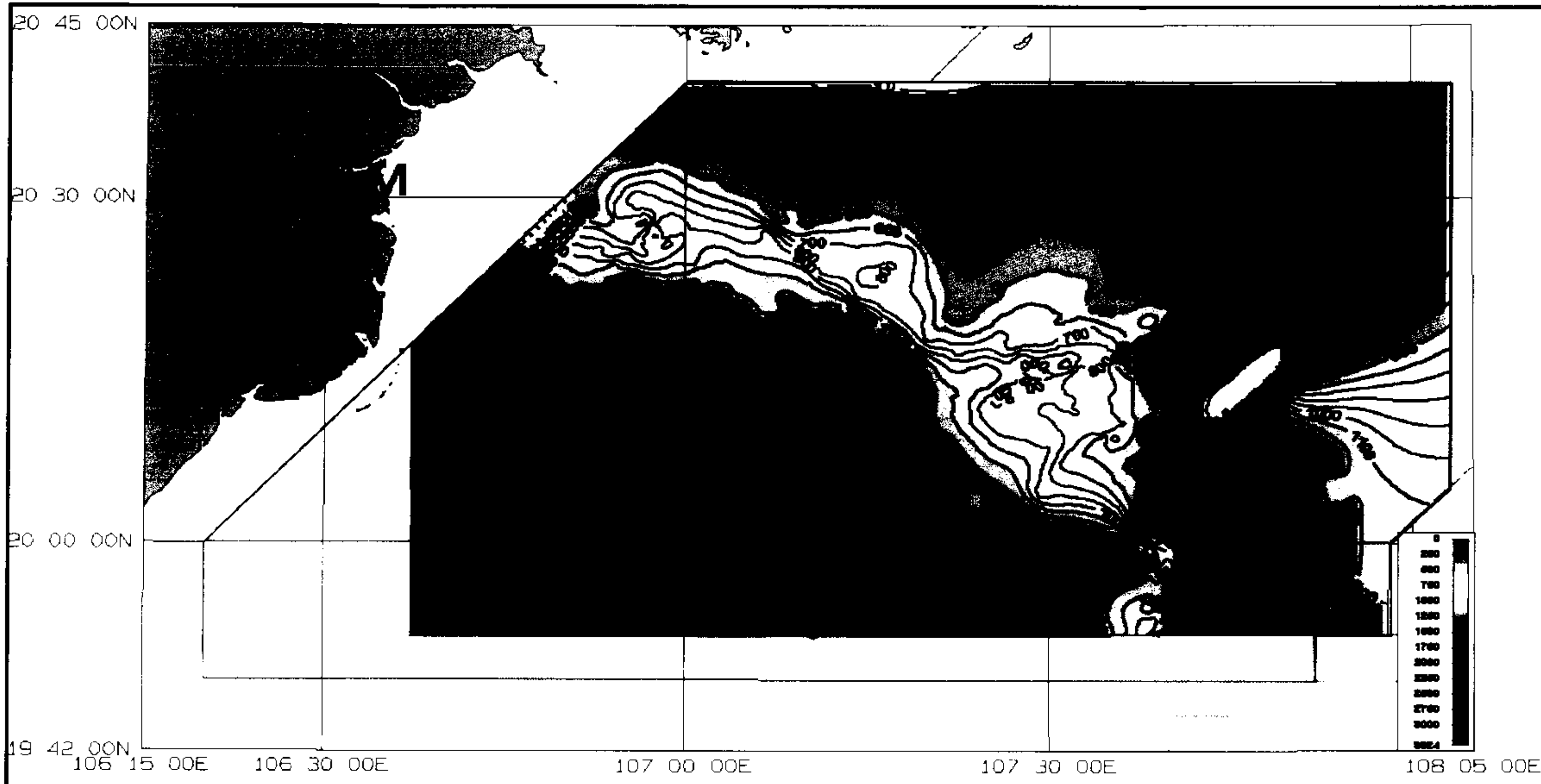
Sequence stratigraphic interpretation such as identification of sequence boundaries, maximum flooding surfaces, reflector terminations (onlap, downlap, toplap, truncation) were conducted on hardcopies of four selected key lines (Figure 1.3 and see Enclosures 6 to 9). All the six bounding surfaces identified from the key lines were later transferred to the remaining of seismic data using landmark workstation (Seiswork 2D).

The interpreted horizons in Seiswork 2D were later exported to Petrosys. Using this software, time map, depth map and isochore map were produced. For this mapping exercise, only two surfaces, SBM2 and SBP4 were produced (Figures 3.3 & 3.4). The red color corresponds to the lowest area in milliseconds while the magenta color corresponds to the highest area in milliseconds.



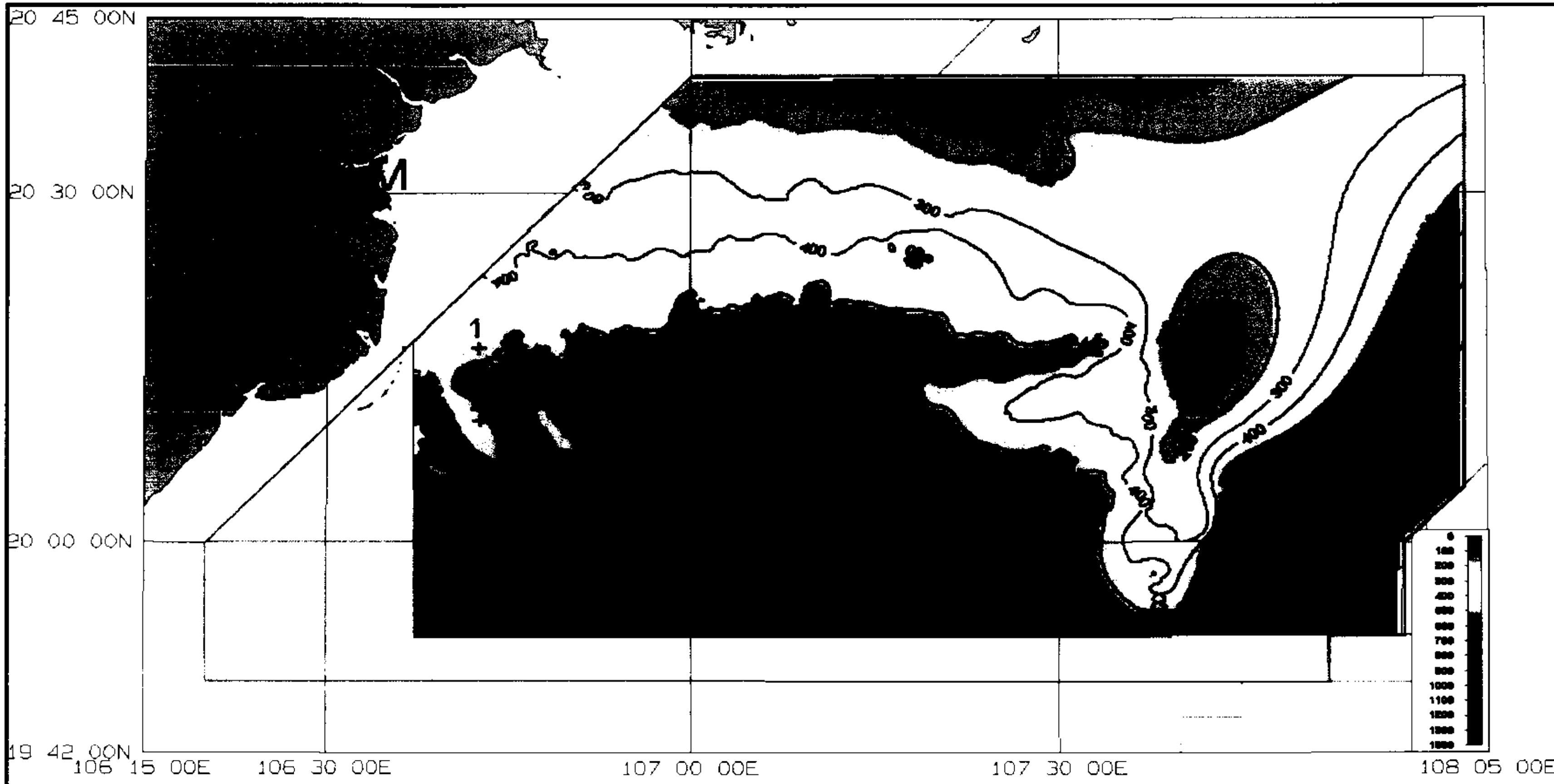
*See Enclosure 1 for further details

Figure 3.2 : Well correlation in Blocks A & B



*See Enclosure 2 for further details

Figure 3.3 : SBM2 (Base Miocene) time map



*See Enclosure 3 for further details

Figure 3.4 : SBP4 (Base Pliocene) time map

To produce depth map, information from the well such as check shot or Vertical Seismic Profiling (VSP) data are required to generate time-depth graph conversion and polynomial function. All eight wells showed consistent two way time (TWT) to depth relationship. An average velocity function (Figure 3.5) was used to convert the time map to depth map (Figures 3.6 & 3.7). The red color corresponds to the lowest area in depth or the area closest to the surface and magenta color correspond to the highest area in depth or represent basin region in this block.

Another interesting tool provided by Petrosys is the 3D viewer. Both the time and depth maps can be viewed with 3D visualization and it provides better understanding in the visualization of shapes or structures at a particular horizon. Figures 3.8 and 3.9 showed the difference between 3D in time and in depth at SBM2 and SBP4.

Isochron maps were produced by subtracting two horizons of two way time map. The isochron maps were later used as an input to generate the paleogeographic maps. The paleogeographic maps combined with well data and after G&G information were used to generate the Common Risk Segment Maps (CCRS).

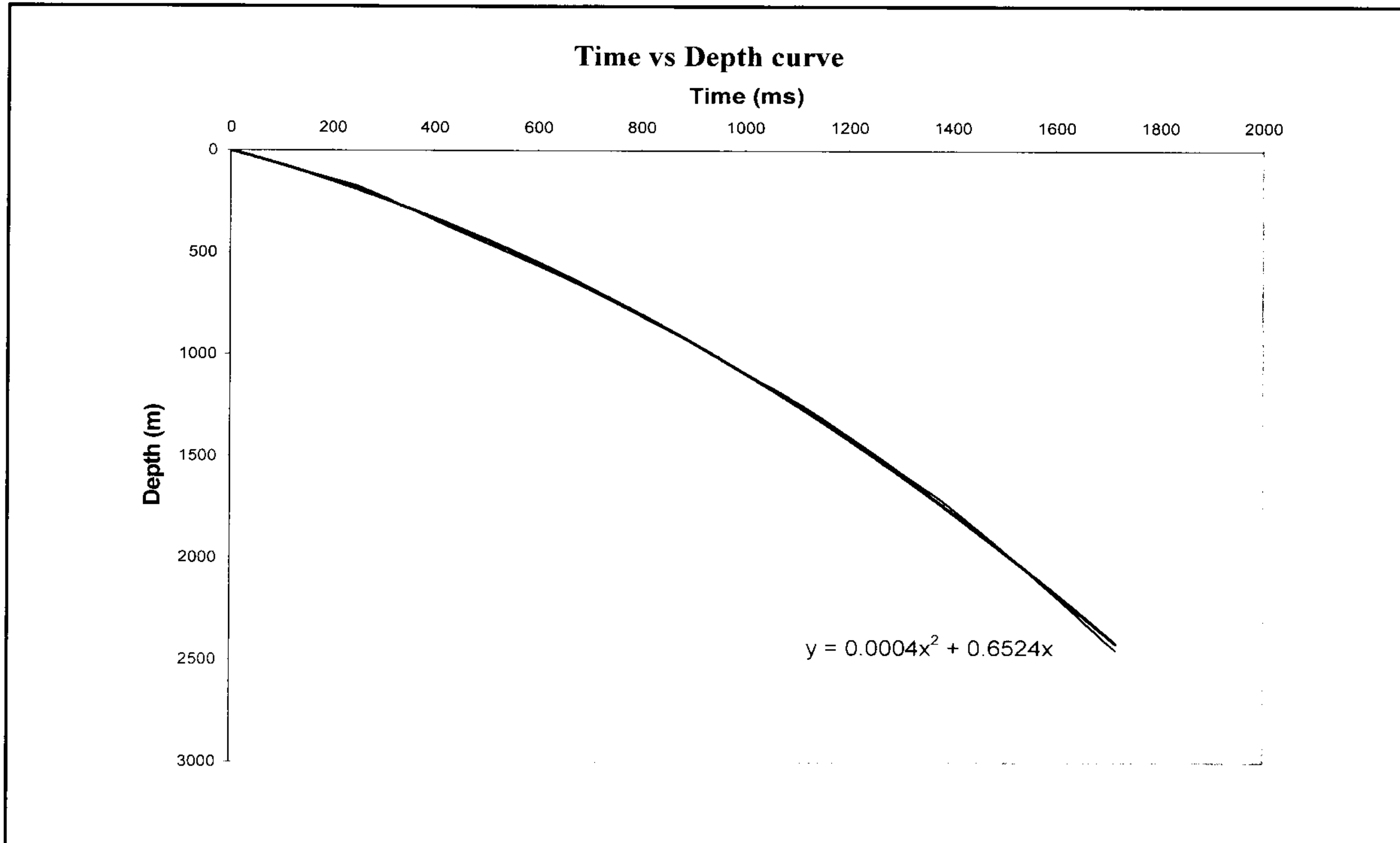
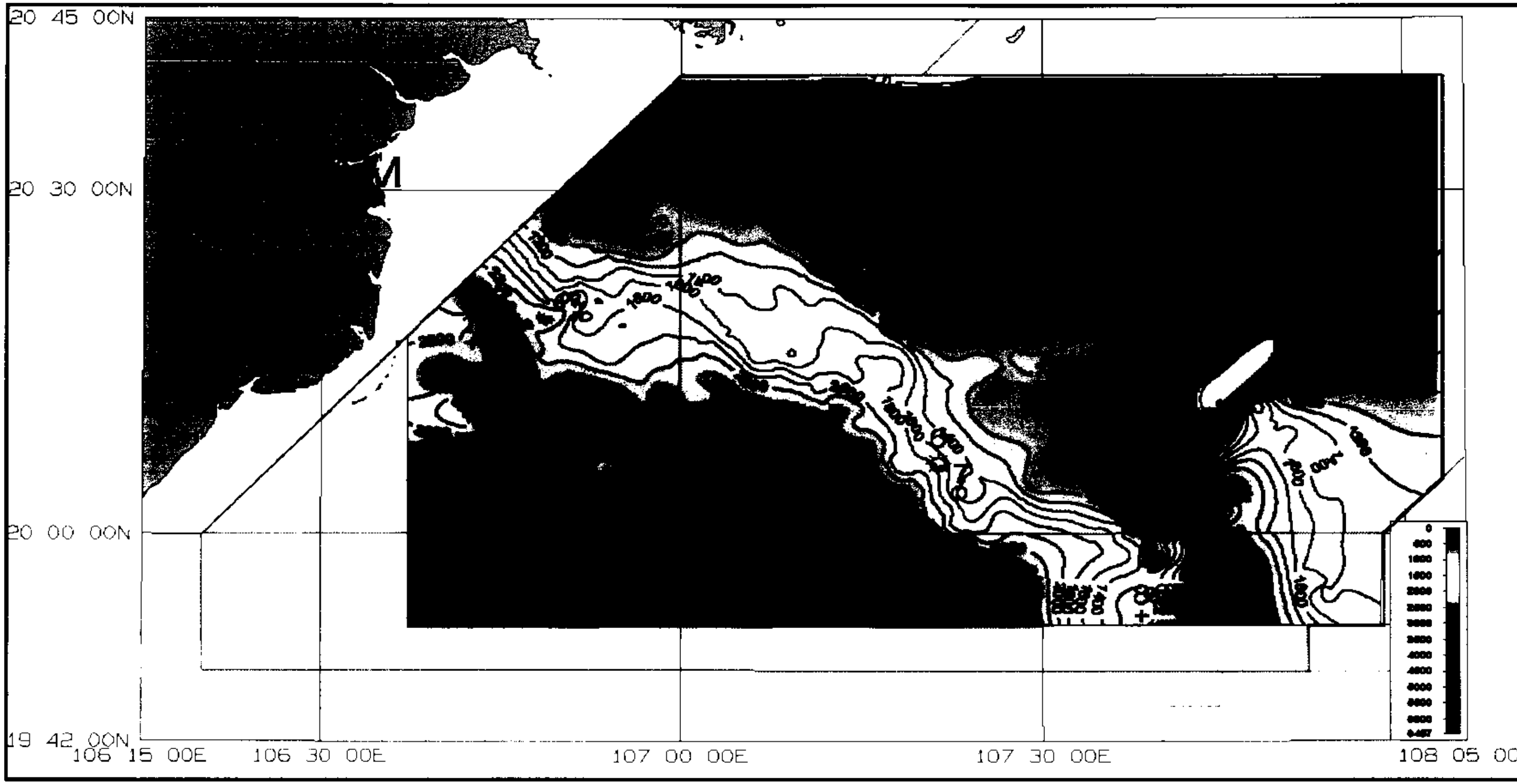
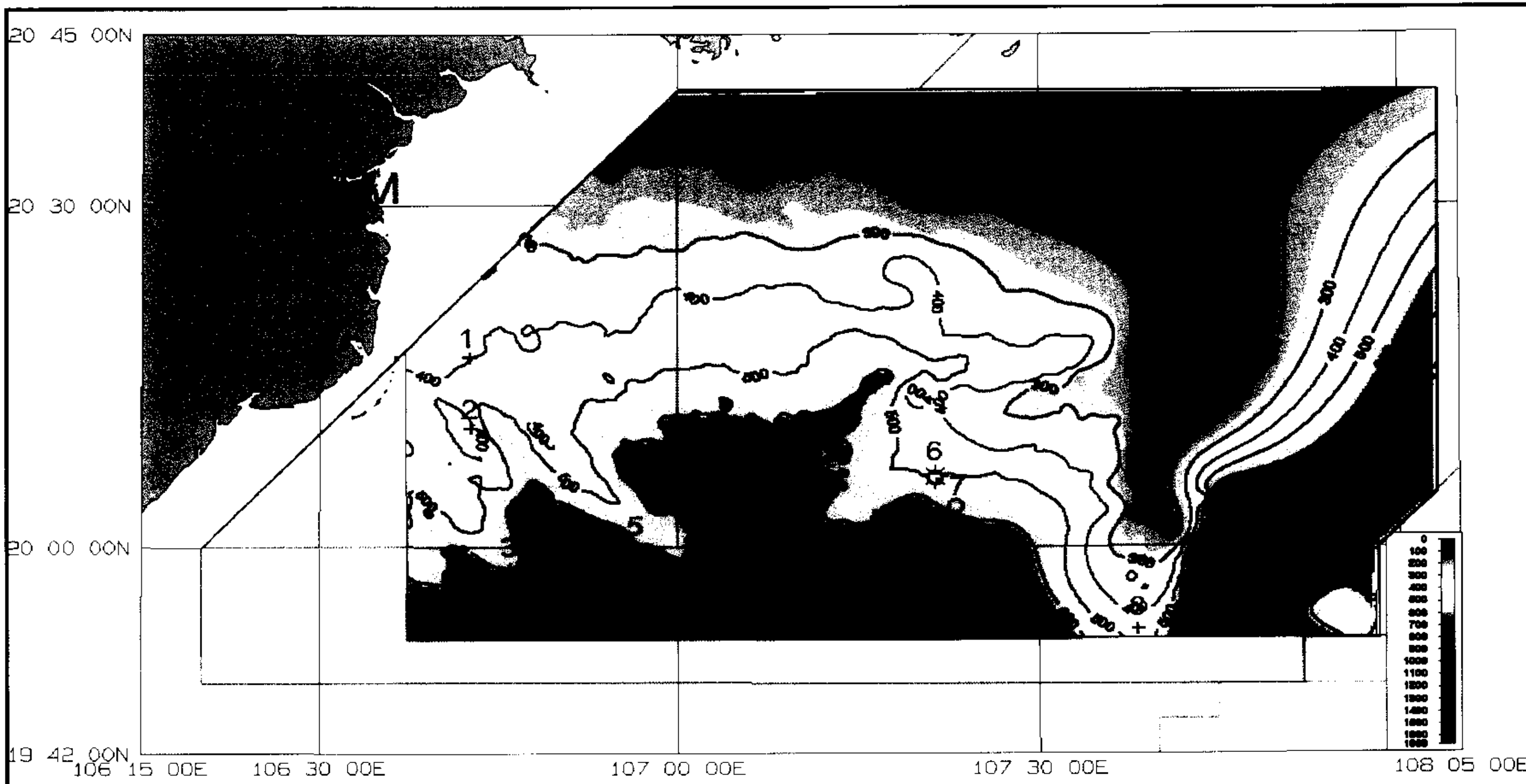


Figure 3.5 : Average Time vs Depth curve



*See Enclosure 4 for further details

Figure 3.6 : SBM2 (Base Miocene) depth map



*See Enclosure 5 for further details

Figure 3.7 : SBP4 (Base Pliocene) depth map

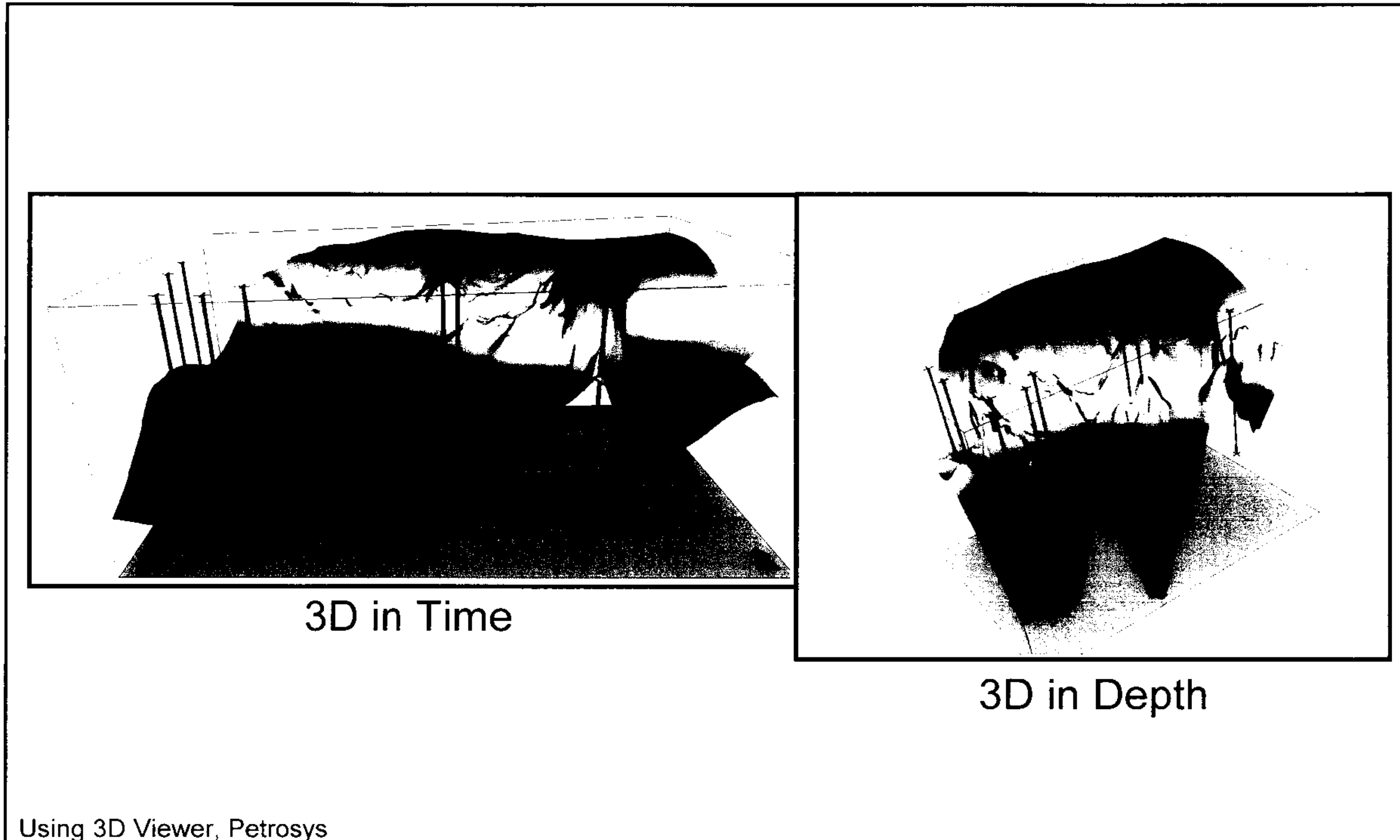


Figure 3.8 : The difference between 3D in time and depth for SBM2 (Base Miocene) section

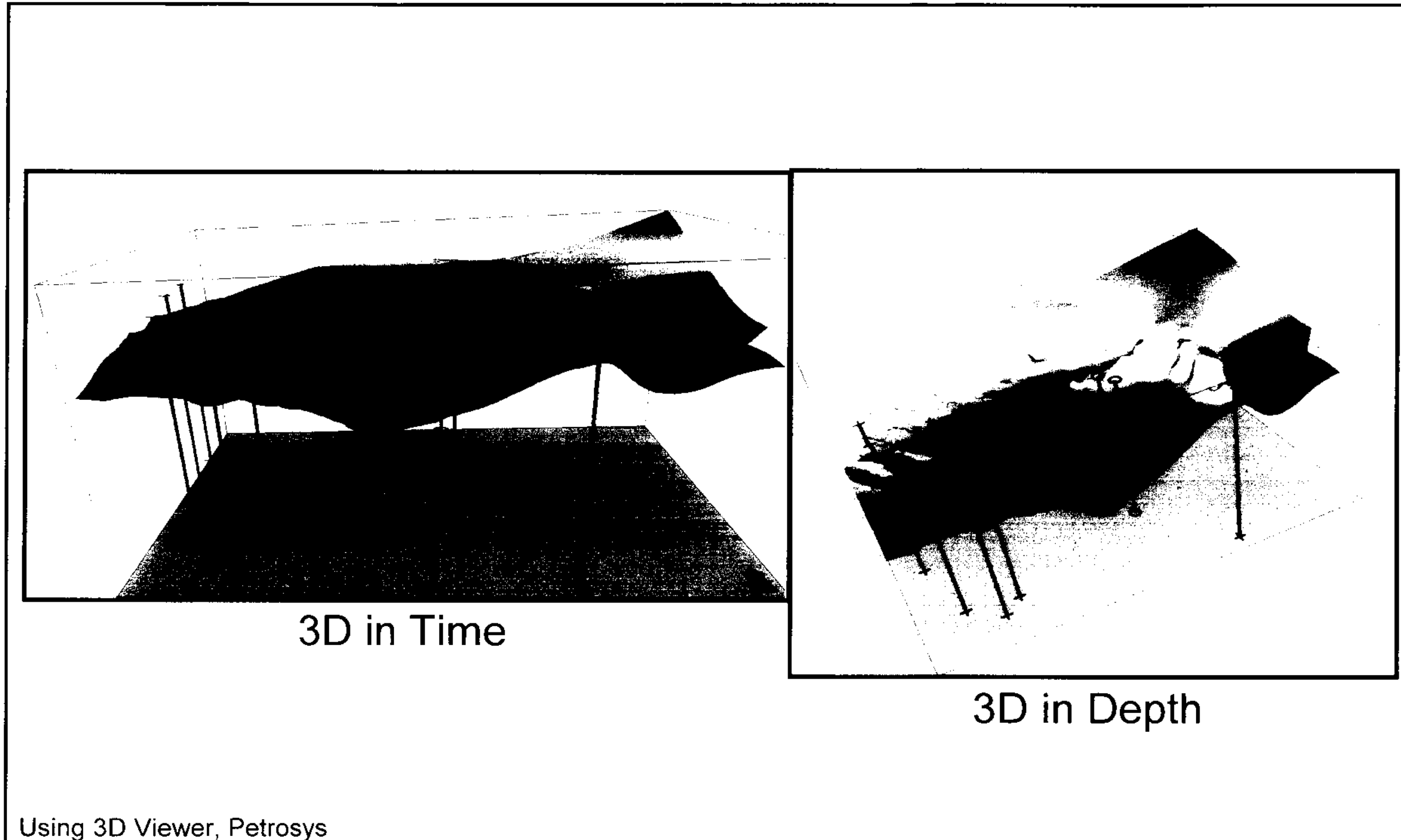


Figure 3.9 : The difference between 3D in time and depth for SBP4 (Base Pliocene) section

CHAPTER 4
TECTONIC SETTING & BASIN EVOLUTION

4.1 INTRODUCTION

The Vietnam continental shelf area constitutes a part of the Cenozoic sedimentary basin that lies within a transition zone from the continental crust of Indochina to the sub oceanic crust of the eastern deep water basin. The basin that developed here are rift basins with multiphase history or stages of extension, rifting and sea floor spreading (Pigott & Ru, (1994); Lee & Lawyer, (1994). The evolution of SHB resulted from the movement of 5 plates; (1) Indian plate, (2) Eurasian plate, (3) Indochina plate, (4) Sunda plate and (5) South China plate.

Tectonic evolution in the area had provided major regular sedimentation along the Indochina margin such as fluvial and lacustrine delta deposits during Oligocene up to shallow marine, shelf and slope deposits during Quaternary. The tectonic evolution also created a structural framework with a mechanism for hydrocarbon trapping in the SHB (Othman & Jaafar, 2006).

4.2 T ECTONIC SETTING & BASIN EVOLUTION

During Late Cretaceous to Early Eocene, the movement of the Indian plate to the North created NW-SE regional extension (Figure 4.1). This regional extension caused the formation of a NE-SW trending proto-East Vietnam Sea, as well as regional uplift and a series of rift basins along the southern margin of China (Nielsen et al. 1999). Based on Dien & Dzung (1994), they interpreted the molasses-type deposits dominated by alluvial, fluvial conglomerates and sandstone was deposited during this time (Figure 4.2). Other authors interpreted the terrestrial redbeds and lacustrine mudstones were deposited in this basin (Pigott & Ru, 1994; Zhou et al., 1995).

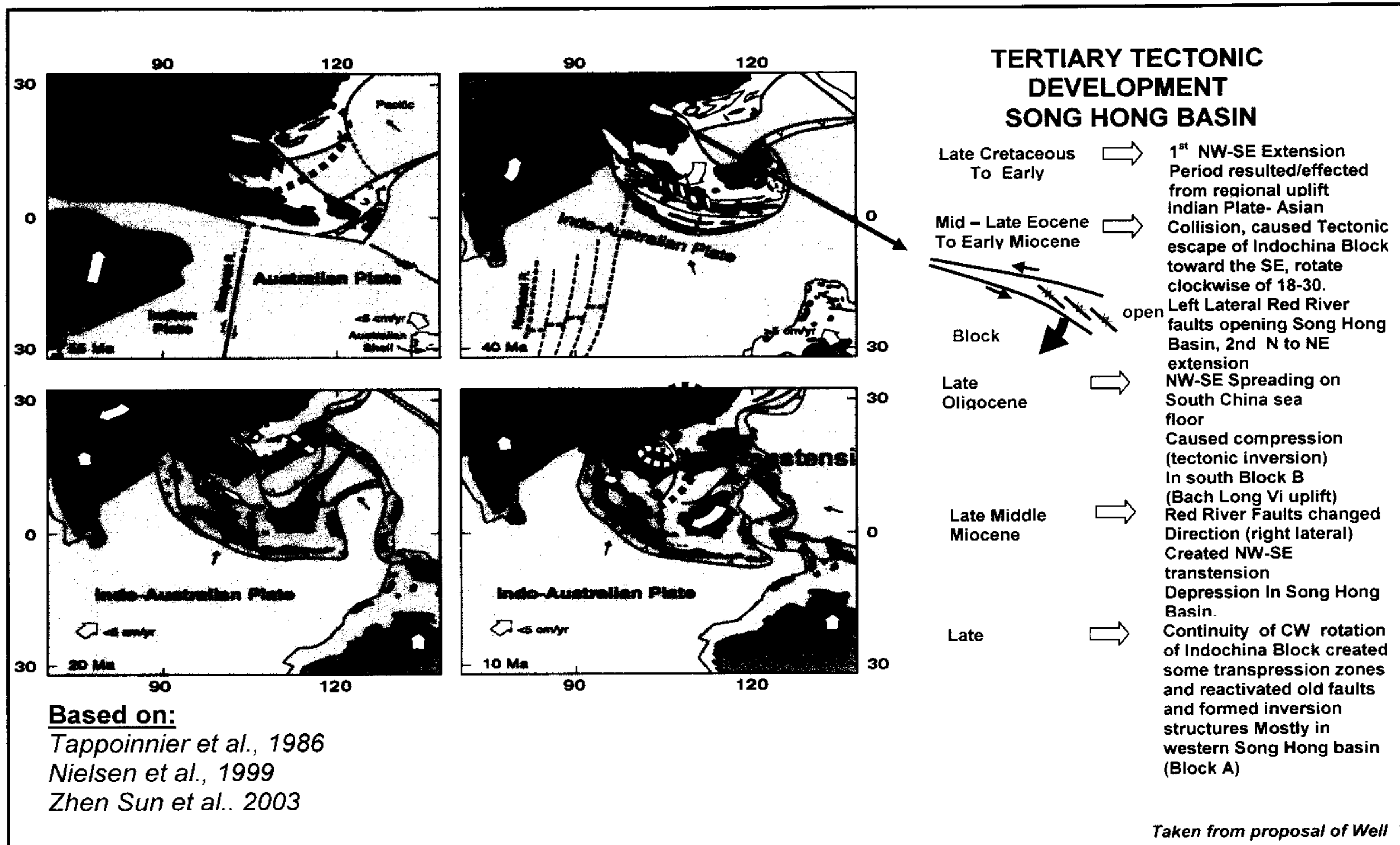


Figure 4.1 : Plate Tectonic setting of Song Hong Basin

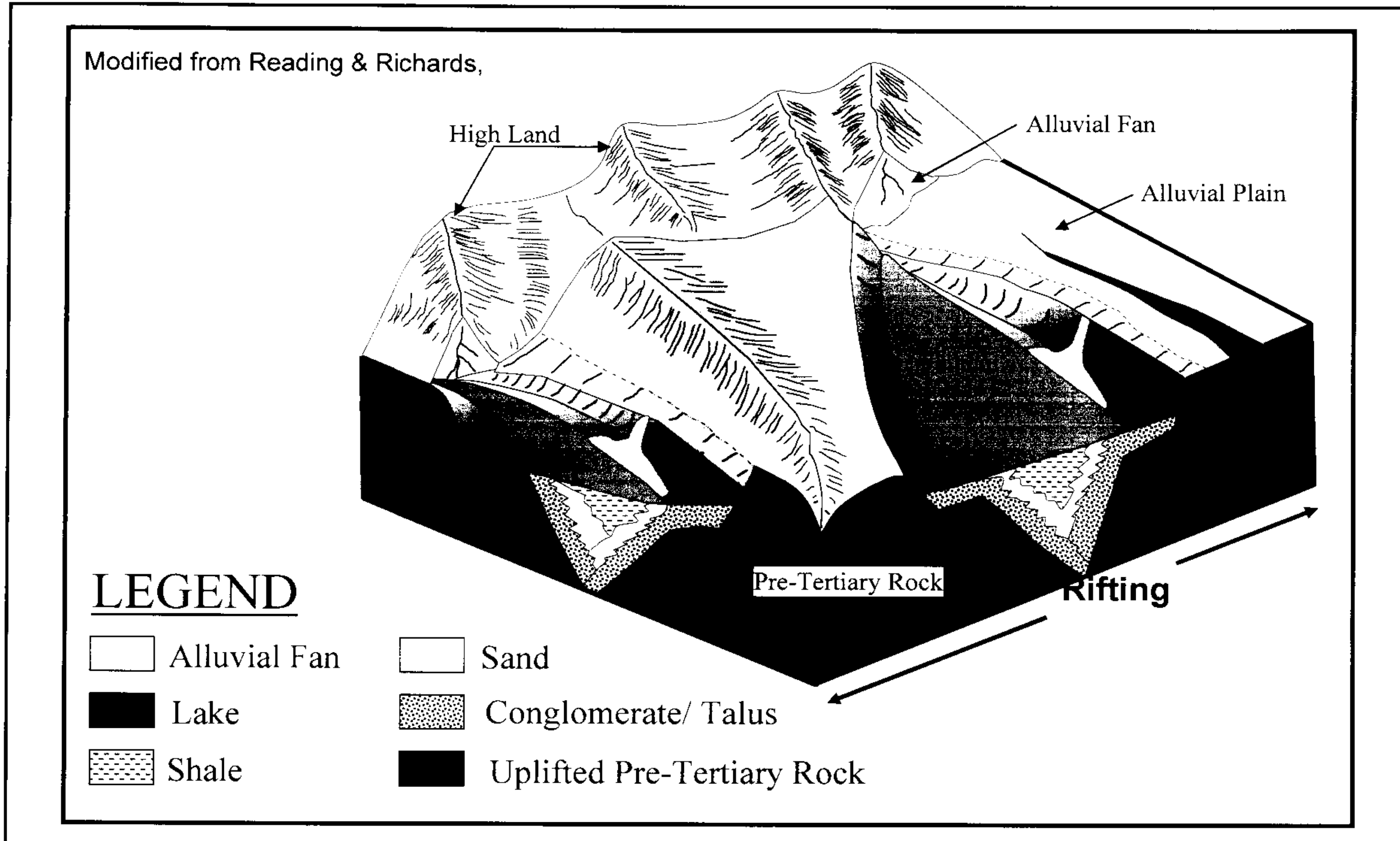


Figure 4.2 : Illustrated 3D model – Eocene to Middle Oligocene

From Middle - Late Eocene to Early Miocene, a second phase of regional N-S extension was accruing. This extension started when the continental of Indian Plate collided with the Eurasian Plate (Tapponnier et al., 1990; Huchon et al., 1994; Lee & Lawver, 1994). The impact caused the Indochina Plate to move towards SE and rotated 18^0 - 30^0 clockwise and resulted in the opening of the East Vietnam Sea. The left-lateral movements along Red River Fault system started the formation of the SHB. The strike-slip movement occurred mainly along the Song Chay and Song Lo fault zones (Figure 1.2). The displacements between these two faults are more than 200 km and possibly up to 500 km (Peltzer & Tapponnier, 1988; Briais et al., 1993; Leloup et al., 1995). During the rifting phase, structures like grabens and half-grabens were formed inside and the adjacent basin. At the same time, the grabens were being filled with the Dinh Cao Formation (Figure 4.3), which comprised fluvial and lacustrine sediments and provide potentially good source rocks.

However, during Late Oligocene, the spreading of the South China Sea floor caused compression and created tectonic inversion in the SHB. Evidence of tectonic inversion could be seen in Figure 4.4. Several wells were drilled to test the hydrocarbon potential of this inversion structure. This compression also produced major uplift and erosion that created major break-up unconformity separating the syn-rift and post-rift sections (Figure 4.5).

During Early Miocene, the left-lateral transtension along the Red River Fault system continued, causing rapid subsidence of the SHB. The changing of depositional environment, from fluvial and lacustrine to near shore marine such as coastal plain, deltaic and marginal marine facies brought sandstone with good reservoir potential (Figure 4.6). These rapid subsidences also caused transgression and back stepping sedimentation during Early Miocene time (Othman & Jaafar, 2006). By Middle Miocene time, sea floor spreading in the East Vietnam Sea and left lateral movement on the Song Hong Fault ceased (Briais et al., 1993; Huchon et al., 1994; Lee & Lawver, 1994, 1995; Leloup et al., 1995).

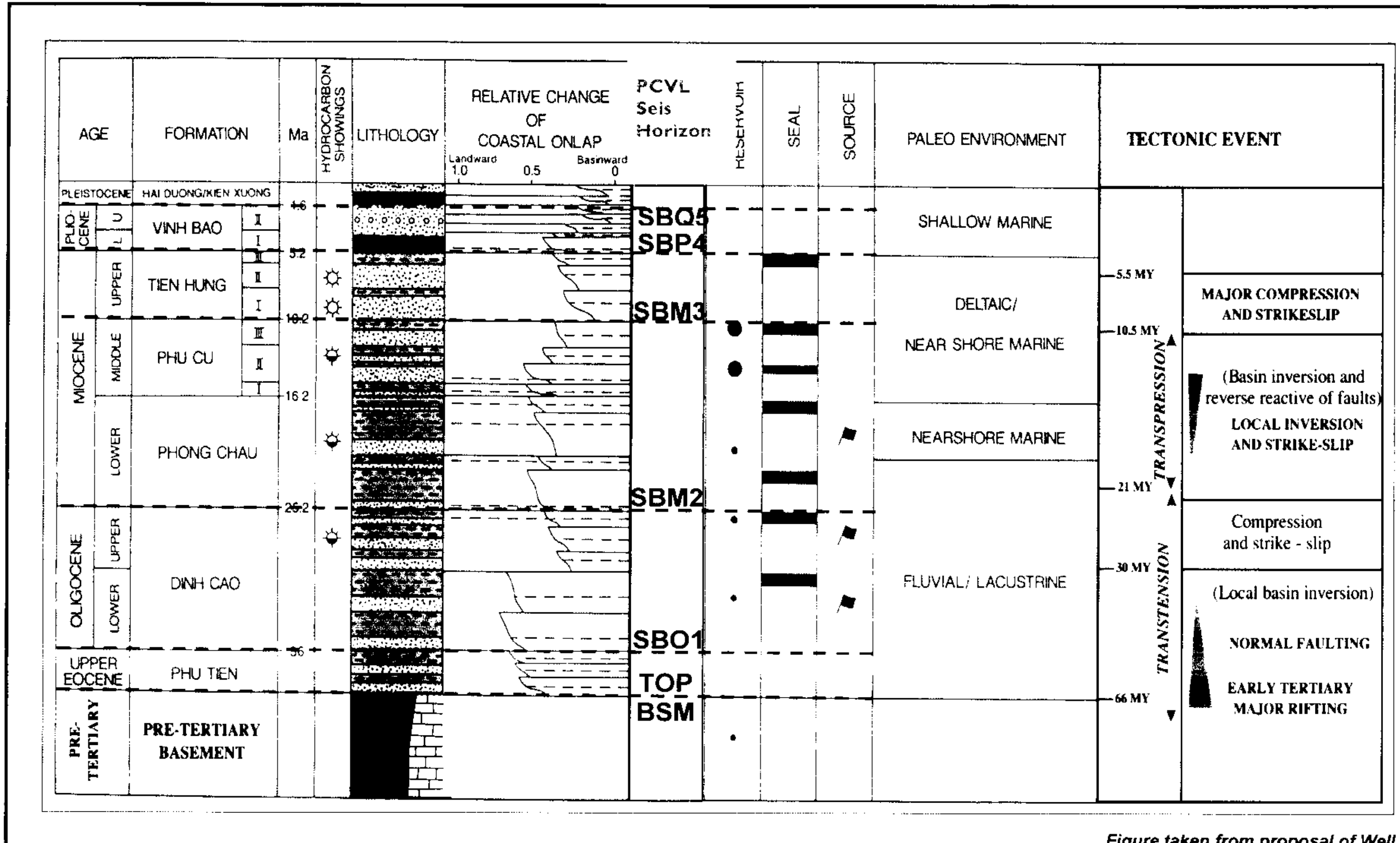


Figure 4.3 : Tectonic Stratigraphic of Northern Song Hong basin

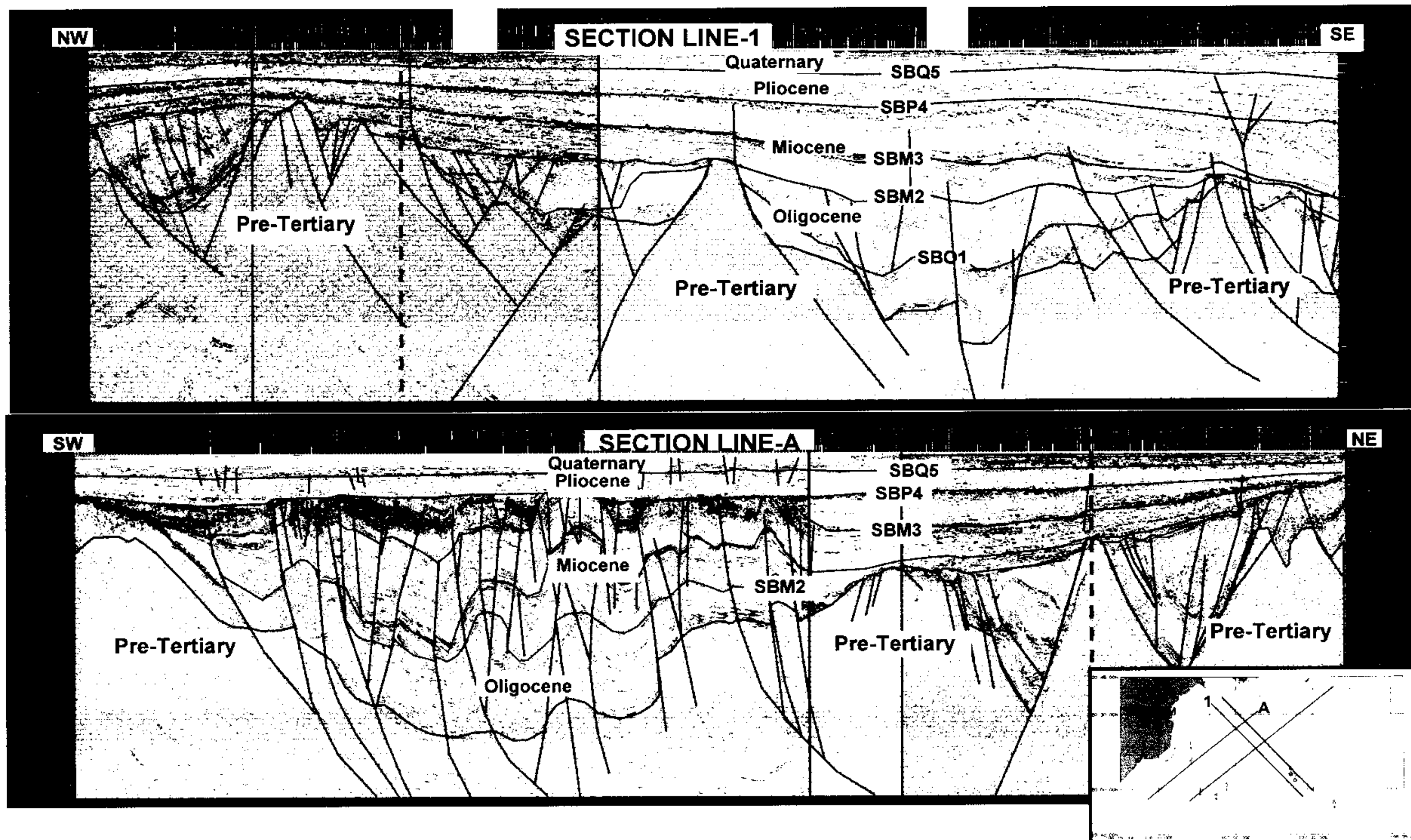


Figure 4.4 : Evidence of tectonic setting and development of Song Hong Basin from seismic section

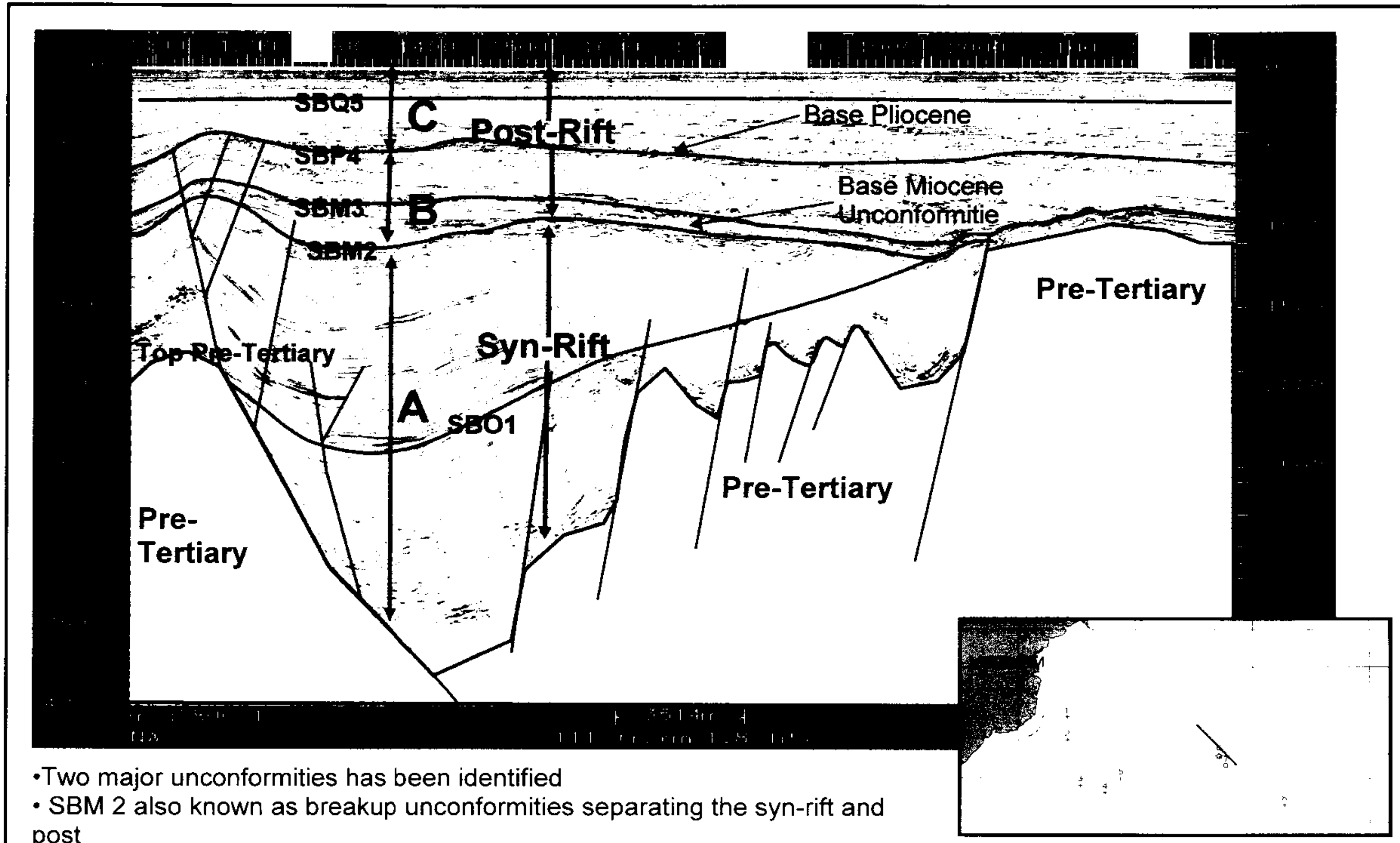


Figure 4.5 : The six identified sequence boundaries in the study area

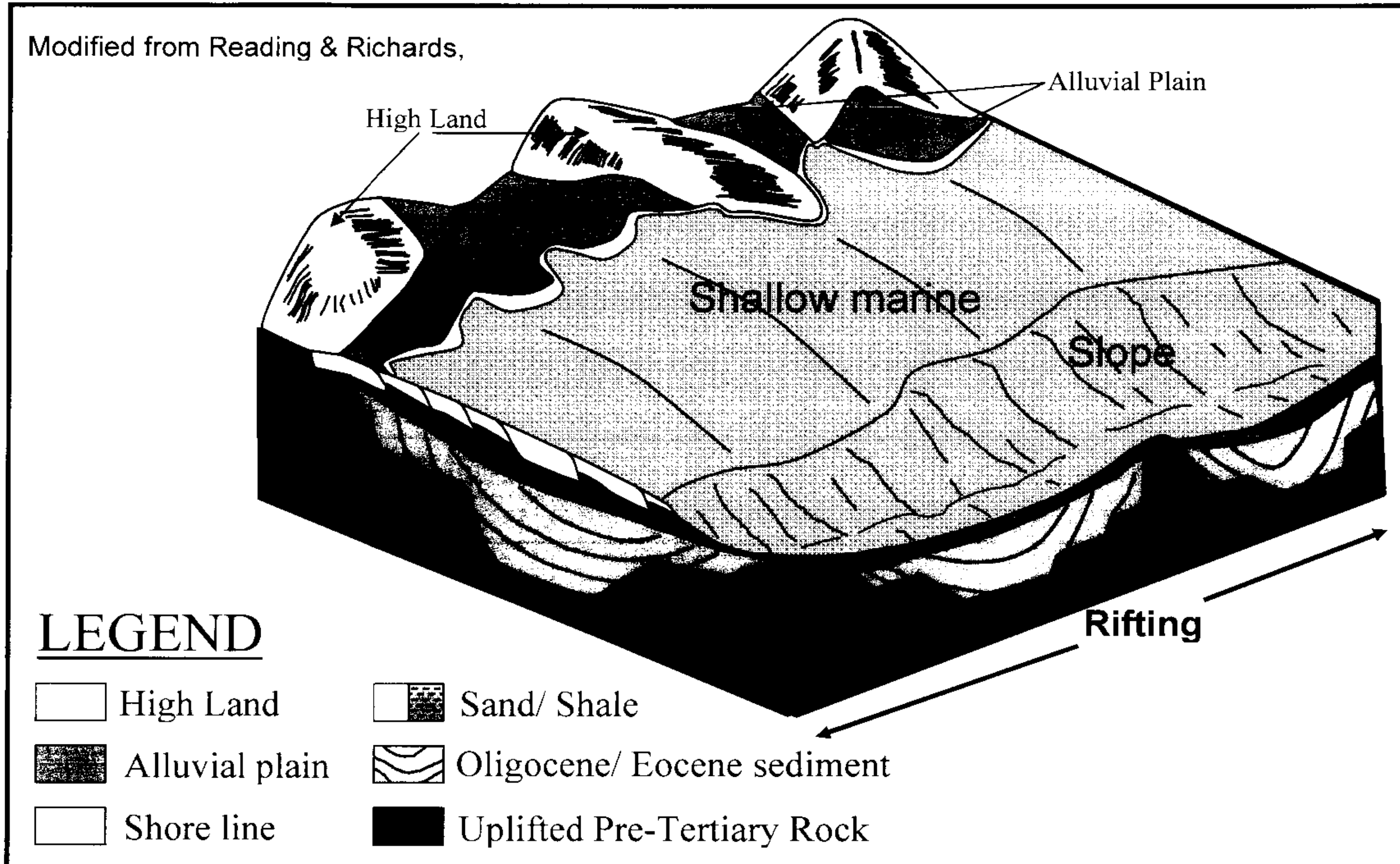


Figure 4.6 : Illustrated 3D Model – Lower to Middle Miocene

During Middle Miocene, relative movement along the Song Hong fault system changed from left lateral to current right lateral displacement (Allen et al., 1984). As the Indian Plate continued its collision with Eurasia Plate, the movement of the Indochina Plate was blocked by the Sundaland Plate. To compensate with this, the South China plate was drifted to the East (Lee & Lawver, 1994). Evidence of change in the displacement direction is expressed in the Song Hong basin by the formation of a distinct unconformity near the base of Middle Miocene, which in places shows deep channel incision, and a conspicuous lateral shift of depocenters (Vejbñk et al., 1996).

However, other authors have suggested that the change from left to right lateral displacement occurred during the Late Miocene to earliest Pliocene time (Phach, 1994; Pigott & Ru, 1994). The change of movement at the SHB caused an up-lift and folding of pre-existing sediments, where the relative sea level fell at the same time and the exposed area would be eroded. Nielsen et al. (1999) suggested, the strike-slip activity caused; (1) reversal of faults, (2) creation of more inversion structure and, (3) widespread unconformity. Evidence of these inversion structures can be seen on Enclosures 1 to 4. Several wells had been drilled to test this structure, like Wells 2 and 3.

During Pliocene to Quaternary, renewed and increasing subsidence of the SHB provided thick, draping and undisturbed sediments which overlay on top of the Upper Miocene unconformities (Nielsen et al., 1999) (Figure 4.4). The sediments were dominated by onshore marine to shallow marine mudstone, siltstones and sandstones with minor proportions of lagoonal and possibly fluvial deposits (Figure 4.7). This thick sediment is considered as a good seal for the Late Miocene inverted structure.

The geodynamic and tectonic evolution in the area formed the structural framework for the hydrocarbon trapping mechanism in the SHB (Othman & Jaafar, 2006). The relationship between tectonic events and structural formation can be summarized as follows: -

i. Eocene to Oligocene

Block faulting created horst and graben structures during the rifting phase

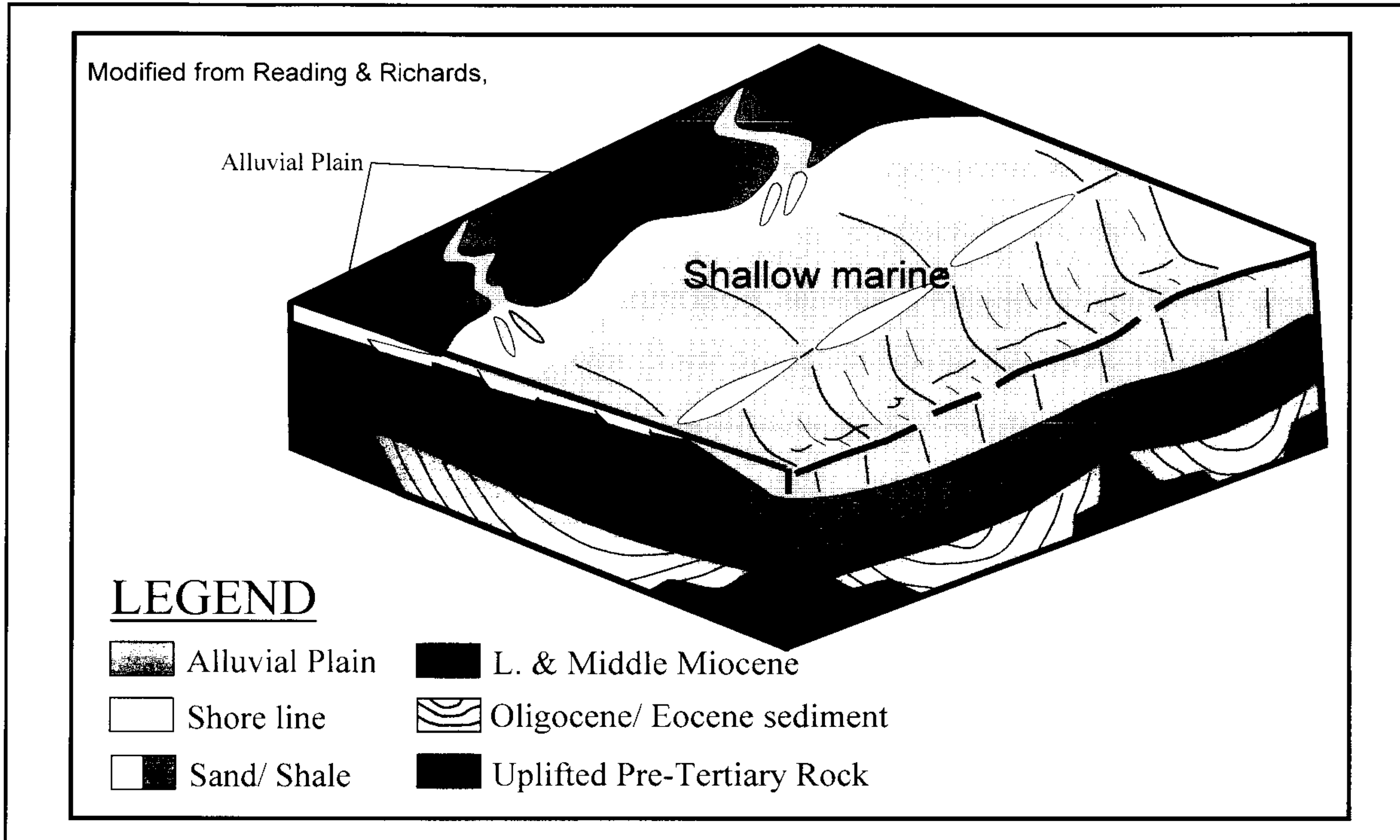


Figure 4.7 : Illustrated 3D Model – Upper Miocene to Pliocene

ii. Late Oligocene

NW-SE opening of the South China Sea caused compression or tectonic inversion to some parts of the SHB.

iii. Middle Miocene

The change of displacement direction caused the formation of distinct unconformity, which in places showed deep channel incision and possible deposition of basin floor fans to the south of Blocks A and B.

iv. Late Miocene

The continuous strike slip activity, which culminated in the Late Miocene, caused the reversal of faults and the formation of inversion structures.

CHAPTER 5
SEQUENCE STRATIGRAPHY

5.1 SEQUENCE STRATIGRAPHY

Based on seismic interpretation, six major sequence boundaries (SB) have been identified. The identified SB was later validated with well data. The six identified SB are named as Top Basement, SBO1, SBM2, SBM3, SBP4 and SBQ5 (Figures 5.1 – 5.4).

Figure 4.5 shows, in the syn rift section (A), data qualities are poor and the structures are highly deformed. Interpretation could not be carried out easily. However, the data quality in the Miocene section (B) gets better with good frequency and lateral continuity. Inverted folds and fault dependent folds are also present in this section, which could be produced by compressional force during the opening of South China Sea. The last section (C) represents a tectonically quiet area with good frequency and lateral continuity of seismic reflectors.

The stratigraphic column in Figure 4.3 shows that in the northern part of SHB, the pre-Tertiary Basement comprises carbonate, granite and metamorphic rock. From Upper Eocene until Quaternary, interbeded sand and shale which are representing of a potential reservoir, source rock and seal were found in this basin. Fluvial/ lacustrine sand and shale were deposited from Upper Eocene to middle of Lower Miocene. Starting middle Lower Miocene until Upper Miocene, sand, shale and thin coal layers were deposited in deltaic/ near shore marine. From the Pliocene until present time, shallow marine sediments had been deposited.

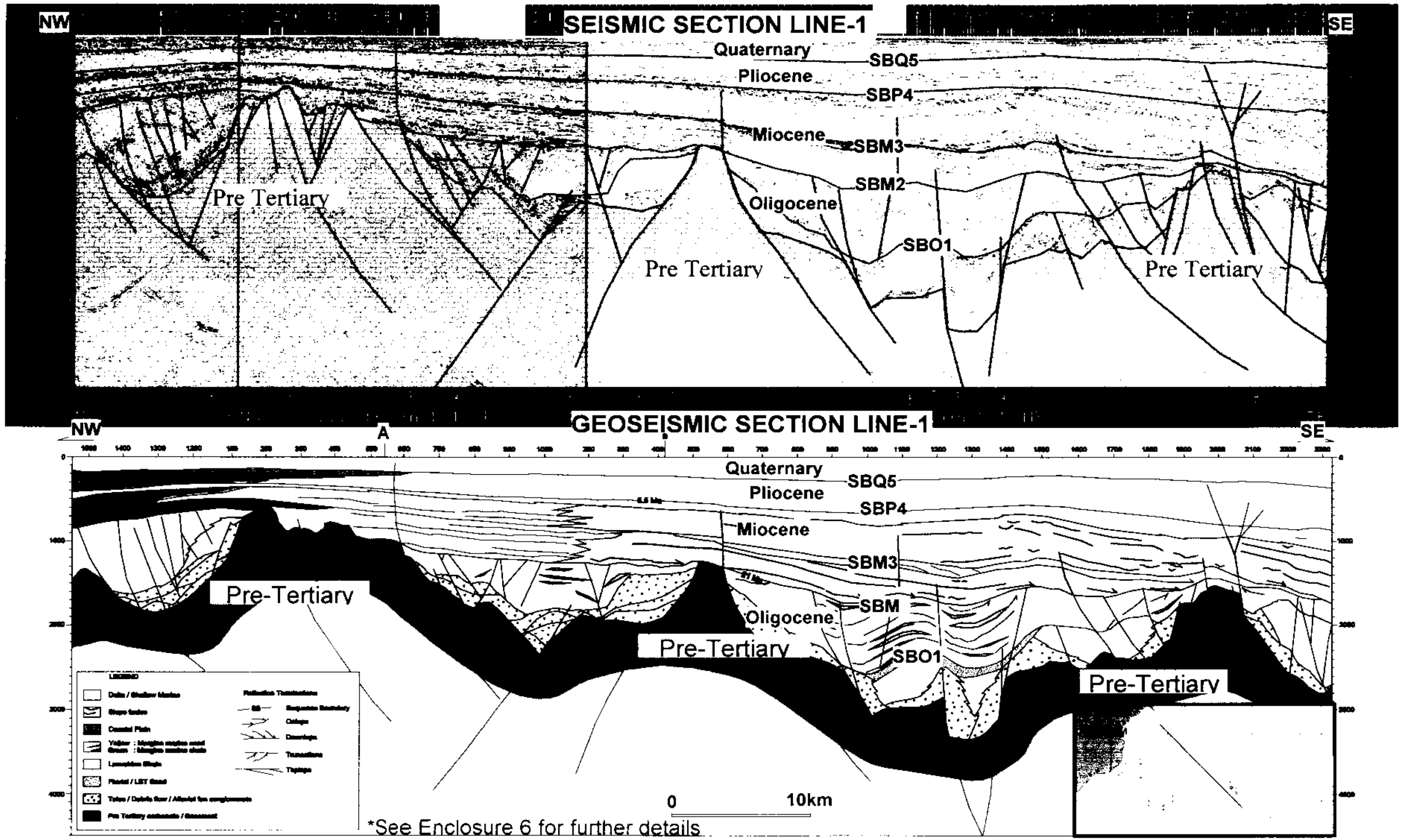


Figure 5.1 : Geoseismic Section Line 1

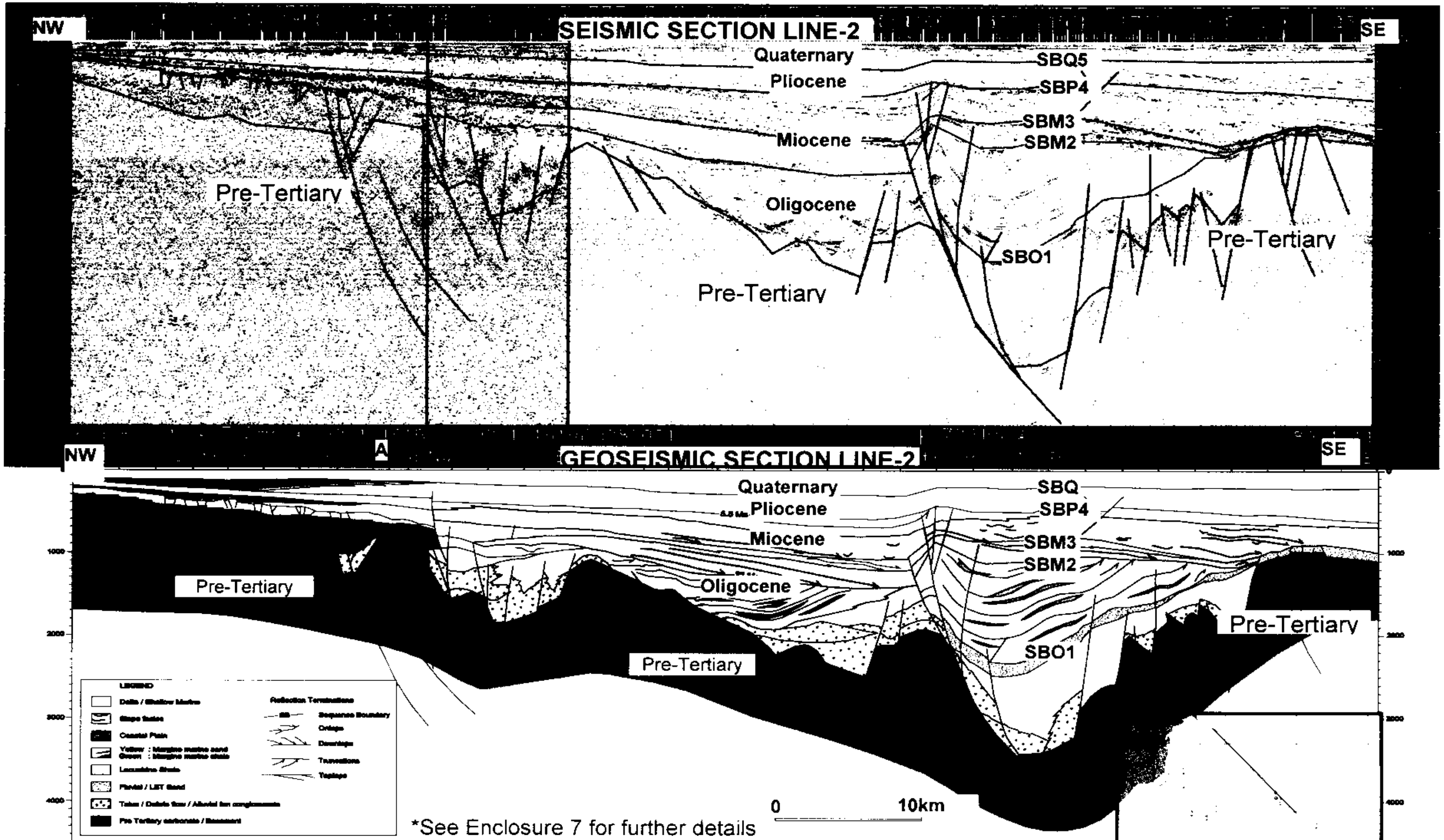


Figure 5.2 : Geoseismic Section Line 2

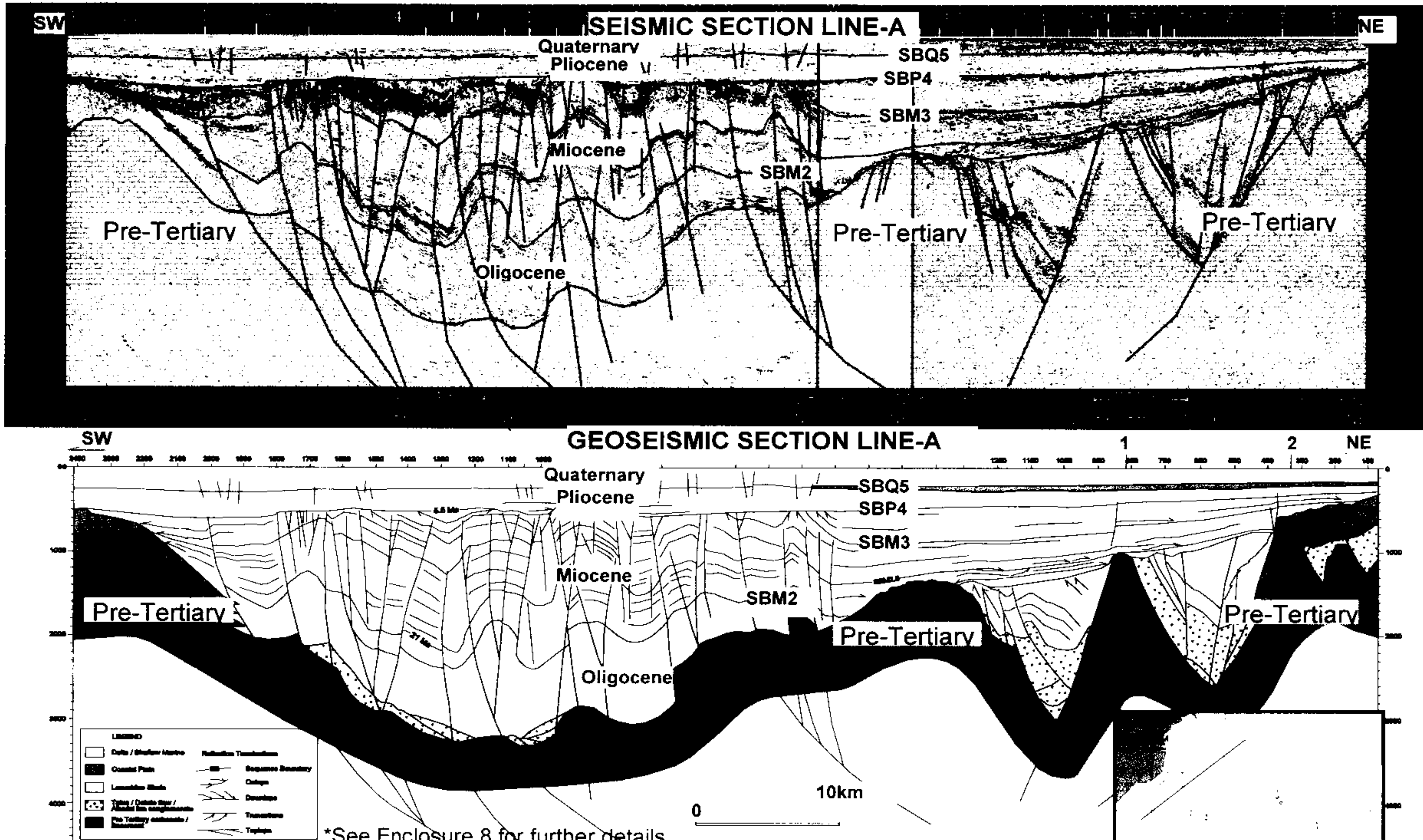


Figure 5.3 : Geoseismic Section Line A

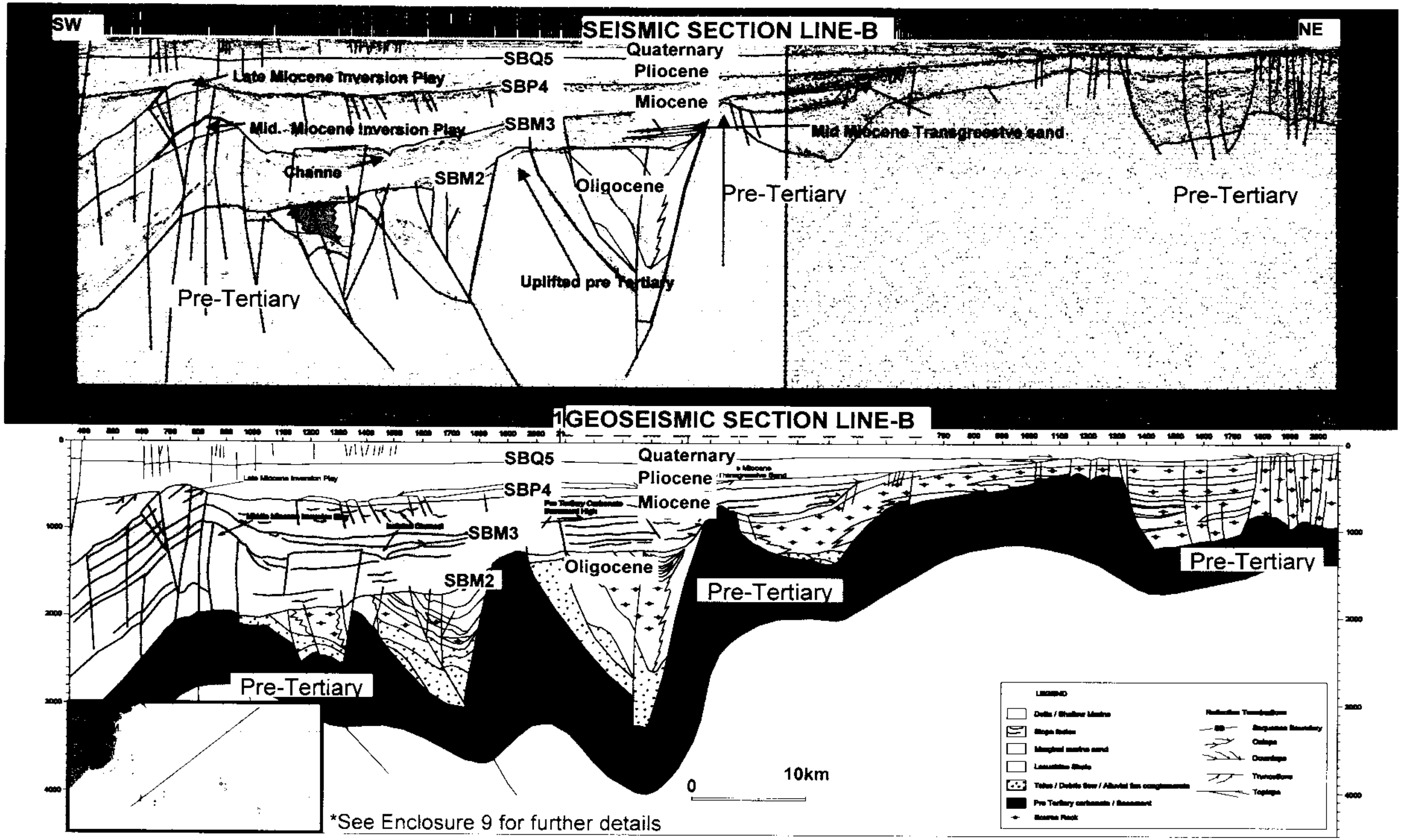


Figure 5.4 : Geoseismic Section Line B

5.2 MEGA SEQUENCE

Figure 5.5 shows the chronostratigraphic model for the deposition of sediments in SHB (Othman & Jaafar, 2006). The model suggests that the top Pre-Tertiary unconformity experienced the longest hiatus or non-depositional period. During Eocene, transtensional rifting of Pre-Tertiary rocks created the SHB. As the rifting and subsidence continued, sedimentation took place in the Upper Eocene. However, the continuous subsidence and sedimentation had been punctuated by a series of compressional events and uplifting in the Late Oligocene, which is believed to corresponds to the opening of the SCS. The uplift had produced a strong erosion and unconformity in the Late Oligocene. Seismic data suggests that SBM2 is the breakup unconformity separating syn-rift and post rift section (Figure 4.5).

The depositional pattern of the SHB can be divided into three mega sequences (2^{nd} Order sequences) (Othman & Jaafar, 2006). The first mega sequence which started from Oligocene to Lower Miocene suggested a retrogradational pattern or transgressive period. The rise of sea level resulted from rapid subsidence from continuous transtensional rifting and followed by subsidence from thermal cooling. The second mega sequence from Lower to Middle Miocene showed a progradational pattern resulting from a series of sea level drops during middle Miocene as indicated by the extensive incision and deposition of basin floor fans. The third mega sequence from Upper Miocene to Recent suggested a slight progradational to aggradational pattern; this pattern is normally produced when sediment supply is in balance with the accommodation space produced by the rising of sea level. The identified three mega sequences in the study area shows some agreement or good matching with the global sea level chart by Haq et al., (1989) (Figure 5.5).

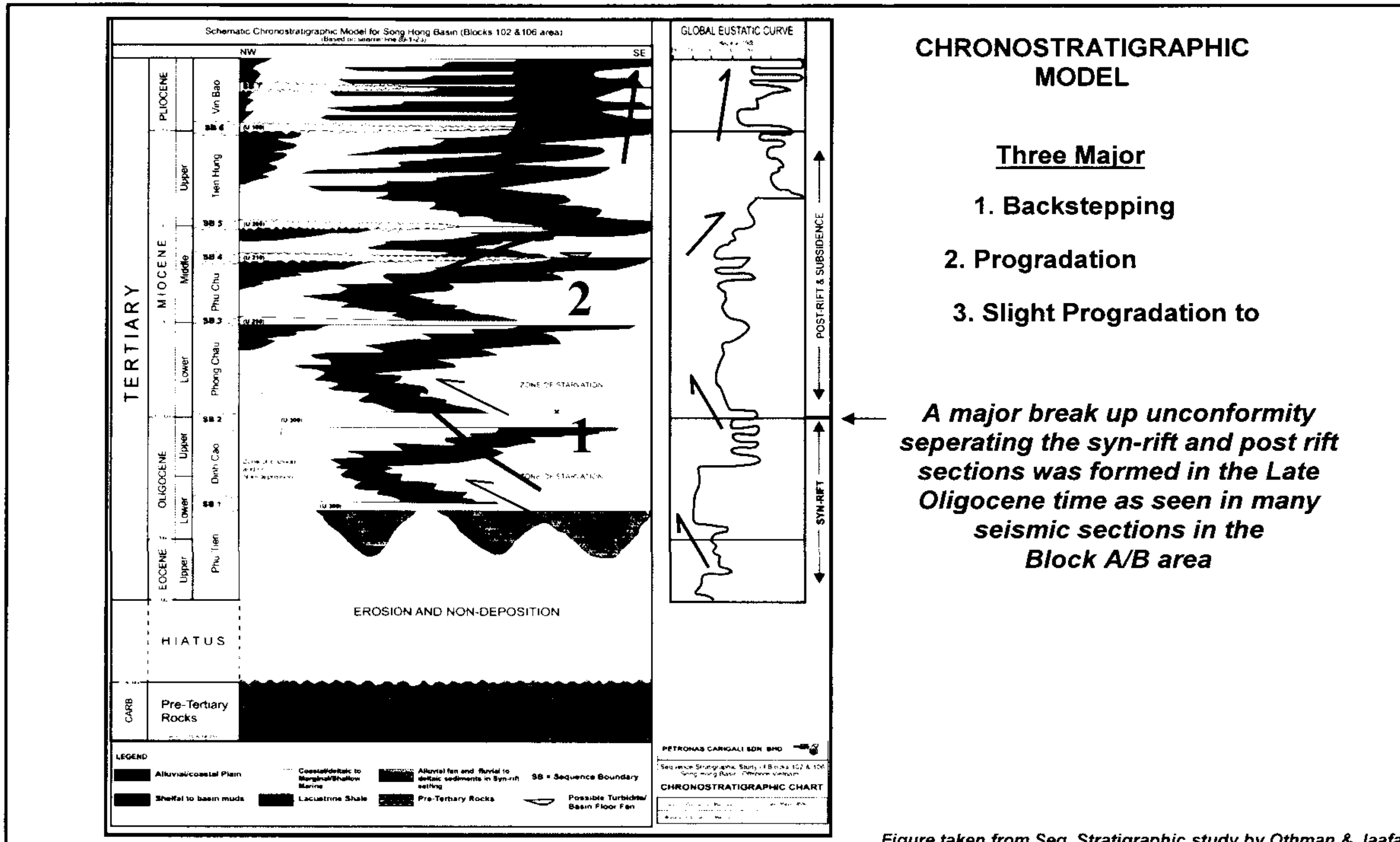


Figure 5.5 : A chronostratigraphic model for deposition in Blocks A and B

5.3 DEPOSITIONAL SEQUENCE STRATIGRAPHY

The depositional sequence stratigraphy studies in this topic are based on Othman and Jaafar, 2006.

5.3.1 TOP PRE-TERTIARY TO SBO1 – UPPER EOCENE TO LOWER OLIGOCENE

Horst and grabens at pre Tertiary rocks are resulted from the rifting of the Pre Tertiary rocks due to the transtensional strike slip movement in the late Eocene time. During the rifting stage, most of the area was exposed to subareal erosion and only small isolated fault depressions received fluvial and shallow lacustrine sediments (Figure 4.2). Locally, the coarse clastics such as conglomerate or carbonate talus were accumulated near major fault scarps where graben continued to deepen. Alluvial fans developed along the northern fault boundaries and some of these fans later evolved into fan deltas as regional subsidence continued (Figures 5.1 & 5.2).

High energy fluvial sands and prograding lacustrine deltas became the main contributor for potential reservoir in this sequence. Further to the south, in the lower energy environment, lacustrine shale would be deposited. This lacustrine shale is believed to be the main source rock that generated and expelled hydrocarbon in the SHB and surrounding. However, it is not known if any of the wells drilled previously had ever penetrated the complete section of this sequence. Well 8 had penetrated the Oligocene section it was not known whether it was the lower or upper part of the Oligocene section since no complete well data was made available for this study.

5.3.2 SBO1 TO SBM2 – LOWER TO UPPER OLIGOCENE

As the subsidence continued and the basin deepened, the isolated lakes opened out or evolved into marginal marine or shallow marine environments. This section was the transition from lacustrine to shallow marine environments. The deposition was dominated by the fluvial, deltas to shallow marine. Seismic data showed progradation and downlaping into the basin that suggested the sediment source came from northwest direction (Figures 5.1 & 5.2). The potential reservoir for this section would come from the prograding deltas and shallow marine sands.

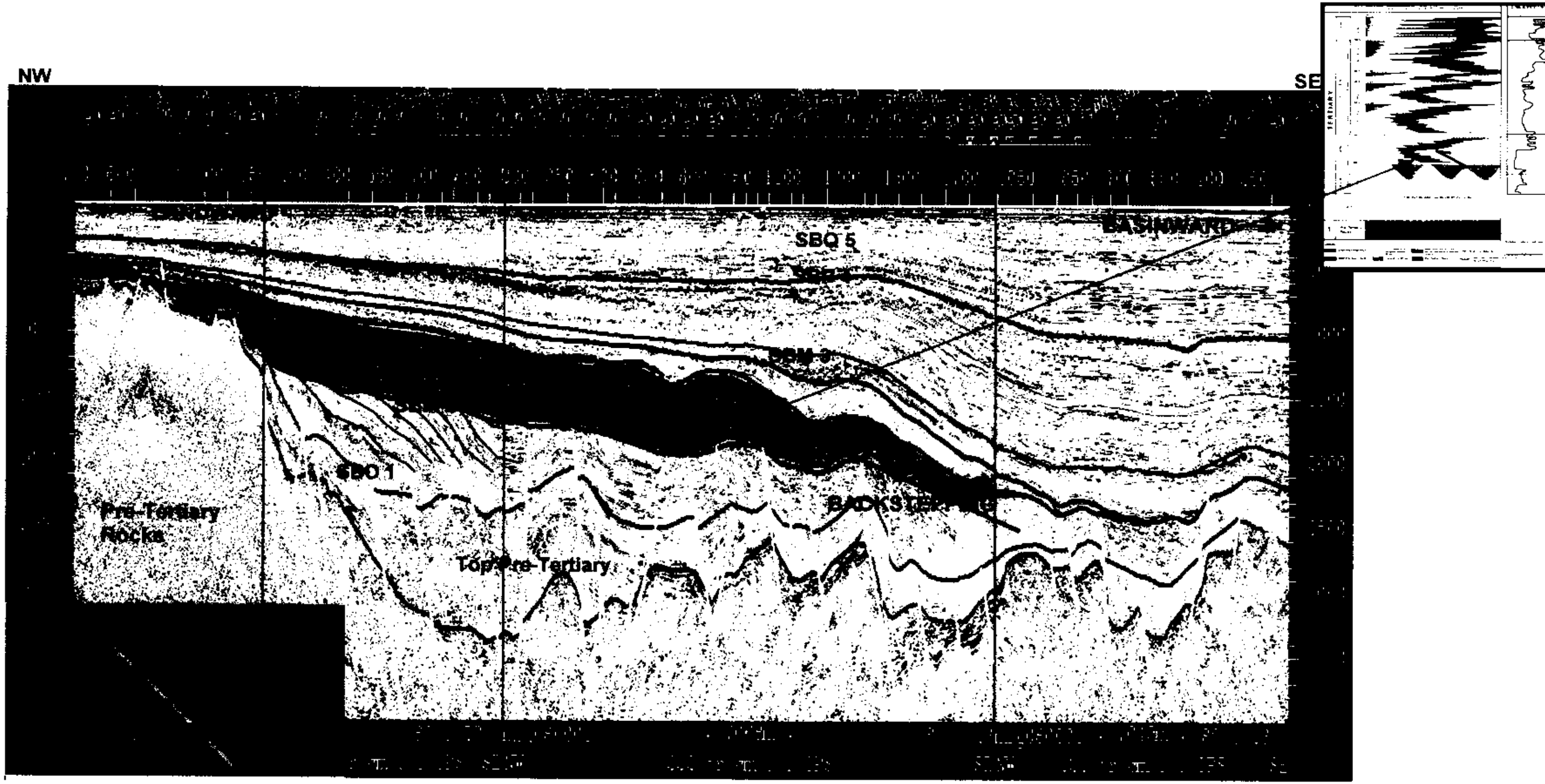
This sequence had been uplifted and inverted by compressional force released due to the opening of South China Sea during the Late Oligocene time. As a result, many structures suitable for hydrocarbon traps were formed and a significant amount of the section had been eroded and truncated to leave major angular unconformity, which is also believed to be the break up unconformity that separated the syn-rift and post rift units.

Interpretation of system tracts in the syn-rift and the early post rift sections was not attempted due to restricted distributions of these sediments in the grabens and half-grabens and to poor seismic resolution.

5.3.3 SBM2 TO SBM3 – LOWER MIOCENE TO UPPER MIOCENE

After the inversion and erosion in the late Oligocene, the basin experienced a rapid subsidence, which could be attributed to the thermal cooling after the rifting stage. The rapid rise of the sea level or transgression is clearly shown by landward backstepping in the depositional pattern for this package (Figure 5.6). The rapid rise of the sea level completely changed the environment from lacustrine to shallow marine (Figures 5.7 & 5.8).

Potential reservoirs were formed by the onlaping transgressive shallow marine sands and the prograding deltaic/ shallow marine HST sands while the Maximum Flooding surface provided seals for the transgressive sands.



Rapid Subsidence after the rifting (Thermal Cooling). Increase of water level (Transgression) completely changed the Lacustrine Environment to Marginal/Shallow Marine. Depositional pattern backstepping landward

Figure taken from Seq. Stratigraphic study by Othman & Jaafar.

Figure 5.6 : Sequence from SBM 2 to SBM 3

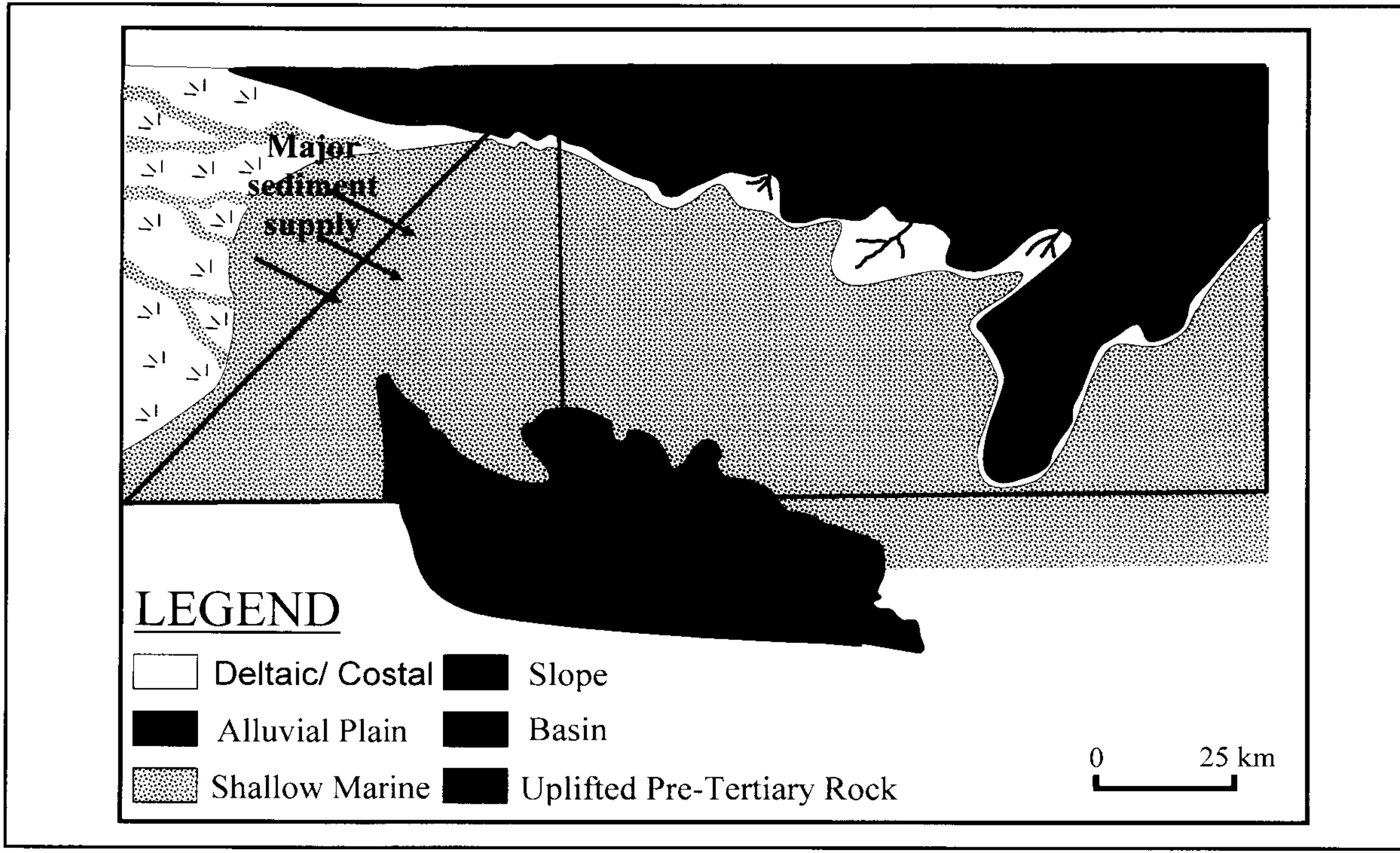


Figure 5.7 : Paleogeographic map – Lower Miocene

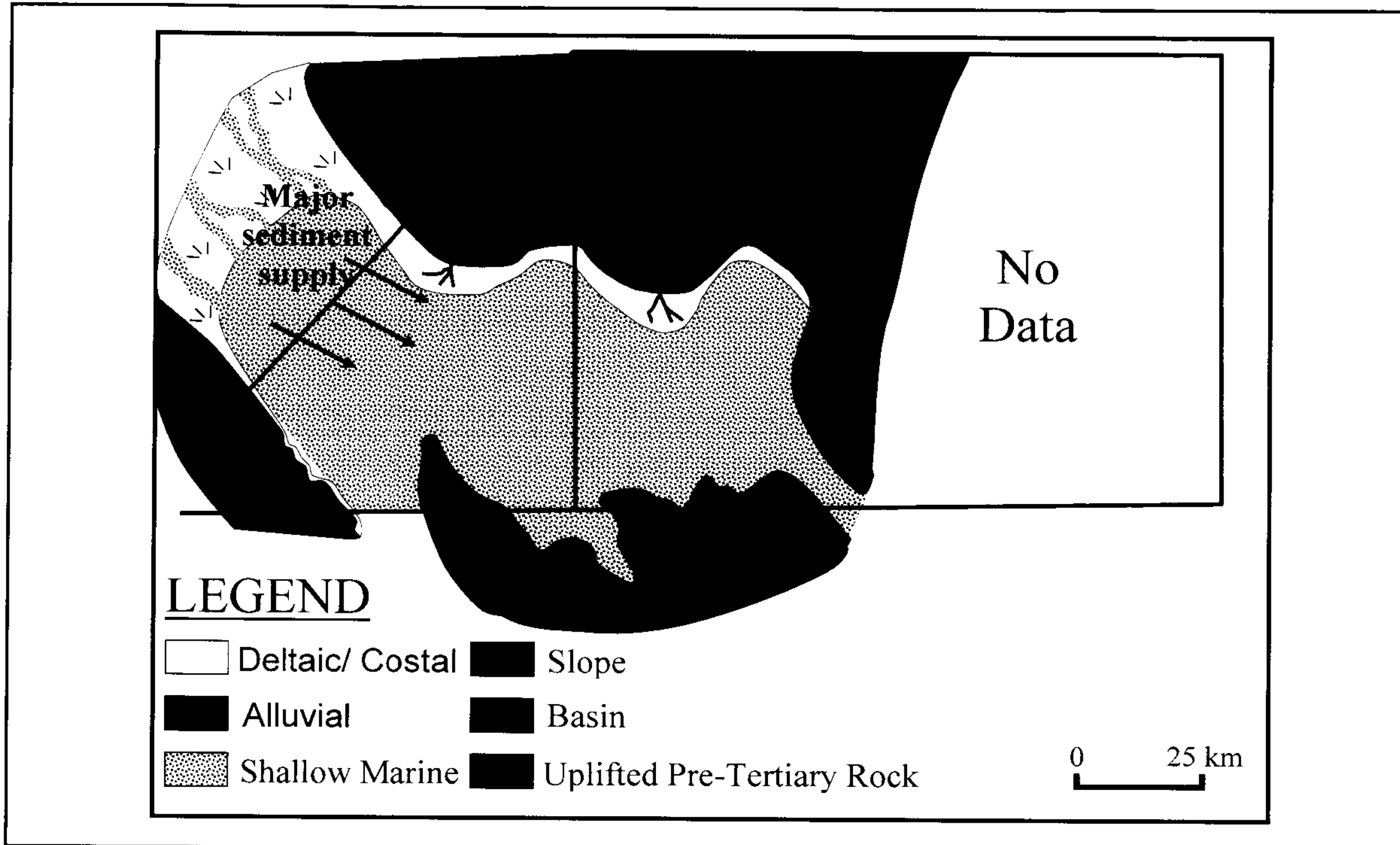


Figure 5.8 : Paleogeographic map – Middle Miocene

Interpretation on seismic data in this section also shows there is a possibility that basin floor fan were deposited to the south of study area especially at the basinal part. However, seismic data to the south of study area is very limited and is a different in order to trace more potential deepwater reservoir. Other potential reservoirs in this sequence are the lowstand incised valleys on the shelf.

5.3.4 SBM3 TO SBP4 – UPPER MIOCENE TO BASE PLIOCENE

This sequence shows a basinward diverging seismic configuration, which suggests rapid sediment supply keeping up with the rapid rise of sea level (Figure 5.9) and resulted in a slight progradational to aggradational stacking pattern (Figure 5.10). The chaotic seismic feature with deep channel cuts along the slope, suggests an active slumping activities during deposition. The rapid sedimentation did not allow sufficient time for the sediment to get consolidated. Induced by gravity pull, the soft and mobile sediment moved along the ramp or slope setting of mud flows to produce slumping with deep channel cuts in the lower part of the slope.

Good reservoir potential is expected in the northwestern part of the Block B, the proximal area near to the paleo-coast line (Enclosures 6 & 7). To the south and SW along the paleo slope and basin area where slumping was active the environment were expected to be muddy and there would be low of reservoir potential. The late Miocene inversion initiated by the strike slip activity along the Song Hong fault system caused this section to be uplifted, eroded and resulted in the formation of a significant unconformity (Base Pliocene unconformity) that provided traps and seals for hydrocarbon accumulation. However, two exploration wells, which are Wells 2 and 3, drilled by Company B in this section found to be dry.

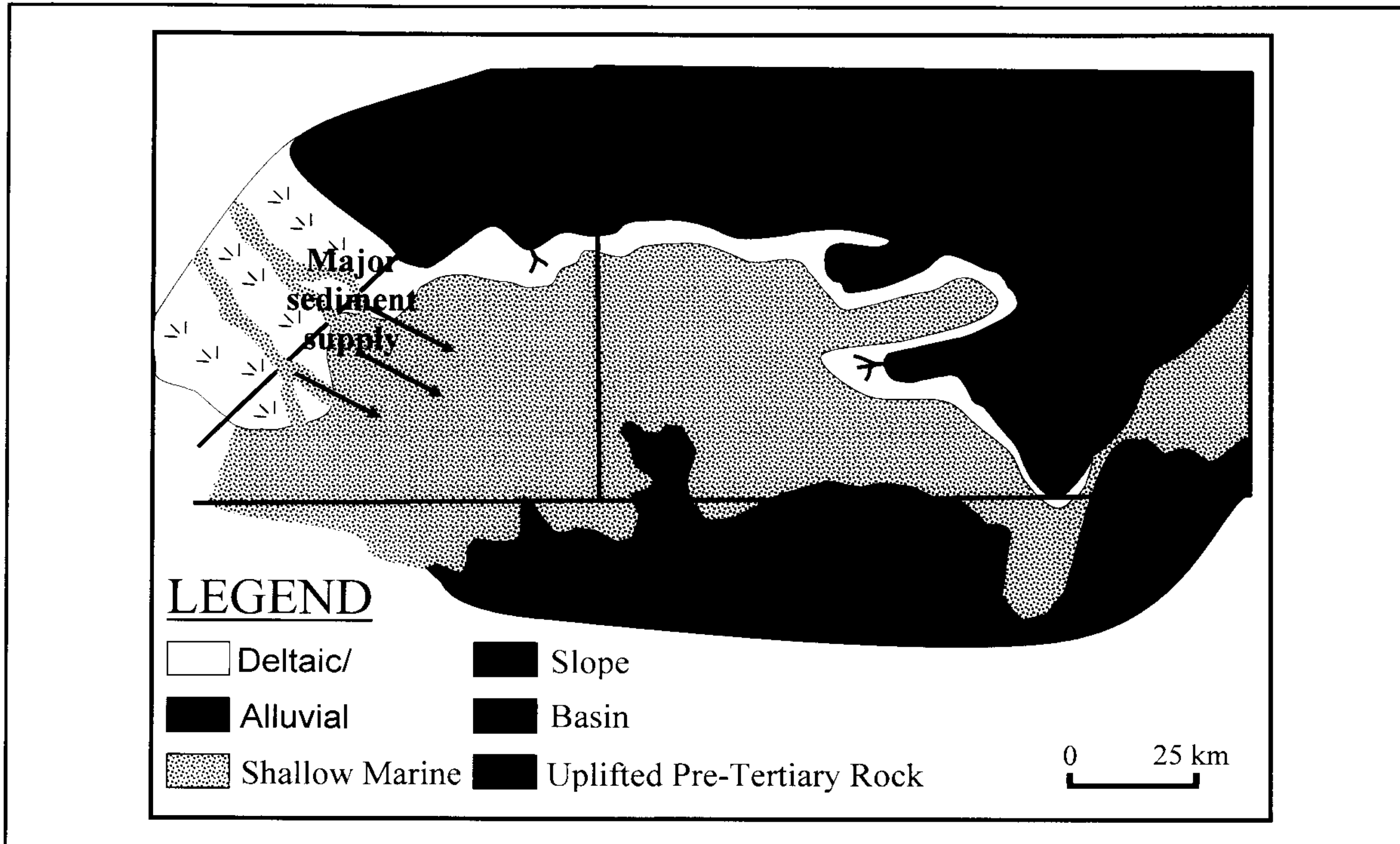
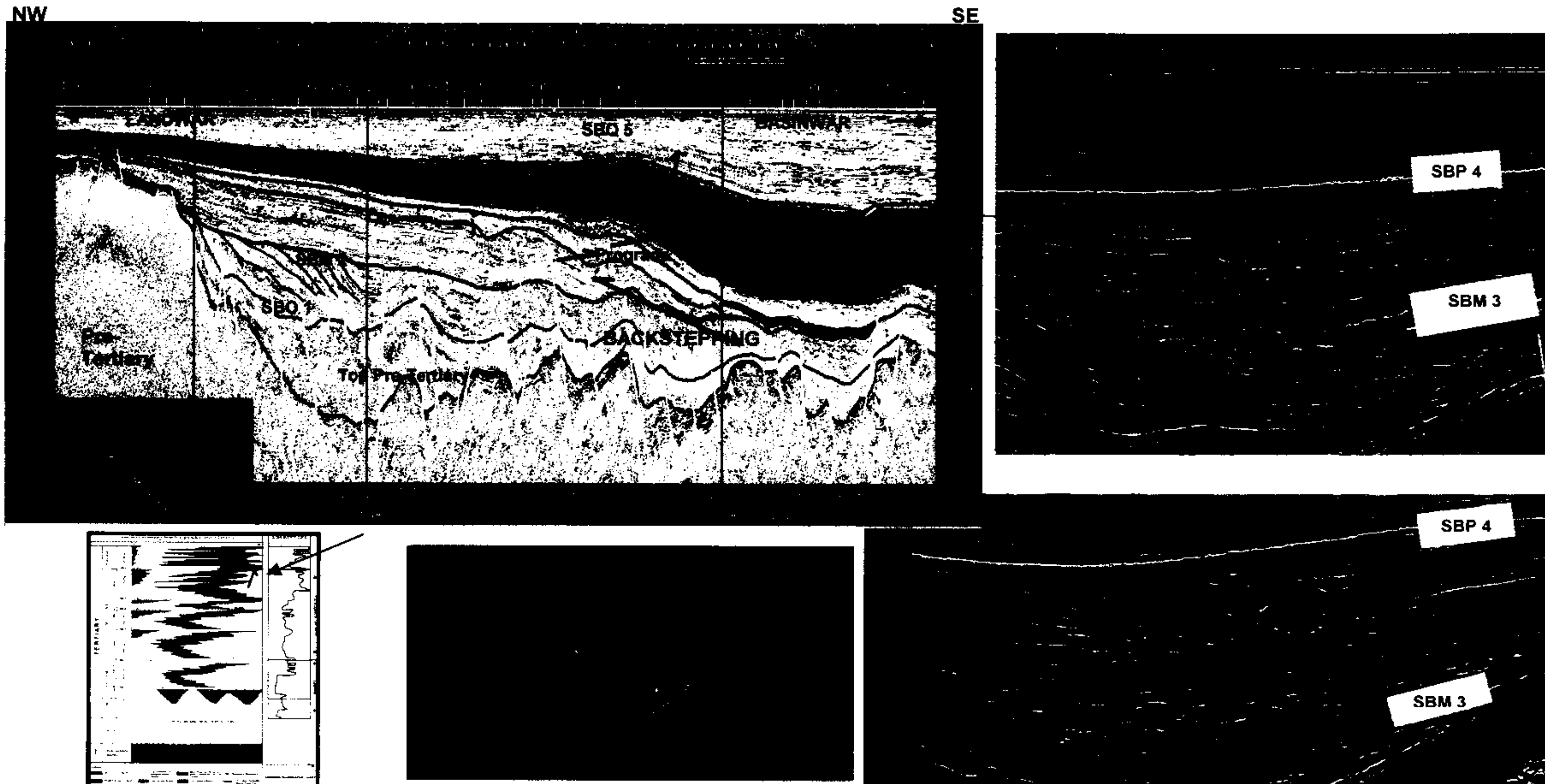


Figure 5.9 : Paleogeographic Map – Upper Miocene to Base Pliocene



The rapid sediment supply try to keep up with the rising of sea level, depositional pattern is diverging basinward (slight progradational to aggradational pattern). Rapid sediment supply produced unconsolidated sediment which induced slumping and channeling activities in the ramp and slope settings.

Figure taken from Seq. Stratigraphic study by Othman & Jaafar,

Figure 5.10 : Sequence from SBM 3 to SBM 4

5.3.5 SBP4 TO SEA BED – PLIOCENE TO RECENT

This sequence is composed of a young and undisturbed section with an aggradational stacking pattern. Due to its shallowness, unconsolidated sediments and lack of structure, this section is considered non-prospective in terms of hydrocarbon potential.

CHAPTER 6
PLAY FAIRWAY ANALYSIS

6.1 PLAY FAIRWAY ANALYSIS

Gross Depositional Environment (GDE) map is generated based on the integration of structure map, isochron map, well data and paleo-reconstructions analysis. From the GDE map, it is possible to construct a map highlighting areas of Common Risk Segments (CRS) on specific criteria such as reservoir, source rock and seal (Figures 6.1 – 6.3). These CRS maps are also known as 'traffic light' maps because normally it uses green, yellow and red colors. The red color represents or shows high risk area, where yellow for moderate and green for low risk.

Superimposition of CRS maps of reservoir, source rock and seal produces Composite Common Risk Segments (CCRS) maps (Figure 6.4). The superimpositions were carried out by honoring the higher risk elements. This play fairway maps can be constructed from CCRS maps to show areas or corridors of low risk for the combined parameters of reservoir, source rock and seal. It provides a good geological tool to constrain and evaluate the ranking of prospects and leads.

The CRS maps show reservoir distribution in lowest risk areas with a green color. Examples of such areas are the deltaic/ costal plain, uplifted pre-tertiary carbonate rock and shallow marine areas that are close to the coast. Both alluvial plain and shallow marine areas that are close to the slope are interpreted as medium risk reservoir and are designed as yellow in color. Areas that are interpreted as high risk include slope and basin areas are indicated in red color.

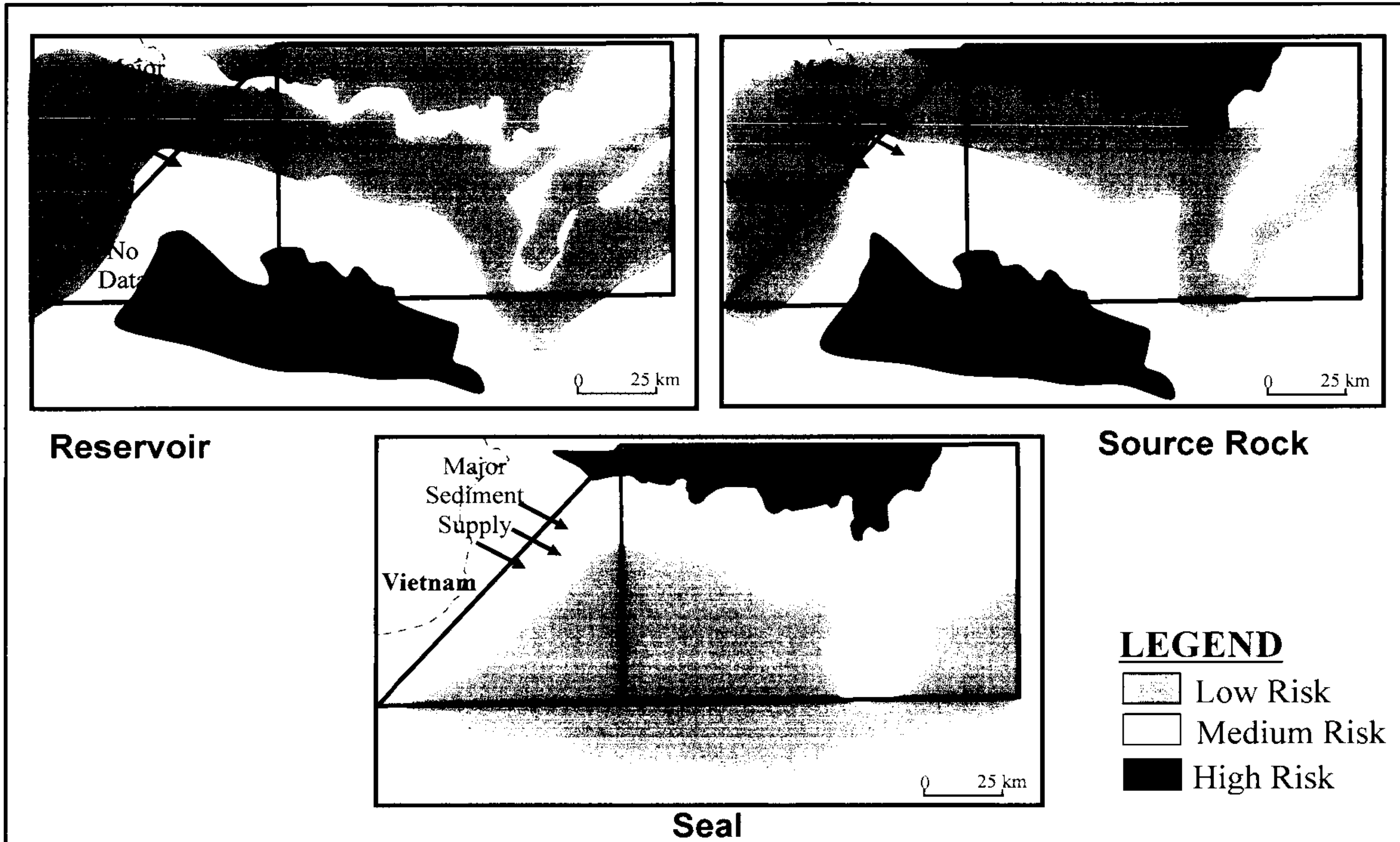


Figure 6.1 : Common Risk Segment (CRS) Maps Lower Miocene

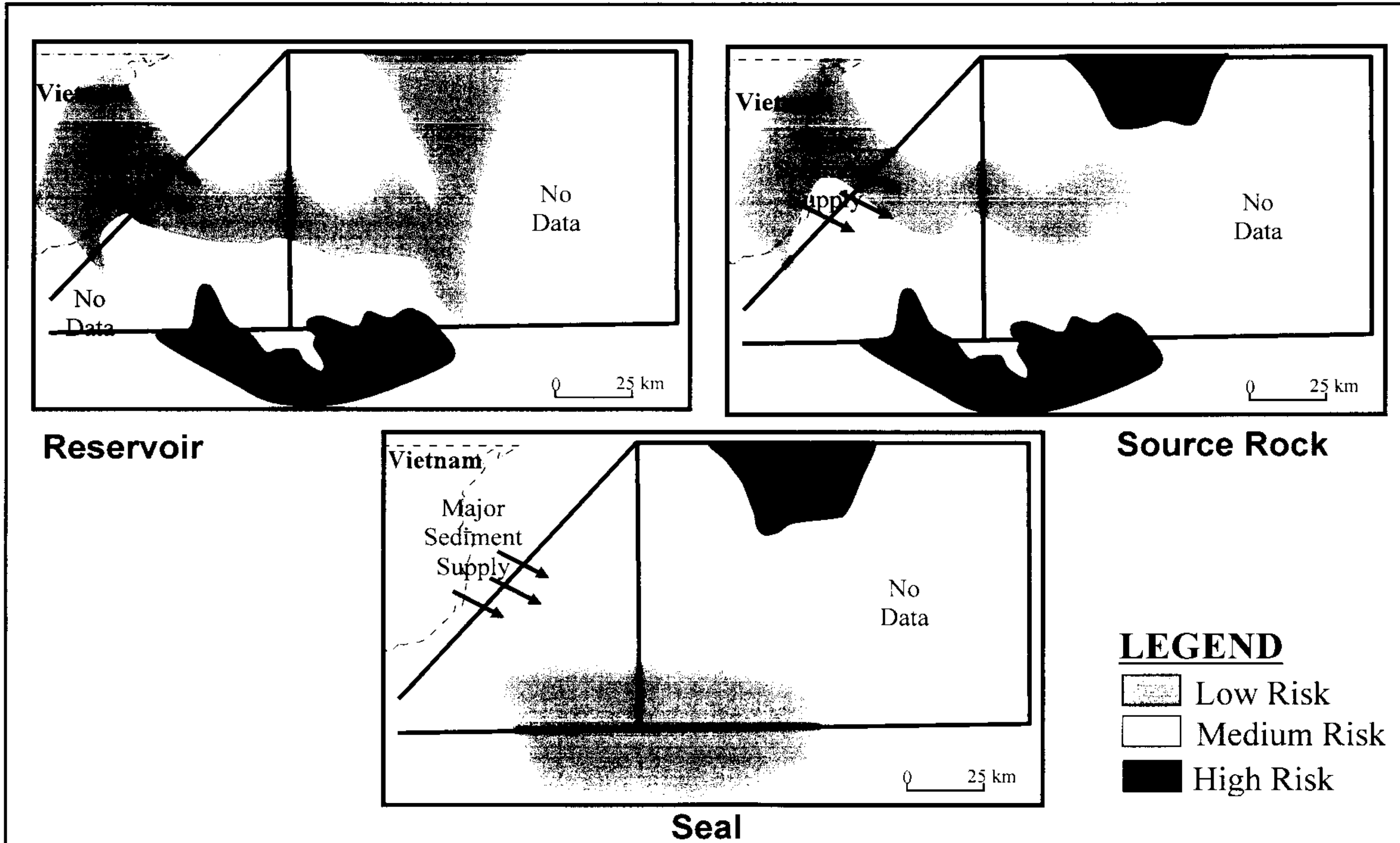


Figure 6.2 : Common Risk Segment (CRS) Maps Middle Miocene

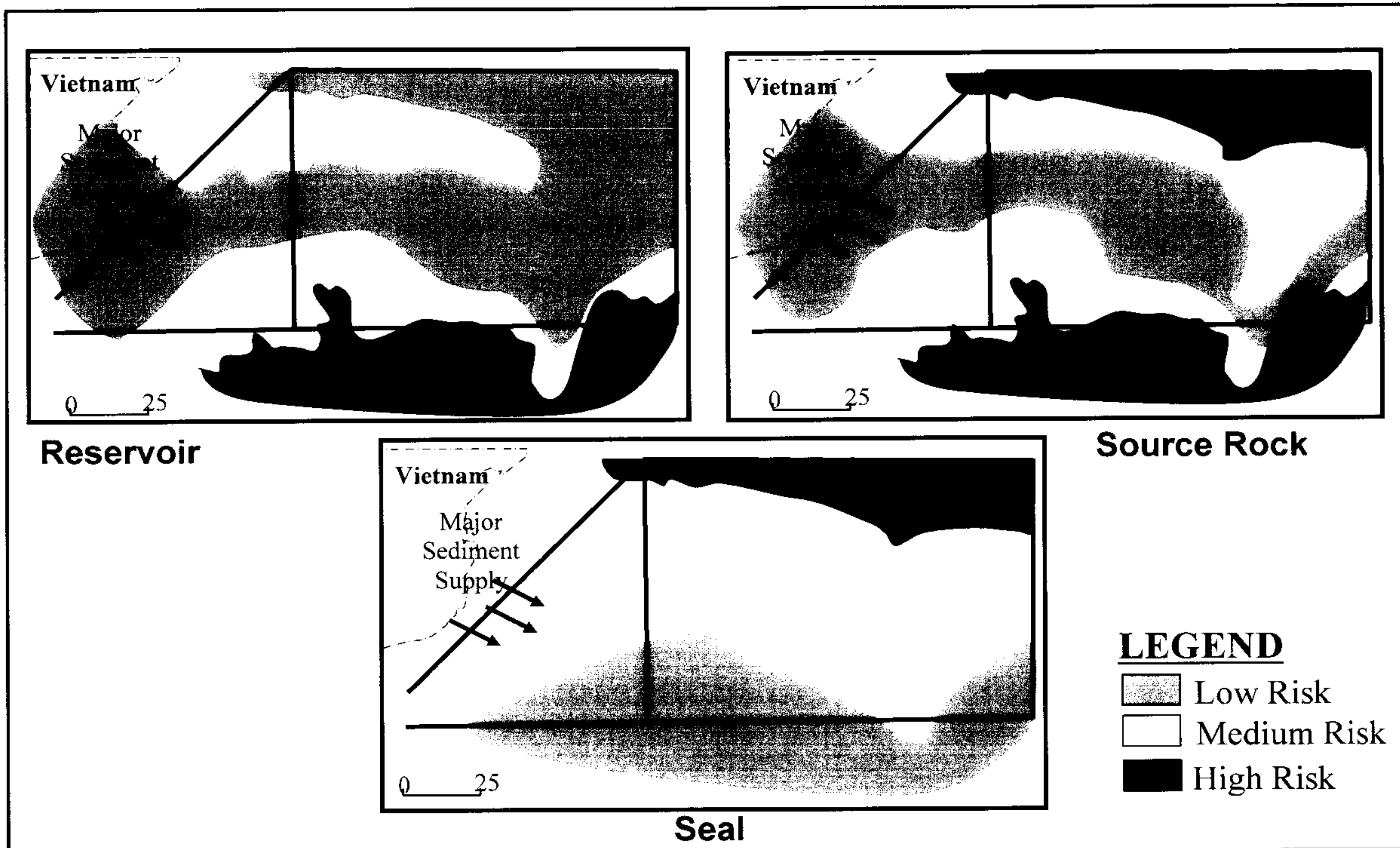


Figure 6.3 : Common Risk Segment (CRS) Maps base Pliocene

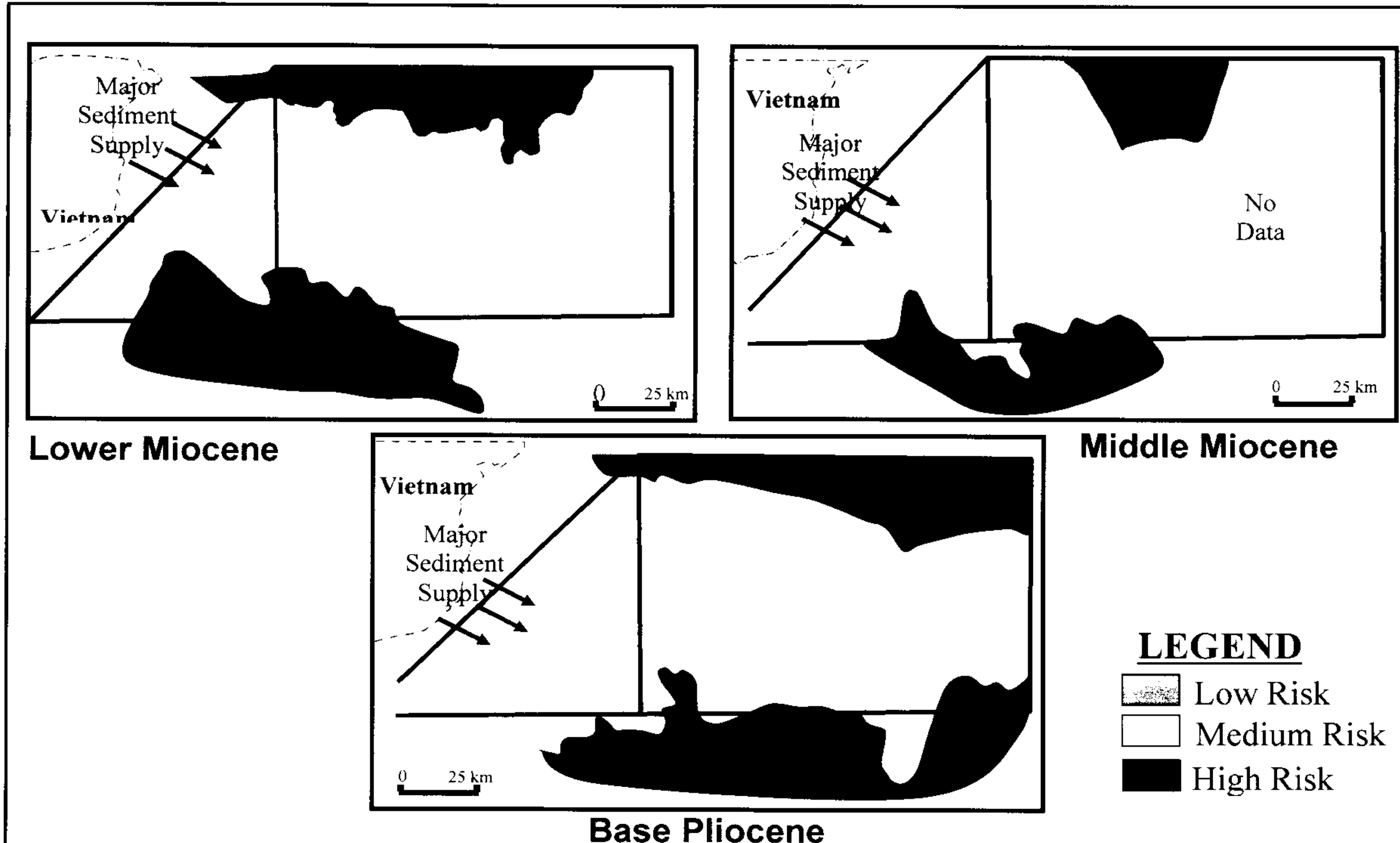


Figure 6.4 : Composite Common Risk Segment (CCRS) Maps

Depositional environments such as shallow marine and deltaic are the best representatives of source rock Type II and Type III. Hence it is classified as the lowest risk of source rock ranking and is indicated in green color. Alluvial plain and shallow marine that are close to the slope are interpreted as medium risk due to less sediment supply. Uplifted pre-Tertiary carbonates rock and slope-basin, are interpreted as high risk zones for potential source rock.

Areas at the slopes and basins that are covered with thick shale are considered potentially as the best potential location to obtain good seal rocks. Such areas are indicated as green in color. Area such as deltaic/ costal, alluvial plain and shallow marine are interpreted as having a medium risk for getting seal rocks and are indicated in yellow. Areas with uplifted pre-Tertiary carbonates rock are indicated in red because such areas are considered as high risk zones for seal rocks.

In conclusion, CCRS results showed that exploration at the Miocene Section in this block is considered as medium to high risk area for exploration at Miocene section. Distribution of medium risk areas are deltaic/ costal, alluvial plain and shallow marine environment. However the slope, basin and uplifted pre-Tertiary carbonate rocks are considered as high risk areas.

CHAPTER 7
PETROLEUM SYSTEM

7.1 RESERVOIR POTENTIAL

There are two types of reservoir in the SHB, which are sandstone and fractured carbonate. Based on seismic and well data, the potential sandstone can be found in the Miocene and Oligocene sections. Potential reservoirs also can be found in the uplift pre-Tertiary carbonate rock.

7.1.1 SANDSTONE RESERVOIR

During the Early stage of rifting, the fluvial sand and lacustrine deltaic sediments were deposited inside this syn-rift basin (Figure 4.6). In the late Oligocene to Early Miocene section, the paleogeographic map shows delta progradation and downlap features suggest a good reservoir development from the deltaic and shallow marine sands (Figures 5.7 – 5.9). Well 5 and Well 8 had been drilled to test the reservoir potential in this area. Result showed that, the porosity in this section is varies from 6 – 14% with permeability varying from 0.1 to 10mD. The porosity for the Oligocene reservoir is expected to be lower than the Miocene reservoir due to burial factor. This fact can be seen at Well 1 where the Oligocene reservoir is very tight due to its very low porosity with an average value less than 6% and water bearing.

However, at the Beibuwan Basin, the discovery well showed that the porosity of Eocene sandstone ranged from 15 – 19%, and its permeability, between 300 – 89mD. The porosity of Oligocene sandstone is 27% with a permeability of 1 244 mD.

The Lower Miocene sequence is interpreted as a transgressive sequence. The reservoir potential is interpreted to come from shallow marine to coastal sand near the edge of the basin. A total of 27 m net hydrocarbon zones were encountered from two layers of gas sand (Sand A and Sand B) from this sequence at Well 1 (Figure 7.1). The net gas for Sand A is about 4.3 m. The porosity is around 14% and water saturation (Sw) around 50%, while for Sand B, the net gas sand is about 22.7 m with a porosity of 15% and Sw around 28%. Production test (DST#1) of Sand B flow 23 MMscf/d of gas with 0.5% CO_2 and no H_2S on 128/ 64" choke size.

The reservoir potential for the Middle Miocene sequence comes from the shallow marine transgressive sands, lowstand channel sands or incised valley on the shelf and a possible basin floor fan or ponded turbidite in the basinal area towards the south of study the area (Othman & Jaafar, 2006). The prograding shallow marine sand may also be present during the highstand system tract as tested by Well 6 that encountered 2.5 m of net oil sand (Figure 7.2). Porosity for this reservoir is around 18% with Sw around 57%.

In the Middle Miocene sequence, a total of 43 m net hydrocarbon zones were found in Well 1 from four layers of gas sand (Figure 7.3). The net gas Sand C is about 13.1 m with a porosity of 19 % and Sw 52%. For Sand D, the net gas is around 22.9 m with porosity of 21% and Sw 39%. A second production test (DST#2) had been carried out in this sand. DST#2, which was, commingled with 1 add-on (from two sand intervals) flow 24 MMscf/d of gas with 0.5% CO_2 & no H_2S in 128/64" choke size. A total of 5.6 m net gas sand was found at Sand E, where the porosity is about 17% and Sw 66%. The last interval is Sand F with a net gas sand of 1.4 m, porosity of 22% and Sw of 66%.

In the Upper Miocene sequence, deltaic and shallow marine sediments showed good reservoir potential in the proximal area toward NW in Block A (Figures 5.1 & 5.2). Based on Wells 2 and 3 results, this section is very sandy and has a good reservoir development. The porosity ranges from 3 -- 12% and permeability from 1 to 2.2mD

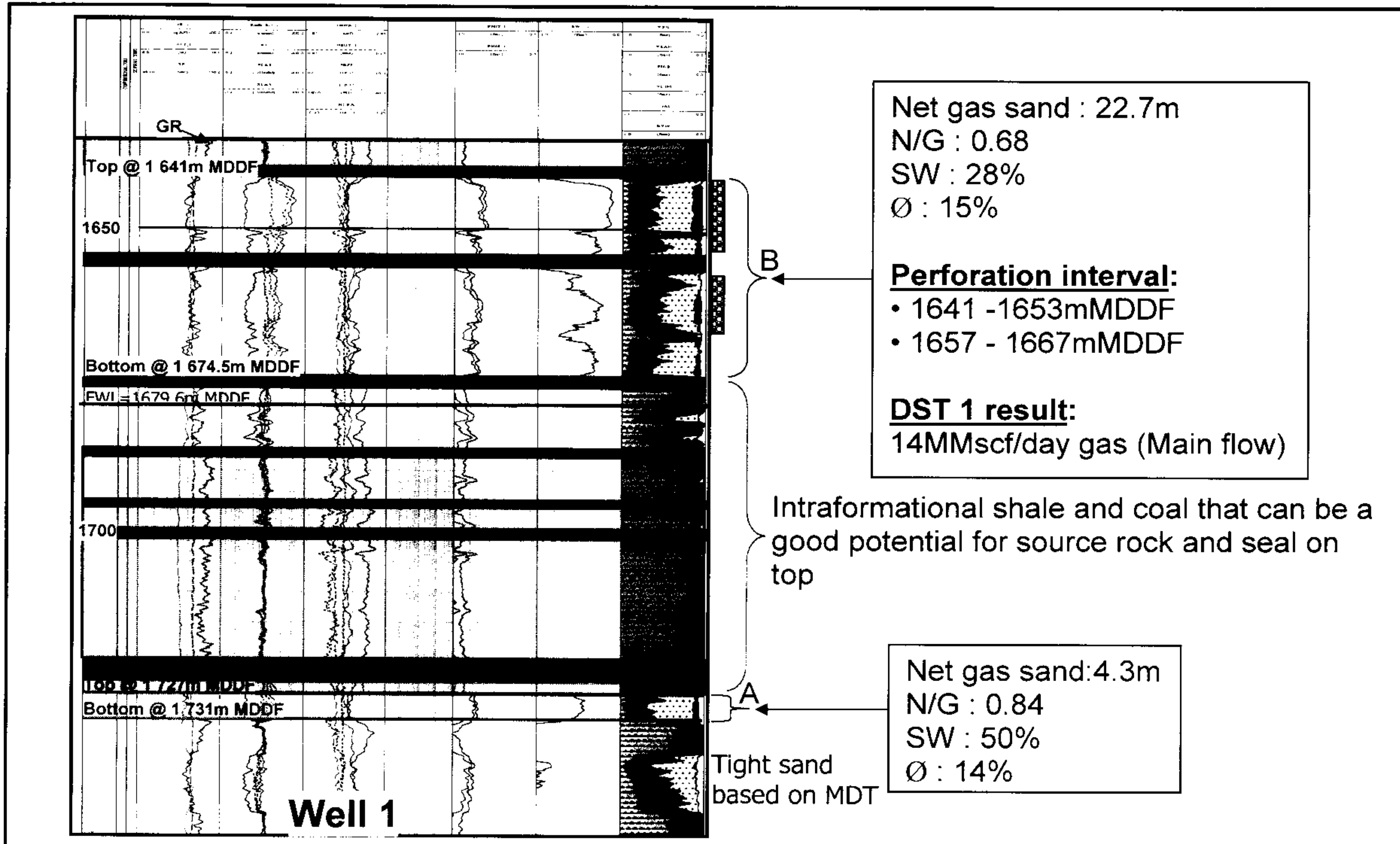


Figure 7.1 : Bottom section of well 1 shows the potential of reservoir, seal and source rock

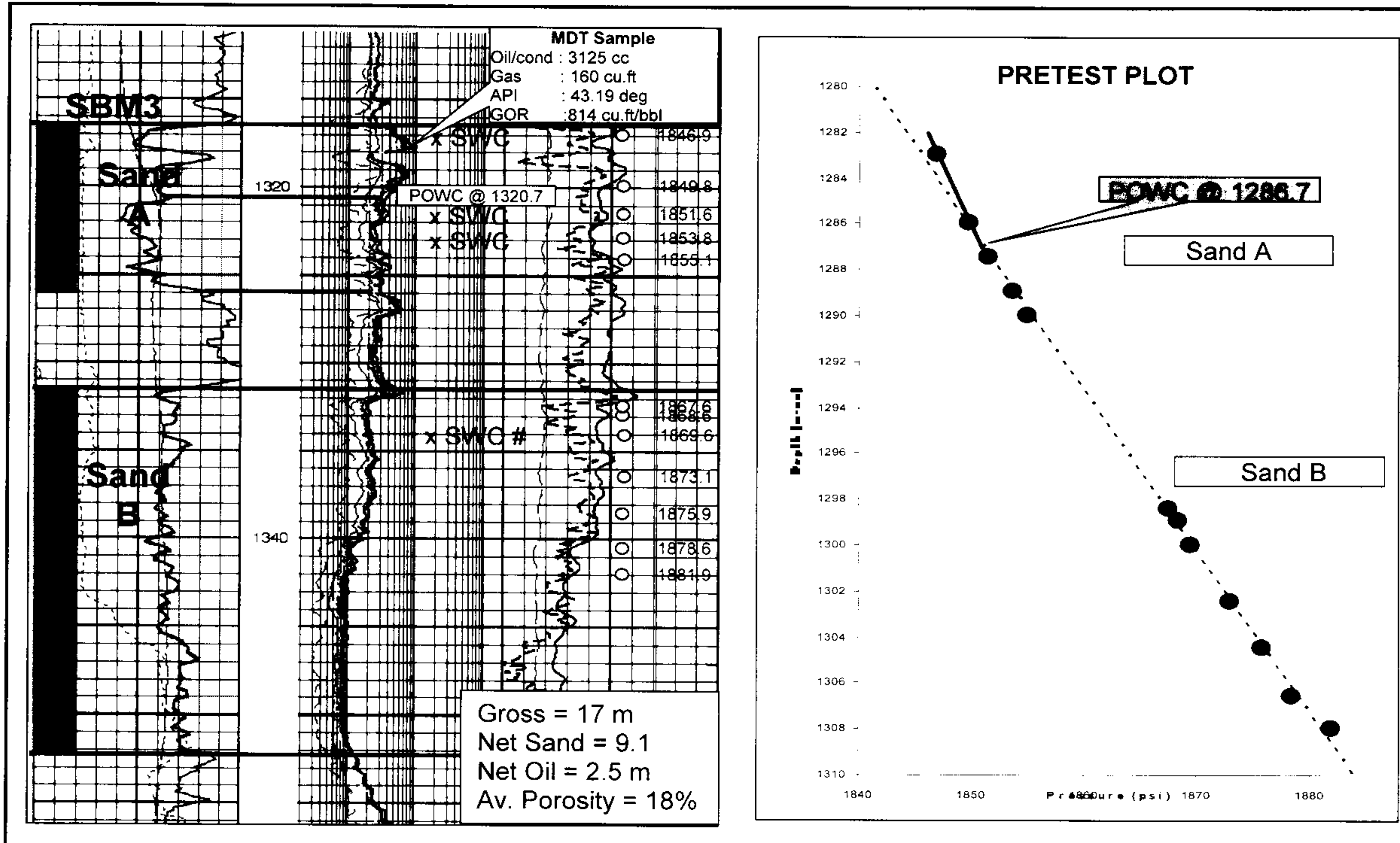


Figure 7.2 : MDT result and Pretest Plot of the hydrocarbon bearing reservoirs in Well 6

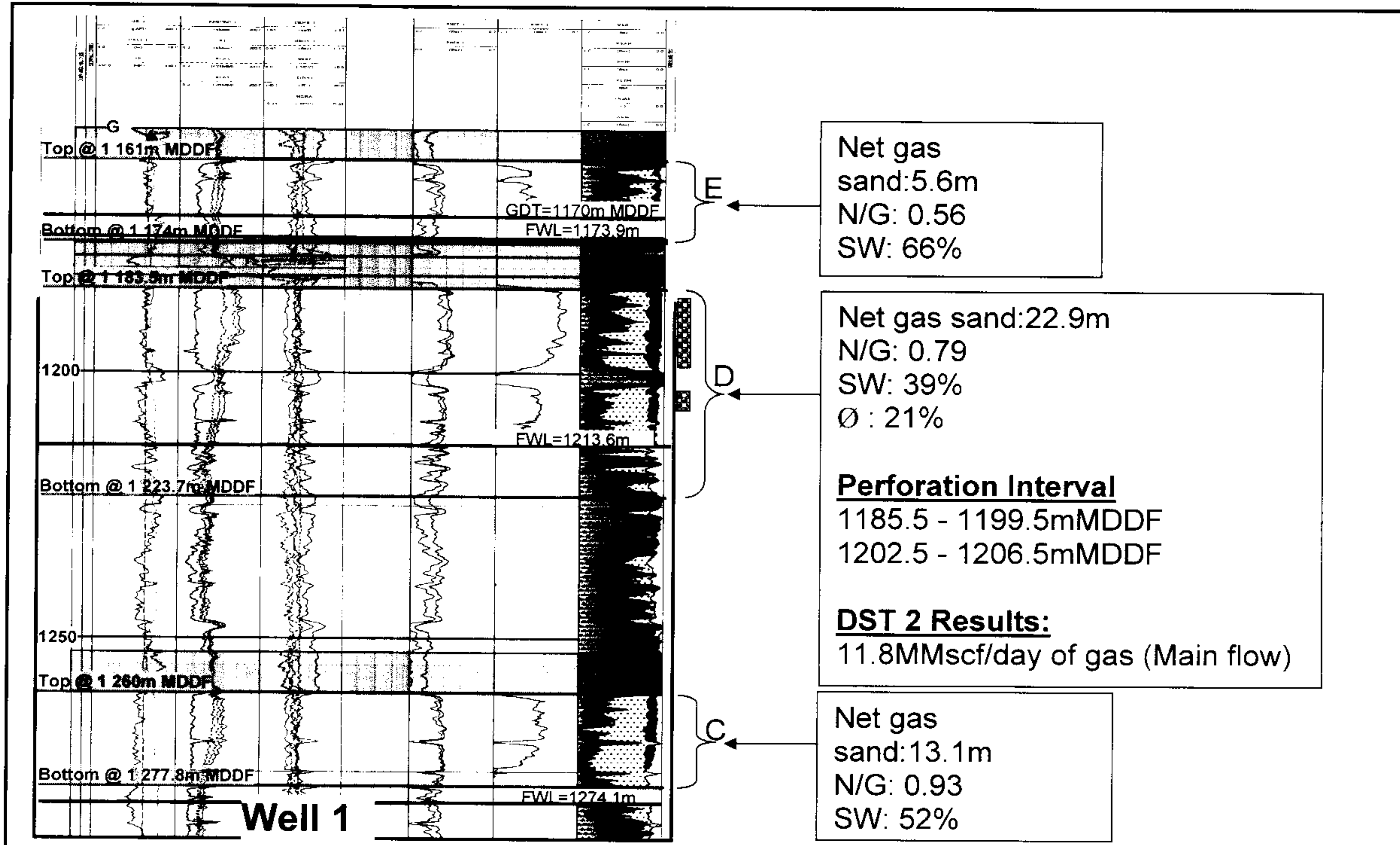


Figure 7.3 : Upper section of well 1 shows the potential of reservoir, seal and source rock

The Miocene section from discovery wells in the adjacent Beibuwan basin exhibit average porosity of 24% to 31% and permeability of 642 mD to 1 479 mD. The regional trend shows that the reservoir quality and thickness decreasing basinward from NW to SE.

7.1.2 FRACTURED CARBONATE RESERVOIR

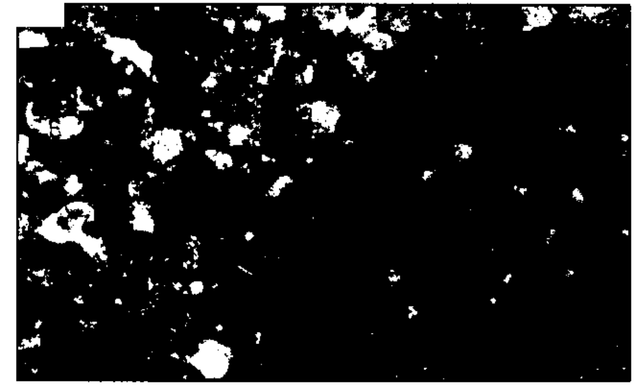
Direct evidence of oil and gas seepages was found on Upper Devonian – Lower Carboniferous fractured carbonate outcrops (Figure 7.4) along the coasts of Vietnam and Hainan Island (Chen et al,. 1998: Traynor & Sladen, 1997). In mid-1996, Anzoil was reported to test heavy oil and gas from carbonates, probably Devonian age in Well B10-STB-1x (Long, 1998). This well was reported to have an average porosity of 8% and flow about 165 BOD from the fractured carbonate section.

Using this finding, Company C drilled Well 6 in 2004 and Well 7 in 2006 to test fractured and karstified pre-Tertiary carbonate rock. Well 6 penetrated 257m and Well 7 penetrated 534m of the pre-Tertiary Carbonate section. Both wells exhibited hydrocarbon shows. In Well 6, out of 23 bullets of Side Wall Core (SWC) attempted, only 4 were recovered. Petrographic analysis on SWC showed that the carbonate is Packstone with 50% fossils (algae, forams) and 50% calcite (Figure 7.4).

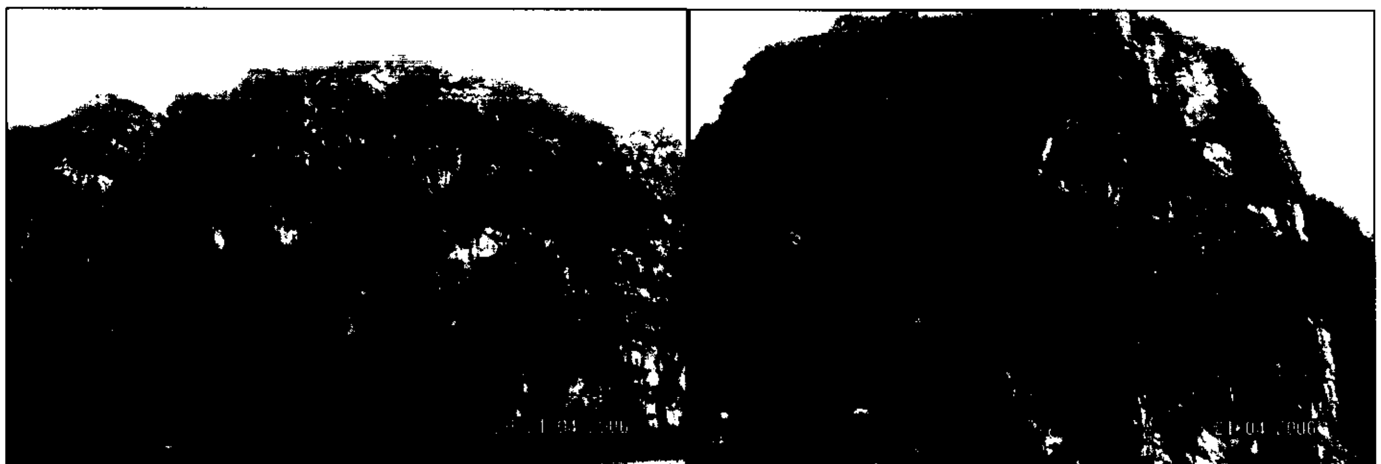
Based on electric log, reservoir properties and total mud loses, in-house study suggested that three types of porosities are present;

I. Matrix or inter granular porosity,
II. Vuggy and cavity – secondary porosity due to chemical activity such as dolitimization or kartification process,
III. Fractured porosity – secondary porosity due to tectonic process from two stages of extensional and two stages of compressional event during pre-Tertiary to Tertiary period.

SWC at 1806 Well 6: Crystalline carbonate at upper part, composed of 100% calcite.



SWC at 1885 Well 6: Packestone carbonate; composed of 50% fossils and 50% micrite cement



Outcrops of Ha Long Bay show bedded and fractured

Picture taken fromOthman & Jaafar, 2006

Figure 7.4 : Thin section and outcrops of carbonates with good visible porosity suggest that the pre-Tertiary carbonates as potential reservoir

The secondary porosity is the major type of pores in the system that accounts for the significant volumes and conductivity in the reservoir. Based on Well 6 results the pre-Tertiary fractured basement is divided into two zones:

i) Zone 1 (1710 - 1830 mMD):

This zone is highly fractured and faulted in the NW-SE direction. There are two major cavities at 1711 and 1735 mMD which were detected by FMI images and other data such as calipers and drilling data (ROP and mud loses). The mineral composition of two samples from the upper part was found to be mostly crystalline carbonate. The porosity and permeability are quite high in the upper part mainly dependent upon secondary pores like caverns and fractures zone.

ii) Zone 2 (1830 – 1964 mMD):

This zone is less fractured. The fractures are dominantly oriented in the WNW-ESE direction. Two samples from lower parts were found to contain mainly fossils and fossil fragments in micrite calcite cement known as packstone carbonates. The porosity and permeability in this zone are much lower, with the average porosity around 2% and permeability less than 500mD mainly from intergranulars and fossils.

7.2 SOURCE ROCK POTENTIAL

Analysis carried out on cutting samples, oil samples and outcrop samples proved that the Eocene-Oligocene and Lower Miocene sections are the main source rock generating hydrocarbon in the SHB. These Paleogene lacustrine mudstones, coals and coaly mudstone together with Miocene coals/ coaly mudstones form a good to excellent source rock in South East Asia (Wang & Sun, 1994). Nielson et al. (1999), has divided the potential source rocks in SHB into 4 category; (1) oil-prone Eocene-Lower Oligocene lacustrine mudstones; (2) oil- and gas-prone Middle Miocene coal beds; (3) gas-prone Upper Oligocene-Lower Miocene coal beds; and (4) gas- and oil-prone Miocene offshore marine mudstones. The first and second potential source rocks are important based on discovery wells and producing field data.

During late Eocene to Oligocene time, lacustrine shales had been deposited in the syn-rift setting and was the main source rock for Blocks A and B. These organic-rich lacustrine shales were probably deposited in grabens and half grabens, when sedimentation was outpaced by rift-induced subsidence, allowing stratified, oxygen-poor water columns to be established in tectonically controlled lakes (Nielsen et al., 1999).

In 2004, Petersen et al., has come out with two evidences to confirm that Eocene-Oligocene source rocks came from lacustrine shales; The evidence were based on (1) outcrop sample analysis, (2) oil sample from B10-STB-1X well. The outcrops samples were taken from Bach Long Vi Island and Dong Ho. The TOC content for the Dong Ho samples ranged from 8 – 17wt.% with HI values exceeding 500 mg HC/ g TOC. The sample from Bach Long Vi island contained 2 – 7 wt.% TOC and HI values of 200 – 700 mg HC/ g TOC. The organic matter analysis result corresponded to Type I kerogen. Oil sample analysis also proved that oil was generated from lacustrine mudstone with contribution from higher land plant organic matter. However, results from geochemical studies of the well sample (Figure 7.5) suggested that the source rock consisted mainly of Type II/ III organic matters of lacustrine and fluvial origin. Figure 7.5 shows the result of HI vs Tmax from six wells in the study area.

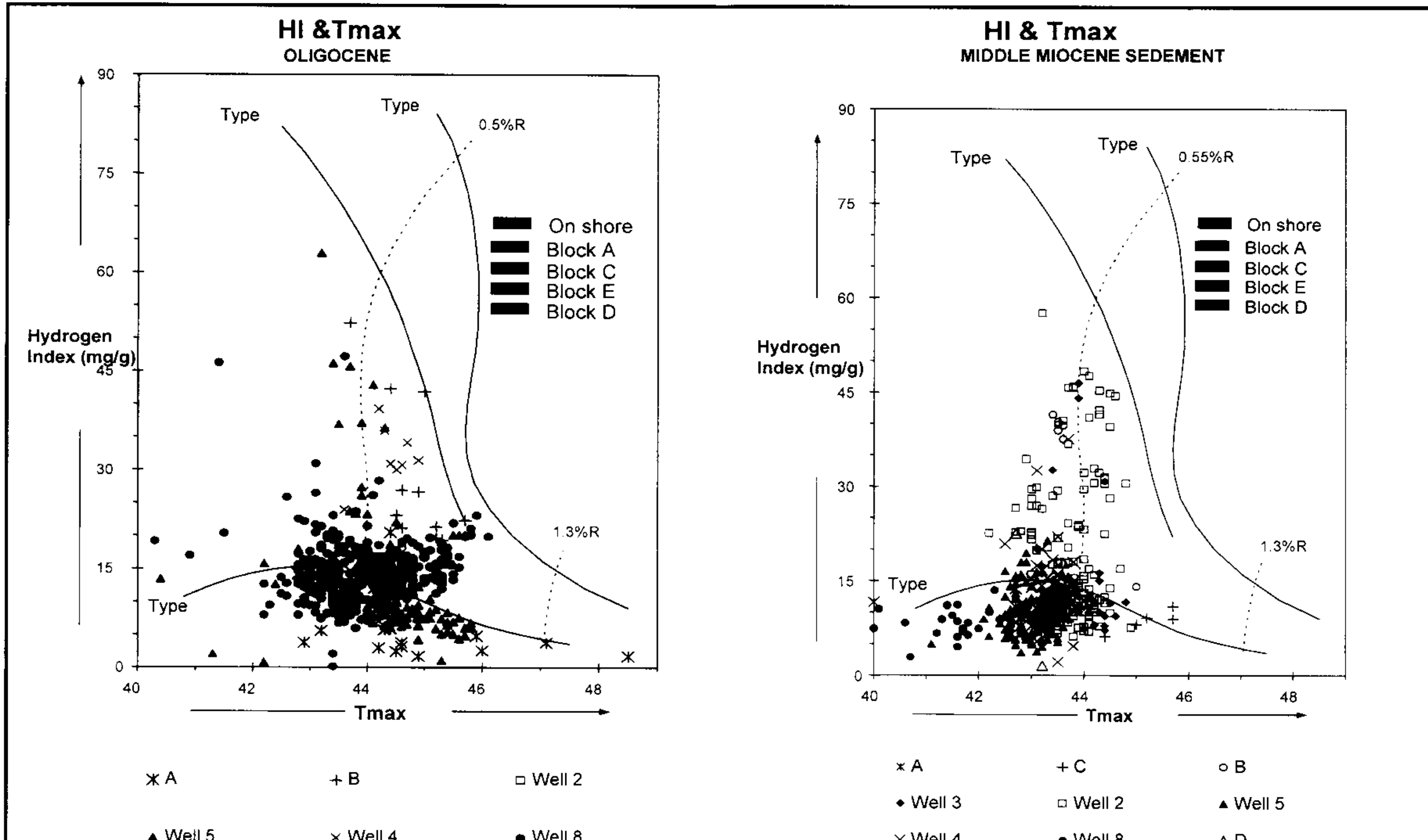


Figure taken from Geochemical Characteristic of Block A & B, Interim Workshop by Company V, 2004

Figure 7.5 : HI vs Tmax Diagram to classify Source Rock during Oligocene and Miocene

Another potential source rock in the study area is shale and coal beds in the Miocene section (Figure 7.1). The early Miocene fluvio deltaic coal and shale/ mudstone and middle Miocene coal and shallow marine shale showed high TOC (0.5 – 2%) and HI values (100 – 200mg/g) in many well sections (Figures 7.6 & 7.7). Geochemical studies on samples from various wells (Table 7.2.1) concluded that the source rocks are of Type II/ III kerogen (Figure 7.5). The early Miocene sediments has reached the maturity stage while the middle Miocene sediments is marginally mature and the upper Miocene source rock still immature.

WELL	STRATA	TOC	S1	S2	HI	SAMPLES
2	Mid -Low Miocene	1.26	0.19	2.07	145	55
	Oligocene	1.37	0.22	3.28	194	19
3	Upp. - Mid Miocene	0.89	0.28	0.90	98	5
	Mid -Low Miocene	1.05	0.28	1.47	120	39
4	Upp. - Mid Miocene	0.76	0.18	1.19	131	114
	Mid -Low Miocene	0.60	0.17	0.78	121	282
5	Upp. - Mid Miocene	0.64	0.01	0.41	59	71
	Mid -Low Miocene	0.70	0.21	1.04	102	288
6	Mid Miocene	0.38	1.05	0.78	205	4
		0.48	0.97	2.19	456	
		0.56	1.20	2.91	520	
		0.74	2.63	3.47	469	
	Early Miocene	0.97	4.94	3.93	405	4
		0.88	1.94	3.42	389	
		1.00	1.64	2.76	276	
		0.18	0.79	1.25	694	
8	Upp. - Mid Miocene	0.34	0.02	0.21	62	9
	Oligocene	0.65	0.04	1.03	148	487

Table 7.2.1: Results of TOC and Rock-Eval Pyrolysis carried out by Company V on cutting samples from wells drilled in Blocks A & B and the surrounding areas.

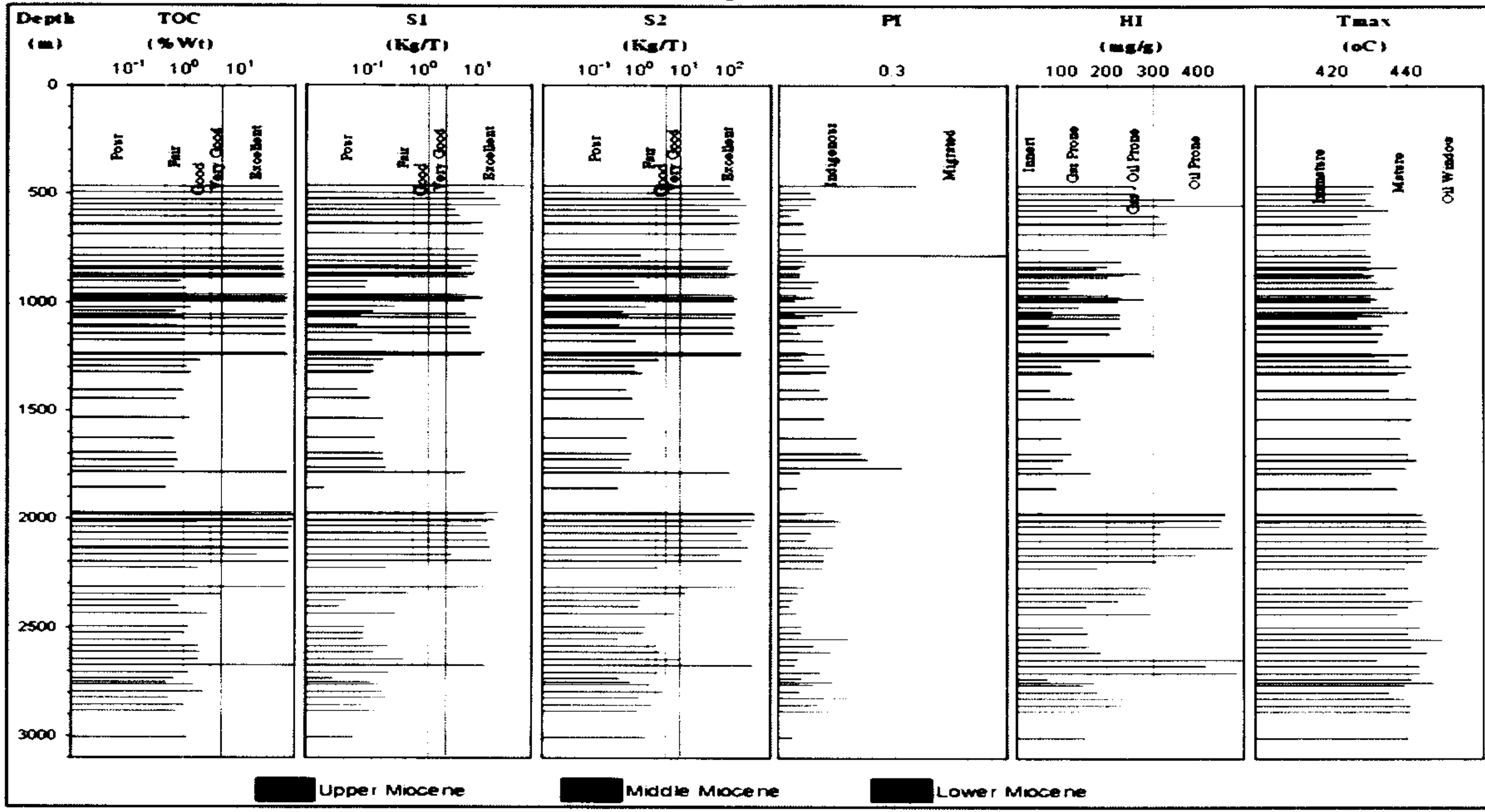


Figure taken from Geochemical Characteristic of Block A & B, Interim Workshop by Company V, 2004

Figure 7.6 : Pyrolyis chart of Eocene at Well 2

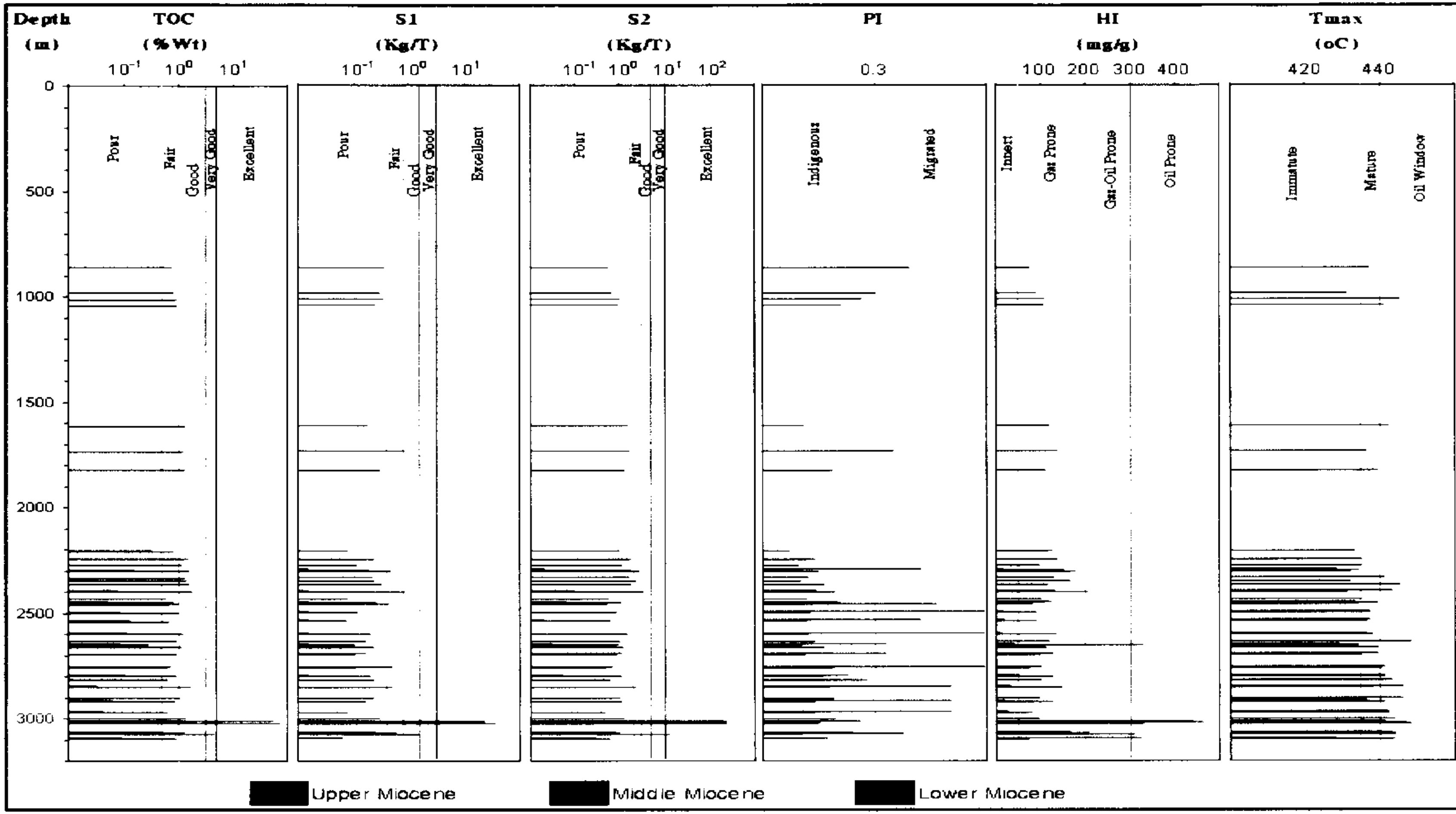


Figure taken from Geochemical Characteristic of Block A & B, Interim Workshop by Company V, 2004

Figure 7.7 : Pyrolyis chart of Eocene at Well 3

7.3 SEAL POTENTIAL

The significant amount of hydrocarbon found in Well 1 and Well 6 proved that the petroleum system is working and an effective seal is present in SHB. The interpreted potential seal in the study area are the intra formational shale of Lower Miocene, Middle Miocene and Upper Oligocene marine and non-marine shale (Othman & Jaafar, 2006). The unconformities could also be one of the potential seals in the SHB (Enclosure 9). The shale layer above the unconformities will be a good seal for the inversion structure and stratigraphic play. In the Oligocene section, the seal is formed by lacustrine shale and in the Miocene section, it comes from shallow marine shale (Figure 4.3).

Figure 7.8 shows there are about 25 meter of intra formational shales overlying the oil bearing sands at Well 6. Integration of seismic and wells data shows the presence of a thick Middle to Upper Miocene shallow marine shale, with more than 200 meters in thickness and good lateral continuity. Based on logs from Well 1 (Figures 7.1 & 7.3), 5 to 30 m of shale acts as an effective seal for five layers of gas bearing reservoirs.

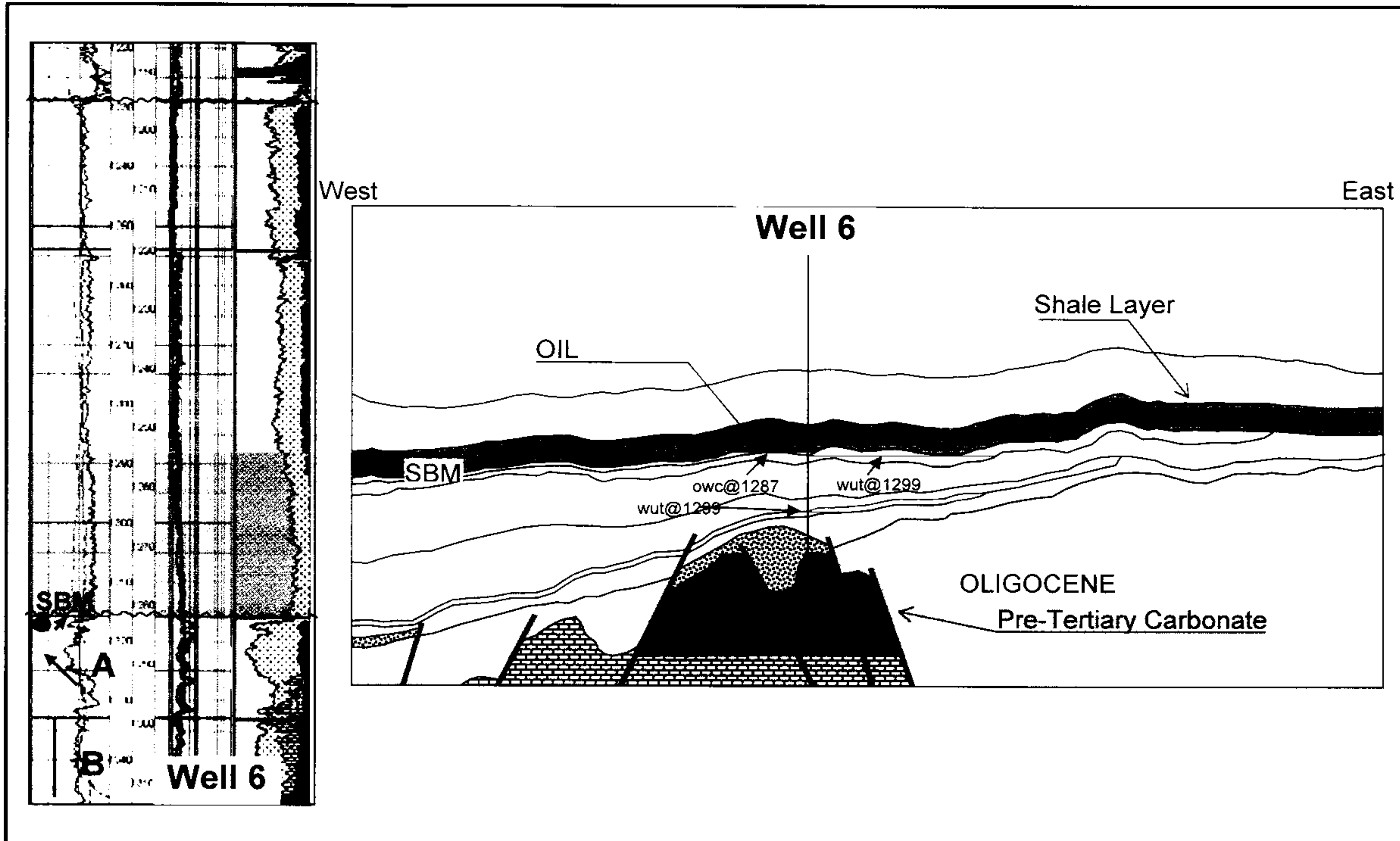


Figure 7.8 : Thick shale as a regional seal in the Miocene section

7.4 PLAY POTENTIAL

The potential play and traps in Blocks A & B had been studied in detailed by Othman and Jaafar in 2006. The study is based on regional seismic interpretation, seismic facies analysis and validation with available well data. Nine potential plays have been identified. Five play types have been tested by exploration wells and another four considered as potential plays in these blocks. More detailed interpretation of recent data is required to mature the identified play types into prospect level and drilling candidate.

All the identified new and existing plays in the study area are listed in the table below;

PLAY TYPES	STATUS
1. Pre-Tertiary Karstified Carbonate	Tested by Well 6 and 7
2. Late Oligocene Inversion	Tested by Well 8
3. Middle Miocene shallow marine sands capped by unconformity.	Tested by Well 6 and 7
4. Late Miocene Inversion	Tested by Well 2 and 3
5. Ponded Turbidites/ Basin Floor Fan	Not Tested
6. M. Miocene Lowstand Channel	Not Tested
7.Lower to Mid. Miocene shallow marine sand	Not Tested
8. Fault dependent Oligocene Syn-Rift.	Tested by Well 5
9. L. Miocene Draped Anticline	Not Tested

Table 7.4.1: Nine play types that proposed by Othman and Jaafar 2006

7.4.1 PRE TERTIARY KARSTIFIED CARBONATE PLAY

An uplifted Pre-Tertiary carbonate play is the main and proven play in SHB (Figures 5.4 & 7.9). The horsts and grabens had been created from the rifting stage during Eocene and Oligocene times provided the fundamentals for this play. The karstification and dissolution of the limestone by meteoric and groundwater solutions created the secondary porosity for the carbonate reservoir. A series of tectonic inversion that took place in the Song Hong basin had popped up further these horst blocks to a higher position to form a good trap for hydrocarbon accumulation. Thick middle Miocene shale combined with intra-formational shale sealed this reservoir. The buried hills play had been tested by wells drilled previously with encouraging results. The B10-STB-1X drilled onshore Vietnam was reported to flow 165 BOPD, 33 degree API from this play. Wells 6 and 7 which were drilled by Company C back in 2004 and 2006 penetrated and encountered hydrocarbon in the Pre Tertiary carbonate section. However, due to the operational problems, the carbonate section could not be conclusively tested.

7.4.2 LATE OLIGOCENE INVERSION PLAY

The inversion structure was produced by the compressional event due to the opening of the South China Sea during Late Oligocene (Figure 5.4). This play is considered among the best plays in the study area where its location was close to the main potential source rock, which is believed to be early Oligocene lacustrine shale. The main reservoir for this play is coastal/ deltaic to shallow marine sands deposited in the marginal marine setting. The transgressive shale deposited above the late Oligocene unconformity provided good seal for the play. No exploration well had been drilled to test this play inside the study area. However, to the south of Block B, only Well 8 had penetrated the top part of the Oligocene section but the result is dry. The prospectivity of this play remains good because in Bei Bu Wan basin, a couple of wells were reported to flow oil from the Oligocene section.

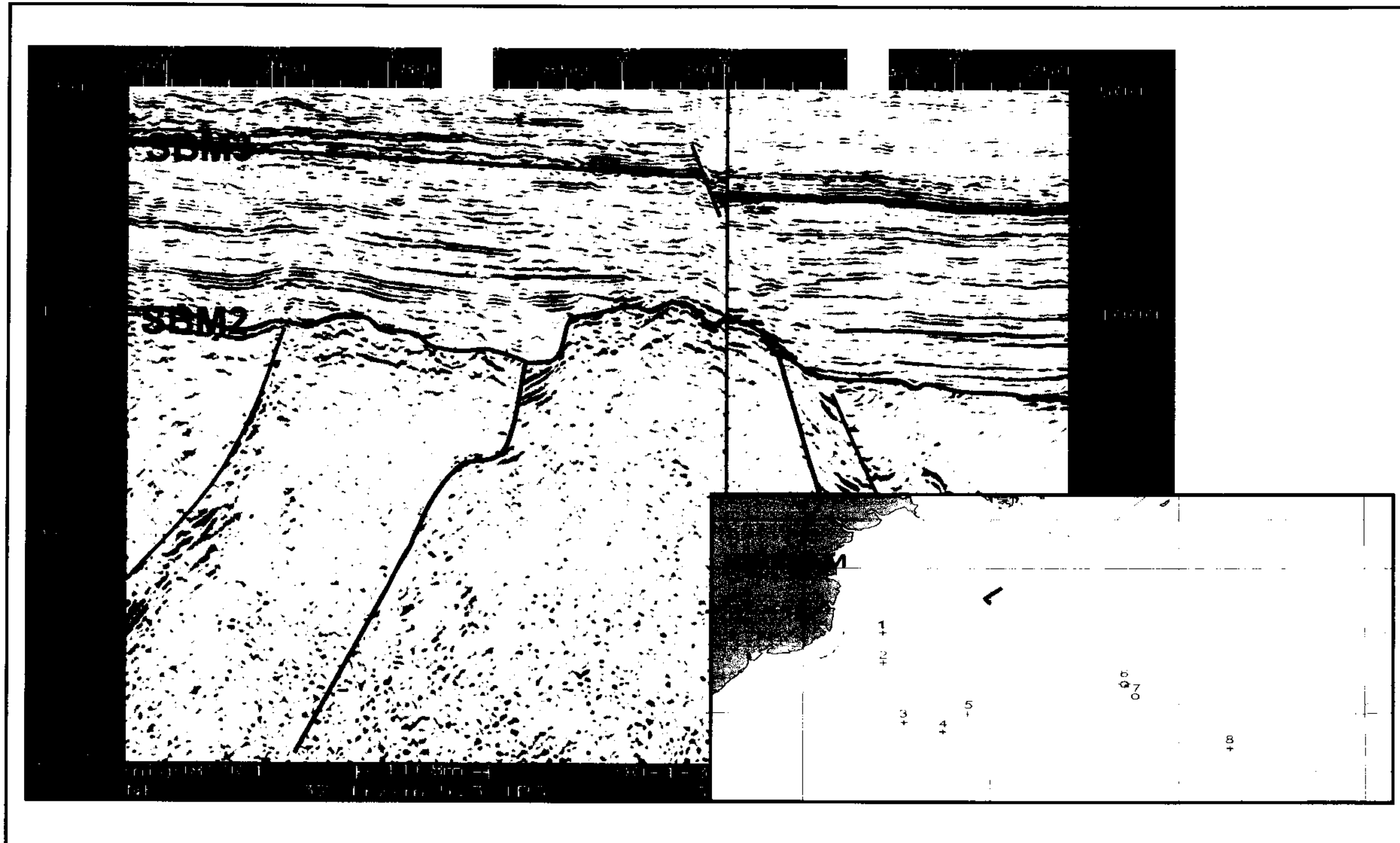


Figure 7.9 : Uplifted pre-Tertiary carbonate rock

7.4.3 MIDDLE MIOCENE SHALLOW MARINE SAND PLAY

This play had been proven to be hydrocarbon bearing by Well 1 and Well 6, where Well 1 encountered significant gas reservoirs and Well 6 penetrated 2.5 m net oil sand. The seal for this play was provided by intraformational seal (Figures 7.1 – 7.3). The thick shale above reservoir acted as a regional seal. This hydrocarbon sand are expected to be better developed to the south and SW, while towards NE of Well 1, the sand become thinner and get eroded. Since this play was proven to be hydrocarbon bearing, prospects with better and bigger closures and good reservoir potential are targeted for future exploration drilling in Blocks A and B.

7.4.4 LATE MIOCENE INVERSION PLAY

The late Miocene inverted structure was produced by the strike slip activity along the Song Hong Fault System due to the movement of South China blocks to the east. Most of the inverted structures were found in Block A since it is located in the center of the Song Hong Fault system or in the weak zone. In contrast Block B, is located in a stable area. The inverted structure provided a good four way dip closure (Figures 5.4 & 7.10) with the Upper Miocene coastal and shallow marine sand becoming the reservoir for this play.

However, this play had been tested by two dry wells, Wells 2 and 3, which were drilled by Company B. Geochemistry and maturity modeling analyses carried out by Company V suggested that the main risk associated with this play is the timing of hydrocarbon migration. The results showed that the peak of the hydrocarbon generation and migration during middle Miocene (17-14 Ma), which pre-dated the closure formation in the late Miocene time. In view of the above, the late Miocene inversion play should be avoided in future exploration drilling campaign as the play had been tested by two dry wells and the petroleum system is not working due to the late closure formation.

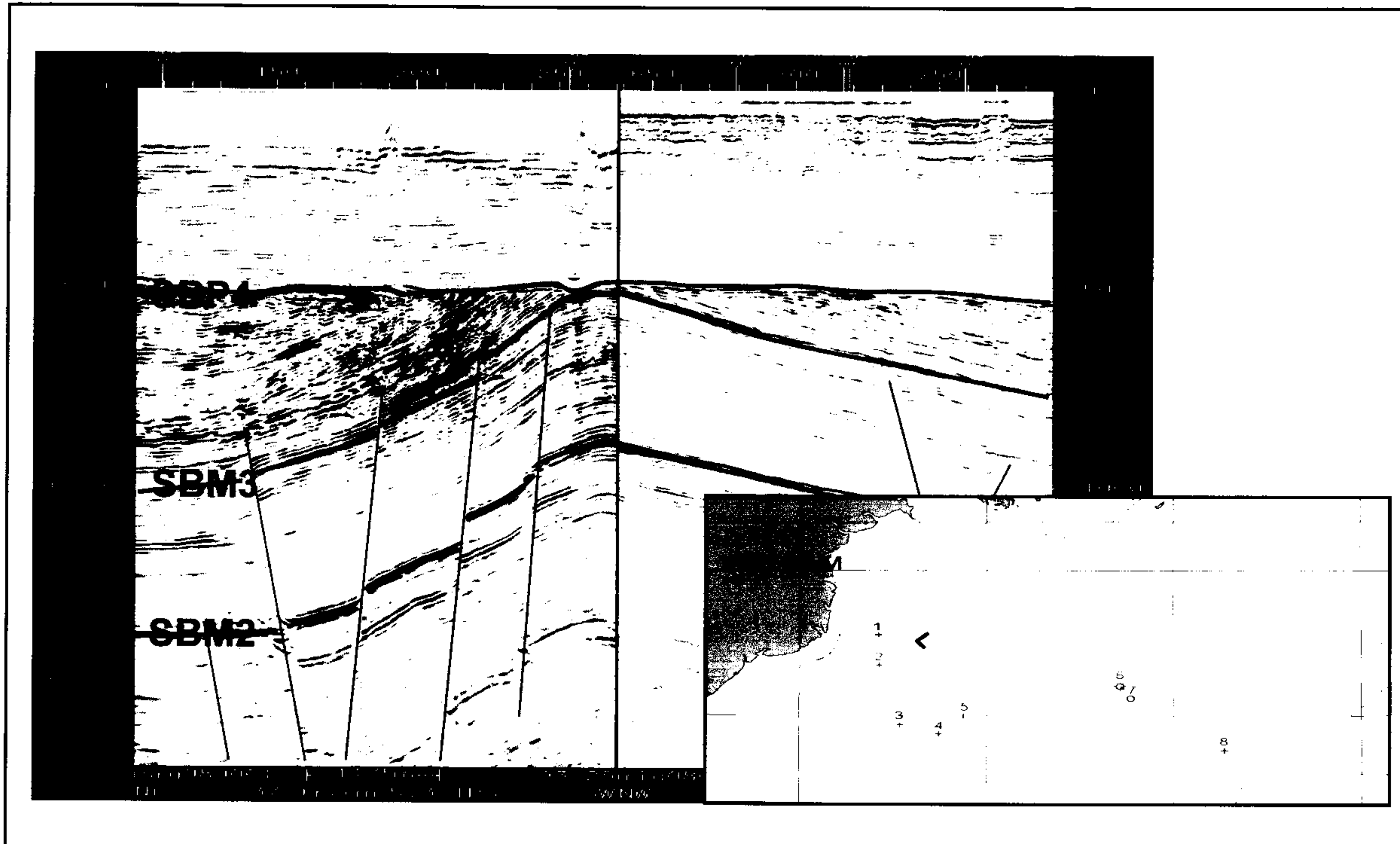


Figure 7.10 : Late Miocene inversion structure

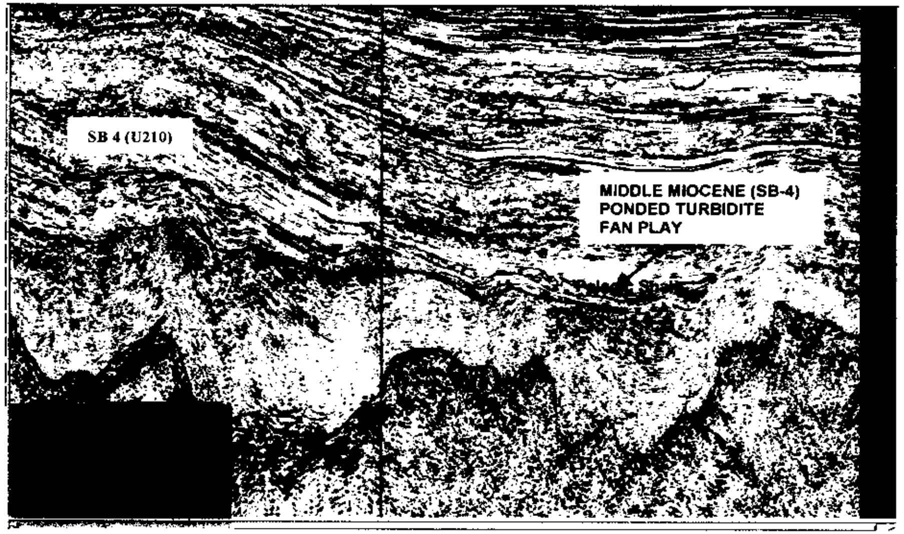
7.4.5 PONDED TURBIDITE/ BASIN FLOOR FAN PLAY

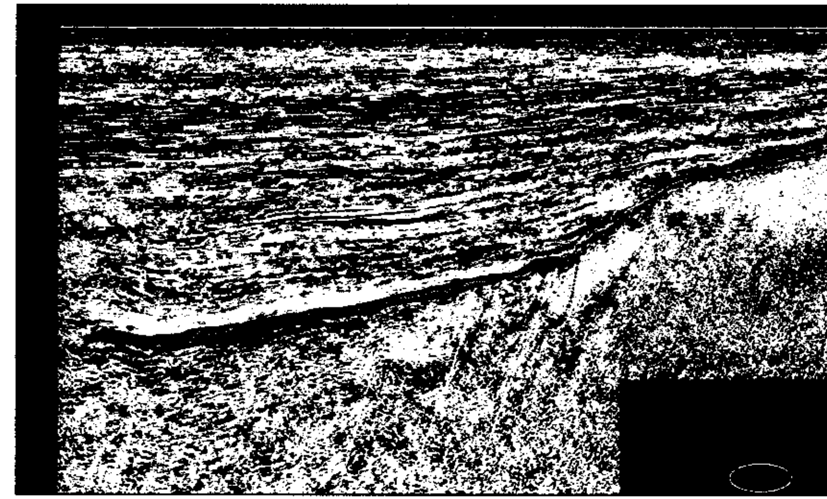
Middle Miocene times were associated with the regression and drops of sea level due to the change of strike slip displacement from left lateral to right lateral. The lowstand system tract of this sea level drops produced Type-1 sequence where the eroded part on the shelf would be deposited into the deeper part of the basin (Figure 7.11). The sediment supply came from the NW area and the channel fairway running from northwest to southeast. The basin floor fan or turbidite would be deposited in the basin center to the south or SE.

Investigations on seismic data to the south of the study area showed a possible basin floor fan or shingle turbidite/ ponded turbidite being deposited. The ponded turbidite is believed to have a good reservoir potential because the sediments that had been eroded on the shelf were most likely sandy. The deepwater shale or pelagic shale provided a good seal for this play. However, due to the limitation of the seismic data in that area, the full potential and distribution of the basin floor fan could not be fully assessed. No well had been drilled to test this play.

7.4.6 MIDDLE MIOCENE CHANNEL SAND PLAY

During the middle Miocene lowstand system tract the northwestern part of Block A was exposed and the environment of deposition was controlled by the fluvial system in the coastal plain setting. This lowstand channel might have a good reservoir potential and could be one of the targeted plays in this area. One of the lines clearly showed the lowstand channel. Thus channel was lens shaped, and it could be sand filled (Figures 5.10 & 7.12). The transgressive shale immediately overlying the channel provided the seal for this play.





Active incisions on the shelf led to the deposition of basin floor fan. Pelagic shale is the potential seal for this play. The potential basin floor fan located outside and to the south of Block B.

Figure taken from Seq. Stratigraphic study by Othman & Jaafar, 2006

Figure 7.11 : Example of possible ponded turbidite/ basin floor fan play

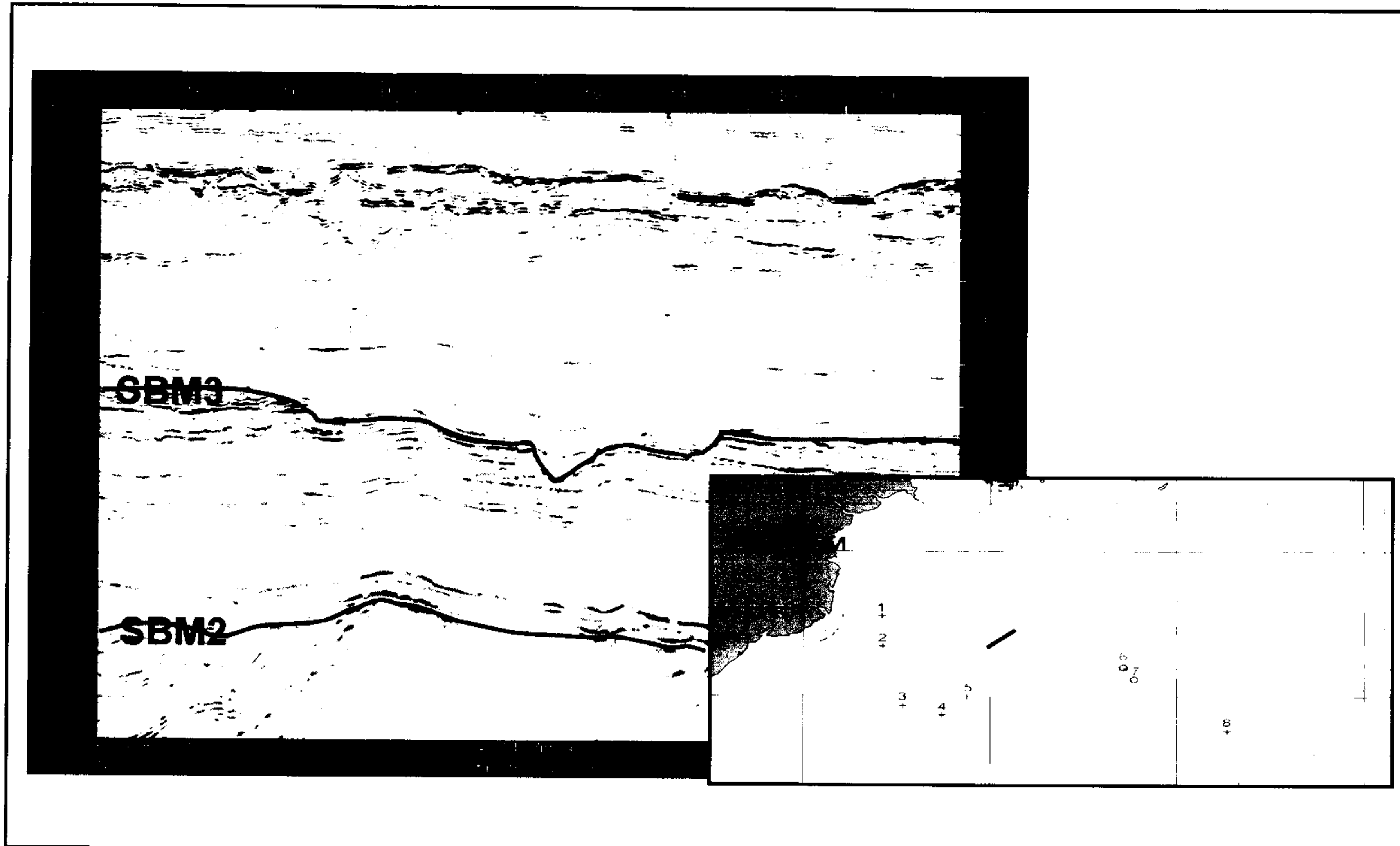


Figure 7.12 : Middle Miocene low stand channel play

7.4.7 LOWER TO MIDDLE MIOCENE ONLAPING SAND PLAY

The major transgression during lower Miocene and extended to the early Middle Miocene had caused the deposition of the onlaping shallow marine/ coastal sands in the area to the NE margin of the Song Hong basin (middle and southern part of Block B) (Figures 5.2 & 7.13). The onlaping sands or stratigraphic pinching could provide stratigraphic traps for hydrocarbon accumulation. The intra-formational shale within the transgressive sequence would provide a good seal for this play. However, this play is yet to be tested.

7.4.8 FAULT DEPENDENT OLIGOCENE SYN-RIFT PLAY

A couple of seismic lines in the study area showed a strong amplitude anomaly at the lower part of the syn-rift and overlying the Pre-Tertiary rock (Figure 5.4). The strong amplitude normally occurred at the edge of the horst and confined by faults. There is a possibility that this strong reflector was associated with carbonate talus or carbonate debris eroded from the pre Tertiary carbonate rock. However, the bedding or layering shown by the seismic reflectors ruled out this possibility.

It is worth to investigate further the potential of this amplitude anomaly, which is believed to be high energy fluvial sediments deposited in the early stage of the rifting. This strong amplitude could be a good reservoir because it was close to the potential lacustrine shale source rock that could make the petroleum system work effectively.

7.4.9 LOWER MIOCENE DRAPED ANTICLINE

The rejuvenation of the basement faults (Pre-Tertiary rock) had caused the overlying sediment to be pushed up to form a gentle four way dip closure (Figure 7.14). Seismic data indicates the upper part of the Oligocene section, the Lower Miocene and upper part of Lower Miocene sections had been gently popped up due to the basement fault reactivation. The main risk for this play is the reservoir presence and effectiveness.

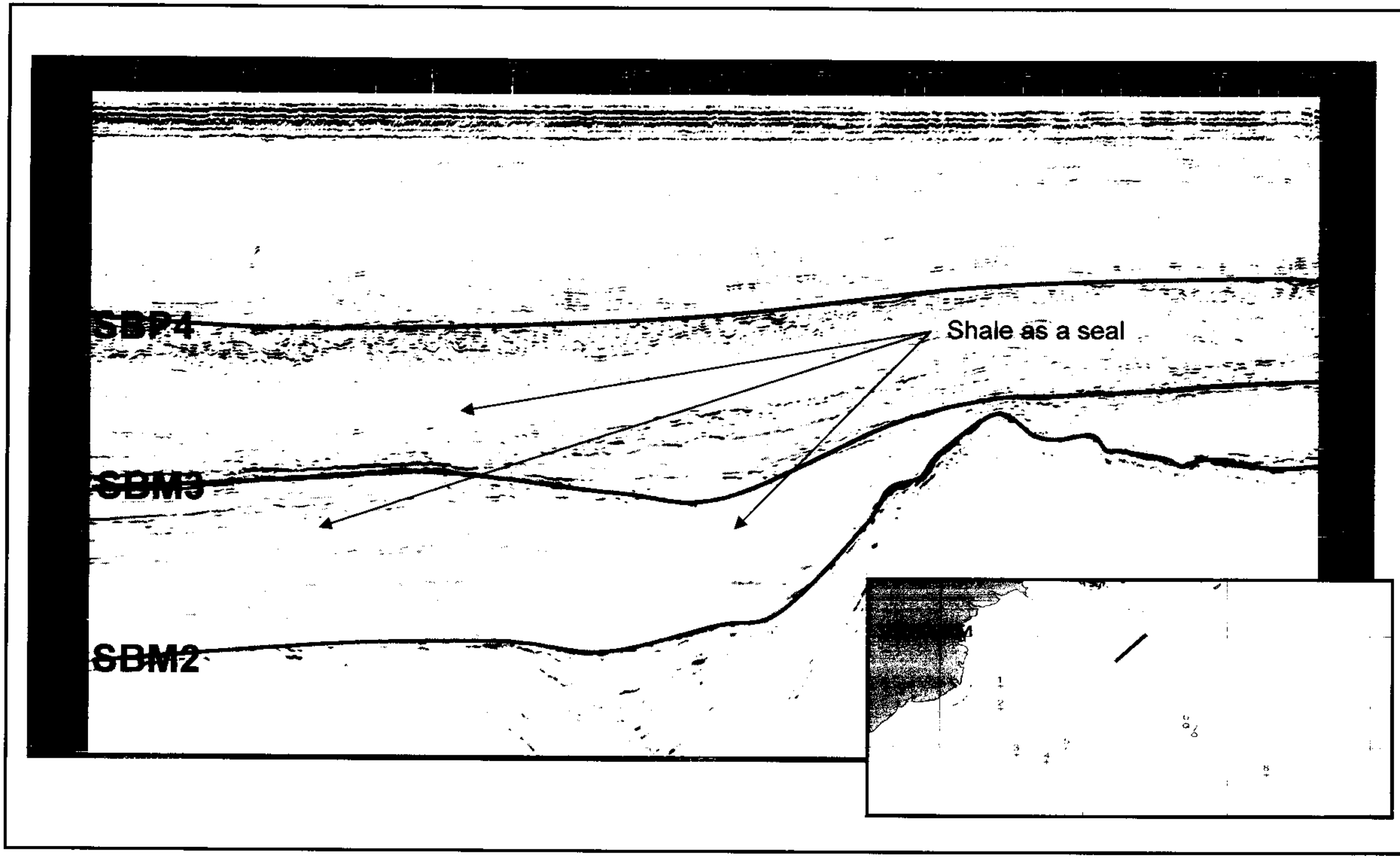


Figure 7.13 :Stratigraphy traps at Miocene section

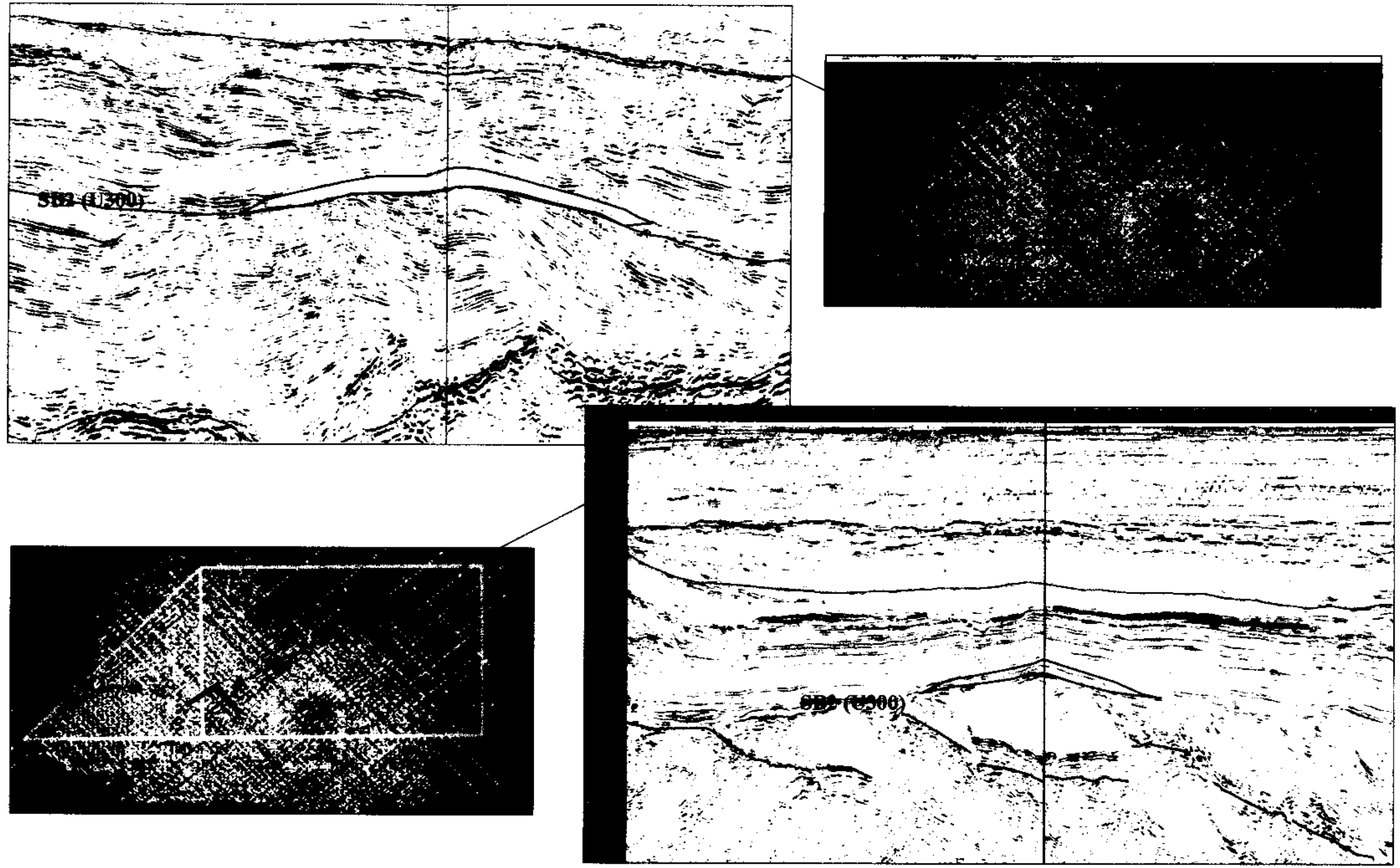


Figure taken from Seq. Stratigraphic study by Othman & Jaafar, 2006

Figure 7.14 : Lower Miocene four way dips draped anticline play

It is known that the Lower Miocene section was deposited during the transgressive period. Hence, reservoir distribution might not be good in the early transgression. However, in the upper part of Lower Miocene some shallow marine sand reservoir might be present.

7.5 MIGRATION

Faults and carrier beds are the conduits for hydrocarbon migration in the SHB (Othman & Jaafar, 2006) (Figure 7.15). Maturity modeling by Nielsen et al., (1999), differentiated the hydrocarbon generation into three important source rock; (1) Upper Eocene – Lower Oligocene syn rift lacustrine shale and coals, (2) Lower Miocene coal beds (3) Middle Miocene coal beds.

The maturity modeling carried out by VPI, 2004 results demonstrated that Upper Eocene – Lower Oligocene source rocks are in a favorable position for hydrocarbon generation, as they are presently within the gas window in large parts of the Hanoi Trough (Figure 7.16). In the shallow part of the trough, this syn-rift deposition is in the condensate to oil window. In the offshore areas at Wells 3, 4 and 5, the top of the Upper Eocene – Lower Oligocene source rocks had already passed out of the oil window between 15 - 17 Ma (Middle Miocene) and is currently generating gas to over mature (Figure 7.17). Thus oil generation stopped before the Late Miocene inversion structures were developed and ready to trap the hydrocarbons.

Lower Miocene coal beds with high Hydrogen Index (HI) and S2 occurred in well sections in the Hanoi Trough and in Well 5. This source rock is immature in the northeastern part of the Song Hong Basin. However, in the offshore areas at Wells 2, 3, 4 and 5 it ranges from immature over main oil to dry gas. In Wells 2 and 3 hydrocarbons were generated prior to the formation of the Late Miocene inversion structures, conforming to the lack of significant amounts of hydrocarbon in those wells.

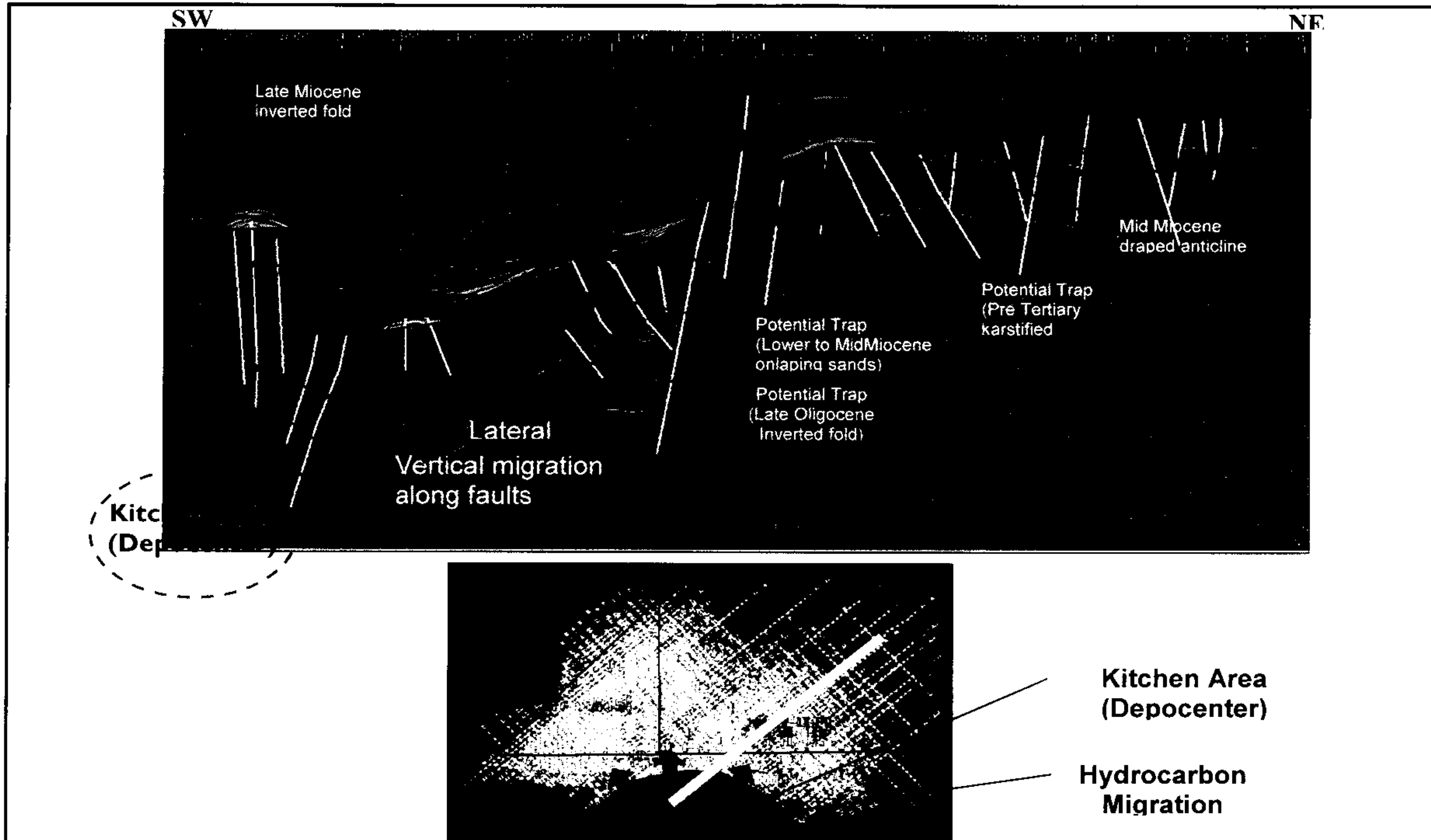


Figure taken from Seq. Stratigraphic study by Othman & Jaafar, 2006

Figure 7.15 : Conceptual Model for Petroleum system in Blocks A and B

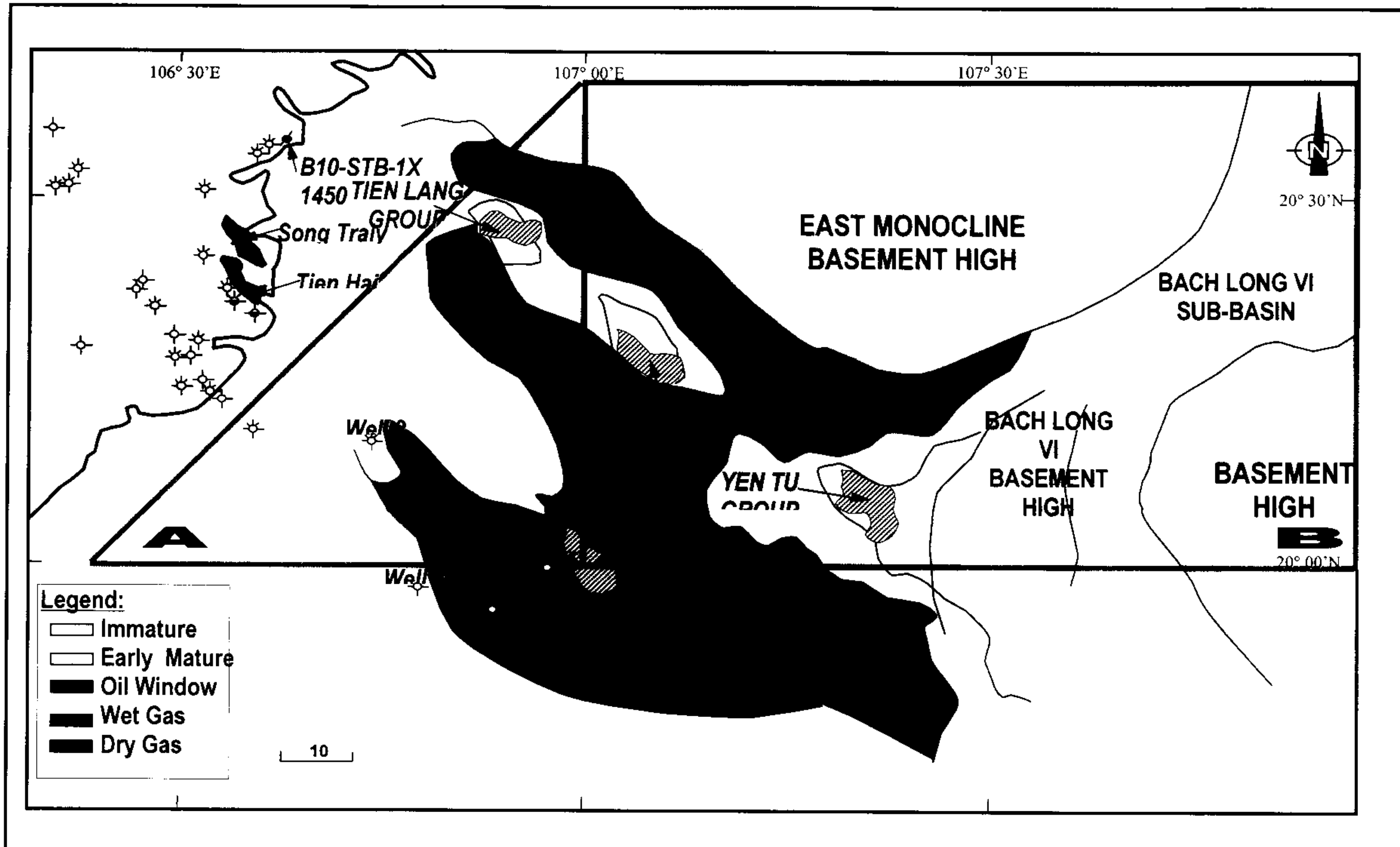
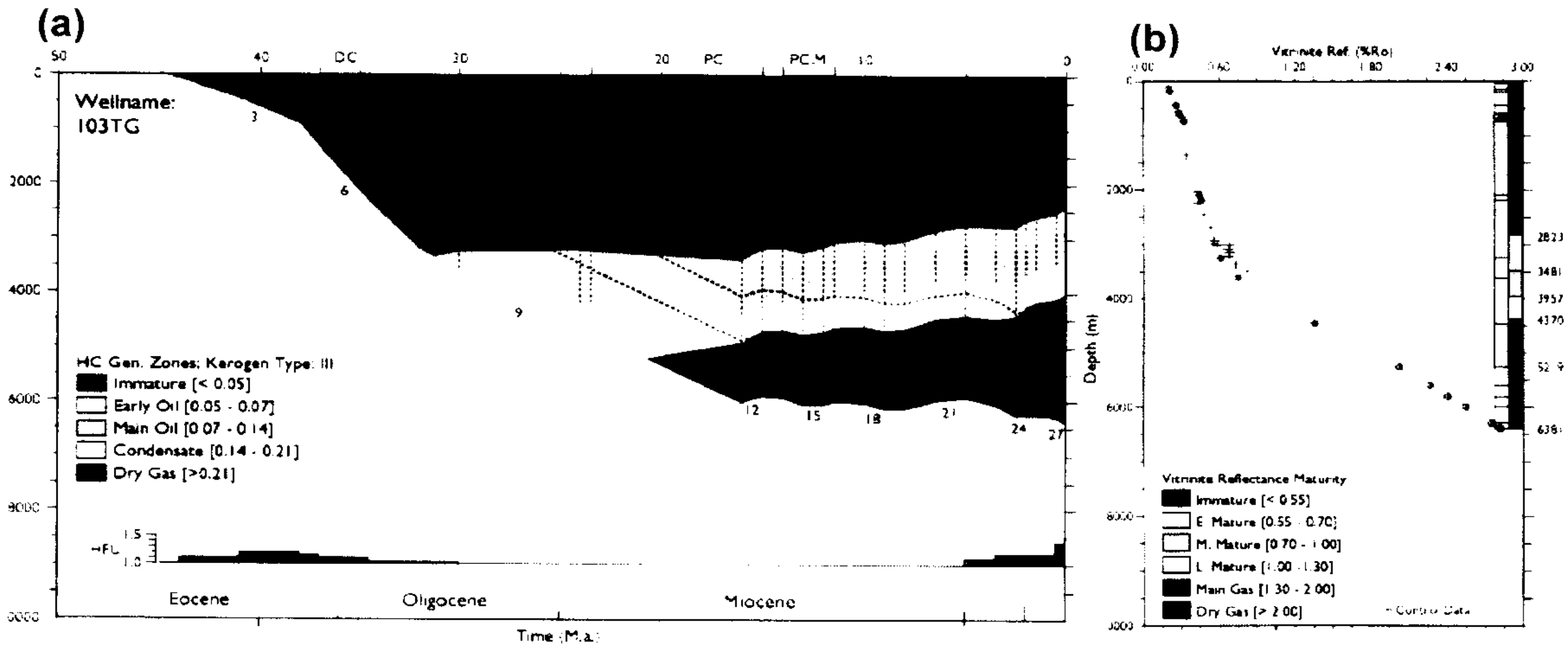


Figure 7.16 : Present day maturity for Eocene – Oligocene horizons



a : Plot showing subsidence history and development with time hydrocarbon generation zone. The used heat flow history is annotated that relative to one heat flow unit (HFU) in the lower part of the figures.

b : The plot is to compare measured vitrinite reflectance (crosses) with the results of the modeling (filled dots). The result shows a good fit between

Figure 7.17 : Result of maturity modeling by Nielsen et. Al., 1999 at Well 5

Maturity modeling by Nielsen et al., (1999) suggested that the middle Miocene coal beds are immature in Wells 2, 4 and 5. However, in Well 3, the model entered the early oil window at 13 Ma, and the main oil and condensate windows at 8 Ma and 1 Ma, respectively. After 11 Ma, hydrocarbon generation did not occur, due to no further significant subsidence.

Based on the evaluation by Company V on Blocks A & B, the Eocene-Oligocene source rock in the central grabens started to generate hydrocarbon at 27 – 28 my. The Oligocene source rock was already at the late oil migration and entered the early gas phase from 10 my to present. The Eocene source rock entered the early gas phase and present at the peak of gas generation. Source rocks in marginal half grabens started to generate hydrocarbon from 6 to 12 my. The Early Miocene source rock started to generate oil from 8 – 10 my and entered the wet gas phase from 5 to 8 my.

CHAPTER 8
CONCLUSIONS

6.1 CONCLUSIONS

SHB is a rift basin that was initiated by the rifting of the pre Tertiary Rock in late Eocene to Oligocene time. The basin formation and tectonic evolution was very much controlled by the strike slip movements of the Red River Fault system following the impact of collision between Indian Plate and Eurasia Plate. A series of compressional and extension events from Oligocene to Late Miocene created inversion structures and stratigraphic traps.

The discovery of Well 1 proved the presence of working petroleum system in Blocks A and B and upgrade the hydrocarbon prospectivity of the blocks

The main source rock for the Petroleum System is believed to be deposited in the lacustrine syn-rift setting during Eocene to Oligocene time. Other potential source rocks are the Lower to Middle Miocene shallow marine coal and shale.

The pre Tertiary fractured and karstified carbonate rock is proven to be hydrocarbon bearing in B10-STB-1X and become the main target reservoir in the study area. Other potential reservoirs are fluvial, costal and deltaic to shallow marine sands.

Lower and Middle Miocene sections are proven and tested to be hydrocarbon bearing by Well 1 and Well 6.

The Composite Common Risk Segment (CCRS) mapping showed that the area in the middle of Block B and northern part of Block A are the moderate risk areas for petroleum system exploration.

REFERENCES

Allen, C.R., Gillespie, A.R., Yuan, H., Sieh, K.E.,Buchun, Z., 1984. Red River and associated faults, Yunnan Province, China: Quaternary geology, slip rates, and seismic hazard. Bulletin of the Geology Society of America 95, 686-700.

Briais, A., Patriat, P., Tapponnier, P., 1993. Updated interpretation of magnetic anomalies and sea floor spreading stages in the East Vietnam Sea: implication for the Tertiary tectonics of southeast Asia. Journal of Geophysical Research 98 (B4), 6229-6328.

Chen, H., Li, S., Sun, Y., Zhang, Q., 1998. Two Petroleum system charge the YA13-1 gas field in Yingehai and Qiondongnan Basins, South China Sea. American Association of Petroleum Geologists Bulletin 82 (5A), 757-772.

Dinh, N.V., Truong, L.V., 1995. Geological structure and hydrocarbon potential of Song Hong Basin. In: Tri, T.V. (Ed.), Proceedings of the IGCP Symposium on Geology of SE Asia, Hanoi, No. 5-6. Journal of Geology Series B, pp. 377-379.

Dien, P.T., Dzung, N.V., 1994. Basin analysis for the Cenozoic formation of Vietnam. In: International Symposium/Workshop on Geology, Exploration and Development Potential of Energy and Mineral Resources of Vietnam and Adjoining Regions. Abstracts, Hanoi, Vietnam, p. 71.

Gong, Z., Li, S., 1997. Basin Analysis and Oil-Gas Accumulation on the Northern Continental Margin of South China Sea. Scientific Publishing House, Beijing, China.

Guo, L., Zhong, Z., Wang, L., Shi, Y., Li, H., Liu, S,. 2001. Regional tectonic evolution around Yinggehai basin of South China Sea. Geological Journal of China Universities 7 (1), 1-12.

Hao Fang, Li Sitian, Sun Yongchuan, Zhan Qiming, 1998. Geology, compositional heterogeneities, and geochemical origin of the Yangcheng gas field, Qiongdongnan Basin, South China Sea. American Association of Petroleum Geologist Bulletin 82 (7), 1372-1384.

Hirayama, J. (Ed.), 1991. Total sedimentary isopach maps offshore east Asia. CCOP Technical Bulletin 23.

Huchon, P., Le Pichon, X., Rangin, C., 1994. Indochina Peninsula and the collision of India and Eurasia. Geology 22, 27-30.

Lee, T-Y., Lawver, L.A., 1994. Cenozoic plate reconstruction of the East Vietnam Sea region. Tectonophysics 235, 149-180.

Leloup, P.H., Lacassin, R., Tapponnier, P., Schärer, U., Dalai, Z., Xiaohan, L., Liangshang, Z., Shaocheng, J., Trinh, P.T., 1995. The Ailo-Red River shear zone (Yunan, China), Tertiary transform boundary of Indochina. Tectonophysics 251, 3-88.

Long, P.G., 1998. Reservoir and caprock characterization in the Song Hong Basin. In: Toan, T.N., Quy, N.H.(Eds), Proceedings from the Conference on Vietnam Petroleum Institute 20 years Development and Prospects, Hanoi, May 1998, pp. 258-272.

Nielsen, L.H., Mathiesen, A., Bidstrup, T., Vejbaek, O.V., Dien, P.T., Tiem, P.V., 1999. Modelling of hydrocarbon generation in the Cenozoic Song Hong Basi, Vietnam: a highly prospective basin. Journal of Asian Earth Sciences 17, 269-294.

Othman Ali Mahmud, Jaafar Unir, 2006. Sequence Stratigraphic Study of Blocks A & B, Song Hong Basin Northern Vietnam. In-House report, Unpublished.

Petersen, H.I., Nytoff, H.P., Nielsen, L.H., 2004. Characterisation of oil and potential source rocks in the northeastern Song Hong Basin, Vietna: indication of a lacustrine-coal sourced petroleum system. Organic Geochemistry 35, 493-515.

Pigott, J.D., Ru, K., 1994. Basin superposition on the northern margin of the South China Sea. Tectonophysics 235, 27-50.

Ru, K., 1988. The development of superposed basin in the northern margin of South China Sea and its tectonic significance. Oil and Gas Geology 9, 12-18.

Sun Shu, Li Jilang, Chen Haihong, Peng Haipo, Hs, K.J., Shelton, J.W., 1989. Mesozoic and Cenozoic sedimentary history of South China. American Association of Petroleum Geologist Bulletin 73 (10), 1247-1269.

Tapponnier, P., Lacassin, R., Leloup, P.H., Schärer, U., Zhou, D., Wu, H., Liu, X., S., Zhang, L., Zhong, J., 1990. The Ailo Shan/ Red River metamorphic belt: Tertiary left-leteral shear between Indochina and South China. Nature, London 343, 431-437.

Traynor, J.J., Sladen, C., 1997. Seepage in Vietnam-onshore and offshore examples. Marine and Petroleum Geology 14, 345-362.

Vejbæk, O.V., Madsen, L., Team, P.V. 1996. Seismic interpretation of the Song Hong Basin, Vietnam. In: Nielsen, L.H., Dien, P.T. (Eds.), Basin analysis and modeling of the Cenozoic Song Hong Basin, Vietnam. Unpublished confidential Report, Geological Survey of Denmark and Greenland (GEUS) and Vietnam Petroleum Institute.

Vu, Nguyen Ging, Robitnowitz, P.D., 1996. Gravity modeling of the Hanoi Basin: an insight into its crustal structure and implication for the formation of the basin. International workshop and Exhibition on Geophysics, Abstracts, Hanoi, pp. 125-126.

Wang, C., Sun, Y., 1994. Development of Paleogene depressions and deposition of lacustrine source rock in the Pearl River Mouth Basin, northern margin of the South China Sea. Ameracan Association of Petroleum Geologist Bulletin 78, 1711-1728.

Well 1, Post Drilling Well Evaluation Report, Blocks A & B PSC, Vietnam. In-house report, 2006. Unpublished.

Well 6, Post Drilling Well Evaluation Report, Blocks A & B PSC, Vietnam. In-house report, 2005. Unpublished.

Well 7, Post Drilling Well Evaluation Report, Blocks A & B PSC, Vietnam. In-house report, 2006. Unpublished.

Zhen Sun, Di Zhou, Zhihong Zhong, Zuoxun Zeng, Shimin Wu, 2003. Experimental evidence for the dynamics of the formation of the Yinggehai basin, NW South China Sea. Tectonophysics 372, 41-58.

Zhou, D., Ru, K., Chen, H-Z., 1995. Kinematics of Cenozoic extension on the South China Sea continental margin and its implication for the Tectonic evolution of the Region. Tectonophysics 251, 161-177.