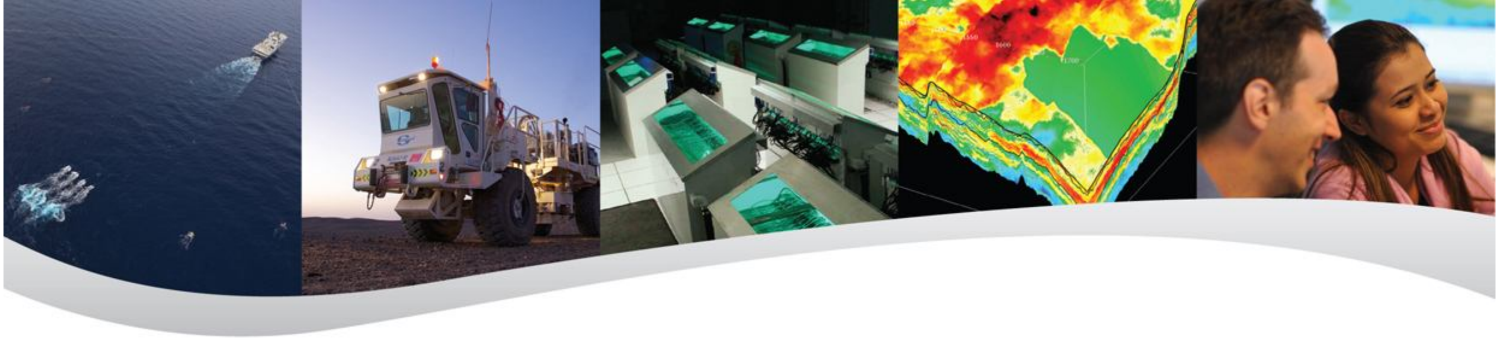

Robertson

COMPETENT PERSONS REPORT
BUNGA MAS PSC, South Sumatra, Indonesia

FOR
ARCTIC BAY VENTURES

Robertson (UK) Limited Reference No: BP444
August 2014

GeoConsulting

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Robertson (UK) Limited Reference No: BP444				
Rev	Date	Originator	Checked & Approved	Issue Purpose
01	August 8th 2014	JC, AS, PW	TC	Final CPR

Date	Originator	Checked & Approved
Signed:		Turlough Cooling

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The seismic coverage over the block consists of four seismic surveys carried out between 1985 and 2010. Half of the data is derived from rasterised 2D lines and the other half is more recently acquired 2D data. Different reprocessing had been applied to different lines and thus the data is not internally consistent. Quality of the data is variable depending on origin and reprocessing, but is generally very poor over the crestal area of structures. A good structural model was created by the Licence holder to estimate where the various horizons should be in no data and poor data areas. This being a model-based seismic interpretation, there is increased risk in the area particularly with regard to the depth and size of the various prospects and leads. The prospect areas and lead areas used in this report are based on the maps in Kingdom Projects that were supplied to us by the Operator and also on certain polygons created by the Operator based on their maps.

Target reservoir intervals are:-

- The Late Miocene Muara Enim Formation is also referred to as the Middle Palembang Formation
- Mid-Miocene Air Benakat Formation: In some older reports, the Air Benakat Formation is referred to as the Lower Palembang
- Early Miocene Gumai Formation. This is normally regarded as a regional shale seal, but in its upper parts there are sands developed and these form the target for many of the prospects detailed in this document.
- Early Miocene Batu Raja Limestone Formation: This consists of an upper bioclastic limestone and a lower massive limestone section.
- Oligocene Talang Akar Formation.
- Eocene-Oligocene Lemat Formation.

Petrophysical review indicates that the VClay and porosity determinations are straightforward and reliable whereas the greatest uncertainty is the formation water resistivity, Rw, which can result in elevated uncertainty for calculated hydrocarbon saturation. Obtaining reliable formation water samples will be key to asset characterisation and valuation.

Seismic data is adequate for the definition of certain prospects to within a reasonable range of volumetric uncertainty but for some prospects the range of volumetric uncertainty is much wider. The mapped structures all exist but the method of mapping involves the application of a concept, or “model”, to assist with mapping structures that are hard to see on the noisy, low-resolution 2D seismic lines.

Volumetric estimates and Chance of Success values provided by the Operator have been reviewed. In general these are found to be reasonable, with additional risk applied in several cases, in particular to reservoir quality. Where oil cases have been specified by the Operator an additional fluid risk has been incorporated.

The Chance of Success definitions are shown in Table 0.1 for the Western area prospects. The Chance of Success, under the AIM Guidance Note, is the estimated likelihood that the Prospective Resources will be matured into Contingent Resources.

For the Western prospects, a summary of prospective resources is provided in Table 0.2.

PROSPECT	Fluid	CLOSURE	SEAL	RESERVOIR	CHARGE	Chance of Success
MELATI EAST MEF	Oil	0.95	0.63	0.80	0.90	0.43
MELATI WEST MEF	Oil	0.95	0.63	0.70	0.72	0.30
PHINISI BATU RAJA	Gas	0.95	0.42	0.60	0.64	0.15
PHINISI TALANG AKAR	Gas	0.95	0.42	0.90	0.64	0.23
PHINISI BRF STRATIGRAPHIC	Gas	0.50	0.48	0.70	0.44	0.07

Table 0.1 Chance of Success, Western Area Prospects

PROSPECTIVE OIL RESOURCES SUMMARY	UNRISKED RESOURCES						RISK (CoS)	RISKED RESOURCES		
	STOIIP (MMBO)			RECOVERABLE (MMBO)				RECOVERABLE (MMBO)		
	Low	Best	High	Low	Best	High		Low	Best	High
MELATI EAST MEF	**14.22**	**17.43**	**21.88**	**2.37**	**2.93**	**3.67**	**0.43**	**1.02**	**1.26**	**1.58**
MELATI WEST MEF	**27.59**	**40.28**	**58.80**	**4.60**	**6.79**	**9.86**	**0.30**	**1.39**	**2.05**	**2.97**
TOTALS	**41.81**	**57.70**	**80.68**	**6.97**	**9.72**	**13.53**		**15.51**	**19.09**	**23.56**
PROSPECTIVE GAS RESOURCES SUMMARY	**UNRISKED RESOURCES**						**RISK (CoS)**	**RISKED RESOURCES**		
	GIIP (BCF)			**RECOVERABLE (BCF)**				**RECOVERABLE (BCF)**		
	Low	**Best**	**High**	**Low**	**Best**	**High**		**Low**	**Best**	**High**
PHINISI BATU RAJA	**0.21**	**0.36**	**0.61**	**0.16**	**0.27**	**0.46**	**0.15**	**0.02**	**0.04**	**0.07**
PHINISI TALANG AKAR	**0.16**	**0.32**	**0.63**	**0.12**	**0.24**	**0.47**	**0.23**	**0.03**	**0.06**	**0.11**
PHINISI BRF STRATIGRAPHIC	**41.16**	**68.16**	**112.86**	**31.00**	**51.40**	**84.10**	**0.07**	**2.30**	**3.81**	**6.23**
TOTALS	**41.53**	**68.83**	**114.09**	**31.28**	**51.91**	**85.03**		**20.27**	**26.30**	**34.52**

Table 0.2 Prospective Resource Summary Tabulation, Bunga Mas, Western Area Prospects

For the Eastern area prospects, the chance of success breakdown is given in Table 0.3 and prospective resource summary is provided as Table 0.4.

PROSPECT	Fluid	CLOSURE	SEAL	RESERVOIR	CHARGE	Chance of Success
ANGGREK ABF & GUF	Oil	0.80	0.63	0.70	0.72	0.25
ANGGREK (NW) ABF & GUF	Oil	0.80	0.63	0.50	0.72	0.18
ANGGREK DEEP GUF	Oil	0.65	0.63	0.60	0.72	0.18
BAKUNG KANA ABF & GUF	Oil	0.80	0.63	0.70	0.54	0.19
BAKUNG DEEP 1 GUF	Oil	0.80	0.63	0.50	0.54	0.14
BAKUNG DEEP 2 GUF	Oil	0.60	0.63	0.50	0.54	0.10
SAKURA ANTHURIUM ABF & GUF	Oil	0.80	0.63	0.70	0.54	0.19
SAKURA DEEP 1 GUF	Oil	0.80	0.63	0.70	0.54	0.19
SAKURA DEEP 2 GUF	Oil	0.65	0.63	0.60	0.54	0.13

Table 0.3 Chance of Success, Eastern Area Prospects

PROSPECTIVE OIL RESOURCES SUMMARY		UNRISKED RESOURCES						RISK (COS)	RISKED RESOURCES		
		OIL IN PLACE (MMBO)			RECOVERABLE(MMBO)				RECOVERABLE(MMBO)		
		Low	Best	High	Low	Best	High		Low	Best	High
ANGGREK	GUF	13.63	18.51	25.15	2.04	2.78	3.77	0.25	0.52	0.71	0.96
ANGGREK NW	GUF	1.89	2.51	3.35	0.28	0.38	0.50	0.18	0.05	0.07	0.09
ANGGREK DEEP	AFLAT	0.76	1.43	2.70	0.11	0.21	0.40	0.18	0.02	0.04	0.07
BAKUNG-KANA	GUF	26.65	39.50	58.56	3.81	5.68	8.42	0.19	0.73	1.08	1.60
BAKUNG DEEP 1	BSTR1	6.40	11.45	20.50	0.96	1.72	3.07	0.14	0.13	0.23	0.42
BAKUNG DEEP 2	BSR2	0.83	2.61	8.26	0.12	0.39	1.24	0.10	0.01	0.04	0.13
BAKUNG NE	GUF	1.42	2.42	4.10	0.21	0.36	0.62				
BAKUNG NW	GUF	3.88	4.83	6.02	0.58	0.73	0.90				
SAKURA-ANTHURIUM	GUF	16.58	24.71	36.82	2.49	3.71	5.52	0.19	0.47	0.71	1.05
SAKURA DEEP 1	SSTR1-1	0.76	1.39	2.56	0.11	0.21	0.38	0.19	0.02	0.04	0.07
SAKURA DEEP 1 N	SSTR1-1	2.85	4.65	7.59	0.43	0.70	1.14				
SAKURA DEEP 2	SSTR2	1.03	1.80	3.13	0.15	0.27	0.47	0.13	0.02	0.04	0.06
MATAHARI NW	GUF	0.78	1.57	3.15	0.20	0.39	0.79				
RAMOK NE	GUF	0.99	1.30	1.71	0.15	0.19	0.26				
PILONA 3-1	GUF	0.05	0.20	0.75	0.01	0.03	0.11				
TOTALS		78.49	118.89	184.34	11.66	17.75	27.60		1.98	2.95	4.46

Table 0.4 Prospective Resource Summary Tabulation, Bunga Mas, Eastern Area Prospects

After review of the volumes in place and scoping economics, specific prospects were high-graded for taking forward to production forecasting and economic modelling. These prospects are Bunga Melati East (MEF27 & MEF34 sands), Bunga Melati West (MEF27 & MEF34 sands), Bakung Kana Gumai Formation (GUF) and Phinisi Stratigraphic (Batu Raja limestone Formation).

Assumptions underlying the production forecast profiles are detailed in Table 0.6 and Table 0.7.

	Low Estimate	Best Estimate	High Estimate
Initial production oil rate	100 bopd	100 bopd	100 bopd
Recoverable volume of oil per well	80,000 bbls	80,000 bbls	80,000 bbls
Decline rate per annum	45 %	45 %	45 %
Cumulative production in 2035	6.97 MMbbls	9.72 MMbbls	13.53 MMbbls

Table 0.5: Assumptions used for the production profiles: Melati prospect

The number of wells assumed for the Bunga Melati development is 86 wells in the Low Estimate, 120 for the Best Estimate and 168 wells for the High Estimate case.

	Low Estimate	Best Estimate	High Estimate
Initial production oil rate	100 bopd	100 bopd	100 bopd
Recoverable volume of oil per well	80,000 bbls	80,000 bbls	80,000 bbls
Decline rate per annum	45 %	45 %	45 %
Cumulative production in 2035	3.81 MMbbls	5.68 MMbbls	8.42 MMbbls

Table 0.6 Assumptions used for Oil Production Profiles: Bakung Kana Prospects

For the Bakung Kana production forecast we assume 47, 70 and 104 wells respectively for the Low, Best and High resource estimates.

	Low Estimate	Best Estimate	High Estimate
Initial production gas rate	4.25 MMscfd	4.5 MMscfd	4.5 MMscfd
Recoverable volume of gas per well	4.4 BCF	4.7 BCF	4.7 BCF
Decline rate per annum	35 %	35 %	35 %
Cumulative production in 2035	31.0 BCF	51.4 BCF	84.1 BCF

Table 0.7 Assumptions used for Gas Production Profiles: Phinisi Stratigraphic Prospect

The likely development for the Phinisi Stratigraphic prospect would be to drill as many as 7, 11 and 18 wells (Low, Best and High Estimates respectively) to explore, appraise and develop this field.

Utilising the production forecasts the produced volumes at year 2035 are as shown in Table 0.8:

	Low Estimate	Best Estimate	High Estimate
Bunga Melati	6.97 MMbbls	9.72 MMbbls	13.53 MMbbls
Bakung Kana	3.81 MMbbls	5.68 MMbbls	8.42 MMbbls
Phinisi Stratigraphic	31.0 BCF	51.4 BCF	84.1 BCF

Table 0.8 Prospective Oil and Gas Resources in the Bunga Mas PSC, at year 2035

Robertson has reviewed Arctic Bay's proposed facilities, associated costs and schedule for developing the clusters. These have been compared against regional benchmarks and our internal database, and are considered to be reasonable and consistent with the maturity of the prospects. They have therefore been used as the basis of the evaluation but with adjustments made for well counts and schedule. Table 0.9 summarises the capex in 2014 terms assumed by Robertson for each cluster in the economic evaluation.

		Well	Facilities	Total
Development	**Case**	**capex, $MM**	**capex, $MM**	**capex**
Bakung Kana	Low	73.8	13.7	87.5
	Best	105.0	16.3	121.3
	High	150.6	20.3	170.9
Melati (East and West)	Low	146.3	24.3	170.5
	Best	203.5	28.2	231.7
	High	283.0	33.8	316.8
Phinisi	Low	33.8	25.4	59.2
	Best	50.5	25.9	76.4
	High	79.7	36.9	116.5

Table 0.9 Capex (100% block) Assumptions by Development

Operating costs for the oil prospects are assumed to be $20/bbl, with an additional $2/bbl for trucking costs to the Pertamina terminal. Operating costs for the gas prospect are assumed to be $0.8/mcf. G&A costs of $1.3MM per year have also been included for each cluster. Well abandonment, decommissioning and site restoration costs are assumed at 10% of the total capex.

Robertson has estimated unrisked NPVs for each of the prospects on a stand-alone basis, assuming that they are successfully drilled, appraised and developed. The brought forward unrecovered cost balance is assumed to be equally divided between Bakung-Kana and Melati, although it should be noted that any variation in this allocation will impact the relative values of the clusters. Results are tabulated below in Table 0.10 for the low, best and high prospective resource cases at the base oil price case.

Table 0.10 Unrisked NPV Summary by Prospect / Cluster

	Unrisked NPV10 ($MM)					
	100% block			**net Arctic Bay**		
Prospect / development	Low estimate	Best estimate	High estimate	Low estimate	Best estimate	High estimate
Bakung Kana	8.3	12.9	18.1	4.2	6.6	9.2
Melati (East and West)	12.3	16.6	20.7	6.3	8.5	10.6
Phinisi	-0.8	13.2	27.8	-0.4	6.7	14.2

The NPVs presented above are not deemed to represent the market value of the block, and in particular must be further adjusted to account for geological, technical and commercial risks.

1 INTRODUCTION

This document is a Competent Persons Report relating to assets owned by Arctic Bay Ventures in South Sumatra, Indonesia (Figure 1.1, Figure 1.2). Arctic Bay Ventures owns the Bunga Mas International Company (BMIC) which has a PSC in place relating to the Bunga Mas Permit.

Figure 1.1 Area of interest, South Sumatra

Arctic Bay Ventures, through BMIC, have a 51% stake in the Bunga Mas PSC as Operator. Samudra Energy holds the remaining 49% and is scheduled to become Operator of the Block.

Work carried out and completed as part of the PSC Licence commitments include G&G studies, 725km of 2D seismic and the drilling of six wells. A further four wells are part of a firm commitment on the Licence.

The PSC expires in 2015 but can be extended upon submission of a Field Development Plan. Discoveries and identified potential are displayed in Figure 1.3. The structure of the area and potential objectives are shown in Figure 1.4. Six exploration wells have been drilled in the period 2010-2012, resulting in 1 gas discovery (Talang Akar Formation, Bunga-Melati-1). Further, Akasia-1 flowed a small amount of condensate from the Air Benakat Formation and Matahari-1 successfully tested gas from a small accumulation within the Air Benakat Formation (these results are discussed in a following paragraph and are detailed in Table 1.1).

The Bunga Mas PSC is located within the South Sumatran Basin (Figure 1.1, Figure 1.2) and is a rich petroleum province.

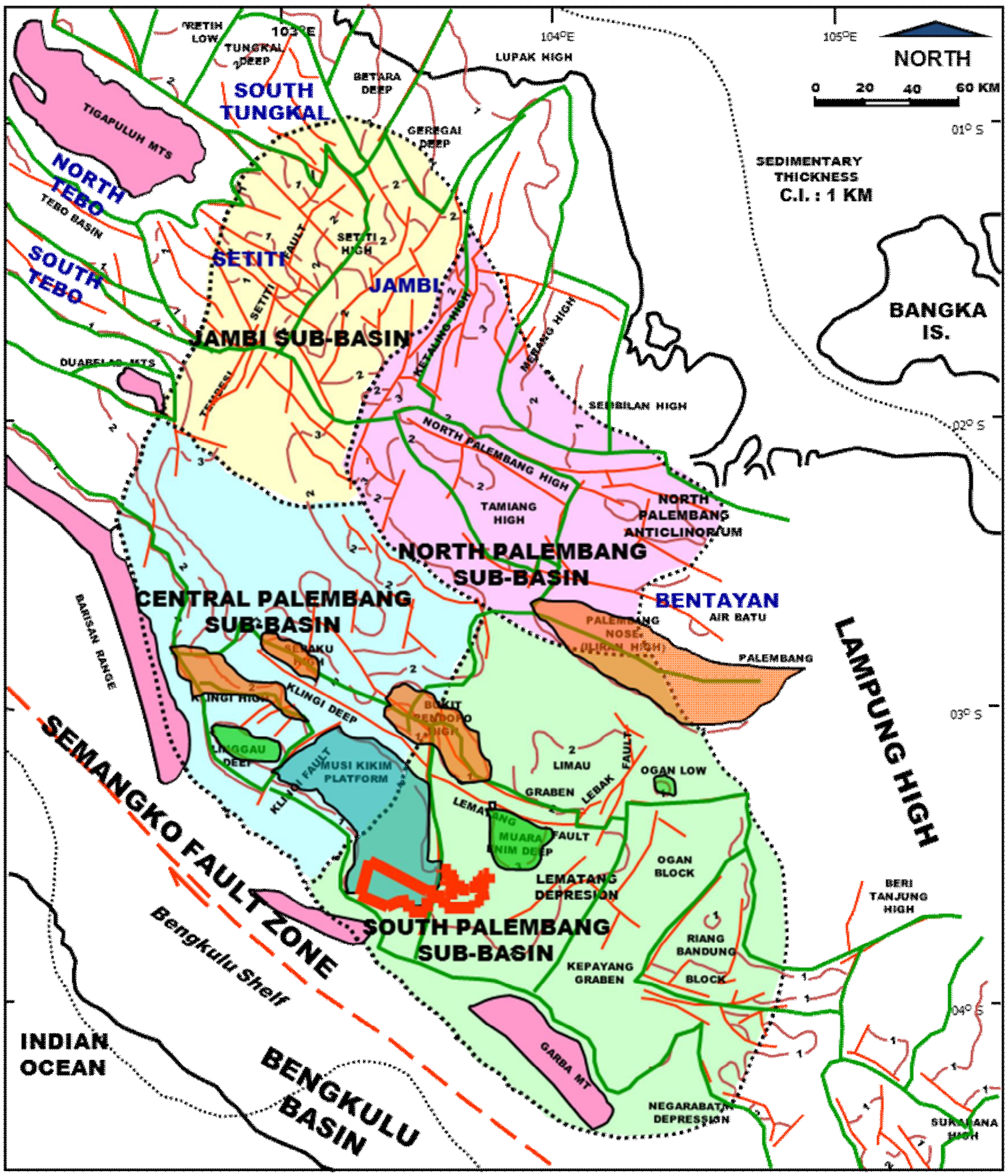

Figure 1.2 Geological Setting (PSC outlined in red)

The South Sumatran Basin hosts proven reserves of 4.3 BBOE in reservoirs of pre-Tertiary Basement to upper Miocene in age. The USGS estimates that there is potential in the basin for the discovery of additional reserves of 3.7 BBOE.

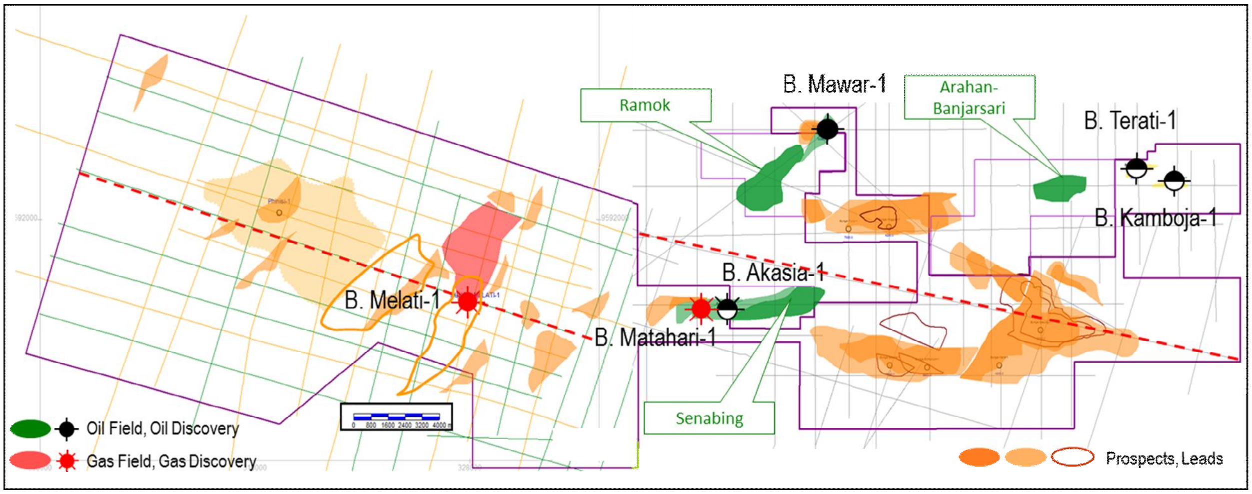

Figure 1.3 Bunga Mas PSC Area showing Fields, Discoveries, with identified Prospects and Leads

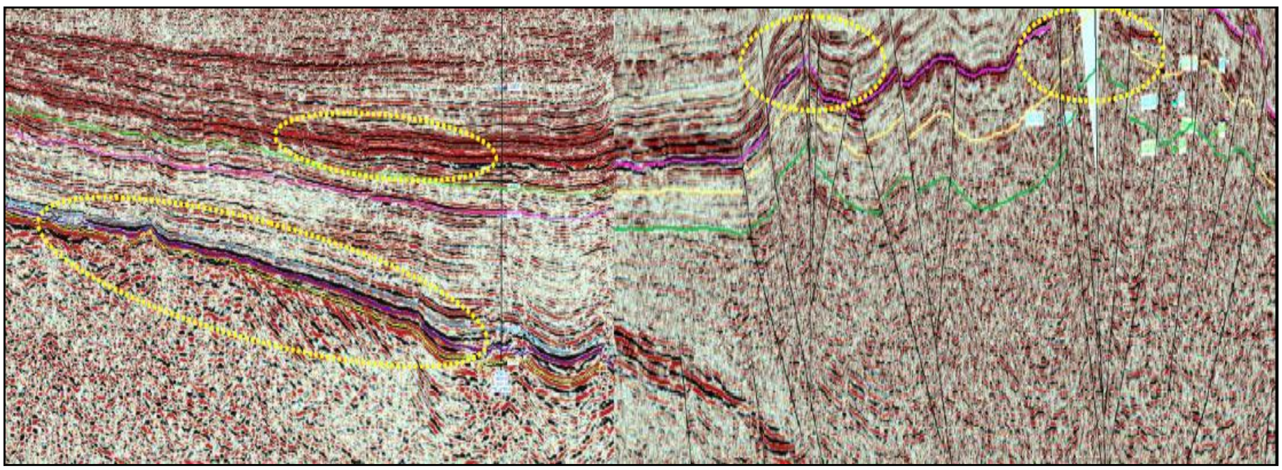

Figure 1.4 Seismic Line across Bunga Mas PSC showing Western Platform and Eastern Inverted Zone, & potential objectives

Figure 1.4 clearly illustrates the East-West difference in structural style within the PSC area. In the East, structural plays dominate and in the West stratigraphic plays are considered to offer greatest potential.

Source rocks are found in the Oligocene Talang Akar section of the rift basin, but more regionally in the early Miocene Gumai shale which is present throughout the PSC Licence area. These source rocks also provide the top-seals for hydrocarbon accumulations. The Gumai shale acts as a regional seal.

Reservoir intervals are found in the Eocene-Oligocene Lemat and Talang Akar Formations, the early Miocene Batu Raja limestone Formation, some sands are present in the upper parts of the Gumai shale, but major sand developments occur in the Middle to Upper Miocene of the Air Benakat and Muara Enim Formations.

Of these reservoirs, the Talang Akar (in the rifted eastern area) and the Batu Raja limestone plus the Air Benakat and Muara Enim reservoirs are the most important targets. Many of the prospects detailed in this report target under-explored sands in the Gumai shale Formation.

Well	Formation	Depth (MD)	Gas rate MMscfd	Oil rate bbl/d	Water rate bbl/d
Melati-1	Talang Akar	8,192-8,220 ft	11.8 (48/64" choke)	31 (48/64" choke)	145 (48/64" choke)
Melati-1	Batu Raja	7,555-7,685 ft	Too low to be measured		
Melati-1	Gumai	5,058-5,073 ft	No flow		
Melati-1	Muara Enim	3,422-3,535 ft 2,745-2,790 ft	Not conclusive		
Terati-1	Gumai	2,950-2,960 ft 2,978-3,020 ft	Traces of gas		720 (28/64" choke)
Terati-1	Gumai	2,840-2,880 ft	No flow		
Akasia-1	Air Benakat	1,380-1,390 ft 1,396-1,411 ft	Tested small condensate flow. Formation damage is suspected.		
Matahari-1	Air Benakat	1,963-1,978 ft 1,946-1,958 ft	1.595 (32/64" choke) 0.67 (36/64" choke)		
Mawar-1	Muara Enim	2,072-2,082 ft	Testing under progress		
Mawar-1	Air Benakat	2,252-2,266 ft	Water formation recovered		
Mawar-1	Air Benakat	2,312-2,320 ft	0.2 (72/64" choke)	86 (72/64" choke)	
Mawar-1	Gumai	3,756-3,762 ft	Too low to be measured		

Table 1.1 Bunga Mas, Drilling and Testing Results 2010-2014

Testing of the three wells Bunga Akasia-1, Bunga Matahari-1 and Bunga Mawar-1 occurred in early to mid-2014 (Table 1.1). The Akasia well tested a small condensate flow from 30% porosity sand; formation damage is suspected. The Matahari well did not find the hoped-for oil, but tested gas from a 4mD sand at 0.67 MMscf/d and a further 1.595 MMscf/d from a 14mD sand. Contacted GIIP was estimated at 1.4 BCF, making it uneconomic as a stand-alone development. At the time of writing this report, testing of Mawar-1 well was not fully complete but one test is reported to have flowed at 86 BOPD with a small amount of gas. The Melati well tested gas at a stabilized rate of 6.5 MMscf/d and water at a rate of 989 BWPD (40/64" choke).

The above tested wells are still under evaluation by the Operator and they have not been included as discoveries for volumetric and economic evaluation in this report.

An annotated seismic line illustrates the petroleum system as understood by Arctic Bay Ventures (Figure 1.5):

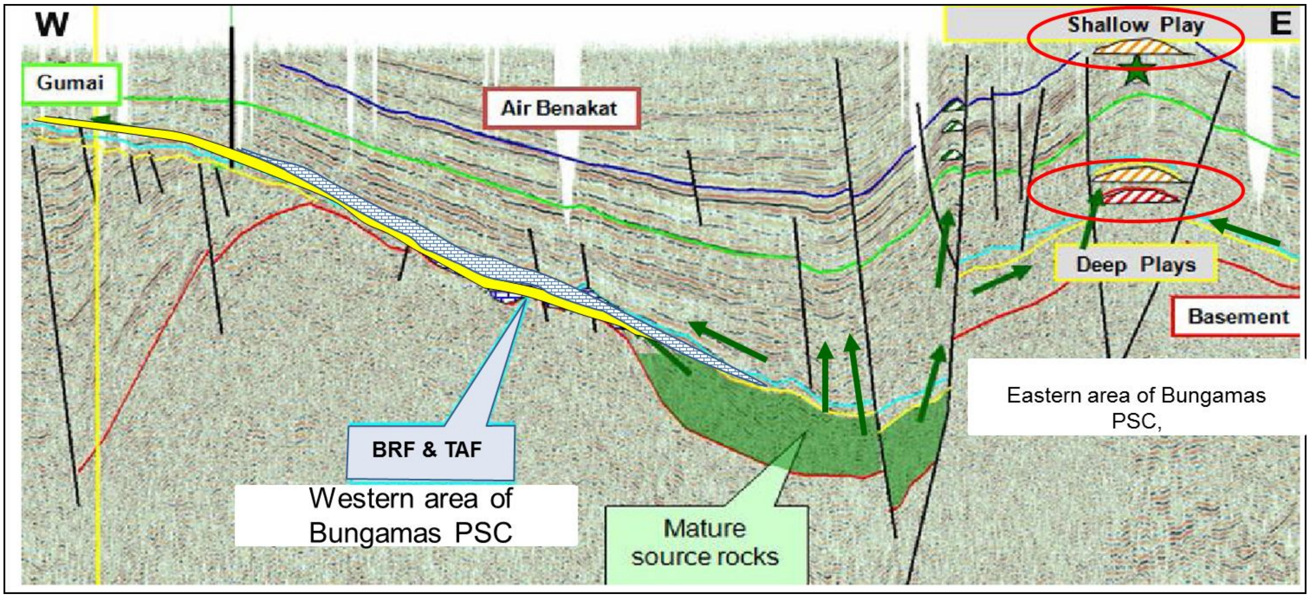

Figure 1.5 Schematic illustration of petroleum system in Bunga Mas PSC Licence area

2 GEOLOGY

The South Sumatra Basin initially formed by means of a rifting phase in the Late Eocene. This is aligned NE-SW in the Jambi sub-basin and N-S in the Palembang sub-basin in the south. The Bunga Mas PSC is located on the edge of one of these north-south rifts, the Lematang Depression. The western part of the block is on the Musi High and the eastern part of the block is in the Lematang Depression. The basement highs at the sides of the rifts were subjected to erosion and provided sediment that was transported into the rift in the form of alluvial fans and screes. These rift valley sediments make up the Lahat Formation which overlies the rift opening Kikim Tuffs. Within the rifts the fluvio-deltaic Talang Akar sands, shales and coals were deposited. The coals and high gamma ray shales form the source rocks for the area. The Talang Akar Formation became gradually marine as the basin subsided. The rift margin eventually subsided and the Batu Raja carbonate buildups formed initially on the edges of the rift during Late Oligocene to Early Miocene.

With further subsidence, basement highs were covered with carbonate platform environments and patch reefs similar to the modern day Java Sea. The top of the Batu Raja Limestone usually forms a distinct seismic horizon; however, the laterally equivalent “Batu Raja” shales are carbonate rich and also have a seismic contrast with the overlying Gumai Shales. Where the Batu Raja is highly porous the contrast with the overlying shales is reduced. Basin subsidence resulted in the area being covered by the marine Gumai Shales which act as a regional seal. There are local marine sands deposited within the Gumai Shales and these sands downlap onto the underlying formation and occasionally act as thief beds. This was followed by a regressive phase during which the Air Benakat was deposited. During the Middle Miocene wrenching occurred associated with the early Barisan Fault movements. This was followed by a compressional phase during the Plio-Pleistocene associated with the main buildup of the Barisan range. This resulted in parallel fold trends associated with high-angle compressional faults. The Muara Enim sands and coals were deposited in the Late Miocene.

2.1 Trap styles within the Bunga Mas PSC

The western part of the Bunga Mas PSC is on the edge of the Musi High and the plays comprise the marine Talang Akar, which onlaps the edges of the rift margins, and the Batu Raja carbonates which could form build-ups as well as shallow marine carbonate sands and platform limestones.

The eastern part of the Bunga Mas PSC lies over the rift area and the traps consist of a series of highly faulted folds. Due to the recent nature of the compression these folds form surface features which resulted in the early discovery of shallow fields in the area.

2.2 Source Rocks

Studies of source rock maturity indicate that the Gumai shale could have expelled “up to 2.5 MMbbl/km^2 of oil”. Mapping shows that an average of approximately 1.8 MMbbl/km^2 oil could have been expelled from large areas. In addition, “up to 3Bcf/km^2 gas may have been expelled from the Gumai Dark Gray Shale source rock”, although an average value lies in the 0.8 to 1 Bcf/km^2 range.

Similar studies of the Talang Akar source rock indicate 0.6 to 0.8 MMbbl/km^2 oil (0.8MMbbl/km^2 over wide areas) and an average of 8 Bcf/km^2 gas (maximum 20Bcf/km2 locally).

The range of burial depths for these undoubtedly rich source rocks in combination with the complexity of the migration pathways means that fluid type is uncertain, oil, gas and condensate have been expelled and may be found in combination in many fields.

2.3 Migration

Migration pathways up faults are thought to be important for the movement of generated hydrocarbons into structural traps in the Eastern part of the PSC Licence. In the Western area of the PSC, migration must occur along carrier beds into stratigraphic traps primarily in the Talang Akar sandstones, Batu Raja limestones and the overlying Air Benakat sands.

2.4 Reservoirs

Target reservoir intervals are summarized below:

- The Late Miocene Muara Enim Formation is sometimes referred to as the Middle Palembang Formation and prospects occur at a depth range of 2175-2900 feet subsea.
- Mid-Miocene Air Benakat Formation: In some older reports, the Air Benakat Formation is referred to as the Lower Palembang. Prospect depth ranges from 350-2000 feet subsea.
- Early Miocene Gumai Formation. This is normally regarded as a regional shale seal, but in its upper parts there are sands developed and these form the target for many of the prospects detailed in this document. Target depths for the Gumai Formation reservoir sands lie between 200 feet and 8475 feet subsea.
- Early Miocene Batu Raja Limestone Formation: This consists of an upper bioclastic limestone and a lower massive limestone section with target depths ranging from approximately 4400-5060 feet subsea.
- Oligocene Talang Akar Formation, in which prospects occur at 5650-7510 feet subsea.
- Eocene-Oligocene syn-rift Lemat Formation.

Reservoir quality declines at a regional level towards the South West as this is more distant from major sediment input points. However, high porosity good permeability reservoir sands still exist in the area, however there tend to be dirtier, lower permeability sands developed.

Reservoir quality is not well documented by means of analogue well data by the Operator and global reservoir property averages have been used in Operator’s volumetric estimations. For example, most Eastern Area prospects utilise the same reservoir property ranges for reservoirs at a range of burial depths from 200 feet to 2850 feet. Therefore, the ranges used for volumetric calculations must be considered indicative and in this sense may be considered reasonable for the purposes of prospective resource estimation. We have checked the ranges used for net-to-gross and porosity and find them to be generally reasonable. However, there is far greater uncertainty regarding the hydrocarbon saturation. This discussion is amplified in the next section dealing with the petrophysical interpretation.

3 PETROPHYSICAL REVIEW

The objective of this study was to verify that the stated estimates of reservoir properties are reasonable. The three wells evaluated in this report are Bunga Matahari-1, Akasia-1 and Mawar-1. The wells are shaly sandstone reservoirs with possible gas present. The evaluation steps were:

- Review the original data provided for quality
- Review the parameters used in original interpretations
- Analyse all three wells to reproduce the original results
- Evaluate key parameters to study effects of variations

3.1 Quality Review

Wells Matahari-1 and Akasia-1 showed no particular problems with the key data; neutron porosity and bulk density (used in the computation of effective porosity), resistivity (used in conjunction with the effective porosity to compute water saturation) and the gamma ray (for computation of VCl, clay volume). However, Bunga Mawar-1 has a major problem with the neutron porosity. This tool has a maximum hole-size of 17" unless special equipment is used. The borehole in this well averages 18" and is often much more. The tool has a number of corrections for the environment, including hole-size and effective stand-off. The latter is very difficult to gauge and increases with increasing hole-size. Its effect is to increase the tool's apparent reading, just as seen in this well (Figure 3.1). The measurement was not used in the calculations.

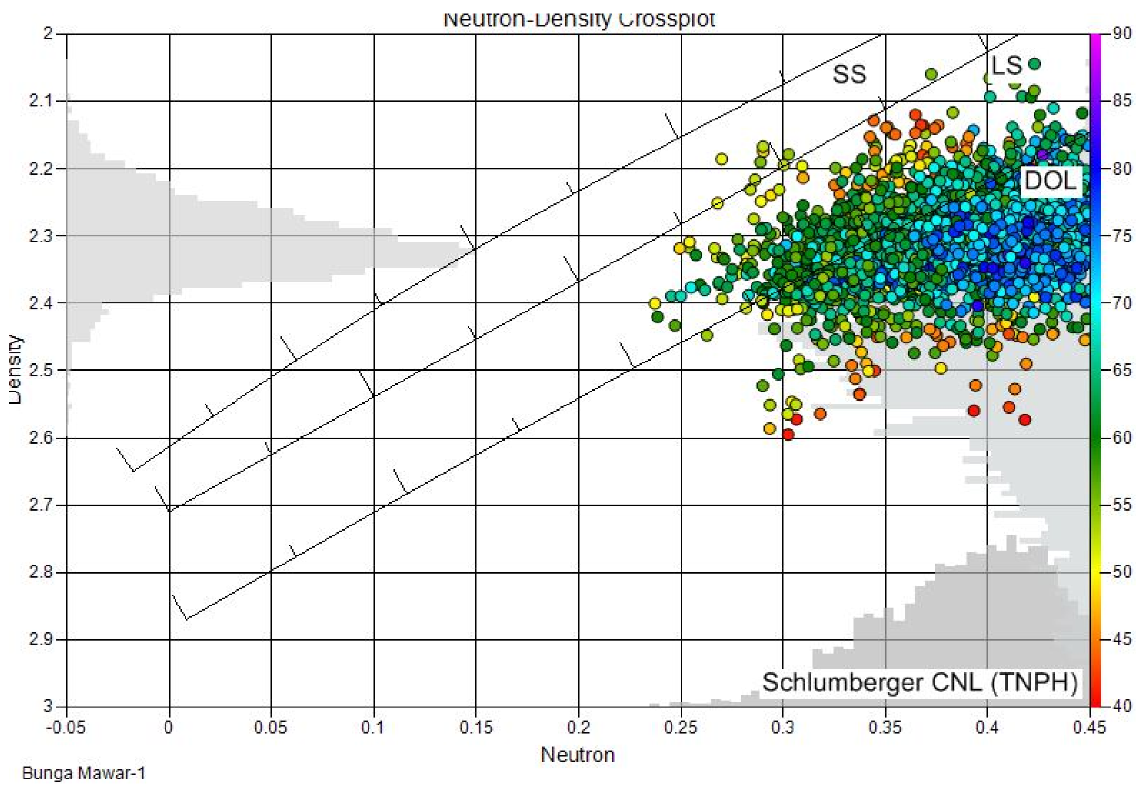

Figure 3.1 Bunga Mawar-1; Neutron Density crossplot shows Neutron log readings that are too high

3.2 Review of Parameters

The parameters used in the original analysis are consistent with shaly sandstone. The most difficult parameter and most important in this region is the formation water resistivity. Values were taken from Melati-1 DST measurements hence can be considered as accurate.

3.3 Review of Calculations

It is simple to reproduce the values noted in the various reports. Clay volume and porosity calculations provided by the operator can be regarded as largely unproblematic and reliable. The major uncertainty is water saturation.

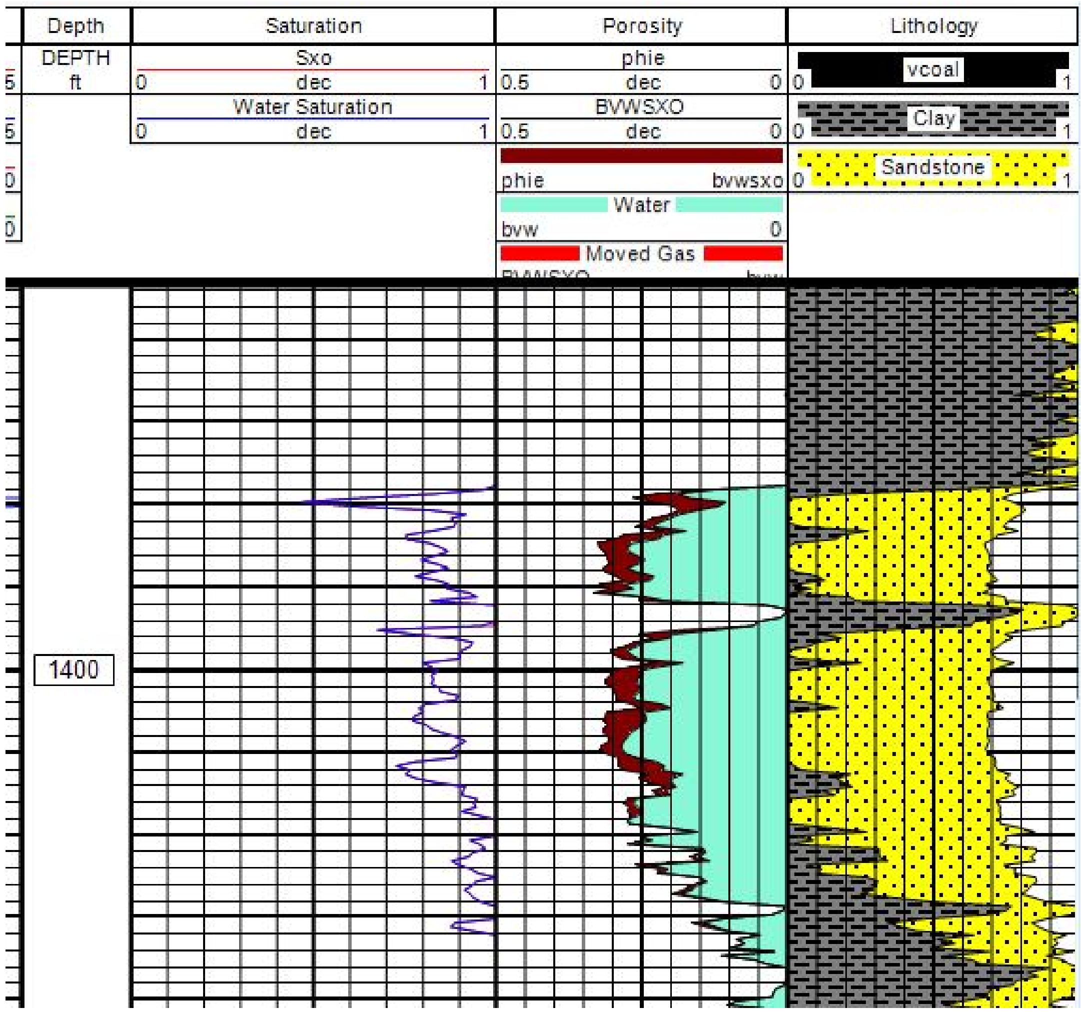

Figure 3.2 Akasia-1 well CPI Plot

The water saturations computed range from 75% to 90% in the zone of interest. The porosity is around 30%.

Figure 3.2 shows Akasia-1 with a good porosity but very little gas, 10-25%. The large amount of water present could be irreducible however without Magnetic Resonance or detailed core analysis it is impossible to say. The same results were found for the other wells in their zones of interest. The water saturations are all around 80% in good to very good porosities. In Mawar-1, the density log was used for the porosity. This does give a difference with an evaluation using the neutron as well.

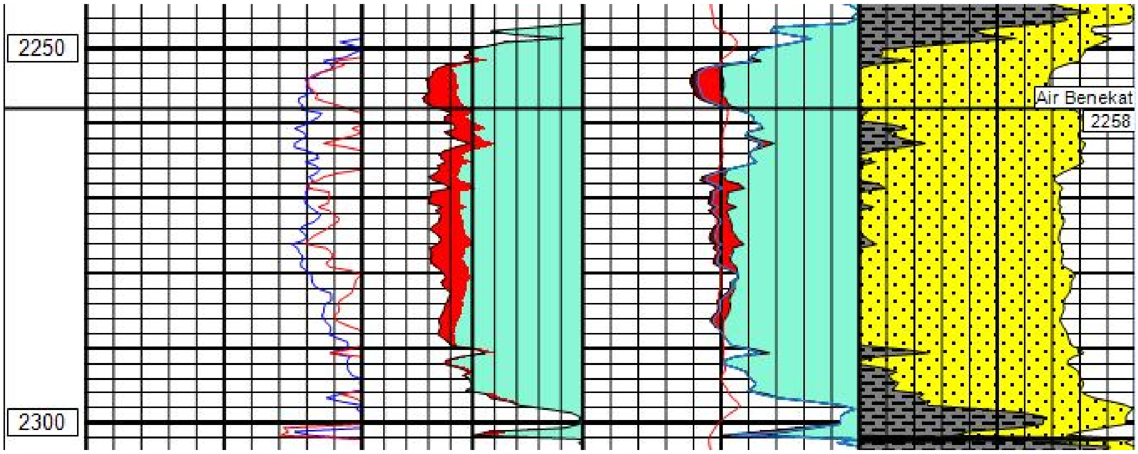

Figure 3.3 Mawar-1 CPI

Figure 3.3 shows the computed water saturations for Mawar-1 well. The result on the right, beside the lithology track, uses the density only. The next track shows the answer with the neutron included. The result with the density gives a much lower porosity and different profile from the combined answer.

3.4 Evaluation of Key Parameters

The key parameter in these evaluations is the formation water resistivity, Rw. The Rw derived from DST water samples is 14000-16000ppm Cl. There are alternative log based measurements to confirm the Rw value. One important one in this type of sandstone reservoir uses the SP deflection from a shale baseline. There is a good SP curve in the Matahari well as seen in the figure below.

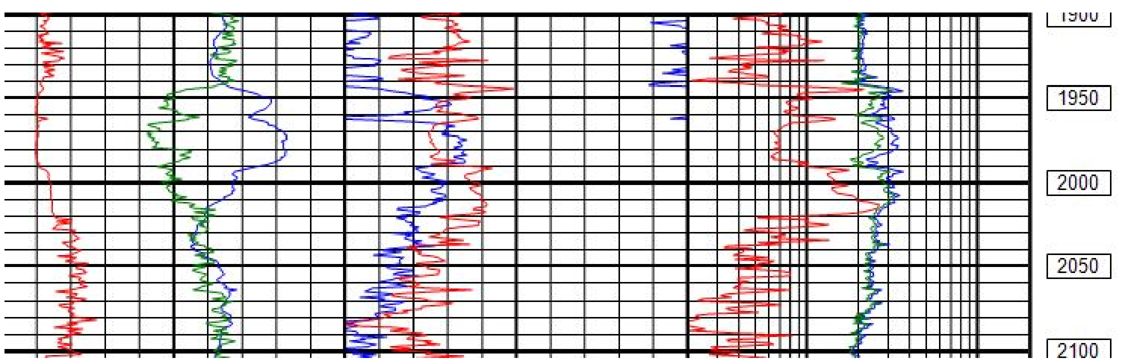

Figure 3.4 the SP curve shows a clear deflection between 1950-2000ft.

Using this SSP and the Rmf (mud filtrate resistivity) value, a figure of 0.08 was computed for Rw. This is much lower than the salinity derived number and necessarily results in much more hydrocarbon. It is also much more consistent with Rw measurements from other wells in the area, specifically in the Air Benakat Formation of Matahari-1 where Rw= 0.164 @192F and in the Gumai Formation of well Mawar-1 where Rw= 0.124@214F. The other method uses the Archie equation in a water zone where the equation reduces to become:

$$R_w = \varphi_e^2 R_t$$

In the wells this also gives a lower value of Rw than the DST sample derived version.

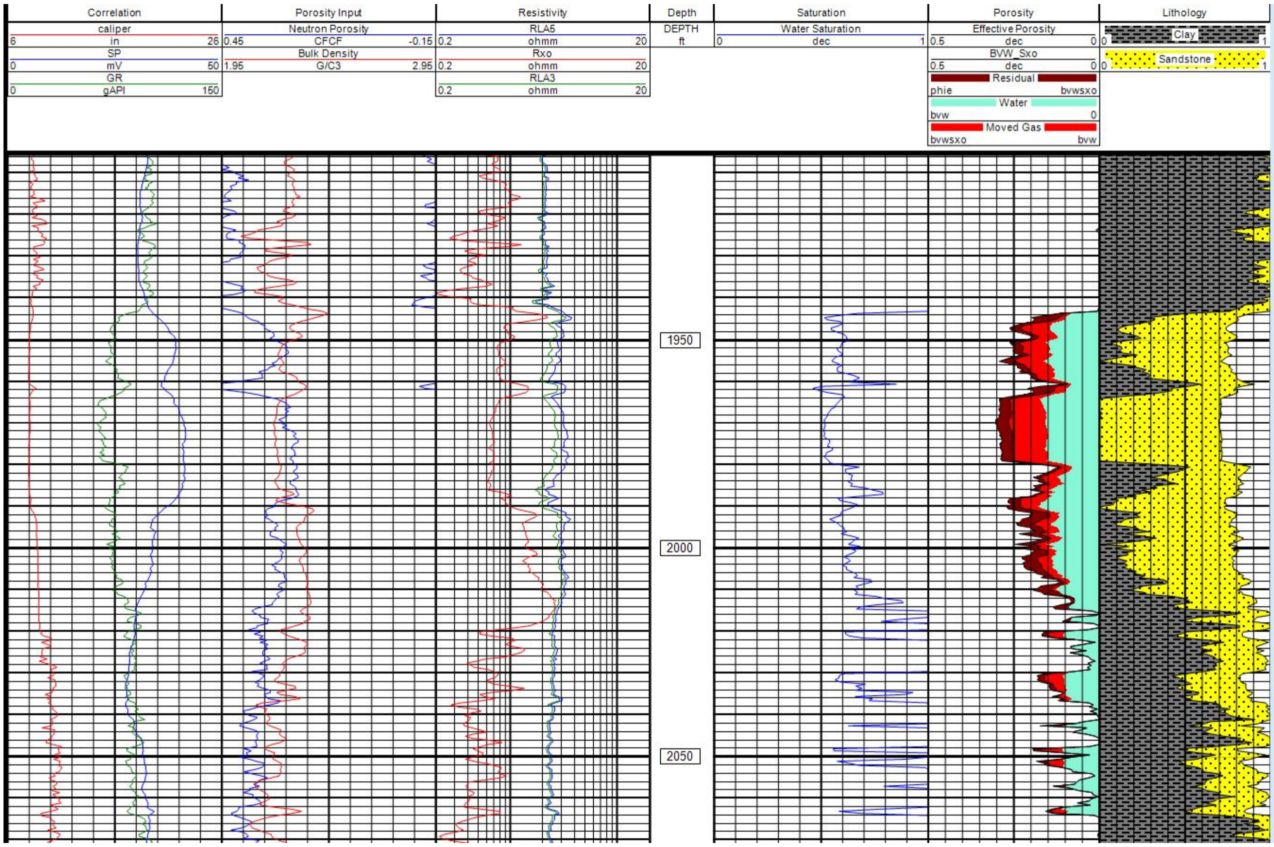

Figure 3.5 Matahari-1 CPI Result Utilising changed values of Rw.

The lower value of Rw results in significantly increased amounts of hydrocarbon. Here in Matahari-1, the water saturation drops from 80% to nearly 50%.

3.5 Conclusion

Given the uncertainty in the value of Rw it is difficult to be precise about the gas saturation in these wells. However, the gas saturation remains below 50% in all cases. A definite clean, uncontaminated water sample will assist in removing the doubt.

4 SEISMIC EVALUATION

CGG Robertson has reviewed the Operator's interpretations, prospects, their closures, closing contours and the areas stated by the Operator. Our review allows validation of the Operator's estimates and the following sections describe the results of our review and the variations we carried forward to our volumetric and economic analyses.

The area is covered by four different seismic surveys. It is not known if the acquisition parameters for each survey were the same or not. Each of the surveys has been subjected to different processing leaving significant differences in the results. For example, there appears to be a time shift of about 0.35 seconds on one of the data sets. In terms of seismic data quality, there are areas dominated by noise and other areas with complete data gaps which mean regional ties are uncertain. It is not possible to obtain a consistent interpretation over the whole area. The only way that a reliable interpretation can be made is if all surveys were reprocessed the same way and tied together. Even if this were done, variations caused by different acquisition parameters could remain and is not possible within the scope of this report because the older two surveys are rasterised data. In an attempt to overcome the differences, the operator has created a "conceptual model" on which to base the horizon (and structural) mapping. The model used is well matched to the regional picture of the South Sumatra Basin, but it remains a model and the underlying seismic data is, in places, used to guide mapping rather than being a firm basis for mapping.

Transpressional wrenching and further compression in fairly recent times created steeply faulted east-west anticlines and these form the bulk of the identified leads and prospects. Most of the structures are anticlines between steep faults and these are frequently visible as surface features as the compression is ongoing at the present day. Between the faults that bound the structures there is frequently no data and the mapping is model driven. These data limitations mean that there is a high risk the structures' shape, area and depth will not be as mapped. The areas used in this report are based on the maps present in the operator's Kingdom Projects and the polygons created by the operator based on those maps.

Surveys within the block:

- 86LM -rasterised
- WGS84_90 -rasterised
- BMIC_08
- BMIC_10

Processing carried out on each survey (names used in the Kingdom Project):

- Amplitude Time 86LM & WGS84_90 (rasterised)
- Elnusa Stack Filter Eql on survey BMIC_10
- Kreasindon Final Stack on survey BMIC_10
- Horizon1 Stack Filter Eql on survey BMIC_08
- Spektrum2 Sel on survey BMIC_08

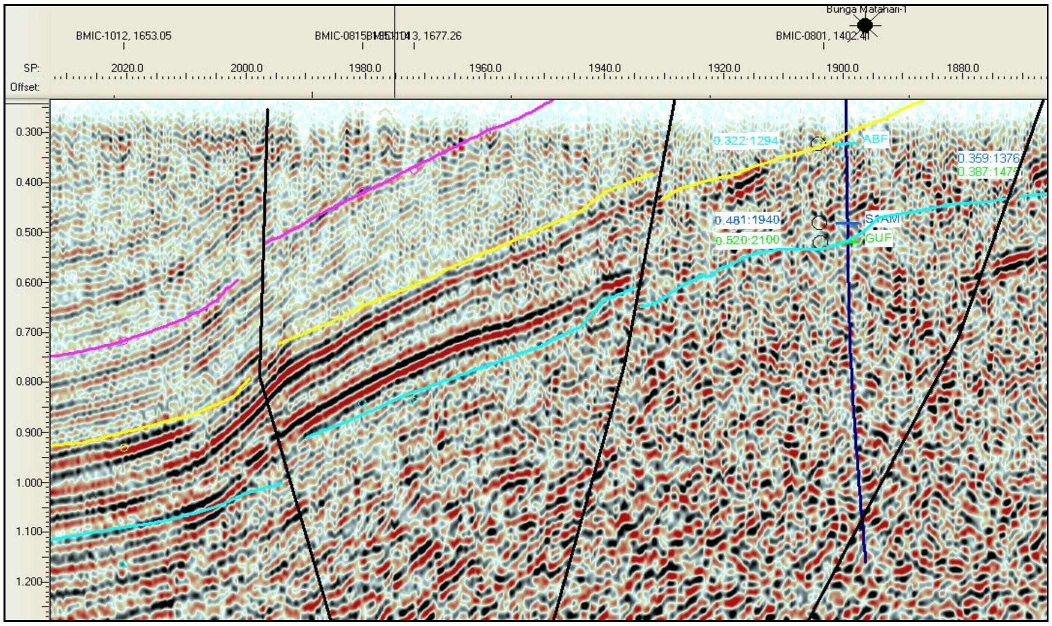

Figure 4.1 Line BMIC-0826 – Amplitude Time

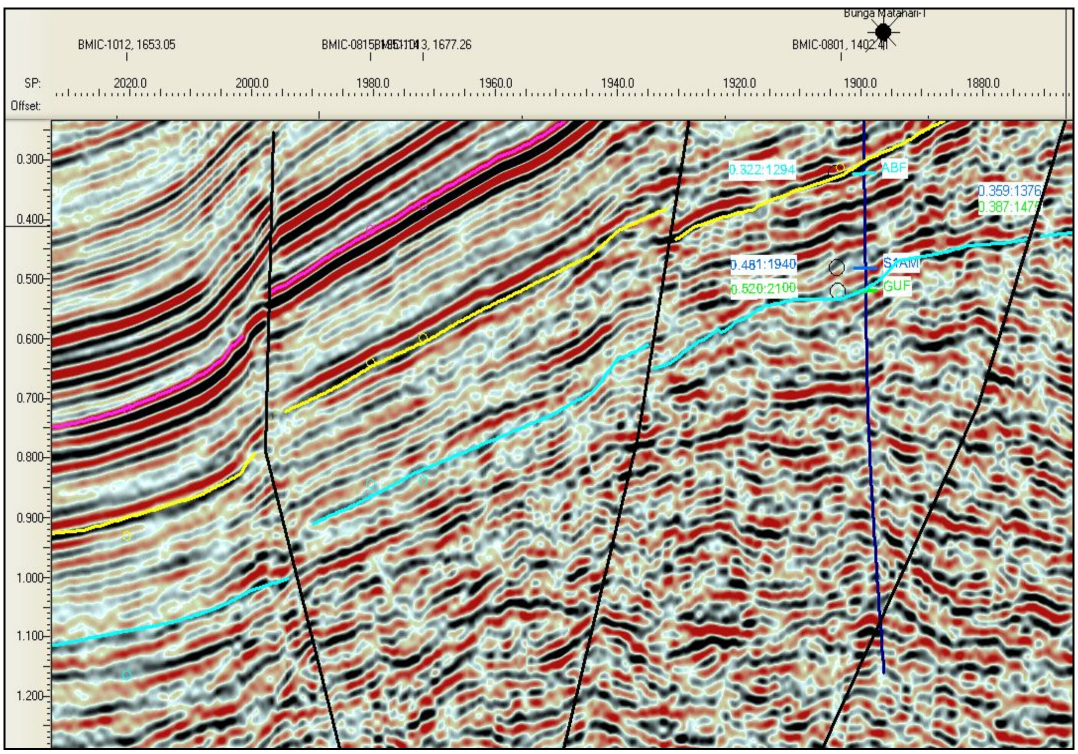

Figure 4.2 Line BMIC-0826 Spektrum2 Sel.

Note: the time difference in the bright events in this example and the same events in Figure 4.1. The picks are the same times and were picked on the Spektrum2 processed set.

4.1 Western Area Prospects

4.1.1 Melati Prospect (Talang Akar Formation)

This feature was tested by the well Bunga Melati-1. The reservoir is the Talang Akar sandstone and the structure is completely fault bounded. The seismic event is clear in the NW-SE lines, but is not as easy to pick in the NE-SW lines. The closing contour is 8150’, which is presumably derived from the well data as the top Talang Akar Formation (“TAF”) depth map in the Kingdom project has depths around 7500 feet. We assume that the shape of contours will not change when the map is moved onto the deeper well pick, and the areas will remain valid for the deeper reservoir level. The only boundary that could be taken for the closure was the faults which delimit the block into which the well was drilled. The faults are not clearly seen on the seismic lines and therefore the area of the minimum, most likely and maximum were all taken as the area within the faults on the map.

Melati	TAF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	8.119	8.119	8.119
Working Interest	8.119	8.119	8.119
Depth	8150'	8150'	8150'

Table 4.1 Melati Prospect: Talang Akar areas.

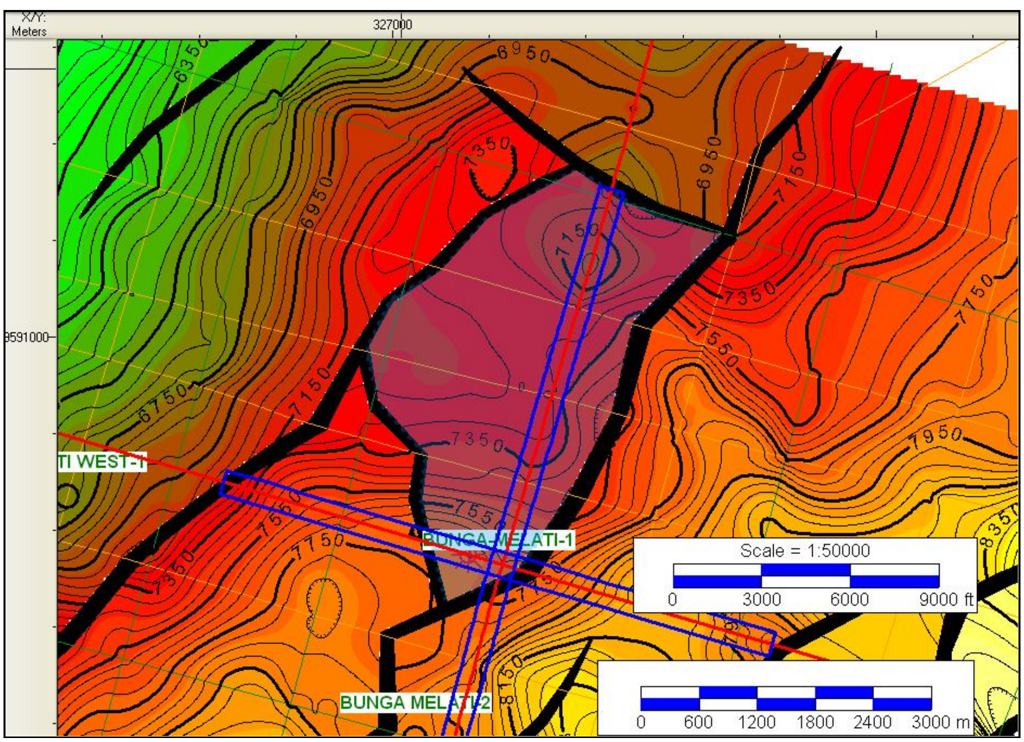

Figure 4.3 Depth Map top TAF showing the Melati structure.

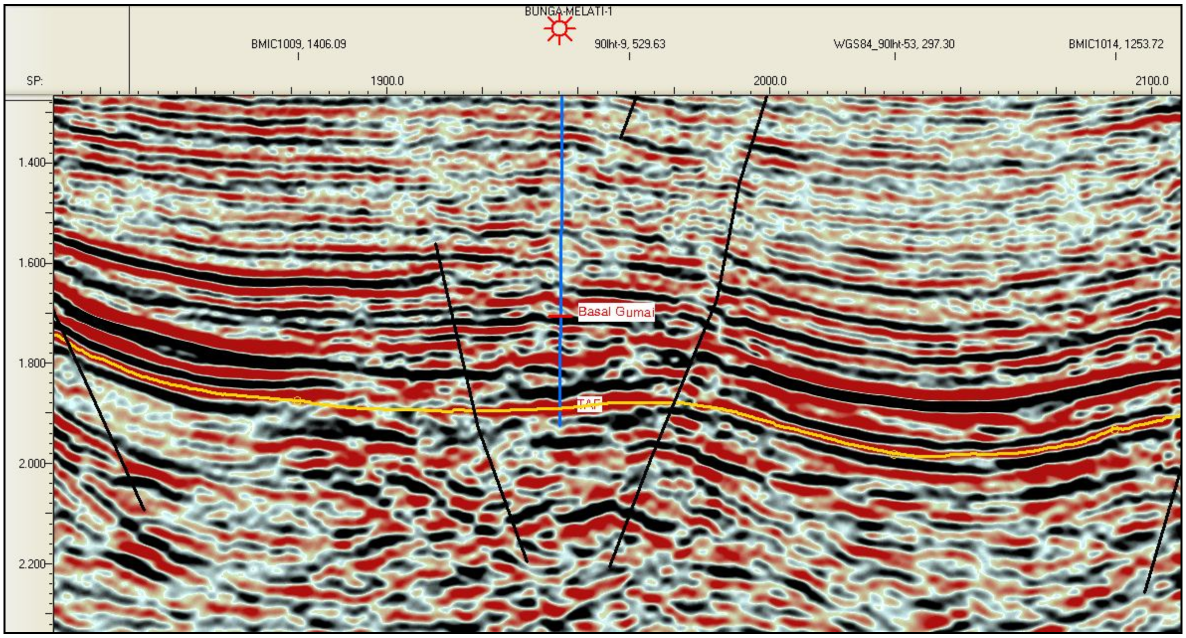

Figure 4.4 NW-SE seismic line through Bunga Melati-1

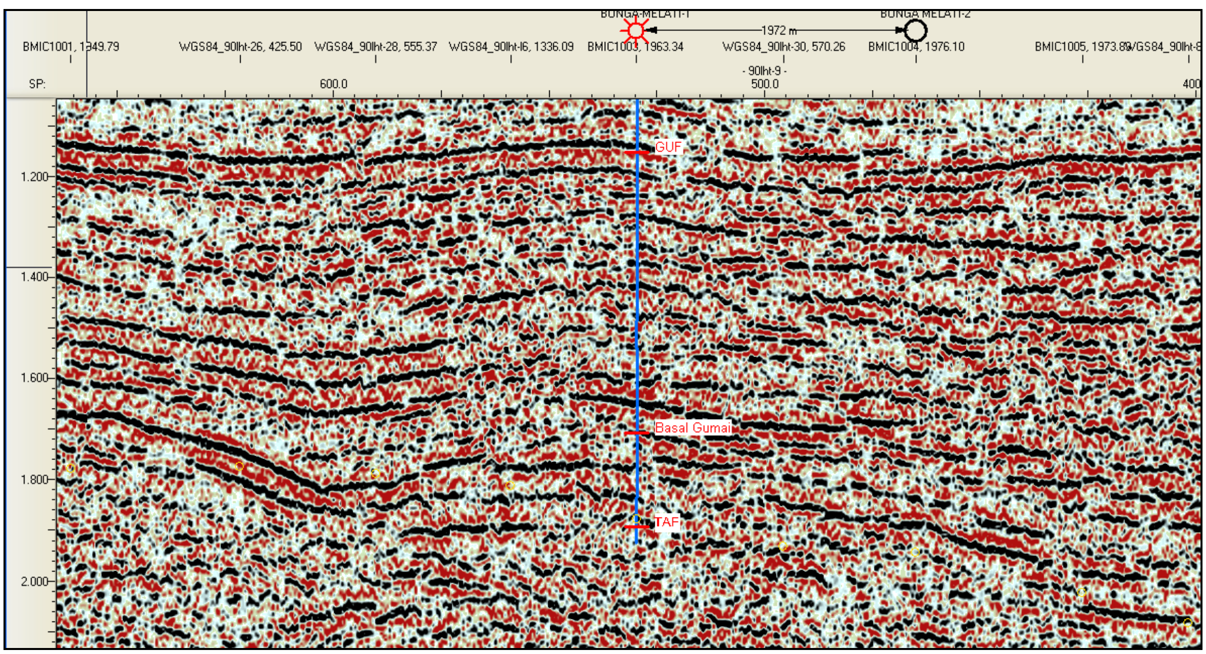

Figure 4.5 NE-SW Seismic line adjacent to Bunga Melati-1

4.1.2 Melati East & Melati West Prospects

In the area of the Bunga Melati-1 well two prospects have been defined within two Muara Enim Formation ("MEF") Sandstones. Part of the Melati East prospect extends beyond the PSC boundary. The two sands (MEF27 & MEF34) are tied to the Bunga Melati-1 well and the events are clear on the seismic and easily picked.

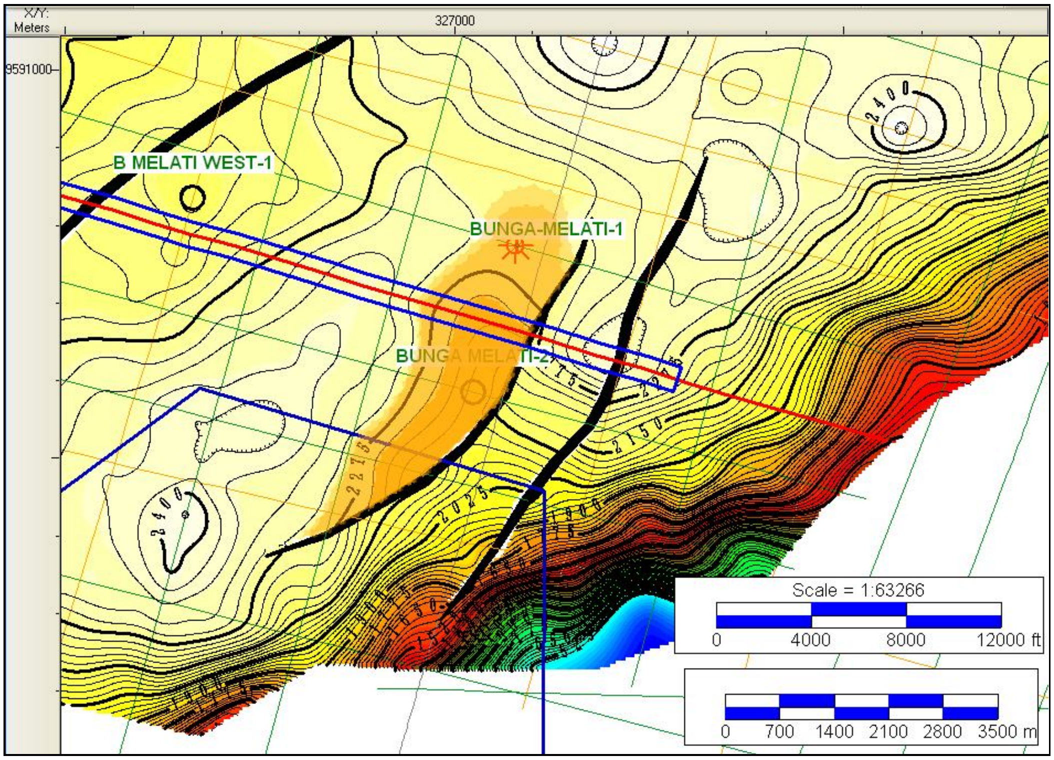

Figure 4.6 Muara Enim Sand 27 map showing the Melati East

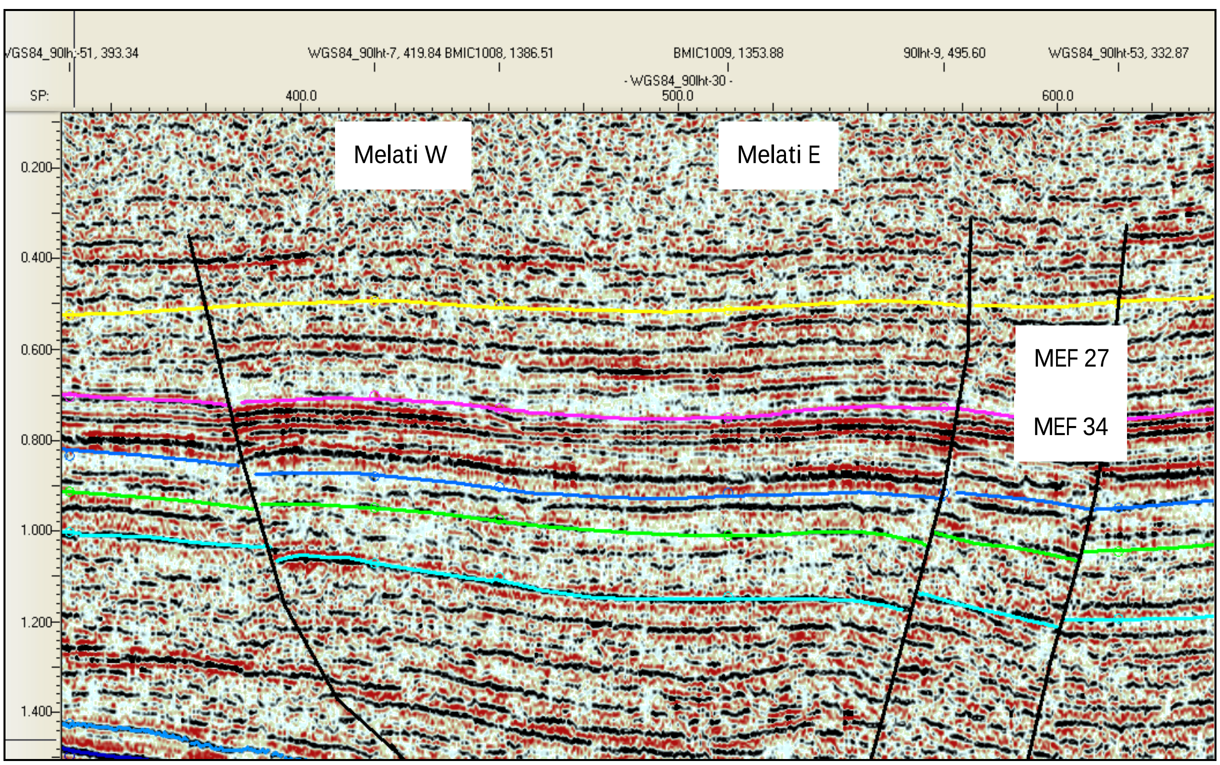

Figure 4.7 West –East Seismic line through Melati West and Melati East Prospects

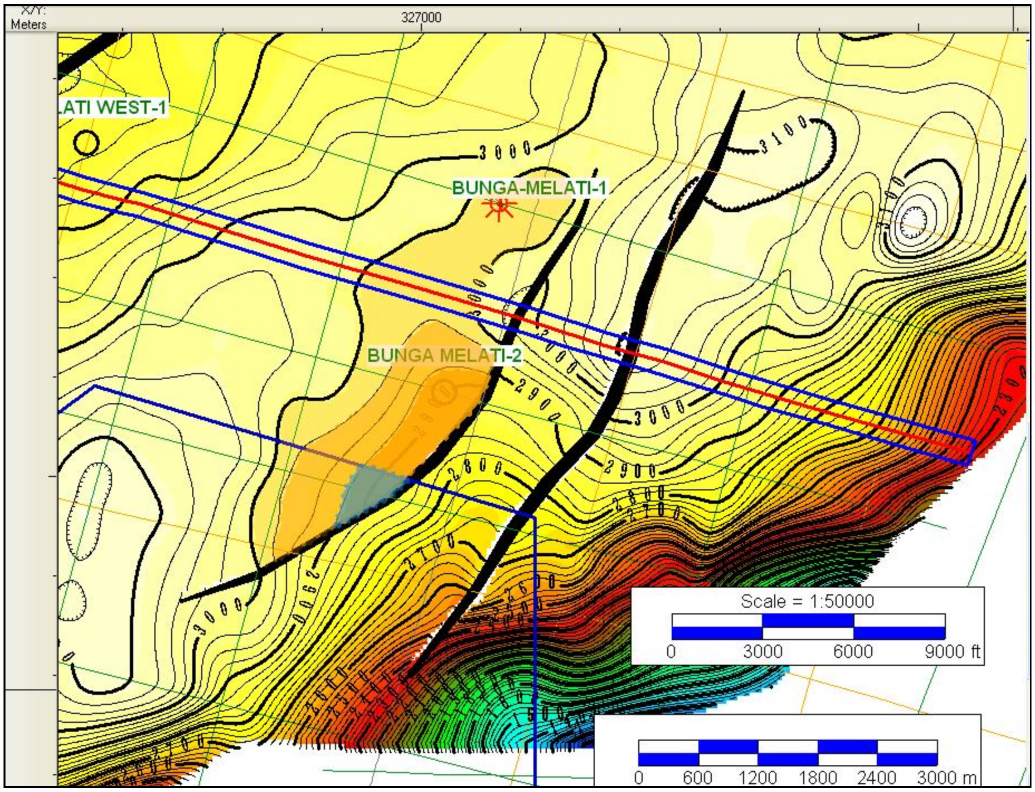

Figure 4.8 Muara Enim Sand 34 map showing the Melati East

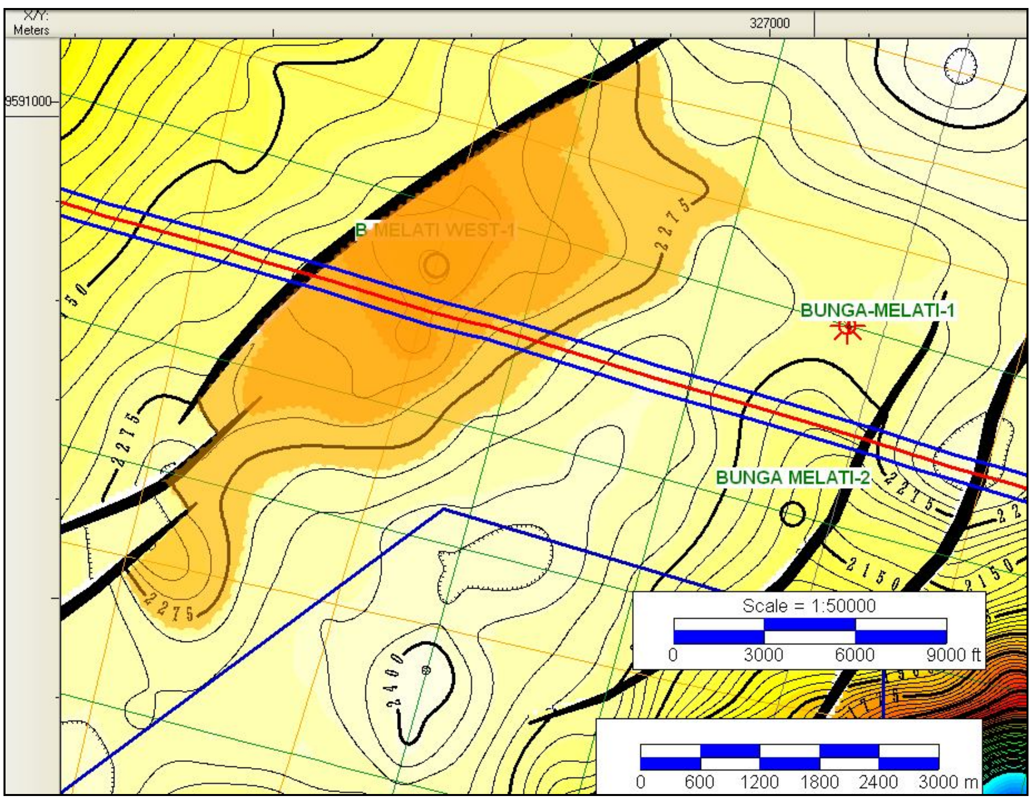

Figure 4.9 Muara Enim Sand 27 map showing the Melati West

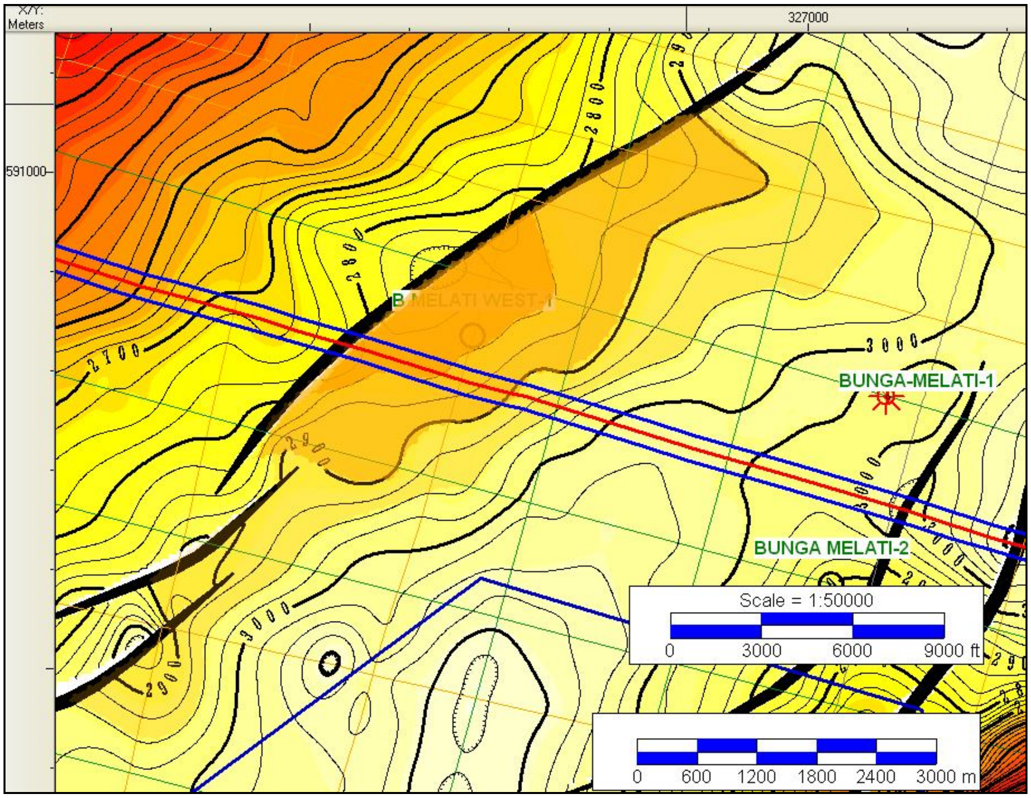

Figure 4.10 Muara Enim Sand 34 map showing the Melati West

Melati East	MEF 27			Melati West	MEF 27		
	Area	(Sq Km)			Area	(Sq Km)	
	Min	M/L	Max		Min	M/L	Max
Area	2.157	5.012	5.712	Area	1.985	5.765	12.568
Working Interest	1.769	4.143	4.75	Working Interest	1.985	5.765	12.568
Depth	2250	2285	2295	Depth	2210	2240	2290
	MEF 34				MEF 34		
	Area	(Sq Km)			Area	(Sq Km)	
	Min	M/L	Max		Min	M/L	Max
Area	0.844	2.274	4.882	Area	1.808	6.654	13.719
Working Interest	0.627	1.456	3.799	Working Interest	1.808	6.654	13.719
Depth	2925	2975	3000	Depth	2850	2900	2950

Table 4.2 Melati East & West Prospect areas.

4.1.3 Phinisi Prospect (Batu Raja Formation)

The Phinisi Batu Raja Formation ("BRF") has a fault controlled closure. The target horizon is the porous Batu Raja Massive Limestone. Both the bioclastic and massive limestones horizons were picked on seismic. The depth map is labelled "Dark Blue" which is the colour of the massive limestone pick, but matching the time map contours with the seismic sections demonstrates the maps are the top of the Bioclastic Batu Raja. Hence, the depth map shows closure at 4775' which is the depth of the bioclastic section. The Bunga Mas company presentations provide a block wide map of the Batu Raja massive limestone which indicated a lowest closing contour of 5160'. There was no time or depth map of the massive limestone available in the company's Kingdom projects. Therefore, for this report, the contours of the top bioclastic limestone depth map were planimetered. Resulting areas are close to the areas shown on the Bunga Mas company database for the underlying massive limestone. Planimetered areas were 0.648 Sq Km (min); 1.065 Sq Km (m/L) and 1.891 Sq Km (max) as opposed to the Bunga Mas spreadsheet which had areas of 0.5, 0.9 & 2.0 respectively.

Phinisi closure	BRF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.648	1.065	1.891
Working Interest	0.648	1.065	1.891
Depth	4700'	4725'	4775'

Table 4.3 Phinisi Prospect: Batu Raja Prospect Areas

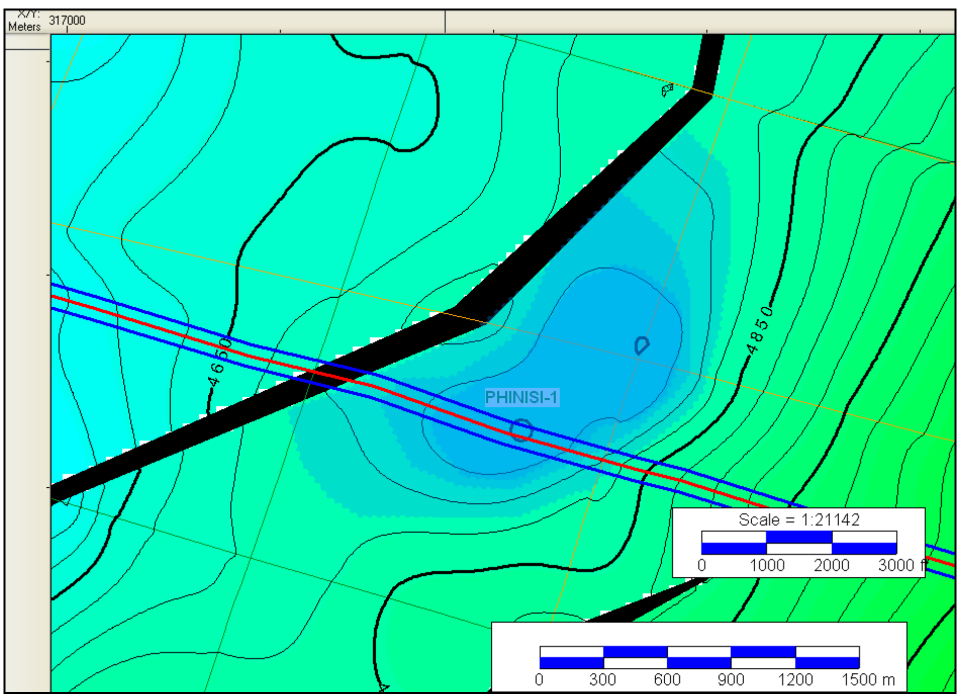

Figure 4.11 Phinisi top BRF (bioclastic) depth map

4.1.4 Phinisi TAF

There is also a closure at Talang Akar level and therefore an objective for Phinisi. The TAF depth map on the workstation has depths shallower than are shown on the Bunga Mas spreadsheet. For this report the closing contours on the map have been planimetered and the areas are smaller than those should on the Bunga Mas spreadsheet. The spreadsheet shows areas of 0.5, 0.9 and 2.0 sq km for min, M/L and max and depths of the closing contour as 5611', 5670' and 5730' respectively. The areas planimetered and depths for this report area shown in Table 4.4 and the map they are based on is shown in Figure 4.12.

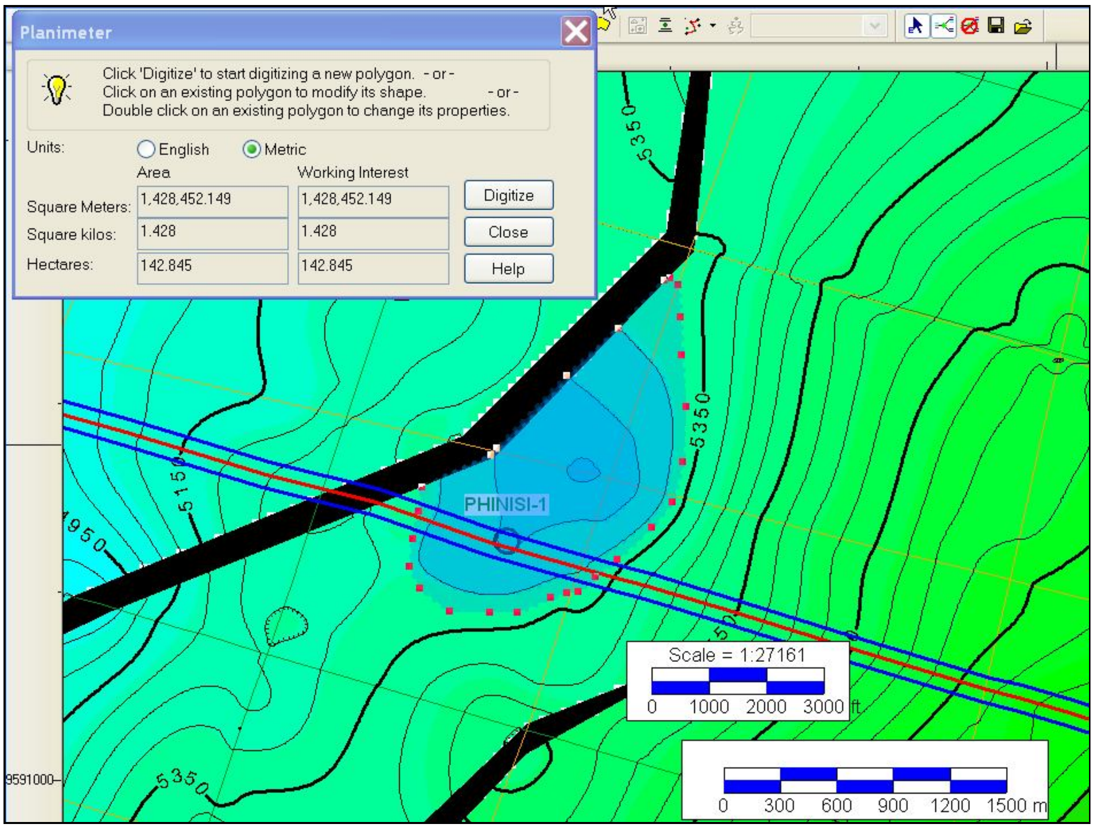

Figure 4.12 Phinisi TAF depth map

Phinisi	TAF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.016	0.449	1.428
Working Interest	0.016	0.449	1.428
Depth	5200	5250	5325

Table 4.4 Phinisi Talang Akar prospect areas

4.1.5 Phinisi Stratigraphic Trap (Batu Raja Limestone Formation)

The Phinisi location also has a separate stratigraphic trap prospect. The outline of this is based on Acoustic Impedance of less than 10,000. The area of this anomaly provides the area of the trap. We have been able to replicate the operator's most likely and maximum case areas, but we have delineated a much smaller minimum case. There is an AVO seismic study illustrating however we view this prospect as highly risky.

Phinisi	BRF - STRATIGRAPHIC		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.46	12.91	28.552
Working Interest	0.46	12.91	28.552
Depth	4450	5000	5750

Table 4.5 Phinisi Stratigraphic trap areas

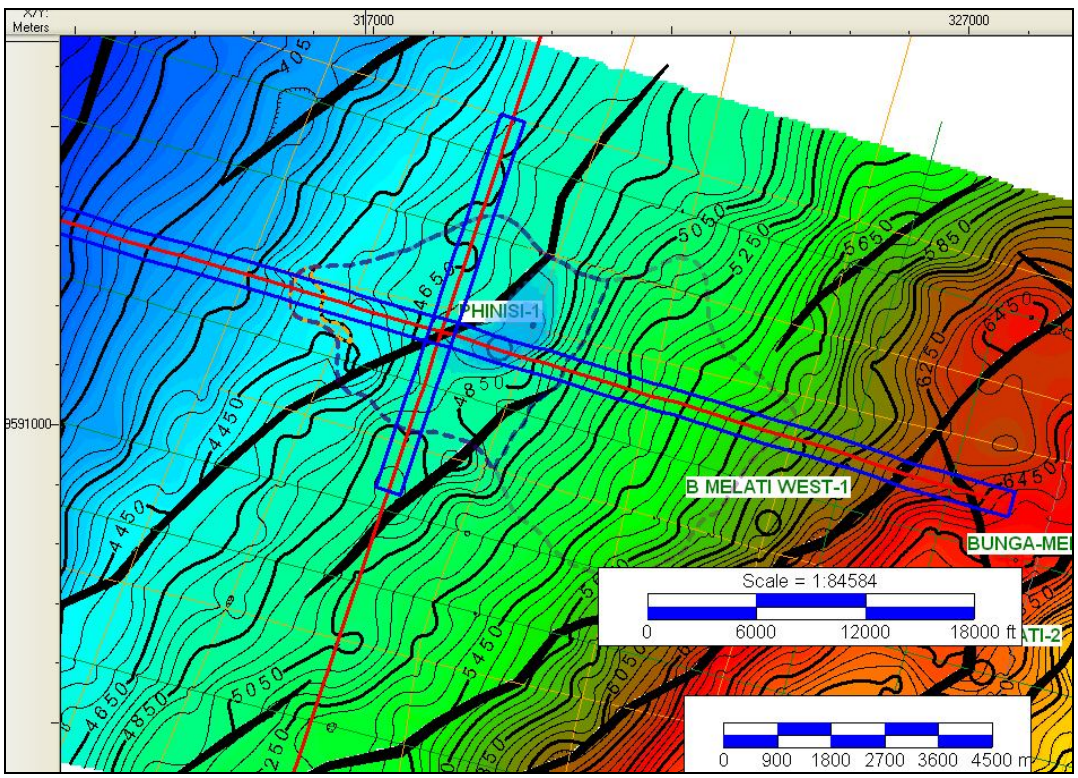

Figure 4.13 Phinisi Stratigraphic trap Top Batu Raja Platform map showing max; m/l; & min area polygons

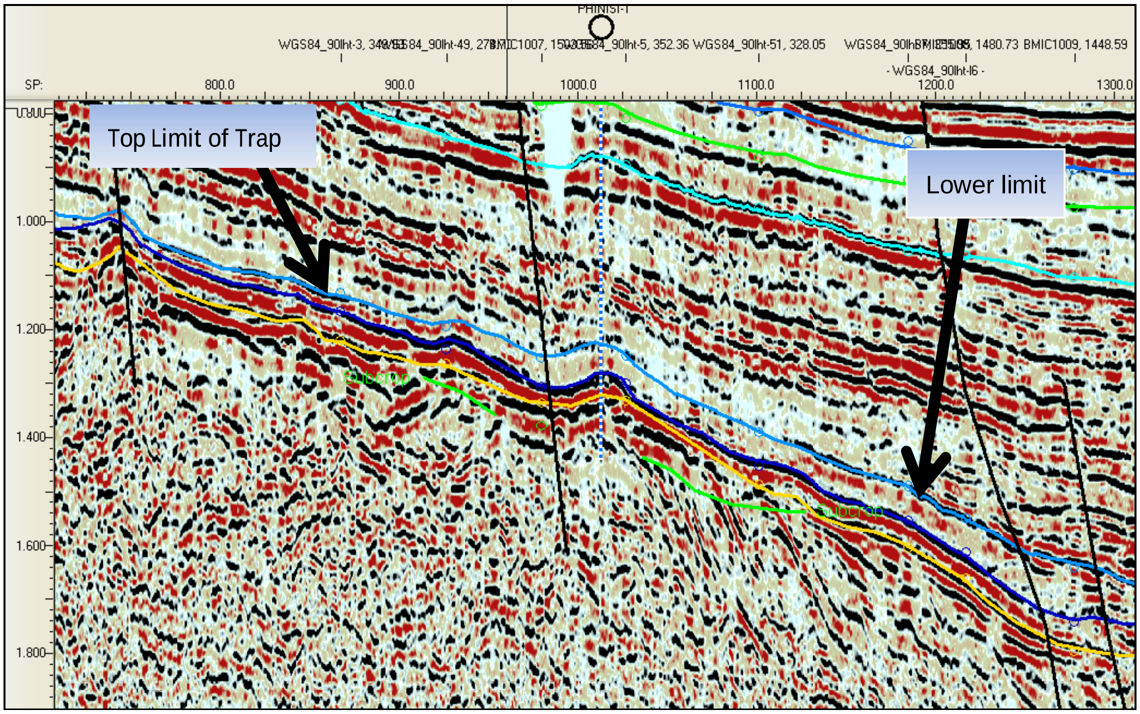

Figure 4.14 Seismic line across Phinisi stratigraphic trap prospect

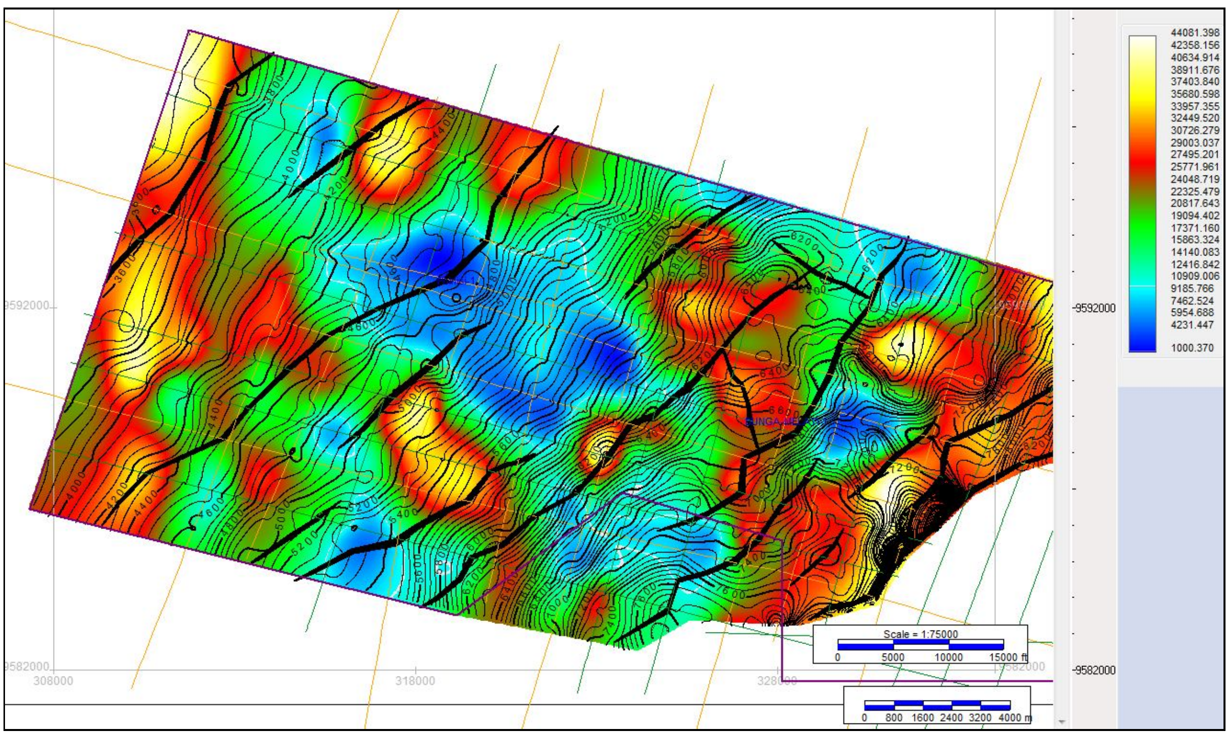

Figure 4.15 Batu Raja Acoustic Impedance map over Phinisi area

4.2 Eastern Area Prospects

4.2.1 Mawar Prospect: Gumai Formation

The Mawar structure is a faulted anticline. The Gumai Sandstone was drilled by the Bunga Mawar-1 well. A single zone at this level was tested (DST1, 3756-3762 ft) and recovered condensate with some gas to surface. No measurable flow was established. The Mawar prospect is down thrown from the NE Ramok prospect which is a potential extension of the Ramok field. The Ramok field produced 1.84 MMBO from the Air Benakat Formation and was abandoned in 1936.

On the Top Gumai Formation ("GUF") map shown in Figure 4.16 the lowest closing contour is shallower than the maximum closure quoted in the operator's database and the polygon for the maximum case crosses contours. Part of the structure is also outside the block.

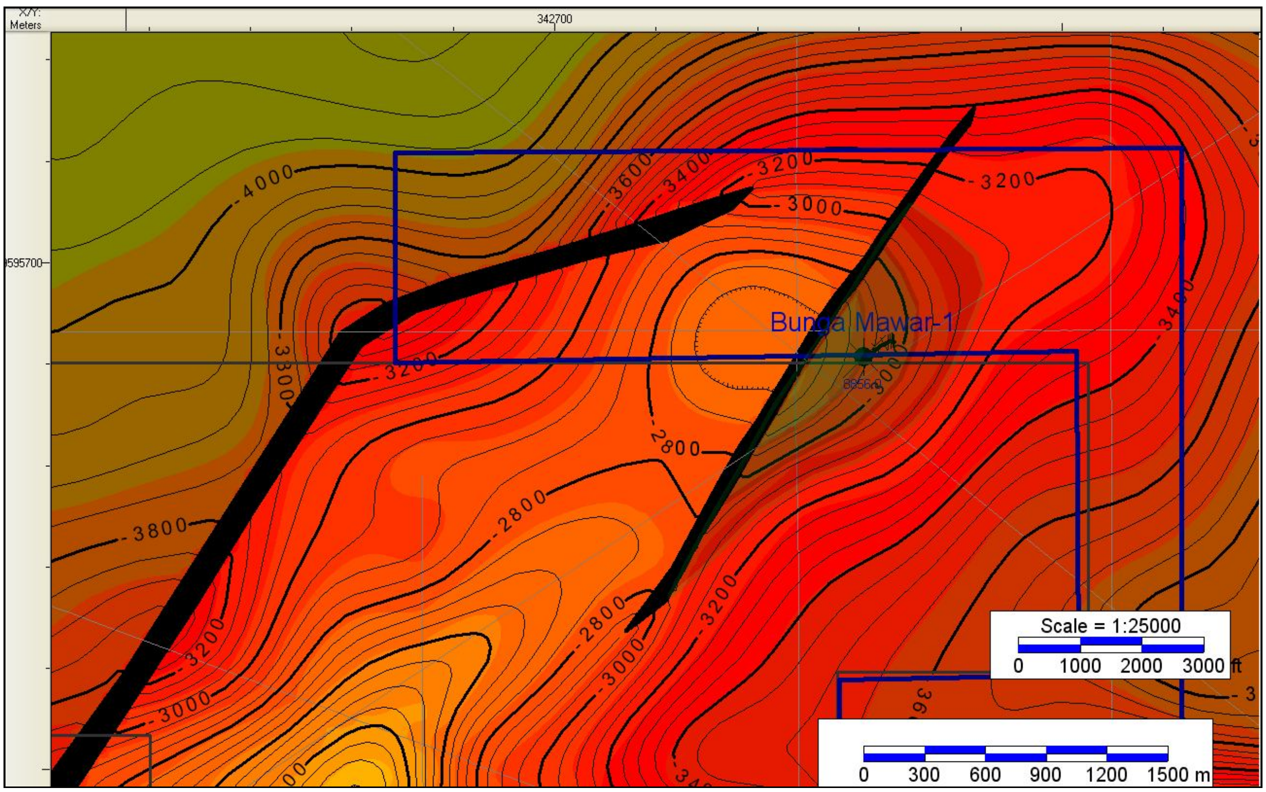

Figure 4.16 Mawar top Gumai Formation depth map

The Mangoes Coal beds of the Muara Enim Formation mask the deeper events as can be seen in Figure 4.18 and thus the horizon picks become more unreliable away from the well.

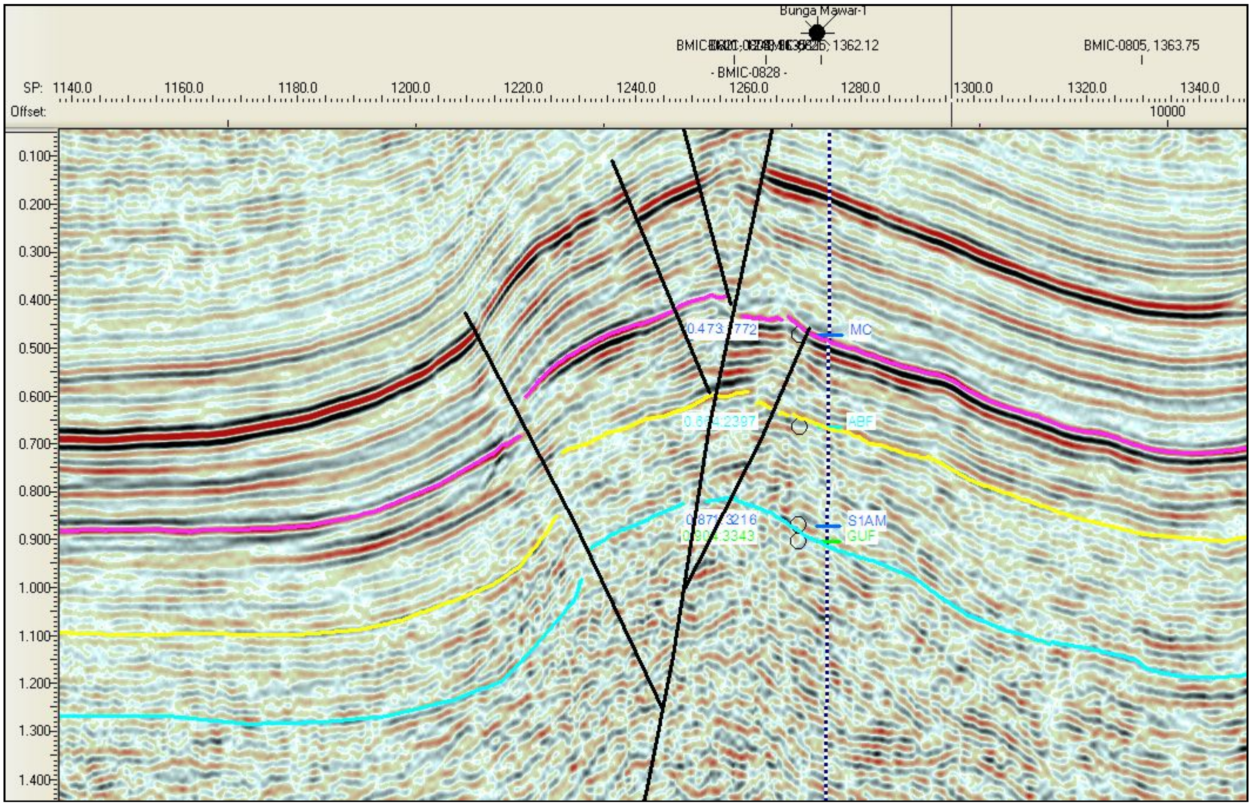

Figure 4.17 NW-SE Seismic line across Mawar.

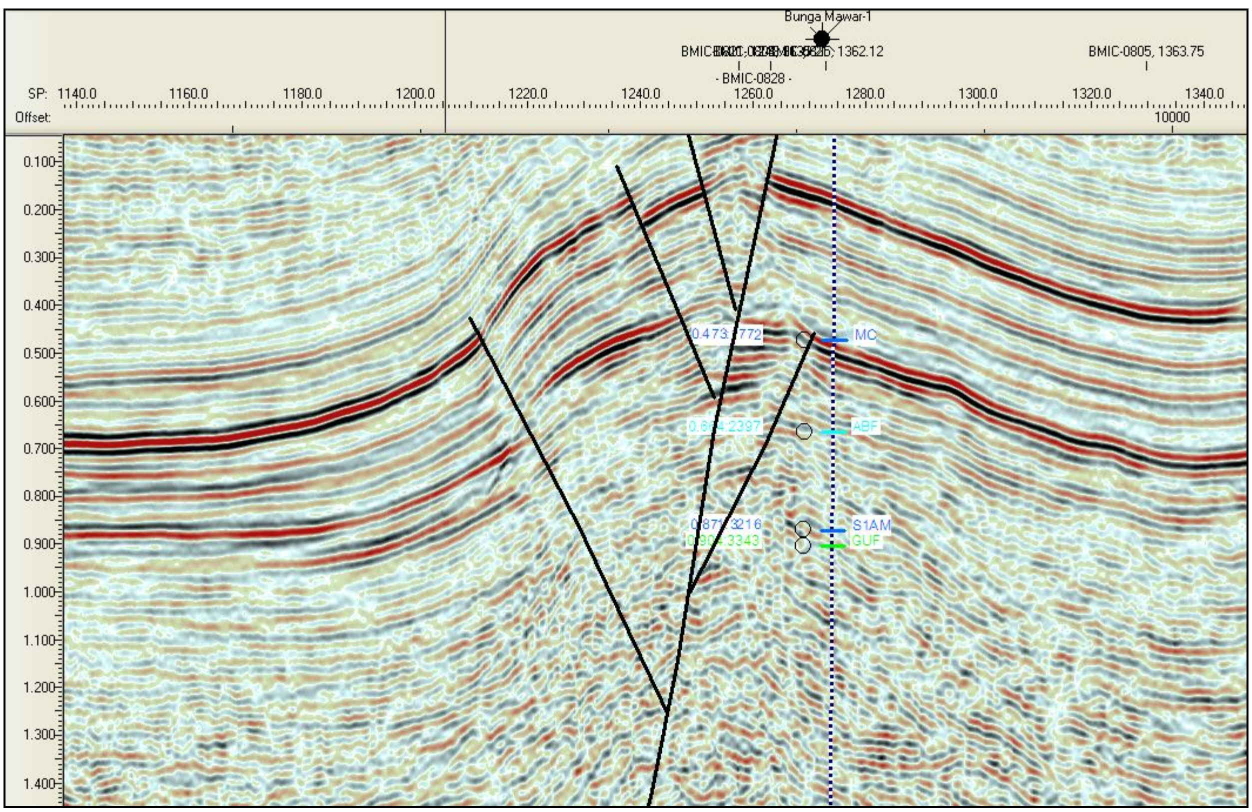

Figure 4.18 NW –SE Seismic line across Mawar without picked horizons.

Calculated areas are based on the polygons on the GUF map and thus match the areas in the Bunga Mas spreadsheet.

Mawar	GUF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.139	0.406	0.907
Working Interest	0.055	0.172	0.399
Depth	2925'	3025'	3125'

Table 4.6 Mawar GUF areas. Note: the lowest closing contour on the map is 3050'

4.2.2 Mawar Prospect: Air Benakat Formation

The Air Benakat Formation ("ABF") is the horizon that produced at the nearby Ramok Field. The ABF horizon is a fairly reliable pick on the seismic. The polygons for the various closure cases were used to create areas for this report and are the same as stated in the operator's database (Table 4.7).

Mawar	ABF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.127	0.7	2.034
Working Interest	0.025	0.256	1.015
Depth	2025'	2125'	2250'

Table 4.7 Mawar ABF areas Note: half the prospect is outside the block.

The Mawar-1 well tested two zones in this Formation (DST2, 2312-2320 ft; DST3, 2252-2259 ft and 2265-2272 ft). The lower zone flowed a maximum of 86 BOPD with 0.2 MMscf/d on 22/64" choke. The upper zone did not flow hydrocarbons.

A further test of the overlying Muara Enim Formation (DST4, 2072-2082 ft) is ongoing at the time of writing this report.

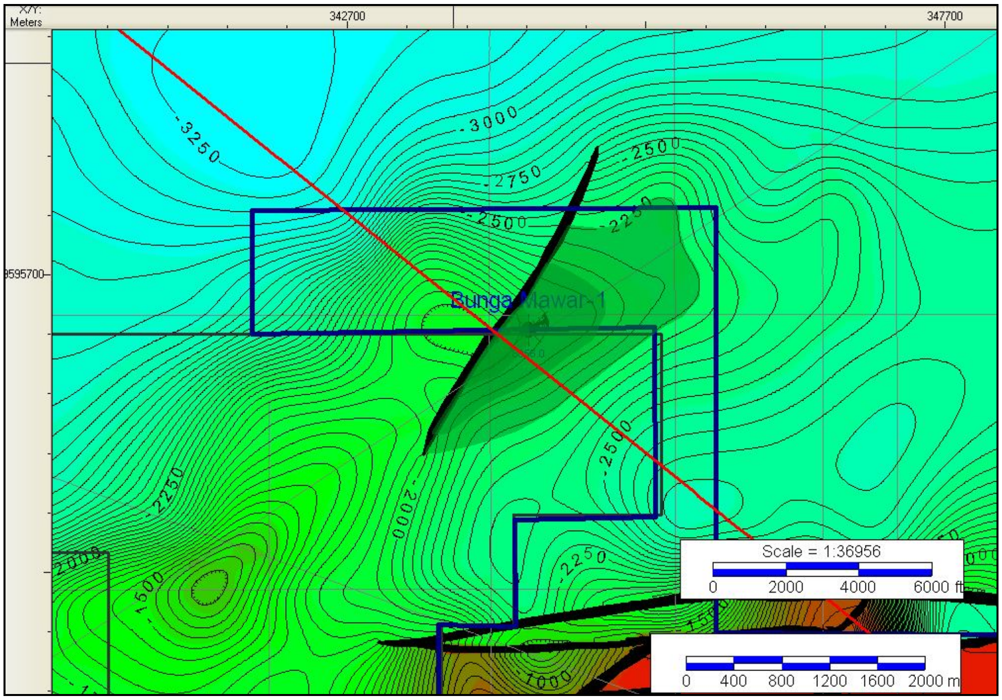

Figure 4.19 Mawar top Air Benakat Depth Map

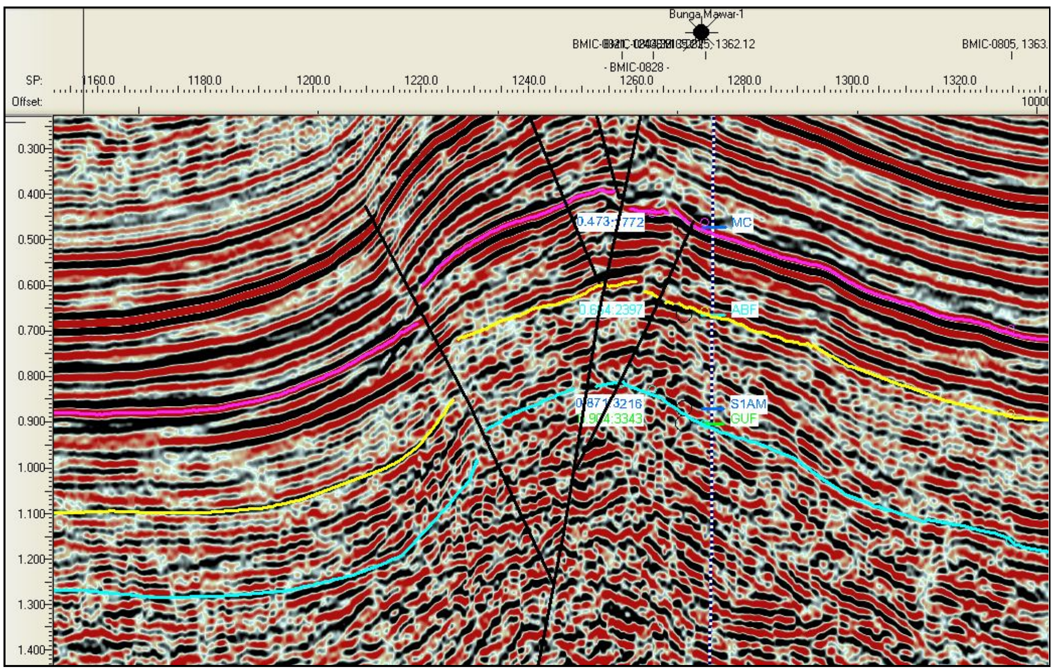

Figure 4.20 NW-SE seismic line across the Mawar Structure.

The pick for the ABF through the well and over the structure is at the base of the high amplitude events, but north of the structure the pick is deeper than these events.

4.2.3 Ramok NE Prospect: Gumai Formation

As for the Mawar prospect the GUF pick on this prospect is not clear and the prospect lies across a fault from the Bunga Mawar-1 well control. However, this feature is in line and not fault separated from the Ramok oil field which produced from the Air Benakat Formation.

The areas for the structure in this report are the very close to those contained in the operator's database as they have been independently planimetered.

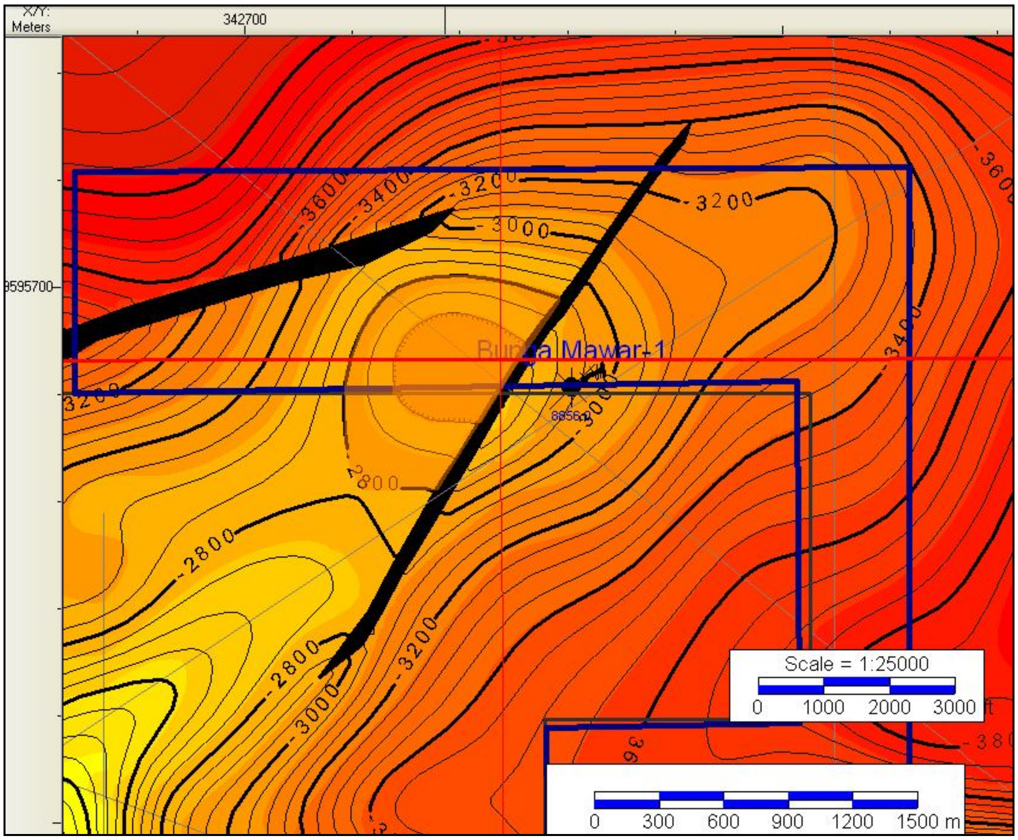

Figure 4.21 Ramok NE top Gumai Formation depth map

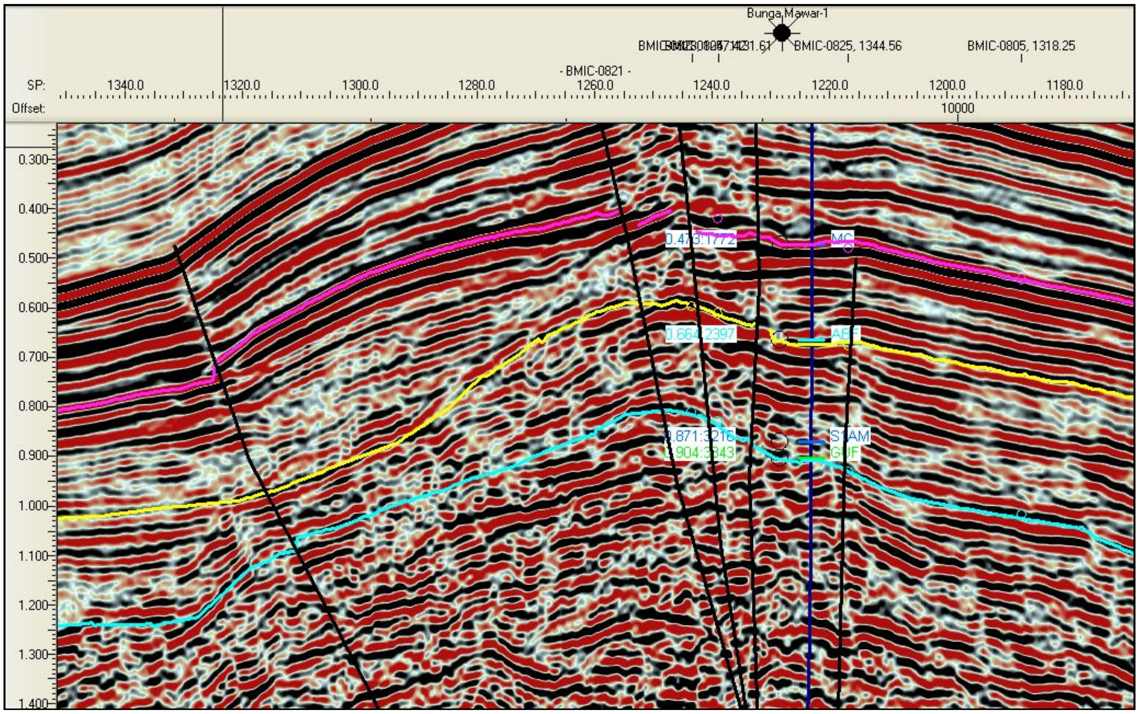

Figure 4.22 W-E seismic line through Ramok NE.

Ramok NE	GUF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.225	0.418	0.639
Working Interest	0.158	0.272	0.37
Depth	2700'	2750'	2800'

Table 4.8 Ramok NE areas

4.2.4 Akasia Prospect, Gumai Formation

Akasia is a faulted anticline which is in the same overall structure as the Senabing Field. The Senabing Field produced 1.66 MMBO from the Air Benakat Formation up until the abandonment in 1931. The Bunga Akasia-1 well was drilled on this structure. The well has thin Gumai sandstones, but the presentations only show hydrocarbons in the Muara Enim and Air Benakat Formations. The seismic horizons are not as clear within the area of the structure. The areas in this report are based on the Akasia top GUF map and are close to those in the Bunga Mas spreadsheet.

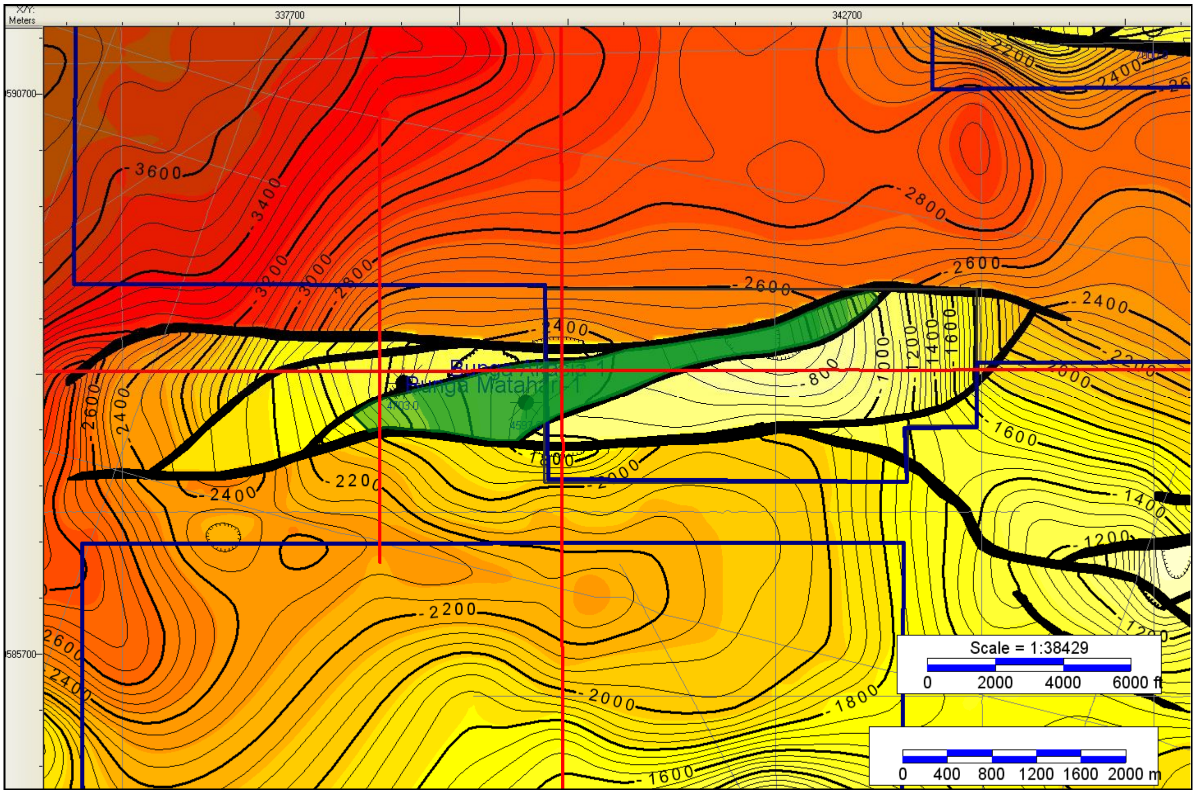

Figure 4.23 Akasia top Gumai depth map

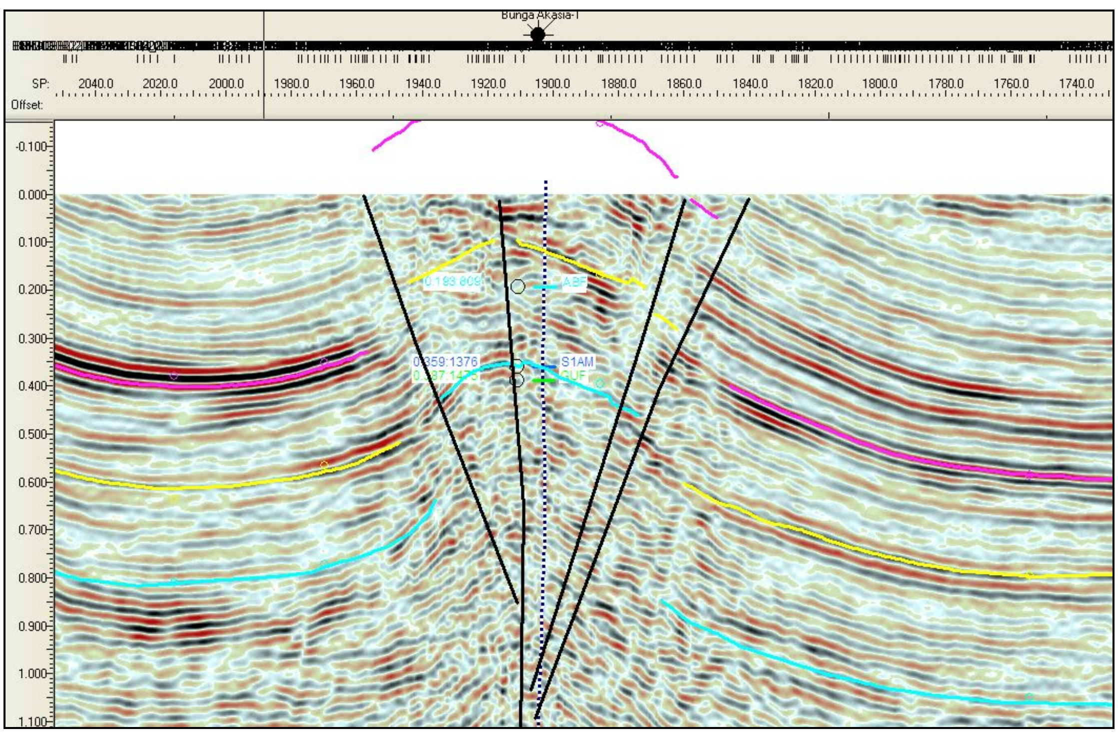

Figure 4.24 N-S seismic line across Akasia

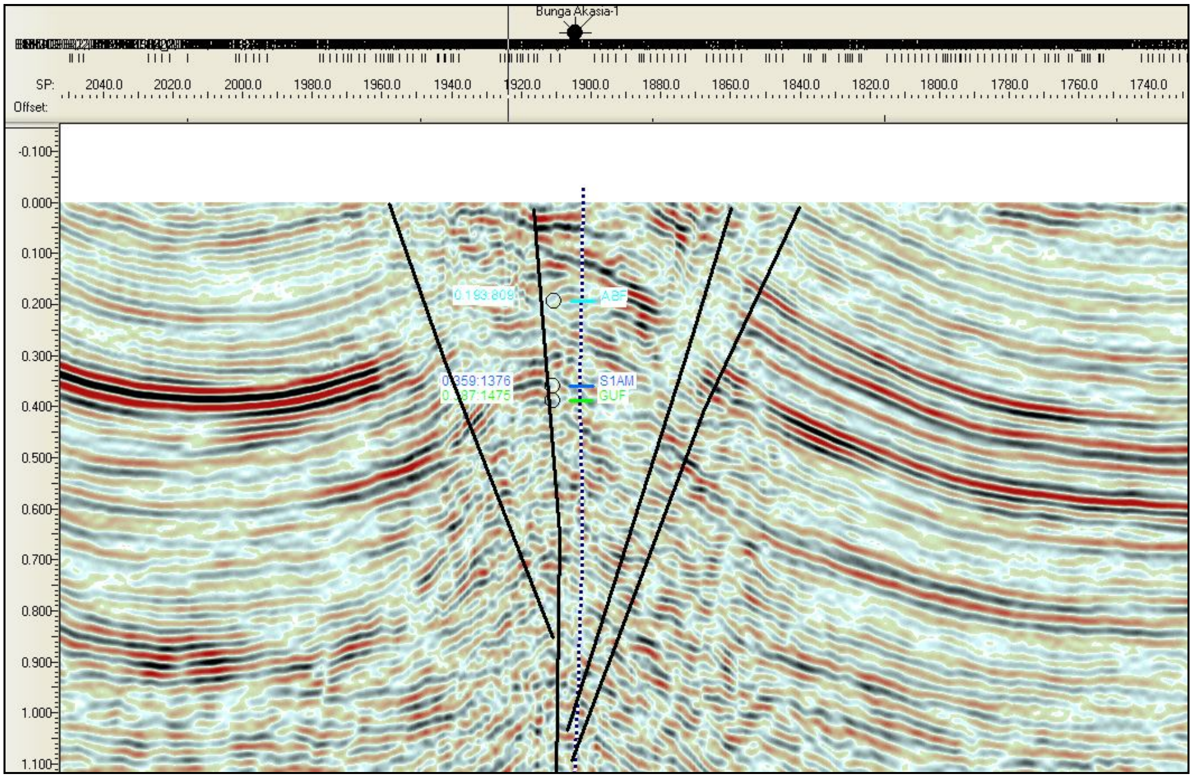

Figure 4.25 N-S unpicked seismic line across the Akasia structure showing the lack of pick clarity within the structure.

Akasia	GUF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.674	1.303	1.5
Working Interest	0.08	0.65	0.806
Depth	1075'	1325'	1600'

Table 4.9 Akasia GUF areas

4.2.5 Akasia – ABF

This is downdip and within the same fault block as the Senabing Field which produced from this horizon and it was penetrated by the Bunga Akasia-1 well. Bunga Akasia-1 tested a single zone (DST2, 1946-1958 ft) and recovered 10 litres of condensate (60°API) and gas to surface. No measurable flow of hydrocarbons was established.

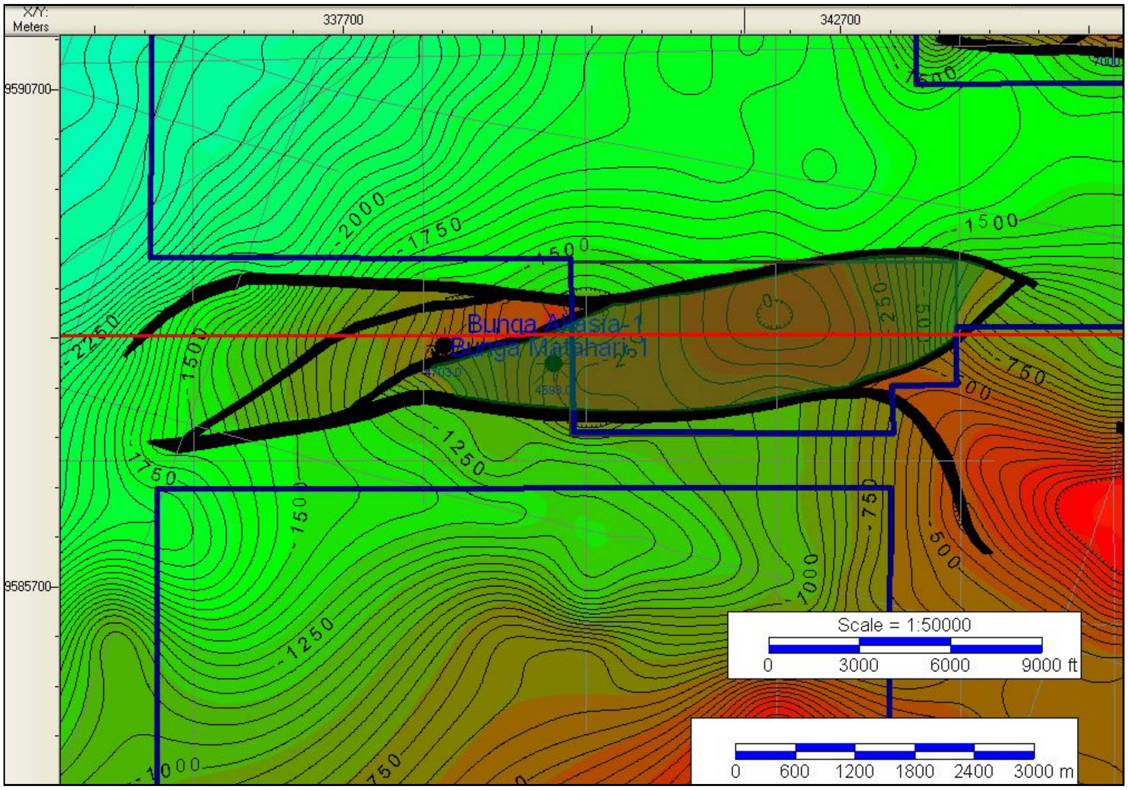

Figure 4.26 Akasia top Air Benakat Formation depth map (extension of Senabing Field).

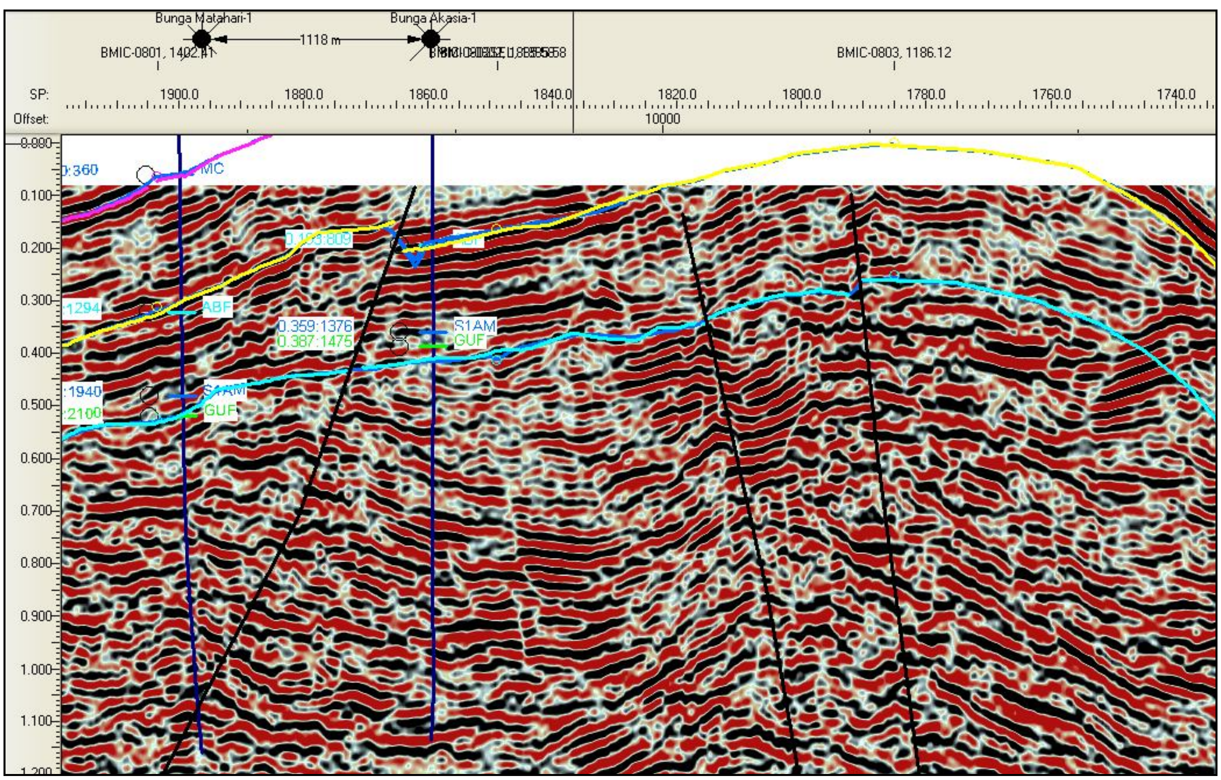

Figure 4.27 W-E seismic line across Akasia

Akasia	ABF	(Extension to Senabing)	
	Area	(Sq Km)	
	Min	M/L	Max
Area	3.934	4.662	5.16
Working Interest	0.161	0.525	0.754
Depth	350'	550'	750'

Table 4.10 Akasia ABF areas

4.2.6 Matahari – GUF

This is within the same faulted fold complex as Senabing and Akasia, but it lies in the next fault block to the west. This fault block has been drilled by well Bunga Matahari-1. The seismic horizons are tied to the well and the area were based on the top GUF depth map shown in Figure 4.28 and the polygons already on the workstation and thus the areas tie in well with those on the Bunga Mas spreadsheet.

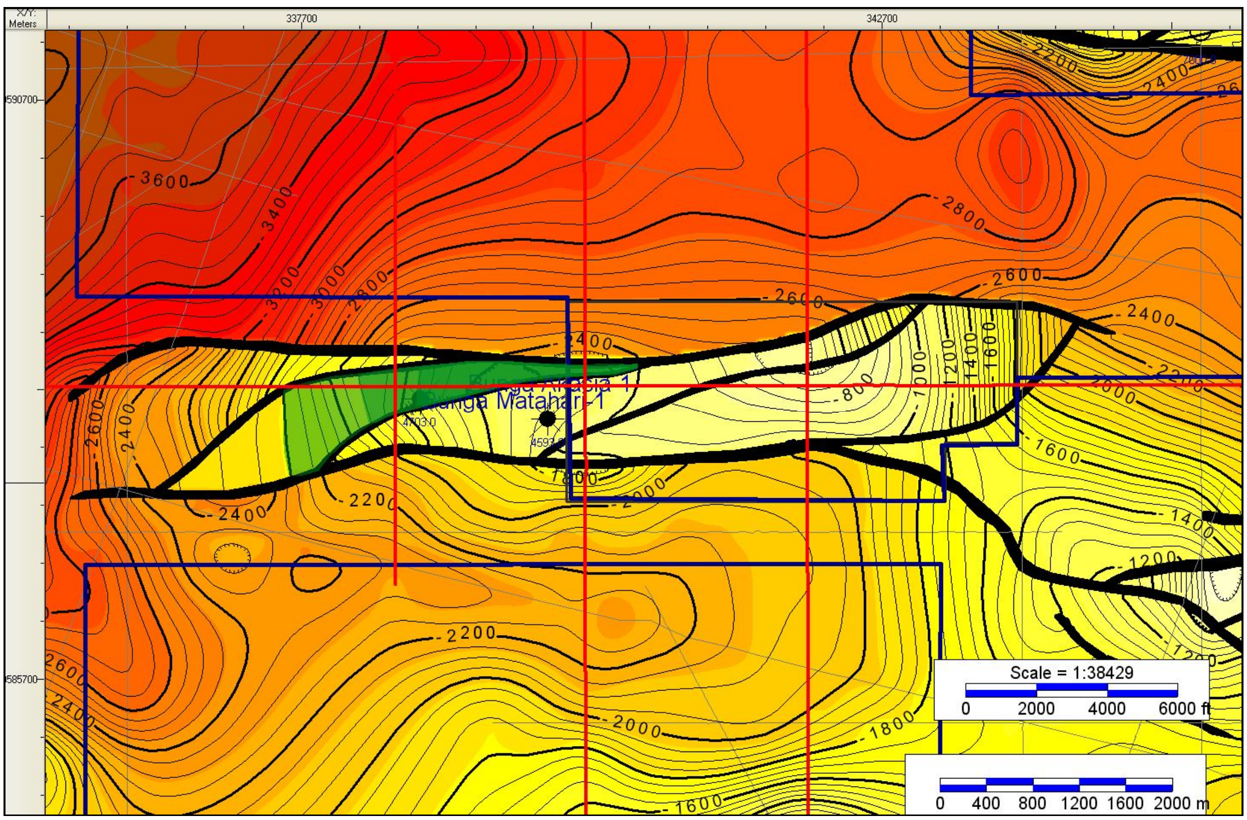

Figure 4.28 Matahari top Gumai depth Map with closure polygons

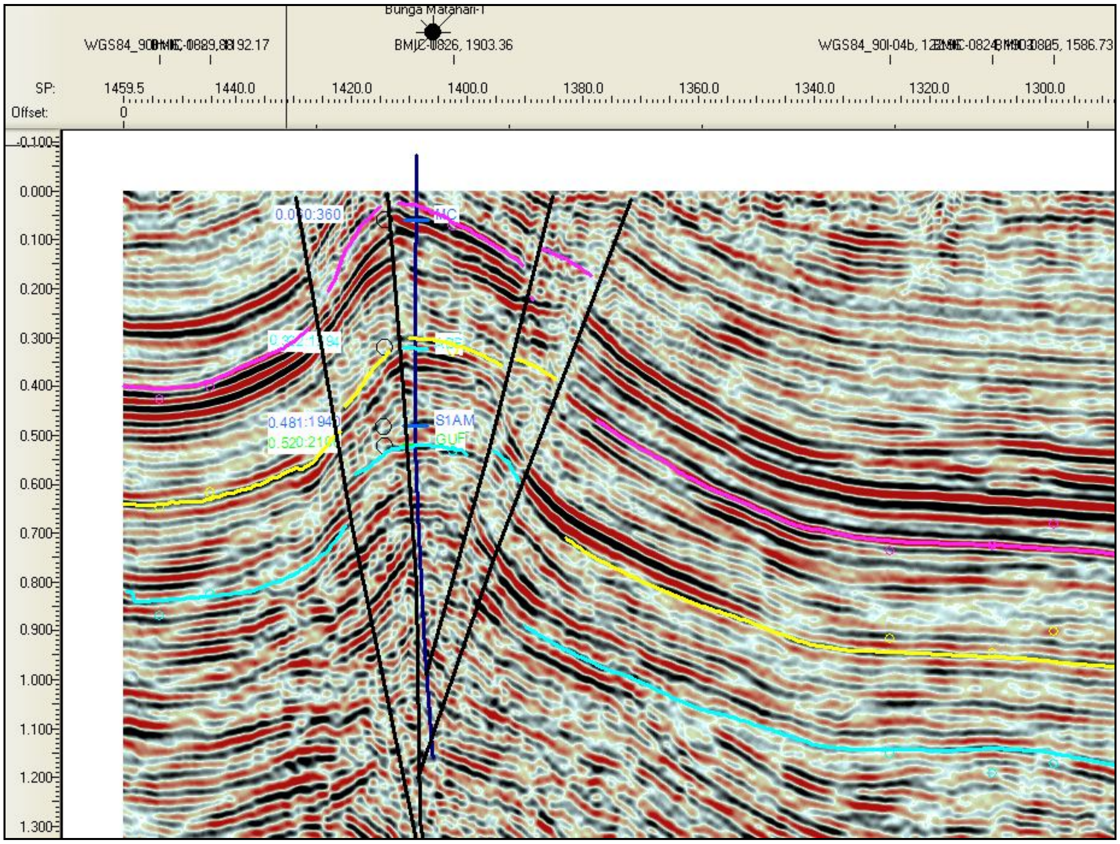

Figure 4.29 N_S seismic section through the Bunga Matahari 1 well

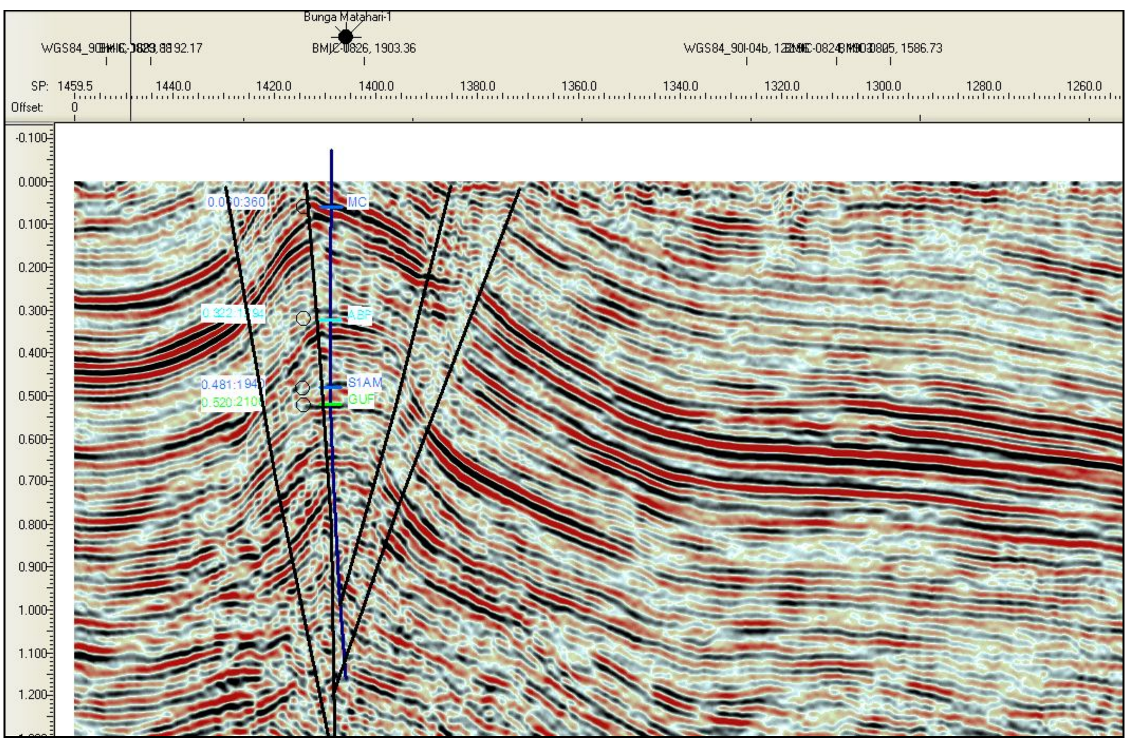

Figure 4.30 N_S seismic section through the Bunga Matahari well without picked horizons

Matahari	GUF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.294	0.449	0.889
Working Interest	0.219	0.374	0.814
Depth	1350'	1500'	1800'

Table 4.11 Matahari GUF areas

4.2.7 Matahari – ABF

This is downdip of the Senabing Field and across a mapped fault. The seismic event looks clear on the line adjacent to the Bunga Matahari 1 well. The well flowed gas (87% methane, 0.3% CO_2) from two zones in this Formation (DST1, 1963-1978 ft; DST2, 1946-1958 ft) at a combined rate of 2.9 MMscf/d.

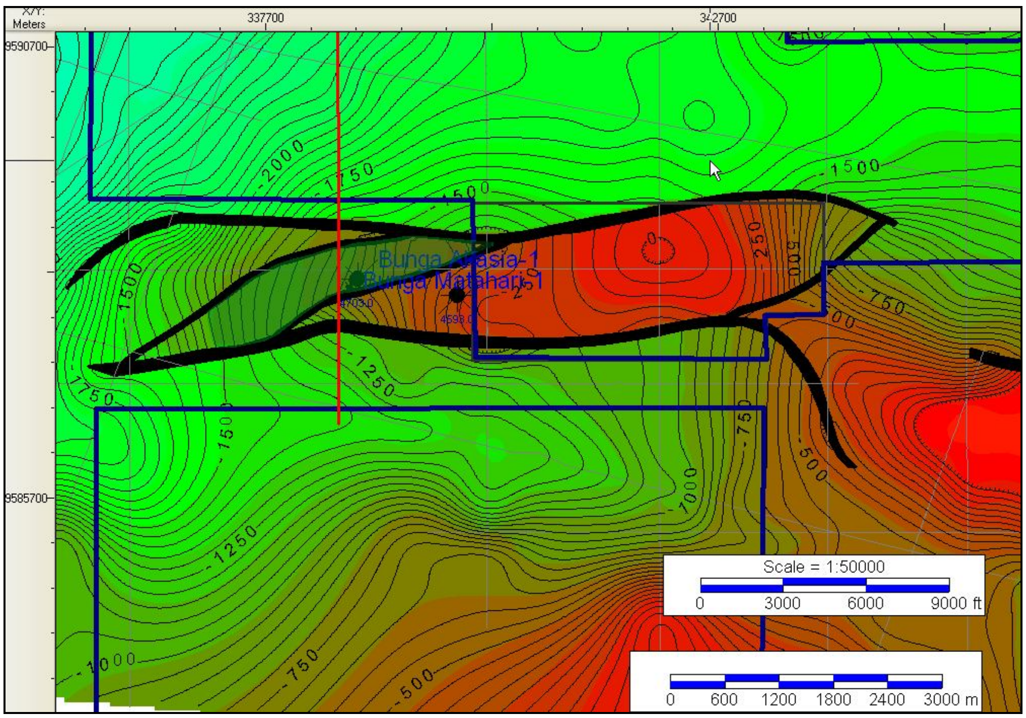

Figure 4.31 Matahari top ABF depth map with closure polygons

Matahari	ABF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.51	0.672	1.433
Working Interest	0.498	0.66	1.421
Depth	650'	750'	1150'

Table 4.12 Matahari ABF areas

4.2.8 Matahari NW – GUF

This lead is the next fault block west as Matahari and is part of the same overall structure. This fault block does not have a well in it. There are clear seismic events and the events tied well with the Spektrum2_Sel processed data. This data had been shifted up 0.35 seconds from the original amplitude (time) data.

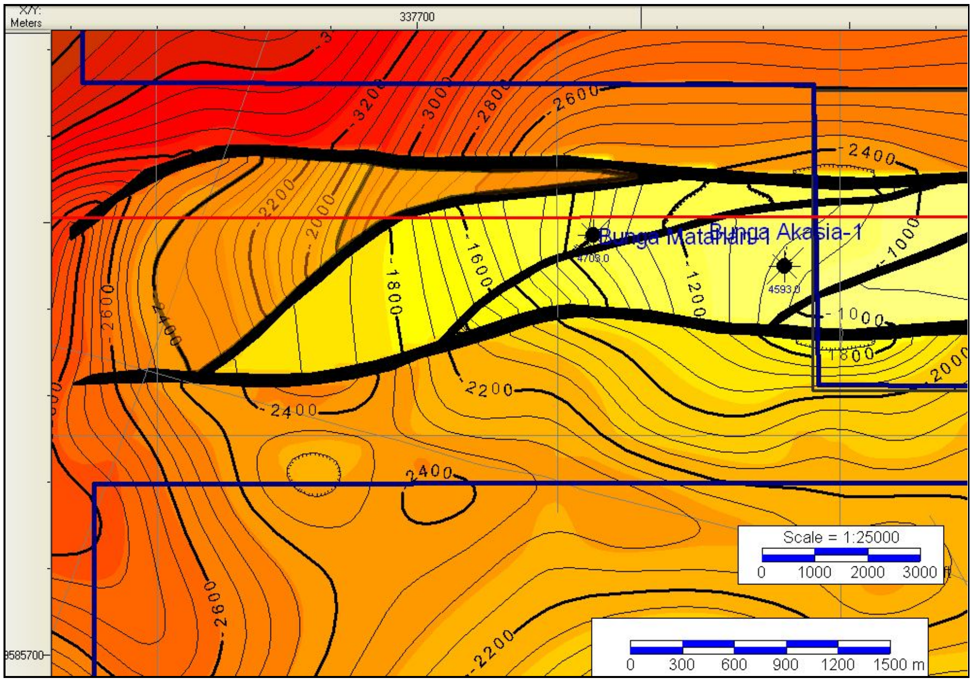

Figure 4.32 Matahari NW GUF depth map

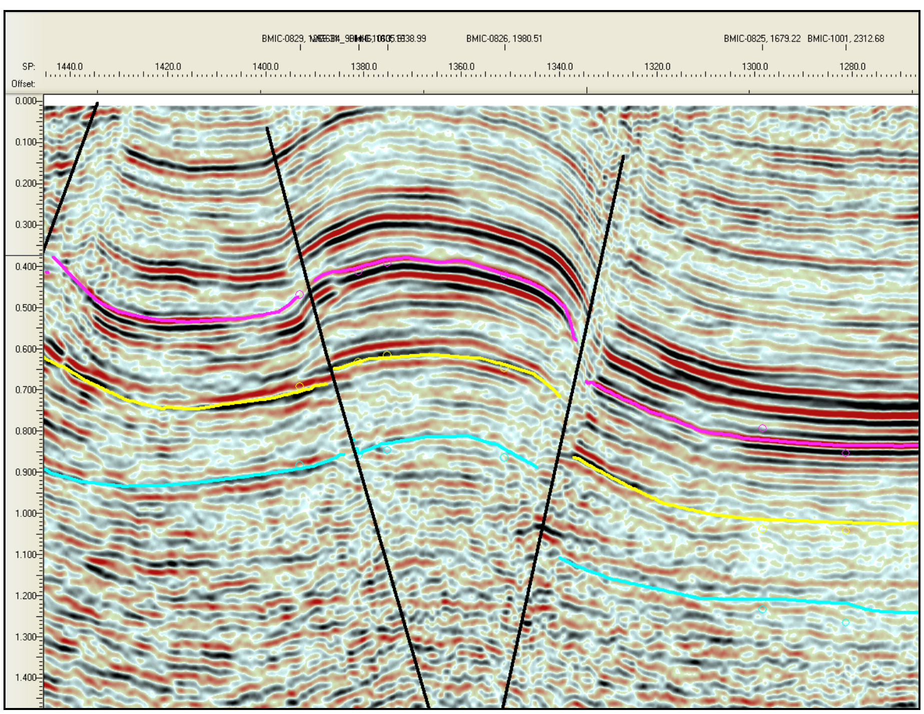

Figure 4.33 Matahari NW N-S Seismic line

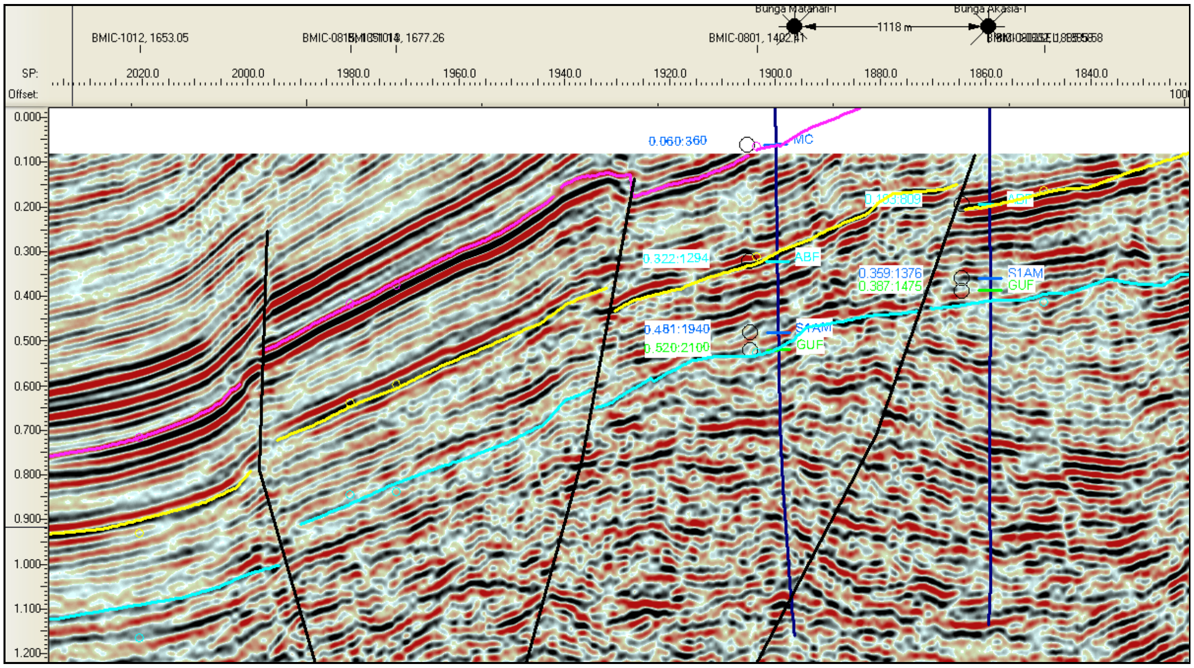

Figure 4.34 W-E Seismic line across Matahari NW.

Matahari NW	GUF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.077	0.263	1.145
Working Interest	0.077	0.263	1.145
Depth	1600'	1900'	2400'

Table 4.13 Matahari NW GUF areas

4.2.9 Matahari NW – ABF

This is the formation that Senabing Field produced from and this is an undrilled fault block of the same overall feature. The ABF horizon is clear on the seismic.

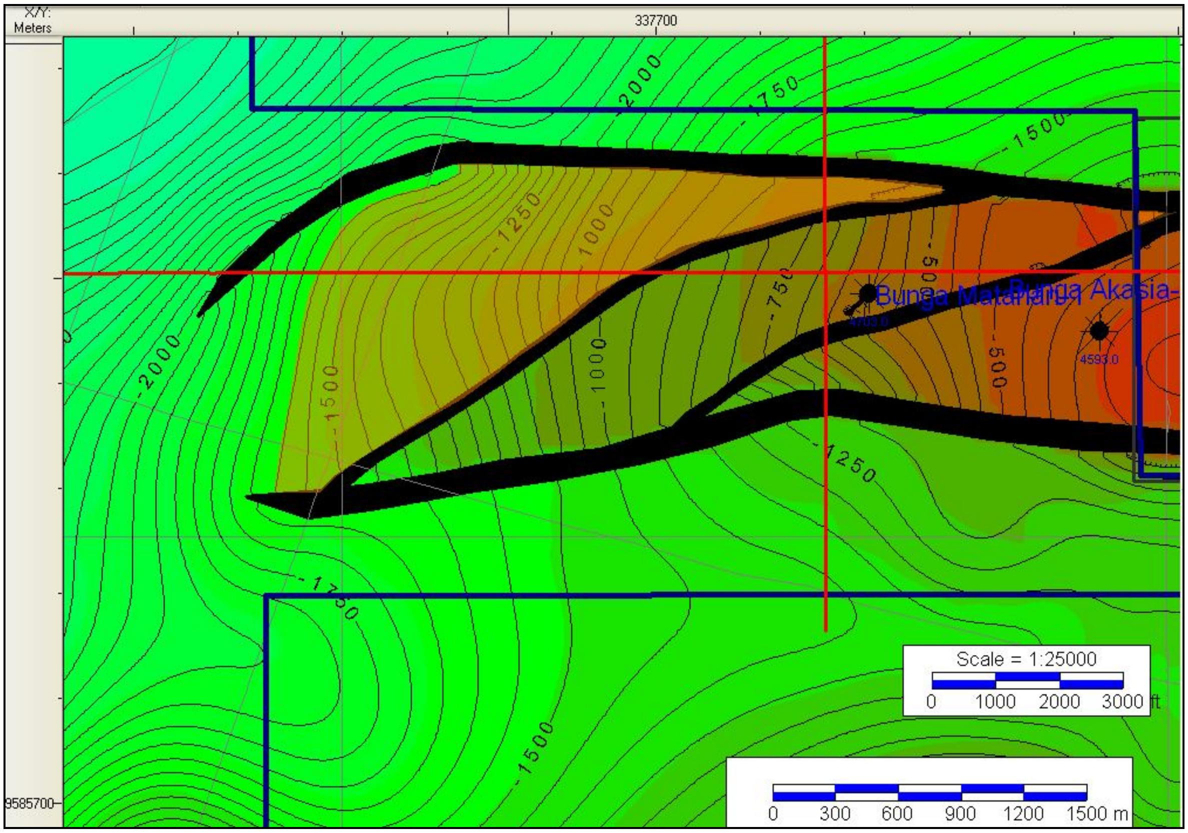

Figure 4.35 Matahari NW ABF depth map

Matahari NW	ABF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.412	0.697	1.855
Working Interest	0.412	0.697	1.855
Depth	1000'	1200'	1600'

Table 4.14 Matahari NW ABF areas

4.2.10 Bakung Kana Prospect; Gumai Formation

The Bakung Kana Prospect is a complex faulted anticline. The anticline and faults follow the same trend as the other prospects created by transpressional movements of the recent Barisan Mountain building. The prospect is truncated at the western end by a SW-NE fault. However, the quality of the seismic, the limited amount of seismic over the feature and the fact that 3 different surveys are involved and each survey has had different degrees and types of processing mean that the accuracy of the structure mapping is uncertain. Faults are difficult to pick and the variations in surveys and processing mean that the potential fault pattern is not unique. The horizons are difficult to confirm and thus the trap size and configuration are risky. The polygons in the workstation software are based on the model used to map this feature and these polygons were used to confirm the area quoted.

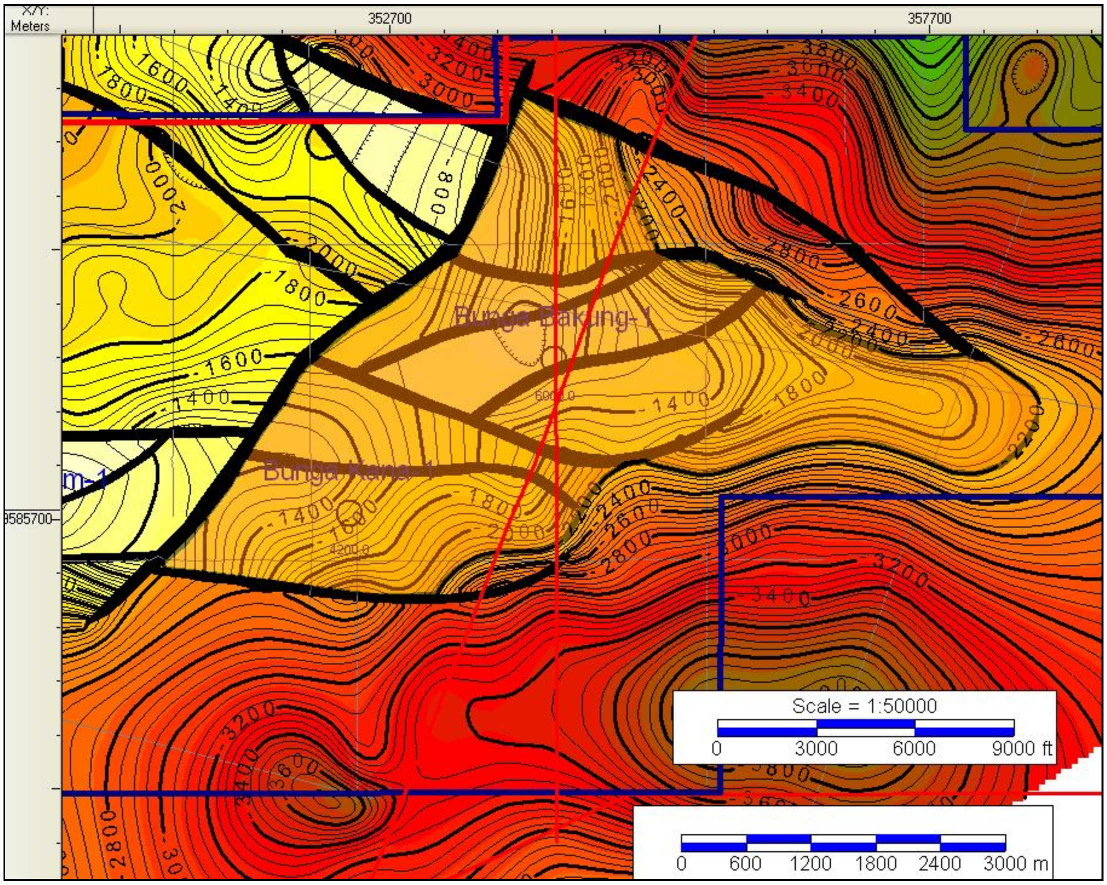

Figure 4.36 Bakung Kana top GUF depth map

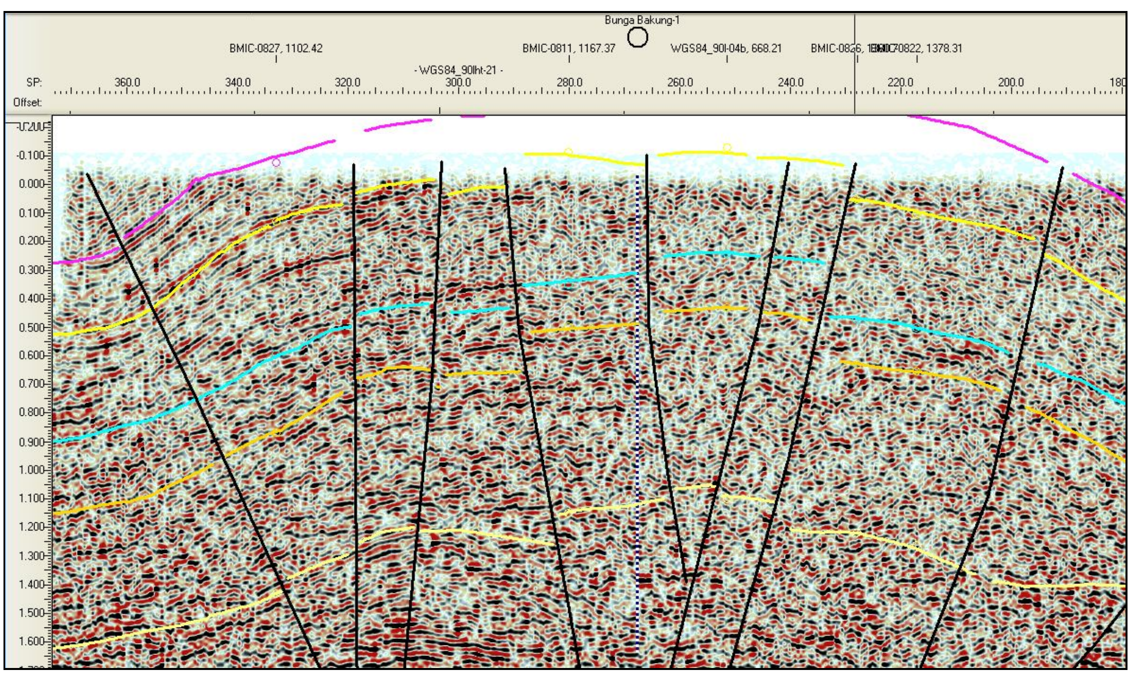

Figure 4.37 SW-NE Seismic line across Bakung Kana

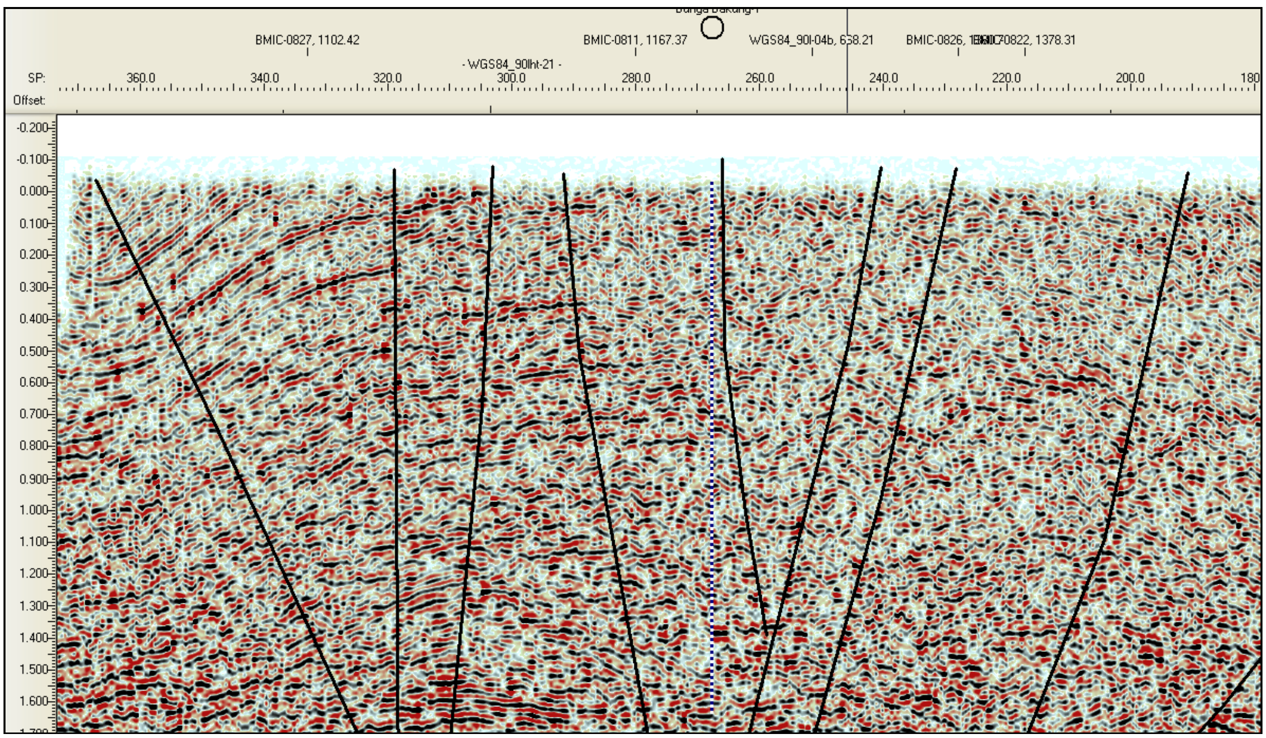

Figure 4.38 SW-NE Seismic line across Bakung Kana – unpicked

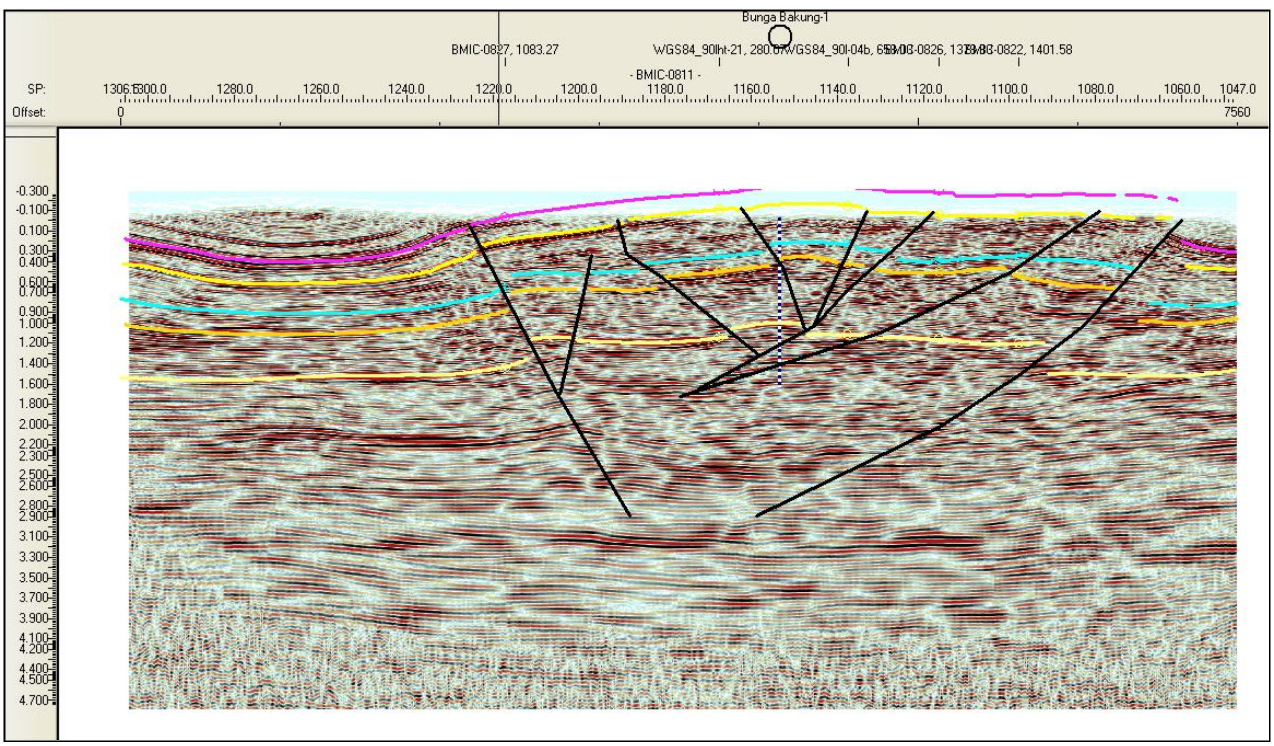

Figure 4.39 S-N Seismic line across Bakung Kana

Bakung Kana	GUF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.829	8.115	15.689
Working Interest	0.829	8.115	15.689
Depth	900'	1525'	2200'

Table 4.15 Bakung Kana GUF areas

4.2.11 Bakung Kana Deep Prospect

There are two deep events mapped, but it is not known what these events are apart from the fact they are deeper than the top Gumai. They may be reservoir sands or even tight limestones. There have been no well penetrations that these events have been tied to. There are inconsistencies in the depth conversion in that the deep events are shallower in parts than the overlying Gumai. This is demonstrated in Figure 4.40 in which the Gumai event has been subtracted from the Deep Event. The areas that are positive (reds & browns) are where the deep event is shallower than the Gumai. This problem does not occur in the time maps therefore it is likely to be caused by a depth conversion error.

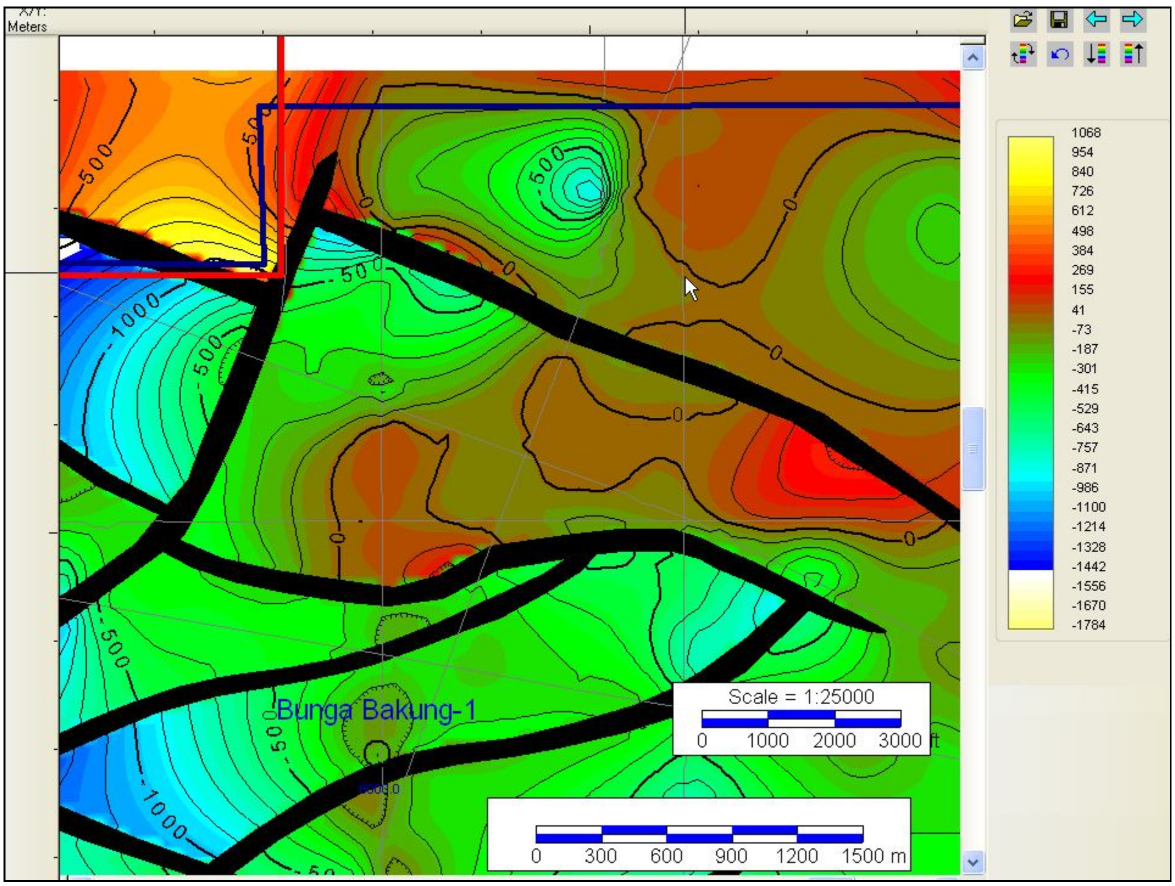

Figure 4.40 Bakung Deep map minus Bakung GUF map

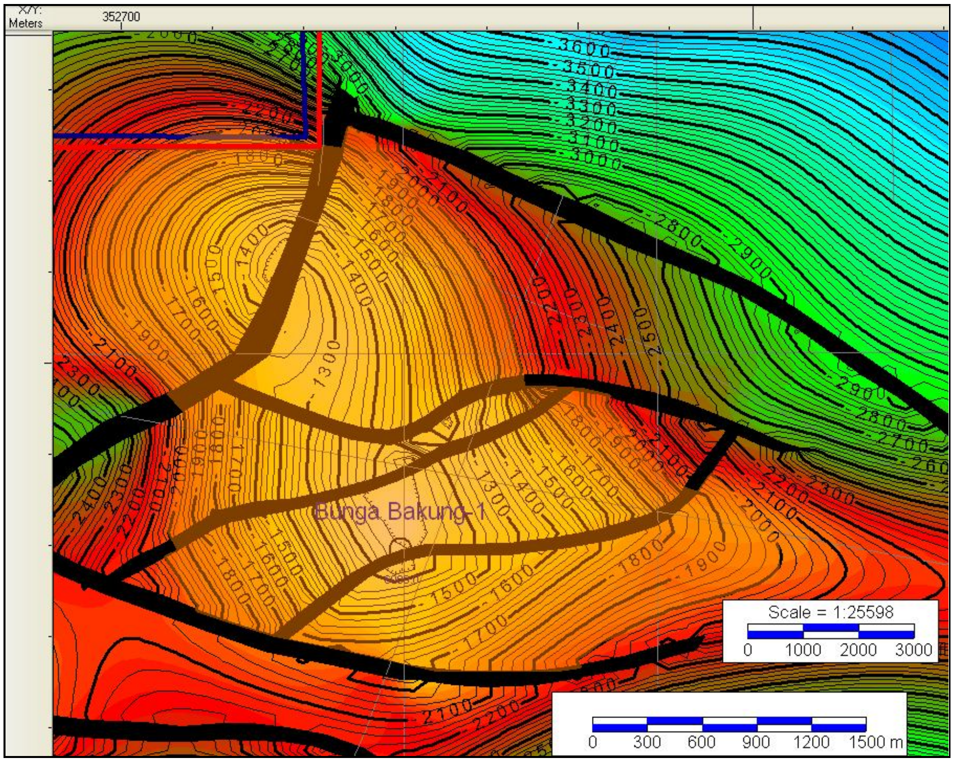

Figure 4.41 Bakung Deep Strong event depth map 1

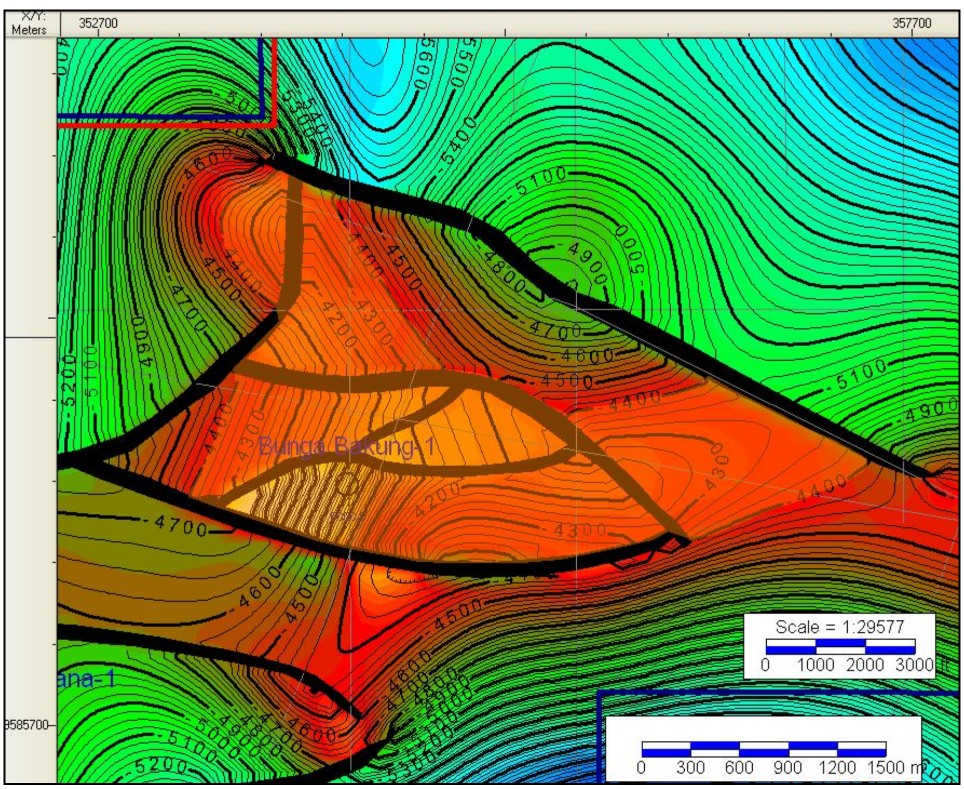

Figure 4.42 Bakung Deep Strong event 2 depth map

	Bakung Deep 1				Bakung Deep 2		
	Area (Sq Km)				Area (Sq Km)		
	Min	M/L	Max		Min	M/L	Max
Area	0.241	2.103	6.691	Area	0.171	0.263	4.465
Working Interest	0.241	2.103	6.691	Working Interest	0.171	0.263	4.465
Depth	1200'	1475'	2000'	Depth	3550'	3800'	4400'

Table 4.16 Bakung Deep; 'Strong Event' Areas

4.2.12 Bakung North East Lead

This lead is highly faulted and may be part of the overall Bakung Kana structure:

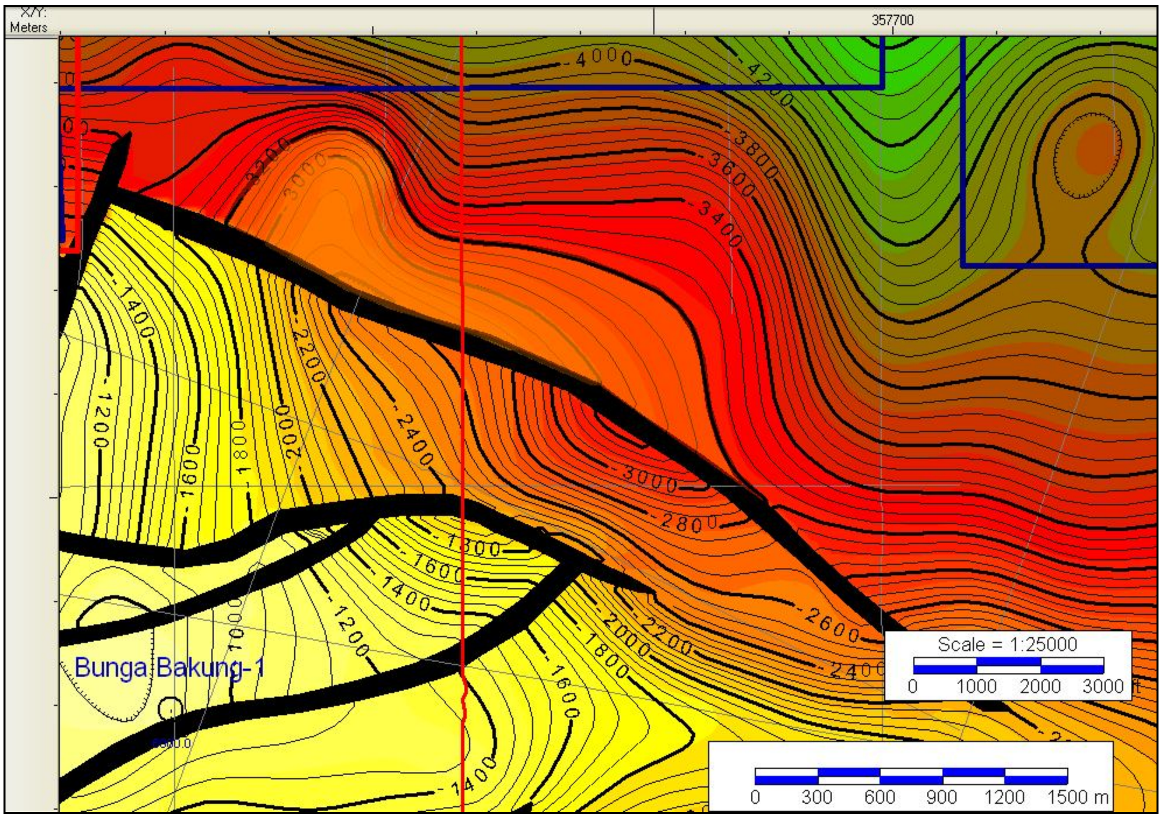

Figure 4.43 Bakung NE lead GUF depth map

The map is based on the Spektrum2_Sel reprocessing which has the seismic events shallower.

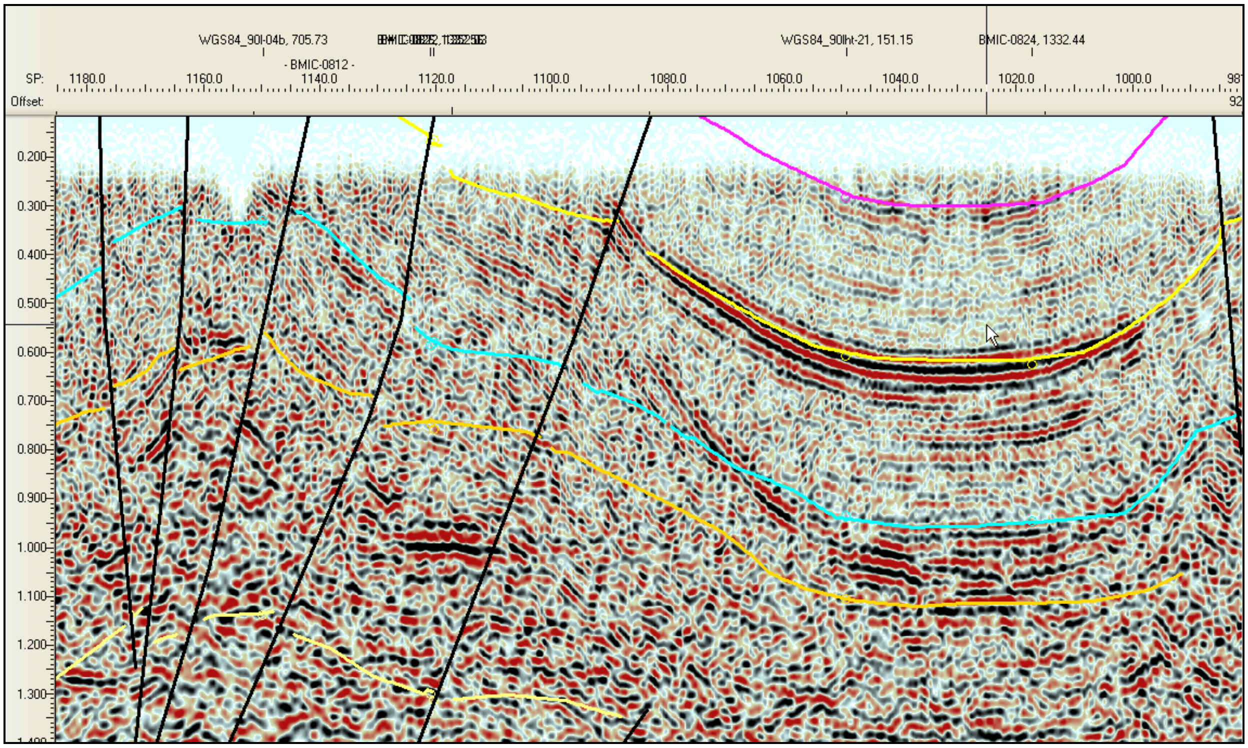

Figure 4.44 S-N Seismic line across Bakung NE from the initial processing

Horizons are based on the Spektrum2_Sel reprocessing

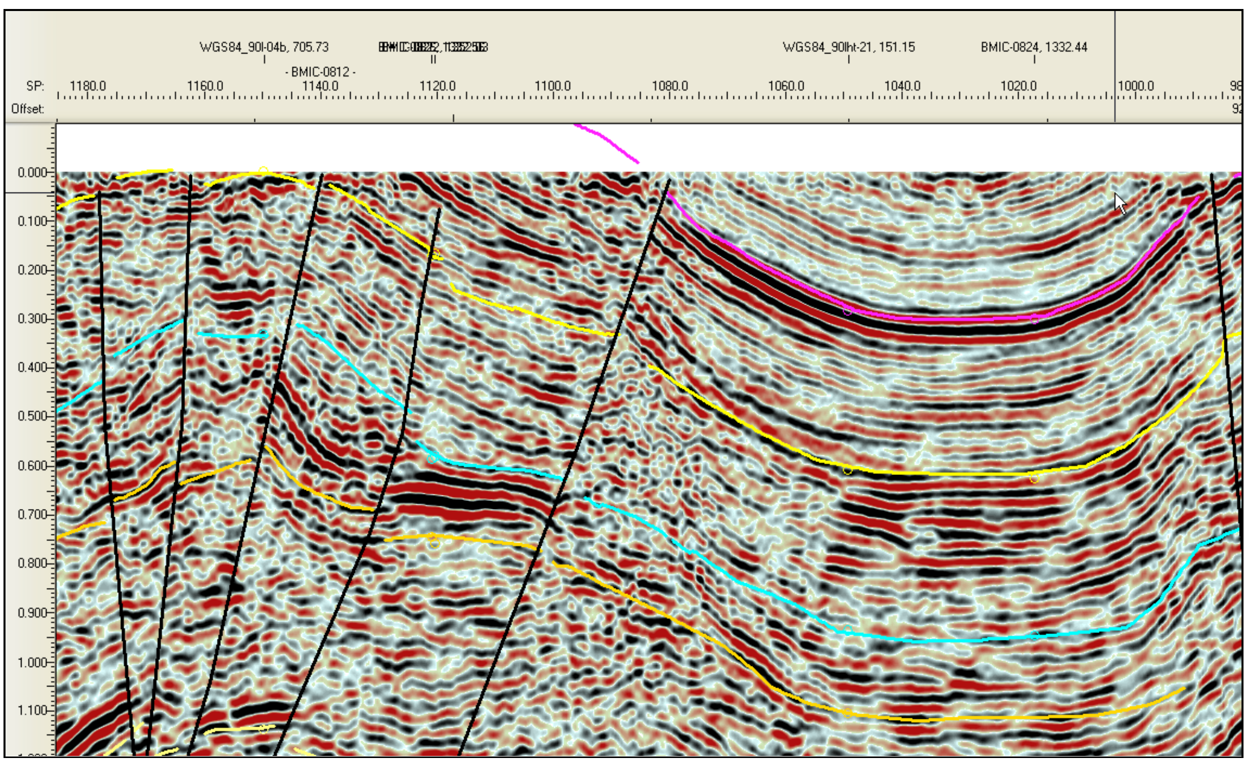

Figure 4.45 S-N Seismic line across Bakung NE Spektrum2_Sel reprocessing

	Bakung NE Lead		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.188	0.46	1.272
Working Interest	0.188	0.46	1.272
Depth	2900'	3000'	3200'

Table 4.17 Bakung NE GUF Areas

4.2.13 Bakung North West Extension (Lead)

This lead is an extension of the Bakung structure. The extension is to the west of the SW-NE fault that separates it from the main Bakung Kana prospect.

This lead only has two seismic lines across it, one of which has no data over the structure and the other only has limited data. The data gap was present on all datasets available at the time of writing this report. Therefore this lead cannot be defined seismically and the areas are taken from the polygons based on the maps which are based on the model used for the horizons.

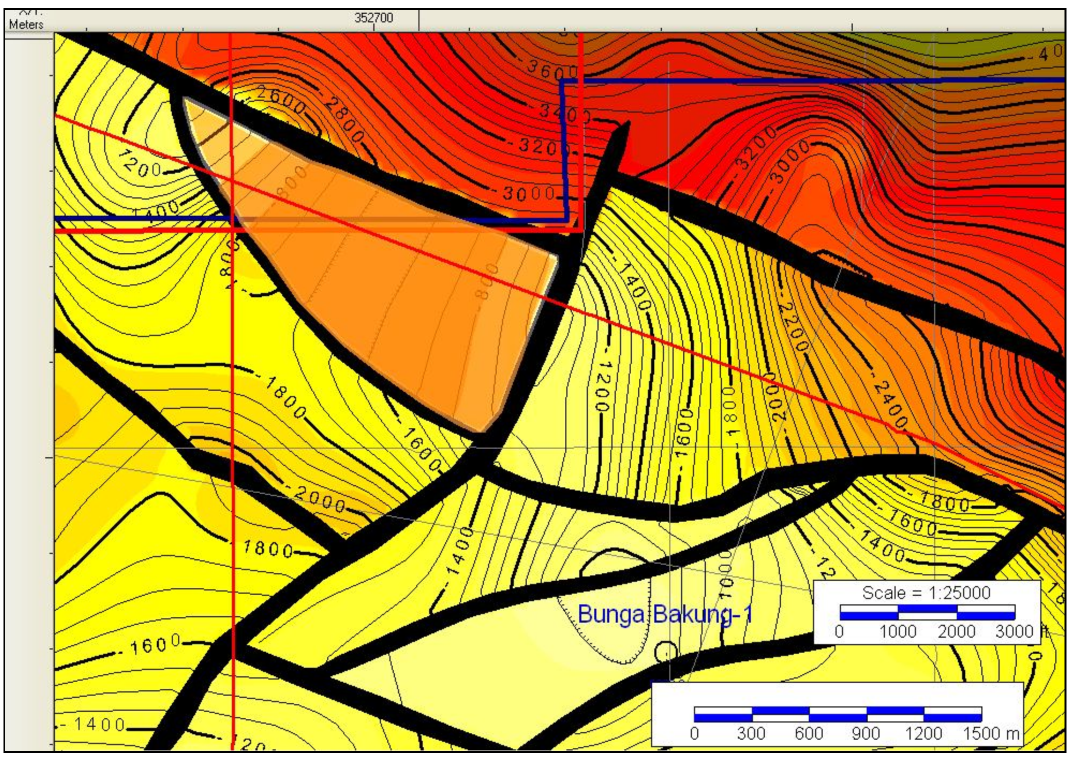

Figure 4.46 Bakung NW extension GUF Depth map

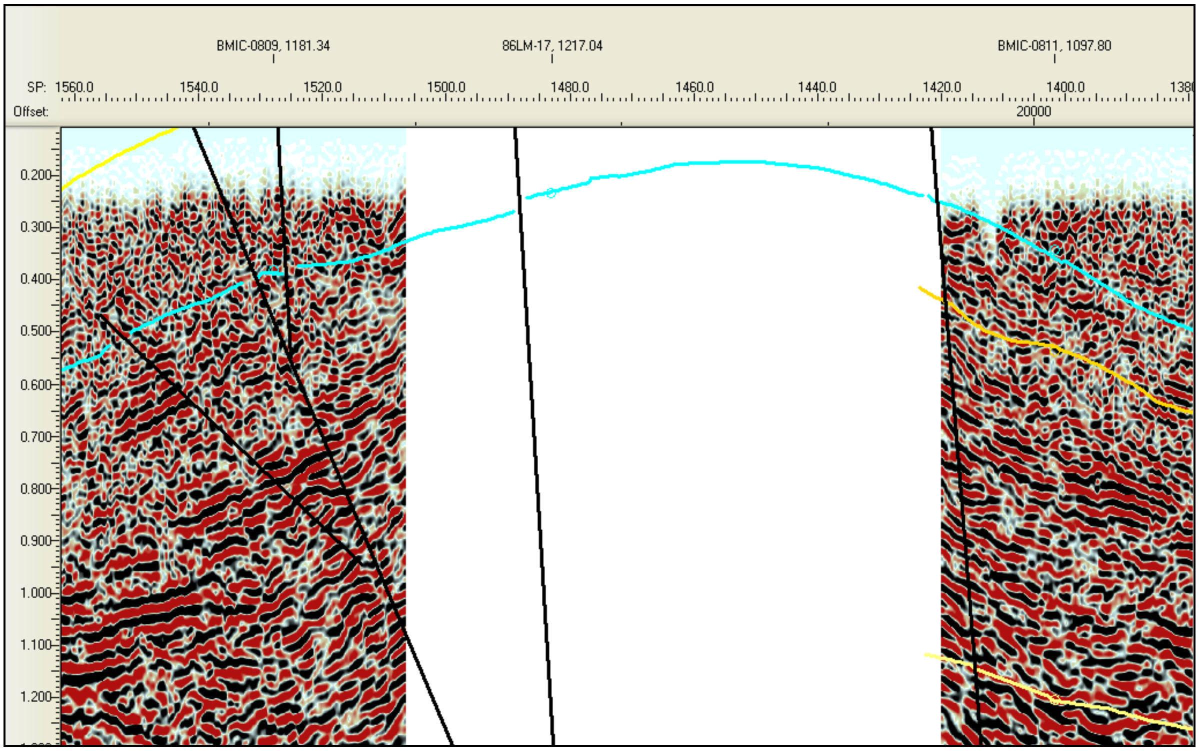

Figure 4.47 NW-SE seismic line over Bakung NW showing the data gap over the structure

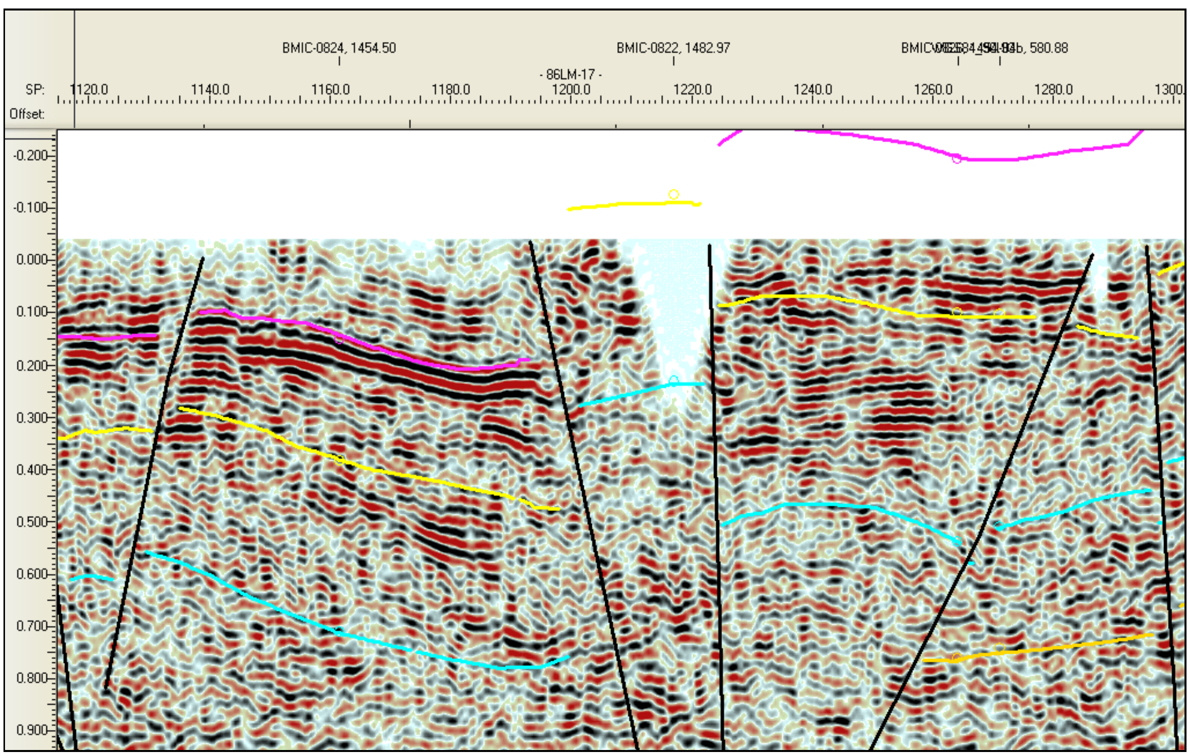

Figure 4.48 N-S seismic line across the western end of the lead. Note the limited data between the bounding faults

	Bakung NW Extension		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.951	1.306	1.417
Working Interest	0.813	1.052	1.053
Depth	800'	900'	1100'

Table 4.18 Bakung NW GUF areas

4.2.14 Anggrek Prospect: Gumai Formation

This is a fault bounded anticlinal structure. The seismic data is clear either side of the structure, outside the bounding faults, but between the faults there is only noise and no data over the structure. Therefore, all the areas are based on operator's polygons and maps. The lead is on trend with the Arahan-Banairsari field.

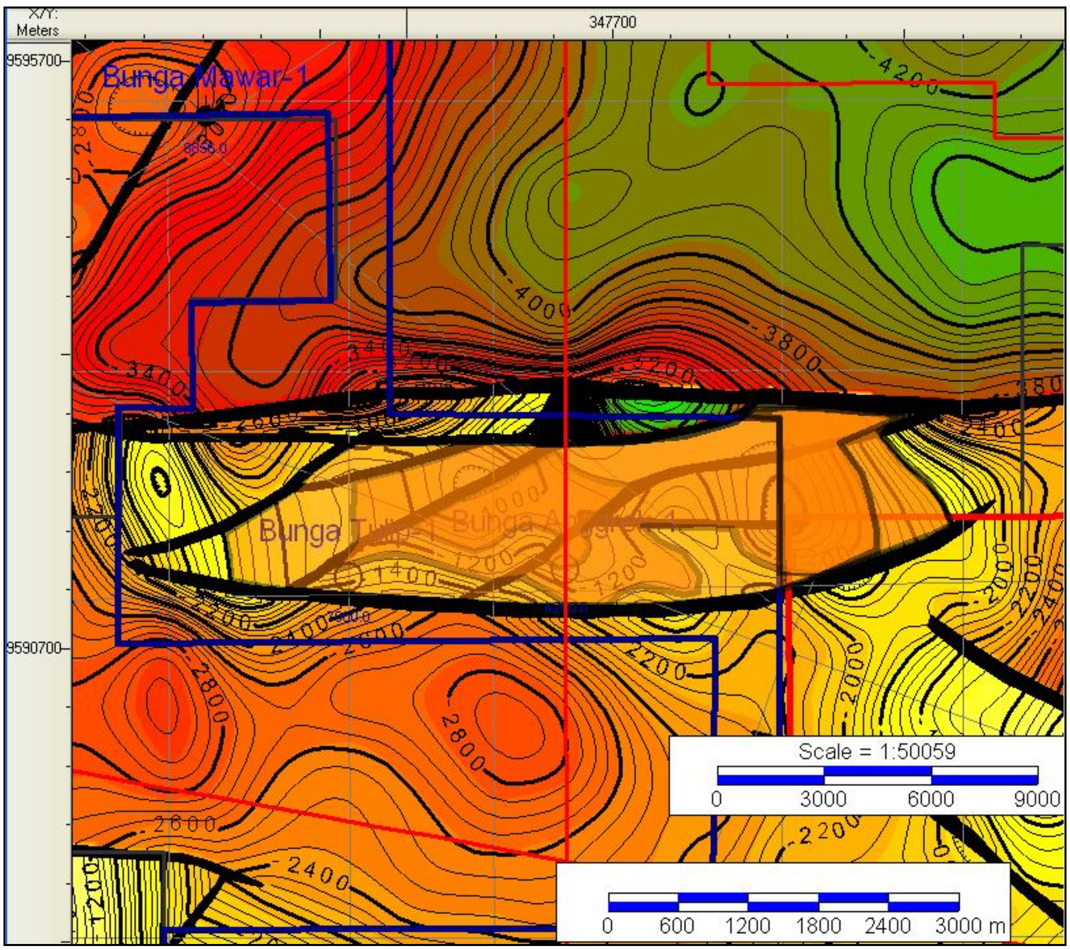

Figure 4.49 Anggrek top GUF depth map

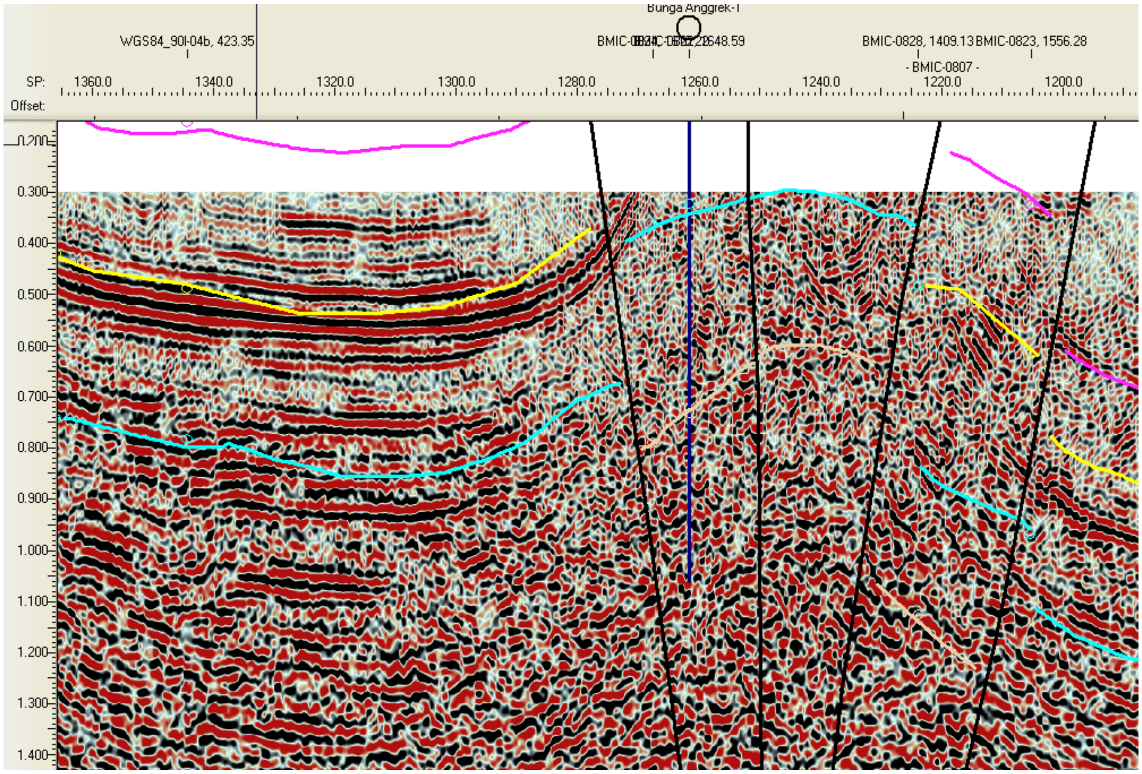

Figure 4.50 N-S Seismic line across Anggrek

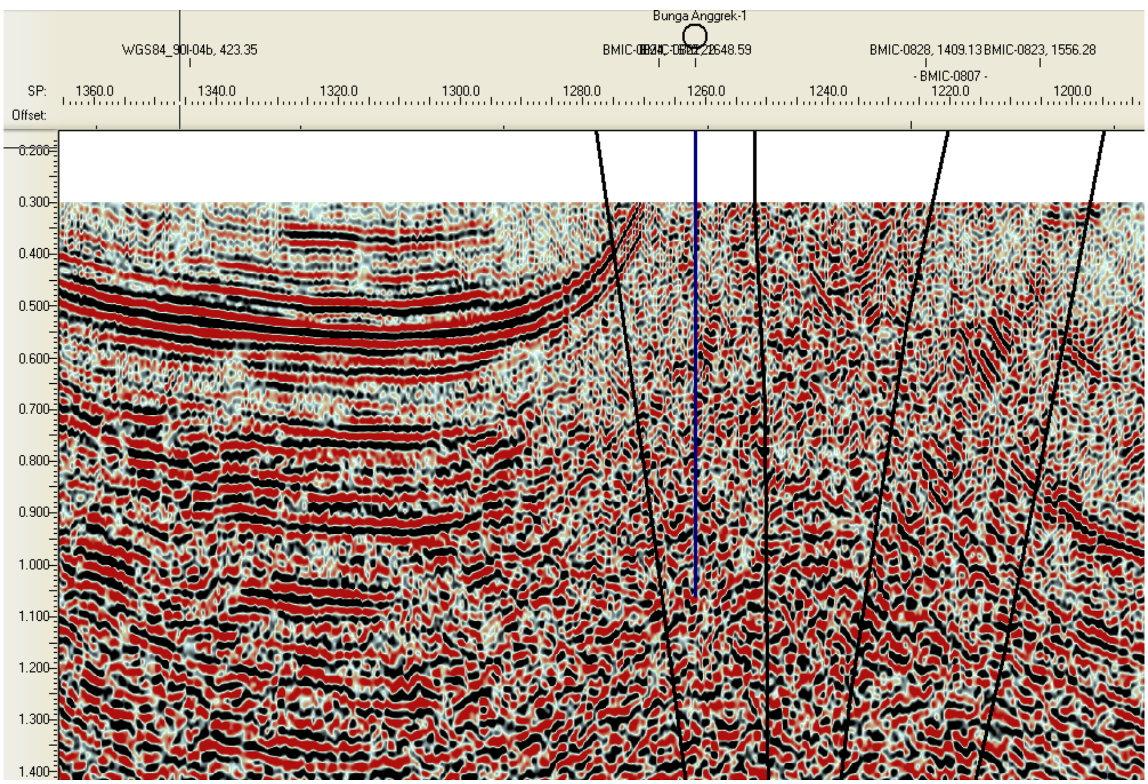

Figure 4.51 N-S Seismic line across Anggrek, unpicked to show the lack of data over the structure.

Anggrek	GUF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.821	5.059	7.609
Working Interest	0.821	4.016	6.057
Depth	1100'	1275'	1600'

Table 4.19 Anggrek GUF areas

4.2.15 Anggrek Deep Lead

There are no wells within the fault block and the picks for this deep event do not extend beyond the faults and thus it cannot be stated what is generating the reflection.

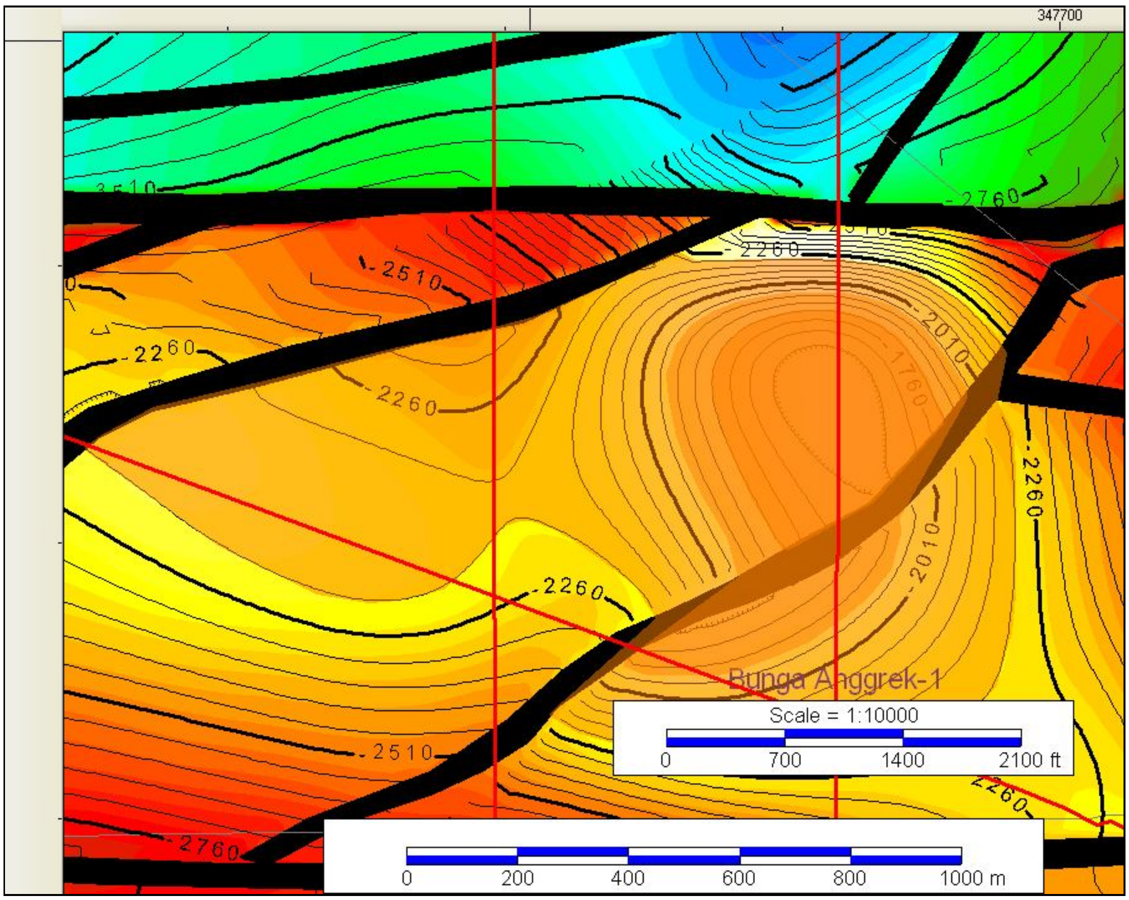

Figure 4.52 Anggrek Deep event depth map.

The deep structure is the pink event shown in Figure 4.50.

Anggrek	Deep		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.12	0.253	0.925
Working Interest	0.12	0.253	0.925
Depth	1800'	1925'	2200'

Table 4.20 Anggrek Deep areas

4.2.16 Anggrek North West Lead; Gumai Formation

This feature is only defined by one north-south seismic line and the roll over mapped may not exist outside the model used to create it. On the one seismic line the events below the Muara Enim Coals are masked and cannot be seismically defined.

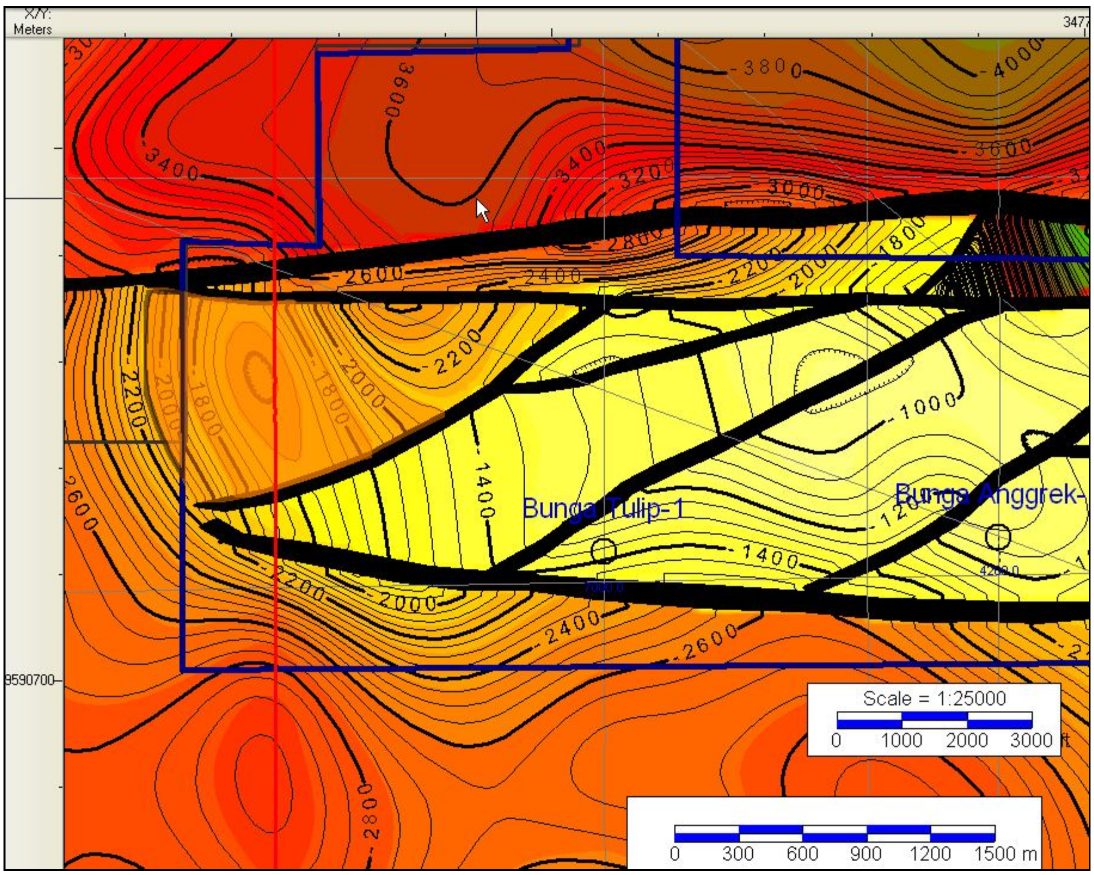

Figure 4.53 Anggrek NW, GUF depth map

The seismic line is shown in Figure 4.54 and the light blue GUF pick lies above what looks like a Muara Enim coal reflector. This puts doubts on the validity of this structure.

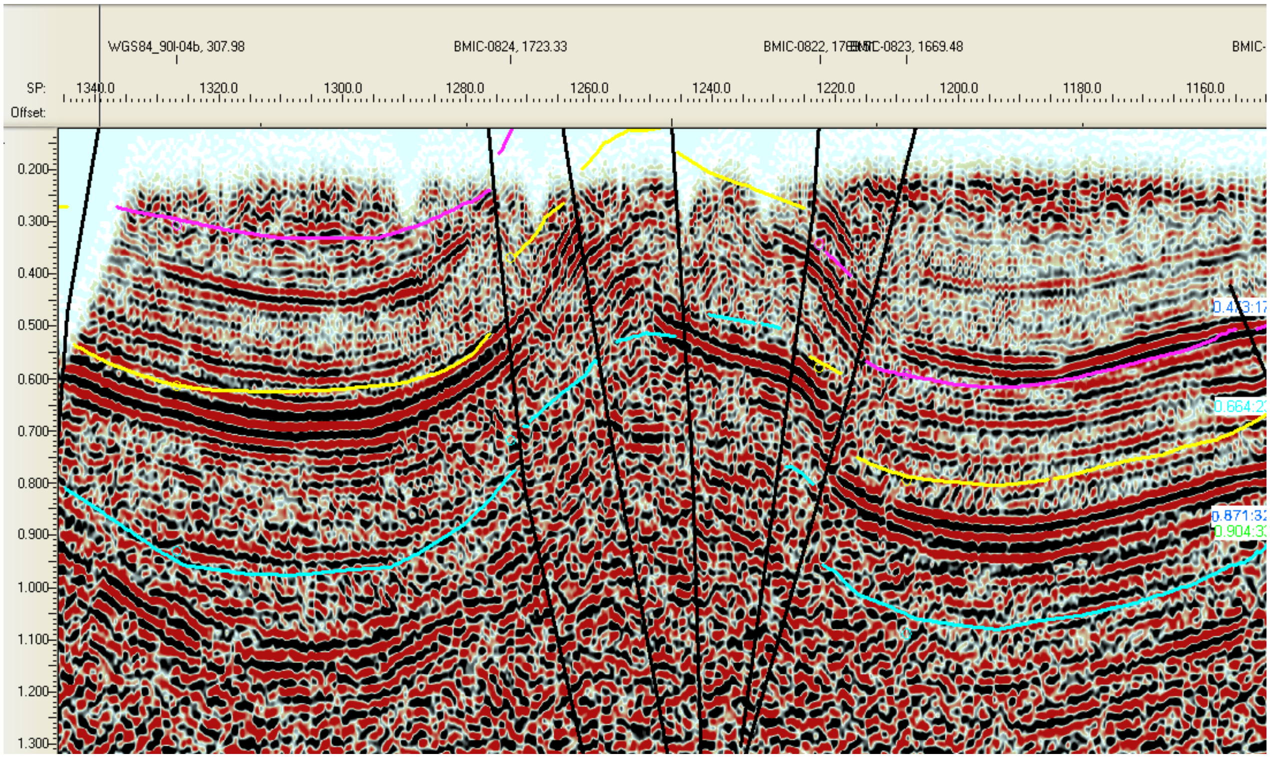

Figure 4.54 N-S Seismic line across Anggrek NW.

	Anggrek NW - GUF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	**0.148**	**0.54**	**0.866**
Working Interest	**0.148**	**0.54**	**0.761**
Depth	**1650'**	**1850'**	**2100'**

Table 4.21 Anggrek NW GUF areas

4.2.17 Sakura Prospect; Gumai Formation

Sakura is another transpressional faulted anticline with east west faults bounding the structure and crossed by SW-NE trending faults. There is no data between the faults and only noise where the structure is mapped. The bounding faults can only be determined by the end of data and the start of noise. The cross faults are difficult to pick and there is no east-west seismic line to help show them. The picks and maps are purely based on the model. The areas are based on the map within the workstation software as the horizons could not be picked.

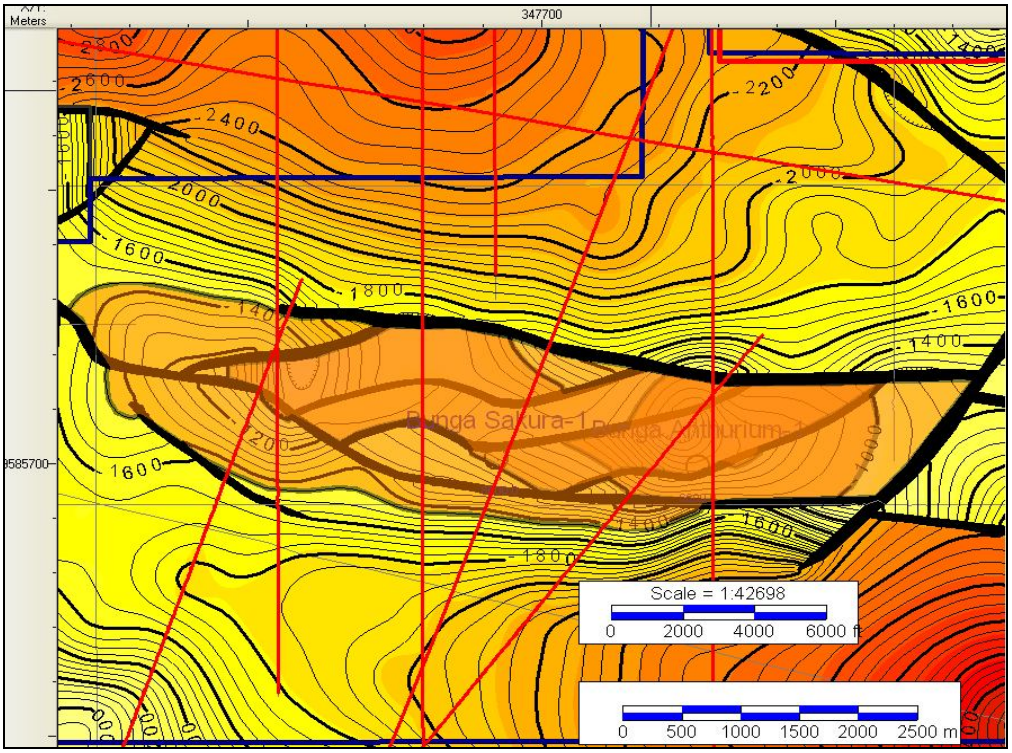

Figure 4.55 Sakura top GUF depth map

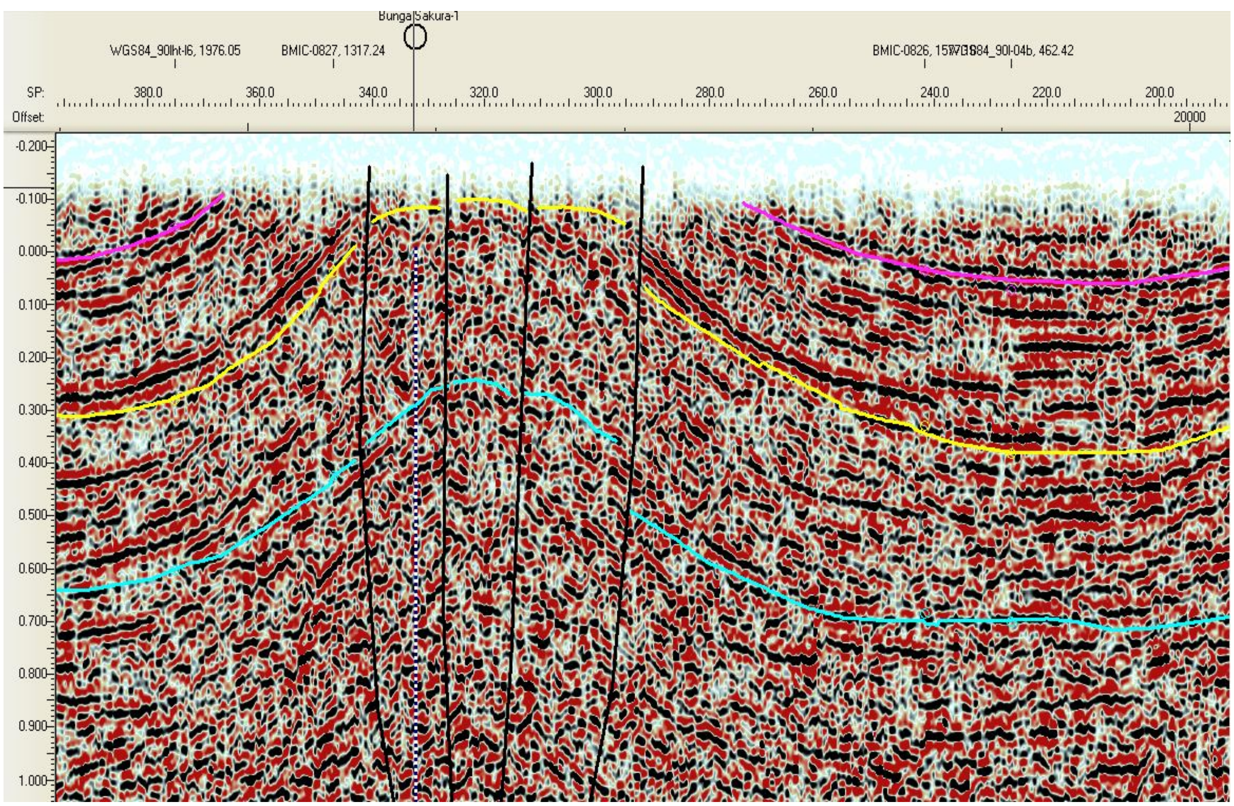

Figure 4.56 N-S seismic line across the Sakura structure

Sakura	GUF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	1.322	5.063	9.924
Working Interest	1.322	5.063	9.924
Depth	750'	1000'	1450'

Table 4.22 Sakura GUF areas

4.2.18 Sakura Deep Lead

The seismic data is poor and it is difficult to see what is being picked. The picking is restricted to the area close to the feature and not linked to any control. There is only one line across the feature and thus the horizon is unknown and the structure is purely model based. The areas in this report are based on polygons drawn by the operator on the model based maps. There are two deep events.

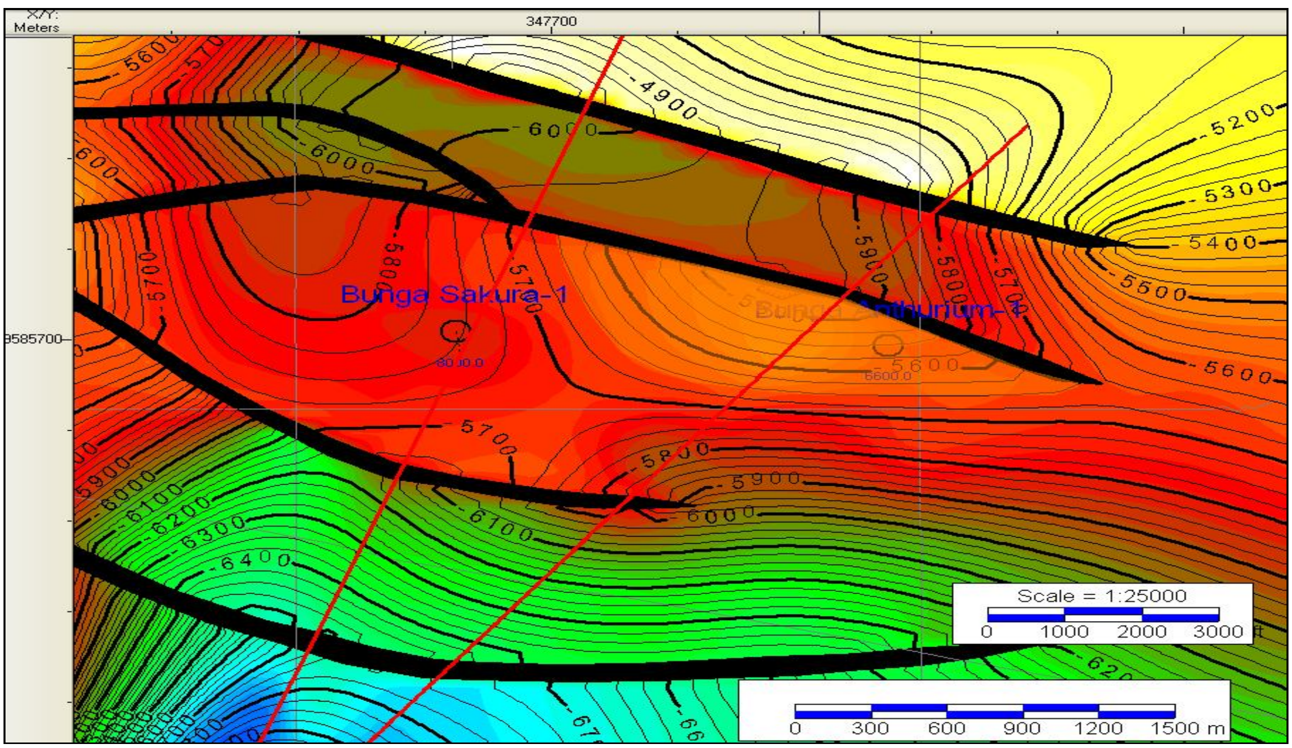

Figure 4.57 Sakura Deep horizon 1 depth map.

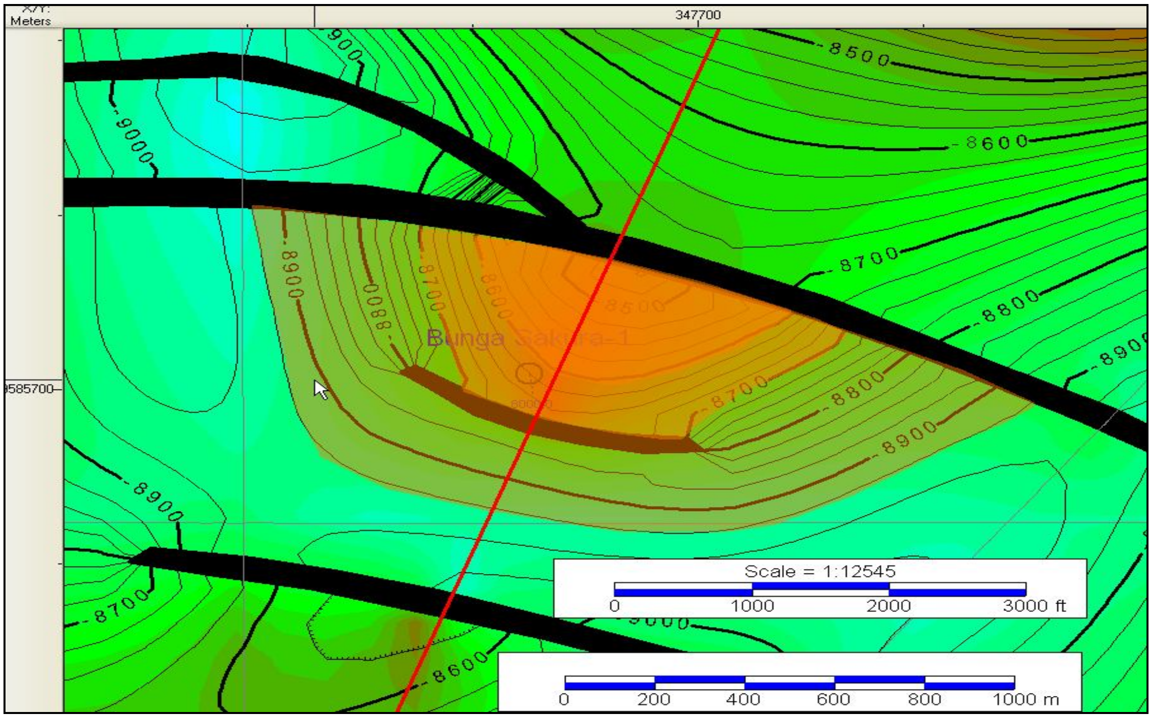

Figure 4.58 Sakura Deep horizon 2 depth map.

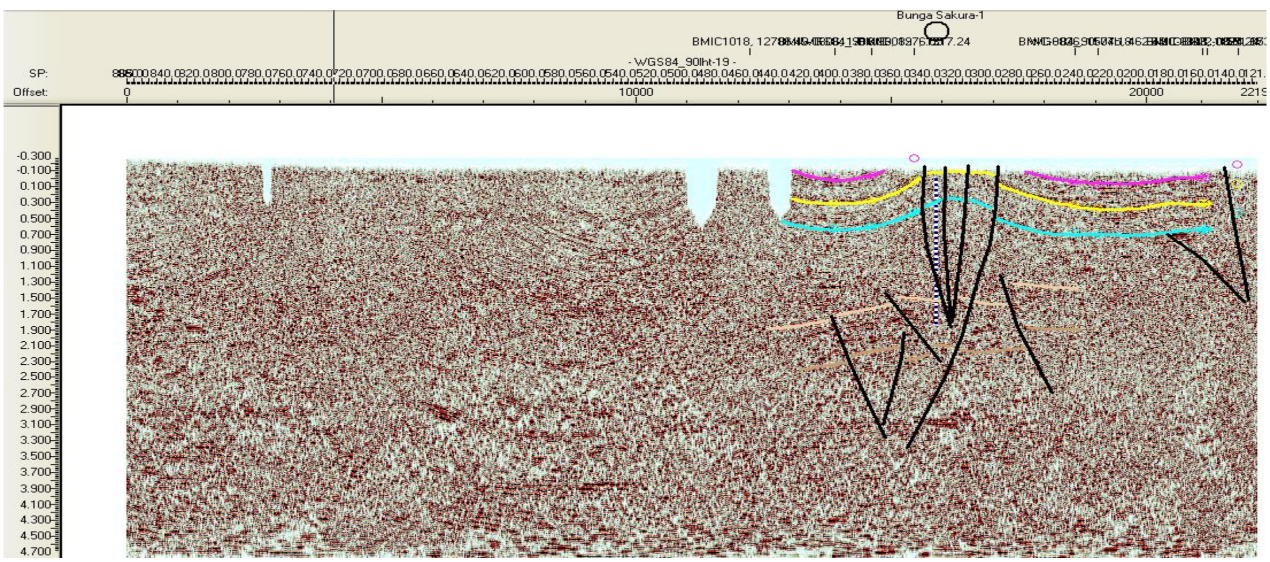

Figure 4.59 NE-SW Seismic line across Sakura deep 1.

Only the area close to the feature has been picked and the horizons are not tied and there is no data between the faults.

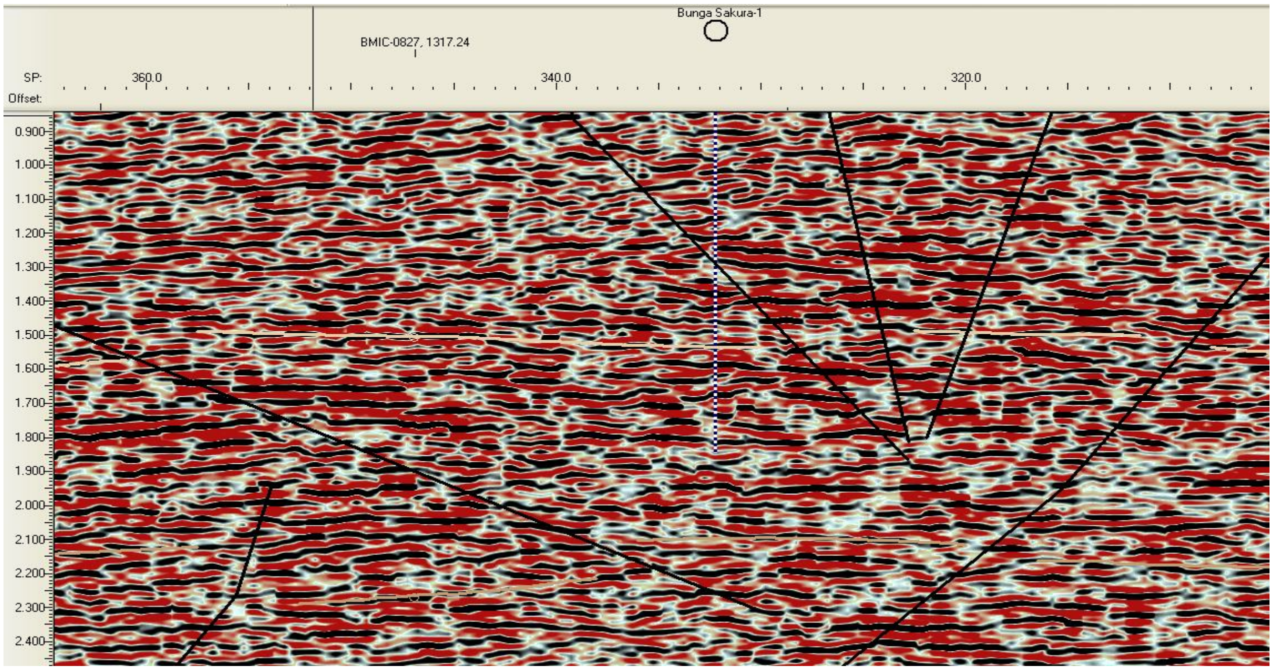

Figure 4.60 NE-SW line across Sakura Deep 2.

	Sakura Deep 1				Sakura Deep 2		
	Area (Sq Km)				Area (Sq Km)		
	Min	M/L	Max		Min	M/L	Max
Area	0.08	0.251	0.855	Area	0.168	0.336	0.995
Working Interest	0.08	0.251	0.855	Working Interest	0.168	0.336	0.995
Depth	5500'	5550'	5650'	Depth	8600'	8700'	8925'

Table 4.23 Sakura Deep areas

4.2.19 Sakura North Lead

This lead is on the north of the northern bounding fault of Sakura and is an unknown deep event. The structure is created by the dip of the horizon away from the fault. It is difficult to judge if it is a real dipping event.

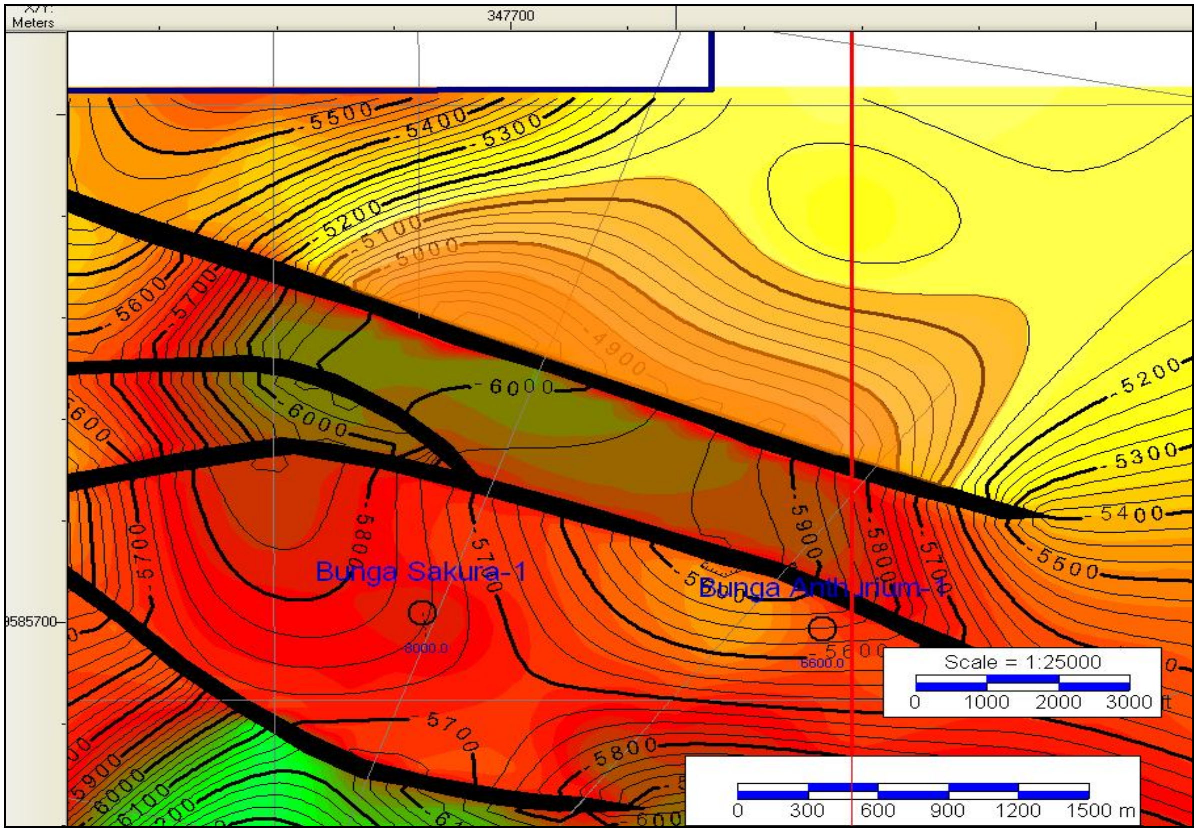

Figure 4.61 Sakura North Deep Horizon depth map

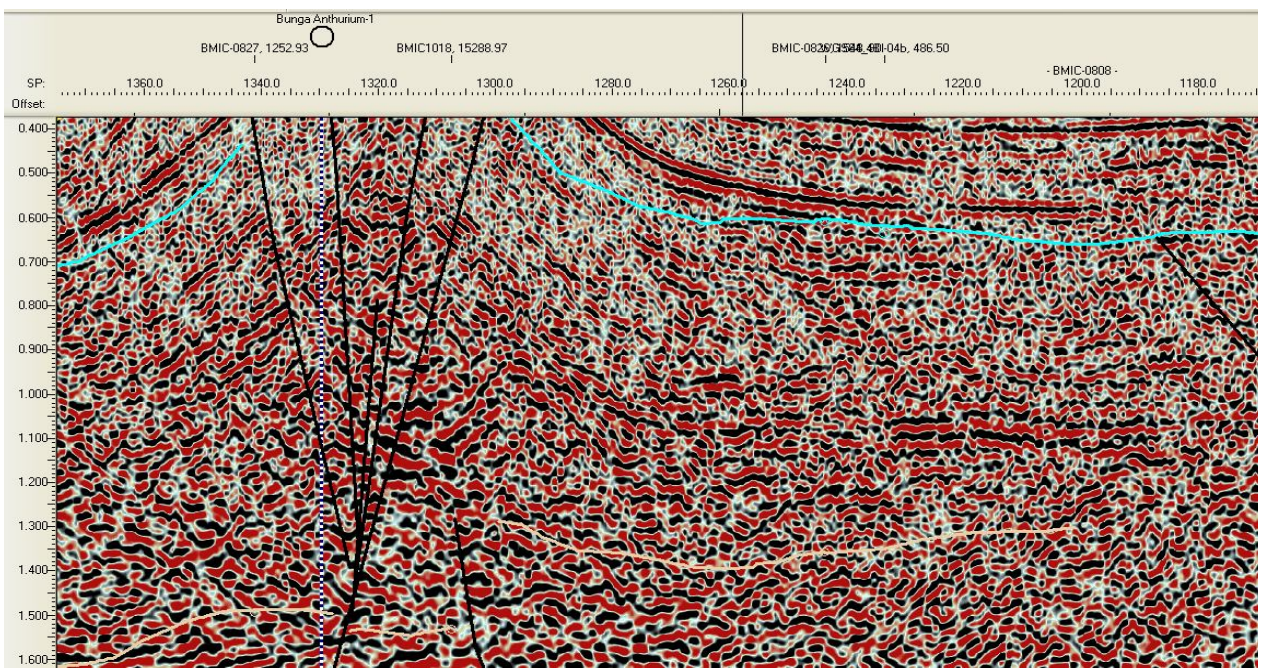

Figure 4.62 N-S Seismic line across Sakura North Deep

	Sakura N Deep 1		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.397	0.908	2.258
Working Interest	0.397	0.908	2.258
Depth	4925'	5000'	5125'

Table 4.24 Sakura North Deep areas

4.2.20 Pilona 3-1 Prospect

This is a faulted anticline north-west of Bakung NW. It is only defined by two seismic lines and lines predominantly outside the block.

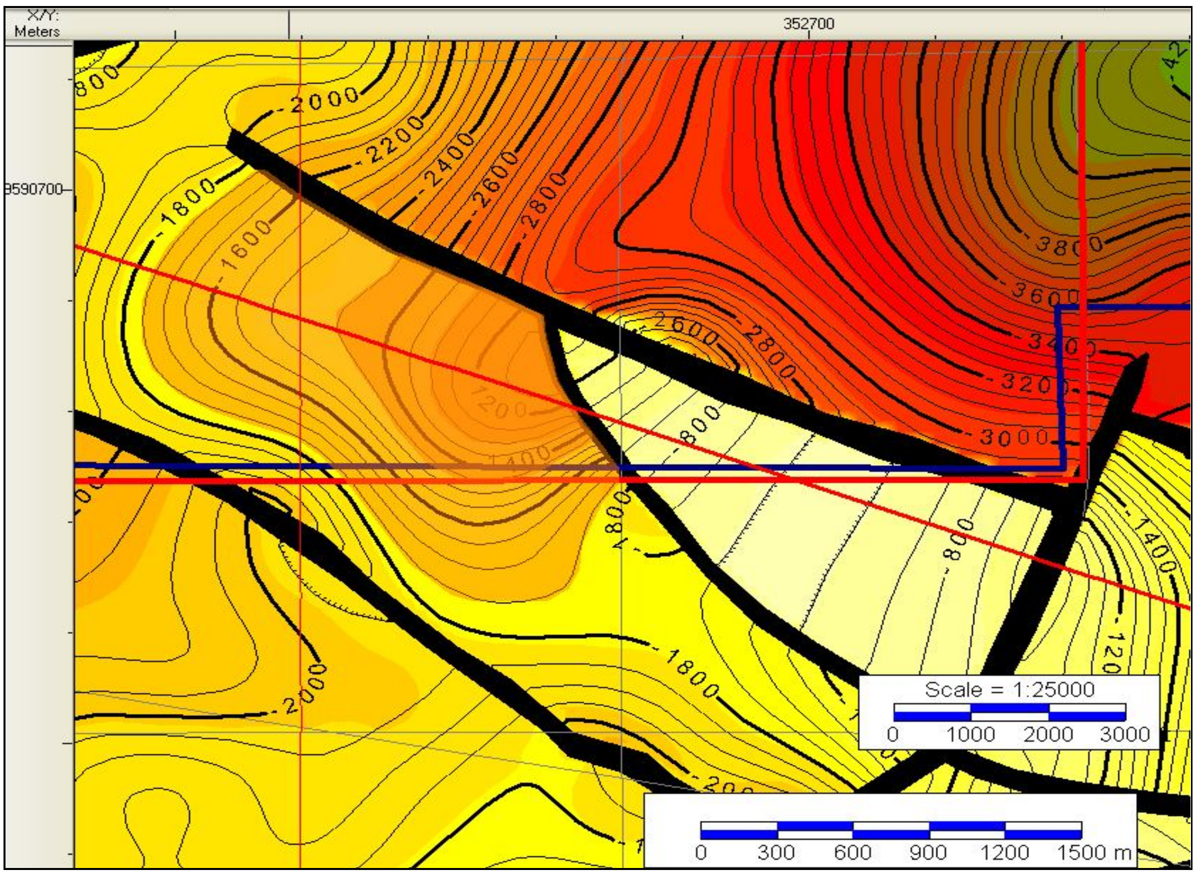

Figure 4.63 Pilona 3-1 top GUF depth map

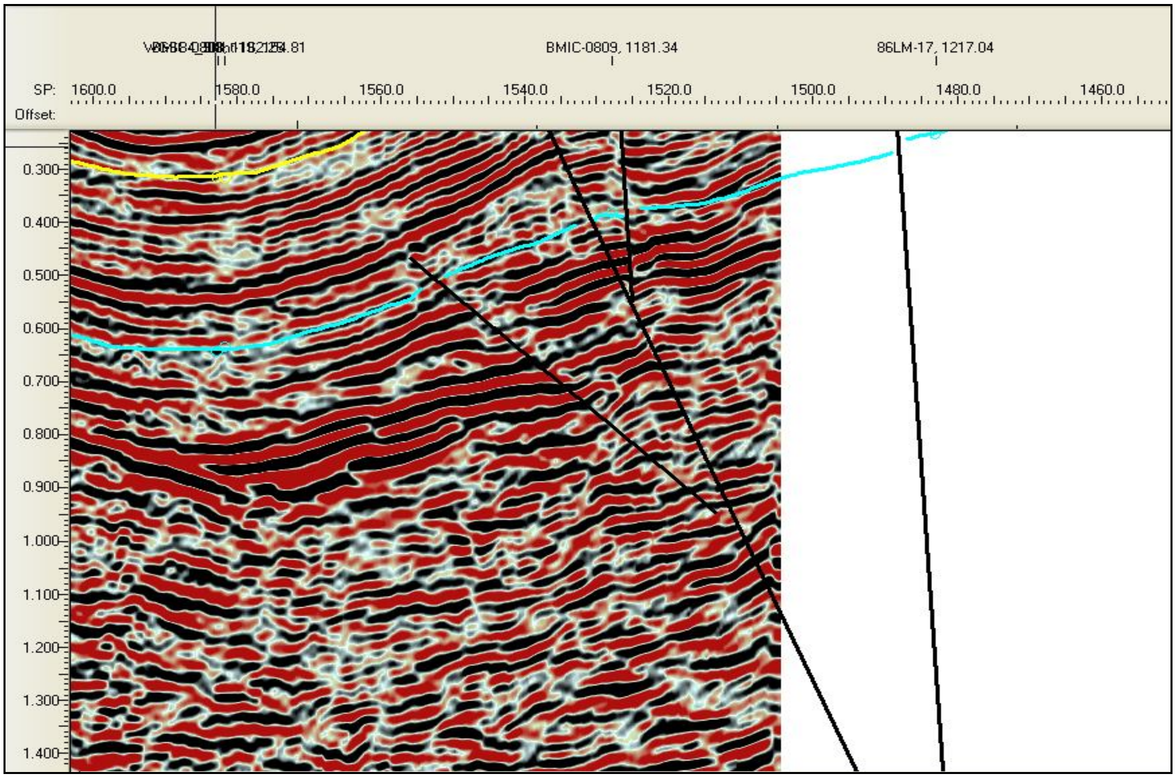

Figure 4.64 Seismic line across Pilona 3-1 lead

Pilona 3-1	GUF		
	Area	(Sq Km)	
	Min	M/L	Max
Area	0.268	0.605	1.935
Working Interest	0	0.021	0.471
Depth	1300'	1450'	1750'

Table 4.25 Pilona 3-1 areas

5 VOLUMETRIC ESTIMATION AND CHANCE OF SUCCESS

Volumetric estimates and Chance of Success values provided by the Operator have been reviewed. In general these are found to be reasonable, with additional risk applied in several cases, in particular to reservoir quality.

The Chance of Success definitions are shown in Table 5.1 for the Western area prospects.

For the Western prospects, a summary of contingent resources (relating to the gas discovery in Bunga Melati, Talang Akar Formation) is given in Table 5.2, and a summary of prospective resources is provided in Table 5.3.

PROSPECT	Fluid	CLOSURE	SEAL	RESERVOIR	CHARGE	Chance of Success
MELATI EAST MEF	Oil	0.95	0.63	0.80	0.90	0.43
MELATI WEST MEF	Oil	0.95	0.63	0.70	0.72	0.30
PHINISI BATU RAJA	Gas	0.95	0.42	0.60	0.64	0.15
PHINISI TALANG AKAR	Gas	0.95	0.42	0.90	0.64	0.23
PHINISI BRF STRATIGRAPHIC	Gas	0.50	0.48	0.70	0.44	0.07

Table 5.1 Chance of Success, Western Area Prospects

The Chance of Success, under the AIM Guidance Note, is the estimated likelihood that the Prospective Resources will be matured into Contingent Resources

CONTINGENT RESOURCES SUMMARY	PROBABILISTIC RESOURCES						RISK (CoS)	RISKED RESOURCES		
	GAS IN PLACE (BSCF)			RECOVERABLE (BSCF)				RECOVERABLE (BSCF)		
	1C	2C	3C	1C	2C	3C		1C	2C	3C
B MELATI TAF (NET OF CO_2)	29.18	35.04	42.07	21.83	26.30	31.68	0.30	6.55	7.89	9.51
TOTALS	29.18	35.04	42.07	21.83	26.30	31.68		6.55	7.89	9.51

Table 5.2 Contingent Resource Summary Tabulation, Bunga Mas, Western Area Discovery Bunga Melati TAF

PROSPECTIVE OIL RESOURCES SUMMARY	UNRISKED RESOURCES						RISK (CoS)	RISKED RESOURCES		
	STOIIP (MMBO)			RECOVERABLE (MMBO)				RECOVERABLE (MMBO)		
	Low	Best	High	Low	Best	High		Low	Best	High
MELATI EAST MEF	14.22	17.43	21.88	2.37	2.93	3.67	0.43	1.02	1.26	1.58
MELATI WEST MEF	27.59	40.28	58.80	4.60	6.79	9.86	0.30	1.39	2.05	2.97
TOTALS	41.81	57.70	80.68	6.97	9.72	13.53		15.51	19.09	23.56
PROSPECTIVE GAS RESOURCES SUMMARY	**UNRISKED RESOURCES**						**RISK (CoS)**	**RISKED RESOURCES**		
	GIIP (BCF)			RECOVERABLE (BCF)				RECOVERABLE (BCF)		
	Low	Best	High	Low	Best	High		Low	Best	High
PHINISI BATU RAJA	0.21	0.36	0.61	0.16	0.27	0.46	0.15	0.02	0.04	0.07
PHINISI TALANG AKAR	0.16	0.32	0.63	0.12	0.24	0.47	0.23	0.03	0.06	0.11
PHINISI BRF STRATIGRAPHIC	41.16	68.16	112.86	31.00	51.40	84.10	0.07	2.30	3.81	6.23
TOTALS	41.53	68.83	114.09	31.28	51.91	85.03		20.27	26.30	34.52

Table 5.3 Prospective Resource Summary Tabulation, Bunga Mas, Western Area Prospects

For the Eastern area prospects, the chance of success breakdown is given in Table 5.4 and prospective resource summary is provided as Table 5.5.

PROSPECT	Fluid	CLOSURE	SEAL	RESERVOIR	CHARGE	Chance of Success
ANGGREK ABF & GUF	Oil	0.80	0.63	0.70	0.72	0.25
ANGGREK (NW) ABF & GUF	Oil	0.80	0.63	0.50	0.72	0.18
ANGGREK DEEP GUF	Oil	0.65	0.63	0.60	0.72	0.18
BAKUNG KANA ABF & GUF	Oil	0.80	0.63	0.70	0.54	0.19
BAKUNG DEEP 1 GUF	Oil	0.80	0.63	0.50	0.54	0.14
BAKUNG DEEP 2 GUF	Oil	0.60	0.63	0.50	0.54	0.10
SAKURA ANTHURIUM ABF & GUF	Oil	0.80	0.63	0.70	0.54	0.19
SAKURA DEEP 1 GUF	Oil	0.80	0.63	0.70	0.54	0.19
SAKURA DEEP 2 GUF	Oil	0.65	0.63	0.60	0.54	0.13

Table 5.4 Chance of Success, Eastern Area Prospects

The Chance of Success, under the AIM Guidance Note, is the estimated likelihood that the Prospective Resources will be matured into Contingent Resources

PROSPECTIVE OIL RESOURCES SUMMARY		UNRISKED RESOURCES						RISK (COS)	RISKED RESOURCES		
		OIL IN PLACE (MMBO)			RECOVERABLE(MMBO)				RECOVERABLE(MMBO)		
		Low	Best	High	Low	Best	High		Low	Best	High
ANGGREK	GUF	13.63	18.51	25.15	2.04	2.78	3.77	0.25	0.52	0.71	0.96
ANGGREK NW	GUF	1.89	2.51	3.35	0.28	0.38	0.50	0.18	0.05	0.07	0.09
ANGGREK DEEP	AFLAT	0.76	1.43	2.70	0.11	0.21	0.40	0.18	0.02	0.04	0.07
BAKUNG-KANA	GUF	26.65	39.50	58.56	3.81	5.68	8.42	0.19	0.73	1.08	1.60
BAKUNG DEEP 1	BSTR1	6.40	11.45	20.50	0.96	1.72	3.07	0.14	0.13	0.23	0.42
BAKUNG DEEP 2	BSR2	0.83	2.61	8.26	0.12	0.39	1.24	0.10	0.01	0.04	0.13
BAKUNG NE	GUF	1.42	2.42	4.10	0.21	0.36	0.62				
BAKUNG NW	GUF	3.88	4.83	6.02	0.58	0.73	0.90				
SAKURA-ANTHURIUM	GUF	16.58	24.71	36.82	2.49	3.71	5.52	0.19	0.47	0.71	1.05
SAKURA DEEP 1	SSTR1-1	0.76	1.39	2.56	0.11	0.21	0.38	0.19	0.02	0.04	0.07
SAKURA DEEP 1 N	SSTR1-1	2.85	4.65	7.59	0.43	0.70	1.14				
SAKURA DEEP 2	SSTR2	1.03	1.80	3.13	0.15	0.27	0.47	0.13	0.02	0.04	0.06
MATAHARI NW	GUF	0.78	1.57	3.15	0.20	0.39	0.79				
RAMOK NE	GUF	0.99	1.30	1.71	0.15	0.19	0.26				
PILONA 3-1	GUF	0.05	0.20	0.75	0.01	0.03	0.11				
TOTALS		**78.49**	**118.89**	**184.34**	**11.66**	**17.75**	**27.60**		**1.98**	**2.95**	**4.46**

Table 5.5 Prospective Resource Summary Tabulation, Bunga Mas, Eastern Area Prospects

6 RESERVOIR ENGINEERING

The following section provides CGG Robertson's views on production profiles for the following prospects: Melati (oil), Bakung-Kana (oil) and Phinisi Stratigraphic (gas). As no production data is available for the studied prospects, the assumptions used to generate the production profiles rely on data available for nearby analogue fields.

6.1 Melati Prospect, Muara Enim Formation Sands

The targeted reservoirs are sands MEF27 & MEF34 within the Muara Enim Formation. For the evaluation, Melati West and Melati East are assumed to be a single development. Based on analogue fields, the assumptions used to generate the production forecast profiles are summarized in Table 6.1.

Table 6.1 Assumptions used for the production profiles: Melati prospect

	Low Estimate	Best Estimate	High Estimate
Initial production oil rate	100 bopd	100 bopd	100 bopd
Recoverable volume of oil per well	80,000 bbls	80,000 bbls	80,000 bbls
Decline rate per annum	45 %	45 %	45 %
Cumulative production in 2035	6.97 MMbbls	9.72 MMbbls	13.53 MMbbls

An oil exponential decline is used to generate the production profiles (Figure 6.1**Error! Reference source not found.**). Due to the absence of production data and to the uncertainties regarding the future drainage mechanisms (aquifer presence and strength, reservoir connectivity and heterogeneity), this approach is believed to represent a fit-for purpose approach at this stage of the exploration of the reservoir.

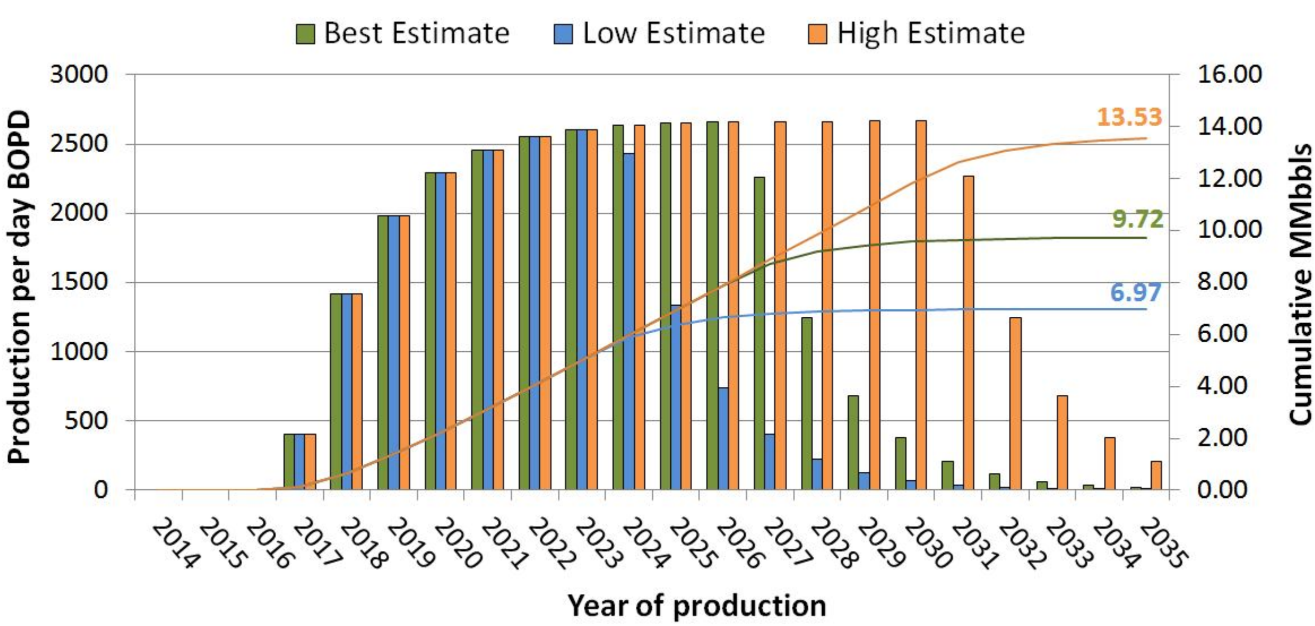

Figure 6.1 Production profiles for the Melati prospect, MEF27 & MEF34 Sands

The likely development for this prospect would be to drill as many as 86, 120 and 168 wells (Low, Best and High Estimates respectively) to explore, appraise and develop the field. Under these scenarios, the technical recovery factor is 17 % of the initial oil in place. It is a reasonable number taking into account the uncertainties on the lateral extent, continuity, connectivity and properties of the reservoir as well as the uncertainties on the drive mechanisms.

6.2 Bakung-Kana Prospect, Gumai Formation

The targeted reservoir is within the Gumai Formation. The quality of the reservoir is assumed to be similar to the one of the shallower formations: Air Benakat and Muara Enim. These assumptions have been taken into account in order to estimate the initial production oil rate and the recoverable volume of oil per well.

The assumptions used to generate the production forecast profiles are summarized in the Table 6.2.

Table 6.2 Assumptions used for the production profiles: Bakung-Kana prospect, Gumai Formation Sands

	Low Estimate	Best Estimate	High Estimate
Initial production oil rate	100 bopd	100 bopd	100 bopd
Recoverable volume of oil per well	80,000 bbls	80,000 bbls	80,000 bbls
Decline rate per annum	45 %	45 %	45 %
Cumulative production in 2035	3.81 MMbbls	5.68 MMbbls	8.42 MMbbls

An oil exponential decline is used to generate the production profiles (Figure 6.2). Due to the absence of production data and to the uncertainties regarding the future drainage mechanisms (aquifer presence and strength, reservoir connectivity and heterogeneity), this approach is believed to represent a fit-for purpose approach at this stage of the exploration of the reservoir.

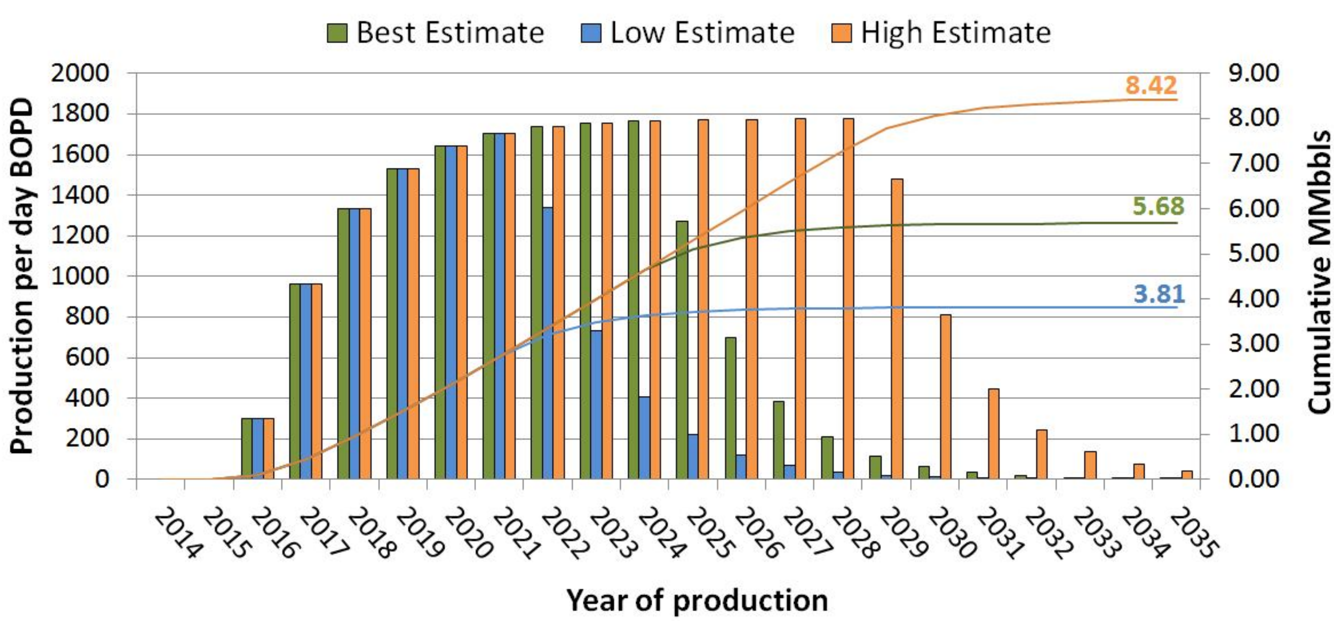

Figure 6.2 Production profiles for the Bakung-Kana prospect, Gumai Formation Sands

The likely development for this prospect would be to drill as many as 47, 70 and 104 wells (Low, Best and High Estimates respectively) to explore, appraise and develop the field. Under these scenarios, the technical recovery factor is 14 % of the initial oil in place. It is a reasonable number taking into account the uncertainties on the lateral extent, continuity, connectivity and properties of the reservoir as well as the uncertainties regarding the drive mechanisms.

6.3 Phinisi Stratigraphic Prospect, Batu Raja Limestone

The main target reservoir is within the Batu Raja limestone Formation and the major gas accumulation is postulated to lie in the Phinisi Stratigraphic trap as delineated by seismic anomalies. The Low, Best and High Estimate cases are based on the following recoverable volumes of gas: 31, 51.4 and 84.1 BCF respectively. The assumed technical recovery factor in order to get these values is 75 %.

The assumptions used to generate the production forecast profiles are summarized in the Table 6.3. The estimated initial production gas rate is lower than the one tested on the well Melati-1 (average of 9.6 MMscfd for the Talang Akar Formation) due to the expected quality of the reservoir in the Batu Raja Formation. For the same reasons, a significant decline rate of 35 % per annum has been used.

Table 6.3 Assumptions used for the production profiles: Phinisi Stratigraphic Prospect, Batu Raja Limestone

	Low Estimate	Best Estimate	High Estimate
Initial production gas rate	4.25 MMscfd	4.5 MMscfd	4.5 MMscfd
Recoverable volume of gas per well	4.4 BCF	4.7 BCF	4.7 BCF
Decline rate per annum	35 %	35 %	35 %
Cumulative production in 2035	31.0 BCF	51.4 BCF	84.1 BCF

A gas exponential decline is used to generate the production forecast profiles (Figure 6.3). Due to the absence of production data and to the uncertainties regarding the future drainage mechanisms (aquifer presence and strength, reservoir connectivity and heterogeneity), this approach is believed to represent a fit-for purpose approach at this stage of the exploration of the reservoir
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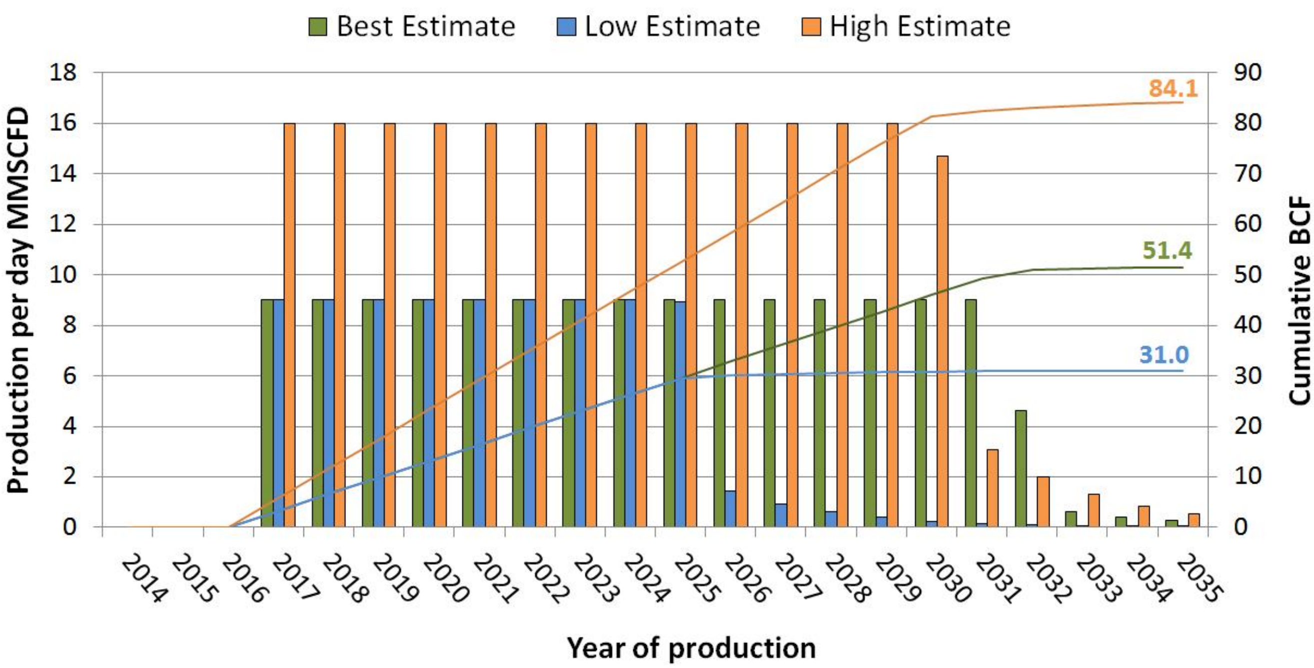


Figure 6.3 Production profiles for the Phinisi prospect

The likely development for this prospect would be to drill as many as 7, 11 and 18 wells (Low, Best and High Estimates respectively) to explore, appraise and develop this field.

7 ECONOMIC EVALUATION

7.1 Methodology

Unrisked economics have been derived for the following prospects / clusters:-

- Bakung Kana
- Melati (East and West)
- Phinisi

The economics were calculated using an Excel™ spreadsheet model developed by Robertson. The model uses oil industry standard discounted cash flow techniques to calculate NPVs based on estimated future production profiles, product prices, capital and operating costs, and the fiscal terms applicable to the Bunga Mas PSC.

7.2 Assumptions

7.2.1 General

General assumptions used for the economic evaluation were:

- Discount date of 1st January 2014
- Discount rate 10%
- Mid-Year Discount Methodology

Costs are assumed to be in 2014 terms and have been inflated at 2% per annum.

Cessation of production is assumed to occur when operating cash flows become negative or at the expiry of the concession, whichever is the earlier.

7.2.2 Licence Expiry

The PSC licence currently ends on 6th October 2015. It is assumed that this will be extended to the full PSC period of 30 years to 6th October 2035 on commercial discovery and POD acceptance.

7.2.3 Oil Price

The mid Brent crude price assumption is based on the current Brent futures price curve for the next five years with the price inflated by 2% per year thereafter. For the first five months of 2014, the actual posted prices have been used. Low and high cases have been estimated by flexing the base prices by +/- 30% respectively.

Bunga Mas crude is expected to be of similar quality to crude from the neighbouring Pilona TAC fields. There are no crude assays available for the Bunga Mas block, so the Brent price differential is based on recent sales data from Pilona TAC, which sold at a 6% average discount to Brent in 2013.

Table 7.1 Oil price assumptions

Year	Brent Price ($/bbl) - nominal		
	Low price	Base Price	High price
2014	94.8	110.2	125.6
2015	75.7	108.2	140.6
2016	72.6	103.7	134.9
2017	70.7	101.0	131.4
2018	69.7	99.6	129.5
2019	69.2	98.9	128.5
2020+	+ 2% per year		

7.2.4 Gas Prices

Indonesian domestic gas prices are regulated by the Energy and Mineral Resources Ministry, and are currently estimated to be approximately $6/MMbtu in Sumatra. This price, escalated at 2% per year, has been used in the economic evaluation.

7.2.5 Fiscal terms

The Bunga Mas PSC is understood to be subject to the following fiscal terms:-

- First Tranche Petroleum (FTP) – the first 10% of revenues are allocated to the Indonesian State.
- Cost oil (gas) – the next 100% of revenues is available to the contractor for cost recovery. Unrecovered costs can be carried forward indefinitely, and any excess is treated as profit oil (gas).
- Profit oil (gas) – The remaining revenue after FTP and cost recovery is shared between the Contractor and the Indonesian State in the ratio of 35.7143% to 64.2857% for oil, and 71.4286% to 28.5714% for gas.
- Domestic Market Obligation (DMO), whereby 25% of oil production due to the Contractor must be sold to the State at 25% of the prevailing market price. A five year DMO holiday for each prospect is assumed. It is assumed that if required the gas DMO would be supplied at the full price.
- Income tax – the Contractor's entitlement revenue less allowable costs is taxed at the rate of 44%. Tangible capital costs are assumed to be depreciated at 20% reducing balance with 20% of well costs assumed to be tangible.

Contractor cash flow is therefore determined as follows:-

Cost oil + Profit oil – Capex – Opex – abandonment - DMO cost - income tax

No other taxes have been included, and abandonment costs are assumed to be pre-funded over field life.

Unrecovered costs are estimated to be $108.4MM at the end of Q2 2014 comprising $102.0MM brought forward from Q4 2013 plus estimated testing and G&A costs incurred in Q1 and Q2 2014 of $6.4MM. Any remaining expenditure from the 2014 WP&B relating to the three clusters is deemed to be included in the G&A and well cost streams input into the economic model.

7.2.6 Working interest

It is assumed that Arctic Bay have a 51% working interest in the Bunga Mas PSC.

7.3 Development scenarios

Arctic Bay have assumed that the oil prospects, if successfully drilled, will be developed as clusters. Each cluster will consist of individual wells tied back to a central processing area (CPA) with of the following facilities:-

- Wellheads and gathering lines
- Test/production separators
- Produced water handling and treatment
- Flaring system
- Utilities (water, telecoms and power)
- Fire system
- Meters and loading arms/pumps
- Workshops and offices

Production is assumed to be trucked by road to the nearest Pertamina custody meter, which is approximately 35 km away from Bakung Kana and 55km from Melati. Produced water after treatment is assumed to be re-injected. Dedicated storage tank facilities at the Pertamina oil terminal will also be required.

Facilities for developing the Phinisi gas prospect, if successfully drilled, will include:

- Wellheads and gathering lines
- Flaring system
- Utilities (water, telecoms and power)
- Fire system
- Workshops and offices
- CO_2 removal unit and injection system
- Gas dehydration unit
- Condensate handling and storage system

Gas is assumed to be exported by pipeline to the nearest grid tie-in point located approximately 25 km away.

Robertson has reviewed Arctic Bay's proposed facilities, and associated costs and schedule. These have been compared against regional benchmarks and our internal database, and are considered to be reasonable and consistent with the maturity of the prospects. They have therefore been used as the basis of the evaluation but with adjustments made for well counts and schedule.

The following table summarises the capex in 2014 terms assumed by Robertson for each cluster in the economic evaluation. Costs include engineering, project management, environmental permitting, land purchase and site preparation, as well as all equipment procurement, fabrication and construction. Costs for wellhead equipment and gathering lines have been phased in line with the drilling sequence.

Table 7.2 Capex (100% block) assumptions by development

Development	Case	Well capex, $MM	Facilities capex, $MM	Total capex
Bakung Kana	Low	73.8	13.7	87.5
	Best	105.0	16.3	121.3
	High	150.6	20.3	170.9
Melati (East and West)	Low	146.3	24.3	170.5
	Best	203.5	28.2	231.7
	High	283.0	33.8	316.8
Phinisi	Low	33.8	25.4	59.2
	Best	50.5	25.9	76.4
	High	79.7	36.9	116.5

Well costs assumed for Bakung Kana, Melati and Phinisi are tabulated below. One water disposal well is assumed for every eight development wells on the oil prospects.

Table 7.3 Assumed well costs

Well cost, $MM	Well Type		
Development	Exploration	Appraisal	Development
Bakung Kana	4.5	2.0	1.2
Melati (East and West)	2.0	2.0	1.5
Phinisi	5.0	5.0	4.2

Operating costs for the oil prospects are assumed to be $20/bbl, with an additional $2/bbl for trucking costs to the Pertamina terminal. Operating costs for the gas prospect are assumed to be $0.8/mcf. G&A costs of $1.3MM per year have also been included for each cluster. Well abandonment, decommissioning and site restoration costs are assumed at 10% of the total capex.

The development schedule used is tabulated below, with initial production in the first year assumed to be produced from the re-completed E&A wells.

Table 7.4 Assumed Drilling and Production Schedule

Development	Exploration well	First production
Bakung Kana	2014	2016
Melati (East and West)	2015	2017
Phinisi	2015	2017

7.4 Results

Robertson has estimated unrisked NPVs for each of the prospects on a stand-alone basis, assuming that they are successfully drilled, appraised and developed. The brought forward unrecovered cost balance is assumed to be equally divided between Bakung-Kana and Melati, although it should be noted that any variation in this allocation will impact the relative values of the clusters.

Results are tabulated below for the low, best and high resource cases at the base oil price case.

Table 7.5 Unrisked NPV Summary by Prospect / Cluster

	Unrisked NPV10 ($MM)					
	100% block			net Arctic Bay		
Prospect / development	Low estimate	Best estimate	High estimate	Low estimate	Best estimate	High estimate
Bakung Kana	8.3	12.9	18.1	4.2	6.6	9.2
Melati (East and West)	12.3	16.6	20.7	6.3	8.5	10.6
Phinisi	-0.8	13.2	27.8	-0.4	6.7	14.2

The NPVs presented above are not deemed to represent the market value of the block, and in particular must be further adjusted to account for geological, technical and commercial risks.

As a sensitivity, NPVs for the best estimate resources have also been calculated at low and high oil prices.

Table 7.6 Unrisked NPV Price Sensitivity

	Unrisked NPV10 ($MM)					
	100% block			net Arctic Bay		
Prospect / development	Low price	Base price	High price	Low price	Base price	High price
Bakung Kana	-8.8	12.9	28.3	-4.5	6.6	14.4
Melati (East and West)	-14.9	16.6	38.8	-7.6	8.5	19.8
Phinisi	-4.5	13.2	30.7	-2.3	6.7	15.7

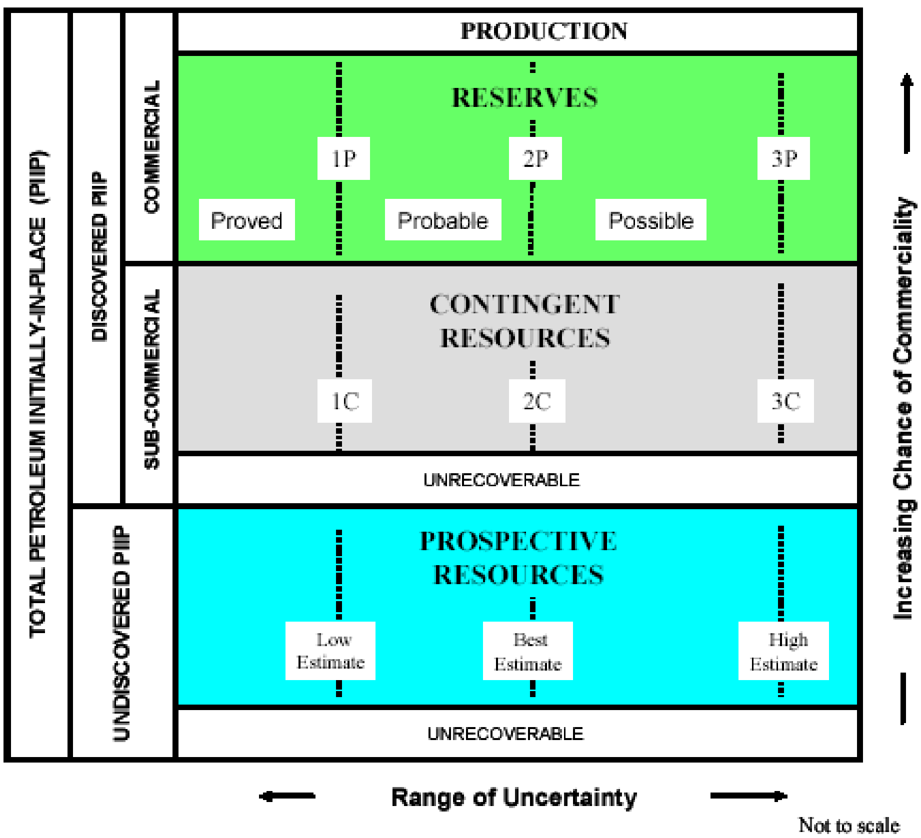
Detailed cash flow breakdowns (100% block) for each prospect / cluster are tabulated in Appendix C.

Star charts illustrating the sensitivity of NPV (100% block) for each of the prospects / clusters are contained in Appendix D.

8 APPENDIX A: DEFINITIONS

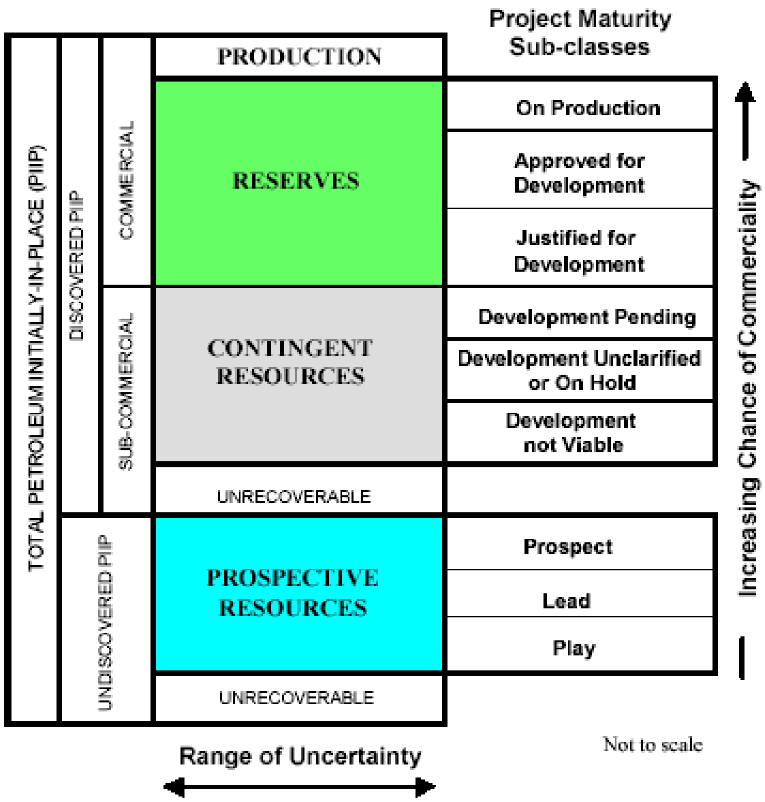
8.1 Definitions

The petroleum reserves and resources definitions used in this report are those published by the Society of Petroleum Engineers and World Petroleum Congress in 1998, supplemented with guidelines for their evaluation, published by the Society of Petroleum Engineers in 2001 and 2007. The main definitions and extracts from the SPE Petroleum Resources Management System (2007) are presented below.



Source: SPE Petroleum Resources Management System 2007

Figure 8.1 Resources Classification Framework



Source: SPE Petroleum Resources Management System 2007

Figure 8.2 Resources Classification Framework: Sub-classes based on Project Maturity

8.1.1 Total Petroleum Initially-In-Place

Total Petroleum Initially-In-Place is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to “total resources”).

8.1.2 Discovered Petroleum Initially-In-Place

Discovered Petroleum Initially-In-Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

8.1.3 Undiscovered Petroleum Initially-In-Place

Undiscovered Petroleum Initially-In-Place is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

8.2 Production

Production is the cumulative quantity of petroleum that has been recovered at a given date. Production is measured in terms of the sales product specifications and raw production (sales plus non-sales) quantities required to support engineering analyses based on reservoir voidage.

8.3 Reserves

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations, from a given date forward, under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by development and production status.

The following outlines what is necessary for the definition of Reserve to be applied.

- A project must be sufficiently defined to establish its commercial viability
- There must be a reasonable expectation that all required internal and external approvals will be forthcoming
- There is evidence of firm intention to proceed with development within a reasonable time frame
- A reasonable timetable for development must be in evidence
- There should be a development plan in sufficient detail to support the assessment of commerciality
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria must have been undertaken
- There must be a reasonable expectation that there will be a market for all, or at least the expected sales quantities, of production required to justify development
- Evidence that the necessary production and transportation facilities are available or can be made available
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated

The “decision gate” whereby a Contingent Resource moves to the Reserves class is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.

8.3.1 Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from existing wells and facilities. Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

8.3.2 Developed Non-Producing Reserves

Developed Non-producing Reserves include shut-in and behind-pipe reserves.

Shut-in reserves are expected to be recovered from:

- Completion intervals that are open at the time of the estimate but that have not yet started producing
- Wells that were shut-in for market conditions or pipeline connections, or
- Wells not capable of production for mechanical reasons.

Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

8.3.3 Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments such as

- From new wells on undrilled acreage in known accumulations
- From deepening existing wells to a different (but known) reservoir
- From infill wells that will increase recovery, or
- Where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to:
    - Recomplete an existing well or
    - Install production or transportation facilities for primary or improved recovery projects

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favourable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program, where the response provides support for the analysis on which the project is based.

Where reserves remain undeveloped beyond a reasonable timeframe, or have remained undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay is justified, a reasonable time frame is generally considered to be less than five years.

8.3.4 Proved Reserves

Proved Reserves are those quantities of petroleum that, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

8.3.5 Probable Reserves

Probable Reserves are those additional reserves that analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved + Probable Reserves (2P).

When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

8.3.6 Possible Reserves

Possible Reserves are those additional reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved + Probable + Possible (3P), which is equivalent to the high estimate scenario.

When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

8.4 Contingent Resources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

The term accumulation is used to identify an individual body of moveable petroleum. The key requirement in determining whether an accumulation is known (and hence contains Reserves or Contingent Resources) is that each accumulation/reservoir must have been penetrated by a well. In general, the well must have clearly demonstrated the existence of moveable petroleum in that reservoir by flow to surface, or at least some recovery of a sample of petroleum from the well. However, where log and/or core data exist, this may suffice provided there is a good analogy to a nearby, geologically comparable, known accumulation.

Estimated recoverable quantities within such discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively.

1C denotes low estimate scenario of Contingent Resources
2C denotes best estimate scenario of Contingent Resources
3C denotes high estimate scenario of Contingent Resources

Contingent Resources are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status.

8.4.1 Contingent Resources: Development Pending

1C Contingent Resources are a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are expected to be resolved within a reasonable time frame.

8.4.2 Contingent Resources: Development Un-Clarified/On Hold

2C Contingent Resources are a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development.

8.4.3 Contingent Resources: Development Not Viable

3C Contingent Resources are a discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential. The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognised in the event of a major change in technology or commercial conditions.

8.5 Prospective Resources

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. They are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

8.5.1 Prospect

A Prospect is classified as a potential accumulation that is sufficiently well defined to represent a viable drilling target.

8.5.2 Lead

A Lead is classified as a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

8.5.3 Play

A Play is classified as a prospective trend of potential prospects that requires more data acquisition and/or evaluation in order to define specific Leads or Prospects.

8.6 Unrecoverable Resources

Unrecoverable Resources are that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities that are estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

9 APPENDIX B: NOMENCLATURE

acre	43,560 square feet
AOF	absolute open flow
API	American Petroleum Institute
	(ºAPI for oil gravity, API units for gamma
	ray measurement)
av.	Average
AVO	Amplitude vs. Off-Set
BBO	billion (10^9) barrels of oil
bbl, bbls	barrel, barrels
BCF	billion cubic feet
bcm	billion cubic metres
BCPD	barrels of condensate per day
BHT	bottom hole temperature
BHP	bottom hole pressure
BOE	barrel of oil equivalent, with gas converted
	at 1 BOE = 6,000 scf
BOPD	barrels of oil per day
BPD	barrels per day
Btu	British thermal units
BV	bulk volume
c.	circa
CCA	conventional core analysis
CD-ROM	compact disc with read only memory
cgm	computer graphics meta file
CNG	compressed natural gas
CO_2	carbon dioxide
COE	crude oil equivalent
1-D, 2-D, 3-D	1-, 2-, 3-dimensions
DHI	direct hydrocarbon indicators
DHC	dry hole cost
DPT	deeper pool test
DROI	discounted return on investment
DST	drill-stem test
DWT	deadweight tonnage
E	East
E & P	exploration & production
EAEG	European Association of Exploration
	Geophysicists
e.g.	for example
EOR	enhanced oil recovery
ESP	Electrical Submersible Pump
et al.	and others
EUR	estimated ultimately recoverable
	(reserves)
FPSO	Floating production storage unit
ft/s	feet per second
G & A	general & administration
G & G	geological & geophysical
g/cm^3	grams per cubic centimetre
Ga	billion (10^9) years
GIIP	gas initially in place
GIS	Geographical Information Systems
GOC	gas-oil contact
GOR	gas to oil ratio
GR	gamma ray (log)
GWC	gas-water contact
H_2S	hydrogen sulphide
ha	hectare(s)
HI	hydrogen index
HP	high pressure
Hz	hertz
IDC	intangible drilling costs
IOR	improved oil recovery
IRR	internal rate of return
J & A	junked & abandoned
km	kilometres (1,000 metres)
km^2	square kilometres
kWh	kilowatt-hours
LoF	life of field
LP	low pressure
LST	lowstand systems tract
LVL	low-velocity layer
M & A	mergers & acquisitions
m	metres
M	thousands
MM	million
m^3/day	cubic metres per day
Ma	million years (before present)
mbdf	metres below derrick floor
mbsl	metres below sea level

MBOPD	thousand bbls of oil per day
MCFD	thousand cubic feet per day
MCFGD	thousand cubic feet of gas per day
mD	millidarcies
MD	measured depth
mdst.	mudstone
MFS	maximum flooding surface
mg/gTOC	units for hydrogen index
mGal	milligals
MHz	megahertz
million m^3	million cubic metres
ml	millilitres
mls	miles
MMBO	million bbls of oil
MMBOE	million bbls of oil equivalent
MMBOPD	million bbls of oil per day
MMCFGD	million cubic feet of gas per day
MMTOE	million tons of oil equivalent
mmsl	metres below mean sea level
mN/m	interfacial tension measured unit
MPa	megapascals
mSS	metres subsea
m/s	metres per second
msec	millisecond(s)
MSL	mean sea level
N	north
NaCl	sodium chloride
NFW	new field wildcat
NGL	natural gas liquids
NPV	net present value
no.	number (not #)
OAE	oceanic anoxic event
OI	oxygen index
OWC	oil-water contact
P90	proved
P50	proved + probable
P10	proved + probable + possible
P & A	plugged & abandoned
pbu	pressure build-up
perm.	permeability
PESGB	Petroleum Exploration Society of Great Britain
pH	-log H ion concentration
phi	unit grain size measurement
Ø	porosity
plc	public limited company
por.	porosity
poroperm	porosity-permeability
ppm	parts per million
psi	pounds per square inch
RFT	repeat formation test
ROI	return on investment
ROP	rate of penetration
RT	rotary table
S	South
SCAL	special core analysis
SCF	standard cubic feet, measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
SCF/STB	standard cubic feet per stock tank barrel
SS	sub-sea
ST	sidetrack (well)
STB	stock tank barrels
std. dev.	standard deviation
STOIIP	stock tank oil initially in place
Sw	water saturation
TCF	trillion (10^{12}) cubic feet
TD	total depth
TDC	tangible drilling costs
Therm	105 Btu
TVD	true vertical depth
TVDSS	true vertical depth subsea
TWT	two-way time
US$	US dollar, the currency of the United States of America
UV	ultra-violet
VDR	virtual dataroom
W	West
WHFP	wellhead flowing pressure
WHSP	wellhead shut-in pressure
WD	water depth
wt%	percent by weight
XRD	X-ray diffraction (analysis)

10 Appendix C

Figure 10.1 Gross Cash-flow at Base Price (Bakung Kana)

Best Estimate	Years																			
	Total	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032-2035
NCF	**34.7**	-10.3	-3.9	-7.5	4.3	8.3	10.2	13.0	7.4	3.8	4.0	4.1	5.0	3.9	2.3	1.3	0.4	-0.7	-1.5	-9.3
Revenue	**505.8**	0.0	0.0	9.6	30.1	40.9	46.8	51.1	54.1	56.3	58.0	59.5	43.7	24.5	13.8	7.7	4.3	2.4	1.4	1.6
Royalty	**0.0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capex	**135.8**	9.0	2.6	12.5	12.4	12.7	12.9	13.2	13.5	13.7	14.0	14.3	4.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Opex	**35.5**	1.3	1.3	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.8	1.8	7.7
Abex	**13.6**	0.0	0.0	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	2.7
Tax	**46.4**	0.0	0.0	0.0	3.1	6.3	7.9	8.0	5.9	3.1	3.2	3.3	2.9	1.7	0.8	0.3	0.0	0.0	0.0	0.0
Discounted Cashflow	**12.9**	-9.8	-3.4	-5.9	3.1	5.4	6.0	7.0	3.6	1.7	1.6	1.5	1.7	1.2	0.6	0.3	0.1	-0.2	-0.3	-1.4

Figure 10.2 Gross Cash-flow at Base Price (Melati East and West)

Best Estimate	Years																			
	Total	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032-2035
NCF	**58.4**	-1.3	-5.4	-6.0	-13.1	3.3	8.4	13.5	15.9	5.0	4.8	5.5	5.2	5.9	6.8	7.8	4.8	2.9	1.4	-6.8
Revenue	**890.9**	0.0	0.0	0.0	12.5	43.7	60.5	71.3	78.1	82.7	86.0	88.7	91.0	93.2	80.9	45.4	25.5	14.3	8.0	9.2
Royalty	**0.0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capex	**274.4**	0.0	4.1	4.7	19.4	22.6	24.7	23.5	25.7	24.5	26.8	25.5	27.8	26.5	18.7	0.0	0.0	0.0	0.0	0.0
Opex	**35.5**	1.3	1.3	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.8	1.8	7.7
Abex	**27.2**	0.0	0.0	0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	5.7
Tax	**61.1**	0.0	0.0	0.0	0.0	2.6	6.9	10.7	9.5	4.0	4.0	4.4	4.3	4.7	4.4	3.2	1.5	0.6	0.2	0.0
Discounted Cashflow	**16.6**	-1.2	-4.7	-4.8	-9.4	2.1	5.0	7.3	7.8	2.2	2.0	2.0	1.7	1.8	1.9	2.0	1.1	0.6	0.3	-1.0

Figure 10-3 Gross Cash-flow at Base Price (Phinisi)

Best Estimate	Years																			
	Total	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032-2035
NCF	**53.6**	-1.3	-6.4	-7.1	-15.4	7.6	7.8	7.8	11.8	7.0	7.2	7.4	7.6	7.8	6.8	4.3	2.6	1.4	0.5	-3.9
Revenue	**332.2**	0.0	0.0	0.0	18.8	22.1	24.4	26.2	27.6	28.7	29.6	30.4	31.2	31.9	21.2	14.0	9.3	6.2	4.1	6.5
Royalty	**0.0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capex	**85.1**	0.0	5.1	5.7	26.8	6.8	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	0.0	0.0	0.0	0.0	0.0	0.0
Opex	**35.5**	1.3	1.3	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.8	1.8	7.7
Abex	**8.7**	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1.8
Tax	**55.1**	0.0	0.0	0.0	2.9	2.6	3.4	4.1	2.5	5.4	5.7	5.9	6.0	6.2	4.7	2.9	1.7	0.8	0.4	0.0
Discounted Cashflow	**13.2**	-1.2	-5.6	-5.6	-11.1	4.9	4.6	4.2	5.8	3.1	2.9	2.7	2.6	2.4	1.9	1.1	0.6	0.3	0.1	-0.5

11 APPENDIX D

Star Diagrams at Base price

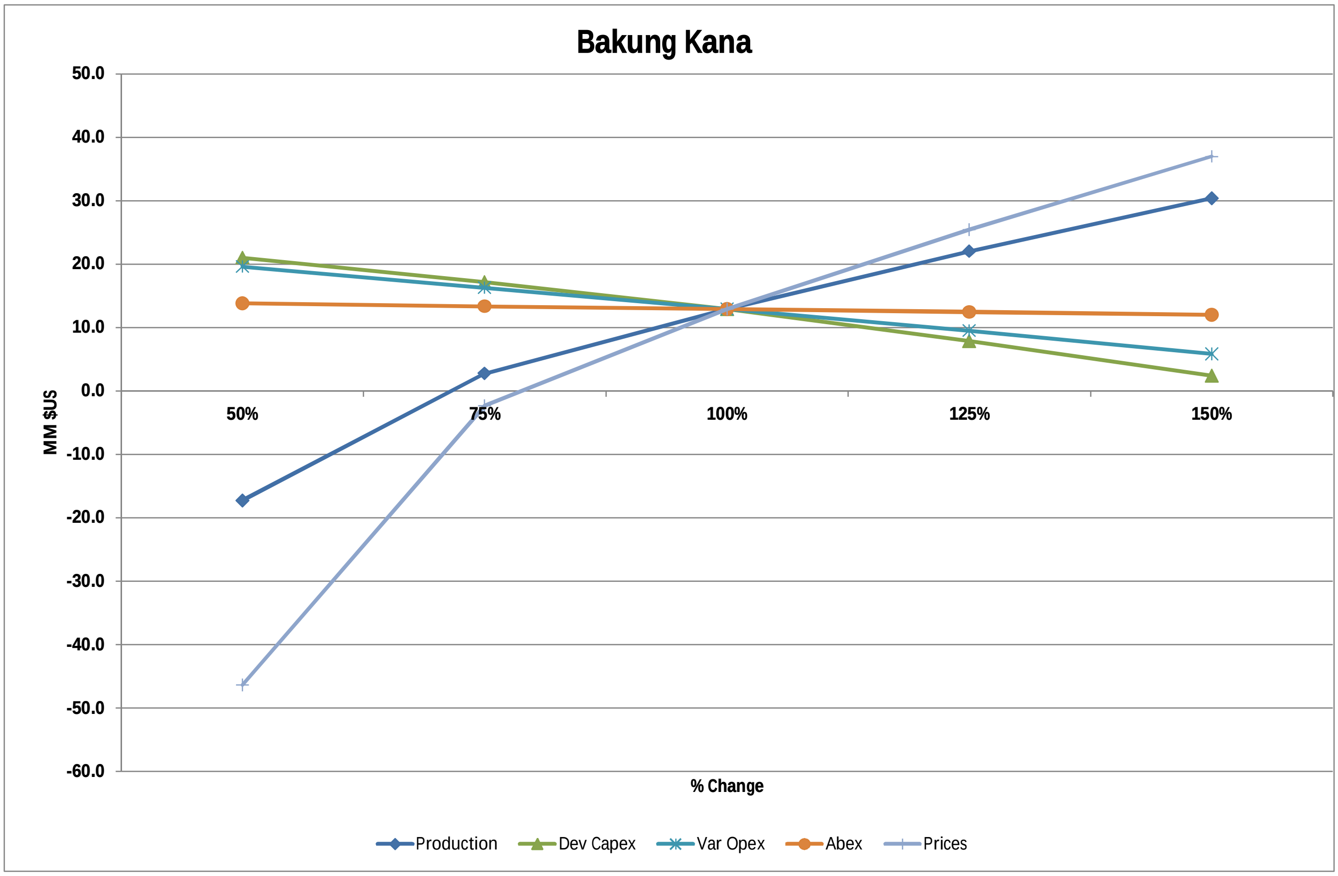


Figure 11.1 Sensitivity Analysis at Base price and Best Estimate

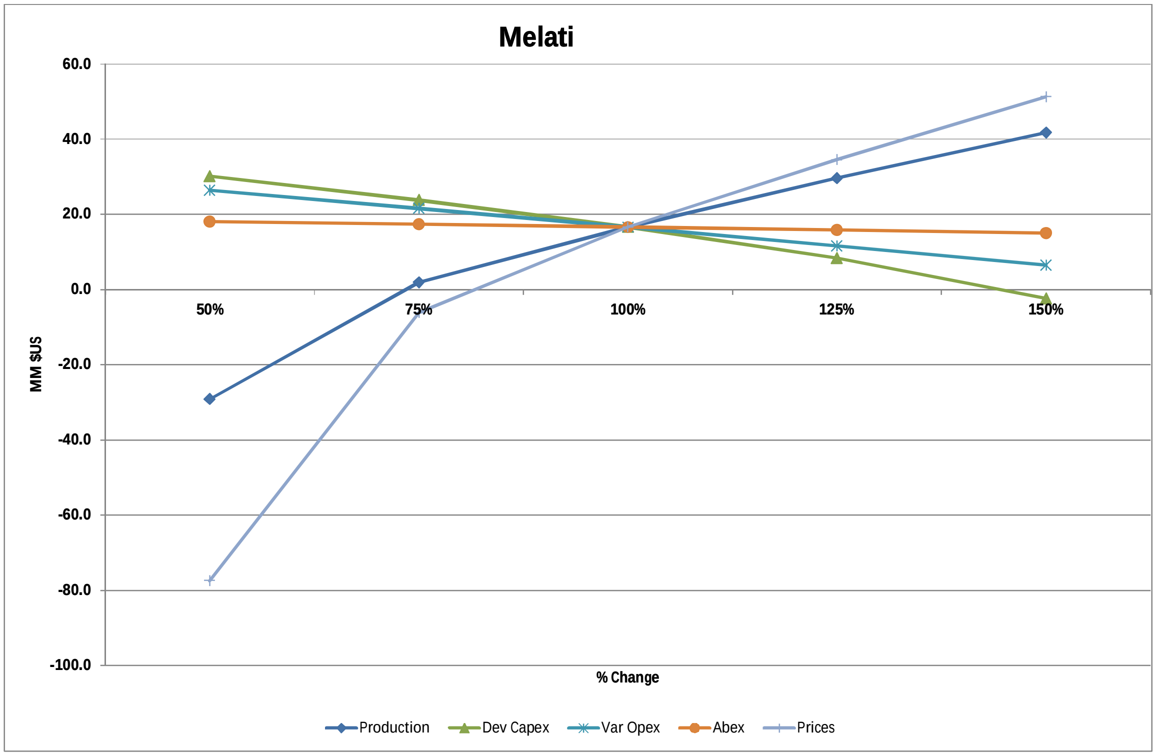


Figure 11.2 Sensitivity Analysis at Base price and Best Estimate

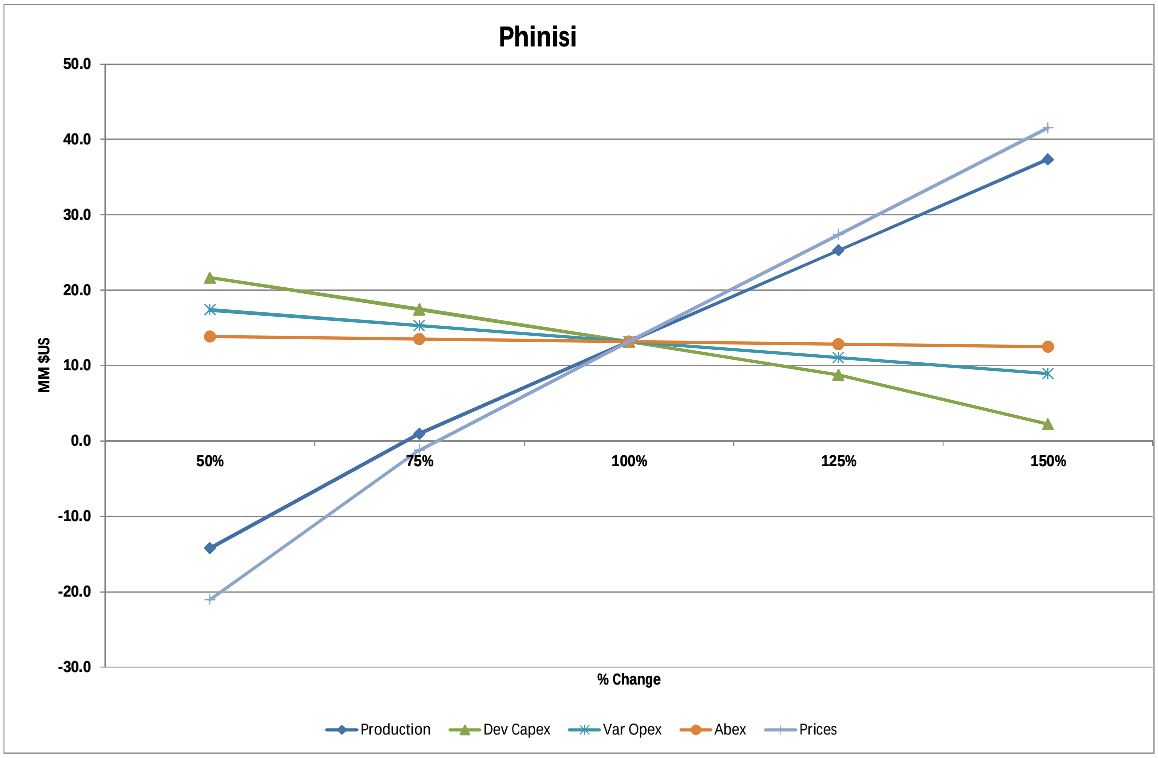


Figure 11.3 Sensitivity Analysis at Base price and Best Estimate

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